Considering strategic market feedback in transmission expansion planning: a bi-level approach

Isaac-Camilo Gonzalez-Romero[1*], Sonja Wogrin[1], Tomas Gomez[1]

Abstract

The growing penetration of renewable technologies, as well as the increasing needs of storage technologies, has introduced new challenges into the design of electricity markets. Therefore, centralized TSOs decide network expansion, by aiming to maximize social welfare, while decentralized generation companies decide their investments by maximizing their own profit. In this sense, generation companies have to face the intermittency of renewable energy, as well as to manage the new dynamics of different types of storage according to short and long-term economic signals. This environment may create new opportunities for strategic market behavior of these competitive generation companies. However, traditional (and widely utilized) cost minimization planning models do not account for this type of interaction. As an alternative, we present a bi-level proactive transmission expansion framework in which a centralized TSO represents the upper level while the decentralized generation companies that trade in the market represent the lower level. We study the policy implications of planning the system under a traditional cost minimization approach instead of a proactive framework (in which distinctive technology ownership and degrees of competition can be considered), that accounts for potential strategic behavior of market agents.

Highlights

- A proactive transmission expansion planning framework (bi-level programing) is proposed
- A methodology to compute the cost of disregarding strategic market feedback in proactive transmission expansion planning is proposed
- Policy objectives of a merchant investor and a social planner are compared
- Short and long-term coupling storage constraints are jointly considered for storage expansion (dispatchable Hydro and Batteries)

Key Words

Proactive planning, Storage, Renewables, Strategic market behavior, Transmission expansion, Generation expansion, Bi-level programing

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1. Introduction

In modern electricity markets, centralized and regulated transmission system operators (TSOs) decide network expansion, by aiming to minimize total costs (or maximize welfare), while decentralized generation companies (GENCOs) decide their generation investment by maximizing their own profit. This market structure creates contradictory incentives between these two market participants and can lead to different outputs depending on who is considered as the leader in the market. We first introduce the existing

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regulatory approaches for transmission and generation expansion planning. Then, we present the relevant literature and finally, we state our research question and objectives.

1.1.1 Regulatory Approaches

Originally, power systems were planned by vertically integrated utilities (that owns the transmission and generation companies, see Figure 1) with a cost-minimization objective, in which Generation Expansion Planning (GEP), Transmission Expansion Planning (TEP) and operation decisions were simultaneously taken under the assumptions of inelastic demand, perfect information and in the absence of competition.

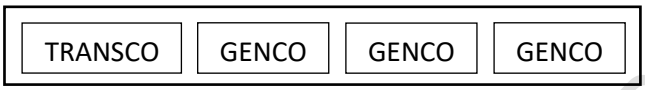


Figure 1: Cost-minimizing centralized approach

However, such a planning framework is highly questionable in modern markets. The generation business has been liberalized by allowing GENCOs to invest and operate freely, while transmission investment decisions are still regulated and operated by a centralized transmission company (TRANSCO). As seen in Figure 2 and Figure 3, this liberalized framework can be modeled considering two main regulatory approaches:

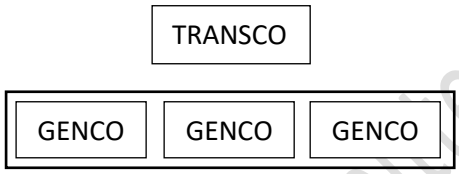


Figure 3: Proactive Approach



Figure 2: Reactive Approach

In the proactive approach, we consider that the TSO[2] is the leader in the market that takes its transmission investment decisions (TEP) by anticipating the generation investment (GEP) and operation decisions of GENCOs. In the reactive approach, the TSO is the follower that reacts to GENCOs decisions. Please note that a proactive approach with inelastic demand and perfect competition is equivalent to the previously presented cost-minimizing approach.

Despite the theoretical optimality of the proactive approach [1], most of the TSOs in the world follow a reactive approach [2]. Some countries [3] are applying regulations similar to the proactive approach (as originally proposed by [4]). For example, the US government approved a regulation that includes the concept of anticipative (proactive) transmission planning [5]. Similarly, the Chilean government approved a regulation that enforces the consideration of coordination between transmission and generation planning [6]. Lastly, in the current European context, ENTSOE plays the role of a centralized and regional coordinator that proposes future planning pathways [7], by anticipating how generation companies can react on a national scope.

As a consequence of the mentioned advantages, we decide to implement a proactive planning approach. It is important to note that, under this framework, GENCOs can

[2] We consider that the TRANSCO is in fact a regulated TSO.

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potentially behave strategically in both generation expansion and operation. From now on, we will call this behavior the 'strategic market feedback'. This potential strategic behavior, on which we will focus, is particularly relevant nowadays given several features: i) construction times for transmission lines are consistently higher compared to construction times for generating units ii) high penetration of intermittent renewable technologies with decreasing capital costs iii) introduction of Battery Energy Storage Systems (BESS).

Although energy storage existed already in the form of pumped hydro, BESS (whose global deployment in 2018 has doubled that of 2017 [7]) present additional features: i) they help stabilize market prices [8]; ii) they can be sited anywhere in the network and can react more rapidly to the operational needs; iii) they are natural arbitragers of the market; and, iv) they can either be supplementary (replace the network) or complementary (reinforce transmission services) to the network [9], [10], [11], [12].

Finally, as a consequence of the complex deployment of energy systems, sometimes merchant transmission investors are essential to deploy certain types of projects (international tie-lines or interconnections for off-shore wind farms). Therefore, we also consider the case of an investor that takes its investment decision by trying to maximize its incomes, known as congestions rent.

1.1.2 Literature Review

Recently, there has been continuous research on power systems on what we call 'co-planning equilibrium models for generation and transmission expansion planning (GEPTEP) [3], [8], [13]–[15]. These models refer to the joint GEPTEP considering a decentralized market framework. In contrast to the GEPTEP co-optimization problem (centralized cost-minimizing approach), co-planning problems embrace a more general market structure which considers both sequential (e.g.; first TEP and then GEP) and strategic decisions (e.g.; Cournot competition). This type of structure leads to a hierarchical optimization problem that is complex to solve. For a detailed review of co-planning equilibrium problems please refer to [16].

Typically, GEPTEP co-planning models include three types of market agents, namely: GENCOs, the TSO and the Market Operator (MO). Accordingly, a three-level hierarchical structure is usually considered; some investment decisions GEP (or TEP) are decided in the upper level given some other TEP (or GEP) investment decisions in the middle level[3] and subject to the spot market (where GENCOs and the MO interact)[4] in the lower level. This three-level equilibrium structure implies solving a complex Equilibrium Problem with Equilibrium Constraints (EPEC) whose solution techniques are an active field of research [17]. Alternatively, instead of a three-level structure, we can consider a bi-level equilibrium that implies solving a Mathematical Problem with Equilibrium Constraints (MPEC). Following the proactive approach, we consider the TSO in the upper level (which is in charge of deciding TEP), and simultaneously GENCOs (GEP and operation) and MO in the lower level, as the structure depicted in

[3] Depending if a proactive or reactive approach is considered

[4] Some models even consider a sequence between the market clearing and the operation

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Figure 3. In this paper, and following the approach of [18] and [19], we consider imperfect competition in the lower level (contrary to most works that consider perfect competition) with a conjectured price response framework (based on [20] which presents the single-level equivalent of a bi-level model using conjectural variations). For more details see section 2.3.2.

As mentioned in the previous section, BESS are becoming more and more important as they bring several advantages to the network. To our knowledge, only [21] and [8] have considered comprehensive storage co-planning models. On the one hand, authors in [21] develop a tri-level reactive model, they assume a merchant storage investor in the upper level, while transmission expansion and market operation are modeled in the middle and lower level respectively. On the other hand, authors in [8] model battery expansion in the lower level and choose a pessimistic TSO (with certain uniqueness properties) in the upper level. However, both [21] and [8] assume perfect competition in the market and disregard hydro storage. Additionally, authors in [22] consider a stochastic bi-level model with a merchant transmission investor in the upper level and both wind expansion and strategic operation in the lower level.

In this type of planning models, there is a common trade-off between a detailed representation of technical operating constraints and models tractability. In particular, it is difficult to jointly consider storage facilities that operate in different time horizons because the choice of time representation (i.e., load levels vs representative hours) would naturally facilitate the representation of one storage facility over the other (i.e., pump-hydro vs batteries). Consequently, authors in [18] and [19], apply the same structure as [22], considering Cournot competition in the lower level and modeling both short- and long-term storage by applying the enhanced representative periods approach proposed by [23]. In the present paper, we extend the work of [19] by incorporating different GENCOs ownership structure, introducing a merchant investor and developing a comprehensive policy analysis.

Finally, most of the articles discussed above assume that a regulated transmission planner is in charge of network expansion, however, in some cases (i.e., international tie-lines or interconnections for off-shore wind farms), merchant investors are essential to develop such projects. Articles [8], [15], [22] have addressed this topic in the literature; authors in [15] compare a merchant investor with a social planner by considering perfect competition in the lower level. Additionally, authors in [8] extend the work of [15], by modeling BESS in a zonal pricing scheme under a perfect competition environment. In contrast, authors in [22] model a transmission merchant investor subject to wind expansion and Cournot competition, disregarding storage operation and considering only a 3-node case. In summary, we propose a novel proactive model that considers both social and merchant transmission planners that anticipate the strategic behavior of GENCOs, that in turn, own a diversified portfolio including, renewable and long and short-term storage technologies.

