The Dynamic Impact of Market Integration: Evidence from Renewable Energy Expansion in Chile*

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Abstract

We study the static and dynamic impacts of market integration on renewable energy expansion. Our theory highlights that statically, market integration improves allocative efficiency by gains from trade, and dynamically, it incentivizes new investment in renewable power plants. Using two recent grid expansions in the Chilean electricity market, we show how this market integration changed market prices, generation costs, and renewable investments. With the insight from this descriptive evidence, we build a structural model of power plant entry to quantify the impact of market integration with and without the investment effects. We find that market integration resulted in price convergence across regions, increases in renewable generation, and decreases in generation cost and pollution emissions. Furthermore, a substantial amount of renewable entry would not have occurred in the absence of market integration. We show that ignoring this dynamic effect would substantially understate the benefits of transmission investments.

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1 Introduction

Effective and economical expansion of renewable energy is one of the most urgent and important challenges of addressing climate change. The electricity sector generates one of the largest shares of global greenhouse gas emissions along with the transportation sector.[1] Furthermore, a significant part of the transportation sector is expected to be electrified in the near future. Decarbonizing electricity generation is therefore critical to addressing climate change.

However, many countries are facing a fundamental challenge in expanding renewable energy because the existing network infrastructure (i.e., the transmission grid) was not originally built to accommodate renewables. Conventional power plants, such as thermal plants, were able to be placed reasonably close to demand centers (e.g. large cities), and therefore, minimal transmission networks were required to connect supply and demand. However, renewable energy, such as solar and wind, is often best generated at locations far from demand centers.

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 have to curtail electricity generation from renewables to avoid system breakdowns, even though this means discarding zero-marginal-cost and emissions-free electricity. This curtailment indeed occurs in many electricity markets, and growing number of markets are experiencing negative wholesale market prices when there is excess renewable supply.[2] Second, because the marginal cost of renewable electricity is near zero, local market prices in renewable-intensive regions tend to be low when it cannot be exported to demand centers. These two problems discourage new entry and investment in renewable power plants. Many countries consider these challenges as first-order policy questions. For example, the Biden administration in the United States explicitly included investment in transmission lines and renewable energy as a key part of the Infrastructure Investment and Jobs Act (117th Congress, 2021), which included approximately 1.75 trillion US dollars in spending.

We examine this question by providing theoretical and empirical analyses on the impacts of market integration on renewable expansion and allocative efficiency in wholesale electricity markets. We begin by developing a simple theoretical model that characterizes the static and dynamic impacts of market integration. In the static scenario, we assume that market integration does not affect producers' entry decisions. In this case, the value of market integration can be summarized by a conventional definition of gains from trade. Market integration allows lower-cost power plants to export and replace production from higher-cost power plants, which results in an improvement in allocative efficiency. However, this conventional approach does not incorporate the potential dynamic impact of market integration. When producers can anticipate market integration, they have incentives to invest in new production capacity that will be

[1] Electricity and heat production accounts for 25% of the 2010 global GHG emissions and transportaiton accounts for 14% (IPCC, 2014). In the United Sates, 29% of the GHG emissions in 2019 comes from the transportation sector and 25% comes from the electricity sector (EPA, 2020).

[2] For example, California's wholesale market experienced negative prices 10 percent of the time in 2017 (California ISO, 2018; Cicala, 2021). Wind power is often curtailed in electricity markets in Texas and Spain. The Japanese electricity market experienced large-scale curtailment of solar power in the Kyushu region, which has limited transmission connection to other parts of the country.

profitable in the upcoming integrated market. This investment effect changes the supply curve of production, which results in an equilibrium that is different from the static case. Our model shows that this dynamic impact of market integration can be substantial, and ignoring this impact could understate the impact of market integration.

With this insight, we empirically quantify these theoretical predictions by exploiting two large changes recently occurred in the Chilean electricity market. Until 2017, two major electricity markets in Chile—Sistema Interconectado Norte Grande (SING) and Sistema Interconectado Central (SIC)—had been completely separated with no interconnection between them. Recently, this separation has been recognized as an obstacle to expanding renewable energy because renewable-intensive regions (near Atacama desert) are located far north from demand-centered regions (near Santiago, the capital city) and completely disconnected with another demand center (mining industry) near Antofagasta. To address this problem, the Chilean government completed a new interconnection between Atacama and Antofagasta in November 2017, and a reinforcement transmission line between Atacama and Santiago in June 2019.

Not only do these expansions provide a unique research environment to apply our theoretical and empirical framework to study the impact of market integration, but the Chilean electricity market also offers another unique advantage in the comprehensiveness of its data. We are able to collect nearly all of the data relevant to market transactions, including hourly unit-level marginal costs, hourly node-level demand, hourly node-level market clearing prices, hourly unit-level electricity generation, and plant characteristics such as capacity, technology, year built, and investment.

We begin by presenting visual and statistical evidence of the static impacts of market integration on wholesale electricity prices, production, and cost. First, we show that the market integration resulted in price convergence across regions. Before the market integration, we observe large price differences between regions with high levels of solar production (e.g., Atacama) and demand centers (e.g., Santiago). We show that the market integration substantially reduced this spatial price dispersion by increasing prices in renewable-intensive regions and decreasing prices in demand centers.

Second, we investigate the static impacts of market integration on electricity production and costs. Consistent with our theoretical prediction, we find that market integration provided gains from trade—lower-cost power plants, including renewables, increased their production and replaced production from higher-cost plants, resulting in a decrease in the overall cost of electricity generation per megawatt hour.

Third, we examine how market integration affected new entry of renewable capacity. We find that a rapid growth in renewable capacity started right around the first *announcement* of market integration in 2014, which was three years before the completion of the interconnection in 2017. Despite the fact that the node prices in renewable-intensive regions became near zero before the interconnection, we observe continuing entries of renewable power plants in this period. This evidence suggests that renewable investors made their investment decisions based on the *anticipation* of market integration. This evidence also suggests that the static analysis, which cannot capture the potential impact on anticipatory investment in plant capacity, is likely to understate the impact of market integration, as it is suggested by our theory.

To investigate the potential dynamic impacts of market integration, we build a structural model of power plant entry. In our baseline investment model, which we call one-shot investmnet model, investors consider investment for a new power plant based on the expected value of long-run profit from the investment. The net present value of investment depends on profits from subsequent years. A key element of the future expected profit is transmission constraints from its local region to other regions. The attractiveness of the Chilean market is that its simple geography makes the network model tractable and makes it feasible to conduct counterfactual analysis. We simulate a few counterfactual policies on transmission capacity expansion and examine the impact of market integration on solar entries, market prices, generation costs, and consumer surplus.

Our counterfactual simulations reveal several findings. First, our static result suggests that the market integration in Chile increased 10% of solar generation relative to the counterfactual case with no market integration. In the absence of market integration, the system operator would have had to curtail an excessive amount of solar power due to transmission constraints. Second, this number still understates the impact on solar investment because a substantial amount of solar investment would have become unprofitable without market integration due to low market prices. We simulate the market equilibrium to find the maximum level of solar capacity investment that could be positive in the net present value, using the discounted rate and duration of investment used by the Chilean government's public infrastructure projects. Our dynamic result suggests that the full impact of market integration on solar generation was a 185% increase in solar generation, as opposed to the 10% increase if we ignore this dynamic impact.

Our results indicate that both the static and dynamic impacts of market integration are important factors in the evaluation of transmission investment. In our context, we find that the static effect itself resulted in 7% and 3% reductions in electricity generation cost per megawatt hour in hour 12 (a solar-intensive hour) and all hours, respectively. If we incorporate the dynamic effect on solar investment, these reductions in generation cost are 18% and 8%. Our results also indicate that both the static and dynamic impacts play key roles in allowing price convergence across regions.

Our baseline investment model focuses on the equilibrium quantity of solar investment without modeling the investment path (i.e., the timing of investment). This simple model is parsimonious yet allows us to examine the core of our research question. However, it does not allow us to estimate the investment path. Therefore, we also build an extended model, called the multi-period investment model. This model allows us to take into account changes in commodity prices, transmission status, and solar costs that occur over time. We explicitly model the declining costs of solar power, changing revenues from the market, and the transmission network via the structural model. This model, therefore, incorporates the opportunity cost of solar investment as investors in the model invest each year by considering the opportunity cost of investment that comes from the declining cost of solar investment over time. Given these inputs, we rely on the observed data and our structural model to infer the cost consistent with the observed behavior.

We use both of the investment models to conduct cost-benefit analysis of transmission investments. In particular, we discuss how the cost-benefit calculation can be changed with and without investment effects and how the alternative assumptions on the investment model changes the estimated benefits of transmission investments. We find that ignoring the investment effect of market integration substantially understates the benefit of transmission investments. Furthermore, reductions in environmental externalities provide an additional benefit of market integration. Another key finding is that although the choice of investment model is relevant to the cost-benefit calculation, it does not substantially change our quantitative conclusion. Our main analysis suggests that the cost of transmission expansion can be recovered by between 7.1 and 10.7 years, depending on which investment model and assumptions we use.

Related literature and our contributions—Our study builds on three strands of the literature. First, several earlier studies on wholesale electricity markets develop theoretical models on the impacts of transmission expansion (Bushnell, 1999; Joskow and Tirole, 2000; Borenstein, Bushnell and Stoft, 2000; Joskow and Tirole, 2005). Notably, theoretical models in these studies often start with a hypothetical example of two disconnected electricity markets—"North" and "South"—and consider the integration of these two markets. The grid expansions in Chile provide an empirical analog to these hypothetical settings, which allows us to test predictions from these theoretical models. In addition, previous studies generally focus on static impacts and do not explicitly incorporate potential impacts on the entry of new power plants. Our theory incorporates this dynamic effect and highlights that the dynamic impact on power plant entry and investment can be crucial to examine market integration.

Second, our paper is closely related to Mansur and White (2012) and Cicala (2022), which study how the introduction of market-based dispatch mechanisms affected allocative efficiency in the US electricity markets. Our study is also related to research on the role of transmission lines in electricity markets. For example, Wolak (2015), Ryan (2021), and Burlig, Preonus and Jha (2022) study the competitive and efficiency effects of transmission. Davis and Hausman (2016) examines how the impact of a sudden nuclear power plant closure on market efficiency interacts with transmission constraints. While our paper benefits from insights from this literature, our research question is different in three folds. First, we study the impact of market integration by itself, keeping the dispatch mechanism unchanged. In our setting, the two separated markets in Chile had the same dispatch mechanism before the integration, and this mechanism did not change after the integration. This allows us to isolate the effects of market integration from the impacts of dispatch mechanisms. Second, we focus on the role of market integration on renewable investment rather than the competitive impacts of transmission. Third, previous studies in this literature generally focus on allocative efficiency in a static scenario in which the set of power plants is considered fixed. Our paper explicitly considers both of the static and dynamic impacts of market integration by incorporating a dynamic impact on power plant entries. Finally, our study shows that a commonly-used event study approach might understate the benefit of transmission lines, and we provide a method to correct for such bias.

Third, our project relates to recent studies on the role of transmission expansion in renewable energy policy (Abrell and Rausch, 2016; Dorsey-Palmateer, 2020; Brown and Botterud, 2021; Fell, Kaffine and Novan, 2021; LaRiviere and Lyu, 2022; Yang, 2022). For example, Fell, Kaffine and Novan (2021) finds that relaxing transmission constraints between the wind-rich areas and the demand centers in Texas increased the environmental benefit of wind because the transmission expansion allowed wind to offset pollution near highly populated areas. Our study contributes to this literature in two ways. First, we show that transmission expansion incentivizes the new entries of renewables, and therefore, estimating both of the static and dynamic impacts of market integration is important to quantify the full benefit of transmission investments on renewable expansion. Second, in addition to non-market environmental benefits, we also evaluate the benefits of a variety of market outcomes in a wholesale electricity market, such as market prices and generation costs. We find that the economic benefits of market integration on these outcomes are substantial because renewable expansion can significantly lower the system-wide costs and prices of electricity when it is combined with transmission expansion. In our cost-benefit analysis, we show that incorporating the dynamic effect substantially changes the cost-benefit of transmission investments.[3]

Fourth, our paper relates to the literature computing optimal investment in solar power. A growing literature has examined household decisions with dynamic structural models at the household level in the context of residential rooftop solar installation (De Groote and Verboven, 2019; Feger, Pavanini and Radulescu, 2022). In these settings, households choose the optimal timing in which to invest in solar panels considering the option value of waiting for lower costs of solar vs. missed opportunities in the form of higher subsidies. In residential settings, households only have one rooftop on which to install panels, and therefore the optimal timing of investment is critical to each household. Our context is different because what we study is firms that build utility-scale solar plants in Atacama desert and surrounding regions. They do not have subsidy and are able to build multiple large-scale solar plants at any point in time. Our data suggest that these firms can enter competitively, thus driving the equilibrium profits to zero, in expectation. We therefore model that firms enter as long as there are profitable opportunities. Nevertheless, our multi-investment model explicitly models the declining costs of solar power, changing revenues from the market, and the transmission network via the structural model. This model, therefore, incorporates the opportunity cost of solar investment as investors in the model invest each year by considering the opportunity cost of investment that comes from the declining cost of solar investment and changes in marginal revenue from solar investment over time.

Finally, our study provides important policy implications for renewable energy policy around the world. The lack of market integration between renewable-intensive regions and demand centers has become a major obstacle to decarbonization in many countries, including the United States (Cicala, 2021). Chile is one of the very first countries that have tackled this problem by enhancing electricity market integration. Our empirical evidence from the Chilean electricity market highlights the importance of transmission projects in allowing investment into renewable energy,

[3] Another related study is Rivera, Ruiz-Tagle and Spiller (2021), which studies the effect of increased solar production on health outcomes in Chile, although this study's focus is not transmission expansion.

which is a crucial market force to accelerate decarbonization.

2 Theoretical Framework

Our goal is to understand the static and dynamic benefits of integrating markets, and how to recover them from data. To understand the challenge, it is useful to provide some intuition with a stylized example, which is represented in Figure 1. Imagine there are two regions, A and B, which are operating in autarky. Region A has lower costs. Equilibrium prices in autarky are given by $p_A < p_B$. In the static model, we assume that market integration does not affect renewable investments. In this case, the equilibrium from integrating markets with full trade is given by p^*. Costs on average fall (gains from trade), prices in one region (weakly) go up, and prices in the other region (weakly) go down. When compared to the outcomes under autarky, the gains from trade are given by the classical triangle marked in dots (the triangle e_B, e_A, and e^*), which can be compared to the costs of building the line for a full cost-benefit evaluation.[4]

[Figure 1 about here]

Imagine now that region A is also the one with the best available solar resources. In the absence of a transmission line between A and B, such resources might not be profitable, but they would be attractive if the two regions were interconnected. Once the two regions are interconnected, new investment enters the market in the anticipation of the profitable environment. In Figure 1, we represent the equilibrium outcome after renewable plants are built in region A. Under full trade, the dynamic equilibrium would be e^{**} with the equilibrium price p^{**}. The cost savings from this new equilibrium are described by the whole shaded area. To get at the full dynamic gains from trade, one would need to compare these benefits to the costs of building the line and the costs of the solar investment.

From an empirical perspective, it is useful to compare the costs of production before and after the transmission line is expanded, e.g., using an event-study-like *ceteris paribus* comparison. From Figure 1, in the absence of solar investment, the benefits from the expansion should identify the static gains from trade. In a model without frictions, incremental investment (the causal part of the investment) happens exactly when transmission is expanded, and thus the dynamic gains from trade can also be identified. However, in the presence of frictions, the timing of expansion might not coincide perfectly with investment. Consider a situation in which investors enter the market before the transmission line is fully developed in anticipation of the change, as in our application. Under such a scenario, a comparison of the "before-and-after" market outcomes in a commonly-used "event study design" could lead to the conclusion that the event-study gains from trade equal the larger shaded triangle (the triangle e_B, $\tilde{e}_A$, and e^{**}). This calculation will not only understate the gross cost savings, but it would also fail to account for the fact that solar investments would not have been profitable during the "before" period alone.

[4] Our theory model in this section focuses a case of cost-based dispatch with no firm conduct because Chile uses the cost-based dispatch as we describe in Section 3.2. The model needs to be modified when firms' market conducts need to be incorporated.

More generally, we expect an event-study approach to underestimate gross cost savings in the presence of differential timing. Note that this is also true if investment were delayed, as cost savings would not include any dynamic impacts in the event window. When it comes to price differences, the event-study approach will overestimate the overall impacts of the transmission line on price convergence in the presence of anticipated investments as long as $p_A < p_B$. Early investments will increase the price difference, which will tend to converge after the grid is expanded. Price reductions will be generally understated. If investments are delayed, the new price would be p^* as opposed to p^{**}, understating price reductions. The price reduction will also be understated in the presence of anticipated investment, as early solar investment tends to depress average prices in the "before" period.

To show these economic predictions more formally, we derive the equilibrium equations under a stylized model with linear marginal cost functions that we can solve in closed form. Assume there are two regions $r = \{A, B\}$ with demands $D_A \leq D_B$ and marginal cost functions $C_A(q_A) = \beta_A q_A$ and $C_B(q_B) = \beta_B q_B$, where q_A and q_B represent non-solar production in each region. For simplicity, consider the case in which $\beta_A \leq \beta_B$ so that under autarky $p_A \leq p_B$, as in Figure 1. We will compare the equilibrium under market integration (full trade) and autarky (no trade).

In autarky, the equilibrium is trivial and given by the intersection of the marginal cost curve and demand.

$$p_A = \beta_A D_A,\ q_A = D_A,\ p_B = \beta_B D_B,\ q_B = D_B.$$

Define total demand as D. In the absence of solar investment, equilibrium outcomes under full trade are given by:

$$p^* = \frac{\beta_A \beta_B}{\beta_A + \beta_B} D,\ q_A = \frac{\beta_B}{\beta_A + \beta_B} D,\ q_B = \frac{\beta_A}{\beta_A + \beta_B} D.$$

Importantly, we also consider endogenous investment in solar in the presence of market integration. Assume there is some cost to solar production, c, which can only be built in region A.[5] For simplicity, assume $p_A < c < p^*$, so that investment only occurs under market integration. We also assume that entry of solar follows a zero profit condition. In this new environment, the equilibrium solar production becomes,

$$q^{solar} = D - \frac{\beta_A + \beta_B}{\beta_A \beta_B} c.$$

Intuitively, solar covers any demand not produced by the regions at price $p^{**} = c$, which becomes the equilibrium price under full trade.[6]

If investment is anticipated, but market integration has not yet occurred, the equilibrium is also modified under

[5] Solar production involves mostly fixed costs. The cost c is intended to capture the strike price at which solar panels are profitable.

[6] We assume that c is such that solar investment is at an interior solution, i.e., $q^{solar} \geq 0$, as implied by $p_A < c < p^*$.

autarky. Taking q^{solar} as given, the autarky equilibrium with anticipated investment becomes,

$$p_A = (1 + \frac{\beta_A}{\beta_B})c - \beta_A D_B,\ q_A = \frac{\beta_A + \beta_B}{\beta_A \beta_B}c - D_B,\ p_B = \beta_B D_B,\ q_B = D_B.$$

The price and non-solar production in region A will be lower in this new equilibrium with anticipation, while prices and production in region B remain at the same level in autarky.

Armed with this basic model, we show the following observations.[7]

Observation 1. *In the presence of investment anticipation or delay,* ***gross cost savings*** *from a grid expansion will be underestimated around the event window. Furthermore,* ***net cost benefits*** *accounting for the investment costs of solar will be*

- *underestimated if expansion is delayed, and*
- *overestimated if expansion is anticipated but its investment costs ignored.*

Visually, it is clear that gross cost savings are largest when the full shaded area is considered.[8] In the presence of delayed investments, gains from trade realized around the event window are only equal to the static gains, which are by construction smaller. If investment is anticipated, gains from trade only equal the triangle expanding the quantity beyond autarky, but miss the cost savings induced by the solar expansion in the North.

Observation 2. *In the presence of investment anticipation or delay,* ***price reductions*** *from a grid expansion will be underestimated around the event window.*

It is easy to see that with investment anticipation, prices before market integration will tend to be lower than without anticipation, due to the depressing effect of solar production. Therefore, price reductions will be less salient if solar investment has already occurred. In the presence of investment delays, the key is to show that price reductions are larger in the dynamic equilibrium than in the static one with no solar investment. This is again due to the depressing effects on prices from solar entry, which only occur in the dynamic case.

Observation 3. *In the presence of investment anticipation or delay, reductions in* ***regional price differences*** *(price convergence) around the event window will be*

- *overestimated in the presence of anticipation,*
- *correct in the presence of delayed investment as long as prices converge both with and without investment. Otherwise, price convergence will be overestimated.*

[7] Most of our results should be true under quite general conditions, but our proofs are based on the stylized cost curves in this basic model.
[8] See Appendix for mathematical proofs of all results.

Prices in region A are depressed in the presence of anticipation of investments, as shown in Figure 1 when comparing p_A to $\tilde{p}_A$. Therefore, the price gap in prices $p_B - \tilde{p}_A$ is overstated. If investment is delayed but prices converge, then there is no bias in the case of delayed investments. However, in the presence of transmission line bottlenecks, price convergence will be overstated. As can be seen from Figure 1, there is more trade in the presence of solar investment (e^{**}) than without it (e^{*}). Therefore, if the price gap does not go to zero, price convergence will be higher when the cost curves between the two regions are more similar (static curves).

In our empirical analysis below, we consider these insights and provide empirical quantification to the theoretical predictions described in this section.

3 Background and Data

In this section, we describe institutional details about the Chilean Electricity Market and data to be used for our empirical analysis.

3.1 Market Integration in the Chilean Electricity Market

In Figure 2, we summarize the recent market integration of the Chilean Electricity Market. Prior to November 2017 (the left panel), the electric power grid in Chile was organized into two main systems—Sistema Interconectado del Norte Grande (SING) in the northern region and Sistema Interconectado Central (SIC) in the central-southern region. There was no interconnection between these two systems, and each system was dispatched fully separately.

[Figure 2 about here]

In November 2017, these two systems were connected for the first time, with a double circuit 500kV transmission line with a firm capacity of 1500 MW. As we show in the middle panel of Figure 2, the interconnection connected Antofagasta region in SING and Atacama region in SIC. The integrated new system—Sistema Electrico Nacional (SEN)—consists of over 99% of the installed capacity for the country.[9]

In June 2019, this interconnection was extended by another double circuit 500kV transmission line (the right panel of Figure 2) to reinforce the connection between Atacama and Santiago. In this paper, we use "interconnection" to refer to the interconnection line (Antogagasta–Atacama) built in 2017 and "reinforcement" to refer to the reinforcement line (Atacama–Santiago) built in June 2019. As we show in our analysis below, both of interconnection and reinforcement played key roles in integrating the Chilean electricity market.

A major policy objective of this integration was to connect solar-abundant regions to electricity demand centers. Atacama is a solar-abundant region with relatively low electricity demand. Antofagasta is one of the demand centers

[9] The remaining 1% is served by two other isolated systems in the south of SIC outside the map in Figure 2.

for its mining industry, and Santiago is the largest demand center for its commercial, industrial, and residential electricity demand. There are two ways to interpret Chile's market integration in the context of the theoretical framework presented in Figure 1. Atacama can be considered to be region A (the solar-abundant region), and the interconnection and reinforcement connected it to region B (Antofagasta and Santiago, two demand centers) sequentially. Note that Antofagasta is also abundant with solar resources, although it is less so than Atacama. Therefore, another interpretation is that the interconnection and reinforcement—combined together—connected the solar-rich regions in the north (Antofagasta and Atacama) with Santiago, the largest demand center in the country.

Long-distance transmission investment involves policy decisions, permit acquisitions, and major construction, all of which can take considerable time. Therefore, it is important to recognize that market players may be able to anticipate new transmission lines long before they are built, which may influence their decisions regarding construction of new power plants. It is thus critically important to factor this anticipation in the analysis of the long-run impacts of such investment.

In the case of the Chilean integration, the 2017 interconnection was anticipated as far as 3 years in advance. Chile passed a modification to the "General Electric Services Law" on February 7 in 2014, which promoted the idea of the interconnection of SING and SIC in the near future. The construction of the interconnection began in August 2015. Our empirical analysis therefore aims to incorporate the potential anticipation impacts on the investment in new power plants.

3.2 Cost-Based Dispatch and Pricing in the Chilean Electricity Market

Similar to other Latin American countries, Chile uses cost-based dispatch to clear demand and supply in its spot market. Power plants submit the technical characteristics of their units as well as natural gas or other input contracts with the input prices to the Load Economic Dispatch Center (CDEC), which is the Independent System Operator (ISO) in Chile. Based on this information, the CDEC computes unit-level start-up cost and variable operating cost everyday and uses these costs, demand, and their network model to determine least-cost dispatch under transmission constraints.

