Equilibrium Analysis of a Tax on Carbon Emissions with Pass-through Restrictions and Side-payment Rules

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ABSTRACT

Chile was the first country in Latin America to impose a tax on carbon-emitting electricity generators. However, the current regulation does not allow firms to include emission charges as costs for the dispatch and pricing of electricity in real time. The regulation also includes side-payment rules to reduce the economic losses of some carbon-emitting generating units. In this paper we develop an equilibrium model with endogenous investments in generation capacity to quantify the long-run economic inefficiencies of an emissions policy with such features in a competitive setting. We benchmark this policy against a standard tax on carbon emissions and a cap-and-trade program. Our results indicate that a carbon tax with such features can, at best, yield some reductions in carbon emissions at a much higher cost than standard emission policies. These findings highlight the critical importance of promoting short-run efficiency by pricing carbon emissions in the spot market in order to incentivize efficient investments in generating capacity in the long run.

Keywords: Carbon tax, Equilibrium modeling, Market design

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1. INTRODUCTION

Threats of global warming are the main driver behind the implementation of climate and environmental policies that seek to curb carbon emissions. To date, nearly 25% of global carbon[1] emissions come from the burning of fossil fuels to produce electricity, which is why most of the existing climate policies are targeted to this sector of the economy (Field et al., 2014). Some of these policies include carbon taxes and cap-and-trade programs (Chen and Tseng, 2011), renewable targets (Lyon and Yin, 2010), feed-in tariffs (Couture and Gagnon, 2010), and production tax credits (Wiser et al., 2007). The focus of this paper is on the long-term effects of a carbon tax with pass-through restrictions and side-payment rules, inspired by the current carbon emissions policy used in the electricity market in Chile.

A carbon tax is a market-based regulation that forces agents to internalize the costs that carbon emissions impose on the environment. In theory, if the tax is set to a value that equals the social cost of carbon (SCC) emissions and the market is perfectly competitive, agents will adjust their

1. Throughout this article we use the terms "carbon" and "CO_2" interchangeably.

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consumption and production decisions until the marginal benefit that results from an additional unit of carbon emissions equals the SCC (Pigou, 1920; Metcalf and Weisbach, 2009). The result is a reduction of carbon emissions to the socially optimal levels, accounting for all future externalities that will be caused by carbon emissions that result from the current use of fossil fuels. However, practice is much more difficult than theory since estimates of the SCC are rather sensitive to assumptions about key factors such as discount rates, future emissions, and how climate will actually respond to increasing levels of carbon dioxide in the atmosphere (Pearce, 2003; Tol, 2008; Nordhaus, 2017).

In electricity markets, carbon pricing policies aim at displacing carbon-intensive generation (e.g., coal) for other technologies with lower emissions rates (e.g., natural gas, hydro, wind, solar, etc.) by incorporating the SCC in the operating cost of each generation unit (Cramton et al., 2017). This can be accomplished directly, through a tax on CO_2 emissions, or indirectly, through a CO_2 cap-and-trade program (Chen and Tseng, 2011). As shown in Fabra and Reguant (2014), carbon pricing can have an immediate effect in the dispatch of generators in the short term if firms choose to pass through the full costs of emissions regulations. The result is a change in the system's supply curve that leads to an increase of electricity prices.[2] In the long run, carbon pricing changes investment incentives since carbon-intensive technologies are dispatched less often and become less profitable than cleaner technologies (Chen and Tseng, 2011; Nelson et al., 2012). Hereinafter, we refer to this pricing mechanism as a standard carbon tax or as a standard cap-and-trade program.

Currently, there are 47 jurisdictions that have adopted some form of carbon tax or cap-and-trade program, which cover nearly 15% of global greenhouse gas emissions (WB, 2017). Most of these initiatives have been implemented in relatively developed countries or individual states in Europe, North America, and Australia, with a few exceptions in developing nations. In South America, Chile was the first country to enact a carbon tax, which became active on January 1 2017 (IEA, 2018). The tax was set to 5 $\$/tCO_2$ and applies to all stationary sources with a capacity of at least 50 MW. Although the tax rate is modest compared to carbon taxes in developed countries such as Denmark (27 $\$/tCO_2$), France (36 $\$/tCO_2$), Switzerland (87 $\$/tCO_2$), and Sweden (140 $\$/tCO_2$) (WB, 2017), this initiative has been described as a positive first step to reduce carbon emissions in the electric power sector.[3,4]

However, there is one aspect of the carbon tax in Chile that sets it apart from other tax or cap-and-trade programs in the rest of the world. The law has a pass-through restriction that states that carbon charges cannot be reflected in the dispatch and pricing of electricity in the real-time market. The regulation also states that generation firms that face the tax and that cannot cover their full costs (i.e., marginal cost plus carbon charges) from spot prices—that, as mentioned, do not reflect carbon charges—should receive a side payment that is financed by all units operating at a given hour, including inframarginal generators that do not use fossil fuels. Clearly, the current implementation of the carbon tax in Chile has no effect on carbon emissions in the short term due to the existing pass-through restriction. However, the policy does change investment incentives in

2. However, there might be hours when electricity prices and emissions won't change significantly if the carbon price is low enough such that the operating costs—including the cost adder from emissions— of the marginal generators remain at the same levels as before the implementation of the carbon policy.

3. *"Power generation is the largest GHG emitter and, so far, the only direct measure used to limit its emissions is a carbon tax. Chile is the first country in South America to introduce carbon taxation, and the IEA applauds this."* (IEA, 2018, p. 14).

4. *"It is also clear, however, that it will take a long time before these ideal charging systems are widely implemented across large carbon emitting countries. With the odd exception (e.g., Chile), countries have yet to introduce a comprehensive set of charges on the major air pollutants with charges aligned to estimates of air pollution costs."* (Cramton et al., 2017, p. 14).

the long term since firms are forced to absorb an administrative definition of carbon emission costs every year.

In this paper, we develop an equilibrium model with endogenous investments in generation capacity to study the long-term economic effects of the current emissions policy used in Chile. We benchmark the efficiency of this policy using two additional equilibrium models that assume a standard carbon tax implementation and a cap-and-trade program without pass-through restrictions and side-payment rules. Since we assume perfectly competitive markets, we compute equilibria for the two benchmark models using linear programs. For the Chilean emissions policy we find an equilibrium using an iterative Gauss-Seidel algorithm, which allows us to consider the pass-through restriction and the side-payment rules that determine the annual carbon charges per generator.

We study the effect of these policies using three different case studies that resemble different hypothetical market conditions in Chile for year 2050 under increasing tax levels. Our results indicate that the current implementation of the carbon tax in Chile is rather inefficient compared to emissions policies without pass-through restrictions and side-payment rules. Furthermore, we find that increasing the tax level under the current implementation in Chile yields, in general, higher average electricity prices and higher emissions levels than under a standard carbon tax. In fact, under the current policy in Chile carbon emissions can even increase as a result of a rise of the tax level. This implementation is also detrimental for the development of carbon-free technologies with low marginal costs, such as wind and solar, which must also absorb some carbon charges to support the side-payments for generators that do emit carbon dioxide in periods when prices are not sufficient to recover their full costs, which is it at odds with the current renewable and environmental goals of the country.

While there is a large body of literature focused on the impact of standard implementations of carbon taxes and cap-and-trade programs in competitive electricity markets (Nelson et al., 2012; Vera and Sauma, 2015; Eser et al., 2016), there are few studies that have quantified the effects of carbon pricing rules in imperfect markets. The market failure that receives most attention is market power. For instance, Downward (2010); Pérez de Arce and Sauma (2016); Limpaitoon et al. (2014); Siddiqui et al. (2016) demonstrate that if electricity markets are not perfectly competitive, environmental policies can have unintended consequences on electricity prices, investments, and carbon emissions. Policy uncertainty and risk aversion can also have an impact on the effectiveness of carbon policies (Bergen and Muñoz, 2018). However, to our best knowledge, the existing literature on the impacts of policy exceptions and administrative rules is limited to features such as priority dispatch[5] of renewable generators (Deng et al., 2015) and the potential for carbon leakage or emissions spillover when carbon policies are only applied to subregions of interconnected electric power systems (Chen, 2009; Bushnell and Chen, 2012).

In this context, we contribute to the existing literature by analyzing the economic effects of the current pass-through restrictions and side-payment rules of the carbon emissions policy used in the Chilean electricity market. Our analyses demonstrate how a regulator's (presumed) predisposition to avoid price increases in the short term as a consequence of a carbon tax—in this case, by implementing pass-through restrictions—can lead to inefficient market outcomes in the long term. We want to highlight that such predisposition to try to protect one side of the market (i.e., customers) through second-best policies instead of implementing first-best ones that focus on overall market efficiency is not unique to this case. There are many examples of regulatory authorities elsewhere that also choose policy instruments or market designs that aim at protecting consumers in the short

5. A generation unit has dispatch priority if the system operator is required to always accommodate the full available output of a the unit in question, even if such instruction involves not supplying demand at minimum cost for consumers.

run at the expense of potential reductions of market efficiency in the long run (Hogan, 2005; Joskow, 2008; Szolgayova et al., 2008; Jenkins, 2014; Newbery, 2016; Cramton, 2017; Munoz et al., 2018). We demonstrate that pass-through restrictions can be detrimental in the long term, even if they do protect consumers from price increases in the very short term as a consequence of the implementation of a carbon tax. Based on previous work by Greenberg and Murphy (1985), we also contribute to the existing literature by developing an assessment framework to compute long-term equilibria in electricity markets subject to complex carbon tax rules that cannot be represented through closed mathematical forms.

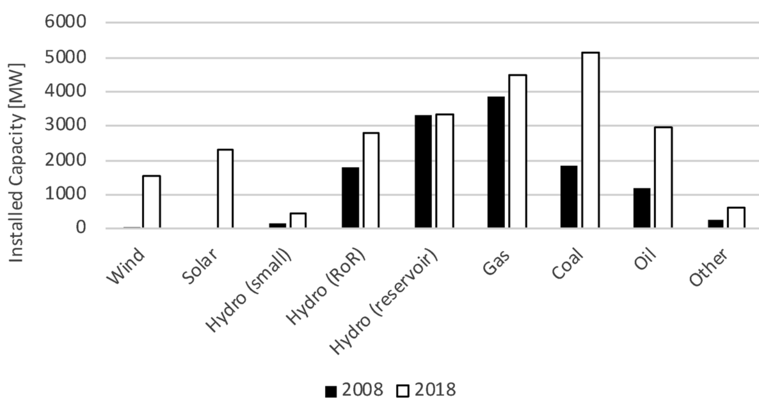
We structure the rest of the paper as follows. In Section 2 we provide a brief overview of the Chilean electricity market and a detailed description of the current policy used in Chile. In Section 3 we describe the equilibrium models used to analyze the long-term effects of such carbon policy. In Section 4 we present some general findings. In Section 5 we present a summary of data assumptions for our case studies and our results. Finally, in Section 6 we conclude and provide some policy recommendations.

