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Analysis of generation investments under price controls in cross-border trade of electricity

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ABSTRACT

Price controls are commonly employed in Latin America and other regions to prevent price increases in exporting regions during cross-border trade of electricity. This paper introduces a methodology to evaluate the economic impact of price controls on generation investments, dispatch decisions, and carbon emissions in the context of cross-border electricity trade. We propose a non-linear adjusting function to represent a price-control rule, which can be incorporated into equilibrium models for generation firms and price-sensitive consumers. By employing fixed-point iterations between the adjusting function and an optimization problem that determines equilibrium investments and dispatch decisions for generation firms in a competitive environment, we obtain an equilibrium solution. We apply the proposed methodology to analyze the current price controls governing cross-border electricity trade between Chile and Argentina, with a focus on the exporting country. Our findings reveal that existing price controls can impede incentives for renewable energy investments, particularly in wind and solar, while stimulating investments in fossil fuel-based generation capacity. Moreover, these controls lead to increased CO_2 emissions compared to a scenario without price controls. Additionally, we observe that the inefficiency resulting from price controls is proportionate to the volume of exports relative to local demand and the price elasticity of demand in the importing region.

1. Introduction

Cross-border trade of electricity though transmission interconnections is an essential form of international trade, enabling neighboring countries to expand their generation and demand resources across larger geographic areas. This diversification offers numerous benefits, including the reduction of fuel costs; mitigation of variability in renewable resources such as wind, solar, and hydro; deferral of local investments in generation and transmission infrastructure; as well as significant emissions reductions (Kristiansen et al., 2018; Konstantelos et al., 2017).

For instance, in the United States, the implementation of the Western Imbalance Market in 2014, which facilitated partial integration of different power systems in the western region, has yielded substantial advantages. This market has generated nearly $900 million in gross benefits and contributed to the avoidance of 500,000 metric tons of CO_2 emissions (CAISO, 2019). Similarly, a recent study conducted in Latin America revealed that increased integration of power systems in the region could lead to efficient incorporation of renewable resources and potential cost savings of up to $20 billion by 2030 (Martinez-Conde-Del-Campo, 2017). Furthermore, such integration would enable a significant reduction in CO_2 emissions by 15% compared to a baseline scenario without integration and cross-border trade of electricity.

In spite of the significant overall economic and environmental benefits associated with transmission interconnections and power system integration, certain challenges impede the unrestricted trade of electricity and other commodities across countries. One such challenge arises from the potential winners and losers created by trade agreements. In particular, prices in exporting regions can increase as a result of a rise

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[1] This issue could be further exacerbated if customers who face a local price increase are also responsible for bearing the costs of new transmission interconnections. However, the presence of state ownership of generation, as observed in countries like Norway, may reduce the pressure to implement compensatory measures.

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in demand from an importing region with high electricity prices (Kristiansen et al., 2018). In the absence of compensatory mechanisms, this local price increase can exert substantial political pressure on regulators, potentially resulting in the obstruction of a transmission interconnection.[1] Such an interconnection would otherwise enhance the aggregate welfare in the newly connected regions.

To address this challenge, some countries have also implemented intermediate solutions that fall between the extremes of completely unrestricted trade and no trade at all. One such option involves implementing trade agreements that incorporate mechanisms to shield certain customers from price increases in exporting regions. These mechanisms generally take the form of direct subsidies or indirect subsidies through price controls. For instance, in oil-exporting countries, subsidies for domestic energy consumption can be so substantial that they account for nearly 10% of the local GDP (Burniaux et al., 2011). In Saudi Arabia, power and water-desalination utilities procure crude oil from Saudi Aramco at prices lower than export prices, with administered prices varying accross different consuming sectors (Matar et al., 2015). However, in 2018, these prices were sharply increased in an attempt to reduce subsidy levels (Aldubyan and Gasim, 2021). In addition to energy-related subsidies, many countries, such as Argentina, also provide subsidies for the local consumption of non-energy related goods, including agricultural products (Lema et al., 2018).

While subsidies and price controls can safeguard specific customer groups against price increases resulting from cross-border trade, abundant evidence suggests that these mechanisms undermine market efficiency. Price controls, in particular, can lead to fiscal deficits, diminish profit margins, facilitate market power abuse, distort price signals for local investments, promote fossil fuel consumption, and increase greenhouse gas emissions (Marchán et al., 2017; Shi and Sun, 2017; Brown et al., 2017; Weare, 2003; Saha et al., 2019). Additionally, government policies, administrative rules, and various market design features have been shown to significantly influence investment incentives within power systems (Bahar and Sauvage, 2013; Doorman and Botterud, 2008; Wogan et al., 2019; Rioux et al., 2017; Liu and Alvarado, 2006). However, the extent of the distortions caused by price controls and subsidies in commodity markets, especially electricity markets, remains less clear.

One way to measure the impacts of price controls and subsidies is to employ equilibrium models formulated as Mixed-Complementarity Problems (MCP) with additional variables and constraints that replicate the effects of administrative measures (Matar et al., 2015; Fuller et al., 2013; Murphy et al., 2017, 2019; Vlachos and Biskas, 2011). For instance, Murphy et al. (2019) utilized MCP-based models to examine the impact of price controls within multi-sector economic-equilibrium models. In their formulation, new dual variables were introduced to account for value-added or sales taxes. In another study, Vlachos and Biskas (2011) employed an MCP framework to investigate the consequences of administrative price differentiation within a multizone bidding system. MCP-based approaches offer the advantage of being solvable in a single step, utilizing readily available packages such as PATH or mixed-integer linear solvers when complementarity constraints are reformulated as disjunctive ones. However, these approaches can be restrictive due to solution package-imposed size limits. Additionally, they are only applicable to administrative rules that can be expressed in closed form, such as setting administrative prices equal to average prices over space or time.

Another approach to model administrative price controls is through iterative solution approaches that update price signals based on results from previous iterations. Unlike MCP-based approaches, iterative algorithms can accommodate administrative rules that cannot be expressed in closed form, which are prevalent in real-world scenarios. Iterative approaches have been extensively utilized to model energy policies and government interventions in markets (Hogan, 1975; Greenberg and Murphy, 1985; Capros et al., 2008; Diaz et al., 2020). For example, the Project Independence Evaluation System (PIES) is an early example of a multi-sector energy model that utilized iterative solution approaches. PIES involved solving a sequence of linear programs and econometric demand equations. Similarly, in another study (Greenberg and Murphy, 1985), a method was described for computing regulated market equilibrium by iteratively adjusting parameters in equilibrium models that do not explicitly account for price controls. In this approach, tariffs were defined as functions of the dual variables of supply and demand balance equations, enabling the incorporation of taxes, rebates, average cost pricing structures, and price caps. More recently, a framework proposed in Diaz et al. (2020) allows for the analysis of long-term effects of carbon emissions policies, considering pass-through restrictions and side-payment rules.

