“GREEN HYDROGEN PRODUCTION IN THE METROPOLITAN REGION IN CHILE: ASSESSMENT OF FUTURE FEASIBILITY”

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Green hydrogen production in the Metropolitan Region in Chile: Assessment of future feasibility

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Abstract

Currently, most of the green hydrogen projects in Chile are located in the north and south of the country, while a significant part of the local demand is expected to be concentrated in the central zone, specifically in the Metropolitan Region. This work assesses the future feasibility of green hydrogen production in the Metropolitan Region of Chile in order to discuss the policies that can be taken to ensure the supply of green hydrogen in this region. Chile has an unbundled electrical system where electricity producers settle their differences between generation and contracted PPA sales on a spot market with a centralised cost-based dispatch design. A different approach to the traditional levelized cost of energy analysis is used in which the break-even point of an on-grid green hydrogen plant depends on the cost of electricity. I calculate the willingness to pay for electricity from the plant and contrast with electricity prices in the Metropolitan Region. Under an optimistic scenario of hydrogen plant inputs and a current forecast of electricity prices until 2040, the feasibility of green hydrogen production is barely possible. The analysis identifies a number of key variables that can be taken into account by policy makers in order to support the realisation of this scenario.

Keywords: Green hydrogen, Willingness to pay for electricity, Spot electricity price, Public policies.

Non-technical Summary

This work answers the question of whether green hydrogen production in the Metropolitan Region of Chile is close or further away to be feasible. This region is located in the central zone of Chile and has a low attractiveness to produce green hydrogen, because conditions in the north and south of the country are more favourable. For this reason, only a few green hydrogen projects have been announced in the Metropolitan Region, while a large demand for green hydrogen is expected in the region, creating a future gap between supply and demand.

The government of Chile is committed to the goals set by the Paris Agreement for 2050, and since the Metropolitan Region is the region with the highest net CO2 emissions in the country, it is important that the government has a plan to meet the demand for green hydrogen in this region, which would contribute significantly to the decarbonisation goals. Therefore, the answer to the research question is relevant as it will allow policy makers to implement efficient measures to ensure the supply of green hydrogen in the region. If the feasibility of green hydrogen production is close, it would be efficient to design policies that encourage production in the Metropolitan Region, whereas if it is far away, it may be more efficient to design policies that encourage transport from regions with favourable production conditions to the Metropolitan Region.

Green hydrogen is produced by splitting the water molecule in a process called electrolysis, which is electricity intensive, so the cost of electricity is a very significant cost for a green hydrogen plant. For the hydrogen to be considered green, the electricity used in the electrolysis process must come from renewable energy sources. Green hydrogen plants can obtain the electricity either by having their own installed renewable energy capacity, typically solar or wind farms, or by connecting to the grid and contracting energy from electricity producers. There is literature to support that grid connected plants can achieve the same or even more competitive cost of hydrogen production than off-grid plants. In this work it is assumed that the hydrogen plant is connected to the grid.

To answer the research question, I compare the willingness to pay for electricity that a green hydrogen plant would have in the coming years with the electricity prices in the Metropolitan Region. In order to identify all the variables that could have a relevant impact on the feasibility of the plant, I perform an electricity price regression that allows me to identify the main determinants of the electricity price in the region. The results show that under an optimistic future scenario of hydrogen plant revenues and costs and the projected electricity prices in the region, the production of green hydrogen could be feasible. The price of hydrogen, plant investment costs, corporate taxes, project discount rate, grid connection costs, installed capacity mix and variable costs of conventional power plants are important variables that the government needs to consider when designing policies to promote the feasibility of green hydrogen production in the Metropolitan Region.

Contents

1 Introduction

Chile has joined the global initiative to reduce emissions, participating in the Paris Agreement and subsequently approving the Climate Change Framework Law, which sets the goal of being carbon neutral by 2050. According to the latest measurement of greenhouse gas emissions in the country for 2020, carried out by the Ministry of the Environment, there is a clear upward trend: Chile emitted 16,200, 30,800 and 62,500 kt of CO2 in 1999, 2009 and 2019 respectively [25]. The development of the green hydrogen industry has proven to be a key strategy for Chile to face this challenge: the introduction of hydrogen can contribute to Chile's 2050 target an additional 50% reduction in emissions compared to a scenario without hydrogen [11]. In addition, it would entail the development of a new industry capable of diversifying the current production matrix, allowing the current problem of economic stagnation to be addressed. Comparing the last two decades, we can see that the country has gone from an average annual growth rate of 4.8% between 2004 and 2013 to a growth rate of 1.9% between 2014 and 2023.

The National Green Hydrogen Strategy (NGHS) announced in 2020 aims to take advantage of the great opportunity that the country has in this matter [24]. The completion of the first wave of the NGHS that establishes the application of green hydrogen in the domestic market is crucial since it will allow Chile to begin to i) generate learning about the technologies associated with the production of hydrogen based on electrolysis and ii) quickly reduce emissions by replacing gray hydrogen and other replaceable fossil fuels with H2. However, the large availability of renewable energy in the north and south, which enables hydrogen to be produced on a large scale, is encouraging private companies to focus on large projects in these areas, aiming to meet the greater international demand. Although this is the rational behaviour we should expect from companies, it has led to a lack of projects in the Metropolitan Region that allow for iteration and testing of green hydrogen production and distribution, and are insufficient to meet the expected demand.

According to a 2023 study by copper producer Angloamerican, green hydrogen demand in the Metropolitan Region is expected to be 50,000 tonnes in 2030 and 170,000 tonnes in 2040. In 2019, the Metropolitan Region was responsible for 36% of the country's net CO2 emissions, with an increasing trend, mainly due to fuel consumption in the transport sector. In the absence of gas pipelines throughout Chile, hydrogen transport between regions requires the use of highways. Hydrogen's low density and boiling point imply high transport costs over long distances, due to the amount of energy required to maintain low temperatures and the risks of high-pressure compression, depending on whether it is transported as a liquid or a gas. However, only 8% of announced green hydrogen projects are located in the Metropolitan Region [26], and most of these are demonstration projects initiated by non-energy companies and focused on green hydrogen self-consumption. Therefore, if the aim is to advance the NGHS by starting to meet local demand, reducing the country's emissions and generating knowledge, it is necessary to have a strategy for the Metropolitan Region. The role of the government is to create the right incentives for the private sector to move in the socially optimal direction.

This work assesses the feasibility of a green hydrogen plant in the Metropolitan Region now and seeks to determine whether, under various sets of realistic assumptions, there is a scenario in which such a plant would be feasible the next decades. Answering this question is important because it provides policy insights for the government to decide on the optimal strategy and market conditions that should be created to ensure green hydrogen supply in the Metropolitan Region. It is known that hydrogen production is not currently feasible in the Metropolitan Region, but it is not clear how far we are from feasibility and whether we will get closer or further away in the coming decades. Finding a near-feasibility scenario could motivate thinking about concrete measures to promote green hydrogen production in the Metropolitan Region. On the other hand, the realisation that there is no feasibility scenario, even under optimistic assumptions, could motivate thinking about measures that have more to do with transporting gH2 to the Metropolitan Region from the North or South, than with producing gH2 in the Metropolitan Region.

What is expected from this work is to provide useful inputs and perspectives to consider in the strategic choices that the government have to make in order to successfully promote the development of this new industry. The Metropolitan Region has certain sites with characteristics that make it ideal for the rapid implementation of a hydrogen plant based on electrolysis, given the advantages of connection to the electrical grid, easy access to water and proximity to potential consumers. This means lower initial investment costs and shorter times to get a plant up and running, which is essential to gain experience in the production and distribution of green hydrogen and to start both meeting local demand and helping to reduce CO2 emissions. Meeting these short-term objectives will determine the success of the long-term challenges outlined above.

The following sections provide a literature review, conceptual models to introduce the methodology and a description of the Chilean electricity market. I then describe the methodology and data used to answer the research question. I replicate the methodology developed in Van Leewen and Mulder (2018), where the feasibility of the plant can be assessed by estimating the willinges to pay for electricity of a power-to-gas plant and constrasting with the electricity prices of the market. A sensitivity analysis is carried out on the variables used in the economic evaluation of the plant and in the electricity price regression, in order to identify different possible feasibility scenarios. Finally, in the conclusion discusses the possible actions that could be taken based on the results obtained, taking into account the limitations of the work.

2 Chilean electricity markets

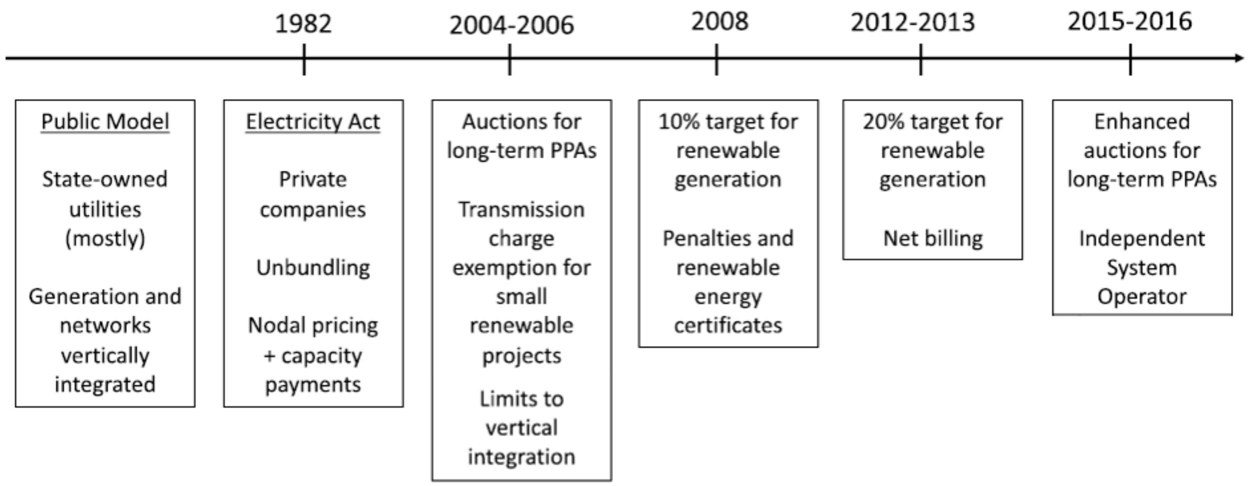
2.1 Background

With the enactment of the Electricity Law in 1982, Chile became the first country to unbundle the electricity sector, resulting in separate private generation, transmission and distribution segments. The generation segment corresponds to a competitive market with free entry of companies, while the transmission and distribution segments are natural monopolies with regulated tariffs. Chilean electricity producers settle their differences between generation and contracted PPA sales on an hourly cost-based dispatched spot market. As a result, the energy revenue structure of electricity producers in Chile consists mainly of contracted PPAs (forward market) and spot market sales. Since 2020, producers are able to participate in a market for ancillary services (fast frequency control and primary, secondary and tertiary reserves), which are auctioned daily in a competitive pay-as-you-bid process and co-optimised with energy. The Chilean electricity market is the only electricity market in the world that combines a cost-based mechanism for energy and a pay-as-bid auction for the procurement of ancillary services, without a binding day-ahead market [2].

