UNIVERSIDAD PONTIFICIA COMILLAS

ESCUELA TÉCNICA SUPERIOR DE INGENIERÍA (ICAI)

OFFICIAL MASTER'S DEGREE IN THE
ELECTRIC POWER INDUSTRY

Master's Thesis

ASSESSMENT AND INCENTIVE ALIGNMENT OF THE TSO REMUNERATION FRAMEWORK: APPLICATION TO THE SPANISH CASE

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Co-Supervisor: Tomás Gómez San Román, Miguel Ángel Ruiz Hernández

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Abstract

Electricity transmission regulation has traditionally been built around asset-based remuneration, cost recovery and financial stability. This approach remains essential, since transmission networks are capital-intensive natural monopolies and are critical for security of supply. However, the energy transition is changing the nature of the regulatory problem. Higher renewable penetration, electrification, storage, flexibility resources and more volatile power flows increase the interaction between long-term network investment and short-term system operation. As a result, transmission efficiency can no longer be assessed only through the remuneration of assets, but also through system-level outcomes such as technical constraints, balancing needs, renewable curtailment, connection capacity and the efficient use of existing infrastructure.

This thesis analyses whether the Spanish remuneration framework for the Transmission System Operator (TSO) provides sufficient incentives to align its decisions with the minimization of total system costs over time. Spain is a particularly relevant case because Red Eléctrica performs both the Transmission Owner (TO) and System Operator (SO) functions, while these activities are remunerated separately. The TO function is mainly remunerated through an asset-based framework linked to recognized investment, depreciation and financial return, whereas the SO function is remunerated separately and includes specific operational incentives. This creates a relevant question: whether technical interdependence between investment and operation is matched by sufficiently integrated economic signals.

The thesis first reviews the theoretical foundations of transmission regulation, including natural monopoly theory, asset-based remuneration, incentive regulation, output-based mechanisms, the CAPEX-OPEX problem, and TO-SO coordination. It then examines international regulatory trends in the United Kingdom and France, where regulators are increasingly using incentives linked to project delivery, connections, innovation, flexibility, and system-cost reduction. The Spanish framework is then analysed in detail, including TO and SO remunerations, network planning, investment limits, and the treatment of system operation costs.

Based on this diagnosis, the thesis proposes a complementary package of six output-based incentives. Three incentives are linked to the SO function: technical constraints cost internalization, efficiency of energy balancing, and additional tertiary balancing capacity. Three incentives are linked to the TO function: acceleration of strategic investment projects, innovative grid solutions, and flexible connection solutions. The package is not intended to replace the existing Spanish remuneration framework or transfer all system-operation risk to the TSO. Instead, it introduces a limited, capped, and partially cost-reflective incentive layer in areas where the TSO may reasonably influence system outcomes.

The proposed mechanisms are implemented through a regulatory-parametric model. The model is not a physical simulation of the transmission network, but a transparent tool to assess incentive magnitude, proportionality, sensitivity, and risk. Historical back testing of SO incentives over 2015–2024 shows that the proposed mechanisms would not have generated a systematic reward, with an aggregate result of approximately −15.6 M€,

mainly due to the deterioration of technical constraints and balancing indicators in recent years. The reference application of the full package produces a total incentive of around +1.69 M€, equivalent to approximately 0.10% of the combined TO and SO base remuneration. This result combines rewards and penalties across different mechanisms, showing that the package operates as a differentiated performance signal rather than as a uniform bonus.

The thesis concludes that the Spanish framework is robust in terms of cost recovery, planning, and regulatory stability, but remains incomplete from an output-based perspective. A carefully designed incentive layer could improve alignment between TSO remuneration and long-term system efficiency, provided that strong safeguards are included. These include partial exposure, caps and floors, ex ante benchmarks, justified-delay exclusions, overlap adjustments, auditability, and periodic recalibration. The main contribution of the thesis is therefore to provide a structured regulatory and methodological framework for discussing how Spanish transmission remuneration could evolve towards more output-oriented incentives while preserving security of supply, consumer protection, and financial stability.

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1. Introduction

1.1. Context and motivation

Electricity transmission networks have traditionally been regulated as natural monopolies due to their high investment costs, the strong economies of scale associated with grid development, and their essential role in guaranteeing security of supply and market functioning. For this reason, transmission regulation has historically focused on ensuring cost recovery, financial stability, and the timely expansion and maintenance of network infrastructure. This regulatory approach is well established across most jurisdictions around the world, and is also the case in Spain [1], [2].

However, the environment in which transmission networks operate has changed profoundly over the last decade. The rapid deployment of renewable energy sources, particularly wind and solar generation, has altered both the geographical location of generation and the temporal profile of power injections. In parallel, electrification, changing consumption patterns, and the growing relevance of flexibility resources, understood here as the capacity of generation, demand, or storage units to adjust their power output or consumption in response to system needs, thereby supporting real-time balance, congestion management, and the integration of variable renewable energy, have increased the complexity of system operation. As a result, transmission networks are no longer required only to transport electricity efficiently under relatively stable conditions, but also to accommodate a system characterized by greater variability, uncertainty, and spatial imbalance between generation and demand [3].

This transformation has made the interaction between network infrastructure and system operation increasingly important. In the European market design, electricity is traded sequentially through day-ahead, intraday, and balancing stages. Although this structure promotes market coordination and transparency, it also implies that market outcomes are not always fully consistent with the physical and security constraints of the network. These constraints must therefore be resolved ex post through redispatch, balancing actions, countertrading, and other operational measures that ensure the secure operation of the system in real time. Under conditions of rising renewable penetration and network saturation, these corrective actions become more frequent and economically significant [4].

In this context, a central regulatory issue emerges. The key question is no longer only whether the transmission framework ensures adequate remuneration of network assets, but whether it creates appropriate incentives for minimizing total system costs over time. This requires considering not only the direct cost of investment in network infrastructure, but also the operational consequences of those investment decisions, including their effect on congestion management, balancing needs, renewable curtailment, and overall system efficiency. In other words, the relevant benchmark is not merely the recovery of efficient capital expenditures (CAPEX), but the extent to which the regulatory framework encourages an efficient trade-off between CAPEX and the operational expenditures (OPEX) that arise from system constraints [5], [6].

This CAPEX–OPEX interaction has become one of the most relevant challenges in network regulation. A transmission reinforcement may increase regulated asset remuneration, but at the same time reduce future redispatch costs, curtailment, reserve requirements, or other operational expenditures borne by the system. On the contrary, postponing or avoiding network investment may appear efficient from an asset-remuneration perspective while increasing system costs elsewhere. If these effects are not properly internalized in the regulatory design, the decisions taken by the regulated entity may diverge from those that would be chosen by a social planner seeking to minimize the long-term cost of supplying electricity securely and efficiently. The issue is therefore not simply one of accounting separation between categories of costs, but one of incentive alignment between private regulatory signals and system-wide economic efficiency.

The Spanish case is especially interesting in this regard and will be the main scope of this thesis. In Spain, Red Eléctrica de España (REE) performs both the transmission ownership and the system operation functions, while being fully unbundled from generation and supply. **¡Error! No se encuentra el origen de la referencia.** summarizes t his interaction conceptually. Formally, however, these two activities are subject to differentiated regulatory treatment. Transmission ownership follows a predominantly asset-based remuneration scheme, linked to the recognized asset base, depreciation, and regulated financial return [7], [8], while system operation is remunerated separately and covers activities associated with balancing, congestion management, and security of supply [2], [9]. This institutional configuration is especially interesting because investment and operation remain technically interdependent, yet the economic signals governing each function are not fully integrated. As a result, the same entity participates in both dimensions of decision-making, but under a framework in which the financial consequences of those decisions may be only partially connected.

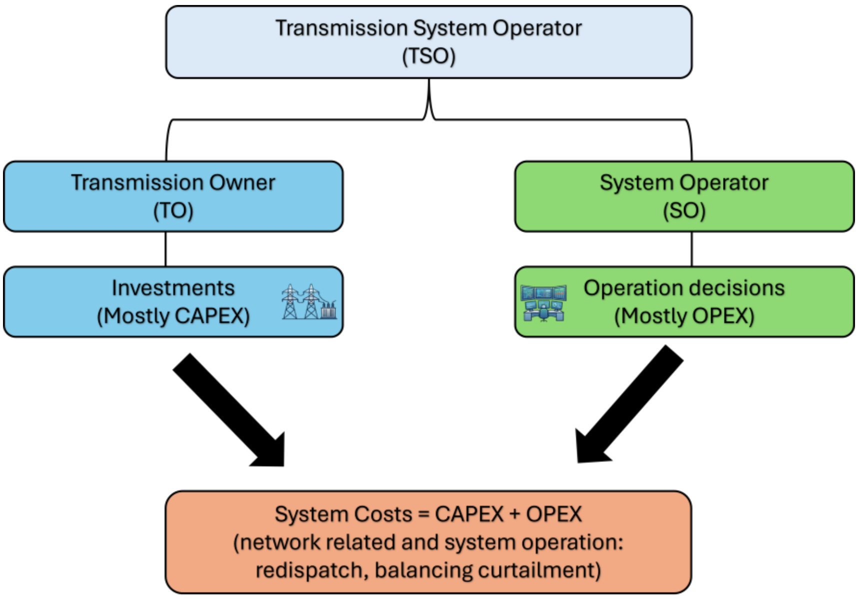


Figure 1 Conceptual representation of the misalignment between transmission investment (CAPEX) and system operation (OPEX) under separated remuneration schemes. The lack of direct exposure to system-level costs (e.g., congestion, balancing, curtailment) may lead to suboptimal decisions from a total system cost perspective. Source: own elaboration.

This separation can generate a structural misalignment. From a technical perspective, investment planning and system operation are closely linked: network topology, asset capacity, the timing of reinforcements, and the availability of alternative solutions directly affect the need for redispatch and other corrective actions [10]. From a regulatory perspective, however, the costs associated with those operational measures are often treated as system costs, socialized through tariffs or charges, and not fully attributed to the investment decisions that help create or alleviate them. Consequently, the regulated entity may face strong incentives to comply with reliability standards and asset-related regulatory requirements, but weaker incentives to internalize the broader economic impact of its decisions on total system costs.

This problem becomes more acute as renewable penetration increases. Higher shares of variable generation typically intensify congestion patterns, increase the need for corrective redispatch and balancing actions, and raise the value of timely and well-targeted network expansion. They also make the choice between traditional grid reinforcement and alternative non-wire solutions, such as dynamic line rating, storage, flexibility procurement, or more advanced operational tools, more relevant from both a technical and an economic point of view. In such a context, regulatory frameworks focused primarily on input-based remuneration may prove insufficient, especially if they do not expose the Transmission System Operator (TSO) to measurable system-level outcomes linked to cost efficiency and operational performance.

Literature has widely discussed CAPEX bias, incentive regulation, and the growing need to move from purely input-based mechanisms towards more output-oriented regulatory approaches [11], [12], [13]. However, much of this debate has focused on distribution networks or on transmission planning in isolation, rather than on the joint interaction between transmission investment and real-time system operation under separated remuneration structures. This leaves an important analytical space, particularly in cases such as Spain, where both functions coexist within the same entity but are regulated through differentiated schemes. The question is therefore not only whether the current framework functions adequately in formal terms, but whether it can guide coordinated decision-making in a system where operational and investment choices are increasingly intertwined.

Against this background, the motivation of this thesis is to assess whether current regulatory arrangements provide the right incentives for the TSO to act consistently with the objective of long-term system cost minimization. The analysis is not intended to challenge the rationale for regulating transmission activities, nor the need to preserve system security as the overriding operational priority. Rather, it seeks to examine whether the existing framework properly aligns the incentives associated with transmission ownership and system operation, and whether alternative or complementary mechanisms could improve that alignment in a context of accelerating energy transition. In doing so, the thesis aims to contribute to a broader regulatory discussion that is becoming increasingly relevant across Europe: how to design transmission remuneration frameworks that preserve reliability and investment adequacy while also promoting efficient coordination between infrastructure development, system operation, and total system cost outcomes.

While the literature has extensively examined incentive regulation, CAPEX-OPEX distortions and output-based mechanisms in electricity networks, less attention has been devoted to the joint interaction between transmission ownership remuneration, system operation incentives, and system-level operational costs under separated Transmission Owner (TO) and System Operator (SO) regulatory schemes. This thesis contributes to this discussion by developing a regulatory-parametric framework that links these dimensions and assesses whether selective output-based incentives could improve the alignment between TSO remuneration and long-term system cost efficiency.

1.2. Research question and hypothesis

The discussion developed in the previous section leads to a central analytical concern. As power systems become more dependent on variable renewable generation, the boundary between transmission planning and system operation becomes increasingly blurred. Network investment decisions shape future operating conditions, while operational constraints reveal, and in some cases amplify, the economic consequences of previous planning choices. In this context, the adequacy of transmission regulation can no longer be assessed solely in terms of cost recovery, investment sufficiency, or compliance with reliability standards. It must also be evaluated in terms of whether it creates incentives that are consistent with the broader objective of long-term system efficiency.

Against this background, the central research question of this thesis is therefore:

To what extent do current regulatory frameworks for electricity transmission and system operation align the incentives of the Transmission System Operator with the objective of minimizing total system costs over time?

This question is deliberately framed in broad terms because the issue under examination is structural rather than purely national. Although the thesis focuses empirically on the Spanish case, the underlying problem is relevant across many electricity systems undergoing rapid decarbonization. In most jurisdictions, transmission remuneration continues to rely predominantly on asset-based logic, while operational performance is addressed through separate mechanisms, regulatory obligations, or specific incentives. Such an arrangement may provide stability and predictability, but it does not necessarily ensure that investment choices, operational decisions, and system-level cost outcomes are jointly optimized. The core concern of this thesis is therefore not whether the current framework functions in a formal regulatory sense, but whether it generates the right economic signals when investment and operation become increasingly interdependent.

This central question raises several related concerns. One is whether current regulatory arrangements adequately internalize the operational consequences of transmission investment decisions, including their effects on congestion management, balancing requirements, renewable curtailment, and other system costs. Another is whether the separation between transmission ownership and system operation, whether institutional or merely regulatory, undermines incentive alignment by fragmenting decisions across cost categories that are technically interdependent. In this context, it is also important to assess whether the performance signals attached to system operation are not only insufficient to promote cost-efficient behavior, but may at times generate distorted, or even perverse, incentives by encouraging decisions that are rational under the regulatory framework yet suboptimal from a total system cost perspective. Finally, the analysis must consider whether current frameworks encourage efficient choices not only in terms of how much to invest, but also when to invest, through which solutions, and with what regard for the operational costs that such choices may create or avoid over time.

These questions highlight a distinction central to the thesis: the difference between the objective function of a regulated entity and that of a social planner. A social planner concerned with overall welfare would seek to minimize the long-term cost of delivering electricity securely, taking into account both infrastructure expenditure and the operational costs associated with network constraints. By contrast, a regulated TSO responds to the incentives embedded in the remuneration framework and may therefore optimize against a narrower set of signals. The purpose of the thesis is not to assume inefficiency a priori, but to examine whether the current regulatory design causes these two objective functions to diverge in a systematic way.

On this basis, the thesis advances the following working hypothesis:

Current regulatory frameworks for transmission system operators, while generally effective in ensuring cost recovery, financial stability, and security of supply, do not fully align TSO incentives with the minimization of total system costs over time.

This hypothesis does not imply that TSOs systematically act inefficiently, nor that security considerations should be subordinated to short-term cost minimization. On the contrary, system security remains the overriding constraint under any credible regulatory arrangement. The argument is more specific: when the economic costs of congestion management, balancing actions, or curtailment are largely socialized and remain only partially connected to the remuneration of the regulated entity, the framework may fail to reward decisions that are efficient from a total system cost perspective. In such cases, the resulting outcome may be individually rational under the prevailing incentives yet still fall short of the coordinated solution that would emerge if planning and operation were evaluated under a more integrated economic logic.

A second element of the hypothesis concerns the nature of the regulatory instruments themselves. The thesis postulates that frameworks predominantly based on input recognition and asset remuneration are increasingly unsuitable for power systems in which operational outcomes have become more economically significant. While such frameworks remain necessary to support investment adequacy and regulatory predictability, they may need to be complemented by more output-oriented mechanisms capable of capturing system-level performance. In this sense, the thesis hypothesizes that properly weighted incentive schemes linked to measurable outcomes, such as congestion-related costs, curtailment, balancing efficiency, or the cost savings associated with better coordination between planning and operation, could improve alignment between the behavior of the regulated entity and the objective of long-term cost efficiency.

A third and related hypothesis is that this issue becomes particularly salient in systems where transmission ownership and system operation are performed by the same entity but regulated through differentiated remuneration schemes, as in the Spanish case. Under such arrangements, technical interdependence coexists with partial economic separation. This may create a situation in which the entity has the information and capability to coordinate decisions across both dimensions, but does not face a sufficiently integrated set of incentives to do so in a system-optimal manner. The thesis, therefore, explores whether improved coordination mechanisms, shared performance signals, or carefully designed cost-sharing approaches could narrow the gap between private regulatory incentives and broader system efficiency.

1.3. Scope and Structure of the Thesis

This thesis adopts a regulatory and economic perspective to examine the interaction between transmission investment decisions and system operation in contemporary electricity systems. As argued in the previous sections, the growing penetration of renewable generation has made this interaction increasingly relevant, both from a system performance perspective and from the standpoint of regulatory design. The purpose of the thesis is therefore not to provide a purely technical analysis of power system operation, nor to develop a full engineering optimization of network expansion, but to assess whether the incentives embedded in the current remuneration framework are consistent with the objective of long-term total system cost minimization.

The analysis is centered on the transmission level, where the coordination between long-term infrastructure decisions and real-time system operation becomes particularly consequential. Transmission planning determines the capacity, topology, and robustness of the network over time, while system operation reveals the practical and economic implications of those decisions through congestion management, redispatch, balancing actions, and the integration of variable renewable generation. For this reason, the thesis focuses on the Transmission System Operator as the key regulated entity through which these dimensions intersect, paying particular attention to the relationship between transmission ownership and system operation functions.

At the same time, the work remains deliberately focused on scope. First, it approaches the problem primarily from the viewpoint of economic regulation and incentive design, rather than from a detailed engineering or market simulation perspective. Technical concepts are introduced only insofar as necessary to understand their economic relevance and treatment within the regulatory framework. Second, the thesis evaluates performance mainly at the system level, emphasizing aggregate outcomes such as congestion-related costs, balancing requirements, renewable curtailment, operational efficiency, and the broader coordination between planning and operation. It does not aim to produce a detailed asset-by-asset assessment of the transmission network, nor a quantitative forecasting exercise of future investment needs. Third, although the analysis considers the role of alternative solutions to traditional grid reinforcement, such as operational flexibility or non-wire alternatives, these are examined chiefly insofar as they affect the regulatory trade-off between CAPEX and system-level operating costs.

Within this broader analytical framework, the Spanish electricity system is used as the main case study. Spain provides a particularly relevant context for this research for three main reasons. First, it is a system undergoing a rapid transformation driven by renewable integration, electrification, and evolving operational needs. Second, it exhibits increasing attention to system costs associated with congestion management, redispatch, balancing, and other operational constraints. Third, and most importantly for the purposes of this thesis, it presents an institutional configuration in which transmission ownership and system operation are performed by the same entity, while being subject to differentiated remuneration schemes. And at the same time, the TSO is fully unbundled from generation and supply, which guarantees avoiding different perverse incentives that are out of the scope of this thesis. This makes it especially suitable for examining whether technical interdependence is matched by adequate economic coordination within the regulatory framework.

The contribution of the thesis should therefore be understood within these boundaries. It does not seek to provide a definitive quantitative estimate of the exact welfare loss associated with current regulatory arrangements, nor to propose a fully calibrated regulatory reform ready for immediate implementation. Rather, its objective is more analytical and policy-oriented: to identify potential sources of misalignment in the existing framework, to assess their implications conceptually and institutionally, and to explore whether alternative regulatory mechanisms could better align the incentives of the TSO with the objective of minimizing total system costs over time.

In line with this scope, the thesis is structured as follows:

- <u>Chapter 1 – Introduction</u>

  This chapter presents the general context and motivation of the research, defines the central research question and working hypothesis, and clarifies the scope and structure of the thesis.

- <u>Chapter 2 – State of the Art</u>

  Reviews the main literature on transmission regulation, natural monopolies, incentive regulation, CAPEX–OPEX interactions, TOTEX approaches, and TO–SO incentive alignment.

- <u>Chapter 3 – Regulatory Framework (Case Study)</u>

  Describes the Spanish regulatory framework for transmission and system operation, including TO and SO remuneration, network planning, investment limits, and the treatment of system operation costs.

- <u>Chapter 4 – Methodology</u>

  Explains the regulatory-economic methodology used in the thesis, based on the decomposition of current incentives and the design of alternative mechanisms.

- <u>Chapter 5 – Case Study</u>

  Presents the parametrization and Excel-based model that applies the methodology explained in the previous chapter.

- Chapter 6 – Analysis and Results

  Presents the results of the incentive model, assessing the current framework and the proposed incentives in terms of economic magnitude, sensitivity, risk allocation, and impact on TO–SO coordination.

- Chapter 7 – Discussion

  Discusses whether the proposed incentive package improves alignment with system-level outcomes, comparing the results with international practices and identifying implementation risks or limitations.

- Chapter 8 – Conclusions

  Summarizes the main findings, regulatory implications, limitations, and possible directions for further research.

Taken together, this structure is intended to move from the general to the specific, and from diagnosis to policy implications. It begins by framing the conceptual and regulatory problem, then examines the Spanish case in depth, contrasts it with international experience, and finally develops an analytical basis for discussing possible reforms. In this way, the thesis aims to contribute to both the academic discussion on network regulation and the practical debate on how transmission remuneration frameworks should evolve in increasingly complex and renewable-based electricity systems.

2. State of the Art

2.1. Economic regulation of electricity transmission networks

2.1.1. Transmission networks as natural monopolies

Electricity transmission networks have traditionally been considered one of the clearest examples of a natural monopoly within the electricity sector. A natural monopoly exists when the technical and economic characteristics of an activity make it more efficient for a single operator to provide the service than for several competing firms to duplicate the same infrastructure. In the case of transmission, this condition arises mainly from the very high fixed costs of developing the network, the long economic life of assets, the existence of economies of scale and density, and the physical interdependence between all elements of the grid. Building parallel high-voltage networks to serve the same geographical area would normally imply unnecessary duplication of assets, higher total costs for consumers, greater environmental impact, and additional coordination problems, without generating the type of competitive discipline that can exist in other segments of the electricity value chain.

The natural monopoly character of transmission is also reinforced by the specific physical nature of electricity networks. Transmission assets do not operate as isolated facilities, but as part of an interconnected system in which power flows are determined by network topology, impedance, generation patterns, demand location and security constraints. As a result, the use of one part of the grid affects the operating conditions of the rest of the system. This creates strong network externalities: the value and performance of each asset depend not only on its individual cost or capacity, but also on how it contributes to the reliability, efficiency of the entire transmission system and flexibility, i.e., generation side flexibility, demand side flexibility and storage. For this reason, transmission cannot be efficiently coordinated through asset-level competition between parallel infrastructure providers. Instead, it requires centralized planning, coordinated operation and a clear allocation of responsibility for maintaining system security [14].

This does not mean that transmission companies should be allowed to operate without economic discipline. On the contrary, the absence of effective competition is precisely what makes regulation necessary. In competitive markets, firms are disciplined by the risk of losing customers if they charge excessive prices, invest inefficiently or provide poor service. A transmission network operator does not face this same form of market pressure, because users cannot normally choose between alternative transmission networks. Regulation therefore acts as a substitute for competition. Its role is to ensure that the regulated entity recovers the efficient costs of providing the service, earns a reasonable return on necessary investments, maintains adequate quality and reliability standards, and does not extract monopoly rents from consumers.

The regulated nature of transmission has historically led to remuneration frameworks focused on cost recovery and investment adequacy. This is understandable given the capital-intensive nature of the activity. Transmission assets require large upfront investments, have long construction and permitting periods, and are recovered over several decades. If the regulatory framework does not provide sufficient revenue stability, the operator may face difficulties in financing new infrastructure or maintaining the existing grid. For this reason, most transmission regulation has traditionally relied on mechanisms that recognize the value of regulated assets, allow depreciation over their useful life and provide a financial return on the asset base. These mechanisms are essential to preserve investment incentives in a sector where underinvestment may have severe consequences for reliability and long-term system efficiency [10].

However, the fact that transmission is a natural monopoly does not fully determine how it should be regulated. It only explains why regulation is required. A framework that guarantees cost recovery may solve the monopoly problem to finance investments, but it may not be sufficient to ensure that the regulated operator makes decisions aligned with total system efficiency, as these entities are generally integrated into a single entity. This distinction is particularly important in modern power systems, where transmission networks are not merely passive infrastructure used to transport electricity from conventional generation plants to demand centres. They are increasingly central to renewable integration, congestion management, flexibility provision, cross-border exchange, system balancing and security of supply under more volatile operating conditions [3].

In this context, the traditional natural monopoly argument must be complemented with a broader view of incentive design. Since the transmission operator is not exposed to competitive pressure, the regulatory framework must define the economic signals that guide its decisions. These signals affect not only the amount of investment undertaken, but also the timing of network reinforcements, the choice between conventional and innovative solutions, the use of operational flexibility, and the degree to which system-level costs are internalized. Therefore, the central regulatory problem is not limited to preventing excessive monopoly profits. It also involves ensuring that the regulated entity has incentives to behave in a way that is consistent with long-term system cost minimization.

This point is especially relevant for the purpose of this thesis. The natural monopoly nature of transmission justifies the existence of a regulated remuneration framework, but it does not by itself guarantee that the resulting incentives are efficient. Once competition is replaced by regulation, the design of that regulation becomes decisive. If remuneration is mainly linked to recognized assets and cost recovery, the framework may provide strong incentives for investment adequacy and financial stability, but weaker signals regarding operational efficiency, congestion cost reduction, flexibility, innovation or coordination between transmission ownership and system operation. The following sections therefore examine the objectives that transmission regulation must pursue, the logic of asset-based remuneration, and the potential need for complementary incentive mechanisms capable of aligning the regulated TSO with broader system-level outcomes.

The regulation of electricity transmission networks is not limited to controlling the revenues of an infrastructure owner. Its purpose is broader: to define a set of economic, technical and institutional conditions under which the transmission system can be developed and operated in a way that is reliable, financially sustainable, and efficient from the perspective of the electricity system. Since transmission networks are natural monopolies, the regulator must replace the impact that competition would normally play in other markets. However, this substitution is complex because the regulator is not pursuing a single objective. Transmission regulation must simultaneously ensure cost recovery, promote efficient investment, protect consumers, preserve security of supply, and provide incentives for long-term system efficiency [15].

The first objective of transmission regulation is to guarantee the recovery of efficiently incurred costs. Transmission networks are highly capital-intensive assets, with long development periods and useful lives that may extend over several decades. Without a credible expectation of cost recovery, the regulated company would not be able to finance the investments required to expand, reinforce, and maintain the network. This is particularly relevant in electricity transmission because underinvestment can have consequences that go beyond the financial position of the regulated firm. Insufficient network capacity may increase congestion, reduce the ability to integrate renewable generation, limit cross-border exchanges, increase redispatch and balancing costs, or eventually compromise security of supply. Therefore, cost recovery is not simply a protection granted to the regulated company, but a necessary condition for the long-term adequacy of the power system.

Closely related to cost recovery is the objective of investment adequacy. Transmission regulation must ensure that the network is expanded and maintained at a level consistent with expected demand, generation patterns, reliability criteria, and decarbonization objectives. In traditional electricity systems, this mainly involved reinforcing the grid to connect large generation units and supply demand centres. In current power systems, the investment challenge has become more complex. Renewable generation is often located far from demand, power flows are more variable, and the value of transmission reinforcements depends increasingly on their ability to reduce congestion, avoid curtailment, support flexibility, and facilitate electrification. For this reason, investment adequacy should not be interpreted only as building enough assets, but as ensuring that the right investments are made at the right time and in the right locations [10].

A third objective is the preservation of security of supply and system reliability. Transmission networks are critical infrastructure, and their operation is directly linked to the physical balance and stability of the electricity system. Regulation must therefore ensure that the transmission operator has sufficient resources, technical obligations, and incentives to maintain the network available, resilient, and capable of operating under normal and stressed conditions. This includes not only the physical maintenance of assets, but also the coordination of outages, the management of system constraints, the provision of operational security margins, and the capacity to respond to disturbances. In this respect, reliability is not a secondary objective that can be traded freely against short-term cost reductions. It is a binding constraint within which economic efficiency must be pursued [15].

At the same time, regulation must protect consumers from excessive costs. Because users cannot choose between competing transmission networks, the regulated operator could theoretically recover inefficient costs or earn excessive returns if remuneration were not properly controlled. Consumer protection therefore requires that allowed revenues reflect efficient costs, that the rate of return is reasonable, and that investment plans are subject to regulatory scrutiny. This objective is particularly important because transmission costs are ultimately recovered from electricity consumers through tariffs, charges or other regulated mechanisms. A remuneration framework that ensures investment but does not control efficiency may lead to unnecessary costs being socialized across the system.

Efficiency is therefore another central objective of transmission regulation. This includes several dimensions. Productive efficiency requires the network company to provide the required service at the minimum efficient cost, avoiding unnecessary expenditure in construction, operation, and maintenance. Allocative efficiency requires that investment and operation decisions reflect the value they provide to the system and to consumers. Dynamic efficiency requires that the regulatory framework encourages innovation, adaptation, and efficient long-term decision-making rather than only minimizing short-term expenditure. These dimensions are increasingly relevant in systems with high renewable penetration, where the economic value of the transmission network depends not only on asset availability, but also on how effectively the network enables renewable integration, reduces operational constraints, and supports flexibility.