1.1.3 Policy Question and Contributions

Despite the fact that most of the electricity markets in the world are liberalized, transmission planners do not consider these kinds of interactions in the market and they

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continue planning TEP under a traditional cost-minimizing approach (assuming the results of a centralized GEP expansion). Thus, we raise the question of how much the ideal generation capacity investment, assumed by optimistic TSOs in a cost-minimizing approach, differs from reality (as a result of the strategic market interactions between GENCOs)? What is the cost of sub-optimal transmission expansion planning due to overly optimistic generation capacity expansion assumptions? How can we factor in strategic market feedback in an optimal transmission expansion plan? We propose a methodology that allows us to compute the welfare loss between a simple and overly optimistic cost minimization approach, instead of a more complex approach where a TSO foresees strategic market outcomes. In other words, we want to compare how the operation and investment decisions under perfect or Cournot competition can affect the transmission decisions and the overall social welfare.

Additionally we compare how different ownership structures in the market (owning more than one technology) influence the exercise of market power and how they affect overall welfare results. Finally, we also compare distinctive planning objectives for centralized planners and we compare them with a merchant transmission investor.

Our contributions are threefold: i) we carry out a comprehensive policy analysis in which we study the implications of disregarding market feedback (and having distinctive ownership structures) in transmission expansion planning; ii) apart from a social planner we consider a merchant transmission investor who recovers its investment by maximizing congestions rents; iii) we are the first to comprehensively consider strategic investment in both batteries (short-term storage) and pumped-hydro (medium-term storage) in bi-level models.

2. Mathematical Formulation

In this section we present the main structure of the corresponding models, we include the main constraints and main decision variables. The detailed formulation can be found in [19]. Additionally, we include the formulation of a merchant transmission investor.

2.1. Notation

Sets / Indices

$y \in Y$	year
$p \in P$	periods (hours in the year)
$rp \in RP$	representative periods
$\Gamma_{rp,p}$	set of correspondence between rp and p
$d, d' \in D$	nodes
$g \in G$	generator unit g
$LA(d,d')$	set of all possible lines from node d to d'
$LE(d,d')$	set of existing lines from node d to d'
$k \in K$	discretization steps

Parameters

$pMaxFlows_{dd'}$	Maximum flow in line dd'	MW
$pReactance_{dd'}$	Reactance of line dd'	[p.u.]
$pFCost_t$	Fuel cost of technology t	€/MWh
$pInvC_{dd'}$	Annualized investment cost of line dd'	€

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$pDemand_{ypd}$	Demand Intercept at year *y* period p at node d	MW
$pDSlope$	Demand Slope	MW^2/€
pW_{rp}	Weight of each representative day	[p.u.]
pSB	Base Power	MW
θ_g	Conjectural variation of GENCO g	€/MW^2
$\overline{\lambda}$	Price upper bound	€/MW

Variables

$vNewLine_{ydd'}$	Investment status at year y of line from node d to d'	{0,1}/MW
$vFlows_{ypdd'}$	Flows at year y at period p from node *d* to *d'*	MW
$\Delta Flows_{ypdd'}$	Flow step magnitude year y at period p from node *d* to *d'*	MW
$vBinFlow_{ypdd'k}$	Binary variable for flow at year y period p from node d to d'	{0,1}/MW
$vF\lambda_{ypdd'k}$	Flow times price at year y period p from node d to d' and step k	MW
$vDemand_{ypd}$	Demand at year y period p at d	MW
λ_{ypd}	Prices at year *y* period *p* node *d*	€/MW

2.2. Benchmark: Cost Minimization Model (CMM)

Traditionally, capacity expansion has been planned from the point of view of a centralized vertically-integrated utility. In such a framework, depicted in Figure 4, the central planner decides *simultaneously* transmission and generation capacity expansion as well as the market operation by minimizing the total system cost. Additionally, the central planner assumes perfect competition and perfect information.

Single Level	Central planner Decides TEP, GEP, dispatch and power flows Minimizes Total Cost (investment +operation)

Figure 4: Cost Minimization Structure

It is important to note that, there is always a trade-off between how fine time granularity is considered and how detailed market operation is modeled. This disjunctive is especially important for the simultaneous representation of hydro and battery storage. In fact, most models consider either a load blocks (systems states) or representative periods. However, each of these options is more suitable for either of the storage technologies. In order to overcome this issue we consider an enhanced representative periods framework proposed by [23], and applied in [18] and [19], which considers a representative-periods approach together with a transition matrix that gives count of how each representative period is connected to each other. From this framework, it is not only possible to model the battery storage with its intraday charging cycle, but also the hydro operation with its interday charging cycles by taking advantage of the links between representative periods. In this sense, a time window (more than a day, i.e week or month) is chosen to verify the hydro storage balance and follow the yearly evolution of the reservoir. Apart from this consideration, this model includes basic operating constraints.

The main constraints considered are:

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i) Maximum and minimum power outputs for existing and new conventional generators, new investments are considered as continuous variables.
ii) Maximum and minimum power outputs for existing and new wind generators, considering them as non-dispatchable technologies.
iii) Maximum and minimum power outputs and consumption inputs for storage units. Considering both inter-day constraints for short-term technologies (BESS) and intra-day constraints for long-term storage technologies (hydro).
iv) Power flow constraints considering a linearized DC power flow for existing and new lines, we consider binary variables for network expansion.
v) Market clearing condition.

2.3. Bi-level Problem: Proactive Model (PM)

We consider a proactive approach in which the TSO plans the system, as the leader in the market, by anticipating both GEP and operation decisions.

2.3.1. Bi-level Structure

<table>
<tr><td>Upper Level</td><td colspan="3">TSO or Social Planner (decides TEP)
1) Minimizes Total Cost
2) Maximizes Welfare</td></tr>
<tr><td rowspan="2">Lower Level</td><td>GENCOs
(decide GEP and operation)
Maximize Profits</td><td>SO
(decides power flow)
Maximizes
Congestion Rents</td><td>Consumers
(decide demand)
Maximize
Demand Utility</td></tr>
<tr><td colspan="3">Market Clearing Condition</td></tr>
</table>

Figure 5: Bi-level Model Structure

Let us explain the main differences between the CMM (section 2.2) and the PM frameworks.

First, in the upper level, we consider two distinctive objectives for the social planner, namely, cost minimization and welfare maximization. Please note that the cost minimization objective considered here is the same as the one in the CMM framework. Please also note that a welfare maximization objective and a cost minimization only lead to the same results when there is inelastic demand, perfect competition and simultaneous decisions. Therefore, we compare the planning results of considering both planning objectives in an imperfect, elastic and sequential market model.

Second, in the lower level we consider three type players (each one with their own optimization problem), namely, GENCOs, the system operator (SO) and Consumers. The collection of these players' constraints is the same as that of the CMM framework. Finally, the *market clearing condition* couples every player's optimization problem, by ensuring that total supply is equal to the demand at each node. This constraint in the only one that differs from the CMM, given that in CMM the demand is a parameter (inelastic) while in the PM framework it is considered to be variable (elastic demand) see 2.3.2.

Mathematically speaking, Figure 5 shows a structure in which an optimization problem (upper level) is constrained by several optimization problems (lower level). Please note that such a structure cannot be solved directly as an optimization problem, therefore, we need to transform it into a single-level problem. First, we convert the set of optimization problems at the lower level into a set of constraints, by considering the equivalent KKT conditions. These conditions, which include some non-linear complementarity conditions, can be linearized by applying the well-known disjunctive constraints [24] with tight and meaningful big-Ms [25]. To sum up, this process leads to a single-level MIP problem where the upper level optimization problem is subject to a set of linearized equilibrium constraints. For details, please refer to [19].

2.3.2. Market Responsive Framework

Following the work of [26], we consider an affine relation between price and demand as shown in (1), i.e., demand is elastic, where *pDemand* represents the inelastic part of the demand and *pDslope* represents the slope of this function, which can be interpreted as how demand reacts to prices. Therefore, for a given node the demand would be given by (1).

$$vDemand_d = pDemand_d - pDslope_d * \lambda \; \forall d \tag{1}$$

We furthermore define a conjectural variation $\theta_g = \partial\lambda/\partial vProd_g$ that is assumed to be known for every GENCO g. This conjecture corresponds to each GENCO's belief on how much they can impact market prices by varying production $vProd_g$. If $\theta_g = 0$ this represents perfect competition (PC), and if $\theta_g = 1/pDSlope$ (inverse of the slope of the residual demand curve) it represents a Cournot oligopoly (CO). Any intermediate value of the conjecture allows us to model different degrees of competitive behavior.

2.4. Regret Computation: CMM vs PM

In order to compare the benchmark model and the bi-level problem, we compute what we refer to as *regret*. The regret represents the additional cost (or missing welfare) resulting from planning the system in a centralized traditional manner (CMM), where all decisions are considered to be simultaneous and perfectly competitive, compared to planning the system in a more realistic decentralized manner (PM) where TEP decisions are assumed to be taken prior to GEP decisions and considering market feedback given by GENCOs strategic behavior. Given that the CMM model is inelastic, while the PM is elastic, a specific methodology is needed to make these models comparable. This methodology is depicted in Figure 6:

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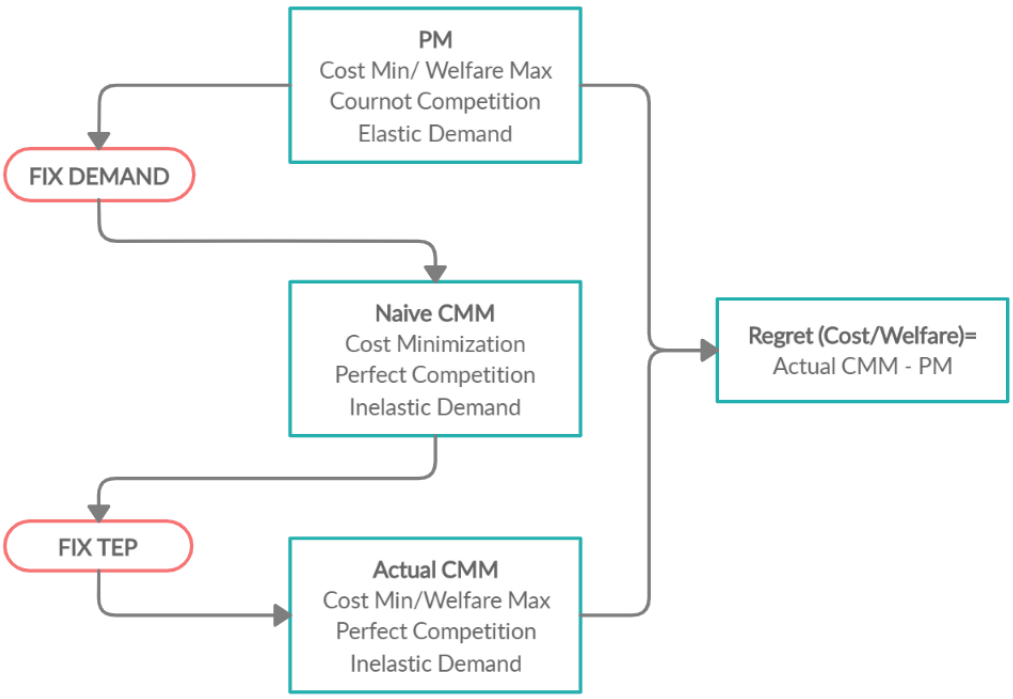


Figure 6: Regret Computation Methodology

i. We solve the *PM model* (considering Cournot competition in the lower level).
ii. For the exact same system demand obtained by the PM, we solve the inelastic CMM, which obtains some TEP and GEP investments (that might differ from the ones obtained by the PM). We refer to this model as the *Naïve CMM*; it is "naïve" because it does not reflect the strategic behavior of GENCOs. Therefore, the TEP and GEP obtained by the Naïve CMM might be erroneous given that they assume perfect competition, which is not always the case.
iii. We fix the TEP solution obtained by the naïve CMM, the one that would actually take place in a centralized planning system and see which would be the reaction of the actual strategic GENCOs. To this purpose, after fixing the TEP solution we re-run the PM model (which is equivalent to just solving the equilibrium problem described by the lower level of PM). This allows us to assess to what extent the "wrong" TEP decision, obtained by the naïve CMM, is going to distort the resulting market equilibrium and GEP decisions made in imperfect markets. The solution of this third model allows us to compute the *Actual CMM* because it accounts for decision errors made by a cost minimization approach.
iv. Therefore, the regret of using a CMM approach is computed as total cost (or welfare) of the Actual CMM minus the total cost (or welfare) of the PM.

2.5. Bi-level Problem: Merchant TSO

Additionally to the social planner considered in Figure 5 (with a cost minimization and welfare maximization objective), we also consider a merchant transmission investor (contrary to a typically centralized regulated entity) that recovers its investment directly from the market operation. Such a model structure is depicted in Figure 6.

Upper Level	Merchant TSO (decides TEP) Maximizes Congestions Rents		
Lower Level	GENCOs (decide GEP and operation) Maximize Profits	SO (decides power flow) Maximizes Congestion Rents	Consumers (decide demand) Maximize Demand Utility
	Market Clearing Condition		

Figure 7: Bi-level Merchant TSO

We consider that those market incomes are derived from the network congestion rents, which are computed as the price difference between two connected nodes times the flow through the corresponding connecting line.

$$arg \underset{vFlows_{ypdd'}}{\text{Maximize}} \sum_{y,p,d} pW_{rp} * vFlows_{ypdd' \in LA} * (\lambda_{ypd'} - \lambda_{ypd}) - \sum_{ydd' \in LC} (Y - y + 1) * pInvC_{dd'} * \left(vNewLine_{ydd'} - vNewLine_{y-1,dd'}\right) \quad (2)$$

$$Subject\ to: Lower\ Level\ Problem$$

Please note that the lower problem is the same as the one of the social planner, which, as mentioned in 2.3, consists of the same constraints enumerated in 2.2 with addition of considering elastic demand. We consider that the only costs for the merchant investor are the investment costs. Let (2) represent the merchant investor's objective function. The first term of this objective function represents the congestion rents ($vFlows_{ypdd'} * \lambda_{ypd}$ - $vFlows_{ypdd'} * \lambda_{ypd'}$) and corresponds to a non-linear, non-convex term, which can cause numerical difficulties when solving the problem. Therefore, we have decided to linearize this term in order to solve the resulting MPEC as a MILP just as the PM models at section 2.3.1. Similar linearization techniques have been applied in bi-level models in [8], [27].

For illustration purposes we demonstrate how to linearize $vFlows_{ypdd'} * \lambda_{ypd'}$. We start by discretizing the variable $vFlows$, by applying a binary expansion as the one proposed in [27]. Equation (3) reconstructs $vFlows$ by starting from the lower bound and adding some slices until the upper bound of $vFlows$ is achieved.

$$vFlows_{ypdd'} = -pMaxFlows_{dd'} + \Delta Flows_{ypdd'} * \sum_{k} 2^k * vBinFlow_{ypdd'k} \quad (3)$$

Where $vBinFlow_{ypdd'k}$ is a binary variable and $\Delta Flows_{ypdd'}$ is the step magnitude in which we divide the variable $vFlows_{ypdd'}$, which is given by (4)

$$\Delta Flows_{ypdd'} = \left|-pMaxFlows_{ypdd'} - pMaxFlows_{ypdd'}\right|/2^K \quad (4)$$

Let us define the binary expansion of $vFlows_{ypdd'} * \lambda_{ypd'}$ in equation (5).

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$$vFlows_{ypdd'} * \lambda_{ypd'} = -pMaxFlows_{dd'} * \lambda_{ypd'} + \Delta Flows_{ypdd'} * \sum_{k} 2^k * vBinFlow_{ypdd'k} * \lambda_{ypd'}. \quad (5)$$

Given that the nonlinear term $vBinFlow_{ypdd'k} * \lambda_{ypd' \in (GAD)}$ is the product of a binary variable and a continuous variable, we can linearize it by renaming the product $vF\lambda_{ypdd'k} = vBinFlow_{ypdd'k} * \lambda_{ypd'}$ and adding the two following equivalent equations:

$$0 \leq \lambda_{ypd' \in (GAD)} - vF\lambda_{ypdd'k} \leq \overline{\lambda} * (1 - vBinFlow_{ypdd'k}) \quad (6)$$

$$0 \leq vF\lambda_{ypdd'k} \leq \overline{\lambda} * (vBinFlow_{ypdd'k}) \quad (7)$$

Please note that we assume that prices are non-negative and therefore $\underline{\lambda}$ is zero.

Thus, we re-formulate the complete problem as follows:

$$\arg \underset{vF\lambda_{ypdd'}}{\text{Maximize}} \sum_{y,p,d} vF\lambda_{ypdd'} - vF\lambda_{ypd'} - \sum_{ydd'} (Y - y + 1) * pInvC_{dd'} * (vNewLine_{ydd'}) \quad (8)$$

$$Subject\ to: Equations\ (3) - (7)\ and\ Lower\ Level\ Problem$$

It is important to note that -as with every linearization technique- the result depends on the steps considered for the discretization. Therefore, the bigger k, the smaller is the step size, and hence, the closer the solution would be to the global optimum.

3. Case study

In order to test the properties of the proposed model we consider two case studies, an illustrative 3-node case, where we study in detail the investment and operation results and a modified 24-IEEE test case where we run a sensitivity analysis to generalize some policy implications.

3.1. Illustrative 3-Node Case

We start out by considering a simple three-node example with: one existing conventional generator (CCGT) located at Node_3; one candidate wind generator located at Node_1; and, one candidate Battery Energy Storage System (BEES) located at Node_2. We consider that each generation unit belongs to a different GENCO. Additionally, we study a green-field approach where there is no existing transmission infrastructure.

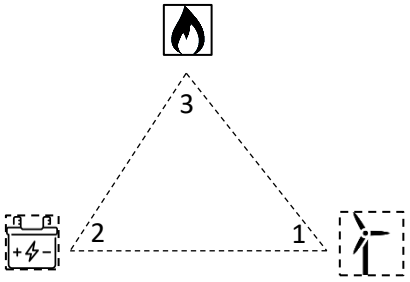


Figure 8: 3-Node System Characteristics

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In Figure 8, dotted lines represent candidate elements, either generation units or transmission lines, while continuous lines represent existing elements. We consider a single representative day for a single target year.

Table I: 3-Node System line characteristics

From Node	To Node	Reactance [p.u]	Life Time (years)	Total Investment Cost (M€)	Annual Investment Cost (M€)	Capacity (MW)
1	2	0,06	40	2	0,125	20
2	3	0,05	40	2	0,125	20
1	3	0,03	40	2	0,125	20

Table II: 3-Node System GENCOs characteristics

	Node	Status	Life Time (years)	Total Capital Cost k€/MW	Annual Capital Cost k€/MW	Variable Cost €/MWh	Maximum Power Capacity MW
CCGT	3	existing			-	50	55
Wind	1	candidate	25	1000	85,80	0	26*
BESS	2	candidate	15	500	54,89	0	10*

Table I shows the technical characteristics of the transmission lines. We consider three candidate lines of 20 MW and 100 km with a total capital cost of 1000€/MW·km and a 5,5% discount rate which leads to the annual cost presented in Table I. Additionally, Table II shows the capital [28] and variable cost of GENCOs as well as their location and technical characteristics. Please note that the BESS has a 4-hour charge/discharge duration which implies a storage typical capacity of 40 MWh. In order to compute annual capital costs for GENCOs we consider a 7% discount rate [29].