In addition, electricity producers in Chile also receive capacity payments, which are set by the regulator as a measure to ensure sufficient investment in new generation capacity in a market without scarcity pricing and high spot price volatility due to the high dependence on hydro resources. Serra (2022) provides a diagnosis of the Chilean energy market and concludes that the current regulation, in particular the unbundled design and the cost-based dispatch system, has provided the right incentives to attract sufficient investment to meet growing energy demand without creating excessive profitability for generation companies. Further evidence of the well-functioning of the market is the fact that, since 2014, the number of bidders in the auctions for the supply of regulated customers has soared and bid prices have fallen sharply. However, this situation can be explained to a large extent by the abrupt fall in the price of NCRE technology, especially solar PV.

In 2014, the integration of the two main electricity systems in the north and south-centre of Chile was announced. The integration was completed in 2017, resulting in the National Electric System (NES), and later the integration was strengthened with the construction of a major transmission line in 2019. Given the country's geography, the NES is a particularly long system, stretching 3,100 km from the city of Arica in the north to the island of Chiloe in the south, covering 98.5% of the country's total population. Gonzales, Ito and Reguant (2023) show that Chile's electricity system integration increases trade between renewable energy intensive zones with high demand centres and reduces grid congestion, leading to both spot price convergence between regions and an increase in renewable energy investment. The authors use a structural model of market integration, inspired by the cost-based dispatch model used by the National Electricity Coordinator in Chile, to analyse the investment effects of Chilean electricity system integration on renewable energy expansion. They find that market integration in Chile increased solar generation by about 180%, reduced spot prices by 8%, and reduced carbon emissions by 5%, not only because of market integration itself, but also because of renewable energy investment in response to the announcement of market integration.

Figure 1: Timeline of main regulatory changes, mainly focused on generation.



Source: Muñoz et al. (2021)

2.2 Spot electricity market

The NES spot market is a national and wholesale electricity market where producers buy and sell electricity to each other. This market is based on a nodal pricing and single-settement system, which means that there is a spot price for each node within the market and that all spot transactions are settled using real-time prices (calculated ex-post operations). The spot market is managed by an independent, not-for-profit system operator called the National Electrical Coordinator (NEC), which sets the hourly spot prices by minimising the cost of operating the system, subject to demand forecasts and transmission constraints. Therefore, the spot market prices at any given time (also known as the producers's opportunity cost) are equal to the marginal cost of the most expensive unit operating to meet all demand at each node at that time. This means that the spot market is a cost-based market, where the National Electrical Coordinator dispatches units on a merit-order basis, starting with units with the lowest declared costs and ending with units with the highest declared costs, which are subject to weekly review. This mechanism ensures that demand on the spot market is always met by the most efficient units available at any given time, and implies that units whose variable costs are lower than the spot market price make a profit on the production fed into the system (scarcity rents), while dispatched units whose variable costs are equal to the spot market price can only recover their variable production costs. As some units have a slow ramp-up time, to ensure the stability and security of the system, dispatching is planned one day in advance and adjustments to the National Electrical Coordinator schedule are made intra-day. Deviations in forecast demand, technical failures in transmission lines, less renewable generation due to weather changes are some of the variations that need to be taken into account. Gonzales et al. (2023) reproduce the market clearing process performed by National Electrical Coordinator through the next constrained optimisation problem:

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

Where $C_{ztj}(q_{ztj})$ is the total production cost of technology j in zone z and hour t with production quantity q_{ztj}, imp_{lzt} are imports into zone z from transmission line l, exp_{lzt} are exports from zone z via line l, D_{zt} is demand in zone z, f_{lz} is the transmission capacity of the line l if zone z is connected to this line, δ_1 is a transmission loss factor for high voltage transmission, which allows the supply from imports to be corrected for losses between zones and δ_2 is a transmission loss factor for low voltage transmission, which allows the total supply to be corrected for losses within each zone. The first constraint states that supply plus net imports must be greater than or equal to demand in each zone, after accounting for transmission losses; the second constraint represents the trade capacity constraints between zones; and the third constraint states that exports from zone z to zone r connected by line l must to be equal to imports into zone r coming through line l. Since running this model is highly complex and requires a large amount of data, in order to understand the main drivers of the spot market price, a reduced form is proposed in the next section.

2.3 Forward electricity market

The power forward market is a national wholesale market where Chilean power generators can sell their energy and power to free consumers (typically medium or large private companies with a connected load of more than 0.5 MW) or to regulated consumers (distribution companies) by signing a contract (PPA) that specifies the price, quantity, duration and other characteristics of the deal. In the case of sales to free customers, the terms of this contract are agreed through bilateral negotiations between the parties, while in the case of sales to regulated customers, a bidding process is conducted by the National Energy Commission where distribution companies auction a future amount of electricity needed and the best bids win the auction. It is worth noting that if not all the auctioned energy is awarded, the distribution companies have to buy the missing electricity on the spot market. The distribution companies then sell this electricity to households and small businesses, charging a regulated distribution service tariff. However, the regulated market is no longer discussed in this paper.

Using data on these bilateral contracts from 2006 to 2014, Bustos and Fuentes (2017) show that electricity prices in the free electricity market in Chile depend strongly mainly on i) forecasted spot market prices, ii) a mark-up margin determined by the market power of the participating electricity producers, and iii) the risks associated with the contract agreements (basically, length and size). The authors predict contract prices after market integration and show that this should lead to a decrease in contract prices due to a decrease in spot prices, spot price variability and market concentration. Bustos et al. (2017) estimate the price for free customers using the following econometric model:

$$P_{it} = \alpha_1 C_t + \alpha_2 VMC_t + \alpha_3 MCI_t + \alpha_4 D_i + \alpha_5 S_i \tag{2}$$

Where P_{it} is the electricity producer's offering price for contract i, at time t; C_t is the cost of providing electricity at time t, which represents the estimation as a function of expectations at the time of the offer with respect to the cost of purchasing energy in the spot market to supply the contracts; VMC_t is the expected variability in the spot price at time t, which represents the electricity producer's risk as a supplier at the time their contract takes effect. From a behavioral perspective, it is expected that as this variance increases (greater risk), prices will increase; D_i the duration of each contract i and S_i the size of client i. The model has been adapted to the current reality, as this paper was written before the market was integrated.

3 Literature Review

In this section we review different approaches that have been used in the literature to assess the feasibility of low carbon hydrogen production based on electrolysis. A peculiarity of hydrogen plants compared to other energy plants is that there are many different characteristics or constraints that differ for each project, depending on the renewable energy source, the availability of connection to the grid, the location of the plant, the parts of the hydrogen chain considered, to name but a few. As a result, there is a wide variety of studies in the literature that differ according to the assumptions, methodology and focus of the authors. Leon et al. (2023) developed a pre-feasibility analysis of green hydrogen production plants in two strategic regions of Chile: Atacama in the north and Magallanes in the south. They performed a financial analysis using the Net Present Value (NPV) approach and determined the optimal sizing of an alkaline electrolyser stack, a seawater desalination system, and renewable solar or wind energy farms depending on the region. They obtained production costs per kilogram of green hydrogen of USD 4.8 kg in the south using wind energy and USD 7.0 kg in the north using photovoltaic solar energy [10]. Using data on government-owned land, San Martin et al. (2024) developed a more holistic methodology to determine the most suitable locations for the installation of green hydrogen industries in Chile, taking into account different technical and environmental aspects such as solar power, wind power, distance to road network, distance to marine terminal, electricity grid, populated areas, coastline and terrain roughness, etc. They found that the most suitable sites were in the north of Chile but highlighted the long distance between the sites and the sea, which makes desalination a challenge [13].

Garcia and Oliva (2023) developed a model to investigate the cost of producing green hydrogen using a solar-wind hybrid energy system at four sites in Chile. The model uses local solar and wind generation data to determine the optimal capacity of the on-site solar PV and wind subsystems and the electrolyser. They found that green hydrogen can be produced at competitive prices ranging from US$2.09/kg to US$3.28/kg, with the Taltal site in the Antofagasta region being the most cost-effective alternative for the construction of the gH2 plant, as it is the site with a high abundance of both renewable energy sources, requiring a lower installed capacity of the electrolyser, wind and solar PV subsystems compared to other sites [7]. Hurtubia and Sauma (2021) analyses the economic and environmental implications of complementing the renewable energy sources (RES) power supply of a hydrogen production plant in Chile with grid electricity during the time when RES are not available, for which they consider the use of both alkaline and PEM electrolysers and introduce a new metric "LCOH&E" which captures the existing trade-off between reducing the Levelized Cost Of Hydrogen (LCOH) by increasing gH2 production with grid electricity and increasing CO2 emissions by producing more gH2 with grid electricity. They show that using only 10% of grid electricity in an ALK electrolyser, it is possible to increase the gH2 production in 25.7%, without significantly increasing CO2 emissions [8]. Wolak et al. (2023) studies the decision to invest in a hydrogen production plant introducing flexibility in the timing and magnitude of investments in renewable-energy generation capacity and the hydrogen-production capacity. They use a compound real options methodology called Compound Least Squares Monte Carlo (CLSM) and real data to simulate different scenarios in the north of Chile and find that in almost 100% of the cases it is preferable to implement the investments in a compound way [16].

Now, with regard to some evidence outside of Chile, Ibagon et al. (2024) developed an optimisation model that identifies the optimal configuration of generation, electrolysis and storage capacity, hydrogen form and energy mix that minimises the total levelised cost of hydrogen ($LCOH_T$), which includes hydrogen production costs, storage, conversion/processing, transportation costs, any penalties for not delivering hydrogen, and grid energy interactions (revenue for selling excess electricity and cost for buying deficit electricity). The authors compared three scenarios in the province of Rio Negro in Argentina: an on-grid scenario selling energy through a PPA; an on-grid scenario selling energy on the spot market; and an off-grid scenario. They obtained $LCOH_T$ of 3.2 US$/kg gH2 for the on-grid with PPA scenario and 3.35 US$/kg gH2 for the off-grid scenario, concluding that grid interconnection is more profitable when the NPV of interconnection costs is less than 5% of the NPV of capital expenditure (CAPEX), if there are no penalties for unmet hydrogen demand [4]. These results are important because they i) show the potential competitiveness of on-grid hydrogen projects in a neighbouring country with recent data and ii) highlight the importance of considering electricity market conditions because of their impact on $LCOH$ and therefore on the development of the hydrogen industry. In hydrogen production, the cost of electricity is by far the most important OPEX item and also the most volatile, so a different approach to assessing the feasibility of a hydrogen plant is interesting, where the calculation of the willingness to pay for electricity is contrasted with an analysis of the electricity price in the region where the project is located.

Van Leewen and Mulder (2018) applied the mentioned approach and assessed the economic feasibility of a power-to-gas plant in different European countries, by calculating the willingness to pay for electricity from a on-grid power-to-gas plant and contrasting it with the day-ahead electricity prices of the respective markets. The authors showed that hydrogen production by electrolysis was not feasible in any of the countries analysed under current conditions, but they found a feasible scenario if optimistic future conditions mainly for investment costs, power-to-gas revenues and electrolyser efficiency were assumed [1]. In this work, the methodology developed in Van Leewen and Mulder (2018) is applied to the case of Chile, specifically to the Metropolitan Region, which allows us to add to the discussion more specific inputs for a hydrogen plant, such as taxes, grid connection costs, among others. On the other hand, I contribute to the literature of Chilean studies by presenting a new methodology and by focusing on a different zone of the country. Most of the current studies focus on the north and south of the country, but there is a need to start thinking about a hydrogen supply plan for the region with the high projected demand for hydrogen and greenhouse gas emissions.