Another objective, sometimes less explicit but increasingly important, is the alignment between the regulated operator's incentives and system-level outcomes. A transmission company may comply with investment plans, maintain asset availability, and recover costs while still facing limited incentives to minimize broader system costs such as redispatch, balancing actions, or renewable curtailment. This is especially relevant when these costs are treated as system costs and are not directly internalized in the remuneration of the entity whose planning or operational decisions may influence them. Therefore, a modern transmission regulatory framework should not only ask whether the operator is financially viable or technically compliant, but also whether its economic signals are aligned with minimizing total system costs over time.

The objective of financial stability also plays a central role. Transmission investments are generally financed under regulated returns, and the perceived stability of the regulatory framework affects the cost of capital of the regulated company. If regulation is unstable, unpredictable, or excessively exposed to short-term political intervention, investors may require higher returns, which can ultimately increase costs for consumers. Conversely, a predictable and credible framework can reduce financing costs and support the timely development of infrastructure. This creates an important reason for maintaining stable asset-based remuneration mechanisms, especially in capital-intensive sectors such as electricity transmission.

However, the pursuit of financial stability should not imply that the regulated operator is insulated from all performance risk. If the remuneration framework guarantees cost recovery without sufficient efficiency incentives, it may weaken the motivation to control costs, innovate, improve delivery performance, or internalize system-level impacts. This is why many regulatory frameworks combine stable base remuneration with additional incentive mechanisms linked to quality, availability, efficiency, innovation, or output delivery. The challenge is to expose the regulated company to those outcomes it can reasonably influence, without transferring risks that are mainly driven by exogenous factors such as weather, fuel prices, demand shocks, administrative delays, or exceptional system events.

These objectives show that transmission regulation has a multidimensional nature. It must ensure that the network operator can finance and maintain essential infrastructure, while also protecting consumers and promoting efficient system outcomes. It must provide enough stability to support long-term investment, but enough incentive pressure to avoid inefficient behaviour. It must preserve security of supply, but also avoid treating security as a justification for unlimited expenditure. In addition, in modern power systems, regulation must increasingly recognize that investment and operation are interdependent: network decisions affect congestion and balancing costs, while operational constraints reveal the economic value of future investment, flexibility, and innovation.

For the purposes of this thesis, this multidimensionality is particularly important. The current analysis does not question the need for regulated cost recovery or financial stability in transmission. On the contrary, these remain fundamental objectives of any credible framework. The relevant issue is whether the traditional set of regulatory objectives is sufficient when system costs, renewable integration, operational flexibility, and coordination between transmission ownership and system operation become increasingly important.

2.1.2. The regulatory trade-off between stability and efficiency

Transmission regulation faces a permanent trade-off between revenue stability and efficiency incentives. On the one hand, the regulated company must receive predictable and sufficient revenues to finance long-lived assets, maintain the existing network, and undertake new investments when required. On the other hand, because the operator does not face direct competitive pressure, the regulatory framework must also create incentives to control costs, avoid inefficient investment, and improve system performance. The difficulty is that these two objectives are not always perfectly aligned: a framework that provides very strong revenue stability may weaken efficiency incentives, while a framework that exposes the operator to excessive performance risk may increase financing costs or discourage necessary investment.

This trade-off is particularly relevant in transmission because the consequences of regulatory failure can be asymmetric. If revenues are too low or too uncertain, the operator may delay investment, reduce maintenance effort, or face a higher cost of capital, which may ultimately compromise reliability or increase long-term system costs. However, if remuneration is too generous or too closely linked to asset expansion, the framework may encourage excessive investment, insufficient cost discipline, or a preference for capital-intensive solutions even when operational, digital, or flexible alternatives would be more efficient. Regulation must therefore avoid both underinvestment and over-remuneration, while ensuring that the network develops in line with system needs.

Traditional asset-based regulation has addressed this problem mainly by prioritizing stability. By recognizing investment costs, allowing depreciation, and providing a regulated financial return, it creates a credible framework for financing infrastructure. This is one of its main strengths and explains why it remains widely used in transmission. However, this stability comes at the cost of relying heavily on regulatory assessment to determine which investments are efficient and which costs should be recognized. Since the operator is not fully exposed to the consequences of its decisions, the regulator must define the allowed revenue, approve investment plans, and monitor performance through specific indicators [14].

The efficiency dimension has become more complex as power systems have evolved. In a conventional system, the main regulatory challenge was to ensure that the network was expanded and maintained at an efficient cost while meeting reliability standards. In a system with high renewable penetration, electrification, and increasing operational complexity, efficiency also depends on how transmission decisions affect congestion, redispatch, balancing needs, curtailment, flexibility, and the timing of new connections. As a result, the relevant question is not only whether the operator invests enough, but whether the regulatory framework encourages the most efficient combination of investment, operation, and alternative solutions over time.

This creates the need for a more balanced regulatory design. The objective should not be to replace stable base remuneration with high-powered incentives, since this could transfer excessive risk to a regulated monopoly that performs an essential system function. Rather, the challenge is to preserve the financial stability required for long-term investment while introducing selective incentives linked to outcomes that the operator can reasonably influence. These incentives may relate to quality of service, availability, cost efficiency, innovation, delivery performance, congestion management, or the use of flexibility. Their design must be carefully limited through caps, floors, sharing factors, and exclusions for non-controllable events, so that the operator is exposed to efficiency signals without being penalized for risks outside its control.

For the purposes of this thesis, this trade-off is central. The Spanish framework, like many transmission remuneration schemes, relies on stable regulated revenues for the transmission owner function and separate remuneration for system operation. This structure provides predictability and supports financing network assets, but it may not fully internalize the impact of TSO decisions on broader system costs. The following sections therefore examine the logic of asset-based regulation, the role of incentive mechanisms, and the CAPEX-OPEX problem in order to assess whether complementary output-based incentives could improve the alignment between TSO remuneration and long-term system efficiency.

2.2. Asset-based regulation and the RAB model

Asset-based regulation is one of the most common approaches used to remunerate electricity transmission networks. Its central logic is that the regulated company is allowed to recover the efficient costs of providing the network service, including both the depreciation of past investments and a financial return on the capital invested. In this framework, the regulator defines the value of the regulated asset base, usually composed of approved network assets, and determines the annual revenue that the network company is entitled to receive. This revenue is then recovered from consumers through regulated tariffs, charges, or settlement mechanisms.

The basic structure of asset-based remuneration normally follows a building-block approach. First, the regulator recognizes the value of the assets used to provide the regulated service. Second, these assets are depreciated over their regulatory useful life, allowing the company to recover the initial investment gradually over time. Third, the non-depreciated asset value receives an allowed financial return, usually based on a regulated cost of capital. Finally, the framework includes recognized operation and maintenance costs, taxes, losses, or other allowed cost items depending on the specific regulatory methodology [15].

Under this model, the remuneration of the network company is strongly linked to the size, composition, and regulatory valuation of its asset base. New investments enter the regulated asset base once they are approved and commissioned, and generate remuneration through depreciation and return on capital. This mechanism gives the company a clear route to recover capital expenditure, provided that the investment is recognized as efficient and necessary by the regulator. For this reason, asset-based regulation is especially suited to sectors with long-lived infrastructure, large upfront capital needs, and limited scope for direct competition, such as electricity transmission.

However, the RAB model does not mean that the regulated company can freely invest and automatically recover all costs. In most regulatory frameworks, investment recognition is subject to planning procedures, efficiency checks, technical justification, and regulatory approval. The allowed return is also set administratively, and O&M costs may be recognized through standard unit values, benchmarking, or efficiency factors rather than direct remuneration of actual expenditure. Therefore, the RAB model combines revenue predictability with regulatory control over what costs are considered efficient and recoverable.

For the purpose of this thesis, the key implication is that asset-based regulation provides a stable foundation for transmission remuneration, but it also defines the economic incentives faced by the Transmission Owner function. Since the financial return is linked to recognized capital investment, the model tends to provide strong signals for approved asset deployment, while other types of solutions (such as operational flexibility, digital tools, or measures that avoid conventional reinforcement) may require specific treatment to be equally attractive from a regulatory perspective. This issue becomes central when assessing whether the remuneration framework is neutral between CAPEX, OPEX, and system-level cost reductions.

The main advantage of asset-based regulation is that it provides a stable and credible framework for financing essential infrastructure. Transmission assets require large upfront investments, have long construction and permitting periods, and are recovered over several decades. In this context, investors and lenders need confidence that efficiently incurred costs will be recovered and that the regulated company will earn a reasonable return on capital. By linking remuneration to an approved asset base and a regulated rate of return, the RAB model reduces revenue uncertainty and supports long-term investment planning [15].

This stability is especially important in electricity transmission because delays or insufficiencies in network investment can have significant consequences for the power system. Transmission reinforcements may be needed to connect new generation, integrate renewable resources, support demand growth, improve interconnection capacity, reduce congestion, or preserve security of supply. A remuneration framework that is perceived as unstable or excessively risky could increase the cost of capital and make these investments more expensive for consumers. Therefore, predictable asset-based remuneration can be seen not only as a benefit for the regulated company, but also as a mechanism to lower financing costs and support network adequacy [14].

A second strength of the RAB model is its relative transparency. The main components of allowed revenue can be decomposed into identifiable building blocks: asset value, depreciation, allowed return, recognized O&M costs, and regulatory adjustments. This structure makes the framework easier to audit, monitor, and compare over time. It also allows the regulator to separate different components of remuneration and to apply specific efficiency parameters or incentives to each of them. In the case of transmission, where assets are technically complex and long-lived, this transparency is valuable for both regulatory accountability and investor confidence.

Asset-based regulation also provides a clear institutional framework for public supervision of network development. Since transmission investment has system-wide implications, investment decisions are usually subject to planning processes, regulatory assessment, and public approval. The RAB model is compatible with this approach because remuneration is linked to assets that have been previously approved as necessary or efficient. In this sense, it helps coordinate the financial remuneration of the network company with broader planning objectives, such as reliability, renewable integration, and security of supply.

Nevertheless, the strengths of the RAB model should not be confused with full incentive alignment. The model is effective at supporting investment adequacy and financial stability, but it does not automatically guarantee that the resulting investment and operational decisions minimize total system costs. Its effectiveness depends on the quality of regulatory planning, the accuracy of cost recognition, the design of efficiency incentives, and the treatment of alternatives to conventional investment. This is why many modern regulatory frameworks combine stable asset-based remuneration with additional incentives related to quality, efficiency, innovation, or output delivery.

2.3. Incentive regulation and output-based mechanisms

2.3.1. From cost-of-service regulation to incentive regulation

The discussion above shows that asset-based regulation provides a stable foundation for transmission remuneration, but also that stability alone is not enough to ensure efficient behaviour. If the regulated company is allowed to recover its costs with limited exposure to performance outcomes, the incentive to reduce costs, innovate, or improve service quality may be weaker than in a competitive market. This is the basic rationale behind incentive regulation: since network companies do not face direct competition, regulation must create artificial economic signals that encourage them to act efficiently while preserving the financial stability required for long-term infrastructure investment.

Traditional cost of service regulation is mainly based on the recognition of efficiently incurred costs. Under this approach, the regulated firm is allowed to recover operating costs, depreciation, and a reasonable return on capital. Its main advantage is that it limits financial risk and supports investment, which is particularly relevant in capital-intensive sectors such as electricity transmission. However, it also has a well-known drawback: if most costs can be passed through to consumers, the firm has limited incentives to reduce expenditure or search for more efficient solutions. In its purest form, cost-of-service regulation may therefore protect investment adequacy but provide relatively weak cost-efficiency incentives [14].

Incentive regulation emerged as a response to this limitation. Rather than reimbursing costs directly, the regulator sets an allowed revenue or price path for a given regulatory period, often based on expected efficient costs and productivity assumptions. If the regulated company manages to outperform the benchmark, it may retain part of the gains for a period of time. If it performs worse, it may bear part of the loss. This creates an incentive to improve efficiency, because the company's profit no longer depends only on the volume of recognized costs, but also on its ability to operate below the regulatory allowance. Revenue caps, price caps, efficiency factors, benchmarking mechanisms, and benefit-sharing arrangements are common examples of this logic [14]

The strength of incentive regulation depends on how risk and reward are allocated. A very high-powered incentive scheme may encourage strong cost discipline, but it can also expose the regulated company to risks that it cannot fully control. This is problematic in electricity transmission, where external factors such as demand growth, renewable deployment, permitting delays, weather conditions, or generation availability can significantly affect costs and performance. For this reason, incentive regulation in network industries usually requires a careful balance: the operator should be exposed to variables it can influence, but protected from excessive risk.

In recent years, incentive regulation has increasingly moved beyond narrow cost-efficiency targets. In power systems undergoing rapid transformation, the relevant question is not only whether the network company can reduce its own controllable costs, but whether its decisions improve system-level outcomes. These outcomes may include reliability, asset availability, connection times, congestion management, renewable integration, innovation, flexibility procurement, or delivery of strategic projects. This evolution has led to a growing use of performance-based and output-based mechanisms, where part of the regulated company's remuneration depends on measurable results rather than only on recognized inputs.

For transmission system operators, this shift is particularly relevant. Transmission decisions affect not only the cost of network assets, but also the operation of the wider electricity system. A reinforcement, a digital solution, a dynamic rating system, or a faster connection process may reduce congestion, curtailment, or balancing needs even if these savings do not appear directly in the transmission owner's cost base. Similarly, system operation decisions can influence redispatch and balancing costs that are ultimately borne by the system users. Incentive regulation therefore provides a conceptual basis for linking part of TSO remuneration to outcomes that matter for total system efficiency.

This does not imply that high-powered incentives should replace the existing asset-based framework. In transmission, stable base remuneration remains necessary because the sector involves essential infrastructure, large sunk investments, and security-of-supply responsibilities. The relevant question is more limited and more practical: how can the regulatory framework introduce selective performance incentives without undermining financial stability or transferring uncontrollable risks to the TSO? This question leads naturally to the distinction between input-based and output-based regulation.

2.3.2. Input-based versus output-based regulation

A useful way to understand the evolution of network regulation is to distinguish between input-based and output-based approaches. Input-based regulation remunerates the regulated company mainly according to the resources used to provide the service. These inputs may include capital investment, recognized asset value, depreciation, operating costs, maintenance expenditure, or other cost categories accepted by the regulator. Output-based regulation, by contrast, links part of remuneration to the results delivered by the company. These results may refer to service quality, availability, efficiency, innovation, connection performance, congestion reduction, or other measurable outcomes that the regulator considers valuable.

In practice, most regulatory frameworks combine both approaches. A purely input-based framework may provide stability and investment security, but it can generate weak incentives to improve performance beyond compliance with minimum obligations. A purely output-based framework, on the other hand, would be difficult to apply in transmission because many relevant outcomes are affected by factors outside the operator's control. The regulatory challenge is therefore not to choose between inputs and outputs in absolute terms, but to determine which part of remuneration should remain linked to stable cost recovery and which part can be exposed to performance indicators.

Input-based regulation is particularly suitable for ensuring that essential infrastructure is financed and maintained. It is easier to observe whether an asset has been built, what its recognized cost is, and how it should be depreciated over time. This makes input-based remuneration attractive for transmission networks, where assets are large, long-lived, and subject to public planning. However, its weakness is that it may not fully capture the value created by decisions that reduce system costs without necessarily increasing the regulated asset base. For example, a digital solution that improves the use of existing capacity may be cheaper than a conventional reinforcement, but its regulatory treatment may be less attractive if the framework is mainly designed around capital investment.

Output-based regulation tries to address this problem by remunerating what the network company delivers rather than only what it spends. In electricity transmission, relevant outputs can include high asset availability, reduced interruption time, timely project delivery, faster connection of new users, improved integration of renewable generation, lower congestion-related costs, better use of flexibility, or verified savings from innovative solutions. The purpose is not simply to reward the operator for good performance, but to make part of its economic interest depend on outcomes that are valuable for consumers and for the system as a whole.

The design of output-based incentives must be handled carefully. The selected indicators must be measurable, sufficiently robust, and reasonably attributable to the regulated company. Otherwise, the incentive may reward or penalize outcomes that are mainly driven by external conditions. This is especially important for indicators related to system operation, such as redispatch, balancing energy or curtailment, because these variables depend not only on the TSO, but also on generation availability, weather, demand, market prices, network outages, and policy-driven renewable deployment.

Another important distinction concerns whether the output is directly controllable or only influenceable. Some outputs, such as delivery time of a specific project, may be relatively close to the actions of the regulated company, although still affected by permitting or social acceptance. Other outputs, such as total redispatch costs, are much broader and depend on multiple actors and system conditions. In the latter case, full exposure would be inappropriate, but partial exposure may still be useful if the TSO has relevant information and operational capacity to reduce those costs over time. This is particularly relevant in systems where transmission ownership and system operation are performed by the same entity, as coordination between planning and operation may affect several system outcomes simultaneously.

For the purposes of this thesis, the distinction between input-based and output-based regulation is central. The Spanish transmission framework, like many European frameworks, is mainly built around stable remuneration of approved assets and recognized costs. This is necessary to finance infrastructure and preserve security of supply. However, the increasing importance of congestion, balancing, flexibility, connection capacity, and project timing suggests that a purely input-oriented approach may be incomplete. The proposed incentive framework developed later in this thesis does not seek to replace asset-based remuneration, but to complement it with selective output-based signals linked to system-level outcomes that the TSO can reasonably influence.

In this sense, output-based regulation provides the conceptual bridge between the traditional remuneration of transmission assets and the more specific problem of CAPEX-OPEX alignment. If the regulatory framework rewards only the deployment of capital assets, it may not be neutral between conventional investment and alternative solutions that reduce system costs through operation, flexibility, or innovation. The following section therefore examines the CAPEX-OPEX problem in network regulation and explains why this issue is particularly relevant for transmission system operators in systems with growing renewable penetration.

2.4. The CAPEX-OPEX problem in network regulation

A central limitation of traditional asset-based regulation is that it may treat capital expenditure and operating expenditure differently. In simplified terms, CAPEX is usually incorporated into the regulated asset base and remunerated through depreciation and an allowed return, while OPEX is normally recovered through separate allowances, efficiency factors, or cost recognition mechanisms. This distinction is not problematic by itself, since capital and operating costs have different economic characteristics. However, it can create a regulatory bias if the framework makes capital-intensive solutions more attractive for the regulated company than operational, digital, or flexible alternatives that could deliver the same system benefit at lower total cost.

This issue is often referred to as CAPEX bias. The problem is not that investment in network infrastructure is undesirable. On the contrary, transmission expansion is essential for security of supply, renewable integration, and long-term decarbonization. The concern is more specific: when remuneration is strongly linked to the recognized asset base, the regulated company may have stronger financial incentives to deploy conventional infrastructure than to implement solutions whose benefits come through avoided costs, better use of existing assets, or lower system operation expenditure. In this situation, a solution can be efficient from the perspective of total system costs but less attractive under the regulated company's remuneration framework [11], [16].

In transmission, this trade-off is particularly relevant because investment and operation are closely connected. A new line, substation, or transformer may reduce congestion, redispatch, balancing needs or renewable curtailment over many years. Conversely, delaying a reinforcement may avoid immediate CAPEX but increase operational costs ultimately borne by the system. Between these two options, there may also be intermediate solutions, such as dynamic line rating, grid monitoring, automation, topology optimization, flexibility procurement, or conditional connection arrangements. These alternatives may defer, reduce, or avoid conventional reinforcement, but their regulatory treatment is often less straightforward than that of traditional network assets.

The economic question is therefore not simply whether CAPEX or OPEX should be minimized separately. A lower level of investment is not necessarily efficient if it leads to persistent congestion and high redispatch costs. Equally, a higher level of investment is not necessarily efficient if the same outcome could have been achieved through a cheaper operational or technological solution. The relevant benchmark is total system cost over time, including both network expenditure and the operational costs affected by network constraints. This is why the CAPEX-OPEX problem is closely linked to the broader objective of incentive alignment.

This trade-off also becomes more complex when transmission ownership and system operation are remunerated separately. The Transmission Owner may be remunerated mainly through asset-based mechanisms, while the System Operator manages technical constraints, balancing actions and other operational measures whose costs are often socialized as system costs. Even if both functions are performed by the same corporate entity, the regulatory signals attached to each activity may remain fragmented. As a result, the framework may fail to fully internalize the value of decisions that reduce operational costs through better planning, faster delivery, flexibility, or innovation.

The relevance of the CAPEX-OPEX problem increases in systems with high renewable penetration. Renewable generation is variable, geographically uneven, and often located far from demand centres. This increases the value of transmission capacity, but also the value of operational tools that make better use of existing infrastructure. In such a context, regulatory neutrality between conventional reinforcement and alternative solutions becomes more important. If the framework rewards only or mainly asset deployment, it may under-incentivize measures that reduce congestion, accelerate connections, or improve flexibility without significantly increasing the regulated asset base.

For this reason, modern transmission regulation needs to assess whether the regulated company is encouraged to choose the most efficient solution, rather than the solution that is most naturally remunerated by the existing framework. This does not require abandoning asset-based remuneration, which remains necessary for financing large infrastructure. It does require, however, complementary mechanisms that recognize the value of avoided system costs, efficient timing, innovative solutions, and flexible alternatives where these can be measured with sufficient robustness.

One regulatory response to the CAPEX-OPEX problem is the use of TOTEX-based approaches. Under a TOTEX logic, the regulator considers capital and operating expenditure together, rather than treating them as two fully separate categories. The aim is to make the regulated company indifferent between CAPEX and OPEX solutions, as long as they deliver the required output at the lowest efficient total cost. In principle, this can reduce the incentive to prefer capital-intensive investments simply because they enter the regulated asset base [17].

The main appeal of TOTEX regulation is that it shifts attention from the type of expenditure to the value of the solution. If a network need can be addressed either by building a conventional asset, procuring flexibility, improving monitoring, or applying a digital solution, the regulatory framework should not distort the choice in favour of one category of spending. What matters is whether the solution delivers the required level of reliability, capacity, or system benefit at minimum efficient cost. This logic is particularly relevant in networks where flexibility, digitalization, and non-wire alternatives are becoming increasingly important.

However, the application of TOTEX in transmission is not straightforward. Transmission investments are large, long-lived, and often subject to public planning processes. Their benefits may extend over several decades and affect multiple dimensions of the system, including security of supply, renewable integration, interconnection capacity, and market efficiency. By contrast, many OPEX-based or flexibility-based solutions have shorter time horizons, different risk profiles, and more uncertain benefits. Comparing these options under a single TOTEX framework requires strong assumptions about useful life, risk allocation, counterfactual investment costs, and the value of avoided system costs.

Furthermore, the main appeal of TOTEX regulation is that it seeks to reduce the regulatory relevance of whether a solution is classified as CAPEX or OPEX. In principle, this should make the regulated company more neutral between conventional investment, operational measures, and flexible alternatives. However, this neutrality depends critically on the detailed design of the mechanism. As discussed by Ruiz et al., a TOTEX framework with a fixed capitalization rate may introduce its own distortions when that rate does not match the actual CAPEX-OPEX composition, useful life, and risk profile of the available solutions. In such cases, the model may not simply remove CAPEX bias, but may instead create a form of OPEX bias by making operational or short-lived solutions relatively more attractive than long-lived network assets [16].

For these reasons, this thesis does not propose a full TOTEX reform of the Spanish transmission framework. Such a reform would go beyond the scope of the analysis and would require a deeper redesign of the current remuneration model. Instead, TOTEX is used as a conceptual reference: it highlights the importance of regulatory neutrality between capital-intensive and non-capital-intensive solutions. The practical proposal developed later in the thesis follows a more selective approach, based on targeted output-based incentives for specific outcomes such as technical constraints, balancing energy, project timing, innovative grid solutions, and flexible connections.

This approach is less ambitious than a full TOTEX model, but also more compatible with the existing Spanish framework. It preserves the asset-based remuneration needed for conventional transmission investment, while adding limited economic signals where the current framework may not sufficiently recognize system-level benefits. In that sense, the proposed model does not attempt to replace RAB-based regulation, but to complement it with mechanisms that partially correct CAPEX-OPEX distortions where they are most relevant for TSO incentive alignment.

2.5. Coordination between Transmission Ownership and System Operation

Transmission ownership and system operation are often described as different regulatory functions, but from a power system perspective they are deeply interdependent. The Transmission Owner function is mainly associated with the construction, maintenance and availability of network assets. The System Operator function is responsible for maintaining the real-time balance, ensuring operational security, managing constraints and coordinating the use of system resources. In most regulatory frameworks, network planning, the identification of reinforcement needs and the proposal of new infrastructure, is formally attributed to the System Operator, given its system-wide view of grid performance, congestion patterns and security requirements. The resulting plan is submitted to the competent public authority for regulatory approval. Upon approval, the Transmission Owner is responsible for financing and constructing the authorized facilities. This sequence, SO plans, regulator approves, TO builds, establishes the conceptual framework governing network facility development and clarifies the respective role of each function.

Network planning determines the physical capacity, topology and robustness of the transmission system. These characteristics affect power flows, congestion patterns, security margins, curtailment needs, and the amount of redispatch or balancing actions required to operate the system securely. A transmission reinforcement may reduce congestion in a constrained area, improve the integration of renewable generation or reduce the need for corrective actions. Conversely, a delayed or insufficient reinforcement may increase operational costs over time, even if the asset-based remuneration of the network company remains formally separate from those costs. For this reason, transmission investment cannot be evaluated only by looking at the cost of the asset itself, but also by considering the operational costs that the investment may create, reduce or avoid.

The relationship also works in the opposite direction. System operation reveals the practical consequences of the existing network configuration. Recurrent technical constraints, persistent redispatch needs, renewable curtailment or increasing balancing requirements may indicate that the network is becoming insufficient in specific areas or that existing assets are not being used optimally. These operational signals can therefore support better planning decisions, helping to identify where conventional reinforcements are justified and where alternative measures may be more efficient. In this sense, the operational signals generated by the SO are highly valuable for informing network planning decisions and for guiding the investment and construction priorities of the Transmission Owner.

This interaction has become more important with the transformation of power systems. In systems with high renewable penetration, generation is more variable, less geographically aligned with demand and more dependent on weather conditions. As a result, transmission networks must accommodate more volatile flow patterns and greater uncertainty. The value of a network investment may depend not only on its contribution to peak demand coverage, but also on its ability to reduce congestion, enable renewable integration, accelerate connections, limit curtailment or improve the effectiveness of balancing resources. Similarly, operational tools such as dynamic line rating, grid monitoring, topology optimization, flexibility procurement or conditional connection arrangements may defer or reduce the need for conventional reinforcements.

Therefore, the efficient coordination between TO and SO functions is not only a technical matter. It is also an economic and regulatory issue. If investment and operation are assessed separately, the system may fail to capture the full value of decisions that improve total cost efficiency. A measure that looks expensive from a narrow network-cost perspective may be efficient if it substantially reduces future redispatch or curtailment. Conversely, avoiding investment may appear efficient in the short term while increasing system operation costs over time. The relevant benchmark is thus the combined effect of network expenditure and operational costs, rather than the isolated optimization of each category.

This point is particularly relevant for this thesis because the proposed analysis focuses precisely on the gap between technically interconnected decisions and separated remuneration signals. The issue is not whether TO and SO teams are able to coordinate in practice, nor whether system security is properly considered. The issue is whether the remuneration framework gives sufficient economic weight to the system-level effects that arise from this coordination. This distinction becomes essential when assessing the alignment between TSO incentives and long-term system cost minimization.

Regarding the regulatory separation, the institutional organization of TO and SO functions differs across jurisdictions. In some systems, transmission ownership and system operation are performed by separate entities. In others, both functions are integrated within the same company, although subject to accounting, functional or regulatory separation. From an incentive perspective, the relevant issue is not only whether the functions are institutionally separated, but whether the economic signals attached to each function are aligned with the same system objective.

A separated remuneration framework may be justified for transparency and regulatory accountability. Transmission ownership and system operation involve different activities, cost structures and risks. The TO function is typically capital-intensive and linked to long-lived assets, while the SO function is more closely related to operational coordination, security management and short-term system actions. Treating them separately can help regulators identify costs, assign responsibilities and avoid cross-subsidization between activities. In this sense, regulatory separation is not necessarily a weakness; it may be necessary to ensure clarity and accountability.

However, separation can also create fragmented incentives. If the TO is mainly remunerated through recognized assets and O&M allowances, while the SO manages congestion, balancing and other operational measures whose costs are recovered as system costs, neither function may face a fully integrated signal reflecting total system cost. The TO may not be directly rewarded for investments that reduce redispatch or curtailment if those savings occur outside the asset remuneration framework. The SO may have limited exposure to the cost of operational actions if these costs are largely socialized, even when better forecasting, coordination or flexibility activation could reduce them. The result is not necessarily inefficient behaviour, but a possible divergence between the regulated entity's incentives and the outcome that would minimize total system costs.

This problem can also arise when both functions are performed by the same corporate entity. Corporate integration may facilitate information sharing, internal coordination and a better understanding of the interaction between planning and operation. However, if the regulatory remuneration of each function remains separate, the economic signals may still be incomplete. The entity may have the technical ability to coordinate decisions across TO and SO dimensions, but the remuneration framework may not fully reward the system benefits of doing so. In other words, integration of functions does not automatically imply integration of incentives.

The risk of misalignment is especially relevant for outcomes that are valuable for the system but difficult to attribute to a single decision. Reductions in congestion, balancing costs or curtailment may result from a combination of network investment, operational decisions, market conditions, generation availability, demand patterns and weather. Because of this complexity, regulators often hesitate to expose the TSO directly to such outcomes. This caution is reasonable, since full exposure could penalize the operator for factors outside its control or create undesirable incentives under security-critical conditions. Nevertheless, the absence of any meaningful exposure may also weaken the incentive to consider system-level cost impacts.

A balanced regulatory approach should therefore recognize both sides of the problem. On the one hand, TO and SO remuneration cannot be merged mechanically, and the TSO should not be made responsible for all system costs. On the other hand, a framework that treats network investment, system operation and system costs as largely separate dimensions may fail to encourage efficient coordination. The challenge is to design selective mechanisms that expose the TSO only partially, and only to outcomes it can reasonably influence. This can be done through output-based incentives, sharing factors, caps, exclusions for exceptional events and clear rules to avoid double remuneration.

