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Promoting efficiency with neutral operational/capital incentives under uncertainty: A comparison of electricity distribution remuneration schemes

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ABSTRACT

The proliferation of decentralized renewable generation and the electrification of demand require new investment in electricity networks. In this context, combining traditional investment in grid infrastructure with smart-grid solutions is required to minimize consumers' costs. Because electricity distribution is a regulated monopoly, the efficient combination of both solutions critically depends on the incentives embedded in remuneration schemes. This paper formulates a methodology to quantitatively assess how different distribution remuneration schemes: cost of service, revenue cap, and total expenditure with a fixed capitalization rate, impact the investment decisions of a profit-maximizing distribution company. Our results show that the total expenditure scheme with a fixed capitalization rate, despite common belief among actual regulators, leads to cost misallocation, which, when combined with efficiency incentives, creates distortive investment signals. In contrast, the revenue cap scheme, if designed with a sufficiently high incentive rate, not only fosters efficiency but also mitigates the capital-intensive solutions advantage. Furthermore, once efficiency is properly incentivized, adaptable planning can deliver substantial savings and should be prioritized by regulators, following the shift from cost-of-service to revenue cap with profit-sharing schemes.

1. Introduction

Decarbonization of the energy sector involves the proliferation of decentralized renewable generation, and the electrification of energy uses, such as transportation, heating and cooling, and industrial processes. This requires renovation and new investment in electricity distribution networks [1].

In this context, the combination of traditional investment in grid infrastructure with smart grid solutions is required to minimize consumer costs [2]. The uptake of new technologies, such as digitalization and the integration of more distributed energy resources (DER) into distribution networks, presents new challenges and opportunities in network planning and operation. Investments in traditional grid infrastructure, including power transformers and lines, remain necessary. However, smart grid solutions offer new competitive alternatives to find optimal investment plans [3]. These solutions include the acquisition of flexibility[1] from DER through flexible connection agreements, local flexibility markets, or bilateral contracts, as well as network reconfiguration [5], among others. Smart grid flexibility solutions can be leveraged to defer traditional network reinforcement. They can also accelerate connections of new users by improving the utilization of existing network infrastructure [6]. Electricity distribution is a regulated natural monopoly, and as acknowledged by the Council of European Energy Regulators (CEER) [7]: "The distribution system operator's (DSO's) decisions when planning, expanding and managing their networks are led by the incentives in the revenue/remuneration regime and direct regulatory requirements." So, the use of smart grid flexibility solutions by DSOs will depend on the incentives present in their remuneration scheme. Thus, regulatory frameworks and, in particular, remuneration schemes should be revisited to ensure they incentivize optimal planning through a combination of smart-grid flexibility

Abbreviations: ARR, Allowed rate of return; CAPEX, Capital expenditure; CC, Cost of capital; CEER, Council of European Energy Regulators; CoS, Cost-of-service; DER, Distributed energy resources; DSO, Distribution system operator; ESO, electricity system operator; EV, Electric vehicle; IR, Incentive rate; LDC, Load duration curve MSC: Minimum system cost; OPEX, Operational expenditure; RAB, Regulated asset base; R&D, Research and development; TOTEX, Total expenditure; UK, United Kingdom; VoLL, Value of lost load.

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[1] Flexibility may be defined as "the modification of generation injection and/or consumption patterns in reaction to an external signal (price signal or activation) in order to provide a service within the energy system" [4].

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Nomenclature

Notation

Sets:

b	forecasted base scenarios without noise $\{1, \ldots, B\}$.
h	hours in the year $\{1, \ldots, 8760\}$.
s	forecasted scenarios with added noise $\{1, \ldots, S\}$.
t, a	years in the planning period $\{1, \ldots, T\}$.

Parameters:

ARR	allowed rate of return set by the regulator (%).
CC	actual cost of capital of the distribution company (%).
CR	capitalization rate under the TOTEX approach (%).
ENS_t^{ref}	reference for energy not served set by the regulator for the quality incentive (€).
$F_{s,t}^{act}$	amount of flexibility to activate in scenario s and year t (MWh).
$F_{s,t}^{res}$	amount of flexible energy to reserve in scenario s and year t (MWh).
FLT	lead time for flexibility (years).
$\mathrm{FR}^{\mathrm{Cost}}$	flexibility reserve cost (€/MW/h).
$\mathrm{FU}^{\mathrm{Cost}}$	flexibility utilization cost (€/MWh).
G^{inv}	investment required for grid reinforcement (€).
G^{ul}	useful life of the grid reinforcement (years).
IR	incentive rate for the profit-sharing calculation (%).
OM^{cost}	Annual operation and maintenance cost of the grid asset (€).
Pr_s	probability of scenario s (%).
R^{ul}	useful life of the slow money under the TOTEX approach (years).
RT_t	revenue trajectory set by regulator under revenue cap approach (€).
RT_t^{TOTEX}	revenue trajectory set by regulator under TOTEX approach (€).
$VoLL$	value of lost load (€/MWh).

Variables:

$dep_{s,t}$	depreciation cost in scenario s and year t (€).
$dep_{s,t}^{TOTEX}$	depreciation cost under TOTEX capitalization rules in scenario s and year t (€).
$ens_{s,t}$	energy not served in scenario s and year t (MWh).
$\mathrm{f}_{s,t}^{act}$	flexibility to activate in scenario s and year t (MWh).
$f_{s,t}^{res}$	flexibility to activate in scenario s and year t (MWh).
$fm_{s,t}$	value of fast money in scenario s and year t (€).
$g_{s,t}$	binary variable equal to 1 if grid reinforcement is in operation at year t and scenario s, 0 otherwise.
$i_{s,t}^{G}$	binary variable equal to 1 if a grid reinforcement becomes operational sometime during year t in scenario s; 0 otherwise.
$psi_{s,t}$	profit sharing incentive resulting in scenario s and year t (€).
$r_{s,t}^{F}$	binary variable equal to 1 if flexibility is reserved for scenario s and year t, 0 otherwise.
$rab_{s,t}$	value of the regulated asset base at the beginning of year t in scenario s (€).
$rab_{s,t}^{TOTEX}$	value of the regulated asset base under TOTEX capitalization rules at the beginning of year t in scenario s (€).
$sm_{s,t}$	value slow money in scenario s and year t (€).
$totex_{s,t}$	total expenditure, investments (i.e., CAPEX) plus OPEX, in scenario s and year t.

Additional Parameters (used in the Annex):

ENS_t^{ref}	reference for energy not served set by the regulator for the quality incentive (MWh).
$ENS_{s,t}^{0}$	energy not served without any intervention to solve grid problems at scenario s and year t (MWh).
$ENS_{s,t}^{F}$	energy not served if flexibility is reserved at scenario s and year t (MWh).
$ENS_{s,t}^{G}$	energy not served if grid is reinforced at scenario s and year t (MWh).
FLT	lead time for flexibility. (years).
GLT	lead time for grid reinforcement. (years).
M	a large numerical value with the purpose of relaxing the constraint.
$P_{s,t}$	actual peak load in scenario s and year t (MW).
$\in$	a small numerical value with the purpose of avoiding strict inequalities when formulating constraints.

Additional Variables (used in the Annex):

$\delta_{s,t}$	1 if no intervention is made, 0 if either grid is reinforced or flexibility is reserved for scenario s and year t.
f^1	1 if flexibility is reserved at year 1 for all scenarios s, 0 otherwise.
i^1	1 if decided to invest in grid reinforcement at year 1 for all scenarios s,0 otherwise.
$r_{s,t}^{F}$	1 if flexibility is reserved for scenario s and year t, 0 otherwise.
tr^F	trigger level for reserving flexibility (MW).
tr^G	trigger level for investment in grid reinforcement (MW).
$tr_{s,t}^{G-act}$	1 if peak load in scenario s' and year (t-1) reaches or surpasses the grid reinforcement trigger; 0 otherwise.

solutions and traditional grid investment [8].

Flexibility solutions, as a planning alternative to defer grid investment, offer the most value when uncertainty is considered in the planning scenarios and adaptable wait-and-see strategies (i.e., real options approach) are used [9]. This is especially important in the current context characterized by high uncertainty about the growth rate of electricity demand [10]. There is a risk of overinvestment in grid assets, leading to higher tariffs if lower-demand scenarios materialize. Conversely, underinvestment may result in congested grids and delayed connections for new users if higher demand scenarios materialize. There is a need for regulatory frameworks to evolve from deterministic investment analysis towards a probabilistic approach with adaptable strategies [9]. However, the expected benefit of enabling adaptable planning in a particular regulatory framework may vary depending on the actual remuneration scheme. This leads to the first research question addressed in this article: *What is the value of enabling adaptable planning under different remuneration schemes?*

Moreover, smart grid flexibility solutions mainly represent an operational expenditure (OPEX) for DSOs. For instance, an annual contract with an industrial consumer to procure reductions in consumption during peak network utilization periods announced by the DSO. On the other hand, grid investments in distribution feeders or power transformers represent a capital expenditure (CAPEX) for DSOs. Both researchers [11,12,13,14] and regulatory bodies like Ofgem [15], CEER [16], and the Danish utility regulator [17] have emphasized the importance of establishing neutral OPEX/CAPEX incentives in DSO remuneration schemes. Incentive neutrality aims to promote overall system efficiency and remove barriers for innovative smart grid flexibility solutions.

The DSO remuneration schemes that set the DSO's allowed revenues for a regulatory period of several years can be classified into ex-ante or ex-post approaches. The ex-post approach, also known as cost-of-service, presents a potential moral hazard, as DSOs are not encouraged to pursue cost efficiencies. That may result in high costs for network users [18]. The ex-ante approach, which sets a trajectory for the allowed revenues over the regulatory period, i.e., a multi-year revenue trajectory, encourages DSOs to pursue cost efficiency [11]. However, establishing an ex-ante revenue trajectory is not straightforward, as regulators face the challenge of information asymmetry. The ex-ante revenue trajectory may underestimate the distribution company's cost-saving opportunities, leading to allocative inefficiency and rent extraction by the DSO. This is known as the adverse selection problem [18].

A recommended approach is to combine both approaches, resulting in an ex-ante approach with an ex-post profit-sharing mechanism [18]. This multi-year revenue trajectory, with a profit-sharing mechanism, incentivizes the DSO to pursue cost efficiency while sharing some of the savings with network users [19]. In this paper, this scheme is referred to as a revenue cap. Still, this approach may present a bias toward CAPEX solutions because investments are capitalized and remunerated over time with an attractive rate of return, while this attractive rate of return does not apply to OPEX. This issue raises the second addressed research question: *To what extent does a CAPEX advantage create inefficient investment signals under a revenue cap scheme?*

A widely accepted practice among regulators, believed to achieve incentive neutrality, is the implementation of a fixed capitalization rate[2] that affects both CAPEX and OPEX. This remuneration scheme is known as the total expenditure (TOTEX) approach. However, this widespread acceptance relies on conceptual appeal rather than on quantitative evidence. As a consequence, the third fundamental question is posed: *Does the TOTEX scheme, with a fixed capitalization rate, truly achieve CAPEX/OPEX neutrality in practice?*

There is a need for a quantitative assessment of the actual incentives provided by the three remuneration schemes previously presented. This assessment should focus on how these schemes influence DSOs when planning investments in the distribution network. The analysis must consider the competitive context and synergies between smart grid flexibility and traditional grid solutions, as well as the significant uncertainty in load growth associated with decarbonization planning scenarios.

This paper develops a methodology to quantitatively assess how three distribution remuneration schemes influence the investment decisions of a profit-maximizing DSO. The first is the cost-of-service approach, representing the most common traditional regulatory model. The second is the revenue cap approach, reflecting a modern, incentive-based framework. The third is the TOTEX approach with a fixed capitalization rate, an innovative approach designed to promote incentive neutrality. Each remuneration scheme is formulated mathematically as a stochastic optimization model, with the decision variables representing the planning decisions regarding the use and timing of the network planning solutions. The objective function represents a DSO that maximizes profit, subject to network constraints (the physical representation of the system), planning constraints (including lead time for the different interventions), and regulatory constraints (representing the remuneration scheme).

These three formulations are applied to an illustrative case study involving a congested substation that requires a combination of planning solutions. OPEX solutions based on flexibility contracts for peak load reduction compete with CAPEX solutions involving grid reinforcement, i.e., in a new feeder. The results show that the TOTEX with a fixed capitalization rate scheme, despite common belief among regulators, leads to cost misallocation. A cost misallocation which, when combined with efficiency incentives, creates distortive investment signals. In contrast, the revenue cap scheme, if designed with a sufficiently high incentive rate, not only fosters efficiency but also mitigates the CAPEX-intensive solutions advantage. Furthermore, once efficiency is properly incentivized, adaptable planning can deliver substantial savings and should be prioritized by regulators, following the shift from a cost-of-service approach to a revenue cap with profit-sharing.

The main contributions of the paper can be summarized as follows:

- This paper presents three mathematical formulations portraying stylized versions of three DSO remuneration schemes: cost-of-service, revenue cap, and TOTEX with a fixed capitalization rate to evaluate the economic incentives for DSO's planning investment decisions.
- The presented models integrate adaptable planning in the study of remuneration schemes. This integration provides valuable insights for regulators.
- These models allow for quantitatively assessing the effect of an allowed rate of return higher than the DSO's actual cost of capital (a source of CAPEX bias) and the potential cost savings associated with allowing adaptable planning under each remuneration scheme. These models and potential adaptations may serve as tools to help regulators establish priorities for the evolution of remuneration schemes.
- Results obtained in a representative case study show that:
  - The cost-of-service remuneration scheme disincentivizes DSOs from adopting flexibility solutions, hindering potential cost savings for the system.
  - On the other hand, the revenue cap remuneration scheme results in network plans close to minimum system costs with a small bias toward CAPEX grid investment solutions. The CAPEX advantage results in no major inefficiencies, except when the incentive rate is set at low levels, as shown in the case study with a 30% incentive rate.
  - Despite current overrating by regulators, the TOTEX with a fixed capitalization rate scheme misallocates costs and structurally favors short-term, OPEX-intensive solutions over long-term, CAPEX solutions. This results in inefficient outcomes despite its theoretical appeal.
  - The study finds that adaptable planning has the potential to bring additional efficiencies in a context characterized by high uncertainty about future demand growth and the availability of smart grid flexibility solutions. Enabling adaptable planning would bring significant efficiencies under schemes with incentives for overall efficiency, such as revenue-cap and TOTEX approaches, and only minor efficiencies under the cost-of-service approach.

This paper is organized as follows. Section 2 reviews previous studies on DSO remuneration focused on neutralizing OPEX/CAPEX incentives and adaptable planning. Section 3 presents the methodology of this study, including the mathematical formulation for stylized versions of three remuneration schemes (i.e., cost-of-service, revenue cap, and TOTEX). Section 4 describes the case study to test the proposed methodology. Section 5 presents the case study results and discusses regulatory recommendations derived from them. Finally, Section 6 summarizes the articlés conclusions and indicates future research lines.