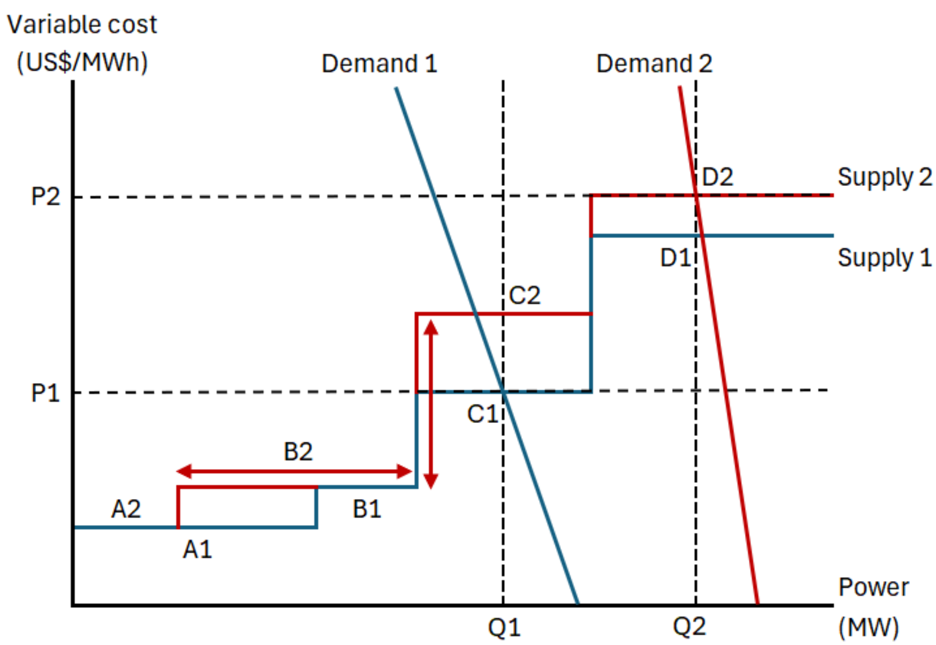
4 Conceptual Model

In this section, we first review the mechanism by which electricity prices are determined from a microeconomic perspective and the different dimensions of electricity markets. This will allow us to understand the clearing market process in electricity markets in order to later specify a model capable of explaining spot market prices. We then examine the different variables that affect the cost of producing green hydrogen and the willingness to pay for electricity.

4.1 Electricity markets

Although electricity markets are far from perfectly competitive, the use of the perfectly competitive scenario is very useful for understanding the fundamentals of these markets. Figure 1 shows two equilibrium prices and quantities for two different time periods in an electricity market. The market

Figure 2: Electricity supply and demand in two different time periods

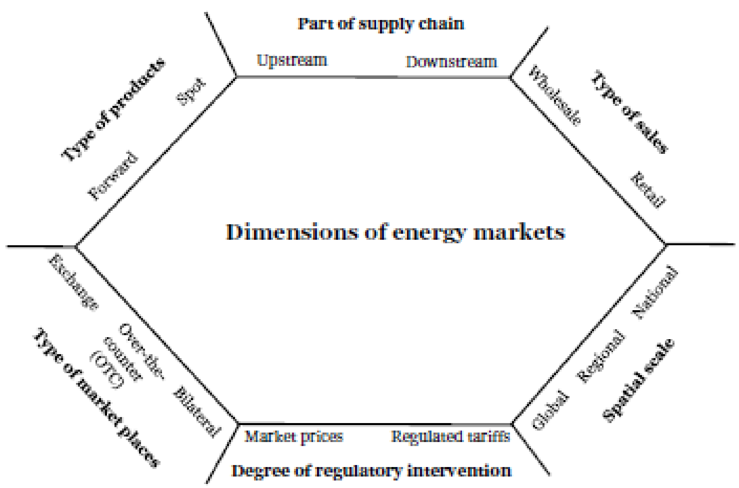


Note: Own elaboration. P:Price, Q:Quantity,{A,B,C,D}:Generation technologies,{1,2}:Supply and demand scenarios.

equilibrium price and quantity at any given time is determined by the interaction of the supply and demand curves at that time. Both the position and the slope of the supply and demand curves change over time. In the case of the demand, for example, electricity consumption increases in the evening because more appliances are used when people come home from work and electricity is less substitutable for domestic tasks in the absence of natural light. This can be an interpretation of the shift from curve Demand 1 to curve Demand 2 in Figure 1. The steepness of the two demand curves fairly represents the actual demand curves in electricity markets, as electricity is an essential commodity for human activities and therefore changes in price lead to small changes in the quantity demanded.

In the case of the supply, for example, more solar power is available during the day than at night and in summer than in winter; hydro power varies greatly depending on the season, as water levels in reservoirs and rivers are higher after winter and lower after summer, to name but a few. This can be an interpretation of the shift from curve Supply 1 to curve Supply 2 in Figure 1. The non-linearity of the supply curve is thus due to the different availability and marginal costs of the underlying generation technologies at any given time. Note that the steeper the marginal cost difference between technologies, the steeper the supply curve. Note also that the different technologies are ranked on the supply curve in ascending order of marginal cost, known as the merit-order. In markets where the first unit of electricity is supplied by the plant with the lowest

Figure 3: Dimensions of Energy Markets



Source: Regulating Energy Markets. Mulder (2023)

marginal cost and the last unit of electricity is supplied by the plant with the highest marginal cost, the latter is called the price setting plant. Thus, in this type of market, the variable costs of the price setting plants, as well as the demand peaks, are crucial to understanding the equilibrium price and quantity. The variable costs of energy production of a given plant in period i can be defined as $VC = E_i \cdot (Fuel_i \cdot Consumption + NFC)$, where E_i is energy generation in the time period i, FC_i is the fuel cost in the time period i, $Consumption$ is the fuel consumption of each power unit and NFC are the non-fuel variable costs as water, oil, filters, spares, among others.

Finally, the different dimensions shown in Figure 2 allow us to distinguish not only between energy markets such as oil and electricity, but also between different types of electricity markets. Electricity markets can be spot or forward, wholesale or retail, regional or national, with more or less intervention; and conducted on an exchange, OTC or bilaterally.

4.2 Green hydrogen production

Since hydrogen cannot be found in its natural state in the universe, a conversion process is required to separate the hydrogen from the associated molecule in order to obtain it. Hydrogen can then be considered a tertiary or secondary energy carrier, depending on whether the conversion process is carried out using a secondary (electricity) or primary (gas) energy carrier. The most common process today is called Steam Methane Reforming (SMR), where hydrogen is produced from the combination of natural gas and steam. Nearly 95% of the world's hydrogen is produced from conventional fossil fuels, with almost 50% coming from SMR, followed by naphta reforming and coal gasification [17]. The other method of producing hydrogen is called electrolysis, where an electrolser is used to separate the hydrogen from the water molecule using electricity. If this electricity comes from renewable sources, the hydrogen produced is called green hydrogen. Today, about 50 million tonnes of hydrogen are produced annually, most of which is used as a feedstock for ammonia production and 35 % for oil refining. [12].

Next I develop a conceptual model that will form the basis of our operational model in the next section. In general, for a project to be profitable, the present value of future cash flows must exceed or equal the initial investment:

$$I_0 \geq \sum_{t}^{n} \frac{CF_t}{(1+r)^n} \tag{3}$$

Where I_0 is the investment in the project in period 0, CF_t is the cash flow of the project in period t, n is the life of the project in years and r is the discount rate. Without taking account the depreciation and assuming a fixed tax rate T over the n periods, equation (1) can be expressed as follows

$$\sum_{t=0}^{n} \frac{CAPEX_t}{(1+r)^n} = (1-T) \cdot \sum_{t=0}^{n} \frac{Revenues_t - OPEX_t}{(1+r)^n} \tag{4}$$

Note that we can rewrite equation (4) to solve for any variable and calculate the value that, for example, the cost of electricity must bring to the plant in order to be profitable. This represents then the willingness to pay (WTP) of the plant for the electricity costs and can be expressed as follows:

$$\sum_{t=0}^{n} \frac{Electricity\,WTP_t}{(1+r)^n} \leq \sum_{t=0}^{n} \frac{(1-T)(Revenue_t - Other\,OPEX_t) - CAPEX_t}{(1+r)^n} \tag{5}$$

5 Method of Research

Firstly, I assess the current feasibility scenario of a green hydrogen plant in the metropolitan region by comparing the WTP for electricity with the current electricity prices in the region. Secondly, I apply the same analysis to assess future feasibility, but considering different future scenarios for plant inputs and an electricity price forecast from the National Electricity Coordinator. Finally, I estimate a regression of electricity prices in the Metropolitan Region to understand their main drivers and discuss how possible variations in them may affect the future feasibility of the plant.

5.1 Operational model

5.1.1 WTP for electricity

Since our analysis is based on electricity prices for one year, we can use equation (5) to calculate a yearly equation for the plant's breakeven point, for which we first define the annual values for each input. The yearly cost of electricity for a hydrogen plant with an electrolysis capacity of 1 MW depends on the price of electricity and the number of operating hours during the year. Considering 8.760 hours in a year, the hours of operation of the plant can be defined as $h = capacity factor \cdot 8.760$. Then, the yearly electricity cost can be expressed as follows:

$$Yearly\ electricity\ cost = Electricity\ price \cdot h \tag{6}$$

The power consumption is the amount of energy required by a hydrogen plant to produce 1kg of hydrogen and is a function of the higher heating value (HHV) of hydrogen and the efficiency of the electrolysers. The HHV of hydrogen, measured in Nm^3, is the maximum amount of energy released when hydrogen reacts with oxygen to form water, and to express it in kg it must be divided by the density oh hydrogen. On the other hand, the efficiency of an electrolyser is the % of chemical energy that is ultimately stored in the hydrogen produced after conversion from electrical energy. The efficiency of electrolysers varies depending on the underlying technology. The lower the efficiency of the electrolyser, the more energy is required to produce $1kg$ of gH2. The power consumption of a plant can then be expressed as follows:

$$Power\ consumption = \frac{HHV}{density} \cdot \frac{1}{electrolyser\ efficiency} \tag{7}$$

For an electrolysis-based hydrogen project, where the hydrogen is not used for storage and electricity generation but only sold as a fuel, the revenues in a year depends on the price of hydrogen, typically expressed in US dollars per kg of gH2 and the number of kg sold . On the other hand, within the other OPEX there are both variable and fixed costs, tipically known as COGS (cost of goods sold) and G&A (general and administrative expenses). The former is mainly the cost of electricity and water, while the latter the cost of salaries and storage. For the sake of simplicity, we will now refer to the G&A as OPEX. Finally, considering a plant lifetime of n years, a discount rate of r, a initial investment of $CAPEX_0$ and future investments of $CAPEX_n$, the yearly CAPEX can be expresed as follows:

$$Yearly\, CAPEX = CRF \cdot (CAPEX_0 + \sum_{t=1}^{n} PV_t \cdot CAPEX_t) \tag{8}$$