2. UNDERSTANDING THE CHILEAN ELECTRICITY MARKET AND THE CURRENT CARBON TAX

2.1 Overview of the Chilean electricity market

The electricity demand per year in Chile is approximately 75.6 TWh (2018), with a peak demand of 13.7 GW occurring during the winter (CEN, 2016). The generation mix includes mainly hydro (28%), coal (22%) and gas (19%) units, with an increasing participation of variable renewable generation from wind and solar resources (16%). As we show in Figure 1, in the last 10 years, the installed generation capacity has almost doubled from 12.4 GW to 23.7 GW, with large additions of wind, solar, coal, and diesel units (CNE, 2019).

Figure 1: Installed generation per technology in the Chilean electric power system (CNE, 2019).



Electricity demand grows approximately 2.8% per year (CNE, 2017) and it is envisioned that most of the new capacity additions will take advantage of the vast renewable resources available in the country. Indeed, Chile features the highest solar irradiance in the world, which can reach values of Global Horizontal Irradiance (GHI) of up to 1200 W/m^2 under clear skies (Escobar et al., 2015). Furthermore, the proved solar power potential is 1800 GW only in the northern region of the country, which is large compared to the total electricity demand of the system. Consequently, there has been a rapid development of 2300 MW in solar power projects in the last 5 years, with some projects featuring Power Purchase Agreements (PPAs) for prices as low as 21.5 US$/MWh. Wind resources are also abundant in Chile and present a potential of approximately 38 GW (Moreno et al., 2017). As in the case of solar power, wind power generation is also rapidly growing, featuring 1200 MW in investments since 2013 (CNE, 2019). Although the country presents a significant amount of installed capacity in hydro generation and features other 20 GW of untapped hydro potential, developing these projects is becoming increasingly difficult due to their socio-environmental impacts. In fact, most of these projects are located in the Andes mountain (including Patagonia) and present vivid social opposition (Matamala et al., 2019).

In terms of market organization, generation, transmission and distribution assets are unbundled, with a fully market-based generation sector. Transmission and distribution sectors, though, remain as regulated monopolies. The retail service is undertaken by distribution companies, which is regulated through auctions that are periodically organized by the regulator. Hence, the regulator, through a competitive tender process, purchases energy from generation companies that offer energy at the lowest prices in the auction. These purchases are formalized via PPAs, signed between the set of generators that win the auction process and distribution companies. In this manner, all the electricity demand of regulated consumers is contracted through PPAs whose prices (cleared in the auctions) are passed-through to consumers (Reus et al., 2018). Notice that, under this approach, consumers do not have the choice to switch their retailers.

Although generation investments are fully market-driven (i.e. generation companies decide freely where, when, and how much to build according to market prices), the operation of the system is based on a centrally-planned cost-based dispatch mechanism (Munoz et al., 2018). Here, the system operator audits variable costs of thermal plants and, for hydro plants, it allocates water resources by running a stochastic dynamic optimization program that finds the minimum cost dispatch among all thermal and hydro units, considering multiple scenarios of hydro conditions (Pereira and Pinto, 1991). This design was justified due to a high level of concentration in the generation market, dominated by three main firms, in which hydro plants had the potential to exercise market power through a strategic use of water for power generation (Villar and Rudnick, 2003; Arellano, 2004). These three firms remain dominant until today and own 56% of the total installed generation capacity. Nevertheless, the market is experiencing the fast entry of new firms that have secured PPAs in the public long-term auctions coordinated by the regulator (Reus et al., 2018). In fact, in the last 5 years, more than 200 new generation firms have commissioned nearly 300 new generation power plants connected at the transmission level, adding a total installed capacity of 6.4 GW to the national power system. Furthermore, this figure represents about 88% of the total installed capacity added since 2013 (CNE, 2019).

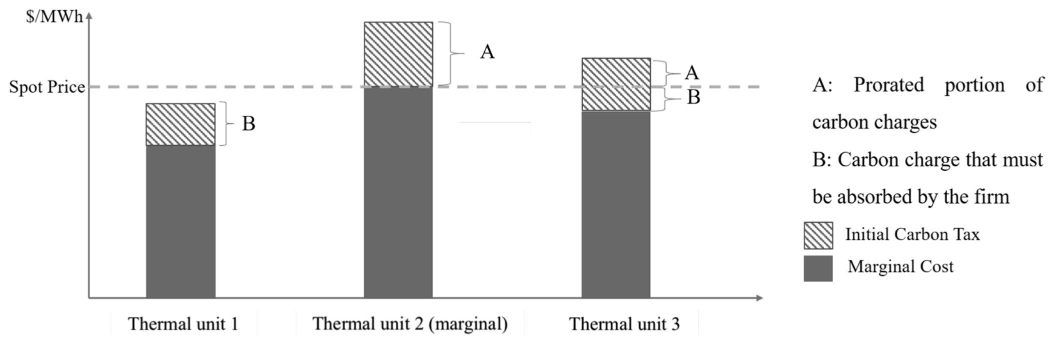
2.2 Description of the current carbon tax

The current carbon tax used in Chile is charged to firms once a year based on observed emissions levels from the previous 12 months. It applies to all generation resources with an installed capacity greater than or equal to 50 MW.[6] It differs from a standard implementation because of two specific provisions. First, the regulation includes a pass-through restriction that prevents firms

6. The carbon tax applies to all stationary sources with thermal capacity greater than or equal to 50 MW, including large heaters that are not used to produce electricity. Here we only focus on the impact of the carbon tax on the electric power system.

from including any carbon charges as part of the (audited) cost of generation used for the dispatch and pricing of electricity in real time. Generation firms are expected to absorb 100% of the carbon tax since the system operator (SO) disregards this cost adder when choosing dispatch levels for all existing generation resources to supply demand hour by hour at minimum cost.[7] The carbon tax is also disregarded in the medium- and long-term optimization of hydro resources, a process that is centrally managed by the SO, even though individual hydro generation units are owned by private firms. It is through this optimization that the SO determines the (expected) opportunity cost of using an additional unit of water to generate electricity at the present time, defined as the incremental cost of having to supply that energy with other generation technology in the future, such as a coal- or natural gas-fueled generator. In the short term, the SO uses this opportunity cost—also known as the *value of water*—as the marginal cost of hydro generation resources with reservoirs for the dispatch and pricing of electricity (Pereira and Pinto, 1991).

Figure 2: Possible scenarios of carbon charges faced by thermal units in the spot market in Chile



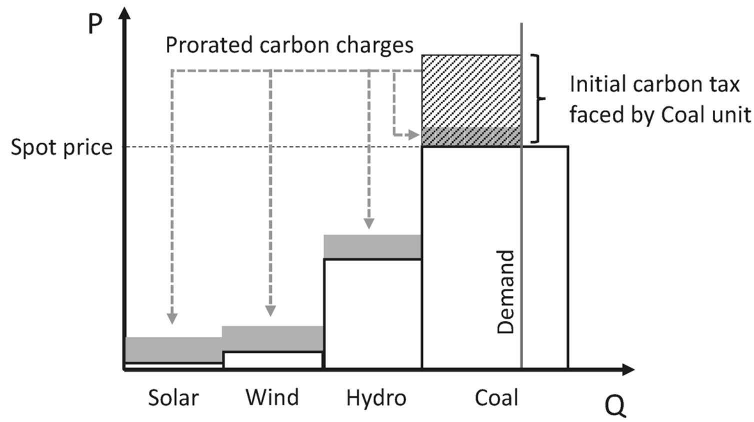
A second provision establishes a side-payment rule among generation units. This states that any portion of the carbon charge faced by a specific generator that cannot be covered from sales at the hourly spot price must be socialized or prorated among all running units, in proportion to the fraction of demand they supply at the hour in question. Figure 2 shows scenarios for three different thermal units that are dispatched in one period, grey bars denote marginal costs and bars with striped lines show the initial carbon taxes faced by each unit. In the example, the marginal cost plus the carbon charge faced by unit 1 is below the spot price, which means that the unit must bear the full cost of the tax, as in a standard implementation of the carbon policy. In contrast, units 2 and 3 do not earn enough revenues from sales at the spot price to cover the carbon tax. Unit 2, in this example, is a marginal generator and, by definition, sets the spot price at a level equal to its marginal cost (that does not include the carbon tax). Unit 3 is an inframarginal generator, meaning that its marginal cost of operation is below the spot price, yet, the carbon charge is large enough such that there is a fraction of it that cannot be covered from the revenues acquired over that period.

Figure 3 depicts a supply curve for one hour that illustrates how the provision that prorates the fraction of carbon charges that are above the spot price results in side-payments among gener-

7. In practice, some generation firms with existing PPAs might be able to pass through the carbon charge to the buyer if the contract allows it. In fact, some generation firms in Chile hold PPAs with base prices that are indexed to fuel prices (Reus et al., 2018) or that include clauses that stipulate that the buyer will bear future cost shocks that could result from unanticipated changes in regulation. However, an analysis on how prices or hedge clauses of PPAs will impact long-term investment decisions as a consequence of the current carbon policy in Chile is beyond the scope of this study.

ators. Here a coal unit sets the spot price and is the only dispatched generator that produces carbon emissions. The carbon charge is prorated among all running units, including the coal power plant itself, in proportion to their fraction of supplied demand (i.e. their fraction of the total production[8]). The grey bars show the resulting side-payments from wind, solar, and hydro units to the coal power plant over that period. Note that, as mentioned before, there is also a fraction of the carbon charge that must be borne by the coal plant itself and this is also indicated in grey. The net effect of this rule is a reduction of economic losses for the coal power plant and a reduction of profits for the other technologies.

Figure 3: Illustration of how the side-payment rule results in carbon charges for non-emitting generation technologies.



Naturally, the example in Figure 3 is an unfavorable scenario for non-emitting technologies considering the portion of carbon charges that is prorated changes hour by hour depending on the spot price and dispatch levels. For instance, if demand is low or if renewable or hydro resources are abundant, there could be hours when all thermal units will be turned off. On the other hand, if demand is high and a few number of diesel units are operating and setting the spot price, side-payments would be rather small within that hour. This is because the marginal cost of diesel units is frequently high enough such than the rest of polluting technologies would earn enough revenues to cover their marginal costs and carbon charges. Consequently, in that case, the only portion of carbon charges that would be compensated through side payments will be the one related to the carbon emissions that result from the operation of diesel units. Also note that a thermal unit facing carbon charges in one hour should not necessarily lead to side payments if a non-emitting generation unit sets a high enough spot price. For example, in a hydro system an extended period of drought can drive the opportunity cost of water for generation above the marginal cost of generation from coal, natural gas, or even diesel.[9] In that scenario, there could be hours when all running thermal units would have to absorb 100% of their carbon charges without receiving side payments from other generators.

8. If PPAs are ignored, as we do in this paper, a generator's fraction of the demand supplied is equal to its fraction of the overall production.

9. In April 2015 the opportunity cost of water in the Rapel hydroelectric power plant in central Chile was approximately 150 $/MWh. Marginal costs for coal, natural gas, and diesel units in the same period were 40 $/MWh, 80 $/MWh, and 120 $/MWh, respectively (SYSTEP, 2015).