The lowest cost dispatch means that the ISO ranks power plants from those with lower marginal costs to those with higher marginal costs and decide a set of power plants that can meet demand with the overall lowest cost that is possible under transmission constraints. Therefore, the resulting spot market price is equal to the marginal cost of the most expensive unit of generation in use. In the presence of transmission constraints between regions, the spot prices can differ across regions. The most spatially disaggregated price points are called nodes, and the CDEC publishes the hourly spot prices at the node level.

This cost-based dispatch mechanism is different from bid-based dispatch, which is a common dispatch method in many countries including the United States. In bid-based dispatch, power plants submit their supply bids in an auction market. Their bids do not have to be equal to their marginal costs. In contrast, in cost-based dispatch, plants are required to submit their marginal costs to the system operator who uses this information to clear the market.

Compared to bid-based dispatch, cost-based dispatch has an advantage of reducing the risk of system-wide and local market power, particularly in markets with insufficient transmission capacity (Wolak, 2003). This setting makes our modeling and analysis tractable because market power is less likely to be a large issue than bid-based markets. Note that cost-based dispatch may not fully eliminate the exercises of market power if large firms could manipulate their reported costs or plant maintenance/outage schedules. However, based on our analysis on the reported costs and availability of power plants in Appendix C, we do not find evidence of large firms exercising market power in our sample period.[10]

To hedge spot market risk, generators can also sign long-term contracts with customers.[11] Customers with installed demand capacity over 500 kW can have bilateral contracts with generators. Other customers are called "regulated customers" because they are served by local distribution companies with regulated retail prices. These customers cannot have direct contract with generators. Instead, the long-term contracts are auctioned in a centralized auction between local distribution companies and generators. Generators with long-term contracts can either generate electricity or purchase it from the spot market. Thus, these long-term contracts are equivalent to financial positions and their price should be reflective of the market price expectations.

3.3 Data and Summary Statistics

A key advantage of studying the Chilean electricity market is that nearly all of the data relevant to market transactions are available. Although many countries including the United States make part of their electricity market data available, Chile is one of the very few countries in which nearly all micro data, including plant-level generation, cost, market dispatch mechanisms, and market clearing prices are available.[12] We use several data sets for our empirical analysis.

Hourly and daily marginal cost at the unit level: As described in the previous section, generators in the Chilean electricity market submit their marginal cost information every day to the system operator. For power plants in SIC regions, we use unit-level costs for three segments of the day: block 1 (midnight to 8 am), block 2 (8 am to 6 pm), and block 3 (6 pm to midnight). For power plants in SING regions, we use unit-level daily cost data. We use this data from 2014 through 2019.

Hourly demand at the node level: Our data cover 2017 through 2019.[13]

[10] The cost-based market in Chile makes our analysis more parsimonious as market power is less of an issue. At the same time, the analysis based on the Chilean market abstracts from an additional potential benefit of market integration that comes from an increased competition. If such an effect exists, the full benefit of market integration can be larger in a market with bid-based dispatch compared to a market with cost-based dispatch.

[11] Long-term contracts are optional to generators. They can participate in the spot market without long-term contracts. Bustos-Salvagno (2015) provides detailed description about the long-run contracts in the Chilean electricity market.

[12] Another country that makes much of the electricity market data publicly available is Spain (Reguant, 2014; Fabra and Reguant, 2014).

[13] For the multi-period structural model, we go back to 2014 to simulate early investment in solar power. We lack detailed demand data from 2014-2016. To approximate expected demand during that period, we re-scale the disaggregate demand data from 2017 to match the aggregate average hourly supply that we observe in 2014-2016. While this is not perfectly accurate, it provides an approximation to compute market outcomes during

Hourly market clearing prices at the node level: The system operator uses marginal costs, demand, and transmission constraints to clear the market. The hourly market clearing prices are available at the node level. We collect this data from SING, SIC, and SEN for 2008 through 2019.

Hourly electricity generation at the unit level. With the spot market outcomes, the system operator dispatches generation. We use hourly electricity generation at the unit level from 2014 to 2019.

Plant characteristics and investment. This data include plant-level capacity, year built, and investment.

The summary statistics in Table 1 show key characteristics of the Chilean electricity market. First, approximately 25% of electricity generation comes from SING (the northern system) and 75% comes from SIC (the southern system). Second, hourly system demand does not vary much across hours as it is suggested by the hourly generation at noon and midnight in the table. This implies that electricity demand in Chile does not have much of peak and off-peak hours, as it is the case in many other electricity markets, including California, DC, Japan, and Spain-Portugal (Borenstein, Bushnell and Wolak, 2002; Wolak, 2011; Ito and Reguant, 2016; Ito, Ida and Tanaka, 2018, 2021). Third, before the introduction of the interconnection, the average node price was higher in SIC than SING at noon, whereas it was higher in SING than SIC at midnight. The post-interconnection average node prices suggest price convergence both at noon and midnight between the SIC and SING regions, which we empirically investigate more in the next section.

[Table 1 about here]

4 Descriptive Analysis of Market Integration

In this section, we use detailed data on hourly price, cost, electricity generation, and plant entries to provide descriptive analysis of market integration. An advantage of this analysis is that we can explore empirical evidence with minimal reliance on modeling assumptions. A key limitation is that descriptive analysis by itself is not sufficient to examine the full impact of market integration with investment effects. We will investigate this point in Section 5.

4.1 Impacts of Market Integration on Wholesale Electricity Prices

One of the theoretical predictions in Section 2 is that market integration could result in convergence in wholesale electricity prices between regions. We test this prediction in Figure 2. As mentioned in Section 3.3, we have data on the hourly wholesale electricity prices at the node level. Using these data, we calculate the commune-level average prices, weighted by the hourly generation at the node level, and make heat maps for three periods: 1) before the interconnection, 2) after the interconnection and before the reinforcement, and 3) after the reinforcement. The heat maps show the average node prices at noon, which tends to be one of the most congested hours in the transmission network in Chile because of solar generation.

those years, which are used to compute solar revenues.

Prior to the interconnection (the left heat map), there was a steep price difference between Atacama and other regions. This is because zero-marginal-cost solar generation in Atacama depressed the market price toward zero and it was not possible to export this excess solar production to other regions—there was no interconnection to the north (Antofagasta) and not enough transmission capacity to the south (Santiago).

The interconnection (the middle heat map) made it possible for the low-cost solar power to be exported to the north, which lowered the price difference between Atacama and Antofagasta. However, the interconnection by itself had a limited impact on the price difference between Atacama and Santiago. The right heat map shows that a nationwide price convergence was achieved only after the openness of the reinforcement line in 2019.

In Figure 3, we examine the price convergence using time-series data. Panels A shows the price difference between Antofagasta and Atacama (the two end points of the interconnection), and Panel B shows the price difference between Santiago and Atacama (the two end points of the reinforcement). 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.[14]

[Figure 3 about here]

Panel A shows that there was large volatility in the price difference between Antofagasta and Atacama before the interconnection. Because these two regions were fully separated markets at this time, differences in demand or supply in each region could make the price difference between the two markets. After the interconnection, the price difference converged to zero in nearly all weeks for midnight and most weeks for noon.

Panel B suggests that the interconnection slightly reduced the price difference between Santiago and Atacama, but it was not enough to get the price convergence. This is because the transmission capacity between Santiago and Atacama has not been enough between these regions until the reinforcement was opened in 2019. After the reinforcement, the price difference converged to zero in nearly all weeks for midnight and most weeks for noon.

Our theory (Observation 3 in Section 2) implies that the price convergence observed at the time of market integration (i.e., the change in the regional price difference before and after the market integration) could overstate the price convergence effect of market integraion if the solar investments occurred in anticipation of the grid expansions. That is, the price convergence observed in Figure 3 may reflect $p_B - \tilde{p}_A$ rather than $p_B - p_A$ in Figure 1. We investigate this investment effect in Section 5.

4.2 Impacts of Market Integration on Generation Costs

Another theoretical prediction in Section 2 is that grid expansion could bring a textbook example of gains from trade. With market integration, the system operator can dispatch power plants in a way that minimizes total generation cost

[14] We use prices in Kapatur (a node in Antofagasta region), Cardones (a node in Atacama region), and Polpaico (a node in Santiago region) to calculate the price differences. These are the nodes nearest to each end point of the interconnection and reinforcement.

in all regions as opposed to minimizing each region's cost separately. We therefore predict that the interconnection and reinforcement made lower-cost power plants produce more and higher-cost plants produce less, resulting in reductions in nationwide generation cost per MWh.

One way to measure this efficiency gain is to examine how generation cost per MWh changed before and after the grid expansions. However, the observed change in generation cost may not accurately measure the efficiency gain if other changes over time (e.g., changes in input costs) are not properly controlled for. To address this challenge, we use insights from Cicala (2022) and take advantage of the fact that we can compute the "nationwide merit-order cost." This nationwide merit-order cost is the least possible dispatch cost per MWh that can be obtained in the absence of trade constraints in the Chilean electricity markets and can be a useful control that takes into account non-linearities in the costs of producing electricity as a function of commodity prices (coal and gas) and hydro availability.

We have data on demand, unit-level capacity, and unit-level generation costs every hour. Based on this information, we can identify which units should be dispatched to meet the demand at the lowest system-level cost, assuming there is no trade constraint. We use c_t^* to denote this nationwide merit-order cost (USD/MWh) at time t and c_t to denote the observed generation cost per MWh at the national level.[15] Using c_t^* as one of the control variables in X_t, we estimate the following equation by the OLS:

$$c_t = \beta_1 I_t + \beta_2 R_t + \beta_3 X_t + \theta_m + u_t, \tag{1}$$

where $I_t = 1$ after the interconnection (November 21, 2017), $R_t = 1$ after the reinforcement (June 11, 2019), X_t is a vector of control variables that includes the nationwide merit-order cost c_t^*, θ_m is the month fixed effects to control for seasonality, and u_t is the error term. We calculate heteroskedasticity- and autocorrelation-consistent standard errors.[16]

Table 2 shows the results. A key advantage of this approach is that many time-variant factors, such as input prices, can be flexibly controlled by c_t^*, and therefore, results are robust to the inclusion of additional controls. Columns 4 and 8—the specifications that include all control variables—imply that the interconnection and reinforcement reduced the generation cost by 2.42 and 0.96 USD/MWh for hour 12 and by 2.07 and 0.61 USD/MWh for all hours.

[Table 2 about here]

Our theory (Observation 1 in Section 2) suggests that the cost reduction estimated by comparing before and after

[15] Cicala (2022) calculates the merit-order cost within each power control area, whereas our nationwide merit-order cost is defined as the least dispatch cost at the national level, as opposed to SING only or SIC only. In addition, an alternative control variable is the minimum dispatch cost in the absence of market integration (i.e., the least possible generation cost that can be obtained in the absence of market integration). We use this approach in Table A.4 and find that results are similar to Table 2.

[16] There are two approaches to using c_t^* as a control variable. One approach is to define the out-of-merit cost $c_t - c_t^*$, which shows how much the observed cost deviates from the least possible dispatch cost, and use it as a dependent variable. In this way, we could test how market integration changed the deviation between c_t and c_t^*. Another approach is to use c_t as a dependent variable and c_t^* as a control variable. We find that both approaches produce essentially identical results because empirically the coefficient for c_t^* is close to one in the second approach. This is because c_t and c_t^* generally move in a parallel way (Figure A.1). We show the result of the second approach in this section and include the result of the first approach in the appendix (Table A.3).

the market integration (i.e., our results in Table 2) could understate the full cost saving if the solar investments occurred in anticipation of the grid expansions.[17] We investigate the anticipatory investment in Section 4.3 and incorporate such investment effects in Section 5.

4.3 Impacts of Market Integration on Renewable Expansion

Observations 1, 2, and 3 in our theory imply that the before-and-after analysis may not capture the full impacts of market integration if the entry of power plants occurs in anticipation of market integration.[18] This is particularly relevant to electricity grid expansions because the announcement and subsequent construction of transmission lines generally start long ahead of the opening of the lines.

To investigate the importance of this point in our empirical context, we examine the entry of solar plants in Figure 4. The red-connected line shows the cumulative installed capacity for solar plants in Atacama. The green solid line shows the average price at noon, and the green dashed line shows the average price at midnight.[19] Before 2014, there were nearly no solar plants in this region, and the prices were similar between noon and midnight. When more solar plants started to enter, the prices at noon started to decline and reached near zero in 2015. This is because zero-marginal cost solar generation depressed spot market prices to zero in the local market, and that low-cost electricity could not move to other regions because of transmission constraints. The transmission constraint was relaxed when the interconnection was opened in 2017. The interconnection made the price at noon get back to positive levels and shrunk the difference in prices between noon and midnight. Furthermore, the reinforcement in 2019 further narrowed this price difference.[20].

[Figure 4 about here]

The evolution of solar entries indicates that investors were likely to make the investment decision in anticipation of market integration. Between mid-2015 and mid-2017, the price in Atacama had been near zero. However, the solar entries had a steady increase in this period. This investment decision does not make sense without the anticipation that the grid expansions were going to alleviate transmission congestion and increase local prices.

There are several reasons why the anticipatory investment occurred. First, as we explained in Section 3.1, the relevant law was passed in 2014, and the construction of the interconnection line started in 2015, two years before the interconnection was opened. Therefore, market participants had publicly available information about the upcoming

[17] The event study model, such as Equation (1), identifies the effect of an event by comparing outcomes before and after the event, assuming that the event affects outcomes in the post-event period but does not affect pre-period outcomes. In our context, if the event induces anticipatory investments, it could lower the generation cost in the pre-event period, which could result in the underestimation of the event's impact on cost savings.

[18] A before-and-after analysis will also produce biased results if entry is delayed. We focus here on anticipation because it appears to be clearly present in our application.

[19] We calculate the weighted average node prices in this figure using plant-level daily solar generation as weight.

[20] In Figure A.9 in the appendix, we also show that in addition to the price at noon, the solar-relevant prices can be also analyzed by the weighted average prices weighted by solar potential. We find that this weighted price is nearly identical to the price at noon. In that figure, we also show that the declining prices in 2014–15 were largely due to the declines in natural gas price.

market integration. Second, uncertainty in obtaining permits and competing constructions was likely to be another reason to rush firms into the anticipatory investment. Third, the fixed-price power purchase agreements were likely to make the anticipatory investment financially possible. Many solar plants in Chile were built with long-run fixed-price contracts. Because the information about the market integration was publicly available, the long-run contract prices, which were determined by a centralized auction for the regulated market and by bilateral agreements for the unregulated market, were likely to reflect the expected long-run local prices. If this is the case, solar plants were able to receive non-zero prices even during the pre-interconnection period.[21]

These findings from Figure 4 suggest that incorporating the investment effects of market integration is important to understand the value of the transmission expansion. In addition, the evidence of the anticipatory investment suggests that the before-and-after analysis presented in Sections 4.1 and 4.2 may not capture the full impact of market integration. In the next section, we address this question by developing a structural model of market integration.[22]

5 A Structural Model of Market Integration

In this section, we build a structural model of solar plant entry to investigate the impacts of market integration with and without investment effects. The model is composed by two parts. First, a short-run economic dispatch model is used to clear the market every week to determine power plant dispatch for each hour (Section 5.1). We take advantage of the fact that many relevant variables, such as hourly demand and daily cost at the power plant unit level, are observable in our data and that Chile's simple geography allows us to build a tractable trade model built into the dispatch model.

The second part of the model is about solar investors' investment decisions. We begin with a one-shot investment model in Section 5.2 to solve for the equilibrium entry of solar plants. We use this model to simulate the impacts of the transmission expansion project in Section 5.3. We also extend our model to investment models with multiple periods in Section 5.4.

5.1 Dispatch Model

The system operator in Chile uses the cost-based dispatch described in Section 3.2. The operator's objective is to dispatch power plants by minimizing the total generation cost given demand and transmission constraints. As a result

[21] A subset of the power purchase agreements for the regulated customers (i.e., customers with less than 500kW) are publicly available, and we show time-series variation in Figure A.10. In this data, we confirmed that the average contracted price for solar plants was $78 in the 2015 auction and $52 in the 2016 auction. This suggests that solar plants were indeed able to obtain non-zero prices even before the interconnection. Unfortunately, the publicly-available data include only a small subset of the long-run contracts, and therefore, we mainly use the spot market data for our empirical analysis.

[22] We focus on solar investment, as this seems to be the largest margin of adjustment. However, other power plants could also endogenously respond to solar investment and the transmission expansion. In Figure A.8, we examine the entry and potential exit of thermal plants. We find that entry of thermal plants slowed down around 2014-2015 relative to total generation growth, which is consistent with their expected long-run profitability going down. We also find suggestive evidence on potential exits of thermal plants in response to the market integration, although correctly identifying the exists of power plants is challenging in electricity markets, as we describe in Appendix D.

of the optimization, the production decisions of each plant and hourly local market prices will be determined. We model that the operator finds the optimal dispatch for each hour t to minimize the weekly total generation cost.[23]

Mathematically, we solve the following constrained optimization problem for each week:

$$
\begin{aligned}
\min_{\mathbf{q},\mathbf{imp},\mathbf{exp}} \quad & \sum_{z,t,j} C_{ztj}\left(q_{ztj}\right), \\
\text{s.t.} \quad & \sum_{j} q_{ztj} + \sum_{l}\Big(\left(1-\delta_1\right) imp_{lzt} - exp_{lzt}\Big) \geq \frac{D_{zt}}{1-\delta_2}, \quad \forall z, t, \\
& 0 \leq imp_{lzt} \leq f_{lz}, \quad 0 \leq exp_{lzt} \leq f_{lz}, \quad \forall l, z, t, \\
& \sum_{z} (imp_{lzt} - exp_{lzt}) = 0, \quad \forall l, t,
\end{aligned}
\tag{2}
$$

where $C_{ztj}\left(q_{ztj}\right)$ is the total generation cost from technology j in zone z and hour t with production quantity q_{ztj}. The technology j includes coal, diesel, natural gas, other thermal, hydro, solar, and wind. We allow the cost function $C_{ztj}\left(q_{ztj}\right)$ to differ by zone and technology and explain details in the "cost functions" section below.[24]

The first constraint in equation (2) describes that supply plus net imports need to be larger than or equal to demand in each zone, after accounting for transmission losses. imp_{lzt} are imports into zone z coming from transmission line l, exp_{lzt} are exports out of zone z through transmission line l, and D_{zt} is demand in zone z. δ_1 represents a transmission loss factor for high-voltage transmission, which is relevant for transmission between zones. With this transmission loss, supply from imports can be expressed by $\left(1-\delta_1\right) imp_{lzt}$. δ_2 is a transmission loss factor for low-voltage transmission, which is relevant for transmission inside each zone. With this transmission loss, the total supply needs to meet the adjusted demand quantity, $D_{zt}/(1-\delta_2)$.

The second constraint represents trade capacity constraints between zones. To model the trade between zones, we benefit from Chile's geography, as we can express the transmission network as a vertical line. Our model includes $l = 1, ..., L$ inter-regional transmission lines with net flow transmission capacity F_l, connecting each contiguous zone. f_{lz} is the transmission capacity of the line if zone z is connected to that line.[25] Finally, exports going out of zone z into zone r, connected via line l, need to equal imports in zone r coming via line l, which is represented in the last equation.

The operator minimizes the total cost with respect to the vectors of production quantities, imports, and exports ($\mathbf{q}$, $\mathbf{imp}$, and $\mathbf{exp}$). The market clearing process produces equilibrium quantities, imports, and exports consistent with cost minimization. We also obtain the market clearing prices at each zone (p_{zt}), defined as the shadow value on the demand constraint of each zone z.

[23]In practice, the Chilean operator takes into account seasonal dynamics using a longer horizon than a week. We abstract away from these dynamics and instead include hydropower constraints to reflect water use over the seasons.

[24]Further details are also provided in Appendix Appendix B.

[25]For example, line 1 connects zones 1 and 2. Transmission capacity f_{1z} is only positive for the two regions connected with the line, and only after the interconnection. f_{1z} is zero for any other zone.

We take advantage of the fact that many of the elements in the dispatch model are observable in our data, including production costs, hourly demand at the node level, hydro availability, and transmission grid. However, some of these variables do not map directly into our model. We take several steps to estimate each of its elements.

Network model We separate the Chilean electricity market into eleven zones from the north to the south, as shown in Figure A.2. All provinces in SING belong to one zone, as it was a physically isolated region before the interconnection. We split the other provinces (i.e., provinces in SIC) into additional ten zones using the k-means clustering algorithm based on the time series of average nodal prices at the province level, in the spirit of Mercadal (2021).[26]

To estimate the transmission capacity between these eleven zones, we calculate trade flows between the zones in our data. Based on these trade flows, we set the available transmission capacity to the 95th percentile of the trade flows observed in the data.[27] Table A.1 shows the estimated trade capacity between the eleven zones. We find that this approach captures well the transmission expansions created by the interconnection in 2017 and the reinforcement in 2019. For example, the transmission capacity for line 1 (the connection between SING and SIC) was expanded by about 600 MW by the interconnection, and the transmission capacity for lines 2 to 4 was expanded by about 1,100 MW by the reinforcement. The eleven zones appear to do well at describing the main bottlenecks in the system, and the geographical split and transmission capacity appears to be consistent with engineering models of the Chilean electricity market, such as Haas et al. (2018), which features four zones.

Cost functions We allow the cost function $C_{ztj}(q_{ztj})$ to differ by zone and technology. For coal, diesel, and other non-gas thermal generators, we directly use the unit-level marginal costs observed in the daily cost data.[28] In addition to the marginal costs, we also include ramping costs as parts of the cost function for coal power plants. Estimating these parameters is beyond the scope of our exercise, so we use parameters from engineering constraints and the existing empirical evidence (Wolak, 2007; Reguant, 2014; Gowrisankaran et al., 2023) – we assume that coal power plants can only ramp up or down their production by 10% of their capacity at any given hour.[29]

We also observe unit-level marginal costs for natural gas power plants. However, gas power plants usually have several marginal costs that differ by the type of long-term natural gas contract being used. Unfortunately, our data do

[26] Our algorithm is simpler than Mercadal (2021), as we do not add an outer loop to discipline the k-means clustering algorithm. In addition, we make one adjustment to the result of the k-means clustering algorithm. The north and the south of Santiago are initially assigned to the same zone based on the algorithm because these two regions had similar time-series price variation. Because these two regions are not contiguous, we define these regions to be separate zones.

[27] We do not use the maximum flow because our zones do not reflect the exact network configuration. The maximum flow constructed with our zone tends to be an outlier. We also constraint the trade constraints to be non-decreasing over time.

[28] For plants in SING, we observe daily costs. For plants in SIC, we observe daily costs for each of the three "blocks", where blocks are defined as three of the eight-hour segments of the day. Therefore, we use block-level daily cost for plants in SIC.

[29] We also extended the model to have startup costs. We set plants' minimum operational capacity (conditional on running) to 40% and set startup costs to the equivalent marginal costs of eight hours running at minimum capacity as a proxy for the necessary fuel to start up a plant. However, the computational cost of adding startup costs was quite large due to the need to compute equilibrium solar investment for our counterfactuals. Yet, we found that the extended version of the model with startup costs did not improve the model fit compared to the main model with ramping cost because ramping costs sufficiently discipline coal production in the model (Figure A.6) and did not lead to significant differences in aggregate market outcomes or solar profitability. Therefore, we have decided to use the model that includes ramping costs but startup costs.

not specify which natural gas contract is used for each hour or how much quantity of natural gas is available under each contract type consistently throughout the sample. Differences in marginal costs by contract type can be large, as some gas contracts have a zero marginal cost due to their take-or-pay nature. For this reason, we estimate an hourly zone-level supply curve for natural gas generators based on hourly nodal prices and observed hourly generation from natural gas power plants for every month of the sample. We also include limits to hourly generation set to the minimum and maximum observed generation at each month of the sample.[30]

Hydro production is very dependent on expectations of future availability of water, which the Chilean central operator estimates using medium- and long-term forecasting models. Because our model is much more limited, we estimate supply curves based on hydro production and nodal prices at the zone level, as with natural gas. We regress the observed equilibrium quantities of hydro on equilibrium prices and estimate a month-of-sample supply curve. Additionally, we constrain the amount of water to be used during a week to equal the observed total amount used in that same period, to reflect the nature of limits to hydro availability.[31] We also include minimum and maximum hydro limits to reflect flow regulations and capacity constraints based on the minimum and maximum observed generation at each month of the sample.