Where $PV_t = (1+r)^{-t}$ is the discount factor and $CRF = r(1+r)^n \cdot [(1+r)^n - 1]^{-1}$ is the capital recovery factor that allows the total $Yearly\, CAPEX$ to be distributed in each year of n. With all this, we can calculate our yearly break-even equation for the hydrogen plant as follows:

$$Y.\, Electricity\, WTP_{long-term} = Y.\, Revenues - (Y.\, H_2O + Y.\, OPEX + Y.\, CAPEX) \tag{9}$$

In addition, if we want to solve for the electricity price in the left-hand side expressing it in US$/MWh, we can divide the right hand by 1MW and the operating hours, and the terms expressed in US$/kg gH2 by power consumption. The resulting equation represents the maximum electricity price that the plant is willing to pay for electricity in an hour to be profitable, as follows:

$$Electricity\, WTP_{long-term} = \frac{(H_2\, price - h_2o\, costs)}{Power\, consumption} - (OPEX + CAPEX) \cdot h^{-1} \tag{10}$$

Note that we say long term WTP for electricity because includes all the fixed costs. However, in each hour, the hydrogen plant will operate if the marginal revenue is greater than the marginal cost of operating in that hour, so the short-term WTP for electricity from the plant is calculated by estimating the following equation:

$$Electricity\, WTP_{short-term} = \frac{H_2\, price - h_2o\, costs}{Power\, consumption} \tag{11}$$

Having said the above, the first step is to calculate the number of hours that a green hydrogen plant in the Metropolitan Region would be willing to operate at current electricity market prices. The number of operating hours can be determined by assessing the plant's short-term WTP for electricity on the price duration curve of a node in the Metropolitan Region. The price duration curve is the one where all hours within a year are ranked from the lowest to the highest electricity price. The long term WTP for the plant's electricity can then be calculated by evaluating the number of hours obtained in the first step of the long term WTP curve. This curve represents all the points at which the plant is feasible, and the feasibility of the plant can also be determined by assessing the intersection between the long-term WTP curve and the average spot price curve, which we do later to assess future feasibility. If we don't find an intersection, it means that the plant is not willing to pay any price for electricity and therefore will not operate under the given conditions. A zone of intersection indicates a range of electricity prices that the plant would be willing to pay in the long term to operate a certain number of hours.

5.1.2 Electricity price regression

I assess the feasibility of operating the plant in the future using the National Electricity Coordinator's forecast of spot market prices in the metropolitan region and a long-term WTP for electricity band constructed using literature-based assumptions of future hydrogen production input values. As we have seen, Chilean electricity prices only have a spot market and a PPA (forward) market. In this work, electricity prices from the spot market are used as there is no data available on PPA market prices. Although the spot market prices are not the prices that a hydrogen plant would pay when connected to the grid in practice, an analysis of the spot market prices provides valuable guidance and allows to answer the question of whether the economic feasibility will increase or decrease in the future, as they represent the electricity producer's opportunity costs and determine the electricity prices in the forward market.

However, we will also discuss the other variables that determine the final cost that a on-grid plant pays for electricity and therefore have an impact on hydrogen production feasibility. The National Electrical Coordinator's spot price forecast is the most accurate that can be used as it takes into account all current Chilean policies and plans in the energy market, such as targets for renewable energy penetration, carbon taxes, greenhouse gas emission reductions, energy efficiency, etc. However, the coordinators don't share the inputs used in their calculation or a sensitivity analysis. Therefore, I specify a reduced model to understand the main drivers of the spot price in the Metropolitan Region, the possible deviations from the National Electrical Coordinator's forecast, and discuss how this may affect the feasibility of hydrogen production in the future. We use OLS to estimate the following reduced form of the spot electricity price:

$$MC_t = \beta_0 + \beta_1 C_t + \beta_2 I_t + \beta_3 H_t + \beta_4 V_t + \beta_5 HD + \beta_6 MD + u_t \tag{12}$$

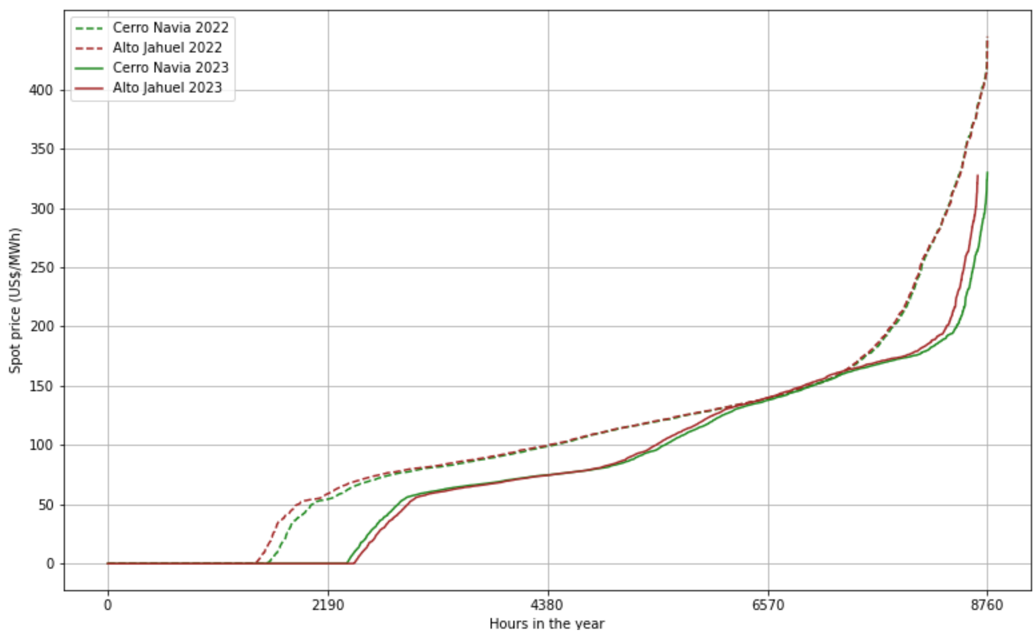
Where MC_t represents the marginal cost (electricity price) of the spot market, C_t electricity consumption, I_t a vector with installed capacity by technology, H_t hydro availability, V_t is a vector with variable costs of each technology, HD is vector with hourly dummies, MD is a vector with monthly dummies and finally, u_t corresponds to the error term.

As the Metropolitan Region is part of an integrated electricity system, the spot price in this region is determined by the demand and supply of the whole system. For this reason, we used data on electricity consumption and installed capacity of the whole system for solar, wind, hydro, natural gas, diesel and coal technologies. As we've seen, with a few exceptions, spot prices tend to be the same in two different regions of the country, so transmission constraints shouldn't be a problem for our regression. In addition, a high-voltage transmission line between the north and the south is commissioned in 2029, which will significantly reduce congestion. To solve the problem of the double causality problem between electricity price and electricity consumption, we lag the latter and use the electricity consumption of the previous period. Hydropower availability is measured by the water levels of hydroelectric plants with reservoirs. These aren't all the hydroelectric plants in the system, but they are the largest ones and they are spread across different zones of the system, so changes in reservoir levels fairly represent changes in hydro availability in the whole system. Finally, in the first model, only fuel prices are used instead of variable costs, as the specific fuel consumption and other non-fuel variable costs of each plant are sought.

5.2 Data

5.2.1 Chilean electricity market

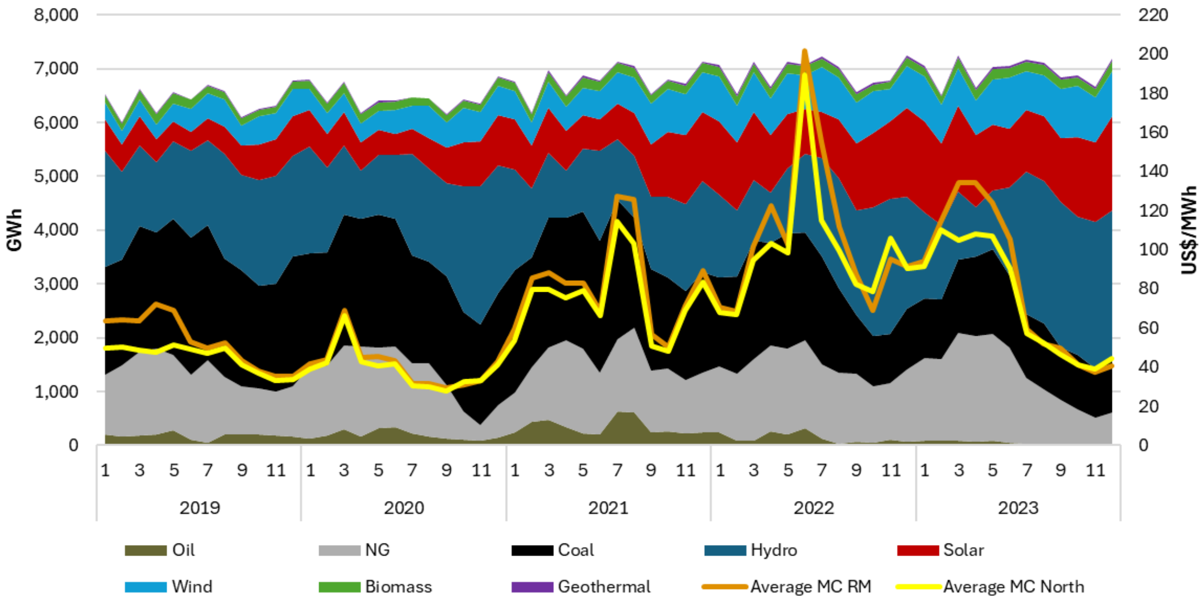
Figure 4: Price duration curve of spot prices in two nodes in the Metropolitan region



Note: Own elaboration using spot prices data from the website of the National Electrical Coordinator.

In Figure 4, we can observe that the market spot price in two of the main substations in Metropolitan Region are very similar for both years. This means that any of the two substations is representative of the region and therefore allows us to choose one to use going forward. We will use the Cerro Navia substation as it is the closest to Pudahuel, a district identified as a potential green hydrogen hub and a project like the one analysed in this work could be carried out. It also can be notice the steep slope of the curves, which means the presence of a high volatility of the sport price in the region. Extreme values are reached in particularly for the last decile. In 2023, although more than 25% of the time the spot price is equal to 0 and more than 33% of the time is above 100 US$/MWh.

