Powering Change: Chile's Energy Transition*

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Abstract

This paper studies Chile's shift from a fossil fuel-dependent energy system to a global leader in renewable electricity generation within a decade. We begin by documenting the aggregate trends in energy investments and generation, highlighting the rapid growth of renewable energy source capacity. We then examine the key institutional and market forces behind this transformation, focusing on the interaction between regulatory frameworks and the evolving electricity demand from the private sector. Our analysis underscores the importance of coherent policy design and market responsiveness in facilitating large-scale energy transitions.

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1 Introduction

The economic expansion of renewable energy is a key aspect in any effort to mitigate global and local pollution. The electricity sector is one of the main contributors to global and local pollution, along with the transportation sector and residential wood burning. As transportation and residential energy use are expected to become increasingly electrified in the coming years, cleaner and more abundant electricity generation will be critical to achieving meaningful emissions reductions.[1]

We begin these notes by documenting the rapid expansion of renewable energy sources in Chile over the last decade. We then shed some light on what may explain it. We find that it is a combination of external market forces (e.g., lower costs of critical inputs) and some policy interventions, particularly investment in transmission lines, reforms to auction design, and the price stabilization regime introduced to promote investments in small and medium-sized renewable energy projects. We document that other market interventions, such as the quotas for renewable energy, the carbon tax, and the schedule to phase-out coal-fired plants, have played a minor role, if any.

Given the country's decarbonization goals (Antosiewicz et al., 2020) and increasing electricity demand for the coming years, the contribution of renewable energies remains far from complete.[2] With that in mind, we offer insights on policy interventions that have been effective and those that require reform, including the carbon tax, the phase-out of coal-fired units (and eventually, of gas-fired units), and incentives for PMGD investments.

2 Chile's Energy Generation and Demand

Over the past fifteen years, Chile has undergone a profound transformation in its electricity generation matrix, marked by a steady decline in fossil fuel dependency and a rapid expansion of renewable sources, particularly solar and wind. This section documents the key patterns of this transition using a series of figures.

As shown in Figure 1(a), Chile's reliance on fossil-fuel-based electricity closely tracked the OECD average between 2010 and 2020, with both hovering around 60% and gradually declining to 50%. However, from 2021 onward, Chile diverged significantly from this trend, reducing its fossil share by 20 percentage points in just four years. A key driver of this shift is the surge in solar generation, depicted in Figure 1(b). In 2015, solar accounted for only 2% of electricity generation

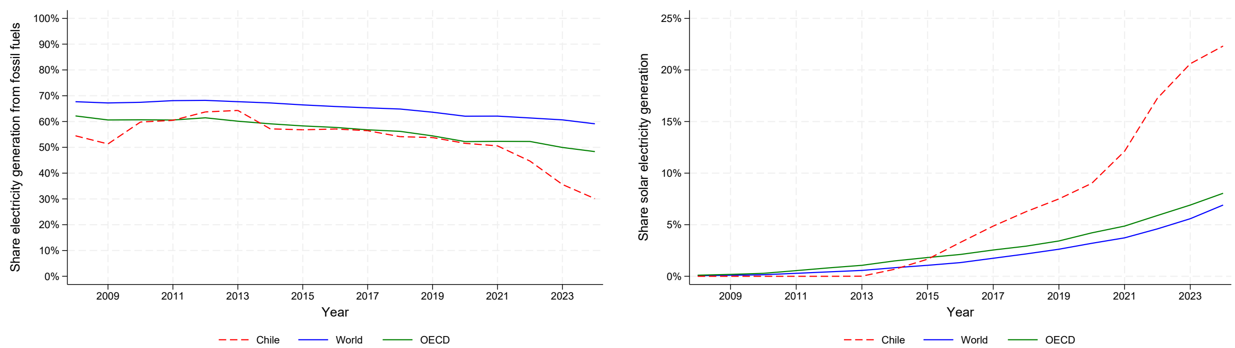
[1] For example, RedPE (2020) show that for 2019 wood burning represented 87% of particulate matter emissions.

[2] Chile already had near-universal electricity access prior to the renewable expansion. Since 2008, coverage exceeded 99%, comparable to Costa Rica and above countries such as Colombia, Ecuador, El Salvador, and Bolivia (SDG, 2021). Nevertheless, small-scale renewable and off-grid projects have remained important for supplying isolated rural communities.

–similar to the OECD average. By 2024, this share increased tenfold to 22%, positioning Chile among the global leaders in solar energy production.

Figure 1: Electricity Generation by Source

(a) Fossil-fuels (b) Solar



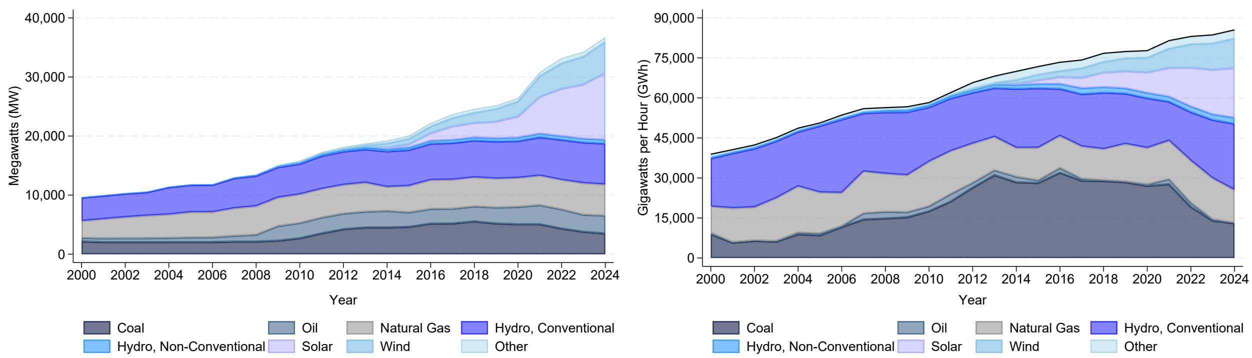
Note: This figure displays the share of electricity generated from different sources. Panel (a) shows the share of electricity generated from fossil-fuel sources (coal, oil, and natural gas). Panel (b) shows the share of electricity generated from solar. Both figures compare Chile, OECD countries, and the World. The source is `OurWorldinData.org/energy`.

Figures 2(a) and 2(b) illustrate the evolution of Chile's electricity generation capacity and actual energy generation over the past two decades. Several patterns stand out. First, total installed capacity increased more than threefold, from approximately 10 gigawatts in 2000 to 35 gigawatts in 2024. Notably, the expansion after 2014 was driven almost entirely by solar and wind, while the capacity of other sources remained relatively constant. By 2024, solar alone accounted for nearly 30% of total installed capacity. Appendix Figure A1 shows annual added capacity by technology.

Despite the fact that renewable sources, such as solar and wind, face inherent intermittency and typically operate with lower average utilization rates than thermal technologies, the added capacity has effectively translated into a significant fraction of Chile's total generation. According to Figure 2(b), solar and wind together contributed nearly one-third of total electricity generation by 2024, displacing coal and natural gas as the dominant sources in Chile's power mix and leaving a substantial share of their installed capacity idle.

Figure 2: Energy Generation Mix in Chile

(a) Installed Capacity (MW) (b) Energy Generation (GWh)



Note: This panel displays time series for the electric market in Chile at the year level, between 2000 and 2024. Figure 2(a) shows the cumulative installed capacity, and Figure 2(b) shows energy generation. In both figures, the category "hydro, conventional" includes dams or run-of-river hydropower plants with an installed capacity above 20 MW. Category "hydro, non-conventional" includes only mini run-of-river plants with an installed capacity below 20 MW, as stated in the ERNC Law. "Other" includes biomass, biogas, cogeneration, petcoke, and geothermal energy.

The remainder of the paper aims to shed light on the underlying drivers of this remarkable shift in Chile's electricity generation mix. In particular, we seek to disentangle the extent to which the transition was driven by market forces, such as declining technology costs and investor responses, from the degree to which it can be attributed to policy interventions and regulatory design, while also considering the role of electricity demand dynamics and their interaction with the rapid expansion of generation capacity.

3 Market Forces Spurring Energy Transition

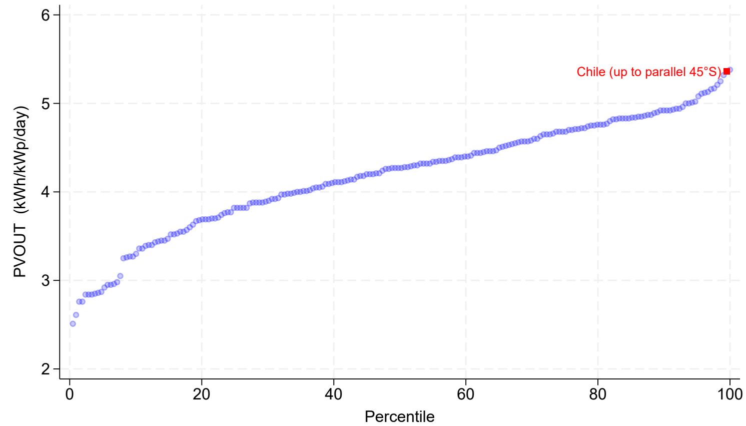
3.1 Potential for Solar Generation

Atacama Desert in northern Chile has some of the highest solar irradiance levels on Earth, making it an ideal location for large-scale solar installations. Suri et al. (2020) calculates the PV power output (PVOUT), which represents the amount of power generated per unit of the installed PV capacity over the long-term, and it is measured in kilowatt hours per installed kilowatt-peak of the system capacity (kWh/kWp)[3] Figure 3 displays the solar potential of every country ranked by percentiles. Chile (up to parallel 45 S), in red, has 5.36 kWh/kWp, ranks second across all 209 countries, underscoring the exceptional solar energy potential in the northern regions.[4]

[3]This calculation takes into account the air temperature affecting the system performance, the system configuration, shading and soiling, and topographic and land-use constraints

[4]As a reference, the country with the highest potential for solar generation is Namibia with 5.38 kWh/kWp, the country with the lowest potential is Ireland with 2.51 kWh/kWp.

Figure 3: Solar Potential by Country

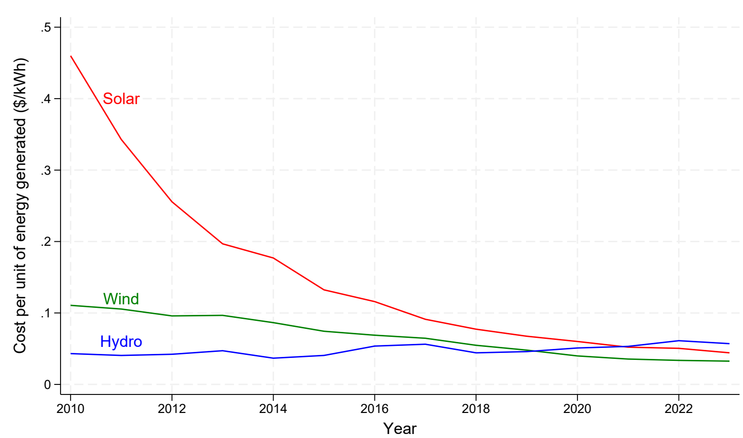


Note: This figure shows solar power output (PVOUT), defined as the specific yield, is used to illustrate potential for generation. PVOUT represents the amount of power generated per unit of the installed PV capacity over the long-term, and it is measured in kilowatthours per installed kilowatt-peak of the system capacity (kWh/kWp). The source is "Global Photovoltaic Power Potential by Country" report published by the World Bank.

3.2 Declining Technology Costs

A key factor enabling the rapid global adoption of renewable energy has been the decline in their cost. Figure 4 displays the global average levelized cost of electricity (LCOE) for different renewable technologies. The source of these calculations is IRENA (2024) and relates the evolution of *total installed cost* (per kW of capacity) and the *capacity factor* to create a measure of cost of electricity by type of investment.

Figure 4: Cost of Energy for Renewables



Note: This figure shows the world's average cost per unit of energy generated across the lifetime of a new power plant. This data is expressed in US dollars per kilowatt-hour. It is adjusted for inflation. The source is `OurWorldinData.org/energy`.

Since 2010, utility-scale solar PV has seen dramatic cost reductions, with its global average levelized cost of electricity (LCOE) falling by 90%, from USD 0.460/kWh to USD 0.044/kWh by 2023—making it 56% cheaper than (weighted average) fossil fuel alternatives. This decline coincided with a massive expansion in global installed solar capacity, from 40 GW in 2010 to over 1,400 GW in 2023. The primary driver of falling costs has been a 96% drop in module prices, supported by efficiency gains, manufacturing scale, supply chain integration, and reduced material usage. Total installed costs fell 86%, from USD 5,310/kW to USD 758/kW. In parallel, solar PV capacity factors rose by 17%, thanks to improved technology, better geographic deployment, and the growing use of trackers and bifacial modules that enhance energy yields.[5]

3.3 The Effect of Renewables on Electricity Prices

We now turn to the impact of renewables on electricity prices, distinguishing between spot and long-term contract prices.

