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Integration of Green Hydrogen in the Chilean Industry: the case study of copper mining CAEX hauling trucks

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Abstract

Green hydrogen is becoming a key pillar in today's energy transition towards decarbonization due to its advantageous qualities as a carbon-free energy carrier. Fast-growing economies with vast amounts of renewable energy sources like Chile are positioning to be majors green hydrogen producers in the near term due to the cheap electricity that can be achieved from solar PV or onshore wind energy. In this work, an overview of the main Chilean industries and most promising technological opportunities for integrating green hydrogen was done and it was found that the copper mining industry has the potential of decarbonizing the transportation of extracted materials in open pit mines with the replacement of diesel with green hydrogen in CAEX hauling trucks through the retrofit with dual hydrogen (60%) - diesel (40%) internal combustion engines (H_2ICE) or reconversion into fuel cell electric vehicles (FCEV).

Three major mining zones where identified and the potential hydrogen demand for the major copper mines in this zones was estimated for future scenarios considering the mines lifetime, energy projections and hydrogen market penetration of 10% by 2030 and 37% by 2050. On average, each H_2ICE and FCEV trucks would need 600 and 1,000 kg of hydrogen respectively. A sub-area from Zone 1 in the north of Chile was selected as case of study and the levelized cost of hydrogen (LCOH) was calculated for different configurations considering off-grid plants and on-grid plants with PPA. The lowest LCOH achieved was of 3.11 $/kg with an oversized off-grid solar plant by 2030 and the lowest LCOH for 2050 was 1.44 $/kg obtained with CSP + TES. In order to ensure competitivity with diesel, green hydrogen should be lower than 2.80 $/kg, so economies of scale have to be achieved and electrolyzers capital investments cost have to be reduced at least down to the range of 600 – 700 $/kW in 2030 for being able to produce cheap and competitive solar green hydrogen in Chile.

An estimation was done of the potential size and design of a green hydrogen supply chain from on-site solar hydrogen production to the hydrogen refueling stations (HRS) in each copper mine of the case of study. The most significant annual hydrogen demand was of 4,103 ton in Centinela mine for 17 H_2ICE trucks or 10 FCEV trucks that would require a HRS with daily capacity of 11,241 kilograms and a H_2 plant of 82 MW coupled with a solar PV plant of 114 MW. Finally, an analysis about the truck's on-board storage challenge was performed considering crucial parameters like refueling filling rates, tanks weight, space availability and diesel truck's performance. Globally, with today's existing HRS technologies and standards, there is no an optimum storage configuration that could match the same operational performance than diesel CAEX trucks unless a much more competitive price of green hydrogen could compensate the potential economic losses due to higher filling times, frequency or extra weight. A reasonable range of on-board capacity storage system could be of 75 – 300 kilogram with type IV tanks at 350 or 700 bar for H_2ICE and FCEV retrofitted CAEX trucks.

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Glossary

AWE: Alkaline Water Electrolysis .

BTE: Brake Thermal Efficiency.

BMEP: Brake Mean Effective Pressure.

CAPEX: Capital expenditures.

CAEX: Camión de Extracción – Extraction Truck.

C_{EL}: Electrolyzer specific electric consumption.

CF: Capacity Factor.

C_{LPS}: Low pressure storage capacity.

FCEV: Fuel Cell Electric Vehicle.

GH_2: Gaseous Hydrogen.

HRS: Hydrogen Refueling Station.

H_2: Hydrogen.

H_2ICE: Hydrogen dual fuel Internal Combustion Engine.

HDV: Heavy Duty Vehicle.

ICE: Internal Combustion Engine.

LH_2: Liquid Hydrogen.

LCOH: Levelized Cost of Hydrogen.

M_{H2}: Annual Hydrogen demand.

OPEX: Operational expenditures.

PEM: Polymer Electrolyte Membrane Electrolysis.

P_{H_2}: Hydrogen load.

P_{H_2}: Electrolyzer capacity.

RES: Renewable Energy Source.

SOE: Solid Oxide Electrolysis.

W_c: Compressor capacity.

1. INTRODUCTION

1.1. Context

One of the most challenging problems nowadays in the world is the global warming menace, which it has already shown some hints of what devastating consequences it can produce in the future as wildfires, droughts and heat waves are increasing, big ice caps are melting and sea level is rising. The earth is gradually increasing its temperature mainly because of the greenhouse effect produced by gas emissions generated by human activities like transportation, energy production, industry and agriculture among others, where carbon dioxide (CO_2), vapor (H_2O) and methane (CH_4) are the main greenhouse gases contributing to this effect. Almost every human activity requires energy and practically all the energy produced by humankind in the last century came from the burning of fossil fuels such as coal and oil, which produces considerable amounts of CO_2 emissions and other toxics and harmful gasses.

As the climate crisis escalates at the same time the world's energy demand increases, it is imminent to double the efforts of replacing fossil fuels with cleaner energy sources in order to reduce greenhouse gas emissions and hope achieving a carbon-free future, or at least as close as possible. The biggest efforts to battle climate change have been concentrated in shifting energy from fossil fuels to energy from renewable sources, such as solar, wind, biomass and ocean energy. According to the IEA, the share of renewables in global electricity generation jumped from 20% in 2010 to 27% in 2019 and to 29% in 2020 where renewable energy use increased in 3%, driven primarily by a 7% growth in electricity generation from renewable sources as demand for all other fuels declined (IEA, 2020).

Even thou renewable energies are increasing exponentially as costs decrease and economies of scale are reached, the targets established by the Paris Agreement to keep global temperature rise bellow 2 °C and push the efforts to limit temperature increase even lower to 1.5 °C are still considered slightly ambitious and yet seem far away to achieve considering all the efforts done until now. Major investments in renewables must be matched by the increase of storage technologies and energy efficiency as this type of energies depend on the availability and intermittency of the resource (water, sun, wind). This characteristic of renewable energies makes them less efficient as lower capacity factors are achieved compared to fossil fuels power plants which may operate at any time during the day, with much higher capacity factors and consequently, they can satisfy great part of the energy demand, specially the higher energy requirements during peak hours. Replacing fossil fuels completely with renewable energy would require a considerable ramp-up in manufacturing capacity of solar panels and wind turbines considering the fact that fossil fuels account for almost 84% of the world's energy use (IRENA, 2017) and that replacing a typical 1,000 MW fossil fuel power plant would require huge solar or wind power plants. By 2030, yearly build-outs of solar and wind capacity would need to be eight and five times larger, respectively than today's levels (Mckinsey, 2021).

