Natural gas to complement solar intermittency: Long-run consequences of policy interventions*

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Abstract

Natural gas has become pivotal in the energy transition, as it can complement renewable energy at a lower emission rate compared to alternative fossil fuels. In countries with scarce natural gas reserves, firms might exhibit insufficient import levels relative to governmental preferences. In this paper, we study several policies designed to incentivize larger natural gas orders and examine their impact on long-term solar entry. Our research is conducted in Chile, a notable solar energy adopter, which implemented a policy to encourage natural gas procurement. We find that while the policy displaces coal usage, it simultaneously increases natural gas imports to an extent that counterbalances its positive effects on emissions, incurring a net pollution cost of $20 million per year. Removing this policy would not only result in a short-term reduction in emissions but also stimulate increased solar energy adoption in the long run by 10%. Among the policies we examined, implementing a carbon price proves most effective, as it raises natural gas imports, lowers emissions in the short run by $191 million annually, and enhances solar energy entry in the long term by 54%.

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1 Introduction

Renewable energy is a crucial element in combatting climate change, given its capability to mitigate greenhouse gas emissions. However, renewable sources are not capable of consistently meeting energy demands throughout the day. Alternative technologies are required to supply energy during periods when they are not available, ensuring system reliability while ideally avoiding reliance on environmentally detrimental and costly options, such as diesel generators.

This paper analyzes policies aimed at ensuring the reliability of the electric system and their impact on long-term renewable investment. Specifically, our focus is on mechanisms that warrant the availability of natural gas, their effects on the entry of solar power into the market, and the extent to which they complement the intermittent nature of solar generation.

The intermittency of solar and wind power is of significant concern. The time-varying generation profile of renewable energy affects not only its economic value (Borenstein 2008; Joskow 2011; Gowrisankaran, Reynolds, and Samano 2016) but also its positive environmental impact (Cullen 2013; Dorsey-Palmateer 2019; Kaffine, McBee, and Ericson 2020). Therefore, accounting for the intermittency of renewable technologies is crucial for policy design, as it affects production patterns and can consequently impact long-run investment (Ambec and Crampes 2019).

To overcome the intermittency problem, regulators of the electricity industry need to mix renewable with non-renewable energy sources.[1] Among the high-emission fossil fuel options to complement renewables, natural gas emerges as the most environmentally friendly choice, emitting 50% less than coal. Moreover, it exhibits low ramping times, facilitating swift backup responses in situations of unexpected solar or wind energy shortages. Nevertheless, not all countries possess natural gas reserves. This leads to a significant reliance on imports, with over half of the internationally traded gas done via liquefied natural gas (LNG) vessels.

In the context of LNG procurement, institutional factors lead to frictions that add risk to the purchasing decision. Consequently, companies involved in LNG generation tend to order less natural gas than the government would ideally prefer. From a social planner's perspective, this constitutes a missing money problem (Joskow 2006, 2008) where the inherent value of LNG generation capacity (distinct from the sale of energy) is not priced adequately. Higher LNG procurements (i.e., incrementing capacity) improve reliability even when LNG is not actually used to produce. Not pricing for this positive externality,[2] combined with firms not considering emissions reduction coming from LNG displacing other fossil fuels, are the fundamental causes of under-investment.

1. An alternative is the use of batteries as a clean complement to renewables. Current economic constraints, unfortunately, render batteries not yet financially feasible (Porzio et al. 2023), prompting electricity markets to resort to fossil fuels as complements to renewable energy.

2. Capacity payments, for example, have been studied as a solution to the missing money problem (Cramton, Ockenfels, and Stoft 2013; Fabra 2018). Many electricity markets, including those in Spain and several South American countries, have adopted these payments to address this issue. While capacity payments or similar solutions are a step in the right direction, they do not necessarily guarantee reliability (Hogan 2017). With an increasing share of renewables entering electricity markets, additional reforms (or policies) are needed to accommodate intermittent generation at scale (Joskow 2019).

In this paper, we investigate diverse policies aimed at incrementing the capacity of LNG and how they indirectly affect long-run investment in clean technology. To do so, we start by assessing the impact of a policy implemented in Chile designed to increase LNG procurement, focusing on the extent to which it promotes or discourages the adoption of renewable energy sources, particularly solar, in the long run. We compare the outcomes of this policy with a counterfactual framework where the government directly dictates LNG orders and another where no policy intervention occurs. Then, we explore other counterfactual policies designed to incentivize larger LNG orders and examine their potential effects on long-term investments in solar power.

The policy implemented in Chile had the objective of mitigating the potential under-ordering of LNG. By addressing this issue, the policy sought to reduce the reliance on more carbon-intensive technologies such as coal and diesel in the electricity sector.

Chile operates on a cost-based dispatch system, where power plants are prioritized based on their marginal costs, and only the most economical plants are utilized to generate energy. The policy provided natural gas with the highest priority in the dispatch, allowing it to be dispatched at a virtual zero marginal cost. As LNG needs to be stored in special tanks, this prioritization occurred when projections indicated that the consumption of liquefied natural gas would be insufficient to deplete the existing LNG storage tank before the arrival of the next shipment. By granting natural gas this priority, the policy ensured that there would be adequate space in the storage tank to accommodate the incoming shipment of LNG.

The artificial prioritization of natural gas had several implications, including reductions in spot market prices and changes in the order of technology dispatch, possibly impacting the profitability of solar power plants, among other generation technologies operating within the electricity market.

We center our study on Chile, where, by 2019, about 44% of its total electricity came from renewable sources, mainly hydro, solar, and wind power. The geographical characteristics of Chile's northern region grant it the advantage of receiving one of the highest solar radiation levels globally, rendering it a prime candidate for solar power generation. Also, due to the absence of domestic natural gas reserves, Chile relies on the importation of liquefied natural gas via ships, which led to the implementation of the aforementioned policy.

Chile's experience as an LNG importer is not an isolated case. In the last ten years, there has been a global increase in LNG trade. Between 2012 and 2022, the number of countries constructing LNG regasification facilities has grown by 70%, going from 26 to 44 nations, and this trend is expected to persist. Studying Chile, positioned among the front runners of the energy transition, can provide valuable policy insights that can serve as a model for other countries in the future.

We begin our study by developing a simple theoretical model to explore the incentives that drive firms to order LNG, how these incentives are influenced by the implemented policy in Chile, and how they compare to the optimal quantity desired by a social planner. Through simulations, we assess how these incentives determine the quantity of liquefied natural gas ordered by firms. Furthermore, we investigate how the optimal

LNG order changes with the entry of solar power plants for firms both subject and not subject to the policy and compare these results with the planner's optimal order.

Our model indicates that given the uncertainty faced, firms have incentives to hold back on their LNG orders. This is because using more expensive technologies instead of LNG would raise their infra-marginal plants' revenue. The policy induces firms to place larger LNG orders by increasing the returns on natural gas across the demand distribution, approaching the desired quantity by the planner when the renewable energy installed capacity is low. As the installed solar capacity rises, incentives reach a critical point where the planner would opt for a lower LNG order compared to firms under the policy. As solar capacity continues to expand, the optimal order converges to zero for the firm and the planner; however, in the absence of the policy, the firm's optimal amount of LNG converges to zero at a rate that better aligns with the planner's optimal order. Therefore, the LNG prioritization policy —the policy implemented in Chile— is useful up to a certain level of solar capacity installed. This can be explained since, even though intermittent, solar power is not uncertain (as opposed to wind generation). The greater the solar capacity, the better daytime demand is covered, leaving natural gas to be predominantly utilized during hours without sunlight. This leads to a decrease in the optimal LNG order, with the policy's effectiveness diminishing as solar capacity increases.

We construct a structural model consisting of three parts to examine the short and long-term effects of the policy and study whether alternative solutions might yield better outcomes. First, we develop a cost-based dispatch optimization model, which emulates the complex nature of Chile's real dispatch process. The actual dispatch optimization involves handling multiple interrelated variables, such as transmission congestion, occasional transmission line disruptions, short and long-term weather patterns (affecting hydro-power availability), and LNG availability, among others. Due to the intricacy of the true dispatch process, we construct a simplified version of this optimization with the primary objective of accurately capturing price trends.

For the second part of the structural model, we endogenize the liquefied natural gas orders undertaken by importing firms. In our model, we take into account seasonal variations on the demand and supply side of the market, which will affect the optimal LNG order. Demand-side seasonality arises from factors such as heightened air conditioning use during summer or reduced daylight hours in winter, while supply-side seasonality manifests through scenarios like diminished solar capacity in winter or augmented hydro-power capacity due to elevated rainy conditions. These seasonal variations exhibit notable volatility over successive years, prompting firms to assign probability distributions to potential residual demand scenarios that may be encountered during each specific period. Ultimately, firms choose the amount of LNG that maximizes their expected profits, internalizing that given the implemented policy, any amount of LNG surplus that remains in the storage tank will enter dispatch at a virtual zero marginal cost.

Due to the significant uncertainty firms face during the LNG ordering process, their expectations regarding their residual demand become pivotal in determining the actual quantity of LNG they decide to order. We calibrate their expected demand probabilities by minimizing the difference between the model's estimated order with the actual amount of LNG ordered by each firm. We find that firms held high demand expectations in 2019, which coincides with large quantities of natural gas being dispatched at an artificial zero marginal cost in reality (given that realized residual demand was not as high). Once the expected demand probabilities have been calibrated, we estimate firms' LNG procurement and achieve a correlation of 88.33% between the model's predictions and the true LNG orders observed in 2019.

The last part of our structural model involves the estimation of solar plants' entry into the Chilean electricity market. We assume that entry into solar power generation is competitive and model the equilibrium quantity of solar investment by applying a zero-profit condition. We consider a 25-year life span for solar panels to account for their operational longevity, and entry costs are such that firms make zero profits under the prevailing market conditions.

We use the developed structural model to assess the impact of the LNG prioritization policy and compare its outcomes with four alternative counterfactual scenarios that we designed. We start by analyzing a scenario where the government, which aims to minimize expected energy supply costs and emissions, directly places LNG orders for firms. These are the optimal orders in the absence of any policy. We then compare these outcomes with a regular dispatch, a baseline scenario where firms place orders without specific policies or subsidies. Next, we analyze the actual framework, where any amount of natural gas could be granted the highest priority for dispatch.

The remaining two counterfactuals are unrelated to the LNG prioritization policy and are designed to explore alternative policies that could yield better outcomes. These include a government subsidy covering 50% of the fuel cost associated with LNG imports and a carbon price of $51 USD/Ton CO_2 that adds the adverse environmental impact of a generation technology into its marginal cost (potentially enhancing the dispatch priority for LNG). Examining these policies is relevant for various reasons. Subsidies have been extensively explored in economic literature as potential remedies for market imperfections and could provide a solution for the missing money problem with a simple transfer. Simultaneously, accounting for the social marginal cost of each technology is a current topic of discussion in Chile, and several economists advocate for a carbon tax over quantity-based approaches like the existing LNG prioritization policy (Weitzman 1974; Metcalf and Weisbach 2009; Hassler, Krusell, and Nycander 2016). While our approach does not tax emissions, it incorporates the negative environmental impact into the marginal cost of each technology, forcing it to be accounted for on the dispatch.

Our findings confirm that firms operating within a regular dispatch framework would under-order LNG from the government's perspective. Therefore, policies that encourage larger natural gas procurement could be important to enhance reliability.

Consequently, we find that the three policies we examine have a significant impact on the purchased quantities of LNG. Under the LNG prioritization policy, the volume of liquefied natural gas ordered increases by approximately 50% compared to the regular dispatch. Even though the usage of natural gas at zero marginal cost makes spot market prices drop, the policy enables them to obtain returns for the excess gas ordered, a benefit that would not have been possible without the policy. This incentivizes firms to increase their LNG orders when anticipating favorable market conditions.

Notably, the artificial introduction of natural gas does result in a significant displacement of coal usage. The substantial amount of LNG ordered under the policy, however, offsets the emission reduction resulting from this displacement due to the forced utilization of all the excess gas. Therefore, we find that in 2019, the LNG prioritization policy ultimately increased emissions by $20 million.

With the government subsidy, firms order approximately 92% more than under the regular dispatch. The subsidy, then, could potentially achieve heightened order quantities as the LNG prioritization policy; nonetheless, this approach entails significant public expenditure.

When including a carbon price into the technologies' marginal costs, we observe an increase in LNG orders, with firms ordering 65% more than under a regular dispatch. This change is due to coal and diesel being dirtier than LNG, resulting in a higher marginal cost for these fossil fuels. Consequently, natural gas is granted, on average, a higher priority in the dispatch order among fossil fuels. This enhanced priority, coupled with the rise in spot market prices resulting from increased marginal costs, serves as a strong incentive for firms to import more LNG.

The policy incorporating the carbon price is the most effective at displacing polluting technologies, resulting in an annual reduction of $191 million in the short run. However, it achieves this while raising prices by approximately 40-70% compared to a regular dispatch. This increase in prices, unfortunately, would eventually be borne by consumers in the medium to long term. The government subsidy, on the other hand, yields short-term results similar to regular dispatch.

In the long term, switching from the current policy to either a regular dispatch or a government subsidy would result in a 10% increase in the national installed solar capacity. Conversely, adopting a social marginal cost approach (a carbon price) would stimulate solar capacity adoption by 54%. These shifts would lead to a reduction of $29 million and $349 million in emissions in the long term, respectively.

We further show that under several robustness checks, our findings remain consistent: the social marginal cost approach achieves the best reduction in emissions without compromising reliability. This holds true when firms have low or average demand expectations (instead of high as in 2019) and even if renewable capacity is reduced. We also demonstrate that removing transmission congestion between markets, thereby enhancing trade, significantly improves long-term renewable entry into the market for nearly all the policies we examine.

Further studies should be done in electricity markets heavily reliant on inherently uncertain technologies like wind, which might find such policies as the LNG prioritization policy advantageous, given natural gas's superior ramping capabilities that could bolster system reliability.

Related Literature Our findings contribute to a growing literature exploring environmental regulation promoting renewable entry. Much of this research focuses on assessing the environmental benefits of renewable energy generation and developing cost-effective policy frameworks to encourage its adoption (Fischer and Newell 2008; Cullen 2013; Edenhofer et al. 2013; Novan 2015). Our study evaluates policies on their ability to encourage renewable energy adoption, but it also analyzes their long-term impact on the reliability of electricity markets. Moreover, our analysis adds to the literature by considering policies that reduce emissions not only through renewable adoption but also when selecting sources that ensure system reliability.

Several prominent studies have delved into environmental policies and their interaction with dynamic investment decisions. While existing research has primarily concentrated on dynamic investments in wind power (Cullen 2015; Cullen and Reynolds 2017), or the dynamic effects of a carbon price on investment and air pollution (Weber 2021), our study evaluates the effects of various policies on dynamic investment in solar power.

Our estimation and modeling strategy closely aligns with the work of Gonzales, Ito, and Reguant (2023), who also investigated dynamic investment in solar power within the Chilean electricity market framework. Our study distinguishes itself from theirs in two key aspects. First, we incorporate firms' LNG import decisions directly into our model. With this approach, we endogeneize firm responses into our estimations of how different policies impact system reliability. By doing this, our paper provides an important insight into how policies can influence long-term investment decisions in solar generation, considering the available LNG capacity based on firms' responses to these policies. Second, while Gonzales, Ito, and Reguant (2023) primarily concentrate on the impact of transmission expansion and gains from trade on allocative efficiency and renewable energy entry, our research focuses on assessing the dynamic effects of various environmental policies on system reliability and examining how these policies interact with and influence the adoption of solar energy over time. To the best of our knowledge, our paper is the first to delve into environmental regulations that address accommodating LNG imports and investigates how they would impact long-term renewable investments in electricity markets.

Our paper also contributes to a body of literature on policies addressing under-investment in electricity markets (Hogan et al. 2005; Joskow and Tirole 2007; Joskow 2008; Cramton, Ockenfels, and Stoft 2013; Fabra 2018) and their impact on renewable investment (Llobet and Padilla 2018; Mays, Morton, and O'Neill 2019). Our research distinguishes itself within this literature by investigating a novel policy that aims to enhance imports of natural gas. We assess the effectiveness of this policy in reducing emissions and promoting the long-term entry of renewable energy sources into the electricity market. Furthermore, we contrast it with other policy alternatives, such as subsidies or carbon pricing, to overcome the under-investment in natural gas.

Previous research in this literature has argued that policies intended to solve the under-investment problem could have effects on the strategic behavior of firms (Teirilä and Ritz 2019; McRae and Wolak 2020). A key advantage of our research is that we operate within the context of Chile's audited cost-based dispatch system. This allows us to abstract our research from strategic behavior among firms within the spot market. Therefore, our study provides a clearer evaluation of the effects of the policies under consideration without it being confounded with potentially ignored market power effects in the spot market.

Lastly, our research contributes to the literature that explores resource adequacy in electricity markets with intermittent renewables. While Ambec and Crampes (2012) and Elliott (2022) focus on wind intermittency, several researchers examine the relationship between reliability and hydroelectric generation (Wolak 2003; McRae and Wolak 2020). This current paper, on the other hand, examines the short and long-run interplay of solar intermittency and reliability. As highlighted by Wolak (2022), the growing integration of intermittent renewable energy sources adds complexity to the task of ensuring a steady and sufficient energy supply to meet hourly demands throughout the year. While policies often emphasize the expansion of renewables, it is imperative to consider the long-term resource adequacy of the electricity supply. In our study, we highlight the critical role of having an adequate supply of liquefied natural gas to offset the use of coal and diesel when (intermittent) renewables are unavailable. Our research aligns closely with the work of Elliott (2022), who investigates the design of electricity markets to reduce emissions and prevent blackouts. While Elliot's focus lies in market design, our research centers on environmental policies, their influence on LNG imports, and their long-term impact on incentives for renewable energy investment.

It is worth noting that Chile boasts sufficient installed capacity, minimizing the risk of blackouts. Consequently, our focus on reliability centers on avoiding the use of environmentally detrimental fossil fuels for electricity generation. To the best of our knowledge, our study is the first to address how decisions regarding LNG imports influence this critical aspect and further relate it to solar power entry. Therefore, our paper introduces a novel empirical framework for quantifying the trade-off between over- or under-investment in LNG imports and the long-term promotion of renewable energy entry into the electricity market.

Outline The paper is organized as follows. Section 2 provides institutional details on the Chilean electricity market dispatch process and delves into the policy that granted natural gas the highest dispatch priority. In section 3, we introduce the analytical model and the simulations that show how firms' incentives change with the Chilean policy. Section 4 describes the data and presents descriptive statistics about the electricity market and the impact the policy had on it. Section 5 presents the structural model, outlines the estimation methodology, and evaluates the model's goodness of fit. In section 6, we present and analyze the outcomes of the counterfactual scenarios, and finally, section 7 concludes.

2 Dispatch in Chile, LNG procurement, and the policy in place

This section explains how the spot energy market operates in this country and delves into Chile's efforts to regulate their imports of liquefied natural gas through the implementation of a policy we refer to as "the inflexibility policy".[3]

3. The historical context behind Chile's predominant reliance on LNG imports via vessels, as opposed to pipelines, can be found in Appendix A.

2.1 Operation of a cost-based dispatch spot market

In Chile, the coordination of power plants is overseen by the National Electric Coordinator (CEN). Unlike the commonly employed bid-based dispatch method prevalent in the United States, Chile utilizes a cost-based dispatch method (administered by the CEN) to allocate and clear supply and demand in the spot market. Cost-based dispatch implies power plants can only "bid" their true marginal cost of generating energy, and the quantity dispatched will be determined by the Coordinator.[4]

To run this cost-based dispatch method, the CEN obtains comprehensive information regarding power plant units, encompassing start-up, ramping, and shutdown costs, as well as other technical characteristics and input prices.[5] Then, it undertakes a process of ranking power plants based on their marginal costs, arranging them in ascending order from lowest to highest. Finally, it determines which units should be engaged to satisfy the demand while minimizing the overall cost.

Having a cost-based dispatch system will have implications for the procurement process of LNG, as it is explained in the next section.

2.2 The intricacies of LNG procurement and a policy to counteract their effects

Despite its importance in global energy markets, the transportation of LNG comes with considerable costs. The lower energy density of gas in comparison to oil or coal results in a relatively higher share of the delivered cost attributed to transportation expenses, making geographical proximity to resource-rich regions a critical factor influencing affordability (IEA (2019)). In addition, LNG necessitates dedicated infrastructure, including cryogenic storage tanks for maintaining extremely low temperatures and dock facilities for ship reception. The establishment of such infrastructure is associated with significant costs and prolonged construction periods, often exceeding a year. Besides, the presence of these storage tanks implies there is limited capacity, giving rise to a challenge for importing firms to accommodate forthcoming shipments adequately.