For the purposes of this thesis, this provides the direct link between the theoretical discussion and the proposed regulatory framework. The objective is not to claim that separated TO and SO remuneration is inherently wrong. Rather, the argument is that, in a system where planning and operation are increasingly interdependent, separated remuneration may need complementary incentives to better reflect system-level outcomes. This is the basis for the later proposal of targeted incentives related to technical constraints, balancing energy, liquidity, project timing, innovative grid solutions and flexible connections.

2.6. International regulatory trends

2.6.1. Output-based regulation in the United Kingdom

The United Kingdom represents one of the clearest examples of the gradual evolution of transmission regulation from a mainly cost-based framework towards a broader output-based approach. The RIIO model does not abandon the traditional objective of ensuring cost recovery for monopoly network companies. However, it adds a more explicit link between allowed revenues, incentives, innovation and delivered outputs. This reflects a general regulatory trend: in a system where network companies remain regulated monopolies, the regulator increasingly seeks to reproduce some of the performance discipline that would otherwise come from competition.

The main idea behind this approach is that consumers should not only pay for expenditure, but for outcomes. Transmission companies are therefore assessed not only on whether they incur efficient costs, but also on whether they deliver infrastructure, reliability, connections, innovation and environmental improvements in a way that creates value for the system. This is particularly relevant in the context of the energy transition, where the timing and location of network reinforcements can strongly affect congestion, renewable integration and total system costs. Ofgem's RIIO-ET3 framework explicitly links the need for major transmission upgrades to the reduction of constraint costs, the integration of low-carbon generation and the connection of new demand, while maintaining consumer protection through cost assessment and uncertainty mechanisms [18].

A second important feature of the UK approach is the use of differentiated instruments depending on the type of output being regulated. Some obligations are treated as licence requirements or deliverables, while others are linked to financial or reputational incentives. This distinction is important because not all outputs should be incentivized in the same way. For example, reliability and security-related obligations may require strict compliance, while innovation, early delivery or enhanced coordination with the system operator may be better suited to reward-based or sharing mechanisms. In this sense, the

UK framework illustrates a more granular view of incentive regulation, where the regulatory tool is adapted to the nature of the outcome.

The UK case is also relevant because it explicitly addresses the interface between transmission ownership and system operation. Under the British model, Transmission Owners are separate from the National Energy System Operator. This separation makes coordination between asset owners and the system operator a regulatory issue. Incentives such as SO:TO optimisation are designed to encourage TOs to provide enhanced services or operational support that can reduce the cost of operating the transmission system. The specific details of this mechanism are jurisdiction-specific, but the underlying principle is more general: where network owners can influence system operation costs, regulation may need to create a direct economic signal to make that value visible [19].

For the purposes of this thesis, the UK experience is therefore useful less as a template to be copied and more as evidence of a broader regulatory direction. It shows that stable asset-based remuneration can coexist with output-based incentives, innovation funding, delivery incentives and mechanisms aimed at reducing system costs. It also shows that transmission regulation is increasingly concerned with whether network companies deliver the right outcomes at the right time, not only whether they recover efficient costs. This is directly connected to the Spanish case, where the question is whether the remuneration of the TSO sufficiently reflects outcomes such as technical constraints, balancing needs, flexibility and project timing.

2.6.2. Performance incentives in France

France provides a complementary example of performance-oriented regulation within a more traditional tariff framework. The *Tarif d'Utilisation des Réseaux Publics d'Électricité* (TURPE) framework for *Réseau de Transport d'Électricité* (RTE) remains based on the definition of an allowed revenue intended to cover the costs of an efficient network operator. It therefore preserves the basic logic of regulated cost recovery. At the same time, recent tariff decisions show a clear movement towards more explicit incentives on performance dimensions that are becoming increasingly important for the electricity system.

The general direction of the French framework is particularly relevant. *La Commission de régulation de l´énergie* (CRE) identifies the transformation of the electricity system, including electrification, renewable development, ageing infrastructure and increasing connection needs, as a reason to adapt the regulation of the transmission network. TURPE 7 HTB is built around the need to finance a significant increase in investment while also maintaining a high level of performance and cost control. This illustrates a common regulatory challenge across Europe: transmission operators need more resources to expand and adapt the grid, but regulators also need to ensure that this higher investment effort is accompanied by efficiency, prioritization and measurable delivery [20].

Within this context, the French framework gives increasing attention to outputs such as connection delays, investment cost control, flexibility and interconnection performance. These areas are not accidental. They correspond to problems that are becoming central in systems with high renewable penetration and growing demand for electrification. Delays in connections may slow down new generation or industrial demand. Inefficient investment may increase tariffs without delivering proportional system value. Lack of flexibility may force the system to rely excessively on conventional reinforcement. Poor interconnection management may reduce the efficiency of cross-border exchanges. The French case therefore confirms that modern transmission regulation is no longer focused only on asset remuneration, but also on the quality and usefulness of the outcomes delivered by the network operator.

The treatment of flexibility is especially important from a state-of-the-art perspective. CRE explicitly recognizes that flexibility can serve the network either as a complement or as a substitute for conventional reinforcement. This is a significant regulatory development because it addresses the CAPEX-OPEX problem discussed earlier in this chapter. If flexibility, automation or conditional connection arrangements can reduce costs or accelerate access to the network, the regulatory framework must be able to recognize that value. Otherwise, traditional reinforcement may remain the most natural solution from the point of view of remuneration, even when it is not always the most efficient solution from a system perspective.

The French experience also highlights the importance of partial exposure and regulatory safeguards. Performance incentives are not designed as full transfers of system-cost risk to the operator. Instead, they tend to rely on specific indicators, predefined targets, caps, ex post verification and regulatory oversight. This is important because many relevant outcomes are only partially controllable by the TSO. Connection delays, congestion, curtailment or flexibility needs depend not only on the network operator, but also on permitting, generation development, demand growth, market conditions and public policy. The French framework therefore supports a cautious interpretation of output-based regulation: incentives can be useful, but only if the regulated company is exposed to outcomes that are measurable and reasonably influenceable.

For this thesis, France is useful because it provides a practical example of how a conventional tariff framework can incorporate performance-oriented elements without becoming a full TOTEX or market-based model. The lesson is not that Spain should replicate the French tariff, but that European regulation is increasingly moving towards selective incentives on connections, flexibility, cost control and system-relevant outputs. These are precisely the types of outcomes that become relevant when evaluating whether the TSO remuneration framework is aligned with long-term system efficiency.

2.7. Research gap and contribution of the thesis

The literature reviewed in this chapter provides a solid basis for understanding the regulation of electricity transmission networks. Classical contributions on network regulation explain why transmission remains a regulated monopoly activity and why incentive mechanisms are needed to replace, at least partially, the discipline that competition provides in other segments of the electricity sector. In this context, incentive regulation has been widely analysed as a way to improve cost efficiency, service quality and investment performance in regulated electricity networks. Similarly, the transmission investment literature has shown that network expansion decisions cannot be assessed only through simple economic investment rules, since congestion, losses, reliability criteria, uncertainty and system security are deeply interdependent.

A second strand of literature focuses on the CAPEX-OPEX problem. This literature is particularly relevant for electricity networks because conventional asset-based remuneration may create stronger incentives for capital-intensive solutions than for operational or flexible alternatives. Contributions on CAPEX bias show that the different regulatory treatment of capital and operating expenditure can distort the choices made by regulated network companies, especially when CAPEX and OPEX are substitutes. More recent work on TOTEX and fixed-OPEX-CAPEX-share approaches has proposed ways to reduce this distortion by treating expenditure more neutrally, although these solutions also raise implementation challenges related to capitalization rates, asset lives, risk allocation and regulatory complexity.

A third relevant strand concerns system costs. In power systems with increasing renewable penetration, costs related to congestion management, balancing, reserves and other system operation needs are becoming more important. Recent literature has therefore examined how these costs should be allocated among users and how cost-reflective signals can be designed without creating distortions. This is directly connected to the motivation of this thesis, since many of the costs affected by transmission planning and system operation are not necessarily borne directly by the regulated TSO, but are recovered through system-wide mechanisms.

However, these strands of literature are often treated separately. The regulation literature analyses the design of incentive schemes for regulated networks. The investment literature studies how transmission expansion should be planned and financed. The CAPEX-OPEX literature focuses on expenditure classification and the bias between capital and operating solutions. The system cost literature examines how congestion, balancing or ancillary service costs should be allocated across users. What is less frequently addressed is the combined question of how the remuneration of the Transmission Owner and System Operator functions should be aligned when investment decisions, operational decisions and system-level costs are technically interdependent but regulated through differentiated mechanisms.

This gap is especially relevant for the Spanish case. In Spain, the same corporate entity performs both transmission ownership and system operation, while both functions remain subject to differentiated remuneration schemes. This creates a specific regulatory configuration: technical integration coexists with separate economic signals. As a result, the key question is not simply whether transmission investment is adequately remunerated, nor whether the system operator performs its duties securely, but whether the combined remuneration framework provides coherent incentives across both functions. In other words, the relevant issue is whether the TSO is sufficiently exposed, in a controlled and proportionate way, to the system-level outcomes that its planning, investment and operational decisions can influence.

The contribution of this thesis is therefore threefold. First, it provides an integrated regulatory assessment of the TO and SO remuneration frameworks, treating them not as isolated schemes but as interacting components of the same incentive problem. Second, it connects the theoretical discussion on incentive regulation, CAPEX-OPEX bias and system costs with a practical case study: the Spanish TSO remuneration framework. Third, it develops a regulatory-parametric incentive model that allows a set of complementary output-based incentives to be defined, calibrated and evaluated in terms of economic magnitude, risk exposure, sensitivity and proportionality.

This contribution is deliberately analytical rather than prescriptive. The thesis does not claim to estimate the exact welfare loss generated by the current framework, nor does it propose to replace asset-based remuneration with a fully output-based or TOTEX model. Instead, it explores whether selective incentives could complement the existing framework by linking a limited part of TSO remuneration to measurable outcomes such as technical constraints, balancing energy, liquidity of system services, project timing, innovative grid solutions and flexible connections. This approach reflects the broader direction observed in international regulatory practice, where stable base remuneration is increasingly combined with targeted incentives for delivery, flexibility, innovation and system efficiency.

The research gap can therefore be summarized as follows: while existing literature provides strong foundations on network regulation, transmission investment, CAPEX-OPEX distortions and system cost allocation, there remains room for a more integrated analysis of how TO and SO remuneration signals interact in a renewable-intensive power system. This thesis aims to contribute to that discussion by proposing and quantitatively testing a structured incentive framework designed to improve the alignment between TSO remuneration and long-term system cost efficiency.

3. Regulatory Framework: The Spanish Case

The theoretical discussion developed in the previous chapter provides the basis for analysing the Spanish transmission framework from an incentive-alignment perspective. Spain is a particularly relevant case because the transmission network owner and the system operator functions are performed by the same corporate entity, Red Eléctrica de España, while their remuneration is regulated through differentiated mechanisms. This creates a distinctive configuration: planning, investment and operation are technically interconnected, but the economic signals attached to each function are not necessarily fully integrated. The purpose of this chapter is therefore to describe the current Spanish framework before introducing any alternative incentive design, identifying how the remuneration of the Transmission Owner and System Operator functions is structured and where potential gaps may arise.

The chapter first presents the institutional structure of the Spanish transmission system and the regulatory separation between the TO and SO functions. It then examines the remuneration of transmission ownership, including asset-based remuneration, recognized O&M costs, availability and quality incentives, and the role of network planning. The System Operator remuneration framework is analysed separately, with particular attention to the existing performance incentives and their relationship with system operation outcomes. Finally, the chapter discusses the treatment of system operation costs, especially technical constraints, redispatch, balancing energy, and renewable curtailment. This empirical and regulatory diagnosis is essential for the rest of the thesis: the proposed incentive framework developed later is not intended to replace the current model, but to assess whether selective, measurable, and capped output-based incentives could complement it by improving the alignment between TSO remuneration and system-level efficiency.

3.1. Institutional structure of the Spanish transmission system

For the case of Spain, the transmission system is organized around a highly centralized TSO model. Red Eléctrica de España, currently integrated within the Redeia group, performs the two core functions that are most relevant for this thesis: it acts as the owner and manager of the transmission grid, and it also acts as the system operator. This institutional configuration distinguishes Spain from systems where transmission ownership and system operation are carried out by separate entities. In Spain, both dimensions are integrated within the same corporate group, although they remain subject to differentiated regulatory treatment and remuneration mechanisms.

From a legal perspective, the Spanish Electricity Sector Law [21] assigns the system operator the main function of guaranteeing the continuity and security of electricity supply and ensuring the correct coordination of the generation and transmission system. The same provision establishes that the system operator is also the transmission grid manager and must act under the principles of transparency, objectivity, independence, and economic efficiency. The law also includes unbundling requirements preventing control links between the system operator or transmission grid manager and companies performing generation or supply activities. This institutional design is important for the thesis because it means that the Spanish TSO is not vertically integrated with competitive market activities, but it does combine within the same entity the two regulated functions whose incentive alignment is analysed in this work.

The transmission activity itself is defined around a high-voltage network that connects generation, distribution networks, large consumers, and international interconnections. Spanish law distinguishes between the primary and secondary transmission networks. The primary transmission network includes lines, substations, transformers, and other electrical elements at nominal voltages equal to or above 380 kV, as well as international interconnections and, where applicable, interconnections with non-mainland systems. The secondary transmission network includes facilities at nominal voltages equal to or above 220 kV not included in the primary network, as well as other lower-voltage assets that perform transmission functions. In non-mainland systems, facilities at 66 kV or above and certain island interconnections are also considered part of the transmission network.

Red Eléctrica's role as a single transmission agent has been progressively consolidated. According to the company's own description of the Spanish model, Law 17/2007 [22] confirmed Red Eléctrica as transmission grid manager and attributed to it the role of sole transmission agent under an exclusivity regime. The subsequent acquisition of remaining transmission assets in the peninsula, the Balearic Islands, and the Canary Islands [23] consolidated the model of a single transmission owner and system operator. As grid manager, Red Eléctrica is responsible for the development and expansion of the transmission network, its maintenance, the management of electricity flows between external systems and the peninsula, and the guarantee of third-party access to the transmission grid under equal conditions.

This structure has clear advantages from a system coordination perspective. A single TSO can internalize technical information across planning, network development, outage coordination, and real-time operation. This is especially relevant in a system with high renewable penetration, where grid topology, connection queues, congestion patterns, and operational security constraints are increasingly interdependent. In principle, the integration of TO and SO functions within the same entity should facilitate information sharing and reduce coordination problems between long-term planning and short-term operation.

However, the institutional integration of these functions does not imply that their economic incentives are fully integrated. The Spanish framework still differentiates the remuneration of transmission ownership from the remuneration of system operation. The former is mainly linked to the regulated asset base, depreciation, financial return, recognized O&M costs, and quality or availability incentives. The latter is linked to the specific regulated remuneration of the system operator and to a set of performance indicators associated with system operation. This distinction is central for the thesis: the same entity may have access to information from both investment and operation, but the financial signals attached to each function may still be fragmented.

The role of the regulator and the public administration is also essential. The CNMC establishes the annual remuneration of regulated activities, including electricity transmission and the system operator, applies the relevant remuneration methodologies, sets access tariffs, and performs settlement functions for regulated revenues. At the same time, transmission network development is embedded in a public planning framework, in which the government defines the binding transmission plan and Red Eléctrica executes network development according to the approved plan. This means that the TSO does not decide transmission expansion independently: investment decisions are shaped by planning procedures, regulatory approval, remuneration rules, and budgetary limits.

Therefore, the Spanish institutional structure combines three features that are particularly relevant for incentive analysis. First, transmission ownership and system operation are integrated within Red Eléctrica, which should facilitate technical coordination. Second, both functions are regulated separately, which may create differentiated economic signals. Third, network development is not a purely corporate decision, but the result of a regulated planning process involving public authorities and the regulator. The following sections examine these elements in more detail by analysing the remuneration of the Transmission Owner function, the treatment of transmission planning and investment limits, and the remuneration and incentives of the System Operator function.

3.2. Remuneration of the Transmission Owner function

The remuneration of the Transmission Owner function in Spain is mainly based on an asset-based regulatory approach. Its purpose is to allow transmission companies to recover the efficient costs of building, operating, and maintaining the transmission network, while receiving an adequate return for an activity legally treated as low risk. Since 2020, the methodology has been defined by Circular 5/2019 [7] of the CNMC, and the latter modification Circular 7/2025, [8] which establishes the remuneration criteria for transmission assets under homogeneous principles and at the lowest possible cost for the electricity system. The framework is explicitly designed to provide regulatory stability, reduce financing costs, incentivize efficient management, and support the modernization and renewal of the network.

The methodology follows the general principle that only the costs required by an efficient and well-managed company should be recognized. The CNMC sets the remuneration of the transmission company annually by resolution, based on the assets that were in service two years before the remuneration year. This regulatory lag means that assets commissioned in year n begin to accrue and receive remuneration from year n+2. The remuneration framework is also structured around six-year regulatory periods, during which the main technical and economic parameters are defined before the start of the period.

Under Circular 5/2019, the annual remuneration of the transmission company was composed of four main elements: investment remuneration, operation and maintenance remuneration, remuneration for the extension of useful life, and an availability incentive. In simplified terms, the original structure can be expressed as:

$$R_n^i = RI_n^i + ROM_n^i + REVU_n^i + ID_n^i \tag{1}$$

Where RI_n^i is investment remuneration, ROM_n^i is operation and maintenance remuneration, $REVU_n^i$ is remuneration linked to the extension of useful life of assets, and ID_n^i is the incentive associated with the availability of the transmission network.

Circular 7/2025 [8] modifies this structure for the 2026–2031 regulatory period. The revised formula replaces the previous availability incentive with a broader quality incentive and introduces a new term for the remuneration of work in progress associated with certain singular installations:

$$R_n^i = RI_n^i + ROM_n^i + REVU_n^i + ICal_n^i + ROC_n^i \tag{2}$$

In this updated expression, $I\_Cal_n^i$ is the quality incentive, linked to both network availability and the reduction of average interruption time, while ROC_n^i remunerates the financial cost of construction-period expenditure for singular installations. This change is relevant because the methodology is being adapted to a context of increasing investment needs, longer construction periods, and new network functionalities linked to digitalization, flexibility, and the energy transition.

The investment remuneration component is the core of the asset-based framework. It is composed of two elements: depreciation and financial return. Depreciation allows the company to recover the recognized investment value over the regulatory useful life of the asset. The financial return remunerates the net investment value that has not yet been depreciated, applying the regulated financial rate of return set for the corresponding regulatory period. This creates a RAB-like mechanism: once an asset is recognized as eligible for remuneration, it generates annual income through both depreciation and return on capital.

The regulatory useful life of transmission assets is generally set at 40 years, but the updated framework introduces specific values for several technologies. Dispatch and telecontrol centres have a regulatory life of 12 years; uprating of overhead lines is assigned 8 years; STATCOMs 25 years; Dynamic Line Rating systems 12 years; network-integrated batteries 20 years; and autonomy equipment 12 years. This is important for the thesis because the Spanish methodology is beginning to recognize non-conventional network solutions explicitly within the asset base. However, these solutions are still treated mainly through an investment-recognition logic, rather than through a direct sharing of the system benefits they may generate.

The recognition of investment value has also evolved. In the 2019 framework, investment remuneration relied on audited costs and reference unit values, with limits on the recognized value when actual investment exceeded standardized values without sufficient justification. This was intended to prevent inefficient cost overruns from being automatically passed through to the system. Circular 7/2025 modifies this approach for assets commissioned after 2023 by giving greater relevance to audited investment values, while introducing an adjustment every three years against reference unit values for those asset categories that have them. The resulting design is therefore hybrid: it recognizes real audited expenditure, but preserves an ex post efficiency check through standardized cost references.

The second major component is remuneration for operation and maintenance. This is not a pure pass-through of actual O&M expenditure. Instead, it is calculated using reference unit values by asset family, physical units, and an efficiency factor. The objective is to recognize the efficient cost of maintaining and operating the transmission network while avoiding full reimbursement of all actual costs. This gives the framework a certain incentive-efficiency dimension, because the company is not simply compensated for every euro spent. However, the signal remains closely linked to the physical asset base and to the standardized cost of maintaining it. It does not directly expose the transmission owner to broader system-operation outcomes, such as congestion, redispatch, balancing needs, or renewable curtailment.

The remuneration for useful life extension is another relevant element. Once an asset reaches the end of its regulatory useful life, its investment remuneration becomes zero. Nevertheless, if the asset remains in operation, the methodology allows additional O&M-related remuneration linked to the extension of its useful life. If renewal or improvement works are carried out on assets that have exceeded, or are close to exceeding, their regulatory life, those works must be included in the transmission planning framework to be remunerated as new investment. This mechanism is relevant because it avoids creating a purely mechanical incentive to replace assets once their regulatory life ends, and instead allows continued operation where it is technically and economically justified.

Singular installations receive specific treatment. These are assets whose design, configuration, operating conditions, or technical characteristics are not adequately represented by standard reference unit values. Examples include submarine links, direct-current facilities, converter stations, dispatch and telecontrol centres, and certain pilot projects. Pilot projects may be recognized as singular investments when the company demonstrates a quantifiable benefit for the system in terms of security, quality, efficiency, objectivity, or transparency, and when the required cost-benefit and technical justification are provided. Circular 7/2025 strengthens this area by introducing the remuneration of construction-period financial costs for singular installations, reflecting the long construction periods, technical complexity, and strategic value of some transmission projects.

The explicit performance incentive for the transmission owner has also changed. Under Circular 5/2019, the main incentive was linked to network availability and could generate both bonuses and penalties. Circular 7/2025 replaces this with a broader quality incentive, combining a sub-incentive for availability and a sub-incentive for the reduction of average interruption time. For the 2026–2031 period, the framework sets the weight of the availability component at 0.6, an availability objective of 98%, and an average interruption time objective of 0.75 minutes. It also establishes limits for the quality incentive, including a maximum bonus of 0.5% and a maximum penalty of -1% of the total remuneration for transmission companies.

This quality incentive is important, but its scope should be interpreted carefully. It creates a direct economic signal for the transmission owner to maintain a highly available and reliable network, which is essential for the security of supply. However, it remains focused on asset availability and interruption quality, not on the wider operational costs that may arise from network constraints. In other words, the existing TO incentive framework rewards the condition and reliability of the transmission grid, but it does not directly reward the transmission owner for reducing redispatch, balancing costs, congestion-related costs, or renewable curtailment.

The remuneration framework also contains mechanisms intended to protect the system from inefficient or inappropriate cost recognition. These include annual regulatory resolutions, audit obligations, CNMC inspection powers, adjustments when regulated assets are used for non-regulated activities, and a financial prudence penalty when the company's financial ratios fall outside recommended ranges. Circular 7/2025 increases the intensity of this prudence-related penalty from the fourth year of the 2026–2031 regulatory period, reinforcing the idea that the transport activity should remain financially sustainable and consistent with its low-risk regulated nature.

For the purposes of this thesis, the Spanish TO remuneration framework has two main implications. First, it provides a stable and predictable structure for investment recovery, financial viability, and network reliability. This is necessary in a sector characterized by long-lived assets, high upfront costs, and security-of-supply obligations. Second, despite recent improvements, the framework remains predominantly input- and asset-oriented. It recognizes investment, O&M, useful life extension, quality, and certain new technologies, but it does not directly internalize the system-level value of reducing technical constraints, avoiding redispatch, enabling flexibility, accelerating strategically valuable projects, or choosing non-conventional solutions when these reduce total system costs. This does not mean that the existing methodology is inadequate for its core purpose. Rather, it shows why complementary output-based incentives may be useful in areas where the economic value of transmission increasingly depends on its interaction with system operation.

3.3. Transmission network planning and investment limits

Transmission network planning is a central element of the Spanish regulatory framework because it determines which network developments are considered necessary, when they are expected to be commissioned, and which investments may subsequently be eligible for regulated remuneration. In Spain, the planning of the electricity system is carried out by the State with the participation of the Autonomous Communities. It is binding for the transmission facilities, while being based on expectations and forecasts of generation and demand. This distinction is important: while generation and demand evolve through market and policy-driven decisions, the development of the transmission grid is subject to an administratively approved planning process.

The legal process is initiated by the Ministry, currently MITERD, with the request for the initial proposal to the System Operator and Transmission Grid Manager. The procedure begins with a publication in the Official State Gazette, opening a non-extendable three-month period for stakeholders to submit proposals for the development of the transmission network. The proposal must respect the principles of the Electricity Sector Law, including the economic and financial sustainability of the electricity system, the investment limits established in the remuneration framework for transmission, and the environmental assessment requirements applicable to plans and programmes [24].

The current binding plan is the Plan de Desarrollo de la Red de Transporte de Energía Eléctrica 2021–2026, approved by the Council of Ministers in March 2022 after being submitted to the Congress of Deputies. Its purpose is not simply to identify new assets, but to determine the network developments required to meet the expected evolution of demand, generation, and system needs under the energy transition. The plan explicitly links transmission development to renewable integration, security of supply, reduction of structural technical constraints, interconnection needs, environmental compatibility, economic efficiency, and the maximization of the use of existing grid assets [25].

From a regulatory perspective, the 2021–2026 planning process is a step towards a more system-oriented assessment of transmission needs. It includes analysis of alternatives, multicriteria cost-benefit assessment, consideration of new network components and indicators related to renewable integration, constraints, losses, energy not supplied, and environmental impact. The process also recognizes that the plan must remain adaptable through technical adjustments and punctual modifications when unexpected needs arise, for example, due to security of supply, new demand, or critical infrastructure required for the energy transition.

However, this planning framework should not be interpreted as a complete solution to the incentive-alignment problem. The published documents provide valuable information on the motivations and expected benefits of network developments, but they do not always allow the reader to fully reconstruct the underlying economic assessment behind each decision. In particular, the public documentation does not always provide a detailed quantitative comparison between alternatives, nor a full breakdown of the contribution of each benefit category to the final decision. This matters because, from an incentive perspective, it is different whether a project is mainly justified by congestion reduction, renewable integration, avoided losses, security of supply, or connection of new demand.

This limitation is also visible in the initial proposal for the 2025–2030 horizon, which is not yet the final approved plan. The proposal represents a clear improvement in terms of structure and information, as the project includes motivations, alternatives considered, European dimension, maps, CAPEX, OPEX, ten-year remuneration costs, environmental and social impact, and contribution to planning principles. However, the same documentation also states that no cost-benefit analysis is carried out for actions included in the starting grid because they are already advanced in permitting or construction. It also indicates that several benefits included in the socioeconomic indicator, such as technical constraints, losses, renewable curtailment, CO_2 emissions, and avoided energy not supplied, cannot be disaggregated because their evaluation is interrelated [26].

This does not invalidate the planning process. Rather, it means that planning should be seen as a necessary regulatory control mechanism, but not as a substitute for incentives linked to execution, verified benefits, and efficient alternatives. The existence of an alternatives section is positive, but if the quantitative comparison between conventional reinforcement, uprating, dynamic line rating, flexibility, or other non-wire alternatives is not fully transparent, it becomes difficult to assess ex post whether the selected option was neutral from a CAPEX-OPEX perspective. This is directly connected to the State of the Art: a planning framework may include system-oriented criteria, but the remuneration framework may still need complementary output-based incentives to reinforce timely delivery, flexibility, and efficient use of existing assets.

Investment limits add a second layer to this problem. Under the existing framework, the annual volume of transmission investment commissioned in a given year with the right to remuneration charged to the system has traditionally been limited to 0.065% of expected Spanish GDP, excluding international interconnections with countries of the internal electricity market, except during 2020–2022, when this limit was temporarily increased to 0.075% of GDP as part of the measures adopted after the COVID-19 crisis. These limits are economically justified because regulated network investments are ultimately recovered from consumers through regulated charges. At the same time, when they become binding or nearly binding, the planning process necessarily becomes a prioritization exercise.

The practical relevance of this constraint can be seen in the 2021–2026 planning numbers. The estimated total investment cost of the plan was around €6.96 billion, of which approximately €5.70 billion corresponded to investment subject to the limit and around €1.26 billion to investments not subject to the limit, mainly interconnections. The estimated limit for the period was also around €5.70 billion, meaning that the plan practically exhausted the available investment allowance for transmission reinforcements subject to the cap. This does not imply that the limit is inadequate, but it highlights why project prioritization, timing, and the choice between conventional and alternative solutions become especially important.

The ongoing 2025–2030 planning process reinforces the tension between growing network needs, investment limits, and efficient prioritization. The process was initiated under Order TED/1375/2023 [24] and, according to the executive summary of the initial proposal, more than 5,000 proposals were received from 330 subjects during the proposal phase. Red Eléctrica, acting as System Operator and responsible for preparing the initial planning proposal, then carried out the technical studies required to identify future transmission needs under MITERD's criteria.

The scale of the challenge is materially larger than in the previous planning period. The 2030 study scenario considers 375 TWh of annual peninsular demand and a peak demand of 61.4 GW, compared with 344 TWh and 53.8 GW in the National Energy and Climate Plan (NECP) scenario. To put these figures into perspective, the annual demand level would imply an increase from an approximate 2025 reference of 254 TWh to 375 TWh by 2030, equivalent to an annual growth rate of around 8%. In terms of peak demand, using the latest comparable planning baseline of 46.8 GW for the 2026 horizon, the 2030 value of 61.4 GW would require an average increase of around 7% per year between 2026 and 2030. These figures illustrate that the planning challenge is not only driven by higher final demand levels, but also by the speed at which both annual consumption and peak requirements are expected to increase. The proposal also states that renewable and storage requests largely exceed NECP values: photovoltaic proposals exceed the NECP path by more than five times, wind by around two times, and storage by around nine times [27].

