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Dynamics of power-transmission capacity expansion under regulated remuneration

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ABSTRACT

Efficient provision of electricity requires timely expansions of power transmission capacity. However, regulation does not always send the right signals to generate the required (and timely) investments. Therefore, it is important to evaluate the effect of alternative regulations on investment on transmission capacity. In this paper, considering regulated remuneration, we perform this evaluation with a behavioral simulation model of the transmission capacity expansion, in which capacity is endogenously determined by the demand/supply relation. Two planning approaches were considered: centralized planning where the investments are fully coordinated by a central organism, and decentralized planning where the capacity expansions are driven by the investors' rationality on the power market evolution. The model is applied to the Colombian case. The decentralized approach has lower costs (usage charges) than centralized expansion, but lower transmission capacity margins. As low transmission capacity margins create supply risks in high demand periods, regulators can increase coordination in decentralized planning by directly promoting investments that increase security of supply.

1. Introduction

Electricity markets need timely transmission capacity expansions to maintain the security of supply. Efficient expansion prevents blackouts and shortages that generate price rises, welfare losses for demand and generators, and increases in operating and maintenance (O&M) costs for grid operators. Defining such expansions is a complex task. Under traditional market conditions, the expansion considers technical, economic, and environmental issues, taking into account uncertainty about electricity demand, capital constraints, and environmental impacts, among others [1]. Nowadays, the new role of the transmission in modern electricity markets must consider distributed generation from renewable sources [2,3], and the regional planning in a context of markets integration [4]. Besides, electricity transmission exhibits negative externalities [5,6] and economies of scale [7–9] that complicate the allocation of transmission costs to market players and the estimation of the profitability of investments. As a result, it is possible to face an excess or a lack of investment in transmission capacity [10,11]. These features are crucial when planning and defining mechanisms for capacity expansion in power transmission.

Expansion of transmission capacity can be centrally planned so that investments in transmission and generation are fully coordinated using capacity auctions. This is normally the approach in regulated and vertically integrated monopolies, or in deregulated markets with a central transmission capacity planner. The goal in this approach is to minimize the long-term system cost (the social cost) while ensuring security of supply [12]. The main drawback of centrally planning expansion is that expansion alternatives respond to reliability criteria. Then, intuitively, the emphasis on maintaining reliability could lead to over investment and increased consumer costs. Additionally, traditional centralized planning are reactive [13], therefore it does not respond to market competition along the value chain of the power industry.

Decentralized planning has been proposed to attract investment from third parties (merchant expansion) in deregulated markets [14,15]. Under decentralized planning, market agents can plan and build transmission projects by themselves. Decentralized expansion of transmission is associated with nodal pricing markets in which new investments are compensated by the value of congestion [16,17]. However, it is difficult, if not impossible, to have a fully decentralized expansion of transmission in current markets [18] because some investments, such as the investments required for maintaining and upgrading facilities, can only be implemented by the incumbent and, therefore, they are not open for competition. Moreover, network externalities and uncertainty increase the risk of not recovering investment costs [19,20] and regulation is still needed to control market power and free riding [14,18], and for offering incentives to develop

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Nomenclature

Parameters

ω	desired margin of transmission capacity (%)
α	construction delay (years)
β	useful life (years)
γ	planning delay (years)
μ_1	sensitivity of usage charges to installed transmission capacity (COP/(kW * kWh))
μ_2	sensitivity of usage charges to electricity demand (COP/kWh^2)
μ_3	sensitivity of compensations to the ratio between the desired transmission capacity margin and the current margin (COP/(kW^2 * h))

Exogenous variables

$E_d(t)$	electricity demand in the year t (GWh)

Stock variables

$C_{uc}(t)$	capacity under construction in the year t (MW)
$I_{tc}(t)$	installed transmission capacity in the year t (MW)

Auxiliary variables

$P_d(t)$	power demand in the year t (MW)
$C_m(t)$	current transmission capacity margin in the year t (MW)
$C_o(t)$	compensations in the year t (COP/MWh)
$D_m(t)$	desired margin of transmission capacity in the year t (MW)
$E_c(t)$	expected capacity in the year t (MW)
$I(t)$	level of investment in the year t (MW)
$I_{uc}(t)$	investment driven by usage charges in the year t (MW)
$I_{co}(t)$	investment driven by compensations in the year t (MW)
$R_c(t)$	rate of construction in the year t (MW/year)
$R_d(t)$	rate of decommissioning in the year t (MW/year)
$R_i(t)$	rate of investment in the year t (MW/year)
$U_c(t)$	usage charges in the year t (COP/MWh)

projects that increase the systems' efficiency [16].

The aim of this paper is to assess the long-term behavior of transmission capacity expansion under both scenarios: centralized planning with auctioning competition and market-driven decentralized planning. Comprehensive surveys and models for power transmission expansion can be found in [1,4,21,22]. Most studies approach the problem of planning expansions and focus on minimizing transmission costs (including expansion), subject to physical constraints and including the future supply and demand projections [23,24]. The expansion problem is formulated as a mathematical optimization problem and solved using techniques such as genetic algorithms [25–27], tabu search [28,29], among others. Although these models effectively support decision making, they do not focus on the dynamics of capacity expansion in particular, or on the dynamics of over and under investment that may lead to capacity cycles similar to the ones observed in power generation [30,31].