We are not aware of sources that describe the rationale that supports the implementation of pass-through restrictions and side-payment rules used in the carbon tax in Chile, but we can think of two factors that likely influenced the choice of the regulator. First, the country uses a cost- instead of a bid-based electricity market design and, consequently, it is the regulator and not generation firms who determines what costs (e.g., fuel, operation and maintenance, opportunity costs, etc.) can be accounted for in the dispatch of generation units in real time (Munoz et al., 2018). Accounting for carbon taxes in the dispatch in a cost-based market design requires close monitoring of emissions levels for all generators in real time, which might have been perceived as a technical challenge by the regulator. This is in contrast to how bid-based markets operate since individual firms have incentives and, most importantly, are actually allowed to include all opportunity costs of carbon policies in their bids (Fabra and Reguant, 2014). Second, adjusting the marginal costs of thermal units upwards by the carbon tax and, potentially, changing the dispatch order of generators increases electricity prices in the very short term, with immediate political implications for current and future government administrations.

In this context, we demonstrate next how the current emissions policy in Chile changes long-term incentives for investments in generation technologies. To do so, our assessment needs to account for pass-through restrictions, administrative side-payment rules, as well as demand and resource variability, that make deriving closed-form solutions for analytical models very challenging.

3. METHODOLOGY

We study the long-term effects of the current tax on carbon emissions in Chile using three different equilibrium models. The first model replicates the implementation of the existing policy in Chile that, as explained earlier, assumes that carbon charges cannot affect the short-term dispatch and pricing of electricity and that some carbon charges are prorated among all running generation units. The second model assumes a standard carbon tax, where carbon charges are explicitly accounted for in the dispatch problem solved by the SO, affecting both dispatch decisions and spot prices. The third model assumes that carbon emissions are controlled using a carbon cap-and trade policy, as in the state of California in the US. We employ these equilibrium models to compare the long-term effect of the carbon pricing mechanism implemented in Chile (Model 1) against standard implementations elsewhere (models 2 and 3).

For simplicity, we assume that all generation firms and the SO have access to perfect information, all firms are price takers, and investments and dispatch decisions are all made simultaneously, as in an open-loop game. We also ignore transmission constraints, but they could be accounted for using the same approach described in the next subsections. These assumptions on firm behavior allow us to find equilibrium investments, dispatch, and emission levels for models 2 and 3 by solving an equivalent Integrated Resources Planning (IRP) problem that we formulate as a linear program. For Model 1 we find the equilibrium using a Gauss-Seidel strategy that iterates between a linear program and a nonlinear adjustment function that determines annual carbon charges per generator.

3.1 Model 1: Equilibrium under a carbon tax with pass-through restrictions and side-payment rules

We assume a set of generation technologies G indexed i with marginal costs MC_i, annualized investment costs I_i per MW, forced outage rates FOR_i, and maximum annual capacity factors

CF_i.[10] Operations occur over a set of hours T indexed t that represent one year, where $|T|$ is the number of representative hours. Firms can invest once, at the beginning of the year, and new generation capacities become available instantaneously. Hourly demand D_t is inelastic and we do not consider the possibility of demand curtailment. The parameter $W_{i,t}$ is an hourly capacity factor that we use to capture the short-term variability of wind and solar resources.

Since the Chilean electricity market operates on a cost-based scheme, we assume that the only decision variables for generation firms in our model are their investment levels x_i in MW.[11] Consequently, under the current carbon tax in Chile, the SO takes generators' capacities $x_i \ \forall i$ as fixed parameters and finds dispatch schedules $y_{i,t}$ for all generators and demand curtailment levels u_t to meet demand at minimum cost, ignoring all carbon charges, solving the following optimization problem:

$$min \ \sum_{t \in T} \sum_{i \in G} MC_i \cdot y_{i,t} \tag{1}$$

$$s.t. \ D_t - \sum_{i \in G} y_{i,t} = 0 \qquad (p_t) \qquad \forall t \in T \tag{2}$$

$$y_{i,t} - (1 - FOR_i) \cdot W_{i,t} \cdot x_i \leq 0 \qquad (\lambda_{i,t}) \qquad \forall i \in G, t \in T \tag{3}$$

$$\sum_{t \in T} y_{i,t} - T \cdot CF_i \cdot x_i \leq 0 \qquad (\eta_i) \qquad \forall i \in G \tag{4}$$

$$y_{i,t} \geq 0 \qquad \forall i \in G, t \in T \tag{5}$$

The Lagrange multiplier p_t is the hourly electricity price, which we assume can go up to the scarcity level needed to supply 100% of demand without curtailments.[12] Variables $\lambda_{i,t}$ and η_i are the Lagrange multipliers of the constraints that impose maximum generation limits (3) and maximum annual capacity factors (3), respectively. Defining θ_i as the marginal value of an additional MW of capacity of technology *i*, over a set period *T*, the profits from sales to the spot market for each generator *i* can be computed as follows:

$$\sum_{t \in T} (p_t - MC_i) \cdot y_{i,t} = \sum_{t \in T} \left[(1 - FOR_i) \cdot W_{i,t} \cdot \lambda_{i,t} + |T| \cdot CF_i \cdot \eta_i \right] \cdot x_i = \theta_i \cdot x_i \tag{6}$$

The SO determines annual carbon charges based on the resulting hourly energy prices, dispatch schedules, and emission rates E_i per generator. Since carbon charges only exist for installed generators (i.e., $x_i > 0$), we compute them per unit of installed capacity β_i, which yield a total of $\beta_i \cdot x_i$ carbon charges per generator *i* per year. This is equivalent to assuming that generators perceive the carbon tax as a capacity charge.

10. By including both forced outage rates and maximum annual capacity factors in the dispatch we assume that the SO conducts an annual optimization of all available resources, including stored water in large hydro power plants, under perfect information.

11. This replicates the electricity market in Chile, where the SO fully controls the dispatch of a power unit given its available capacity and marginal cost data; other decisions that can be made by power plant owners include maintenance, import levels of fuels, etc., but these are beyond the scope of this paper.

12. Note that this is equivalent to assuming that demand can be curtailed at a cost of *VOLL*, but this cost is large enough such that demand is never curtailed. Reducing the magnitude of *VOLL* until the scarcity price is equal to *VOLL* and some demand is curtailed does not change our conclusions. More elaborate capacity mechanisms could be included explicitly in our equilibrium models using methods such as the ones proposed by Bothwell and Hobbs (2017).

We determine β_i for each generator with the following algorithm that emulates the current side-payment rules used in Chile:

1. Determine the amount of initial carbon charges per MWh per generator, defined as $\alpha_{i,t}$, that cannot be covered with the spot price. If $MC_i + TAX \cdot E_i - p_t \leq 0$, then $\alpha_{i,t} = 0$; otherwise, $\alpha_{i,t} = MC_i + TAX \cdot E_i - p_t$.
2. Compute the total amount of carbon charges that must be prorated among all running units $\sum_{i \in G} \alpha_{i,t} \cdot y_{i,t}$ and the fraction of them that should be allocated to each generator i at a given hour t as $\frac{y_{i,t}}{\sum_{i \in G} y_{i,t}}$.
3. Determine final annual carbon charges per MW, β_i, for each generator. Non-emitting technologies must bear side payments that amount to $\beta_i = \sum_{t \in T} \left(\frac{y_{i,t}}{x_i} \right) \left(\frac{\sum_{i \in G} \alpha_{i,t} \cdot y_{i,t}}{\sum_{i \in G} y_{i,t}} \right)$, while emitting generators face carbon charges equal to $\beta_i = \sum_{t \in T} \left(\frac{y_{i,t}}{x_i} \right) \left[TAX \cdot E_i - \alpha_{i,t} + \left(\frac{\sum_{i \in G} \alpha_{i,t} \cdot y_{i,t}}{\sum_{i \in G} y_{i,t}} \right) \right]$. Total carbon charges per year for a generator $i \in G$ are equal to $\beta_i \cdot x_i$.[13]

Note that, by design, the aggregate amount of carbon charges $\sum_{i \in G} \beta_i \cdot x_i$ is equal to $\sum_{i \in G} \sum_{t \in T} E_i \cdot TAX \cdot y_{i,t}$. This is true because the pass-through restriction requires firms to absorb all carbon charges, which we model as a capacity charge. Note that the equality also holds if side-payment rules were removed and $\beta_i = \left(\frac{1}{\bar{x}_i} \right) \cdot \sum_{t \in T} E_i \cdot TAX \cdot y_{i,t} \quad \forall i \in G$ for all emitting generators.

Finally, generation firms choose investment levels solving the following optimization program, acting as price takers with respect to θ_i and β_i:

$$max \quad (\theta_i - \beta_i - I_i) \cdot x_i \tag{7}$$

$$s.t. \quad x_i \geq 0 \tag{8}$$

It is a well-known result that the solution of a competitive[14] equilibrium problem on investments and operations defined by equations (1)–(8) can be computed using a linear optimization program if carbon charges β_i per generator are treated as fixed parameters (Samuelson, 1952). However, as we described in the three-step algorithm in the previous page, annual carbon charges β_i are actually nonlinear functions of prices p_t, dispatch $y_{i,y}$, and investments variables x_i; therefore, they must be determined endogenously. Following Greenberg and Murphy (1985), we compute a

13. Note that due to constraint (3), it is possible that $\sum_{t \in T} \frac{y_{i,t}}{x_i} \to K$ as $x_i \to 0$, where K is a strictly positive number. This could make β_i discontinuous at $x_i = 0$ since, by definition, units with no capacity in the system should bear no carbon charges. However, total annual charges $\beta_i \cdot x_i$ are convergent to zero as $x_i \to 0$ $\forall i \in G$. In our numerical experiments we verify that the equilibrium solutions found are not sensitive to the choice of the starting point of the algorithm.

14. Here we focus on understanding the long-term effects of carbon emission policies with administrative restrictions in a competitive setting. As we state in Munoz et al. (2017a), today the electricity market in Chile is much more competitive than what it has been for the last two or three decades. Furthermore, because 100% of demand is contracted through PPAs between generators and consumers (i.e., vertical arrangements), it is not clear if generators have strong incentives to exercise market power, at least not in the short term (Bushnell et al., 2008). Accounting for strategic investment decisions by generation firms is outside the scope of this study.

regulated[15] market equilibrium using a Gauss-Seidel algorithm that iterates between the linear program defined by equation (9) and the administrative nonlinear function determined by the algorithm described in steps 1–3 to update the values of β_i per generator.

$$\begin{aligned} &min \quad \sum_{i \in G} (I_i + \beta_i) \cdot x_i + \sum_{t \in T} \sum_{i \in G} MC_i \cdot y_{i,t} \\ &s.t. \quad \text{constraints } (2) - (5) \text{ and } (8)\ \forall i \in G \end{aligned} \tag{9}$$

Greenberg and Murphy (1985) show that convergence of the algorithm is only guaranteed if the administrative function to update the values of β_i is Lipshitz continuous and retains the contraction property. In our case these properties are not met and for some combination of parameters the algorithm is not convergent. Yet, the range of parameters for which it is convergent to points that satisfy the Karush-Kuhn-Tucker (KKT) conditions is broad enough to illustrate some of the possible effects on investments of the current emissions policy used in Chile.