2. State of the art

This section provides the background on two key topics for regulating electricity distribution in the current context, characterized by high uncertainty and the increasing availability of smart grid solutions as alternatives or complements to traditional grid investment. First, on

[2] Under TOTEX approach, the regulator fixes a capitalization rate for the regulatory period that affects both CAPEX and OPEX. The capitalization rate is the portion of expenditures that are capitalized (i.e., included in the regulatory asset base) and remunerated over time with the rate of return. This fixed capitalization rate is also known as fixed OPEX/CAPEX share abbreviated as FOCS.

establishing neutral OPEX/CAPEX incentives in DSO remuneration schemes, and second, on using adaptable investment strategies for dealing with uncertainty.

Different studies addressing the regulatory challenges for distribution networks have highlighted, among other issues, the need to address these two topics. The Massachusetts Institute of Technology (MIT) [11] presented a report covering a wide range of topics, including recommended regulatory, policy, and market reforms to address current and future challenges in the power system. Regarding the challenges in electricity distribution regulation, it highlights the need to address increasing uncertainty, establish neutral OPEX/CAPEX incentives, and incentivize innovation, among other topics. Bovera et al. [12] proposed an approach to regulate electricity distribution that applies a fixed OPEX/CAPEX share (i.e., fixed capitalization rate) and an incentive based on expenditure reduction compared to the expenditure baseline, among other regulatory tools. Bovera et al. [12] agreed with MIT [11] in highlighting the need to address increasing uncertainty and establish neutral OPEX/CAPEX incentives in the regulation of electricity distribution. Anaya and Pollitt [13] presented a study that identified regulatory changes needed to incentivize distribution utilities to use flexibility. The recommendations are based on a questionnaire sent to DSOs, regulators, and experts in the field from seven countries. Regarding DSO remuneration, the study highlights that some jurisdictions, such as Germany and the Netherlands, should improve their remuneration schemes to promote flexibility when cost-efficient. Jenkins and Pérez-Arriaga [14] presented a complete set of recommendations for evolving the remuneration schemes of electricity distribution. The study highlights the need to incentivize efficiency with neutral OPEX/CAPEX incentives, introduce mechanisms to manage uncertainty, and promote long-term innovation along with output-based incentives. Sections 2.1 and 2.2 highlight the need for a quantitative assessment to make regulatory recommendations.

2.1. Establishing neutral OPEX/CAPEX incentives

The CAPEX bias in regulated monopolies has been discussed by researchers and regulatory agencies for several years. The CAPEX bias is the incentive present in remuneration schemes to favor CAPEX-intensive solutions over OPEX solutions. Smart grid solutions are becoming increasingly relevant in electricity distribution networks. One example is the procurement of local flexibility, which is mainly an OPEX. This trend has raised the need to neutralize incentives between CAPEX and OPEX. Doing so is essential to achieving overall cost efficiency and removing barriers to innovative solutions, thereby supporting the evolution of power systems. As described by the Council of European Energy Regulators (CEER) [16], the CAPEX bias has different sources. Next, the hybrid regulatory framework and the CAPEX advantage, as sources of CAPEX bias, are discussed based on current literature.

The first source of bias emerges when different regulatory approaches are applied to OPEX and CAPEX. This is commonly referred to as a hybrid regulatory framework. Ex-ante frameworks have typically been applied to OPEX, while CAPEX is covered under an ex-post (i.e., cost-of-service) approach [18], and this is still the case nowadays in some countries (e.g., France, Italy, and Sweden) [20]. This asymmetry creates a bias in favor of CAPEX-intensive solutions, as cost-efficiency incentives apply only to OPEX. Consequently, a DSO is discouraged from pursuing cost-effective OPEX alternatives such as procuring flexibility to defer network reinforcement. The DSO would be penalized in two ways when choosing the OPEX alternative, as reducing CAPEX (i.e., deferring network reinforcement) would decrease the regulated asset base and, therefore, the companýs returns or profits [11]. Moreover, increasing OPEX (i.e., procuring flexibility) would reduce the companýs returns because the efficiency incentive is applied only to OPEX, even if the overall system cost is reduced.

The second source of bias is the CAPEX-advantage, which has been widely discussed. This effect, first noted by Averch & Johnson [21], is a result of the difference between the allowed rate of return set by the regulator and the actual cost of capital of the regulated company under cost-of-service regulations. This spread creates an incentive to overinvest. The rate of return is ideally set equal to the company's actual cost of capital, thereby allowing the DSO to attract private investment necessary to finance infrastructure. However, establishing the allowed rate of return equal to the distribution companýs actual cost of capital is difficult for regulators due to information asymmetry and lack of publicly traded unbundled DSOs for comparison, as noted by CEER [16].

The effect of the CAPEX advantage bias is mitigated in ex-ante regulatory approaches compared to cost-of-service approaches, because the incentive rate rewards cost-efficiency, while the CAPEX advantage favors CAPEX-intensive solutions. Jamasb [22] pointed out that a sufficiently high rate of return may provide an incentive to overinvest that offsets the efficiency incentive set by the incentive rate. This is the case when the profit from a CAPEX solution, due to the spread between the allowed rate of return and the cost of capital, exceeds the portion of savings that the DSO is allowed to keep as profit with the OPEX solution.

To address the CAPEX advantage that persists even in ex-ante regulatory frameworks, Ofgem introduced the TOTEX (total expenditure) approach [15]. TOTEX is the sum of fast money (expenditures remunerated in the year they are incurred, similar to OPEX) and slow money (expenditures that are capitalized and remunerated over time through depreciation and a return on capital, as traditionally with CAPEX). The regulator sets a fixed capitalization rate ex-ante for the entire regulatory period. The capitalization rate is the portion of expenditures that is capitalized (i.e., considered slow money), therefore added to the regulated asset base (RAB), regardless of whether they are investments or OPEX. This approach is widely accepted by researchers of the aforementioned studies [11,12,13,14] and regulatory bodies like Ofgem [15], CEER [16] and the Danish utility regulator [17], as a proper way to establish neutral OPEX/CAPEX incentives. Nevertheless, despite this consensus, the discussions on incentive neutrality remain conceptual. Therefore, it is necessary to conduct a quantitative analysis to verify whether the TOTEX approach truly delivers incentive neutrality between CAPEX and OPEX.

The CAPEX advantage comes from the asymmetry of information that regulators face when establishing the allowed rate of return for distribution companies. Joskow [19] highlights the complex implementation and evaluation of price caps in a practical setting, as well as the need to consider the asymmetry of information that regulators face. Therefore, when addressing the OPEX/CAPEX neutrality issue, it is essential to consider the CAPEX advantage. Still, there is no systematic quantitative analysis of the extent of this bias under different regulatory frameworks. This study addresses this gap by evaluating the impact of CAPEX advantage on cost-of-service, revenue cap, and TOTEX schemes under large demand uncertainty, thereby providing evidence-based insights to enhance regulatory design.

Next, some relevant empirical and model-based studies that conduct quantitative assessments of incentives in regulatory frameworks are detailed, and the gap that this study covers is identified.

Joskow [19] also noted that there is little systematic analysis of the effect of different incentive regulation schemes in the distribution network based on empirical evidence (to the best of our knowledge, none of them focused on the OPEX/CAPEX neutrality issue), while there are more of these studies in the telecommunication industry (another regulated sector). An empirical study of the U.S. telecommunications industry [23] found that price-cap regulation promotes an efficient combination of OPEX and CAPEX. This would suggest that the CAPEX bias due to the CAPEX advantage in this regulatory environment is negligible. Regarding electricity distribution, it remains necessary to quantitatively assess whether revenue-cap schemes exhibit a significant CAPEX bias and to verify if TOTEX frameworks truly provide neutral incentives between OPEX and CAPEX.

Regarding quantitative assessments based on models, Vilaplana et al. [24] uses system dynamics to assess investments in the distribution network based on historical data of the Portuguese distribution system, the study suggests that mature digital technologies, allowing a more active role of the DSO, are properly incentivized when compared to traditional investment under the current regulatory framework in Portugal, which includes a revenue cap scheme, benefiting both network users and DSOs. The study suggests that immature digital technologies may be unattractive to DSOs; this may highlight the need to promote innovation. The study does not address the OPEX/CAPEX neutrality issue, but it highlights the need to evaluate how changes in the regulatory framework may affect the DSO decisions.

Few studies model a regulatory framework to study the incentives for DSOs. As mentioned before, it is relevant to consider a DSO maximizing profits under a specific regulatory framework to evaluate how incentives may affect DSO investment decisions. Siano [25] modeled optimal wind turbine location from both the DSO and the developer perspectives. The DSO model considers some incentives (i.e., incentive to reduce losses, innovation incentive, and incentive to connect DG). Huang and Söder [26] studied the performance of various incentives in distribution network investment. The study conducts a quantitative analysis of the impact of the load-factor incentive and power-loss reduction incentive present in the Swedish regulatory framework. A profit-maximizing DSO operating under a revenue cap regime was considered.

To the best of our knowledge, there is no study that quantitatively analyzes the investment decisions of a profit-maximizing DSO under different regulatory approaches (e.g., cost-of-service, revenue cap, TOTEX), nor is there any quantitative study that explicitly examines how the CAPEX advantage affects the DSO decisions across these regulatory frameworks.

In conclusion, there is a lack of quantitative analysis regarding the OPEX/CAPEX neutrality issue. This paper proposes a methodology and a case study to address this gap. The consensus among prior studies indicates the theoretical ability of the TOTEX approach to ensure OPEX/CAPEX incentive neutrality. However, no previous studies provided quantitative evidence of this incentive neutrality. This paper provides quantitative evidence of how TOTEX frameworks influence OPEX/CAPEX incentives by introducing a structural OPEX bias.

2.2. Dealing with uncertainty: Adaptable investment strategies

DSOs face significant operational and planning challenges due to the increase in intermittent renewable generation and the penetration of distributed energy resources. Different European countries have already experienced congestions in distribution networks [27]. Germany is already noticing this effect, increasingly facing congestions due to generation peaks in wind farms. At the same time, the Netherlands is also experiencing congestions due to peaks from renewable generation and increasing loads from data centers. Norway is experiencing an increasing penetration of electric vehicles (EVs) and associated congestions due to EV charging. The United Kingdom is facing congestions mainly due to renewable generation and EVs. While congestions in distribution grids in some other countries are not yet a relevant issue, congestions are likely to occur due to the increasing penetration of renewables and distributed energy resources (DERs). This may compromise the distribution network's hosting capacity, delaying grid connections or limiting the operation of existing resources [28].

However, the uptake pace of new technologies (i.e., penetration of EVs and other DERs) is uncertain, as noted by network planners such as the UK electricity system operator, National Grid (ESO). Their annual report includes projections for peak electricity demand in the United Kingdom up to 2050 [29]. Among the scenarios projected by National Grid in the UK, there are different paths to achieving net-zero objectives and even the possibility of not reaching them by 2050. Likewise, Moberg [30] shows how sparse the forecasts of electricity demand by 2045 in Sweden are, with predictions from various institutions ranging between a minimum of 16% [31] to a maximum of 125% [32] increase in electricity demand.

Network reinforcements usually occur in discrete steps requiring substantial upfront investments in response to gradual demand growth. This often results in idle grid assets for long periods in anticipation of a demand that will eventually increase [33]. In this context, characterized by large uncertainty regarding the penetration of distributed energy resources (DERs) in the coming years, it is important to consider two possible scenarios. If the demand growth materializes at the lower end of the forecasted scenarios, while network plans are prepared for the highest growth conditions, this may negatively impact system costs as a large share of assets may remain idle [10]. Conversely, a lack of investments may delay connections if demand growth materializes at the higher end. This is why the combination of flexibility solutions with adaptable investment strategies is particularly valuable, as they enable DSOs to maintain high service levels, deferring the need to invest in traditional grid reinforcements until the need for reinforcement is confirmed, depending on the observed demand growth [34].

Considering flexibility solutions as a temporary alternative to investments in the distribution network is a common practice under some regulatory frameworks, such as the UK, while some other countries, like Spain and Italy, are still adapting their regulatory frameworks [20].

Previous research has shown that the cost-saving potential of flexibility services increases when uncertainty is explicitly modeled and adaptable investment strategies are adopted [9]. Unlike traditional investment plans, adaptable strategies based on the real options framework allow investment decisions to be dynamically adjusted as new information unfolds throughout the planning period [9,35].

Schachter et al. presented a real options approach for distribution network planning in [9]. This study implements a decision rule based on a trigger for the grid investment decision. Instead of deciding the year for grid reinforcement, a trigger level is fixed (e.g., 58 MW), and the timing of the investment decision depends on the evolution of the peak load throughout the years. Whenever the observed peak load surpasses this trigger level, the decision to invest in grid reinforcement is made. This methodology results in adaptable plans that are particularly beneficial for planning under uncertainty.

In [9], the trigger level was established deterministically based on the best-view scenario. The work presented in [35] extends the work of [9] by including the trigger as a variable in an optimization model for the minimum-cost network plan. The decision to reserve flexibility is also based on a trigger rule that is optimized in the same model.

This paper extends and builds upon the work in [35]. Adding the consideration of the remuneration scheme and a profit-maximizing DSO, along with adaptable planning based on triggers. The results of a case study enable us to draw conclusions about current regulatory approaches. They also provide insights into potential future developments.

To the best of our knowledge, no prior study assessed the potential cost savings from allowing adaptable investment strategies under different regulatory frameworks (cost-of-service, revenue cap, and TOTEX). This study fills this gap through a methodology and a case study.

3. Methodology

This paper presents a methodology to evaluate the network planning decisions made by a profit-maximizing DSO under a particular remuneration scheme.