While reducing investment costs might be challenging, opportunities exist to mitigate import costs. Firms that import LNG can sign long-term contracts not only for supply assurance (Bolton and Whinston (1993)) but also to reduce transaction costs (MacKay (2022)) and search cost frictions (Tolvanen, Darmouni, and Essig Aberg (2021)). Additionally, LNG shippers commonly adopt a practice where they offer price concessions to buyers who either engage in procurement well in advance of actual delivery or agree to take-or-pay clauses[6] as part of their purchase contract, which can make them inflexible to fluctuations in demand and costs (Masten and Crocker (1985), Zahur (2022)). Importing firms, therefore, typically place orders several months in advance, seeking to minimize transportation expenses. This exposes them to significant uncertainty concerning their residual demand, thus, making it harder to manage the LNG stored and the

4. Plants will usually run at capacity, except for the one generating at the margin.

5. The CEN audits power plants to confirm the information submitted.

6. A take-or-pay clause is a contractual provision that obligates a buyer to either accept and pay for a specified quantity of a commodity from a seller on a predetermined date or incur a fixed penalty fee if the buyer fails to fulfill the agreed-upon obligation. In the context of LNG procurement, firms are required to pay for the entire quantity of LNG they order, irrespective of their storage capacity, to accommodate the received shipments.

incoming orders. Potentially, this could lead to LNG being hastily burnt, without generating energy, to create room for the imminent vessel or instances where some cargo of the subsequent shipment cannot be accommodated. In consequence, this risk may lead them to order a lesser quantity of natural gas than what would be considered optimal by the government. Such under-ordering could potentially hinder the ability to counterbalance, without using dirty and costly technology, fluctuations in renewable energy output, deal with unanticipated power plant shutdowns, or address transmission constraints.

Even though this challenge is widespread for LNG-importing companies globally, in Chile, the operation of a cost-based dispatch market further drives firms to adopt strategies to minimize the marginal costs of their power plants. In order to increase their chances of being called upon for dispatch, power plants need to have lower marginal costs. For firms incorporating natural gas in their technology mix, considerations extend beyond fuel prices and include import costs as well.

In order to reduce costs, LNG firms in Chile sign contracts months in advance of the scheduled arrival date with shipping companies and usually include take-or-pay clauses. Considering the limited storage capacity of the country,[7] firms have to make accurate demand estimations to determine the appropriate order quantity and avoid overordering, which would entail the burning of gas without its actual dispatch.

Furthermore, the countercyclical relationship between natural gas and hydroelectric generation[8] involves examining rainfall and thaw patterns throughout the year to accurately predict demand. As a result, firms must navigate a significant degree of uncertainty when signing contracts.

Exposure to such risks might prompt firms to order less LNG than the National Energy Commission (CNE)[9] deems optimal, as the CNE seeks to minimize the cost of supplying energy and emissions. Notably, having LNG in the technology mix is important since the use of coal or diesel for power generation can result in significant pollution.

To address this issue, the entity introduced a policy in September 2016 aimed at reducing firms' risk exposure and, hopefully, encouraging higher LNG orders. Under this policy, firms were allowed to declare a portion of their natural gas volume as "inflexible" if its non-use for energy generation would result in significant economic detriment to the firm.[10] Moreover, the declared inflexible volume could correspond solely to the quantity necessary for unloading the next shipment. Consequently, the Coordinator would assign a zero to the fuel component of the inflexible volume's marginal cost[11], granting it a higher dispatch priority than it would have under normal circumstances.

7. Storage capacity comprises two tanks located in Quintero, situated in the central region, and one in Mejillones, situated in the northern region. During the periods of 2016 and 2017, there was a contemplation of constructing an additional storage tank in Quintero. However, due to the substantial investment costs involved (the Quintero tanks incurred an expenditure of $1.25 billion in 2009) and not unusual instances of incomplete utilization of tank capacity, the realization of the project did not materialize.

8. Chile has a substantial amount of hydroelectric capacity for generation. More details can be found in Section 4.

9. The CNE is a governmental organization entrusted with the mandate of ensuring the effective operation and advancement of the energy sector within the country. It is actively involved in the analysis of market prices and the formulation of standards and policies aimed at regulating and promoting the growth of the industry.

10. Declarations that were subject to rigorous verification processes conducted by the Coordinator.

11. The non-fuel marginal costs associated with inflexible gas were slightly higher than zero. Inflexible gas had, then, lower priority than renewable energy.

It is important to note that the policy formalized an existing practice already being implemented by the Coordinator and firms. However, in June 2019, a modification was made to it. Under the updated version, the Coordinator began considering the total marginal costs (fuel and non-fuel costs) of the inflexible volume as zero rather than solely the fuel costs. This change effectively assigned the highest dispatch priority to inflexible LNG.

Following this update, renewable generation fringe firms raised concerns regarding the negative implications of the "LNG prioritization policy." Specifically, they contended the policy had short-term impacts on spot market prices, hindered the entry of renewable generation plants in the long term, contributed to renewable energy curtailment, facilitated market concentration and the exercise of market power, failed to incentivize investment in LNG infrastructure, and socialized the costs and risks associated with LNG to all market participants.

Conversely, proponents of the policy argued that its absence would result in increased costs and uncertainty for natural gas projects, thereby rendering the energy transition more expensive and environmentally detrimental by necessitating diesel usage as a backup for renewable energy. As such, the overall effects of the inflexibility policy remained ambiguous.

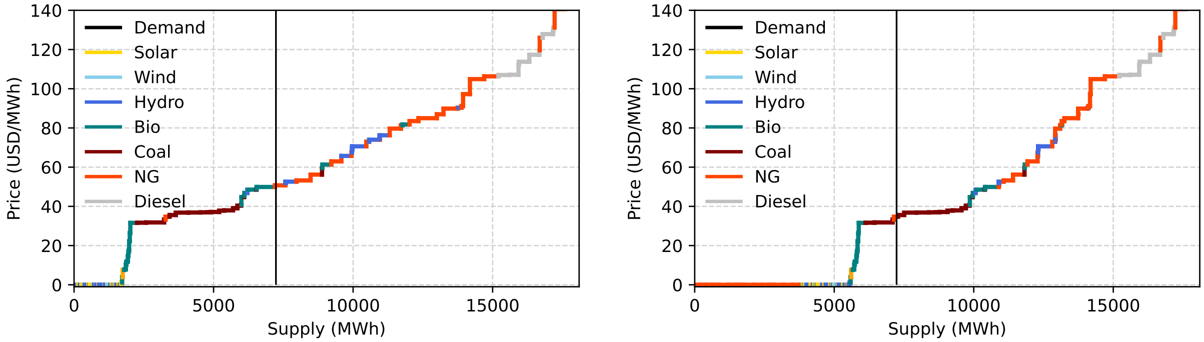
Finally, in October 2021, the technical norm underwent its most recent modification. The primary objective of this update was to reduce the volume of natural gas declared as inflexible. As a consequence, the revised norm established a maximum limit on the inflexible volume, with its marginal costs no longer necessarily being zero. Instead, the Coordinator calculates the opportunity cost of natural gas and utilizes it to determine the hourly pricing. This approach mirrors the regular practice employed for hydroelectric generation, which factors in the opportunity cost associated with dam water. Importantly, since the implementation of the new technical norm, the volume of natural gas declared as inflexible has effectively diminished.

2.2.1 Descriptive impact of the policy

To gain a deeper understanding of the consequences of prioritizing natural gas in the dispatch process, Figure 1 provides a visual representation of the resulting shift in the supply curve for 5 am on July 11, 2019.

The implementation of the LNG prioritization policy results in the dispatch of multiple LNG plants. These plants contribute energy at negligible or zero marginal costs, leading to a displacement of the supply curve towards the right and subsequently reducing prices. Panel (a) of Figure 1 illustrates the price levels that would have prevailed in the absence of the LNG prioritization policy, indicating an equilibrium spot price of approximately 55 USD/MWh. On the contrary, panel (b) demonstrates the actual outcomes observed in reality, where the prioritization of inflexible natural gas in the dispatch process is evident by the accumulation of red data points on the left side of the supply curve. The equilibrium spot price in this LNG prioritization policy scenario, as a result, decreases significantly to approximately 36 USD/MWh, and naturally, the plants that would have operated infra-marginally in Panel (a) experience a decline in profits under the policy. Being

Figure 1: Example: Supply curve on July 11, 2019, 5 a.m.



(a) No LNG prioritization

(b) Reality: 3 firms declared inflexible LNG

renewable plants infra-marginal due to their low marginal costs, this decline in prices could affect their entry into the electricity market in the long term.

In fact, on July 11, 2019, at 5 a.m., the renewable energy generation reached a level of 2,156 MW, which is close to the lower limit of its capacity due to minimal wind and no solar input during that hour. Back-of-the-envelope calculations, assuming that the policy does not result in the displacement of renewable energy from the dispatch, reveal that the observed price reduction corresponds to a potential revenue decrease of approximately $41,000 within a single hour for renewable energy generation. If this trend persists across numerous hours throughout the year, the cumulative impact on the profitability of renewable energy sources could be significant.

3 Theoretical Model and Simulations

In this section, we present a simple theoretical model to elucidate the forces influencing firms that own LNG plants to increase their gas orders under the 2019 LNG prioritization policy.[12] We then simulate its results to show how the policy can change incentives for the firms that import LNG.

3.1 Theoretical model

We consider four distinct energy sources for generation: renewables (solar), hydro (dams), LNG, and diesel. A crucial distinction between liquefied natural gas and other fuels lies in its requirement to place orders prior to demand realization. Upon order arrival, LNG necessitates storage within dedicated tanks. Liquefied natural gas generation capacity, thus, will be given by the amount of gas ordered. This diverges from our consideration of the other energy sources, for which capacity is fixed, and there is no fuel limit such that generation spans the range between zero and that established threshold.

12. The effects under the first technical norm of 2016 are comparable, but for clarity of exposition, we assume total marginal costs of zero, thus analyzing the 2019 policy.

At the end of a period, a new shipment of gas arrives. We assume that no gas must be left in the storage tank by that time, so any unused gas must be burnt.

To begin, we outline the planner's objective of minimizing the sum of energy supply costs and environmental costs. Under the baseline scenario (regular dispatch), the planner solves:

$$
\begin{aligned}
\min_{q} \quad & c_g\, q + e_g\, q \\
& + \int_0^{\bar{q}_r} c_r\, Q\, dF(Q) \\
& + \int_{\bar{q}_r}^{\bar{q}_r+\bar{q}_h} (\, c_r\, \bar{q}_r + c_h(Q-\bar{q}_r)\,)\; dF(Q) \\
& + \int_{\bar{q}_r+\bar{q}_h}^{\bar{q}_r+\bar{q}_h+q} (\, c_r\, \bar{q}_r + c_h\, \bar{q}_h\,)\; dF(Q) \\
& + \int_{\bar{q}_r+\bar{q}_h+q}^{\infty} (\, c_r\, \bar{q}_r + c_h\, \bar{q}_h + (c_d+e_d)(Q-\bar{q}_r-\bar{q}_h-q)\,)\; dF(Q)
\end{aligned}
$$

where subscripts r, g, h, and d stand for renewable, LNG, hydro, and diesel, respectively. $\bar{q}$ corresponds to the maximum capacity associated with each fuel, and c denotes their respective marginal costs.[13] Within this framework, Q symbolizes the energy demand and $F(Q)$ its distribution. Lastly, e_g and e_d represent emissions stemming from LNG and diesel, respectively.

Some key elements of the model can be grasped from this equation: first, liquefied natural gas must be ordered before demand realizes at a marginal cost of c_g. Also, we get the dispatch priority of energy sources: solar has the highest priority, followed by hydro, LNG, and diesel, implying that $c_r < c_h < c_g < c_d$.[14] And last, there are environmental costs associated with burning gas (e_g) or diesel (e_d), where $e_d >> e_g$.

By taking first-order conditions, we obtain:

$$
\underbrace{\mathbb{P}\left(Q > \bar{q}_r + \bar{q}_h + q\right)(c_d + e_d)}_{\text{Marginal benefit of purchasing LNG}} = \underbrace{c_g + e_g}_{\text{Marginal cost of purchasing LNG}} \tag{1}
$$

Equation (1) indicates the planner internalizes that purchasing gas reduces the probability of using diesel, which is much more expensive and more environmentally polluting than LNG. The planner prefers to minimize the cost of generating energy in addition to minimizing the negative externality of emitting greenhouse gases. Therefore, the planner will continue ordering LNG until the marginal benefit of reducing the probability of using diesel (in terms of costs and emissions) equals the marginal cost and emissions associated with using LNG.

Moving from the planner to the firms' perspective in the model, we consider a single firm in the market

13. For clarity, we incorporate a marginal cost of solar, c_r, although it is effectively zero.

14. To simplify the model, we are disregarding the non-fuel marginal costs of each technology. The relevant aspect of the model, nonetheless, lies in the fuel costs, as that is where LNG encounters uncertainty.

that exclusively owns an LNG storage tank, and we assume that there are no storage costs. Alongside this firm, there exists one fringe firm for each of the other generation technologies. The firm with the LNG storage facility aims to maximize its profits by solving the following optimization problem:

$$\begin{aligned}\max_{q} \quad & - c_g \, q \\ & + \int_{\bar{q}_r+\bar{q}_h}^{\bar{q}_r+\bar{q}_h+q} \left(\, c_g(Q-(\bar{q}_r+\bar{q}_h)) \, \right) \, dF(Q) \\ & + \mathbb{P}(Q > \bar{q}_r+\bar{q}_h+q) \left(\, c_d \, q \, \right)\end{aligned}$$

Notice that spot market prices are determined by the marginal costs of the technology generating at the margin. This means that if $Q \in (\bar{q}_r+\bar{q}_h, \bar{q}_r+\bar{q}_h+q)$ the price would be c_g; if Q is larger, the price would be c_d.

While firms might consider emissions, it is reasonable to assume that they do not prioritize them as much as the planner. Hence, we consider the environmental cost of each fuel to be zero for the firm. The first-order conditions are as follows:

$$0 = - \, c_g + c_g \, \frac{\partial \mathbb{P}(Q \leq \bar{q}_r+\bar{q}_h+q)}{\partial q} \; q + \frac{\partial \mathbb{P}(Q > \bar{q}_r+\bar{q}_h+q)}{\partial q} c_d \, q + \mathbb{P}(Q > \bar{q}_r+\bar{q}_h+q) c_d$$

which is equivalent to:

$$\underbrace{\underbrace{\underbrace{\frac{\partial \mathbb{P}(Q > \bar{q}_r+\bar{q}_h+q)}{\partial q}}_{(-),\text{ Negative term}}(c_d - c_g)q}_{\text{Withholding incentive}} + \mathbb{P}(Q > \bar{q}_r+\bar{q}_h+q)c_d}_{\text{Marginal benefit of purchasing LNG}} = \underbrace{c_g}_{\text{Marginal cost of purchasing LNG}} \tag{2}$$

The importing firm possesses a withholding incentive that is absent in the planner's decision framework. It acknowledges that by diminishing its gas procurement, the probability of higher infra-marginal returns is heightened, as this action increases the likelihood of resorting to diesel, and thus the probability of higher prices rises.

Even if we were to disregard the emissions externality that the planner takes into account (i.e., $e_d = 0$ and $e_g = 0$), the amplified cost of supplying energy originating from diesel, in addition to the firm's withholding incentive, drive the misalignment between the incentives of the firm and those of the planner.

In our simulations, we show the firm places orders that fall below the optimal quantity determined by the planner.

How the LNG prioritization policy changed firm's incentives.

The policy was introduced to enhance the reliability of the system, with a specific focus on reducing the usage of expensive and dirty technologies for generation purposes. This policy aimed to alleviate the uncertainty confronted by LNG-importing firms, as they need to place their orders before actual demand is realized. Hence, the dispatch order was modified, granting priority to gas over renewables. In order to evaluate the effectiveness of this policy in incentivizing firms accordingly, it is essential to analyze the new profit function for LNG firms, which is now represented as follows:

$$\begin{aligned}
\max_{q} \quad & -c_g \; q \\
& + \int_0^q \left(\; c_g^{inflex} \; Q \; \right) \; dF(Q) \\
& + \mathbb{P}(q \leq Q \leq q + \bar{q}_r)(c_r \; q) \\
& + \mathbb{P}(q + \bar{q}_r \leq Q \leq q + \bar{q}_r + \bar{q}_h)(c_h \; q) \\
& + \mathbb{P}(Q > q + \bar{q}_r + \bar{q}_h)(c_d \; q)
\end{aligned}$$

where c_g^{inflex}, with $c_g^{inflex} \leq c_r$, represents the new price of LNG in the spot market, ensuring the highest priority of dispatch.

We make the simplifying assumption that, under the policy, all gas is inflexible. This reduces the perceived benefits of the policy for LNG firms.[15] Nevertheless, even under this conservative framework, our simulations still demonstrate that firms order more gas than under regular dispatch.

The first-order conditions for this modified profit function are as follows:

$$\begin{aligned}
& \underbrace{\frac{\partial \mathbb{P}(Q \leq q)}{\partial q}}_{(+)} \; c_g^{inflex} \; q \; + \\
& \underbrace{\frac{\partial \mathbb{P}(q \leq Q \leq q + \bar{q}_r)}{\partial q}}_{(?)} \; c_r \; q + \underbrace{\frac{\partial \mathbb{P}(q + \bar{q}_r \leq Q \leq q + \bar{q}_r + \bar{q}_h)}{\partial q}}_{(?)} \; c_h \; q \\
& + \mathbb{P}(q \leq Q \leq q + \bar{q}_r) \; c_r + \mathbb{P}(q + \bar{q}_r \leq Q \leq q + \bar{q}_r + \bar{q}_h) \; c_h \\
& + \underbrace{\frac{\partial \mathbb{P}(Q > q + \bar{q}_r + \bar{q}_h)}{\partial q}}_{(-)} \; c_d \; q + \; \mathbb{P}(Q > q + \bar{q}_r + \bar{q}_h) \; c_d = c_g
\end{aligned}$$

The last line in the equation shows a similar result to what was obtained in equation (2), which is the withholding incentive perceived by the firm to heighten the likelihood of encountering high prices coming from diesel. However, the present equation's first and third lines introduce three positive terms. These terms stem from the firm's recognition that during instances of low demand realization, gas will invariably enter

15. In reality, firms would only dispatch their excess LNG at zero cost instead of all of it.

the dispatch, enabling partial cost recovery from imported LNG. This reduces the losses incurred by the firm in cases of low realized demand, thereby incentivizing a larger ordering volume in comparison to the regular dispatch order analyzed above.

Moreover, the second line introduces two terms denoted as "(?)" due to their sign dependence on the functional form of demand. The firm realizes that ordering more might yield higher infra-marginal returns. Yet, at the same time, it recognizes the policy's full priority on the dispatch of gas, implying that a higher LNG order compels demand to be higher to secure greater returns for its infra-marginal LNG unit. Given the indeterminable sign of these two terms through mere analytical equations, we resort to simulation of the objective functions presented within this section. This simulation serves to examine whether the LNG prioritization policy ultimately amplifies or diminishes firms' incentives to procure LNG.

3.2 Simulations

This section provides the results derived from the simulations of the theoretical model. The simulations encompass the evaluation of the firm's profit function under the regular and policy dispatch rules and the planner's objective function. Figure 2 illustrates the first set of results, where the solar capacity is held constant at 200 MW.[16] The principal focus of the outcomes presented by this figure is to assess the static implications of the LNG prioritization policy.

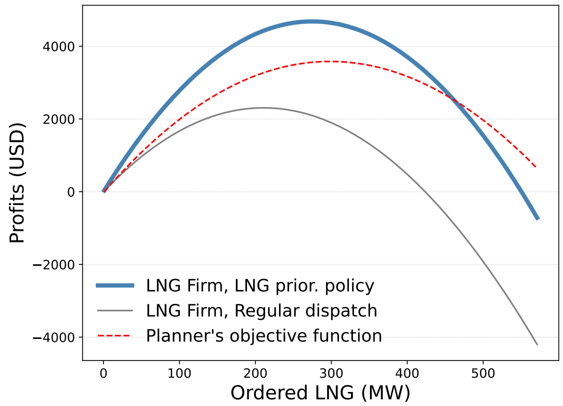
In Panel (a) of Figure 2, an important distinction is observed in the objective functions between the firm and the social planner. The firm's withholding incentive prompts a lesser order of LNG compared to the planner's optimal amount since it knows that withholding the gas order could increase its infra-marginal rents. However, with the introduction of the policy, which enables the firm to recuperate a portion of the incurred LNG import costs, the firm's ordering behavior tends to align more closely with the planner's optimal stance. The policy works as an insurance mechanism for the firm, mitigating the impact of demand uncertainty. With the policy in place, the firm receives revenue at more points along the demand distribution, which enhances its ability to order more LNG compared to a scenario without the policy.

The convergence between the firm under the policy and the planner's incentives is further elucidated in Panel (b). The optimal quantity of LNG ordered by the firm within the regular dispatch framework remains below the planner's optimal level, but the implementation of the policy acts to rectify this discrepancy, leading to an increment of the firm's marginal benefit and subsequently bringing the optimal order magnitude closer to the planner's optimal benchmark. Notably, in instances where the ordered quantity is large, the firm recognizes the potential erosion of its infra-marginal returns by dispatching a large amount of gas at zero marginal cost. Consequently, at that point, its marginal benefit is lower than the scenario of regular dispatch.