The operational implications are significant. With only the starting grid, more than 3,200 GWh/year of new demand associated with the energy transition and digitalization would not be supplied, and more than 29,000 GWh/year of renewable producible energy could not be integrated due to transmission limitations, equivalent to around 12% curtailment. The initial proposal therefore includes €13.122 billion investment, of which €1.973 billion correspond to international interconnections and €11.143 billion to national transmission reinforcements. If the new CNMC reference investment values under consultation were applied, the total would be around €13.6 billion.

This increase in investment needs is consistent with the draft Royal Decree on investment plans. The ordinary transmission investment limit remains 0.065% of nominal Spanish GDP, but the draft introduces an additional €720 million per year for the 2026–2030 period, equivalent to €3.6 billion over five years, if approved in those terms. This represents a relevant increase in the investment envelope, but not an elimination of expenditure discipline: additional investment is still framed around planning, transparency, execution monitoring, and system-cost sustainability [28].

The delivery of transmission projects is therefore a relevant issue in itself. Network reinforcements often face long lead times due to permitting, environmental assessment, public consultation, procurement, construction complexity, and social acceptance. At the

European level, ACER has warned that delays in expanding grid capacity may prevent the system from capturing the benefits of market integration, renewable integration, and security of supply, noting that cross-border interconnection projects can take around ten years from inception to operation [29]. In Spain, this risk is also visible in the need to modify the 2021–2026 plan through exceptional amendments: the 2024 modification added 73 actions and €489 million of associated investment for strategic projects linked to industrial decarbonization, hydrogen, renewable integration, and key technologies. A concrete example of long delivery times is the Bay of Biscay interconnection, whose current official schedule targets final commissioning in 2028 after a long process of studies, authorisations, and construction. These examples do not imply poor performance by the TSO, since many delays depend on permitting and external constraints. However, they show that project timing has material system value and that planning approval alone does not guarantee timely delivery.

From an incentive perspective, the higher investment limit may reduce the risk that necessary projects are blocked by the cap, but it does not by itself ensure timely delivery, efficient prioritization, or the selection of flexible and innovative alternatives when they provide similar system benefits at lower cost. Planning remains mainly an ex-ante control mechanism. It identifies valuable outcomes, such as reducing technical constraints, integrating renewables, supplying new demand, and maximizing existing grid capacity, but it does not automatically create an output-based incentive for the TSO to deliver those outcomes efficiently. This is the link with the proposed TO incentives on strategic project acceleration, innovative grid solutions, and flexible connections.

3.4. Remuneration of the System Operator function

The remuneration of the System Operator function is regulated separately from the remuneration of the Transmission Owner function, as noted above. This is essential in the Spanish framework because Red Eléctrica performs both activities, but they are not remunerated under the same logic. While the TO framework is mainly asset-based, the SO framework is designed to remunerate the services effectively provided by the operator and to include incentives, either positive or negative, linked to the reduction of system operation costs or to other regulatory objectives. Circular 4/2019 also reflects this separation through regulatory accounting: Red Eléctrica must keep separate accounts for transmission, peninsular system operation, and non-peninsular system operation [2].

The basic remuneration formula introduced by Circular 4/2019 is:

$$RT_n^{OS} = BRet_n^{OS} + RxInc_n^{OS} + CR_n^{OS} \tag{3}$$

where RT_n^{OS} is the total remuneration of the System Operator in year n, $BRet_n^{OS}$ is the base remuneration, $RxInc_n^{OS}$ is the remuneration by incentives, and CR_n^{OS} is the annual amount of the regulatory account for new obligations. The formula shows that the SO is remunerated through three blocks: a relatively stable base remuneration, a limited incentive component, and a mechanism to recover justified costs linked to new regulatory obligations.

The base remuneration is defined for three-year regulatory periods and is calculated as:

$$BRet_p^{OS} = BOpex_p^{OS} + BMarg\_Opex_p^{OS} + BAmort_p^{OS} + BRF_p^{OS} \quad (4)$$

The first term, $BOpex_p^{OS}$, covers the recognized operating costs of the SO activity. These costs must come from the separate accounts of system operation and must correspond to the costs of an efficient and well-managed company. Importantly, Circular 4/2019 excludes from this term any costs already recovered through transmission remuneration, which avoids double remuneration between the TO and SO functions. $BMarg\_Opex_p^{OS}$ is a 5% margin on recognized OPEX. $BAmort_p^{OS}$ remunerates standard depreciation of assets used by the SO, and BRF_p^{OS} remunerates the standard net fixed assets assigned to system operation.

This structure is different from the TO remuneration model. The SO base remuneration is not mainly driven by transmission assets, but by the operational resources, systems, software, staff, and regulatory tasks required to operate the electricity system. It is also important to note what is not included: the SO remuneration does not directly cover the cost of redispatch, balancing energy, or ancillary services themselves. These are system operation costs settled through market and system mechanisms. Therefore, the SO may influence these costs, but does not bear them directly through its own remuneration.

The third term, CR_n^{OS}, is the regulatory account for new obligations. It allows the SO to recover additional costs derived from European regulation, national regulation, or relevant European projects, provided that these costs are justified, efficient, and additional to those already included in the base remuneration. This mechanism gives flexibility to the framework, because system operation is increasingly affected by European market integration, digitalization, new balancing platforms, and changing regulatory tasks.

The most relevant part for this thesis is $RxInc_n^{OS}$, the incentive component. Circular 4/2019 introduced SO incentives for the first time. In the first regulatory period, 2020–2022, the framework included three incentives: reduction of energy programmed for technical constraints, improvement of demand forecasts, and improvement of renewable generation forecasts. The overall incentive band was limited to +2% / -2% of the base remuneration, with the limits divided across the three incentives. This first design was therefore already output-oriented, but relatively simple: it focused on technical constraints and forecast quality.

Circular 1/2023 is especially important because it reformulated the incentive framework for the 2023–2025 period. The CNMC explicitly states that, after the experience gained with the first application of Circular 4/2019, the incentives had to be revised to ensure that they fulfilled their purpose, improve the optimization of resources in system operation, and adapt the framework better to energy-transition objectives. The updated framework, therefore, expands the incentive scheme from three to six incentives [9].

The first block is now called incentives for redispatch optimization. It contains two mechanisms. The first rewards the minimization of the annual energy programmed for the resolution of technical constraints, considering both constraints in the day-ahead base schedule and real-time constraints in the peninsular transmission network. The second is the incentive for the efficient setting of upward thermal reserve, based on the TNA indicator, which refers to upward tertiary energy offered and not assigned when thermal units are programmed because upward reserve is insufficient. This second incentive only applies if thermal units are scheduled for insufficient upward reserve on more than 20 days in the year.

The second block concerns forecasting quality. It keeps the incentives for demand and renewable generation forecasts, but defines them more precisely. Demand forecasting is assessed in three horizons: annual, day-ahead, and intraday. Renewable forecasting is assessed for wind and solar photovoltaic generation in the day-ahead and intraday horizons. These incentives are relevant because better forecasts can reduce uncertainty in dispatch, balancing, and constraint management. However, they remain indirect indicators: they reward forecast accuracy, not the actual balancing or redispatch cost avoided.

The third block is linked to energy transition and market development. One incentive measures the efficiency of the SO in responding to queries from system agents, using a weighted average response time TMR across eight services. The other rewards the increase in the volume of power or energy offered in ancillary services that require prior qualification by the SO. For 2023–2025, this last incentive is applied to the replacement reserve service and is only positive: it can reward increased participation and competition, but it does not penalize the SO if the indicator does not improve.

For 2023–2025, the total incentive exposure remains limited. The upper limit LS is set at +2% of the base remuneration, while the lower limit LI is set at $-(5/6)\cdot 2\%$, approximately −1.67%. The positive limit is divided equally across the six incentives, while the negative limit applies only to the five bidirectional incentives, because the ancillary-services incentive has no negative component. This design is cautious: the SO is exposed to performance, but only within a narrow band.

This evolution is directly relevant to the thesis. The Spanish framework already recognizes that the SO can influence system-level outcomes such as technical constraints, reserve needs, forecast quality, and liquidity in ancillary services. Therefore, the starting point is not a framework with no incentives. However, the current incentives remain mostly based on volumes, forecast errors, response times, or offered quantities. They do not fully monetize the system costs avoided by better operation. For instance, the technical-constraints incentive rewards lower programmed energy, but it does not directly distinguish between the economic cost of day-ahead and real-time constraints. Similarly, the forecasting incentives measure forecast accuracy, but not the actual reduction in balancing costs caused by better forecasts.

The implication is that the current SO remuneration framework is a useful but incomplete step towards incentive alignment. It introduces output-based signals while avoiding excessive exposure to variables that the SO cannot fully control. This caution is justified because technical constraints, balancing needs, and ancillary-service liquidity depend on many external factors, including weather, demand, renewable availability, generator behaviour, network outages, and security requirements. Nevertheless, the limited and partly non-cost-reflective nature of the current incentives leaves room for complementary mechanisms. This is precisely the role of the proposed SO incentives later in the thesis: to assess whether a limited part of RT^{OS} could be linked more directly to measurable system-cost outcomes, especially technical constraints, balancing energy, and the availability of flexible resources.

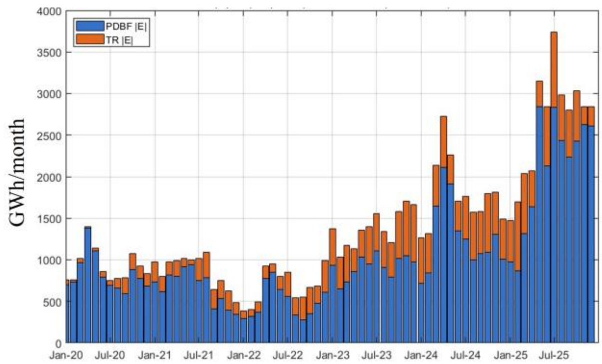
3.5. Treatment of system operation costs

The previous sections described how the Transmission Owner and System Operator functions are remunerated. However, an essential part of the Spanish framework is that several costs incurred in the real-time operation of the electricity system are not part of the regulated remuneration of the SO itself. Technical constraints, redispatch actions, balancing energy, and ancillary services are system operation costs settled through specific market and settlement mechanisms. This distinction is central for the thesis: the SO and the TO may influence some of these costs through forecasting, operational decisions, network planning, or timely investment delivery, but these costs do not directly enter their remuneration in the same way as recognized assets, O&M, or regulated incentives.

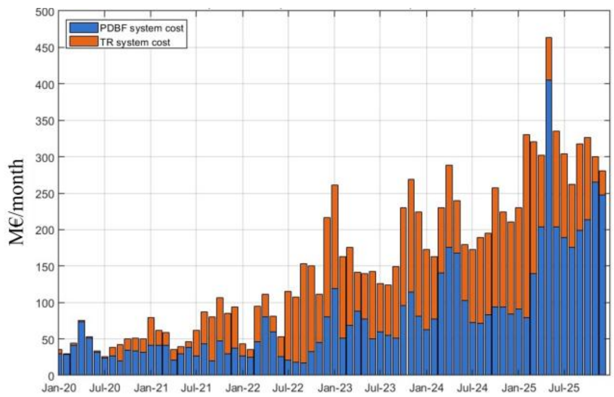
3.5.1. Technical constraints and redispatch costs

Technical constraints arise when the market schedule is not fully compatible with the physical and security limits of the electricity system. The day-ahead and intraday markets clear energy according to economic bids, but the resulting schedules must later be checked against network constraints, security criteria, reserve needs, voltage limits, and other operational requirements. When the schedule is not feasible, the System Operator must modify generation or demand schedules through redispatch mechanisms. In Spain, this process is generally reflected in the resolution of technical constraints, both after the day-ahead base schedule and in real time.

The current SO incentive framework already recognizes the relevance of this issue. Circular 1/2023 defines an incentive for the minimization of programmed energy for technical constraints. It considers, in absolute value, both the energy programmed to solve constraints in the day-ahead (PDBF) and the energy programmed to solve real-time (TR) constraints in the peninsular transmission network. It excludes regulation reserve energy, constraints identified in the distribution network, and certain second schedules caused by unavailability events. The indicator is therefore a volume-based measure of redispatch intensity, and treats both day-ahead and real-time technical constraints energy as a single aggregate, even though each category may carry a substantially different cost per MWh. Figure 2 below helps visualize why this aggregation matters: the relative share and trajectory of each component have diverged over time, suggesting that a single undifferentiated metric may obscure important cost dynamics.



a)



b)

Figure 2 Evolution of redispatching energy (a) and costs (b) each month from January 2020 to December 2025. Energy and costs corresponding to day-ahead redispatch (PDBF) in blue and those in real time (TR) in orange. It is easily observed the increasing trend these last years. Source: own elaboration with data from Red Eléctrica (https://www.esios.ree.es/)

The distinction between day-ahead technical constraints and real-time technical constraints is relevant from an incentive perspective, and Figure 2 underscores this point. Constraints solved after the day-ahead base schedule are linked to the feasibility of the scheduled dispatch before real-time operation and tend to involve larger, more predictable volumes. Real-time constraints, by contrast, are closer to actual system conditions and may reflect unexpected deviations, outages, forecast errors or security requirements occurring closer to delivery. As Figure 2 Evolution of redispatching energy (a) and costs (b) each month from January 2020 to December 2025. Energy and costs corresponding to day-ahead redispatch (PDBF) in blue and those in real time (TR) in orange. It is easily observed the increasing trend these last years. Source: own elaboration with data from Red Eléctrica (https://www.esios.ree.es/) shows, the two categories have followed different trajectories, which implies that their underlying drivers, and therefore the appropriate regulatory treatment, are not the same. Both categories are operationally necessary, but they do not necessarily carry the same economic meaning or the same degree of controllability. Analysing their historical evolution separately, as Figure 3 allows, helps identify whether the increase in redispatch is mainly structural, operational or related to real-time uncertainty.

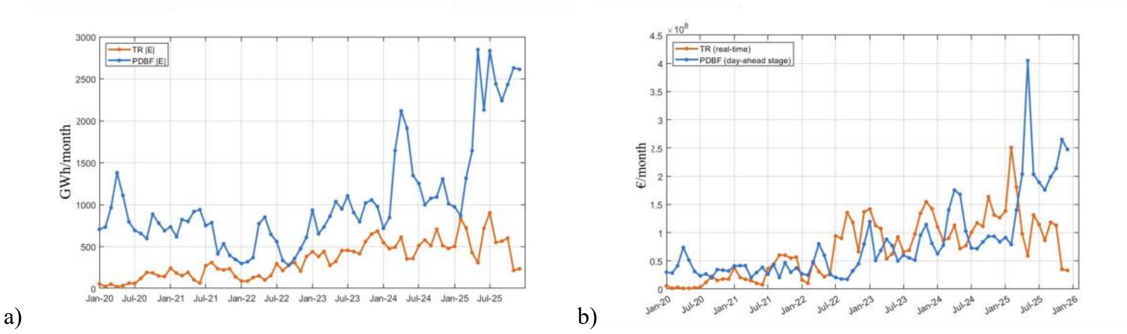


Figure 3. Evolution of redispatching energy (a) and costs (b) each month from January 2020 to December 2025. Energy and costs corresponding to day-ahead redispatch (PDBF) in blue and those in real time (TR) in orange. It is observed that the cost of the day-ahead is lower than real time for similar amounts of energy Source: own elaboration with data from Red Eléctrica (https://www.esios.ree.es/)

The historical data used in this thesis, reflected in the figures, show that technical constraints have become a relevant and growing component of system operation costs in Spain, particularly relative to the wholesale electricity price, as shown in Figure 4. This does not imply that all redispatch is inefficient; in many cases, it is the correct and necessary response to maintain secure operation. However, the upward trend visible in Figure 4 suggests that the market outcome and the physical network are becoming less aligned, potentially driven by renewable integration, network limitations, changing flow patterns, insufficient flexibility, or delays in network development. The magnitude of these volumes is what makes technical constraints a useful diagnostic variable for the thesis: they sit at the intersection between network planning and system operation. System-level costs and their evolution over time provide a tangible measure of how well the system is adapting to the energy transition.

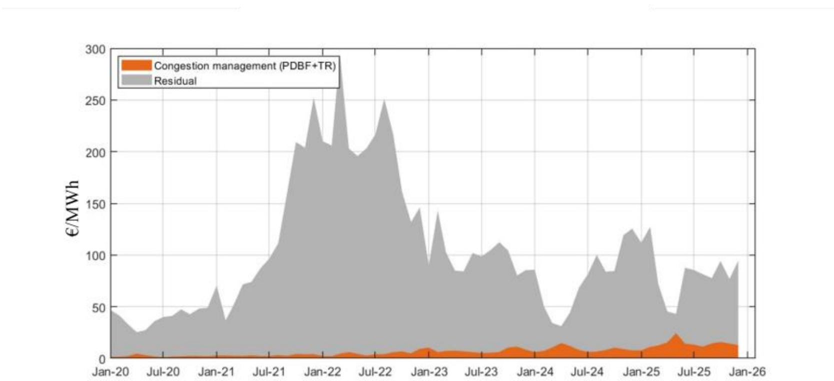


Figure 4. Evolution of the final energy wholesale price with the one corresponding to technical constraints highlighted in orange. It is seen the increasing trend these last years. Source: own elaboration with data from Red Eléctrica (https://www.esios.ree.es/)

A recent example of this relevance is the reinforced operation adopted after the Iberian blackout of 28 April 2025. From 30 April onwards, Red Eléctrica applied a more conservative programming criterion aimed at increasing system stability while the causes of the incident and the behaviour of voltage-control resources were being assessed. This episode does not imply that reinforced operation was inefficient: after a major system incident, a more conservative security criterion may be justified. However, it clearly illustrates that operational security decisions can have material and immediate cost consequences for the system and, ultimately, for consumers. It also reinforces the relevance of the figures shown above: technical constraints and reinforced redispatch are not marginal accounting items, but mechanisms through which system security, renewable integration, and consumer costs become directly connected [4].

Figure 5 illustrates the practical magnitude of this incentive within the SO remuneration framework. The orange bars show the remuneration associated specifically with the technical-constraints incentive, while the blue bars represent the total incentive remuneration obtained by the SO in each year. Two points are especially relevant. First, the technical-constraints incentive has had a limited monetary impact in absolute terms, remaining within a few hundred thousand euros per year despite the much larger scale of technical-constraint costs borne by the system. Second, since the reform introduced for the 2023–2025 period, the individual cap of each incentive has become smaller because the global incentive band is divided across six indicators instead of three. As a result, even when the technical-constraints indicator reaches a penalty or reward close to its limit, the economic signal remains modest relative to the SO base remuneration. Figure 5 also shows that the total incentive remuneration may move in the opposite direction to the technical-constraints incentive, as other indicators can offset its effect. This reinforces the idea that the current framework recognizes technical constraints as a relevant operational outcome, but only exposes the SO to them in a limited and indirect way.

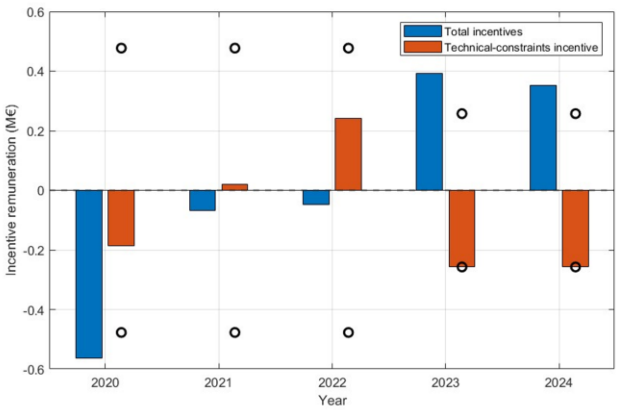


Figure 5. Incentive remuneration given to the SO since 2020 for the reduction of technical constraints (orange) and the complete incentive remuneration (blue). Black dots show the individual incentive limit. It is shown that technical constraints incentive has a small value, and even reduced since 2023, where the limit is close to 250 k€, compared to the base remuneration (98 M€). Source: own elaboration with data from the CNMC remuneration reports

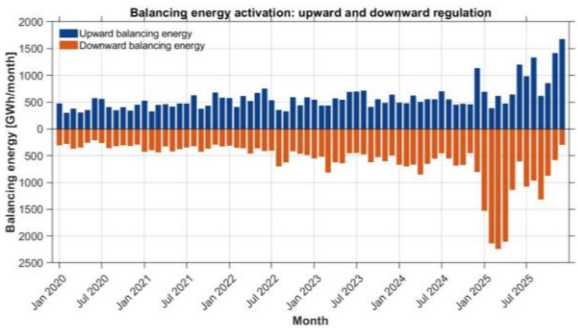
3.5.2. Balancing energy and ancillary services

In addition to technical constraints, the System Operator must maintain a continuous balance between generation and demand. Even after the day-ahead and intraday markets, actual demand, renewable generation, plant availability, and network conditions may differ from scheduled values. Balancing services correct these deviations and maintain frequency and system security.

A first relevant service is secondary regulation, corresponding to automatic frequency restoration reserves, or aFRR. The Spanish P.O. 7.2 defines secondary regulation as a balancing service for the automatic activation of active power with the objective of maintaining system frequency and correcting the imbalance of the Spanish peninsular load-frequency control block. The procedure covers both the secondary reserve market and the secondary regulation energy market, and it also incorporates the European balancing context through platforms such as IGCC and PICASSO [30].

The secondary regulation mechanism, therefore, has two distinct dimensions. First, the SO determines and procures the required upward and downward reserve bands for the following day. Providers submit reserve offers in MW and €/MW, separately for upward and downward reserves, and the SO assigns reserves to cover the system requirement at minimum cost, subject to the technical rules of the procedure. Second, when real-time deviations occur, secondary regulation energy is automatically activated. Providers submit energy offers in MW and €/MWh, and the activation process uses the available offers to correct the system imbalance.

This distinction matters for the thesis because the cost of the secondary reserve band and the cost of activated secondary energy are not the same type of signal. The reserve band reflects the cost of keeping flexibility available, while the activated energy reflects the actual use of that flexibility. From an incentive-alignment perspective, it would not be appropriate to simply minimize reserve procurement, since insufficient reserve would weaken system security. A more relevant question is whether better forecasting, liquidity, market design, and operational coordination can reduce the need for costly activation while preserving adequate reserve levels as shown in Figure 6



a)

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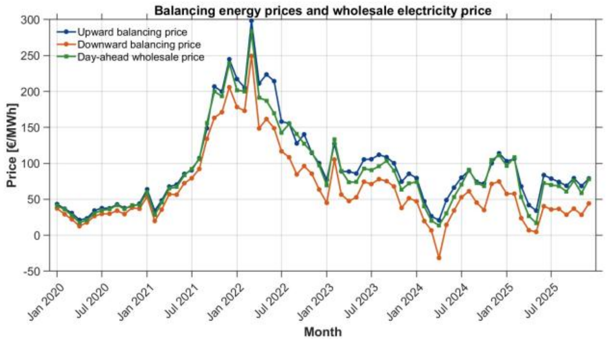

Figure 6. a) Monthly upward and downward balancing energy activation volumes in the Spanish power system from 2020 to 2025. The figure illustrates the evolution of balancing needs over time, reflecting the increasing operational requirements associated with renewable integration, variability of demand, and system flexibility requirements. b) Monthly balancing energy prices and wholesale prices for upward and downward regulation in the Spanish power system from 2020 to 2025. The figure shows the temporal evolution of balancing costs. Source: own elaboration with data from the Red Eléctrica (esios.ree.es)

A second relevant service is tertiary regulation, corresponding to manual frequency restoration reserves, or mFRR. The Spanish P.O. 7.3 defines tertiary regulation as a balancing service with manual activation, used to maintain frequency and the generation-demand balance and to restore the use of automatic secondary regulation reserves. The product has a maximum activation time of 15 minutes and is linked to the European mFRR balancing framework, including the MARI platform, although local activation and fallback mechanisms remain relevant under specific conditions.

Tertiary regulation is especially relevant because it provides manual flexibility close to real time. It can be activated upward or downward depending on the system's need, and its cost depends on the volume and price of available offers. As with secondary regulation, the SO cannot fully control the underlying need for activation, since it depends on forecast errors, renewable variability, generation outages, demand deviations, and market behaviour. However, the SO can influence some drivers indirectly through forecasting, reserve sizing, operational coordination, and the development of a broader pool of qualified balancing providers.

The current Spanish SO incentives partially address these issues. The incentive linked to TNA seeks to improve the efficient setting of upward thermal reserve, and the ancillary-services incentive rewards higher volumes of offers in selected services requiring prior qualification. Circular 1/2023, therefore, moves in the direction of linking SO remuneration to balancing-related outcomes and market liquidity. However, the framework still does not directly expose the SO to the monetary value of balancing energy activated. This is the rationale for the proposed SO-2 and SO-3 incentives: SO-2 focuses on balancing energy as a measurable cost proxy, while SO-3 focuses on the availability and liquidity of flexible resources.

3.5.3. Renewable curtailment and network limitations

Renewable curtailment is another relevant outcome in a system with high wind and solar penetration. Curtailment may arise from market conditions, technical constraints, local network limitations, voltage-control requirements, minimum synchronous generation needs, congestion, or lack of flexibility. It should therefore not be interpreted mechanically as a failure of the transmission framework. However, from a system-efficiency perspective, renewable energy that cannot be integrated represents a lost low-variable-cost resource and may signal that the system lacks sufficient network capacity, flexibility, or operational tools at specific times and locations.

The relevance of curtailment is also reflected in network planning documents. The proposed 2025–2030 planning sheets include avoided renewable curtailment as one of the benefits considered in the cost-benefit and multicriteria assessment. In particular, avoided curtailment is linked to technical constraints caused by overloads that would appear in the reference scenario due to insufficient transmission capacity. This reinforces the connection between curtailment, network development, and system operation: some curtailment may be reduced through conventional reinforcement, while other cases may be better addressed through dynamic line ratings, storage, flexibility, operational measures, or more efficient connection solutions [25].

However, renewable curtailment is not used in this thesis as a direct incentive metric even though it has significantly increased, especially since the blackout, as seen on Figure 7. This is deliberate. A simple incentive to minimize curtailment could create a misleading signal, because reducing curtailment is not always equivalent to minimizing total system costs. In some cases, accepting a limited level of curtailment may be more efficient than building costly network reinforcements used only in a small number of hours. In other cases, curtailment may be required for system security or voltage control. For this reason, exposing the TSO directly to curtailment could create undesirable incentives if the mechanism were not carefully designed.

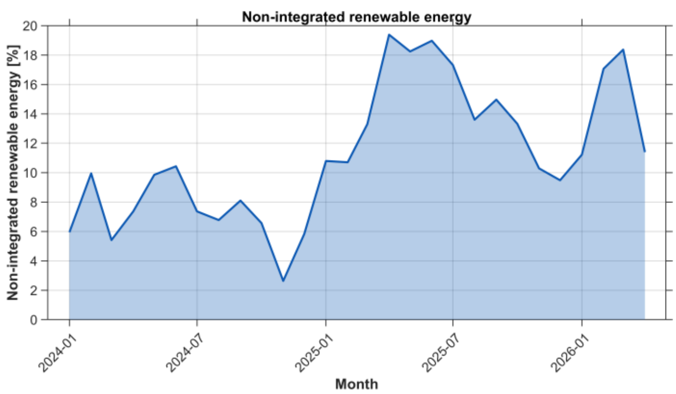

Figure 7. Percentage of total renewable energy not integrated from January 2024 to April 2026. We can see that, especially since the blackout (April 2025), it has significantly increased. Source: own elaboration with data from the Red Eléctrica (esios.ree.es)

Curtailment is therefore treated as a complementary indicator of system stress and renewable integration, rather than as a central variable of the proposed incentive model. It helps illustrate the broader system value of transmission, flexibility, and timely network development, but the thesis focuses instead on variables more directly connected to cost efficiency: technical constraints, balancing energy, and ancillary-service liquidity.

The key regulatory issue is that many operation-related costs are borne by the system rather than directly by the TSO. Technical constraints, balancing energy and ancillary services are settled through the electricity market and system mechanisms and ultimately affect agents and consumers. The SO remuneration, by contrast, mainly covers the resources needed to operate the system and includes only a limited incentive component. This separation is reasonable from a risk-allocation perspective, because the SO should not be financially responsible for all system operation costs. Many of these costs depend on weather, demand, market prices, generation availability, renewable output, network outages, and security standards.

The objective is not to transfer all redispatch, balancing or curtailment risk to the TSO. Full exposure would be inappropriate and could conflict with secure operation. The objective is more limited: to assess whether carefully designed, capped, and partially cost-reflective incentives could improve the alignment between TSO remuneration and system-level outcomes. Technical constraints, balancing energy and ancillary-service liquidity, are therefore selected later as the main SO-side variables because they are measurable, economically relevant, and already partially recognized in the current regulatory framework.

Overall, the treatment of system operation costs confirms the central argument of the thesis. The Spanish framework remunerates the SO and includes incentives for selected operational outcomes, but many relevant costs remain largely external to TSO remuneration. As the system becomes more renewable, volatile, and dependent on flexibility, this separation becomes increasingly important. The proposed incentive model developed in Methodology builds on this diagnosis by introducing complementary mechanisms that preserve regulatory caution while giving greater economic weight to avoided system costs.

3.6. Relative magnitude of regulated remuneration and existing incentives

The previous sections have described the remuneration methodologies of the Transmission Owner and System Operator functions separately. However, it is also useful to compare their relative economic structure, because the strength of any regulatory incentive depends not only on its design, but also on its magnitude compared with the base remuneration it affects. For this reason, this section provides an illustrative comparison between the main remuneration components of the SO and TO functions.

Figure 8 shows that the two activities have very different remuneration structures. The SO remuneration is mainly OPEX-driven, reflecting the operational, digital, and coordination-intensive nature of system operation. By contrast, the TO remuneration is dominated by CAPEX-like components, mainly investment remuneration, depreciation, and financial return on recognized assets. This confirms the logic described in sections 3.2 and 3.4: the TO function is structurally asset-based, while the SO function is more closely linked to operational resources and regulatory tasks.