The methodology considers a DSO planning tool to solve potential grid problems (e.g., congestion) during a planning horizon of several years in a specific region of the distribution network. The methodology assumes a single-node capacity-limited network model, which is a reasonable assumption for the purpose of this study. The potential solutions include traditional grid reinforcements (e.g., building a new feeder or transformer) and flexibility solutions (e.g., contracting services with flexibility providers that commit to reducing a certain amount of load within a specific timeframe upon receiving an activation signal from the DSO). A combination of both solutions is also possible. Fig. 1

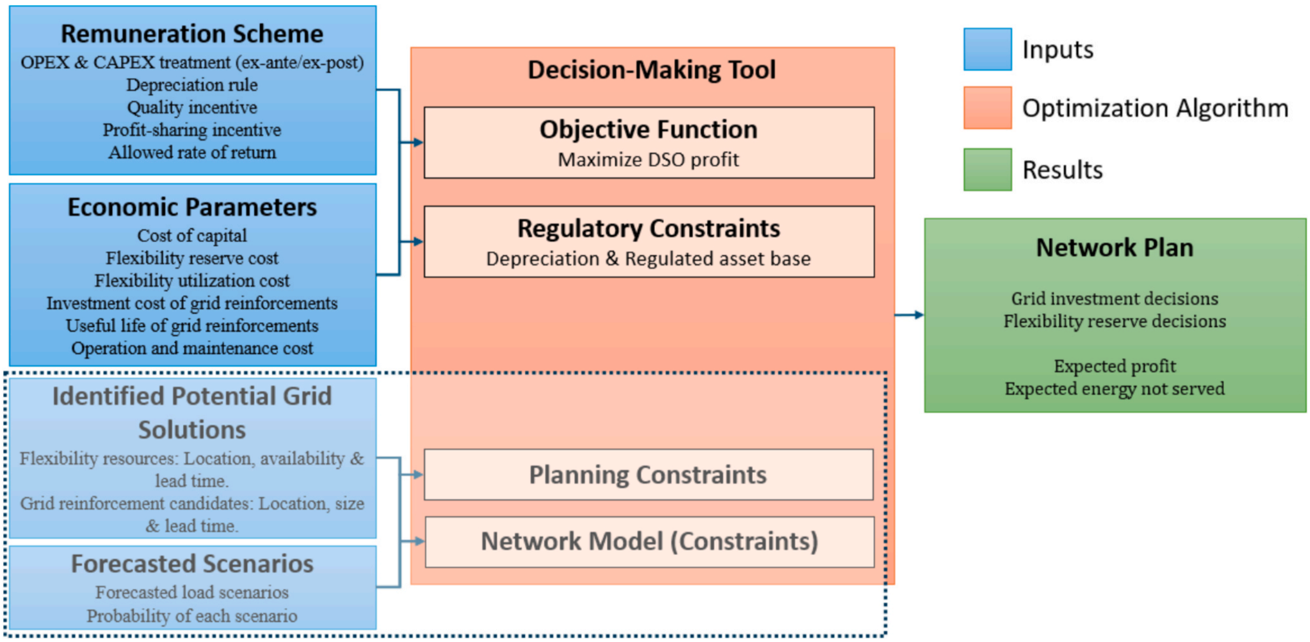

Fig. 1. Methodology summary.

summarizes the proposed methodology.

The remuneration scheme is an input that defines how the DSO recovers its incurred costs (i.e., through the allowed rate of return, depreciation rules, and the treatment of OPEX and CAPEX with ex-ante or ex-post approaches). The scheme includes various incentives (e.g., quality incentives and profit-sharing mechanisms). These elements are essential for calculating the DSO's profit. Under a well-designed remuneration scheme, the network development plan of a profit-maximizing DSO should ideally align with the minimum-cost network development plan.

The methodology includes various economic parameters as inputs (i.e., cost of capital, flexibility costs, investment costs for grid reinforcements, useful life of grid reinforcements, operation and maintenance costs). These parameters are necessary to calculate the DSO's actual costs under each remuneration scheme based on the planning decisions during the planning period.

The identified potential grid solutions are also an input to the model. These include information on the reinforcement candidates (i.e., a new feeder or transformer), such as the location, size, investment cost, and lead time. The candidate solutions also include flexibility resources, with their location, their availability, procurement cost, and lead time. Finally, the forecasted scenarios are also an input to the stochastic optimization model; they capture the uncertainty about the evolution of load during the planning period.

The objective function of the decision-making tool maximizes the DSO's profit, according to the remuneration scheme considered, which determines the DSO's allowed revenues. This objective function considers how OPEX and CAPEX are recovered, as well as any incentives in the remuneration scheme (e.g., a profit-sharing mechanism, a quality incentive, etc.). The calculation includes the incentive resulting from the CAPEX-advantage (i.e., the difference between the allowed rate of return set by the regulator and the actual cost of capital of the DSO). If the regulator sets an allowed rate of return below the cost of capital of the distribution company, this will discourage investment. This would not be desirable for a critical infrastructure, such as the distribution network. On the contrary, if the allowed rate of return is set above the cost of capital of the distribution company, it would create an incentive to overinvest in network assets.

The regulatory constraints calculate different concepts used by regulation to remunerate the DSO (e.g., regulated asset base, depreciation, fast money, slow money, etc.). This calculation derives from the decisions made by the DSO during the planning period (e.g., investing in a new feeder or contracting flexibility with a provider).

In particular, this study implemented the methodology for three distinct remuneration schemes: the Cost-of-Service (CoS) approach, the revenue cap, and the TOTEX approach. Each scheme is modeled by three different elements: the treatment of OPEX and CAPEX, the quality incentive, and, if applicable, a profit-sharing mechanism. These models are described in Section 3.1. The objective function and the regulatory constraints for each remuneration scheme are detailed in the problem formulation, see Section 3.2.

The planning constraints capture the scenario and time interdependencies according to the planning approach (single/multi-scenario, single/multi-stage, adaptable or static decisions). For a brief discussion on the different planning approaches, please see [35]. Adaptable planning is an investment plan defined by specific decision rules (e.g., invest in a new transformer whenever the peak load reaches 40 MW) that result in investment decisions according to the unfolding information in each scenario during the planning period. Consequently, faster load-growth scenarios result in earlier investments than scenarios with slower load-growth. In contrast, static decisions are fixed in time (i.e., invest in a new transformer in year 3), resulting in the same decision for all scenarios. The planning constraints consider the lead time of planning actions (e.g., the time between the investment decision and the commissioning of the reinforcement) and the irreversibility of reinforcements.

The network model ensures that the physical and operational limits of the power grid are respected and calculates quality-of-service indicators (e.g., energy not served) based on the adopted grid solution in each unfolding load scenario. The complexity and detail of these constraints may vary, encompassing single-node or multi-node models, capacity limit models, AC power flows, or DC power flows. The methodology in this paper assumes a simple network model (i.e., a single node with a capacity limit) and a single investment candidate; however, the methodology may be extended to consider more complex network models.

Both the planning constraints and the network modeling constraints are shaded and grouped by a dotted line in Fig. 1 because they are not the focus of this paper and are not included in this section; the details of the constraints used for the case study are provided in the Annex, explaining their rationale.

The output of the decision-making tool is the network plan, which describes the decisions made by the DSO, such as the expected timing of the planned reinforcements, the expected use of flexibility, and the outputs or performance of this plan, such as the expected profit and the expected energy not served over the years of the planning period.

3.1. Remuneration schemes

This methodology considers three remuneration schemes that are typically present in different countries. The cost-of-service (CoS), the revenue cap, and the TOTEX.

The three models presented here include a quality incentive. This is a common practice in most remuneration schemes and crucial in frameworks that promote productive efficiency, such as the revenue cap and the TOTEX approaches. Otherwise, cost-efficiency incentives may lead to a deterioration of service quality.

Next, there is a description of the three approaches considered, and Section 3.2 presents their mathematical formulations.

3.1.1. Cost-of-service

Under the CoS, an ex-post approach, the distribution company is allowed to recover the costs incurred in carrying out its activities. A rate of return is set by the regulator to ensure the recovery of costs derived from capital expenditures.

The cost-of-service regulatory approach modeled in this methodology applies to both OPEX and CAPEX (i.e., a non-hybrid remuneration scheme). The profit that the DSO maximizes comes from the quality incentive and the difference between the regulated rate of return and the distribution companýs actual cost of capital.

3.1.2. Revenue cap

Under the revenue cap with a profit-sharing mechanism, the allowed revenue for year t, AR_t, is a weighted average of two values: the value of the revenue trajectory in year t, RT_t, established by the regulator ex-ante, and the DSO actual costs recognized by the regulator ex-post in year t, AC_t. The weight given to the ex-ante trajectory is the incentive rate, IR. See Equation (1).

$$AR_t = IR^*RT_t^* + (1 - IR)^*AC_t = AC_t + IR^*(RT_t - AC_t) \quad (1)$$

Fig. 2 illustrates the calculation of the incentive under the revenue cap approach with a profit-sharing mechanism. When the DSO's actual costs fall below the ex-ante reference established by the regulator, the DSO may retain a percentage of this difference as profit; this percentage is known as the incentive rate. In Fig. 2, the green-shaded area represents the incentive. It equals 60% (assuming a 60% incentive rate) of the gap between the multi-year revenue trajectory (dark blue line) and the DSO's actual costs (the orange line).

The allowed revenue, AR_t, equals the sum of the DSO's actual costs, AC_t, and the incentive from profit-sharing, $IR^*(RT_t^*AC_t)$, as shown in Equation (1). If actual costs exceed the revenue trajectory, the profit-sharing mechanism results in a penalty for the DSO.

3.1.3. TOTEX

The TOTEX approach shares similarities with the revenue cap approach, as both involve the regulator setting a multi-year revenue trajectory complemented by a profit-sharing mechanism. Its distinctive feature is a fixed capitalization rate applied to all DSO expenditures, whether CAPEX or OPEX. This mechanism aims to eliminate the CAPEX-bias, more specifically the CAPEX-advantage, present in traditional remuneration schemes. By this equal treatment of OPEX and CAPEX, the TOTEX approach intends to encourage more economically efficient and unbiased decisions.

Fig. 3 illustrates the fixed capitalization effect under the TOTEX approach and how this mechanism affects the actual costs recognized by the regulator. This is not meant to exactly replicate the UK remuneration scheme; it is intended only to portray the effect of capitalization under the TOTEX approach for comparison. In the TOTEX approach, a portion of the total expenditure, $totex_t^*(CR)$, called slow money, sm_t, is capitalized and goes to the regulated asset base. The remainder, $totex_t^*(1 - CR)$, called fast money, fm_t, is directly remunerated. The capitalization rate, CR, is fixed ex-ante by the regulator. Consequently, a DSO using more operational solutions would capitalize expenditures at the same rate as other DSOs that are more focused on capital expenditures.

The regulated asset base, rab_t^{TOTEX}, is updated according to Equation (2). The slow money, sm_t, is considered as an investment in year t, increasing the value of the asset base. Depreciation during year t, dep_t, decreases the value of the asset base.

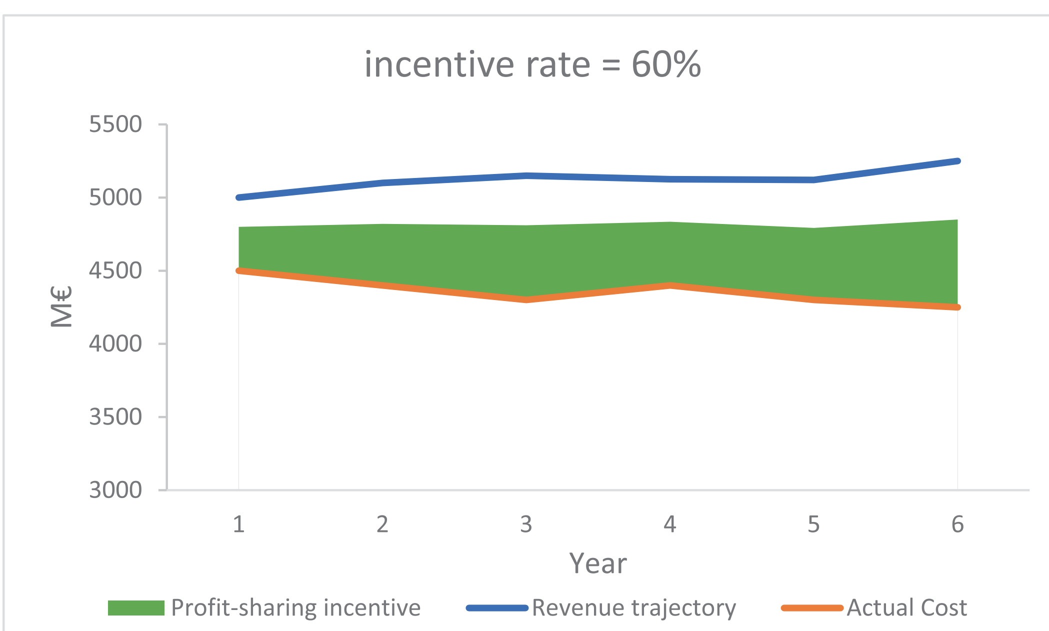

Fig. 2. Illustrative example of a profit-sharing mechanism with a 60% incentive rate.

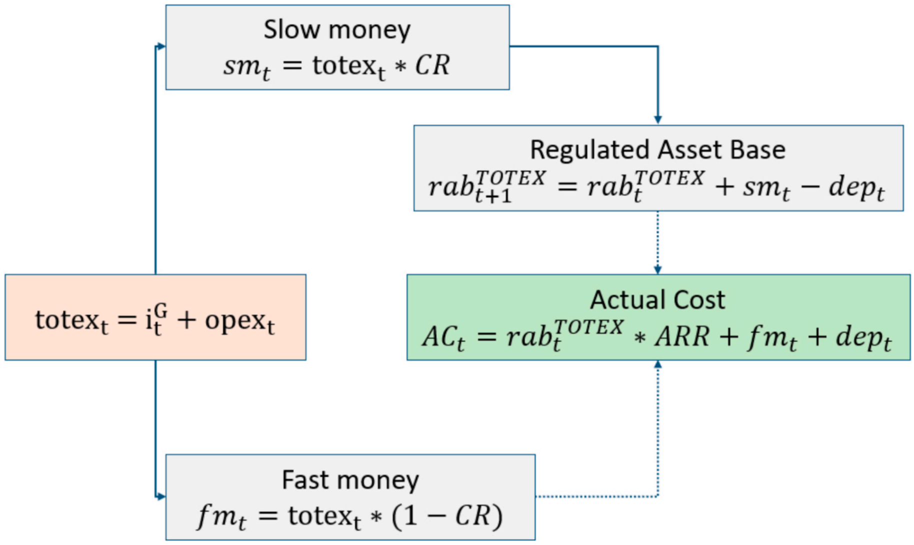

Fig. 3. Illustration of the capitalization under the TOTEX approach.

$$rab_{t+1}^{TOTEX} = rab_t^{TOTEX} + sm_t - dep_t \tag{2}$$

The actual costs in year t are calculated according to Equation (3), as a sum of the incurred capital costs, $rab_t^{TOTEX} * ARR$, where ARR denotes the allowed rate of return), the fast money, fm_t, as if they were operational expenditures, and the depreciation of the regulated asset base, dep_t.

$$AC_t = rab_t^{TOTEX} * ARR + fm_t + dep_t \tag{3}$$

Then, the incentive resulting from the profit-sharing mechanism is calculated by comparing these actual costs to the ex-ante revenue trajectory set by the regulator, as in the total allowance model, see Equation (1).

3.2. Decision-making tool: mathematical formulation

This section presents the mathematical formulation of the remuneration scheme constraints and the objective function under each considered remuneration scheme.

This methodology considers three remuneration schemes. The formulation for these three schemes is presented assuming:

- A single-node, capacity-limited network model.
- A single reinforcement candidate has already been identified.
- A risk-neutral DSO.
- Uniform average price of flexibility that does not depend on the amount of flexibility reserved or activated.
- A forecast by the DSO including different scenarios for future load conditions growth.