Behavioral simulation, also called system dynamics, has been used to simulate the evolution of investment in generation capacity in deregulated energy markets under different regulatory and market scenarios, see for example [30,32–36]. In this paper, a similar methodology is used, where a stylized system dynamics model is developed that captures the essential current conditions based on market incentives for investments in transmission capacity. The analysis focuses on the investment decision in a market with regulated remuneration. The proposed model is calibrated for the Colombian market and capacity evolution is simulated for different regulatory and demand scenarios.

The following section (Section 2) discusses the proposed system dynamics model, with a focus in how the investment decision is made for each planning approach. Section 3.1 discusses transmission capacity expansion in the Colombian market, while Section 3.2 presents the main modelling assumptions for capacity expansion. Section 4 presents the results from running the model and discusses the performance of centralized and decentralized planning. A planning method that combines features of centralized and decentralized planning is also evaluated in Section 4.3. Finally, Section 5 discusses results and their policy implications.

2. Modelling dynamics of capacity expansion

The dynamic model presented in this section is based on the premise that transmission capacity is endogenously determined by the relationships between demand, supply and the planning approach. We followed standard business or system dynamics approach [37], considering first the formulation of the dynamic hypothesis by using a causal loop diagram, and then we developed the formal differential (behavioral)-equation model which is tested in Section 3.

2.1. Dynamic hypothesis

Fig. 1 shows a causal loop diagram[1] of the transmission capacity expansion. A remuneration scheme is assumed, where transmission companies receive regulated payments (usage charges) based on their existing assets (installed capacity), and pay penalties (compensation charges) when these assets are insufficient to maintain a predefined service level.

Usage charges pay transmitters for the annual capital and operating costs of their existing assets. Usage charges are defined for three demand blocks: high, medium and low so that unit charges (per MWh) reflect the higher costs of operating assets during peak-load hours. Usage charges are fixed for the year and are recalculated when new capacity is added. For simplicity, usage charges in the model are average usage charges.

To maintain the reliability of the power transmission, the regulator charges transmitters a compensation penalty if the availability of their assets falls below a predetermined level. Compensations are associated with close capacity margins, and are interpreted as a signal for increasing capacity.

The dynamics of the capacity expansion is represented by one reinforcing loop – *profits* (R1) – and three balancing loops: *reliability* (B1), *control* (B2), and *compensations* (B3). The *profits* loop represents the causal relationship between usage charges and investment in capacity. Users pay transmission charges proportional to the transmission capacity. As transmission capacity increases, the usage charges for asset owners also increase. Assuming efficient costs, the increment in usage charges rise the profitability of transmission, and therefore it increases the willingness to invest in transmission capacity. Installed capacity increases after new projects are completed, taken into account the planning and construction delay.

The second mechanism for investment comes from the *reliability* loop (B1), where investment increases with the margin gap between the desired transmission capacity margin and current power demand. This mechanism requires a regulator to open bids for expansion projects whenever investors fail to make the expansions needed for achieving a safety transmission capacity margin. The *control* loop (B2) represents a

[1] It is a map that shows the cause-effect and feedback relationships among the variables in one domain.

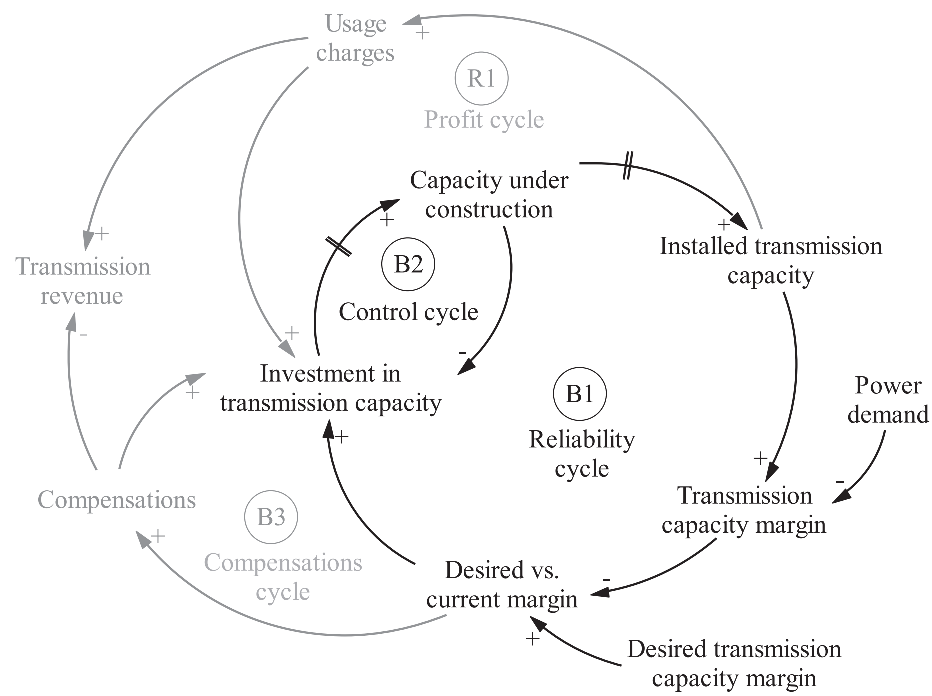

Fig. 1. Causal loop diagram for transmission capacity expansion. Centralized expansion is shown by cycles B1 and B2 in solid lines. Decentralized expansion adds cycles R1 and B3.

mechanism to increase coordination of the investments. In the *control* loop, expansion decisions are adjusted to reach a level of desired capacity, by considering the capacity currently under construction.