3.2 Model 2: Equilibrium under a standard carbon tax

In this model we consider the implementation of a standard tax on carbon emissions that is actually accounted for in the short-term dispatch problem of the SO. We find an equilibrium on investments, dispatch levels, and total emissions for a perfectly competitive market solving the following linear program:

$$\begin{aligned} &min \quad \sum_{i \in G} I_i \cdot x_i + \sum_{t \in T} \sum_{i \in G} (MC_i + E_i \cdot TAX) \cdot y_{i,t} \\ &s.t. \quad \text{constraints } (2) - (5) \text{ and } (8)\ \forall i \in G \end{aligned} \tag{10}$$

If *TAX* is equal to the actual social cost of carbon emissions, the solution of this model yields the socially-optimal mix of generation technologies and emissions levels. The results from this model for a given *TAX* provide a benchmark for the results from the equilibrium model that considers the current carbon tax in Chile (Model 1).

3.3 Model 3: Equilibrium under a carbon cap-and-trade program

We define this third equilibrium model as a second benchmark for Model 1. In this case we assume that the authority enacts a new law that limits the maximum amount of carbon emissions per year to *CAP*. Firms are endowed with an initial number of emission permits that can be traded freely among all generation firms. Once again, if the market is perfectly competitive and there are no transaction costs, the equilibrium can be found by solving the following linear program:

$$min \quad \sum_{i \in G} I_i \cdot x_i + \sum_{t \in T} \sum_{i \in G} MC_i \cdot y_{i,t} \tag{11}$$

$$s.t. \quad \sum_{t \in T} \sum_{i \in G} E_i \cdot y_{i,t} \le CAP \quad (\mu) \tag{12}$$

$$\text{constraints } (2) - (5) \text{ and } (8)\ \forall i \in G$$

15. We use the expression *regulated* market equilibrium because annual carbon charges β_i are the result of an administrative process controlled by the SO or regulator. In contrast to hourly energy prices p_t, equilibrium values of β_i do not balance a supply and demand of carbon emissions per year in a market-clearing constraint.

In equilibrium, the Lagrange multiplier μ is equal to the price of the emission permits. If $CAP_{ST}(TAX)$ denotes the resulting amount of annual carbon emissions in equilibrium under a standard carbon tax (Model 2), setting $CAP = CAP_{ST}(TAX)$ in the equilibrium model with a cap-and-trade program (Model 3) yields a price of emissions permits $\mu = TAX$. Furthermore, if $CAP_{CHT}(TAX)$ denotes the resulting amount of annual carbon emissions in equilibrium under the current carbon tax in Chile (Model 1), setting $CAP = CAP_{CHT}(TAX)$ in the equilibrium model with a cap-and-trade program (Model 3) yields the minimum investment and operation costs to achieve such cap on annual emissions. This comparison allows us to assess how much more expensive is to achieve a desired level of carbon emissions per year using a tax with administrative rules (as it is used in Chile) instead of an standard emissions policy (carbon tax or cap-and-trade program).

4. GENERAL THEORETICAL STATEMENTS

We now provide three simple theoretical statements that build upon the equilibrium models described in the previous section. All proofs are provided in Section A.1 in the Appendix.

The first statement is that if TAX is the true SCC, then the equilibrium solution $(\overline{x}, \overline{y}, \overline{\beta})$ for a carbon tax with pass-through restrictions and side-payment rules (Model 1) always yields a social cost that is higher or equal than the one that results from the equilibrium solution (x^*, y^*) under a standard carbon tax (Model 2), for the same tax level. This is also true if side-payment rules were removed from Model 1. This result is rather intuitive because in Model 2 we actually use the definition of the social cost of a solution as the objective function of the model. Consequently, any feasible solution to constraints (2)–(5) and (8) will always yield a social cost higher than or equal to the optimal one. This statement follows directly from Pigou (1920).

Our second statement is that, if TAX is the true SCC, then the total electricity revenues under a carbon tax with pass-through restrictions and side-payment rules (Model 1) $\sum_{t \in T} D_t \cdot \overline{p}_t$ are always less than or equal to the total electricity revenues under a standard carbon tax (Model 2) $\sum_{t \in T} D_t \cdot p_t^*$, where $\overline{p}_t$ and p_t^* are the hourly equilibrium prices under models 1 and 2, respectively. This is also true if side-payment rules were removed from Model 1.

The third statement is that the demand-weighted average price of electricity under a standard carbon tax (or an equivalent carbon cap-and-trade program) $\frac{\sum_{t \in T} D_t \cdot p_t^*}{\sum_{t \in T} D_t}$ is always less than or equal to the demand-weighted average price of electricity under a carbon tax with pass-through restrictions and side-payment rules (Model 1) $\frac{\sum_{t \in T} D_t \cdot \overline{p}_t}{\sum_{t \in T} D_t}$. This is also true if side-payment rules were removed from Model 1.

The second statement follows directly from the fact we mentioned previously because, in equilibrium, the revenues collected from the sales of electricity must be exactly equal to all system costs (i.e., firms make zero profits in equilibrium). The third statement follows directly from the second one. However, we will show in the next section that the second and third statements do not necessarily hold if there are, for example, resource constraints that allow some technologies to earn Ricardian rents (Peteraf, 1993). Interestingly, all of these results still hold if side-payment rules were removed from the tax policy. Consequently, a regulator that tries to protect consumers by forcing generation firms to absorb all carbon charges—for instance, using a pass-through restriction—might actually end up harming them as a consequence of higher electricity prices than the ones that would result under a standard carbon tax. Nevertheless, these theoretical results do not allow us to quantify the magnitude of the inefficiencies as a result of a carbon tax with pass-through restrictions and side-payment rules. In the next sections we further explore the effects of such administrative restrictions using numerical simulations.

5. NUMERICAL EXPERIMENTS

5.1 Description of Case Studies

We analyze the long-term effects of the current emissions policy used in Chile using a Base Case that captures some of the most important characteristics of the available power resources in the country. In addition, we include case studies A and B to illustrate how the carbon tax with pass-through restrictions and side-payment rules could lead to counterintuitive results if implemented in a different system.[16]

Table 1 shows the set of available technologies for each case study. In all cases we assume that generation capacities are endogenous and that there are no existing power plants in the system (i.e., greenfield). This means that, in a competitive equilibrium, all generation technologies earn zero profits in the long run, with the exception of Large Hydro in the Base Case that is constrained to a maximum investment level.

Table 1: Case Studies

Cases	Set of available technologies
Base Case	—Coal —CCGT —Diesel —Large Hydro (constrained) —Solar PV —Wind
Case A	—Solar PV —CCGT —Diesel
Case B	—Coal —CCGT —Diesel —Solar PV —Wind

We use an hourly demand profile from the National Interconnected System (NIS) for 2013 (CEN, 2016) and scale it to 2050 based on projections from the National Ministry of Energy (ME, 2014). Hourly wind, solar, and hydro run-of-river (RoR) profiles were taken from EEE (2016), EES (2016), and CEN (2016), respectively. Table 10 in the Appendix summarizes the main statistical properties of the hourly demand, wind, and solar profiles used in this study. The assumed forced outage rates for thermal units are based on recent statistics for existing power plants in Chile (CNE, 2019). As in Bushnell (2003), we assume that Large Hydro has some flexibility to store water for high-demand periods. This flexibility is modeled through a maximum annual capacity factor (Equa-

16. Many countries in Latin America have used the Chilean electricity market as a role model for the development of their own markets (Sioshansi and Pfaffenberger, 2006; Pollitt, 2008), which have different portfolios of generation technologies available for investment. Consequently, we believe that these additional case studies provide valuable information for regulators elsewhere about the economic inefficiencies and effects on carbon emissions of the current policy used in Chile if implemented in a different system.

tion 4) of 50% based on historical data.[17] This constraint is not enforced on any other technology. We also constrain investments in Large Hydro up to 3393 MW, which is equal to the current installed capacity of this technology in the country (CNE, 2019). This is in line with the assumptions used in current planning studies done by the Chilean Ministry of Energy (PELP, 2018). Table 2 summarizes our cost assumptions for all technologies. These are the same values used by the National Energy Commission for pricing studies (CNE, 2017).

Table 2: Generation investment alternatives

	Capital Cost [$/kW]	Operation Cost [$/MWh]	Lifespan [years]	Emissions Rate [tCO_2/MWh]	Forced Outrage Rate
Coal	3000	34	35	0.95	0.05
CCGT	1090	88	25	0.44	0.02
Diesel	666	219	25	0.78	0.05
Solar PV	1200	0	25	0	0
Wind	1800	0	35	0	0
Large hydro	3500	0	45	0	0

We want to highlight that none of these case studies exactly replicate actual investment conditions in the electricity market in Chile such that we could make exact predictions about expected generation investments in the country by 2050. Instead, the purpose of these cases is to assess the long-term effects of the current carbon tax used in the country under different hypothetical scenarios, but which include some realistic features such as actual demand projections, hourly wind and solar profiles, and a set of generation technologies that are similar to the ones available today or that will likely be available in the future. Consequently, our numerical experiments only serve us to illustrate how the current emissions policy used in Chile incentivizes portfolios of generation technologies that differ from the socially-optimal ones under a standard tax or cap-and-trade program in idealistic conditions. Aiming to exactly predict the actual effects of the current emissions policy in the country would require much more elaborate case studies and equilibrium models than the ones we utilize here. At the very least, they would require consideration of existing generation capacity and incentives to retire power plants, multi-period projections of input cost and demand parameters, consideration of contractual agreements (PPAs) as well as interactions with other existing environmental policies. Such analysis is beyond the scope of this paper and a subject for future research.

5.2 Numerical Results

The following subsections summarize the results from our numerical experiments. In Section 5.2.1 we present a detailed analysis of the effect of a tax with pass-through restrictions and side-payment rules for the Base Case. In Section 5.2.2 we use cases A and B to show how, depending on the available generation technologies, a carbon tax with such restrictions can result in higher carbon emissions than when the tax level is zero or even lower emissions than under a standard carbon tax, albeit at a much higher cost. Finally, in Section 5.2.3 we quantify the effect of removing side-payment rules while keeping the pass-through restriction.

Under ideal conditions we would have considered a range of tax levels from zero to 100 $\$/tCO_2$ in all case studies, in line with the carbon price required to achieve the temperature targets

17. This is an acceptable approximation for the purpose of our study. Nevertheless, it has been shown that, depending on the characteristics of the system, ignoring water-balance constraints per period and nonlinear-head effects in hydro systems could lead to distorted results (Ramírez-Sagner and Munoz, 2019).

in the Paris Agreement (Stern and Stiglitz, 2017). Unfortunately, in some cases we were not able to find an equilibrium when setting a carbon tax with pass-through restrictions and side-payment rules higher than 25 $\$/tCO_2$ using our iterative approach.[18] For this reason, here we only present results of the effects of increasing tax levels from zero to 30 $\$/tCO_2$ in the Base Case, from zero to 100 $\$/tCO_2$ in Case A, and from zero to 25 $\$/tCO_2$ in Case B. In spite of the discrepancy of tax ranges we analyze in this section, the range of tax levels for which we found equilibria in the Base Case and in Case B is within the range of values of the carbon price trajectory considered by the Chilean government in recent studies (ME, 2014; PELP, 2018). For instance, the latest long-term energy planning study conducted by the Ministry of Energy in Chile considers a scenario of carbon taxes increasing from 5 $\$/tCO_2$ today to 30 $\$/tCO_2$ by 2050 (PELP, 2018).