However, to the best of our knowledge, there is currently no existing research specifically focused on quantifying the long-term effects of government price controls on cross-border trade of electricity, particularly in relation to their impact on generation investment incentives. This paper aims to fill this research gap by proposing an iterative approach to analyze the impact of a government price control rule on cross-border trade of electricity, drawing inspiration from administrative rules observed in Latin America. Our model facilitates the determination of equilibrium generation investment decisions for an exporting country, taking into account an administrative rule that establishes differentiated prices for local consumption and exports. Additionally, we incorporate price elasticity for exports, as there is evidence indicating that demand response can significantly influence long-term investment and operational decisions (Özdemir et al., 2016; Kazerooni and Mutale, 2010; Liu, 2017; De Jonghe et al., 2012; Padmanabhan et al., 2018; Fang et al., 2016; Parvania et al., 2014).

The structure of this paper is organized as follows. In Section Section 2, we provide a brief overview of the Chilean electric power system. In Section Section 3, we outline the proposed equilibrium model and solution approach, which account for price controls, as well as the integration of a demand-response model. Additionally, we include the description of an equilibrium model without price controls, which we utilize to compute socially-optimal outcomes as a benchmark. Section Section 4 is dedicated to discussing the current regulations in Chile and other countries in Latin America regarding cross-border trade of electricity. This serves as an illustrative case of administrative price control. Based on these regulations, we present a series of case studies to evaluate the impact of price controls on investment decisions. Finally, in Section Section 5, we present our conclusions and provide recommendations based on our findings.

2. Brief description of the Chilean electric power system

The electricity demand in Chile is about 75 TWh per year, with a peak demand of 11303 MW (2021) (CEN, 2022). On the supply side, the generation mix contains 7098, 5061, and 5092 MW of hydro, coal, and gas power generation, respectively, with increasing participation of renewables, particularly wind and solar power units, featuring an installed capacity of 3549 and 6203 MW, respectively (CEN, 2022). In terms of cross-border interconnections, Chile is only interconnected with Argentina via a 777 MVA link at 345 kV (CNE, 2017).

The electricity demand grows at an approximate rate of 4.7% per year (CEN, 2022). The country features a significant solar and wind power generation potential of about 1800 and 38 GW, respectively (Moreno et al., 2017). With the current decreasing trend in the investment costs of these technologies, their deployments are progressively increasing and seem even more promising in the future. Furthermore, Chile possesses one of the highest irradiances in the world, with values of Global Horizontal Irradiance (GHI) of up to 1200 W/m^2 (Escobar et al., 2015). Also, new projects are obtaining attractive Power Purchases Agreements (PPA) through competitive auctions with prices as low as 13.32 \$/MWh (CNE, 2021a), presenting significant prospects for supplying both internal demand and exports to other countries in the region.

Although generation investment is a fully competitive, market-driven activity, power system operation is greatly regulated through a centrally planned, cost-based dispatch (Muñoz et al., 2021). Here, in contrast to bid-based designs in most deregulated markets elsewhere, variable costs of thermal generators are audited to input them in the optimization of system operation. At the same time, the scheduling of large-scale hydro reservoirs is determined via stochastic dual dynamic programming (SDDP) following the concepts developed in Pereira and Pinto (1991). This mathematical model captures the storage capability of hydro units and their uncertainties in terms of future hydro inflows.

In this context of significant regulations on system operation and their resulting spot prices, we aim to study the effects of energy exchanges between countries in long-term generation investments under various regulatory arrangements in Chile. Next, we explain in detail the different price controls studied related to system operation and the energy exchanges between Chile and Argentina.

3. Methodology

3.1. Nomenclature

3.1.1. Abbreviations

CM : Centralized model
$DAEC$: Domestic annual energy costs
$EAEC$: Exports annual energy costs
LP : Linear programming
$LRCS$: Long run consumer surplus
$LRPS$: Long run producer surplus
NLP : Non-linear programming
PCM : Price control model
QP : Quadratic programming
TC : Total costs
$TNRC$: Total non-renewable capacity
TRC : Total renewable capacity
TSW : Total social welfare

3.1.2. Parameters

A : Independent coefficient of the demand inverse function ($/MWh)
C : Coefficient of the demand inverse function ($/MWh^2)
CF_i : Annual capacity factor for generator i
D_o : Reference electricity demand at price p_o (MW)
e_t : Price elasticity at time t
FOR_i : Forced outage rates of generator i
I_i : Levelized annual capital cost of generator i ($/MWyear)
K_t : Exported quantity at time t (MW)
MC_i : Marginal cost of generator i ($/MWh)
p_o : Price at demand D_o ($/MWh)
P_{D_t} : Domestic demand at time t (MW)
T_s : Total horizon time (h)
$VOLL$: Value of lost load ($/MWh)
$W_{i,t}$: Hourly capacity factors of generator i at time t

3.1.3. Decision variables

$p_{GD_{i,t}}$: Power dispatch of generator i at time t supplying the domestic demand (MW)
$p_{Go_{i,t}}$: Power dispatch of generator i at time t to satisfy the domestic demand plus the exported power K (MW)
u_t : Load curtailment at time t (MW)
x_i : Expansion capacity of generator i for the price control (MW)

3.1.4. Auxiliary variables

α_t : Price difference at time t (h)
B_i : Annual surplus reduction in per unit of generator i capacity
D_t : Demand at time t (MW)
γ_i : Lagrange multiplier for generator i for the annual capacity factor constraint ($/MWh)
λ_t : Lagrange multiplier at time t for the balance constraint ($/MWh)
$\mu_{i,t}$: Lagrange multiplier for the reliability constraint for generator i at time t ($/MWh)
p_t : Price at demand D_t
$p^*_{1,t}$: Dual variable of balance constraint at time t considering domestic demand only ($/MWh)
$p^*_{2,t}$: Dual variable of balance constraint at time t considering domestic demand and exportation power ($/MWh)
SL_t : Total lost surplus at time t ($/h)
SR_i : Surplus lost for generator i ($/h)
TSL : Total surplus lost for planning horizon T ($/h)

3.1.5. Sets

T : Set of time instants
G : Set of generators

3.2. A model of cross-border trade of electricity with price controls: Price control model (PCM)

Price controls in cross-border trade of electricity aim to protect consumers in the exporting country from short-term increases in electricity prices due to energy exports. For instance, in Chile and Argentina, exports can neither affect the local dispatch schedule nor increase local spot prices. In a simplified setting, where units are dispatched based on a merit-order curve, this rule is equivalent to imposing a cap on the domestic electricity price equal to the market clearing price that would result from only considering the domestic demand for electricity. As we show in Fig. 1, in equilibrium, this administrative rule results in two electricity prices: $p^*_{1,t}$, which corresponds to the clearing electricity price to satisfy the domestic demand P_{D_t}, and $p^*_{2,t}$, which stands for the electricity price to cover the exported power K_t. For simplicity, each step in Fig. 1 represents a generation technology (i.e., wind, solar, large hydro).