Finally, the *compensation* loop (B3) is associated to underinvestment periods that occur when power demand grows faster than the installed capacity, and compensations for reliability issues increase. Lower profits discourage new investments and while demand continues to grow, compensations increase. However, higher compensations become a signal for increasing investment.

There is a differentiation of the elements of centralized planning (black) from decentralized planning (gray) in Fig. 1. Expansion in centralized planning is defined by the interaction of the reliability loop B1 and the control loop B2, where investments depend on the desired transmission capacity margin and are regulated by the capacity currently under construction. On the other hand, expansion in decentralized planning varies with the profit loop R1 and the compensations loop B3, where investments are determined by the investors' market logic. In the next section, we describe the formulations for both approaches.

2.2. Formal model

This section explains the main equations and assumptions of the simulation model. Table 1 presents the corresponding equations. We start out from the installed transmission capacity, which represents operating (existing) capacity, and the capacity under construction, which is the capacity of expansion projects currently under execution and that will be commissioned in the future. Installed transmission

Table 1
Main equations of dynamics model.

Equations and comments	Units	
$I_{tc}(t) = I_{tc}(0) + \int_0^t (R_c(t) - R_d(t)).\, dt$	MW	(1)
Installed transmission capacity I_{tc} increases at a rate of construction R_c, and decreases when operating assets are decommissioned at a rate R_d.		
$C_{uc}(t) = C_{uc}(0) + \int_0^t (R_i(t) - R_c(t)).\, dt$	MW	(2)
Capacity under construction C_{uc} increases at a rate of investments R_i in transmission capacity and decreases at a rate of construction R_c.		
$R_c(t) = (C_{uc}(t))/\alpha$	MW/year	(3)
The rate of construction R_c is the amount of C_{uc}that becomes operative after a construction delay, α.		
$R_d(t) = (I_{tc}(t))/\beta$	MW/year	(4)
The decommissioning rate R_d is the amount of I_{tc} that is uninstalled at the end of their useful life, β.		
$R_i(t) = I(t)/\gamma$	MW/year	(5)
The rate of investment R_i is the capacity of the investment decision I that becomes C_{uc} after a planning horizon γ.		
$U_c(t) = \mu_1 I_{tc}(t) + \mu_2 E_d(t)$	COP/MWh	(6)
Usage charges U_c is sensitive to installed transmission capacity I_{tc} and energy demand E_d variations.		
$C_o(t) = Max\{0, \mu_3(D_m(t) - C_m(t))\}$	COP/MWh	(7)
Compensations C_o are driven by the difference between a desired margin of transmission capacity D_m and the current transmission capacity margin C_m.		
$D_m(t) = \omega * P_d(t)$	MW	(8)
Desired transmission capacity margin D_m is ω times the power demand P_d.		
$C_m(t) = I_{tc}(t) - P_d(t)$	MW	(9)
Current transmission capacity margin C_m is the difference between installed transmission capacity I_{tc} and power demand P_d.		

capacity and capacity under construction are the main state or stock variables. Under construction and installed capacity are defined to differentiate planning delays from construction delays for capacity investments. Then, after a planning delay, investment becomes capacity under construction. Capacity under construction becomes operative after a construction delay, increasing the installed transmission capacity. Installed capacity decreases with the decommissioning rate.

Usage charges and compensations are calculated for expansions made with centralized and decentralized approaches. Usage charges depend on the evolution of energy demand and installed transmission capacity. Similarly, compensations are driven by the difference between a desired transmission capacity margin and the current transmission capacity margin which, in turn, depends on the difference between installed transmission capacity to power demand.

On the other hand, each planning approach implements a different rule for investment decisions, as shown in Table 2 and Table 3. Centralized expansion seeks to achieve a reliability goal. This goal is modelled as a desired transmission capacity margin. Investment needs are determined by the margin gap defined as the difference between the desired transmission capacity margin and current power demand. Investment in new capacity increases with the difference between the desired and effective transmission capacity margins. In this model, when estimating expansion needs, planners consider the capacity currently under construction.

In decentralized expansion, investment is based on the relationship between power demand and installed capacity perceived by the investors and, therefore, by transmission revenues. Transmission revenues are a function of the usage charges received for the new capacity and of the level of compensations needed in the market. Then, part of the investment is driven by usage charges and the rest by compensations, both defined using previsions about power demand and installed capacity. Then, if compensations grow as a result of capacity constraints, transmission companies receive a signal for increasing capacity and decreasing the cost of compensations. After transmission capacity margin grows as a result of investment, usage charges increase, and compensations decrease.

The dynamic model for capacity expansions defined in Sections 2.1 and 2.2 is used to simulate the behavior of transmission capacity over a 15-year time horizon. The Colombian transmission system is used as a case study for calibrating and running the simulation model. The following section describes the case study as well as the procedure and data used for calibrating and validating the behavior of the model.