The decarbonization pathway not only relies in the transition of producing energy from fossil fuels to renewable energies, it also considers the fast integration of innovative clean energy technologies to decarbonize heavy industry, the building sector and the transport sector. This technologies include batteries, electrification, carbon capture, advanced biofuels and hydrogen. This last one, is being considered in the past few years as the new key player in the zero-carbon pathways due to its exceptional and unique properties that make it a powerful enabler for the energy transition when produced with electricity from renewable energy, offering advantages and benefits not only in the energy systems but also for end-use applications. Today's trend of producing electricity from renewables allows a perfect integration of hydrogen in the global energy market, especially in fast growing economies with vast amount of renewable sources like Australia, Saudi Arabia and Chile. The last one is an interesting case to study as this country is positioning itself among the most attractive countries to invest in renewable energies due to its unique geography (very large and narrow) that offers the best solar radiation of the world in the Atacama Desert, strong winds in the Patagonia, geothermal reserves in Cordillera de los Andes, hydropower and waves energy potential along the 4,000 km land and coast. In fact, Chile is considered as a hidden champion of green hydrogen and is in a favorable position to achieve the lower costs of green hydrogen production in the world.

1.1.1. Green Hydrogen: a key role in the energy transition

Hydrogen is the simplest and most abundant molecule in the universe but it cannot be found freely in its natural state, so to obtain it, it is necessary to separate it from other substances by using primary sources like fossil fuels, biomass or water. For this reason, hydrogen is not an energy source but instead it is considered as a versatile and clean energy carrier. Hydrogen can play an important role in the decarbonization of the major sectors of the world economy as it can be used in industry, power and transport applications. The Hydrogen Council defined in 2017 some key roles hydrogen will play in the energy transition:

-Hydrogen can improve the efficiency and flexibility of the energy systems as it is possible to convert via electrolysis the excess of electricity into hydrogen during times of oversupply and then can be used as back-up power during power deficits or used in other applications in industry, transport or residential. This advantage of hydrogen comes as a solution for the mismatching between the variable electricity supply of renewables and the power demand, which automatically reduces the energy curtailment problem of this type of intermittent energy source. The capability of hydrogen to switch on and off as quickly as gas does, gives the necessary flexibility and reliability to maintain the resilience of the system in case of sudden drops of renewable energy supply and hence, avoiding major disbalances in the network. Added to this, hydrogen also represents an optimal opportunity to solve long-term, carbon-free seasonal storage challenges as they have better power capacity or the necessary storage timespan to address seasonal imbalances compared to other type of storage technologies like batteries, compressed air, super-capacitors or even pumped hydro which is sensible to geographical conditions.

-Countries with less renewable energy opportunities may found more attractive economically to import renewable energy from countries with vast renewable resources. Hydrogen can make this happen by exploiting its high energy density that gives the opportunity of storing higher amounts of energy and furthermore, transport it over large distances to other areas by using pipelines, ship carriers or liquid/gaseous tube trailers. However, costs of liquefaction and transport need to drop in order to make hydrogen transportation economically viable. The use of existing gas grids to transport hydrogen is another application considered to integrate hydrogen in current energy systems at larger scale.

-Transport decarbonization is an important pillar of the energy transition, where fuel cell electric vehicles (FCEV) have a crucial role to play in nowadays transport sector dominated by gasoline and diesel. Despite the progression of efficient hybrid vehicles like hybrid electric vehicles (HEV) and plug-in hybrid electric vehicles (PHEV), decarbonization of transport needs imperatively the integration of zero-emission vehicles like FCEV and battery electric vehicles (BEV), or hybrid combinations. In the case of FCEVs, the use of hydrogen allows to drive long distances without needing to refuel before 500 kilometers of driving, they can refuel as quickly as current gasoline/diesel cars and it's infrastructure can build on existing gasoline distribution and retail infrastructure. Another application already explored is the integration in the transport market of synthetic fuels made up of green hydrogen. At last, the total cost of ownership (TCO) of FCEV needs to drop in order to be competitive to current internal combustion engine (ICE) and to reach a larger scale commercialization and penetration not only in the passengers transportation but also in heavy duty and long-range transportation.

-Hydrogen offers a zero-emission alternative for heating in the industrial applications. The decarbonization of industry energy use can be possible by integrating the combustion of hydrogen in the chemical industry where hydrogen is available as by-product where it can be burned to satisfy internal heat demands and fuel cells can provide power in specific industries that need uninterruptable power supply.

-Building heating can use hydrogen as fuel or leverage hydrogen technologies, or a combination of both like fuel cell micro CHP's energy converters, offering higher efficiencies in buildings connected to a natural gas grid and the opportunity of decarbonizing the heating and warm water supply in the residential sector with just small investments and adjustments in the grid (Hydrogen Council, 2017).

1.1.2. Global Hydrogen status

The total world demand of hydrogen in 2020 was around 90 Mt, in which more than 50 Mt were consumed by industry, specifically the chemical production consumed 45 Mt of H_2 as feedstock for the production of 34 Mt of ammonia and 11 Mt of methanol. The rest of the demand came from refineries which used 40 Mt of H_2 as feedstock and reagents for the oil refinement processes, the steel industry consumed 5 Mt of H_2 for the direct iron reduction (DRI) process and less than 1% of the total H_2 demand came from other applications like food and glass production. Almost all the global demand was met by hydrogen production from fossil fuels, with a 59% participation of natural gas and 19% of coal. By-product hydrogen produced in industries designed for other type of products like oil refineries accounted for 21% of the global production and other type of sources such as oil, biomass or water electrolysis represented no more than 1% (IEA, 2021).