Calculations represent a marginal or incremental analysis to evaluate the consequences of the planning decisions made during the analyzed period. The total revenue and costs of the DSO due to the rest of the assets in operation are not calculated.

Formulation is adopted for a multi-stage, multi-scenario adaptable planning approach.

As already mentioned, the presented formulations can be adapted to consider more complex network models or more candidates for planning solutions.

3.2.1. Planning constraints and network model

The planning constraints control the time interdependencies between the DSO decisions (invest in a grid reinforcement or reserve flexibility) and their availability to solve grid problems (the reinforcement entering into service or the flexibility becoming available for activation). The methodology assumes adaptable planning, in which DSO decisions may differ across scenarios.

In distribution network planning, decisions about grid investments are mainly driven by peak load. To manage uncertainty, the implemented approach utilizes trigger-based rules: DSOs either invest immediately or wait until the peak load reaches a threshold. For instance, a DSO may invest in a new feeder now or set a trigger level (e.g., 38 MW) to invest later when peak load reaches that threshold. This approach results in an adaptable plan in which future decisions are contingent on unfolding information (i.e., the actual, observed evolution of the peak load over time). Flexibility works similarly but is temporary and reversible, unlike long-term grid investments. The formulations of the planning constraints included in the Annex are based on the work presented in [35]. This study builds on the work presented in [35] by incorporating regulatory constraints that reflect the remuneration scheme and an objective function representing a DSO aiming to maximize profit under the aforementioned remuneration scheme.

Therefore, the decision variables are the trigger levels rather than the future planning decisions. The future planning decisions are merely consequences (auxiliary variables) in each scenario, determined by the optimized trigger level and the evolution of the peak load. Including the planning constraints, the network model, and the remuneration constraints in the same optimization ensures that trigger levels are optimized.

The network model transforms planning decisions into estimations of the grid operational conditions. This methodology estimates the energy not served as a quality-of-service metric and calculates the associated incentive. The considered network model is a single-node capacity-limited substation.

The details of the planning constraints and the network model used in the case study are provided in the Annex, along with an explanation of their rationale.

3.2.2. Variables

This optimization model involves variables specific to the selected remuneration scheme (see Table 1).

As explained in Section 3.1.3, fixing the capitalization rate in the TOTEX approach changes how the regulated asset base is updated. It uses slow money instead of investments. For this reason, the TOTEX approach presents different variables: the regulated asset base, $rab_{s,t}^{TOTEX}$, the depreciation, $dep_{s,t}^{TOTEX}$, and additional variables for calculations such

Table 1
Variables of the optimization model depending on the selected remuneration scheme.

Variable	CoS	Revenue cap	TOTEX
$g_{s,t}$	✔	✔	
$rab_{s,t}$	✔	✔	
$dep_{s,t}$	✔	✔	
$fm_{s,t}$			✔
$sm_{s,t}$			✔
$totex_{s,t}$			✔
$rab_{s,t}^{TOTEX}$			✔
$dep_{s,t}^{TOTEX}$			✔

as the total expenditure, $totex_{s,t}$, the slow money, $sm_{s,t}$, and the fast money, $fm_{s,t}$.

3.2.3. Cost-of-Service formulation

Under the Cost-of-Service (CoS) approach, the DSO is allowed to recover the incurred cost of the activity. A rate of return is set to recover capital expenditure. This rate of return is set at an attractive level, allowing the company to attract private funds to finance its activity. This approach also considers a quality incentive.

Objective function

Equation (4) shows the objective function of a DSO maximizing the profit under the CoS approach.

$$\max_{ens_{s,t},rab_{s,t}} C = \sum_{t=FLT}^{t=T}\sum_{s} Pr_s * 1/(1+CC)^t * \left[rab_{s,t}*(ARR-CC) + \left(ENS_t^{ref} - ens_{s,t}\right)*VoLL\right] \quad (4)$$

The profit considers two items:

- *Profit from the asset base remuneration (€):* Under the CoS approach, the regulated firm is guaranteed recovery of its costs. Therefore, incurred costs do not appear in the objective function as they do not affect the company's profit. However, the regulator sets an allowed rate of return (ARR) on capital investments. As mentioned in section 1, this ARR may differ from the firm's actual Cost of Capital (CC), potentially resulting in either a profit or a loss over the minimum required return for the DSO. This profit or loss is captured in the term $rab_{s,t}*(ARR-CC)$, where $rab_{s,t}$ denotes the Regulated Asset Base at scenario s and year t, which reflects the net asset value of the investments during the planning period. If ARR equals CC, the firm earns just enough to maintain investor interest. If ARR exceeds CC, the firm gains a surplus return. Conversely, if ARR is below $WACC$, investment becomes unattractive, potentially leading to underinvestment.
- *Profit from the quality incentive (€):* Most remuneration schemes include an incentive to reduce service interruptions. The regulator establishes a reference for quality of service (typically based on historic data and regulator objectives). Overperformers receive a reward while underperformers receive a penalty. This is modeled as $\left(ENS_t^{ref} - ens_{s,t}\right)*VoLL$, where ENS_t^{ref} is the reference for energy not served (MWh) established by the regulator for year t and $ens_{s,t}$ is the energy not served (MWh) in scenario s and year t. $VoLL$ is the value of lost load (€/MWh) established by the regulator used for the incentive calculation.

Each scenario is weighted in the objective function according to its associated probability, Pr_s. This allows the DSO to assign higher probability to the more plausible scenarios and lower probability to less likely ones. Since this analysis considers the DSO perspective, the cost of capital (CC) is applied to bring all the considered costs to the present.

Current decisions only impact future years due to lead time constraints. Therefore, the early years of the planning horizon cannot be influenced by DSO decisions during the planning period. As a result, these initial stages are treated as sunk costs and are excluded from the model cost calculations. The lead time for flexibility is typically shorter than the lead time for grid reinforcement. Therefore, the objective function only considers years where $t > FLT$, as no intervention can influence earlier stages.

Constraints.

Depreciation calculation: The depreciation is assumed to be linear over the asset's useful life. Equation (5) models the annual depreciation for each scenario s and year t. Depreciation is calculated as the ratio of the investment in grid reinforcement, G^{inv}, to the asset's useful life, G^{ul}. This only applies in scenarios and years where the reinforcement is in operation, $g_{s,t} = 1$. Otherwise, there is no depreciation.

$$dep_{s,t} = g_{s,t} * \frac{G^{inv}}{G^{ul}} \quad \forall s,t \quad (5)$$

This constraint ensures that depreciation is accounted only after the asset enters in service and continues annually over its useful life.

Regulated asset base calculation (€): Equation (6) defines how the RAB is updated each year. The RAB in year $t+1$ equals the RAB in year t plus the expenditure for investments entering into service during year t, represented by $i_{s,t}^{G}*G^{inv}$, minus the depreciation of investments already included in the RAB in year t, represented by $dep_{s,t}$. This calculation applies to each scenario separately, ensuring compatibility with adaptable decision-making. Constraint (7) sets the RAB value in year 0 to 0 for all scenarios, so only investment decisions made during the planning period affect the RAB. Previous investments are considered sunk costs and excluded from this analysis.

$$rab_{s,t+1} = rab_{s,t} - dep_{s,t} + i_{s,t}^{G}*G^{inv} \quad \forall s, t < T \quad (6)$$

$$rab_{s,t} = 0 \quad \forall s, t = 1 \quad (7)$$

3.2.4. Revenue cap formulation

Under the revenue cap, the regulator defines an ex-ante multi-year revenue trajectory for the regulatory period. The DSO allowed revenue results in a weighted average between the DSO's actual cost and the ex-ante revenue trajectory. This approach also considers a quality incentive.

Objective function

Equation (8) shows the objective function of a DSO maximizing the profit (€) under a revenue cap approach.

Table 2
Peak load scenarios (MW).

	Year										
	0	1	2	3	4	5	6	7	8	9	10
Consumer transformation	57,7	56,8	57,2	58,1	58,9	60,4	62,9	65,9	68,5	71,5	75,2
System transformation	57,7	58,0	58,2	58,4	58,9	59,6	60,6	62,1	63,3	64,9	66,8
Leading the way	57,7	56,2	54,9	55,0	55,9	57,0	59,0	60,7	62,8	66,3	69,7
Falling short	57,7	61,0	61,8	62,8	63,5	64,4	65,1	66,1	67,4	69,0	70,8

$$\max_{rab_{s,t}dep_{s,t}f^{res}_{s,t}f^{act}_{s,t}om_{s,t}ens_{s,t}} C = \sum_{t=FLT+1}^{T}\sum_{s} Pr_s*1/(1+CC)^{t}*\Big[rab_{s,t}*(ARR - CC) + IR*RT_t - IR(rab_{s,t}*ARR + dep_{s,t} + f^{res}_{s,t}*FR^{Cost} + f^{act}_{s,t}*FU^{Cost} + g_{s,t}*OM^{cost}) + (ENS^{ref}_t - ens_{s,t})*VoLL\Big] \quad (8)$$

The profit considers three items:

- *Profit from the asset base remuneration (€):* This formulation is equivalent to the profit from immobilized capital already presented in the cost-of-service approach. This is modeled as $rab_{s,t}*(ARR - CC)$.
- *Profit-sharing mechanism (€):* The profit-sharing mechanism, as explained in Section 3, is an incentive based on the difference between the revenue trajectory and the actual cost incurred by the DSO. The actual costs (incurred cost recognized by the regulator) considered in each scenario s and year t include:
  o Cost of capital, $rab_{s,t}*ARR$.
  o Depreciation cost, $dep_{s,t}$.
  o Flexibility reserve cost, $f^{res}_{s,t}*FR^{Cost}$.
  o Flexibility activation cost, $f^{act}_{s,t}*FU^{Cost}$.
  o Operation and maintenance costs, $g_{s,t}*OM^{cost}$.

  The incentive resulting from profit-sharing (PSI) is given by Equation (9), consistent with Equation (1).

$$psi_{s,t} = IR*RT_t - IR(rab_{s,t}*ARR + dep_{s,t} + f^{res}_{s,t}*FR^{Cost} + f^{act}_{s,t}*FU^{Cost} + g_{s,t}*OM^{cost}) \quad (9)$$

- *Profit from quality incentives (€):* This formulation is equivalent to the profit from the quality incentive already presented in the cost-of-service approach. This is modeled as $\left(ENS^{ref}_t - ens_{s,t}\right)*VoLL$.

As explained for the cost-of-service approach, the present value of the profit obtained in each year is calculated using the cost of capital, CC, as the discount rate. Each scenario is weighted in the objective function according to its associated probability, Pr_s. The objective function only considers years where $t > FLT$, as no intervention can influence earlier stages.

Constraints.

Depreciation calculation (€): Under the revenue cap approach, depreciation is calculated the same way as in the CoS approach, please see Equation (5) already explained.

Regulated asset base calculation (€): Under the revenue cap approach, capitalization is conducted the same way as in the CoS approach, please see Equations (6) and (7) already explained.

3.2.5. TOTEX formulation

Under the TOTEX approach, similar to the revenue cap approach, the regulator defines an ex-ante revenue trajectory, RT^{TOTEX}_t, and a profit-sharing mechanism applies. However, this approach capitalizes a portion of the DSO's actual expenditures, regardless of whether they are OPEX or CAPEX. This portion is known as slow money, $sm_{s,t}$. The rest of the DSÓs expenditures are considered fast money, $fm_{s,t}$. The fast money is not capitalized and treated as yearly cost.

Objective function

Equation (10) shows the objective function of a DSO maximizing the profit under a TOTEX approach.

$$\max_{i^{1},tr^{G},f^{1},tr^{F}} C = \sum_{t=FLT+1}^{T}\sum_{t,s} Pr_s 1/(1+CC)^{t}*\Big[rab^{TOTEX}_{s,t}*(ARR - CC) + IR*RT^{TOTEX}_t - IR(rab^{TOTEX}_{s,t}*ARR + dep^{TOTEX}_{s,t} + fm_{s,t}) + (ENS^{ref}_t - ens_{s,t})*VoLL\Big] \quad (10)$$

The equation considers three items for profit calculation:

- *Profit from the asset base remuneration (€)*: Similar to the CoS and revenue cap approaches, this is modeled as $rab^{TOTEX}_{s,t}*(ARR - CC)$.
- *Profit-sharing mechanism (€)*: As described in Fig. 3, the actual costs (recognized by the regulator) considered in each scenario s and year t include:
  o Cost of capital, $rab^{TOTEX}_{s,t}*ARR$.
  o Depreciation cost, $dep^{TOTEX}_{s,t}$.
  o Fast money, $fm_{s,t}$.

The incentive resulting from the profit-sharing mechanism, $psi_{s,t}$, is given by the Equation (11). It is consistent with Equation (1), and considers the calculation of actual costs under the TOTEX approach, as illustrated in Fig. 3:

$$psi_{s,t} = IR*RT^{TOTEX}_t - IR(rab^{TOTEX}_{s,t}*ARR + dep^{TOTEX}_{s,t} + fm_{s,t}) \quad (11)$$

- *Profit from quality incentives (€):* As in the CoS and revenue cap approaches, this is modeled as $\left(ENS^{ref}_t - ens_{s,t}\right)*VoLL$.

Constraints.

TOTEX calculation: Equation (12) calculates the DSO's total expenditure in scenario s and year t, $totex_{s,t}$. It is the sum of investments entering into service during year t in scenario s, $G^{inv}*i^{G}_{s,t}$, and the operational expenditures. These operational expenditures include the cost of reserving flexibility, $f^{res}_{s,t}*FR^{Cost}$, the cost of flexibility activation, $f^{act}_{s,t}*FU^{Cost}$, and the operation and maintenance cost, $om_{s,t}$.

$$totex_{s,t} = G^{inv}*i^{G}_{s,t} + f^{res}_{s,t}*FR^{Cost} + f^{act}_{s,t}*FU^{Cost} + g_{s,t}*OM^{cost} \quad \forall s,t \quad (12)$$

Fast money calculation: Equation (13) calculates the fast money in scenario s and year t ($fm_{s,t}$) as the portion of the total expenditure ($totex_{s,t}$) that is not capitalized, according to the fixed capitalization rate (CR).

$$fm_{s,t} = totex_{s,t}*(1 - CR) \quad \forall s,t \quad (13)$$

Slow money constraints: Equation (14) calculates the slow money in scenario s and year t ($sm_{s,t}$) as the portion of the total expenditure ($totex_{s,t}$) that is capitalized, according to the fixed capitalization rate (CR).

$$sm_{s,t} = totex_{s,t}*(CR) \quad \forall s,t \quad (14)$$

Depreciation calculation (TOTEX) (€): Equation (15) calculates the annual depreciation of the regulated asset base according to the TOTEX approach, using the useful life fixed by the regulator (R^{ul}). All the slow money expenditures made prior to year t are depreciated during year t. Since the useful life considered (40 years) is usually greater than the planning period (5–10 years), there is no need to check if the slow money is fully depreciated in this analysis. Equation (16) ensures there is no depreciation in year 1.

$$dep_{s,t}^{TOTEX} = \sum_{a=1}^{a=t-1} sm_{s,a} \Big/ R^{ul} \quad \forall s, t > 1 \tag{15}$$

$$dep_{s,t}^{TOTEX} = 0 \quad \forall s, t = 1 \tag{16}$$

Regulated asset base calculation (TOTEX) (€): Equation (17) defines how the RAB is updated each year under the TOTEX approach. The RAB in year $t+1$ equals the RAB in year t plus the slow money in year t, $sm_{s,t}$, minus the depreciation in year t, $dep_{s,t}^{TOTEX}$. As in the CoS approach, (6), this formulation (17) is compatible with adaptable decision-making. Constraint (18) sets the RAB value to 0 in year 0 for all the scenarios, similar to the CoS and the revenue cap approaches. Investments made before the planning period are treated as sunk costs and excluded from this analysis.

$$rab_{s,t+1}^{TOTEX} = rab_{s,t}^{TOTEX} - dep_{s,t}^{TOTEX} + sm_{s,t} \quad \forall s, t > 1 \tag{17}$$

$$rab_{s,t}^{TOTEX} = 0 \quad \forall s, t = 1 \tag{18}$$

4. Case study

This section presents a case study to illustrate the application of the proposed methodology. The case study consists of a substation in a distribution network that is expected to be congested. This substation has a capacity limit of 60 MW. There are two possible interventions to solve the substation congestion.