3. Case study: expansion of the Colombian transmission capacity

The following subsections briefly describe the structure of the Colombian power system and explain how the model represents the current expansion mechanisms in the case study. Then, the data and procedure used for calibration are presented, as well as the methods used for validating the model's assumptions and behavior.

3.1. Capacity expansion in the Colombian power market

The Colombian electricity market is a uni-nodal centralized system. The Mining and Energy Planning Unit (UPME, in Spanish) is responsible for analyzing a set of feasible expansion and upgrading alternatives, and for choosing one that can be implemented at lowest cost and highest reliability. Transmission and generation expansion are jointly analyzed for different growth scenarios of both electricity demand and peak power demand. The analysis is performed for the whole system, by regions and by disaggregating large consumers. The final transmission expansion plan includes alternatives to improve the current overall economic and technical reliability of the system. The new projects are allocated through a public tender process. The revenue of the bid's winner is regulated by the Energy and Gas Regulatory Commission (CREG, in Spanish).

The expansion plan and other regulatory mechanisms seek, among other objectives, to transmit power reliably at all times, and to reduce the costs of transmission constraints. To achieve this, regulators need to send investors the right signals to increase the capacity of the transmission system [38]. However, the call for bids methodology used in Colombia is more responsive to the need for reliability than to market opportunities. Furthermore, the number of competitors is limited, and the incumbent controls 80% of transmission assets [39].

Usage charges and compensations are the two mechanisms used for remunerating the use of transmission assets and for encouraging investment in capacity. For example, sustained growth in compensations is an early sign of increased demand, and the investors could react to it by increasing their transmission capacity. Usage charges in Colombia are determined based on transmission assets and O&M expenses [40], whereas compensations depend on the quality of the transmission service.

3.2. Data and assumptions

To calibrate the model for the Colombian case study, actual 1995–2015 data were used. Simulations from 2015 to 2030 were then performed, given that this is the planning period used by UPME for making the generation and transmission expansion plans. Those plans contain a detailed description of the current and proposed configuration of the Colombian network (see for example [41]). However, as we mentioned before, in this paper the electricity market is analyzed at an aggregate level; thus, the parameters and variables are established for the whole system, assuming that there are not zonal or nodal differentiations. Furthermore, as we deal with long-run transmission capacity investments, we do not model the short-run details, such as the costs associated with transmission losses and the availability of transmission assets.

Table 4 shows the parameters, exogenous variables and initial conditions of the model. Data was collected from several Colombian institutions. For instance, electricity demand contains actual data from Market Experts – XM [39] and projections from UPME [41]. For this variable, as we mentioned in Section 3.1, in the expansion plan the UPME considers three scenarios of electricity demand growth. The simulations were performed with the medium scenario, which implies an average annual growth rate of the electricity demand of 3.1% [41]. The high and low scenarios with average annual growth rates of 3.3% and 3.0% respectively were employed in the sensitivity analysis of the model.

The useful life was estimated at 40 years, which is the average life of the building units reported by CREG in resolution 11 of 2009 [40]. Relevant information for calculating usage charges, such as usage charges elasticities to transmission capacity and electricity demand were estimated by regressions from actual data provided by XM [39]. A similar process was used to estimate the elasticity of compensations to margin gap. The delays for construction and planning were determined based on construction times reported by the UPME in different expansion plans. The planning delay was set at 1.26 years for centralized planning and at 1 year for decentralized expansion. This is the only parameter in which the models for the planning approaches differ,

Table 2
Investment decision in centralized planning.

Equations and comments	Units	
$\boldsymbol{E_c}(\boldsymbol{t}) = \boldsymbol{forecast}(\boldsymbol{P_d}(\boldsymbol{t}))*(1+\omega)$ Expected capacity $\boldsymbol{E_c}$ is $1+\omega$ times the forecast of power demand $\boldsymbol{P_d}$.	MW	(10)
$\boldsymbol{I}(\boldsymbol{t}) = \boldsymbol{E_c}(\boldsymbol{t}) - \boldsymbol{I_{tc}}(\boldsymbol{t}) - \boldsymbol{C_{uc}}(\boldsymbol{t})$ Investment depends on the difference between the expected capacity $\boldsymbol{E_c}$ and the sum of installed transmission capacity $\boldsymbol{I_{tc}}$ and capacity under construction $\boldsymbol{C_{uc}}$.	MW	(11)

Table 3
Investment decision in decentralized planning.

Equations and comments	Units	
$I(t) = I_{uc}(t) + I_{co}(t)$	MW	(12)
The investment I is the sum of the investment decision driven by usage charges I_{uc} and compensations I_{co}.		
$I_{uc}(t) = Max\{0, forecast(P_d(t)) - I_{tc}(t)\}$	MW	(13)
Investment by usage charges I_{uc} is the difference between power demand forecast P_d and installed transmission capacity I_{tc}.		
$I_{co}(t) = Max\{0, forecast(P_d(t)) - forecast(I_{tc}(t))\}$	MW	(14)
Investment by compensations I_{co} is the difference between the forecasts of both power demand P_d and installed transmission capacity I_{tc}.		

Table 4
Model parameters, exogenous variables and initial conditions.