Spot Market. Chile's electricity dispatch system is centralized, and operated by the Coordinador Eléctrico Nacional (CEN), generators are dispatched according to an "order of merit" based on their short-run marginal costs. Near-zero marginal cost sources, such as solar, wind, and certain hydroelectric plants, are dispatched first. These are followed by low-cost thermal units, typically efficient combined-cycle gas turbines. As demand increases, higher-cost generators, such as coal and diesel plants, are brought online to meet the demand. The marginal unit sets the spot market price for electricity in each hour, that is, the marginal cost of the last generator required to meet system demand. This leads to a stepwise price structure, where spot prices rise whenever a more expensive unit is needed at the margin.

The increasing penetration of renewable energy, particularly sources with zero short-run marginal costs such as solar and wind, shifts the marginal cost distribution to the right, thereby displacing higher-cost generators from the merit order and reducing the spot price. In this market structure, the displacement of costly thermal units occurs endogenously due to market forces. Appendix Figure A2 shows the evolution of the spot market in different nodes of generation, and shows that the spot price has dropped from 200 USD/MWh to roughly 50 USD/MWh since 2012, which coincides with the entry of renewable sources.

Moreover, given that renewable sources vary in their utilization within a day. For instance, solar generation is confined to daylight hours; the displacement of high-cost generation sources by solar only happens within a day. Figure 5 shows the plant-level average marginal cost, including all plants available for generation in 2024. Panel (a) shows the generation capacity during daytime, when solar is available, and panel (b) shows the generation capacity during nighttime when solar

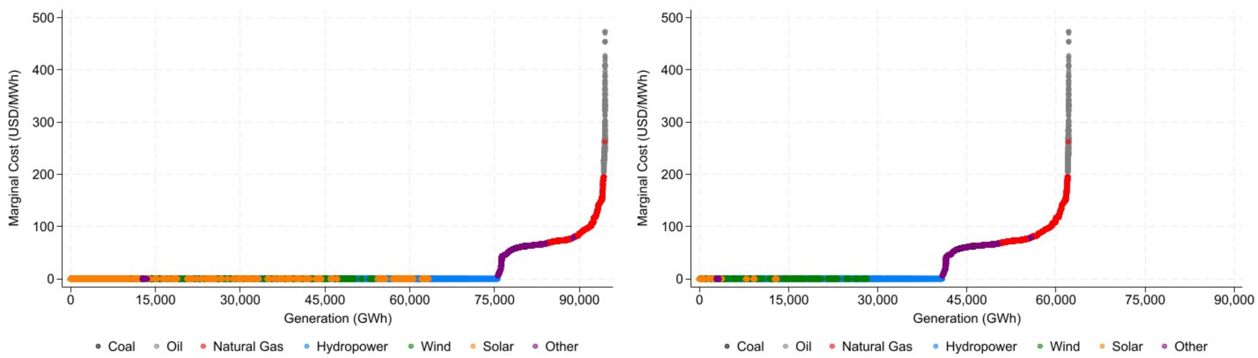
[5] LCOE is a technology-specific measure of installation and operating costs and does not reflect system-level costs or directly map into market electricity prices.

generation is unavailable. Based on the comparison of these two Panels, we see how the availability of solar shifts the curve to the right. Appendix Figure A3 exhibits the distribution of plant-level marginal costs for various regions in Chile.

Figure 5: Marginal Costs by Technology in 2024

(a) Daytime

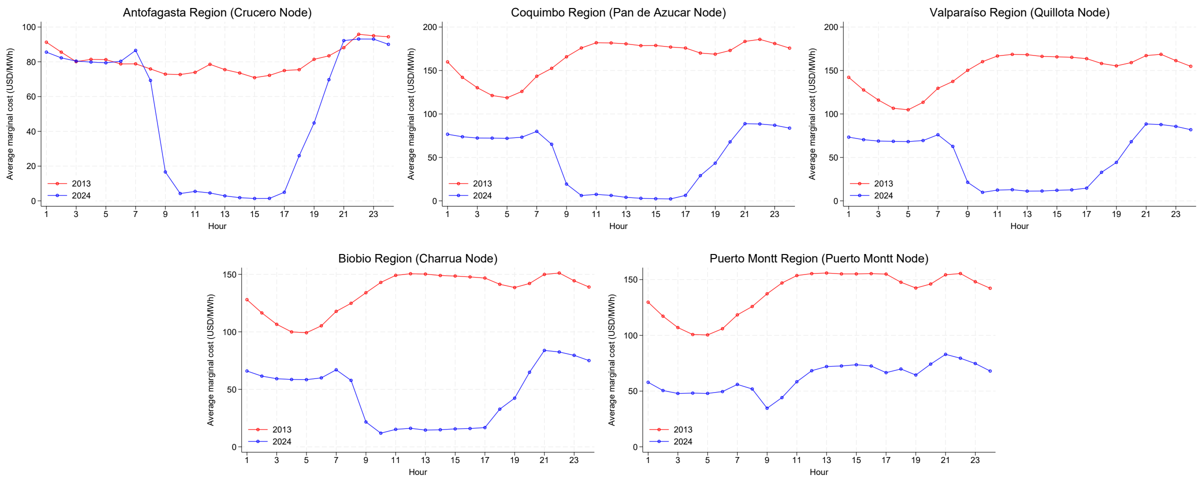
(b) Nighttime



Note: This panel shows the curve of marginal costs pooling all regions in Chile at the daily level in the year 2024 by technology. Each dot represents a generation unit (plant). The y-axis is the marginal cost of the generation unit, measured in USD per MWh. The x-axis displays the maximum production in GWh of the generation unit measured by the 99th percentile of generation in the year, in two different slots of the day: solar time (8:00 to 20:00) and non-solar time (21:00 to 7:00).

As a result, during the day, solar generation replaces high-cost energy sources (see Appendix Figure A4). Spot prices mirror the generation displacement by renewable generation, falling during periods of high solar output and rising when solar availability declines. Figure 6 shows the average hourly spot prices for 2013 (in red) and 2024 (in blue) across various generation nodes, ordered geographically from north to south. In 2013, spot prices were relatively stable throughout the day. By contrast, in 2024, spot prices in solar-rich northern regions drop to near zero during daylight hours and rise sharply at night, highlighting the increasing influence of solar generation on market price dynamics. Also, Figure 6 shows spatial variation in prices across regions. These differences are closely related to transmission constraints, which limit the extent to which low-cost solar generation in the northern regions can be exported to central and southern demand centers, leading to persistent price dispersion across locations.

Figure 6: Spot Market Price by Hour of the Day (USD/MWh)



Note: This figure displays the unweighted average marginal costs at the hour-year, comparing 2013 and 2024, for five of the most representative nodes of the system: Crucero for the northern region "norte grande", including Tarapacá and Antofagasta; Pan de Azucar for the Atacama region; Quillota for the central area, including the Metropolitan Region; Charrua in the Biobío region; Puerto Montt for the southernmost region in Chile. The voltage level of the nodes reported is 220 KV. The source is our own elaboration based on CEN data.

Log-term Contracts. Long-term contracts are typically signed between generators and two types of buyers: regulated consumers, represented by distribution companies, and unregulated consumers, primarily large industrial or mining firms with high energy demand. These long-term contracts—typically lasting 10 to 20 years—reduce price volatility for buyers by locking in stable rates and support investment by providing generators with predictable revenue, which is essential for financing capital-intensive renewable projects.

Although contract prices are agreed upon bilaterally for unregulated customers and through auctions for regulated customers, they remain fixed (or indexed) for the duration of the contract. The actual physical dispatch is managed centrally by the Coordinador Eléctrico Nacional (CEN), and payments between market agents are settled through the spot market. Hence, if a generator has a contract, it must supply the contracted quantity regardless of the spot price. If its actual generation is lower than its contracted amount, it must buy the difference at the spot price. If it over-generates, it sells the surplus at the spot price. As a result, contract prices are intrinsically linked to the spot price, as the latter determines the cost or revenue of deviations from contracted quantities and represents the shadow cost for generation.

3.4 Discussion

The three facts presented in this section: (i) Chile's exceptional solar resource endowment, (ii) the substantial decline in solar generation costs –now approximately 56% lower than fossil-fuel-based alternatives– and (iii) the fact that renewables operates at near zero marginal cost, suggest that the rapid reduction of fossil-fuel generation (mainly explained by penetration of solar energy) may be driven, at least in part, by market forces, even in the absence of direct government intervention. In the next section, we discuss the role of policy interventions in promoting the shift towards renewable energy sources.

4 Policy Interventions

The country has experimented with various policy interventions, many of which follow a command-and-control logic, to accelerate the shift to cleaner sources of power generation, particularly solar and wind. We discuss their impact and whether there is room for potential improvements.

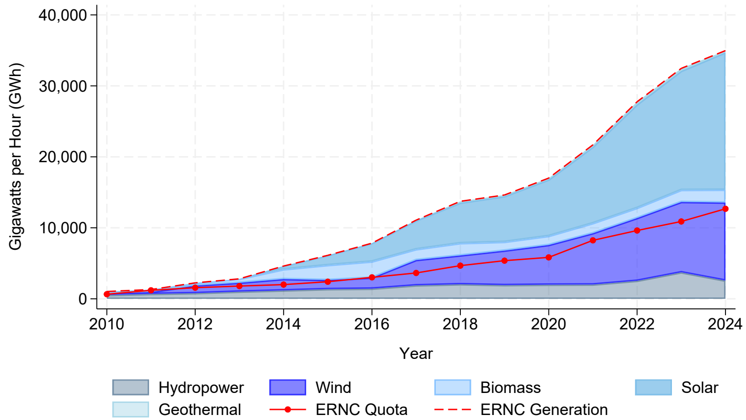
4.1 NCRE Quotas

In 2008, Law 20,257 established an obligation for electricity companies to source a percentage of their energy sales from Non-conventional renewable energy SOURCES (NCRE or ERNC in Spanish). It defined a target of 10% by the year 2024 to be reached gradually. For contracts concluded after August 31, 2007, and before July 1, 2013, the obligation was 5% for the years between 2010 and 2014, increasing by 0.5 percentage points per year from 2015 until reaching 10% in 2024. In October 2013, under Law 20.698, this goal was modified to 20% by the year 2025. Thus, for contracts entered into effect after July 1, 2013, the obligation was 5% in 2013, increasing by one percentage point per year from 2014 until 2020, and then by 1.5 percentage points from 2021 to 2024.

The laws provided some flexibility to comply with the quota obligations. Compliance can be achieved with indifference as to the interconnected system in which injections were made (SIC or SING), that is, a company supplying energy in the SIC can use NCRE credits produced in the SING for accreditation purposes. In addition, any electricity company that exceeds its non-conventional renewable energy injection obligation may transfer its surplus to another electric company, which may be done even between companies of different electric systems.

As documented by Watts and Perez (2018) and shown in Figure 7, NCRE generation has far exceeded the quota obligations. By 2012, the quota obligation was already not binding, or barely so. Therefore, it is hard to attribute any responsibility to the quota obligations for the subsequent expansion of renewables. It is important to emphasize that there are no reasons for a generating company to move forward costly compliance investments. Anticipation could certainly happen in other contexts, when there are strategic interactions among rival suppliers, for example, after the announcement of a large transmission investment, as documented by Gonzales et al. (2023).

Figure 7: Compliance with NCRE Quotas



Note: This figure exhibits compliance levels for ERNC quotas between 2010 and 2024. The red dashed line is the total volume of ERNC generation, while the red dotted line is the ERNC quota in that year. Energy production is decomposed according to ERNC technologies. The data source is the author's elaboration based on data from the Ministry of Energy.

4.2 The CO_2 Tax

In 2017, the country introduced a carbon tax of USD 5 per ton of CO2 emitted. Initially this tax applied to facilities with boilers and/or turbines that produce over 50 MWt of heat power, primarily targeting the electricity sector. The tax was later reformed through amendments in 2020. Following the broader tax reform, which took effect on January 1, 2023, the carbon tax applies to installations emitting 25,000 tCO2 or more, as well as those that release more than 100 tons of particulate matter into the air annually. The amendments also introduced the possibility of using offsets to reduce tax payments, for which a regulation was established and took effect on February 24, 2023.

Given its low level and poor implementation, the tax has had a minor effect, if any, on the evolution of the power generation sector. As explained by Diaz et al. (2020), the implementation of the tax greatly differs from a standard implementation for two reasons. First, the system operator is prevented from including the tax in the merit order of dispatch among the different technologies, so the clearing price remains unchanged. The system operator is also prevented from including the tax in the medium- and long-term optimization of hydro resources. And second, all running power-generation units, whether clean or dirty, must cover the tax bill, in proportion to their generation. Beyond these design problems, the tax also fails to be applied to all stationary and non-stationary sources.