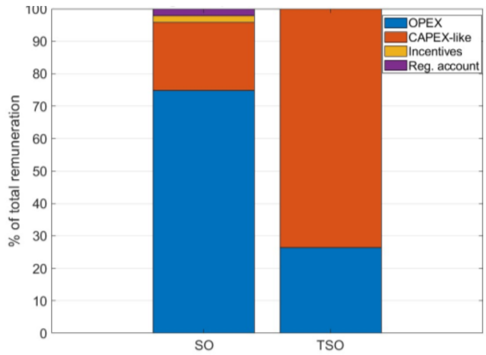

Figure 8. Percentage decomposition between the remuneration of the System Operator (SO) and the Transmission Owner (TO) in Spain given the maximum incentive given. Source: Own elaboration with data from 2022 (last available data for the TO) by the CNMC

The CAPEX/OPEX comparison reinforces this difference as seen on Figure 9. In the illustrative year considered, the SO presents a CAPEX/OPEX ratio of approximately 0.28, while the TO presents a ratio of around 2.78. This means that, economically, the TO framework is much more exposed to investment-related remuneration, whereas the SO framework is mainly driven by recognized operating costs. This distinction is relevant for the thesis because potential misalignments will not arise in the same way for both functions. For the TO, the key issue is whether an asset-based framework adequately values timing, flexibility, and non-conventional alternatives. For the SO, the key issue is whether operational outcomes such as technical constraints, balancing energy, and ancillary-service liquidity are sufficiently reflected in remuneration.

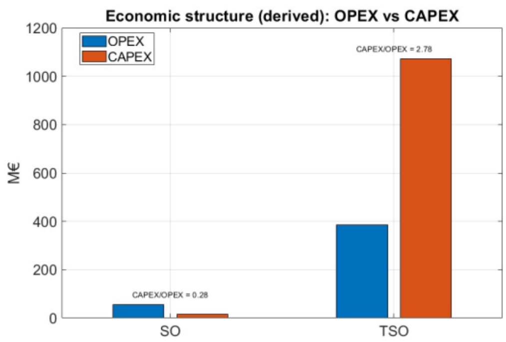

Figure 9. CAPEX and OPEX at the remuneration of the System Operator (SO) and the Transmission Owner (TO) in Spain. Source: Own elaboration with data from 2022 by the CNMC

Figure 10 shows that the realized incentive component is relatively small in both cases, especially for the TO function. In the illustrative year, SO incentives represent around 1.9% of total SO remuneration, close to the regulatory cap of the current framework, while TO incentives represent only around 0.13% of total TO remuneration. This does not mean that these incentives are irrelevant: even small percentages can create behavioural signals if indicators are well designed. However, it does suggest that the explicit incentive layer is modest compared with the total regulated remuneration, particularly in the asset-heavy TO framework.

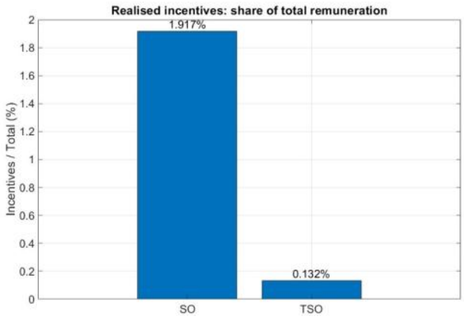

Figure 10. Percentage that would take the maximum incentive of the total remuneration applying the updated regulation of 2025 and compared with the last available remuneration (2022). Source: Own elaboration with data by the CNMC

This comparison supports one of the central arguments of the thesis. The Spanish framework already contains incentive mechanisms, especially for the SO after the reform introduced by Circular 1/2023, but their economic weight remains limited. Moreover, the largest remuneration component of the integrated TSO is still linked to recognized network assets rather than to system-level outcomes. This is consistent with the need for caution in a regulated monopoly, but it also leaves room for complementary, capped, and measurable incentives that give greater weight to outcomes such as technical constraints, balancing energy, timely delivery of strategic projects, and efficient use of innovative or flexible solutions.

Overall, the relative magnitude of remuneration and incentives shows that the issue is not the absence of regulation or the absence of incentives. The issue is whether the existing incentive layer is sufficiently aligned with the system-level effects that the TSO can reasonably influence. This diagnosis provides the quantitative bridge between the description of the Spanish framework and the preliminary assessment developed in the next section.

3.7. Preliminary assessment of the Spanish framework

The Spanish framework presents several strengths from a regulatory perspective. First, it provides a stable remuneration structure for long-lived transmission assets, which is necessary in an activity characterized by high upfront investment costs, long asset lives, and security-of-supply obligations. Second, the institutional model separates the remuneration and accounting treatment of the Transmission Owner and System Operator functions, even though both are performed by Red Eléctrica. This separation reduces the risk of double remuneration and allows each activity to be assessed according to its own cost drivers. Third, the development of the transmission network is embedded in a public planning process, with participation of public authorities, regulatory oversight, environmental assessment, and investment limits. Therefore, the Spanish framework cannot be described as lacking regulation or control mechanisms; on the contrary, it is a structured and highly regulated system.

However, the previous sections also show that this framework remains only partially aligned with system-cost outcomes. The TO remuneration is still mainly asset-based: its main economic signal is linked to recognized investment, depreciation, financial return, and standardized O&M remuneration. This is coherent with the nature of transmission as a capital-intensive regulated activity, but it does not directly expose the TO to the system value of reducing technical constraints, avoiding redispatch, accelerating strategic projects, or using flexible and innovative alternatives when they are more efficient than conventional reinforcement. The recent recognition of technologies such as Dynamic Line Rating, STATCOMs, or network-integrated batteries is a positive step, but these solutions are still mainly treated through an investment-recognition logic rather than through a direct sharing of verified system benefits.

The planning framework partly addresses this issue because it already incorporates system-oriented criteria. The 2021–2026 plan and the initial 2025–2030 proposal consider objectives such as renewable integration, reduction of technical constraints, reduction of losses, security of supply, efficient use of the existing network, and socioeconomic benefits. This is important because the Spanish planning process is not purely asset-driven. Nevertheless, planning remains mostly an ex-ante control mechanism. It identifies the investments and actions considered necessary, but it does not by itself create a direct economic incentive for timely delivery, verified avoided system costs, or the selection of non-wire alternatives when they provide similar value at lower cost. The limited public disaggregation of some cost-benefit results also makes ex post attribution of benefits more difficult.

The SO framework is more explicitly output-oriented, especially after the reform introduced by Circular 1/2023. The updated incentive scheme recognizes relevant outcomes such as minimization of technical-constraint volumes, efficient setting of upward thermal reserve, improved demand and renewable forecasting, faster response to agents, and greater offer availability in ancillary services. This is a significant feature of the Spanish framework: the SO already has performance incentives, and these incentives are explicitly connected to operational efficiency and energy-transition objectives.

Even so, the economic exposure of the SO remains limited and only partly cost-reflective. The current incentives are based mainly on volumes, forecast errors, response times, or offer quantities, rather than on the monetary value of avoided system costs. This cautious design is justified because the SO should not be fully exposed to variables that depend heavily on weather, demand, renewable output, generator behaviour, network outages, market prices or security requirements. However, the consequence is that the incentive signal may be small compared with the scale of the system costs that the SO can influence indirectly.

This creates the central incentive-alignment issue analysed in this thesis. Spain has an integrated TSO from an institutional point of view, since Red Eléctrica performs both transmission ownership and system operation. This can facilitate coordination and information sharing. However, the remuneration of both functions remains differentiated, and many relevant system costs are settled outside the direct remuneration of the TSO. As a result, technical integration does not automatically imply economic incentive alignment. Network planning, project delivery, redispatch, balancing needs, renewable curtailment, and flexibility availability are increasingly interdependent, but the financial signals attached to these outcomes remain fragmented.

The preliminary conclusion is therefore nuanced. The Spanish framework is robust in terms of regulatory stability, cost recovery, planning control, and security-oriented operation. It also already includes incentive mechanisms, particularly for the SO. The issue is not the absence of incentives, but their limited materiality and partial connection with system-level cost efficiency. This does not justify transferring all redispatch, balancing, or curtailment risk to the TSO. Such an approach would be inappropriate and could create perverse incentives against secure operation. However, it does justify analysing whether a limited layer of complementary, capped and measurable incentives could improve alignment where the TSO has a reasonable degree of influence.

This is the logic applied for the methodology developed in the next chapter. The proposed framework does not seek to replace the existing TO and SO remuneration methodologies. Instead, it tests whether selected output-based incentives can complement the current model by giving greater economic weight to technical constraints, balancing energy, liquidity of balancing resources, strategic project delivery, innovative grid solutions, and flexible connection arrangements. The objective is therefore not to make the TSO fully responsible for system costs, but to assess whether partial and carefully calibrated exposure can improve the consistency between TSO remuneration and long-term system efficiency.

4. Methodology

4.1. Methodological approach

The methodology of this thesis is designed to assess incentive alignment in the Spanish TSO remuneration framework from a regulatory and economic perspective. The objective is not to simulate the physical operation of the transmission network or to determine an optimal expansion plan, but to evaluate whether a set of complementary incentives could improve the link between TSO remuneration and system-level efficiency. For this reason, the thesis develops a regulatory-parametric incentive model.

This methodological choice follows directly from the diagnosis developed in Chapter 3. The Spanish framework already contains detailed remuneration rules for the Transmission Owner and System Operator functions, as well as planning procedures, investment limits and specific SO incentives. The relevant issue is therefore not the absence of regulation, but whether the existing economic signals are sufficiently aligned with outcomes such as technical constraints, balancing energy, availability of flexible resources, project delivery, innovative grid solutions and efficient connection arrangements. These outcomes are partly influenced by the TSO, but they are also affected by exogenous factors such as demand, renewable output, market behaviour, weather conditions, outages and security requirements. A methodology based on partial, capped and measurable incentives is therefore more appropriate than full exposure to system costs.

The analysis is structured in four steps. First, the current Spanish remuneration framework is decomposed into its main TO and SO components, distinguishing between asset-based remuneration, recognized operating costs, existing incentives and system operation costs settled outside TSO remuneration. Second, based on the gaps identified in the previous chapter and on the international regulatory trends reviewed in Chapter 2, a set of six complementary incentives is defined: three related to the SO function and three related to the TO function. Third, each incentive is translated into a parametric formula using observable variables, reference values, sharing factors and caps or floors. Fourth, the resulting incentive package is implemented in an Excel-based model to evaluate its economic magnitude, sensitivity, and risk profile.

The methodology is based on several design principles:

The first is measurability. Each incentive must be linked to variables that can be observed, reported, and audited. This is necessary to avoid discretionary remuneration and to make the framework implementable in a regulatory context.

The second is controllability. The TSO should only be exposed to outcomes over which it has a reasonable degree of influence. Since variables such as redispatch, balancing needs or connection delays are not fully controllable, the proposed incentives use partial exposure rather than full cost transfer.

The third principle is cost-reflectiveness. Where possible, the incentive should approximate the economic value of the outcome being targeted. This is especially relevant for technical constraints and balancing energy, where pure volume indicators may fail to reflect the actual cost implications of different actions. However, the model does not use volatile real-time market prices directly as the basis for remuneration. Instead, it uses reference prices and benchmark values to provide a more stable regulatory signal.

The fourth principle is proportionality. The proposed incentives are not intended to dominate the existing remuneration framework. Transmission and system operation are security-critical regulated activities, and excessive exposure could create undesirable incentives or increase the regulatory risk borne by the TSO. For this reason, all incentives are subject to caps, floors, or positive-only designs, depending on the degree of controllability and the nature of the targeted outcome.

Finally, the methodology preserves the priority of security of supply. The proposed incentives should not encourage the TSO to reduce redispatch, balancing actions, reserves, or curtailment when these are required for secure operation. The objective is not to minimize operational interventions mechanically, but to create a limited economic signal for reducing avoidable system costs while maintaining reliability and operational security.

The quantitative assessment combines three types of analysis. The first is a historical back-testing exercise, mainly applied to SO-related incentives where historical data are available. This allows the thesis to evaluate how the proposed incentive logic would have behaved in previous years regarding system operation, as it is concerning for the reasons mentioned in previous chapters. The second is a reference application of the full incentive package, including both SO and TO incentives, to assess the order of magnitude of the total remuneration impact in an example scenario. The third consists of sensitivity analysis and Monte Carlo simulation, used to test whether the results are robust to changes in key parameters such as reference prices, sharing factors, caps, and estimated benefits.

The results of the model should therefore be interpreted as a regulatory assessment, not as a forecast of future remuneration. The aim is to test whether the proposed incentive package is coherent, proportionate, and capable of strengthening the link between TSO remuneration and system-level efficiency. In this sense, the methodology provides a bridge between the qualitative regulatory diagnosis of the Spanish framework and the quantitative analysis presented in the results chapter.

4.2. Description of the proposed incentive package

The proposed incentive package is designed as a complementary layer to the existing Spanish TO and SO remuneration frameworks. It does not replace the current methodologies described in Chapter 3, nor does it transfer all system-operation risk to the TSO. Its objective is narrower: to test whether a limited set of measurable, capped, and partially cost-reflective incentives could improve the alignment between TSO remuneration and long-term system efficiency.

The package contains six incentives: three linked to the System Operator function and three linked to the Transmission Owner function. The SO incentives focus on operational outcomes that are already partially recognized in the Spanish framework, such as technical constraints, balancing needs, and availability of ancillary-service resources. The TO incentives focus on investment timing, innovative grid solutions, and flexible connections, which are areas where asset-based remuneration and planning controls may not fully capture the system value of timely or non-conventional solutions.

Conceptually, the package combines three sources of inspiration. First, it builds on the Spanish SO incentive framework, especially the 2023 reform, which already recognizes technical constraints, reserve setting, forecasts, response times, and ancillary-service participation as relevant operational outputs [9]. Second, it draws on the UK RIIO approach, where transmission regulation uses financial output delivery incentives for project delivery, connections, innovative delivery, and SO:TO optimisation, including mechanisms aimed at reducing constraint costs through enhanced TO services to the system operator [18]. Third, it reflects the French regulatory trend towards linking transmission regulation to connection performance, flexibility, and efficient use of network resources, while preserving a regulated tariff framework, as well as the mechanisms that unlink the SO from price volatility [20].

Incentive	Function	Main objective	Direction
SO-1	System Operator	Internalize a proxy of technical-constraint costs	Bidirectional
SO-2	System Operator	Incentivize lower balancing-energy cost proxy	Bidirectional
SO-3	System Operator	Increase liquidity and availability of balancing resources	Positive-only
TO-1	Transmission Owner	Incentivize timely delivery of strategic projects	Bidirectional
TO-2	Transmission Owner	Reward verified benefits from innovative grid solutions	Positive-only
TO-3	Transmission Owner	Reward efficient flexible connection solutions	Positive-only

Table 1. Summary of proposed incentives: objective, function, and direction of adjustment

4.2.1. SO-1: Technical constraints cost internalization

The first SO incentive targets technical constraints. The current Spanish framework already includes an incentive for reducing the volume of energy programmed to solve technical constraints, which is a relevant starting point, because technical constraints are one of the most visible links between system operation, network limitations, and consumer costs. However, the existing incentive is mainly volume-based, as it aggregates energy programmed after the day-ahead base schedule and energy programmed in real time, even though these two categories may have different drivers, different controllability, and different economic impacts.

The proposed SO-1 incentive keeps the logic of rewarding lower technical-constraint intensity, but makes the signal more cost-reflective. Instead of using only total programmed energy, the incentive applies differentiated reference prices to day-ahead and real-time technical constraints:

$$\mathrm{C_{TC,n}} = \mathrm{E_{PDBF,n}} \cdot \mathrm{P_{PDBF}^{ref}} + \mathrm{E_{TR,n}} \cdot \mathrm{P_{TR}^{ref}} \tag{5}$$

where $\mathrm{C_{TC,n}}$ is the technical-constraints cost proxy in year n; $E_{PDBF,n}$ is the energy programmed to solve technical constraints after the day-ahead base schedule; $E_{TR,n}$ is the energy programmed to solve real-time technical constraints; and P_{PDBF}^{ref} and P_{TR}^{ref} are the reference prices assigned to each category.

The incentive is then calculated through a limited sharing mechanism:

$$\mathrm{I_{SO1,n}^{raw}} = \mathrm{s_{SO1}} \cdot (\mathrm{C_{TC,n}^{ref}} - \mathrm{C_{TC,n}}) \tag{6}$$

$$\mathrm{I_{SO1,n}} = \min\left(\mathrm{Cap_{SO1}^{+}}, \max\left(-\mathrm{Cap_{SO1}^{-}}, \mathrm{I_{SO1,n}^{raw}}\right)\right) \tag{7}$$

where $I_{SO1,n}^{raw}$ is the uncapped incentive, s_{SO1} is the sharing factor, $C_{RRTT,n}^{ref}$ is the reference cost level, and Cap_{SO1}^{+} and Cap_{SO1}^{-} are the positive and negative limits.

The incentive is positive when the observed cost proxy is below the reference and negative when it is above it. The use of reference prices is deliberate. Using actual redispatch prices could expose the SO to market conditions that it does not control, while using only volumes may fail to reflect the true cost-relevance of different redispatch actions. SO-1, therefore, seeks a middle ground: it introduces a more economically meaningful signal than the current volume-only approach, but keeps exposure partial, predictable, and capped. This fixed-price mechanism is already established in France for different incentives regarding system operation, including balancing and losses.

4.2.2. SO-2: Balancing energy incentive

The second SO incentive focuses on balancing energy. In a system with increasing renewable penetration, deviations between scheduled and actual generation or demand become more relevant. These deviations require balancing actions to maintain frequency, security, and the generation-demand balance. The current Spanish framework addresses some drivers of balancing costs through demand and renewable forecast incentives and through the TNA incentive related to upward thermal reserve. However, it does not directly link SO remuneration to the economic impact of activated balancing energy.

The proposed SO-2 incentive introduces a limited profit-sharing mechanism based on a balancing-energy cost proxy. A key design choice is to distinguish between upward and downward balancing energy. Upward balancing is generally required when the system is short, meaning that generation must increase or demand must be reduced. Downward balancing is generally required when the system is long, meaning that generation must decrease or demand must increase. These two actions can have different price levels, opportunity costs and system implications. Treating them with a single average reference price would therefore weaken the signal and could distort the interpretation of the incentive.

The balancing cost proxy is defined as:

$$C_{BAL,n} = E_{up,n} \cdot P_{up}^{ref} + E_{down,n} \cdot P_{down}^{ref} \tag{8}$$

where $C_{BAL,n}$ is the balancing-energy cost proxy in year n; $E_{up,n}$ and $E_{down,n}$ are the upward and downward balancing energy volumes; and P_{up}^{ref} and P_{down}^{ref} are the corresponding reference prices.

The incentive is then calculated as:

$$I_{SO2,n}^{raw} = s_{SO2} \cdot \left(C_{BAL,n}^{ref} - C_{BAL,n}\right) \tag{9}$$

$$I_{SO2,n} = min\left(Cap_{SO2}^{+}, max\left(-Cap_{SO2}^{-}, I_{SO2,n}^{raw}\right)\right) \tag{10}$$

Where $s_{SO2}$is the profit-sharing percentage, $C_{BAL,n}^{ref}$is the reference balancing cost, and Cap_{SO2}^{+} and Cap_{SO2}^{-}limit the maximum reward and penalty.

This incentive should not be interpreted as a mechanism to minimize balancing activation at any cost. Balancing energy is often necessary for secure operation, and the SO should not be encouraged to reduce reserve adequacy or avoid balancing actions when operationally required. The intended signal is narrower if balancing energy costs are reduced relative to a reference level, and this reduction is partly associated with better forecasting, coordination, reserve management, or operational efficiency; the SO receives a limited share of the estimated savings. Conversely, if the cost proxy is above the reference, the SO bears a limited share of the deviation. The cap and floor prevent excessive risk transfer.

4.2.3. SO-3: Liquidity and availability of balancing resources

The third SO incentive targets the liquidity and availability of qualified resources in tertiary regulation, corresponding to manual Frequency Restoration Reserves (mFRR). Its logic is different from SO-1 and SO-2. Rather than exposing the SO to a cost proxy, it rewards the operator for facilitating the entry and effective participation of additional resources in a balancing service that is increasingly relevant for system flexibility.

The focus on tertiary regulation is deliberate. Compared with automatic secondary regulation, tertiary regulation is a more suitable entry point for an incentive aimed at competition and participation. It is activated manually, has a maximum activation time of 15 minutes, and is managed through market-based mechanisms. This makes it more accessible for new flexible resources such as batteries, demand response, aggregators, and hybrid renewable-storage facilities, which are expected to become increasingly important in future balancing markets. The Spanish operating procedure for tertiary regulation defines it as a balancing service used to maintain frequency and the generation-demand balance, and to restore the use of automatic secondary regulation reserves.

The purpose of SO-3 is therefore to incentivize the SO to accelerate the processes under its responsibility that enable new providers to participate in tertiary regulation. These may include technical qualification, validation tests, platform integration, communication with market participants, and operational approval. A broader pool of qualified providers can increase competition, reduce dependence on a limited set of conventional technologies, and improve the availability of flexible resources close to real time.

The proposed indicator is based on the increase in qualified tertiary balancing capacity:

$$\Delta Q_n^{mFRR} = max\left(0, Q_n^{mFRR} - Q_n^{mFRR,ref}\right) \tag{11}$$

Where Q_n^{mFRR} is the qualified tertiary regulation capacity available in year n, $Q_n^{mFRR,ref}$ is the reference baseline, and ΔQ_n^{mFRR} is the positive increase above that baseline.

The incentive is then calculated as:

$$I_{SO3,n} = min(Cap_{SO3}^{+}, \alpha_{SO3} \cdot \Delta Q_n^{mFRR}) \tag{12}$$

Where α_{SO3} is the unit reward per additional MW of qualified tertiary balancing capacity and Cap_{SO3}^{+} is the maximum reward.

The incentive is positive only because the SO does not fully control the entry of new market participants. The decision of batteries, aggregators, demand-response providers, or other technologies to participate depends on investment decisions, expected revenues, technical requirements, and broader regulatory conditions. However, the SO can influence the speed, transparency, and efficiency of the qualification process. For this reason, SO-3 does not penalize the operator for limited market response but rewards progress in enabling additional tertiary balancing capacity. This makes the incentive complementary to SO-1 and SO-2: while those mechanisms target system-cost proxies, SO-3 strengthens the competitive and flexible resource base that can help reduce those costs over time.

4.2.4. TO-1: Acceleration of strategic investment projects

The first TO incentive focuses on project delivery timing. Transmission planning identifies projects that are expected to provide system value, but the mere inclusion of a project in the plan does not fully internalize the economic consequences of its timing. A delayed project may increase technical constraints, renewable curtailment, connection delays, or balancing needs. Conversely, timely or early delivery of a strategically relevant project may reduce system costs and support renewable integration or new demand connection.

The proposed TO-1 incentive introduces a bidirectional signal around the commissioning date of selected strategic projects. The reference point is a regulatory target date, adjusted for justified delays outside the TO's control:

$$M_k^{adj} = M_k^{actual} - M_k^{target} - M_k^{justified} \tag{13}$$

Where M_k^{actual} is the actual commissioning month of project k, M_k^{target} is the target commissioning month, $M_k^{justified}$ represents justified delay months, and M_k^{adj} is the adjusted delay or acceleration. If M_k^{adj} is positive, the project is delayed after accounting for justified causes. If it is negative, the project has been delivered ahead of the adjusted target.

The raw incentive is:

$$I_{TO1,k}^{raw} = -\beta_{TO1} \cdot TOTEX_k^{eligible} \cdot M_k^{adj} \tag{14}$$

$$I_{TO1,k} = min\left(Cap_{TO1,k}^{+}, max\left(-Cap_{TO1,k}^{-}, I_{TO1,k}^{raw}\right)\right) \tag{15}$$

Where β_{TO1} is the monthly incentive rate, $TOTEX_k^{eligible}$ is the eligible investment value of the project with the estimated OPEX included, and $Cap_{TO1,k}^{+}$ and $Cap_{TO1,k}^{-}$ limit the maximum bonus and penalty.

This mechanism is conceptually related to UK-style delivery incentives, but it must be adapted carefully to the Spanish planning framework. The objective is not to reward rushed construction or penalize the TO for delays caused by permitting, environmental litigation, public opposition, or third-party dependencies. The incentive should apply only to projects with clear strategic value and only after excluding justified delays. Its purpose is to make timing economically visible when timing has system value. Furthermore, it must be considered that the target date for a project is a sensible aspect, as artificially delaying it may create perverse incentives during the planning phase. This is why transmission network expansion plans must take this into account while evaluating the proposals, and it should be correctly addressed by the stakeholders involved in the planning.

4.2.5. TO-2: Innovative grid solutions

The second TO incentive focuses on innovative grid solutions that can increase the effective capacity, controllability, or flexibility of the transmission network without necessarily relying on conventional reinforcement. Examples include Dynamic Line Rating, advanced monitoring systems, automation, FACTS, STATCOMs, topology optimisation tools, or other grid-enhancing technologies. The rationale is that an asset-based remuneration framework may recognize these technologies as investments, but it does not necessarily create a strong signal to deploy them where they generate the greatest system value.

The logic of TO-2 is therefore to create a profit-sharing mechanism based on verified net benefits. The incentive would allow the TO to retain a percentage of the net system benefit generated by an innovative solution, after subtracting its annualized cost and adjusting for any overlap with other incentives. In simplified form:

$$NB_{TO2,n} = B_n^{verified} - C_{solution,n}^{annual} \quad (16)$$

$$I_{TO2,n} = min\left(Cap_{TO2}^{+}, s_{TO2} \cdot NB_{TO2,n}\right) \quad (17)$$

Where $NB_{TO2,n}$ is the verified net benefit in year n, $B_n^{verified}$ is the measured gross system benefit of the solution, $C_{solution,n}^{annual}$ is the annualized cost of deploying and operating the solution, s_{TO2} is the sharing factor, and Cap_{TO2}^{+} is the annual reward cap.

The benefit could come from avoided redispatch, lower technical-constraint costs, deferred reinforcement, reduced losses, improved use of the existing network, or avoided curtailment, provided that the effect can be measured against a credible counterfactual. The incentive should not remunerate the technology simply because it is innovative; it should remunerate the verified system value that the technology creates.

A key design principle is that these technologies should not automatically be treated in the same way as conventional reinforcements within the expansion plan. If an innovative solution is already included in the approved transmission planning because it solves a specific need identified in that process, its investment cost can be treated through the normal remuneration framework. In that case, TO-2 should only apply to additional verified benefits not already captured in the planning assessment or in the regulated asset remuneration. Conversely, where the solution is not part of the expansion plan but can reduce system costs or improve the use of existing assets, TO-2 provides a specific economic signal to deploy it where it is most valuable.

This design helps mitigate a potential CAPEX-intensive bias. Under a conventional asset-based framework, the TO may have a clearer remuneration path for large physical reinforcements than for smaller, more operational or digital solutions whose benefits appear mainly as avoided system costs. By allowing the TO to retain a share of verified net benefits, the incentive makes the choice between conventional reinforcement and innovative alternatives more neutral from a regulatory perspective. The TO would have an economic reason to prioritize those solutions and locations where the expected system benefit is highest.

To avoid abuse, the mechanism should be subject to an annual eligible investment limit and to ex post verification. The annual limit prevents the incentive from becoming an open-ended route for remunerating any technology outside the planning framework. The ex-post verification ensures that profit-sharing is granted only when the solution produces measurable benefits for the system. If benefits are lower than expected, the incentive would be reduced accordingly; if the net benefit is negative, the mechanism could generate no reward or, in stricter designs, a limited clawback. However, the main regulatory logic is not punitive, but to reward deployment where innovative solutions demonstrably reduce system costs.

TO-2 is therefore designed to complement, not bypass, transmission planning. The planning process should remain the main route for large structural reinforcements and for technologies that solve needs already identified ex ante. The role of this incentive is narrower: to encourage the TO to identify and deploy innovative grid solutions in cases where they provide measurable system benefits, avoid unnecessary CAPEX-intensive alternatives, and improve the efficient use of the existing transmission network.

4.2.6. TO-3: Flexible connection solutions

The third TO incentive focuses on the cost efficiency of connecting new demand, generation, or storage to the transmission network. Its objective is similar to the previous formulation: to encourage solutions that increase connection capacity efficiently and avoid unnecessary conventional reinforcement. However, instead of comparing a flexible solution with a specific avoided reinforcement project, the incentive is defined through a reference unit cost of connection, expressed in €/MW connected.

The rationale is that connection needs are increasing rapidly due to renewable deployment, storage, industrial electrification, hydrogen-related demand, and data centres. In this context, the relevant question is not only how much investment is carried out, but how efficiently each additional MW of connection capacity is enabled. A conventional asset-based framework may provide a clear remuneration path for reinforcement investments, but it may not create a strong enough signal to minimize the unit cost of connecting new capacity when flexible, modular, or operational alternatives are available.

The proposed incentive, therefore, compares the actual unit cost of connection with a regulatory reference value. This reference can be based on historical connection costs, expected unit access costs, or benchmark values defined by the regulator. Where data allow, the reference could be differentiated by voltage level, type of connection, geographical area, or type of user. In a simpler implementation, a single €/MW reference can be used as an initial approximation.

The actual unit cost is defined as:

$$UC_{TO3,n}^{actual} = \frac{C_{conn,n}^{eligible}}{MW_n^{connected}} \tag{18}$$

Where $UC_{TO3,n}^{actual}$ is the actual unit connection cost in year n, $C_{conn,n}^{eligible}$ is the eligible cost associated with enabling the relevant connections, and $MW_n^{connected}$ is the total amount of capacity effectively connected or enabled under the mechanism.

The saving relative to the reference is then:

$$\Delta UC_{TO3,n} = UC_{conn,n}^{ref} - UC_{TO3,n}^{actual} \tag{19}$$

where $UC_{conn,n}^{ref}$ is the reference unit cost of connection. If the actual unit cost is below the reference, the difference represents an estimated saving per MW connected.