In a perfectly competitive market without price controls, all producers that supply the domestic and exported quantities are paid a single price, $p^*_{2,t}$. In contrast, under the current price controls in Chile and Argentina, at a given period t, generators that are used to meet the domestic demand are paid $p^*_{1,t}$, whereas generators that are used for

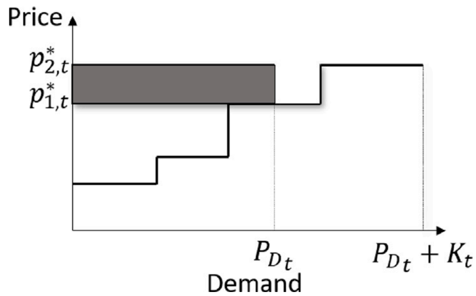

Fig. 1. Electricity prices in a competitive electricity market.

exports are paid $p^*_{2,t}$. Consequently, generators that are used to meet the domestic demand in the exporting region face a reduction in surplus, represented by the gray area in Fig. 1. Those generators that export electricity at some periods of time can also supply the domestic demand at some other periods of time and vice-versa. The corresponding lost surplus (SL) can be expressed for a given hour t as in Eq. (1a), where P_{D_t} represents the domestic demand at time t and K_t represents the export quantity at time t.

$$SL_t = \alpha_t P_{D_t} = (p^*_{2,t} - p^*_{1,t}) \cdot \sum_{i\in G} p_{GD_{i,t}} \qquad \forall t \in T \tag{1a}$$

$$\alpha_t = p^*_{2,t} - p^*_{1,t} \qquad \forall t \in T \tag{1b}$$

$$P_{D_t} = \sum_{i\in G} p_{GD_{i,t}} \qquad \forall t \in T \tag{1c}$$

The total surplus loss TSL corresponding for a planning horizon T (e.g., one year) is:

$$TSL = \sum_{t\in T} (\alpha_t \cdot P_{D_t}) \tag{2}$$

Each generation technology type i that satisfies the domestic demand faces a surplus reduction that can be expressed as follows:

$$SR_i = \sum_{t\in T} (\alpha_t \cdot p_{GD_{i,t}}) \quad \forall i \in G \tag{3}$$

By design, this price control scheme protects domestic customers from short-term price increases as a result of cross-border exports. However, this administrative rule also affects investment incentives for generation firms in the exporting region because units that are used to supply the domestic demand are paid a lower price than those that are used for exports.

Here we propose an equilibrium model and a solution approach to measure the effect of this type of administrative price control on long-term investment decisions and social welfare. Our model is based on an iterative solution approach that updates price signals using results from previous iterations. This approach has the advantage of accommodating administrative rules that cannot be written in closed form and which are common in practice. Specifically, we find an equilibrium solution using a Gauss–Seidel iterative approach that hierarchically solves two linear programs. One model finds equilibrium investment or expansion decisions considering a first-order approximation of the economic impacts of price controls and the other one determines the optimal economic dispatch subject to fixed capacities and price controls. We formulate the price-control rule as a non-linear adjusting function that is approximated in the model used to determine investment decisions. We assume price-taking behavior, which implies that minimizing total system costs is equivalent to solving an equilibrium model where each firm maximizes profit. Next, we describe the formulation of each model.

3.2.1. General expansion model

The general expansion model described in Eqs. (4)–(8) finds investment x_i and dispatch decisions $p_{Go_{i,t}}$ that minimize total system costs.

$$\min_{p_{Go_{i,t}}, x_i, u_t} \quad \sum_{t\in T}\sum_{i\in G} MC_i \cdot p_{Go_{i,t}} + \sum_{i\in G} (I_i + B_i) \cdot x_i + \sum_{t\in T} VOLL \cdot u_t \tag{4}$$

subject to:

$$P_{D_t} + K_t - \sum_{i\in G} p_{Go_{i,t}} - u_t = 0 \quad (p^*_{2,t}) \quad \forall t \in T \tag{5}$$

$$p_{Go_{i,t}} - (1 - FOR_i) \cdot W_{i,t}\, x_i \le 0 \quad (\mu_{i,t}) \quad \forall t \in T, \forall i \in G \tag{6}$$

$$\sum_{t\in T} p_{Go_{i,t}} - T_s \cdot CF_i \cdot x_i \le 0 \quad (\gamma_i) \quad \forall i \in G \tag{7}$$

$$p_{Go_{i,t}} \ge 0 \quad \forall t \in T,\ \forall i \in G \tag{8}$$

Variables $p^*_{2,t}$ are the Lagrange multipliers of the balance constraint Eq. (5) and can take values as high as the cost of curtailing demand ($VOLL$). Reliability considerations are accounted for by means of forced outage rates in constraint Eq. (6). We also use hourly capacity factors to capture the short-term variability of solar, wind, and hydro resources, and annual capacity factors to model energy-constrained resources such as large hydro units. The model has hourly resolution; the set T comprises 8760 h. While the analysis in time scales of hours can be more related to energy than power, we enforce energy balance constraints (i.e., Eq. (5) in the previous model) for each single hour. Accordingly, within each hour, the energy and the power considered in those equations are equivalent.

In the objective function defined in Eq. (4), B_i is a nonlinear function that we approximate with a fixed parameter, which is iteratively updated as explained later in Section 3.2.3. This function captures the impact of price controls in generators' revenues and it is expressed in per unit of generator capacity (\$/MWyear). As in Diaz et al. (2020), we model this annual surplus reduction as an annual extra investment cost B_i that is imposed on those generators supplying demand in the exporting region. Following the definition of surplus reduction in Eq. (3), we compute values for B_i as follows:

$$B_i = \frac{1}{x_i} \cdot SR_i = \frac{1}{x_i} \sum_{t\in T} (\alpha_t \cdot p_{GD_{i,t}}) \quad \forall i \in G \tag{9}$$

By definition, those generators with $x_i = 0$ do not bear surplus losses since they do not participate in the dispatch.