It is evident that the tax needs to be corrected not only in its implementation, ensuring that dirty units internalize their external costs and this is reflected in the clearing price, but also in its rate (the current rate is extremely low by international standards) and coverage. Various governments have proposed to increase the rate to \$ 35 per ton of CO_2 by 2035. This may be problematic if competing fuels (e.g., gasoline and diesel for transportation; natural gas for residential heating and industrial production) are not taxed accordingly. Taxing only the electricity generation sector may backfire, discouraging end-users, including industrial and residential customers, from switching away from fossil fuels. We are not aware of any studies examining these substitution possibilities. In any case, without wide coverage, it may be preferable to consider other instruments for supporting the faster expansion of renewable energies, such as promoting PMGD.

4.3 Phasing Out of Coal-Fired Plants

In 2019, the government announced the phase-out of all coal-fired power plants by 2040, according to a predetermined schedule. Regarding the initial announcement, decommissions have mostly occurred ahead of schedule. For instance, the first two power plants to be phased out, Tocopilla with a capacity of 170 MW and Tarapacá with a capacity of 158 MW, were both initially scheduled for phase-out by May 2020; however, they were ultimately shut down in June and December 2019, respectively. Other examples include Bocamina 1 and 2, with installed capacities of 128 MW and 350 MW, respectively. Bocamina 1 was scheduled for decommissioning by December 2023, but was shut down three years earlier, in December 2020. Bocamina 2 was initially set to be phased out by December 2040, but was decommissioned ahead of schedule in September 2022. In April 2021, the original announcement was revised to establish that by the end of 2025, 50% of the installed capacity as of 2019 should be phased out.

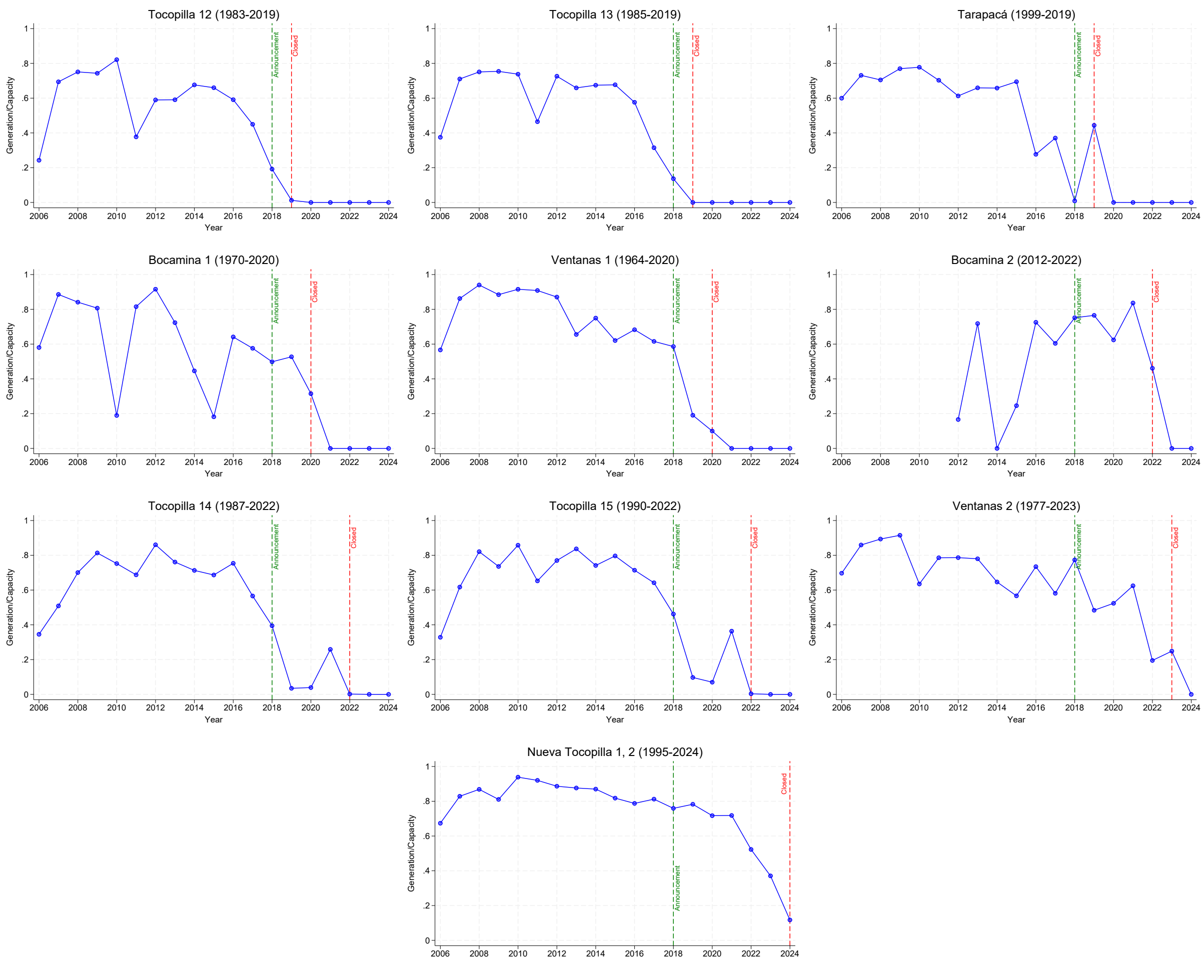
There are three reactions to this approach of phasing out a technology. The first is its command-and-control logic. It would have been far more effective to have used a price instrument, such as a tax, to achieve a similar goal more efficiently and also to raise revenue to pay for eventual subsidies elsewhere in the system. Alternatively, the government could have established a quota in terms of a stock of coal to be phased out in the next 10 or 20 years and let the market decide the best way to use that quota over time. The system operator could have administered it at a low cost.

The second reaction is that any decarbonization-related retirement framework should be consistent with security-of-supply, operational feasibility, and market adequacy considerations. It should also incorporate safeguard mechanisms to address potential reversals or adjustments if system conditions change. International experience–such as recent developments in Europe–illustrates that shifts in fuel availability, security concerns, or demand dynamics may require the temporary reactivation or extended operation of existing thermal capacity. Incorporating flexibility and contingency measures is therefore essential to ensure system resilience while advancing decarbonization objectives.

The third reaction is that these announcements initially appear to have had a significant impact on the market. However, Figure 8 depicts a less optimistic view of the policy impact. Many of the plants that were retired were already suffering a sharp decline in their utilization. Part of this decline has little to do with the announcement and more to do with the constant expansion of renewable energy sources. Indeed, Rivera et al. (2024) shows that a substantial share of the retired plants were effectively displaced by solar generation added to the northern grid (SEN).

Nevertheless, it would be useful to conduct a counterfactual analysis estimating the utilization of these plants without the phase-out announcements, and ultimately, the amount of CO_2 and local pollutants mitigated by them. This requires, among other things, evaluating how much of the coal generation phased out has been replaced by natural-gas generation.

Figure 8: Capacity Factor of Coal Plants Phased Out by 2024



Note: This panel shows the average capacity factor and phase-out timeline of ten coal-fired power plants in the context of the Decarbonization Plan. Capacity factor is computed by $\frac{\text{Generation MWh}_t}{\text{Capacity MW}_t \cdot 8760}$, at the power plant level in year t. The green vertical line marks the announcement of the Decarbonization Plan in 2018, when generation companies committed not to build any additional coal-fired plants from that year onward. The red vertical line indicates the year each plant was decommissioned as part of the official phase-out schedule. In parentheses, the years of commissioning and retirement for each plant are shown. The source is our own elaboration based on CEN data.

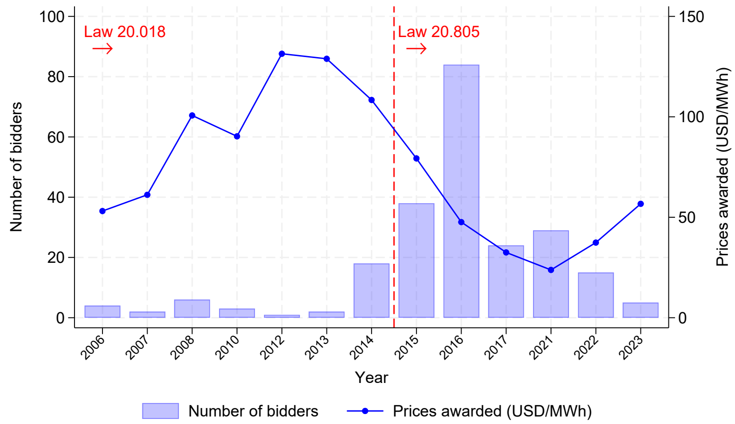
4.4 Auction Design for Residential and Small Customers

Residential and small electricity customers, often referred to as regulated customers, receive electricity from utilities that source it through long-term contracts with generators. These contracts account for roughly 40% of the annual electricity and are assigned and priced based on auctions designed by the Comisión Nacional de Energía (CNE). In 2015, Chile implemented a reform aimed at enhancing competition, reducing electricity prices, and facilitating the integration of renewable energy sources. These changes, encapsulated in Law 20.805, restructured the auction design to better accommodate the characteristics of renewable technologies, particularly solar and wind.

The main changes introduced by Law 20.805 involved, first, dividing electricity contracts into specific time blocks (e.g., daytime, nighttime), which enabled intermittent renewable sources, such as solar and wind, to compete more effectively by focusing on time slots that align with their generation patterns. Second, the length of contracts was increased from 15 to 20 years, providing greater revenue certainty for investors and improving the bankability of renewable energy projects. Lastly, the period between the auction award and the supply initiation was extended from 3 to 5 years, affording developers additional time for project development, permitting, and construction, which is particularly beneficial for complex renewable projects.

We don't aim to isolate the effect of each policy change, but rather to describe how auction participation and outcomes evolved before and after the 2015 reform. Figure 9 presents the evolution of the number of bidders and average awarded prices across auction years. Before the reform, with the exception of 2014, auctions typically attracted only 3 to 4 bidders. Following the reform, participation rose sharply, peaking in 2016 with 84 bidders. Although the number of participants declined somewhat in subsequent years, it remained well above pre-reform levels, suggesting a sustained increase in participation (and competition). The solid blue line represents the average (weighted) prices awarded per tender and shows a clear decline between 2014 and 2021, coinciding with the increase in competition, from roughly USD 120 per MWh in 2013 to USD 25 per MWh in 2021.

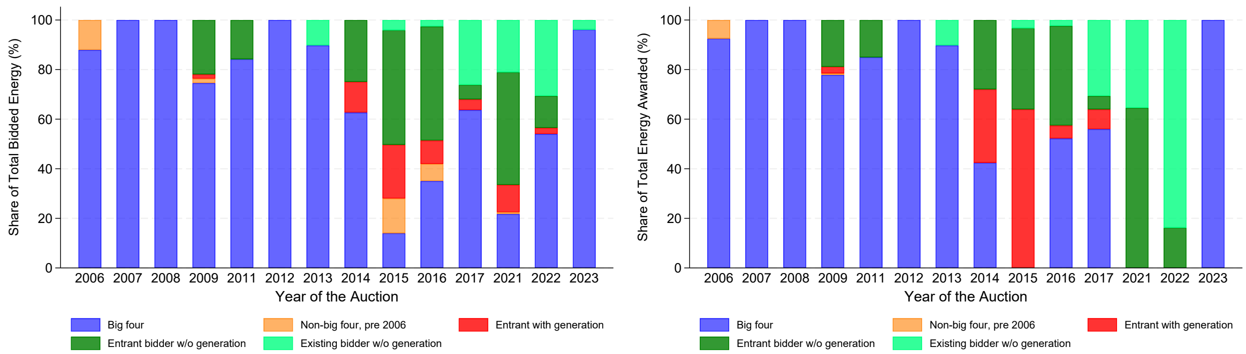
Figure 9: Auction Participation and Awarded Price, 2006-2023



Note: This figure displays time series with results from tenders between 2006 and 2023. It compares the number of bidders and average (weighted) prices awarded per tender. The red dashed line represents the introduction of Law 20.805, which modified the auction design by splitting long-term contracts according to different time slots. Some years are omitted because no auction was conducted that year. The data source is the author's elaboration based on data from the Ministry of Energy.

To better understand the nature of increased participation, we examine the composition of firms bidding in electricity auctions over time. Panel (a) of Figure 10 breaks down bidders into five categories based on their market history and generation status. The "Big Four" –ENEL, Colbún, AES, and ENGIE– represent the incumbent firms operating in Chile since before 2000. "Non-Big Four, pre-2006" refers to other firms that were active before the introduction of energy auctions. Two categories capture new entrants: those entering with existing generation capacity ("Entrant with generation") and those entering without it ("Entrant without generation"). A fifth group, "Existing bidder without generation," comprises firms that have previously bid in auctions but do not yet own or operate generation assets. The figure shows that the post-2015 surge in participation was primarily driven by new entrants, particularly those without generation capacity, rather than an expansion by incumbents. This shift suggests that the auction reforms lowered entry barriers and opened space for newer, mainly renewable-focused players to compete in the regulated market. The latter is relevant for two reasons: first, enhanced competition should result in lower electricity prices, and second, the large number of entrants without generation suggests that the new auction design induced generation investments that would not have occurred otherwise.