Variable	Centralized planning	Units	Source
Parameters			
α	2.05	years	UPME
β	40.00	years	CREG
γ	1.26	years	UPME
ω	50%	%	XM
μ_1	7.14E−07	COP/(kW * kWh)	Regressions
μ_2	2.04E−10	COP/(kWh^2)	Regressions
μ_3	9.23E−09	COP/(kW^2 * h)	Regressions
Exogenous variables			
E_d	Annual data	GWh	XM, UPME
Initial conditions			
$C_{uc}(0)$	544	MW	XM, UPME
$I_{tc}(0)$	10,095	MW	XM, UPME

given that the main difference is the investment decision rule. The assumption is that the process of opening a call for bids increases planning delays in the centralized approach.

The desired transmission capacity margin was set at 50%. This margin is equal to the difference between the peak power demand and the average power demand, and was calibrated using actual data from XM [39]. The total transmission capacity of the power system was assumed to be equal to the peak power demand. From 1995 to 2015, peak power demand grew at an average annual rate of 1.8%, to reach 10,095 MW in 2015. For the 2015–2030 horizon, peak power demand is expected to grow at a 2.4% annual rate, boosted by the demand of large consumers and expected exports [41].

Finally, the initial conditions: capacity under construction and initial installed capacity, defined for 2015, were estimated at 554 MW and 10,095 MW respectively [42,41]. The parameters in Table 4 define the reference mode for the model. Using these parameters, the model for centralized planning was calibrated. The next subsection shows the model validation of structure and behavior.

3.3. Validation

Validation in system dynamics models focuses not only on behavioral reproduction tests, but also on model assumptions and structure. Thus, a subset of the tests proposed by [43] for validating the structure and behavior of the models was used. The structural and behavioral validation tests indicate that, in both models, material and energy conservation laws are followed, and that the models behave consistently. The equations were tested for dimensional consistency and a test of extreme conditions was applied, along with sensitivity analysis. For the centralized planning model, the model's performance was compared to the planning process described by UPME [38].

Behavioral or pattern replication tests assess the ability of the model to replicate past comportment. Thus, the simulated installed capacity for centrally planned expansion is compared with actual values. Table 5 presents a summary of the statistics for the historical adjustment. Note that the coefficient of determination –R^2– has a value close to 1 which indicates a strong capability of the model to replicate past behavior. Additionally, it is confirmed with a low value of the mean absolute percentage error (MAPE), below 6.0%. Theil's decomposition of the mean square error (MSE) [44] shows that 26% of the MSE is caused by bias, 35% by the variance, and 39% by the covariance, which highlights the balanced distribution of the error. In Fig. 2, visual inspection indicated that the simulated installed capacity matches the historical tendency of the transmission capacity.

In the next section, validated models are used to compare the centralized and decentralized expansions of the transmission capacity.

4. Simulation results

This section presents simulation results using the validated model described in Section 2.2 and adjusted with data for the Colombian case (Section 3.2). As an exogenous variable, both centralized and decentralized models receive the electricity demand from UPME's 2016–2030 expansion plan in its medium scenario [41]. Then, their performance is compared with the expected annual transmission capacity, which we assumed as being equal to the peak power demand expected by the UPME in such plan, as we mentioned before.

4.1. Comparison of centralized and decentralized transmission expansion

As shown in Fig. 3a, the installed capacity for centralized expansion grows at an annual average rate of 3.3% and it is consistently above the power demand, which grows at 3.1% per year. In decentralized expansion, the transmission capacity margin narrows following an initial excess capacity period (2015–2021) after which the installed capacity closely matches power demand, and both increase at annual average rates of approximately 2.8%. This behavior is consistent with capacity under construction, which declines between 2015 and 2019, to later experience growth and declining periods. After 2019 capacity under construction in decentralized expansion is around 1100 MW, approximately 600 MW below the capacity under construction in the centralized expansion (Fig. 3b).

Excess capacity under centralized expansion results from the desire to maintain a transmission capacity margin. Under centralized expansion planners are willing to promote investments to increase transmission capacity, and therefore, relieve compensations. These compensations are a signal for investment under decentralized planning: when transmission capacity margins are low and compensation costs increase, transmission companies invest in new capacity.

Over-investment is also possible in decentralized expansion. As new capacity enters with a delay, investors continue to respond to compensation signals, and the over-investment period only ends after the new capacity enters and compensations decrease.

Usage charges are larger in centralized expansion (Fig. 4a) because more capacity is installed than when expansion is decentralized. In fact,

Table 5
Summary of statistics for the historical adjustment.

Statistic	Value
Coefficient of determination, R^2	0.94
Mean absolute error, MAE (MW)	474.60
Mean absolute percentage error, MAPE (%)	5,64
MAE/Mean (%)	5,59
Root mean square error, RMSE (MW)	544.63
U^{M*}	0.26
U^{S*}	0.35
U^{C*}	0.39

* UM, US, and UC are the fractions of the mean square error (MSE) due to bias, variance, and covariance respectively, and represent the Theil inequality statistics [44].