The incentive is calculated by applying a sharing factor to this unit saving and multiplying it by the total connected capacity:

$$I_{TO3,n}^{raw} = s_{TO3} \cdot \Delta UC_{TO3,n} \cdot MW_n^{connected} \tag{20}$$

$$I_{TO3,n} = min\left(Cap_{TO3}^{+}, I_{TO3,n}^{raw}\right) \tag{21}$$

Where s_{TO3} is the profit-sharing percentage and Cap_{TO3}^{+} is the annual cap. If the actual cost exceeds the benchmark, no reward is granted under this incentive, although inefficient costs would still be subject to the ordinary regulatory review and cost-recognition rules.

This design creates a direct incentive to reduce the cost per MW connected, rather than simply increasing the asset base. If the TO can connect more capacity using lower-cost solutions, for example, through flexible connection arrangements, grid automation, dynamic ratings, modular reinforcements, or better use of existing capacity, it retains a share of the estimated savings. The logic is that the TO will have an incentive to prioritize those locations and solutions where the difference between the reference €/MW and the actual €/MW is largest, provided that the connection is technically secure and delivers the required service.

The mechanism must include safeguards. First, only the capacity that is effectively connected or enabled should count. Second, the lower unit cost should not come from reducing connection quality, transferring excessive risk to users, or creating future congestion that is not reflected in the calculation. Third, the reference cost must be periodically reviewed to avoid rewarding normal cost reductions indefinitely. Finally, the incentive should be capped to prevent excessive remuneration and to preserve the role of the ordinary planning and investment approval process.

TO-3, therefore, complements the planning framework without bypassing it. Large structural reinforcements should continue to be assessed through transmission planning, but the incentive gives the TO an additional economic reason to find cheaper and faster ways to connect new capacity when this is feasible. In this sense, the mechanism reduces the potential bias towards CAPEX-intensive solutions and links part of the TO remuneration to the efficient delivery of connection capacity, measured in €/MW rather than only in total regulated investment.

5. Case Study

5.1. Data, calibration, and parameter setting

The formulas defined in the previous chapter require two types of inputs. The first group consists of design parameters, such as sharing factors, reference prices, unit rewards, and caps. These parameters define the regulatory rule of each incentive. The second group consists of application inputs, such as reference volumes, actual volumes, eligible TOTEX, connected MW, or the number of projects included in the reference application. This distinction is important because the same incentive design could be applied to different historical years or future regulatory periods by changing the application inputs without modifying the underlying regulatory logic.

The values used in this thesis define a reference calibration for the Excel-based model. They are not intended to be final regulatory parameters, but a transparent and internally consistent set of assumptions used to test the magnitude, proportionality, and risk profile of the proposed incentive package. The calibration is designed so that the resulting incentives are larger and more visible than the explicit incentive component currently observed in the Spanish framework, which remains relatively small compared with total TO and SO remuneration. However, the proposed parameters still preserve partial exposure through sharing factors, caps, and asymmetric designs where appropriate.

The calibration also follows a differentiated logic across incentives. It would not be appropriate to assign the same cap or sharing factor to all mechanisms, because their controllability and expected system impact are different. Technical constraints and balancing energy are partly influenced by the SO, but they also depend on exogenous factors such as weather, demand, renewable output, outages, and market behaviour. By contrast, connection efficiency or deployment of innovative grid solutions may require stronger incentives because they are closer to investment and implementation decisions. Therefore, the model uses incentive-specific caps and sharing factors.

The reference calibration used in the model is summarized below.

Incentive	Main design parameters	Reference application inputs
SO-1	Sharing factor: 0.5% $P_{PDBF}^{ref} = 124$ €/MWh $P_{TR}^{ref} = 312$ €/MWh Cap/floor: ±5 M€	$E_{PDBF}^{ref} = 12.0$ TWh $E_{TR}^{ref} = 5.0$ TWh $C_{RRTT}^{ref} = 3{,}048$ M€

SO-2	Sharing factor: 1.5% $P_{BAL}^{ref,up}$ = 77 €/MWh $P_{BAL}^{ref,down}$ =42€/MWh cap/floor: ±5 M€	$E_{BAL}^{ref,up}$ = 6.5 TWh $E_{BAL}^{ref,down}$ =7.5 TWh C_{BAL}^{ref} =815.5 M€
SO-3	Unit reward: 3,500 €/MW Cap: 1.5 M€	Baseline: 400 MW Enabled capacity: 600 MW Incremental capacity: 200 MW
TO-1	Bonus: 1% per year Penalty: 0.5% per year Maximum: 4 years	25 strategic projects Total TOTEX base 902.7 M€ 8% projects before target (1-3 months) 45% on target or 2 months later 30% moderated delay (3-8 months) 12% severe delay (9-18 months) 5% extreme delay (19-30 months)
TO-2	Sharing factor: 5% Cap: 4 M€	15 innovative solutions Inv. limit at 9 M€
TO-3	Reference cost: 4,000 €/MW Sharing factor: 50% Cap: 4 M€	Achieved cost: 3,400 €/MW Connected capacity: 3,000 MW

Table 2. Proposed incentive package: design parameters and reference application inputs

For **SO-1**, the reference cost is constructed from differentiated prices for technical constraints solved after the day-ahead base schedule and for real-time technical constraints. The model uses a reference price of 124 €/MWh for PDBF constraints and 312 €/MWh for real-time constraints. These values are obtained from the average of the last three available years, which provides a recent but relatively stable reference. The reference cost is therefore not an arbitrary additional parameter, but the result of multiplying the reference energy volumes by the corresponding reference prices:

$$C_{TC}^{ref} = E_{PDBF}^{ref} \cdot P_{PDBF}^{ref} + E_{TR}^{ref} \cdot P_{TR}^{ref} \tag{22}$$

Using 12.0 TWh for PDBF and 5.0 TWh for real-time constraints gives a reference cost of 3,048 M€. The sharing factor is set at 0.5%, reflecting the fact that technical constraints are only partially controllable by the SO. This gives the operator a measurable economic signal while avoiding excessive exposure to structural network conditions or security-driven redispatch. The annual cap and floor are both set at 5 M€, which represents an increase relative to the current Spanish framework, but keeping the incentive limited in relation to the SO base remuneration. For the example scenario, the real values are determined to be 15.0 TWh for PDBF and 4.5 TWh for real-time, representing a similar scenario to the real one in Spain, where the TSO manages to improve the real-time energy while dramatically increasing the day-ahead one.

For **SO-2**, the model follows the same logic but applies it to balancing energy. The calibration distinguishes upward and downward balancing because they are not economically equivalent. Upward balancing is generally associated with a short system position and may require increasing generation or reducing demand. Downward balancing is generally associated with a long system position and may require reducing generation or increasing demand. Their prices, marginal technologies, and system implications can differ significantly, so a single average balancing price would weaken the incentive signal.

The reference prices are set at 77 €/MWh for upward balancing and 42 €/MWh for downward balancing, again based on the average of the last three available years. The reference cost is calculated as:

$$C_{BAL}^{ref} = E_{BAL}^{ref,up} \cdot P_{BAL}^{ref,up} + E_{BAL}^{ref,down} \cdot P_{BAL}^{ref,down} \tag{23}$$

With 6.5 TWh of upward balancing energy and 7.5 TWh of downward balancing energy, the resulting reference cost is 815.5 M€. The sharing factor is set at 1.5%, higher than in SO-1, because the incentive is intended to give more visibility to balancing costs while still preserving partial exposure. For the value used to calculate the incentive on the example scenario, it is determined 6.0 TWh for upward energy and 6.5 TWh for downward energy, representing a scenario where the TSO has managed to improve forecast and reserve management.

For **SO-3**, the model uses a unit reward of 3,500 €/MW of additional qualified or enabled tertiary balancing capacity. This value is close to the Portuguese reference of approximately 3,595 €/MW [31], used as an external benchmark for the value of additional balancing availability. The parameter should be recalibrated before any real implementation in Spain, using Spanish data on mFRR qualification, expected participation, and system value. However, it provides a reasonable reference for testing the order of magnitude of the incentive. The baseline is set at 400 MW, while the reference application assumes 600 MW of enabled capacity, resulting in 200 MW of incremental capacity. The reward is capped at 1.5 M€.

For **TO-1**, the calibration is based on a 1% bonus and a 0.5% penalty per year over the eligible project TOTEX. The asymmetry is intentional. Early delivery of strategic transmission projects may reduce constraints, enable new demand or generation, and improve security of supply. However, delays are often partly driven by permitting, environmental procedures, public acceptance, procurement constraints, or third-party dependencies. Therefore, the penalty is set below the reward to avoid excessive exposure to factors that may not be fully controllable.

The reference application includes 25 strategic projects, with an aggregate eligible base of 902.7 M€, coherent with the expansion planning. Project timing is generated through a calibrated delay distribution intended to reflect a realistic portfolio of transmission projects rather than a single deterministic assumption. In the model, 8% of projects are assumed to be delivered early, between 1 and 3 months before the target date; 45% are assumed to be close to schedule, between 0 and 2 months of delay; 30% experience moderate delays of 3 to 8 months; 12% experience severe delays of 9 to 18 months; and 5% experience extreme delays of 19 to 30 months. This structure is deliberately not too punitive: most projects are assumed to be either on time or moderately delayed, while long delays are possible but limited to a small share of the portfolio.

The incentive is limited to a maximum of four years, implying a maximum bonus of 4% and a maximum penalty of 2% of eligible TOTEX. This avoids excessive remuneration or penalization in very long projects. The resulting mechanism is therefore not designed to punish the TO for all delays, but to make project timing economically visible when it has system value. In a real implementation, the target date should be based on a regulatory reference such as a P50 delivery date, and justified delays outside the TO's control should be excluded.

For **TO-2**, the model applies a 5% sharing factor to verified net benefits from innovative grid solutions. The calibration is deliberately moderate. International examples, particularly in the United Kingdom, include stronger sharing of benefits in some grid-enhancing or constraint-cost reduction mechanisms, but the Spanish application proposed here is treated as a first pilot-type design. A 5% sharing factor gives the TO an incentive to identify and deploy valuable solutions without creating excessive remuneration where attribution is uncertain.

The reference application includes 15 innovative solutions. Both benefits and costs are generated using bounded distributions rather than fixed deterministic values. The gross benefit of each solution is calibrated around a minimum of 2.8 M€, a mode of 3.1 M€, and a maximum of 3.4 M€. Eligible costs are calibrated around a minimum of 0.483 M€, a mode of 0.545 M€, and a maximum of 0.825 M€. This reflects the assumption that innovative grid solutions may have relatively moderate costs compared with the system benefits they can create, but without assuming the very high benefit-to-cost ratios sometimes observed in highly specific international examples such as Dynamic Line Rating applications.

In the reference application, this calibration produces aggregate eligible costs of around 8.6 M€ across the 15 solutions, which is close to an assumed limit of 9 M€. The corresponding gross benefits and net benefits are calculated project by project, with the incentive applied only to the verified net value after subtracting eligible costs and adjusting for any overlap with other incentives. The annual incentive is capped at 4 M€, which protects consumers against excessive remuneration and prevents the mechanism from becoming an open-ended route to remunerate technologies outside the ordinary planning framework.

The logic of TO-2 is therefore not to remunerate a technology simply because it is innovative. The incentive only makes sense if the solution creates measurable system value, for example, by improving the use of existing assets, reducing technical constraints, deferring conventional reinforcement, lowering losses, or enabling flexibility. If the same benefit is already captured through SO-1 or another mechanism, the overlap adjustment must be applied to avoid double remuneration. This is essential for keeping the incentive compatible with the rest of the package.

For **TO-3**, the calibration uses a reference unit cost of 4,000 €/MW connected. This is an illustrative benchmark based on the order of magnitude of unit access costs associated with 220 kV and 400 kV positions. In a full regulatory implementation, this value should be calculated using Spanish historical connection costs and, ideally, differentiated by voltage level, connection type, location, and user category. The reference application assumes an achieved cost of 3,400 €/MW and 3,000 MW of connected or enabled capacity. These values represent a scenario in which the TSO reduces connection costs through flexibility, process optimisation and more efficient use of existing infrastructure.

The relatively high sharing factor is justified because reducing the unit cost of connection may be difficult and may require a strong economic signal. The mechanism is intended to encourage the TO to identify lower-cost ways of enabling connection capacity, such as better use of existing substations, modular reinforcements, automation, flexible connection arrangements, or dynamic ratings. The incentive is capped at 4 M€ to avoid excessive remuneration and preserve the role of ordinary planning and regulatory cost review.

Overall, the calibration is designed to be internally consistent. SO-1 and SO-2 use low sharing factors because they are linked to system-operation outcomes with relevant exogenous drivers. SO-3 uses a unit reward because it targets the enabling of flexible tertiary balancing capacity rather than direct cost savings. TO-1 uses asymmetric bonuses and penalties to reflect the system value of timely delivery while recognizing that delays are not fully controllable. TO-2 uses a moderate profit-sharing factor to encourage innovation without over-remunerating uncertain benefits. TO-3 uses a stronger sharing factor because it rewards reductions in the unit cost of connection capacity and aims to offset a possible bias towards conventional reinforcement.

The reference calibration is therefore a central case for quantitative analysis, not a definitive tariff proposal. The robustness of the results is assessed later through sensitivity analysis and Monte Carlo simulation, where reference prices, sharing factors, caps, benefit estimates, and benchmark values are varied. This allows the thesis to evaluate whether the proposed incentive package remains proportionate and economically meaningful under reasonable parameter uncertainty.

5.2. Excel-based regulatory-parametric model

The Excel model applies the six proposed incentives separately and then aggregates them into SO, TO, and total results. This separation is important because the thesis studies an integrated TSO in institutional terms, but with differentiated remuneration for the Transmission Owner and System Operator functions. The model therefore preserves this separation: SO and TO remuneration is calculated each from the incentives described in Methodology.

5.2.1. Model structure

The model is organized into different worksheets, each with a specific function. The structure follows a logical flow from assumptions to calculations and then to outputs. The first sheets contain the introductory information, the regulatory parameters, and the catalogue of incentives. The following sheets contain the SO and TO inputs. The calculation sheets then apply the formulas, while the final sheets summarize results, test sensitivity, evaluate uncertainty, and check consistency.

The model distinguishes between three types of information: design parameters, application inputs, and outputs. Design parameters define the regulatory rule, such as sharing factors, reference prices, unit rewards, and caps. Application inputs define the numerical case to which the rule is applied, such as energy volumes, enabled MW, project delays, eligible costs, or connected capacity. Outputs are the calculated incentives after applying the formulas, caps, and floors.

The calculation process follows a simple sequence. First, the regulatory parameters are set in the parameter sheet. Second, the SO and TO input sheets define the values used in the reference application. Third, the calculation sheets compute the raw incentive for each mechanism. Fourth, the model applies the corresponding caps, floors, or one-sided limits. Fifth, the results are aggregated into SO, TO, and total incentive values. Finally, the sensitivity, Monte Carlo, risk, and check sheets are used to assess robustness and consistency.

The historical SO module has a specific role. Since technical constraints and balancing energy have observable historical data, the SO-side operation incentives SO-1 and SO-2 can be easily tested retrospectively. This makes it possible to examine how the proposed logic would have behaved in previous years and whether the incentive would have generated persistent rewards, persistent penalties, or a more balanced outcome. This assessment will be a relevant analysis of this thesis. However, this type of back-testing is more difficult for TO incentives because project delivery, justified delays, innovative-solution benefits, and connection-cost counterfactuals require more detailed project-level information, so it is left out of the analysis.

5.2.2. Sensitivity and uncertainty analysis

The model includes sensitivity and uncertainty analysis because several parameters cannot be defined with full certainty. Reference prices, sharing factors, caps, project delays, innovative-solution benefits, and connection benchmarks are all subject to regulatory judgement. A single fixed calibration is therefore not enough to evaluate whether the incentive package is robust.

The sensitivity analysis modifies selected parameters while keeping the rest of the model constant. This allows the thesis to identify which assumptions have the greatest impact on the final incentive result. The relevant parameters include the sharing factors of SO-1 and SO-2, the unit reward of SO-3, the bonus and penalty rates of TO-1, the sharing factor of TO-2, the sharing factor of TO-3, and other parameters that directly affect the size of each incentive. The objective is not to optimize these parameters, but to understand which of them are most relevant for regulatory design.

The Monte Carlo module extends this logic by allowing several uncertain variables to change simultaneously. Instead of analysing one parameter at a time, the model generates a distribution of possible outcomes under parameter uncertainty. This helps assess whether the proposed package produces a reasonable range of incentive values, whether it creates excessive downside risk, and how often caps or floors may become binding, especially for the first two incentives, which are most relevant to system costs.

This analysis should not be interpreted as a probabilistic forecast of future TSO remuneration. The simulated distributions depend on the ranges and assumptions introduced in the model, and, therefore, they are not predictions of what will happen in future regulatory periods. Their purpose is methodological: to test whether the incentive design remains proportionate and internally consistent when reasonable uncertainty is introduced.

The risk analysis complements the sensitivity and Monte Carlo modules by comparing maximum positive and negative exposure. This is relevant because the proposed package is deliberately asymmetric. Some incentives are bidirectional, such as SO-1, SO-2, and TO-1, while others are mainly designed as positive incentives because the TSO does not fully control the underlying market response or because the policy objective is to encourage additional behaviour rather than penalize non-adoption. The model, therefore, allows the thesis to assess not only the expected incentive value, but also the balance between reward, penalty, and controllability.

Overall, the Excel-based model provides the quantitative bridge between the proposed incentive design and the results chapter. It does not replace detailed regulatory assessment, official cost-benefit analysis, or system operation studies. However, it offers a structured way to test whether the proposed incentives are material enough to matter, limited enough to be proportionate, and transparent enough to be considered as a potential complement to the existing Spanish remuneration framework.

6. Analysis and Results

6.1. Historical results for SO incentives

The first part of the results chapter applies the proposed SO incentives retrospectively to historical data. The purpose of this exercise is not to assess past regulatory compliance, nor to attribute responsibility for the evolution of system operation costs. It is a counterfactual back-testing exercise: the proposed incentive formulas are applied to past values in order to analyse the type of economic signal that the mechanism would have generated under historical system conditions.

The historical analysis focuses on the SO-side incentives because they are based on annual operational variables for which consistent time series are available. In particular, the back-testing covers SO-1, related to technical constraints, and SO-2, related to balancing energy. SO-3 is kept neutral in the historical module because it depends on the amount of qualified or enabled tertiary balancing capacity, for which a sufficiently consistent historical series is not included in the model, similar to what occurs with the TO incentives. This avoids introducing assumptions that would be less verifiable than the energy-based data used for SO-1 and SO-2.

A key methodological choice is the definition of the annual benchmark. For each year, the reference is calculated using a lagged three-year rolling average of previous observed values. This means that the benchmark for year t is based only on information that would have been available before year t, giving the reference an ex-ante regulatory interpretation. When fewer than three previous years are available, the model uses the available lagged observations. The first year of the series is set as neutral, since no previous data exist to define a meaningful reference.

$$X_t^{ref} = \frac{1}{N}\sum_{i=1}^{N} X_{t-i} \tag{24}$$

Where X_t^{ref} is the benchmark value for year t, X_{t-i} are the observed values in previous years, and N is the number of lagged observations used, up to a maximum of three.

This approach has two advantages. First, it avoids hindsight bias because the benchmark does not use information from the year being evaluated. Second, it smooths isolated annual fluctuations while still allowing the reference to adapt over time. This is relevant in the Spanish system, where congestion patterns, balancing needs, and renewable penetration have changed significantly during the period analysed. A fixed benchmark would be simpler, but it could become less representative as the system evolves.

The year 2025 is excluded from the historical back-testing. This is because the Iberian blackout and the subsequent reinforced operation introduced an exceptional security-driven regime that could distort the interpretation of the historical series. Including 2025 would mix the regular behaviour of technical constraints and balancing energy with an extraordinary operational response. Since the objective of this section is to evaluate the standard behaviour of the proposed incentive logic, the historical sample is limited to 2015–2024.

As seen on Figure 11, for SO-1, the historical result is negative over the full period. The cumulative incentive between 2015 and 2024 is approximately −10.5 M€, equivalent to an average of around −1.05 M€/year. However, the result is not uniformly negative. The incentive would have generated positive values in some years, especially when technical-constraint volumes improved relative to the rolling benchmark. For example, 2017, 2018, 2019, and 2022 show positive SO-1 values. By contrast, 2023 and 2024 reached the negative floor of −5 M€, reflecting a strong deterioration of the technical-constraint cost proxy relative to the historical benchmark.

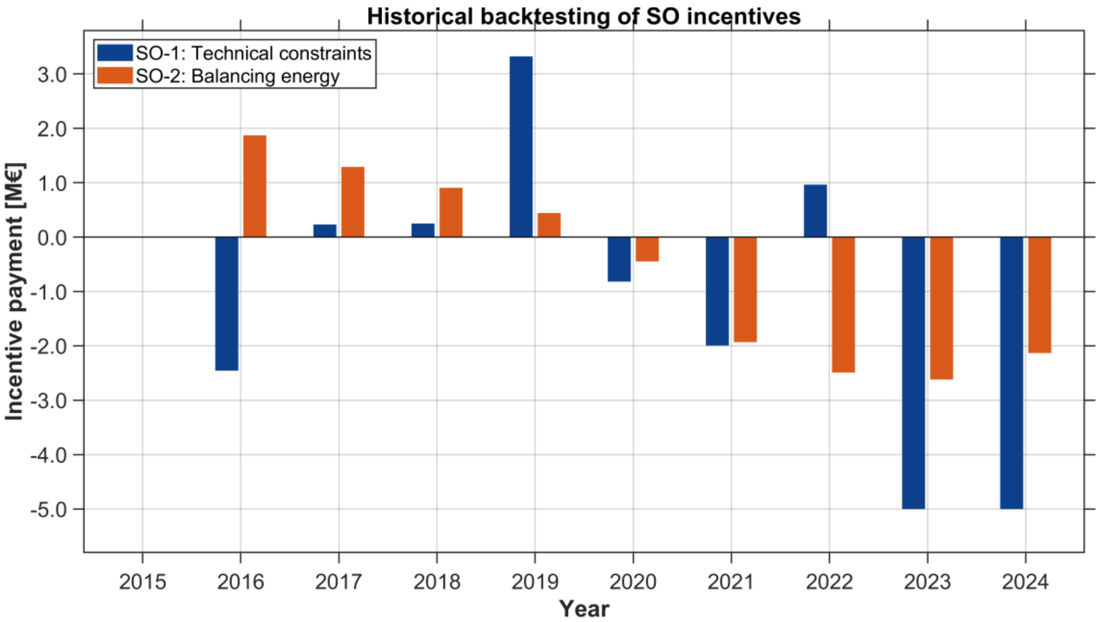

Figure 11. Historical back-testing of SO-1, SO-2 and aggregate SO incentive, 2015–2024

This result should be interpreted carefully. It does not imply that all redispatch in those years was inefficient or avoidable. Technical constraints may be necessary for secure operation, especially in a system with high renewable penetration, network limitations, and changing flow patterns. What the result shows is more limited: under the proposed cost-proxy logic, the increase in technical constraints in recent years would have produced a strong negative regulatory signal.

For SO-2, the historical result is also negative over the full period, although less severe than SO-1. The cumulative incentive between 2015 and 2024 is approximately −5.1 M€, equivalent to an average of around −0.51 M€/year. The first part of the period shows positive values, especially between 2016 and 2019, when balancing-energy volumes were below the rolling benchmark. From 2020 onwards, the signal becomes negative, suggesting that balancing-energy needs increased relative to the adaptive historical reference.

Again, this should not be read as a direct judgement on the SO's performance. Balancing energy depends on several external factors, including renewable forecast errors, demand deviations, generation availability, market behaviour and weather conditions. The result simply indicates that, if the proposed incentive had been applied, the SO would have faced a negative signal in years where balancing energy increased compared with recent historical values.

The aggregate historical SO result combines SO-1, SO-2 and the neutral SO-3 component. Over the 2015–2024 period, the total cumulative SO incentive is approximately −15.6 M€, with an average annual value close to −1.56 M€/year.

Incentive	Total 2015–2024	Annual average
SO-1: Technical constraints	−10.50 M€	−1.05 M€/year
SO-2: Balancing energy	−5.11 M€	−0.51 M€/year
Total SO	**−15.61 M€**	**−1.56 M€/year**

Table 3. Historical application of SO incentives, 2015–2024

6.2. Results of the reference full-package application

This section presents the results of the reference application of the complete incentive package. Unlike the historical backtesting in Section 5.1, which only applies the SO-side incentives to past data, this exercise applies the six proposed incentives simultaneously under the central calibration defined in Chapter 4. The objective is to assess the magnitude, sign, and internal balance of the full package when SO and TO incentives are considered together.

The results should not be interpreted as a forecast of future remuneration or as a final regulatory proposal. They correspond to one controlled application of the model, based on fixed input values and calibrated parameters. Their purpose is to test whether the proposed incentives generate a meaningful economic signal while remaining proportionate relative to the regulated base remuneration.

6.2.1. Aggregate and incentive results

The reference application produces a total incentive of approximately +1.69 M€. This value results from a net positive SO incentive of +0.83 M€ and a net positive TO incentive of +0.87 M€. However, the aggregate result hides important differences across individual incentives. The package does not reward all dimensions simultaneously: some incentives are positive, while others generate penalties.

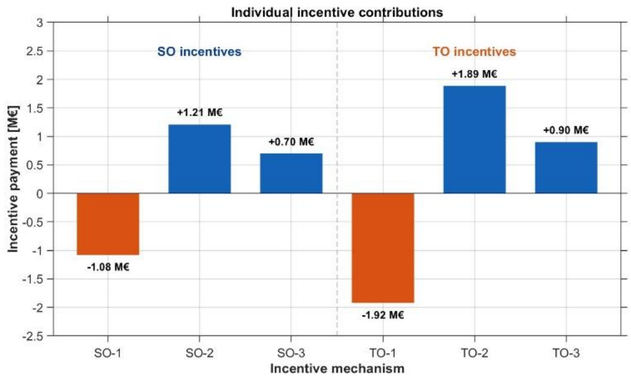

Figure 12. Incentive remuneration by mechanism in the reference application

Incentive	Result
SO-1: Technical constraints cost internalization	−1.080 M€
SO-2: Balancing energy incentive	+1.208 M€
SO-3: Liquidity and availability of tertiary balancing resources	+0.700 M€
TO-1: Acceleration of strategic investment projects	−1.920 M€
TO-2: Innovative grid solutions	+1.886 M€
TO-3: Flexible connection solutions	+0.900 M€
Total incentive package	**+1.694 M€**

Table 4. Reference application: individual incentive results

This result is important because it shows that the proposed framework behaves as a performance-sensitive package rather than as a simple additional remuneration layer. The SO is penalized for the technical-constraint cost proxy, but rewarded for balancing energy and tertiary balancing capacity. Similarly, the TO is penalized for project delays, but rewarded for innovative grid solutions and efficient connection-cost performance.

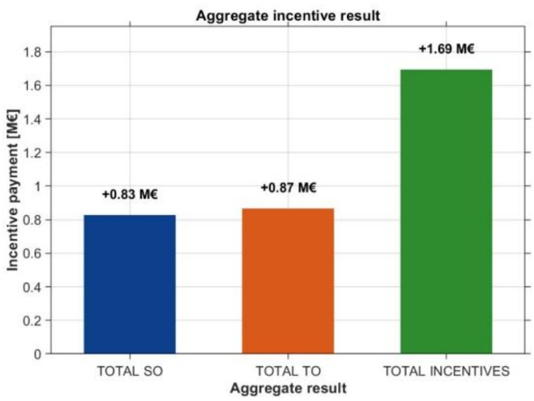

Figure 13. Incentive remuneration by mechanism separated by activity and total incentive remuneration

In relative terms, the incentive remains limited compared with the total regulated base remuneration. The SO incentive represents approximately 0.84% of the SO remuneration, while the TO incentive represents only around 0.06% of the TO remuneration. At the aggregate level, the total package represents approximately 0.10% of the combined TO and SO remuneration base.

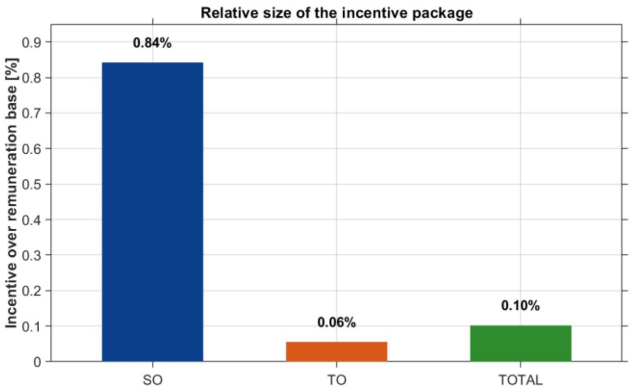

Figure 14. Incentive remuneration as a percentage of the total base remuneration

Scope	Incentive result	Base Remuneration	Share of base
SO	0.828 M€	98.255 M€	0.842%
TO	0.867 M€	1,564.891 M€	0.055%
Total	**1.694 M€**	**1,663.146 M€**	**0.102%**

Table 5. Aggregate incentive results as a share of the regulated base remuneration

This confirms that the package is economically visible but not disruptive. It gives a clearer incentive signal than the current Spanish framework, especially for system-level outcomes, but it does not dominate the existing remuneration structure. This is consistent with the methodological objective of the thesis: the proposed framework is intended to complement the current remuneration model, not to replace it.

6.2.2. Interpretation of SO incentives

The SO block produces a net positive result of +0.828 M€, but this value is the result of three different effects. The reference application assumes a situation in which the TSO improves some operational dimensions, particularly balancing energy and tertiary balancing capacity, while technical constraints evolve less favourably. This makes the SO result useful for testing the internal balance of the proposed package: the model does not simply reward the SO when one indicator improves, but evaluates each outcome separately.