- First, reinforce the grid by building a new feeder that redirects part of the load (a maximum of 20 MW) to an adjacent substation. The new feeder entails an investment of 432 k€, a useful life of 40 years, and a three-year commissioning lead time.[3]
- Second, contract flexibility from connected users. There are 4 MW of available flexibility for peak reduction each year of the planning period. The cost for reserving flexibility is 33.35 €/MW/h, and the cost for flexibility activation is 200.68 €/MWh based on[37].[4] The considered lead time for flexibility is one year.

The allowed rate of return, established by the regulator, is 5.58%[5] which in the first analysis is considered equal to the cost of capital of the regulated company, and the value of lost load (VoLL) is 4500 \$/MWh.

4.1. Scenarios for peak load evolution

The scenarios for peak load evolution presented in Table 2 are taken from [35], which are adapted from the “Future Energy scenarios 2023” elaborated by National Grid in the UK [29]. These four base scenarios represent the long-term uncertainty based on National Grid ESO projections. The Consumer transformation represents a scenario with high levels of consumer engagement, providing flexibility to the system and improving energy efficiency in their homes, combined with high penetration of EVs and heat pumps. The System transformation is a scenario characterized by lower consumer engagement, more use of hydrogen and natural gas compared to the first scenario. Leading the way is a scenario characterized by high investment in decarbonization technologies and high customer engagement, along with energy efficiency improvements reaching net-zero targets by 2046. Falling short represents a scenario where net-zero targets are not met in 2050, and the uptake of electric vehicles is slow.

Then, in [35], a Monte Carlo simulation is performed to add noise to these scenarios, representing the short-term uncertainties. The increase or decrease in the materialized noise is modeled as a normal distribution with a mean of 0 and a standard deviation of 0.4%. The simulation generated a total of 160 scenarios, 40 per base scenario. The dataset is included in the supplementary material.

4.2. Load duration curve

Fig. 4 shows the load duration curve for the substation under study in year 0 with a peak load of 57.7 MW. An assumption is that this load duration curve will maintain its form with all hourly values growing at the same rate as the peak load. The load duration curve is taken from [35], which is based on 2019 data from the Spanish Transmission System Operator database [39]. The resulting LDC used in this case study is available in the supplementary material.

4.3. Details on considered remuneration schemes

First, the ex-post (cost-of-service) approach is considered. This traditional method involves recovering the incurred costs. Next, the ex-ante (revenue cap) approach with a 50% profit-sharing mechanism is examined. The DSO shares 50% of any profits or losses relative to this cap. For this approach, the ex-ante revenue trajectory is determined by the cost of the network plan under the cost-of-service approach. This decision is motivated by the regulatory logic underlying both frameworks. Under cost-of-service regulation, the DSO is remunerated based on the incurred costs, subject to regulatory approval of the investment plans. In contrast, the revenue cap framework establishes an ex-ante trajectory of allowed revenues, which implicitly reflects the regulator’s assessment of what constitutes reasonable and efficient costs. Using the incurred costs under the cost-of-service ensures comparability of results across the two remuneration schemes. Similarly, the reference for the quality of service (defined as ENS_t^{ref} in the methodology) is the expected energy not served under the cost-of-service scheme.

Finally, the TOTEX approach incorporates a fixed capitalization rate of 80% to total expenditures (both capital and operational), alongside a 50% profit-sharing mechanism. The revenue trajectory under the TOTEX approach is derived from the network planning decisions made under cost-of-service, with cost components recalculated according to the TOTEX capitalization rules. As for the revenue cap approach, the reference for the quality-of-service incentive in the TOTEX approach is the expected energy not served under the cost-of-service scheme.

5. Results & discussion

This section presents the case study results, focusing on the DSO's planning decisions over a 10-year period under the three selected remuneration schemes. The models were implemented in Pyomo and solved using the GUROBI solver.

Table 3 presents the results of the case study, considering traditional planning with fixed static planning decisions at each year of the planning period. The first column of Table 3 presents the decisions made under a cost-minimizing strategy obtained from an optimization model with the objective function set to cost minimization rather than the DSO's profit maximization. A key objective for any remuneration scheme is to incentivize DSOs to achieve the minimum system cost (MSC) solution. However, this outcome is not always attainable. Consequently, the MSC solution serves as a benchmark for evaluating the performance of a particular remuneration scheme in guiding the DSO's planning decisions. Table 3 also includes the expected flexibility activation (MWh),

[3] The International Energy Agency indicates in [36] that the lead time for investments in the distribution network in Europe varies between 2 and 4 years.

[4] Average availability and utilization payments from February 2021 tender based on the report by Aurora Energy Research [37]. Conversion rate considered 1.15 Euro/GBP.

[5] 5.58% is the WACC established by the Spanish regulator CNMC [38].

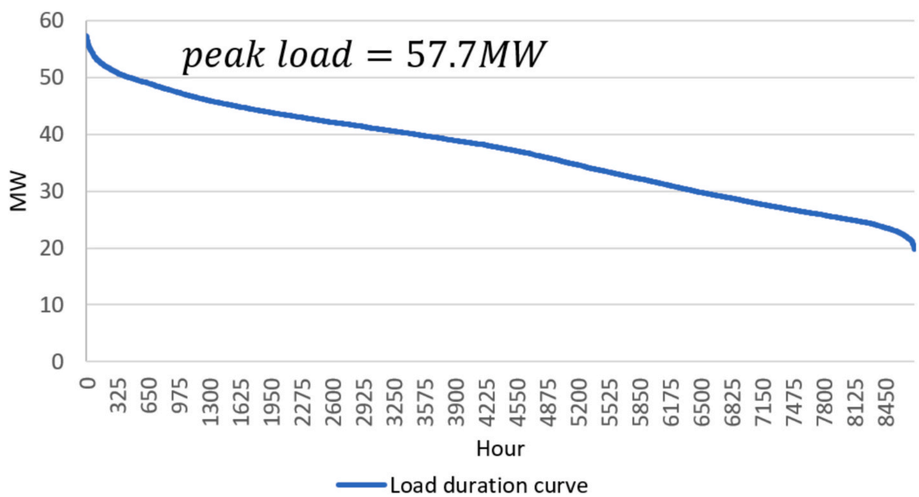

Fig. 4. Load duration curve at year 0 used for the case study.

Table 3
DSO decisions under the different remuneration schemes with traditional planning.

	MSC (benchmark)	Cost-of-Service	Revenue cap	TOTEX
Investment	1 Feeder	1 Feeder	1 Feeder	1 Feeder
% of scenarios with reinforcement	100%	100%	100%	100%
Expected year of grid investment (year)	3	1	3	3
Expected Flexibility Reserve (MW_h)	759	155	759	759
Expected Flexibility Activation (MWh)	75	16	75	75
Expected ENS (MWh)	2.61	0.75	2.61	2.61
Expected cost of the network plan (€)	165,290	191,056	165,290	165,290

Table 4
DSO decisions under the different remuneration schemes with adaptable planning.

	MSC (benchmark)	Cost-of-Service	Revenue cap	TOTEX
Investment	1 Feeder	1 Feeder	1 Feeder	1 Feeder
% of scenarios with reinforcement	100%	100%	100%	100%
Expected year of grid investment (year)	3.06	1.00	2.98	2.99
Expected Flexibility Reserve (MW_h)	270	68	257	260
Expected Flexibility Activation (MWh)	60.6	16	57.5	58.3
Expected ENS (MWh)	1.41	0.63	1.35	1.36
Expected cost of the network plan (€)	144,731	188,161	145,904	145,912

the expected energy not served (MWh), and the expected cost of the network plan (€),[6] for each remuneration scheme and for the minimum cost solution.

Table 3 shows that the cost-of-service leads to the highest-cost network plan (191,056 €), 15.6% higher than the cost of the MSC network plan. The expected year for the grid investment decision is year 1 (the first year of the planning period), so there is no utilization of flexibility to delay network reinforcement under the cost-of-service remuneration scheme. In contrast, the revenue cap and the TOTEX approaches lead to the exact same network plan, which coincides with the minimum-cost network plan.

Table 4 presents the DSO investment decisions for the case study, considering adaptable planning, see Annex. Under the cost-of-service scheme, results show little difference compared to the traditional planning approach, with a slight reduction in expected cost (1.5%), and again, no use of flexibility to delay grid reinforcement. The expected year for the investment decision is year 1.

The MSC and the TOTEX yield nearly identical solutions, with a 12% decrease in expected cost compared to traditional planning. The network plan under the revenue cap shows a 5% lower expected flexibility activation (57.5 MWh) than MSC (60.6 MWh). Although this difference does not significantly impact the expected cost of the network plan. These results suggest a CAPEX bias in the revenue cap approach. Under this scheme, flexibility activation reaches 57.5 MWh. This bias is observed when the cost difference between the CAPEX and the OPEX solutions is small. This is why the impact on the expected cost is almost negligible, with a 0.8% increase compared to MSC (145,904 € vs 144,731 €). The bias is also reflected in the expected year of the grid investment, presenting a small reduction in the revenue cap approach (2.98 years) compared to MSC (3.06 years). The TOTEX and revenue cap approaches show very similar overall results. The expected flexibility activation under the TOTEX approach increases by 1.3% compared to the revenue cap (58.3 MWh vs 57.5 MWh), while the expected cost of the network plan increases by a negligible 0.005% (145,912 € vs 145,904 €).

The expected year of grid investment is shown as a decimal number because, with adaptable planning, the investment decision in each scenario may differ depending on peak load evolution; a higher demand growth will result in an earlier investment decision and vice versa. Thus, the decimal number represents the expected year of grid investment across the 160 scenarios, considering adaptable planning.

These results show that allowing adaptable planning may have little to no cost-reduction effect under cost-of-service approaches, while it may have a significant impact under revenue cap and TOTEX approaches (reducing costs by 12%).

Table 5 presents the expected present value of the costs incurred by

[6] The expected cost of the network plan includes the expected flexibility cost (reserve and activation), the expected cost related to investments (cost of capital and depreciation of the grid asset), the expected cost of energy not served valued at 4,500 €/MWh, and the expected operation and maintenance cost of the grid asset. The discount rate, to calculate the present value of these costs, is the Allowed rate of return established by the regulator (5.58% in this assumption).

Table 5
Expected present value (€) of the main economic figures under each remuneration scheme with adaptable planning.

	MSC (benchmark)	Cost-of-Service	Revenue Cap	TOTEX
Incurred Cost (OPEX) (€)	29,941	25,573	29,737	72,001
Incurred Cost (CAPEX related) (€)	109,865	160,130	110,151	93,745
Total Incurred Costs (a) (€)	139,806	185,703	139,888	165,746
Quality incentive (b) (€)	–	0	−2,393	−2,456
Incentive from profit-sharing (c) (€)	–	–	22,908	23,159
Total allowed revenue (a + b + c) (€)	–	185,703	160,403	186,449
DSO Profit (b + c) (€)	–	0	20,515	20,703
Residual RAB* (€)	378,941	356,714	378,805	334,346
Productive inefficiency (€)	–	43,430	8	19
Allocative inefficiency (€)	–	–	20,515 €	20,703

*The residual RAB represents the value of the regulatory asset base at the end of the planning period.

the DSO and the incentives considering adaptable planning; these are economic figures corresponding to the case presented in Table 4. The incurred cost related to capital expenditures includes the depreciation and the cost of capital for the investment in the feeder.

As expected, the cost-of-service approach incurs the highest CAPEX-related cost because there is no deferral of grid reinforcement, whereas the revenue cap approach and the MSC present similar costs in this category, as their year for grid investment is very similar in Table 4.

The TOTEX approach, however, shows an artificially low number in this category because the capitalization rate is fixed. Thus, the value of the regulated asset base differs from the value of the actual asset base. With a fixed capitalization rate of 80%, 20% of the CAPEX (i.e., 20% of the investment in the feeder) is considered fast money and not capitalized, increasing "OPEX" and decreasing the regulated asset base, thereby decreasing the cost of "CAPEX". This is why we see lower CAPEX-related costs and higher OPEX, even though the network plan was almost identical to MSC, as shown in Table 4.

Table 5 shows further consequences of the fixed capitalization rate in the TOTEX approach. It not only inflates the OPEX figure and decreases the CAPEX figure. The impact is also reflected in the residual RAB (i.e., the net value of the regulated asset base at the end of the planning period): 334,346 € under the TOTEX approach, compared to 378,941 € for the MSC case and 378,805 € for the revenue cap framework. This variation occurs despite the expected year of grid investment being similar across the two approaches (revenue cap and TOTEX) and the MSC benchmark, as shown in Table 4.

Looking at the total allowed revenue, which represents the amount of money that network users would pay through tariffs. Although they would pay more during the regulatory period (the 10 years studied) under the TOTEX approach (with total allowed revenue of 186,449 € versus 160,403 € under the revenue cap), future payments under TOTEX would be lower due to the smaller residual RAB (334,346 € vs 378,805 €).

In conclusion, the fixed capitalization rate in this case temporarily increased payments of connected users while decreasing future payment obligations through a lower RAB.

For a fair comparison of the DSO's planning decisions across the different remuneration schemes, the selected metric is the expected cost of the network plan, presented in Table 4. As previously discussed, this metric eliminates the distortion in the incurred costs caused by the fixed capitalization rate. Thus, resulting in similar values across the MSC, the revenue cap, and the TOTEX, along with a similar expected timing of investment decisions.