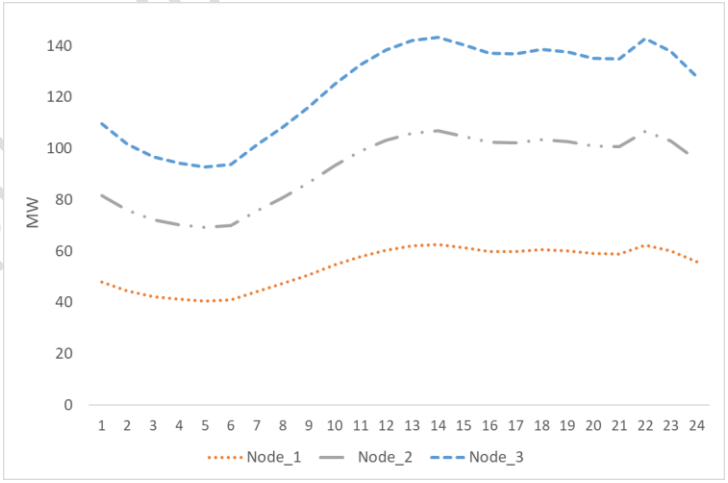


Figure 9: Hourly Demand Intercept

Figure 9 shows the hourly demand intercept at the 3 different nodes; additionally, for Node_2 and Node_3 we consider a constant demand slope (β) of 1,6 €/MWh^2 and for Node_1 a slope of 2.5 €/MWh^2. These values are aligned with what is usually found in the literature [4], [22]. Finally, for this 3-Node case, we study two main ownership

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structures i) single ownership structure (SG), where each GENCO can own only one type of technology and ii) mixed ownership structure (MX) where we allow generators to own more than one type of technology in a single node.

3.1.1.Results: Single Ownership structure (SG)

In this section we study capacity expansion planning considering a PM model with a *welfare-maximizing* social planner that anticipates different strategic market behavior, namely: Perfect Competition (PC), Cournot Oligopoly (CO), and Intermediate Competition (IC). The corresponding conjectural variations, defined in 2.3.2, appear in Table III. Additionally, we consider a SG ownership structure where every GENCO can only own a single technology at each node.

Table III: Conjectural variations for each degree of competition.

PC	IC	CO
0	(1/ β)/2	1/ β

Table IV: Economic results for the PM planning with distinctive market structures

	Units	**PC**	**IC**	**CO**
TEP	Lines	1-2/1-3/2-3	1-2/1-3/2-3	1-3/2-3
	MW	60,00	60,00	40,00
GEP				
BESS	MW	15,41	11,13	3,28
	MWh	61,64	44,50	13,14
Wind	MW	91,27	52,27	33,23
Total GEP	MW	106,68	63,39	36,52
Demand	TWh	6,94	5,38	4,31
Total Cost	M€	23,66	23,53	21,17
Relative Cost	M€/TWh	3,41	4,37	4,92
Total PS	M€	34,29	51,52	50,61
Total CS	M€	51,43	28,56	21,26
Total SW	M€	85,72	80,07	71,87

3.1.1.1. Investment Results

Table IV shows the economic results of planning the system under perfect, intermediate and Cournot competition. In the PC case the social planer decides to build all three candidate lines; this implies that, compared to the CO case, less congestions appear in the transmission lines (see Figure 10). In contrast, in the CO case only two lines are built and therefore less total generation is built because there is less transmission capacity to transport the excess of the wind (which cannot be used by the battery). Additionally, in the IC case all lines are built and therefore the energy excess from wind can be directly profited by storage, resulting in BESS investments more similar to the PC case.

As seen in Table IV the aforementioned investment plans lead to satisfying a total demand 38% lower in the CO case compared to the PC case. However, the total cost of the system in the PC case rises up to 23,66 M€, which is higher than the 21,17 M€ of the CO case. At first sight, this might seem counterintuitive; however, the relative cost (cost per unit of demand supplied) is lower in the PC case[5]. In contrast, the PC case naturally reaches

[5] Please keep in mind that, considering a social welfare maximization in the PM model (by incorporating the consumers' preferences via the utility of demand) is not the same as minimizing total costs.

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the maximum social welfare which, in turn, is 19% higher than the CO case. As we can see, the decrease in the social welfare under de CO case is lower than the decrease in the total demand supplied, this happens because the proportion between the producer and consumer surplus is interchanged (evidencing a higher economic inefficiency than what is directly seen from the welfare loss). Please note that, in the Cournot case, the social planner avoids building a third line, which otherwise would have led to a worse-off situation. Let us analyze this in detail in section 3.1.1.3. Finally, in terms of total demand, cost and welfare, the IC case is indeed intermediate between the perfect competition and Cournot oligopoly. However, even though the IC investments seem closer to PC case, the actual operation results are closer to the Cournot case, leading to a hidden welfare loss not reflected by the total social welfare.

3.1.1.2. *Operation Results*

The behavior described in section 3.1.1.1 can be better understood by analyzing how production, flows and prices evolve within the representative day; as shown in Figure 10 and Figure 11. First, let us take a look at the PC case. Figure 10 shows the expected utilization of transmission lines, and therefore when transmission lines are congested (as indicated by areas S1- S4 depicted in Figure 10) distinctive nodal prices arise (see corresponding S1-S4 areas in Figure 11). Second, please note that there is not a single period at which prices directly reflect units' marginal cost. As seen in Figure 12, prices at Node_3 are always greater than 50 €/MWh, because at every hour the capacity of the CCGT_3 unit is at its maximum (as a consequence of a static greenfield planning model), and therefore prices reflect the consumers demand response. This means that the energy that consumers are willing to demand at a price of 50 €/MWh exceeds the available capacity of generators, and therefore consumers are willing to pay a price higher than 50 €/MWh.

This can be appreciated in Figure 12, where *non-consumed energy*[6] is illustrated. Please note that this concept refers to actual demand consumers renounce given the resulting price in the market. This non-consumed energy is computed as the actual energy consumed minus the demand intercept at each hour, relative to this demand intercept (this ratio is 0 when prices are 0 and it is 1 when prices are at its maximum).

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[6] Please note that the non-consumed energy concept is different from the non-served energy concept that is applied to inelastic models when consumers have an infinite (or very high) willingness to pay for energy.

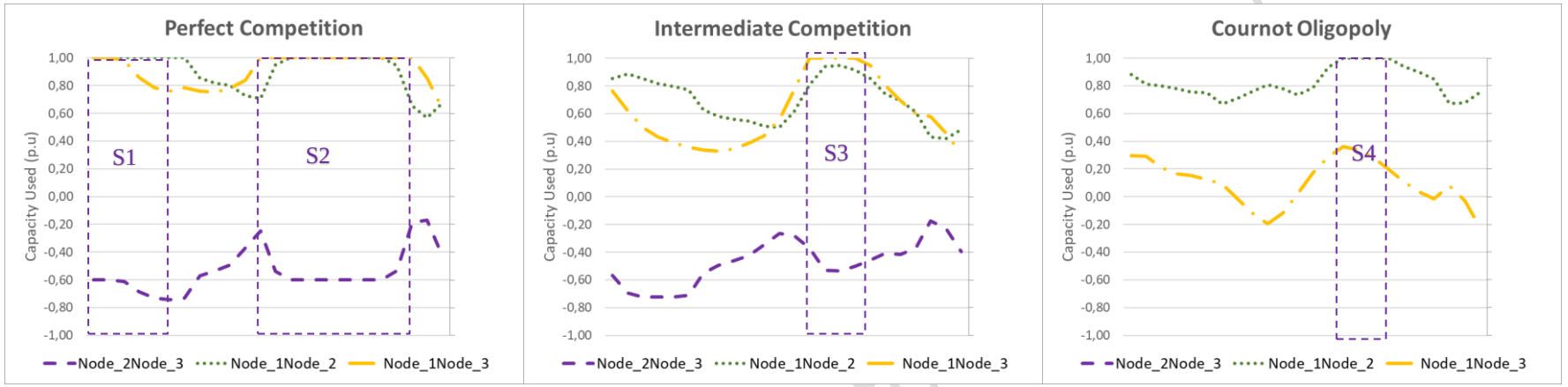


Figure 10: Flows through lines[7]

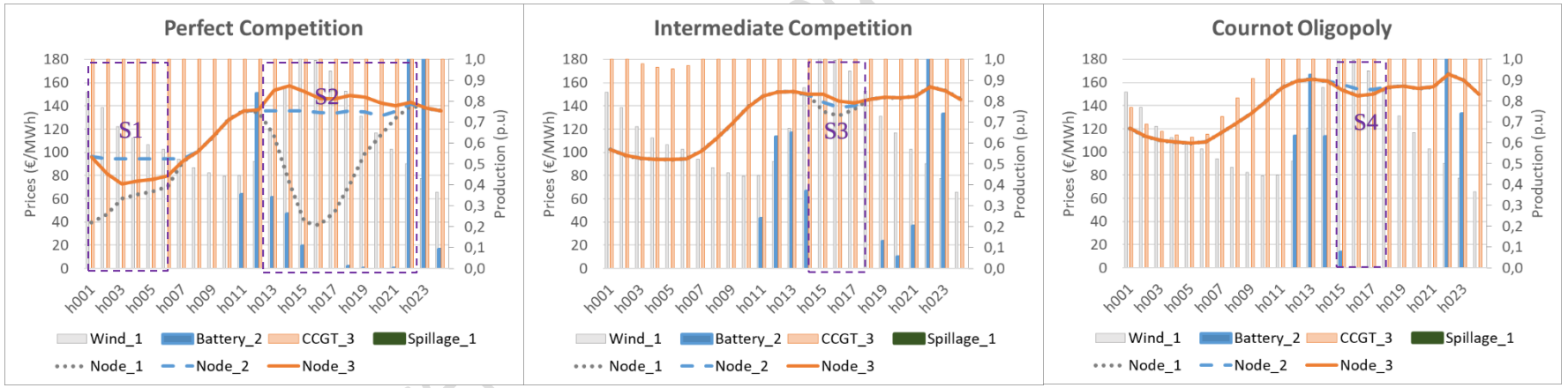


Figure 11: Prices (represented by lines) and Production (represented by bars)

[7] Please note that a negative capacity usage means that the flows go in the contrary direction of the lines.