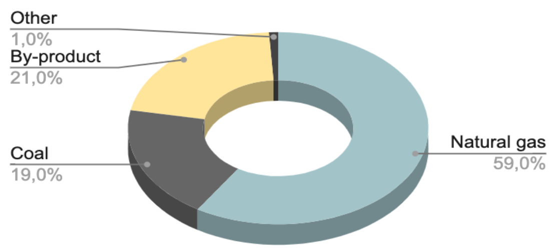

Figure 1: Global hydrogen production by source. (IEA, 2021)

Hydrogen can be produced from different type of energy sources and technologies, it can be extracted from fossil fuels and biomass, or from water using electricity. It is often classified by colors, where green, blue, black, grey and brown refer to hydrogen produced by renewable electricity, fossil fuels with CO_2 capture, coal, natural gas and lignite respectively.

H_2 from natural gas

The majority of the hydrogen produced nowadays come from fossil fuels, especially from natural gas and the most widespread and mature technology is steam methane reformation (SMR), in which 30 - 40% of natural gas is combusted to fuel the process where hot steam at 700 - 1,000 °C reacts with the rest of natural gas or methane at 3 - 25 bar in the presence of a catalyst to produce hydrogen, carbon monoxide, and a relatively small amount of carbon dioxide. Subsequently, in what is called the "water-gas shift reaction," the carbon monoxide and steam are reacted using a catalyst to produce carbon dioxide and more hydrogen. In a final process step called "pressure-swing adsorption," carbon dioxide and other impurities are removed from the gas stream, leaving essentially pure hydrogen. SMR has favorable economics and good efficiencies and will remain in the near term the dominant technology for hydrogen production in large scale.

Hydrogen produced by fossil fuels is very CO_2 intensive, almost 10 kg CO_2/kg H_2 is produced from natural gas, 12 kg CO_2/kg H_2 from oil products and 19 kg CO_2/kg H_2 from coal. For this reason, efforts are being made to increase carbon capture and storage (CCUS) in hydrogen production as only 1% includes this type of technology in what is called the blue hydrogen. Blue hydrogen plants can reduce their carbon emissions up to 90% depending on how CCUS is integrated in SMR plants (IEA, 2019).

H_2 from coal

Hydrogen can also be produced with the process of coal gasification, a well-established technology dominated by China, which operates more than 80% of the existing 130 coal gasification plants in the world mainly used in the chemical and fertilizer industries for the production of ammonia. This type of hydrogen production technology generates almost as twice CO_2 emissions than natural gas (IEA, 2019). The gasification process consists in the partial oxidation of coal which is chemically transformed into synthetic gas. This gas may include some or all of the outputs that may generally contain CO, H_2, CH_2, ash, tar, H2S, NH_3, HCl and HCN. The product gas then needs to be purified from the contaminants, particles and some other substances which really decrease its calorific value by applying various gas clean-up processes like water gas shift (WGS), and the useful gases, such as CO, H_2 and CH_4 are separated accordingly. In the gasification process, it is clear that four different types of coal are generally utilized in a suitable manner which are lignite, sub-bituminous coal, bituminous coals, and anthracites. However, it is important to note that, according to the open literature, these materials are generally gasified at higher temperatures than 900 °C by applying the techniques like fixed bed gasification, moving bed gasification, fluidized bed gasification, entrained flow gasification and plasma gasification (Midilli, 2021).

H_2 from water electrolysis

Hydrogen production from water electrolysis consists basically in decomposing water molecules into hydrogen and oxygen by flowing electricity between two electrodes plates separated by a electrolyte solution. A direct current (DC) is applied to the system and electrons flow from the negative terminal of the DC power source to the cathode, where they are consumed by hydrogen ions (protons) to form hydrogen atoms. In the general process of water electrolysis, hydrogen ions move toward the cathode, whereas hydroxide ions move toward the anode. A diaphragm is used to separate the two compartments. Gas receivers are used to collect hydrogen and oxygen gases, which are formed at the cathode and anode, respectively. There are mainly three types of water electrolysis technologies: Alkaline Water Electrolysis (AWE), Solid Oxide Electrolysis (SOE) and Polymer Electrolyte Membrane Electrolysis (PEM). A brief description of this technologies is discussed next.

Alkaline Water Electrolysis (AWE)**:** It is a mature technology and commercially established up to the megawatt level. Initially in this process two molecules of alkaline solution (KOH/NaOH) are reduced into one molecule of hydrogen (H_2) and two hydroxyl ion (OH-) in the cathode. The hydroxyde ions are transferred through the electrolyte to the anode where they are oxidized into half a molecule of oxygen (O_2) and one molecule of water (H_2O) and they lose electrons that return to the positive terminal of the DC power source. A diaphragm is used as separator between the anode and cathode to avoid the mixing of produced gases and typically nickel based metals are used as electrodes. Alkaline electrolysis operates at lower temperatures such as 30 - 80 °C, have limited current densities below 400 mW/cm2, low operating pressure and low energy efficiency (Kumar, 2019).

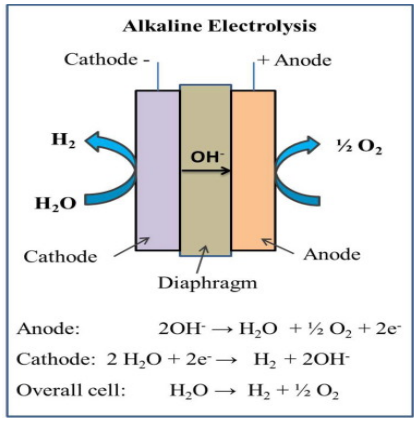

Figure 2: Alkaline Electrolysis system description. (Kumar, 2019)

Polymer Electrolyte Membrane (PEM): Instead of using a potassium hydroxide electrolyte solution like the alkaline water electrolysis (AWE), PEM electrolysis uses a solid polymer membrane as electrolyte where water molecules and ionic particles are transferred across it from the anode to the cathode, where it is decomposed into oxygen, protons and electrons. The electrons exit the cell through an external circuit and recombine with protons at the cathode to release hydrogen gas. PEM electrolysis has become interesting due to its compactness, higher energy density, high purity hydrogen production, higher operating pressure and offer flexible operation which make it more suitable to integrate it with intermittent renewable energy than AWE electrolysis. However, PEM electrolysis requires expensive electrode catalysts like platinium and their stack lifetime is shorter than AWE (Rahim, 2016).