Figure 10: Auctions with Regulated Customers



(a) Energy Bidded

(b) Energy Awarded

Note: This panel of figures presents the results from energy auctions conducted between 2006 and 2023 for five distinct groups of bidders. The group labeled as "big four" includes the four largest firms operating in the energy market since 2000 (ENEL Generación, Colbún, AES Andes, and ENGIE). "Non-big four, pre-2006" refers to firms that were active in the market before the introduction of energy auctions in 2006 but are not part of the big four. "Entrant with generation" denotes bidders that entered one or more auctions while already producing electricity. "Existing bidder without generation" refers to bidders participating in their second or subsequent auctions who do not have any electricity generation at the time of the tender. Finally, "entrant bidder without generation" refers to bidders participating in an auction for the first time who had no electricity generation in the year the tender took place.

4.5 Transmission Investments

Many countries, including Chile, have seen the expansion of renewable energies challenged by two closely related factors. One is that the existing network infrastructure (i.e., the transmission grid) was, in many cases, not originally built to accommodate renewables. Conventional power plants, such as coal- and gas-fired plants, are often located closer to demand centers, thereby reducing transmission requirements that connect supply and demand. However, renewable energy sources, such as solar and wind, are often generated at locations far from demand centers.

And the second reason is that expanding transmission lines is typically a highly demanding endeavor due to a combination of technical, regulatory, environmental, and social challenges. The process often requires significant capital investment and long planning horizons, as it involves designing and constructing infrastructure across vast distances. Navigating regulatory approvals can be complex and time-consuming, involving multiple jurisdictions and compliance with strict environmental standards. Additionally, securing land rights or easements frequently leads to legal disputes or public opposition, especially when the proposed lines cross private property or ecologically sensitive areas. These factors, taken together, make transmission line expansion a slow and resource-intensive process.

As explained by Gonzales et al. (2023), two problems arise from the lack of market integration between renewable-intensive regions and demand centers. First, when renewable supply exceeds local demand and cannot be exported to other areas, electricity system operators must curtail electricity generation from renewables to avoid system breakdowns, even though this means discarding zero-marginal-cost, emissions-free electricity. This curtailment indeed occurs in many electricity markets, and a growing number of markets are experiencing negative wholesale market prices when there is excess renewable supply. Second, because the marginal cost of renewable electricity is near zero, local market prices in renewable-intensive regions tend to be low when the excess energy cannot be exported to demand centers. These two problems discourage new entry and investment in renewable power plants.

In their recent paper Gonzales et al. (2023) study the value of transmission investments supporting the expansion of renewable energies by exploiting two recent investments that took place in Chile: (i) the interconnection line between Atacama and Antofagasta in November 2017, and (ii) the reinforcement line between Atacama and Santiago in June 2019. Appendix Figure A6 displays a map of market integration via interconnection lines and variations in electricity prices.

Panel A of Figure 11 compares the spot-price evolution in Atacama and Antofagasta for two different hours of the day, and Panel B compares the spot-price evolution in Atacama and Santiago for the same two hours of the day. There are several results worth highlighting. One is the price difference between the different markets before the transmission lines (i) and (ii) were installed. This is particularly noticeable at noon, when the solar capacity is fully available. Two years before (i) was in place, prices in Atacama, an area rich in solar availability, were significantly lower than in Antofagasta and Santiago, approximately 50 USD/MWh lower. This is an indication of the large gains of exporting solar power from Atacama to these two demand centers (much of the demand from Antofagasta comes from the mining sector).

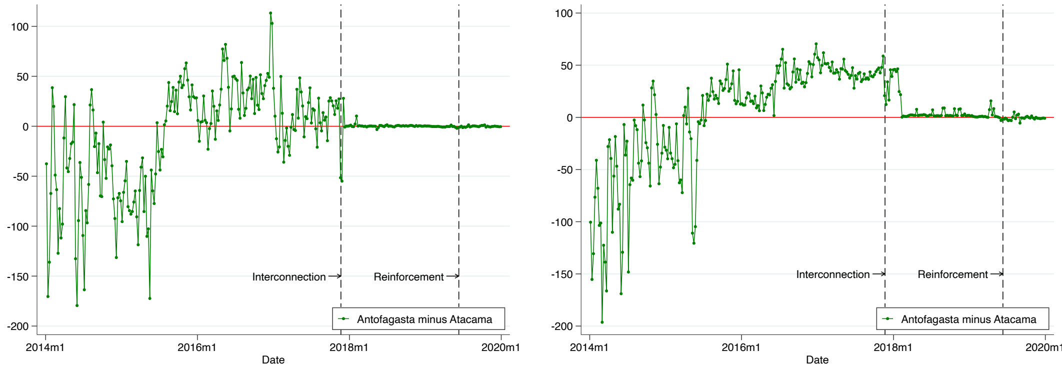
If we go back two years, to 2014-2016, the price difference at noon is no longer that large. In fact, it completely disappears for the Antofagasta-Atacama pair and approximately halves for the Santiago-Atacama pair. So, the question is, what explains the price difference increase a couple of years before the interconnection line (i) is completed? The authors make a compelling case that investments in solar, taking place after the announcement of the construction of the line and years before it is completed. These early investments respond to a race to be able to export power to demand centers once the line is completed. In equilibrium, these rents are dissipated even before the market integration materializes.

Another result is that transmission lines lead to a virtually perfect price convergence in the two markets they integrated. The paper disentangles the value of the transmission lines between the gains from trade (while keeping solar investments fixed) and the gains from additional investments. They refer to the latter as the investment effect. The authors estimate that the full impact of market integration on solar generation was a 178% increase in solar generation, as opposed to the 10% increase if we ignore the investment effect. So the investment effect is far more important than the static gains from trade.

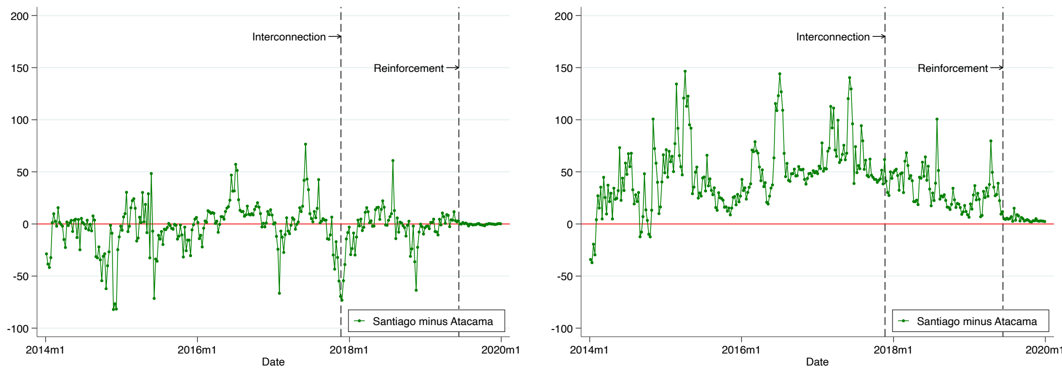
Unfortunately, the perfect market integration observed in 2020 has not remained over the years.

Figure 11: Price Convergence (USD/MWh) (Gonzales et al., 2023)

(a) Panel A: Price Difference Between Antofagasta and Atacama (USD/MWh)



(b) Panel B: Price Difference Between Santiago and Atacama (USD/MWh)



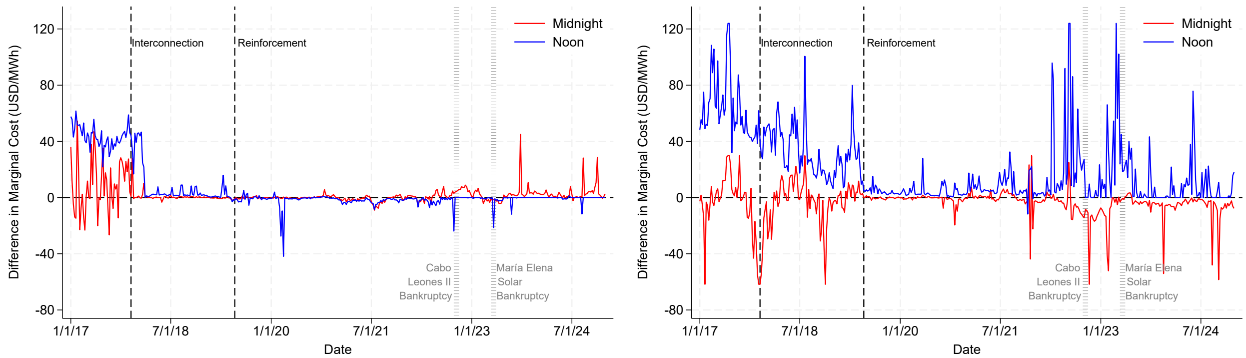
Note: This panel of figures depicts the impacts of market integration on price convergence. Panel A shows the price difference between Antofagasta and Atacama, and Panel B shows the price difference between Santiago and Atacama. In both panels, the left-hand side shows the gap at midnight (0:00-1:00), and the right-hand side shows the gap at noon (12:00-13:00). See Gonzales et al. (2023) for a better understanding of the calculations behind each of the figures above.

Transmission lines are becoming increasingly congested, resulting in significant price differences, as illustrated in Figure 12. Given the existing transmission capacity, these congestion episodes may be interpreted as over-investment in solar capacity in Atacama. But why did this happen among rational economic agents? This over-investment is in sharp contrast to the investment response to the announcements in 2017 and 2019 studied by Gonzales et al. (2023). We do not have a clear explanation for this recent surge in over-investment. We do not see a market failure that requires attention.

One solution to this transmission congestion problem is to invest more in transmission lines. This is not only a costly endeavor, but also difficult to evaluate. By no means should the goal be to invest to eliminate congestion in the system. Another is investments in batteries, a technology that is becoming more competitive. While the latter does not require any policy intervention (provided pollution externalities from dirty units are properly internalized), investments in transmission lines require design, planning, and coordination by the system operator.

Figure 12: Price Convergence (USD/MWh), Follow Up

(a) Antofagasta vs Atacama (b) Santiago vs Atacama



Note: This panel of figures depicts the impacts of market integration on price convergence. Left hand graph shows the price difference between Antofagasta and Atacama, and right-hand graph shows the price difference between Santiago and Atacama. In both panels, the left-hand side shows the gap at midnight (0:00-1:00), and the right-hand side shows the gap at noon (12:00-13:00). Following Gonzales et al. (2023), for each week, we calculate the weekly averages of hourly prices in each region. We then take the difference between these weekly averages and plot them over time. Prices in Antofagasta are proxied by those in node Kapatur; Prices in Atacama are proxied by node Cardones, and Polpaico for Santiago region. These are the nodes nearest to each end point of the interconnection and reinforcement.

A third alternative is to bring the production of electricity with renewable energy closer to demand centers. In fact, this has been the result of the price stabilization regime introduced to promote investments in small and medium-sized renewable energy projects (under 9 MW), known as “Small Means of Distributed Generation” or PMGD in Spanish. This policy has been highly criticized by many industry observers, suggesting that it has worked more as a subsidy than a price-stabilization instrument. While the policy wasn’t intended to function in this manner, in practice, it has worked that way, at least on average. However, in the absence of taxes on dirty technologies, this potential subsidy may not appear particularly unfavorable, at least conceptually speaking. We will look into it next.

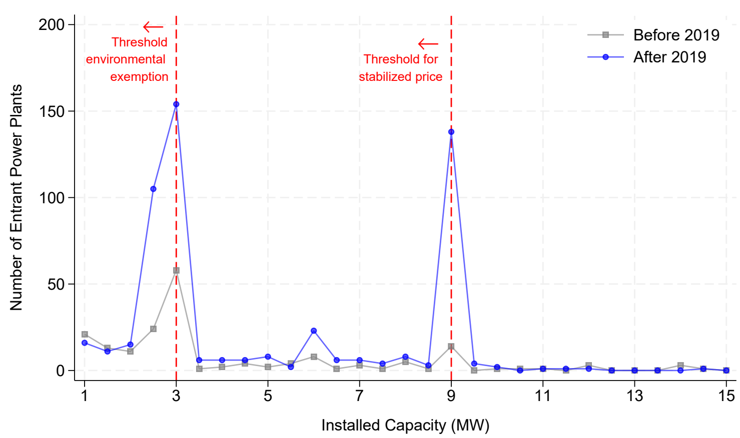
4.6 PMGD “Subsidies”

Since its 2004 amendment, the General Electricity Services Law (LGSE) has recognized the existence of a “price stabilization mechanism” for generation units whose deliverable power surpluses to the electrical system do not exceed 9 MW, alongside a self-dispatch operation system.

Decree 244 of 2005 set out the details of the price stabilization mechanism, establishing that Small Means of Distributed Generation (PMGD) and Small Means of Generation (PMG) would have the option to sell their energy either at the instantaneous marginal cost (spot price) or at a stabilized price (hereinafter “PE”), as defined in the same regulation, with a mandatory stay period of 4 years under each regime. In that decree, the PE was defined as equal to the short-term node price, determined semiannually by the National Energy Commission (CNE) in the node price decree. The difference in valuation between the PE and the marginal cost (CMg) would be paid by the remaining generators, proportionally to their energy withdrawals. Among other aspects, Decree 244 also established the obligation for distribution companies to allow the connection of PMGDs and to provide relevant technical information, and it defined the procedure for requesting a connection.