3.2.2. Local dispatch model

The local power dispatch model finds optimal dispatch levels to supply the local demand only and fixed generation capacities x_i. We formulate the local power dispatch model as follows:

$$\min_{p_{GD_{i,t}}} \quad \sum_{t\in T}\sum_{i\in G} MC_i \cdot p_{GD_{i,t}} \tag{10}$$

subject to:

$$P_{D_t} - \sum_{i\in G} p_{GD_{i,t}} = 0 \quad (p^*_{1,t}) \quad \forall t \in T \tag{11}$$

$$p_{GD_{i,t}} - p_{Go_{i,t}} \le 0 \quad \forall t \in T, \quad \forall i \in G \tag{12}$$

$$\sum_{t\in T} p_{GD_{i,t}} - T_s \cdot CF_i \cdot x_i \le 0 \quad \forall i \in G \tag{13}$$

$$p_{GD_{i,t}} \ge 0 \quad \forall t \in T, \quad \forall i \in G \tag{14}$$

The decision variables of the model Eqs. (10)–(14) are the dispatch levels of generators, $p_{GD_{i,t}}$, that supply the domestic demand. The Lagrange multiplier of the energy balance constraint Eq. (11) is the

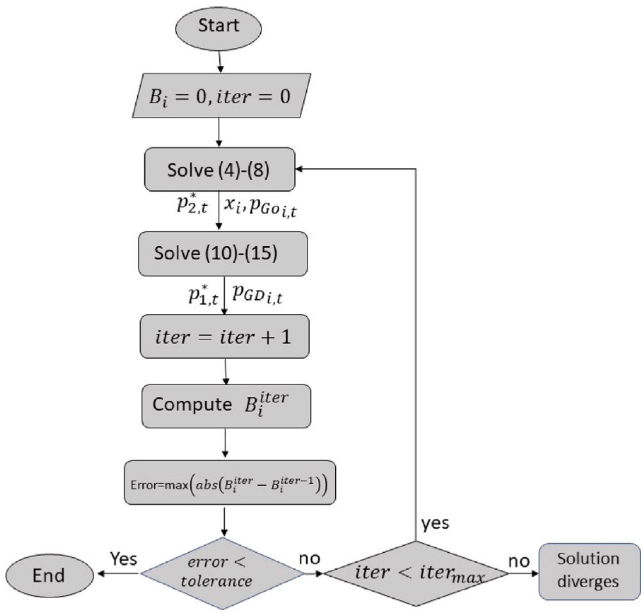

Fig. 2. Block diagram of the Price Control Model (PCM).

price $p^*_{1,t}$. Notice that we use constraint Eq. (12) to cap the dispatch levels at $p_{Go_{i,t}}$, the levels found in the general expansion model that simultaneously considers both domestic demand and exports. This constraint avoids an infeasible reschedule of power when transitioning from the general expansion model to the local power dispatch model.[2]

We employ these results to compute the variables α_t that measure the price differences between the economic dispatch that considers both local demand and exports and the economic dispatch that is subject to price controls:

$$\begin{aligned} &if \quad p^*_{2,t} - p^*_{1,t} > 0 \rightarrow \alpha_t = p^*_{2,t} - p^*_{1,t} \\ &otherwise \quad \alpha_t = 0 \end{aligned} \tag{15}$$

Our load dispatch model assumes a cost-based dispatch. In a bid-based dispatch, some of the distortions induced by price control rules may be eliminated or, at least, mitigated. We leave this issue to be explored in future research works.

3.2.3. Iterative method to compute market equilibria

The adjusting function in Eq. (9) depends on the dual variables $p^*_{1,t}$ and $p^*_{2,t}$ of the energy balance constrains; hence, conventional solvers for linear programming cannot be directly applied to solve both models simultaneously. To address this limitation, we use a Gauss–Seidel approach that iteratively updates the value of B_i in the general expansion model and the investments levels x_i in the local dispatch model until we find a market equilibrium.[3] We update the values of B_i as follows:

$$B_i^{iter+1} = \frac{1}{x_i^{iter}} \cdot \sum_{t \in T} \alpha_t^{iter} \cdot p_{GD_{i,t}}^{iter} \quad \forall i \in G \tag{16}$$

Variables $p^*_{1,t}$, and $p_{GD_{i,t}}$ required in Eq. (16) are computed from the local dispatch model. Fig. 2 depicts a block diagram of the major steps of the proposed methodology.

For simplicity, we assume that all generators are price takers and that all investments are endogenous (i.e., there is no existing generation capacity). Additionally, we ignore transmission constraints and assume that all cross-border trade is unidirectional. This last simplification allows us to test the model not only with fixed hourly profiles for exports, but also with price-sensitive demand functions. The latter indicates the amount of power demanded over the cross-border transmission line depending on the price of electricity (Mertens et al., 2020).

3.3. Accounting for price elasticity of demand on exports

Price elasticity of demand plays an important role in capacity expansion decisions. In fact, it has been demonstrated that demand response considerations in planning models lead to more efficient generation capacity investment decisions (Özdemir et al., 2016; Kazerooni and Mutale, 2010; Liu, 2017; De Jonghe et al., 2012; Padmanabhan et al., 2018; Fang et al., 2016; Parvania et al., 2014). Herein, demand response is used to emulate the price elasticity of demand on exports. This enables the importer country to modify its import quantities according to electricity prices.

A typical short-term demand function neglecting cross-elasticity price effects has the following form:

$$D_t = D_o + e_t \cdot \frac{D_o}{p_o} \cdot (p_t - p_o) \quad \forall t \in T \tag{17}$$

where D_o is a reference quantity demand at a price p_o. This price may be assumed constant for all hours, such as in the case of a uniform pricing structure, or may be based on an hourly pricing scheme, which is preferred in this paper to properly account for time variation of spot prices. The parameter e_t is an hourly price elasticity parameter that reflects the extent of change in demand because of the price variation. It may take different values at each hour, or it may be supposed constant as in this paper. Since e_t is negative, a price p_t higher than p_o yields a drop in the quantity D_t, whereas a price p_t lower than p_o results in a rise of the demand. The inverse demand function, which relates the price as a function of the demand can be written as in Eq. (18),

$$p_t = A + C \cdot D_t \quad \forall t \in T \tag{18}$$

where the coefficients A and C are usually obtained from statistical analysis. Demand response integration in resource planning can be achieved by formulating a competitive equilibrium where producers and consumers maximize their profit and surplus, respectively. Consumer surplus can be expressed as in Eq. (19),

$$Consumer\ surplus = \sum_{t \in T} (A \cdot D_t + \frac{1}{2} \cdot C \cdot D_t^2 - p_t^* \cdot D_t) \tag{19}$$

where p_t^* is the market clearing price. The objective function (4) can be modified to account for the consumer surplus as follows:

$$\begin{aligned} \min_{p_{Go_{i,t}}, x_i, u_t, K_t} \quad & \sum_{t \in T} \sum_{i \in G} MC_i \cdot p_{Go_{i,t}} + \sum_{i \in G} (I_i + B_i) \cdot x_i \\ & + \sum_{t \in T} VOLL \cdot u_t - \sum_{t \in T} (A \cdot K_t + \frac{1}{2} \cdot C \cdot K_t^2) \end{aligned} \tag{20}$$

where $D_t = K_t$ assuming that only price elasticity of the power being exported K_t is considered. Although price elasticity of the domestic demand can also be accounted for, here we are only interested in evaluating the effect of the price elasticity of the power being exported on capacity expansion decisions. The problem of minimizing Eq. (20) subjected to constraints Eqs. (5)–(8) may be solved by means of complementarity programming, quadratic programming, and piecewise integration-based models (De Jonghe et al., 2012). Complementarity programming models are based on solving a set of optimality conditions such as the KKT and market clearing conditions (Fuller et al., 2013). For the concerned problem, the following conditions hold:

$$0 \le MC_i - \lambda_t - \mu_{i,t} - \gamma_i \perp p_{Go_{i,t}} \ge 0 \quad \forall i \in G \quad \forall t \in T \tag{21}$$

$$\begin{aligned} 0 \le I_{G_i} + B_i + & \sum_{t \in T} (\mu_{i,t} \cdot (1 - FOR_i) \cdot W_{i,t}) \\ & + \gamma_i \cdot T_s \cdot CF_i \perp x_i \quad \forall i \in G \quad \forall t \in T \end{aligned} \tag{22}$$

[2] For instance, if for a given hour t_o, the general expansion model yields a dispatch of power of large hydro consistent with $p_{Go_{hydro,t_o}}$, no more power than this value can be dispatched in the local power dispatch model.