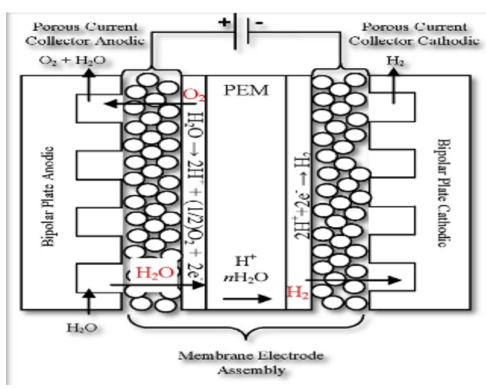

Figure 3:PEM electrolysis system description. (Rahim, 2016)

***Solide Oxide Electrolysis (SOEC)*:** It is the least developed electrolysis technology and is not yet at a commercial level. The working principle of SOECs can be considered as the reverse operation of solid oxide fuel cell (SOFC). In the cathode, water steam is reduced to hydrogen and oxygen ions, which in turn migrates through the solid electrolyte towards the anode and oxidizes to form oxygen gas by releasing electrons. SOECs operate with high temperatures, low pressures and uses ceramic as electrolyte and nickel-based ceramics for electrodes. One of the key challenges for the development of SOEC electrolyzers is the degradation of materials that results from the high operating temperatures by using steam (Pandiyan, 2019).

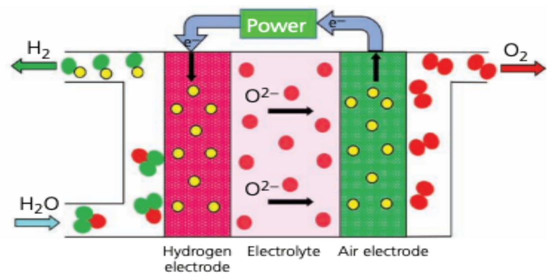

Figure 4: SOEC electrolysis system description. (Pandiyan, 2019)

1.1.3. Chile: Potential Green Hydrogen leader

Today green hydrogen is still far from being competitive with fossil fuel based hydrogen as electrolyzers capital investment and expenditure (CAPEX) is high due that the technology is still in an early stage and electricity is no cheap everywhere in the planet, especially if compared to the low prices of natural gas, oil or coal in the main countries producers of hydrogen. However, in countries with vast amount of renewable energy sources, electricity costs are dropping considerably and green hydrogen is becoming attractive to develop in this areas. This is the case of Chile, an emerging country with a fast growing economy, stable political context and unique renewable energy potential that has positioned itself as one of the selected group of countries to enable and lead the energetic transition.

In order to understand the potential of Chile on becoming a top producer of green hydrogen, it is necessary to contextualize some crucial aspects regarding its historic energy matrix, economy indicators, renewable energy expansion, climate change contribution and analysis of the industry in order to identify the key industrial sectors where green hydrogen could be integrated and furthermore, produced at large scale to satisfy its internal demand and supply international markets.

Historical energy matrix: from hydro to fossil fuels and renewables

Chile's historic energy matrix has been characterized by an important share between hydroelectricity and fossil fuels, in fact, 1980's energy grid was composed by hydroelectricity with 61% of the market share and fossil fuels 37% (CNE, 2021). In 1982, Chile become the first country in the world to privatize the energy sector, separate generation, transmission, distribution and to develop the first system of free competition in which prices autoregulate by market competition without the intervention of the State. This happened in the context of a military dictatorship government installed in Chile since 1973 after a coup organized by General Augusto Pinochet to the democratic government leaded by marxist president Salvador Allende.

At the end of the 90`s, due to the increasing energy demand and vulnerability to hydroelectric shortages added to the lack of fossil fuel resources in the country, Chile started exporting cheap natural gas from Argentina which lead to important investments (pipelines and natural gas power plants), high competitive market and consequently lower prices of electricity. Unfortunately, in 2004 Argentina decided to cut the exportations towards Chile due to internal political problems, economic crisis and high domestic energy demand that produced a natural gas deficit in the country. In response, Argentina's president Nestor Kirchner prioritized the internal energetic demand and domestic economy assuming the international repercussions that his decision would have in the international political scenario. This cuts of natural gas supply forced companies in Chile to secure their operation by using other types of fuel like oil, forced to operate coal power plants and new natural gas import taxes where established, all this raised the economic cost of Chilean companies and had important economic consequences for the country as the price of energy raised. But the harder impact on Chile's economy was in fact the increase of the international prices of oil and coal. Even though the interruptions of natural gas supply from Argentina started in 2004, it was in 2006 when the higher cuts of supply where registered, surpassing 50% of the internal domestic gas requirements and reaching almost 80%. This situation occurred at the same time oil and coal international prices increased, which tackled Chile's economy by raising internal oil derivative fuels and electricity prices in 11.2% and 7.1% respectively and depleted the country growth potential by lowering the industry growing rate and GDP (Huneeus, 2007).

As oil and coal started to increase, specially diesel oil, to compensate the Argentinian natural gas shortages and the critical droughts along the country that reduced the hydroelectric generation, the global financial crisis in 2008 occurred and affected the supply of crude oil worldwide. So in this context, Chile was forced to supply the energetic demand growth by depending more on coal and the production of energy based in this fossil fuel started to increase significantly between 2010-2013 mainly due to the inauguration of coal power plants like Nueva Ventanas (227 MW), Angamos (558 MW) and Campiche (272 MW) among others. This boost in coal utilization for energy production made this fossil fuel to be the most used energy source in the Chilean matrix until now (Yañez, 2017).