In 2020, Decree 244/2005 was repealed and replaced by Decree 88/2020, which modified the stabilized price regime and its associated regulations. Most importantly, this decree revised the stabilized price regime by establishing that the price would be calculated by the National Energy Commission (CNE) based on the short-term node price reports, using six time blocks for the basic energy price: from 00:00 to 03:59; 04:00 to 07:59; 08:00 to 11:59; 12:00 to 15:59; 16:00 to 19:59; and 20:00 to 23:59. As indicated by the bunching around 9 MW in Figure 13, it is clear that this reform had a great impact on PGMD investment (the reform was announced in 2019). The clustering around 3 MW of capacity is explained by the lighter environmental requirements for projects below the 3 MW threshold. Appendix Figure A8 compares spot price and stabilized prices.

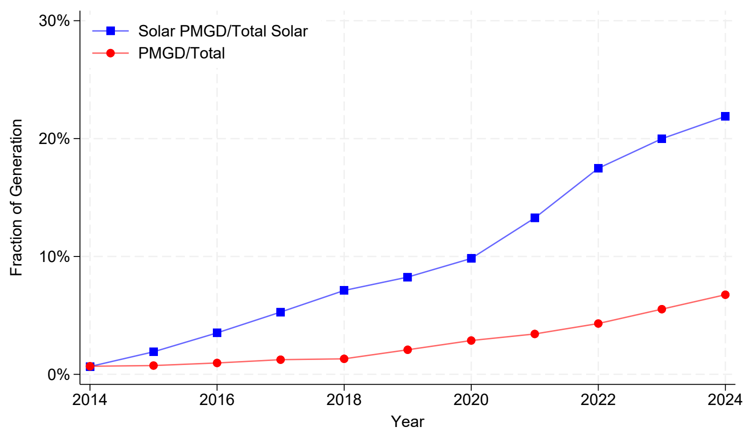
Figure 13: Entry of Power Plants Between 1 and 15 MW



Note: This figure depicts a binned scatterplot for the empirical distribution of the installed capacity from a subsample of PMGD power plants entering the market between 2000 and 2024, with installed capacity between $(0, 15]$ MWs. The installed capacity distribution is discretized into 0.5 MW-wide bins. The data source is the author's elaboration based on data from CEN.

The participation of PMGD in total generation has steadily increased since 2014. Figure 14 shows that, by 2024, more than 20% of the total solar generation stemmed from solar PMGD plants. This drastic expansion of PMGD capacity prompted a consultation with the Competition Tribunal (TDLC) regarding its impact on market competitiveness. The main argument presented to the TDLC is that the stabilized price (PE) would result in a subsidy for PMGDs/PMGs, as it is allegedly linked to past contract prices rather than stabilizing the spot price. It was argued that the alleged subsidy would be anti-competitive, as it would increase the costs of competitors, reducing their output, and raising costs for end customers. It is true that the price-stabilization mechanism was never intended to serve as a subsidy, but rather as a hedge instrument for small investors who lacked access to sign long-term contracts with large customers and/or distribution companies. In practice, however, it has resulted in overall positive transfers to PMGD investors above what they would have obtained had they relied exclusively on the spot market. Thus, the price-stabilization mechanism has indeed worked as a subsidy from an ex-post perspective.

Figure 14: Participation of PMGD in Generation

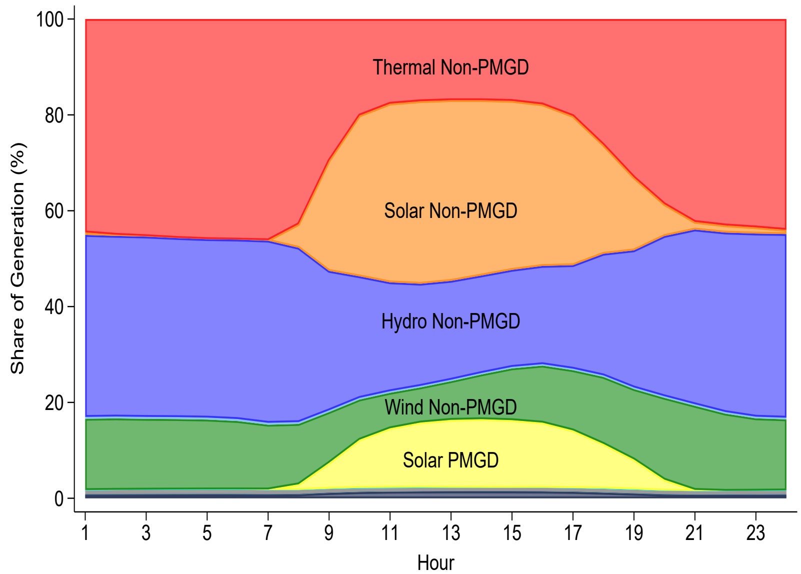


Note: This figure shows the share of energy production from PMGD power plants, segmented by all technologies and by solar only. The blue line represents the share of electricity generated by solar PMGD plants relative to total solar generation (including both PMGD and non-PMGD solar plants). The red line indicates the share of PMGD electricity production relative to total system generation across all technologies. The data is based on the author's calculations using information from the CEN.

In the absence of taxes on dirty technologies and congested transmission lines, this price-stabilization mechanism ("subsidy") may be a reasonable second-best instrument. To evaluate this, we first need to evaluate the type of generation that this technology is displacing. If it is only displacing clean generation, this "subsidy" would have an implicit value of carbon reduction of infinity. If, however, this subsidy is displacing mostly dirty generation, then it may reveal an implicit value of carbon much closer to the values observed in international markets, around $ 80 USD per ton of CO_2.

Figure 15 illustrates the hourly generation profile by technology type for 2024, distinguishing between PMGD and non-PMGD sources. As expected, solar PMGD and non-PMGD solar dominate generation during midday hours (11:00–16:00), reflecting the diurnal pattern of solar resource availability. This surge in solar output displaces thermal generation, which typically peaks during the early morning and evening hours when solar energy is unavailable. Wind generation shows a more stable profile throughout the day, with both PMGD and non-PMGD projects contributing. Hydro and geothermal provide a relatively steady baseline, though hydro output slightly increases in the evening. These patterns highlight how the growth of distributed solar—especially through PMGDs—is reshaping the intraday merit order, compressing spot prices at midday and shifting thermal dispatch to the shoulders of the day.

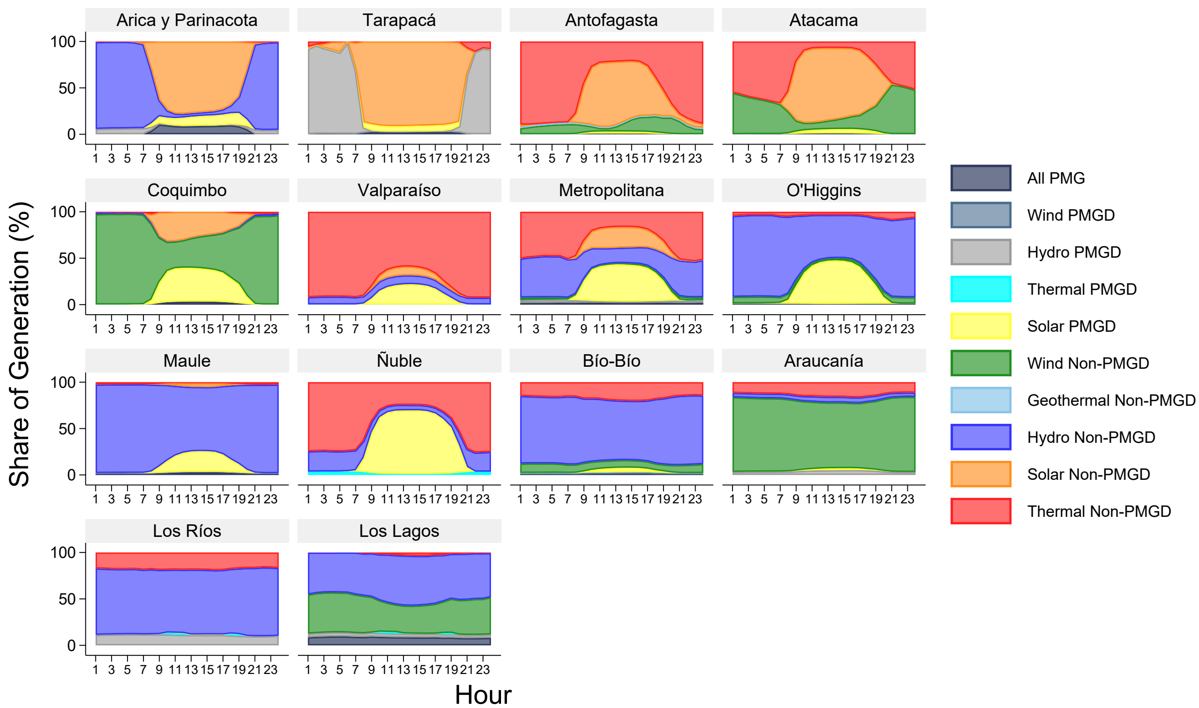
Figure 15: Hour Generation by Technology and Plant in 2024



Note: This figure shows the share of total generation in 2024 by hour of the day. For the sake of simplicity, the category "All PMG" combines power plants in the PMG regime across all technologies. The data source is the author's elaboration based on data from CEN.

The aggregate picture masks important geographic variation. Figure 16 shows substantial regional differences in Chile's daily generation mix. In northern regions, such as Atacama, Antofagasta, and Tarapacá, PMGD generation is limited; however, a large share of total generation comes from non-PMGD solar sources. Central regions, such as Valparaíso and the Metropolitan Region, exhibit a higher presence of PMGD generation, alongside a more balanced mix of hydro and thermal technologies. In contrast, southern regions such as Maule, Bío-Bío, and Los Lagos remain heavily reliant on hydro and thermal generation throughout the day, with minimal solar penetration. We return to these patterns when evaluating the emissions impact of PMGD expansion, as regions with greater thermal displacement potential offer more cost-effective abatement opportunities.

Figure 16: Hour Generation by Technology, Plant, and Region in 2024



Note: This figure shows the share of total generation in 2024 by hour of the day in every region. Regions are ordered by location, not by alphabetical order. Hence, it goes from the northernmost region (Arica y Panacota) to the southernmost region of the SEN (Los Lagos). For the sake of simplicity, the category "All PMG" combines power plants in the PMG regime across all technologies. The data source is the author's elaboration based on data from CEN.

Using this evidence, in the next section, we proceed to calculate the implicit price of CO_2 that stems from the current PMGD "subsidy" design. The intuition behind implicit prices is to measure the hidden cost or value of a policy by comparing the economic transfers it generates to the environmental benefits it achieves, typically expressed as the cost per ton of CO_2 avoided. Moreover, implicit prices can be compared to other, more direct policies implemented in Chile and abroad. Importantly, this framework also allows us to assess how the policy's effectiveness varies with system conditions, particularly in periods or regions where additional renewable generation may exceed local demand and displace little thermal generation.

4.6.1 Implicit Prices

To calculate the implicit prices of the PMGD "subsidy," we adopt a "marginal approach" that quantifies the dollar cost per ton of CO_2 abated due to PMGD expansion in each region and year.[6] The implicit price of CO_2 is defined as the marginal increase in total transfers received by

[6] As a first approximation, this approach neglects transfers across regions/zones. Zamora-Águila (2026) is a first attempt to relax this assumption by modeling integrated market clearing across all regions/zones, taking into account

PMGDs, divided by the estimated reduction in emissions from displaced thermal generation. We implement this calculation by simulating the transfers associated with a 1% increase in PMGD generation. Under this approach, the environmental benefit of additional PMGD generation depends critically on which technologies are displaced at the margin. In periods or regions with high solar penetration, additional generation is less likely to displace thermal sources and may instead crowd out other low-emission generation or contribute to local oversupply, leading to higher implicit prices. The denominator involves gauging the resulting displacement in generation from thermal technologies—coal, oil, natural gas, biomass, and biogas—weighted by their respective emission factors. We assume total electricity generation remains fixed and that PMGD generation displaces other technologies in proportion to their baseline shares in non-PMGD production. The details about this calculation can be found in Appendix B.