Figure 5: Total Generation National Electric System and Spot Price Metropolitan Region

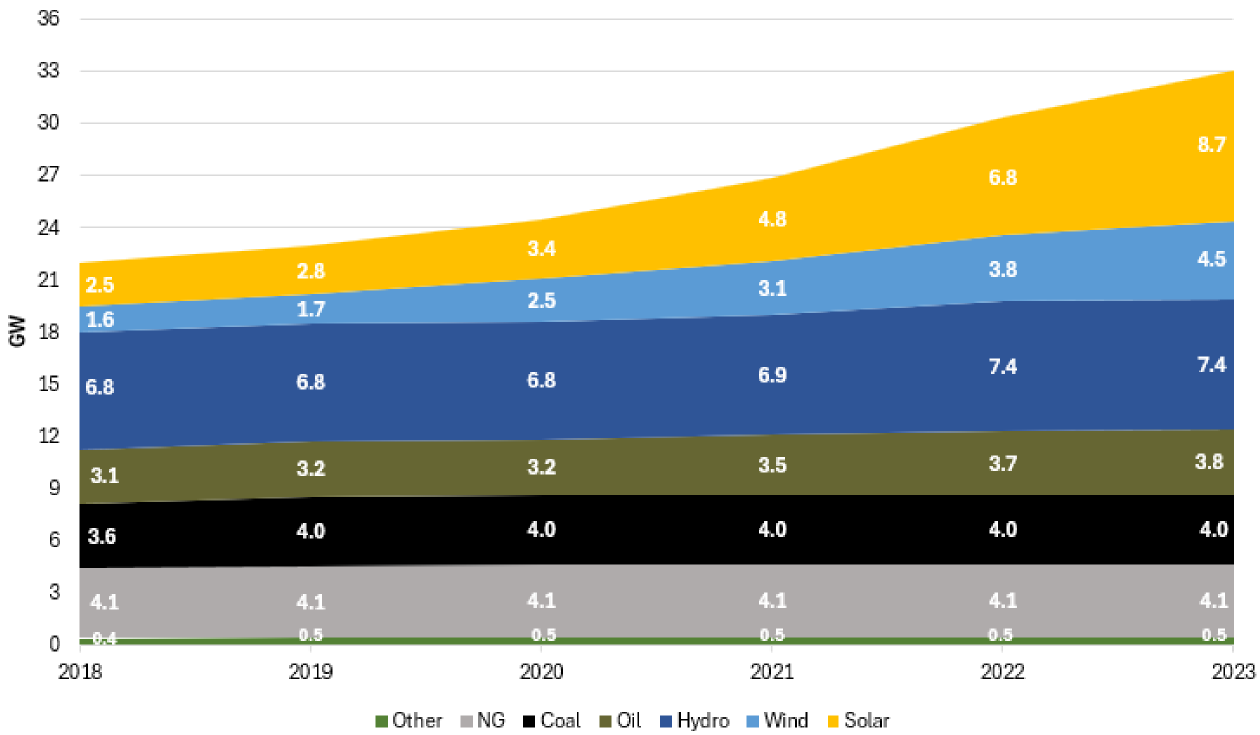


Note: Own elaboration using electricity generation data from the website of the National Electrical Coordinator

Figure 5 shows the total generation by technology and the average monthly spot prices in the Metropolitan Region and the North from 2019 to 2023. The total generation in 2023 is 83,600 GWh, with an average monthly generation of 7,000 GWh and an average hourly generation of 9.5 GWh. According to Chilean regulations, hydropower plants with a capacity of more than 20 MW are considered conventional, in order to encourage investments in hydropower that minimise the impact on the environment. With this in mind, 58% of generation is conventional and 42% renewable, but if all hydro is considered renewable, the proportions shift to 63% and 37% respectively. Total sales in 2023 are 77,300 GWh, of which 60% are to free customers and 40% to distributors (regulated customers).

In the conceptual model section, we saw that the spot price at any given time should be determined by the marginal cost of the most expensive technology dispatched at that time. Note that there is a clear correlation between the share of fossil fuel generation and spot prices, as we predict in theory, and that the spot prices in the Metropolitan Region and the North differ mainly in summer and autumn. The latter can be explained by the fact that during these seasons there is less hydro generation in the central zone and more solar generation in the north, which can't be fully transferred to the metropolitan region due to transmission constraints (curtailment), resulting in a price decoupling. Finally, note that in 2022, spot prices reach extreme values in periods of high fossil generation due to the increase in fuel prices.

Figure 6: Installed Capacity Mix National Electric System

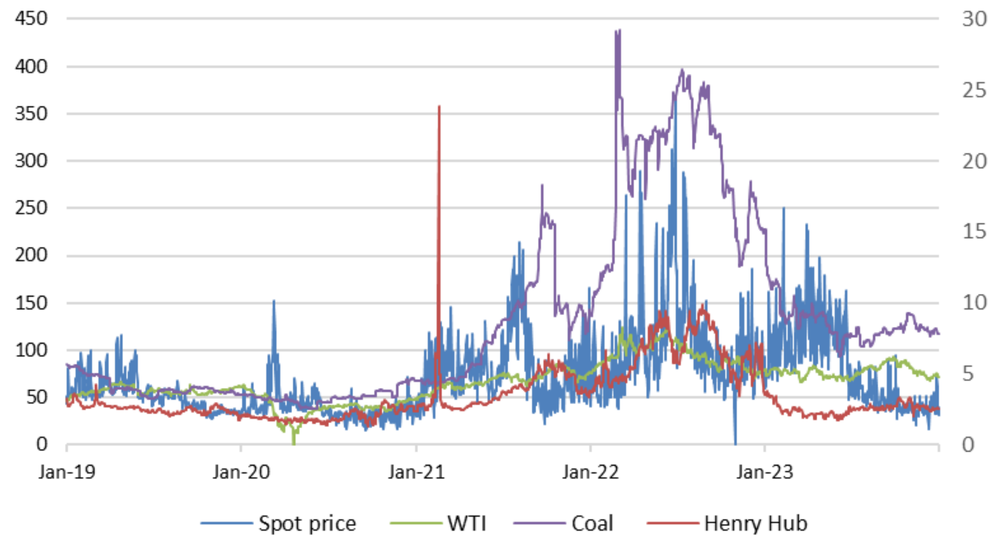


Note: Own elaboration using power capacity data from the website of the National Electrical Coordinator

Figure 6 shows the installed capacity mix in Chile between 2019 and 2023. Chile has almost 34 GW of installed capacity, of which 55% is conventional and 45% non-conventional renewable energy (NCRE). If all hydro capacity is considered renewable, the shares shift to 36% and 64% respectively. As can be seen in the graph, the share of solar and wind capacity in total capacity has increased significantly from 11% and 7% in 2018, to 27% and 13% respectively. While other technologies have also increased their capacity, they have done so very little. We can see that hydro capacity is the second most important technology with a 22% of the total installed capacity. In terms of location, the largest installed capacity is in the Antofagasta Region (North) with 26%, followed by Bio Bio with 15%, Valparaíso with 9%, Maule with 7% and then the Metropolitan Region with 6%.

Figure 7 shows the evolution of daily WTI, Henry Hub and coal prices with daily spot electricity prices in the Metropolitan Area. The correlation between fossil fuel prices and spot electricity markets is evident: As the former start to increase in 2021, the latter also start to increase. Note that in the second half of 2023, after fuel prices have stabilised, spot electricity prices start to fall.

Figure 7: Fuel prices and spot electricity price in Metropolitan Region



Note: Own elaboration using spot prices data from the website of the National Electrical Coordinator and fossil fuels data from webstite of EIA (US Energy Information Administration)

5.2.2 Hydrogen plant inputs

In this section we discuss the different assumptions for the hydrogen plant. The summary with the assumptions and references are in Table 1. I use the current price of grey hydrogen in Europe of 3.2 US$/kg, which is a conservative because assumes that there is no green premium that the market is willing to pay for green hydrogen. Electrolyser efficiency can vary a lot depending on the type of electrolyser, the capacity and and at what % of its capacity is used. For this plant I assume the use of an alkaline electrolyser with an efficiency of 59% and 74% for the current and optimistic scenario.

In theory, it takes 9 litres of water to produce 1kg of hydrogen, which is called the stoichiometric water requirement. However, in practice, depending on the water purity or the water losses as vapour in the electrolysis process, the final amount of water needed may be significantly increase the stoichiometric requirement. Assuming that we use drinking water from the Metropolitan Region at US$0.00145 per litre, and that 15 litres of this type of water are needed to produce 1 kg of hydrogen, the cost per kg of hydrogen is US$0.022. Considering that most applications of hydrogen are in internal combustion engines or fuel cells, which operate at high temperatures where water vapour escapes and therefore the energy contained in this vapour is not used, it is more realistic to use the LHV ($3kWh/Nm^3$) than the HHV ($3.54kW/Nm^3$) to calculate the power consumption of the electrolyser.

For the current scenario I use a CAPEX electrolyser system of 1,000 US$/kW and a CAPEX electrolyser stack of 40% of the CAPEX electrolyser system, which is a fairly average of the literature range that goes from 33% to 47%. On the other hand, the corporate tax rate in Chile is currently 27% and in the OECD it is 22%, so it is reasonable to assume a corporate tax rate of 17% for hydrogen projects in the optimistic scenario, considering that tax incentive measures may be taken in the future. It is worth noting that we are only looking at the cost of producing hydrogen, so the price per kg of gH2 does not include transportation and storage at the customer's site, which can significantly increase the cost to the end user from US$2.73 to US$8.02 in addition to the LCOH.[20].

With regard to the hydrogen storage buffer, it is assumed that the plant will invest in storage capacity for one week, operating 12 hours a day. The hydrogen can be stored in its gaseous state at high pressure between 350 and 700 bar, or in its liquid state, which requires a liquefaction process after electrolysis. I assume gaseous storage because it is currently a more mature technology and a price of 600 and 400 US dollars per kg gH2 is used for the current and optimistic scenario. On the other hand, the OPEX is considered as % of the CAPEX and includes the O&M costs of the electrolyser and storage. Finally, a discount rate of 10% and 6% has been chosen for the current and optimistic scenarios respectively, arguing that in the future the greater development of the industry and the implementation of policies that support the supply or demand of hydrogen could reduce the risk of the projects.