When examining the cost-efficiency of a distribution company, we may distinguish two dimensions. First, productive efficiency (i.e., minimizing cost), which is maximized when the network plan equals the minimum cost network plan. Second, allocative efficiency (i.e., minimizing rent extraction by the regulated company), which is maximized when the allowed revenue for the distribution company is exactly its actual cost.

In the cost-of-service approach, the distribution company's remuneration equals its actual cost. Thus, there is no allocative inefficiency. In contrast, the expected cost of the network plan is 188,161 € vs 144,731 € of the minimum-cost network plan. This results in 43,430 € of productive inefficiency, as shown in Table 5.

In the case of the revenue cap and the TOTEX approaches, the allocative inefficiency is related to the incentives given to the DSO (i.e., profit-sharing and quality incentives), which amount to 20,515 € and 20,703 €, respectively. In contrast, there is little productive inefficiency, 8 € and 19 €, representing less than 0.02% of the total cost.

The results reveal similar total inefficiency (combining productive and allocative inefficiency) for both the revenue cap and TOTEX approaches, each around 21 k€. In contrast, the cost-of-service approach exhibits significantly higher total inefficiency, more than double at 43,430 €.

5.1. Sensitivity analysis

DSOs may encounter different volumes of available flexibility at different costs depending on the availability of flexible resources at a given location, the network topology, and regulatory conditions, among other factors. Therefore, it is valuable to test whether the case study results remain consistent under different values of flexibility cost and availability.

Sensitivity analysis on flexibility cost and flexibility availability.

The case study initially considered 4 MW of available flexibility. In this sensitivity analysis, the figure ranges from 1 MW (25% of the initial value) to 8 MW (two times the initial value). Similarly, the cost of flexibility ranges from 8.34 €/MW/h reserve cost and 50.17 €/MWh activation cost (25% of the initial value), up to 100.05 €/MW/h reserve cost and 625.08 €/MWh activation cost (three times the initial value considered in the case study).

Fig. 5 presents the sensitivity analysis for the difference in the use of flexibility (i.e., MWh of activated flexibility) between the network plan under the TOTEX approach and the MSC network plan. Fig. 6 compares the expected present cost of the network plan under the TOTEX approach with the expected present cost of the MSC network plan. Both Fig. 5 and Fig. 6 considered adaptable planning.

While the initial results of the case study in Table 4 showed that both the TOTEX and the MSC led to similar flexibility activation, Fig. 5 shows that this does not hold across different contour conditions. The TOTEX approach presents an excess of flexibility activation, as shown by the red area in Fig. 5. This occurs when available flexibility is high (over 5 MW, 1.25x initial estimation), and the effect is accentuated at medium and low flexibility prices. When available flexibility is low, the TOTEX approach results in lower flexibility activation (blue colored area). Overall, under the TOTEX approach, the flexibility activation increases by 38.2% compared to the MSC benchmark.

Fig. 6 shows a correlation between the excess of flexibility activation and an increase in the expected cost. The largest increase in expected cost (up to 24% compared to MSC) occurs in cases with high availability of flexibility, at a medium–high price (i.e., between 0.75 and 2 times the initial cost of flexibility). These results suggest the presence of an OPEX bias under the TOTEX approach, linked to the higher use of flexibility. Overall, the TOTEX approach presents a 2.3% increase in cost compared to MSC. The cause of this OPEX bias is analyzed in Section 5.2.

Fig. 7 presents the sensitivity analysis for the difference in flexibility

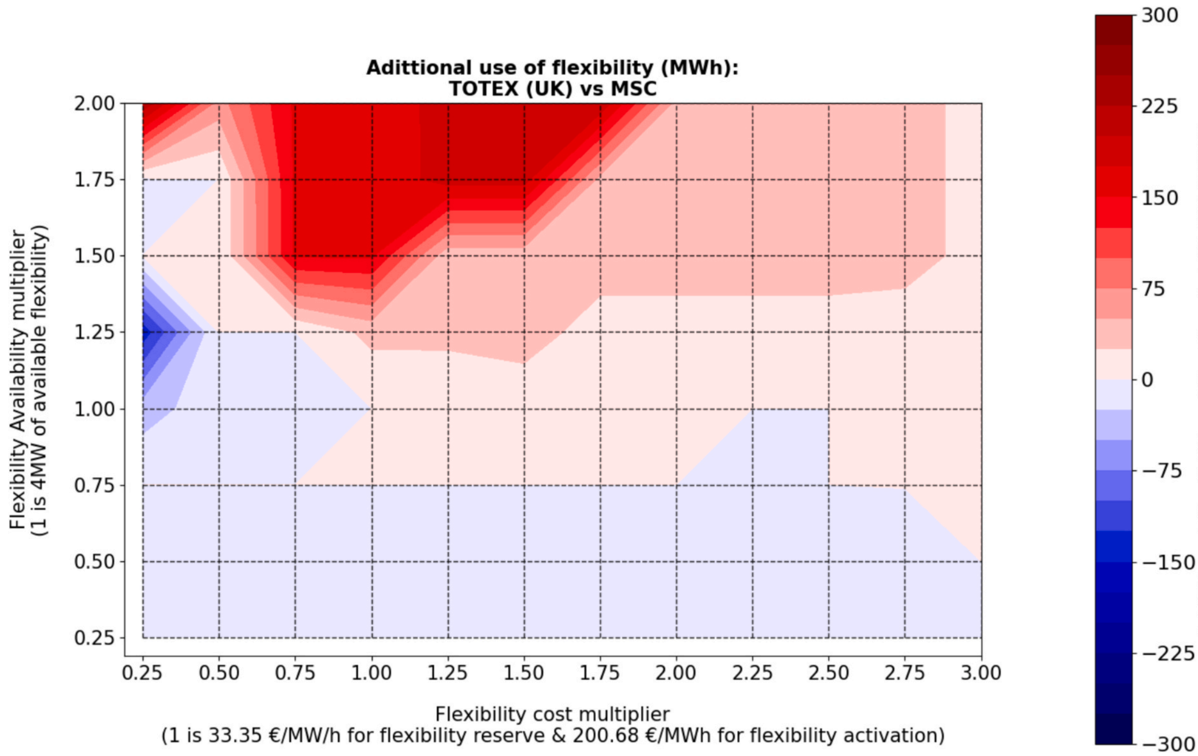

Fig. 5. Sensitivity Analysis of the Increase in Expected Flexibility Activation: TOTEX vs. MSC.

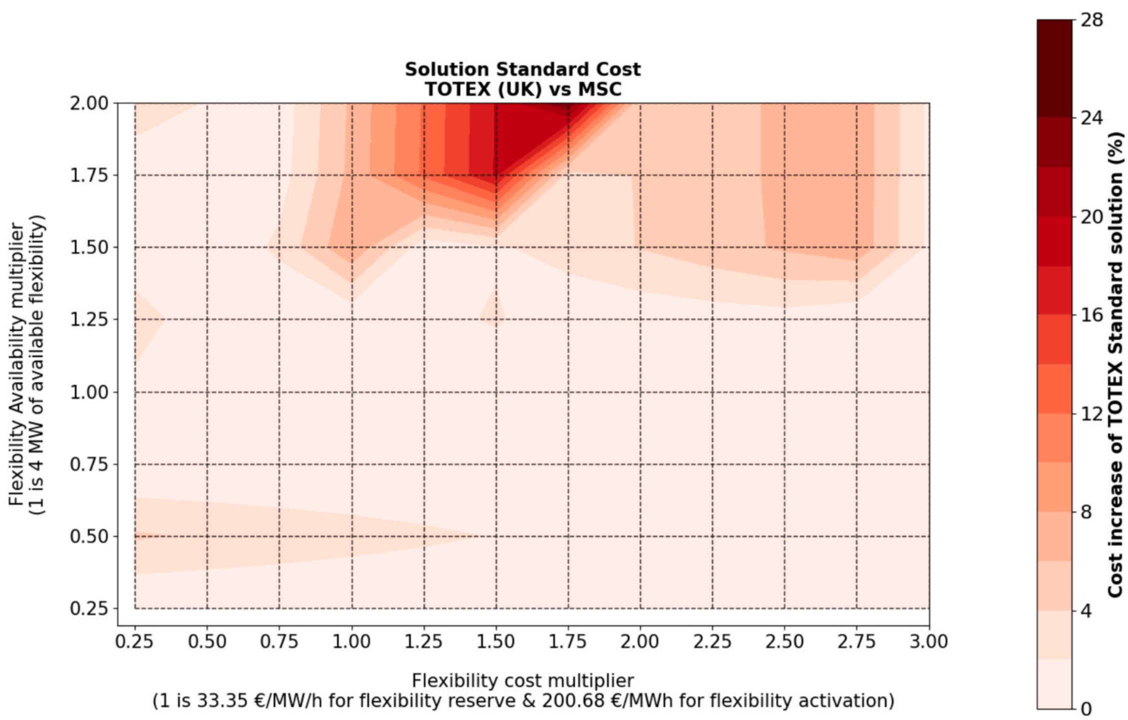

Fig. 6. Sensitivity Analysis of the Percentage Increase in Expected Present Cost: TOTEX vs. MSC.

activation (MWh) between the network plan under the revenue cap scheme and the MSC network plan. Fig. 8 compares the expected present cost of the network plan under the revenue cap with the expected present cost of the MSC network plan. Both Fig. 7 and Fig. 8 consider adaptable planning.

Fig. 7 shows a decrease in expected flexibility activation for the network plan under the revenue cap approach compared to the MSC approach, overall, 12.7% less use of flexibility. This effect is accentuated when there is medium–high availability of flexibility at a low price.

Fig. 8 shows that the impact of different flexibility use on the expected cost is minor, with an overall increase of 0.6%. This indicates a CAPEX bias in the revenue cap approach under the tested conditions. The consequences of this bias primarily arise in cases where the expected costs of the OPEX and CAPEX solutions are similar, resulting in

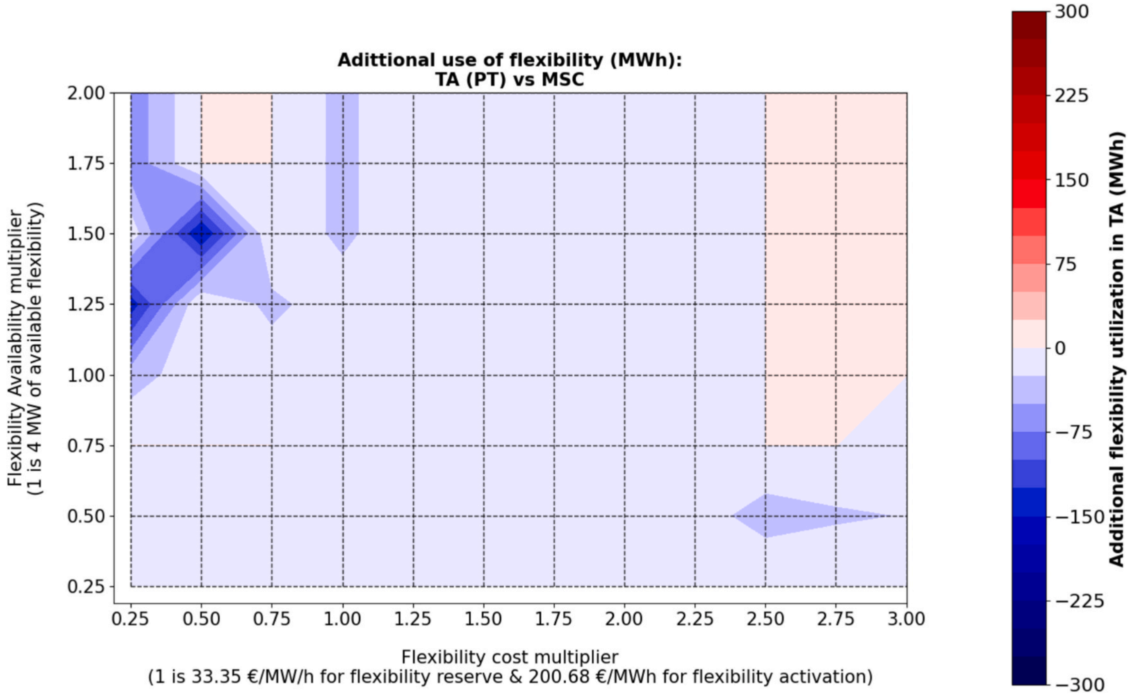

Fig. 7. Sensitivity Analysis of the Increase in Expected Flexibility Use: revenue cap vs. MSC.

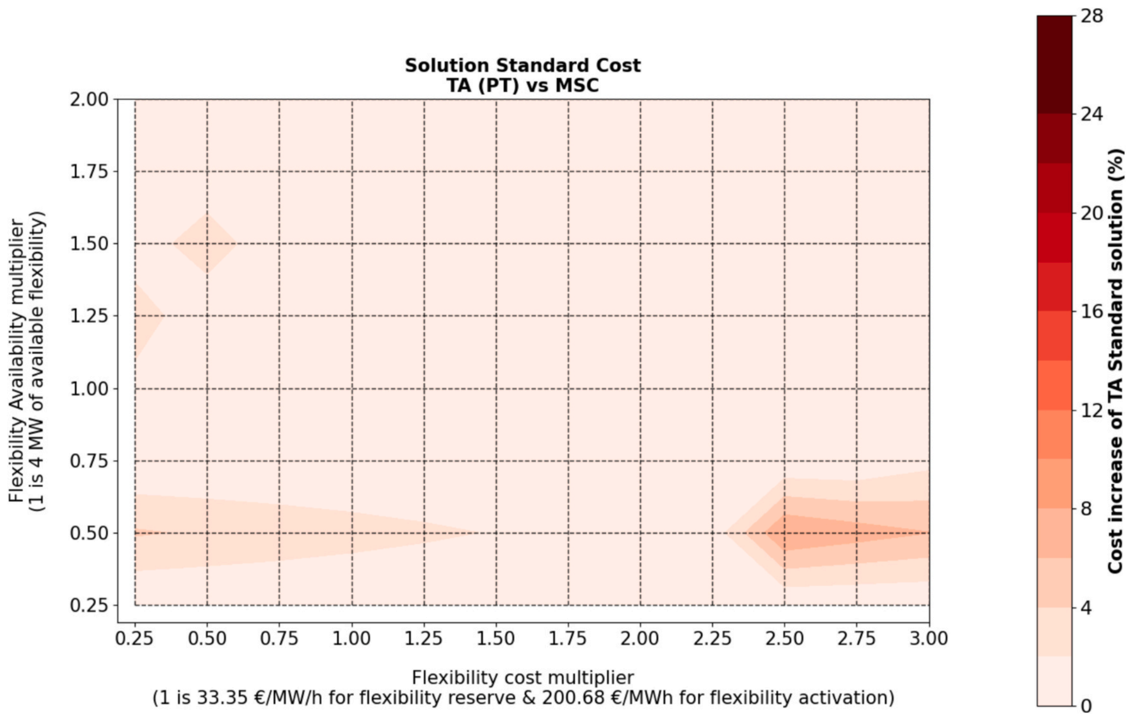

Fig. 8. Sensitivity Analysis of the Percentage Increase in Expected Present Cost: revenue cap vs. MSC.

limited impact on overall cost efficiency. Thus, we preliminarily conclude that the impact of the CAPEX bias on overall planning efficiency under the revenue cap approach is limited. Next, we extend the analysis to examine how the CAPEX-advantage, defined as the difference between the allowed rate of return and the DSO's actual cost of capital, may influence this conclusion.