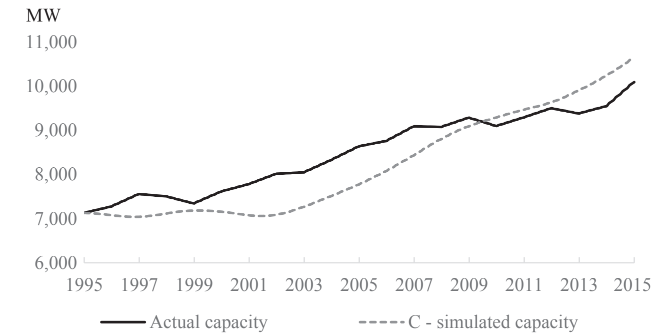

Fig. 2. Comparison of actual transmission capacity and transmission capacity simulated with centralized expansion (C).

the annual average growth rates of 3.2% and 2.6% in the centralized and decentralized expansion respectively are similar to those growth rates observed for the simulated installed capacity which were described before. By contrast, compensation costs are higher in the decentralized expansion (Fig. 4b), which is consistent with the lower transmission capacity margins in this approach, as the demand is so close to the total transmission capacity and the transmitters have additional costs to maintain the reliability of the power infrastructure.

Simulation results show that the decentralized expansion promotes investments and capacity adjustments to timely match demand growth and maintain low transmission capacity margins (see Fig. 3a). However, as discussed before, low transmission capacity margins are associated with compensation charges when the difference between power demand and capacity narrows. Therefore, in the following section, a hybrid mechanism [45] that combines features of centralized and decentralized expansion is proposed to reduce transmission charges while satisfying demand.

4.2. Hybrid expansion mechanism

The hybrid approach integrates both centralized and decentralized planning, where the planner, grid owners, and potential entrants make proposals to expand transmission capacity. Then, technically and economically feasible projects are assigned to their proponents. But when investors fail to make the expansions needed for achieving a safety transmission capacity margin, the planner opens a call for bids to allocate projects. The causal loop diagram for the hybrid approach is shown in Fig. 1. Unlike both centralized and decentralized planning, its behavior emerges from the interactions of all the reinforcing and balancing loops.

Unlike the centralized planning model, in the hybrid approach, investment depends on the difference between the desired and current transmission capacity margin as well as on the market expectations of the transmission companies. Thus, the planner only intervenes in investment decisions when the market does not respond to investment signals. The model in Fig. 1 prevent over-capacity by considering the capacity under construction in the investment function. This hybrid investment function collects the investment decisions of each approach (centralized planning and decentralized planning) and takes the maximum. Parameters are inherited from the two models, except the planning period γ, which is the same as the decentralized approach (Table 4).

4.3. Performance of planning mechanisms

Simulation results suggest that hybrid expansions improve centralized and decentralized planning. When compared to centralized planning, hybrid planning smoothens the amount of required investments each year (Fig. 5), and, in turn, the total installed transmission capacity of the system. The investments go from an annual average of 94 MW on the centralized planning to 86 MW on hybrid expansion. This represents savings for the demand, as the usage charges decrease (Table 6). Although compensations with hybrid planning tend to increase (see Table 6), the net increase in compensations is offset by decreases in usage charges.

On the other hand, hybrid planning reduces the variations of transmission capacity investments compared with the decentralized approach. Consequently, usage charges on average are 5.7% higher (Table 6) mainly because there are more transmission assets. However, as hybrid planning improves the transmission capacity margin, the compensations on average are 44.1% lower than in the decentralized planning (Table 6).

Results suggest that combining centralized and decentralized mechanisms in a hybrid expansion approach improves the timing of capacity expansion and achieves a safety transmission capacity margin. Implementing this methodology in Colombia would require improving information in the market. However, the current roles of planning and regulatory institutions are not expected to grow, as they already propose and assign expansion projects, and define their remuneration.

In principle, the hybrid expansion mechanism promotes competition in transmission because it allows potential entrants to propose new projects, and to bid for the projects proposed by the planner. In practice, it is not very likely that new entrants would be willing to bid for extension projects of transmission assets operated by an incumbent

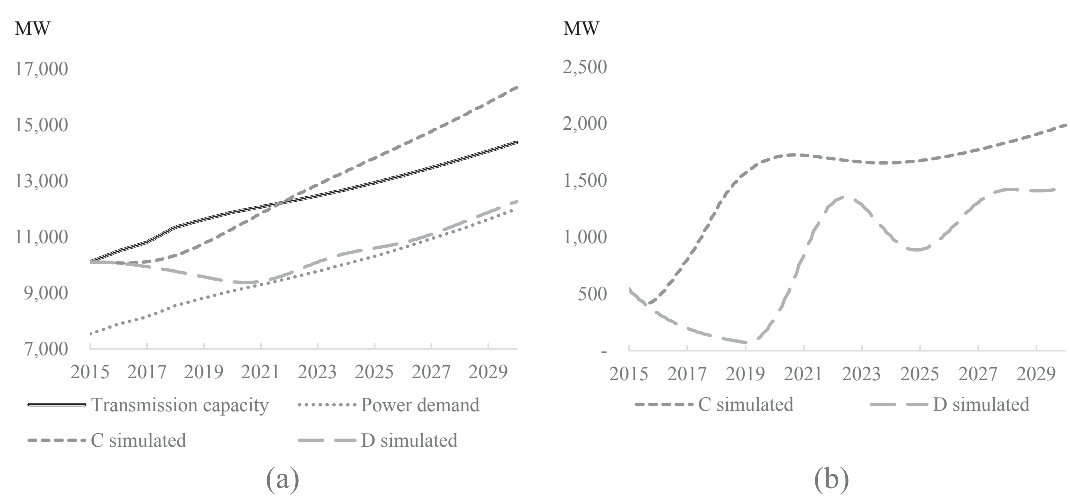

Fig. 3. Comparison of (a) simulated installed capacity with forecasts of power demand and transmission capacity, and (b) simulated capacity under construction for centralized (C) and decentralized (D) planning.