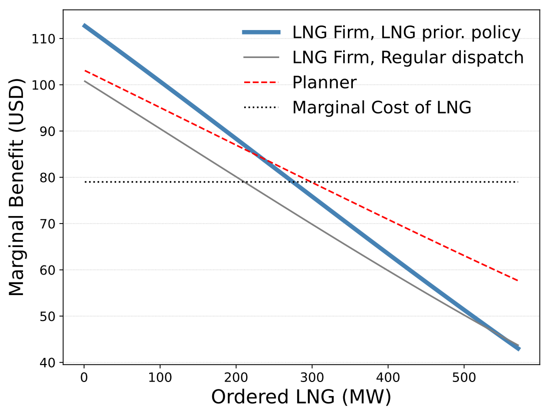
The policy's implementation partially mitigates the disparities in the optimal quantity of LNG ordered by the planner and the firm. Yet, Panel (c) reveals a drawback associated with this inflexible gas approach,

16. Specific capacity levels are of negligible consequence in the context of these simulations.

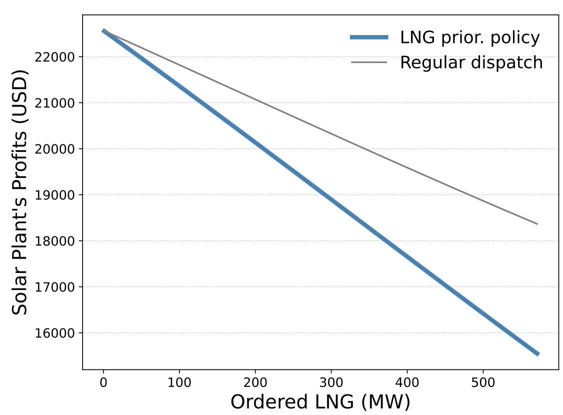
Figure 2: The LNG import gap of the planner and the firm – Regular dispatch vs. LNG prioritization policy



(a) Firm's profit and planner's objective function

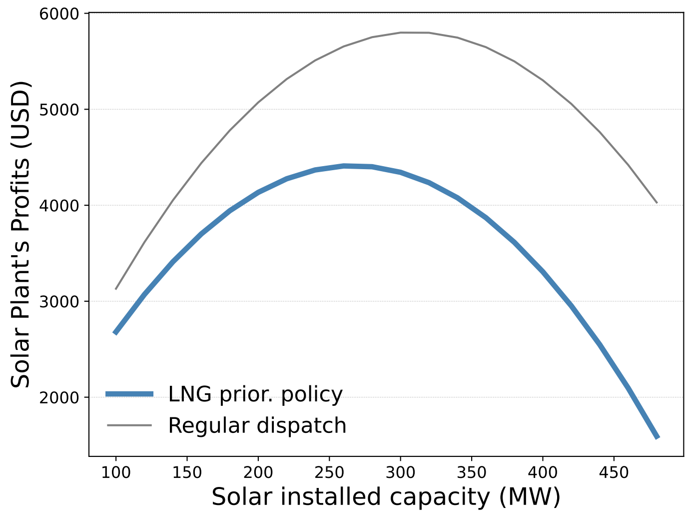


(b) Marginal benefit from the planner and the firm

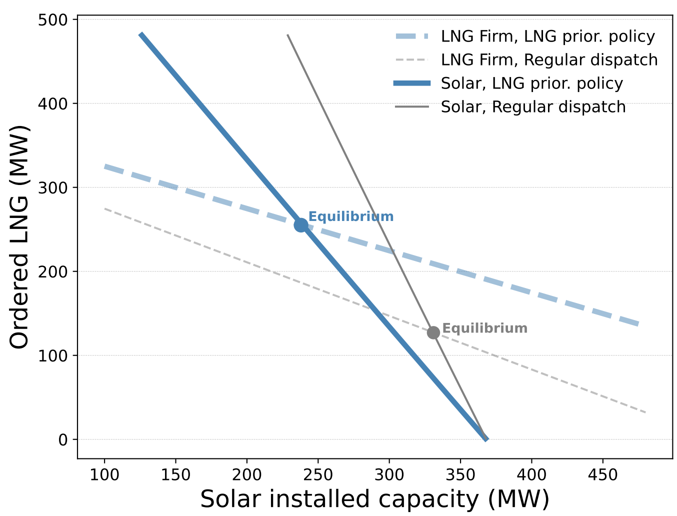


(c) Solar generation profits

Figure 3: Impact on solar investment – Regular dispatch vs. LNG prioritization policy



(a) Solar investment



(b) Best replies for LNG firm and solar

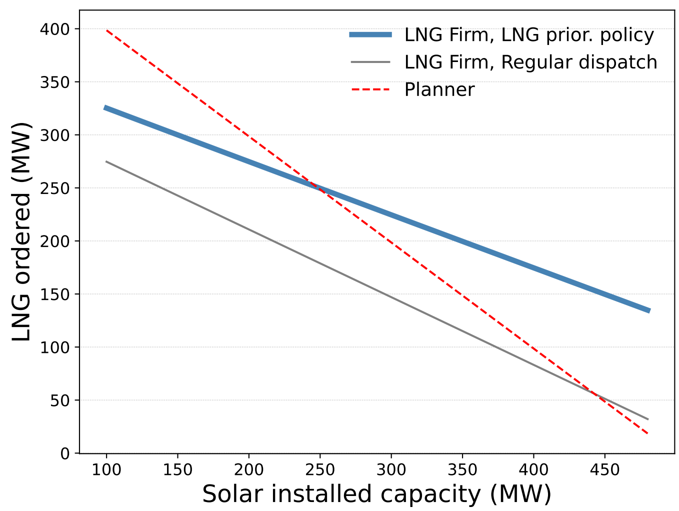


Figure 4: Optimal LNG orders vs. Solar capacity installed

manifesting as consistently diminished solar generation profits when compared to those realized under the regular dispatch scheme. This drawback holds dynamic implications, potentially influencing solar power's market entry. Figure 3 elucidates the enduring ramifications of the policy on solar entry.

In Panel (a) of Figure 3, where the LNG quantity is fixed at 200 MW, it is evident that the LNG prioritization policy results in lower investment in solar power compared to the scenario of regular dispatch. Moreover, solar generation profits diminish across all levels of installed solar capacity. This effect is pervasive across positive ordered LNG values and is anticipated to induce dynamic consequences. As delineated in Panel (b), the equilibrium established under the LNG prioritization policy corresponds to a heightened order of LNG compared to the regular dispatch scenario, accompanied by a reduction in installed solar capacity. While the policy succeeds in narrowing the planner-firm divergence in terms of imported LNG quantity, it exerts a dynamic influence on solar generation, leading to reduced market entry.

Our simulations also reveal that the effects of the policy are contingent upon its timing. Illustrated in Figure 4, the policy demonstrates efficacy if there is limited renewable capacity. However, as the magnitude of installed solar capacity grows, the LNG prioritization policy prompts the firm to procure excessive LNG quantities in comparison to the social planner's optimal amount.

Naturally, with the expansion of renewable capacity, the planner's demand for LNG diminishes, and the appeal for firms to engage in substantial LNG procurement wanes. Nonetheless, the social planner's rate of decline in the marginal benefit of ordering LNG exceeds that of the firm, given that it accounts for the higher cost and negative environmental externalities of using LNG over renewable power. Therefore, there exists an inflection point within the range of installed renewable capacity, where regular dispatch becomes more advantageous for the planner than adhering to the LNG prioritization policy.

The simple theoretical model and its simulations demonstrate how the policy effectively alters the firm's incentives by reducing its exposure to risk and ends up incentivizing increased orders. However, there are detrimental effects on renewable entry in the long run that might not have been contemplated by the social planner. These dynamics warrant further investigation to assess the overall implications of the policy on the energy market and renewable sector. Thus, determining whether the policy is welfare-enhancing requires additional analysis through a structural model, as the theoretical model alone cannot provide a definitive answer.

4 Data and Descriptive Statistics

The National Electric Coordinator of Chile provides extensive access to data pertaining to the country's electricity market. Below, we provide a comprehensive description of the specific data we have collected for the year 2019. In addition, we elaborate on the LNG generation sector with some descriptive evidence on the size of the importing firms, their storage capacity, and their inflexible gas declarations.

- **Hourly demand at the node-level**: The demand for energy at each node in the power grid, which is recorded hourly throughout the entire year. A node represents the most granular spatial point within the power grid.

- **Hourly market clearing prices at the node-level**: Market clearing prices are determined by the marginal generation technology's cost. For each hour, prices are recorded at each node. In the absence of transmission constraints, prices are similar across nodes. However, the presence of transmission constraints results in multiple prices coexisting at the same hour.

- **Hourly generation at plant level**: Detailed hourly generation data is available for each power plant.

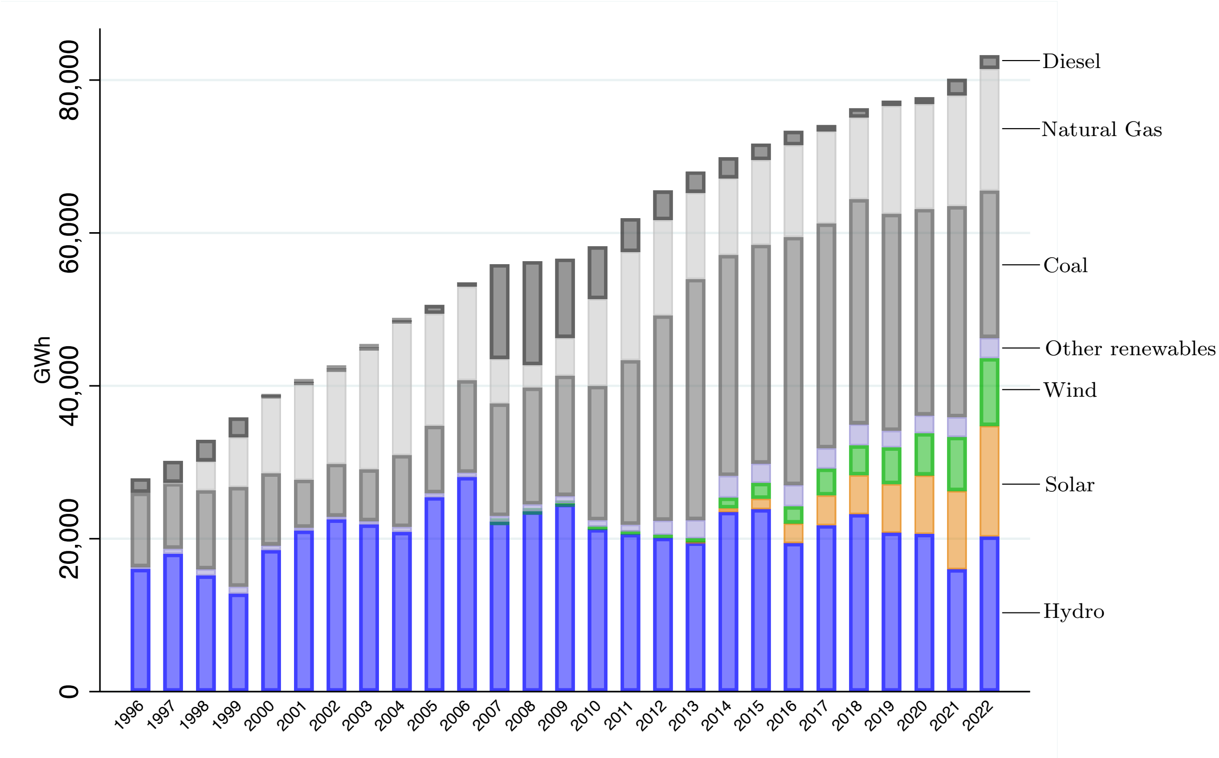
- **Daily marginal and fixed costs at the unit level**: Each power plant has the capability to generate energy using one or multiple units. This dataset includes marginal costs associated with both fuel and non-fuel inputs, as well as start-up, ramping, and shut-down costs for each unit. Specifically, marginal cost information for hydro generation is available for three distinct time segments of the day: block 1 (midnight to 8 am), block 2 (8 am to 6 pm), and block 3 (6 pm to midnight).

- **Plant characteristics**: Data regarding the location and overall generation capacity of power plants are provided, including capacity information at the unit level.

- **Inflexibility declarations**: This dataset includes the inflexibility declarations submitted by firms to the Coordinator, which detail the amount of LNG prioritized in the dispatch (measured in MMBTU) and the specified start and end dates (and hours) during which the prioritized gas is designated for power generation. Only approved declarations are considered in our study.

- **LNG annual delivery program**: Comprises information regarding the arrival dates of liquefied natural gas vessels throughout the year 2019.

Figure 5: Annual energy volume generation by fuel type



The CEN assumes the responsibility of dispatch coordination for the National Electric System (SEN), which encompasses over 99% of the installed capacity in the country. Figure 5 shows the evolution of its generation technology matrix over the years, where the introduction of numerous solar and wind power plants into the electricity market has been predominantly driven by an interconnection established in November 2017 and subsequently reinforced in June 2019.[17]

A summary of the data from the SEN collected for the year 2019 is presented in Table 1. This year was chosen due to its proximity to the present time and its pre-pandemic status, allowing us to minimize the confounding effects that may have emerged as a result of the COVID-19 pandemic. It is important to note, as pointed out in Section 2.2, that the LNG prioritization policy also underwent updates by the end of 2021, which may have further impacted the observed dynamics on more recent post-COVID dates.

Renewable energy plants possess a smaller generation capacity compared to other fuel types. Notably, on average, natural gas plants exhibit the largest generation capacity, which is approximately 70 times greater than that of solar (and 20 times greater than wind). Moreover, the total installed capacity of natural gas is substantial in comparison to solar and wind power, even surpassing half of the average daily demand. These observations imply that altering the dispatch order could exert a significant influence on the supply curve, particularly in scenarios where a substantial amount of natural gas is declared as inflexible. Additionally,

17. Further details on this development can be found in Gonzales, Ito, and Reguant 2023.

compared to natural gas, solar and wind generation are characterized by lower costs, implying that the inflexible declaration would result in the displacement of these technologies in the dispatch priority.

Table 1: Plants' marginal costs and capacity by fuel type (2019)

	Number of plants	**Total capacity installed** (MW)	**Marginal Costs*** (US$/MWh)			**Capacity** (MWh)		
			p25	*Mean*	*p75*	*p25*	*Mean*	*p75*
Solar	165	2,503	—	—	—	0	4	1
Wind	34	2,204	—	—	—	1	16	20
Hydro (rivers)	139	2,996	—	—	—	0	10	8
Hydro (dams)	9	3,142	50	67	76	50	155	214
*Bio***	21	465	11	26	42	11	22	33
Coal	18	4,289	32	40	49	161	231	345
Natural gas	26	4,621	62	86	96	179	281	380
Diesel	72	6,241	156	178	201	8	103	154
Hourly Demand (MWh)			7,416	8,139	8,848			

*We assume solar, wind and run-of-the-river hydro marginal costs are 0. **Bio refers to biomass, biogas, geothermal, and cogeneration.

Table 1 helps to intuit the potential side effects of the policy on the electricity market. In the next section, we use our data to show how the policy can indeed affect the supply curve and prices and, in consequence, affect market dynamics.

4.1 The LNG generation sector

Within the natural gas sector, there are four dominant firms, namely Colbun, Enel, Engie, and Tamakaya, whose combined installed capacity constitutes 86% of the total capacity installed. While other smaller firms also utilize LNG for energy generation, their capacity is insufficient to exert a notable impact on the spot market in the event of declaring gas as inflexible.[18] The relative scale of these four firms within the Chilean electricity market is provided by table 2.

Table 2: Import firms' generation by year (GW)

	Only LNG				**Complete technology mix**			
Firm	2016	2017	2018	2019	2016	2017	2018	2019
Colbun	3,594	3,780	3,859	4,506	11,141	12,532	12,862	11,594
Enel	4,525	4,493	3,695	4,208	16,930	17,466	18,076	19,119
Engie	1,426	1,042	1,331	1,954	6,090	4,184	3,563	4,246
Tamakaya	269	843	1,823	1,636	289	961	1,829	1,636
Relative to Chile*	82%	84%	91%	87%	48%	48%	47%	47%

*Refers to the amount of the country's generation covered by the four importing firms.

Evidently, these entities have consistently maintained a dominant position in the LNG sector over nu-

18. Insights obtained through discussions with electrical engineers employed by one of these four firms have corroborated this observation.

merous years, contributing to a substantial share of power generation derived from this technology, ranging from 82% to 91%. In addition, to these firms, natural gas constitutes an important share of their business, as it accounts for approximately one-quarter of their total electricity generation (to a greater degree for Tamakaya, which primarily focuses on natural gas and supplementary diesel-based generation).

Furthermore, table 2 underscores the complexity associated with gas procurement, as the ordered quantities can exhibit significant variations from one year to the next. For instance, Enel's natural gas-based energy generation fluctuated from approximately 4,500 GW in 2017 to 3,700 GW in 2018, subsequently rebounding to 4200 GW in 2019. This can be explained by natural gas orders being placed several months in advance to mitigate transportation costs, thus rendering them subject to uncertainties related to demand fluctuations and water scarcity.

Table 3 delves deeper into the uncertainty analysis, offering insights into the storage capacity dynamics during the year 2019 among different firms within the context of the Mejillones storage tank.[19] The presented storage capacity values are approximations derived from the sum of incoming shipment data and the prescribed maximum inventory thresholds as determined by the Chilean National Energy Commission (CNE).[20] The data reveals pronounced fluctuations in the firms' ordering patterns, shedding light on the prominent uncertainty that ordering each shipment entails.

The uncertainty elucidated in Tables 2 and 3 could potentially induce firms to engage in over-ordering of liquefied natural gas, thereby triggering the dispatch of prioritized gas, as firms may opt to declare gas as inflexible in order to recover some of the importing costs. Table 4 presents the percentage of hours throughout 2019 during which each of these four firms declared gas as inflexible, along with the corresponding proportion of generated Megawatts per hour associated with these declarations. Notably, firm size does not appear to influence the abilities firms have to avoid resorting to declaring gas as inflexible. Both Colbun, the largest, and Tamakaya, the smallest in terms of generation volume among the four firms, utilize more than half of their total LNG orders as prioritized gas. Nevertheless, the declaration of 61% of gas as inflexible by Colbun could potentially have more significant ramifications on the electricity market compared to Tamakaya's 72%, considering the difference in their LNG generation volumes.

Despite these firms being idiosyncratically affected by uncertainty, there exists a shared factor that explains certain overarching patterns in the declarations of inflexibility. In particular, water scarcity holds considerable significance on the uncertainty faced by importing firms due to the inverse relationship between natural gas utilization and hydro generation. The peak period for hydro generation occurs from the end of September to the beginning of January, coinciding with the thaw season and resulting in reduced reliance on natural gas within the system. Conversely, from the end of January to May, a typically dry summer season necessitates an increased reliance on natural gas to avoid resorting to (more) coal and/or diesel generation. The months of June, July, and August pose the highest degree of uncertainty due to the volatile nature of

19. Colbun's operational scope does not encompass the Mejillones tank; its operation is confined to the tanks situated in Quintero. Similarly, Enel's substantial involvement primarily revolves around the tanks located in Quintero.

20. The CNE stipulates the maximum inventory permissible in the tank for each firm before the subsequent shipment arrival, ensuring the full loading of the forthcoming order into the tank.

Table 3: 2019 shipments and storage capacity by firm (Mejillones)

Shipment	Date	Total Load (GW)	**Storage capacity (GW)** *Engie*	*Enel*	*Tamakaya*
1	29-Dec-2018	422	—	—	—
2	14-Feb-2019	363	218	40	232
3	15-Mar-2019	422	244	44	202
4	12-Apr-2019	400	246	43	201
5	24-May-2019	363	247	43	200
6	15-Jun-2019	422	288	36	165
7	14-Jul-2019	363	330	30	110
8	24-Jul-2019	361	264	43	175
9	16-Aug-2019	363	272	48	160
10	20-Sep-2019	422	248	57	173
11	18-Oct-2019	105	236	52	190
12	19-Nov-2019	426	311	50	119
13	23-Dec-2019	363	77	16	399
Mean		368.80	248.47	41.79	193.88
Std. Dev.		84.28	62.91	10.92	73.40

Values assume LNG plants have an efficiency of 44%. Storage is obtained with back-of-the-envelope calculations of shipment load plus maximum inventory allowed. Firms, however, can trade part of their loads; thus, storage presented is only an approximation.