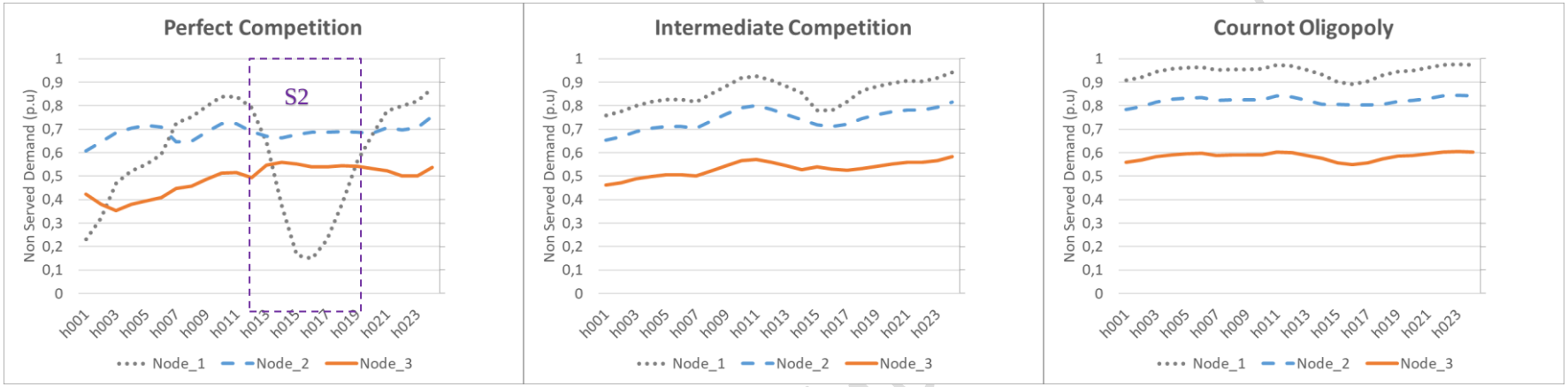


Figure 12: Hourly non-consumed energy per Node

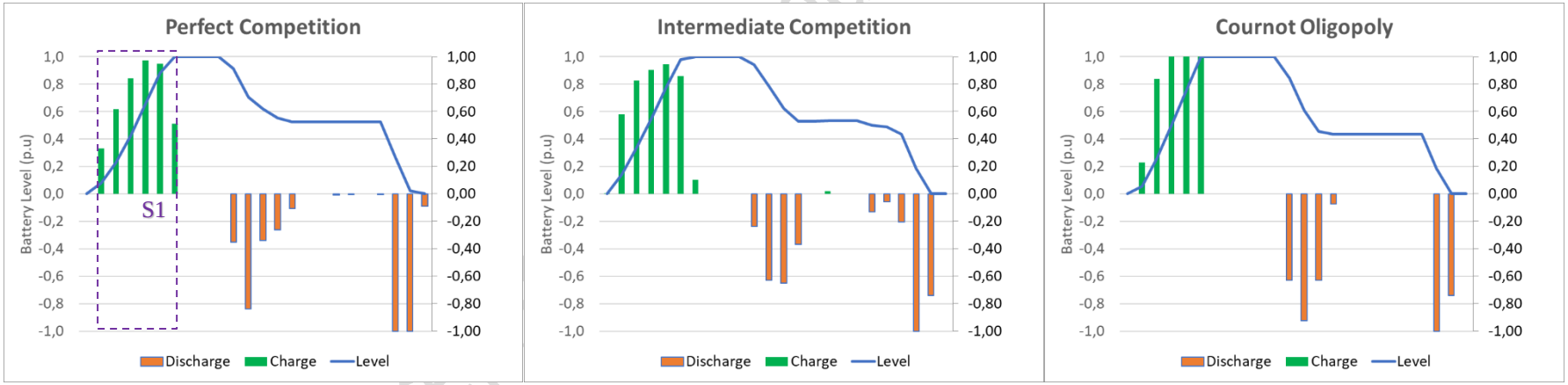


Figure 13: Battery Charge and Discharge (bars) and Battery Level (lines)

In this case when there is high "*non-consumed energy*" prices are high and when there is low *non-consumed energy* prices are low. In fact, price variations in Figure 11 (at hours of distinctive nodal prices) follow exactly the shape of the *non-consumed energy* at each node in Figure 12. Please keep in mind that this happens in the PC case only because generators are at their maximum capacity.

Finally, let us note some features of the battery operation. First, as shown in Figure 11, in the PC case, the battery produces at its maximum during peak hours when prices are higher, which is, in fact, the efficient way in which batteries operate (energy arbitrage). In other words, they charge energy in the low price hours, as seen Figure 13, represented by area S1, and discharge it in the high price hours. Please note that a consequence of the intertemporal arbitrage is price stabilization (because any intertemporal price difference, with idle storage capacity, is an opportunity for price arbitrage), which in this case can be appreciated when there are congestions in the network and nodal prices are isolated, as seen at Node_2 in depicted areas S1 and S2 in Figure 11.

In the CO case nodal prices almost always converge because there is only a short congestion in line 1→2, as seen in area S4. However, in this case, the prices are higher than the PC case given that some generation is withheld, therefore prices contain a mark-up resulting from the elasticity of demand, even when generators have *idle capacity*. The operating results of the IC case are closer to the CO case, as seen from Figure 10 and Figure 11. Finally, from this operation and pricing analysis it is important to note that the IC and CO cases present a higher price convergence, which implies lower congestions, but actually leads to higher prices on average. Therefore, for this case, nodal price convergence might not be an appropriate a-posteriori criterion to evaluate market efficiency[8].

3.1.1.3. *Regret of disregarding market feedback*

In the previous sections we considered a proactive model (PM) where a social planner aimed to maximize social welfare by anticipating different market structures in the lower level. In this section we compute the regret, as introduced in 2.5, of planning the system in a centralized manner instead of planning with a PM model where the social planner anticipates the strategic market feedback i.e., Cournot competition in the lower level. Therefore, we compare the results of the CO model (in section 3.1.1) now called PM_CO, with the Naïve and Actual CMM.

As seen in the previous section, PM_CO invests in lines 1→2 and 1→3 which leads to a total welfare of 71,87 M€ with a supplied demand of 4,31 TWh. Given this exact same demand, imagine we have a Naïve CM planner that designs the system disregarding the strategic market feedback. In such a case the centralized planner based on the Naïve CMM would build lines 1→2 and 2→3 with the expectation that GENCOs would build and operate the most competitive generation capacity (please note that if the Naïve case happened it would actually lead to a higher welfare compared to PM_CO).

[8] In fact, in this case high-prices and price convergence reflect a system planning under imperfect competition

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Table V: PM vs Cost Minimization

	Units	PM_CO	Naïve CM	Actual CMM
	Lines	1-2/1-3	1-2/2-3	1-2/2-3
Total TEP	MW	40,00	40,00	40,00
BESS	MW	3,28	24,93	3,52
	MWh	13,14	99,70	14,08
Wind	MW	33,23	24,54	31,48
Total GEP	MW	36,52	49,46	35,00
Demand	TWh	4,31	4,31	4,25
Total Cost	M€	21,17	36,61	36,22
Relative Cost	M€/TWh	4,92	8,50	8,53
Total PS	M€	50,56	15,33	50,03
Total CS	M€	21,31	56,87	21,29
Total SW	M€	71,87	72,19	71,33
Abs Regret	M€			0,55
% Regret				0,8

However, markets are not perfect and usually we can find an oligopoly in the production, therefore, we evaluate which are the actual results of the strategic market given the TEP decided by the Naïve CMM. We call this result the Actual CMM which leads to a total welfare of 71,33 M€ which is 0,55 M€ lower compared to the PM_CO.

This result is explained as follows: at the PM_CO the energy goes from Node_2 to Node_1 and the energy comes and goes between Node_1 to Node_3, which means the average net energy flows from Node_1 to Node_3 and to Node_2 (as seen in Figure 10). Now, given that at the Actual CMM line 2→3 is built instead of 1→3, the congestions increase, and less wind energy can be evacuated from Node_1 to supply demand at Node_3 trough Node_2. This leads to a lower wind investment, but a slightly larger BESS investment to store also some of the energy coming from Node_3. This shows that building line 2 → 3 instead of 1→3 leads to a 0,8% reduction in the total SW. Please note that either of these results leads to a better-off situation than actually building all possible lines. These findings are contrary to those of [22], where it was suggested that, in the CO case, the social planner would build as much lines as possible (when no storage is considered) to diminish GENCOs market power. We show here that, in the presence of storage units (and depending on demand elasticity), it can be the case that building more lines leads to a lower social welfare.

3.1.2. Results: Mixed Ownership Structure (MX)

In this section we want to investigate what are the welfare effects of considering GENCOs with a multi-technology portfolio. For this purpose, we analyze two cases additional to the Single Ownership (SG) case (base case from section 3.1.1). i) We consider that apart from wind generation, GENCO1 can invest in BESS[9], and we call this the Mixed

[9] With the same technical characteristics as BESS at Node_2 see Table II

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Ownership BESS case (MB). ii) On top of i) let us consider that GENCO2 invests in hydro[10] instead of BESS and we call it the Mixed Ownership Hydro case (MH). Please find a summary of these cases in Table VI.