For solving Model 1 we apply the solution method proposed by Greenberg and Murphy (1985). Although we cannot guarantee that Model 1 has a unique solution for each tax level, we performed a sensitivity analysis using many different starting points for the iterative solution algorithm and always found the same equilibrium solutions. Damping parameters, which avoid large changes in the values of β_i between iterations, were not necessary.[19] Using these parameters only increased the number of iterations needed to reach a fixed point and did not change the cyclic behavior of the algorithm for tax levels above 30 $\$/tCO_2$ in the Base Case and above 25 $\$/tCO_2$in Case B.

All simulations were implemented using the JuMP algebraic modeling language for mathematical optimization (Dunning et al., 2017) and solved with Gurobi 7.5.1 on a computer with an Intel Core i7-2640M processor @2.80GHz and 8GB of RAM. Models 2 and 3 have approximately 70,000 variables and 70,000 constraints, they can be solved in approximately 2 seconds. Model 1 has the same number of variables and constraints, but it must be solved approximately 5 consecutive times until all variables reach a fixed point.[20] We also verify that, in equilibrium, all generation units make zero profits in all cases, except for large hydro in the Base Case that makes a positive profit as a consequence of the resource constraint.

5.2.1 Economic inefficiencies of a carbon tax with pass-through restrictions and side-payment rules in the Base Case

Tables 3 and 4 show results for the market equilibria under the carbon tax with pass-through restrictions and side-payment rules, and the standard tax, respectively, for the Base Case under tax levels that range between 0 and 30 $\$/ tCO_2$. They include final installed capacity per technology, final installed capacity in thermal units (i.e., Coal, CCGT, and Diesel) and in renewables (i.e., Solar and Wind), the resulting demand-weighted average energy price, annual carbon emissions, the social cost, and the overall tax revenues earned by the government from the collection of either form of carbon taxes.

One of the most remarkable inefficiencies of the tax with pass-through restrictions and side-payment rules is the low emissions abatement levels that it achieves as we increase the tax rate. As Table 4 shows, under a standard carbon tax, increasing the tax level from zero to 30 $\$/tCO_2$ yields a reduction of carbon emissions of 75 $MtCO_2$ per year, which is nearly 64% of the annual carbon

18. In some cases, when the algorithm did not converge (e.g., when it cycled between two points), it was possible to force convergence to a KKT point by fixing some investment variables to an arbitrary value (e.g., zero). However, we prefered not to force convergence since those results could distort our analyses.

19. Abusing notation, say $\beta(n)$ was the carbon charge used in iteration n and β^* is the new value that results from computing the new carbon charges. With a damping parameter $\lambda \in (0,1)$ we would set $\beta(n+1)=(1-\lambda)\cdot\beta(n)+\lambda\cdot\beta^*$.

20. We stop iterations until the change of investment levels between iterations is less than or equal to 10^{-5}.

Table 3: Market equilibria for a carbon tax with pass-through restrictions and side-payment rules in the Base Case.

Tax level ($/$tCO_2$)	0	5	10	15	20	25	30
				Capacity (GW)			
Coal	14.84	14.73	14.63	14.54	14.25	13.97	13.82
CCGT	1.17	1.26	1.35	1.42	1.48	1.52	1.55
Diesel	1.55	1.56	1.57	1.59	1.62	1.65	1.66
Large Hydro	3.39	3.39	3.39	3.39	3.39	3.39	3.39
Solar PV	3.43	3.74	4.04	4.32	4.60	4.83	4.97
Wind	0.08	0.08	0.08	0.08	0.66	1.29	1.61
Thermal capacity (GW)	17.55	17.55	17.55	17.55	17.35	17.14	17.04
Renewable capacity (GW)	3.50	3.82	4.12	4.39	5.26	6.11	6.57
Average energy price ($/MWh)	73.89	77.98	82.01	86.01	89.78	93.42	97.10
Emissions (million tCO_2)	117.12	116.27	115.45	114.70	112.39	110.12	108.89
Social cost (million $)	10948	11529	12103	12670	13204	13717	14235
Tax revenues (million $)	0	581	1155	1720	2248	2753	3267

Table 4: Market equilibria under a standard carbon tax in the Base Case.

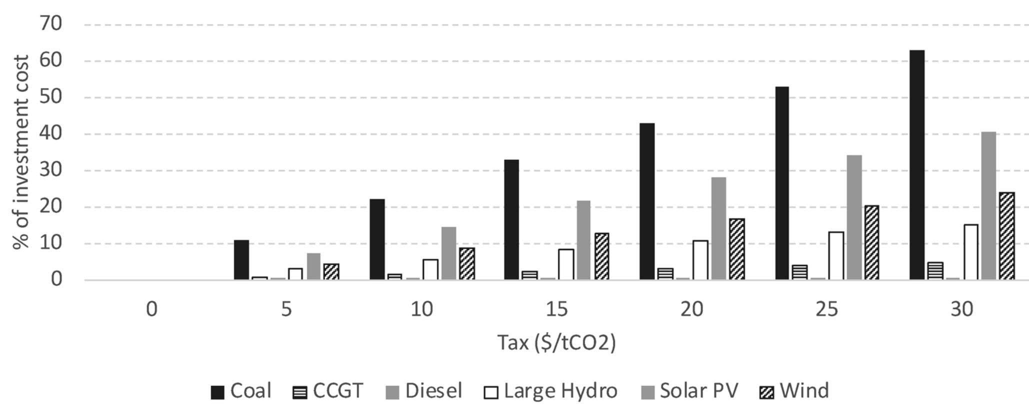
Tax level ($/ tCO_2)	0	5	10	15	20	25	30
				Capacity (GW)			
Coal	14.84	13.49	12.88	9.95	8.51	6.84	6.38
CCGT	1.17	1.96	2.44	3.58	4.45	5.41	5.74
Diesel	1.55	1.58	1.64	2.56	2.88	3.24	3.28
Large Hydro	3.39	3.39	3.39	3.39	3.39	3.39	3.39
Solar PV	3.43	6.04	8.01	12.66	14.89	14.81	15.02
Wind	0.08	1.61	1.92	8.24	11.24	15.40	16.47
Thermal capacity (GW)	17.55	17.03	16.97	16.09	15.83	15.49	15.40
Renewable capacity (GW)	3.50	7.64	9.93	20.90	26.13	30.21	31.50
Average energy price ($/MWh)	73.89	78.43	82.67	86.56	89.17	91.27	93.13
Emissions (million tCO_2)	117.12	105.94	99.73	70.09	56.02	45.23	42.12
Social cost (million $)	10948	11509	12024	12462	12775	13029	13249
Tax revenues (million $)	0	530	997	1051	1120	1131	1263

emissions that result in the case where there is no carbon tax (117.12 MtCO_2). However, increasing the tax rate from zero to 30 $/$tCO_2$ when there are pass-through restrictions and side-payment rules only reduces carbon emissions by 7% (8.23 MtCO_2) with respect to the scenario where there is no carbon tax. Consequently, the administrative restrictions of the emissions policy provide economic incentives for generation firms to achieve only an 11% of the reductions in carbon emissions that would result under a standard tax of 30 $/$tCO_2$.These results are mainly a consequence of the relatively weak incentives for investments in non-emitting generation technologies (i.e., hydro, solar, and wind) fostered by the current carbon tax policy used in Chile.

Under a standard carbon tax, an increase in the tax rate from zero to 30 $/$tCO_2$ provides strong economic incentives to replace 8.46 GW of coal with solar, wind, CCGT, and diesel generation capacity. While the share of installed capacity of CCGT and diesel technologies increase as we increase the tax level, the total installed capacity of thermal units decreases from 17.55 GW to 15.40 GW. Additionally, the total share of renewable capacity increases by a factor 8 from 3.5 GW to 31.50 GW because these technologies become cheaper than conventional units that produce carbon emissions and face the tax. This large increase in renewable capacity is also possible because large hydro offers some flexibility to offset the variability of wind and solar generation (Hirth, 2016).[21] However, under the tax with administrative restrictions, the same increase in the tax rate only reduces investments in coal generation by 1.02 GW with respect to a scenario with no carbon tax. Furthermore, for a tax of 30 $\$/tCO_2$ total investments in renewable capacity are equal to 6.57 GW, which is equivalent to only 21% of what it could be achieved if pass-through restrictions and side-payment rules were removed from the emissions policy.

Figure 4 provides some insights about the incentives that result from imposing a carbon tax with such administrative rules. This figure shows the annual carbon charges faced by each generation technology in equilibrium as a percentage of their annualized capital costs, i.e. $\frac{\beta_i}{I_i} \cdot 100\%$, for different tax levels. In this case, coal is the technology that faces the largest fraction of annual carbon charges with respect to its capital cost, which provides some evidence that the emissions policy does, in fact, make the most carbon-intensive technology less attractive for investment. However, side-payment rules create perverse incentives since technologies that do not produce any carbon emissions must also bear some carbon charges. In this case, annual carbon charges increase annual fixed costs by 15% for large hydro, 24% for wind, and 40% for solar when the tax reaches a level of 30 $\$/tCO_2$, which partially explains the large difference on investments in renewables with respect to the case with a standard carbon tax.

Figure 4: Annual carbon charges as a percentage of annualized investment costs for each generation technology under the tax with pass-through restrictions and side-payment rules.



Tables 3 and 4 also show the social cost of each market equilibrium, which we measure as $\sum_{i \in G} I_i \cdot x_i + \sum_{t \in T} \sum_{i \in G} (MC_i + E_i \cdot TAX) \cdot y_{i,t}$, assuming that TAX is the true social cost of carbon emissions. By definition, the standard tax yields the lowest social cost since its equilibrium is computed by solving an optimization problem that minimizes the expression presented previously (see Equation (??)). However, when we impose pass-through restrictions and side-payment rules, investments, generation dispatch levels, and carbon emissions change. We find that in this case the economic inefficiency of the carbon policy with administrative restriction increases as we raise the tax rate. For instance, for a tax of 30 $\$/tCO_2$ the market equilibrium under the current tax scheme

21. We acknowledge that the flexibility of hydro is overstated in our model since we assume that the SO has access to a perfect foresight of demand levels, hydro resources, as well as wind and solar availability for every hour in a year. In reality, hydro resources are scheduled using medium- and long-term planning algorithms that consider different sources of uncertainty such as seasonal hydro inflows and demand levels, e.g.Pereira and Pinto (1991). However, we do not expect this overstatement of flexibility to alter our main conclusions.

used in Chile imposes a social cost that is \$986 million more expensive per year than the equilibrium reached under a standard carbon tax. Although the current tax level in Chile is only 5 $\$/tCO_2$, which results in relatively low social costs [22], the long-term goal of the government is to increase it to, at least, 25 $\$/tCO_2$ by 2030 (ME, 2014). As our results suggest, for such tax levels the economic inefficiency caused by the current administrative rules could be significant.