Solar capacity To determine maximum and minimum capacities for solar power, we take advantage of the extremely predictable solar potential in the Atacama region.[32] While our data are very detailed regarding solar output, we lack data on solar *curtailment*. Solar curtailment is important in our application, as indicated by the zero prices in the Atacama region before the transmission expansion. We estimate capacity factors by week of year and hour of day based on data from 2019, which is the period in which curtailment is less prevalent thanks to the reinforcement. Given that we do not observe zero prices during that period, we assume that curtailment is not occurring. We use these capacity factors times the installed (or counterfactual) capacity to model potential solar output in other years.

Goodness of fit While the final model is a stylized representation of the Chilean electricity market that abstracts away from many aspects of electricity market operations, Figure 5 shows that it captures the evolution of prices in the data. The figure also shows that the model captures moments of scarcity in the system with price spikes. Table A.2 in the Appendix shows that we also match well the production attributed to each generation source across the three periods of study. Our baseline model successfully captures an increase in the production of renewable generation when transmission gets expanded and matches well the observed percentage increases in the data. Generation from the other fuel types are also relatively well-matched, except for the share of coal at the end of the sample, which our model

[30] We include further details in Section Appendix B.

[31] We also have solved the model with daily and monthly water use, allowing more reshuffling of hydro resources. Our overall results remain similar, although monthly reshuffling significantly lowers price volatility, counter to our observed data.

[32] Solar potential and availability are very homogeneous in the Atacama desert due to its climatic conditions, (lack of) geographical features, and lack of cloud cover throughout most of the year. Figure A.4 plots the 5th and 95th percentile of the distribution of hourly capacity factors in zones 1 and 2. One can see that there is very limited variation in capacity factors even within an entire season. Monthly distributions are even tighter.

overpredicts. This is because the transmission line makes coal from the northern zones more attractive in our model.[33]

[Figure 5 about here]

5.2 Investment Model

The second part of the model is an investor's decision regarding investment in new renewable plants. Our primary objective is to model and estimate how solar investment changes in response to changes in trade capacity between zones. With this investment model and the dispatch model described in section 5.1, we can simulate counterfactual scenarios with different levels of transmission capacity. We begin with a one-shot investment model in this section and extend it to a multi-period investment model in Section 5.4.

We assume that entry into solar power generation is competitive and then solve for the equilibrium solar investment that is consistent with a zero-profit entry condition presented below. The assumption of a competitive environment in the entry of solar power is consistent with our data. First, we show solar generation market shares in solar-intensive regions, zone 1 (Antofagasta) and zone 2 (Atacama), in the Appendix Table A.7. Enel is the largest firm, with 24% solar generation market share, but the other 76% of the shares consist of many firms, including smaller-scale new entrants. The Herfindahl–Hirschman index (HHI) based on these market shares is 1066, which suggests a competitive environment. While some large incumbent firms such as AES have not invested in the early deployment of solar, several others have entered the market. Second, we find that many suppliers participated in the auctions for the Power Purchase Agreement (PPA), and the data suggest that these auctions were competitive.[34]

With the market clearing process in equation (2) in mind, renewable investors will expand investment in new renewable plants k until the following zero-profit condition at a given zone is satisfied:

$$E\left[\sum_{y\in Y}\frac{\sum_h p_{zyh}(\mathbf{k})\times q_{zyh}(\mathbf{k})}{(1+r)^y}\right] = c_z\ k_z, \quad \forall z \tag{3}$$

where y indexes a year, h indexes an hour, r is the discount rate, p_{zyh} is the market clearing price at zone z from the solution of equation (2), k_z is solar capacity in zone z, and $\mathbf{k}$ is a vector of solar capacity in each zone. Due to the direct cannibalization effect of solar power on market prices, the marginal revenue of solar investment is decreasing in k_z. As we explain below, we use data on $\mathbf{k}$, the dispatch model in equation (2), and the equilibrium condition in equation (3) to estimate c_z, which is the investment cost per unit of capacity at zone z. To model market expectations in the long run, we use the distribution of fundamentals (demand and costs) from data in 2018 and 2019. We assume that once built, solar panels last for 25 years, which is the standard lifespan of a panel assumed in the industry.

[33]Note that this will tend to reduce the value of the line due to greater environmental externalities than those observed in the data, and therefore affect our cost-benefit analysis conservatively.

[34]For example, 38 firms participated in the 2015 auction, of which 5 won; 84 firms participated in the 2016 auction, of which 22 won; 24 firms participated in the 2017 auction, of which 5 won; and 29 participated in 2021 auction, of which 5 won.

In principle, we could solve for solar investment in every zone, but it would be computationally complex. We focus on solar in zones 1 (Antofagasta) and 2 (Atacama) because most of all utility-scale solar investment occurs in these two zones. The latitude and radiation in the north of Chile make these areas substantially more productive than other parts of the country, and therefore, these two regions play a major role in expansion in solar power.

The first step is to estimate c_z based on the data and equation (3). Our data provide the observed levels of solar investment (k_z). With this investment levels and transmission constraints in the presence of the interconnection and reinforcement, we can run the dispatch model in equation (2) to obtain the equilibrium $p_{zyh}(k_z)$ and $q_{zyh}(k_z)$. For the interest rate r, we use $r = 0.0583$ based on Moore et al. (2020).[35] These variables and equation (3) allow us to estimate c_z. We find that $c_1 = 1.84$ and $c_2 = 1.67$ million per MW installed.

The second step is to run counterfactual policy simulations based on the data, equations (2) and (3), and the estimated c_z. We can change f_{lz} in equation (2) to reflect transmission capacity in a counterfactual scenario. With this counterfactual levels of transmission constraints, we solve for the dispatch model at a given level of solar investment k_z. The solution of the dispatch model produces the equilibrium hourly prices and production, $p_{zyh}(k)$ and $q_{zyh}(k_z)$, at a given k_z. We then search for the equilibrium k_z^* that simultaneously satisfy the zero profit condition (3) in each zone. We use this procedure to run counterfactual policy simulations in section 5.3.

Goodness of fit Admittedly, the investment model in equation (3) is a stylized representation of the investors' expectations and solar investment in this market. However, even with such a stylized model, our estimated costs per MW installed (c_1 and c_2) are on a similar order of magnitude as the solar installation costs observed in our data. In the power plant investment data collected by the CLAPES UC-CBC, we observe completion dates and costs for large-scale solar installations at the plant level.[36] For the 107 completed projects in all regions, the average cost is 1.95 million dollars per MW. For projects at the end of our sample period, five solar plants in zone 1 and another five in zone 2 were completed during 2017 to 2019, with a capacity-weighted average cost of 1.97 million per MW for zone 1 and 1.63 million per MW for zone 2. The costs estimated from our estimation ($c_1 = 1.84$ and $c_2 = 1.67$) fall within this range.

5.3 Simulating the Benefits from Market Integration

In this section, we use the model presented in sections 5.1 and 5.2 to solve for the market equilibrium for three scenarios that help us quantify the impact of market integration with and without investment effects. As described in Section 5.2, we use the distribution of fundamentals, such as hourly demand and daily costs, from data in 2018 and 2019 (the last two years of our sample period) to model market expectations in the long run. The first scenario is

[35] This number is nearly identical to 0.06, the discount rate used by the Chilean government for their public investment projects.

[36] See https://www.cbc.cl/ppicbc/.

Actual scenario, in which transmission capacity is expanded by the interconnection and reinforcement, as it actually happened in Chile. This scenario serves as our baseline.

As a second scenario, we simulate a counterfactual as if the interconnection and reinforcement lines had not been built. The absence of market integration would reduce the profitable level of solar investment, but we purposely hold solar investment fixed in this scenario. Instead of solving for equation (3), we assume that solar investment remains the same as *Actual scenario*. With this solar investment level, we change f_{lz} in equation (2) to reflect the transmission constraints in the absence of the interconnection and reinforcement. We call this second scenario *No market integration (without investment effects)*.

In a third scenario, we further incorporate the investment effects of market integration. We change f_{lz} in equation (2) to reflect transmission capacity in the absence of the interconnection and reinforcement. With this counterfactual levels of transmission constraints, we simultaneously solve for the dispatch model in equation (2) and investment model in equation (3) to find the equilibrium solar investment, dispatch quantities, and market cleaning prices, as described in Section 5.2. For expositional purposes, we find it helpful to show the counterfactual solar investment level as a percentage of what is built in *Actual scenario*. We call this third scenario *No market integration (with investment effects)*.[37]

Panel A in Figure 6 shows the equilibrium prices at noon in the Atacama region for the three scenarios. The actual scenario (market integration), which is the first scenario simulated by our model, shows the same pattern as what we see in the observed data in Figure 4. The price is often zero before the interconnection in 2017 because some solar production cannot be exported to other regions. After the interconnection, the price increases to around 50 USD/MWh as this region can export solar power to other regions. In contrast, in the counterfactual scenario of no market integration without investment effects, the price would not increase and continue to be zero in many days because some solar production still cannot be exported to other regions. This is certainly not a realistic equilibrium in a dynamic sense because solar power would be unprofitable.

[Figure 6 about here]

Once we account for investment effects, we find that only a small portion of the observed solar capacity would have entered in the absence of market integration, based on the assumption that investors need to have the net present value of their investments become positive in 25 years. Our counterfactual simulation results show that the equilibrium solar plant capacity in zone 1 (Antofagasta) and zone 2 (Atacama) would be 15% and 20% of the solar capacity in the actual scenario, respectively. These reductions in solar investment brings the equilibrium prices back up to higher levels, as shown in Panel A in Figure 6.

[37] We can define the entry threshold as a percentage because solar production in the Atacama desert is very homogeneous. Therefore, the location of the solar panels is not as relevant as in other applications (e.g., more heterogeneous solar areas or wind power applications). Figure A.4 in the Appendix shows that the range between the 10th and 90th quantile of solar output is very narrow in the northern part of Chile. Note that part of the range is directly explained by the solar movement within a season. Within-month variation is even smaller.

Panel B in Figure 6 presents solar generation (GWh/day) for the three scenarios. After the interconnection in 2017, we observe a higher level of solar generation in the actual scenario compared to the counterfactual scenario of no market integration without investment effects. This difference shows how much solar power cannot be produced without market integration because of the inability to export solar power (i.e., curtailment). One can see that curtailment increases as solar capacity grows, representing a substantial share of output. Table 3 shows that curtailment in zone 2 is 16% on average at the end of the period (column 2). Once investment effects are accounted for (column 3), the difference in solar production is much larger, with solar generation remaining substantially below what is observed in the actual scenario.

In columns 1 to 3 in Table 3, we provide a summarized quantitative comparison between these three counterfactuals. Column 1 shows the actual scenario, and columns 2 and 3 show the counterfactual sceinro of no market integration with and without investment effects. Using the results in this table, we examine additional theoretical predictions described in Section 2. Market integration increases solar production by 10% if we ignore the investment effects and 185% if we incorporate them. In line with Observation 1, in the presence of anticipated solar investments, ignoring investment effects understates the reduction in generation costs—it predicts a reduction in generation costs of 3% on average (7% at noon, an hour with high solar generation). Once we incorporate the investment effects, the reduction in generation costs is 8% on average and 18% at noon. These results also imply that 3% is an upper bound on the *net* benefits of investment accounting for solar investment costs, as shown in Observation 1 in Section 2.

[Table 3 about here]

The equilibrium prices presented in Table 3 suggest that market integration can successfully reduce prices at the system level. The prices in columns 1 to 3 are consistent with the theoretical prediction from Observation 2 in Section 2. In the presence of anticipatory investment, price reductions from market integration would be underestimated if the investment effects are not incorporated. Indeed, the price reductions from column 2 (without investment effects) to column 1 are underestimated compared to the reductions from column 3 (with investment effects) to column 1.

Furthermore, prices in Atacama (a solar-intensive region in the north) and Santiago (a demand center in the central-south) are consistent with Observation 3. If we do not incorporate investment effects, the price in Atacama is predicted to be very low in the absence of market integration (6.4 USD/MWh in column 2). This is because it ignores the fact that some solar entry would be unprofitable without market integration. As a result, the impact of market integration on price convergence between these two regions is overstated when investment effects are ignored, as shown in Observation 3 in Section 2. Column 2 suggests that if we ignore the investment effects, the price difference between Atacama and Santiago is 53.9 USD/MWh with no market integration and 6.4 USD/MWh with market integration. Thus, it is tempting to conclude that the price convergence effect of market integration is 44.5 (=53.9-6.4) USD/MWh. However, once the investment effects are accounted for in column 3, the price difference without market integration is

13.7 USD/MWh, implying that the price convergence effect is 7.3 (=13.7-6.4) USD/MWh.[38]

5.4 An Extension to a Multi-period Investment Model

The investment model in the previous section focuses on the equilibrium quantity of solar investment without modeling the investment path (i.e., the timing of investment). As described above, this simple model is parsimonious yet allows us to examine the core of our research question. To estimate the investment path, we need to add additional assumptions and structures to the model. Below, we begin by describing our multi-period investment model and how we estimate the necessary parameters in the model. We then use the model and estimated parameters to conduct counterfactual simulations and contrast the results with the ones obtained with the one-shot investment model.

Estimation Our multi-period investment model solves for the zero profit condition that rationalizes the observed solar investment path in the data between 2014 and 2019. We assume that a life-span of solar plants is 25 years and, therefore, solar investors consider 25 years of revenue. The equilibrium condition is that in each year between 2014 and 2019, the marginal revenue from solar investment in year y has to be equal to the marginal cost of solar investment in year y. For the final investment year in 2019, this condition can be written by,

$$E\Big[\Pi_{z,19} \mid \mathbf{k}_{19}\Big] + \sum_{t=1}^{t=24} \left(\frac{1}{1+r}\right)^t E\Big[\Pi_{z,\text{post19}} \mid \mathbf{k}_{19}\Big] = c_{z,19}(\Delta k_{z,19}), \quad \forall z \tag{4}$$

where $\Pi_{z,y}$ is the marginal revenue from solar investment in zone z and year y, $\mathbf{k}_y$ is a vector of solar capacity in each zone in year y, and r is the discount rate. The first term is the expected marginal revenue in 2019, and the second term is the expected marginal revenue in the post-2019 period. The left-hand size of the equation, therefore, characterizes the marginal revenue for the 25-year period with respect to a unit increase in solar investment in 2019. The right-hand side of the equation is the marginal cost of solar investment as a function of $\Delta k_{z,19}$, which is the *incremental* solar capacity in 2019 in zone z.

We observe each year's solar investment from the data, and can calculate the marginal revenue from solar investment by using the dispatch model in equation (2).[39] Therefore, our objective is to use this equilibrium condition to estimate the marginal cost function $c_{z,19}(\Delta k_{z,19})$.

We then solve for the equilibrium condition for investment in 2018, taking into account future expectations.

$$E\Big[\Pi_{z,18} \mid \mathbf{k}_{18}\Big] + \left(\frac{1}{1+r}\right) E\Big[\Pi_{z,19} \mid \mathbf{k}_{19}\Big] + \sum_{t=2}^{t=24} \left(\frac{1}{1+r}\right)^t E\Big[\Pi_{z,\text{post19}} \mid \mathbf{k}_{19}\Big] = c_{z,18}(\Delta k_{z,18}). \quad \forall z \tag{5}$$

[38] Note that Observation 3 is derived under the assumption that market integration results in full price convergence. As shown by the column under the actual scenario, we observe that regional prices converge, but the convergence is incomplete.

[39] Same as the one-shot model, we use the distribution of fundamentals (demand and costs) from data in 2018 and 2019 to model market expectation in the post-2019 period.

Similar to equation (4), the left-hand side of this equation is the marginal revenue from solar investment in 2018, and the right-hand side is the marginal cost in 2018. We proceed similarly to solve for the equilibrium conditions for solar investment in 2017, 2016, 2015, and 2014. This procedure allows us to estimate the marginal cost functions $c_{z,y}(\Delta k_{z,y})$.

For the marginal cost functions, we include a few structures that help us understand and rationalize the observed investment path in the data. First, to better capture that firms might not be able to build all solar panels in one year, we model each year's marginal cost function to be increasing in the incremental solar investment $\Delta k_{z,y}$. If we assume a constant marginal cost in each year, the model tends to find it optimal to only invest in a year, which is inconsistent with what we observe in our data, as shown in Figure 4.

It is important to clarify that because the marginal cost functions and expectations over time are different in this multi-period model and the one-shot model presented in Section 5.2, results from these two models are not directly comparable. They can be thought of as alternative models. Although we will contrast the results from these investment models and discuss the implications, we want to emphasize this point.

Second, we introduce a behavioral parameter $\gamma_{z,y}$ that reflects a potential wedge between the observed (or accounting) marginal cost of solar investment and the *perceived* marginal cost. Recall that we observe plant-level solar investment cost per unit of capacity in our data. However, this cost does not necessarily fully characterize the marginal cost *perceived* by investors. For example, as shown in Figure 4, solar investment occurred much earlier than the transmission line was built. In this period, the observed solar investment cost was declining over time. Therefore, the trend in the observed solar cost could not explain this anticipatory investment. Firms may have perceived that earlier investment had values that are unobserved in our data. For this reason, we use behavioral parameters $\gamma_{z,y}$ that allows the model to have the perceived marginal cost to be different from the observed solar cost. We discuss below alternative interpretations of $\gamma_{z,y}$ and their implications for the counterfactual simulations.

Specifically, we model the marginal cost functions by,

$$c_{z,y}(\Delta k_{z,y}) = \gamma_{z,y}\alpha_y + \beta\Delta k_{z,y}, \tag{6}$$

where α_y and β are estimated from the observed solar cost data as described below. With the estimated α_y and β, the only unknown parameters will be $\gamma_{z,y}$, which will be estimated from the investment equilibrium conditions in equations (4) and (5). The behavioral parameters $\gamma_{z,y}$ shifts the marginal cost curve up or down in each period and each zone to reflect a potential wedge between the observed and perceived marginal costs.

We use the following procedure to estimate α_y and β from the observed solar cost data. We allow it to change over time to reflect the declining trends in the observed solar cost. We assume that the marginal cost of solar investment *within* a given year increases linearly with the new capacity added in that year.[40] One challenge in estimating a linear supply curve for every year is the limited number of observations—in some years, few (if any) solar plants were built. Therefore, we assume that the slope of the linear cost curves does not change over time, while the intercept α_y declines linearly with time to reflect the decline in solar cost. Normalize the year 2014 to zero (i.e., $y = 0$ for 2014), we estimate α_y and β by the following OLS regression,

$$c_{iy}^{obs} = \underbrace{\theta_0 + \theta_1 * y}_{\alpha_y} + \beta * \text{CumulCapacity}_{iy} + \epsilon_{iy}. \tag{7}$$

Here c_{iy}^{obs} is the observed investment cost of plant i (which entered in year y). $\text{CumulCapacity}_{iy}$ is a plant i's capacity, plus the sum of capacity for plants that entered in year y and had lower costs than plant i. We weight the regression by plant i's capacity. Panel A in Table A.8 shows the regression estimation for the cost function, confirming declines in costs over time (of 0.21 million USD/MW per year) and increasing marginal costs within a year.

Taking α_y and β from the previous step, the only remaining unknowns in equations (4) and (5) and other years' investment equilibrium conditions are $\gamma_{z,y}$. We find $\gamma_{z,y}$ that makes the marginal revenue from solar investment in year y to be equal to the marginal cost in year y. We repeat this estimation for each year. Note that we assume that firms have rational expectations of future outcomes and use the realized investment levels in future years to model their expectations.[41]

Panel A of Figure 7 and Panel B in Table A.8 show the estimation results for $\gamma_{z,y}$. The estimated $\gamma_{z,y}$ are substantially lower than one before 2017 (i.e., before the interconnection). This implies that the perceived marginal cost of solar investment is lower than the observed marginal cost in these years. There are a few reasons that could explain why $\gamma_{z,y}$ is below one before 2017. First, γ could capture anticipation effects regarding the grid expansion. There could be unobserved benefits for firms to invest early, for example, to make sure to secure permits and complete plant constructions before the interconnection. Second, there was an unexpected delay in the completion of the new transmission lines, and therefore, some investors might have invested earlier than the completion.[42] Third, firms might have had different expectations about future demand and other supply conditions than those in our model. Fourth, during this period, the regulator announced renewable targets for 2025. Even though our data suggests that these targets have not been binding, there could have been more uncertainty in 2015, encouraging early investments.[43]

[40] Among the twenty-five solar plants that entered Atacama by the end of 2019, we match eighteen of them in the CBC data, which accounts for 97.5% of the solar capacity. Among the nineteen plants that had entered SING by 2019, we match fifteen of them in the CBC data, accounting for 95.7% of the solar capacity. We also included one solar plant that finished construction in 2019, even though it did not have positive generation until 2020.

[41] We also experimented with a scenario in which firms have expectations that follow a random walk, i.e., they only have a best guess on future investment. We decided to use the simpler approach as the general implications of the simulations were similar.

[42] The constructions of the interconnection and reinforcement were delayed by 9 months and 17 months, respectively, relative to the completion schedule initially announced.

[43] On October 22, 2013, Law 20698 was enacted, establishing the goal for renewable energy generation (solar and wind) of 20% of the total by 2025. In October 2020, the goal was already exceeded with a generation of 22.8%, a percentage that has been growing. In January 2023, it reached 33.4%.

[Figure 7 about here]

The relatively large increases in $\gamma_{z,y}$ around 2017 in Figure 7 could suggest that the first two reasons (i.e., the anticipation effects of the grid expansion) could be major reasons why $\gamma_{z,y}$ are substantially lower than one before 2017. However, our model cannot rule out the possibility that other factors could contribute to $\gamma_{z,y}$ as well. Therefore, in our counterfactual policy simulations below, we show results with a different set of assumptions on the interpretation of $\gamma_{z,y}$.

Simulating the Benefits from Market Integration with the Multi-period Investment Model We use the multi-period investment model described above to simulate the counterfactual scenario of "no market integration." The simulation procedure is similar to the one presented for the one-shot investment model in Section 5.2. We change f_{lz} in equation (2) to reflect the transmission capacity in the absence of the interconnection and reinforcement. With this counterfactual level of transmission constraints, we simultaneously solve for the dispatch model in equation (2) and the multi-period investment model in equations (4) and (5) to find the equilibrium solar investment, dispatch quantities, and market cleaning prices.[44]

As described above, the interpretation of $\gamma_{z,y}$ matters to this counterfactual simulation, and therefore, we show results with three different assumptions on the interpretation of $\gamma_{z,y}$. In the first counterfactual, we assume that the wedge between the observed solar cost and the perceived solar cost is due to the anticipation effects of the transmission expansion. In this case, this wedge would disappear, and therefore $\gamma_{z,y} = 1$, in the counterfactual scenario of no market integration.

In the second counterfactual, we assume that this wedge is entirely due to factors unrelated to the anticipation effects of the transmission expansion. In this case, even in the "no market integration" counterfactual scenario, the wedge between the observed solar cost and perceived solar cost stays the same as the actual scenario. That is, we assume $\gamma_{z,y} = \hat{\gamma}_{z,y}$, where $\hat{\gamma}_{z,y}$ are the estimated γ in the previous section. These first and second counterfactuals provide bounds of the simulation results with the multi-period investment model as the first counterfactual assumes that the wedge would completely disappear without market integration, and the second counterfactual assumes that the entire wedge remains the same as in the actual scenario.

In a third counterfactual, we correct for the possibility that firms were too optimistic to expect the transmission expansions to be completed by the time when their solar panels were connected to the grid. To do so, we re-estimate $\gamma_{z,y}$ by calculating solar revenues in 2014–2019 as if there was full market integration (i.e., both of the interconnection and reinforcement) during the entire period. We call the estimate from this approach $\tilde{\gamma}_{z,y}$. We do not claim that this

[44] To solve for a counterfactual equilibrium, we use a shooting algorithm in which we guess the final level of investment k_{19}. Taking k_{19} as given, we can compute the incremental level of investment Δk_{19} consistent with Equation (4). Once we know Δk_{19}, we can move to 2018, set $k_{18} = k_{19} - \Delta k_{19}$, and compute the incremental investment consistent with the zero profit condition in 2018. We use the same approach backward and solve for 2017, 2016, 2015, and 2014 following a similar procedure. To discipline the shooting algorithm, we assume that no investment had happened before 2014, and therefore $\Delta k_{14} = k_{14}$ in equilibrium.

approach can correct all relevant anticipation effect of the grid expansion as the anticipation effect could influence investors' decisions in many different ways. Rather, this approach attempts to correct one aspect of it, which is investors' potential optimism about the timing of grid expansion. The resulting behavioral parameters, $\tilde{\gamma}_{z,y}$ are closer to one than those without this correction, although we find it still below one, as shown in Appendix Table A.8. We use $\gamma_{z,y} = \tilde{\gamma}_{z,y}$ in the third counterfactual to simulate the counterfactual of "no market integration."[45]

Panel B in Figure 7 presents the predicted cumulative investment levels over time for the actual scenario (with full market integration) and the counterfactual scenario of no market integration. We present the predicted cumulative investment levels as a percentage of the actual scenario's cumulative investment level in the final investment year 2019. By construction, the investment levels in the actual scenario matches the observed investment levels in our data. As shown in this figure and Figure 4, in the actual scenario with market integration, most of the solar investment happened in anticipation of grid expansion in 2017.