Table 4: Number of hours and generation with inflexible gas by firm (2019)

Firm	**Hours inflexible per year**	**Generation inflexible per year***
Colbun	56.63%	61.09%
Enel	24.82%	22.93%
Engie	33.89%	39.57%
Tamakaya	67.28%	71.98%

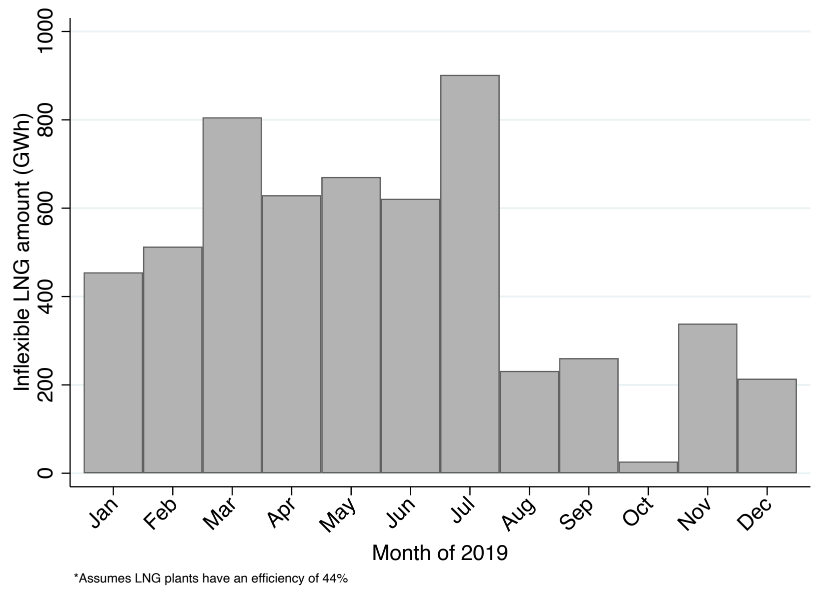
*Assuming LNG plants have an efficiency of 44%.

rainfall.

Figure 6 examines the distribution of prioritized gas generation throughout each month of 2019. A distinct pattern emerges in the utilization of prioritized gas, where months characterized by relatively predictable conditions and higher hydro capacities (September to December) exhibit significantly lower levels of prioritized gas usage. Conversely, months marked by greater uncertainty (such as January to May, with unexpected rainfall during dry months and the inherently challenging predictability of June and July, as explained above) tend to witness a notable increase in the declaration of gas as inflexible.

Undeniably, it becomes apparent that the months characterized by heightened uncertainty correspond to periods exhibiting elevated utilization of prioritized gas. This observation aligns with the underlying

Figure 6: Distribution of prioritized gas generation in 2019



rationale of the LNG prioritization policy, which allows firms to over-order LNG as a form of insurance against unpredictable circumstances.

5 Structural Model

In practice, firms importing LNG determine the amount of gas to order for the following year in September, aiming to maximize their expected profits. Uncertain factors like energy demand and rainfall will affect their power plants' residual demand and, in consequence, influence their procurement decision. Policies designed to mitigate the uncertainty these companies face could contribute to the short-term reliability of the system. Yet, they might also carry potential adverse consequences for the energy sector in the long term.

We develop a comprehensive structural model to investigate the entry of solar capacity in the context of different dispatch and liquefied natural gas import policies. To replicate how firms estimate their residual demand, we build a transmission network dispatch model based on the work by Gonzales, Ito, and Reguant 2023, described in Section 5.1. This model enables us to simulate spot market prices and generation patterns under different demand scenarios, which allows us to calculate importing firms' expected profits. Given these expected profits are conditional on the amount of LNG available, in Section 5.2, we elaborate on how we use this model to get the LNG orders that maximize them. Finally, we construct a model to estimate the equilibrium entry of solar panels. We discuss this last part in Section 5.3.

Ultimately, with this structural model, we are able to study different policies by simulating counterfactual scenarios and use the dispatch model (accounting for the change in the firms' optimal LNG orders) to estimate the equilibrium entry of solar panels.

5.1 Dispatch model

The system operator is tasked with solving a complex optimization problem that considers multiple variables simultaneously, such as transmission congestion, occasional transmission line breakdowns, short and long-term rain (affecting hydropower availability), LNG availability, plants going offline for maintenance, start-up and ramping costs, among others. Our objective is to construct a simplified version of this model that adequately captures price trends to enable credible estimation of LNG orders and renewable energy entry.

Our simplified dispatch model aims to minimize energy supply costs while accounting for transmission constraints and allocating generation across different power plants. We allow for different market prices due to transmission constraints, and the equilibrium price in each market is determined by the technology at the margin.

To solve the optimization problem for each window, where a "window" represents the period between the arrival of two consecutive LNG vessels, we formulate the following constrained optimization problem:

$$\min_{\mathbf{q},\,\mathbf{imp},\,\mathbf{exp}} \quad \sum_{m,j,f,t} c_{mjft}\, q_{mjft} \tag{3}$$

$$s.t. \quad \sum_{j,f} q_{mjft} + \sum_{l} (imp_{lmt} - exp_{lmt}) = D_{mt} \qquad \forall m,t \qquad \text{(Market clearing)}$$

$$0 \leq \sum_{f} q_{mjft} \leq k_{mjt} \qquad \forall m,j,t \qquad \text{(Capacity)}$$

$$\sum_{m} (imp_{lmt} - exp_{lmt}) = 0, \qquad \forall l,t \qquad \text{(Balance)}$$

$$0 \leq imp_{lmt} \leq flow_{lm}, \quad 0 \leq exp_{lmt} \leq flow_{lm}, \qquad \forall l,m,t \qquad \text{(Transmission)}$$

$$\sum_{m,j \in J_z,t} q_{m,j,f=LNG,t} + q_{m,j,f=Inflex,t} \leq O_z^{LNG}, \qquad \forall z \qquad \text{(LNG)}$$

$$\sum_{m,j \in J_z,t} q_{m,j,f=Inflex,t} = O_z^{Inflex} \qquad \forall z \qquad \text{(Inflexible)}$$

$$\sum_{z} O_z^{Inflex} \leq \sum_{m,t} D_{mt} \qquad \text{(Consistency)}$$

where m, j, and t represent the market, plant, and hour indices, respectively. The index f denotes the type of fuel used for energy generation, where a single plant can use different fuels but not simultaneously (e.g., coal, diesel, or LNG). Variables q_{jt}, c_{jt}, and k_{jt} correspond to the quantity dispatched, marginal costs, and generation capacity of plant j in hour t.

The objective of the Coordinator is to minimize the cost of supplying energy while adhering to various constraints that ensure the system's needs are met. The first constraint in our model guarantees that demand for each market-hour (D_{mt}) is satisfied. It considers imported and exported energy via transmission lines (l) and the energy available for generation in each market. When generating energy, the "Capacity" constraint ensures no plant exceeds its available capacity (k_{mjt}).

The model incorporates transmission lines labeled as $l = 1, \ldots, L$, interconnecting neighboring markets. In this context, $flow_{lm}$ represents the transmission capacity of line l when market m is connected to that line,[21] and imp_{lmt} and exp_{lmt} denote imports and exports, respectively, from market m through line l at hour t. The third constraint, called "Balance", ensures that the net imports and exports balance out in the model, while the fourth constraint ("Transmission") accounts for transmission constraints by limiting the flow through each transmission line (l).

The "LNG" and "Inflex" constraints pertain to the utilization of liquefied natural gas. The index z stands for a firm that orders LNG, while J_z represents the set of plants owned by firm z that can generate energy using natural gas. The variable O_z^{LNG} represents the amount of LNG ordered by firm z for a given window, and the total energy generated using natural gas during that window must not exceed this amount. Additionally, a portion of the natural gas is designated as inflexible, and the "Inflex" constraint ensures that all inflexible (i.e., prioritized) natural gas is fully utilized within the window.[22] The "Consistency" constraint prevents the inflexible gas used for generation from being higher than demand. This last constraint, however, is never binding.

It is worth noting that marginal costs for most fuels remain stable over time; however, marginal costs for natural gas and hydropower exhibit high volatility. Natural gas costs depend on the commodity price at the time of purchase, including transportation costs, as explained in Section 2.2. Conversely, hydropower costs depend on current reservoir levels and anticipated rainfall for the upcoming months. While we maintain the exact marginal costs we observe in the data for hydropower, we take the average marginal cost of LNG for each firm-window. This will help us model the amount of gas ordered by each firm, $O_z^{LNG}\ \forall\, z$, as explained below in Section 5.2.

After establishing the structure of the dispatch model, the next step involves defining the concept of a market and determining the calibration of transmission flows, $flow_{lm}\ \forall\, l, m$, among them.

5.1.1 Market definition and transmission flow calibration

In this section, we start by defining what a market is in our model, and then we elaborate on how we determine the transmission flows between them. Given we do not directly observe $flow_{lm}$, the transmission flows we define in this section help simulate the congestion we observe in the data.

The extensive margin of transmission line congestion becomes evident in the data through price disparities observed nationwide.[23] In an ideal scenario without congestion, all nodes would exhibit the same hourly price. However, due to the unavailability of the intensive margin on congestion data and the computational challenges associated with modeling prices for the 940 nodes in our dataset, we employ k-means clustering to aggregate nodes into six markets.

The clustering process considers both price patterns and geographical proximity as criteria (Mercadal

21. If market m is not connected to line l, then $flow_{lm} = 0$.

22. Below, in Section 5.2.1, we explain how the amount of prioritized LNG, $O_z^{Inflex}\ \forall\, z$, is defined.

23. Notably, price variations range from 40 to 200 USD/MWh across all nodes throughout the year.

(2022), Gonzales, Ito, and Reguant (2023)). Figure 7 illustrates the size and geographical locations of the six markets within the National Electric System (SEN) under investigation, with the remaining white area representing other electric systems, collectively accounting for 1% of the country's energy demand.

In our model, each market is characterized by its unique price and demand dynamics, with power supply originating from plants within its geographical boundaries. Import and export activities between markets are permitted, provided they comply with the transmission flows of the respective transmission lines. The underlying assumption is that congestion is absent within markets but may lead to price disparities between markets if transmission lines become congested. Appendix B presents Figure B1, illustrating price variations across different markets.

Taking advantage of Chile's elongated yet narrow geographical shape, we employ a transmission line modeling approach that facilitates unidirectional energy flow from the north to the south of the country. Consequently, market 2 can trade with 1 and 3 but not the remaining markets. Notice that this is a simplification allowed by the clustering approach. In practice, the optimization model the Coordinator uses is more complex: there exists more than one line between markets, and the amount of energy that can be carried could be affected by some (but not all) transmission lines being down for repair.

We represent our model's transmission lines connecting the six markets using a matrix, denoted as T, as follows:

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

Each row corresponds to one of the six markets from north to south, while each column represents a transmission line. We use the values of this matrix to define $flow_{lm} = T_{lm} * F_l$, with F_l, the number of Megawatts allowed to be passed through markets by transmission line l. To calibrate F_l, we rely on available data, including the observed energy generation and demand levels for each market. By analyzing these factors, we can calculate the energy transmission between (our definition of) markets and identify the threshold at which price differentials emerge. Additional details and data regarding the transmission flows for 2019 are provided in Appendix B.

5.1.2 Model fit: Dispatch

We compare the average market price for each market-hour with the prices we obtain from our dispatch model. Estimated prices will be determined by the technology generating at the margin.[24]

The correlation between real average market prices and our estimated prices, as obtained from our

24. Specifically, prices are obtained as the optimal dual variable coming from the "Market clearing" constraint.

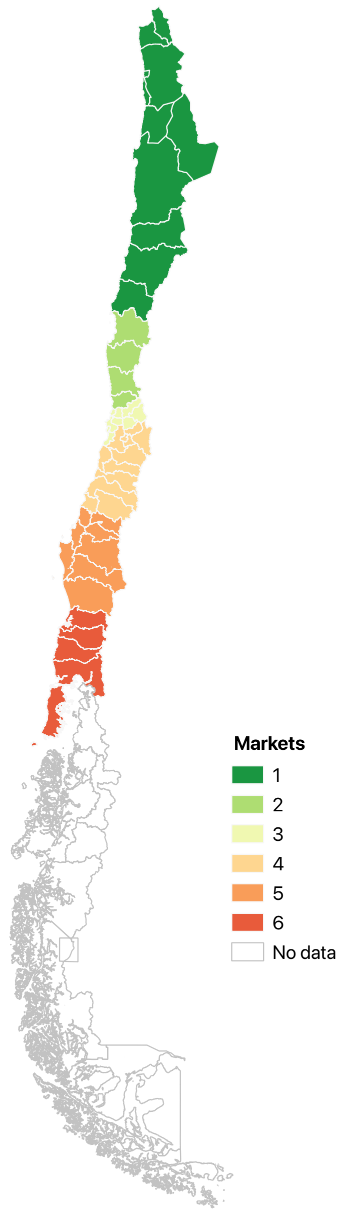


Figure 7: Markets' locations

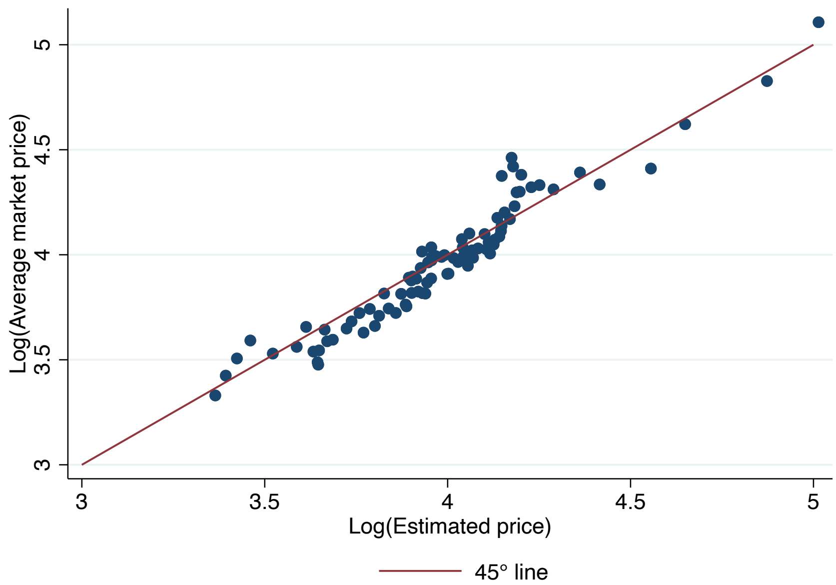


Figure 8: Real vs. estimated prices (log-log binscatter plot)

dispatch model, is 72.9%. Figure 8, depicted as a binscatter plot at a log-log scale, illustrates the performance of our model at estimating prices, which we deem accurate since most data points closely align with the 45-degree line. To derive these price estimates, our model was provided with the actual LNG utilization for generation and the prioritized gas amount determined based on our analysis of inflexibility declarations.

Figure C1, presented in Appendix C, illustrates the price matching across markets 1, 2, and 3 for each hour throughout October 2019. Additionally, Figure C2 compares real and estimated prices specifically for the twelfth hour of every day in 2019, focusing on markets 4, 5, and 6. Our model demonstrates strong performance in capturing overall price trends, although it does not precisely replicate peak prices. This discrepancy can be attributed to the simplifications made in the model, such as the omission of factors like plant outages, ramping costs, and transmission line failures, as mentioned above.

5.2 Endogeneizing LNG orders

To study the effects of various policies on renewable entry and system reliability, our model must incorporate the potential adjustments in LNG orders that firms would make under counterfactual scenarios. In this section, we explain how we endogenize the import decision-making process of these firms within our model.

5.2.1 Liquefied natural gas orders model

We employ a grid search methodology to determine the quantity of LNG import that maximizes firms' expected profits, where each point on the grid represents a specific LNG import amount for an entire window. Since dispatch decisions are determined by marginal costs and, in practice, firms cannot strategically manipulate quantities and prices in the spot market, we solve the grid search as a single-agent problem for the firm. In this context, the underlying assumption from our model is that firms' import decisions are influenced solely by demand uncertainty and LNG prices while considering other firms' decisions as given.

To begin with, we take the quantity of LNG imported by each firm based on the grid and solve the dispatch problem outlined in Section 5.1, utilizing zero LNG as inflexible (i.e., $O_z^{Inflex} = 0 \; \forall \, z$). Following the optimization process, it is possible that the LNG amount utilized for dispatch does not exactly match the total imported quantity for the window. However, in reality, under the LNG prioritization policy, no surplus gas should remain in the tank at the end of the window.[25] Accordingly, we designate any excess LNG from each firm as inflexible, and the dispatch model is re-solved. This iterative process continues until the excess LNG for each firm is equal to or less than 100 MW.[26]

The described algorithm encompasses five distinct demand realizations.[27] For each demand realization, the corresponding profits are calculated. We then derive the expected earnings for each of the four firms by utilizing probabilities we estimate[28] and, finally, we keep the amount of LNG that maximizes each firm's expected profits.

For computational feasibility, each window is solved independently. Therefore, we assume all LNG is utilized within the specific window without carrying over any unused quantities to subsequent windows. In other words, our assumption is that there is no remaining LNG in the tank when a new shipment arrives. In reality, the ratio between the inventory level and the total amount of LNG utilized for generation within a window is relatively small, with a median value of 7.96%,[29] which deems our assumption as sensible.

In the next section, we explain how we estimate the demand probabilities, which are key for estimating LNG orders.

5.2.2 Calibrating demand probabilities

Firms that import LNG are confronted with considerable uncertainty when procuring natural gas. Energy demand continues to rise annually, and accurate rainfall predictions become pivotal due to the substantial installed capacity in hydroelectric generation.[30] Ultimately, the primary concern for these firms revolves around precisely forecasting the residual demand they are likely to encounter.

Firms' choices concerning their LNG orders are notably impacted by their evaluations of the probability of encountering high-demand versus low-demand windows. In the event that firms anticipate high demand for the upcoming year, larger LNG orders are expected to be placed as opposed to a scenario where firms

25. More precisely, gas left in the tank should not exceed the maximum inventory possible. We elaborate on this below in this section.

26. The value of 100 MW, used as the threshold for excess LNG in the iterative process, is selected as an arbitrary figure. It is chosen to be sufficiently small to be considered negligible within the timeframe of four to six weeks, which corresponds to the duration between LNG shipments (referred to as windows).

27. We elaborate on this in Section 5.2.2

28. The estimation of these probabilities is described in Section 5.2.2 below.

29. We were able to obtain data on the inventory level of the Mejillones' tank at the time of the arrival of a new shipment for Enel, Engie, and Tamakaya during 2019.

30. See Section 2.2 for more details.

expect lower demand. A similar effect would occur in our model: if the calibrated probabilities put more weight on high-demand realizations, we would estimate larger LNG orders due to the expectation of higher natural gas utilization. These demand probabilities thus play a crucial role as tuning parameters in our model.

To elucidate the process of calibrating these probabilities, certain terms need to be defined. Let $\Pi_{z,w}(\mathbf{q}_w, \mathbf{k}, \mathbf{D}|rule)$ represent the profit of firm z within window w, which depends on the vector of LNG available for generation from all importing firms ($\mathbf{q}_w$), the vector of hourly generation capacities of all plants ($\mathbf{k}$), the vector of hourly demand ($\mathbf{D}$) and the specific dispatch rule ($rule$).[31] Additionally, let $q^*_{z,w}(\mathbf{q}_{-z,w}, \mathbf{k}, \mathbf{D}, rule; \theta_{z,w}) = \arg\max_{q_{z,w}} \mathbb{E}[\Pi_{z,w}|\theta_{z,w}]$ denote the optimal quantity of LNG ordered by firm z for window w, where $\mathbf{q}_{-z,w}$ is the amount imported by other firms (taken as given) and $\theta_{z,w}$ corresponds to the vector of probabilities of different demand realizations for firm z within window w. Then, to calibrate $\theta_{z,w}$, we solve

$$\min_{\theta_{z,w}} \quad ||q^*_{z,w}(\mathbf{q}_{-z,w}, \mathbf{k}, \mathbf{D}, rule; \theta_{z,w}) - Q_{z,w}||, \tag{4}$$

with $Q_{z,w}$ the observed LNG amount ordered by firm z for window w. As all parameters enter the minimization in equation 4 in a nonlinear fashion, we make some simplifying assumptions to reduce the degrees of freedom and make the problem computationally tractable. Specifically, in the model, uncertainty will stem from five distinct demand realizations, serving as proxies for the various possible residual demands these firms may face in reality. These realizations primarily impact markets with LNG plants, namely markets 1 and 3, which in turn influence other markets' demand through energy transmission. Each demand scenario represents a different level of demand, with the lowest demand scenario assuming it to be 80% of the realized value in 2019 and the other scenarios considering 90%, 100%, 130%, and 170% of the realized demand.[32]

The variations in hourly realized demand, stemming from factors like seasonality, wind, or rainfall, and technological generation capacity shifts over the year (for example, more hydro in the thaw and rainfall season or more solar power during the summer), help us to determine the optimal LNG order quantity $q^*_{z,w}(\mathbf{q}_{-z,w}, \mathbf{k}, \mathbf{D}, rule; \theta_{z,w})$ for a given $\theta_{z,w}$. Yet, five different realizations of demand would imply the calibration of five different values for the probability vector $\theta_{z,w}$ for each firm and window. To simplify the number of parameters to calibrate, we assume the vector of probabilities $\theta_{z,w}$ comes from a Beta distribution. Here, the parameter β is fixed at 2, while the parameter α remains to be calibrated. The distribution's support, spanning from 0 to 1, is evenly divided into five intervals, corresponding to the five different demand realizations. The probabilities associated with each demand realization are assigned based on the cumulative distribution values of the Beta distribution within each interval. Specifically, the interval $[0, 0.2]$ corresponds to the lowest demand scenario, $(0.2, 0.4]$ to the subsequent scenario, and so forth.