Sensitivity analysis on the cost of capital and the incentive rate. As explained in Section 2, an allowed rate of return exceeding the distribution companý s actual cost of capital is a source of CAPEX-bias (i.e., the CAPEX advantage). The TOTEX approach is designed to mitigate this CAPEX advantage. The presented case study considers a 5.58% allowed rate of return, equal to the distribution companý s actual cost of capital. In order to consider the effect of the CAPEX-advantage, a sensitivity analysis is conducted assuming 5.58%, 4.58% and 3.58% as the distribution companý s actual cost of capital while maintaining 5.58% as the allowed rate of return. Since, as discussed in Section 2, the CAPEX advantage may counter the effect of the profit-sharing mechanism, the sensitivity analysis includes variations in the incentive rate, at

30% and 70% in addition to the 50% initially considered. The analysis also considers variations in flexibility costs and availability, as shown in the previous sensitivity analysis (Figs. 5-8).

Table 6 shows the results of the sensitivity analysis. Each cell represents the overall percentage increase in expected cost and activated flexibility for a given distribution companýs cost of capital and a given incentive rate. The results presented in the previous analysis (Figs. 5 to 8), corresponding to a 50% incentive rate and a cost of capital of 5.58%, showed a 0.6% increase in expected cost for the revenue cap approach, along with a 12.7% decrease in flexibility use. While the TOTEX approach presented a 2.3% expected cost increase and a 38.2% increase in flexibility use. These are the numbers that Table 6 summarizes for a 50% incentive rate and a 5.58% cost of capital.

Table 6 shows that increasing the incentive rate under the revenue cap approach reduces the cost of the network plan, decreasing the difference with the benchmark (MSC approach). With a 70% incentive rate and a 5.58% cost of capital, the difference in expected cost is only 0.1%. As expected, increasing the incentive rate increases productive efficiency and the use of flexibility closer to the MSC network plan. Conversely, a lower cost of capital increases the CAPEX advantage, leading to more inefficient solutions and lower flexibility use, as expected when this source of CAPEX-bias grows.

The effect of this sensitivity analysis on the network plan under the TOTEX approach is not so straightforward. The base case, with a 50% incentive rate and a cost of capital of 5.58%, showed a 2.3% increase in cost compared to the MSC network plan, as shown in Fig. 6. One may think that increasing the incentive rate up to 70% would lead to a more efficient network plan. However, it leads to a 3.1% cost difference compared to MSC. While the excess use of flexibility goes from 38.2% to 57.2%. Therefore, a higher incentive rate amplified the OPEX bias already present in the base case (Figs. 5 and 6), resulting in a less efficient solution.

A clear and consistent result of the TOTEX approach is that increasing the incentive rate leads to greater use of flexibility. While this may result in either more efficient or less efficient solutions, it shows again that the TOTEX approach introduces an OPEX bias, which is accentuated when the incentive rate increases. Similarly, a larger spread between the ARR and the CC leads to lower use of OPEX solutions (flexibility in this case). However, the effect on overall efficiency is mixed, as a wider spread may lead to either more efficient or less efficient solutions.

Next, we discuss the regulatory implications deriving from these results.

5.2. Discussion and regulatory implications

As discussed in the introduction, dealing with uncertainty and neutralizing incentives between OPEX-intensive and CAPEX-intensive solutions are key regulatory challenges for distribution networks in the upcoming years.

Establishing neutral incentives in DSO remuneration schemes is key to promoting smart-grid flexibility solutions, given the bias toward CAPEX solutions present in traditional regulation. Next, we discuss the different nature of OPEX and CAPEX and, in light of the case study results, whether equal treatment of CAPEX and OPEX is a desirable feature in DSO remuneration schemes.

Does equal OPEX/CAPEX treatment lead to neutral incentives? The nature of OPEX and CAPEX.

Under traditional capitalization approaches, investments are treated as capital expenditures (CAPEX) and are not recognized as immediate costs. Instead, their value is depreciated over the assets' useful life, with an additional allowance for the return on assets during that period. This cost-accounting method spreads the investments financial impact over its operational lifespan.

Treating an investment as an immediate cost would unfairly penalize it in cost-efficiency comparisons, especially for grid assets with long lifespans (e.g., 40 years), since the full cost would be assigned in the first year while the asset remains in service for decades.

In contrast, operational expenditures (OPEX) are a recurring cost for business operations (maintenance, labor, etc.). These operational expenditures are traditionally treated as costs. Capitalizing them would result in a cost misallocation by spreading the cost of a short-term solution over many years.

To illustrate this concept, please consider a simplified case with a five-year planning horizon. Suppose that the DSO must choose between a one-time 100 k€ investment with a 40-year useful life and an operational alternative costing 20 k€ per year. If the CAPEX is not capitalized, both options would appear to cost 100 k€ over the five years, disregarding the time value of money. However, this comparison is misleading. The investment alternative will continue to deliver value for 35 more years, while the operational solution would not address any grid issues beyond the five-year period. Thus, failing to capitalize the investment would distort the analysis and bias decisions toward the short-term OPEX alternative.

Now consider the impact of applying a fixed capitalization rate to the same simple case. The TOTEX approach sets a fixed capitalization as a measure to neutralize OPEX/CAPEX incentives. With an 80% capitalization rate, both the investment and operational alternatives would have the same "fast money" cost (i.e., 20 k€) and a total addition to the RAB of 80 k€ during the five years. However, the operational solution provides no long-term benefit and is not cost-efficient. In contrast, under traditional capitalization, with a 5.58% rate of return, a 40-year useful life of the asset, and constant annuity payments accounting for depreciation and cost of capital, the cost of the investment alternative would be 6.48 k€/year. Therefore, the investment alternative delivers significant savings over the operational alternative (20 k€/year).

This leads to a critical issue: capitalizing OPEX causes a misallocation of costs. Spreading the cost of a short-term solution over many years (some of which may fall outside the regulatory period) understates the actual cost incurred during the relevant regulatory period. When combined with cost-efficiency incentives such as profit-sharing, this understatement rewards non-existent efficiency, introducing a new bias, this time favoring OPEX over CAPEX. Therefore, while the intention of capitalizing OPEX is to neutralize CAPEX/OPEX incentives, it in fact creates a different distortion in the form of an OPEX bias. This bias was observed in the case study results (Figs. 5 and 6, and Table 6). In conclusion, CAPEX and OPEX differ in nature, and treating them equally does not lead to neutral incentives. Therefore, capitalizing OPEX should

Table 6
Sensitivity analysis of expected cost and expected flexibility use compared to MSC benchmark. Variations in incentive rate (IR) and cost of capital (CC).

		Revenue Cap			TOTEX		
		IR = 30%	**IR = 50%**	**IR = 70%**	**IR = 30%**	**IR = 50%**	**IR = 70%**
Cost of capital = 5.58%	Cost Increase in the network plan	2.1%	0.6%	0.1%	2.5%	2.3%	3.1%
	Flexibility use Increase	−22.6%	−12.7%	−5%	4.3%	38.2%	57.2%
Cost of capital = 4.58%	Cost Increase in the network plan	3.8%	1.9%	0.4%	2.6%	2.5%	1.9%
	Flexibility use Increase	−39.9%	−25.1%	−13.1%	−22.8%	10.95%	36,6%
Cost of capital = 3.58%	Cost Increase in the network plan	13.6%	3.7%	1.6%	5.5%	2.1%	1,3%
	Flexibility use Increase	−67.7%	−38.3%	−25.4%	−42.2%	−12%	17%

not be the preferred method to achieve incentive neutrality between OPEX and CAPEX solutions.

Therefore, a key strength of this study is its demonstration, through quantitative modeling, that the TOTEX scheme does not achieve neutrality but rather introduces a structural OPEX bias. This finding directly challenges the consensus among many regulators and highlights the risk of implementing theoretically appealing policies without rigorous quantitative assessment.

Table 6 shows that the results under the revenue cap approach are easier to interpret. For example, a regulator may increase the incentive rate in a given period to enhance productive efficiency. Conversely, a low use of flexibility in the network plans may indicate a significant spread between the allowed rate of return (ARR) and the distribution company's actual cost of capital (CC). In contrast, the TOTEX approach showed mixed effects, not only distorting efficiency incentives by favoring OPEX solutions but also complicating the analysis and potential future regulatory adjustments. Moreover, the case study results do not show an overall efficiency improvement under the TOTEX compared with the revenue cap, further questioning its suitability. In addition, implementing the revenue cap is straightforward compared to the more complex TOTEX with a fixed capitalization rate implementation. Since simplicity is a guiding principle of regulation, the revenue cap is recommended over the TOTEX approach.

This study does not analyze the effects of multiple regulatory periods on DSO incentives. However, as highlighted in [16], CAPEX-based solutions provide long-term stability of returns (CAPEX stability bias) for the regulated firm over the asset's lifespan (typically around 40 years). This stability of returns spans several regulatory periods. Future research should assess how investment decisions made in one period shape the allowed revenues in subsequent periods. Such analysis may find a structural bias toward CAPEX solutions. For this purpose, future research should consider the adjustments that regulators introduce at the beginning of each regulatory period. This analysis exceeds the scope of this paper. In any case, addressing this long-term bias should not come at the cost of creating short-term distortions, such as those previously discussed, caused by fixing a capitalization rate for the total expenditure.

Priorities in remuneration schemes emerging from this study.

Results showed that both the revenue cap and the TOTEX approaches significantly benefit from adaptable planning. This improves productive efficiency under both remuneration schemes. On the other hand, adaptable planning brings little to no benefit under the cost-of-service approach. However, note that enabling multi-scenario adaptable planning could incentivize DSOs to include extreme or high-cost scenarios in their investment plans to justify elevated expenditures. This is particularly important at the start of the regulatory period when DSOs present plans to the regulator, who sets the allowed revenue baseline. Therefore, regulators should exercise caution when permitting multi-scenario planning approaches, especially if allowed revenue baselines are predominantly based on DSO-submitted investment plans, rather than on benchmarking methods or externally derived parameters and calculations.

After the presented findings, the following regulatory recommendations emerge. First, regulators should prioritize transitioning away from cost-of-service remuneration schemes or hybrid approaches toward an ex-ante revenue cap with a profit-sharing mechanism. This shift enables more effective use of flexibility solutions while promoting cost-efficiency. Second, once efficiency is properly incentivized, enabling adaptable planning can bring additional efficiencies. Third, regulators may want to achieve OPEX/CAPEX incentive neutrality, but implementing a TOTEX scheme with a fixed capitalization rate is not recommended. Regulators may achieve better outcomes by refining revenue cap schemes rather than adopting a fixed capitalization rate or other similar schemes that capitalize OPEX.

Long-term regulatory effectiveness requires acknowledging the asymmetry of information between DSOs and regulators. Allocative inefficiencies resulting from cost-efficiency incentive mechanisms should not be viewed as a regulatory failure but as a necessary cost for revealing firms' efficiency potential. This allocative inefficiency can be addressed by adjusting the revenue baseline of future periods in light of previously achieved efficiencies. Hence, the goal should not be to eliminate inefficiency entirely, but to manage and learn from it in order to progressively improve the regulation.

5.3. Limitations of the study and future research

This study does not assess two of the sources of CAPEX bias described in [16], which are the CAPEX stability and the OPEX risk. These sources of CAPEX bias are less discussed in the literature and are outside of the scope of this paper. However, they represent potential future research lines, in particular, the CAPEX stability, which provides long-term incentives for CAPEX solutions.

This study considers a single regulatory period; therefore, it does not assess how rules for setting the allowed revenue baseline in the following periods may create incentives to alter investment decisions in the current regulatory period. As mentioned, this is a relevant topic for further research that falls outside the scope of this study.

In terms of service quality, the presented methodology focuses on estimating the energy not served as an indicator; future research may consider other metrics if deemed necessary, such as energy losses, the number and frequency of supply interruptions, etc.

A limitation of this study is that revenue trajectories for the revenue cap and TOTEX schemes were derived from the cost-of-service plan. This assumption facilitates comparability of results. However, regulators often use alternative methods such as benchmarking and various baseline-setting approaches. This could influence the magnitude of the resulting incentives. While such changes would affect the distribution company's profits and the calculated allocative inefficiency, they would not alter the planning decisions. The planning decisions are determined by the incentive structure rather than the revenue baseline for a risk-neutral decision-maker, considering a single regulatory period.

A possible extension of this work is to incorporate option-valuation methods to calculate the value of flexibility in distribution network planning [40]. While this may be useful from the DSO perspective, it may not be prudent from a regulatory perspective. As noted by [41], if the regulator recognizes the option value of flexibility solutions, the DSO may attempt to justify large expenditures for contingencies that, in most cases, will never materialize.

Regarding uncertainty, some researchers have begun to assess the endogenous uncertainties in distribution network planning [42]. Distribution networks may enable specific activities for connected users. For example, if a DSO invests in smart-grid technologies, it enables connected users to offer demand response through markets or bilateral contracts. At the same time, greater availability of flexibility enables DSOs to make different planning decisions. In this way, present investment decisions of DSOs may shape future scenarios. Therefore, a DSO may treat future scenarios as a combination of exogenous and endogenous uncertainties. However, regulators should exercise caution when recognizing the value of some investments that act as enablers of promising future scenarios that may never materialize. This may create an incentive for DSOs to depict overly optimistic scenarios to justify investments in the distribution network.

Finally, the network model and planning constraints presented in the Annex consider only a single reinforcement candidate, whereas a DSO may need to evaluate multiple reinforcement options simultaneously. Moreover, the network model assumes a single-node capacity-limited network element, which, in our case study, is the net load supplied by a substation. Future research may consider a multi-node network model with power-flow calculations, enabling the simultaneous analysis of multiple congested elements. It would also enable the assessment of different remedial actions, including flexibility solutions allocated across various system nodes.

6. Conclusions

The results of this research lead to the following conclusions.

The cost-of-service approach leads to the least efficient outcomes, with investment decisions deviating significantly from the optimal plan, resulting in expected costs 15% to 30% higher than the MSC benchmark. The cost-of-service approach fails to incentivize cost minimization, showing high productive inefficiency and no use of flexibility solutions to delay network reinforcement. Moreover, adaptable planning under this approach delivers results similar to traditional planning, with negligible cost reduction (1.5% in the case study). This again highlights the limited use of flexibility solutions due to the absence of efficiency incentives. Overall, these results show that a CAPEX bias is present to a large extent under cost-of-service remuneration schemes.

In contrast, the network plans under both the revenue cap and TOTEX approaches achieve results close to the MSC benchmark. Allowing adaptable planning brings significant benefits in terms of productive efficiency under both remuneration schemes.