Table 1: Implicit Price Estimation (USD/ton CO_2)

Region	2021	2022	2023	2024
Arica and Parinacota	–	–	3,723.45	190,500.25
Tarapacá	83.03	118.23	542.37	1,025.46
Antofagasta	58.47	125.41	368.37	359.40
Atacama	27.72	108.23	333.56	382.32
Coquimbo	700.01	1,163.08	40,404.06	15,264.61
Valparaíso	-2.17	18.99	91.23	100.87
Metropolitan Region	-22.29	9.34	199.14	301.44
O'Higgins	-90.93	21.69	413.50	1,914.07
Maule	-512.77	-355.84	3,670.72	11,655.90
Ñuble	-80.81	-26.96	336.40	659.61
Bío-Bío	-41.30	-61.67	99.46	176.57
Araucanía	-1,462.28	-2,650.27	22.06	264.67
Los Ríos	-554.56	-1,163.30	-2,576.65	-5,292.76
Los Lagos	-486.82	-1,452.49	-1,057.35	-245.39
All Regions	-37.98	-16.04	222.70	325.20

Note: This table shows estimates for the implicit price derived from the stabilized pricing regime to PMGDs, measured in USD per ton of CO_2. Appendix B addresses the details behind the estimations.

Table 1 shows the results. First, there is substantial heterogeneity across regions, reflecting differences in the local electricity mix and the degree to which PMGD generation displaces thermal

transmission constraints and PMGD investments. Due to the transmission constraints, the numbers in Zamora-Águila (2026) still show significant variation across regions.

sources (Figure 16 illustrates the mix of displaced generation technologies across regions). Regions with more thermal generation, such as Antofagasta, Atacama, and Valparaíso, tend to exhibit lower implicit prices (e.g., below USD 400/ton in 2024), indicating more effective displacement of high-emission technologies. In contrast, regions with limited thermal generation, such as Arica and Parinacota or Coquimbo, show very high implicit prices in some years, exceeding USD 190,000/ton in 2024 for Arica and over USD 40,000/ton in 2023 for Coquimbo. These extremely high values suggest that subsidies in those areas yield little to no emissions abatement. These patterns are consistent with differences in local system conditions. In particular, regions with limited thermal generation or high penetration of solar energy are more likely to experience periods of excess supply, during which additional PMGD generation delivers little emissions abatement. In these cases, the subsidy effectively compensates production in hours when the marginal system value of electricity is low.

Second, there is a clear upward trend over time in the average implicit price across regions.[7] This pattern reflects, in part, the growing gap between stabilized (subsidized) prices and spot prices, as discussed earlier. This upward trend is also consistent with increasing solar penetration in the system. As solar capacity expands, additional generation increasingly occurs during hours with already abundant supply, reducing the extent to which it displaces thermal generation. As a result, the environmental effectiveness of the subsidy declines, while the associated transfers remain significant.

To place the estimated national average implicit price of USD 325 per ton of CO_2 in context, it is instructive to compare it with existing carbon pricing mechanisms. For example, the U.S. federal social cost of carbon (USD 51/ton, proposed to rise to around USD 100) provides a meaningful benchmark, as does the European Union Emissions Trading System (EU ETS). In recent years, EU ETS allowance prices have fluctuated between EUR 80–100 per ton (approximately USD 85–105), reflecting the market-based cost of CO_2 abatement in a mature cap-and-trade system. Similarly, Canada's federal carbon pricing plan set a CAD 65/ton (about USD 48) carbon price in 2023, with legislated increases to CAD 170/ton (approximately USD 125) by 2030.

At the global level, the IMF recommends a minimum global carbon price floor of USD 75 per ton by 2030 for high-income countries to meet climate goals cost-effectively. Thus, in comparison, the USD 325/ton implied by the PMGD subsidy at the national level is higher than these international benchmarks. Our preliminary numbers suggest that while the PMGD program may support distributed solar adoption, it does not appear as a cost-effective climate policy, particularly when judged by its emissions abatement impact per dollar spent.

However, our analysis suggests that targeting the PMGD subsidy to regions with high thermal generation, such as Valparaíso, Bío-Bío, Ñuble, would substantially improve its cost-effectiveness

[7] Negative implicit prices arise in region-year combinations where the stabilized price fell below the spot price, effectively a negative subsidy.

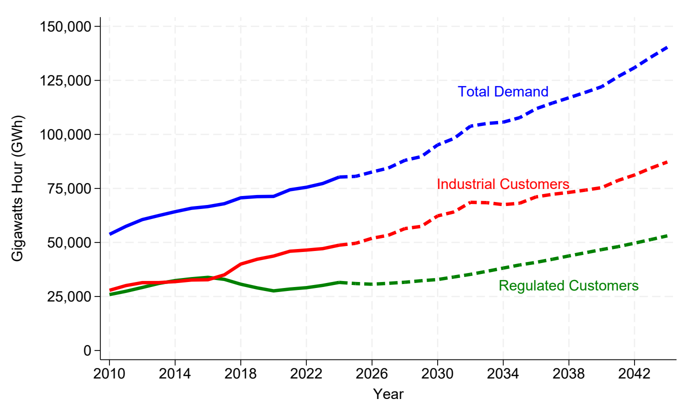
by maximizing emissions reductions per dollar spent. These regions exhibit much lower implicit prices, reflecting greater displacement of high-emission sources. Compared to the current uniform design, a geographically targeted approach would yield greater environmental impact at a lower cost.

In addition to the potential environmental implications highlighted by the implicit prices estimated here, future changes to the design of the PMGD subsidy should also consider its effects on investment, which are sizable. In a recent paper, Bermúdez (2025) examines the impact of the price stabilization regime for PMGDs on solar plant adoption. In a counterfactual scenario where the stabilized price for solar PMGDs is removed, the author estimates that, by the end of 2024, 47.5% of the cumulative installed capacity would not have been installed. These findings underscore the importance of carefully evaluating the trade-offs between sustaining investment in distributed renewable generation and avoiding unintended consequences, such as supporting projects with limited environmental returns.

5 Conclusions

The goal of these notes has been twofold. On the one hand, we aimed to shed light on the factors that have contributed to the rapid growth of renewable energy in Chile over the past decade. We documented that it was a combination of market forces and policy interventions. On the other hand, we proposed some ideas for improving existing policies that have been shown to be either ineffective or poorly implemented.

Figure 17: National Electric System Demand, 2000-2043



Note: This figure shows observed and forecasted demand, by type of client, between 2010 and 2043. Medium-sized power systems (SSMM) are not included here. The data source is the author's elaboration based on the Demand Forecast Report 2024 by the Ministry of Energy.

Another policy initiative often questioned is the promotion of faster adoption of rooftop solar panels, which is closely linked to residential consumer behavior. In contrast to the rapid expansion observed in other countries, Chile's growth has been limited, reaching only around 480 MW..[8] Currently, Chile only offers net-billing benefits and installation subsidies for rooftop solar, notably lacking a storage component, which can play a crucial role in adoption (Bollinger et al., 2024). Compared to the price stabilization mechanism (i.e., the PMGD subsidy) and the self-dispatch regime of PMGDs, incentives for rooftop solar remain relatively small. Therefore, the massive growth of distributed generation in Chile in recent years can be attributed mostly to the expansion of PMGDs.

Given Chile's decarbonization goals and the projected growth in electricity demand (see Figure 17), designing effective policies to support the expansion of renewable energy remains a central challenge in the years ahead. This paper has highlighted several of those challenges.[9] However, other important issues fall outside the scope of our analysis, including the role of storage and the design of discriminatory auctions –whether by technology or geographic region– to better align procurement with system needs.[10] These trade-offs have been examined in recent literature (e.g., Butters et al. (2021), Bollinger et al. (2024), Fabra and Montero (2023)), and we plan to explore these dimensions in future research.

[8] As a reference, California has over 10 GW of installed capacity and China more than 30 GW.

[9] Some of our estimates, including the implicit carbon prices, are preliminary and will be refined in future work.

[10] In its January 2026 report, ACERA, Chile's Renewable Energy and Storage Association, indicates that as of December 2025, Chile had 1,575 MW of storage capacity (i.e., batteries) in operation, 737 MW in testing, and 6,770 MW under construction. If execution stays on track, ACERA estimates that the system could have about 9 GW of storage operational by 2027, with an average duration above 4 hours. Given Chile's peak load demand of 13 GW, it remains to understand what may explain this remarkable interest in storage investment and whether it is socially efficient.

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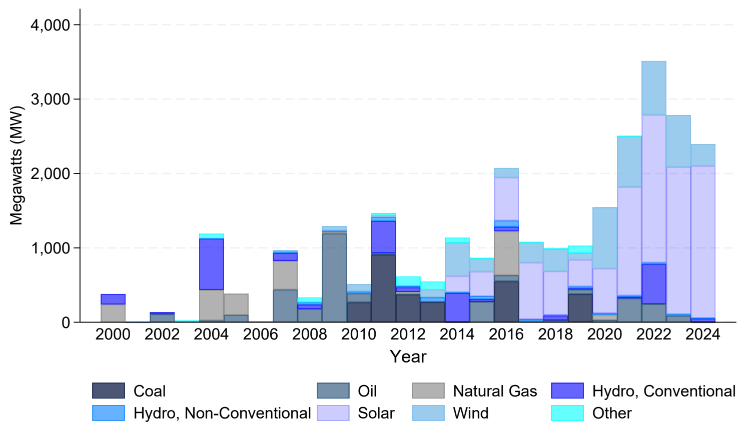
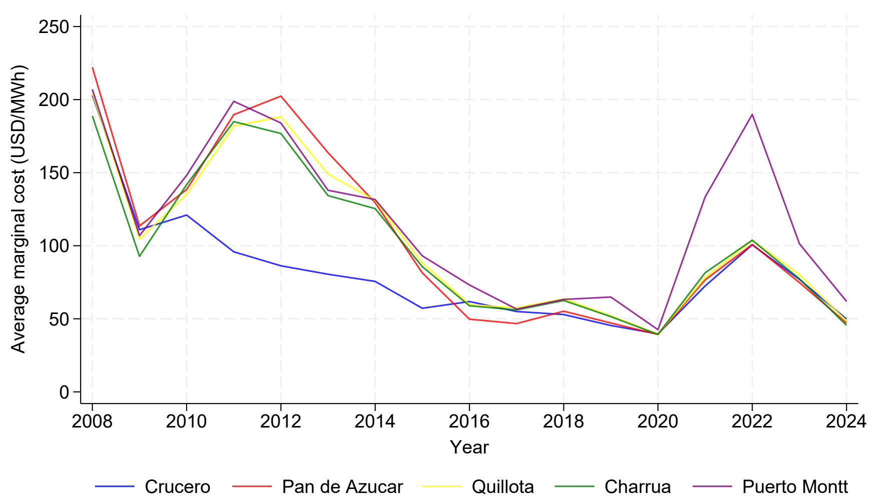
A Additional Figures

Figure A1: New Capacity Investments



Note: This figure displays the volume of new capacity (measured in MW) additions per year and by technology. The category "hydro, conventional" includes dams or run-of-river plants with an installed capacity above 20 MW. Category "hydro, non-conventional" includes only mini run-of-river plants with an installed capacity below 20 MW. Category "other" includes biomass, biogas, cogeneration, petcoke, and geothermal energy. The data source is the author's elaboration based on data from CEN.

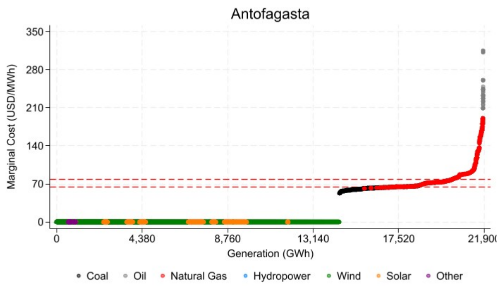
Figure A2: Spot Market Price (USD/MWh)



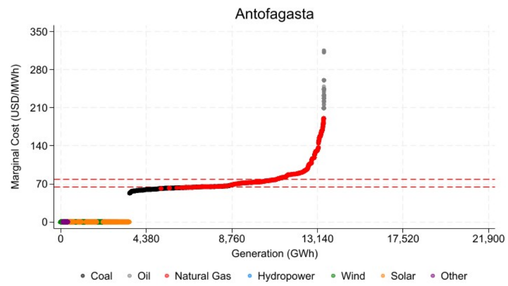
Note: This figure displays time series for the unweighted average marginal costs at the year level for five of the most representative nodes of the system: Crucero for the northern region "norte grande", including Tarapacá and Antofagasta; Pan de Azucar for the Atacama region; Quillota for the central area, including the Metropolitan Region; Charrua in the Biobío region; Puerto Montt for the southernmost region in Chile. The voltage level of the nodes reported is 220 KV. The common increase in 2022 spot prices is explained by the invasion of Ukraine. The further increase in Puerto Montt is due to severe transmission congestion. The data source is the author's elaboration based on data from CEN.