31. For the demand probabilities calibration, the dispatch rule is under the LNG prioritization policy, while we alter the rule for estimating LNG orders within counterfactual policy analyses in Section 6.

32. The highest demand scenario varies between 160% and 210% depending on the window. The inclusion of high-demand scenarios is essential to ensure the model can account for over-the-top orders we observe during certain periods.

To get the value of α that minimizes equation 4 for each firm-window combination, we implement the grid search algorithm described in Section 5.2.1, maintaining the LNG prioritization policy as the dispatch rule.[33] For each value of α, there exists an LNG quantity $q_{z,w}(\mathbf{k}, \mathbf{D}, rule; \alpha)$ that maximizes expected profits. By comparing this quantity with the observed LNG amount ordered by firm z for the window w, $Q_{z,w}$, we find the value of α that minimizes the difference between the two.

It is worth noting that while we do not have direct observations of the exact quantity of LNG ordered by firms, $Q_{z,w}$, we can use the assumption of no inventories at the time of a new shipment's arrival to assume further the total amount of LNG used for generation within a given window (which is observable) represents the amount of LNG ordered by the firms.

Furthermore, we estimate the demand probabilities for the case where firms have common beliefs, i.e., $\theta_{z,w} = \theta_w \ \ \forall \ z$. Our results prove to be consistent even under these common beliefs, as demonstrated in Appendix D.

5.2.3 Model fit: LNG orders

In this section, we analyze the estimated LNG orders and compare them to the actual amount ordered by each firm for each window.

To derive the estimated LNG orders, the first step involved obtaining the demand probabilities. This required estimating the parameter α for each firm-window. The values for α can be found in table D2 in Appendix D, while table D1 presents the corresponding probabilities for different values of the parameter.

We searched for values of α within the interval $[2, 12]$ which predominantly represent high-demand scenarios. This aligns with 2019 having the inflexibility condition frequently utilized, suggesting that firms had anticipated high demand but encountered a different reality.[34] The values of α presented in table D2 confirm all fall within the specified interval.

The probabilities exhibit considerable heterogeneity both across different firms in a window and within the same firm throughout the year. According to our estimation, Engie, for instance, usually expected lower demand compared to other firms, while Tamakaya exhibited a higher expected demand outlook through 2019. Notably, Engie and Tamakaya were the firms with higher utilization of inflexible gas, as indicated in Table 4. Thus, it is evident that firms' expectations regarding residual demand alone cannot fully account for the activation of the inflexibility condition. This observation supports the idea that multiple factors, including the volatile nature of hydro marginal costs, seasonal variations in demand, and renewable capacity, among others, can influence the utilization of prioritized gas.

With these probabilities, we proceeded to estimate the quantity of LNG firms would order for each window in 2019. Figure 9 displays our estimated LNG orders for each firm, with a correlation between the estimated and actual orders of 88.33%.

33. We base this estimation on the policy in effect from 2016 and the subsequent change that occurred from June 2019, as this is what firms considered when ordering $Q_{z,w}$.

34. This could have been driven by factors such as anticipated lower hydro capacity due to reduced rainfall.

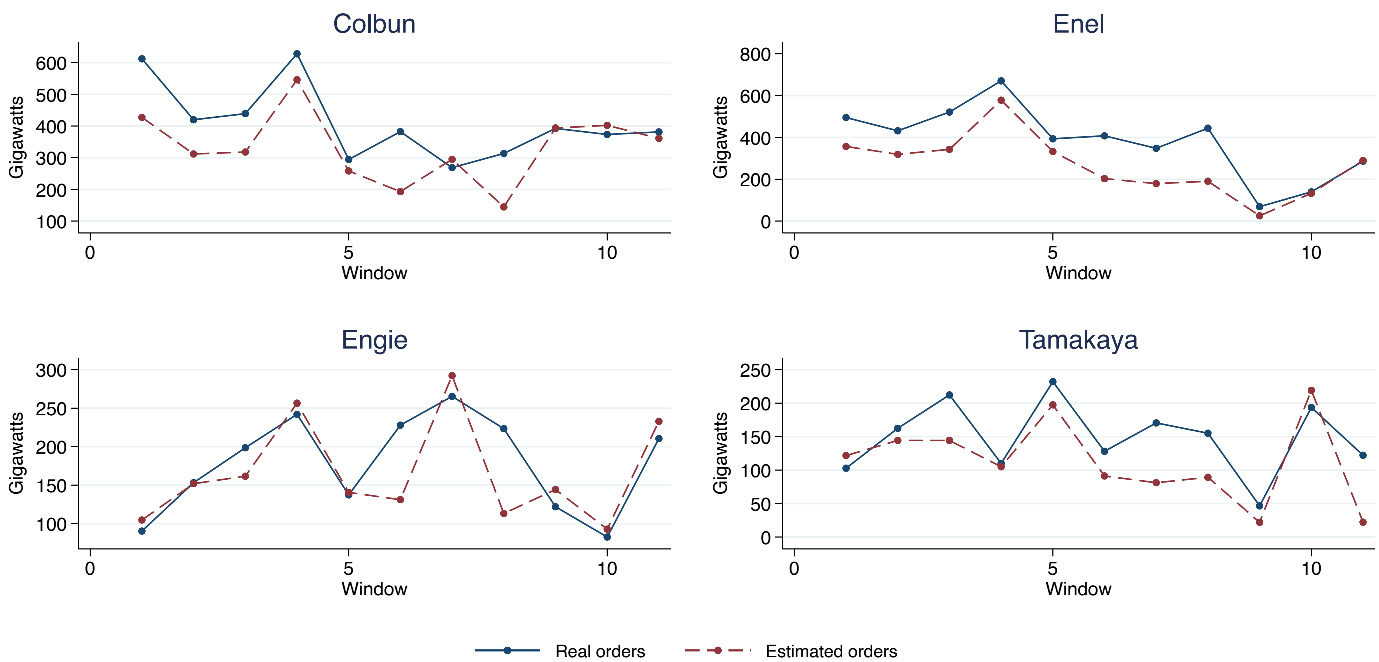


Figure 9: Real vs. estimated LNG orders, 2019

Adjustments were made to the observed marginal costs of LNG in our analysis to obtain these estimates. While we observed varying levels of LNG marginal costs for the same firm-window, arising from different shipments with different prices and stored LNG series, our model does not accommodate multiple marginal costs for each firm at each window. Considering that our model assumes no inventory remaining at the end of the window, the LNG should have a single price associated with the shipment received at the window's outset. Hence, we calculated the average marginal cost of LNG for each firm-window, which served as their marginal cost in the model. Importantly, this consistent marginal cost is maintained across the counterfactual scenarios discussed in Section 6.

5.3 Renewable investment model

The final segment of our structural model involves the estimation of solar plants' entry into the Chilean electricity market. As of 2019, approximately 63% of the country's solar plants were installed in the north, with the remaining 36% in the central region. However, most of the installed capacity is concentrated exclusively in the north. Hence, our analysis focuses on markets 1, 2, and 3, which collectively account for an average of 89.9% of the total solar generation capacity in the country.

Following the approach of Gonzales, Ito, and Reguant (2023), we assume that entry into solar power generation is competitive and model the equilibrium quantity of solar investment by applying the zero-profit condition as follows:

$$\mathbb{E}\left[\Pi_{m,19}|\mathbf{k}_{19}\right] + \sum_{t=1}^{t=24}\left(\frac{1}{1+r}\right)^{t}\mathbb{E}\left[\Pi_{m,19+t}|\mathbf{k}_{19}\right] = c_{m,19}(\Delta k_{m,19}), \quad \forall m \tag{5}$$

In this equation, $\Pi_{m,19}$ represents the marginal revenue from solar investment in market m for the year 2019, $\mathbf{k}_{19}$ is a vector representing the solar capacity in each market during 2019, and r is the discount rate, which we assume to be 5.83% (Moore, Boardman, and Vining (2020), Gonzales, Ito, and Reguant 2023). The left-hand side of the equation characterizes the expected marginal revenue over a 25-year period resulting from a unit increase in solar investment in 2019,[35] while the right-hand side represents the marginal cost of solar investment as a function of the incremental solar capacity in 2019 in market m, denoted by $\Delta k_{m,19}$. The marginal cost function is modeled as follows:

$$c_{m,19}(\Delta k_{m,19}) = \gamma_{m,19}\,\alpha_{19} + \beta\,\Delta k_{m,19} \tag{6}$$

Here, $\gamma_{m,19}$ serves as a behavioral parameter that captures how firms perceive the marginal costs of solar investment compared to the observed marginal costs of 2019. The mismatch between perceived and observed marginal costs could be attributed to various factors, such as unexpected delays in the completion of new transmission lines and unobserved benefits from firms' investment decisions in other years distinct from 2019, among others. Gonzales, Ito, and Reguant (2023) provide estimates for the values of $\hat{\gamma}_{m,19}$, $\hat{\alpha}_{19}$, and $\hat{\beta}$ based on data on solar investment and observed marginal costs. Specifically, we use: $\hat{\gamma}_{1,19} = 1.4$, $\hat{\gamma}_{2,19} = 1.35$, $\hat{\gamma}_{3,19} = 1.35$, $\hat{\alpha}_{19} = 1.17$, and $\hat{\beta} = 0.002$.[36]

It is important to remark that they estimate $\gamma_{1,19}$ such that the marginal revenue of 2019 equals the marginal cost of investment in the same year. Therefore, with their estimates, we should not observe any further investment if no disturbances are made to the current market equilibrium.

As we model the entry of new solar power plants, we acknowledge that their actual generation may differ throughout the year, depending on factors such as panel size, location, and inclination. For instance, if we predict the entry of 100 MW of solar capacity into a specific market, this new plant's output won't remain constant at 100 MW throughout the year. To account for this variability, we assume that the hourly output of the entering solar capacity will be governed by the average hourly "performance" of existing solar plants within that market. To calculate the market's average hourly performance, we first determine the hourly performance of each solar plant by dividing its hourly generation by its maximum output over the entire year. Subsequently, we compute the average hourly performance by taking the mean value over all solar power plants operating within the market. The hourly output of the new entrant will be given by its installed capacity times the hourly average performance of the market. Figure 10 shows the average hourly

35. The model implicitly assumes the life span of solar plants is 25 years. We use the distribution of fundamentals (demand and costs) from 2019 to model market expectations in the long run.

36. We adopt the parameters corresponding to their market 1 for our markets 1 and 2, as we define markets differently from their study.

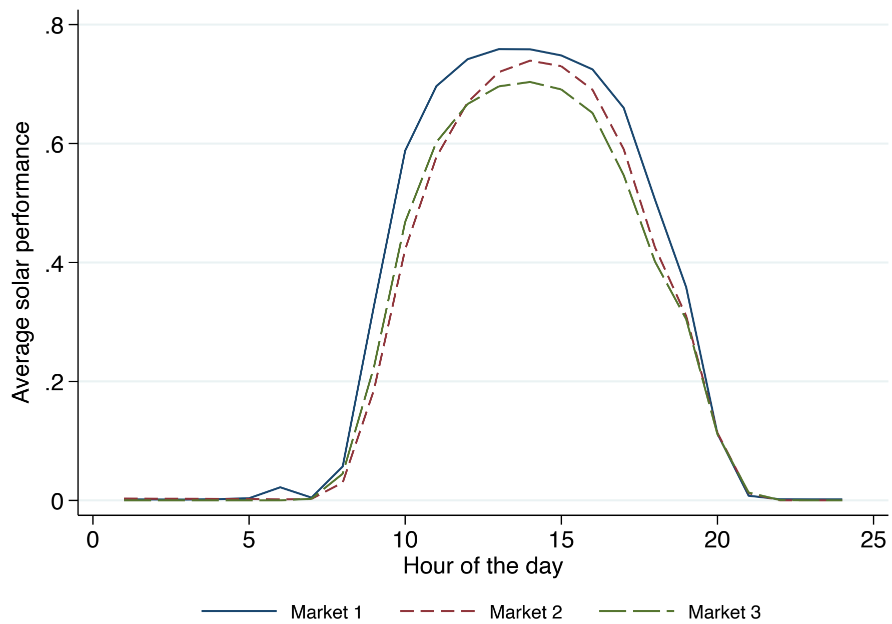


Figure 10: Average performance of solar plants by market-hour

performance across the studied markets. As would be expected, solar panel performance tends to be higher on average in markets located farther north within the country.[37]

6 Policy implications

This section studies the effectiveness of the LNG prioritization policy and alternative solutions that aim to enhance LNG orders. We compare these approaches to a scenario where the government places socially optimal orders. Additionally, we show what would happen with LNG orders under a framework devoid of any policy. We also evaluate whether, under these different settings, solar energy investment is promoted while maintaining system reliability without excessive coal and diesel usage.

These policies have varying short and long-term effects and are critically contingent on firms' demand expectations for the upcoming year at the time of placing their orders. We begin by outlining these policies and their corresponding effects on LNG import quantities.

6.1 Counterfactual policies and their imported LNG quantity

We start by considering a scenario named "Government orders" where the government places the LNG orders. Here, the objective function of the government is to minimize the expected cost of supplying energy and emissions. We consider this as the optimal amount to be ordered for the year.

37. Note that this figure is provided for explanatory purposes at the hour-of-day level. In our model, we compute performance at the hour-of-year level, considering seasonal variations in solar output.

Next, we introduce a scenario labeled "Regular dispatch," which represents a framework devoid of any specific policy targeting LNG orders. The goal is to assess whether firms would under-order LNG, from the government's perspective, in the absence of policies incentivizing natural gas orders. This case will also serve as a benchmark against which we can assess the value and efficacy of the policies by comparing their associated costs and benefits to those under regular dispatch. For this and the rest of the counterfactuals studied, firms will place LNG orders that maximize their expected profits.

We then move on to a policy closely resembling actual events. In this scenario, any excess amount of natural gas could be declared as inflexible, much like the reality in 2019. The only difference lies in the policy change that occurred in the middle of 2019, where the inflexible gas's marginal cost was modified to be zero instead of just considering its fuel marginal costs.[38] For this alternative scenario, we set the inflexible marginal cost to zero throughout the entire year of 2019, and we refer to this policy as the "LNG prioritization" policy. In this counterfactual, as in reality, firms can only declare an amount of inflexible gas that allows for the complete loading of the next shipment. As a consequence, they cannot strategically determine the quantity of LNG to declare.

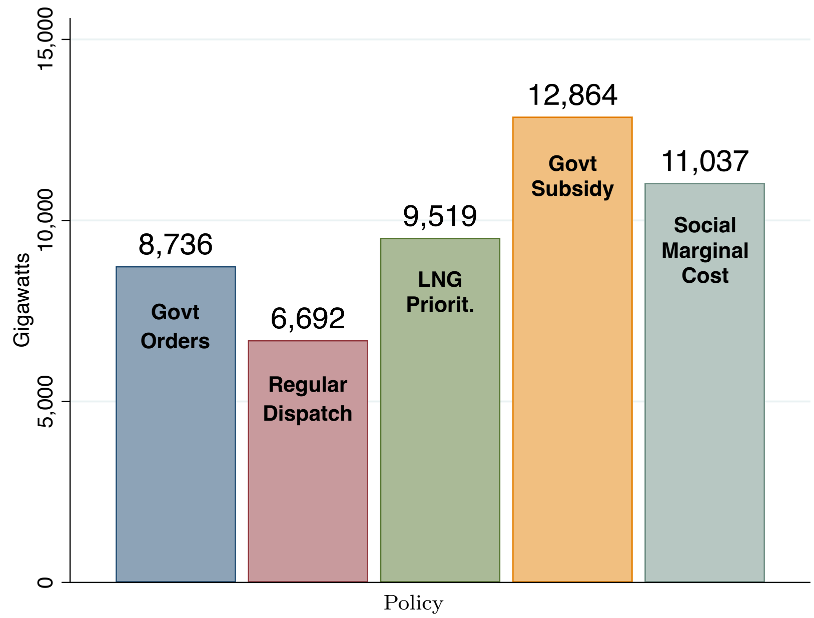
Shifting away from the LNG prioritization policy, we explore two alternative counterfactual policies in which no inflexible gas declarations are allowed. In the first one, the government steps in with a subsidy that covers half of each firm's LNG importation costs. This counterfactual policy is referred to as the "Government subsidy" policy. By introducing a subsidy, firms would be less exposed to losses associated with excessive LNG orders. Our aim is to investigate whether such a solution could yield similar outcomes for importing firms, allowing them to place larger orders while avoiding the long-term negative impact on renewable energy entry (since spot market prices would remain unaffected).

Afterward, we examine whether incorporating a carbon price (which accounts for the adverse environmental impact produced by a generation technology) into its marginal cost could enhance the dispatch priority for LNG. The underlying concept here is to account for the fact that natural gas is a cleaner source of energy compared to coal or diesel. By factoring in the carbon price within the cost structure, the dispatch order might be altered, potentially elevating LNG's priority above other fossil fuels on average. This shift, coupled with the boosted infra-marginal returns due to higher spot market prices (as the social marginal costs of the technologies are higher than their private marginal costs), could incentivize firms to import more LNG without adversely affecting renewable energy entry. Hence, dispatch priority will be determined based on the social marginal cost of fuels rather than the private marginal cost of fuels. For this counterfactual analysis, named "Social marginal costs," we consider the U.S. carbon price of $51 per ton of CO2 equivalent emitted.

In analyzing these counterfactual scenarios, our aim is to understand the potential implications of different policies targeting LNG orders on the energy market, their effects on renewable energy entry, and their broader impact on energy costs and emissions in both the short and long run. Throughout this section, we will present

38. The policy change has minimal effects, with the estimated LNG orders accounting for the policy change having a 99% correlation with the estimated orders coming from this counterfactual. Nevertheless, opting for a single policy throughout the entire year provides a more streamlined analysis.

Figure 11: Estimated LNG orders (Gigawatts per year)



the results for each scenario considering the high demand expectations we estimated for firms.

Figure 11 provides the estimated quantities of LNG ordered for the year 2019 under each of the described counterfactual policies.

The figure illustrates that in a regular dispatch scenario, firms' LNG orders fall below the optimal level required for reliability from the government's standpoint. Thus, policies encouraging higher orders become imperative to enhance reliability. Notably, the three policies studied not only increment LNG procurement but also surpass the optimal quantity the government would have ordered.

Particularly, results show that under the "LNG prioritization" policy, the volume of liquefied natural gas ordered is approximately 50% higher than under regular dispatch. Declaring gas as inflexible, even if it results in lower spot market prices, allows them to obtain returns for the excess gas that would not have been possible without the policy. Hence, firms anticipate increased returns across the demand distribution, even though these returns might be lower than their marginal costs if gas is used in an inflexible manner. This incentive encourages firms to order more LNG.

Figure 11 highlights that alternatives to the LNG prioritization policy can also reduce firms' exposure to risk and achieve even larger orders of LNG. Specifically, both the government subsidy and the addition of a carbon price in technologies' marginal costs incentivize firms to order more LNG. The former does so by lowering LNG marginal costs via a subsidy, enabling firms to earn profits in the spot market even when they are operating on the margin. The latter not only allows firms to profit when operating on the margin through the addition of the environmental cost but also alters dispatch priorities, making some coal more expensive than LNG. This dual impact on LNG, both elevated priority in dispatch and increased returns for each Megawatt of LNG utilized in generation, motivates firms to place larger orders.

These results will have notable implications for short-term prices, emissions, energy costs, and technology usage. Additionally, they will influence investment decisions in solar power generation in the long run. We elaborate on this in the upcoming sections.

6.2 Short-run consequences

Variations in the quantity of ordered liquefied natural gas would exert immediate effects on the electricity market. For example, the dispatch of out-of-merit gas at a marginal cost of zero would lead to price reductions, displace in-merit technologies, and, thereby, alter the generation technology mix and impact emission levels. In this section, we concentrate on the short-run consequences of the policies mentioned in the previous section, where the LNG prioritization policy closely resembles the real-world situation.

Table 5 illustrates the Gigawatts of energy generated and the corresponding profits earned by each technology under the different counterfactual scenarios. Interestingly, the outcomes for Government orders, Regular dispatch, and Government subsidy counterfactuals are nearly identical, and the similarity among them can be attributed to two key factors. Firstly, the realized demand in 2019 was lower than both firms' and the government's high expectations. Consequently, even under the Regular dispatch scenario, firms had incentives to order gas that was sufficient post facto. Secondly, the uniformity in dispatch rules across these scenarios implies that once an adequate amount of LNG is available based on the realized demand, outcomes remain unchanged regardless of the specific scenario. Therefore, the results appear highly comparable across these three counterfactuals.[39]

Other policies, however, can have a significant impact on technology displacement and, consequently, their profits. Although the LNG prioritization policy does not manage to displace diesel, it does reduce coal usage by approximately 7% when compared to the Regular dispatch, which no other policy, except the Social marginal costs, achieves. This displacement is due to the forced prioritization of gas. However, in contrast to the LNG prioritization policy, the Social marginal costs policy accomplishes two significant outcomes through its changes in dispatch priority: it reduces diesel usage and increases hydropower generation. These achievements can have significant short-term implications for emissions, as we show below.