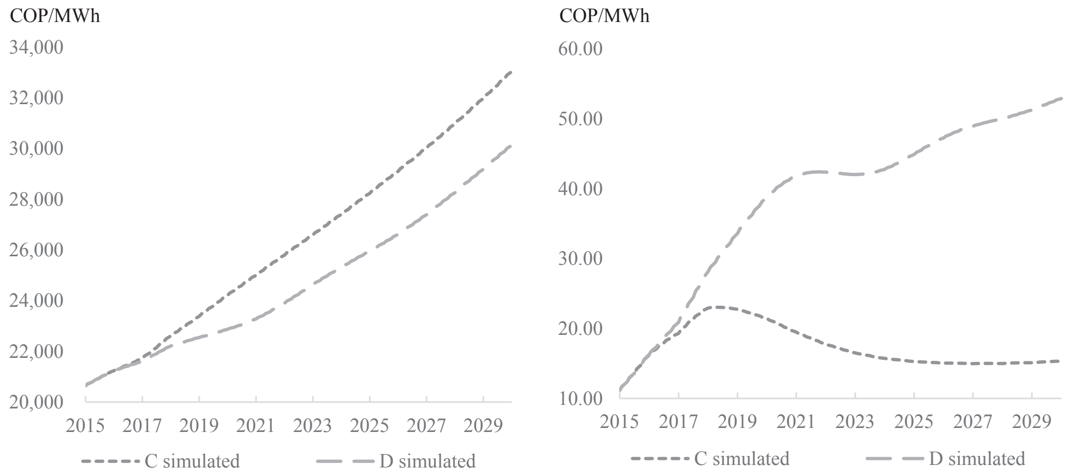

Fig. 4. Simulated (a) usage charges, and (b) compensation charges for centralized (C) and decentralized (D) transmission expansion.

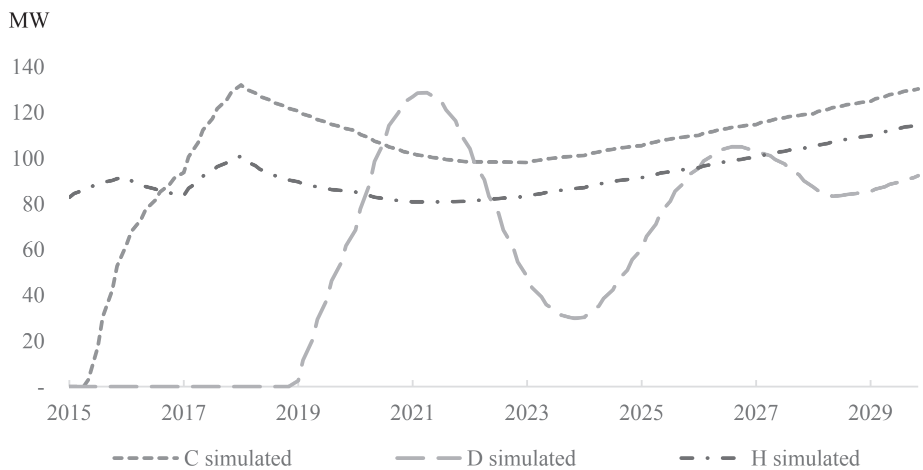

Fig. 5. Simulated annual capacity expansions for centralized (C), decentralized (D) and hybrid (H) approaches.

Table 6
Evolution of annual usage charges and compensations under centralized (C), decentralized (D) and hybrid (H) expansion approaches.

Year	Usage charges (Thousands of million COP)			Compensations (Thousands of million COP)			Hybrid planning (H) performance			
							Usage charges (%)		Compensations (%)	
	C	D	H	C	D	H	H vs C	H vs D	H vs C	H vs D
2015	1363	1363	1363	0.7	0.7	0.7	0.0	0.0	0.0	0.0
2016	1466	1466	1472	1.1	1.1	1.0	0.4	0.4	−6.8	−7.3
2017	1547	1539	1563	1.4	1.5	1.2	1.0	1.6	−14.8	−21.3
2018	1692	1662	1713	1.7	2.1	1.4	1.3	3.1	−16.0	−31.5
2019	1804	1739	1824	1.8	2.6	1.5	1.1	4.9	−14.6	−42.2
2020	1922	1815	1935	1.7	3.1	1.5	0.7	6.6	−10.2	−50.3
2021	2034	1893	2038	1.6	3.4	1.5	0.2	7.6	−3.6	−55.0
2022	2151	1992	2145	1.5	3.5	1.6	−0.2	7.7	4.5	−56.1
2023	2273	2104	2258	1.4	3.6	1.6	−0.6	7.3	13.2	−55.5
2024	2405	2222	2382	1.4	3.8	1.7	−1.0	7.2	21.8	−55.2
2025	2548	2342	2517	1.4	4.1	1.8	−1.2	7.5	29.7	−55.9
2026	2703	2472	2663	1.4	4.4	1.9	−1.5	7.7	36.9	−56.4
2027	2871	2620	2823	1.4	4.7	2.1	−1.7	7.7	43.5	−56.1
2028	3053	2786	2996	1.5	4.9	2.2	−1.9	7.5	49.6	−55.1
2029	3252	2967	3186	1.5	5.2	2.4	−2.0	7.4	55.2	−54.3
2030	3469	3164	3394	1.6	5.6	2.6	− −2.2	7.3	60.2	−53.6