[3] The convergence is guaranteed if the non-linear adjustment function is Lipschitz continuous and retains a contraction property (Diaz et al., 2020).

$$\sum_{i \in G} p_{Go_{i,t}} - P_{D_t} - K_t = 0, \quad p^*_{2,t} \quad free \quad \forall t \in T \tag{23}$$

$$0 \leq -(p_{Go_{i,t}} - (1 - FOR_i) \cdot W_{i,t} \cdot x_i) \perp \mu_{i,t} \geq 0 \quad \forall i \in G \quad \forall t \in T \tag{24}$$

$$0 \leq -(\sum_{t \in T} p_{Go_{i,t}} - T_s \cdot CF_i \cdot x_i) \perp \gamma_i \geq 0 \quad \forall i \in G \tag{25}$$

$$0 \leq -A - C \cdot K_t + p^*_{2,t} \perp K_t \geq 0 \quad \forall t \in T \tag{26}$$

The set Eqs. (21)–(26) represent an MCP because of the existence of non-negative and free variables. In this formulation, B_i is assumed as a parameter; however, it depends on dual variables and capacity expansion decisions x_i according to Eq. (9). KKT condition Eq. (26) accounts for surplus maximizing of the importer country. Alternatively, if the matrix C of the inverse demand function is symmetric, and the demand/supply functions are linear, a Quadratic Programming (QP) model, which is a subset of the more general complementarity programming models, may be used. Assuming B_i as a parameter, the QP formulation of the general expansion model considering price elasticity of the demand on exports K_t, and neglecting cross-elasticity price effects, can be modeled by the objective function Eq. (20) and constraints Eqs. (5)–(8).

The main disadvantage of this approach is that some Non-Linear Programming (NLP) solvers may not be able to achieve a global optimum solution (Fuller et al., 2013). A piecewise integration model, referred to as the PIES algorithm (Hogan, 1975) is an alternative to model demand response. The PIES algorithm is based on incorporating a linear approximation of the consumer surplus to the objective function. The resultant formulation is an iterative-based LP model and convergence is attained when self-price elasticities are dominant. A similar iterative approach is conceived in Özdemir et al. (2016) to incorporate demand response in transmission planning. According to this approach, an iteration procedure between an NLP model and a demand function is developed. The demand is assumed to be a parameter that is iteratively updated by using the Lagrange multipliers for the energy balance. Using an analogous iterative approach, we incorporate demand response associated with the power being exported K_t in the price control model by reformulating the demand function Eq. (17) as follows:

$$K_t^{iter} = K_t^0 + e_t \cdot \frac{K_t^0}{p^{*\,0}_{2,t}} \cdot (p^{*\,iter}_{2,t} - p^{*\,0}_{2,t}) \quad \forall t \in T \tag{27}$$

Eq. (27) is enforced for each single hour, in the same manner as energy balance constraints. Accordingly, within each hour, the energy and the power considered in those equations are equivalent. As previously defined, the price $p^*_{2,t}$ corresponds to the dual variable of the balance constrain Eq. (5). In this formulation, for fixed values of B_i and K_t, the first order optimality conditions of the LP problem Eqs. (4)–(8) are equivalent to the KKT conditions Eqs. (21)–(25).

3.4. Centralized unregulated model

We refer to the Centralized Model (CM) as the model that finds an equilibrium assuming no price controls. This means that there is a unique price for the electricity for both domestic demand and exports. We find his equilibrium using a variant of the general expansion model where we set $B_i = 0$ for all technologies. By definition, this model finds the socially-optimal investment and dispatch decisions, as well as the optimal levels of carbon emissions.

The CM is basically a market-based model with a single price market.

4. Case study, results and analysis

4.1. Cross-border trade price control in Chile

The interconnection between Chile and Argentina is ruled by Order 7 of the Chilean Ministry of Energy, which states that the exchange of power is based on an interruptible interconnection agreement (i.e., exportation relies upon a trade opportunity) (Minenergía, 2019a). One of the main aspects contemplated in the regulatory framework of Order 7 is the adopted price control rule. According to this rule, which is also used by other countries in South America, only generation units that are not dispatched to meet the domestic demand are able to export power. Furthermore, the rule states that the dispatch of these additional generation units cannot affect the domestic electricity price. Additionally, a particular rule applied in the case of Chile is that power can only flow from Chile to Argentina, prohibiting power imports.

While it is clear that, with this type of price control, exports do not increase domestic electricity prices, its long-term effects on investment decisions are unknown. In particular, it is not clear if new transmission interconnections will actually deliver the same economic benefits as those observed without the administrative price controls in cross-border trade of electricity (Levy et al., 2020). For instance, some studies find that interconnections facilitate the integration of renewables by allowing countries to export part of their generation when solar and wind resources are abundant. This is of particular importance for countries with high-quality renewable resources, such as Chile. A recent indicative plan finds that 73% of all the electricity produced in Chile will come from solar and wind resources by 2030 (Minenergía, 2019b). Moreover, given the vast potential of solar power in Northern Chile, there are prospects to export part of this power to other countries in the region.

Hence, to study the long-run effects of this price control, particularly on renewable generation investments such as solar and wind power generation going forward, we study three case studies as presented next.

4.2. Case studies

The following three case studies aim to determine and analyze the long-term equilibria of the Chilean electricity market, connected to the Argentinian electricity market through a 5 GW interconnector. While generation capacity investments are modeled in the Chilean market in a greenfield fashion, the Argentinean market is modeled with the existing capacity and without new investments. There are mainly two reasons behind the setting mentioned above. First, our primary focus is to study the implications of the price control rule in Chile (only). Second, generation investment decisions in Argentina depend on further regulations that are out of the scope of this paper. The three case studies are presented below.

Simulations are carried out using Python®, the optimization library Pyomo, and Pandas for efficient data manipulation and analysis. These simulations are run on a laptop with an Intel i5 processor @ 1.5 GHz, 8 GB RAM. All models converged, but convergence cannot be guaranteed in general due to the non linear nature of the models.