Table 1: Hydrogen plant input values for current scenario and references

Parameters	**Current Scenario**	**References**
Plant lifetime (years)	20	[15]
Discount rate (%)	10	[28],[14], [23]
Tax rate (%)	27	[29]
Electrolyser Stack lifetime (years)	8	[28]
Electrolyser Stack (% CAPEX)	40	[22], [28]
LHV (kWh/kg H2)	33.33	-
Hydrogen price (USD/kg H2)	3.2	[30]
Electrolyser CAPEX (USD/kW)	1000	[34], [35]
Electrolyser efficiency (%)	59	[23], [18], [28]
Storage CAPEX (USD/kg H2)	600	[14], [4]
Water needed (L/ kg H2)	18	[19]
Installation & design (% CAPEX)	30	[1]
OPEX (% CAPEX)	4	[23]

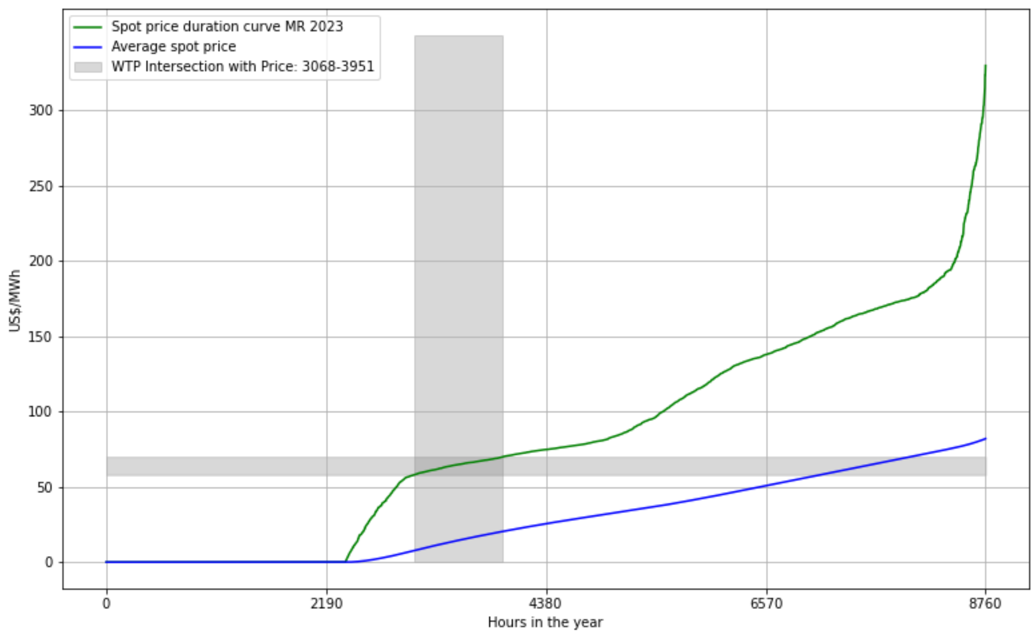
Note: These references include those used for future scenarios in Table 2.

6 Results

6.1 Current economic feasibility

We can see in Figure 6 the WTP short-term, represented by a constant band, and the price duration curve. Using the assumptions discussed in Section 4 and a price band between US$2.9 and US$3.5, we get a range of WTP short-term between US$58 and US$70, where the average WTP short-term is approximately 64 US$/MWh. By assessing the intersection between this constant and the price duration curve, we can see that the plant would be willing to operate approximately 3.500 hours (40%). Note that there is another curve in the graph, which represents the cumulative average spot prices of electricity in the Metropolitan Region.

Figure 8: Short term WTP, price duration curve and hours of operation

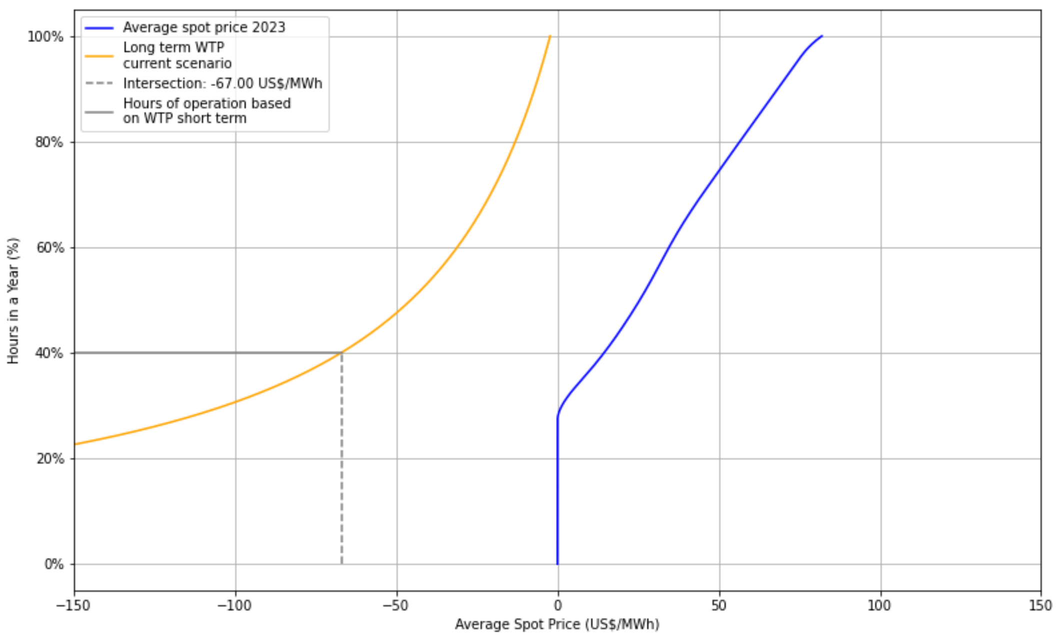


Note: Own elaboration using spot prices data from the website of the National Electrical Coordinator

Using all the parameters established for the hydrogen plant in the data section, the long term WTP is illustred in Figure 9, as well as the average spot price curve. The WTP long-term curve represents the different average electricity prices and % of hours of operation in the year where the plant is feasible. Note that the long-term WTP curve has a pronounced convexity, which is due to the high sensitivity to the electricity price. In the extremes of the graph, we can see that if the plant operates a bit over 20% of the year, is willing to pay an average price of electricity of -150 US$, and if operates the 100% of the year, is willing to pay a price less than 0 $US/MWh.

Therefore, is evident that there is no intersection between the long term WTP curve and the price curve, which means that under current conditions there is no price in the metropolitan region at which the plant can get feasibility, even though when the plant operates every hour of the year. If we replace the operating hours obtained in stage 1, as there is a positive correlation between hours of operation and average spot price, we consequently obtain a lower long-term WTP for electricity of -67 $US/MWh. As we are going to see in the following section, long term WTP could be located downwards if some relevant variables as the price of electrolysers, discount rate or hydrogen price changes in the future. In this case, as long as the average electricity price stays in the same place or further to the left, we could see an intersection.

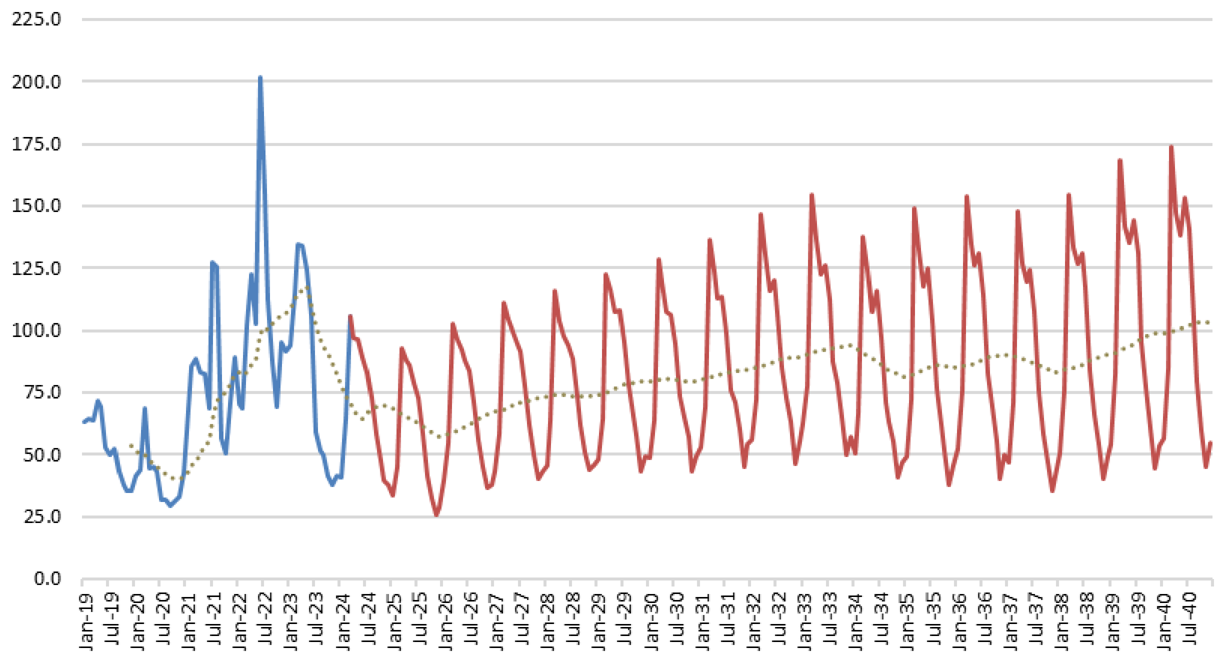
Figure 9: Long term WTP and average price of electricity



Note: Own elaboration using power capacity data from the website of the National Electrical Coordinator and previous results

6.2 Economic feasibility in the future

Figure 10: Monthly Spot Price in the Metropolitan Region



Note: Own elaboration using spot prices data and spot prices forecast from the website of the National Electrical Coordinator

Figure 10 shows the monthly average spot market prices for 2019-2023 in the Metropolitan Region in blue, as well as the National Electrical Coordinator forecast series for 2024-2040 in red. First of all, a pronounced monthly seasonality can be seen, with a minimum in the months of September-October and a maximum in the months of March. As discussed in previous sections, this is probably related to the availability of solar and hydroelectric generation. The high prices in 2021 and 2022 can probably be explained by the high fuel prices during the pandemic and the Ukraine-Russia war. The dotted line represents a 12-month media movement and tells us that after a price stabilisation in 2024, spot prices in the Metropolitan Region are expected to behave similarly in 2025 and start a constant increase for the next 15 years. We can also see that volatility is also expected to increase. As we said in the previous sections, a spot price forecast made by the National Electrical Coordinator is the best option to use to answer the research question of this thesis. However, we are also interested in understanding the explanation of the spot price in order to discuss under which scenarios this forecast can vary and therefore affect the feasibility of hydrogen production in the region, so in the absence of a document explaining the National Electrical Coordinator forecast, I specify a reduced form of the spot electricity price.

Figure 11: Yearly Average Spot Price in Metropolitan Region

Year	Average Price	Max.	Min.	Dif.
2019	53	72	35	37
2020	41	69	29	39
2021	82	127	50	77
2022	107	202	69	133
2023	82	134	38	97
2024	69	105	38	67
2025	57	93	26	67
2026	67	103	37	66
2027	73	111	40	71
2028	74	116	44	72
2029	80	123	43	79
2030	80	129	43	85
2031	84	136	45	91
2032	89	146	46	100
2033	94	154	50	104
2034	81	137	41	97
2035	85	149	38	111
2036	90	154	40	114
2037	83	148	36	112
2038	90	155	40	114
2039	99	168	44	124
2040	103	174	45	129

Using the National Electrical Coordinator spot price forecast and different scenarios for hydrogen production inputs, I construct Figure 12. Firstly, we can see in Figure 11 that according to the National Electrical Coordinator forecast, the annual average spot price is expected to be US$103MWh in 2040, which is 25% higher than the annual average spot price of US$82MWh in 2023. I calculate the forecasted average spot curve by applying this factor (1.25x) to the values of current average spot price curve. This transformation is based on the assumption that the number of hours with a value of 0 is the same, which is not so unrealistic as these zero values occur in hourly hours and this hardly changes from year to year. Also, there are many solar projects under construction, so the supply of solar energy is expected to increase significantly more than the demand. On the other hand, the band for the long-term WTP curve is constructed using the input values in Table 2. I assume that a pessimistic scenario for the future is the one where there are no improvements and the current values of the inputs remain. The other two scenarios, conservative and optimistic, consider favourable conditions in 6 variables: hydrogen price, electrolyser CAPEX, electrolyser efficiency, storage CAPEX and discount rate and taxes.