The first incentive, SO-1, generates a penalty of −1.080 M€. The reference technical-constraints cost is 3,048 M€, while the observed cost proxy in the reference application is 3,264 M€. The difference is therefore 216 M€ above the reference. Applying the 0.5% sharing factor gives the final penalty of −1.080 M€, below the negative cap of 5 M€.

This result comes from the assumed evolution of the two technical-constraint components. The scenario assumes that the TSO manages to reduce real-time technical-constraint energy, from 5.0 TWh in the reference to 4.5 TWh in the observed value. This could be interpreted as an improvement in real-time operation, reserve management or short-term system coordination. However, the same scenario also assumes a significant increase in PDBF technical-constraint energy, from 12.0 TWh to 15.0 TWh. This increase more than offsets the improvement in real-time constraints, leading to a higher total cost proxy.

This result is relevant because it shows that SO-1 is sensitive to the composition of redispatch. Even if the TSO improves the real-time component, the incentive remains negative if the overall technical-constraint cost proxy worsens. The mechanism therefore avoids rewarding partial improvements when the aggregate effect on system costs is adverse. In regulatory terms, this is consistent with the objective of internalizing the economic impact of technical constraints, rather than only tracking isolated operational improvements.

The second incentive, SO-2, produces a reward of +1.208 M€. The reference balancing-energy cost is 815.5 M€, while the observed cost proxy is 735.0 M€. This gives an estimated saving of 80.5 M€. Applying the 1.5% sharing factor results in a reward of approximately 1.2 M€.

In this case, the scenario assumes that the TSO manages to reduce balancing energy in both directions. Upward balancing energy decreases from 6.5 TWh to 6.0 TWh, while downward balancing energy decreases from 7.5 TWh to 6.5 TWh. This represents a situation in which the system requires fewer balancing activations relative to the reference level, possibly associated with better forecasting, improved reserve management, higher operational flexibility or more efficient coordination close to real time.

The positive SO-2 result therefore illustrates the intended logic of the incentive. When balancing-energy volumes fall below the benchmark, the SO receives a limited share of the estimated system saving. The use of separate upward and downward reference prices is important here, because the two directions do not have the same economic meaning or cost impact. The reward is not granted for reducing balancing indiscriminately, but for reducing the cost proxy while preserving the assumption that system security remains satisfied.

The third incentive, SO-3, gives a reward of +0.700 M€. The reference application assumes that the TSO enables additional tertiary balancing capacity, increasing qualified or available capacity from 400 MW to 600 MW. This produces an incremental capacity of 200 MW. With a unit reward of 3,500 €/MW, the resulting incentive is 0.700 M€.

This scenario represents a case in which the TSO manages to accelerate the qualification or effective integration of additional resources for tertiary regulation. This may include faster technical validation, improved platform integration, clearer qualification procedures, or more efficient interaction with potential providers. The incentive is especially relevant for technologies such as batteries, aggregators, demand response, and hybrid renewable-storage assets, which may play an increasing role in future balancing markets.

Unlike SO-1 and SO-2, SO-3 does not measure avoided system costs directly. It rewards an enabling condition: a broader pool of qualified tertiary balancing resources. The rationale is that more available mFRR capacity can increase competition, reduce dependence on conventional providers and provide the SO with more flexibility to manage real-time imbalances. Therefore, SO-3 complements the cost-proxy incentives by strengthening the resource base that may help reduce balancing and redispatch costs over time.

Overall, the SO results show a mixed but coherent operational signal. The package penalizes the deterioration in the technical-constraint cost proxy, rewards the reduction in balancing-energy needs, and provides an additional reward for increasing tertiary balancing capacity. The net result is positive, but only because the improvements in SO-2 and SO-3 more than offset the penalty in SO-1. This is precisely the intended behaviour of the package: each incentive reacts to a different operational outcome, allowing the framework to distinguish between areas where performance improves and areas where system costs worsen.

6.2.3. Interpretation of TO incentives

The TO block produces a net positive result of +0.867 M€, but this aggregate value also comes from offsetting effects. The reference application assumes a portfolio in which the TO faces delays in strategic project delivery while achieving positive results in innovative grid solutions and connection-cost efficiency. This makes the TO block useful for testing whether the proposed package can penalize weak delivery performance while still rewarding solutions that create system value.

The first TO incentive, TO-1, generates a penalty of−1.920 M€. The reference application includes 25 strategic projects, with an eligible cost base of approximately 902.7 M€. The incentive applies a bonus of 1% per year for early delivery and a penalty of 0.5% per year for delays, with the exposure limited to a maximum of four years.

In this scenario, the project portfolio is not assumed to perform uniformly. Some projects are delivered early or close to their target date, but others experience moderate, severe or extreme delays. The negative aggregate result indicates that the effect of delayed projects is larger than the reward obtained from early deliveries. This does not represent an assessment of actual Spanish transmission projects. It is an illustrative portfolio used to test the incentive logic.

The result shows the role of TO-1 clearly. Project timing becomes economically visible, but the penalty remains limited. This is important because the delivery of transmission infrastructure can have material system value: delayed projects may contribute to persistent constraints, connection delays or lower renewable integration. At the same time, delays may be caused by permitting, environmental procedures, public acceptance, procurement constraints or dependencies on third parties. For this reason, the penalty rate is lower than the bonus rate, and justified delays would need to be excluded in a real implementation.

The second TO incentive, TO-2, produces a reward of +1.886 M€. The reference application assumes that the TO deploys 15 innovative grid solutions, with aggregate eligible costs of around 8.6 M€, close to the assumed annual investment limit of 9 M€. The model applies a 5% sharing factor to the verified net benefits generated by these solutions, after subtracting eligible costs and accounting for possible overlaps with other incentives.

The scenario, therefore, represents a case in which innovative solutions create measurable system value. These benefits may come from better use of existing assets, reduced technical constraints, deferred conventional reinforcement, lower losses, or additional operational flexibility. The incentive is not paid simply because a technology is innovative. It is paid because the solution is assumed to generate a positive net benefit for the system.

This result is particularly relevant for the CAPEX-OPEX discussion developed earlier in the thesis. Under a conventional asset-based framework, the TO may have a clearer remuneration path for large conventional reinforcements than for smaller grid-enhancing technologies or operational solutions. TO-2 tries to correct this by allowing the TO to retain a limited share of verified system benefits. In the reference application, the reward remains below the 4 M€ cap, so the cap does not bind.

The third TO incentive, TO-3, generates a reward of +0.900 M€. The reference unit connection cost is set at 4,000 €/MW, while the achieved unit cost in the scenario is 3,400 €/MW. This implies a saving of 600 €/MW. Applied to 3,000 MW of connected or enabled capacity, the gross saving proxy is 1.8 M€. With a 50% sharing factor, the resulting incentive is 0.900 M€.

This scenario assumes that the TO manages to reduce the unit cost of enabling new connection capacity. This could be achieved through better use of existing substations, modular reinforcements, automation, flexible connection arrangements, dynamic ratings, or other measures that allow more MW to be connected without relying exclusively on conventional reinforcement. The logic of TO-3 is therefore different from a pure investment incentive: it rewards efficiency per MW connected, rather than the total volume of investment.

Taken together, the TO results show a coherent signal. The package penalizes the assumed delays in strategic project delivery, but rewards the deployment of innovative solutions and the reduction of connection unit costs. The positive TO result does not mean that all TO performance dimensions improve. Rather, it shows that benefits from innovation and connection efficiency slightly more than offset the penalty associated with project timing.

This is consistent with the objective of the proposed framework. The TO should not only be remunerated for expanding the regulated asset base, but also receive signals related to when projects are delivered, whether innovative alternatives create system value, and whether connection capacity can be enabled efficiently. The reference application suggests that these signals can be introduced without destabilizing the TO remuneration framework, since the net TO incentive remains small relative to the total TO base remuneration.

6.3. Sensitivity analysis

The sensitivity analysis evaluates how the total incentive package changes when the main regulatory design parameters are modified. The objective is not to find an optimal parameter value, but to identify which assumptions have the strongest effect on the final remuneration outcome. This is important because several parameters in the model, such as sharing factors, unit rewards, and penalty rates, would ultimately require regulatory judgement if the mechanism were implemented.

The analysis varies each selected parameter by ±20% around its central value, while keeping all other parameters constant. The central value of the total incentive package is 1.694 M€. Reference prices are not included in this one-way sensitivity exercise, because they are treated as external calibration inputs based on historical averages rather than as pure regulatory design levers. The focus is therefore placed on parameters that the regulator could directly adjust: sharing factors, unit rewards and penalty rates.

Parameter	Affected incentive	Range under ±20% variation
SO-1 sharing factor	SO-1	**0.432 M€**
SO-2 sharing factor	SO-2	**0.483 M€**
SO-3 €/MW reward	SO-3	**0.280 M€**
TO-1 penalty rate	TO-1	**0.768 M€**
TO-2 sharing factor	TO-2	**0.754 M€**
TO-3 sharing factor	TO-3	**0.360 M€**

Table 6. One-way sensitivity analysis: range of incentive results under ±20% parameter variation

The most relevant result is that the package is mainly driven by TO-1 and TO-2. The penalty rate applied to project delays has the largest impact, with a range of approximately 0.768 M€ when varied by ±20%. This reflects the size of the eligible project portfolio: even a relatively small percentage applied to a large investment base can create a meaningful remuneration effect. It also confirms that project delivery is one of the most important risk drivers in the proposed package.

The second most important parameter is the TO-2 sharing factor, with a range of approximately 0.754 M€. This is consistent with the logic of the incentive. Innovative grid solutions may generate significant verified net benefits, so the percentage of those benefits retained by the TO has a strong effect on the final result. This does not mean that the sharing factor should necessarily be lower or higher; it means that this parameter would need particular attention in a real regulatory design, because it determines how benefits are divided between consumers and the regulated company.

The SO parameters have a lower but still relevant effect. The SO-2 sharing factor has a range of approximately 0.483 M€, while the SO-1 sharing factor has a range of approximately 0.432 M€. The interpretation of these two parameters is different. Since SO-2 is positive in the reference application, increasing its sharing factor increases the total incentive. By contrast, SO-1 is negative in the reference application, so increasing its sharing factor makes the total package less favourable to the TSO. This is useful because it shows that the same regulatory lever can have opposite effects depending on whether the underlying performance indicator is above or below the benchmark.

The two remaining parameters have a smaller impact. The TO-3 sharing factor produces a range of around 0.360 M€, while the SO-3 unit reward produces a range of around 0.280 M€. These incentives are still meaningful, but they are less dominant in the total package. This is reasonable because SO-3 is based on an incremental capacity of 200 MW, and TO-3 is based on a unit connection-cost saving that remains limited by the annual cap.

The sensitivity analysis, therefore, suggests that the proposed package is not excessively dependent on a single parameter. The largest drivers are TO-1 and TO-2, but the total incentive remains within a relatively narrow range under the ±20% variations considered. This supports the idea that the package is proportionate: parameter changes affect the result, but they do not radically alter the order of magnitude of the remuneration impact.

In addition to the one-way sensitivity analysis, the model includes two two-way sensitivity matrices. The first matrix combines the SO-1 sharing factor and the SO-2 sharing factor. This comparison is more coherent than comparing an SO incentive with a TO incentive, because both SO-1 and SO-2 are operational, bidirectional, and cost-proxy based mechanisms. SO-1 reflects the cost proxy associated with technical constraints, while SO-2 reflects the cost proxy associated with balancing energy. The matrix, therefore, tests how the total package changes when the regulator assigns more or less weight to these two SO-side cost drivers.

SO-2 α \ SO-1 α	0,40%	0,45%	0,50%	0,55%	0,60%
1,20%	1.668.666 €	1.560.666 €	1.452.666 €	1.344.666 €	1.236.666 €
1,35%	1.789.416 €	1.681.416 €	1.573.416 €	1.465.416 €	1.357.416 €
1,50%	1.910.166 €	1.802.166 €	**1.694.166 €**	1.586.166 €	1.478.166 €
1,65%	2.030.916 €	1.922.916 €	1.814.916 €	1.706.916 €	1.598.916 €
1,80%	2.151.666 €	2.043.666 €	1.935.666 €	1.827.666 €	1.719.666 €

Table 7. Two-way sensitivity matrix: aggregate SO incentive (M€), SO-1 vs SO-2 sharing factors

The result is relevant because SO-1 and SO-2 move in opposite directions in the reference application. SO-1 is negative, since the technical-constraint cost proxy is above the benchmark, while SO-2 is positive, since balancing-energy volumes improve relative to the reference. As a result, increasing the SO-1 sharing factor strengthens the penalty, whereas increasing the SO-2 sharing factor increases the reward. The matrix, therefore, illustrates the internal balance of the SO incentive block: the total SO signal depends not only on whether operational indicators improve or deteriorate, but also on the regulatory weight assigned to each type of system-operation outcome.

This comparison is useful from a regulatory perspective. A framework that gives excessive weight to SO-1 could become too punitive in periods of high technical constraints, especially when those constraints are partly driven by structural network limitations, renewable location, or security requirements. Conversely, a framework that gives excessive weight to SO-2 could overemphasize balancing-energy performance relative to congestion management. The two-way matrix, therefore, supports the need to calibrate SO-1 and SO-2 jointly, rather than treating their sharing factors as independent parameters.

The second two-way matrix combines the TO-1 penalty rate with the TO-3 sharing factor. This comparison tests the interaction between project delivery risk and connection-cost efficiency within the TO block.

TO-1 penal. \ TO-3 α	40,00%	45,00%	50,00%	55,00%	60,00%
0,40%	1.898.079 €	1.988.079 €	2.078.079 €	2.168.079 €	2.258.079 €
0,45%	1.706.123 €	1.796.123 €	1.886.123 €	1.976.123 €	2.066.123 €
0,50%	1.514.166 €	1.604.166 €	1.694.166 €	1.784.166 €	1.874.166 €
0,55%	1.322.210 €	1.412.210 €	1.502.210 €	1.592.210 €	1.682.210 €
0,60%	1.130.253 €	1.220.253 €	1.310.253 €	1.400.253 €	1.490.253 €

Table 8. Two-way sensitivity matrix: aggregate TO incentive (M€), TO-1 penalty rate vs TO-3 sharing factor

This matrix is useful to analyse execution risk. A higher TO-1 penalty rate reduces the total incentive when the project portfolio is delayed, while a higher TO-3 sharing factor increases the reward for reducing the unit cost of connection capacity. The result shows that efficient connections can partially compensate for project-delay penalties, but they do not eliminate the relevance of timing. This is consistent with the design objective: the TO should have incentives both to deliver strategic projects on time and to reduce the cost of enabling new connection capacity.

Overall, the sensitivity analysis confirms three points. First, the package is most sensitive to TO-side parameters, especially project-delay penalties and innovation benefit sharing. Second, SO-side parameters remain relevant and should be calibrated jointly, because SO-1 and SO-2 may produce opposite signals depending on the evolution of technical constraints and balancing energy. Third, the proposed incentives interact with each other in a way that makes the total package more balanced than any individual mechanism. This is important because the objective of the framework is not to maximize one specific incentive, but to create a coherent set of signals across operation, investment delivery, innovation, and connection efficiency.

6.4. Monte Carlo and risk analysis

The Monte Carlo analysis complements the deterministic reference application by introducing uncertainty in the SO-side operational variables. Its objective is not to forecast future remuneration, but to test how the proposed incentives behave when the main energy-volume inputs fluctuate around the reference values. This is especially relevant for SO-1 and SO-2, because technical constraints and balancing energy are affected by variables that are only partly controllable by the SO, such as renewable output, demand, outages, market schedules, forecast errors, and system-security requirements.

The Monte Carlo simulation is applied only to SO-1 and SO-2. This is a deliberate methodological choice. These two incentives are based on continuous and historically observable variables, so it is reasonable to simulate deviations around their central values. By contrast, SO-3, TO-1, TO-2, and TO-3 depend on more discrete or project-specific assumptions, such as enabled tertiary capacity, project delays, verified benefits from innovative solutions, or achieved connection costs. Simulating these variables without robust project-level distributions would add apparent sophistication but also a false sense of precision. For this reason, they are assessed through deterministic inputs, sensitivity analysis, and the risk-exposure framework.

In the current calibration, the simulation uses 1,000 iterations. The volumes of technical constraints and balancing energy are randomly varied around their reference values using truncated distributions, so that negative physical volumes are avoided. The reference prices are kept practically fixed in the simulation, which means that the Monte Carlo mainly tests volume uncertainty rather than price volatility. This is consistent with the regulatory logic of the proposed incentives: prices are treated as stable reference parameters, while operational volumes are allowed to fluctuate.

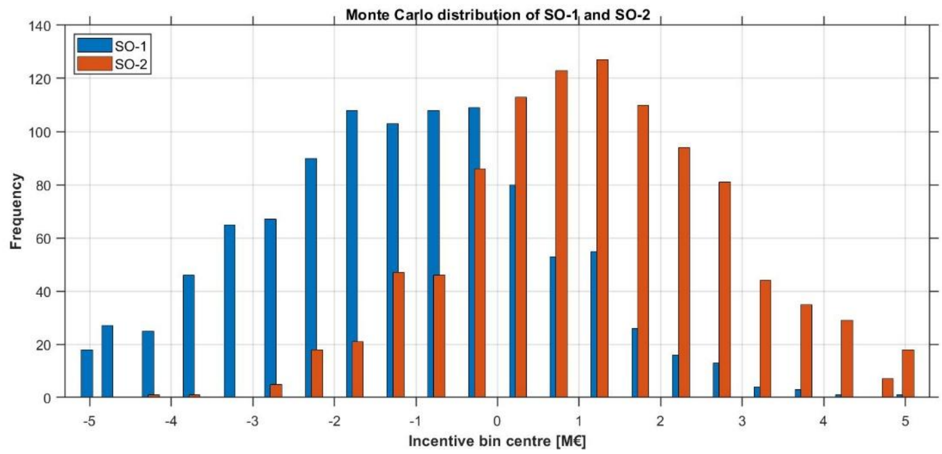

Figure 15. Montecarlo analysis results for SO-1 incentive (blue) and SO-2 incentive (orange)

The results show clearly different risk profiles for SO-1 and SO-2. For SO-1, the simulated mean is approximately −1.06 M€, close to the deterministic value of −1.08 M€. The distribution is relatively wide, with a standard deviation of around 1.66 M€. The median is also negative, around −1.04 M€, and the probability of a penalty is approximately 75%. The negative floor is reached in a small share of simulations, around 0.8%, while the positive cap is not reached in the current run.

Metric	SO-1
Mean	−1.06 M€
Standard deviation	1.66 M€
P10	−3.22 M€
Median	−1.04 M€
P90	+1.06 M€
Probability of reward	25%
Probability of penalty	75%
Probability of a negative cap	0.8%

Table 9. Monte Carlo simulation results for SO-1 (1,000 iterations)

This result confirms that SO-1 is materially exposed to uncertainty. Even though the central scenario is negative, there are simulated cases in which the incentive becomes positive. This reflects the fact that technical-constraint volumes may vary substantially around the reference level. However, the distribution remains skewed towards penalties because the central scenario already assumes a technical-constraint cost proxy above the benchmark.

For SO-2, the result is more favourable to the SO. The simulated mean is approximately +1.18 M€, close to the deterministic value of +1.21 M€. The median is around +1.15 M€, and the probability of a reward is approximately 76%. The positive cap is reached in a small share of simulations, around 0.8%, while the negative cap is not reached in the current run.

Metric	SO-2
Mean	+1.18 M€
Standard deviation	1.59 M€
P10	−0.84 M€
Median	+1.15 M€
P90	+3.30 M€
Probability of reward	76%
Probability of penalty	24%
Probability of a positive cap	0.8%

Table 10. Monte Carlo simulation results for SO-2 (1,000 iterations)

This confirms that SO-2 has a positive expected signal in the reference calibration, but it is not risk-free. Around one quarter of the simulations produce a penalty, which means that the reward depends on maintaining balancing-energy volumes below the benchmark. The distribution therefore behaves as intended: the SO receives a reward when balancing needs improve, but the mechanism can also generate a penalty if balancing volumes deteriorate.

The comparison between SO-1 and SO-2 is useful because the two incentives have opposite central signs. SO-1 starts from a negative position due to higher technical-constraint costs, while SO-2 starts from a positive position due to lower balancing-energy costs. The Monte Carlo analysis, therefore, shows that the SO block does not produce a mechanically positive or negative result. It depends on the relative evolution of different operational variables.

The risk analysis extends the assessment to the full incentive package. Unlike the Monte Carlo simulation, which is limited to SO-1 and SO-2, the risk analysis considers the maximum positive and negative exposure of all six incentives. This is important because the package is deliberately asymmetric. Some mechanisms are bidirectional, while others are designed mainly as positive incentives to encourage additional behaviour without penalizing outcomes that are not fully under the TSO's control.

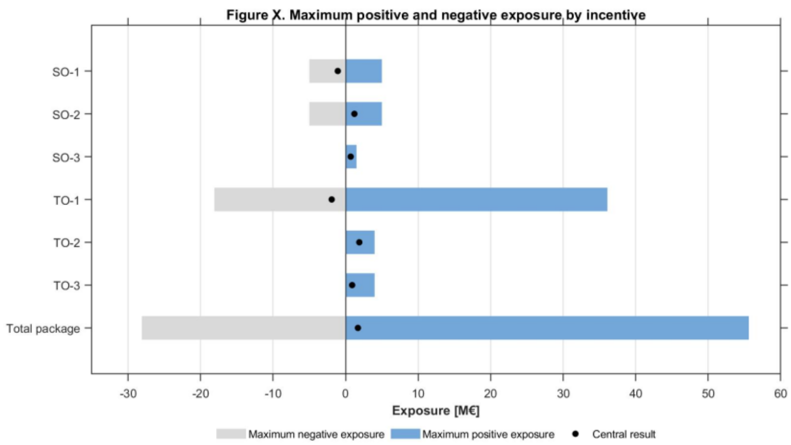

Figure 16. Maximum positive and negative exposure by incentive

Incentive	Maximum positive exposure	Maximum negative exposure	Central result
SO-1	5.0 M€	−5.0 M€	−1.080 M€
SO-2	5.0 M€	−5.0 M€	+1.208 M€
SO-3	1.5 M€	0.0 M€	+0.700 M€
TO-1	36.1 M€	−18.1 M€	−1.920 M€
TO-2	4.0 M€	0.0 M€	+1.886 M€
TO-3	4.0 M€	0.0 M€	+0.900 M€
Total package	**55.6 M€**	**−28.1 M€**	**+1.694 M€**

Table 11. Risk exposure analysis: cap limits and central results by incentive.

The largest theoretical exposure comes from TO-1, because it is applied to a large eligible project cost base. Its maximum positive exposure is around 36.1 M€, while its maximum negative exposure is around 18.1 M€. This reflects the asymmetric design of the incentive: early delivery is rewarded more strongly than delay is penalized. The reason is that project acceleration can generate high system value, while delays may be partly driven by factors outside the TO's direct control.

The SO incentives have symmetric caps. SO-1 and SO-2 can each generate a maximum reward or penalty of 5 M€. This symmetry is appropriate because both mechanisms are based on deviations from a benchmark cost proxy. However, the use of caps is essential. Without caps, extreme years of technical constraints or balancing energy could transfer excessive operational risk to the SO, which would be inconsistent with the principle of partial controllability.

SO-3, TO-2, and TO-3 are one-sided in the reference design. SO-3 rewards additional enabled tertiary balancing capacity, TO-2 rewards verified net benefits from innovative grid solutions, and TO-3 rewards reductions in the unit cost of connection capacity. In these cases, a negative incentive is not used in the base design because the underlying outcome depends significantly on third-party behaviour, project-specific conditions or regulatory verification. The risk is managed instead through caps, eligibility criteria, ex post verification and benchmark review.

At the aggregate level, the package has a maximum positive exposure of approximately 55.6 M€ and a maximum negative exposure of approximately −28.1 M€. This gives an overall asymmetry ratio close to 2:1 between potential rewards and penalties. The central result, however, is much smaller: +1.69 M€, equivalent to around 0.10% of the combined base remuneration.

This distinction is important. The theoretical exposure shows the outer limits of the package, while the central result shows the impact under the reference application. The package is designed to be capable of generating material incentives in exceptional cases, but the reference outcome remains modest. This is consistent with the objective of introducing a complementary output-based layer without destabilizing the existing remuneration framework.

The risk analysis also shows that three of the six incentives are penalizable: SO-1, SO-2 and TO-1. These are the mechanisms where the model assumes that the TSO has enough influence over the outcome to justify bidirectional exposure, although always with caps and partial sharing. The remaining incentives are mainly designed to encourage additional enabling behaviour, such as increasing tertiary balancing capacity, deploying innovative solutions or reducing connection unit costs.

Overall, the Monte Carlo and risk analysis support three conclusions. First, the SO incentives are exposed to operational uncertainty, but their distributions remain bounded by caps and floors. Second, the full package is asymmetric by design, with larger potential upside than downside, because several mechanisms are intended to encourage new behaviours rather than punish non-adoption. Third, the central incentive remains small relative to the base remuneration, while the maximum exposure is large enough to make the package relevant in cases of strong performance or underperformance.

The results therefore reinforce the main regulatory interpretation of the model. A complementary incentive layer can create economic signals linked to system outcomes, but it must be designed with partial exposure, clear caps, careful benchmark definition and safeguards against excessive risk transfer. This is particularly important for a TSO, whose decisions affect system costs but whose control over those costs is always incomplete.

7. Discussion

7.1. Incentive alignment and system-cost efficiency

The results of the quantitative analysis suggest that the proposed framework can improve incentive alignment, but only in a partial and complementary way. The objective of the package is not to replace the current Spanish remuneration framework, nor to expose the TSO directly to all system costs. The Spanish model already provides important regulatory functions: it ensures cost recovery for the transmission activity, supports financial stability, separates TO and SO remuneration, and preserves system security as the central operational priority. The issue identified in this thesis is more specific, as some system-level outcomes that are increasingly important in a renewable-based system are only weakly reflected in the economic incentives faced by the TSO.

The current framework is therefore not completely misaligned. It is better described as incomplete from the perspective of output-based incentive regulation. The TO remuneration remains mainly linked to recognized assets, depreciation, financial return, and standard operation and maintenance costs. The SO remuneration includes a set of incentives, especially after Circular 1/2023 for the Spanish case, but these incentives remain limited in magnitude and are often based on technical indicators rather than on the estimated economic value of avoided system costs. This creates a situation where the TSO is technically responsible for many outcomes that affect total system efficiency, but only partially exposed to them in remuneration terms.

The proposed incentive package addresses this gap by introducing a limited economic signal on six outcomes: technical constraints, balancing energy, mFRR capacity, project timing, innovative grid solutions and connection-cost efficiency. These variables do not cover all possible dimensions of TSO performance, but they represent areas where the link between TSO decisions and system efficiency is particularly relevant. They also reflect the main diagnosis of the Spanish case: the transition increases the importance of operational flexibility, timely network development, efficient use of existing assets, and the ability to connect new generation, storage, and demand without relying exclusively on conventional reinforcement.

The historical back-testing of SO incentives shows why this type of signal may be useful. The proposed SO-1 and SO-2 mechanisms would have generated both rewards and penalties depending on whether technical constraints and balancing energy improved or deteriorated relative to an adaptive historical benchmark. This is important because it suggests that the incentives are not designed as a systematic reward. They behave as performance-sensitive signals. In years where the cost proxies improve, the SO receives part of the estimated benefit; in years where they deteriorate, the SO faces a limited penalty. This is a more balanced approach than a purely fixed remuneration layer.

The reference full-package application also supports this interpretation. The total result is positive, but the package does not reward every dimension at the same time. SO-1 penalizes the deterioration in the technical-constraint cost proxy, while SO-2 and SO-3 reward improvements in balancing energy and tertiary balancing capacity. On the TO side, TO-1 penalizes delays in the illustrative portfolio of strategic projects, while TO-2 and TO-3 reward innovative solutions and lower unit connection costs. This mixed result is relevant because it shows that the model can distinguish between different areas of performance. The TSO is not simply rewarded for being the regulated entity; remuneration varies with the specific outcome being measured.

The size of the incentive is also relevant for assessing alignment. The total incentive in the reference application represents around 0.10% of the combined TO and SO base remuneration. This is small compared with total regulated remuneration, but it is not irrelevant as a directional signal. For the SO, the incentive is proportionally more visible because the SO base remuneration is much smaller than the TO base. For the TO, the absolute incentive may be similar in magnitude, but its relative weight is much lower. This asymmetry is consistent with the structure of the Spanish framework: operational incentives can have a more noticeable effect on the SO remuneration, while TO incentives need to remain carefully limited because the asset-based base remuneration is much larger.

The proposed framework also improves the treatment of the TO-SO interaction. One of the central problems discussed in the thesis is that transmission ownership and system operation are technically interdependent, even if they are remunerated separately. Network investment, project delivery, innovative grid solutions, and connection capacity can affect technical constraints, balancing needs, and renewable integration. Conversely, persistent operational costs can reveal structural network limitations or insufficient flexibility. The proposed package does not fully solve this coordination problem, but it makes some of these links economically visible. For example, the incentive that internalizes part of the cost of technical constraints (SO-1) is designed to directly reduce system costs systematically, while the innovative solutions one (TO-2) can reward alternatives that reduce those constraints at the same time. The overlap adjustment is therefore essential to avoid double remuneration, but the coexistence of both incentives reflects that the same system outcome may depend on both operational and investment-related decisions.

From this perspective, the main contribution of the proposed framework is not that each individual mechanism is perfect, but that the package moves the remuneration logic closer to system outcomes. On the system operation side, the framework introduces cost-reflective proxies for technical constraints and balancing energy, while also creating a signal to increase the availability of flexible balancing resources. On the transmission ownership side, it links remuneration to the timely delivery of strategic projects, the verified benefits of innovative grid solutions, and the efficiency of new connection capacity. Taken together, these mechanisms reduce the gap between what is valuable for the system and what is financially visible for the TSO.