Results from the sensitivity analysis show that the TOTEX approach, while promising in theory and contrary to the regulator's prevailing belief, presents an OPEX bias. The fixed capitalization rate in the TOTEX misallocates capital and operational costs, artificially favoring OPEX-intensive flexibility solutions over CAPEX-intensive grid investment. This bias resulted in an expected cost increase of up to 24% compared to MSC. The more pronounced cost increase occurred in cases with high availability of flexibility, at a medium–high price (i.e., between 0.75 and 2 times the cost of flexibility in the base case).

The revenue cap approach strikes a better balance. This approach presents a CAPEX bias due to the CAPEX advantage. The CAPEX advantage is accentuated as the allowed rate of return set by the regulator exceeds the DSO cost of capital by wider margins. However, in the analyzed case study, the impact of this CAPEX bias on overall efficiency is limited, with expected cost increases of less than 2% and 4% compared to the benchmark when applying incentive rates of 70% and 50%, respectively. The sensitivity analysis shows that the regulators can mitigate this bias by increasing the incentive rate.

The effects of different regulatory decisions are easier to interpret under the revenue cap scheme compared to the TOTEX approach. This clarity simplifies the analysis of DSO performance in previous regulatory periods, and supports informed adjustments for the next one. As a result, the revenue cap emerges as a more practical regulatory choice.

Regulators should prioritize transitioning away from cost-of-service remuneration schemes or hybrid approaches toward ex-ante revenue cap approaches with a profit-sharing mechanism. This shift enables more effective use of flexibility solutions while promoting cost-efficiency. Once efficiency is incentivized by an appropriate remuneration scheme, enabling adaptable planning can bring additional efficiencies. Third, regulators may want to achieve OPEX/CAPEX neutral incentives by implementing TOTEX with a capitalization rate, but, based on the results, this practice is not recommended.

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CRediT authorship contribution statement

Miguel A. Ruiz: Writing – original draft, Visualization, Validation, Software, Methodology, Formal analysis, Conceptualization. **Tomás Gómez:** Writing – review & editing, Visualization, Supervision, Conceptualization. **José P. Chaves-Ávila:** Writing – review & editing, Visualization, Supervision, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Appendix A

The network model and planning constraints used in this study are derived from a previous study [35]. The considered network model is a single-node capacity-limited substation. The methodology may be extended to consider more complex network models (e.g., multi-node network models that include thermal and voltage operational limits). The planning constraints consider adaptable planning based on a real options approach. Next, we present the formulation of these constraints to ensure the replicability of the presented results. For a detailed explanation and discussion of the planning approach, its details, and implications, please refer to [35].

Planning constraints.

Grid reinforcement constraints.

The decision to reinforce the grid follows a trigger-based rule, where the trigger level, tr^G determines whether grid reinforcement is required in future periods (t > 1).

Constraint (19) ensures that the trigger for grid reinforcement is activated when the previous year's peak load exceeds the trigger level.

Constraint (19) ensures that no grid trigger activation occurs if the previous year's peak load remains below the trigger level, tr^G.

$$tr^{G-act}_{s,t}*(M+\epsilon)-\epsilon \geq P_{s,t-1}-tr^{G} \qquad \forall s, 2 \leq t \leq T-GLT \tag{19}$$

$$\left(1-tr^{G-act}_{s,t}\right)*(M+\epsilon)-\epsilon \geq t_r{}^{G}-P_{s,t-1} \qquad \forall s, 2 \leq t \leq T-GLT \tag{20}$$

The trigger level functions as a rule for future decisions (t > 1). Additionally, any investment decision after $T-GLT$ would result in grid reinforcement being commissioned beyond the last year of the planning period T. Therefore, there is no trigger activation beyond $T-GLT$ or in t = 1 considered in this analysis. Constraint (21) enforces this logic.

$$tr^{G-act}_{s,t}=0 \qquad \forall s, t > (T-GLT) \cup \mathrm{t}=1 \tag{21}$$

The grid reinforcement is modeled as a one-time commitment, allowed at most once per scenario during the planning period. This restriction is enforced by constraint (22).

$$\sum_{t} i^{G}_{s,t} \leq 1 \qquad \forall s \tag{22}$$

Constraint (23) guarantees that if grid reinforcement is made in year 1, the decision is binding for every scenario.

$$i^G_{s,t=1} = i^1 \quad \forall s \tag{23}$$

Constraint (24) requires that grid reinforcement decisions (for t > 1) can only occur following trigger activation.

$$i^G_{s,t} \leq tr^{G-act}_{s,t} \quad \forall s, t \geq 2 \tag{24}$$

Constraint (25) ensures that the grid investment is made in at the first grid trigger activation.

$$\sum_{t=1}^{a} i^G_{s,t} \geq tr^{G-act}_{s,t=a} \quad \forall s, a \tag{25}$$

Constraint (26) ensures that no trigger activation occurs during year 1.

$$tr^{G-act}_{s,t=1} = 0 \quad \forall s \tag{26}$$

Constraint (27) enforces the lead time between the reinforcement decision and commissioning, and ensures that once the asset enters service in a given scenario, it remains operational throughout the planning horizon.

$$g_{s,t=a+GLT} = \sum_{t=1}^{a} i^G_{s,t} \quad \forall s, a \leq T - GLT \tag{27}$$

Constraint (33) ensures that grid reinforcement cannot become operational before year GLT + 1, since the earliest decision to reinforce can only be made at t = 1.

$$g_{s,t} = 0 \forall s, t \leq GLT \tag{28}$$

Flexibility reserve constraints

The decision to reserve flexibility also follows a trigger-based rule, where the trigger level, tr^F determines whether flexibility reserve is required in future periods (t > 1).

Constraint (29) ensures that flexibility is only reserved when the previous year's peak load exceeds the trigger level and no grid reinforcement is scheduled for commissioning in year t + FLT.

Constraint (30) ensures that no flexibility is reserved if the previous year's peak load remains below the trigger level, tr^F.

$$\left(r^F_{s,t} + g_{s,t+FLT}\right)^*(M + \epsilon) - \epsilon \geq P_{s,t-1} - tr^F \quad \forall s, 2 \leq t \leq T - FLT \tag{29}$$

$$(1 - r^F_{s,t})^*(M + \epsilon) - \epsilon \geq tr^F - P_{s,t-1} \forall s, 2 \leq t \leq T - FLT \tag{30}$$

Constraint (31) enforces that the decision to reserve flexibility in year 1, denoted as f^1, must apply uniformly across all scenarios.

$$r^F_{s,t=1} = f^1 \forall s \tag{31}$$

Constraint (37) ensures that no flexibility is reserved after year T − FLT, as doing so would lead to activation beyond the planning horizon.

$$r^F_{s,t} = 0 \forall s, t > T - FLT \tag{32}$$

Constraint (33) ensures that flexibility is not reserved in year t if grid reinforcement is already scheduled for commissioning in year t + FLT. This is based on the assumption that the reinforcement fully resolves future network congestion.

$$r^F_{s,t} \leq 1 - g_{s,t+FLT} \forall s, 1 \leq t \leq T - FLT \tag{33}$$

Network model

Calculation of the energy not served.

The rule for determining the flexibility to reserve in each scenario and year is based on the real options framework and the latest available information. At the start of year t, the methodology calculates the flexibility to be reserved for activation in year t + FLT, using base scenario forecasts and the observed peak load evolution from year 0 to t − 1. Fig. 9 illustrates this decision-making process for scenario s.

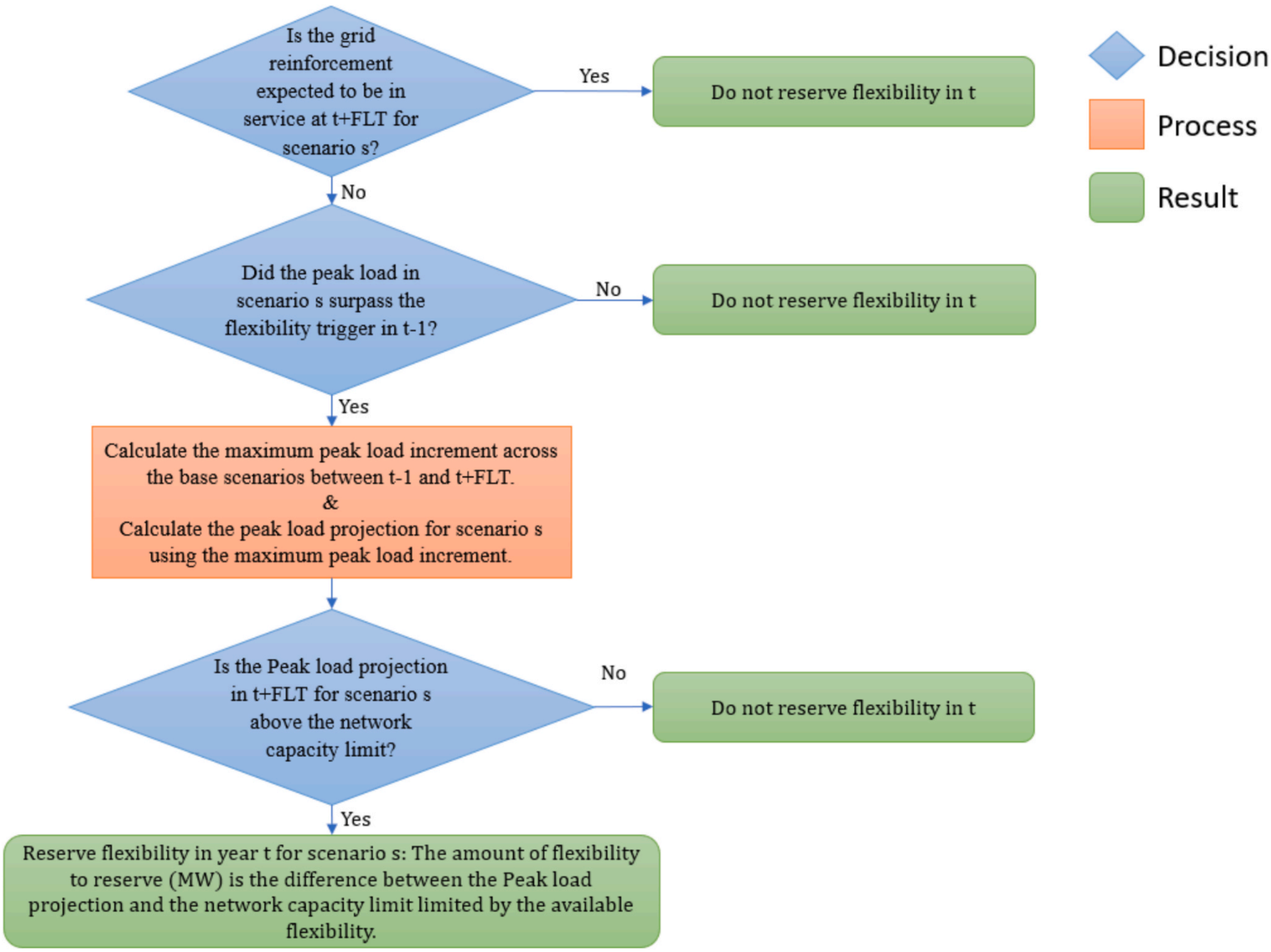

Fig. 9. Decision-making process to reserve flexibility using the real options approach

Calculation of the energy not served.

Fig. 10 shows how energy not served (ENS, yellow area) is calculated for scenario s and year t when flexibility is reserved but no grid reinforcement is in place. Flexibility, activated during peak hours (green area), temporarily increases network capacity.

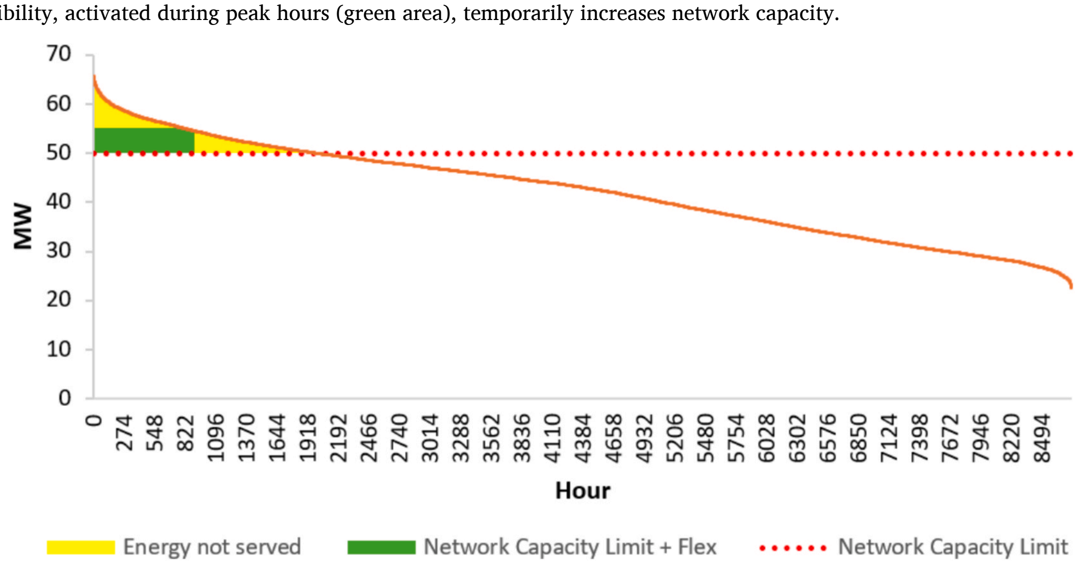

Fig. 10. Illustration of the network capacity limit, the load duration curve, and the amount of energy not served if flexibility is reserved.

Flexibility activation and energy not served constraints.

Constraint (34) ensures that the energy not served in each scenario and year reflects the type of intervention applied. This is $ENS^0_{s,t}$ if no action is taken, $ENS^F_{s,t}$ if flexibility is reserved, $ENS^G_{s,t}$ if grid reinforcement is commissioned.

Constraint (35) ensures that variable δ takes a value of 1 when no intervention is made at each year t and scenario s.

$$ens_{s,t} \geq ENS^0_{s,t} * \delta_{s,t} + ENS^F_{s,t} * r^F_{s,t-FLT} + ENS^G_{s,t} * g_{s,t} \qquad \forall s, t \geq 1 + FLT \tag{34}$$

$$r^F_{s,t-FLT} + g_{s,t} \geq 1 - \delta_{s,t} \qquad \forall s, t \geq 1 + FLT \tag{35}$$

Considering more complex network models (e.g., multi-node network models and including voltage operational limits) would require additional constraints, such as enforcing power flow equations between nodes and enforcing the desired technical performance metrics. The model may also be extended to consider additional reinforcement and flexibility solutions as alternatives by adding more variables that represent the different possible interventions.

Data availability

The data used in this study are available, within the manuscript, and in previously published studies where they have already been employed.

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