In Figure 12, we can see that under the conservative scenario input values, and the plant operating all hours of the year, the WTP for electricity from the plant is much higher than the WTP in the current scenario, going from almost US$0MWh to of US$25MWh. While in the conservative scenario the plant reach positive WTP long term values, is still not enough to reach feasibility. If we compare

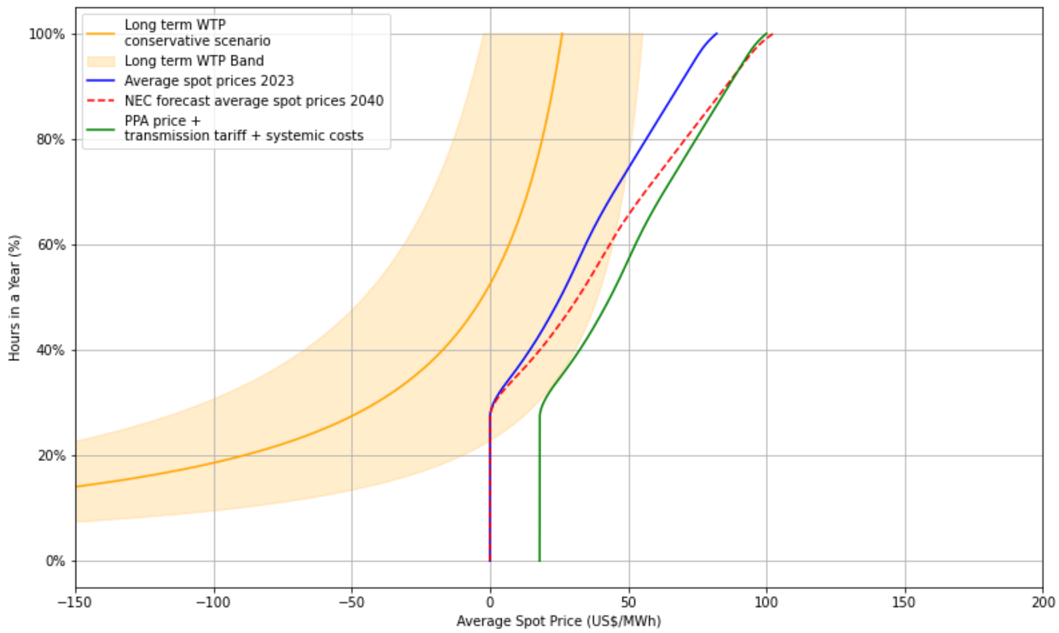
Table 2: Hydrogen plant input values for current and future scenarios

Parameters	Current Scenario	Conservative Future	Optimistic Future
Plant lifetime (years)	20	20	20
Discount rate (%)	10	8	6
Tax rate (%)	27	22	17
Electrolyser Stack lifetime (years)	8	9	10
Electrolyser Stack (% CAPEX)	40	40	40
LHV (kWh/kg H2)	33.33	33.33	33.33
Hydrogen price (USD/kg H2)	3.2	3.7	4.2
Electrolyser CAPEX (USD/kW)	1000	700	400
Electrolyser efficiency (%)	59	67	74
Storage CAPEX (USD/kg H2)	600	500	400
Water needed (L/ kg H2)	15	15	15
Installation & design (% CAPEX)	30	30	30
OPEX (% CAPEX)	7.5	5.5	4

the conservative scenario with the prices in 2023 and 2040, we can see that the maximum electricity price that the plant is willing to pay is only 50% and 45% of the year respectively, aproximately the half of the time that the plant should operate to be able to pay those prices. This allows us to demonstrate the importance of electricity prices and draw our first conclusion: Even if all 6 key inputs mentioned above take more favourable values in the future and the plant operates all year round, the high electricity prices are not allowing to reach feasibility. Now, under the optimistic scenario of the input values of the hydrogen plant, we can see that there is a significant intersection zone between WTP long-term curve and both average prices curve. It should be noted that this analysis is based on the assumption that the plant pays spot prices. It could be argued that this assumption is not so unrealistic, since these prices correspond to the opportunity cost of electricity for a hydrogen plant that decides not to connect to the grid but to produce its own renewable energy. However, this scenario implies significant additional costs, as own generation implies higher CAPEX, resulting in a more left-shifted long term WTP curve.

Since the spot market is only for electricity producers, the hydrogen plant has to sign a PPA with an electricity producer. If we calculate the average price of the forecasted prices between 2024 and 2040, we get a price of US$82MWh, which is coincidently the average price of electricity in 2023. Thus, we can assume that, in average, the blue curve is representative of the average electricity prices between 2024 and 2040, which in turn can be a good proxy of a PPA price for that period of time. With this, we could quickly conclude that by considering the blue curve as PPA prices and the optimistic scenario of the inputs values for the hydrogen plant, the plant is feasible and would be willing to pay 50$US/MWh operating 75% of time. However, as we have mentioned in the previous sections, signing a PPA and connecting to the grid implies additional costs than only the PPA price of electricity. In addition to this, free customers have to pay for connection to the grid. Transmission tariffs currently stand at 15 CLP/kWh, equivalent to around US$0.016/kWh (US$16/MWh). On top of this, Chilean law states that the systemic costs (energy losses and ancilliary services) have to be paid by the customers proportionally to their consumption, which can easily implied an adittional charge of US$3/MWh.

Figure 12: Forecast WTP LT and Average Price



Note: Own elaboration using spot prices data from the website of the National Electrical Coordinatorand, transmission tariffs and from the National Energy Commission, and previous results

Thus, adding the transmission tariffs and system costs to the blue curve, we arrive at a total cost of electricity for the plant that goes from US$18 to US$100MWh, represented by the vertical green line in Figure 12. Note that considering this total cost of electricity and the optimistic scenario, there is still a feasibility scenario where the plant is willing to pay 25$US/MWh when operating 35% of the year. This result is interesting, because allow us to conclude that there is a realistic scenario in the near future where hydrogen production in the Metropolitan Region can be possible by connecting to the grid. However, note that the intersection are between the lower band and the green curve is quite small and there is barely a point where the plant is feasible, which means that any unfavourable deviation either in the input values of the optmistic scenario or in the National Electrical Coordinator electricity price forecast, implies that the plant is no longer feasible. Before continuing with the discussion, is important to first understand the determinants of the electricity spot price in the Metropolitan Region.

6.3 Electricity price regression

In this section we discuss 3 models and then choose the better one to make our interpretations. The first model (Appendix Table 5) uses average daily spot prices as the dependent variable and includes all possible independent variables that can be added based on the available data. We can see a high F-statistic and R-squared, which at first glance tells us that the specified model is able to explain the dependent variable. However, high AIC and BIC values can indicate that the model is too complex, and it's easy to see that the coefficients don't make economic sense and follow the predictions of the theory, which can be explained by various problems with the model, but mainly related to the compliance with the OLS assumptions.

The second model uses average daily prices as the dependent variable, includes monthly and weekend dummies, excludes some of the independent variables used in the first model, lags the natural gas price by one period, replaces the demand variable with an instrument, and is estimated using the HC3 covariance to correct for heterocedasticity problems. We can see that the problems of autocorrelation and non-normality of the residuals, heterocedasticity and multicolinearity remain in this model. However, it should be noted that the coefficients are now significant and have economic meaning, in line with what was expected from the theory, which can be explained by i) the addition of monthly and weekend dummies, as well as the demand instrument, which probably corrected the endogeneity problems of the last model, and ii) the exclusion of some independent variables with low variation, which caused a large reduction in the number of conditions, partially solving the multicolinearity problem. Finally, the third model (Appendix Table 5) uses the hourly spot price as the dependent variable and the same independent variables as in model 2, but with the addition of hourly dummies. We can see that while the coefficients remain the same, all the problems mentioned above only increase.

As all variables have a significant effect in the direction expected from the theory, we choose the second model to interpret the results and later discuss the potential impact of electricity price determinants on the feasibility of hydrogen production. First, after controlling for months and weekend days, we see that an increase in fuel prices has a positive impact on the daily average of the spot price. On the other hand, we observe that an increase in the installed GW of solar technology lowers the price, as does an increase in the GW of coal technology. This is interesting because it allows us to conclude that the policy of closing down coal-fired power plants is likely to lead to an increase in the spot price. This is because, being to the left of other more expensive plants on the supply curve, the retirement of coal plants will imply the earlier dispatch of natural gas plants at times that were not previously dispatched. The effect of coal plant retirements could only be offset at night if the reduction in coal generation is replaced by stored renewable energy, such as solar or wind generation stored in BESS, or by an increase in hydro capacity.

Table 3: Spot electricity price regression results. Model 2.

Dep. Variable:	Electricity price	**R-squared (uncentered):**	0.864
Model:	Daily	**Adj. R-squared (uncentered):**	0.863
Method:	OLS	**F-statistic:**	757.4
No. Observations:	1826	**Prob (F-statistic):**	0.00
Covariance Type:	HC3	**Log-Likelihood:**	-8881.6
Df Model:	19	**AIC:**	1.780e+04
Df Residuals:	1807	**BIC:**	1.791e+04

	coef	**std err**	**z**	**P> |z|**	**[0.025**	**0.975]**
HH_lag	2.7	0.686	3.916	0.000	1.3	4.0
IMACEC1	0.7	0.215	3.429	0.001	0.3	1.2
Reservoir_Level	-0.7	0.078	-8.304	0.000	-0.8	-0.5
Solar_GW	-13.8	2.080	-6.632	0.000	-17.9	-9.7
Coal_GW	-31.5	8.072	-3.904	0.000	-47.3	-15.7
Diesel_GW	176.4	18.366	9.604	0.000	140.4	212.4
Month_1	21.2	2.896	7.334	0.000	15.6	27.0
Month_2	24.4	4.014	6.090	0.000	16.6	32.3
Month_3	49.5	3.665	13.496	0.000	42.3	56.6
Month_4	51.9	3.601	14.421	0.000	44.9	59.0
Month_5	48.7	3.681	13.234	0.000	41.5	55.9
Month_6	59.2	4.761	12.440	0.000	49.9	68.6
Month_7	47.2	4.068	11.597	0.000	39.2	55.2
Month_8	36.0	3.761	9.583	0.000	28.7	43.4
Month_9	11.3	2.337	4.821	0.000	6.7	15.8
Month_11	0.9	3.683	0.252	0.801	-6.3	8.1
Month_12	6.5	2.837	2.281	0.023	0.9	12.0
Day_of_week_Saturday	-11.2	1.941	-5.791	0.000	-15.0	-7.4
Day_of_week_Sunday	-18.7	1.838	-10.162	0.000	-22.3	-15.1

Omnibus:	554.388	**Durbin-Watson:**	0.512
Prob(Omnibus):	0.000	**Jarque-Bera (JB):**	2442.563
Skew:	1.391	**Prob(JB):**	0.00
Kurtosis:	7.936	**Cond. No.**	1.62e+04

On the other hand, we see that an increase in the installed capacity of diesel plants leads to an increase in the price of electricity, which is what we would expect from theory, given that these are the plants that are farthest to the right in the merit order, with much higher variable costs than natural gas plants. We also see that the level of water in the reservoirs reduces the price of electricity, which is to be expected, since the higher the level of water in the reservoirs, the more electricity the hydro plants can produce with variable costs equal to zero. On the demand side, we see that the level of monthly economic activity, used as an instrument to correct for the endogeneity problem associated with the use of electricity consumption, has been useful since a positive and significant effect is observed, as predicted by theory. Finally, using the month dummies, we observe that the autumn months have a negative impact on the price of electricity, which can be explained by the decrease in solar energy during these months and by the fact that reservoirs are at their minimum just before winter. With regard to the weekend dummies, we see that they have a negative impact on the electricity price, which is explained by a decrease in the residential demand on these days.