Renewable Energy expansion

The political and economic stability have made Chile one of the fastest growing economies in South America over the past decade. The economic growth of the decade started in 2010 after the great recession, the devastating 8.8 earthquake and the new government leaded by the elected president Sebastián Piñera. The economic growth rate in 2010 reached 5.2%, mainly due to the efforts of reconstruction after the earthquake that lead to an economic dynamism headed by private consumption that increased the internal demand and almost all economic sectors like electricity, gas and water (+13.7%), commerce (+13.3%), communication (+10.5%) and transport (+8,5%) except for the fishing (-13.7%) and industry sector (-1%) which were affected by the earthquake (AmericaEconomía, 2010). The following years the growth rate reached 6.1% in 2011, 5.3% in 2012 and start decreasing in 2013 when it reached 4% (Banco Central, 2014). Even thou the economy started slowing down since 2013, that same year the energetic grid extension Law 20.698 settled a goal of 20% of ERNC (Non-Conventional Renewable Energy) share by 2025, opening the path to important investments in renewable energy for the next decade. It is important to mention that Chile considers as ERNC solar, wind, biomass, geothermal, waves and just mini hydro (up to 20 MW). In 2014, Chile took an important step towards the decarbonization of the grid by enacting a carbon tax of US$ 5 on each metric ton of CO_2 emitted by thermal power plants with a generation capacity of at least 50 MW (IEA, 2021).

Chile was part of the top ten countries that invested more in renewable energies in 2015 with US$ 3,400 million, representing a 141% growth respect of the previous year, only South Africa had a higher growth with 337% (FS-UNEP, 2016). This same year Chile's government released the 2050 Energy Agenda establishing the pillars of a more sustainable energy market, and a new target of 70 % renewable energy market share by 2050. Therefore, this confirmed the intentions of Chile to be part of the world's leaders in renewable energy in the next decades. By 2016, Chile was already the largest producer of solar energy in Latin America with 21 projects for a total installed capacity of 1,102 MW corresponding to 5% of the total 22,045 MW energetic grid, much more if compared to 2012 where only one solar project was installed. In 2019 the energy matrix of Chile was of 25,406 MW and the solar capacity almost doubled with 2,160 MW, wind energy capacity was 2,795 MW and hydro 6,807 MW, the rest installed capacity of the country consisted in fossil fuels where natural gas and coal dominated. At the end of the year, US$ 2,796 million were invested in new renewable projects that already had their environmental evaluation approved, which corresponds to almost 74% of total new energy generation projects in that year (CNE, 2020).

Chile's Energetic matrix: Production and Consumption

Today, Chile's net annual energy generation is still dominated by fossil fuels but the installed capacity in the country is changing as fossil fuels are losing their participation in the energetic matrix as fast as renewable energy grow. There is already 32% of the net installed capacity grid of 27,486 MW contributed by renewables in which 16% corresponds to solar energy and 12% to wind energy. Fossil fuels has a participation of 46% lead by coal with 17% and conventional hydroelectricity represented 22 % of the grid share. In the following figure, the energetic matrix of Chile is shown with more detail:

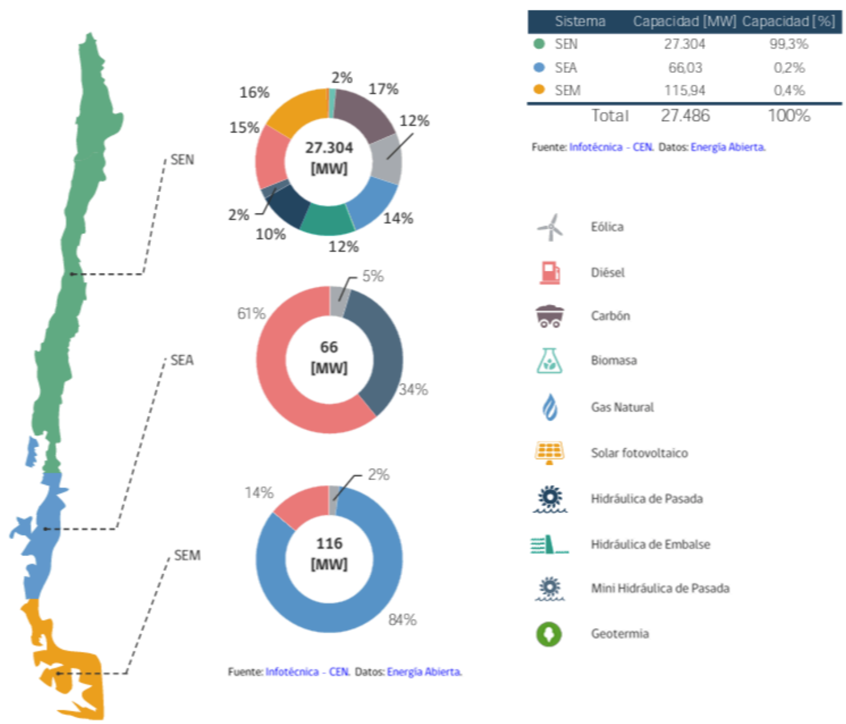

Figure 5: Net installed capacity by technology until January 2022. (CNE, 2022)

According to the Exempt Resolution N 441 that "Update and Communicate projects in construction", in the National Electric System (SEN) a total of 185 energy generation projects where recorded until December 30 of 2021 as projects under construction, reaching an electric capacity of 5,602 MW which have an estimate operation start between December 2020 and October 2024. Of the totality of projects under construction, the majority correspond to renewable projects, specifically 3,572 MW are photovoltaic projects and 696 MW wind plants. This information is key to support the fact that Chile can easily achieve higher ERNC installed capacity than fossil fuels in the next five years from now on.