When it comes to profits, due to its lower prices, the LNG prioritization policy significantly affects those of coal-fired power plants, potentially prompting the retirement of some of these plants in the long term.[40] Nevertheless, the reduction in prices also has a notable impact on the profitability of solar and wind power, resulting in a decrease of 7% and 19%, respectively, when compared to the Regular dispatch. Importantly, despite these changes, there is no observed curtailment of renewable energy generation due to the policy.

In addition, it is worth noting that LNG profits are negative in all scenarios, primarily due to firms overestimating the demand they would encounter during 2019 and consequently ordering more than required.

39. These similarities across counterfactuals disappear, however, when firms expect a lower demand than the realized, as it is shown in Appendix E.

40. Plant retirements are beyond the scope of this paper.

Table 5: Estimated generation and profits by fuel type

	Counterfactual scenario				
	Govt. Orders	Reg. Disp.	LNG Prior.	Govt. Subsidy	Social Marg. Costs
Generation (GW/year)					
LNG	3,984	3,964	9,981	4,010	4,801
Coal	32,053	32,053	29,964	32,053	27,975
Diesel	97	97	97	97	39
Solar	5,928	5,928	5,928	5,928	5,928
Wind	4,697	4,697	4,697	4,697	4,697
Hydro	20,946	20,950	17,371	20,920	23,889
Profits (MM USD)					
LNG	-454.7	-257.4	-318.1	-234.5	-470.0
Coal	830.3	857.0	414.1	822.9	1,738.2
Diesel	0.3	0.3	0.3	0.3	1.6
Solar	271.2	271.7	252.8	271.0	545.6
Wind	277.6	282.0	229.5	277.1	457.5
Hydro	1,049.4	1,058.1	758.1	1,042.8	1,777.0

Despite this, firms rarely experience negative profits by the end of the year. This can be attributed to the fact that firms that import LNG also generate positive profits from other technologies within their technology mix.

As for diesel generation, it appears to remain relatively unaffected by the LNG prioritization policy; however, this may be attributed to potential limitations in our model's ability to accurately capture peak pricing moments throughout the year. Yet, our model does capture a significant reduction in diesel usage under the Social marginal costs policy.[41] While enhancing the dispatch model to better accommodate peak pricing moments might have some impact on diesel displacement under the LNG prioritization policy, this effect is likely to be overshadowed by an even greater reduction in diesel usage resulting from the Social marginal costs policy.

Panel (a) of Table 6 presents the short-run average estimated market prices for each counterfactual policy. The table shows significant price reductions resulting from the implementation of the LNG prioritization policy in comparison to a Regular dispatch rule; in particular, prices drop 21% with the policy.[42] This notably impacts the profits of infra-marginal units, where solar and wind plants are typically positioned.

The Government subsidy and the Social marginal costs policies, even though similar in incentivizing larger LNG imports, differ significantly in their effects on spot market prices. The subsidy, as expected, encourages firms to order more LNG by lowering their import costs, but it does not notably affect prices since it does not alter the regular dispatch rule. Conversely, in the scenario where the social marginal cost

41. The model is also able to capture diesel displacement in the low expected demand counterfactual scenario, presented in Appendix E.

42. Specifically, prices decrease by approximately 19% in markets 1, 2, and 3 due to the inflexibility condition and by 17% in southern markets, which are further away from solar and LNG generation (not shown in the table).

Table 6: Short and long-run implications of the policies

	Counterfactual scenario				
	Govt. Orders	Reg. Disp.	LNG Prior.	Govt. Subsidy	Social Marg. Costs
(a) Short-run					
Avg. Price (USD/MWh)	69.26	69.92	55.38	68.97	102.38
Emissions (MM USD)	1,703	1,703	1,723	1,704	1,512
Energy Costs (MM USD)	2,204	2,203	2,401	2,203	2,269
(b) Long-run					
Solar investment (MW)	255	253	0	252	1,352
Avg. Price (USD/MWh)	68.73	69.26	55.38	68.53	100.55
Emissions (MM USD)	1,694	1,694	1,723	1,694	1,374
Energy Costs (MM USD)	2,165	2,165	2,401	2,165	2,109

Average price is a weighted average considering demand covered by each market. Energy costs refer to spot market generation costs; it does not consider the tax of the carbon price or the cost of a Government subsidy in the corresponding counterfactuals.

is considered, spot market prices increase significantly, around 46% on average, with respect to a regular dispatch.[43] This represents the primary drawback of the policy: while the other policies increase costs for either the government (subsidy) or lower revenue for firms (by reducing spot market prices through inflexible gas use), this policy raises prices, ultimately impacting residential consumers in the medium to long term.

One of the main objectives of the policies under study is to mitigate pollution stemming from energy generation, which is primarily achieved by displacing dirty technology (shown in Table 5). Panel (a) of Table 6 reveals that emission levels remain relatively stable across most policy scenarios. While coal usage decreases compared to the regular dispatch, the substantial increase in LNG consumption counterbalances this reduction, resulting in a $20 million dollars increase in annual emissions under the LNG prioritization policy when compared to Government orders or Regular dispatch. In contrast, the Social marginal costs policy brings about a significant reduction in emissions: by displacing coal and diesel usage and increasing the utilization of hydro and LNG compared to the regular dispatch, it results in savings of $200 million in pollution costs per year.

The government also cares about minimizing the costs associated with supplying energy, which is its objective function in the dispatch problem. In the short term, all policies are equally or more expensive than the Regular dispatch. Panel (a) of Table 6 shows that the government subsidy does not increase energy generation costs since it does not alter prices or the dispatch method. The Social marginal costs policy, on the other hand, results in high energy costs in the short run. Particularly, the costs linked to the Social marginal costs can vary given it is heavily reliant on the opportunity cost of water for hydropower, which can make it relatively expensive, especially in years like 2019 when hydro technology was costly. In addition, the LNG prioritization policy, due to their extensive use of LNG, increases the cost of supplying energy as

43. Around 69% in northern markets and 40% in southern markets.

well. Interestingly, the LNG prioritization policy stands out as the most expensive approach, leading to an annual cost of almost $200 million dollars higher compared to the Regular dispatch.

In the appendix, in Section E, we compare these results with four other counterfactual scenarios. These additional scenarios explore the effects of firms having low and average expectations of demand for the following year instead of high; a situation with reduced renewable capacity by one-third, resembling a country in an earlier stage of the energy transition; and a framework without transmission constraints. We analyze how these policy measures affect outcomes in these varied conditions. We find that when firms have low (average) demand expectations, the LNG prioritization policy achieves the second-largest pollution savings of $11 ($8) million, surpassed only by the Social marginal costs policy. The scenario with reduced renewable capacity, on the other hand, provides analogous results to those discussed in this section. Also, we show that removing transmission constraints enhances the effectiveness of all policies by allowing solar plants to reach more markets within the country and therefore increasing their revenue.

The analysis presented throughout the section demonstrates that implementing the LNG prioritization policy when firms hold high demand expectations can lead to short-term impacts on solar power plants' profits while exhibiting minimal changes in emissions and energy costs. The resulting decline in profits may influence the decisions of potential entrants to the electricity market, potentially impeding the pace of the energy transition. On the other hand, including the pollution costs in the technologies' marginal costs, as in the Social marginal costs policy, might induce more solar plants to enter the market due to increased prices. We further investigate the significance of these effects in the subsequent section.

6.3 Long-run consequences

In this section, we study the long-term effects on the Chilean electricity market that arise from the short-run effects analyzed above.

As of 2019, a total capacity of approximately 2,500 Megawatts of solar power was installed in the country. This capacity was distributed across different markets, with markets 1, 2, and 3 accommodating 1,760, 215, and 275 Megawatts, respectively. Panel (b) of Table 6 presents the estimated amount of Megawatts that would enter nationally under each counterfactual scenario.

When LNG prioritization is allowed, no new entry of solar power capacity would occur. This outcome aligns with our conjectures, considering that the cost parameters were calibrated to ensure that the expected marginal revenue in 2019 matches the marginal cost of investment in the same year. As this counterfactual closely resembles the actual reality, except for the minor policy change introduced in the inflexible condition, the absence of new entries in this scenario provides reassurance in the model.

In the context of the other counterfactual scenarios, our findings reveal a significant boost in installed solar capacity, with increases ranging from 8% to 54%. This notable growth is a direct consequence of reduced reliance on out-of-merit gas and higher spot market prices, which incentivize greater participation of solar power in the market. Particularly, the Social marginal costs policy stands out, as it leads to the most substantial rise in solar power capacity. This is explained by this policy having the highest spot market prices, which, in turn, positively affects the profitability of solar plants, creating favorable conditions for additional solar capacity to enter the electricity market.

Notably, we find that all new solar plant installations are concentrated in markets 1 and 3. For market 3, this suggests a nearly twofold increase in solar capacity under the regular dispatch scenario and approximately a 235% surge in solar capacity under the carbon price counterfactual. With respect to market 1, the introduction of new solar capacity is only observed within the Social marginal costs framework, resulting in a 40% increase in solar capacity.[44]

Panel (b) of Table 6 illustrates how the altered market structure, following solar power entry, maps into emissions. Transitioning from the LNG prioritization policy to a regular dispatch would result in a yearly emissions reduction of $30 million. Alternatively, opting for a social marginal costs mechanism would yield a tenfold larger reduction, approximately $350 million annually in carbon abatement.

Additionally, it can be seen that the Social marginal costs policy, initially costly in the short run, becomes the most economical choice for long-term energy generation due to significant solar adoption. All other policies, except the LNG prioritization policy, also witness reduced energy costs over time due to increased solar investment and further utilization.

Overall, the choice of policy to encourage LNG orders can substantially affect long-term emissions. The most effective option for enhancing reliability and boosting solar power adoption is undeniably accounting for the social marginal costs of the technologies.

Was the LNG prioritization policy justified?

The analysis of the short and long-term implications of the policies reveals that even a regular dispatch performs better in terms of emissions and solar investment compared to the LNG prioritization policy. This analysis, as described earlier, was conducted assuming firms had high demand expectations. These expectations were calibrated using our structural model.

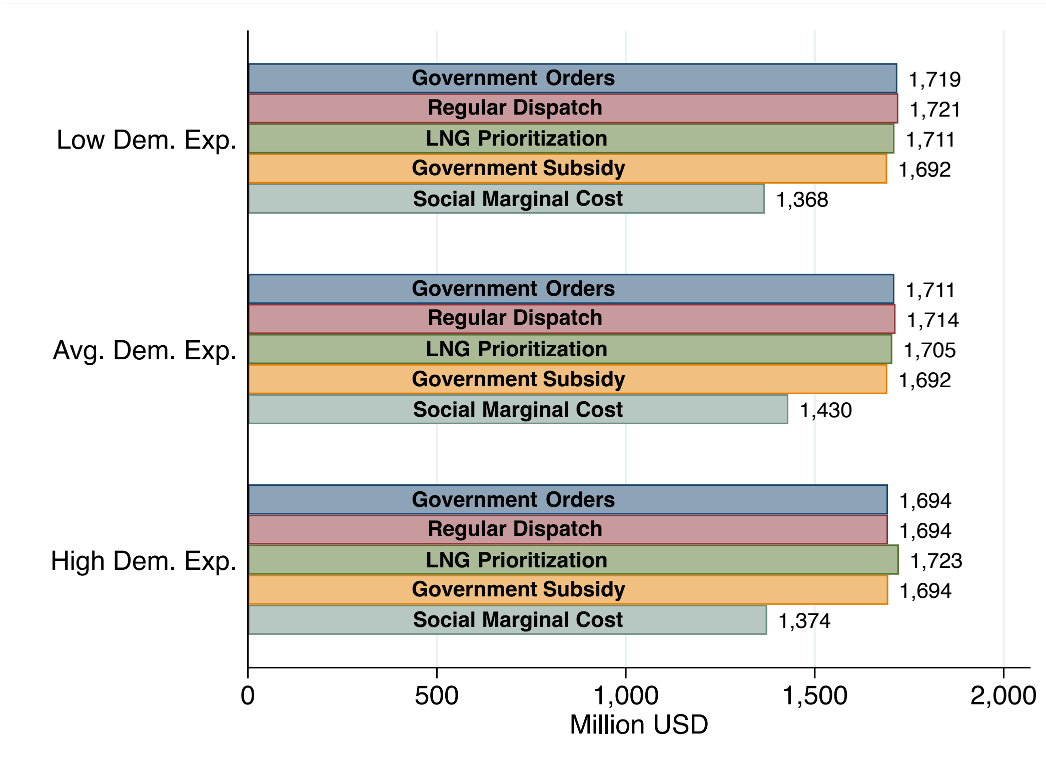
In this section, we explore scenarios where firms have low or average demand expectations instead of high ones.[45] Figure 12 displays long-term emissions resulting from the studied policies under different scenarios of firms' demand expectations: low, average, or high.

Under high demand expectations, the LNG prioritization policy results in the highest long-term emissions, as demonstrated throughout this section. However, under low or average demand expectations, the LNG prioritization policy outperforms a regular dispatch in terms of emissions, making it a better choice than having no policy at all. Moreover, it even surpasses emissions reduction achieved if the Government were

44. We acknowledge the estimates we present do not consider the potential decrease in LNG orders resulting from the entry of solar power, the expected rise in demand in the future, or the potential exit of dirty technology such as coal or diesel, so the long-term effects of each policy might be even larger. In addition, solar generation is primarily affected during daylight hours, while wind generation could be affected during the afternoon and certain hours of the night. If inflexible gas were to be used during peak hours of the night, wind power entry could be harmed as well. Hence, this analysis might underestimate the adverse effects of the policy. The exploration of wind generation entry, however, falls beyond the scope of this research.

45. Detailed analysis and results of these scenarios can be found in Appendix E.

Figure 12: Estimated emissions in the long-run by demand expectations



to make optimal orders under a regular dispatch. While the Government subsidy and the Social marginal cost policy achieve lower emissions, the LNG prioritization policy offers two key advantages: it does not incur any additional cost for the Government, and it does not raise prices for consumers – in fact, it reduces them. Therefore, given the unpredictability of firms' demand expectations, the policy's justification lies in its cost-effectiveness and potential improvement compared to having no policy at all.

Nevertheless, even though the policy can be justified compared to a regular dispatch, its reductions in emissions and solar investment enhancement are significantly lower than those achieved through a social marginal cost approach. Ideally, if the Social marginal cost policy were to be implemented, further policies should be explored to regulate consumer prices without significantly affecting firm revenues.

7 Concluding remarks

In this paper, we study strategies to ensure the reliability of the electric system and their indirect impact on long-term renewable investment. To that end, we start our analysis with a policy implemented in Chile –the LNG prioritization policy– which had the objective of mitigating the potential under-ordering of LNG, and we compare it with alternative solutions that might provide better outcomes.

We construct a simplified analytical model to help us understand the incentives firms had with and without the LNG prioritization policy and further contrast them to the preferences of a social planner. Our model indicates firms are incentivized to procure larger quantities of LNG with the policy in place. However, as solar capacity increases, incentives of the social planner and the firm under the policy start to diverge, with the planner's optimal order getting closer to zero. There is, therefore, a point of diminishing returns for the policy's efficacy in promoting LNG ordering, as it loses its practical utility beyond a certain threshold of installed solar capacity.

We construct a structural model to better understand the short and long-term effects of the policy and study whether alternative solutions might yield better results. Our findings indicate that without any policy, using a regular dispatch approach, firms would order less LNG than the optimal quantity determined by the government. Therefore, implementing policies that encourage larger LNG orders could be beneficial.

We find that orders under the LNG prioritization policy increased by approximately 50%, accompanied by a substantial decrease in spot market prices and coal displacement. However, the extent of over-ordering causes both the level of emissions and the cost of supplying energy to be similar to the framework with a regular dispatch. The efficacy of the policy in influencing the system's reliability, its primary intended objective, becomes negligible. Furthermore, we find that by removing the policy, solar power generation would increase by around 10% in the long run, which implies a $30 million reduction in emissions per year.

Moreover, we observe that incorporating a carbon price, the environmental cost associated with emissions, into each technology's marginal cost leads to higher solar power entry. This occurs because it significantly raises the prices of dirtier technologies compared to cleaner ones, thereby increasing solar plant profits and encouraging greater adoption of solar power (up to a 54% increase in capacity in the long run). In consequence, by adopting this Social marginal cost policy, emissions would decrease by $350 million annually. Unfortunately, the price increase implied by this policy or by a regular dispatch would eventually be passed through to consumers in the medium to long term. Additional policies should be studied to regulate prices perceived by consumers without impacting firm revenue substantially.

In addition, after investigating the unintended consequences of the implemented LNG prioritization policy, we questioned its justification. Our analysis indicates that when firms anticipate low or average demand, the policy would perform better than a regular dispatch, the scenario without any policy. Moreover, the LNG prioritization policy does not incur government costs and does not raise consumer prices; in fact, it lowers them. This makes it a seemingly straightforward solution. However, our findings demonstrate that implementing a Social marginal cost policy would significantly outperform the existing policy.

Future studies should be done in electricity markets heavily reliant on inherently uncertain technologies like wind, which might find policies similar to the one implemented in Chile advantageous, given natural gas's superior ramping capabilities that could bolster system reliability.

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Appendix

A Liquefied natural gas in Chile: Why tanks and not pipelines?

In the early 1990s, hydroelectric generation held a dominant position within the energy matrix of Chile. However, this reliance on hydroelectricity rendered electricity generation susceptible to climatic conditions, which could result in energy rationing during periods of drought. To mitigate this vulnerability, the government strategically decided to diversify the generation technology. In 1995, an agreement was reached to import natural gas from Argentina through pipelines. At that time, hydroelectricity accounted for 57% of electricity generation, with coal and diesel contributing 28% and 13%, respectively. However, by 2005, hydroelectricity's share had decreased to 39%, while natural gas accounted for 36%, and coal and diesel contributed 18% and 5%, respectively (Gamboa and Huneeus 2007).

From 2004 onwards, due to both internal factors and geopolitical considerations, Argentina imposed restrictions on the predetermined export of natural gas and, in some instances, even suspended the supply entirely. In response to this situation, and with a growing demand for electricity driven by an expanding economy, Chile swiftly formulated a plan to reduce its reliance on Argentinian natural gas. The plan involved the construction of storage tanks to receive and store liquefied natural gas (LNG) shipments from other countries via vessels.

In 2009 and 2010, respectively, two LNG storage tanks were commissioned in the central region of Quintero and one tank in the northern region of Mejillones. These tanks are utilized to store LNG in its liquefied form, serving as a critical resource for firms that own natural gas plants. The LNG is subsequently regasified into natural gas and distributed to these plants through pipelines. Presently, this remains the primary method of importing natural gas into Chile.

B Details on transmission flows and model calibration

In this section, we elaborate on how we determine the value of F_l for each transmission line l.

Figure B1 illustrates the hourly price patterns observed in May 2019 for all 940 nodes, with different colors representing distinct markets. Significant price gaps across markets indicate the presence of congestion during certain hours. For instance, on May 16, all markets exhibit similar prices (around 60 dollars), while on May 17, markets display very dissimilar prices (market 1 approximately 40 dollars and the rest considerably higher prices). This disparity indicates congestion between markets, as transmission between them is binding.

It is worth noting that nodes within the same market exhibit similar prices, with slight variations attributable to transmission fees. Our model assumes no price variation within nodes of a market, thereby abstracting from transmission fees. Figure B1 elucidates that these fees only result in minimal price differences.

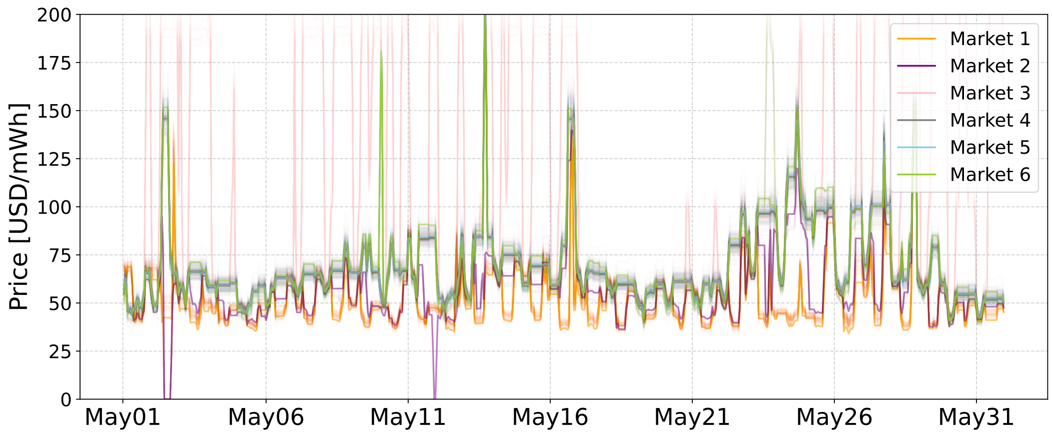


Figure B1: Node prices, May 2019

Figure B1 further demonstrates substantial price variation across markets. As detailed in Section 5.1.1, we determine the transmission capacity for each line based on our data.