A concerning finding is that, for a given tax rate, the carbon tax with administrative restrictions yields higher tax revenues than the standard tax. This result could give weak and conflicting incentives to the regulator to modify the current rules of the carbon tax because of a potential tax loss.[23] For instance, tax revenues for a tax of 30 $\$/tCO_2$ are nearly 158% higher under the tax with administrative restrictions than under a standard carbon policy. Of course, tax losses could be minimized by simply increasing the tax rate if the regulator decides to switch to a standard tax policy. Nevertheless, a large increase in the tax rate could impose challenges of political acceptance, making it necessary to find other sources of tax revenues (e.g., corporate or income taxes) to make up for any potential tax losses.[24]

Another important result is that demand-weighted average energy prices increase under both tax schemes (see Table 3 and 4). Recall that the pass-through restriction is, presumably, a measure to prevent price increases as a result of the carbon tax. Remarkably and as anticipated in Section 5, we observe that such restriction—in combination with the side-payment rules—cause long-term prices to increase as we raise the tax level to values that are even above the equilibrium prices under a standard carbon tax. For instance, for a tax of 30 $\$/tCO_2$ the demand-weighted average energy price under a carbon tax with administrative restrictions is \$97.10 per MWh, which is 4.3% higher than the average price under a standard carbon tax (\$93.13 per MWh). This result contradicts the (potential) goal of the regulator to prevent carbon taxes to change the dispatch and pricing electricity in the short term in order to protect consumers by forcing generation firms to absorb the full costs of the emissions policy. In this case, with a standard carbon tax it would be possible to a) reduce carbon emissions and b) (in most cases) achieve lower energy prices than under the current tax scheme.[25]

Finally, Table 5 shows the market equilibria that result from using a carbon cap-and-trade program (Model 3 described in Section 3.3) to find the most efficient manner to achieve the same levels of carbon emissions that result under the carbon tax with pass-through restrictions and side-payment rules. The first row, namely emissions, indicates the cap on annual carbon emissions (CAP in Equation 12), which is equal to the realized levels of carbon emissions in Table 3 for tax rates ranging from zero to 30 $\$/tCO_2$. The second last row indicates the value of the Lagrange multiplier of constraint (12) or, equivalently, the equilibrium price of carbon emissions permits. Under perfect competition, the price of the permits is equivalent to the carbon tax that would be needed to

22. In this statement we implicitly assume that the tax level imposed by the authority is equal to the true value of carbon emissions. However, if the tax level chosen by the authority is significantly lower than the true value of carbon emissions, any of the three carbon policies considered here would be inefficient.

23. The carbon cap-and-trade program in California is a good example of a carbon policy that has achieved its environmental goals, but that is perceived as a failure in the political arena because auction proceeds from emissions permits have been lower than expected (Bushnell, 2017).

24. Finding other alternatives to raise tax revenues is beyond the scope of our study, but it is a relevant subject that should be addressed in future research.

25. Note that the Proposition in Section 4 only holds if there are no resource constraints. In the Base Case we limit investments in large hydro capacity up to 3.39 GW and this constraint is binding in all experiments. As a result of this constraint, large hydro obtains Ricardian rents and average energy prices under the carbon tax with pass-through restrictions and side-payment rules can be lower than under a standard carbon tax. However, as we increase the tax level above 20 $\$/tCO_2$, the increment in costs due to an inefficient mix of generation resources primes over the economic rents for large hydro and prices under the standard tax become much lower than under the tax with administrative restrictions.

Table 5: Market equilibria under a carbon cap-and-trade policy in the Base Case.

Emissions (million tCO_2)	117.12	116.27	115.45	114.70	112.39	110.12	108.89
	Capacity (GW)						
Coal	14.84	14.73	14.63	14.54	14.26	13.94	13.84
CCGT	1.17	1.27	1.37	1.46	1.67	1.78	1.81
Diesel	1.55	1.55	1.55	1.55	1.55	1.57	1.57
Large hydro	3.39	3.39	3.39	3.39	3.39	3.39	3.39
Solar PV	3.43	3.74	4.04	4.32	4.98	5.38	5.50
Wind	0.08	0.08	0.08	0.08	0.26	0.85	1.05
Thermal capacity (GW)	17.55	17.55	17.55	17.55	17.48	17.28	17.21
Renewable capacity (GW)	3.50	3.81	4.12	4.39	5.24	6.23	6.55
Average energy price ($/MWh)	73.89	74.43	74.93	75.41	76.57	77.18	77.36
Social cost (million $)	10948	11529	12103	12670	13203	13708	14234
Emission permits ($/$tCO_2$)	0	0.58	1.14	1.66	2.92	3.59	3.79
Permit revenues (million $)	0	68	131	190	328	394	413

achieve that same level of emissions in a year or, in more general terms, a measure of the marginal incentives that the current tax scheme used in Chile gives to generation firms to reduce carbon emissions.

The results in Table 5 indicate that with a permit price or standard tax of approximately 12% of the value of a carbon tax with administrative restrictions it is possible to achieve the same level of carbon emissions, but with a lower social cost. Note that the differences in generation investments and social costs between Tables 3 and 5 are rather small. However, demand-weighted average energy prices in the carbon cap-and-trade program are much lower. For example, for a tax of 30 $/$tCO_2$, the average price under the cap-and-trade program is $77.36 per MWh, which is 20.3% lower than under the carbon policy with administrative restrictions ($97.10 per MWh). Again, both achieving the same reductions in carbon emissions.

Perhaps this relatively large difference in average energy prices might seems as a surprise given the small differences in social costs between the market equilibria in Tables 3 and 5. However, social costs do not account for transfer payments between consumers and the government since these only result in a redistribution of economic rents among agents. The last row in 5 shows the total amount of revenues earned by the government from the sales of emissions permits or the implementation of a standard tax at a rate equal to the price of these permits. We find that revenues under an efficient carbon cap-and-trade or standard tax are approximately 87% lower than those reported in Table 3 for the carbon tax with administrative restrictions. This is a concerning result since it shows that, in the long term, a large fraction of the increase in price caused by the carbon tax with administrative restrictions will be used for fiscal purposes, with a rather weak impact on carbon emissions.

5.2.2 Counterintuitive effects of pass-through restrictions and side-payment rules on carbon emissions in Case A and Case B

In the Base Case analyzed in the previous section we found that, in spite of the administrative restrictions of the current carbon tax used in Chile, the policy did incentivize some reductions in carbon emissions, although at a much higher cost than under a standard tax. We now use two additional case studies to show that this result is not general since carbon emissions can either increase or decrease as a consequence of the policy.

Tables 6 and 7 show the market equilibria for different tax levels under an emissions policy with administrative restrictions and under a standard carbon tax, respectively, for Case A. In this hypothetical scenario the only available technologies for investment are CCGT, diesel, and solar. Under perfect competition, we observe the expected effect of a standard carbon tax: increasing the tax rate yields a reduction of carbon emissions, albeit the potential for emission reductions in this case is very small. Table 6 shows an unexpected and counterintuitive increase in emissions as we increase the tax rate. This occurs because, under the tax with administrative restrictions, the solar unit must bear a disproportionately large fraction of the initial carbon charges faced by the CCGT and diesel units.

Table 6: Market equilibria under a carbon tax with pass-through restrictions and side-payment rules in Case A.

Tax ($/$tCO_2$)	0	20	40	60	80	100
			Capacity (GW)			
CCGT	19.15	18.68	18.24	17.79	17.22	16.74
Diesel	1.56	2.04	2.50	2.96	3.55	4.05
Solar PV	23.12	22.99	22.88	22.81	22.75	22.67
Average Energy Price ($/MWh)	90.31	95.72	101.29	107.06	113.20	119.52
Emissions (million tCO_2)	39.41	39.57	39.76	39.98	40.31	40.66
Social Cost (million $)	13366	14166	14991	15845	16754	17689
Tax Revenue (million $)	0	791	1590	2399	3225	4066

Table 7: Market equilibria under a standard carbon tax in Case A.

Tax ($/$tCO_2$)	0	20	40	60	80	100
			Capacity (GW)			
CCGT	19.15	19.18	19.20	19.23	19.25	19.28
Diesel	1.56	1.53	1.51	1.47	1.45	1.43
Solar PV	23.12	23.53	23.95	24.49	25.05	25.51
Average Energy Price ($/MWh)	90.31	95.62	100.89	106.13	111.33	116.49
Emissions (million tCO_2)	39.41	39.15	38.90	38.62	38.34	38.13
Social Cost (million $)	13366	14151	14932	15707	16477	17241
Tax Revenue (million $)	0	783	1556	2317	3067	3813

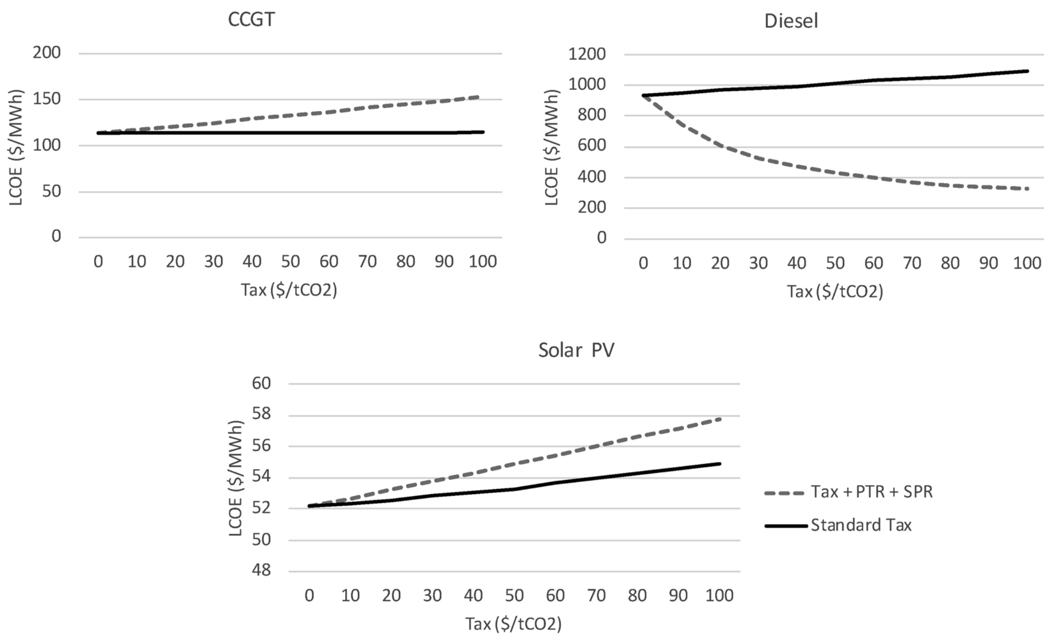
Figure 5 shows the levelized cost of energy (LCOE) for three available generation technologies for different tax levels in equilibrium.The levelized cost of energy was computed as $\frac{\text{sum of all costs over the year}}{\text{sum of all power generated over a year}}$ for the generation technology in question.[26] Note that it has been demonstrated that, in general, it is not possible to build an efficient portfolio of generation technologies just based on their LCOE (Joskow, 2011), particularly when considering renewables. However, the equilibrium levels of LCOE can be helpful to understand why carbon emissions increase under a carbon tax with pass-through restrictions and side-payment rules

Note than increasing the tax level increases the LCOE of solar under both carbon policies. This occurs because there are rather small possibilities for carbon emissions reductions and increas-

26. For the standard carbon tax $LCOE_i = \frac{I_i \cdot x_i + \sum_{t\in T}(MC_i + TAX \cdot E_i)\cdot y_{i,t}}{\sum_{t\in T} y_{i,t}}$ and for the carbon tax with pass-through restrictions and side-payment rules $LCOE_i = \frac{(I_i + \beta_i)\cdot x_i + \sum_{t\in T} MC_i \cdot y_{i,t}}{\sum_{t\in T} y_{i,t}}$.

ing the share of solar results in some curtailment [27] of this resource. Consequently, in both cases the sum of all power generated over a year (denominator) increases at a lower rate than the sum of capital and operating costs over the year (numerator). However, in the case with administrative restrictions (dashed curve), the solar unit must bear a prorated amount of carbon charges from the CCGT and diesel units equal to $\beta_i \cdot x_i$, on top of the capital cost of this technology $I_i \cdot x_i$. This is why, in this case, solar generation becomes more expensive under a tax with administrative restrictions (dashed curve) than under a standard policy (solid black curve), at least in terms of levelized costs.