In terms of energy consumption, the matrix can be divided in two criteria: final consumption by energy source and consumption by sector. According to the Energy National Commission (CNE), in 2018 the energy sources that dominated the energy consumption matrix were diesel (30%), electricity (22%), biomass (13%) and gasoline (12%). The energy source that varied the most in the last decade was biomass, from 18% to 13%, which is mainly due to the fact that firewood is still a dominating source for heating in Chile especially in the colder areas in the south and because of the critical contaminating emissions it produce, biomass has been replaced gradually with more efficient and low-carbon heating systems that use mainly natural gas. In the following figures, the detail of the energy consumption matrix is shown:

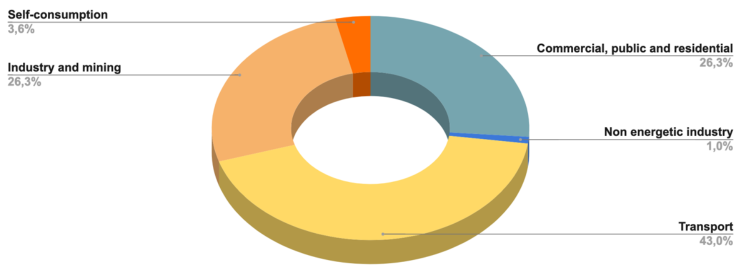

Figure 6: Final consumption matrix by type of sector in 2018. Own elaboration based on CNE.

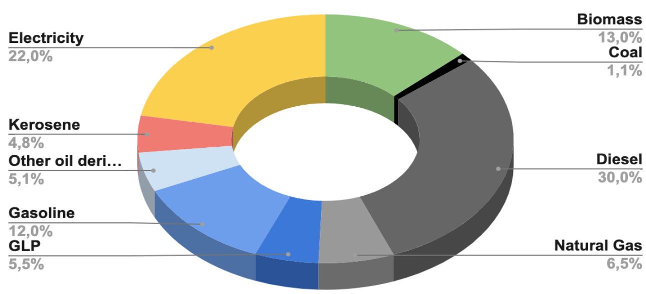

Figure 7: Final consumption matrix by type of energy source in 2018. Own elaboration based on CNE.

Chile and climate change

Even thou Chile is a low-emission country compared to the biggest polluting nations such as China, U.S.A, India and the U.E, it is not exempted from the global climate crisis, in fact, as it is a country with different climates, rich biodiversity and unique geography it makes it very vulnerable to climate change and is already suffering its consequences. According to the United Nations Framework Convention on Climate Change (UNFCCC), Chile fills almost all the key vulnerability criteria defined by the convention, including territories susceptible to drought, desertification and natural disasters, low coastal areas, urban areas with critical atmospheric pollution extensive, forest, desertic and mountain ecosystems. In the period 1961 - 2019 the average temperature increased 0.13 °C per decade, the second driest year since 1981 was 2019 with a rain deficit of 23% (Environment Ministry, 2020). According to the last Climate Change Actualization report of Chile, the total greenhouse emissions in 2018 was 112,312 kTon CO_2 eq., in which 77% corresponded to the energy sector that is divided in electric industry, transportation, manufacture-construction sector and others (UNFCC, 2020).

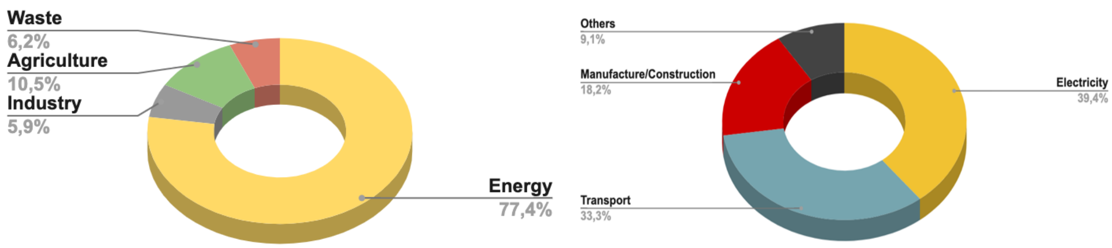

Figure 8: Chile's CO_2 emissions by sector and energy subsectors. (UNFCC, 2020)

GHG	kTon CO2 eq.	%
CO_2	87,603.8	78
CH_4	14,600.6	13
N_2O	6,738.8	6
HFC / SF6	3,369.4	3
Total	112,312.6	100

Table 1: GHG emissions breakout by type of contaminant. (UNFCC, 2020)

1.1.4. Production and demand of hydrogen in Chile

Chile's production of hydrogen is mostly based in the technology of steam methane reformation (SMR) and only few companies produce it. One of them, Hidrógeno Biobío S.A (CHBB) has two plants with capacities of 25,000 Nm^3/h and 6,000 Nm^3/h in charge of the supply of high purity hydrogen to ENAP's Biobío refinery located in Hualpén (VIII Region) and implements a CO_2 recovery system avoiding almost 48% of the emissions from the reformation process. The other main company is Linde Chile S.A which has a plant with capacity of 4,200 kg/h of hydrogen at 21 bar and 30 °C for supplying the demand of 3,003 kg/h from the refinery Aconcagua, also property of ENAP. This plant also distributes hydrogen to external clients with a total demand of 4,500 kg/month. At last, the company Indura operates two small electrolysis plants, one with a capacity of 200 Nm^3/h that supplies the requirements for the process of tin bath for float glass production of the company Lirquen and another plant that supplies hydrogen to Graneros Air Separation Unit (ASU) plant. (CDT, 2019) Assuming a capacity factor of 90 - 95% for the SMR plants and electrolysis plant, it can be estimated that around 55,000 - 58,000 ton of hydrogen can be produced in Chile.

The majority of hydrogen used in Chile is applied for the production of fuels via hydrocracking and hydrotreatments in oil refineries. Almost all the crude oil used in refineries is imported from Brasil, Ecuador and the U.S and the market of oil derivatives in Chile is mainly shared by the National Petroleum Company (ENAP) with 64% of total participation and ENEX with 21% (ENAP, 2021). ENAP is the only company that refines oil in Chile and its market share is divided in 96.2% participation of gasoline, 78.1% of kerosene, 53.4% of diesel and 26.8% of liquified gas with total sales at the end of 2019 of 4,640 Mm^3, 5,450 Mm^3, 1,383 Mm^3 and 654 Mm^3 respectively. The rest of the fuel oil derivatives supply in Chile needs to be imported mainly from U.S, China or Argentina. Finally, as only ENAP is in charge of the oil refinement in Chile, the total hydrogen demand corresponds to ENAP's hydrogen consumption and is estimated to be around 48,000 ton per year which corresponds to 83% of the total hydrogen production capacity in Chile (CNE, 2020).