4.2.1. Case A: Optimized cross-border trading

In this case study, we model the Chilean and Argentinian electricity markets with optimized trading/operation, meaning that the hourly power exchange between the two countries is calculated with a global least-cost dispatch problem that minimizes the total operational costs of the two countries. This is equivalent to find the minimum-cost dispatch of a power system with two nodes. The trading/exchange is constrained to the 5GW interconnector, which cannot be reinforced. The price clearing in Chile follows the prescribed rule, where exports cannot distort spot prices (as per the rule, we do not consider imports to Chile as they are prohibited). Finally, short-run market prices support generation investments that our equilibrium model finds.

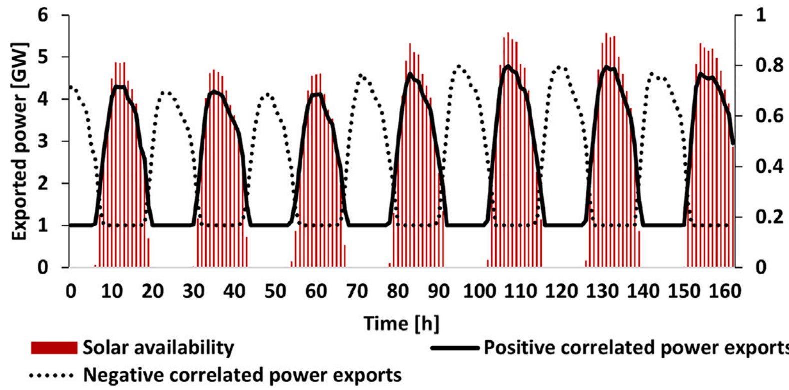

Fig. 3. Block diagram of the Price Control Model (PCM).

Table 1
Generation input data in the Chilean electricity market.

Generation Type	Capital costs ($/KW)	Variable costs ($/MWh)	Lifespan (years)	Forced outage rates	CO_2 factor (tCO_2/MWh)
Coal	3000	34	35	0.05	0.95
CCGT	1090	88	25	0.02	0.44
Diesel	666	219	25	0.05	0.78
Solar PV	1200	0	25	0	0
Wind	1800	0	35	0	0
Hydro	3500	0	45	0	0

4.2.2. Case B: Solar-positive-correlated cross-border trading

We modify the abovementioned case A as follows. Cross-border tradings are not optimized, but given as parameters. These tradings consider that the export profiles across the year are correlated with the solar power generation profiles, as shown in Fig. 3. In this case study, Chile exports an average power of 2.25 GW, representing about 15% of the Chilean domestic demand.

4.2.3. Case C: Solar-negative-correlated cross-border trading

We modify the abovementioned case B by shifting the export profiles (in time) to consider a negative correlation with the solar power generation profiles. Fig. 3 illustrates, for one week, the solar power generation profile (in per unit, p.u.) of the Chilean system and the exported power profiles of cases B and C (both in MW).

Cases A and B present probable future scenarios, while case C represents a counterfactual for comparisons since it is assumed unlikely that exports occur at night given the large potential of low-cost solar power generation in Chile. For the three cases, we obtain both the long-run market equilibria with and without the price control rule (as explained in Sections 3.2 and 3.4, respectively). The latter is also called the centralized generation expansion plan, which is calculated by minimizing total investment and operational costs (as explained in Section 3.4). We also run a parametric sensitivity analysis on export levels and price elasticities.

Generation capital costs, variable costs, lifespans, and forced outage rates (i.e., availability factors) of generation technologies are obtained from Diaz et al. (2020) and shown in Table 1. Also, hourly availability profiles of wind, solar and hydropower generation and that of demand for Chile and Argentina are obtained from IDB (2016). We model the systems by 2030 considering 8760 h.

The VOLL is equalized to 35,000 $/MWh, which is high enough to reduce load curtailments to negligible values. This VOLL can be considered as an intermediate value with respect to the VOLL used in countries like Chile (CNE, 2021b) and Great Britain (ENWL, 2018). The overnight annualized costs of capacity generation are calculated considering a discount rate of 10%. As in Diaz et al. (2020), we consider an upper bound for investments in large hydropower capacity of 3.4 GW, which is equal to the existing capacity of large hydropower plants in Chile (CEN, 2019). In the case of Argentina, the current generation capacity per technology is obtained from CAMMESA (2020).

Table 2
Results of the three case studies with (PCM) and without (CM) the price control.

	Case A		Case B		Case C	
	CM	PCM	CM	PCM	CM	PCM
TC (Billion $)	11.5	12.0	10.6	13.4	11.3	15.7
DAEP (Billion $)	9.6	4.5	9.7	5.4	9.7	6.9
EAEP (Billion $)	3.4	3.5	1.2	1.4	1.9	2.5
LRPS (Billion $)	9.3	3.9	8.2	3.6	8.2	6.1
LRCS (Billion $)	4467.7	4472.8	4467.6	4471.8	4467.6	4470.0
TSW (Billion $)	4477	4477	4476	4476	4476	4476
CO_2 Chile (Mton)	67.1	81.7	65.7	81.7	82.0	49.3
Solar (GW)	5.8	5.7	7.7	7.3	0.5	6.2
Wind (GW)	21.8	17.0	13.8	8.7	14.2	18.2
Hydro (GW)	3.4	3.4	3.4	3.4	3.4	3.4
Diesel (GW)	3.1	1.7	3.0	2.5	3.7	5.6
CCGT (GW)	0	0	2.4	1.5	3.5	6.0
Coal (GW)	9.0	10.8	8.5	10.5	10.6	5.5
TNRC (GW)	12.1	12.5	13.9	14.5	17.8	17.1
TRC (GW)	31.0	26.1	24.9	19.4	18.1	27.8

4.3. Results and discussion

Table 2 shows the results obtained with and without the price control rule. These results are obtained by the Price Control Model (PCM) and the Centralized (planning) Model (CM), respectively. Both models (CM and PCM) are run over cases A, B and C. For these cases, Table 2 shows Total Costs (TC, calculated as the total cost of investment and operation over a year), Domestic Annual Energy Payment in Chile (DAEP, calculated as the hourly demand times the spot price in Chile over a year), Exported Annual Energy Payment (EAEP, calculated as the hourly exported power times the price paid by the Argentinian market), CO_2 emissions in Chile, generation expansion capacity per technology installed in Chile, Total Non-Renewable Capacity (TNRC) installed in Chile, and the Total Renewable Capacity (TRC) installed in Chile.

4.3.1. Effects on total costs and payments

As expected, Table 2 shows that price controls (PCM) always drive a less efficient solution in terms of total costs (TC) in comparison with the central plan (CM). Interestingly, as these total costs become higher under the price control scheme, the associated payments for the traded power too (EAEP), increasing the payments incurred by the Argentinean market to Chilean exporters. This, however, is counteracted by the smaller payments incurred by demand in Chile (DAEP). This decrease in payments from Chilean demand is aligned with the fact that the price control seeks to protect Chilean consumers from the potentially higher prices caused by power exports. In fact, without the price control, higher exports will drive higher prices in Chile. This protection policy, though, may present a downside for producers in Chile, as discussed in the next section.