[Figure 7 about here]

The counterfactual investment levels in this figure suggest that the absence of market integration would reduce investment across all counterfactuals considered. Recall that the simulation with $\gamma_{z,y} = 1$ assumes that the wedge between the observed solar cost and perceived solar cost is entirely driven by the anticipation effect of market integration. In this case, the marginal cost of solar investment in the counterfactual scenario (with no market integration) is equal to the observed solar cost. Because the observed solar cost has been declining over time in this period, the model predicts that firms invest less in earlier years and more in later years, as shown in the figure for the case with $\gamma_{z,y} = 1$. In the final period, the counterfactual investment levels are substantially lower than the actual scenario, at 25% in Atacama and 75% in Antofagasta relative to the actual scenario.

The simulation with $\gamma_{z,y} = \hat{\gamma}_{z,y}$ assumes that the entire wedge between the observed solar cost and perceived solar cost remains in the counterfactual scenario of no market integration. Therefore, even in the counterfactual scenario, the perceived solar costs in the earlier years are substantially lower than the observed solar costs. For this reason, the model predicts more investments in the early years compared to the case with $\gamma_{z,y} = 1$. In the final period, the counterfactual investment levels are 55% in Atacama and 70% in Antofagasta relative to the actual scenario. The simulation with $\gamma_{z,y} = \tilde{\gamma}_{z,y}$ corrects for the possibility that firms were too optimistic to expect the transmission expansions to be completed by the time when their solar panels were connected to the grid. With this approach, we find the level of investment in the final year would be 60% in Atacama and 45% in Antofagasta relative to the actual scenario. Therefore, the possibility of firms' optimistic expectations for the earlier completions of transmission expansion could explain around ten percentage points of the early investment.

[45] In this counterfactual, firms have too optimistic expectations about market integration in the early periods. Therefore, investment is not necessarily consistent with zero-profit investment under the correct expectations (i.e., firms who entered early could lose money, ex post.).

In columns 4 to 6 of Table 3, we present the results of counterfactual simulations with the multi-period investment model. Relative to the one-shot model with investment effects, the benefits of the transmission line are not as high. The reason behind this finding is that the estimated solar cost curve is more attractive in the multi-period model so that it predicts higher levels of counterfactual solar investment than the one predicted by the one-shot model. For example, all models predict that market integration results in a decrease in the system-level price, but the multi-period models predict smaller reductions than the one-shot model. Because the costs of solar are more favorable in the multi-period model, we see that these equilibria feature substantially more curtailment than the one-shot model, with prices in Atacama being lower (columns 4-6) than the one-shot model with less investment (column 3) and curtailment around 1-2% of output.

In addition to the market outcomes, we also calculate the daily CO_2 emissions in the final row of Table 3. Emissions across the counterfactuals tend to be higher without the transmission line project when investment effects are accounted for. As one notable exception, emissions can go down without added transmission in the model that ignores investment effects (column 2). This is because the transmission line project does not contribute to expanding solar capacity, and yet it facilitates the transmission of coal power.[46]

In the next section, we use these findings to provide a cost-benefit analysis of transmission investments. In particular, we discuss how the cost-benefit calculation can be changed with and without investment effects and how the alternative assumptions on the investment model changes the estimated benefits of transmission investments.

6 Cost-Benefit Analysis of Transmission Investments

According to the Chilean government, the costs of the interconnection and the reinforcement lines were $860 million and $1,000 million, respectively (Raby, 2016; Isa-Interchile, 2022). These transmission expansions initially presented doubts regarding its economic benefits. For example, Diario Financiero (2013) describes that consumers at first considered that the costs of new transmission lines may exceed the benefits from a unified market. Discussing the benefits to consumers is important, as these line expansions were paid via an increase in energy fees by consumers.[47]

In Table 4, we use results in Table 3 to calculate the benefits of market integration. We show alternative measures of surplus, including savings in consumer cost, savings in generation cost, savings from reduced environmental externalities, because which benefit measure is most relevant would often depend on what question policymakers have.

[Table 4 about here]

The first benefit measure we show is savings in consumer cost that are generated from grid expansions. We obtain

[46] When the line was first discussed in 2011, it is important to note that this was perceived as one of its benefits. While coal generation has negative externalities, coal was at the time much more secure than natural gas.

[47] In 2015, the government of Chile held a public auction to construct the transmission line. In this auction, the objective was to minimize the cost of construction that consumers pay in the tariff associated with electric transmission.

the change in consumer surplus by multiplying electricity demand with the price difference between the full integration scenario and the rest. We implicitly assume that consumer demand is not directly affected by the transmission line project. This should be seen as a conservative assumption regarding the benefits of the line, as renewable power in Chile, partially enabled by expanded transmission, has substantially brought down the costs of energy in the country. We find that the market integration reduces consumer cost by \$176 million per year if we ignore the investment effect in column 1. The consumer saving is substantially larger and estimated to be between \$240 and \$290 million per year when the investment effects are incorporated in columns 2 and 5.

In addition to considering consumer surplus, the line expansion could have reduced negative emissions externalities (Fell, Kaffine and Novan, 2021) due to the replacement of thermal generation. Market integration might have reduced both global pollutants (CO_2) and local pollutants, such as SO_2 and NO_X. Our counterfactual simulations allow us to quantify the difference in electricity production at the unit-by-hour level. We use this information to calculate the reduction in electricity production from each type of thermal plant such as coal and natural gas. We combine this information with the estimates of the negative externality (USD/MWh) by power plant types in Greenstone and Looney (2012) and Carleton and Greenstone (2021). [48]

In column 1, we find that the savings from reduced environmental externalities is $-\$161$ million per year if we do not incorporate the solar investment effects. This is because if we hold solar capacity unaffected by market integration, our model predicts that integration would increase coal generation, as shown in Table 3. Once the investment effects are incorporated, market integration reduces environmental externalities because it increases solar capacity.

The last rows in Table 4 provide a cost-benefit analysis of transmission investments. In our calculation, the cost of market integration consists of the construction cost of the two transmission lines (\$1860 Million USD) and the solar investment costs. The benefit consists of savings in consumer cost, benefits in solar revenues, and reductions in environmental externalities. For the discount rate, 5.83% is a relevant reference point because this is the discount rate commonly used for public investment in Chile (Moore et al., 2020). To examine how the cost-benefit changes with the assumption on the discount rate, we also report results with 0% and 10% discount rates.[49]

We calculate how many years are required to have the benefits of market integration exceed its cost. Column 1 implies that if we ignore the investment effects, it takes 14.8 years to recover the cost of the investment with a 0% discount rate and more than 25 years with higher discount rates. Columns 2 to 5 suggests that the cost-benefit is much more attractive, with a recovery time between 7.1 and 10.7 years with a 5.8% discount rate. This finding implies that

[48] Greenstone and Looney (2012) estimate that the non-carbon external cost is 3.4 cents per kWh for coal generation and 0.2 cents per kWh for natural gas generation. Carleton and Greenstone (2021) calculate a social cost of carbon to be \$125/ton CO_2.

[49] When calculating solar investment cost, we use the "perceived" solar cost discussed in Section 5.4 by interpreting this cost, rather than accounting solar installation cost by itself, as a welfare-relevant cost measure. For the one-shot investment model, we use the long-run solar cost with and without market integration. In the multi-period model with $\gamma = 1$, we use $\gamma = \hat{\gamma}$ to calculate solar costs with market integration and $\gamma = 1$ without market integration. In the multi-period model with $\gamma = \hat{\gamma}$, we use $\gamma = \hat{\gamma}$ to calculate solar costs with and without market integration. In the multi-period model with $\gamma = \tilde{\gamma}$, we use $\gamma = \tilde{\gamma}$ to calculate solar costs with and without market integration. The long-run solar costs are presented in Section 5.2; the two sets of estimated γ's are shown in Panel B of Appendix Table A.8.

ignoring investment effects substantially understates the benefit of the transmission expansion.

Another key finding is that although the choice of investment model is relevant to the cost-benefit calculation, it does not substantially change our quantitative conclusion. Among the three different assumptions on the multi-period investment model, the most conservative model is the one with $\gamma_{z,y} = \hat{\gamma}_{z,y}$. As described in section 5.4, this approach assumes that the entire wedge between the observed solar cost and perceived solar cost is unrelated to the anticipation effect of market integration. With this assumption, the cost recovery time is 10.7 years. The least conservative model is the one with $\gamma_{z,y} = 1$. This approach assumes that the entire wedge between the observed solar cost and perceived solar cost is because of the anticipation effect of market integration. With this assumption, the cost recovery time is 8 years, which is close to the cost recovery time obtained by the one-shot investment model (7.1 years). Therefore, although the choice of investment models is relevant, a cost recovery time is estimated between 7.1 and 10.7 years, all of which is likely to support the cost-effectiveness of the transmission investments conducted in Chile.

Discussion of limitations There are several limitations to our cost-benefit calculations. In several respects, our calculation is likely to understate the benefits of market integration for at least three reasons. First, coal and natural gas prices were lower than the historical average in our sample period. As these fuel prices return to historical averages in the future, the benefit of renewable power would be larger than in our calculation. Second, our calculation includes the benefits from the entry of solar plants only up to the end of our sample period and does not include potential benefits from additional entrants in the subsequent years. Because these additional entries were unlikely to occur in the absence of market integration, this is another reason why our benefit calculation can be underestimated. Third, before the renewable expansion, Chile relied on imports of natural gas and coal to generate large amounts of electricity, which had been an energy security problem. Therefore, renewable expansion provided a benefit of energy security for the country, which is not incorporated in our calculation. Finally, while we focus here on the time to recover the investment, transmission investments are very long-lived and will continue to provide benefits for several decades.

Another limitation is that our simulations take solar investments in non-solar-rich areas into account but does not allow them to respond to transmission expansion. Because solar power in the north of Chile has unparalleled radiation potential, and land near Santiago is much more scarce, this limitation might not be as relevant as in other applications.[50] However, ignoring this margin makes our cost-benefit more favorable because if Chile did not integrate the market, solar investment in non-solar-rich areas could have increased solar capacity. Unfortunately, allowing endogenous investment in these regions would require substantial assumptions because we have much more limited information on the cost of installed solar as there are a lot fewer large-scale solar investment in these regions in our sample period. In addition, our model does not model detailed aspects of land use, as we benefit from the fact that land in the north

[50] According to the Global Solar Atlas (https://globalsolaratlas.info/), an industry-scale installation near Santiago would get around 2,000 kWh/m^2 per year. In comparison, the same installation in Atacama would get 3,000 kWh/m^2. To this difference, one needs to consider that land use restrictions and costs per m^2 in Santiago are potentially much larger.

of Chile is cheap and homogeneous. Therefore, we want to note that an additional analysis along these lines would be an important topic for further research.

7 Conclusions

We study the static and dynamic impacts of market integration on renewable energy expansion. Our theory highlights that statically, market integration improves allocative efficiency by gains from trade, and dynamically, it incentivizes new entry of renewable power plants. Using two recent grid expansions in the Chilean electricity market, we examine how this market integration changed market prices, generation costs, and renewable investments. Based on the insight from this descriptive evidence, we build a structural model of power plant entry to quantify the impact of market integration with and without the investment effects. We find that market integration resulted in price convergence across regions, increases in renewable generation, and decreases in generation cost and pollution emissions. Furthermore, a substantial amount of renewable entry would not have occurred in the absence of market integration. We show that ignoring this dynamic effect would substantially understate the benefits of transmission investments.

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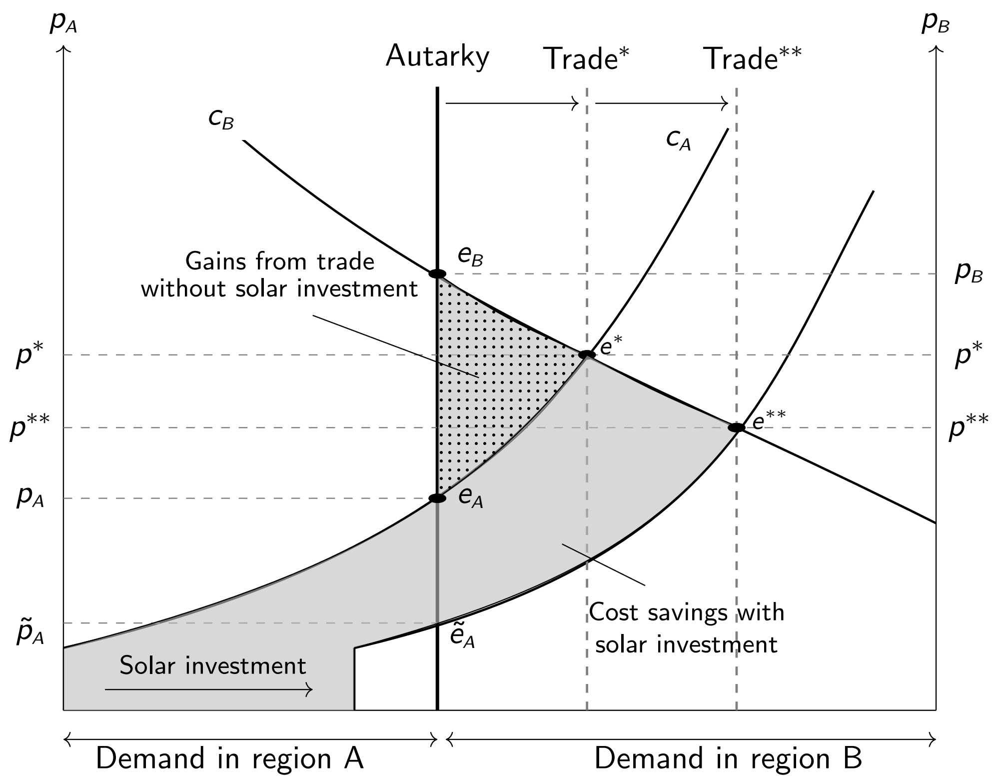
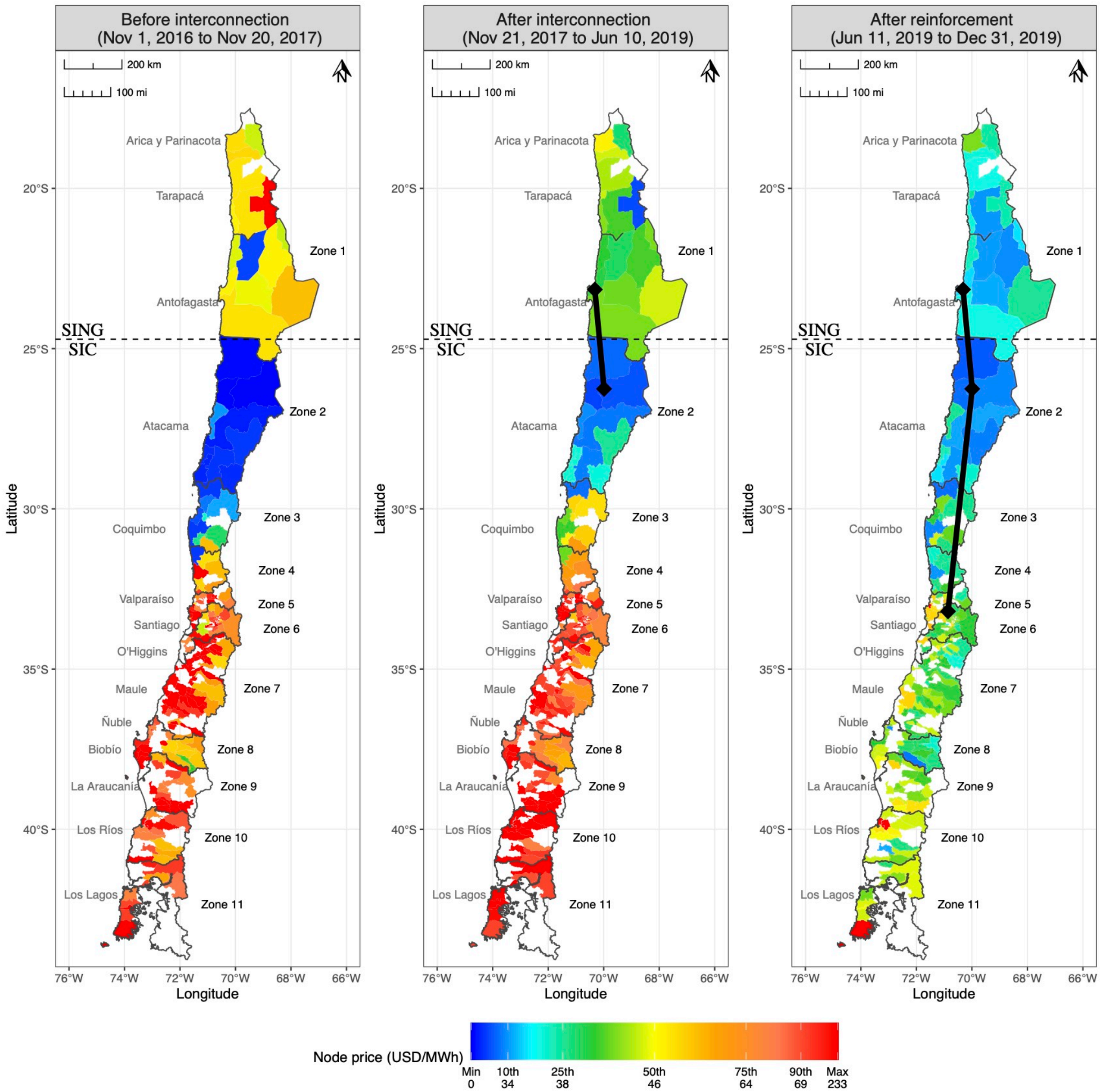
Figures

Figure 1: Static and Dynamic Impacts of Market Integration



Note: This figure summarizes theoretical predictions described in Section 2. The static case considers the impact of market integration, assuming that it does not affect the entry of solar plants. In contrast, the dynamic case takes into account the impact on solar investment. In the static case, the market integration moves the equilibrium to e^*, resulting in the static gains from trade equal to the triangle area e_B, e_A, and e^*. In the dynamic case, the market integration also induces entries of solar plants that have zero marginal cost. As a result, it shifts the cost curve in region A to the right. This equilibrium (e^{**}) generates additional cost savings on the entry of solar plants. We also show that when solar entry occurs in the anticipation of market integration, a commonly used event study design captures only a partial impact (the triangle area e_B, $\tilde{e}_A$, and e^{**}) rather than the full impact of market integration.

Figure 2: Market Integration and Spatial Variation in Electricity Prices

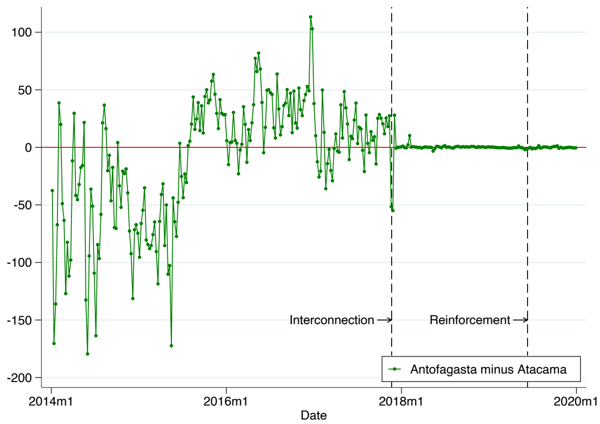


Note: These heat maps examine spatial heterogeneity in wholesale electricity prices. We calculate the commune-level average node prices, weighted by the hourly generation at the node level, and make heat maps for three time periods: 1) before the interconnection, 2) after the interconnection but before the reinforcement, and 3) after the reinforcement. We use the percentiles of the node price distribution to define color categories as shown in the legend. We also show the boundaries of zones defined in Section 5. Zones 1-11 include the following regions (a more detailed mapping is provided in Figure A.2). Zone 1: Arica y Parinacota, Tarapacá, Antofagasta; Zone 2: Atacama, and one commune in Antofagasta; Zone 3: parts of Coquimbo; Zone 4: parts of Coquimbo, parts of Valparaíso; Zone 5: parts of Valparaíso; Zone 6: Santiago, parts of O'Higgins; Zone 7: parts of O'Higgins, Maule, Ñuble; Zone 8: Biobío; Zone 9: La Araucanía; Zone 10: Los Ríos, parts of Los Lagos; Zone 11: parts of Los Lagos.

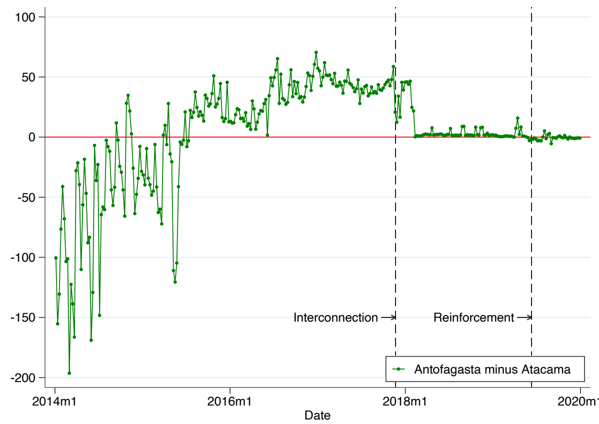
Figure 3: Impacts of Market Integration on Price Convergence

Panel A: Price difference between Antofagasta and Atacama (in USD/MWh)

Midnight (0:00-1:00)

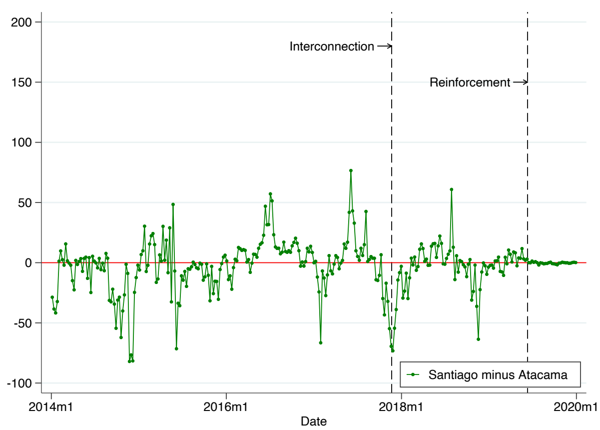


Noon (12:00-13:00)

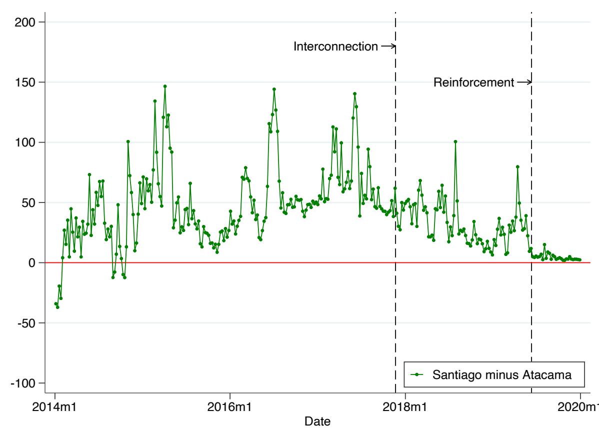


Panel B: Price difference between Santiago and Atacama (in USD/MWh)

Midnight (0:00-1:00)