Figure 5: LCOE of generation technologies in equilibrium. PTR = Pass-through restriction. SPR = Side-payment Rule.



The LCOE of diesel generation also increases under a standard tax for reasons that are similar to ones described previously for solar: the increase in capacity and fuel expenditures as well as in emission charges (numerator) is larger than the increase in the amount of power generated over the year (denominator). However, under a tax with administrative restrictions, diesel only bears a small fraction of its carbon charges (because of the side-payment rules) and, as the tax level is increased, it ends up generating more power over the year because it displaces CCGT and solar generation. The result is a reduction in the LCOE of diesel under this carbon tax. For CCGT, the LCOE remains almost constant as the tax rate is increased under the standard emissions policy. However, under a tax with administrative restrictions the LCOE of CCGT increases for reasons that are similar to the ones we gave for solar generation above. This is why under the tax with pass-through restrictions and side-payment rules the most cost-effective portfolio of generating technologies includes too much diesel and too little solar and CCGT capacity compared to the optimal portfolio under the standard tax.

27. In power systems, wind, solar, or hydro resources are curtailed anytime they are available, but they are not used to generate electricity. For instance, consider a 100 MW solar unit with plenty of radiation such that it can generate power at nameplate capacity for one hour. If due to a constraint in the system (e.g. a minimum generation limit of a coal unit) the SO determines that this unit can only deliver 80 MW over that hour, then the there is a curtailment of 20 MWh of solar energy.

Tables 8 and 9 show the market equilibria under a tax with pass-through restrictions and side-payment rules and under a standard carbon tax, respectively, for Case B (all technologies available for investment, except Large Hydro). Note that, just as we observed in the Base Case, a carbon tax with administrative restrictions can indeed reduce carbon emissions as we increase the tax level. In this case, for a carbon tax of 20 $\$/tCO_2$ the standard policy yields annual carbon emissions that are 39% lower than under a tax with pass-through restrictions and side-payment rules. Surprisingly, when we increase the tax to 25 $\$/tCO_2$, annual carbon emissions under the tax policy with administrative restrictions (50.55 million tCO_2) are slightly lower than under a standard tax (54.92 million tCO_2).

Table 8: Market equilibria under a carbon tax with pass-through restrictions and side-payment rules in Case B.

Tax ($\$/tCO_2$)	0	5	10	15	20	25
	Installed Capacity (GW)					
Coal	16.80	16.25	15.56	14.93	13.36	4.05
CCGT	2.73	3.24	3.57	3.96	4.82	12.08
Diesel	1.55	1.57	1.61	1.64	2.09	3.27
Solar PV	3.54	4.09	4.53	5.00	6.21	16.51
Wind	0.08	0.08	1.04	1.61	3.45	8.82
Thermal Investment (GW)	21.08	21.06	20.74	20.54	20.26	19.40
Renewable Investment (GW)	3.62	4.17	5.57	6.60	9.66	25.32
Average Energy Price (\$/MWh)	74.70	79.04	83.21	87.27	91.02	93.11
Emissions (million tCO_2)	129.11	126.91	122.61	119.03	108.84	50.55
Social Cost (million \$)	11056	11698	12315	12916	13471	13780
Tax Revenue (million \$)	0.00	635	1226	1785	2177	1264

Table 9: Market equilibria under a standard carbon tax in Case A.

Tax ($\$/tCO_2$)	0	5	10	15	20	25
	Installed Capacity (GW)					
Coal	16.80	15.92	15.42	12.90	9.87	7.77
CCGT	2.73	3.15	3.54	4.57	6.51	7.98
Diesel	1.55	1.58	1.59	2.37	2.93	3.24
Solar PV	3.54	4.46	5.55	9.67	14.40	14.39
Wind	0.08	1.35	1.66	6.68	11.65	15.34
Thermal Investment (GW)	21.08	20.64	20.54	19.84	19.31	18.99
Renewable Investment (GW)	3.62	5.82	7.21	16.36	26.05	29.73
Average Energy Price (\$/MWh)	74.70	78.98	83.06	86.81	89.37	91.40
Emissions (million tCO_2)	129.11	122.92	118.89	93.73	66.12	54.92
Social Cost (million \$)	11056	11690	12294	12848	13227	13527
Tax Revenue (million \$)	0	615	1189	1406	1322	1373

How is it possible that a carbon policy with such administrative restrictions yield lower levels of carbon emissions than a standard tax?[28] What occurs is that increasing the tax level from 20 $\$/tCO_2$ to 25 $\$/tCO_2$ under the policy with administrative restrictions makes a combination of

28. We want to highlight that this result is not a numerical error, the proposed solution does satisfy all first-order conditions of the equilibrium problem described in Model 1 and all generation technologies make zero profits. The point is also stable because different starting points used in the Gauss-Seidel algorithm yield the same equilibrium point. However, reducing the marginal cost of coal from 34 \$/MWh to 22 \$/MWh changes the result and annual carbon emissions under the tax with administrative restrictions are higher than under a standard tax when TAX=25 $\$/tCO_2$, in line with what we observe for lower tax levels.

CCGT, solar, and wind generation much more economical than coal. This is why investments in CCGT, solar, and wind generation increase by nearly 200% with respect to equilibrium levels when the tax is equal to 20 $/$tCO_2$. In contrast, investments in coal capacity decrease from 13.36 GW to 4.05 GW. The net effect is a generation portfolio that results in lower annual carbon emissions than the optimal portfolio under the standard carbon policy for the same tax level. Nevertheless, if 25 $/$tCO_2$ is the true social cost of carbon, the optimal portfolio under the carbon tax with pass-through restrictions and side-payment rules is inefficient. Both, the average energy price and the social cost of the equilibrium solution under the tax with administrative restrictions (93.11 $/MWh and $13780m, respectively) are higher than under a standard carbon tax (91.40 $/MWh and $13527m, respectively).

We want to highlight that these two additional case studies, Case A and Case B, show that we cannot actually make general claims about the long-term effects of the carbon policy with pass-through restrictions and side-payment rules on annual carbon emissions. Depending on the portfolio of generation technologies available and other parameters (e.g., capital and variable costs of generation), increasing the tax level under a carbon tax with administrative restrictions can yield a) some reductions in carbon emissions, but not as much as a standard carbon tax (Base Case and Case B, except when TAX=25 $/$tCO_2$), b) reductions in carbon emissions beyond what it is socially optimal (Case B when TAX=25 $/$tCO_2$), or c) an increase in carbon emissions (Case A).

5.2.3 Effects of removing side-payment rules from the carbon emissions policy

A natural question that arises from the previous analyses is whether the inefficiencies of the current emissions policy used in Chile stem from the pass-through restriction, the side-payment rules, or both. Here we partially answer that question by repeating the equilibrium analysis for the Base Case, but assuming that side-payment rules will be removed from the policy. We do so by using a modified version of Model 1 in which we set $\beta_i = \sum_{t \in T} \left(\frac{y_{i,t}}{x_i} \right) \cdot E_i \cdot TAX$, for all generation units $i \in G$. This means that $\beta_i = 0$ for all units that do not produce carbon emissions (e.g., solar, wind, hydro) and $\beta_i > 0$ for technologies that use fossil fuels (e.g., CCGT, diesel, and coal) if they are part of the optimal investment portfolio in equilibrium (i.e., $x_i > 0$).

Figures 6 and 7 summarize the main results for tax rates ranging from zero to 30 $/$tCO_2$. We find that removing side-payment rules does indeed reduce the social costs of a tax with administrative restrictions by a significant amount. However, generation investments still differ from the socially-optimal ones that result from the implementation of a standard carbon tax. Carbon emissions are also higher than the optimal levels when only pass-through restrictions are in place as a consequence of the short-term dispatch and pricing that disregards the social cost of carbon. In particular, for a tax of 15 $/$tCO_2$, carbon emissions under the modified tax policy are 24% lower than under a tax with pass-through restrictions and side-payment rules, but still 32% higher than under a standard carbon tax. We repeated this analysis for Case A and Case B and the findings were similar: removing the side-payment rules did reduce the inefficiency of the current emissions policy, but the results still differ from the socially-optimal ones under the standard carbon tax.

These findings are in line with general microeconomic theory, since pricing commodities at values other than their true marginal cost in the short term (e.g., ignoring negative externalities) leads to market failure and create distorted incentives in the long term (Mas-Colell et al., 1995). Furthermore, only when we account for the social cost of carbon emissions in the dispatch of generation units—affecting both generation outputs and energy spot prices—we provide the right price

Figure 6: Investments Base Case. PTR = Pass-through restriction. SPR = Side-payment Rule

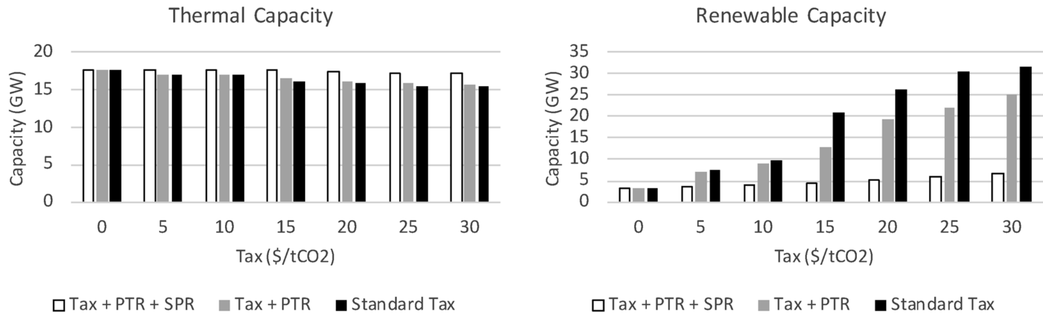
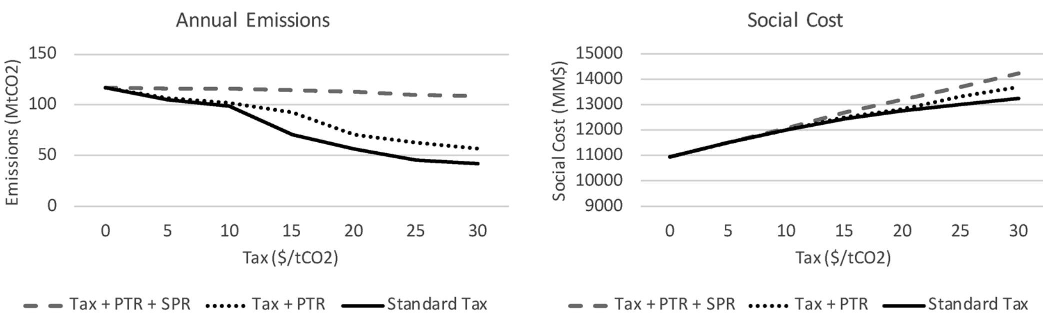


Figure 7: Emissions and Social Cost Base Case. PTR = Pass-through restriction. SPR = Side-payment Rule.



signals for investments.[29] Consequently, *"(i)f carbon emissions are underpriced, then the solution is to properly price them, rather than to alter the market design to disadvantage (carbon-intensive) generation in some non-transparent way"* (Cramton, 2017). The carbon tax with pass-through restrictions and side-payment rules currently used in Chile is one example of a non-transparent policy that aims at curbing carbon emissions and that, simultaneously, tries to protect consumers from price increases in the short term. As our results suggest, the regulator might actually fail to accomplish both goals in the long term, even if side-payment rules were removed from the policy.