Table VI: Battery of cases

	SG	MB	MH
GENCO1	Wind_1	Wind_1 BEES_1	Wind_1 BEES_1
GENCO2	BESS_2	BESS_2	Hydro_2
GENCO3	CCGT_3	CCGT_3	CCGT_3

Additionally, apart from considering distinctive ownership structures we analyze the possible planning differences of planning the system as a social planner vs a merchant investor. This comparison would allow us to understand how inefficient a merchant investor can be (compared to the social planner solution), and would allow policy makers make the right considerations when accepting this kind of investors for isolated or international connections.

3.1.2.1. Social Planner

Table VII: Economic results mixed ownership structure

		Mixed Battery (MB)		**Mixed Hydro (MH)**	
	Units	PC	CO	PC	CO
TEP	Lines	1-2/1-3/2-3	1-2/1-3	1-2/2-3	1-3
	MW	60,00	40,00	40,00	20,00
GEP					
BESS_2	MW	10,69	1,62	0,00	0,00
	MWh	42,77	6,47	0,00	0,00
HYDRO_2	MW	0,00	0,00	12,11	10,96
	MWh	0,00	0,00	2034,5	1841,28
BESS_1	MW	24,02	10,63	27,80	7,93
	MWh	96,08	42,50	111,18	31,72
Wind_1	MW	100,63	33,06	94,45	27,04
Total GEP	MW	138,85	48,97	159,62	75,57
Demand	TWh	7,28	4,32	8,87	5,76
Total Cost	M€	23,68	21,36	23,70	20,45
Total PS	M€	35,07	50,89	45,45	67,84
Total CS	M€	53,28	21,60	66,59	31,65
Total SW	M€	88,35	72,491	112,04	99,49

As shown in Table VII, and in accordance with the results in section 3.1.1, transmission expansion and generation expansion are higher under a perfect competition than under Cournot oligopoly. Unsurprisingly, these investments lead to a higher welfare in the PC case for every ownership structure. However, let us study in detail how consumer surplus (CS) and producer surplus (PS) share vary for every case. Figure 14 shows the welfare

[10] With a capital cost of 140 M€/MW, a 0,80 roundtrip efficiency and a weekly (168h) of typical storage per MW installed.

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distribution for each ownership structure, details of the Mixed Ownership are shown in Table VII while details of Single Ownership is shown in Table IV section 3.1.1.

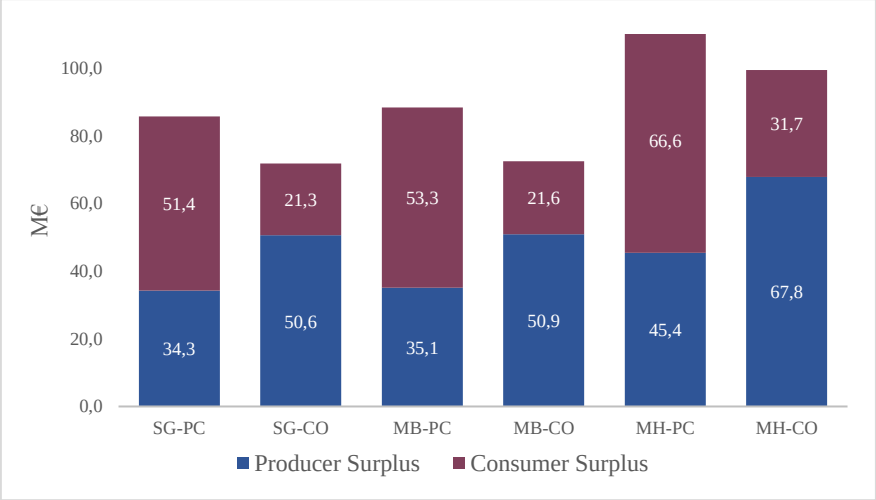


Figure 14: Welfare Distribution

First, we can see a consistency in the welfare distribution among all PC cases and among the CO cases respectively. In PC cases, 60% of welfare corresponds to CS and 40% to the PS, while in the CO case this share is inverted, and lies around the 35% for CS and 65% for PS. Please note that the PS and CS share depend both on the demand elasticity and the degree of competition. However, the PS share is always higher in the CO case compared to the PC case, as a result of the exercise of market power. Therefore, let us define the ratio PS/CS as an additional efficiency measure, whose lowest value would indicate a better-off situation, given that we keep the demand slope fix along the different cases.

Table VIII: PS/CS ratio each Cournot oligopoly case

	SO_CO	MB_CO	MH_CO
PS/CS	2,38	2,35	2,1

Table VIII shows that SG_CO is the most inefficient scenario. Even though in the MB_CO case GENCO 1 increases its profits, as seen in Figure 15, total demand supplied increases more than proportionally and the PS/CS ratio is actually lower. Please also note that at the hydro case (MH) the highest welfare is achieved, for both PC and CO cases (Table VII). Please note that the pumped hydro storage includes some natural inflows that the battery storage does not, and therefore, it represents some extra available power which increases total welfare. Additionally, the PS/CS ratio is lower in the MB case because the additional available hydro energy diminishes the amount of energy that GENCO2 can export, and in overall decreases GENCOs market power. This is also reflected in Figure 15, by the decrease of profits of GENCO1 from case MB_CO to MH_CO, while profits of GENCO2 increase, reflecting a higher competition among GENCOs. Therefore, in this case study, a diversified generation portfolio seems to increase competition and results in more efficient planning and operation management.

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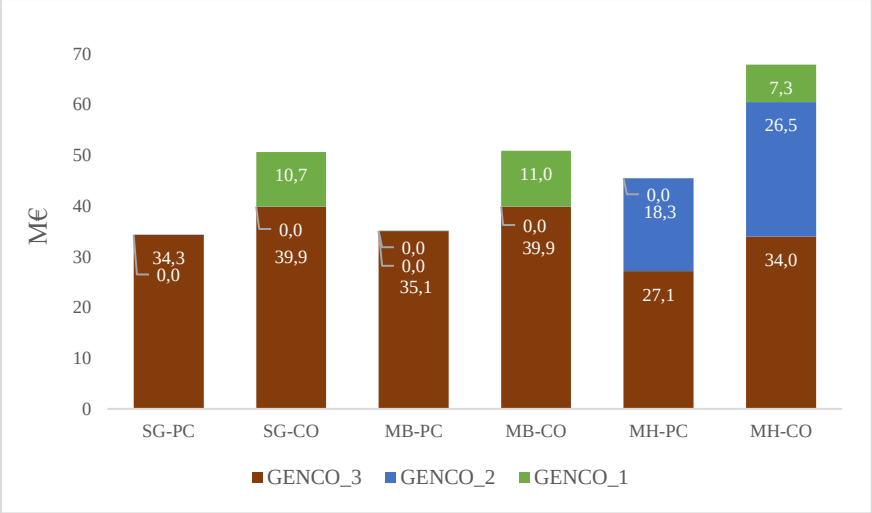


Figure 15: GENCOs profit distribution among different ownership structures

3.1.2.2. Merchant TSO

Finally, we analyze the economic results of a merchant transmission investor. As formulated in section 2.5, we now consider a merchant agent at the upper level, that aims at maximizing its own profit. This type of regulation is not usually applied to a complete system but exists for specific project. For instance, merchant investment is applied for interconnections in Europe [30] and has been expanding in the US, in fact in 2018 the FERC extended the authorization for off-shore wind farms connections by allowing this type of investments, only if the merchant transmission company assumes all market risk [31].

We apply this framework to the MH case from section 3.1.2.1. As seen in Table IX, some interesting results appear when considering a merchant investor. In the PC case, having a merchant investor instead of a social planner leads to a welfare of 110,09 M€, which is 0,52% lower compared to the social welfare achieved by the social planner (see Table VII). It is interesting to note that both planners would invest in two lines, but in a different combination. A social planner would invest in lines 1→2 and 1→3 while merchant investor would invest in lines 1→2 and 2→3. In spite of the lower generation investment of the merchant case, there would be a higher congestion for generation at Node_3 trying to evacuate to Node_2. In contrast, in the CO case, the merchant transmission would invest in line 1→2, which would maximize congestions rents compared lines 1→3 built by social planner. This would lead to a 2,2% lower welfare compared to a social planner.

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Table IX: Economic results of a merchant transmission investor

		Mixed Hydro (MH)	
	Units	PC	CO
TEP	Lines	1-2/2-3	1-2
	MW	40,00	20,00
GEP			
BESS_2	MW	0,00	0,00
	MWh	0,00	0,00
HYDRO_2	MW	14,69	10,98
	MWh	58,78	43,94
BESS_1	MW	17,22	7,98
	TWh	68,87	31,92
Wind_1	M€	71,22	27,72
Total GEP		127,64	75,86
Demand		7,99	5,78
Total Cost	M€	23,70	20,77
Total PS	M€	53,22	69,34
Total CS	M€	56,87	32,43
Total SW	M€	110,09	97,32

3.2.IEEE-24 bus test case

In order to test this model we consider an IEEE-24 modified system as the one considered in [9].