Table 2 also shows the long run consumer surplus (LRCS), long run producer surplus (LRPS), and total social welfare (TSW), computed as the sum of LRCS and LRPS. The smaller payments incurred by local consumers in Chile lead to an increase in the LRCS, as domestic energy costs are reduced by 53.1%, 44.3%, and 28.9% for case studies A, B, and C, respectively. This increase in consumer surplus translates into a reduction of the LRPS of 57.8%, 55.7%, and 25.1% for the corresponding case studies, which may be an issue for private owned generators. In the context of countries where most generation firms are privately owned (like Chile, Peru, and Colombia), this distortion on market efficiency is an important issue. On the contrary, in the case of countries with large share of state-owned generators, such as in the case of Canada, Norway, and France, there is less political pressure to implement such price control mechanisms because it may be easier for them to implement welfare transfers between consumers and producers that compensate the extra benefits of generation firms and the additional cost of consumers of not implementing any price control. However, the analysis of consumer welfare protection mechanisms (similar to price control rules) in markets with state-owned firms is out of the scope of this manuscript.

This demonstrates that the price control benefits Chilean consumers in terms of payments, but harms the total cost and the payments made by markets participant in Argentina to Chilean exporters.

4.3.2. Effects on generation investments

Cases A and B, those considered the more probable future scenarios, deliver significantly less renewable generation investments (TRC) installed in Chile under the price control solutions (PCM) than those associated with the central plan (CM). This detriment occurs for both wind and solar power technologies, while hydropower capacity is maintained at the set upper bound of 3.4 GW. Notably, an increase in coal power generation supports the decrease in renewable generation capacity, which affects CO_2 emissions in Chile, increasing significantly under the price control.

The decrease in renewable generation investments is justified because, under the price control, energy prices in Chile are decreased/limited (compared with the efficient prices observed in the central plan) mainly in hours where the availability of renewables is vast (which is when the Chilean market exports). As a counterfactual, case C shows that, if exports were at night, the price decrease would mainly affect coal power generation that primarily runs at night. This case is, however, unlikely to occur as exports are, in effect, more efficiently carry out when renewable generation is vastly available, as demonstrated in case A, in which the power trading is optimized.

This demonstrates that attempting to maintain lower prices in Chile through regulating prices when the Chilean power system exports may detriment the expansion of solar and wind power generation.

The total renewable and non renewable installed capacity (sum of the last two rows in Table 2) varies in a relatively wide range in cases A, B and C. This happens because, in case C (solar-negative-correlated cross border trading), a considerable amount of exports occur at night were mainly coal generation is satisfying power demand. Since it is more efficient to export power during the day (when renewable generation is vastly available), as showed in Case A, wind power investments more than compensate the decrease in solar power investments in Case C, due to the negative correlation. This can be seen in the values obtained in Table 2.

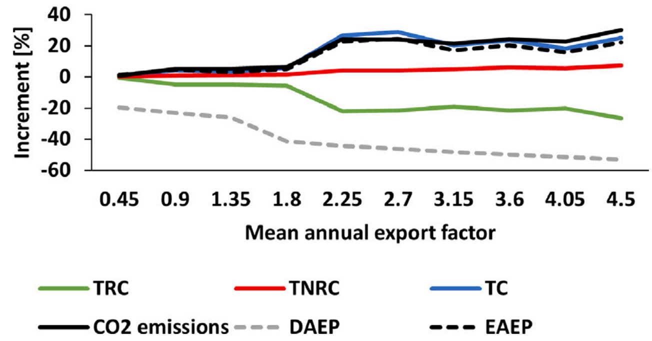

Fig. 4. Sensitivity against exported power K for case B.

4.3.3. Effects of the level of exported power

Fig. 4 shows, for case B, the changes (in %) in CO_2 emissions, total costs, payments made by Chilean demand, payments made by the Argentinean market to Chilean exporters, and amounts of renewable and non-renewable generation capacity built. These changes refer to the market equilibrium solution, under the price control, with respect to that without the price control for various volumes of power exports, where K is a multiplying factor applied on the export profile ($K = 1$ refers to the base case, while $K > 1$ refers to higher export levels and $K < 1$ refers to lower export levels).

We observe that, as power exports increase, changes in all the above-mentioned items are exacerbated. This means that, while export levels increase:

- The total cost of the price control solution becomes higher than that without the price control.
- The investments in non-renewable technologies under the price control solution become higher than those without the price control.
- The CO_2 emission levels under the price control solution become higher than those without the price control.
- The investments in renewable technologies under the price control solution become lower than those without the price control.
- The payment made by the Chilean demand under the price control solution becomes lower than that without the price control.
- The exported annual energy payment (EAEP) becomes higher because proportionally less cheap renewable energy capacity is available for exporting power.

The sensitivity analysis made in this section also provides an intuition of the effects associated to changes in demand paths because different demand paths basically lead to different availability to increase (or reduce) the amount of power that is exported.

4.3.4. Effect of the level of domestic demand

The analysis of changes in the level of the domestic demand may be considered, up to some extent, equivalent to the analysis of changes in the level of power exports, because a decrease in the domestic demand likely induces an increase in the level of exporting power. Thus, similar effects to the ones observed in the previous section are expected. For the completeness of the analysis, we present in this section a sensitivity analysis with respect to changes in the level of the domestic demand. In particular, we computed the effects on the level of investments in renewable capacity of varying the domestic demand in Chile in both

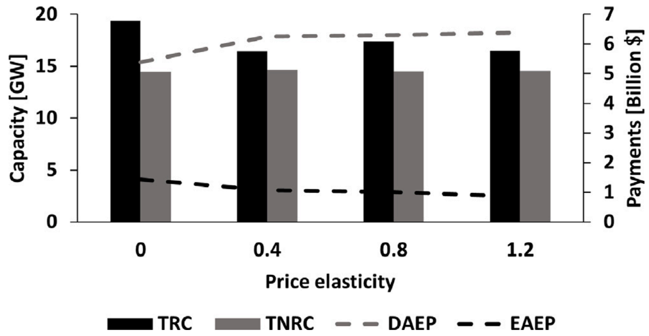

Fig. 5. Sensitivity against price elasticity in Case B.

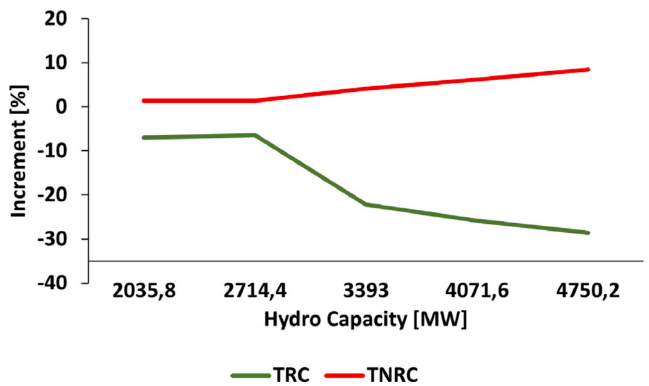

Fig. 6. Sensitivity against hydro capacity in Case B.

directions: a 50% decrease and a 50% increase with respect to the base load for case study B.