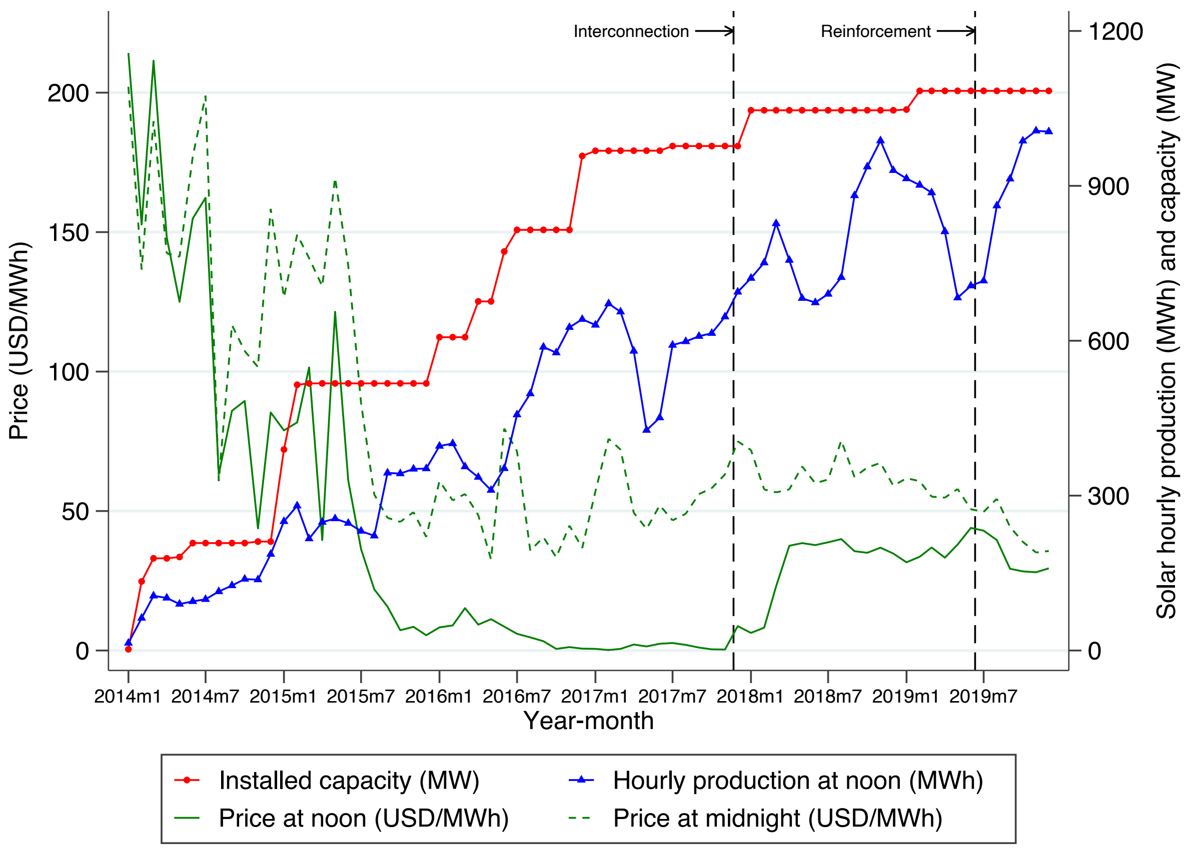


Noon (12:00-13:00)



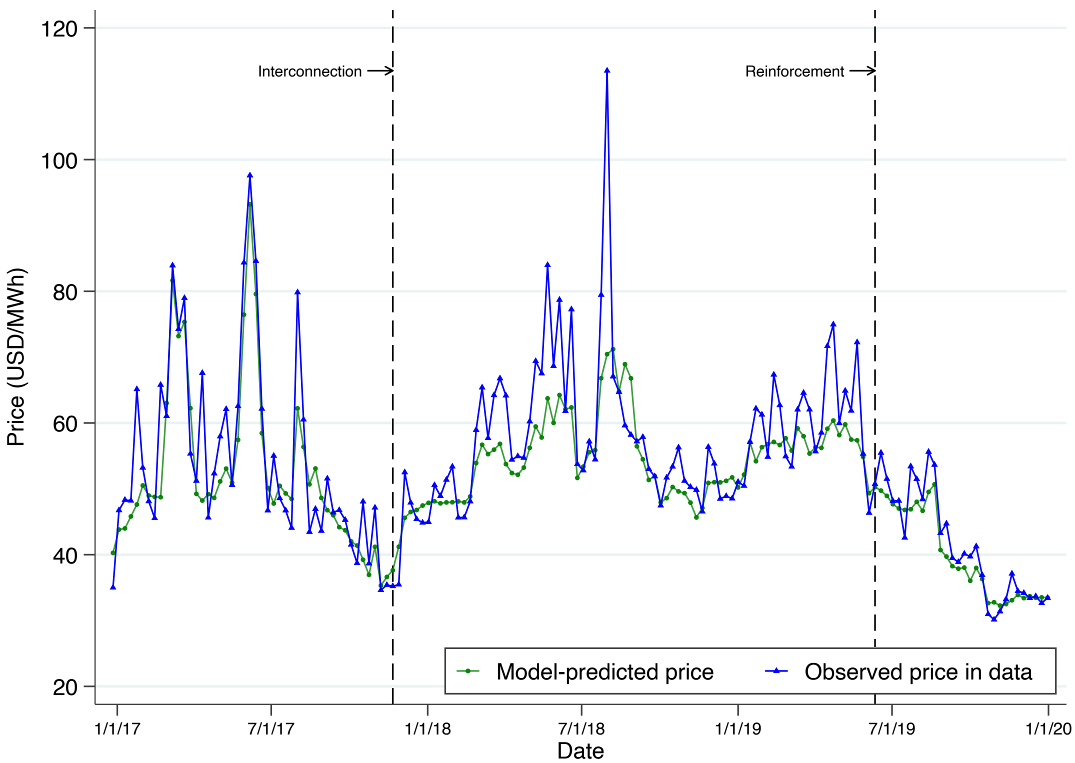
Note: Panels A shows the price difference between Antofagasta and Atacama (the two end points of the interconnection), and Panel B shows the price difference between Santiago and Atacama (the two end points of the reinforcement). For each week, we calculate the weekly averages of hourly prices in each region. We then take the difference between these weekly averages and plot them over time. We use prices in Kapatur (a node in Antofagasta region), Cardones (a node in Atacama region), and Polpaico (a node in Santiago region) to calculate the price differences. These are the nodes nearest to each end point of the interconnection and reinforcement.

Figure 4: Impacts of Market Integration on Solar Expansion



Note: This figure shows the cumulative installed capacity of solar plants, average hourly generation for each month, and node prices for these plants at noon and midnight in Atacama (zone 2). We calculate the weighted average node prices in this figure using plant-level daily solar generation as weight. As more solar enters around 2014-15, the node price at noon began to decline and reached near zero around 2016. Despite the near-zero market price, solar entry continued, which suggests that this investment was considered to be profitable in the long run with the anticipation of market integration in 2017 and 2019, which was publicly announced in 2015.

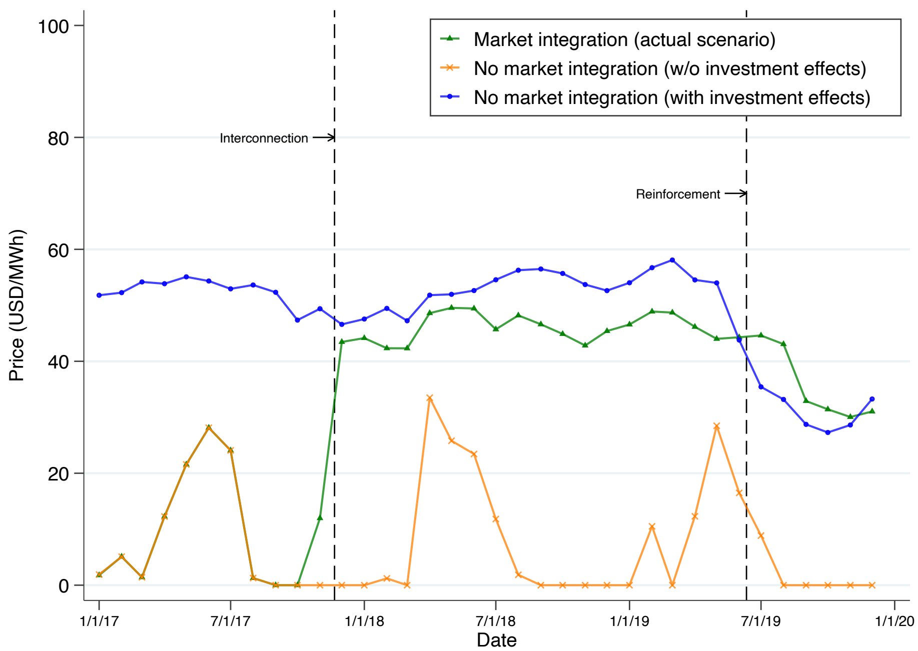
Figure 5: Model Fit: Model-Predicted Market Price and Actual Market Price in the Data



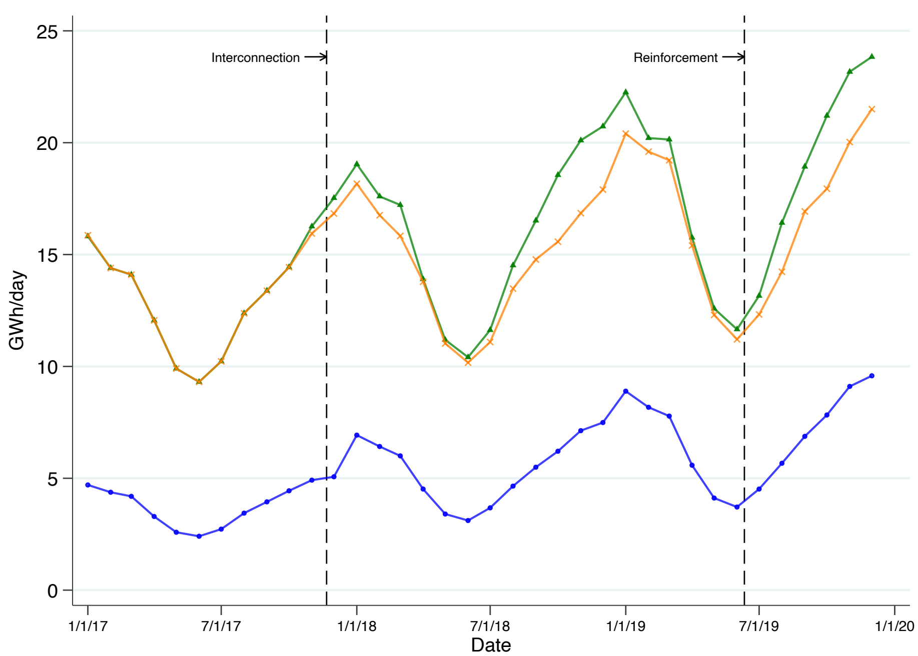
Note: This figure compares the price predicted by the structural model described in Section 5 and actual prices in the data. Each dot represents the weekly average of hourly node prices from all nodes, weighted by the generation at the node level.

Figure 6: Counterfactual Simulation Results

Panel A: Prices in Atacama (Renewable-Intensive Region)



Panel B: Solar Generation

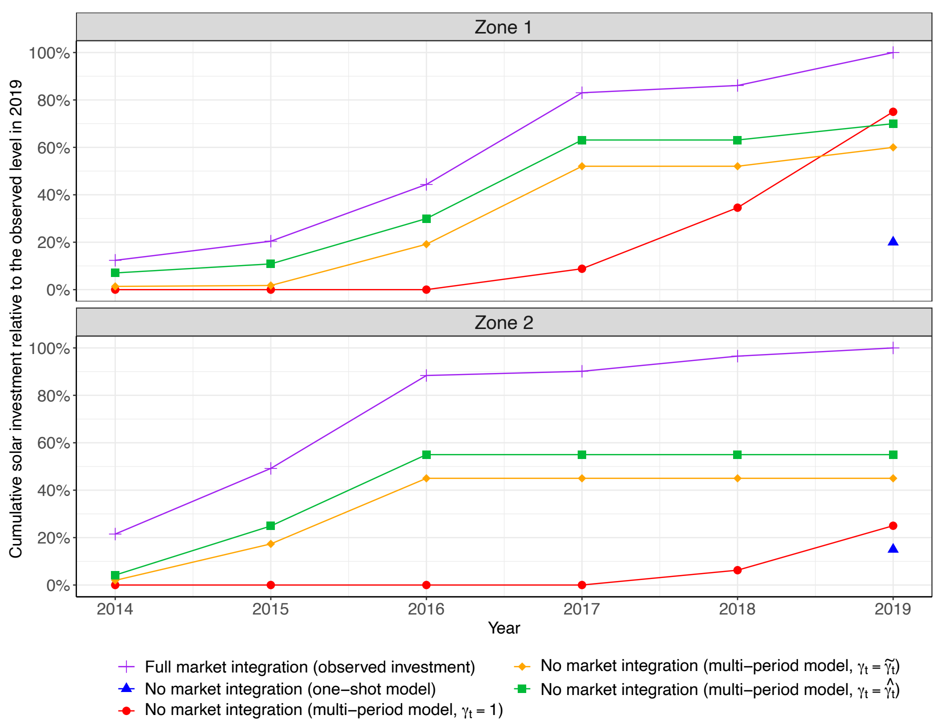


Note: We use the structural model and counterfactual simulations described in Section 5.3 to compute market equilibria for three scenarios. The first scenario is the actual scenario in which market integration happened (the interconnection in November 2017 and the reinforcement in June 2019). The second scenario is a counterfactual case in which the market integration did not happen (no market integration w/o investment effects). The third scenario is equivalent to the second but with investment effects—some entry would not happen without market integration because such an investment would become unprofitable. In this figure, we use the one-shot investment model to compute the counterfactual scenarios (Table A.6 includes results with one-shot and multi-period investment models). Panel A shows the monthly averages of the wholesale electricity prices (USD/MWh) in Atacama region (zone 2). Panel B shows the monthly average of total daily solar electricity generation (GWh/day).

Figure 7: Estimation and Simulation Results from Investment Models

Panel A: Estimates of $\hat{\gamma}_{z,y}$ and $\tilde{\gamma}_{z,y}$

Panel B: Solar investment



Note: Panel A presents the two sets of estimates pf $\gamma_{z,y}$, as described in Section 5.4. Panel B plots solar investment estimated in counterfactuals relative to the observed solar investment level in 2019.

Tables

Table 1: Summary Statistics

	Pre-Interconnection (Nov. 2016 - Nov. 2017)		Post-Interconnection (Nov. 2017 - Dec. 2019)
	SIC	SING	SEN
Hourly total generation at noon (MWh)	6851	2135	9349
	(645)	(186)	(647)
Hourly total generation at midnight (MWh)	5900	2241	8482
	(316)	(195)	(351)
Node price at noon (USD/MWh)	54.46	45.14	52.16
	(35.58)	(16.95)	(25.01)
Node price at midnight (USD/MWh)	52.06	71.66	54.82
	(24.9)	(35.26)	(20.94)
Variable cost: Thermal (USD/MWh)	44.67	42.94	43.73
	(17.28)	(11.12)	(15.08)
Installed capacity (MW)			
Hydro	6225	16	6304
Solar	1315	624	2521
Thermal	6131	3832	10385
Wind	1144	194	2009

Note: This table shows the summary statistics of our data. Installed capacity is defined as the 99th percentile of hourly generation.

Table 2: Static Event Study Analysis of Generation Cost (without Investment Effects)

	Hour 12				All hours			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1(After the interconnection)	-2.76	-2.48	-2.51	-2.42	-2.16	-2.15	-2.15	-2.07
	(0.20)	(0.27)	(0.27)	(0.26)	(0.15)	(0.17)	(0.17)	(0.17)
1(After the reinforcement)	-1.20	-1.13	-1.32	-0.96	-1.08	-0.63	-0.63	-0.61
	(0.20)	(0.55)	(0.58)	(0.58)	(0.14)	(0.35)	(0.37)	(0.37)
Nationwide merit-order cost	1.08	1.10	1.10	1.12	1.01	1.02	1.02	1.03
	(0.02)	(0.03)	(0.02)	(0.03)	(0.01)	(0.01)	(0.01)	(0.01)
Coal price [USD/ton]		-0.03	-0.03	-0.03		-0.01	-0.01	-0.01
		(0.01)	(0.01)	(0.01)		(0.01)	(0.01)	(0.01)
Natural gas price [USD/m^3]			-10.01	-10.36			-0.47	-0.65
			(4.32)	(4.33)			(3.11)	(3.09)
Hydro availability				0.43				0.00
				(0.14)				(0.00)
Scheduled demand (GWh)				-0.51				-0.01
				(0.13)				(0.00)
Sum of effects	-3.95	-3.61	-3.83	-3.38	-3.24	-2.78	-2.79	-2.68
Mean of dependent variable	35.44	35.44	35.44	35.44	38.63	38.63	38.63	38.63
Month FE	No	Yes	Yes	Yes	No	Yes	Yes	Yes
Sample size	1033	1033	1033	1033	1033	1033	1033	1033
R^2	0.92	0.94	0.94	0.94	0.95	0.97	0.97	0.97

Note: This table shows the results of the regression described in equation (1). The dependent variable is the observed hourly generation cost per MWh. We report heteroskedasticity- and autocorrelation-consistent standard errors in parentheses.

Table 3: Counterfactual Simulations to Estimate the Impacts of Market Integration

	(1)	(2)	(3)	(4)	(5)	(6)
	Market integration (Actual scenario)	No market integration (Counterfactual scenarios)				
Modelling assumptions						
Investment effects		No	Yes	Yes	Yes	Yes
Investment model		One	One	Multi	Multi	Multi
Assumption on solar cost				$\gamma = 1$	$\gamma = \tilde{\gamma}$	$\gamma = \hat{\gamma}$
Solar power in Antofagasta (zone 1)						
Investment relative to actual	100%	100%	20%	75%	60%	70%
Investment in MW	693.5	693.5	138.7	520.2	416.1	485.5
Revenue per MW ($1000)	133.8	122.7	133.8	126	128	126.7
Daily solar curtailment (MWh)	0	0	0	0	0	0
Solar output relative to solar potential (%)	100	100	100	100	100	100
Solar power in Atacama (zone 2)						
Investment relative to actual	100%	100%	15%	25%	45%	55%
Investment in MW	1084	1084	162.6	271	487.8	596.2
Revenue per MW ($1000)	121.4	26.3	122.9	115.1	100.9	93.3
Daily solar curtailment (MWh)	0	1410.5	0.2	1.1	41.4	102.8
Solar output relative to solar potential (%)	100	84	100	99.9	98.9	97.9
System-level solar production						
Daily solar production (GWh)	17.6	16.1	6.2	10.1	10.8	12.1
% change relative to actual		(+10%)	(+185%)	(+74%)	(+64%)	(+46%)
Price ($/MWh)						
Daily price (system-level)	49.3	51	53.2	52.8	52.5	52.3
Hour 12 price (system-level)	48.4	48.3	54.1	53.1	52.5	52.1
Hour 12 price in Antofagasta (zone 1)	44.7	42	45	42.6	43.1	42.8
Hour 12 price in Atacama (zone 2)	46	6.4	46.9	44	39.2	36.4
Hour 12 price in Santiago (zone 6)	52.4	60.3	60.6	60.5	60.4	60.4
Price difference (Santiago - Atacama)	6.4	53.9	13.7	16.5	21.2	24
System-level cost ($/MWh)						
Daily cost	35.9	37.1	39	38.2	38.1	37.8
Daily cost, % change relative to actual		(-3%)	(-8%)	(-6%)	(-6%)	(-5%)
Hour 12 cost	31.3	33.7	38.4	36.4	36	35.4
Hour 12 cost, % change relative to actual		(-7%)	(-18%)	(-14%)	(-13%)	(-12%)
Generation by fuel (%)						
Solar	8.4	7.7	3	4.8	5.1	5.8
Wind	5.8	5.6	5.8	5.8	5.8	5.7
Hydro	28.5	28.7	28.7	28.7	28.7	28.7
Coal	40.4	38.2	42	40.5	40.2	39.7
Gas	13.4	16.3	16.9	16.6	16.5	16.5
Other thermal	3.5	3.5	3.5	3.5	3.5	3.5
Emission (1000 tons of CO2)						
Daily CO2 emission	80.8	78.5	85.6	82.7	82.3	81.4

Note: This table summarizes market outcomes under the case of market integration (column 1) and the five counterfactuals without market integration (column 2-6). To make the models as comparable as possible, only outcomes in the post-19 period are considered. The first three rows explain the investment models and the relevant assumptions. For solar power in zones 1 and 2, we present counterfactual solar investment level, annual revenue per MW installed capacity, the average daily curtailment of solar, and the average ratio of daily solar output relative to solar potential. For system-level prices, we show average daily generation-weighted price and generation-weighted price at hour 12. For zone-level prices, we simply show the average price over a year. Additionally, we also show average daily generation share by fuel type and the average daily CO_2 emission.

Table 4: Cost-Benefit Analysis of Transmission Investments

	(1)	(2)	(3)	(4)	(5)
Modelling assumptions					
Investment effects	No	Yes	Yes	Yes	Yes
Investment model	One	One	Multi	Multi	Multi
Assumption on solar cost			$\gamma = 1$	$\gamma = \tilde{\gamma}$	$\gamma = \hat{\gamma}$
Benefits from market integration (million USD/year)					
Savings in consumer cost	176.1	289.5	264.7	251.5	240.4
Savings in generation cost	73.1	221.2	158.8	148.6	129.2
Savings from reduced environmental externality	-161.5	260.2	85.9	62.7	7.3
Increase in solar revenue	110.7	185.8	127.6	121.9	107.3
Costs from market integration (million USD)					
Construction cost of transmission lines	1860	1860	1860	1860	1860
Cost of additional solar investment	0	2559	1306	1448	1074
Years to have benefits exceed costs					
With discount rate = 0	14.8	6	6.6	7.6	8.3
With discount rate = 5.8%	> 25	7.1	8	9.5	10.7
With discount rate = 10%	> 25	8.3	9.7	12.3	14.6

Note: This table presents different components of the costs and benefits of market integration. To make the comparison straightforward, we only include the post-19 period for this exercise. The benefits of the transmission lines include (1) savings in consumer cost, which is the product of price and demand, (2) savings in system-level generation cost, (3) monetized savings from reduced environmental externality due to thermal power generation, and (4) increase in *total* solar revenue in zones 1 and 2. The costs of market integration include the construction cost of the transmission lines and the additional cost of solar investment in zones 1 and 2 (because with investment effects, market integration could lead to higher solar investment). Note that the calculation for "cost of additional solar" depends on our modelling assumption. For the one-shot models, we always use long-run cost of solar, discussed in Section 5.2. For the multi-period model with assumption $\gamma = 1$, we use solar cost implied by $\gamma = 1$ without market integration and cost implied by $\gamma = \hat{\gamma}$ with market integration; for the model with assumption $\gamma = \hat{\gamma}$, we use the cost implied by $\hat{\gamma}$ with and without market integration; for the model with assumption $\gamma = \tilde{\gamma}$, we use the cost implied by $\tilde{\gamma}$ with and without market integration. In the last three rows, we show the number of years required to recover the cost of market integration under different assumptions of government discount rate. We focus on consumer welfare, solar power surplus (in zones 1 and 2), and the value of externalities as the relevant surplus metrics.

Appendix A Proofs

Proof Observation 1

Proof. First, we need to show that gross gains from trade are the largest in the full dynamic comparison.

- If investment effects are ignored, we need to show that total gross costs are larger in the absence of solar investment, which is trivially satisfied. For any positive q^{solar}, total gross costs go down. Numerically,

$$GainsTrade - GainsTrade_{noinvest} = \frac{\beta^A \beta^B}{2(\beta^A + \beta^B)} q^{solar}(2D - q^{solar}) > 0,$$

  for relevant well-defined solution, as $q^{solar} < D$.

- If the investment has already been realized, then the distortion comes in the "before" period. We need to show that autarky costs are smaller with anticipated investment, which is also trivial in a general setting as, for any positive q^{solar}, total gross costs go down. Numerically,

$$GainsTrade - GainsTrade_{investearly} = \beta^A q^{solar}(D^A - \frac{q^{solar}}{2}) > 0,$$

  which is well defined for $q^{solar} \leq D^A$. If $q^{solar} > D^A$, then it is also true as the difference in gains from trade becomes simply $(\beta^A D^{A2})/2$, the costs of producing under autarky in the North.

The second part is a bit more subtle but follows from very general economic principles, as an investment in solar needs to improve outcomes if profitable.

- If investment is delayed and therefore ignored, the gains from the expansion will be lower. Numerically, we need to show that

$$\frac{\beta^A \beta^B}{\beta^A + \beta^B}(D - \frac{q^{solar}}{2}) > c,$$

  which plugging in q^{solar} gives $\frac{c}{2} + \frac{\beta^A \beta^B}{\beta^A + \beta^B}\frac{D}{2} = \frac{c}{2} + \frac{p^*}{2} > c$, which holds as $p^* > c$ by assumption.

- If investment is anticipated but investment costs are ignored, we need to show that the missed gains from trade are smaller than the costs of solar. Numerically, we need to show

$$\beta^A(D^A - \frac{q^{solar}}{2}) < c,$$

  which is by construction true as the equilibrium price is equal to c and larger than $\beta^A(D^A - q^{solar})$, the price in the North under solar investment and autarky.

$\square$

Proof Observation 2

Proof. Price reductions being understated can be shown very generally. In full equilibrium, price reductions are $\overline{p} - p^{**}$, where $\overline{p}$ is the average price under autarky.