This is particularly important in the context of network planning and investment limits. Spanish planning already considers system-oriented criteria, including renewable integration, reduction of technical constraints, security of supply, economic efficiency, and maximization of the existing network. However, planning approval and asset remuneration do not automatically create strong incentives for timely delivery, efficient connection solutions, or deployment of alternatives to conventional reinforcement. The proposed incentives would not replace planning, but they could reinforce its objectives once projects, needs, or outcomes have been identified as valuable for the system.

The framework is also consistent with international regulatory trends. The United Kingdom and France do not provide models that can be directly applied in Spain, but they show that regulators are increasingly moving beyond pure input-based remuneration. RIIO-ET3 includes stronger output and delivery incentives, including mechanisms related to major project delivery, connections, innovative delivery, and SO optimisation. TURPE 7 HTB also reflects a move towards stronger performance orientation in a context of growing investment needs, connection pressure, and the need to mobilize flexibility. The Spanish proposal developed in this thesis follows the same broad direction, but with lower exposure and a more cautious calibration.

However, the improvement in alignment should not be overstated. The proposed model does not prove that the TSO can fully control the selected outcomes. Technical constraints, balancing energy and connection costs are affected by many external factors, including weather, market behaviour, permitting, generation availability, demand growth, and regulatory decisions. This is why the package uses sharing factors, caps, floors, asymmetric exposure, and positive-only incentives where appropriate. The purpose is not to transfer system risk to the TSO, but to create partial exposure where the TSO has some influence.

Therefore, the answer to the question posed in this section is positive but qualified. The proposed framework improves incentive alignment by introducing measurable, capped, and economically meaningful signals linked to system-cost efficiency. It also better reflects the interaction between TO and SO functions and provides incentives for outcomes that are increasingly important in a renewable-based system. Nevertheless, it remains a complementary layer. The core of the Spanish remuneration framework would still be based on regulated cost recovery, asset remuneration, public planning, and operational security. This is appropriate: in transmission regulation, incentive alignment should strengthen the existing framework, not undermine its stability or the priority of secure system operation.

7.2. Regulatory feasibility and implementation conditions

From an institutional perspective, Spain already has some of the necessary conditions. The TO and SO functions are performed by the same corporate group but are remunerated separately, which makes it possible to allocate incentives to each function without changing the basic institutional model. The proposed package respects this separation:

SO incentives are linked to operational variables, while TO incentives are linked to project delivery, innovative solutions, and connection-cost efficiency. Therefore, the framework could, in principle, be implemented through amendments to the existing remuneration methodologies or through specific incentive provisions approved by the regulator.

The first feasibility condition is data availability. SO-1 and SO-2 are the most straightforward mechanisms from this point of view, because they rely on variables already measured in system operation: technical-constraint energy, balancing energy, and reference prices. These variables are not perfect measures of controllable performance, but they are observable and can be audited. SO-3 would require more specific reporting on qualified or enabled tertiary balancing capacity, but this is also a measurable variable if the qualification process, eligible technologies, and service definitions are clearly specified.

The TO incentives are more demanding. TO-1 requires a reliable definition of target delivery dates, actual commissioning dates, and justified delays. This is feasible, but only if target dates are defined ex ante and if the exclusion of non-controllable delays is handled transparently. TO-2 requires verified net benefits from innovative solutions, a more complex because it depends on counterfactuals. The regulator would need to define how benefits are measured, which baseline is used, and how overlaps with other incentives are avoided, but a methodology could also be defined based on international experiences, such as Ofgem's in the UK. TO-3 requires a robust benchmark for the cost per MW connected, ideally differentiated by voltage level, type of connection, and location. Without this differentiation, the incentive could reward differences in project characteristics rather than genuine efficiency.

The Spanish planning and investment framework is moving in a direction that could support this type of implementation. The draft reform of investment plans emphasizes transparency, publication of approved investment plans, compliance reports, information on capacity granted and denied, network utilization, and explanations for delays. These elements are directly relevant to the proposed incentives. If the regulator has better information on planned investments, commissioning delays, capacity availability, and connection outcomes, it becomes easier to design incentives around delivery and efficient use of the network.

The experience of the United Kingdom is useful because similar incentive mechanisms have already been used and adjusted over time. In RIIO-ET3, Ofgem explicitly strengthens the incentive package compared with RIIO-ET2, including major project delivery, connections, innovative delivery, and SO:TO optimisation. This suggests that output-based incentives are not considered marginal tools, but part of the core regulatory framework for transmission. The most relevant example for this thesis is the SO:TO Optimisation incentive, which rewards Transmission Owners for providing enhanced services to the system operator in order to reduce constraint costs. Ofgem reports that this mechanism has saved consumers more than £551 million to date and therefore decided to retain it in RIIO-ET3 [19]. This is strong evidence that a benefit-sharing mechanism can be regulatorily feasible when the benefit is measurable and linked to system-operation cost reductions.

At the same time, the UK experience also shows that these mechanisms require safeguards. Ofgem did not simply maintain the SO:TO Optimisation incentive without changes. It introduced eligibility criteria to distinguish enhanced services from business-as-usual activities and included a clawback mechanism if TOs fail to offer enhanced services requested by the system operator. This is an important lesson for the Spanish proposal. If TO-2 rewards innovative grid solutions, the regulator must ensure that the reward only applies to additional actions that go beyond ordinary obligations or planned asset remuneration. Otherwise, the mechanism could over-reward actions that the TO would have undertaken anyway.

The UK case also supports the feasibility of delivery incentives. RIIO-ET3 includes a Major Projects ODI-F designed to incentivize the timely delivery of significant transmission projects where this provides consumer value. The target delivery date is linked to a P50 delivery date or to the system operator's optimal delivery date, which is conceptually close to the logic proposed for TO-1. However, the UK design is much more powerful than the calibration proposed in this thesis. This difference is important: Spain could adopt the principle of delivery incentives without adopting the same intensity. A more cautious calibration is appropriate for a first application in the Spanish framework.

The French experience leads to a similar conclusion. TURPE 7 HTB remains a cost-recovery tariff framework, but it introduces stronger performance orientation in response to rising investment needs, growing connection pressure, and the need to mobilize flexibility. CRE explicitly identifies the reduction of connection delays, control of investment costs, and use of flexibility as priority regulatory objectives for RTE. This is directly aligned with the logic of TO-1, TO-2, and TO-3: the issue is not only whether the network is expanded, but whether projects are delivered on time, whether costs are controlled, and whether flexibility can reduce delays or avoid inefficient reinforcement [20].

France also provides a useful warning about implementation. Under TURPE 6 HTB, RTE's connection performance was monitored through indicators that were not financially incentivized. CRE notes that results were below the objectives in a context of strong growth in connection requests, and TURPE 7 therefore reinforces the regulatory treatment of connection performance [20]. This supports the idea that monitoring alone may be insufficient when the pressure on the network increases. For Spain, the implication is clear: transparency and reporting are necessary, but they may not be enough without an economic signal tied to delivery or connection outcomes.

Another relevant French lesson concerns controllability. For balancing reserves, CRE recognizes that RTE does not control the prices at which reserves are procured and therefore keeps price variations fully passed through the regulatory account. However, CRE still maintains an incentive on certain reserve-related volumes, using reference costs and a partial incentive rate. This is very close to the logic used in SO-1 and SO-2 in this thesis. The regulator does not expose the operator to market prices that it cannot control, but it does create a limited signal on variables where the operator has some influence. This supports the feasibility of using reference prices and sharing factors rather than direct exposure to actual system costs.

The French case also shows the importance of adapting incentive design when implementation problems appear. CRE reports that, under a previous incentive mechanism related to non-network investments, investment expenditure was close to the forecast trajectory, but capital charges were significantly lower due partly to commissioning delays, especially in information systems. This created a risk of double-counting capital charges. In TURPE 7, CRE adjusted the mechanism and retained an incentive based on investment expenditure, which it considered more predictable and controllable than capital charges. This is relevant for the Spanish proposal because it confirms that incentive design must be linked to variables that are not only theoretically relevant, but also practically auditable and controllable.

These international experiences suggest that the proposed Spanish framework is feasible, but only under strict implementation conditions. First, the incentives must be based on ex ante definitions. Benchmarks, reference prices, target dates and eligible costs should be established before the regulatory period, not adjusted after observing the outcome. Second, the mechanisms must include caps, floors and sharing factors to limit risk exposure. Third, the regulator must define eligibility criteria, especially for TO-2, to avoid rewarding business-as-usual activities. Fourth, overlap adjustments are necessary where the same system benefit could be captured by both an SO and a TO incentive. Fifth, exceptional events and non-controllable causes must be excluded or treated separately.

The proposed package should therefore be implemented progressively. SO-1 and SO-2 are the most immediately feasible because they rely on existing operational data and can be calibrated through reference prices. SO-3 is also feasible if the definition of qualified aFRR and mFRR balancing capacity is made explicit. TO-1 could be implemented for a limited set of strategic projects with clear target dates and high system value. TO-2 should initially be treated as a pilot mechanism, applied only to verified innovative solutions with measurable benefits. TO-3 would require the most careful calibration, because the reference cost per MW connected must be robust enough to avoid rewarding differences in project type or location.

Overall, the regulatory feasibility of the framework is supported by three elements. First, Spain already has a regulated structure where TO and SO remuneration can be separately identified. Second, the variables proposed in the model are measurable, even if some require stronger reporting and verification. Third, international evidence shows that similar mechanisms can be implemented and can create value, but also that they require careful eligibility rules, consumer protection and periodic redesign. The proposal is therefore feasible as a cautious, capped and auditable incentive layer, not as an automatic or open-ended transfer of system-cost risk to the TSO.

7.3. Risks, limitations and safeguards

The proposed incentive framework presents several risks and limitations that must be considered before any real regulatory implementation. These limitations do not invalidate the approach, but they define the conditions under which the framework could be useful. The main challenge is that the proposed incentives are linked to system-level outcomes, while these outcomes are not fully controlled by the TSO. This is especially relevant for technical constraints, balancing energy, connection costs and project delivery, all of which depend on a combination of TSO decisions, market behaviour, permitting procedures, generation availability, demand evolution, weather conditions and broader regulatory choices.

The first risk is therefore the limited controllability of some variables. Technical constraints and balancing energy are influenced by the SO, but they are also affected by the location of generation, renewable output, demand patterns, outages, market schedules and security criteria. Penalizing the SO too strongly for increases in these variables could be unfair and could create incentives that are inconsistent with secure operation. This is why SO-1 and SO-2 are designed with low sharing factors and explicit caps and floors. The model does not transfer the full cost of redispatch or balancing to the SO; it only introduces a limited signal based on cost proxies.

A second and more important risk is the possibility of distorting secure operation. The SO must always prioritize system security over cost minimization. If an incentive were badly calibrated, it could create pressure to reduce redispatch or balancing actions even when they are technically necessary. This would be unacceptable. For this reason, any real implementation should explicitly exclude actions required for system security from being interpreted as inefficient behaviour. The incentive should reward reductions in avoidable or structurally reducible cost proxies, not discourage operational actions that are necessary to maintain frequency, voltage limits, reserve adequacy or network security.

A third limitation is the attribution problem. Even when an outcome improves, it may be difficult to determine whether the improvement was caused by the TSO, market agents, weather, new generation or storage deployment, demand changes, or regulatory reforms. This is particularly relevant for TO-2, where innovative grid solutions may reduce technical constraints or defer reinforcement, but the measured benefit depends on the assumed counterfactual. A weak counterfactual could overstate benefits and lead to excessive remuneration. A very strict counterfactual, on the other hand, could make the incentive unattractive and reduce its practical usefulness.

This attribution problem also creates a risk of double remuneration. The same system benefit may appear in more than one incentive. For example, an innovative grid solution under TO-2 could reduce technical constraints, while SO-1 also rewards a reduction in the technical-constraint cost proxy. Similarly, a flexible connection solution under TO-3 could reduce congestion or avoid future reinforcement costs. If these benefits are not separated carefully, the TSO could be rewarded twice for the same effect. The overlap adjustment included in the model is therefore not a secondary detail, but a necessary safeguard. In a real implementation, the regulator would need to define a hierarchy of benefits and a clear methodology for allocating benefits between incentives. However, this wouldn't necessarily be a bad design, as, if properly measured, it may serve as an even higher bonus for good synchronisation between SO and TO.

A fourth risk concerns benchmark calibration. The proposed incentives rely on reference prices, reference volumes, target dates, unit costs, and benefit estimates. If these benchmarks are too generous, the TSO could receive rewards without genuine performance improvements. If they are too demanding, the mechanism could become punitive and lose credibility. The historical back-testing partially addresses this issue for SO-1 and SO-2 by using lagged rolling benchmarks, but this is still a simplified regulatory reference, not an optimal target. For TO incentives, benchmark calibration is even more difficult because project delivery, innovative solution benefits, and connection-cost efficiency are project-specific.

This is particularly important for TO-3. A single reference value in €/MW connected is useful for modelling, but a real mechanism would require a more detailed benchmark. Connection costs can vary significantly depending on voltage level, location, type of user, available capacity, environmental restrictions, and whether the connection requires new substations, line reinforcements, or only minor adaptations. If the benchmark is not differentiated, the incentive could reward projects that are naturally cheaper rather than projects that are genuinely more efficient. Therefore, TO-3 would require a robust regulatory database of historical connection costs before implementation.

A fifth risk is gaming. Any incentive based on measured variables can create incentives to influence how variables are reported, classified, or timed. For instance, there could be incentives to shift costs between categories, delay recognition of certain impacts, select projects more likely to generate rewards, or classify actions as innovative even when they are close to business-as-usual. This does not mean that the incentives should not be used, but it shows that eligibility rules must be precise. The regulator should define which actions qualify, what evidence is required, how benefits are verified, and when rewards can be clawed back.

The model also has clear methodological limitations. It is a regulatory-parametric model, not a physical simulation of the transmission network. It does not run an optimal power flow, does not estimate nodal congestion, does not determine the optimal expansion plan, and does not prove causality between TSO decisions and system outcomes. Its purpose is more limited: to test the magnitude, proportionality, and risk profile of a possible incentive package. The results should therefore be interpreted as an assessment of regulatory design, not as a forecast of actual future remuneration.

The Monte Carlo analysis is also limited by design. It is applied mainly to SO-1 and SO-2 because these incentives are based on continuous, historically observable variables. Extending the same stochastic treatment to TO-1, TO-2, TO-3, or SO-3 would require project-level probability distributions that are not available in the model. Introducing such distributions without empirical support would create a false sense of precision. For this reason, the remaining incentives are assessed through deterministic reference inputs, sensitivity analysis, and risk exposure indicators rather than through full probabilistic simulation.

Despite these limitations, the framework includes several safeguards. The first safeguard is partial exposure. The TSO does not receive or pay the full value of the system-cost deviation. Instead, only a small share is transferred through the incentive. This preserves the principle that many system costs are affected by external factors and should remain largely socialized through the regulatory framework. The second safeguard is the use of caps and floors, which limit the maximum reward or penalty and prevent extreme outcomes. This is particularly important for SO incentives, where annual system conditions can vary substantially.

The third safeguard is asymmetric design, where appropriate. Not all incentives should be bidirectional. SO-1, SO-2, and TO-1 can reasonably include both rewards and penalties because they are linked to deviations from defined benchmarks. However, SO-3, TO-2, and TO-3 are better interpreted as mechanisms that encourage additional enabling behaviour: more tertiary balancing capacity, verified innovative solutions, and more efficient connection capacity. Penalizing the TSO for not achieving these outcomes could be difficult to justify, especially where market entry, technology deployment, or user behaviour depend strongly on third parties.

The fourth safeguard is the ex-ante definition of benchmarks, prices, eligible costs, target dates, and caps before the regulatory period. Ex post adjustment should be limited to justified corrections, such as excluding non-controllable delays or correcting double-counted benefits. This is necessary to preserve regulatory credibility. If the regulator changes the benchmark after observing the outcome, the incentive loses its function as an economic signal.

The fifth safeguard is auditability and transparency. Each incentive should be based on data that can be verified by the regulator. For SO incentives, this means clear reporting of technical-constraint energy, balancing energy, and reference prices. For TO-1, it means transparent project milestones and justified delay categories. For TO-2, it means ex post verification of benefits and costs. For TO-3, it means a robust record of connection costs and connected capacity. Without this information, the incentives would be difficult to defend and could increase regulatory disputes.

The final safeguard is periodic recalibration. The energy transition changes the system rapidly. A benchmark that is reasonable in one regulatory period may become obsolete in the next. Reference prices, sharing factors, caps, unit rewards, and eligible technologies should therefore be reviewed periodically. This is not a weakness of the mechanism, but a normal requirement for incentive regulation in a changing system.

Overall, the main limitation of the proposed framework is that it cannot perfectly separate controllable performance from external system conditions. This is a structural problem in incentive regulation for transmission networks. The proposed design addresses it through partial exposure, caps, floors, reference prices, ex ante benchmarks, eligibility rules, overlap adjustments, and differentiated treatment of SO and TO incentives. These safeguards do not eliminate all risks, but they make the framework more proportionate and more compatible with the stability and security objectives of the Spanish regulatory model.

8. Conclusions

8.1. Main findings

This thesis has analysed whether the Spanish remuneration framework for electricity transmission and system operation provides sufficient incentives for the TSO to align its decisions with long-term system efficiency. The analysis has focused on the Spanish case, but the underlying issue is broader: as power systems become more renewable, more electrified, and more dependent on flexibility, the value of transmission is no longer limited to building and maintaining assets. It also depends on how effectively the system integrates renewable generation, manages constraints, enables balancing resources, connects new demand and generation, and uses existing network capacity.

The first finding is that the Spanish framework provides a strong basis in terms of regulatory stability. The remuneration of the Transmission Owner function follows a largely asset-based logic, which supports cost recovery, investment financeability, and long-term planning. This is necessary in a sector where investments are capital-intensive, long-lived, and essential for the security of supply. Therefore, the issue is not that the current framework fails to remunerate the TSO or prevents investment. The issue is that the framework remains mainly input-based, while several relevant system outcomes are only partially reflected in remuneration.

The second finding is that the formal separation between the TO and SO remuneration schemes does not remove the technical interdependence between both functions. Network planning and investment decisions affect future technical constraints, balancing needs, connection capacity, and renewable integration. At the same time, persistent operational costs can reveal structural limitations in the network or insufficient flexibility. This means that the economic signals received by the TO and SO functions should not be analysed in isolation. Even if the remuneration schemes are separated for regulatory and accounting purposes, their effects on system efficiency are connected.

The third finding is that Spain already includes incentive mechanisms, especially for the SO function, but their materiality and cost-reflectiveness are limited. The current SO framework recognizes the relevance of technical constraints, forecasts, response times, ancillary-service participation, and other operational indicators. This is an important step towards performance-based regulation. However, some indicators remain technical proxies rather than direct economic measures of system value, and the size of the incentive layer remains small compared with the magnitude of the system costs that the TSO can influence indirectly. The framework, therefore, contains incentives, but these incentives may not be strong enough to fully align remuneration with system-cost efficiency.

The fourth finding is that a complementary output-based incentive layer can be designed without replacing the existing remuneration model. The proposed package introduces six incentives: SO-1 for technical constraints, SO-2 for balancing energy, SO-3 for mFRR balancing capacity, TO-1 for strategic project delivery, TO-2 for innovative grid solutions, and TO-3 for efficient connection capacity. These mechanisms are not intended to make the TSO responsible for all system costs. Instead, they introduce partial, capped, and measurable signals in areas where the TSO has some degree of influence and where system value can be reasonably approximated.

The quantitative results support this logic. The historical back-testing of SO incentives for 2015–2024 shows that the proposed mechanisms would not have produced a systematic reward. On the contrary, the aggregate historical SO result is negative, around −15.6 M€ over the period, mainly due to the deterioration of technical constraints and balancing-energy indicators relative to the rolling benchmark in recent years. This suggests that the mechanism is performance-sensitive: it rewards improvements relative to the reference and penalizes deterioration, while remaining bounded by caps and floors.

The reference full-package application also shows a differentiated signal. The total incentive package is positive, around +1.69 M€, but this result combines both rewards and penalties. SO-1 penalizes the deterioration in the technical-constraint cost proxy, while SO-2 and SO-3 reward improvements in balancing energy and tertiary balancing capacity. On the TO side, TO-1 penalizes delays in the illustrative portfolio of strategic projects, while TO-2 and TO-3 reward innovative grid solutions and lower unit connection costs. The aggregate result is therefore not a uniform bonus, but the outcome of several mechanisms reacting to different dimensions of performance.

The relative magnitude of the package is also relevant. In the reference application, the total incentive represents approximately 0.10% of the combined TO and SO remuneration base. This is small enough to preserve the stability of the existing regulatory framework, but visible enough to create an additional economic signal. The SO-side incentive is proportionally more relevant because the SO base remuneration is much smaller, while the TO-side incentive remains modest compared with the asset-based remuneration of the transmission activity. This asymmetry is consistent with the objective of adding a limited incentive layer rather than transforming the whole remuneration model.

A further finding is that safeguards are essential. The proposed incentives cannot be implemented as full exposure to system-cost deviations, because many relevant variables are only partially controllable by the TSO. Technical constraints, balancing energy, project delays, and connection costs are affected by external factors such as weather, market behaviour, permitting, generation availability, demand growth, and regulatory decisions. For this reason, the framework requires sharing factors, caps, floors, ex ante benchmarks, justified-delay exclusions, overlap adjustments, and ex post verification of benefits.

Overall, the thesis confirms its initial hypothesis in a complex way. The Spanish remuneration framework is robust in terms of cost recovery, planning, and regulatory stability, but it could be improved by adding a carefully designed output-based layer. Such a layer would not eliminate the RAB-based model or transfer excessive risk to the

TSO. Its role would be more limited: to make selected system-level outcomes more economically visible and to improve the alignment between TSO remuneration and long-term system efficiency.

8.2. Contribution of the thesis

The contribution of this thesis is mainly regulatory and methodological. It does not aim to propose a complete reform of the Spanish transmission remuneration framework, nor to replace the existing planning and asset-based remuneration model. Instead, it provides a structured assessment of where incentive alignment may be incomplete and explores how a complementary incentive layer could improve the connection between TSO remuneration and system-level efficiency.

The first contribution is conceptual. The thesis connects several strands of regulation that are often analysed separately: asset-based remuneration, incentive regulation, the CAPEX-OPEX problem, output-based mechanisms, and the coordination between transmission ownership and system operation. This is relevant because the energy transition makes these dimensions increasingly interdependent. In a system with more renewable generation, storage, electrification, and flexibility needs, the efficiency of the transmission framework cannot be evaluated only by looking at investment recovery. It also requires analysing whether the regulated entity receives signals related to operational costs, flexibility, project delivery, connection capacity, and the use of innovative solutions.

The second contribution is the specific application to the Spanish case. Spain is an especially interesting case because the TO and SO functions are performed within the same corporate entity, but their remuneration is regulated separately. This creates a useful setting to study whether technical coordination is sufficient or whether economic signals may remain fragmented. The thesis shows that the Spanish framework has important strengths, particularly in terms of stability, planning, and cost recovery, but also identifies areas where relevant system outcomes may not be fully internalized in remuneration.

The third contribution is the design of an integrated incentive package for both the SO and TO functions. Rather than proposing isolated mechanisms, the thesis develops six incentives that address different parts of the same problem. The SO incentives focus on technical constraints, balancing energy and balancing capacity. The TO incentives focus on project timing, innovative grid solutions, and connection-cost efficiency. This combined approach is relevant because many system costs cannot be attributed exclusively to either operation or investment. They often arise from the interaction between both.

The fourth contribution is methodological. The thesis develops a regulatory-parametric model that translates the incentive design into a quantitative tool. The model is deliberately transparent and auditable. It does not attempt to simulate power flows or determine the optimal expansion plan. Instead, it allows the proposed incentives to be tested in terms of magnitude, proportionality, sensitivity, and risk exposure. This provides a practical way to evaluate whether an incentive package is large enough to matter, but limited enough to remain compatible with the existing remuneration framework.

The historical back-testing also contributes to the analysis by showing how the SO-side incentives would have behaved under past conditions. This helps avoid presenting the framework only as an abstract proposal. The back-testing indicates that the incentives would have generated both rewards and penalties, depending on the evolution of operational variables relative to the benchmark. The resulting amounts are generally larger than those generated by the current explicit incentive layer, illustrating how stronger system-cost signals could affect SO remuneration. This supports the interpretation of the package as a performance-sensitive mechanism rather than as a guaranteed additional remuneration.

Another contribution is the explicit treatment of risk and safeguards. The thesis does not assume that stronger incentives are always better. On the contrary, it emphasizes the need for partial exposure, caps, floors, ex ante benchmarks, justified-delay exclusions, overlap adjustments, and ex post verification. This is important because transmission regulation must preserve system security, consumer protection, and financial stability. The proposed framework, therefore, aims to improve incentive alignment without moving towards excessive risk transfer.

Finally, the thesis contributes to the Spanish regulatory debate by adapting international regulatory practices to the national context. The UK and French experiences show that regulators are increasingly using incentives linked to delivery, connections, innovation, flexibility, and system-cost reduction. However, these mechanisms cannot be copied directly into Spain. The contribution of this thesis is to translate those principles into a cautious Spanish application, compatible with the existing separation between TO and SO remuneration and with the central role of public network planning.

Overall, the thesis provides a structured framework to think about how TSO remuneration could evolve in a system where efficiency depends not only on building assets, but also on delivering projects on time, enabling flexibility, reducing avoidable system costs, and making better use of the existing network. Its main contribution is therefore not a definitive regulatory formula, but a coherent and quantified proposal for how output-based incentives could complement the current Spanish framework.

8.3. Limitations and further research

This thesis has several limitations that should be acknowledged. The first one is methodological. The model developed in this work is a regulatory-parametric model, not a physical or operational simulation of the transmission network. It does not solve an optimal power flow, does not simulate dispatch, and does not estimate the exact causal impact of each network decision on technical constraints, balancing energy or connection costs. This is consistent with the scope of the thesis, which is regulatory and economic rather than technical-operational, but it means that the results should be interpreted as incentive-design outcomes, not as estimates of the optimal operation or expansion of the Spanish transmission system.

A second limitation is the calibration of the proposed parameters. Sharing factors, caps, reference prices, unit rewards, and benchmark values have been selected to create a coherent and proportionate reference application, but they should not be interpreted as final regulatory values. In a real implementation, these parameters would need to be defined by the regulator using more detailed information, stakeholder consultation, and specific analysis of controllability, consumer impact, and expected system value. This is particularly relevant for TO-2 and TO-3, where the estimation of net benefits and reference connection costs requires detailed project-level data.

A third limitation is the availability of historical information. The historical back-testing is applied to SO-1 and SO-2 because technical-constraint and balancing-energy variables are observable over time. However, the same approach cannot be applied with the same reliability to all incentives. SO-3 would require a consistent historical series of qualified tertiary balancing capacity, while TO-1, TO-2, and TO-3 would require detailed data on project milestones, justified delays, innovative-solution benefits, and connection-cost benchmarks. Without this information, applying a full historical or probabilistic analysis to the whole package would introduce assumptions that may be difficult to justify.

A fourth limitation is the attribution problem. Many of the outcomes considered in the proposed framework are influenced by the TSO, but not fully controlled by it. Technical constraints, balancing energy, delays, connection costs, and flexibility availability also depend on market agents, regulatory decisions, permitting processes, generation availability, weather conditions, and demand evolution. The proposed framework addresses this through partial exposure, caps, floors, and safeguards, but it cannot eliminate the difficulty of separating controllable performance from external system conditions.

Further research could improve the analysis in several directions. The first priority would be to calibrate the proposed incentives using real regulatory and project-level data. For TO-1, this would require information on actual planned and realized commissioning dates, together with justified causes of delay. For TO-2, it would require verified evidence on the costs and benefits of innovative grid solutions. For TO-3, it would require a robust database of connection costs by voltage level, location, type of user, and technical solution.

Another possible line of research would be to apply the framework to a real portfolio of projects from the Spanish transmission planning process. This would make it possible to test the TO incentives using actual planned investments, expected commissioning dates, cost-benefit indicators, and connection needs. It would also allow a more realistic analysis of how incentives on project timing, innovation, and connection efficiency interact with the existing planning framework and investment limits.

Furthermore, an interesting extension would be to combine the regulatory-parametric model with a physical or economic-operational model of the power system. For example, an optimal power flow or redispatch simulation could be used to estimate more directly the value of avoided technical constraints, the impact of grid-enhancing technologies, or the benefits of accelerating specific projects. This would not replace the regulatory analysis, but it would provide a stronger technical basis for calibrating some of the proposed incentives.

Further research could also compare the Spanish case with the observed implementation of recent international reforms. RIIO-ET3 and TURPE 7 HTB both include stronger incentive components related to delivery, connections, innovation, flexibility, and system-cost reduction. As these frameworks are applied, their results could provide useful evidence on which mechanisms create consumer value, which require redesign, and how strong the incentives should be. This would help refine the Spanish proposal and avoid copying mechanisms without considering their actual performance.

Finally, future work should analyse the consumer impact of the proposed framework in greater detail. A stronger incentive layer is only justified if the expected system benefits exceed the additional remuneration paid to the TSO. Therefore, future research should assess not only the remuneration impact on the regulated entity but also the expected savings for consumers, the distribution of risks, and the appropriate balance between incentives, pass-through mechanisms, and regulatory oversight.

In conclusion, this thesis shows that the Spanish TSO remuneration framework could be strengthened through a limited, transparent, and output-based incentive layer. The proposed model is not a final regulatory design, but it provides a structured basis for discussing how remuneration can better reflect system-level efficiency in a changing electricity system. As the role of transmission becomes more central to renewable integration, electrification, and flexibility, incentive alignment will become increasingly important. The challenge for regulation is to create signals that are strong enough to matter, but cautious enough to preserve security, stability, and consumer protection.

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