6.4 Discussion

In addition to the variables we identified in the regression that determine electricity prices, there are other variables that may change in the future and increase electricity prices in the metropolitan area. The National Electricity Coordinator's forecast probably assumes the official inauguration of the new Kimal-Lo Aguirre transmission line, which will converge electricity prices in the North and Central zones. However, if there are delays in this project, the reduction of solar energy in the north could be maintained for a while, resulting in higher electricity prices in the Metropolitan Region. On the other hand, Chile plans to increase its carbon tax from US$5 per tonne of CO2 to US$8 per tonne of CO2 and to phase out all coal-fired power plants by 2030. As we have seen in the literature section, such strong climate policies have a positive effect on electricity prices and therefore in hydrogen competitiveness. Rekker, Kessina and Mulder (2023) assess the feasibility of hydrogen production in the Netherlands and, by estimating a quantile regression, they predict price duration curves and determine break-even prices for hydrogen, concluding that strong climate policies leading to both higher fossil fuel prices and a higher share of renewables may increase the price of electricity and thus create less favourable conditions for hydrogen production, so that complementary regulation is needed if the aim is to stimulate green hydrogen [9].

We have to consider some limitations and assumptions made in this work, which may overestimate the feasibility of hydrogen production for different reasons. For example, we didn't include capacity payments, which currently make up a large part of the cost of electricity in Chile, but since renewable energy plants will no longer receive capacity payments in off-peak hours from 2027, we decided not to include them for simplicity. Besides, the PPA price does not take into account the risk premium that is typically added due to the volatility of the spot price. On the other hand, transmission costs are expected to increase slightly in the coming years, as well as do the systemic costs. Serra (2022) highlights that, due to the intermittent and unpredictable nature of renewables, one of the most important challenges associated with the rapid penetration of renewables in the Chilean market is the increase of the ancillary costs, which are part of the systemic costs.

7 Conclusions

This work assesses the future feasibility of green hydrogen production in the Metropolitan Region of Chile by comparing the willingness to pay for electricity from a grid-connected green hydrogen plant for different scenarios with a proxy of future electricity prices constructed using the electricity forecast of the National Electricity Coordinator and the transmission and ancillary costs of the market. First, we conclude that hydrogen production in the Metropolitan Region is not feasible under both the current and a conservative future scenario for plant inputs and current and projected electricity prices. We show that electrolyser CAPEX, storage CAPEX, electrolyser efficiency, hydrogen price, discount rate and taxes are key determinants and only very optimistic values for these variables could allow feasibility in the future. On the other hand, we show that the electricity price plays a crucial role and that under an optimistic scenario of hydrogen plant input values, the electricity price could determine whether the plant decides to operate. In this sense, what happens to electricity demand, installed capacity, fuel prices, hydro conditions and grid connection costs have a significant impact on the feasibility of hydrogen production in the Metropolitan Region.

From the above it can be concluded that the Metropolitan Region is not that far away from the feasibility of hydrogen production and that there are a number of variables that governments could intervene in to promote hydrogen projects in the region. For example, the Chilean government could consider introducing support schemes to ensure a certain level of revenue for projects (feed-in tariffs) or to reduce the initial investment in electrolysers and storage. Tax incentives could also be a good support policy as they are less costly than subsidies. Transmission tariffs and/or system cost exemptions for projects can also be very helpful for projects planning to connect to the grid. On the other hand, policies to encourage the development of BESS or hydropower, or a re-evaluation of the carbon tax and coal plant decommissioning policies could be beneficial not only for hydrogen production but also for household finances. Policies that reduce the risk of projects, such as hydrogen price guarantees, or that make project financing cheaper, such as green loans, reduce the discount rate of the project and can have important effects as well. Future work could analyse the feasibility, challenges and costs of transporting hydrogen from the north and south of the country to the Metropolitan Region. This would allow policy makers to broaden the information base and make the best decision to secure hydrogen supply in this region.

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9 Appendix

In the first model we can see, firstly a high skewness and kurtosis, resulting in Prob(Omnibus) = 0.000 and Prob(JB) = 0, indicate a significant departure from normality in the residuals. Second, the Durbin-Watson value of 0.537 is well below 2, indicating a positive autocorrelation of the residuals, which means that the standard errors may be underestimated and therefore the coefficients overestimated. Third, a high condition number indicates the presence of multicolinearity, which means that the regressors are highly correlated with each other. Fourth, the Breusch-Pagan test indicates the presence of heterocedasticity.

Table 5: Spot electricity price regression results. Model 1.

Dep. Variable:	Electricity price	**R-squared (uncentered):**	0.877
Model:	Daily	**Adj. R-squared (uncentered):**	0.876
Method:	OLS	**F-statistic:**	990.8
No. Observations:	1826	**Prob (F-statistic):**	0.00
Covariance Type:	nonrobust	**Log-Likelihood:**	-8793.1
Df Model:	13	**AIC:**	1.761e+04
Df Residuals:	1813	**BIC:**	1.768e+04

	coef	**std err**	**t**	**P> |t|**	**[0.025**	**0.975]**
Demand_GW	1.1497	0.065	17.770	0.000	1.023	1.277
HH_spot	-0.2088	0.802	-0.260	0.795	-1.783	1.365
Coal_price	-0.1354	0.026	-5.135	0.000	-0.187	-0.084
WTI_spot	0.8400	0.086	9.814	0.000	0.672	1.008
Reservoir_Level	-4.3320	0.273	-15.858	0.000	-4.868	-3.796
Solar_GW	-39.2410	4.648	-8.442	0.000	-48.358	-30.124
Hydro_GW	0.1099	11.362	0.010	0.992	-22.173	22.393
Wind_GW	-46.2663	6.312	-7.330	0.000	-58.645	-33.887
Diesel_GW	110.1177	18.500	5.952	0.000	73.834	146.402
Coal_GW	-127.7714	11.333	-11.274	0.000	-149.998	-105.544
NG_GW	581.7933	45.705	12.729	0.000	492.153	671.434
Inflation_Index	8.3187	0.842	9.883	0.000	6.668	9.969
IMACEC1	-0.6557	0.116	-5.656	0.000	-0.883	-0.428

Omnibus:	593.902	**Durbin-Watson:**	0.537
Prob(Omnibus):	0.000	**Jarque-Bera (JB):**	2973.621
Skew:	1.454	**Prob(JB):**	0.00
Kurtosis:	8.534	**Cond. No.**	5.17e+04

Dep. Variable:	MC_RM	**R-squared (uncentered):**	0.752
Model:	OLS	**Adj. R-squared (uncentered):**	0.751
Method:	Least Squares	**F-statistic:**	3543.
Date:	Fri, 17 May 2024	**Prob (F-statistic):**	0.00
Time:	15:09:10	**Log-Likelihood:**	-2.3094e+05
No. Observations:	43820	**AIC:**	4.620e+05
Df Residuals:	43778	**BIC:**	4.623e+05
Df Model:	42		
Covariance Type:	HC3		

	coef	**std err**	**z**	**P> |z|**	**[0.025**	**0.975]**
HH_lag	2.6915	0.230	11.710	0.000	2.241	3.142
IMACEC1	0.7431	0.070	10.581	0.000	0.605	0.881
Reservoir_Level	-0.6879	0.024	-28.698	0.000	-0.735	-0.641
Solar_GW	-13.7504	0.613	-22.438	0.000	-14.951	-12.549
Coal_GW	-31.8067	2.636	-12.065	0.000	-36.974	-26.640
Diesel_GW	176.2099	5.400	32.634	0.000	165.627	186.793
Month_1	21.2405	1.035	20.522	0.000	19.212	23.269
Month_2	24.3589	1.312	18.569	0.000	21.788	26.930
Month_3	49.3900	1.094	45.146	0.000	47.246	51.534
Month_4	51.8437	1.100	47.129	0.000	49.688	54.000
Month_5	48.6095	1.143	42.542	0.000	46.370	50.849
Month_6	59.1224	1.387	42.632	0.000	56.404	61.841
Month_7	47.1238	1.181	39.906	0.000	44.809	49.438
Month_8	36.0147	1.131	31.851	0.000	33.799	38.231
Month_9	11.2817	0.838	13.463	0.000	9.639	12.924
Month_11	0.9087	1.271	0.715	0.475	-1.582	3.399
Month_12	6.5033	1.074	6.055	0.000	4.398	8.608
Day_of_week_Saturday	-11.2413	0.621	-18.097	0.000	-12.459	-10.024
Day_of_week_Sunday	-18.6547	0.602	-30.977	0.000	-19.835	-17.474
Hour_0	42.5140	1.544	27.529	0.000	39.487	45.541
Hour_1	37.4937	1.482	25.298	0.000	34.589	40.399
Hour_2	33.7007	1.450	23.239	0.000	30.858	36.543
Hour_3	31.9388	1.428	22.373	0.000	29.141	34.737
Hour_4	32.0145	1.422	22.521	0.000	29.228	34.801
Hour_5	34.6848	1.436	24.154	0.000	31.870	37.499
Hour_6	40.7920	1.486	27.442	0.000	37.879	43.705
Hour_7	33.4635	1.470	22.758	0.000	30.582	36.345

Hour_8	10.3074	1.499	6.876	0.000	7.369	13.245
Hour_9	3.8666	1.543	2.506	0.012	0.843	6.890
Hour_10	6.0136	1.567	3.836	0.000	2.941	9.086
Hour_11	5.5989	1.566	3.576	0.000	2.530	8.668
Hour_12	3.0627	1.573	1.947	0.052	-0.020	6.146
Hour_13	1.0270	1.599	0.642	0.521	-2.106	4.160
Hour_15	-0.1577	1.641	-0.096	0.923	-3.374	3.058
Hour_16	5.1592	1.642	3.141	0.002	1.940	8.378
Hour_17	18.1396	1.763	10.290	0.000	14.685	21.595
Hour_18	30.8425	1.793	17.205	0.000	27.329	34.356
Hour_19	51.9870	1.687	30.824	0.000	48.681	55.293
Hour_20	65.0152	1.779	36.551	0.000	61.529	68.501
Hour_21	64.8619	1.778	36.477	0.000	61.377	68.347
Hour_22	58.8596	1.703	34.560	0.000	55.522	62.198
Hour_23	51.7518	1.618	31.982	0.000	48.580	54.923

Omnibus:	12541.596	**Durbin-Watson:**	0.221
Prob(Omnibus):	0.000	**Jarque-Bera (JB):**	52985.018
Skew:	1.358	**Prob(JB):**	0.00
Kurtosis:	7.653	**Cond. No.**	1.76e+04