- Under early investment, price reductions are $\tilde{p} - p^{**}$, where $\tilde{p}$ is the average price under autarky but with solar investment. Because $\tilde{p} < \overline{p}$, it follows that the difference is understated.

- Under late investment, price reductions are $\overline{p} - p^{*}$. Because $p^{**} < p^{*}$, it follows that the difference is understated.

□

Proof Observation 3

Proof. Under the assumption that prices converge after the interconnection, then price convergence is defined by the difference in the early period. Taking advantage that we have assumed that $p^A \leq p^B$,

- If investment is anticipated, $\tilde{p}^A \leq p^A$, and thus $p^B - \tilde{p}^A > p^B - p^A$.

- If investment is delayed, price differences are not distorted.

If the transmission line's capacity is insufficient for prices to converge, the result does not change if investment is anticipated, as the "after" equilibrium prices would be the same. In the case of investment delays, because net trade is smaller in the absence of investment, then price convergence is more likely if there is no investment. Therefore, price convergence might be overstated. Mathematically, net trade with solar investment is given by $\frac{\beta^B D^B - \beta^A (D^A - q^{solar})}{\beta^A + \beta^B}$ and net trade without solar investment is given by $\frac{\beta^B D^B - \beta^A D^A}{\beta^A + \beta^B}$, confirming that unrestricted trade is largest in the solar equilibrium.

If the constraint is binding, price differences will be weakly larger with solar investment. Visually, the offer curve from the North with solar is always to the right of the offer curve without solar. Therefore, for a restricted level of trade, the price difference will always be weakly larger with solar investment. Therefore, convergence will be higher without investment and binding transmission constraints. □

Appendix B Short-run dispatch model details

We present here a fully-fledged characterization of the short-run model with all the constraints explicitly spelled out.

Variables We solve for the following variables:

- q_{it}: Generation of each thermal power plant, excluding natural gas, at most equal to the plant's capacity.
- q_{zt}^{gas}: Natural gas generation at each zone, subject to usage constraints (hourly min, hourly max).
- q_{zt}^{solar}: Solar generation at each zone, at most equal to available solar power that hour-day.
- q_{zt}^{wind}: Wind generation at each zone, at most equal to available wind power that hour-day.
- q_{zt}^{hydro}: Hydro generation at each zone, subject to seasonality and usage constraints (hourly min, hourly max, and total availability).
- D_{zt}: Output reaching final consumers at each zone, equal or greater than demand, when there are constraints that require spilling power beyond renewables (e.g., due to autarky counterfactuals in which must-run production is higher than demand in a given region).
- imp_{lzt} : Power imported to zone z via transmission line l.
- exp_{lzt} : Power exported from zone z via transmission line l.

Objective function The planner minimizes the costs of production:

$$\min \sum_{z,t} \left(\sum_{i \in z} c_{it}\, q_{it} + C_{zt}^{gas}\left(q_{zt}^{gas}\right) + C_{zt}^{hydro}\left(q_{zt}^{hydro}\right) + c^{solar}\, q_{zt}^{solar} + c^{wind}\, q_{zt}^{wind} \right).$$

The costs of coal generation come from the regulatory data. For SING, we use daily cost bids offered into the market. For SIC, we use block cost bids.

The costs for natural gas production are approximated based on the same bidding data. However, we face the challenge that not all cost bids that are offered into the market are available. The algorithm takes into account not only costs but also gas stocks to optimize production. Therefore, we estimate a supply curve at the zone-month level based on realized gas production rather than offered bids. We fit the supply curve as a piece-wise linear function, which is attractive for optimization, with two breakpoints at the 75th and 90th percentile of generation, with the constraint that the curve is weakly increasing and convex. We limit total production to the maximum offered capacity. We also include lower-bound and upper-bound for natural gas production for each zone-month, which is the minimum/maximum hourly observed gas production.

The data for hydro costs are also taken from the same cost bids. However, we face a similar challenge to the case of natural gas, as hydro production is subject to many more constraints than those reflected in the cost bids. We approximate the supply of hydro as a piece-wise linear function, given that hydro production at the zone level is the conjunction of several interrelated plants. We include a small marginal cost to solar and wind production to break ties in the presence of oversupply of renewable production. To circumvent the need for modeling the water basins in detail, we approximate the observed cost of producing water at different levels with an estimated cost function. For each zone-year-month, we regress the generation-weighted average price of hydro plants on total hydro generation in that zone. The coefficient and constant define the hydro supply curve observed during those month conditions.[51] We additionally include a lower and upper bound to hydro production based on the minimum and maximum observed hydro generation in that zone-year-month.[52]

Constraints The model is very simple given Chile's geography. To define the constraints for the network, we define the following matrix, which defines the lines are connected:

$$T = \begin{bmatrix} 1 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\ 1 & 1 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 1 & 1 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 1 & 1 & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 1 & 1 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 1 & 1 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 1 & 1 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 1 & 1 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & 1 & 1 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 1 & 1 \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 1 \end{bmatrix}$$

Rows represent each zone (dim=11) and columns represent each line (dim=10). Ten segments go from North to South. Zone 1 is only connected to zone 2 via line 1; zone 2 is connected to 1 (line 1) and 3 (line 2), etc. In sum, line 1 connects 1 and 2; line 2 connects 2 and 3; line 3 connects 3 and 4; line 4 connects 4 and 5, etc.

The flow variables reflect net flows between zones and are defined as positive variables. For a given line l and zone z, the import or the export is positive, but not both. Exports from zone z in line l appear as imports to the zone to which the line connects. Exports and imports are limited by the size of the line, F_l. The size of the line can change

[51] We constrain the supply curve to be non-decreasing and set the slope equal to zero whenever this constraint is binding. We set the constant term as the mean (generation-weighted average price of hydro plants) in that zone-year-month.

[52] Note that the x-intercept of the hydro supply curve also sets an implicit lower bound on hydro production when the price is zero.

depending on the scenario considered.

$$
\begin{aligned}
&0 \leq imp_{lzt} \leq T_{lz} L_l, && \forall l, \forall z, \forall t \\
&0 \leq exp_{lzt} \leq T_{lz} L_l, && \forall l, \forall z, \forall t, \\
&\sum_z (imp_{lzt} - exp_{lzt}) = 0, && \forall l, \forall t.
\end{aligned}
$$

This definition of flows (separating imports and exports) adds some redundancy but allows us to penalize inflows with high-voltage transmission losses asymmetrically. This is reflected in the market clearing constraint:

$$
\sum_{i \in z} q_{it} + q_{zt}^{gas} + q_{zt}^{hydro} + q_{zt}^{solar} + q_{zt}^{wind} + \sum_l \delta \, imp_{lzt} - \sum_l exp_{lzt} = \frac{D_{zt}}{1-\phi}, \qquad \forall l, \forall z, \forall t,
$$

where δ represents losses across high-voltage lines and ϕ represents losses at the distribution level. We set $\delta = 0.025$ and $\phi = 0.08$.

Appendix C Analysis of Market Power in the Cost-Based Dispatch

As described in Section 3.2, Chile uses cost-based dispatch to clear demand and supply in its spot market. Power plants submit the technical characteristics of their units and natural gas or other input contracts with the input prices to the Load Economic Dispatch Center (CDEC), the Independent System Operator (ISO) in Chile. Based on this information, the CDEC computes daily unit-level start-up and variable operating costs and uses these costs, demand, and their network model to determine the least-cost dispatch under transmission constraints.

This cost-based dispatch mechanism differs from bid-based dispatch, a common dispatch method in many countries including the United States. In bid-based dispatch, power plants submit their supply bids in an auction market. Their bids do not have to be equal to their marginal costs. In contrast, in cost-based dispatch, plants are required to submit their marginal costs to the system operator who uses this information to clear the market.

Wolak (2003) describes that, compared to bid-based dispatch, cost-based dispatch has the advantage of reducing the risk of system-wide and local market power, particularly in markets with insufficient transmission capacity. Yet, cost-based dispatch may not fully eliminate the exercises of market power if large firms could manipulate their reported costs or plant maintenance/outage schedules.

We provide two pieces of evidence that firms were unlikely to exercise market power in the Chilean wholesale electricity market during our sample period. First, the cost-based dispatch system in Chile requires firms to submit all maintenance/outage schedules in advance to the system operator, and this information is made publicly available. Therefore, it is difficult for firms to use maintenance/outages to exercise market power strategically.

Second, we investigate whether firms exercise market power by overstating the marginal costs of their units. Although their daily marginal costs are monitored and validated by the system operator, it could still be possible that firms with high market shares—dominant firms—overstate their marginal costs to increase the market clearing price. To test this possibility, we exploit the market integration in 2017. As we explained in Section 3, the two largest electricity markets (the SING and SIC) had been fully separated until they were integrated in 2017. This means dominant firms in each market would likely lose significant market shares when the SIC and SING were integrated into one market (the SEN). Indeed, our data indicate that Engie had a 33% market share in the SING, which changed to 8% in the SEN. AES Andes had a 47% market share in the SING, which changed to 27% in the SEN. BHP Billiton had a 5% market share in the SING, which changed to 3% in the SEN. Enel had a 34% market share in the SIC, which changed to 27% in the SEN. Colbun had a 23% market share in the SIC, which changed to 16% in the SEN.

The incentives to overstate marginal costs were substantially lowered after the market integration because of the increased competitiveness and decreased market shares. Therefore, if they exercised market power by overstating marginal costs, we would expect *declines* in marginal costs for their units.

We test this hypothesis in Figure A.7. By firm and generation type (coal or gas), we calculate the generation-weighted daily average of marginal costs during the month before and after the integration. Panel A and B show results for coal and natural gas plants, respectively. We do not find evidence of *declines* in marginal costs. For natural gas plants in Enel, we see an increase in marginal cost right before the integration, likely due to a change in its natural gas contract. However, the direction of the change (an increase in marginal costs) is not consistent with a prediction from the possible market power. Therefore, this figure suggests that dominant firms were unlikely to overstate marginal costs in order to increase the market clearing price.

Appendix D Investment Effects on Thermal Power Plants

It is important to note that we focus on solar investment, as this seems to be the largest margin of adjustment. However, other power plants could also endogenously respond to solar investment and transmission expansion.

In Figure A.8, we examine thermal plants' entry and potential exit. In Panel A, we find that entry of thermal plants slowed down around 2014-2015 relative to total generation growth, which is consistent with their expected long-run profitability going down.

Measuring thermal plant exit in our data is not as straightforward as with entry. Our analysis considers plants no longer available if they stop submitting daily costs to the system operator to be dispatched. [53]

In Panel B of Figure A.8, we present thermal plants' cumulative "potential" exit. We consider that a unit potentially exited if it no longer offers its capacity to the system operator and does not produce for at least a year. For these units, we use the last time with submitted bids as the exit time and use unit-level capacity (MW) to show cumulative exit in MW. Although exit appears to be exacerbated after the renewable expansion starts, we observe modest exit of plants, in the order of 344 MW of capacity, relative to the total installed thermal capacity, which was over 15 GW during our main period of study.[54] Interestingly, some exits seem to align quite well with the events. While not in our current counterfactuals, one could bound the impact of these exits by attributing them to the transmission expansion. However, the impacts are expected to be small given the size of the plants.

[53]In practice, some of those power plants could be potentially brought back to the market, i.e., they could be re-opened after a period of "mothballing."

[54]As an alternative definition of exit, we also attempted to focus on plants with zero production during long periods. However, this is problematic because 1) having long periods of zero production is not uncommon for the very expensive peaker plants, and 2) the plants are still available in our analysis for calculating the nationwide merit order and our counterfactuals, therefore, their capacity *can be used*, even if the plants are irrelevant in practice.

Appendix E Estimating a Corrected Event Study

Our theory in Section 2 and empirical findings in sections 5.3 suggest that the conventional event study estimation is likely to underestimate the cost savings from market integration because it does not account for potential dynamic effects. In this subsection, we explore how to correct such dynamic bias in the event-study framework.

The challenge in the event study approach is that it cannot correctly capture investment effects if investment occurs in anticipation of the events. How can we address this problem? Our idea is based on the following thought experiment: What would happen to our regression estimates if investment were coincidental to the transmission expansion, as opposed to anticipated?

To implement dynamic correction for event-study estimation, we take two steps. First, we use our structural model to compute how much of the observed solar investments would have been unprofitable in counterfactual scenarios as we did in Section 5.3. We compute thresholds for both a scenario with only the interconnection, and one with no expansion. In the absence of interconnection and reinforcement, 80% of the observed solar in Antofagasta and 85% in Atacama would have been unprofitable. If the interconnection was built but the reinforcement was not, 50% of the observed solar in Antofagasta and 70% in Atacama would have been unprofitable. This implies that without anticipatory investments, we would have 20% of the observed solar in Antofagasta and 15% in Atacama in the pre-interconnection period, 50% of the observed solar in Antofagasta and 3-% in Atacama in the period after the interconnection and before the reinforcement, and 100% of the observed solar in both zones after the reinforcement. The structural model also provides us the market equilibrium production quantities, prices, and costs with the dynamic correction.

Second, we use these three scenarios to construct a simulated time series in which investment changes occur at the same time at the event. We use the time series with only 20% of solar investment in Antofagasta and 15% in Atacama for the period before the interconnection; we use the time series with 50% of solar investment in Antofagasta and 30% in Atacama for the interim period, and we set investment to 100% for both zones when the reinforcement occurs. We use the equilibrium outcomes from this new time series, corrected by changes in investment, to estimate the event-study regression in equation (1). This implies that our time series, by construction, has structural investment breaks right at the moment in which our two event studies occur.

In Table A.6, we present the event-study regressions with and without dynamic correction. To make the comparison easier, we present only the coefficients on the interconnection and reinforcement dummy variables in this table. Still, the regressions include the same set of control variables as in Column 4 of Table 2. We use the first three columns to present results for hour 12 and the last three columns to show results for all hours.

[Table A.6 about here]

In Column 1-3, we estimate the conventional event-study regression without dynamic correction. Because the anticipatory investment in solar plants occurred well before the events, this method underestimates the benefit of transmission expansions. Column 1 and 2 indicate that costs are reduced by 0.81 and 1.90 \$/MWh at noon thanks to the interconnection and reinforcement, respectively. In column 4-6, we estimate the event study regression with dynamic correction and find that the cost savings from the interconnection and reinforcement are 1.06 and 5.94 \$/MWh at noon. Comparison between columns 3 and 6 suggests that accounting for the dynamic benefits of the lines substantially increases the estimates of cost reductions. This highlights some of the added benefits that might be underestimated by a more naïve event-study design.

Note that in columns 4-6, we use our structural model to compute the market equilibrium, create time-series data based on this result, and estimate the event study regression in equation (1). We take this approach on purpose to compare how the standard event study results differ from the event study results with our dynamic correction. However, perhaps a more obvious way of using the structural model is to do counterfactual simulations to estimate the impact of interconnection and reinforcement separately. We can use the post-period data from each counterfactual directly and estimate the difference between (1) a scenario with solar investment at 20% in Antofagasta & 15% in Atacama under no transmission expansion and (2) a counterfactual scenario with corrected investments for the interconnection event (50% in Antofagasta & 30% in Atacama and interconnection present) and the reinforcement event (100% of investment and full transmission expansion). The advantage of this approach is that we perfectly control for confounding factors, and we can just difference out the two time-series to get at the effects. We compare costs from the 20% & 15% case to the 50% & 30% case between November 2017 and June 2019 to get at the effects of the interconnection, and from the 50% & 30% case to the 100% & 100% case starting in June 2019 to get at the additional effects of the reinforcement.

In columns 7-9, we present results from counterfactual simulations to compare them with results from the event-study estimation. To estimate the impact of the interconnection and reinforcement by counterfactual simulation, we run the same event-study regressions, but excluding the out-of-merit cost, with dependent variable being the *cost difference* between actual scenario and the counterfactual scenario with investment effects. Comparison between columns 6 and 9 suggest that once we make dynamic correction, the event study estimation, which identifies the event impacts based on before-and-after data, and the simulation approach, which identifies the event impacts based on cost difference between the two counterfactuals, produce numerically similar results.

Appendix F Appendix Figures and Tables

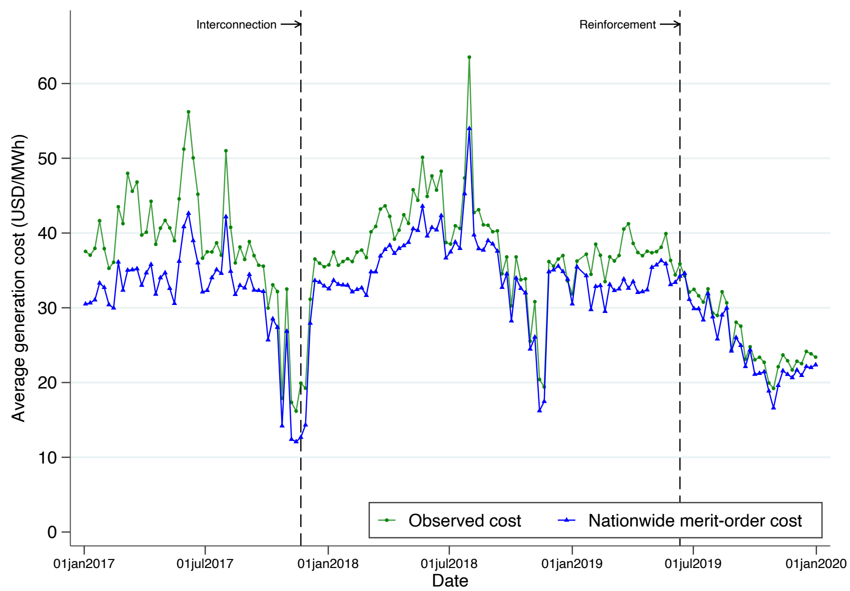
In this online appendix, we provide additional figures and tables from our analysis.

List of Figures in Appendix

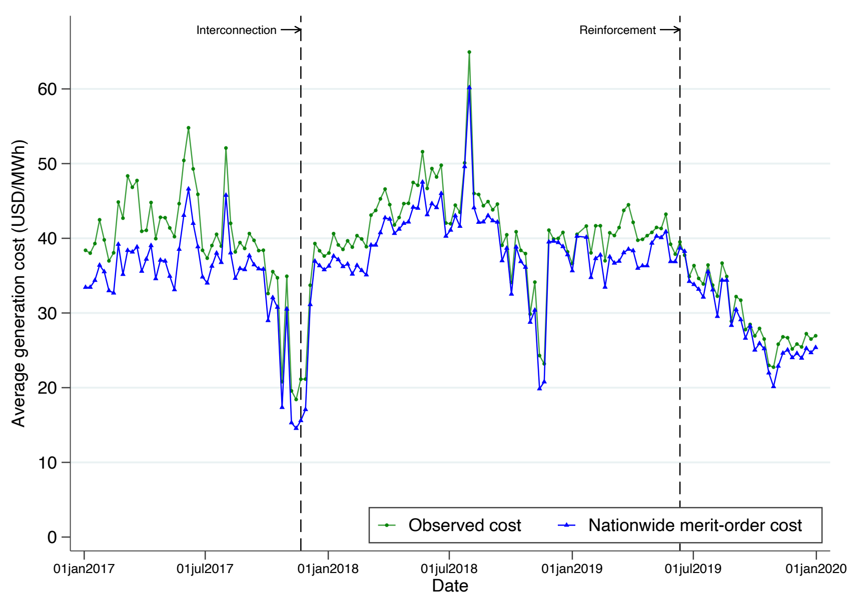
List of Tables in Appendix

Figure A.1: Observed Generation Cost and Nationwide Merit-order Cost

Panel A: Hour 12



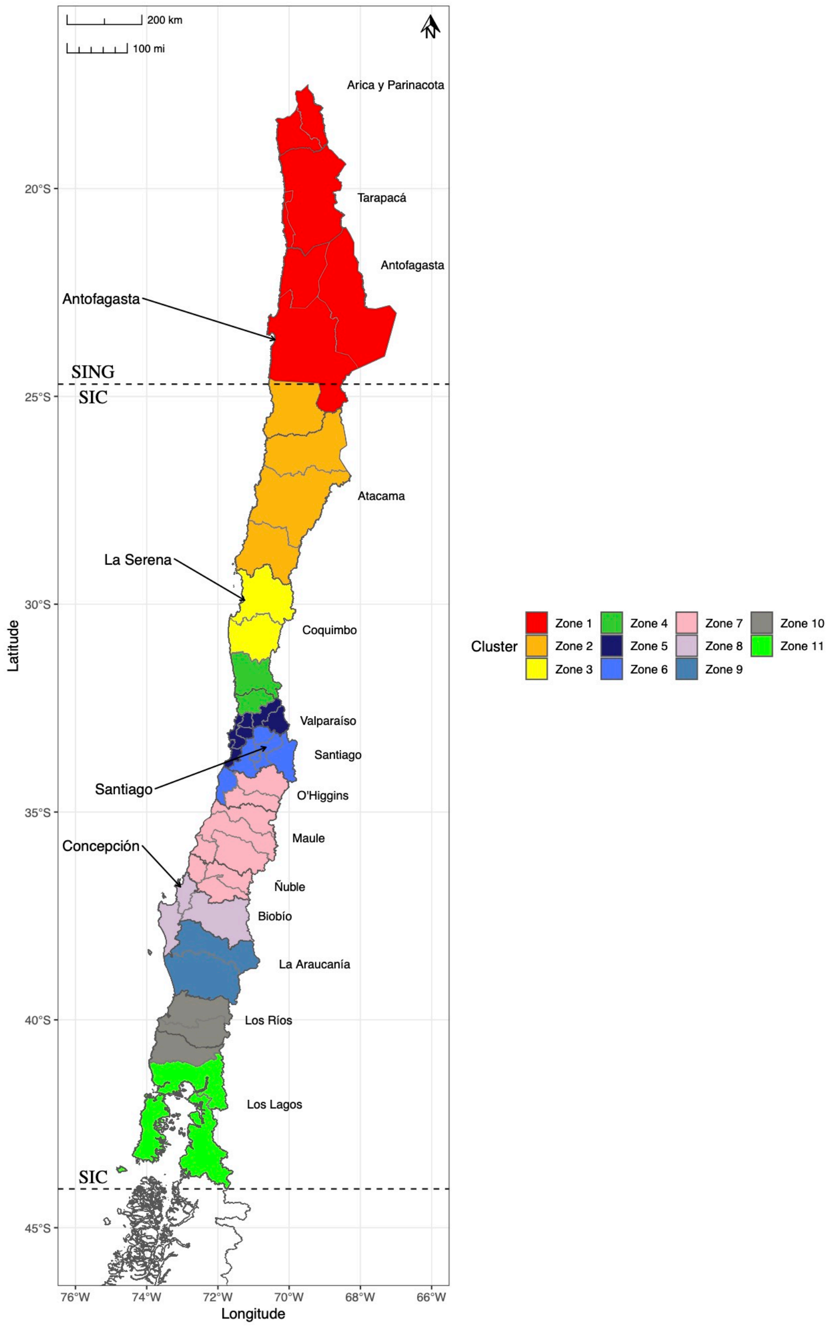
Panel B: All Hours



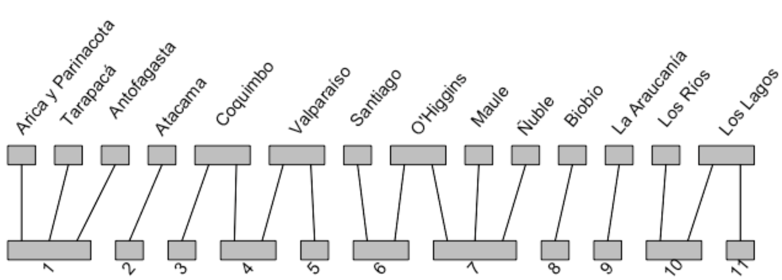
Note: This figure shows the observed system-level generation cost per MWh and the nationwide meri-order cost (the minimum possible generation cost per MWh with full trade), which are relevant to equation (1).