Fuel type	Production [m^3]	Imports [ton]	Exports [ton]
Diesel	3,010,000	5,294,883	234,325
Gasoline	3,497,000	307,146	3,631
Kerosene	790,000	66,278	--
Fuel oil 6	1,049,000	3,547	138,977
GLP	839,000	1,399,239	112,197
Natural Gas	1,292,913,000	4,357,538	--
Crude oil	114,034	7,386,818	51,567

Table 2: Production, imports and exports of fuels in 2020. (CNE, 2020)

Hydrogen is also used in other industrial processes like the oil hydrogeneration in the food industry, as reduction agent in molybdenum roasting processes, for metallurgical thermal treatments like steel bright annealing in controlled atmosphere and as input for the production of industrial gases like oxygen, nitrogen and argon in Air Separation Unit (ASU) plants. This hydrogen market excluding the oil refineries is supplied by Linde's hydrogen plant by using tube trailer trucks and represents less than 1% of the total hydrogen demand with only 300 ton H_2 per year.

Consumers	Nm^3/month	Ton/year	Uses
Watts	125,000	135	Oil hydrogenation
Unilever	80,000	87	Oil hydrogenation
Air Products	30,000	33	-
Linde	30,000	33	-
Molymet	3,000	3	Reduction agent
Air Liquide	2,000	3	-
Thermal treatments	2,000	3	Bright annealing
TOTAL	272,000	300	-

Table 3: Other industry hydrogen demand (CDT, 2020)

Finally, as already mentioned before, the glass industry requires around 150 ton of H_2 per year which is provided from the Indura electrolysis hydrogen plant. The identified hydrogen demand in Chile corresponds to 83% of the total hydrogen production capacity in the country, the remaining demand is not considered because of lack of information.

1.1.5. Chilean industry overview

Chile's economy is dominated by the tertiary sector of good/services and the industrial sector with almost 60% and 32% participation in the total 2020's GDP of around MUS$ 252,000 respectively. The good and services sector includes as main subsectors the personal services such as health and education, financial services like insurances and the commerce-transportation sectors among others. The industry sector can be divided in 5 main subsectors: mining, manufacture, construction, agriculture/forestry and fishing, contributing with MUS$ 80,000 to the national GDP. Taxes and import rights represent the rest of Chile's GDP with around 8% (Banco Central, 2020). The next graph summarizes with more detail the different economic sectors in Chile.

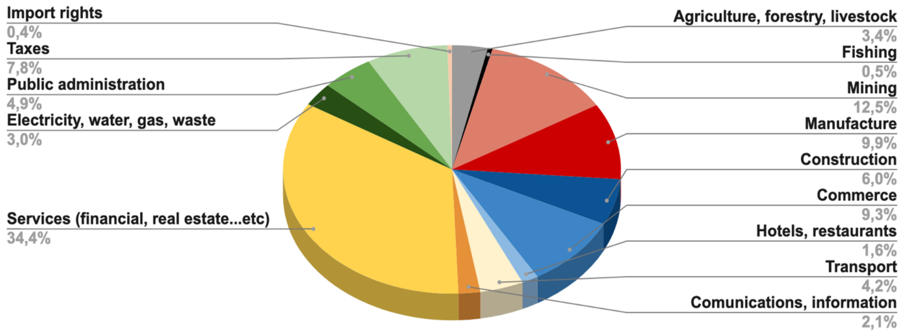

Figure 9: Chile's GDP by sector, elaborated with Central Bank data.

<u>Mining industry</u>

Chile's biggest industry is mining, providing almost 12.5% of 2020 national PIB and 56% of total exportations, corresponding to MUS$ 40,084, where MUS$ 36,356 corresponds to the copper industry. The principal metals extracted and produced in Chile are copper, molybdenum and silver, which represents 28%, 20% and 6% of total world production respectively in 2020. Chile is the world's leading copper producer in the world with an annual production of 5,732 million tones and the second producer of Molybdenum worldwide with 59,381 tones. Mining sector in Chile provided directly and indirectly around 710,000 jobs in 2020, which corresponds to 9.2% of total jobs in the country. Almost 16% of Chile's total investment was directed to the mining sector corresponding to MUS$ 10,036 where 59% correspond to the private mining and the rest to the National Copper Corporation (CODELCO) controlled by the state. The copper industry had an annual total energy consumption of 50,069 GWh in 2020, representing almost 14% of the total aggregated country consumption. About 26,536 GWh are from electric consumption which represented around 34% of Chile's total electric consumption and 23,532 GWh of fuel consumption (Cochilco, 2020).

The most energy intensive processes in copper mining are the open pit processes with 39%, the crushing and grinding with 29%, the solvent extraction and electrowinning (SX-EW) with 13% smelting with 7% and other services with 8%. In terms of fuel consumption, the open pits operations are largely the processes that most fuel consumes in the copper mining industry with 78% of the total consumption, which is mainly due to the extraction and transportation of the raw materials performed by the hauling trucks inside the mine. In terms of emissions, in 2019 the copper industry registered 16,366,000 tones of equivalent CO_2 which represented 15% of the total national emissions. The open pit operations generated 34% of the mining emissions, crushing and grinding generated 34% and the smelting process 15%. The emissions produced from the fuel consumption in mining processes represented 38.2% were 92% was due to the use of diesel and electricity generated 61.8% of total emissions considering an emission factor of the National Electric System (SEN) of 0.4056 tons of CO_2 equivalent per MWh (Cochilco, 2019). In the following figures, the detail of the copper mining emissions by process and by type of energy is showed for the period 2001-2019.