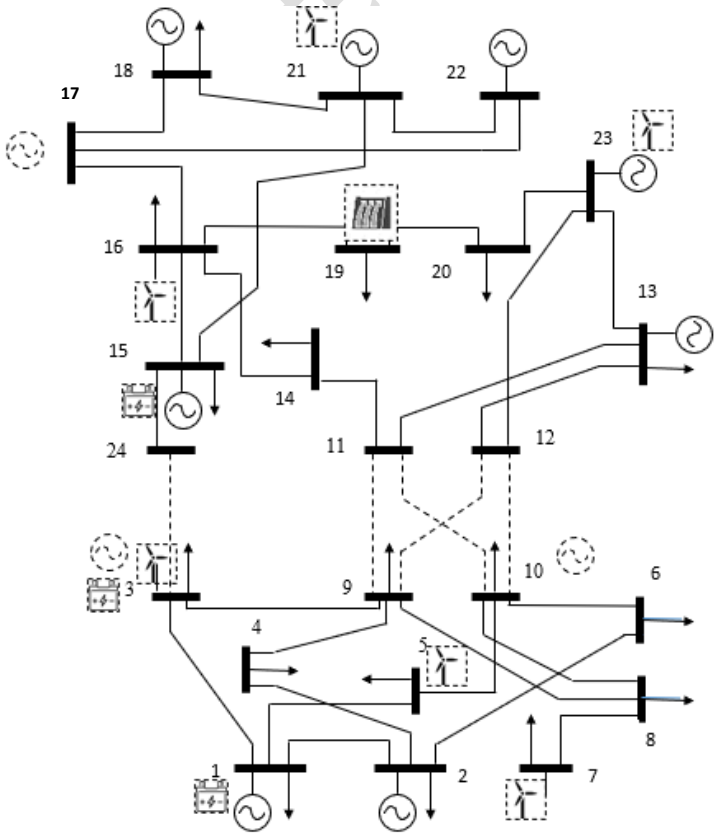


Figure 16: IEEE-24 test case

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As seen in Figure 16, this system is made up of 24 buses, 33 existing lines, and 12 existing conventional generators. Continuous lines represent existing elements and dotted lines represent candidate lines. We consider 3 candidate conventional generators at nodes 3, 10, and 19, as well as 6 wind candidate generators at buses 3, 5, 7, 16, 21, 23.

Additionally, we consider 4 candidate BESS at nodes 1, 3, 15 and 1 hydro candidate at node 19. We consider 4 representative days (h3697-h3720, h8425-8848, h5305-h5328 and h1897-h1920). As seen in Figure 17, we consider different profiles for the wind candidate generators located in the south (nodes 3, 5, 7) and those located in the north (nodes 16, 21, 23). Additionally, we consider a yearly hydro inflow shown in Figure 18, and a 168h window (as defined in 2.2) for the inter-day storage constraints. We consider the same capital costs as in the 3-node case and a cost of 1300 k€/MW for conventional generators considering 30 years life-time and a 7% discount rate (equivalent to 104 M€/MW annually). Finally, we consider a transmission capacity of 50MW for each of the transmission lines (existing and candidates) of the system and a demand slope of 0,55 €/MWh^2.

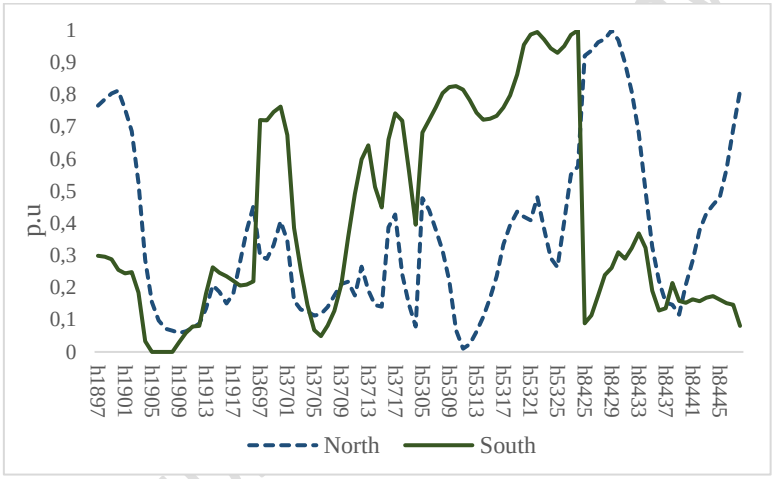


Figure 17: Wind Profiles

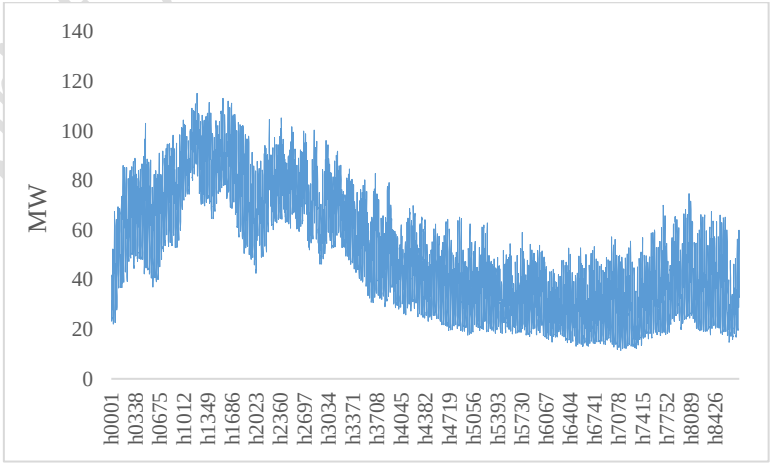


Figure 18: Yearly hydro inflows

3.2.1.Merchant TSO vs Social Planner

In this section we evaluate the 24-Bus case. First, we compare the results of planning the system considering different planners and objective functions. Additional to the previous section, we include a social planner with a cost-minimization objective. Please note that in this subsection, every model considers elastic demand.

Table X shows the economic results of planning the system considering distinctive objective functions for the social planner (maximizing welfare or minimizing cost) and the merchant investor (maximizing congestion rents). We compare the economic efficiency of such regulatory schemes by comparing total welfare at each case.

Let us point out that the welfare-maximizing and cost-minimizing objectives only lead to the same results when there are inelastic demand and perfect competition in the market. However, here we compare what are the planning results of a social planner with either a cost-minimizing or welfare-maximizing objective[11]. It is evident that the social planner with a welfare-maximizing objective achieves the highest social welfare, however it is interesting to note that, in the PC case, considering a cost-minimization objective for the social planner leads to the same sub-optimal equilibrium than the merchant investor who aims to maximize, its own profits. In the CO case, in fact, the merchant investor decisions lead to the worse-off situation overall. These results are case dependent, but they suggest that a social planner that minimizes cost in a market with elastic demand can lead to the same sub-optimal results as a merchant investor that maximizes congestion rents.

Table X: Economics Results 24-Node Case

		Perfect Competition (PC)			Cournot Oligopoly (CO)		
		Max Welfare	Min Cost	Max Rent	Max Welfare	Min Cost	Max Rent
TEP	**MW**	200	200	100	100	100	100
GEP	**MW**	1484,25	1481,77	1481,77	1016,07	1012,37	1012,37
Demand	**TWh**	7,20	7,42	7,42	2,53	2,50	2,71
Total Cost	**M€**	490,43	475,34	475,34	319,22	312,43	316,23
Relative Cost	**M€/TWh**	68,08	64,09	64,09	126,04	124,97	116,78
Cong. Rent	**M€**	187,80	196,15	196,15	153,43	167,08	168,63
Total SW	**M€**	1211,49	1192,06	1192,06	1019,69	1011,52	1010,04

Figure 19 shows how GEP investments are distributed in each case. As we can see in the PC case, there are bigger differences among each regulatory objective, while in the CO case the results are closer to each other. However, the investments in the CO case are always lower than the investment in the PC case. Please note that storage generation is almost non-profitable in the Cournot case, which is similar to the results in the 3-node Greenfield case. As mentioned before, these results are case dependent results, however, from several cases we have noticed that the CO cases tend to underinvest compared to the PC case, especially in BESS and wind while conventional generation and hydro investments tend to remain closer to the PC case. This could be explained, similarly to

[11] Having in mind that the appropriate objective is welfare maximization

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section 3.1, because of the greater market power that BESS and wind can exercise when belonging to the same GENCO.

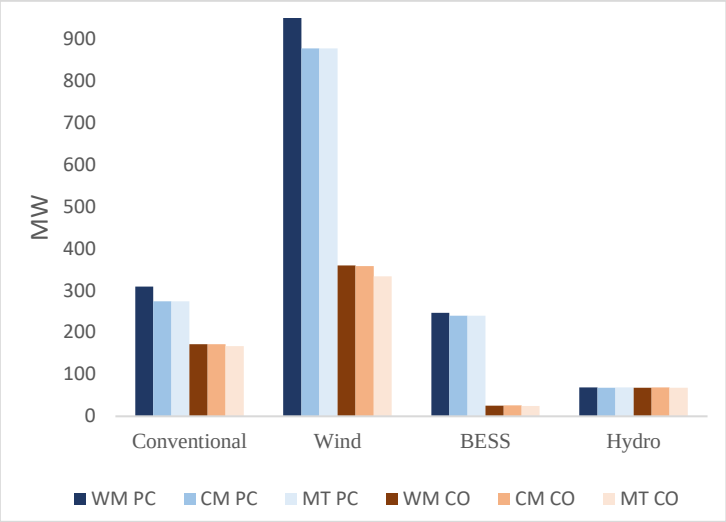


Figure 19: Generation Investment in Conventional Technologies, Wind, BESS and Hydro

3.2.2. Welfare Loss and Generation Mix Distortion

In this section we compute the regret, as defined in 2.4, of disregarding market feedback in transmission expansion planning. The regret is computed as the welfare difference (relative the PM_CO) between the PM_CO case and the Actual CMM. Additionally, we also investigate how the generation mix changes under the different planning paradigms, and we compute the total GEP change by taking the difference between the GEP invested in the PM_CO and the Actual CMM relative to the existing generation capacity (4,32 GW).