Figure A.2: Map of Zones

Panel A: A Map of Chile



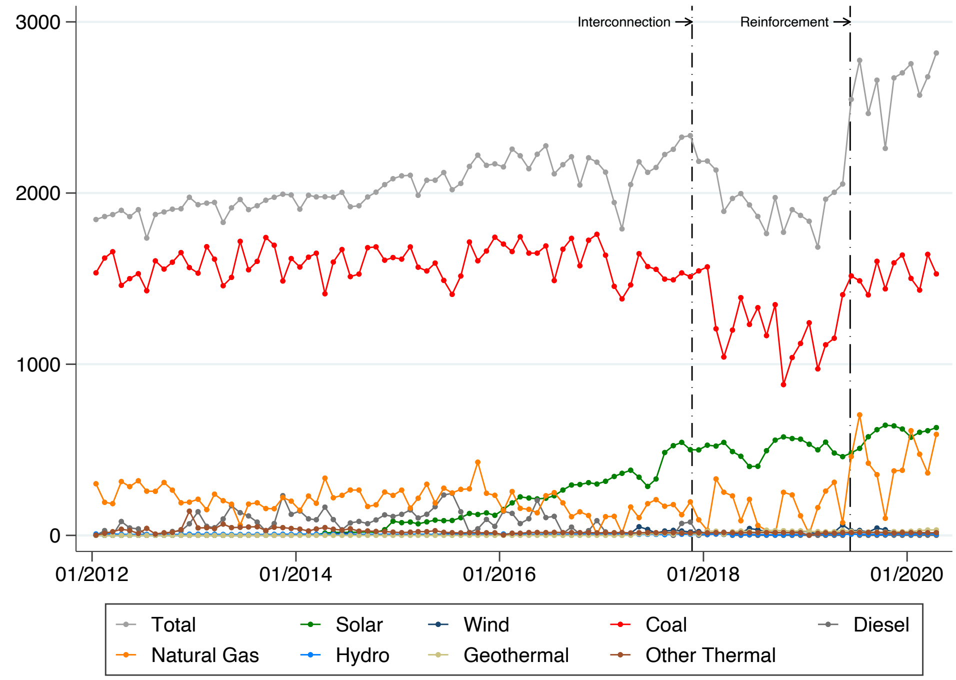
Panel B: Mapping between Regions in Chile and Zones



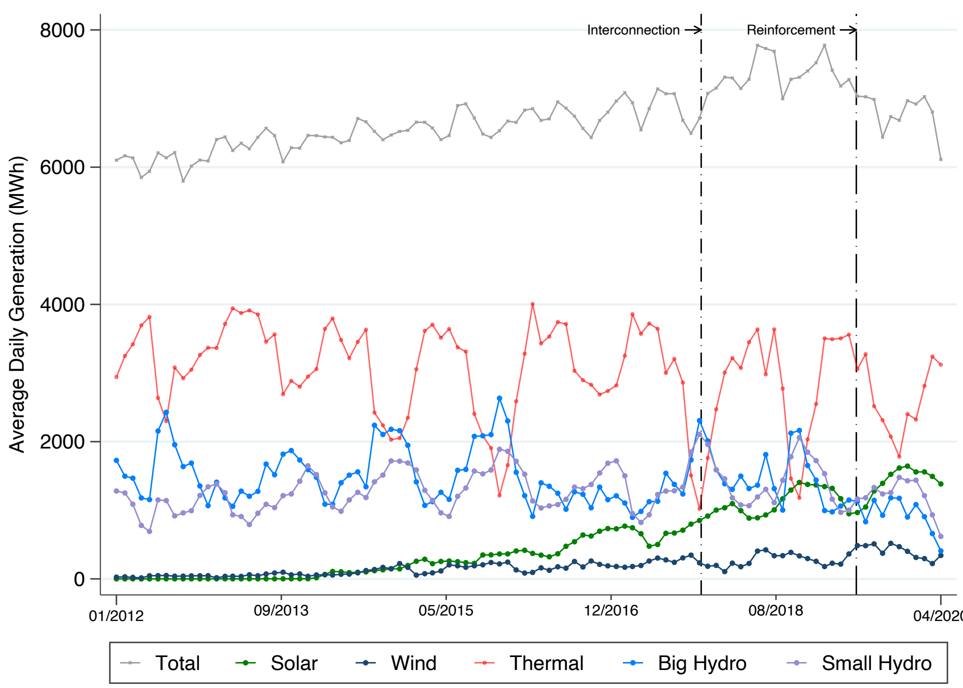
Note: Panel A shows how we divide Chile into 11 zones. Panel B shows the mapping between Regions in Chile and zones.

Figure A.3: Impacts of Market Integration on Electricity Generation by Fuel Type

Panel A: SING (north)



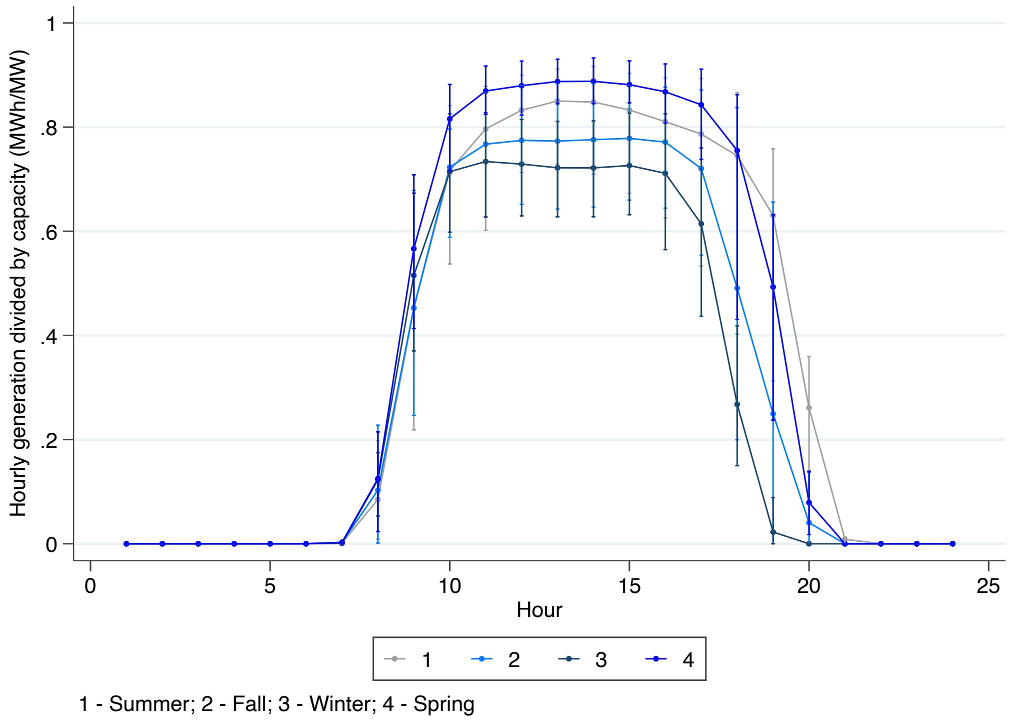
Panel B: SIC (south)



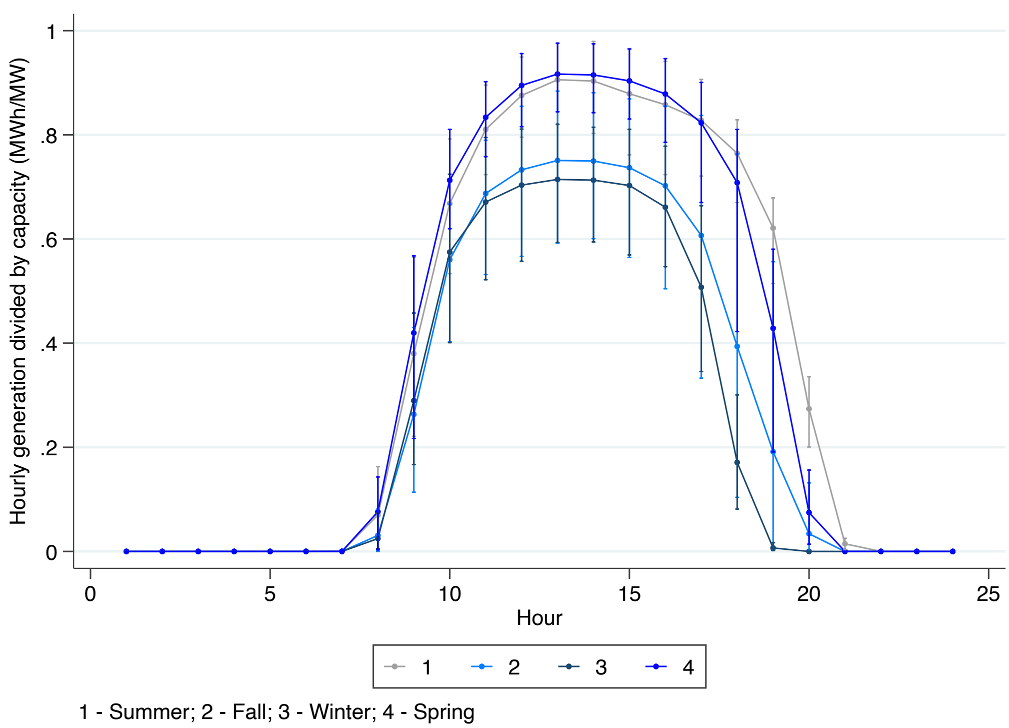
Note: This figure shows the average daily generation (MWh) by fuel type over the calendar months.

Figure A.4: Solar potential in zones 1 and 2: 10 and 90 percentile of capacity factor in 2019

Panel A: Zone 1

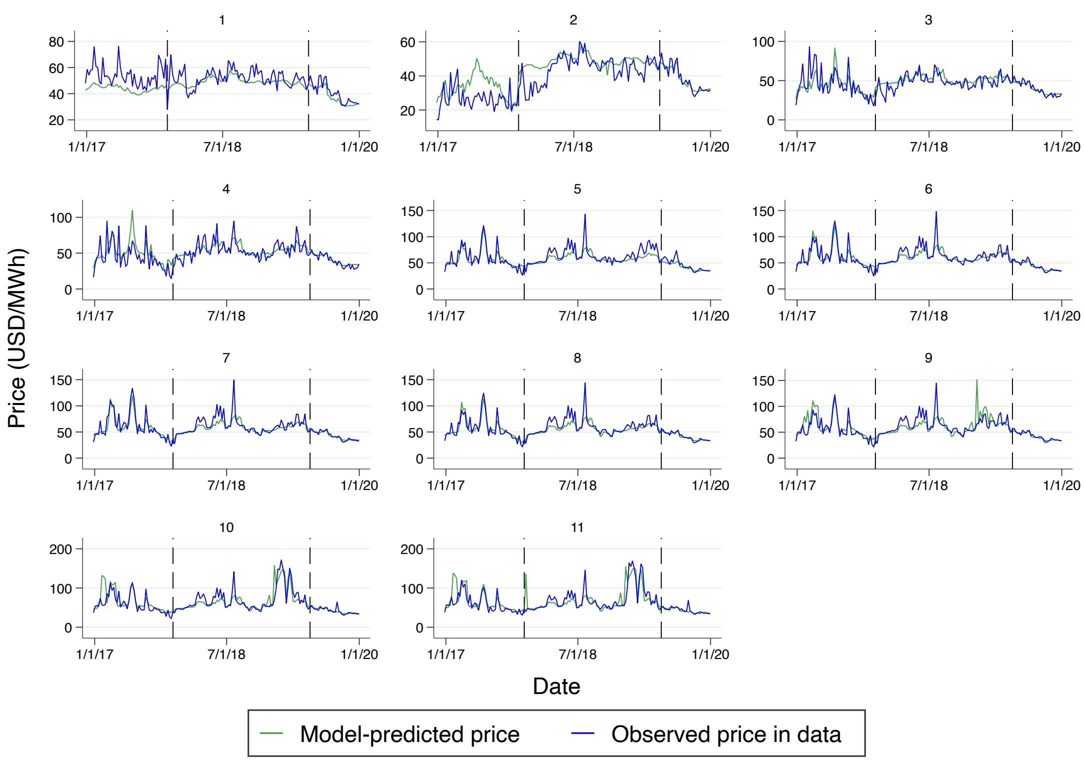


Panel B: Zone 2



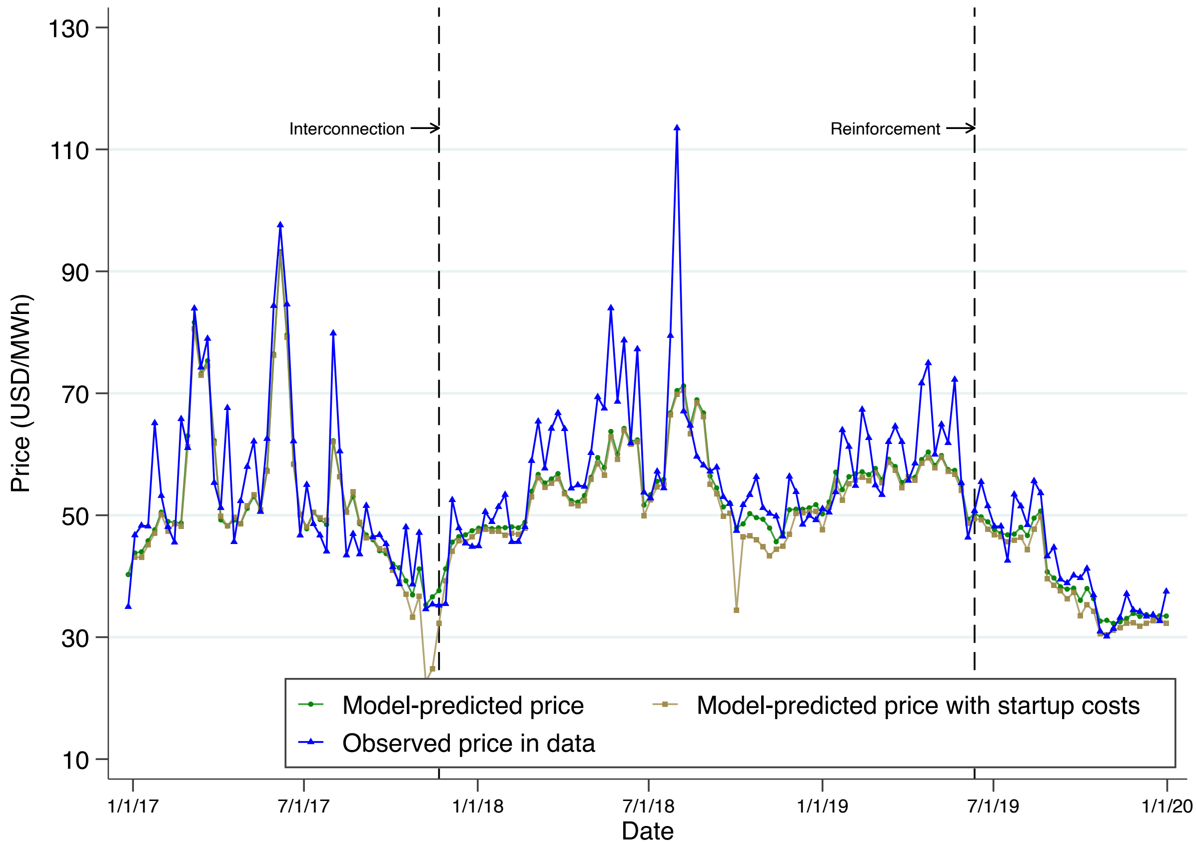
Note: We plot the distribution of solar capacity factor in 2019 for zones 1 and 2, defined as the ratio between hourly solar generation (in MWh) and solar capacity (in MW), by season and by hour of the day. The upper end of each bar is the 90th percentile and the lower end of each bar is the 10th percentile.

Figure A.5: Zone-level price fit



Note: We show how the model-predicted price fits the observed price for each zone. For each zone, we plot weekly generation-weighted average price.

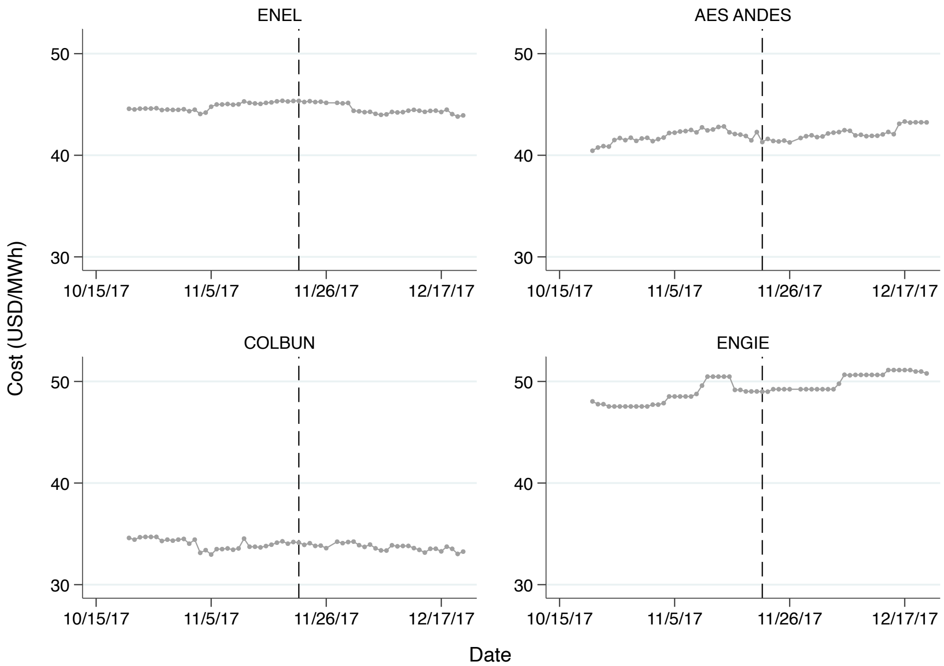
Figure A.6: Price fit with and without startup costs



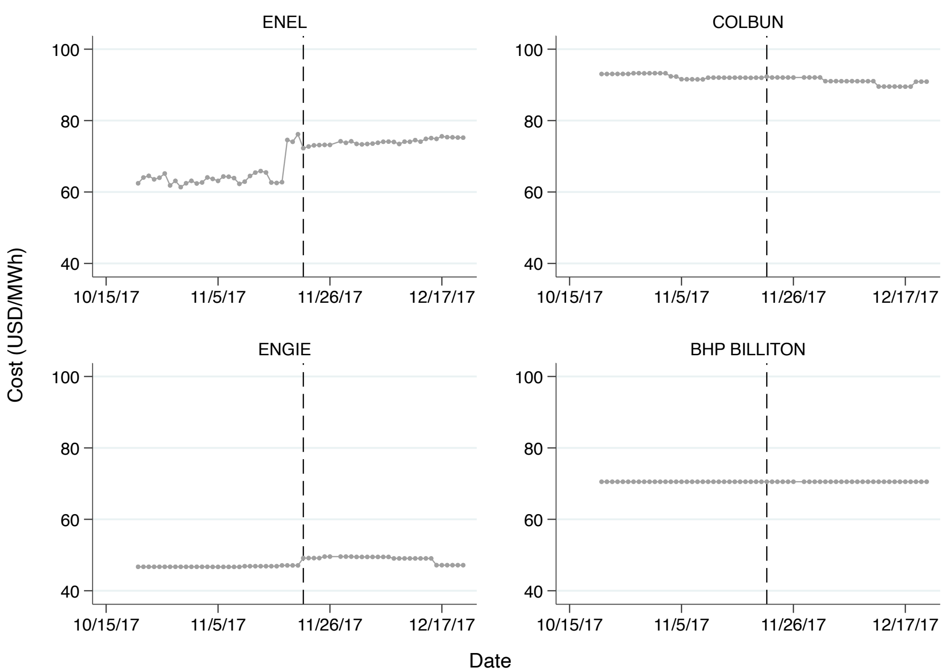
Note: We compare the price predicted by our baseline model and the model with startup costs.

Figure A.7: Analysis of Market Power in the Cost-Based Dispatch

Panel A: Coal Power Plants



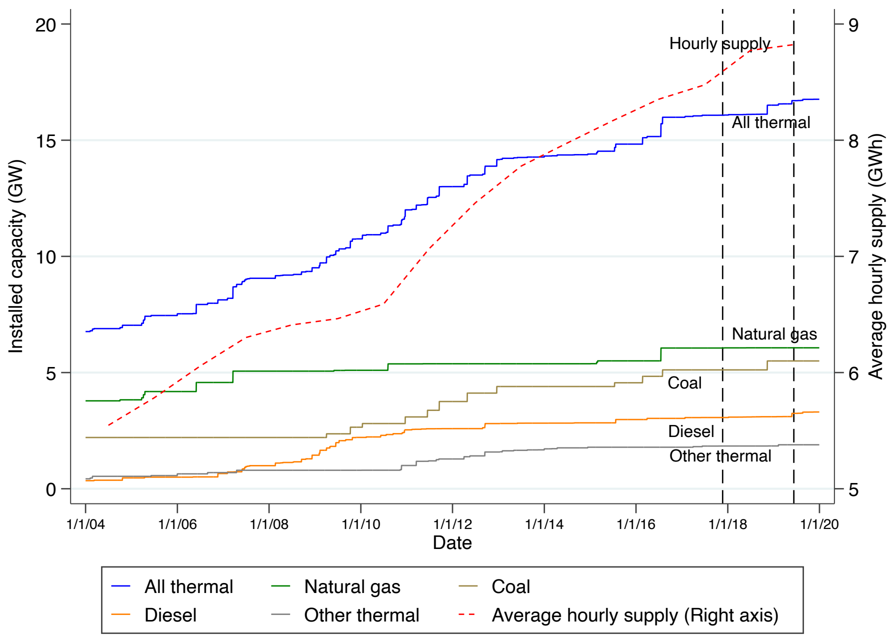
Panel B: Gas Power Plants



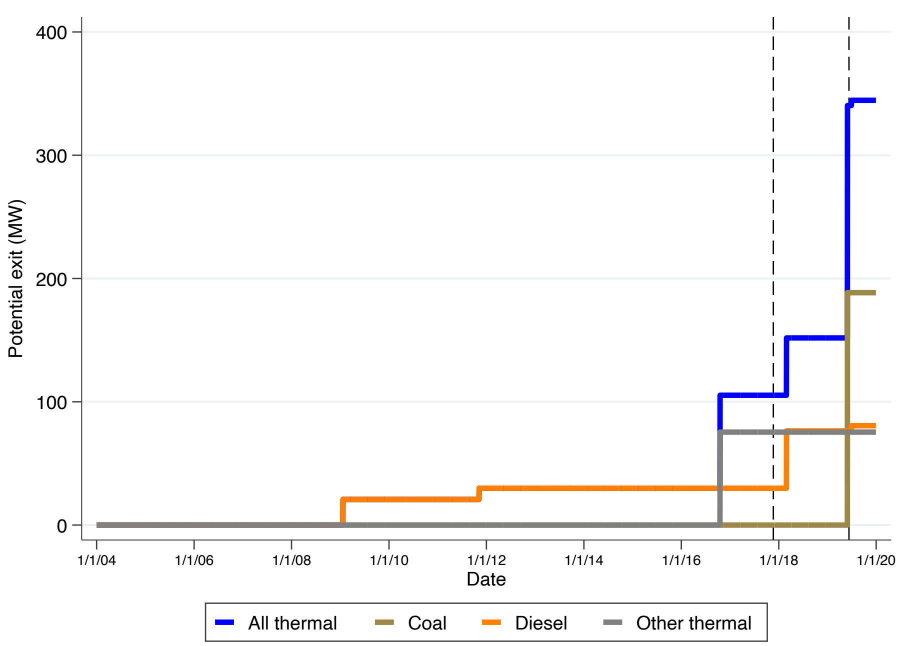
Note: By firm and generation type (coal or gas), we calculate the generation-weighted daily average of marginal costs during a month before and a month after the integration. The figure suggests that we do not find evidence of *declines* in marginal costs when the SIC and SING were integrated into the SEN in November 2017. Note that Engie had a 33% market share in the SING, which changed to 8% in the SEN. AES Andes had a 47% market share in the SING, which changed to 27% in the SEN. BHP Billiton had a 5% market share in the SING, which changed to 3% in the SEN. Enel had a 34% market share in the SIC, which changed to 27% in the SEN. Colbun had a 23% market share in the SIC, which changed to 16% in the SEN.