Results indicate that, for a 50% decrease in the base load of Chile for case study B, the level of investments in renewable capacity is reduced by a 36.8% with respect to the Centralized Model. For a 50% increase in the base load, the level of investments in renewable capacity is only diminished by roughly 1%. These results are in line with the previous results and they are explained by two reasons: first, as domestic demand increases, the likelihood of renewable generation simultaneously supplying both domestic demand and exports may increase; thus, renewable generation may reduce the surplus loss due to the price control rule and, therefore, may become more attractive. Second, as seen from the sensitivity analysis in Section 4.3.3, as export levels increase (due, for example, to a domestic demand reduction), the distortions of the price control rule are accentuated and, hence, less renewable generation capacity is promoted.

4.3.5. Effect of price elasticity

Fig. 5 shows sensitivities of the price control solution in case B for various price elasticity levels. We show that, as the price elasticity increases, the total renewable capacity built reduces by 15%, while the total non-renewable capacity built remains at similar levels. This reduction in the total renewable generation capacity built is justified because of two main reasons. First, as the price elasticity rises, demand decreases as it becomes more sensitive to high prices, driving less generation capacity. Second, as discussed earlier, the price control rule essentially discourages investments in renewable generation (case B). In turn, this reduction in zero marginal cost generation capacity (i.e., renewable generation) tends to increase the energy prices and thus the payments made by demand in Chile. In addition, we verify that export reductions, caused by the response to the price elasticity, primarily drive the reduction in payments made by the Argentinean market to Chilean exporters observed in Fig. 5.

4.3.6. Effect of hydro capacity

Fig. 6 shows the sensitivity of the price control solution in case B for various levels of hydro capacity available to install. As it can be seen in Fig. 6, as the hydro capacity increases, incentives for investments in renewable generation are reduced, while investments in fossil fuel generation are encouraged. Specifically, wind generation capacity is the most affected, and coal, as well as CCGT generation capacity are the most benefited. This result can be explained by the higher availability of hydro generation to supply the domestic demand in Chile, which increases the likelihood that fossil fuel generation will supply exports. Thus, fossil fuel generation is less affected by the revenue reductions associated with the price control rule.

5. Conclusions

This paper presents a novel equilibrium model and solution approach designed to examine the long-term implications of administrative price controls on the expansion of generation capacity in cross-border trade of electricity. The model utilizes a linear program and a non-linear adjustment function to incorporate the price-control rule. The resulting non-linear model is solved using a Gauss-Seidel method. To assess the effects of price controls, we also employ an equilibrium model that does not incorporate such controls as a benchmark for comparison.

Based on our simulation results, we have observed that while price controls may initially shield domestic consumers from price hikes, they can have detrimental effects on long-term investment incentives when compared to a scenario without price controls. Specifically, our case study demonstrates that distorted price signals arising from price controls can lead to diminished incentives for renewable energy investments and heightened incentives for fossil-fuel based generators, specifically coal units. Consequently, both the overall system costs and the levels of CO_2 emissions may experience an increase in comparison to the socially-optimal equilibrium that does not incorporate price controls.

It is important to note that the results obtained in our study are not general and are contingent upon various parameters, such as the volume of exports relative to local demand and the price elasticity of demand in the importing region. In certain parameter configurations, such as when a significant portion of the base load is already supplied by fossil fuel-based generators rather than renewables, we have observed that price controls can actually diminish incentives for investments in fossil fuel-based generators and increase incentives for renewables. However, despite these variations, we consistently find that total system costs still experience an increase compared to the socially-optimal outcome in the absence of price controls.

Future research could explore the interaction between the administrative pricing rule analyzed in this study and other aspects of the electricity market. One potential avenue is to investigate how this pricing rule affects the incentives of generation firms to exercise market power, using variants of the equilibrium models employed in previous studies such as Pozo et al. (2017) and Munoz et al. (2018). Understanding whether administrative pricing rules amplify or diminish the incentives for market power could provide valuable insights.

Additionally, it would be worthwhile to examine the combined impact of the price control examined in this research and other clean-energy policies, such as feed-in tariffs, rebate/incentive programs, carbon policies, and renewable portfolio standards. We hypothesize that price controls may undermine the effectiveness of these clean-energy policies in promoting investments in renewable capacity. Investigating the synergies and trade-offs between price controls and other policy mechanisms could provide a more comprehensive understanding of their overall impact on the energy transition and sustainability goals.

Price control rules have a uniform impact on all generation firms, resulting in a decrease in the domestic market price for all participants. As a consequence, identifying effective hedge instruments for negatively-affected participants, such as generation firms, becomes challenging due to this inherent structural regulatory risk. Traditional risk management tools like power purchase agreements (PPAs), which entail negotiated financial terms between buyers and sellers, are also susceptible to the distortions introduced by price controls, making them less reliable as hedge instruments.

Another possible direction of future research is to consider risk measures in the proposed models, so that risk mitigation strategies can be taken into account in the cross-border trade of electricity. This may be interesting because consumers in one region could be able to pay higher average prices if they are risk averse and the cross-border trade reduces price spikes. Thus, risk sharing can be a motivation for countries agreeing to the expansion of the interconnection.

In addition to the aforementioned research directions, it is crucial for future studies to delve into the intricate interplay between political economy constraints and the regulation of cross-border trade of electricity. It is worth exploring how the specific sociopolitical context, local market structure, and regulatory environment influence decision-making processes. For instance, in countries like Norway where a significant portion of generation assets are publicly owned, welfare transfers between consumers and generators resulting from price increases might be of less concern.

However, in various jurisdictions, decision makers might prioritize attributes such as fairness and equity over economic efficiency when formulating policies related to cross-border electricity trade. Understanding these complex trade-offs is vital for the effective design and implementation of regulations governing electricity trade between regions. By incorporating political economy considerations into the analysis, researchers can provide valuable insights into how different policy choices are influenced by societal and political factors, ultimately contributing to the development of more context-specific and socially desirable regulatory frameworks.

CRediT authorship contribution statement

Juan C. Muñoz: Methodology, Software, Validation, Formal analysis, Investigation, Data curation, Writing – original draft, Writing – review & editing, Visualization. **Enzo Sauma:** Conceptualization, Methodology, Validation, Formal analysis, Investigation, Resources, Writing – original draft, Writing – review & editing, Supervision, Project administration, Funding acquisition. **Francisco D. Muñoz:** Conceptualization, Methodology, Validation, Formal analysis, Investigation, Resources, Writing – original draft, Writing – review & editing, Funding acquisition. **Rodrigo Moreno:** Conceptualization, Methodology, Validation, Formal analysis, Investigation, Resources, Writing – original draft, Writing – review & editing, Project administration, Funding acquisition.

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