Figure A3: Curve of Marginal Costs in 2024 for Selected Regions

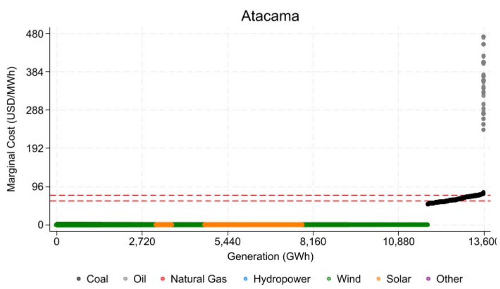
(a) Antofagasta, Daytime



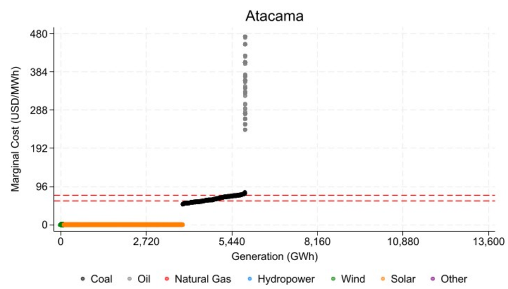
(b) Antofagasta, Nighttime



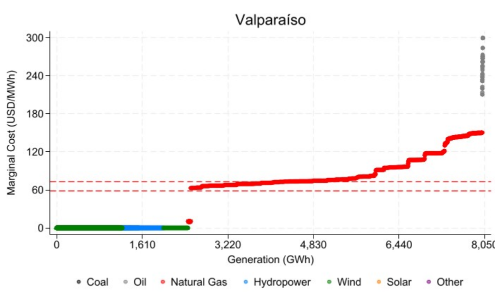
(c) Atacama, Daytime



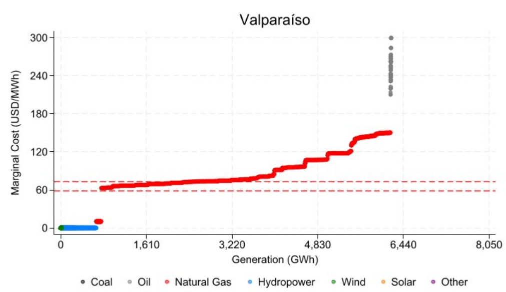
(d) Atacama, Nighttime



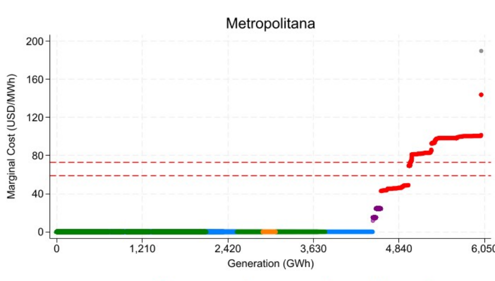
(e) Valparaíso, Daytime



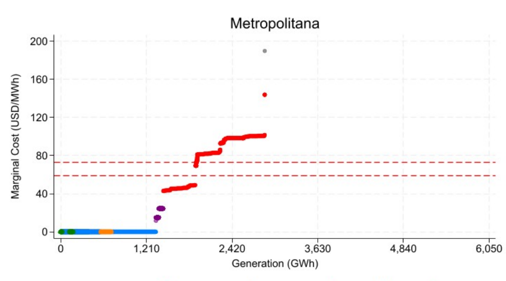
(f) Valparaíso, Nighttime



(g) Región Metropolitana, Daytime

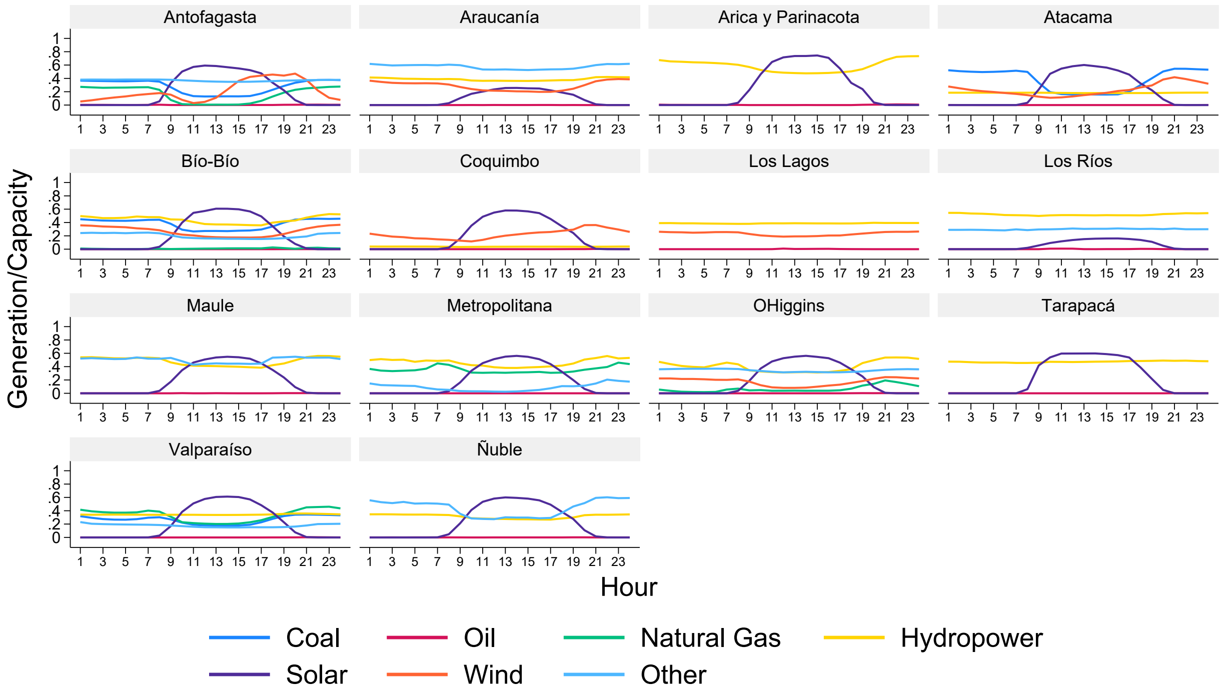


(h) Región Metropolitana, Nighttime



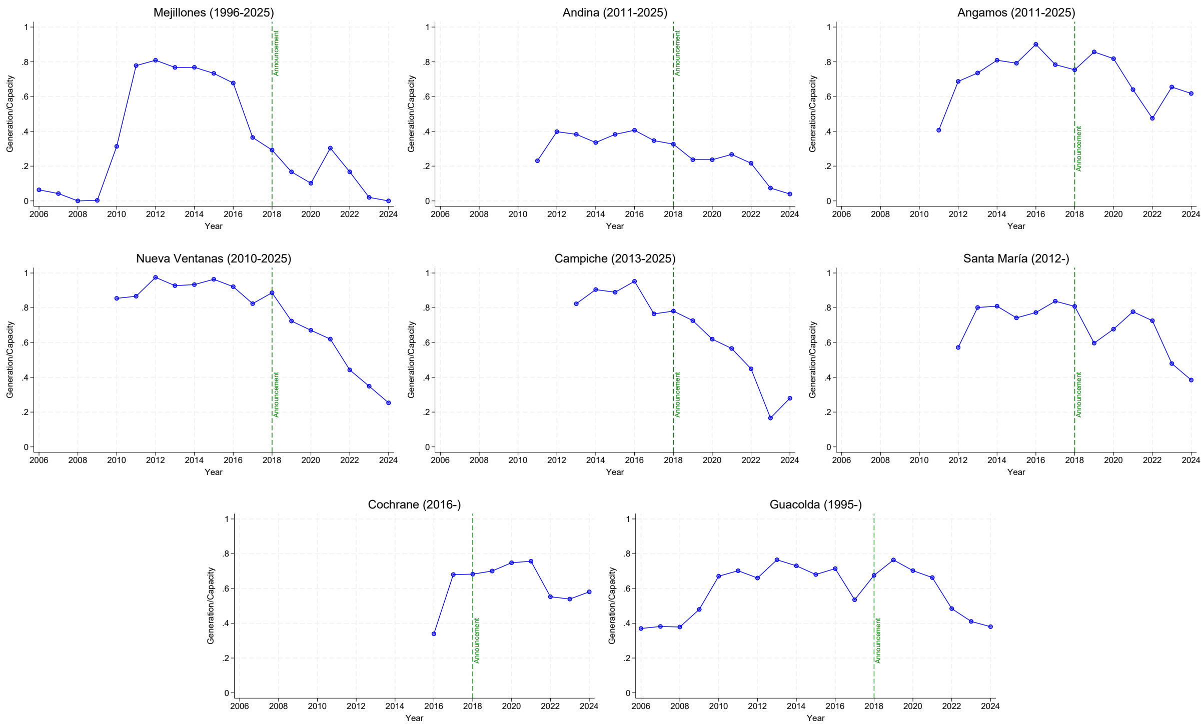
Note: This panel shows the curve of marginal costs for a selected sample of regions in Chile, pooling at the daily level in the year 2024 by technology. The observation represented by each dot is at the generation unit level. The y-axis represents the marginal cost of the generation unit, measured in USD per MWh. The x-axis displays the maximum production in GWh of the generation unit measured by the 99th percentile of generation in the year, in two different slots of the day: solar time (8:00 to 20:00) and non-solar time (21:00 to 7:00). The dashed horizontal lines represent the 35th and 65th percentiles of the spot market price in each time slot of the day over the year at the most representative node in each region. For the Antofagasta region, the spot market price is based on the Crucero 220 kV node. For the Atacama region, the spot market price is from the node Maitencillo 220 kV. For the Valparaiso region, the spot market is from the Quillota 220 kV node. Finally, for the Metropolitan region, the spot market prices correspond to those from the Polpaico 220 kV node.

Figure A4: Median of Capacity Factor by Region in 2024



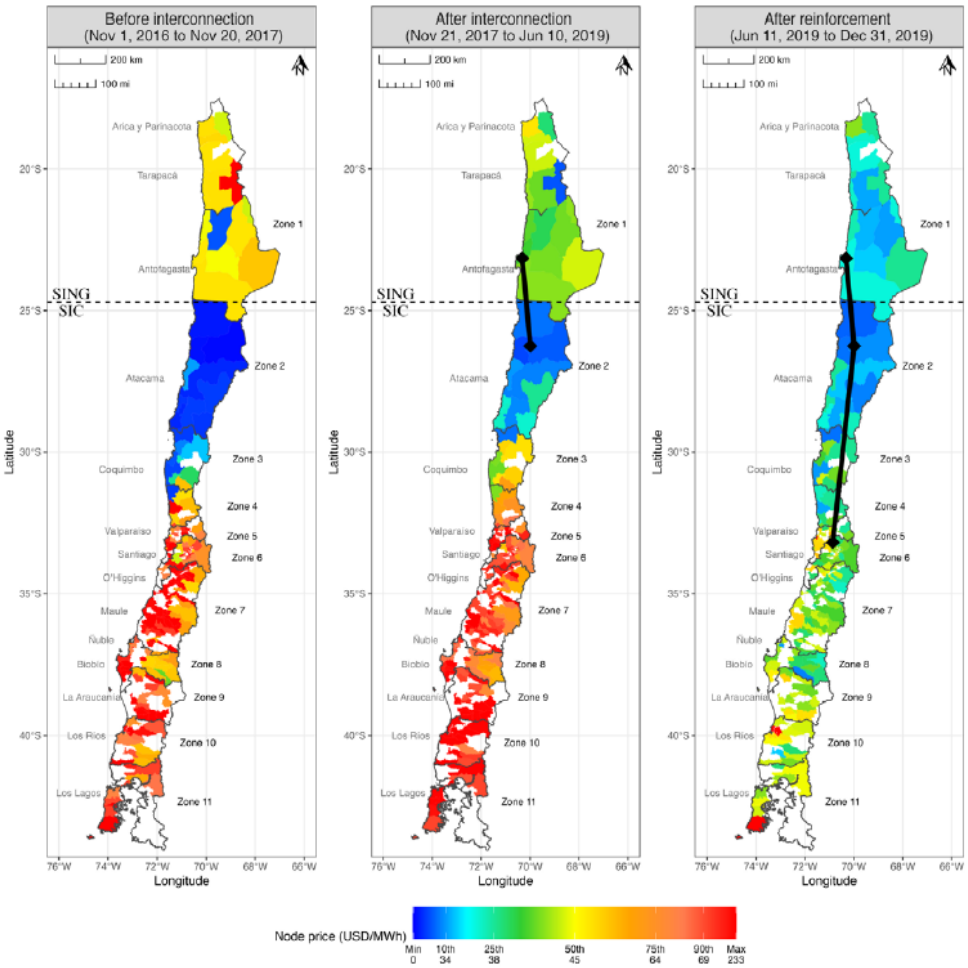
Note: This figure displays the median for capacity factors at each hour of the day, by technology and region in 2024. Capacity factor is measured each hour by $\frac{\text{Generation MWh}_t}{\text{Capacity MW}_t \cdot 366}$.