Figure B2 showcases the relationship between price differences across markets and the actual transmission amount across markets, with each data point representing an hour. Price differences indicate that transmission capacity has been reached. For example, a price difference typically occurs when the transmission amount from market 1 to market 2 ranges between 600 MWh and 800 MWh. In this example, the line capacity would be set at 700 MWh for markets 1 and 2. It should be noted that price differences can occur even when the transmission amount is lower than 600 MWh, as our simplified network model does not precisely reflect the network configuration.

Table B1 presents the results of our data analysis, indicating the number of Megawatts per hour that can flow through each transmission line. Two sets of transmission caps were calculated, considering the reinforcement of transmission lines from Atacama to Santiago (North to Center of the country) in June 2019.

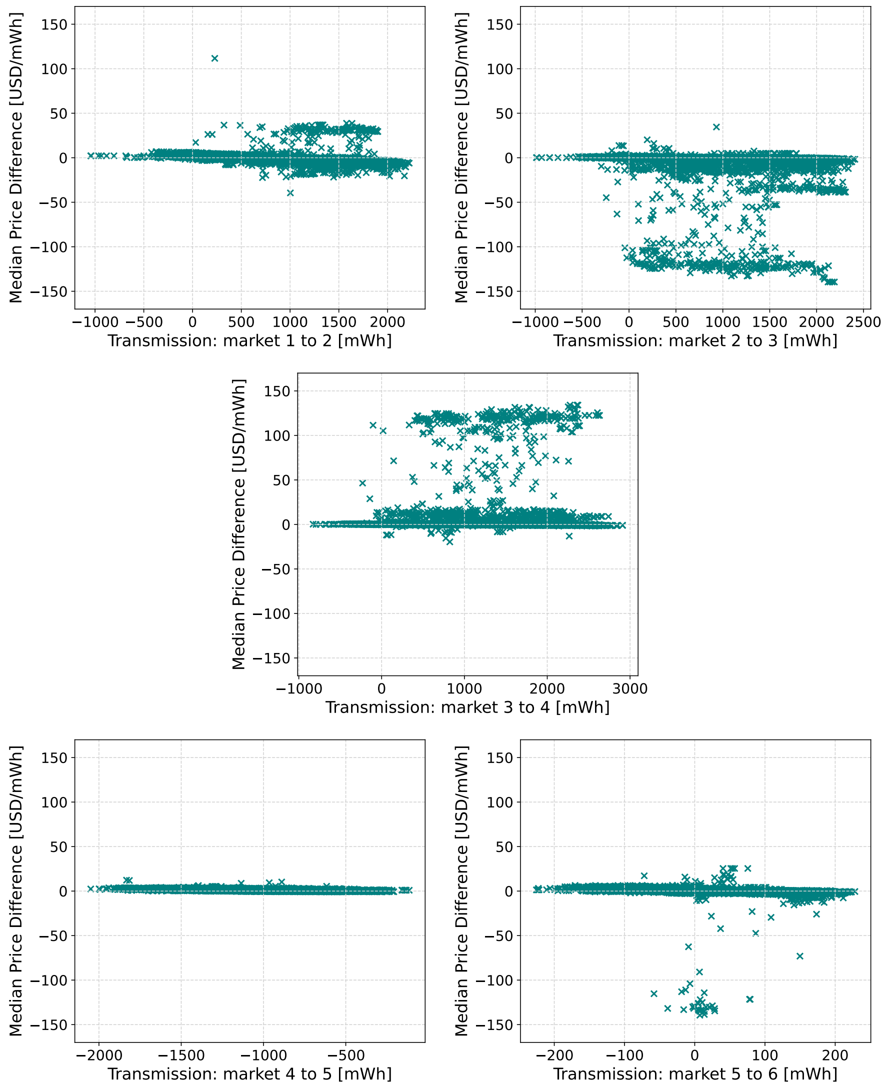


Figure B2: Transmission capacity calibration

This reinforcement alleviated congestion, and we incorporated this information into our model by accounting for two sets of flows. For further details on the reinforcement, refer to Gonzales, Ito, and Reguant (2023).

Table B1: Transmission flows for each line, before and after the Atacama-Santiago reinforcement

	Transmission flows (MWh)	
Line	*Pre-Reinforcement*	*Post-Reinforcement*
1	650	1,500
2	400	1,000
3	1,200	2,000
4	∞	∞
5	150	4,000

C More on dispatch model fit

Using our dispatch model, we estimate prices for all 8,760 hours in 2019 across the six distinct markets. To demonstrate the effectiveness of our model, we have selected a few examples that showcase its goodness of fit.

Throughout the year, there is evident seasonality in price trends, influenced by various factors, including idiosyncratic transmission congestion and potential plant failures specific to each day. Figure C1 illustrates the matching of our model with actual prices for every hour in October 2019, focusing on markets 1, 2, and 3.

In addition to monthly seasonality, there are distinct trends within a day. For instance, hours 12 and 13 exhibit higher solar power generation, while afternoon hours (19, 20) see an increase in wind power. Figure C2 compares real and estimated prices for every hour 12 of the year 2019, specifically for markets 4, 5, and 6.

Our model demonstrates a strong ability to capture price trends and median prices with high accuracy. However, it falls short of precisely capturing peak prices. The overall correlation between real average market prices and our estimated prices is 72.9%.

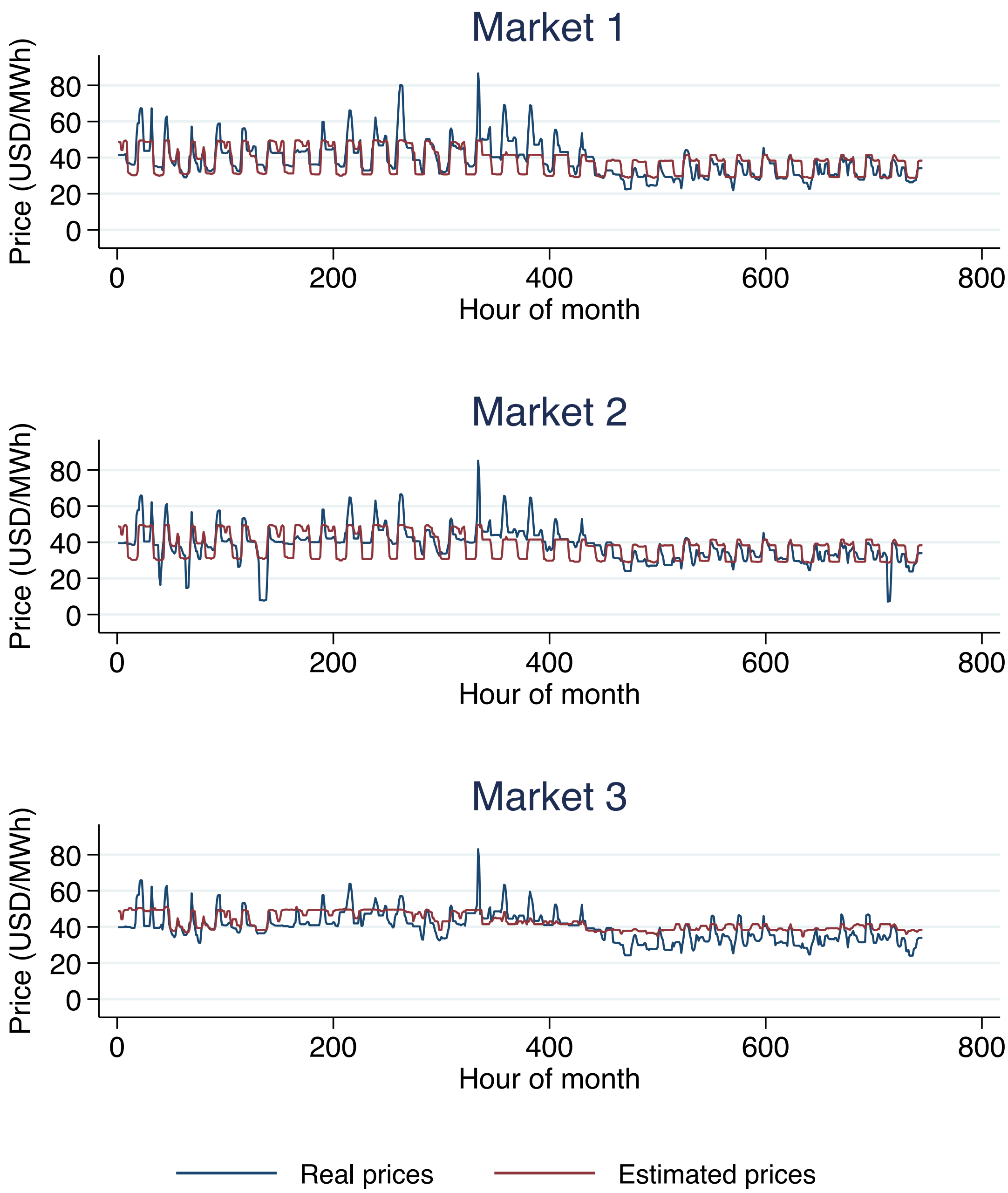


Figure C1: Real vs. estimated prices. October 2019, Markets 1, 2, and 3

D Calibrated values of α: demand probabilities

We consider the demand probabilities θ follow a Beta distribution defined by the density function:

$$\theta_{z,w} \sim \frac{x^{\alpha_{z,w}-1}(1-x)^{\beta_{z,w}-1}}{B(\alpha_{z,w},\beta_{z,w})} \quad \forall z, w$$

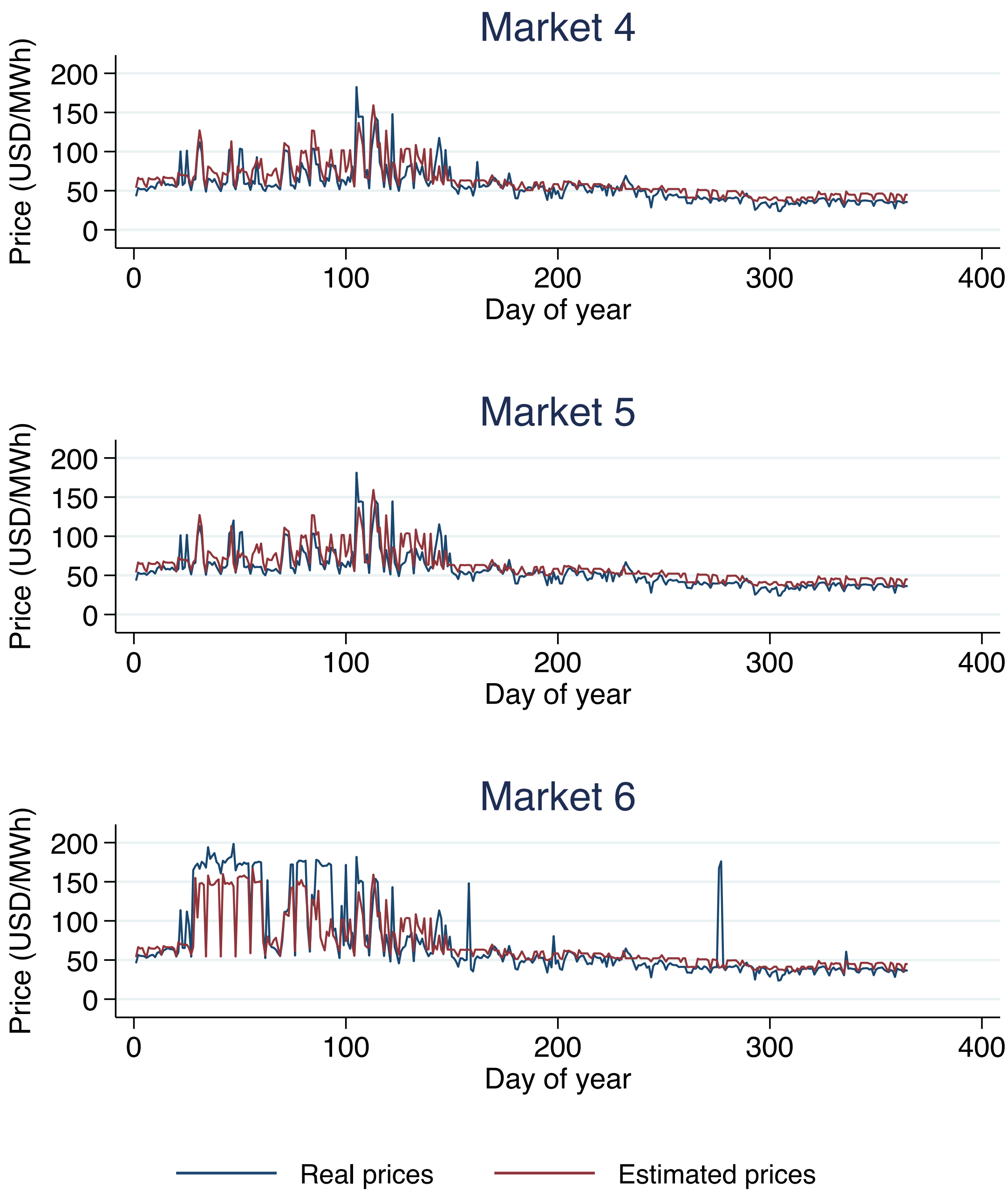


Figure C2: Real vs. estimated prices. Hour 12, 2019, Markets 4, 5, and 6

where $B(\alpha, \beta) = \frac{\Gamma(\alpha)\Gamma(\beta)}{\Gamma(\alpha+\beta)}$, and Γ represents the Gamma function. We set the parameter $\beta_{z,w}$ to 2 for all firms z and windows w, and our aim is to estimate the value of $\alpha_{z,w}$. Table D1 displays values the vector of probabilities θ takes at different values of α.

Given that 2019 experienced multiple inflexibility declarations, we know that firms tended to overestimate their residual demand when they ordered LNG. As a result, we explore values of $\alpha_{z,w}$ ranging from 2 to 12, as shown in Table D1, which places more weight on high realizations of demand.

Table D1: Vector of probabilities θ for different values of α

	Demand relization				
α	*Very low*	*Low*	*Actual*	*High*	*Very high*
2	0.104	0.248	0.296	0.248	0.104
4	0.007	0.080	0.250	0.400	0.263
6	0.000	0.018	0.140	0.418	0.423
8	0.000	0.004	0.067	0.366	0.564
10	0.000	0.001	0.029	0.292	0.678
12	0.000	0.000	0.012	0.221	0.766

For every value of α we maintain $\beta = 2$.

Table D2 provides the calibrated values of $\alpha_{z,w}$ for each firm-window combination. The estimates are primarily concentrated between 4 and 7 and 10 and 11, indicating that firms assign higher probabilities to high and very high-demand realizations, respectively.

Table D2: Calibrated $\hat{\alpha}$ parameters for each window-firm

window	**Colbun**	**Enel**	**Engie**	**Tamakaya**
1	10.4	10.8	2.8	11
2	6	6.6	4.6	8.6
3	7	7.8	4	7
4	5.6	7.4	3.4	7.2
5	6.8	7.2	4.8	8.4
6	5	5.4	4.6	10.4
7	11.2	5.8	11.8	7
8	4.4	5.2	4	10
9	9.6	4.2	9.6	7
10	11.8	7.4	7.2	11.4
11	11	10.6	10.2	8.4

Common beliefs: estimated values of α

In addition to the calibration at the window-firm level, we estimate a common value of α for all firms in every window. Therefore, we get the value of $\hat{\alpha}$ that satisfies

$$\min_{\alpha_w} \quad \sum_z q^*_{z,w}(\mathbf{q}_{-z,w}, \mathbf{k}, \mathbf{D}, rule; \alpha_w) - Q_{z,w}, \tag{7}$$

with $Q_{z,w}$ the observed LNG amount ordered by firm z for window w, $q^*_{z,w}$ the optimal quantity of LNG ordered by firm z for window w, $\mathbf{q}_{-z,w}$ is the amount imported by other firms (taken as given), $\mathbf{k}$ the vector of hourly generation capacities of all plants, **D** the vector of hourly demand and *rule* the specific dispatch rule.

Table D3 shows the estimated $\hat{\alpha}$ under common beliefs of firms for each window.

Table D3: Estimated $\hat{\alpha}$ parameters for each window

Window	**Estimate**
1	11.2
2	10.4
3	10.6
4	7.2
5	8.4
6	10
7	11.8
8	10
9	9.6
10	11.8
11	11

Figure D1 shows that the fit with respect to real orders is still sensible under this specification, with a correlation of 87%.

Furthermore, we calculate the amount of LNG ordered under the different counterfactuals for this common beliefs specification, and the results are robust across policies. Figure D2 exhibits that the LNG prioritization policy, the Government subsidy, and the Social marginal costs increase the level of LNG procurement, in comparison to the Regular dispatch, devoid of any policy. In addition, as with the calibrated probabilities at the firm-window level, firms continue to underorder LNG under the Regular dispatch, falling short of the optimal Government orders.

Nevertheless, the ordered quantities are higher than those based on the calibrated probabilities at the firm-window level. This discrepancy arises because enforcing common beliefs results in significantly elevated demand expectations for some firms. For instance, according to Table D2, window 8 indicates that firms like Colbun, Engie, and Enel had values of $\hat{\alpha}$ at 5.2 or lower. When common beliefs are imposed, as depicted in Table D3, these firms are compelled to adopt higher demand expectations, reaching a value of $\hat{\alpha} = 10$. Consequently, this shift leads to increased LNG procurement across all scenarios, including Government orders, which utilize firms' beliefs to determine orders.

The key distinction between employing common beliefs and calibrated demand probabilities lies in the disparity between orders made under the LNG prioritization policy and Government orders. In the common beliefs scenario, when firms anticipate high demand, the LNG prioritization policy falls short of stimulating enough LNG orders to match the desired volume set by the Government. In this framework, the decrease in infra-marginal profits resulting from LNG prioritization hampers firms from placing orders as substantial as

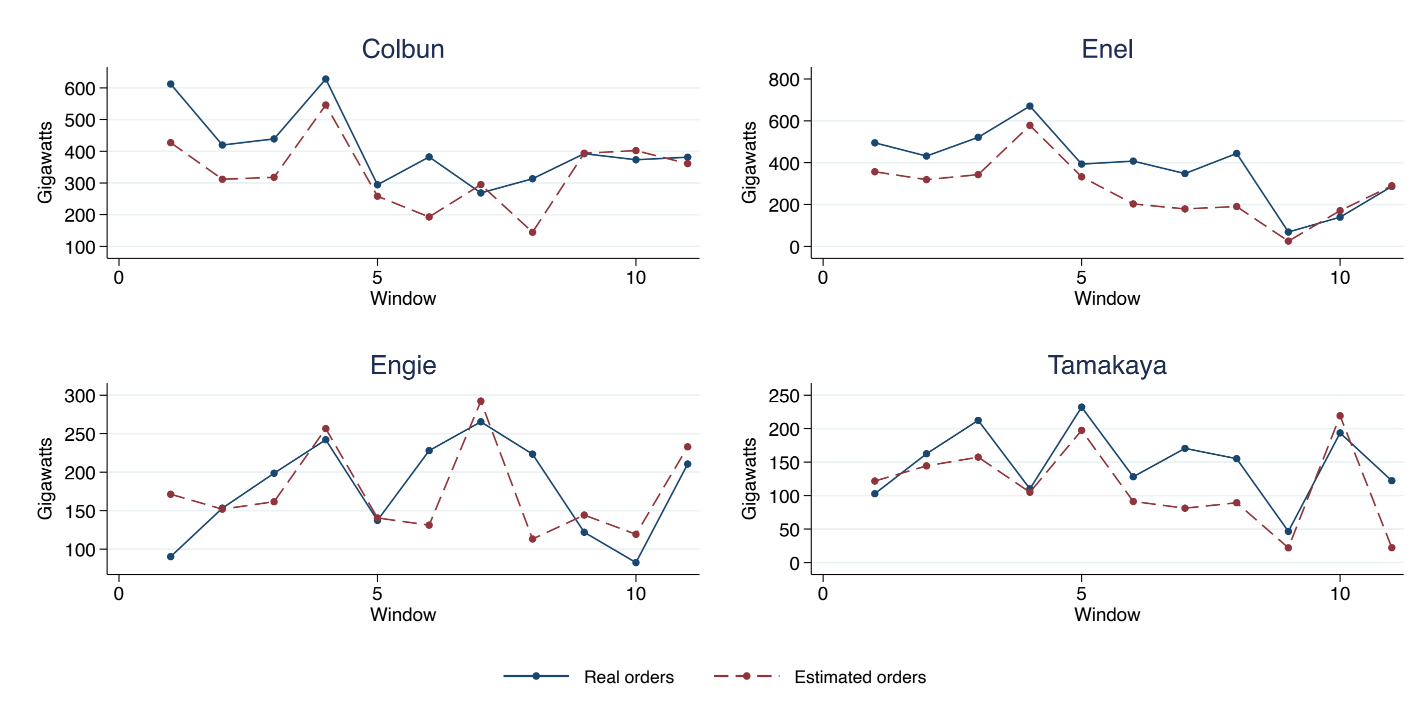
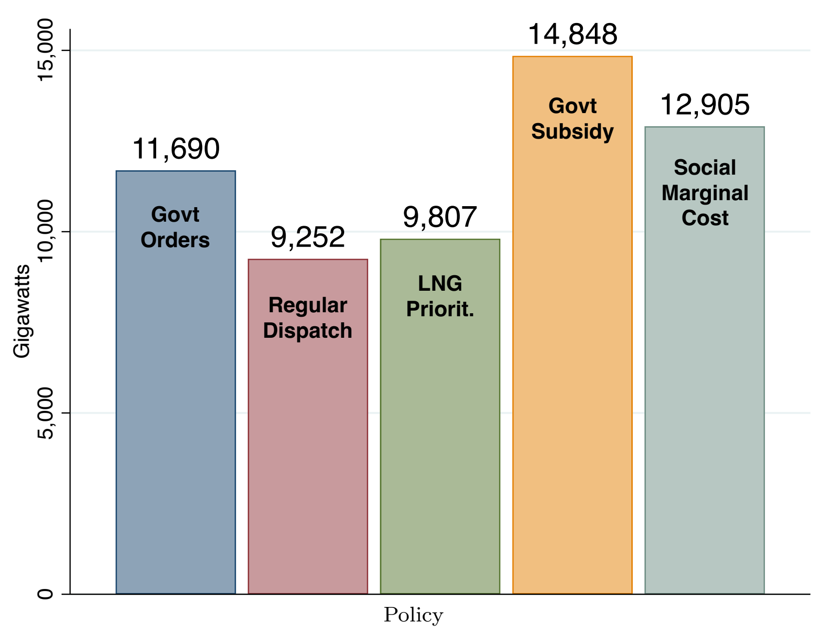