transmission company, and only get a return for their invested capital and maintenance costs, and not from the operation and management activities of such assets. However, the incumbent is likely to be more efficient than an entrant firm is in planning and executing such extensions [16].

If transmission assets are owned by different firms, defining rules for investing in and maintaining facilities becomes more difficult. This is why decentralized planning could be limited to special projects such as

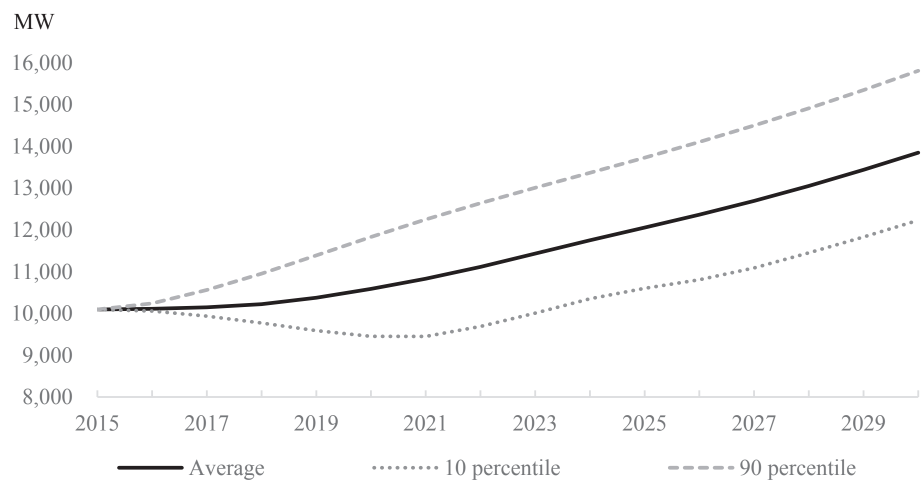

Fig. 6. Sensitivity of installed capacity in the hybrid planning (H) approach to desired transmission capacity. Results shown for average, 10 and 90 percentiles.

regional interconnections or according to [46], to high voltage DC lines as in Europe and Australia, because these assets are controllable.

4.4. Sensitivity analysis

In order to assess the uncertainty associated with different parameter values, we performed a sensitivity analysis applying Monte Carlo simulation with 100 runs using random samples drawn from uniform distributions for each of the following parameters: construction and planning delays, useful life, and elasticities of usage and compensation charges. This analysis tests the boundaries of the proposed model the robustness of its behavior. Results show that the model behavior robust for -+20% changes in those parameters.

We also tested the sensitivity of the model results to two demand scenarios defined by UPME [41] and found results consistent with low and high-electricity demand growth projections. Finally, we focus on the sensitivity of the model to changes in desired transmission capacity margin and again, perform a Monte Carlo simulation with desired margin sampled from a uniform distribution in the range of [10%, 60%].

Fig. 6 shows 100 simulations results where the parameter desired transmission capacity margin was chosen randomly for each simulation in the pre-defined interval. The figure depicts the average installed transmission capacity and the 10th and 90th percentiles for hybrid planning. Visual inspection shows that the model behavior is robust to the desired transmission capacity margin, given that simulation indicates that the model does not “collapse or explode”.

5. Conclusion and policy implications

In this paper, expansion of power transmission capacity is analyzed using a simulation model for centralized and decentralized approaches. Centralized expansion contributes to achieve reliability goals set as a desired transmission capacity margin, but it also requires more timely investment signals to reduce over-investment and usage charges. By contrast, decentralized expansion encourages investment through mechanisms such as usage charges and compensations, but increases compensations because it does not promote excess capacity. Given this complementarity, we also studied a hybrid approach combining the features of centralized and decentralized expansions. This hybrid planning improved investment timing in comparison to the decentralized approach while reducing usage charges versus the centralized approach.

Results indicate potential gains from implementing an expansion scheme for transmission capacity that combines initiatives from companies with signals from regulators. In order to implement a hybrid planning of transmission capacity expansions, while the current roles of the regulator and planner are not expected to change, it is necessary to improve information availability for planners and potential investors. This contributes to reducing the planning delays, and it also helps to coordination of investments, and therefore to control over-investment.

Regarding the implementation of the regulatory schemes, detailed analysis that includes generation and transmission constraints are required to identify optimal investments and their impact on the system’s security. Distributed generation sources (solar and wind) pose additional challenges for planning, and then further research should focus on the impact of their penetration in the system operation and on the expansion and replacement requirements of the grid.

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Appendix A. Supplementary data

Supplementary data associated with this article can be found, in the online version, at https://doi.org/10.1016/j.ijepes.2018.07.029.

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