Figure A5: Capacity Factor for Coal Plants to be Phased Out in 2025 or Later



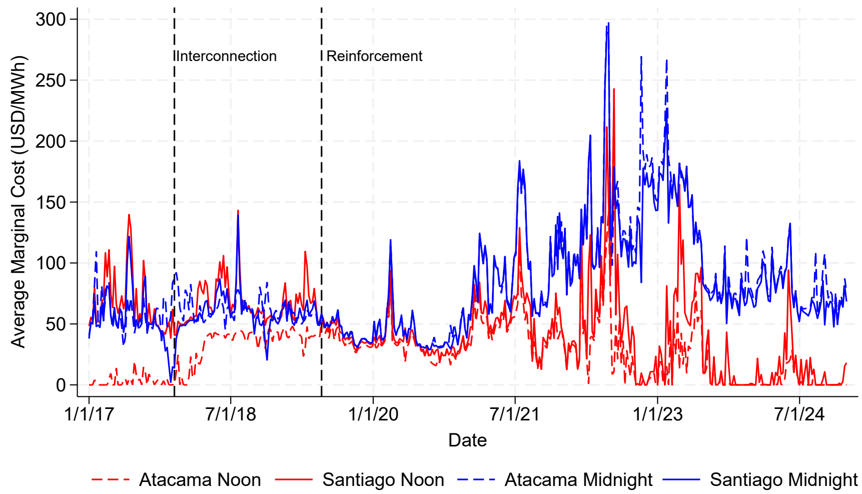
Note: This panel shows the average capacity factor of eight coal-fired power plants that are expected to shut down in 2025 or later in the context of the Decarbonization Plan. Capacity factor is computed by $\frac{\text{Generation MWh}_t}{\text{Capacity MW}_t \cdot 8760}$, at the power plant level in year t. The green vertical line marks the announcement of the Decarbonization Plan in 2018, when generation companies committed not to build any additional coal-fired plants from that year onward. In parentheses, the years of commissioning and retirement for each plant are shown; those without an end year are plants expected to be shut down or reconverted in the years to come. The source is our own elaboration based on CEN data.

Figure A6: Market integration and electricity prices (Gonzales et al., 2023)



Note: These heat maps examine spatial heterogeneity in wholesale electricity prices in three periods: before, after interconnection, and after reinforcement. The commune-level average node prices are weighted by the hourly generation at the node level. We use the percentiles of the node price distribution to define color categories as shown in the legend. This figure was taken directly from Gonzales et al. (2023), for more details, see the paper.

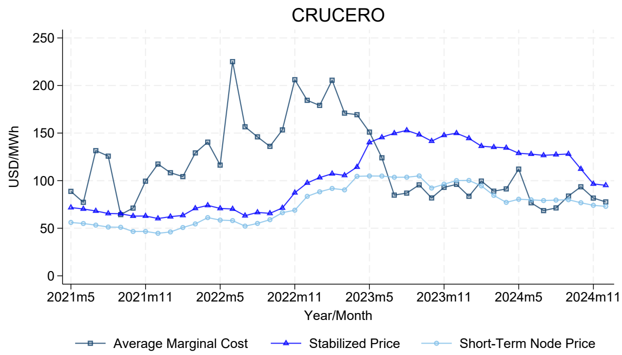
Figure A7: Regional Gaps in Spot Market Prices



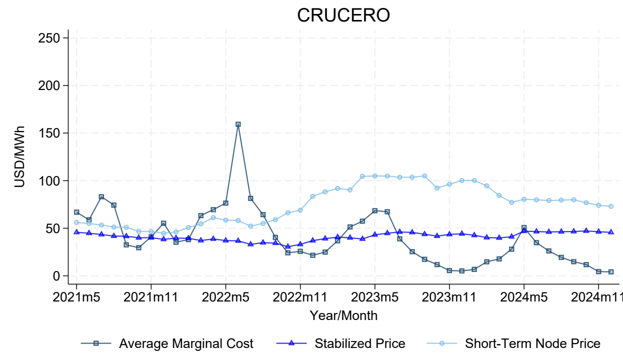
Note: This figure displays the impacts of market integration on price convergence in Atacama and Santiago by time of the day: midnight (0:00-1:00) and noon (12:00-13:00). Following Gonzales et al. (2023), for each week, we calculate the weekly averages of hourly prices in each region and plot them over time. Prices in Antofagasta are proxied by those in node Kapatur; Prices in Atacama are proxied by node Cardones, and Polpaico for Santiago region. These are the nodes nearest to each end point of the interconnection and reinforcement.

Figure A8: Price Comparisons, 2021-2024

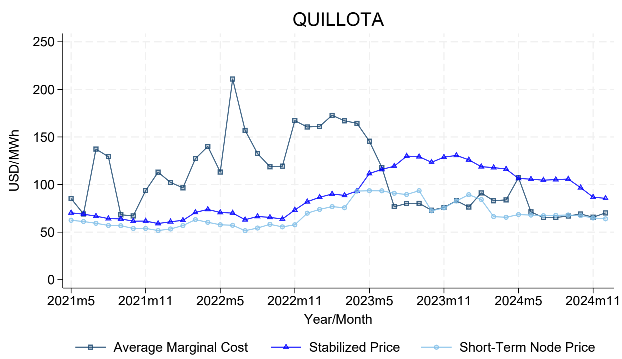
(a) Non-Solar Hours



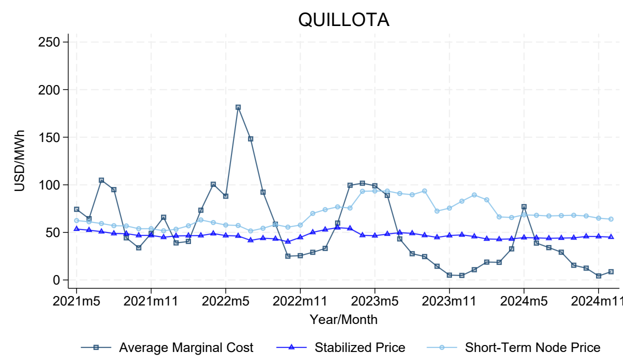
(b) Solar Hours



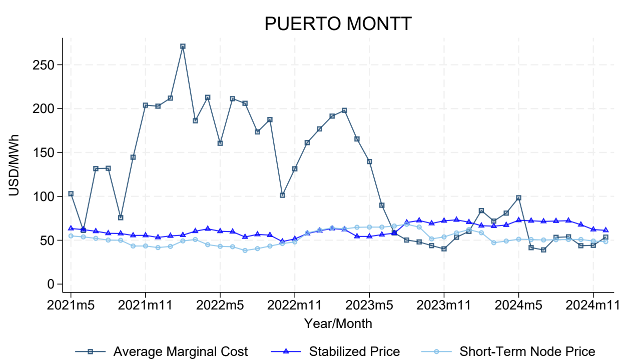
(c) Non-Solar Hours



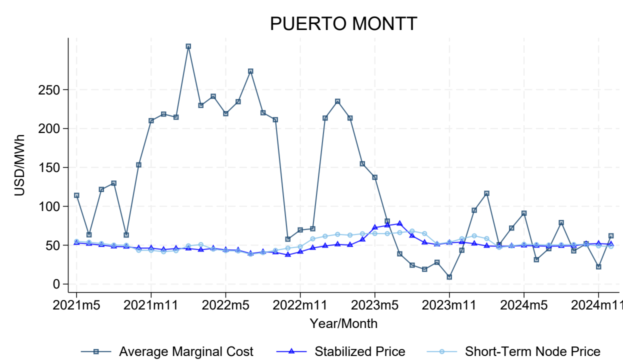
(d) Solar Hours



(e) Non-Solar Hours



(f) Solar Hours



Note: This panel presents a comparison between the three prices that PMGDs may face: the spot market price (marginal cost), the stabilized price, and the short-term node price. The comparison is conducted by distinguishing between non-solar (21:00–7:00) and solar (8:00–20:00) hours, using a selected sample of three representative nodes within the system: Crucero, representing the northern region ("norte grande"), which includes Tarapacá and Antofagasta; Quillota, representing the central region, including the Metropolitan Region; and Puerto Montt, representing the southernmost region of Chile. All reported nodes have a voltage level of 220 kV. The source is our own elaboration based on CEN data.

B Estimation of the Implicit Price

Energy policies around the world are often evaluated based on the implicit prices associated with programs designed to achieve environmental objectives. Calculating these implicit prices provides an approximation of the hidden economic value embedded in public interventions. This section provides a brief explanation of the estimation of implicit prices discussed in Section 4.6.1.

Implicit Price Definition and Assumptions. As we argue throughout the paper, there is a remarkable geographical heterogeneity in the electricity market in Chile, primarily driven by the expansion of intermittent renewable energy sources in certain regions. Hence, we are interested in providing insights on how the implicit price of the subsidy varies across regions. We follow a *marginal* approach for estimating the implicit price $P_{r,t}$ at the region r and year t according to:

$$P_{r,t} = \frac{\Delta T_{r,t}}{\sum_{g \in \mathcal{G}} \phi^g \cdot (\Delta Y^g_{r,t})} \tag{1}$$

Where $\Delta T_{r,t} \equiv T_{r,t} \times 0.01$, represents the marginal change in the transfers perceived by PMGDs after an increase of 1% in electricity generation from PMGDs in region r at year t. In the denominator, $\Delta Y^g_{r,t}$ are the counterfactual generation in MWh from power plants in region r in year t producing with technology $g \in \mathcal{G}$, that would have been observed after a 1% increase in PMGD generation. Finally, ϕ^g is the average factor of tons of CO_2 emissions per MWh for a power plant producing electricity with thermal technology $g \in \mathcal{G}$. In our case, $\mathcal{G} = \{\text{coal, oil, natural gas, biomass, biogas}\}$. Notice that we need to set values for ϕ^g. For these preliminary estimations, we simply take them as given[1] and set $\phi^{coal} = 0.826$, $\phi^{oil} = 0.533$, $\phi^{gas} = 0.364$, $\phi^{biomass} = 0.106$, and $\phi^{biogas} = 0.2$–note that we only consider direct power-plant emissions.

Our *marginal* approach relies on several assumptions. First, we set the total electricity generation to remain fixed after the increase in PMGD generation. Implicitly, we argue that prices hold fixed at the margin, thus avoiding general equilibrium effects. Second, we assume that, after a marginal increase in the PMGD production, the remaining non-PMGD technology is being displaced in that specific region only. Since we are not relying on a merit cost curve to define technology displacements, we do not discuss diversion ratios. In fact, we claim that, after a marginal increase in PMGD generation, non-PMGD technologies are facing a decrease in production, consistent with their baseline representativeness in non-PMGD energy production. Finally, our estimates are interpreted as long-term effects in the sense that this marginal approach relies on the hypothesis of PMGD expansion in capacity.

[1] We rely on raw estimates of average emission factors for coal, natural gas, and oil-fired plants in Chile. See here for a reference. For biomass and biogas we rely on a raw approximation of CO_2 emissions observed in experimental settings.

Estimation Details. We estimate transfers in equation 1 based on two different data sources. We rely on actual transfer data, including payments received by PMGDs from stabilized prices between 2021 and 2024[2] and electricity generation data. A first challenge for estimation is that the transfer data is available at the firm-month level only. We impute the share of the observed monthly generation of the firm by region to the total amount of transfers perceived (paid) in the same month. The data is then aggregated at the year-region level. We restrict transfer of data for PMGD firms only[3]. As shown in Table A1, the final sample of PMGD firms accounts for around two-thirds of the total levels of transfers from stabilized price, yet is quite representative in terms of generation and capacity of all PMGDs in operations.

Table A1: Summary Statistics for Estimation Sample

	2021	2022	2023	2024
Share of PMGD generation	0.93	0.92	0.88	0.88
Share of PMGD capacity	0.85	0.85	0.84	0.85
Share of total transfers	0.31	0.38	0.62	0.61

Note: This table presents the representativeness of the estimation sample used in the computation of implicit prices.

$\Delta Y_{r,t}$, in equation 1 denominator, corresponds to the decrease of thermal electricity production that would have been observed after a 1% increase of PMGD energy production. This exercise is based on a complementary dataset that provides electricity generation at the regional-year-hour level. We set non-PMGD electricity generation as follows:

$$Y_{r,h,t}^{NON-PMGD} = Y_{r,h,t}^{TOTAL} - Y_{r,h,t}^{PMGD}$$

Where $Y_{r,h,t}$ represents electricity generation at the region r, in hour h of year t. Then, we get the share of thermal generation $s_{r,h,t}^{g}$ according to:

$$s_{r,h,t}^{g} = \frac{Y_{r,h,t}^{g}}{Y_{r,h,t}^{NON-PMGD}}$$

These shares are used to impute the new residual thermal generation $\bar{Y}_{r,h,t}^{g} \equiv s_{r,h,t}^{g} \cdot (Y_{r,h,t}^{NON-PMGD})'$ that would have been observed after a 1% increase in PMGD generation at region r, at hour h, and year t. Finally, we get $\Delta Y_{r,t}^{g}$ by aggregating at the region-year level the difference between observed and counterfactual generation as follows:

$$\Delta Y_{r,t}^{g} \equiv \sum_{h \cap t} (Y_{r,h,t}^{g} - \bar{Y}_{r,h,t}^{g})$$

[2]Data is available at the system coordinator webpage.

[3]We define a PMGD firm as any firm reported in the transfer data for whom all of its power plants (regardless the their technology) are PMGD plants. Thus, if a firm is reported with one or more power plants and all of them are PMGDs, then that firm is labeled as a PMGD firm.