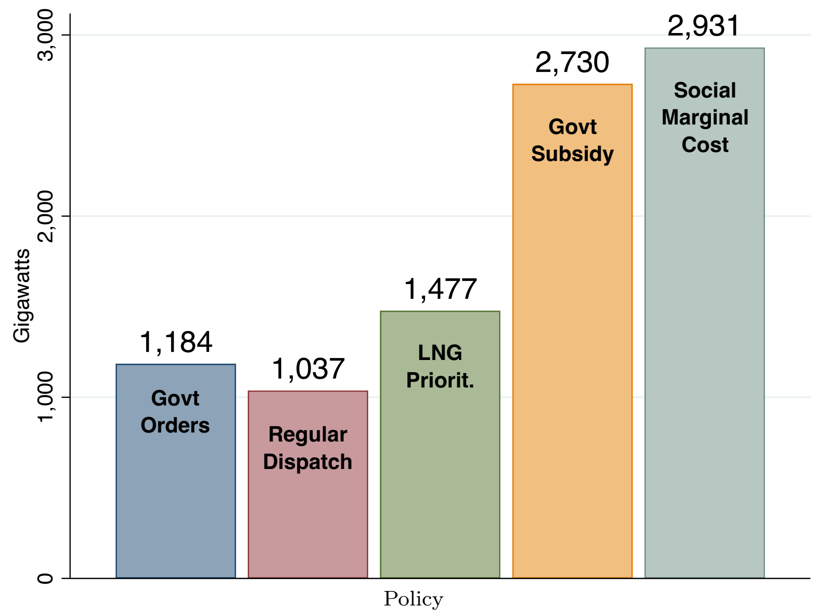
Figure D1: Common beliefs – Real vs. estimated LNG orders, 2019

Figure D2: Common beliefs – Estimated LNG orders (Gigawatts per year)



the Government's ideal quantity. In addition, with common beliefs, the demand expectations for the Government are also higher. These expectations induce the Government to place larger LNG procurement than under the calibrated probabilities. Despite this, the relative differences between policies persist, maintaining the same conclusions regarding which policies to implement under calibrated demand probabilities.

Figure E1: Low demand expectations – Estimated LNG orders (Gigawatts per year)



E Additional counterfactual scenarios

In this section, we delve into four counterfactual scenarios to gain a deeper understanding of the implications of the policies under examination. We start by examining a scenario in which firms possess low and average demand expectations, in contrast to the high expectations discussed throughout the paper. These counterfactuals explore the policy outcomes if firms had more conservative demand expectations, which would have aligned better with the realized demand. Subsequently, we investigate a third scenario in which we reduce renewable capacity by one-third, simulating a country in the early stages of the energy transition. The aim here is to examine whether a policy might be more suitable for countries with less established renewable capacity while another policy could be more appropriate for a nation like Chile, which has a substantial amount of renewable capacity already in place.

E.1 Low demand expectations

We start by analyzing a framework in which firms had low demand expectations. In the interest of simplicity, for the demand scenarios categorized as very low, low, actual, high, and very high, we assign the same probability vector $\theta_{z,w} = [0.25, 0.30, 0.25, 0.15, 0.05]$ to every firm z and window w. The corresponding LNG orders under each counterfactual policy are presented in Figure E1.

Naturally, when firms anticipate low demand, their LNG orders are significantly reduced compared to scenarios where they expect high demand (as shown in Figure 11). However, the underlying trends associated with each policy remain consistent: relying solely on regular dispatch would result in insufficient LNG orders, and the three policies analyzed effectively encourage higher orders and enhance reliability as intended.

Table E1 reveals that when firms hold low demand expectations, the LNG prioritization policy effectively displaces polluting technologies. When importing firms have high demand expectations, the LNG orders under the LNG prioritization policy displace coal, but the substantial amount of LNG counterbalances this effect, resulting in emissions leveling as if no displacement occurred. Conversely, in the low-demand expectation scenario, there is not a large amount of LNG to offset the diesel and coal displacement the policy generates. In addition, as firms do not over-estimate demand, they do not over-order LNG. Consequently, profits derived from LNG remain positive in this scenario instead of turning negative.

Table E1: Estimated generation and profits by fuel type (Low expected demand)

	Counterfactual scenario				
	Govt. Orders	Reg. Disp.	LNG Prior.	Govt. Subsidy	Social Marg. Costs
Generation (GW/year)					
LNG	1,702	1,566	2,181	3,225	3,621
Coal	32,053	32,053	31,965	32,053	27,957
Diesel	2,115	2,250	1,786	611	1,107
Solar	5,928	5,928	5,928	5,928	5,928
Wind	4,697	4,697	4,697	4,697	4,697
Hydro	21,159	21,160	21,100	21,140	24,019
Profits (MM USD)					
LNG	28.8	27.9	48.8	179.2	177.6
Coal	1,064.2	1,066.3	1,044.0	1,036.1	2,017.4
Diesel	0.3	0.3	0.3	0.3	1.7
Solar	279.7	279.8	279.0	278.4	558.2
Wind	305.7	305.9	302.8	302.4	485.1
Hydro	1,208.5	1,210.2	1,192.5	1,189.7	2,058.5

This leads to a reduction in emissions, amounting to $11 million compared to a regular dispatch, as indicated in Panel (a) of Table E2. While this reduction is considerably less than the $110 million achieved by the Social marginal costs policy, it carries the advantage of incurring no costs for either the government or consumers.

In this scenario, where technology displacement occurs, it is crucial to assess whether prices are impacted by the policy, as observed in the case of firms having high demand expectations (Panel (a) of Table 6). Panel (a) of Table E2 indicates that prices decrease only slightly (attributable to the reduced utilization of LNG as inflexible), which is an encouraging outcome given that prices serve as the primary driver for solar investment.

Panel (b) of Table E2 illustrates the long-term investment in solar power and its emissions impact. The Social marginal costs policy remains the most effective choice for reducing emissions. Transitioning from the LNG prioritization policy to a Social marginal costs policy would result in an annual reduction of $361

Table E2: Short and long-run implications of the policies - Low demand expectations

	Counterfactual scenario				
	Govt. Orders	Regular Dispatch	LNG Prior.	Govt. Subsidy	Social Marg. Costs
(a) Short-run					
Avg. Price (USD/MWh)	76.82	76.90	76.18	75.93	113.02
Emissions (MM USD)	1,737	1,740	1,729	1,708	1,530
Energy Costs (MM USD)	2,252	2,255	2,247	2,216	2,298
(b) Long-run					
Solar investment (MW)	342	343	340	325	1,500
Avg. Price (USD/MWh)	75.83	75.87	75.27	74.24	109.11
Emissions (MM USD)	1,719	1,721	1,711	1,692	1,368
Energy Costs (MM USD)	2,195	2,197	2,190	2,163	2,108

Average price is a weighted average considering demand covered by each market. Energy costs refer to spot market generation costs; it does not consider the tax of the carbon price or the cost of a Government subsidy in the corresponding counterfactuals.

million in emissions. As Panel (b) of Table E2 shows, unlike the scenario where firms had high demand expectations, the second-best option would be to retain the LNG prioritization policy.

The estimation reveals that the LNG prioritization policy stimulates nearly the same level of renewable investment as the regular dispatch. In addition, as in each counterfactual scenario, the Social marginal costs policy consistently leads to the highest level of solar power entry. Nevertheless, it also exerts the most adverse effects on consumers.

E.2 Average demand expectations

In this scenario, we center the demand expectations on the realized demand. Specifically, for the demand scenarios categorized as very low, low, actual, high, and very high, we define $\theta_{z,w} = [0.10, 0.25, 0.50, 0.15, 0]$ to every firm z and window w. The corresponding LNG orders under each counterfactual policy are presented in Figure E2.

In this specific scenario, firms tend to order slightly more than under low demand expectations, which is expected. Results are robust to this specification as well. The regular dispatch shows insufficient orders compared to the Government orders, while the three policies under study effectively increase LNG procurement.

Similar to the results shown in Table E1, Table E3 reveals that when firms hold average demand expectations, the LNG prioritization policy also displaces polluting technologies. In this case, profits from LNG are also positive, except under the Government subsidy scenario, which is where firms order the largest quantities. Opposite to when firms hold high demand expectations, there is not a surplus of LNG large enough whose forced prioritization could offset the positive effects of the policy on emissions.

Figure E2: Average demand expectations – Estimated LNG orders (Gigawatts per year)

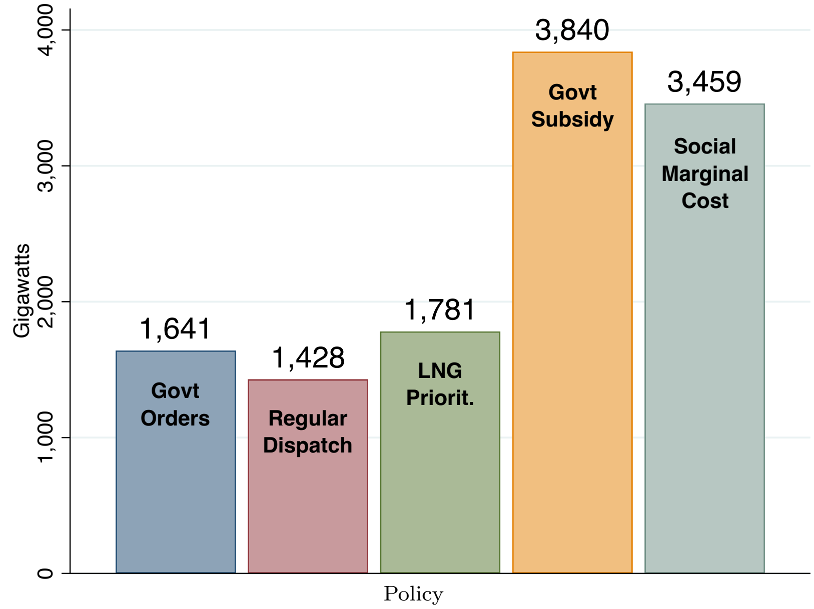


Table E3: Estimated generation and profits by fuel type (Average expected demand)

	Counterfactual scenario				
	Govt. Orders	Reg. Disp.	LNG Prior.	Govt. Subsidy	Social Marg. Costs
Generation (GW/year)					
LNG	2,114	1,950	2,484	3,853	4,149
Coal	32,053	32,053	31,965	32,053	27,928
Diesel	1,708	1,869	1,484	107	613
Solar	5,928	5,928	5,928	5,928	5,928
Wind	4,697	4,697	4,697	4,697	4,697
Hydro	21,154	21,158	21,099	21,043	24,013
Profits (MM USD)					
LNG	31.5	35.8	54.9	-1.3	206.1
Coal	1,058.6	1,060.7	1,040.5	904.8	2,011.4
Diesel	0.3	0.3	0.3	0.3	1.7
Solar	279.3	279.4	278.9	273.6	557.8
Wind	305.3	305.5	302.4	286.7	484.6
Hydro	1,203.9	1,205.4	1,190.6	1,099.3	2,052.5

Therefore, when firms hold average demand expectations, Panel (a) of Table E4 shows the emission reduction coming from the LNG prioritization policy amounts to $8 million compared to the Regular dispatch. Overall, the Government subsidy achieves higher emissions reduction given its substantial displacement of diesel. However, as in all the counterfactual scenarios studied, applying the Social marginal costs is the most effective way of reducing emissions and encouraging solar energy adoption in the long run, as shown by Panel (b) of Table E4.

Table E4: Short and long-run implications of the policies - Average demand expectations

	Govt. Orders	Reg. Disp.	LNG Prior.	Govt. Subsidy	Social Marg. Costs
(a) Short-run					
Avg. Price (USD/MWh)	76.63	76.70	76.08	71.65	112.79
Emissions (MM USD)	1,729	1,732	1,724	1,701	1,519
Energy Costs (MM USD)	2,243	2,245	2,240	2,205	2,289
(b) Long-run					
Solar investment (MW)	341	341	339	262	710
Avg. Price (USD/MWh)	75.72	75.76	75.18	69.95	111.95
Emissions (MM USD)	1,711	1,714	1,705	1,692	1,430
Energy Costs (MM USD)	2,187	2,188	2,184	2,164	2,219

Average price is a weighted average considering demand covered by each market. Energy costs refer to spot market generation costs; it does not consider the tax of the carbon price or the cost of a Government subsidy in the corresponding counterfactuals.

E.3 Reducing renewable installed capacity

In this analysis, we maintain the high demand expectations estimated from the data but modify the market structure by reducing one-third of each market's renewable capacity. To ensure demand can be met, we allocate the removed megawatts of renewable energy among the remaining fossil fuel plants in each market. This approach allows us to examine how different policies would impact a country that lags behind Chile in terms of its progress in the energy transition. The quantity of LNG ordered under each policy for this scenario is presented in Figure E3.

Interestingly, when renewable installed capacity is reduced, the LNG prioritization policy falls short in the amount of LNG to order. The government would like even more gas to compensate for the lack of solar power. In addition, when examining Table E5, we observe limited displacement of diesel and coal from almost all policies. Consequently, the results align with those discussed in Section 6, where firms also had high demand expectations. This is further confirmed by Panel (a) of Table E6, which shows little to no improvement in emissions resulting from the LNG prioritization policy or government subsidy compared to the regular dispatch in this reduced renewable capacity scenario.

Hence, the findings remain consistent; when firms anticipate high demand, a regular dispatch emerges as the second-best choice. The Social marginal costs policy stands out as the first-best option across all counterfactual scenarios.

Figure E3: Reduced renewable installed capacity – Estimated LNG orders (Gigawatts per year)

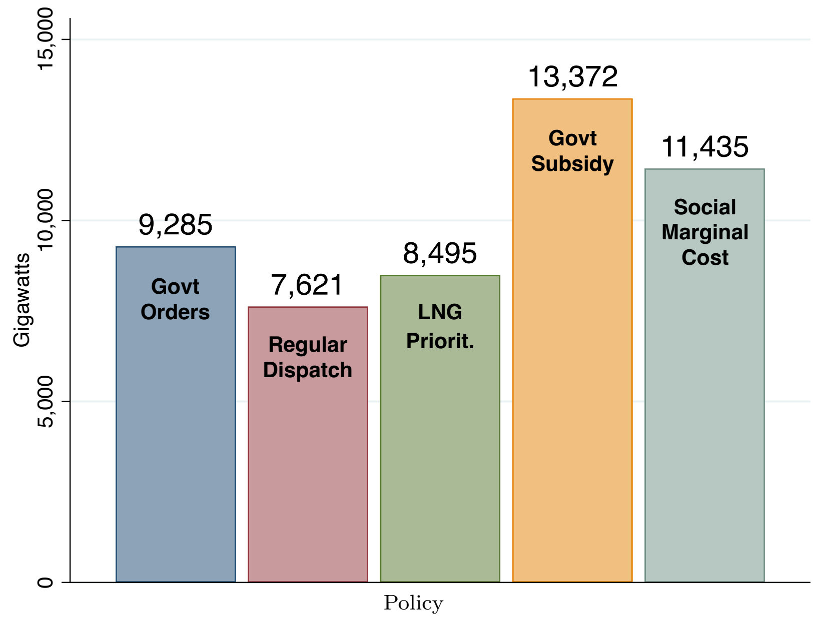


Table E5: Estimated generation and profits by fuel type (Reduced renewable capacity)

	Counterfactual scenario				
	Govt. Orders	Reg. Disp.	LNG Prior.	Govt. Subsidy	Social Marg. Costs
Generation (GW/year)					
LNG	4,579	4,628	9,293	4,671	5,804
Coal	39,533	39,533	37,701	39,533	35,747
Diesel	175	175	173	175	92
Solar	3,114	3,114	3,114	3,114	3,114
Wind	3,644	3,644	3,644	3,644	3,644
Hydro	14,857	14,844	12,417	14,810	17,021
Profits (MM USD)					
LNG	-460.0	-292.9	-202.7	-812.0	-411.9
Coal	1,068.4	1,074.5	678.4	1,046.5	2,251.4
Diesel	4.8	4.8	4.4	4.7	7.5
Solar	160.4	160.2	149.0	159.9	301.2
Wind	209.9	211.6	179.0	209.5	357.0
Hydro	613.5	607.3	449.8	597.7	1,112.7

E.4 Long-run policy effects when solving transmission frictions

Even though large, the effects on solar entry of the different policies presented in Table 6 could be hindered by market frictions, with transmission constraints being a notable example. The improvement in transmission volume is particularly noteworthy as congested lines impose a limit on the profitable solar capacity that can

Table E6: Short and long-run implications of the policies - Reduced renewable capacity

	Govt. Orders	Reg. Disp.	LNG Prior.	Govt. Subsidy	Social Marg. Costs
(a) Short-run					
Avg. Price (USD/MWh)	71.59	71.54	60.86	70.81	104.09
Emissions (MM USD)	2,096	2,097	2,101	2,098	1,927
Energy Costs (MM USD)	2,625	2,624	2,768	2,623	2,688
(b) Long-run					
Solar investment (MW)	329	327	133	322	2,006
Avg. Price (USD/MWh)	70.44	70.77	60.21	70.11	101.69
Emissions (MM USD)	2,084	2,084	2,100	2,085	1,721
Energy Costs (MM USD)	2,570	2,570	2,750	2,570	2,452

Average price is a weighted average considering demand covered by each market. Energy costs refer to spot market generation costs; it does not consider the tax of the carbon price or the cost of a Government subsidy in the corresponding counterfactuals.

be installed, irrespective of whether the policy proves to be advantageous or detrimental to solar power entry. On one hand, congested lines restrict the amount of solar power that can be transported to meet demand in other markets. Therefore, by improving transmission capacity, renewables perceive higher residual demand. On the other hand, improved transmission leads to price convergence across markets. This means that prices in some markets rise while they fall in others, depending on the mix of technologies installed in each market. Markets with a substantial amount of renewables, which typically drive prices to near-zero levels under congestion, will experience price increases when congestion is relieved. Table E7 presents solar investment in the long run if there were no transmission constraints across the country.

Table E7: Long-run implications of the policies - No transmission congestion

	Counterfactual scenario				
	Govt. Orders	Reg. Disp.	LNG Prior.	Govt. Subsidy	Social Marg. Costs
Long-run					
Solar investment (MW)	354	355	84	407	1,278
Avg. Price (USD/MWh)	68.50	68.70	53.17	67.80	98.66
Emissions (MM USD)	1,765	1,765	1,796	1,764	1,418
Energy Costs (MM USD)	2,077	2,080	2,346	2,069	2,053

Average price is a weighted average considering demand covered by each market. Energy costs refer to spot market generation costs; it does not consider the tax of the carbon price or the cost of a Government subsidy in the corresponding counterfactuals.

Even under the LNG prioritization policy, some solar power is able to enter the market when transmission lines are unconstrained. However, under the Government subsidy and Regular dispatch scenarios, the difference is striking when compared to the current transmission congestion, with increases of 60% and 40%, respectively. The only policy where entry is slightly affected by improved transmission lines is the Social marginal costs policy. In this particular scenario, the convergence in prices, resulting from increased trade in the absence of transmission constraints, outweighs the benefits of larger residual demand. This is primarily influenced by the impact on market 3, where the majority of solar power entry takes place, and prices decrease when there is no congestion.

These findings suggest that the policy's effects are, in fact, affected by transmission constraints. Resolving these issues on top of implementing one of the policies studied could potentially lead to even larger long-term benefits.