Table XI: Proactive vs cost minimization: welfare and investment results

	Units	PM CO	Actual CMM	Difference (MW)	Difference (%)
	Lines	3-24/9-11	9-11		
Total TEP	MW	100	50	-50	-50
BESS	MW MWh	92,34	93,78	1,44	1,56
Wind	MW	664,99	663,54	-1,45	-0,22
Thermal	MW	151,96	164,21	12,25	8,06
Total GEP	MW	909,29	921,53	12,24	1,35
Total SW	M€	1035,75	1034,15	1,60	**0,15**

Table XI shows the welfare and investment differences between the Actual CMM and the PM_CO. In this case, the Actual CMM invest only in line 9→11, which leads to 0,28% GEP overinvestment compared to the PM_CO case and a welfare regret of 0,15%. For this specific case these values are almost negligible, therefore in order to understand how these results vary among different system characteristics, we run a sensitivity analysis of the regret computation and the generation mix change. We examine different levels of the

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demand slope, from 0,50 €/MWh^2 to 1 €/MWh^2, and we consider different constrained systems by varying the capacity of all transmission lines from 40 MW to 65 MW.

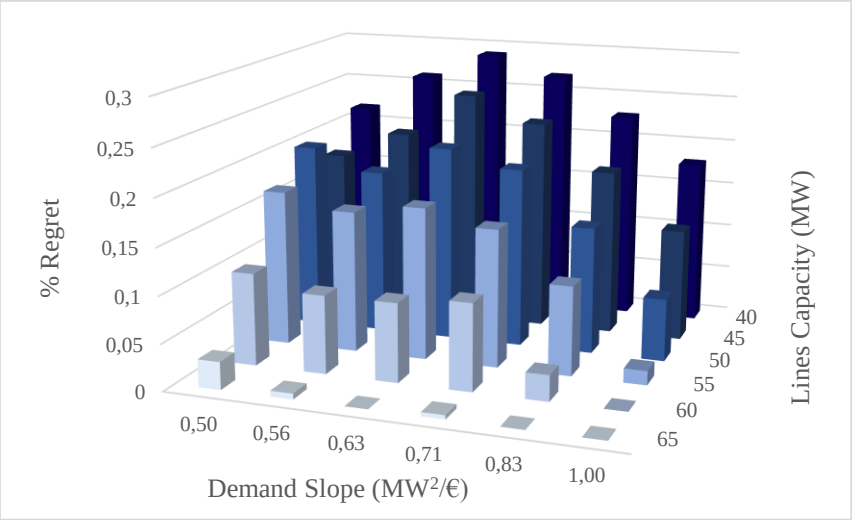


Figure 20: Regret Computation Sensitivity

As we can see in Figure 20, there is a non-linear relationship between regret and demand slope, and there is a non-linear but increasing relationship between regret and system congestion. Even though the percentage numbers of the regret seem relatively small (below 1% in the cases that we have studied here), in absolute terms the regret still ranges in the order of millions of euros. Therefore, disregarding strategic market feedback in a highly congested system can be considered a non-negligible planning regret, this result naturally follows, as a heavily congested system is more prone to present inefficiencies if no proper expansion is undergone. Additionally, there is not a clear evidence on how elasticity affects the regret of disregarding market feedback, but from Figure 20 we can see that low-congested systems are more sensitive to demand elasticity than highly-congested systems.

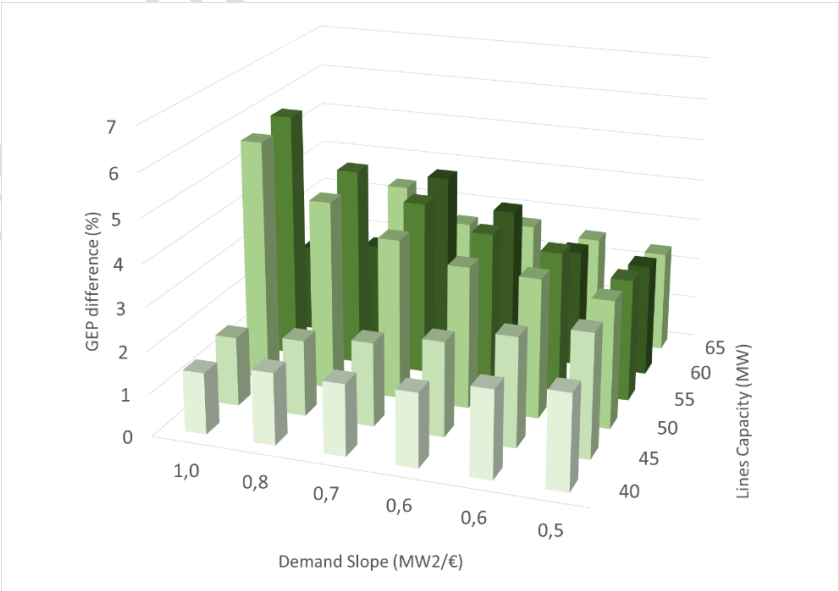


Figure 21: Generation Mix Sensitivity

The relatively small welfare regret, shown in Figure 20, can be somehow misleading if we do not investigate how the generation mix changes. Figure 21 shows how the generation mix changes depending on how constrained or elastic the demand in the system is. Figure 21 shows the existence of a distortion of the capacity mix, ranging from 1% to 7%. In particular, the highest generation-mix distortion is appreciated in mid-congested levels (50 MW and 55 MW transmission capacity) and elastic systems. Therefore, from the previous two graphs we can conclude that, TEP decisions made by a cost-minimizing TSO that disregard strategic market feedback will generate a relatively small welfare loss that tends to increase for highly constrained systems. In this specific case, the decisions of the cost-minimizing TSO will result in a significantly GEP overinvestment when there is a high demand slope, which will imply a higher welfare loss in the case of the most constrained networks.

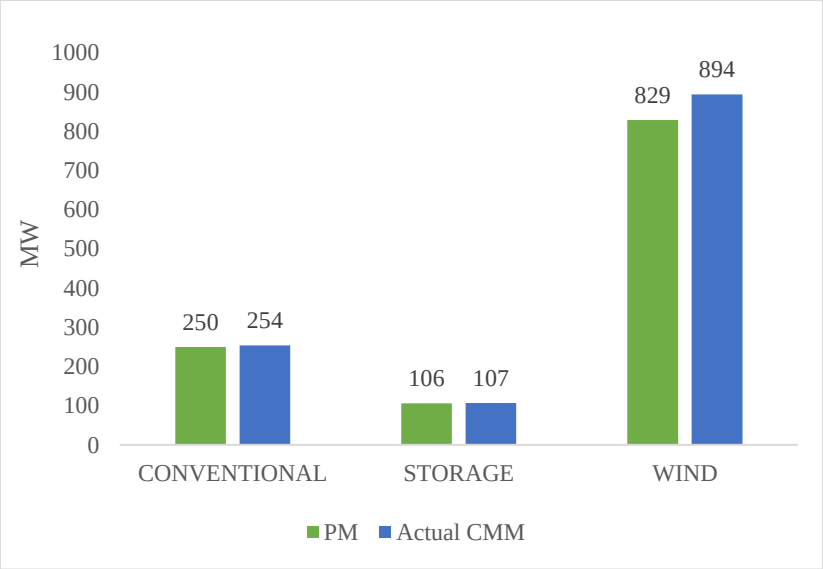


Figure 22: Generation Mix Distortion

From our sensitivity case we show, in Figure 22, the case with 55 MW capacity on transmission lines and a slope of 1 $MW^2/€$. In this case we can see a significant variation in the generation mix, which can affect the robustness of the system. In fact, in the Actual CMM, 60 MW of additional capacity is invested in wind generation, but only 1 MW (MWh) of storage and 4 MW of conventional generation (given a higher demand). This structure would react significantly different to variations in the wind availability that could lead to a high level of stress in the system implying a lower robustness.

In summary for this case study, one can conclude that disregarding market feedback might have a relatively small impact in terms of the overall welfare loss (which we referred to as regret); however, the subsequent impact on the optimal generation mix can be considered non-negligible. In this case study we have observed relative generation mix distortions of up to 7%. The distortion of the optimal generation capacity mix can, in turn, have important results on the robustness of the system. This detail analysis is out of the scope of this paper.

4. Conclusions and Policy Implications

In this paper we proposed a model that represents generation and transmission expansion planning from the perspective of a proactive social planner. This social planner designs the system considering the feedback from either a perfectly competitive market or a Cournot oligopoly. Additionally, we considered also the formulation of a merchant investor that aims to maximize its congestion rents. As a novelty, we included investment and operation of long- (hydro) and short- (BESS) term storage systems.

This model allows us to study different policy issues. First, we evaluated the policy implications of planning the system under different objectives: either for a social planner (maximizing welfare, minimizing cost) or for a merchant investor (and maximizing congestion rents). We tested such planning objectives while considering either Cournot or perfect competition in the market. We concluded that the sub-optimal results of considering cost-minimization or congestion rent maximization are case dependent. Most importantly, we found that in some cases, a congestion-rent maximization can lead to the same welfare loss as a cost-minimization objective if there is some degree of demand response (through demand elasticity). Additionally, for the cases tested, under a Cournot oligopoly, we found that introducing a diversified generation portfolio for GENCOs leads to a better-off situation as it increases the competition among GENCOs.

Finally, we proposed a measure to evaluate the welfare loss of planning the system under the overly-simplistic view of a cost-minimizing vertically-integrated utility instead of a more realistic proactive framework that recognizes the possible strategic feedback (coming from GENCOs operation and investment decisions). We concluded that, if transmission planners disregard strategic market feedback in heavily constrained systems, there is a high chance that they will incur in a non-negligible welfare loss. More importantly, this sub-optimal planning procedure also leads to a significant distortion of the optimal generation mix. This distortion can result in an over/under-investment depending on the system characteristics. Additionally, this sub-optimal generation mix can affect the robustness of the system, in terms of the responsiveness to intermittent resources availability. In future research we plan to explore those implications by extending the model and including uncertainty in the renewable sources. Moreover, alternative RES policy designs could be included in the transmission planner objective function to test more deeply how the social welfare can be affected.

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