6. CONCLUSIONS

The main goal of market-based climate-change policies in electricity markets is to give firms economic incentives to reduce carbon emissions both in the short and long term. Some examples of climate policies in electricity markets include carbon taxes, cap-and-trade programs, and many other forms of regulations that incentivize, for instance, higher shares of generation from renewable energy resources. Under a series of assumptions, such policies can accomplish the desired goals in a cost-effective manner. However, features such as market power, transmission congestion, leakage of carbon emissions, and exceptions can reduce their effectiveness.

29. In our paper we assume that demand is perfectly inelastic. However, in a more general setting demand could be sensitive to electricity prices. In such setting, a carbon tax would also affect consumption decisions if the price of electricity increases as a consequence of the introduction of the carbon tax.

In this paper we conduct a long-term equilibrium analysis of a carbon tax with pass-through restrictions and side-payment rules, inspired by the current emissions policy used in the Chilean electricity market. The short-term effects of the policy are rather evident because it does not alter the dispatch and pricing of electricity, consequently, it does not result in any reductions in carbon emissions. Yet, its long-term implications are much more difficult to anticipate, even in a perfectly competitive setting. Here we develop an equilibrium model that allows us to assess how a carbon tax with such administrative restrictions could lead to unanticipated results. To our best knowledge, this is the first study that addresses this question.

Our main conclusion from the Base Case, which tries to replicate the generation technologies available for development in Chile, is that pass-through restrictions and side-payment rules provide distorted price signals in the short term that lead to inefficient entry and operation of generating resources. A concerning finding is that these restrictions can be particularly harmful for investments in renewable energy technologies. For instance, for a tax of 15 $\$/tCO_2$, investments in renewable capacity under a tax with restrictions are 79% lower than under a standard tax. Removing the side-payment rules but keeping the pass-through restriction yields more developments in renewables, but these are still 40% lower than under a standard tax.

In terms of carbon emissions, we find that for a tax rate of 15 $\$/tCO_2$ a standard carbon tax yields 38% less annual carbon emissions than the same policy with administrative restrictions. Rising the tax rate to 30 $\$/tCO_2$ increases this difference to 61%. We also find that the regulator might face an incentive problem to migrate the present policy to a standard carbon tax or cap-and-trade program if the current tax was solely implemented for fiscal purposes. Our results indicate that tax revenues under the policy with administrative restrictions can be much higher than under a standard carbon tax. Furthermore, we find that removing the side-payment rule but maintaining the pass-through restriction does result in some improvement of the policy in terms of incentives for carbon emissions reductions. However, price signals and, consequently, the generation mix, remain distorted with respect to the first-best design of a standard carbon tax.

We also include two additional test cases, Case A and Case B, which we use to illustrate the lack of robustness of the policy with administrative restrictions when compared to the first-best standard carbon tax. In Case A we show that an increase in the tax rate in the policy with administrative restrictions leads to an increase in carbon emissions. This is a rather surprising result since, to the best of our knowledge, the only setting where a standard carbon tax could lead to an increase in carbon emissions is in electric power markets with congested transmission systems and strategic firms (Downward, 2010). In Case B we show that the exact opposite can occur, the policy with pass-through restrictions and side-payment rules can give firms incentives to reduce carbon emissions beyond the socially-optimal levels, which also result in inefficient generation portfolios. While these two additional case studies might not be of much relevance for Chile, we believe these counterintuitive results provide valuable information for other countries, particularly in Latin America, that have used the electricity market in Chile as a role model for the development of their own markets.

Of course, our analyses have several limitations. First, we assume that demand is perfectly inelastic. While in the short term this is a reasonable assumption, for long-term studies it might be more realistic to use price-sensitive demand functions (Silk and Joutz, 1997). We hypothesize that the inclusion of demand elasticity would reduce demand levels during hours when prices increase as a consequence of carbon charges (i.e., mostly shoulder and peak demand periods, when conventional units are operating), which would result in lower emissions levels overall. However, the magnitude of this effect would depend on the sensitivity of demand to changes in price. Elastic demand functions could be included using a variant of the iterative solution algorithm employed in this study (Ahn and Hogan, 1982). Second, our assumption of a perfectly competitive electricity market is convenient because it allows us to find all equilibria by just solving linear programs. Nevertheless, generation firms could still exercise market power in a cost-based market by making strategic investment decisions (Munoz et al., 2018). This feature could be accounted for using equilibrium models that are similar to the ones used in this article, such that firms could make investment decisions anticipating a cost-based spot market as in Wogrin et al. (2013) or in Munoz et al. (2018). Third, we assume that firms make decisions based on a perfect forecast of the future when, in practice, all investment decisions are made under uncertainty of future fuel prices, demand levels, and environmental policies. Furthermore, firms might not just maximize expected returns but some measure of these (e.g., the Conditional Value-at-Risk) over a subset of possible scenarios. Both uncertainty and risk aversion of investors can be considered with linear programs such as the ones we employed in this study (Inzunza et al., 2016; Munoz et al., 2017b). These are all topics that should be explored in future research.

Finally, we want to highlight that, in general, most firms use Power Purchase Agreements (PPAs) in the form of contract for differences to finance new generation projects. In our analyses we do not explicitly consider a forward market for long-term contracts or PPAs. Nevertheless, our model and results are still valid if, when building new capacity, all firms simultaneously sign new PPAs for the exact quantities each of them produce in the simulated period (Murphy and Smeers, 2005). In practice, many firms have existing PPAs with hedge clauses that allow them to pass through any increase in costs faced by generators, due to changes in the regulation or fuel prices, to contract holders. If a) hedge clauses apply and cannot be renegotiated and b) demand is perfectly inelastic, then we hypothesize the carbon tax with pass-through restrictions and side-payment rules will have no effect on the investment decisions of generation firms or in carbon emissions, neither in the short nor in the long term. Furthermore, if 100% of the country's electricity demand is covered with contracts with those hedge clauses, then it is likely that a carbon tax with a pass-through restriction such as the one used in Chile will become a policy that only collects tax revenues, achieving zero carbon emissions reductions.

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APPENDIX

A.1 Proofs of theoretical results

Second statement: If *TAX* is the true SCC, then the total electricity revenues under a carbon tax with pass-through restrictions and side-payment rules (Model 1) $\sum_{t\in T} D_t \cdot \overline{p}_t$ are always less than or equal to the total electricity revenues under a standard carbon tax (Model 2) $\sum_{t\in T} D_t \cdot p_t^*$, where $\overline{p}_t$ and p_t^* are the hourly equilibrium prices under models 1 and 2, respectively. This is also true if side-payment rules were removed from Model 1.

Proof of second statement: We know that $\sum_{i\in G} I_i \cdot x_i^* + \sum_{t\in T}\sum_{i\in G}(MC_i + E_i \cdot TAX)\cdot y_{i,t}^* \le \sum_{i\in G} I_i \cdot \overline{x}_i + \sum_{t\in T}\sum_{i\in G}(MC_i + E_i \cdot TAX)\cdot \overline{y}_{i,t}$. By definition, annual carbon charges in Model 1 are computed such that $\sum_{i\in G}\overline{\beta}_i \cdot \overline{x}_i = \sum_{i\in G}\sum_{t\in T} E_i \cdot TAX \cdot \overline{y}_{i,t} \quad \forall i \in G$. Re-arranging terms in the previous inequality we get that $\sum_{i\in G} I_i \cdot x_i^* + \sum_{t\in T}\sum_{i\in G}(MC_i + E_i \cdot TAX)\cdot y_{i,t}^* \le \sum_{i\in G}(I_i + \overline{\beta}_i)\cdot \overline{x}_i + \sum_{t\in T}\sum_{i\in G} MC_i \cdot \overline{y}_{i,t}$. Since Model 2 is a linear program, it follows from the theorem of strong duality that there exist hourly prices $p_t^* \ \forall t \in T$ such that $\sum_{i\in G} I_i \cdot x_i^* + \sum_{t\in T}\sum_{i\in G}(MC_i + E_i \cdot TAX)\cdot y_{i,t}^* = \sum_{t\in T} D_t \cdot p_t^*$. For the equilibrium set of annual carbon charges per MW $\overline{\beta}_i$ Model 1 is also a linear program and the strong duality theorem also holds. Consequently, there exist $\overline{p}_t \quad \forall t \in T$ such that $\sum_{i\in G}(I_i + \overline{\beta}_i)\cdot \overline{x}_i + \sum_{t\in T}\sum_{i\in G} MC_i \cdot \overline{y}_{i,t} = \sum_{t\in T} D_t \cdot \overline{p}_t$. It follows directly that $\sum_{t\in T} D_t \cdot p_t^* \le \sum_{t\in T} D_t \cdot \overline{p}$

$\sum_{t\in T} D_t \cdot \overline{p}_t$. Removing the side-payment rules from Model 1 does not change this result.

Third statement: The demand-weighted average price of electricity under a standard carbon tax (or an equivalent carbon cap-and-trade program) $\dfrac{\sum_{t\in T} D_t \cdot p_t^*}{\sum_{t\in T} D_t}$ is always less than or equal to the demand-weighted average price of electricity under a carbon tax with pass-through restrictions and side-payment rules (Model 1) $\dfrac{\sum_{t\in T} D_t \cdot \overline{p}_t}{\sum_{t\in T} D_t}$. This is also true if side-payment rules were removed from Model 1. *Proof of third statement:* It follows directly from the Proposition because $\sum_{t\in T} D_t$ is a strictly positive number.

A.2 Statistical properties of hourly profiles

Table 10: Profile Characteristics

					Correlations		
	Min	Max	Std.Dev.	Average	Wind	Solar	Demand
Wind	0.00	1.00	0.17	0.32	1		
Solar	0.00	0.92	0.35	0.30	–0.10	1	
Demand (MW)	12000	20174	1639	16894.98	0.02	0.42	1