Figure A.8: Entry and Potential Exist of Thermal Plants

Panel A: Entry

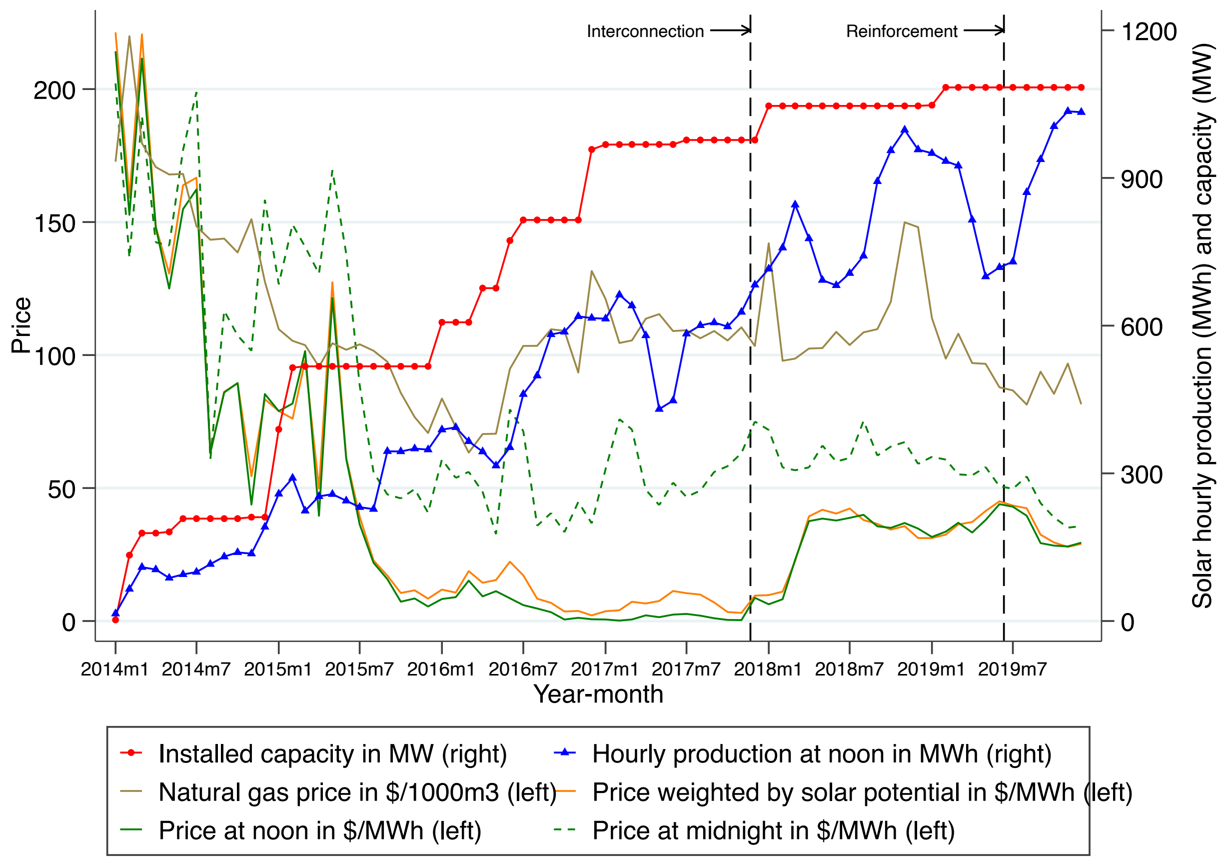


Panel B: Potential Exit



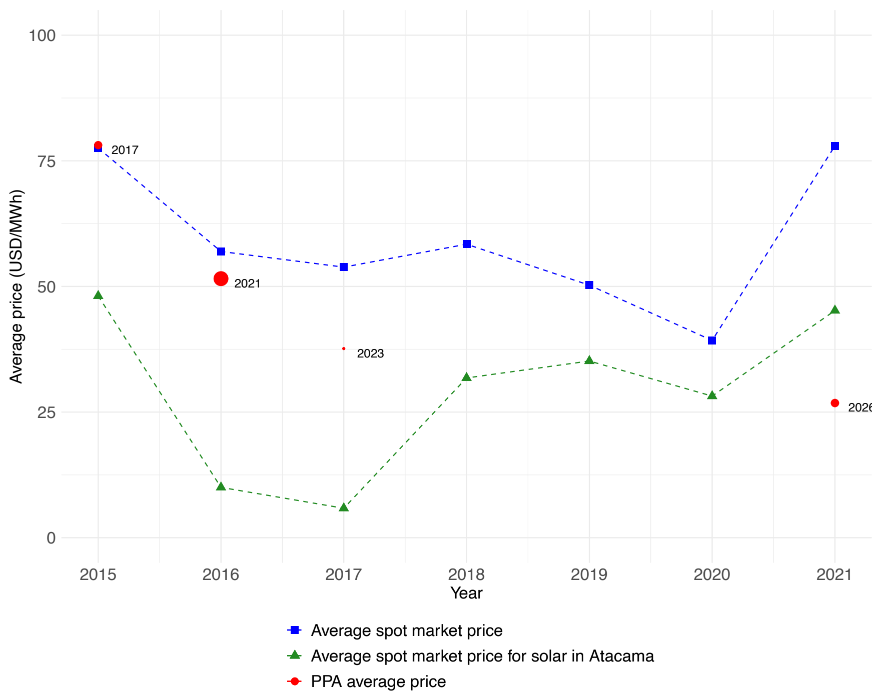
Note: Panel A shows the cumulative entry of thermal plants. We use the first time of positive production to define unit-level entry and use unit-level capacity (MW) to show the cumulative entry in MW. Panel B shows the cumulative "potential" exit of thermal plants. We consider that a unit potentially exited if the unit does no longer offer its capacity to the system operator and do not produce at least for a year. For these units, we use the last time with submitted bids as the time of exit and use unit-level capacity (MW) to show cumulative exit in MW.

Figure A.9: Figure 4 of the Main Text, with International Commodity Prices



Note: This figure is Figure 6 in the main text, with two additional lines. We first include international price of natural gas (Henry Hub price). We also include the monthly average price (in zone 2) weighted by solar potential. We calculate a weight for each hour-of-day based on average hourly solar production in 2019; we then calculate average price for each month in zone 2 based on these weights.

Figure A.10: Average Prices of a Subset of the Power Purchase Agreements (PPA)



Note: A subset of the power purchase agreements for the regulated customers (i.e., customers with less than 500 kW) are publicly available on the website of Licitaciones Eléctricas. Note that this dataset does not include bilateral contracts for customers with over 500 kW. Each dot represents the average price of the PPA for firms that have solar plants in Atacama. Note that data available from the PPA is at the firm level rather than the plant level, and therefore, we need to make a few assumptions to calculate the average price for each region, as we described in the main text of the paper. The number next to each dot is the start year of contracts, and the size of the dots correspond to the quantity contracted. As a reference, we also show the system-level average spot market prices (weighted by generation) and the average spot market prices for solar plants in Atacama region (weighted by generation).

Table A.1: Trade capacity

	Period 1	Period 2	Period 3
Line 1	0.00	570.68	816.87
Line 2	339.75	586.97	1601.96
Line 3	344.15	580.82	1711.40
Line 4	383.44	609.60	1772.79
Line 5	1870.97	1989.78	2737.05
Line 6	1942.99	2059.91	2059.91
Line 7	1502.85	1602.19	1602.19
Line 8	304.43	365.02	365.02
Line 9	217.69	217.69	215.69
Line 10	115.57	116.15	133.29

Note: This table shows the transmission capacity used in our structural model described in Section 5. "Period 1" is Jan 1, 2017 to Nov 20, 2017 (before Interconnection); "Period 2" is Nov 21, 2017 to June 10, 2019 (after Interconnection, before Reinforcement); "Period 3" is June 11, 2019 to Dec 31, 2019 (after Reinforcement).

Table A.2: Generation ratio

	Renewable	Hydro	Coal	Natural gas	Other thermal	Total
Pre-interconnection						
Observed	9.9%	26.9%	39.8%	18.7%	4.7%	100.0%
Model-predicted	11.1%	26.7%	39.6%	18.4%	4.2%	100.0%
Post-interconnection, Pre-reinforcement						
Observed	12.4%	29.7%	37.4%	16.4%	4.2%	100.0%
Model-predicted	12.9%	29.5%	38.7%	15.1%	3.8%	100.0%
Post-reinforcement						
Observed	16.1%	28.5%	36.6%	15.8%	3.1%	100.0%
Model-predicted	16.4%	28.9%	40.1%	11.9%	2.8%	100.0%

Note: This table shows the goodness of fit of our structural model described in Section 5.1.

Table A.3: An Alternative Dependent Variable to Static Event Study Analysis of the Impact of Market Integration

Dependent Variable: Generation Cost minus Nationwide Merit-Order Cost (USD/MWh)

	Hour 12				All hours			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1(After the interconnection)	-2.63	-2.60	-2.62	-2.63	-2.12	-2.14	-2.14	-2.05
	(0.20)	(0.27)	(0.27)	(0.27)	(0.14)	(0.17)	(0.17)	(0.17)
1(After the reinforcement)	-1.92	-1.23	-1.38	-1.18	-1.19	-0.65	-0.65	-0.69
	(0.13)	(0.55)	(0.58)	(0.60)	(0.09)	(0.35)	(0.36)	(0.37)
Coal price [USD/ton]		-0.01	-0.01	-0.01		-0.01	-0.01	-0.00
		(0.01)	(0.01)	(0.01)		(0.01)	(0.01)	(0.01)
Natural gas price [USD/m^3]			-7.97	-7.96			-0.03	0.06
			(3.98)	(3.94)			(3.03)	(2.98)
Hydro availability				0.25				-0.00
				(0.15)				(0.00)
Scheduled demand (GWh)				-0.12				-0.01
				(0.13)				(0.00)
Sum of effects	-4.55	-3.82	-4.00	-3.81	-3.31	-2.79	-2.79	-2.74
Mean of dependent variable	3.94	3.94	3.94	3.94	3.09	3.09	3.09	3.09
Month FE	No	Yes	Yes	Yes	No	Yes	Yes	Yes
Sample size	1033	1033	1033	1033	1033	1033	1033	1033
R^2	0.31	0.49	0.49	0.49	0.35	0.57	0.57	0.57

Note: In our main analysis in Table 2, we use the generation cost (USD/MWh) as a dependent variable and the nationwide merit-order cost (i.e., the least possible generation cost that can be obtained without any trade constraints) as a control variable. In this table, we use the difference between the generation cost and nationwide merit-order cost as a dependent variable. The coefficients for the interconnection and reinforcement are very similar to the ones in Table 2.

Table A.4: An Alternative Control to Static Event Study Analysis of the Impact of Market Integration

Dependent Variable: Generation Cost (USD/MWh)

	Hour 12				All hours			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1(After the interconnection)	-2.78	-3.32	-3.37	-3.27	-2.11	-2.60	-2.61	-2.52
	(0.16)	(0.24)	(0.23)	(0.22)	(0.12)	(0.15)	(0.15)	(0.15)
1(After the reinforcement)	-2.28	-0.49	-0.79	0.12	-1.46	0.09	0.04	0.25
	(0.20)	(0.47)	(0.50)	(0.46)	(0.13)	(0.31)	(0.32)	(0.31)
Minimum dispatch cost with no market integration	0.98	0.96	0.96	1.01	0.98	0.96	0.97	0.99
	(0.01)	(0.02)	(0.02)	(0.02)	(0.01)	(0.01)	(0.01)	(0.01)
Coal price [USD/ton]		0.02	0.03	0.02		0.02	0.03	0.02
		(0.01)	(0.01)	(0.01)		(0.01)	(0.01)	(0.01)
Natural gas price [USD/m^3]			-15.25	-16.31			-2.92	-3.83
			(4.69)	(4.66)			(2.98)	(2.99)
Hydro availability				1.06				0.02
				(0.13)				(0.00)
Scheduled demand (GWh)				-0.96				-0.03
				(0.13)				(0.00)
Sum of effects	-5.06	-3.82	-4.16	-3.15	-3.58	-2.51	-2.58	-2.27
Mean of dependent variable	35.44	35.44	35.44	35.44	38.63	38.63	38.63	38.63
Month FE	No	Yes	Yes	Yes	No	Yes	Yes	Yes
Sample size	1033	1033	1033	1033	1033	1033	1033	1033
R^2	0.93	0.95	0.95	0.95	0.96	0.97	0.97	0.97

Note: In our main analysis in Table 2, we use the nationwide merit-order cost (i.e., the least possible generation cost that can be obtained without any trade constraints) as a control variable. In this table, we use the minimum dispatch cost in the absence of market integration (i.e., the least possible generation cost that can be obtained in the absence of market integration) as a control variable.

Table A.5: Event Study Analysis With and Without Investment Effects

Panel A: Without Investment Effects

	Hour 12				All hours			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1(After the interconnection)	-1.35	-0.70	-0.73	-0.81	-0.76	-0.36	-0.37	-0.41
	(0.13)	(0.13)	(0.13)	(0.13)	(0.08)	(0.08)	(0.08)	(0.07)
1(After the reinforcement)	0.02	-1.30	-1.48	-1.90	-0.07	-0.93	-0.98	-1.10
	(0.10)	(0.25)	(0.26)	(0.29)	(0.05)	(0.14)	(0.14)	(0.15)
Nationwide merit-order cost	1.10	1.13	1.13	1.11	1.04	1.05	1.05	1.03
	(0.01)	(0.01)	(0.01)	(0.02)	(0.01)	(0.01)	(0.01)	(0.01)
Coal price [USD/ton]		-0.04	-0.04	-0.04		-0.03	-0.03	-0.03
		(0.01)	(0.01)	(0.01)		(0.00)	(0.00)	(0.00)
Natural gas price [USD/m^3]			-9.37	-9.02			-2.63	-2.18
			(2.31)	(2.24)			(1.13)	(1.08)
Hydro availability				-0.50				-0.01
				(0.07)				(0.00)
Scheduled demand (GWh)				0.49				0.02
				(0.07)				(0.00)
Sum of effects	-1.34	-2.00	-2.21	-2.70	-0.82	-1.29	-1.35	-1.51
Mean of dependent variable	32.69	32.69	32.69	32.69	36.10	36.10	36.10	36.10
Month FE	No	Yes	Yes	Yes	No	Yes	Yes	Yes
Sample size	1033	1033	1033	1033	1033	1033	1033	1033
R^2	0.97	0.98	0.98	0.98	0.99	0.99	0.99	0.99

Panel B: With Investment Effects

	Hour 12				All hours			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1(After the interconnection)	-1.61	-1.13	-1.13	-1.06	-0.86	-0.62	-0.61	-0.62
	(0.13)	(0.13)	(0.13)	(0.14)	(0.08)	(0.08)	(0.08)	(0.08)
1(After the reinforcement)	-4.69	-5.54	-5.55	-5.94	-2.06	-2.61	-2.58	-2.65
	(0.09)	(0.26)	(0.27)	(0.30)	(0.05)	(0.14)	(0.15)	(0.15)
Nationwide merit-order cost	1.07	1.13	1.13	1.13	1.02	1.05	1.05	1.04
	(0.01)	(0.01)	(0.01)	(0.02)	(0.00)	(0.01)	(0.01)	(0.01)
Coal price [USD/ton]		-0.04	-0.04	-0.04		-0.02	-0.02	-0.02
		(0.01)	(0.01)	(0.01)		(0.00)	(0.00)	(0.00)
Natural gas price [USD/m^3]			-0.73	-0.69			1.53	1.77
			(2.17)	(2.05)			(1.03)	(1.06)
Hydro availability				-0.48				-0.01
				(0.07)				(0.00)
Scheduled demand (GWh)				0.00				0.01
				(0.07)				(0.00)
Sum of effects	-6.31	-6.66	-6.68	-7.00	-2.92	-3.22	-3.19	-3.27
Mean of dependent variable	36.38	36.38	36.38	36.38	37.61	37.61	37.61	37.61
Month FE	No	Yes	Yes	Yes	No	Yes	Yes	Yes
Sample size	1033	1033	1033	1033	1033	1033	1033	1033
R^2	0.98	0.98	0.98	0.98	0.99	0.99	0.99	0.99

Note: This table shows results under two sets of event study regressions described in equation (1). In Panel A, the dependent variable is the system-level average generation cost based on model simulation without investment effects. In Panel B, the dependent variable is the system-level average generation cost based on model simulation with investment effects. We shift the timing of solar investment so that it occurs right after the interconnection and reinforcement (i.e., correct for anticipatory investment effects), use our structural model to obtain market outcomes, and re-run the event study analysis (i.e., there is 20% solar investment left in zone 1 and 15% solar investment left in zone 2 without market integration; There is 50% solar investment left in zone 1 and 30% left in zone 2 with interconnection but without reinforcement; there is 100% solar investment in zones 1 and 2 after reinforcement).

Table A.6: Investment Effects for the Event Study Analysis

	Model cost excluding investment effects			Model cost with investment effects			Difference in model cost with investment effects		
	Inter.	Rein.	Sum	Inter.	Rein.	Sum	Inter.	Rein.	Sum
Hr 0	-0.11 (0.04)	-0.60 (0.09)	-0.71	-0.11 (0.04)	-0.61 (0.09)	-0.72	-0.34 (0.02)	0.25 (0.06)	-0.10
Hr 1	-0.11 (0.04)	-0.39 (0.09)	-0.49	-0.11 (0.04)	-0.40 (0.09)	-0.51	-0.32 (0.02)	0.23 (0.06)	-0.09
Hr 2	-0.13 (0.04)	-0.19 (0.09)	-0.32	-0.14 (0.04)	-0.21 (0.09)	-0.35	-0.30 (0.02)	0.22 (0.06)	-0.08
Hr 3	-0.13 (0.04)	-0.09 (0.09)	-0.22	-0.13 (0.04)	-0.11 (0.09)	-0.24	-0.28 (0.02)	0.21 (0.06)	-0.07
Hr 4	-0.13 (0.04)	-0.08 (0.09)	-0.21	-0.13 (0.04)	-0.10 (0.09)	-0.23	-0.27 (0.02)	0.21 (0.06)	-0.07
Hr 5	-0.12 (0.04)	-0.19 (0.09)	-0.31	-0.13 (0.04)	-0.20 (0.09)	-0.33	-0.28 (0.02)	0.22 (0.06)	-0.06
Hr 6	-0.12 (0.04)	-0.44 (0.09)	-0.56	-0.09 (0.04)	-0.44 (0.09)	-0.53	-0.29 (0.02)	0.23 (0.06)	-0.06
Hr 7	-0.16 (0.04)	-0.90 (0.09)	-1.07	-0.08 (0.04)	-1.29 (0.09)	-1.38	-0.49 (0.02)	-0.16 (0.06)	-0.65
Hr 8	-0.07 (0.04)	-1.49 (0.09)	-1.56	-0.60 (0.04)	-3.71 (0.09)	-4.31	-1.43 (0.02)	-1.60 (0.06)	-3.02
Hr 9	-0.21 (0.04)	-1.84 (0.09)	-2.05	-0.99 (0.04)	-5.36 (0.09)	-6.35	-2.03 (0.02)	-2.84 (0.06)	-4.87
Hr 10	-0.43 (0.04)	-1.97 (0.09)	-2.39	-1.03 (0.04)	-5.84 (0.09)	-6.86	-2.17 (0.02)	-3.17 (0.06)	-5.34
Hr 11	-0.67 (0.04)	-1.91 (0.09)	-2.58	-1.05 (0.04)	-5.91 (0.09)	-6.96	-2.21 (0.02)	-3.30 (0.06)	-5.51
Hr 12	-0.81 (0.04)	-1.90 (0.09)	-2.70	-1.06 (0.04)	-5.94 (0.09)	-7.00	-2.23 (0.02)	-3.40 (0.06)	-5.62
Hr 13	-0.86 (0.04)	-1.92 (0.09)	-2.78	-1.04 (0.04)	-5.98 (0.09)	-7.02	-2.22 (0.02)	-3.45 (0.06)	-5.68
Hr 14	-0.86 (0.04)	-1.92 (0.09)	-2.78	-1.05 (0.04)	-5.94 (0.09)	-6.98	-2.22 (0.02)	-3.43 (0.06)	-5.65
Hr 15	-0.74 (0.04)	-1.89 (0.09)	-2.63	-1.01 (0.04)	-5.73 (0.09)	-6.74	-2.20 (0.02)	-3.31 (0.06)	-5.51
Hr 16	-0.58 (0.04)	-1.79 (0.09)	-2.38	-1.02 (0.04)	-4.99 (0.09)	-6.01	-2.14 (0.02)	-2.70 (0.06)	-4.84
Hr 17	-0.42 (0.04)	-1.46 (0.09)	-1.89	-1.05 (0.04)	-3.01 (0.09)	-4.06	-1.94 (0.02)	-1.03 (0.06)	-2.97
Hr 18	-0.24 (0.04)	-1.17 (0.09)	-1.41	-0.60 (0.04)	-1.87 (0.09)	-2.47	-1.32 (0.02)	-0.35 (0.06)	-1.67
Hr 19	-0.17 (0.04)	-1.07 (0.09)	-1.25	-0.13 (0.04)	-1.42 (0.09)	-1.55	-0.56 (0.02)	-0.06 (0.06)	-0.63
Hr 20	-0.19 (0.04)	-0.95 (0.09)	-1.14	-0.16 (0.04)	-0.94 (0.09)	-1.11	-0.46 (0.02)	0.24 (0.06)	-0.22
Hr 21	-0.17 (0.04)	-0.83 (0.09)	-1.00	-0.17 (0.04)	-0.81 (0.09)	-0.98	-0.49 (0.02)	0.31 (0.06)	-0.18
Hr 22	-0.11 (0.04)	-0.80 (0.09)	-0.92	-0.11 (0.04)	-0.80 (0.09)	-0.92	-0.45 (0.02)	0.30 (0.06)	-0.16
Hr 23	-0.09 (0.04)	-0.73 (0.09)	-0.83	-0.09 (0.04)	-0.75 (0.09)	-0.84	-0.39 (0.02)	0.26 (0.06)	-0.13

Note: This table compares the static impact of Interconnection ("Inter.") and Reinforcement ("Rein.") with the dynamic impact, based on three sets of event study regressions. Column 1-3 shows the static impact of market integration, where the dependent variable is the average hourly generation cost based on model simulation without investment effects. Column 4-6 and Column 7-9 show two estimates for the dynamic impact of market integration. In column 4-6, the dependent variable is average hourly generation cost based on model simulations with investment effects. We shift the timing of solar investment so that it occurs right after the interconnection and reinforcement (i.e., correct for anticipatory investment effects), use our structural model to obtain market outcomes, and re-run the event study analysis. In column 7-9, the dependent variable is the difference in model-simulated cost between the *Actual scenario* case and the No market integration counterfactual with investment effects. We regress this time series on the two event dummies, including the same set of controls as in column 1-6, except for the out-of-merit cost. Column 9 is the sum of column 7 and 8.

Table A.7: Solar Generation Market Shares in Zones 1 and 2 (top 20 firms and the rest)

Firm name	Solar generation market share	System-level all generation market share
ENEL	23.9%	24%
SunEdison	11.4%	0.9%
Acciona	8.8%	1.9%
First Solar	8.5%	0.7%
Ingenostrum	7.7%	0.6%
Pattern Energy	6.5%	0.5%
EIG	6%	0.5%
AustrianSolar	4.2%	0.3%
Etrion Corp.	3.9%	0.3%
Actis	3.7%	0.3%
Element Power Chile	3.2%	0.3%
X-Elio	3.2%	0.2%
Solar Pack	2.4%	0.2%
Solairedirect	1.9%	0.2%
AES ANDES	1.3%	27.3%
NUOVOSOL SPA	0.6%	0%
APOLO DEL NORTE SPA	0.6%	0%
Oxum	0.5%	0%
Distributed Power Partners	0.5%	0%
SOLAR BROTHERS SPA	0.5%	0%
Others (8 firms)	0.9%	8.9%

Note: This table shows solar market share and overall market share for the companies that own solar plants in zones 1 and 2. "Solar generation market share" is the market share among solar generation in zones 1 and 2 during December 2019. "System-level all generation market share" is the company's market share in the entire system, including all technologies, during December 2019; this column does not add up to 100% because there are companies who do not own solar plants in zones 1 and 2.

Table A.8: Solar cost estimation (cost is in million USD/MW)

Panel A: Solar cost regression

	(1)
(Intercept)	2.261
	(0.2756)
Cumulative Capacity Added	0.0020
	(0.0010)
Time	-0.2189
	(0.0843)
R^2	0.27943
Observations	34

Panel B: Estimates for $\alpha_y, \hat{\gamma}_{z,y}, \tilde{\gamma}_{z,y}$

	α_y $(\gamma = 1)$	$\hat{\gamma}_{z,y}$		$\tilde{\gamma}_{z,y}$	
	Zones 1 and 2	Zone 1	Zone 2	Zone 1	Zone 2
2014	2.26	0.71	0.49	0.76	0.60
2015	2.04	0.81	0.44	0.85	0.56
2016	1.82	0.80	0.37	0.82	0.45
2017	1.60	0.80	0.96	0.82	1.02
2018	1.39	1.29	1.09	1.30	1.11
2019	1.17	1.40	1.35	1.40	1.36

Note: In Panel A, we show the regression results of solar marginal cost, as described in Section 5.4, equation (7). In Panel B, we present the intercepts (α_y) of solar marginal cost curve, which are obtained from the regression in Panel A directly. We further compare the two sets of estimates of γ, described in Section 5.4.