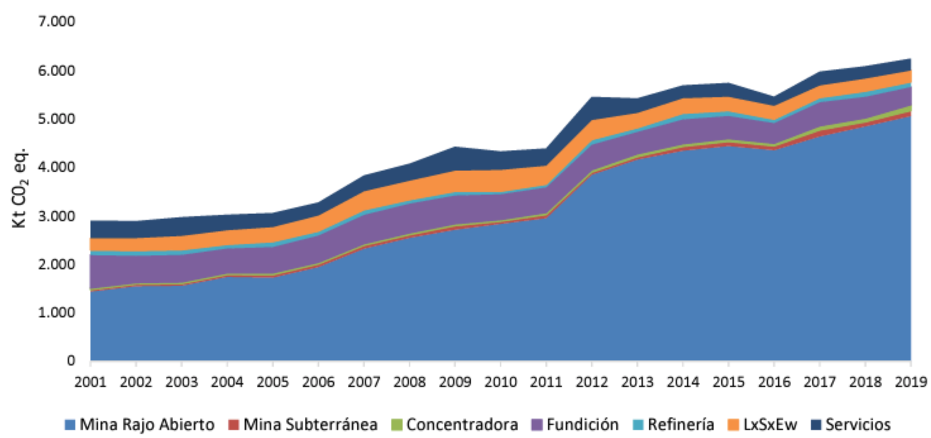

Figure 10: GHG emission from fuel consumption by different processes (Cochilco, 2019).

Manufacture Industry

The second most important industry in Chile is the manufacture sector with 10% of participation in the total GDP and it is represented mainly by the food and drink industry, the production and manufacture of metallic products, machinery and equipment, chemicals, plastic and rubber sector, cellulose/paper industry and oil refinement. The most energetic intensive sub sectors in this industry is the production of wood, manufacture of wood products and cork with 38% of the total manufacture electric consumption, following by the fabrication of non-metallic products like cement or glass and production of metallic products like steel with 14% and 12% respectively (Central Bank, 2020).

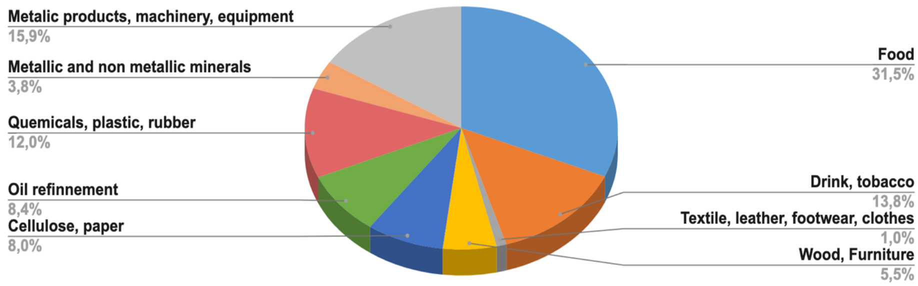

Figure 11:Manufacture industry GDP by sector. Elaboration with Central Bank data.

1.1.6. Hydrogen technological opportunities in Chile's industry

Manufacture: steel, methanol and ammonia

The metallic products, machinery and equipment sector or also known as metallurgical industry is the second biggest sub sector in the manufacture industry where iron and steel are the principal feedstocks needed to make the metallic products of this industry. Iron is extracted in the country and steel is generally produced from the alloy between this mineral and carbon at high temperature using the blast furnace (BF) process. But steel can also be produced via an electric arc furnace (EAF) process that uses steel crap or direct reduced iron (DRI) as their main raw material. Direct reduced iron is the product of the direct reduction of iron ore in the solid state by carbon monoxide and hydrogen derived from natural gas or coal. Even thou DRI represented 7.3% of the total world iron production in 2019, it has increased by 250% since the year 2000 (The Energy and Resources Institute, 2021) an could eventually grow faster in the next years as the opportunity of using green hydrogen instead of hydrogen derived from fossil fuels is a crucial solution to decarbonize this industry, which is the largest in terms of energy consumption and contributes around 7% of global direct CO_2 emissions (IEA, 2019). Chile produced 1,068,600 tons of steel in 2020 (CDT, 2020) and the company CAP concentrates almost all the national production with a capacity of 800,000 ton of liquid steel (CAP, 2020). Considering that producing two millions tons of hydrogen-based steel requires a green hydrogen amount of 144,000 tons (Mckinsey, 2020), Chile would require around 75,000 tons of green hydrogen which is slightly more than the total hydrogen demand in the country, hence, it represents an interesting opportunity for this industrial sector.

In the chemical industry which represents 12% of the total manufacture industry GDP, two opportunities of integrating green hydrogen are identified: methanol and ammonia. The first one is widely produced from natural gas by reforming gas with steam and then converting and distilling the resulting synthesized gas mixture to create pure methanol, but it can also be produced directly from the combination of hydrogen and carbon dioxide. Methanex, the largest producer and supplier of methanol in the world produced 1,050,000 tons in the south of Chile in 2019, which corresponds to 13,8% of the total Methanex Corporation production (Methanex, 2020). This opportunity is already being exploited with the construction of the Hara Oni project in Magallanes region by Siemens which consists in a methanol production plant via green hydrogen produced from the electricity generated by a wind turbine of 3.4 MW. The demonstration phase of this project will initially reach a production of 750,000 liters of e-methanol by 2022 in which part of it will be converted into around 130,000 of e-gasoline (Siemens Energy, 2021).

By the other hand, ammonia is widely used in the agriculture industry as fertilizer and for the production of explosives from ammonium nitrate. Nowadays, the majority of the world's production of ammonia is performed by combining hydrogen from fossil fuel steam reforming and nitrogen via the Haber-Bosch process. In the case of Chile, 302,778 tons of ammonia where imported in 2018 (Banco Central, 2019) mostly to satisfy the demand of ENAEX, company that manufactures explosives for the blasting processes in mining, explosives that are produced with ammonium nitrate which results from the reaction between ammonia and nitric acid. Considering that 177 kilograms are needed to produce one ton of ammonia according to the reaction equations (Rivarolo, 2019), the imported ammonia in Chile could be replaced by producing around 53,600 tons of green hydrogen. But Chile also imports directly ammonium nitrate (13%) and other derivatives of ammonia (30%) for a total of 532,000 tons (CDT, 2019) including ammonia, which could increase the potential green hydrogen demand in the chemical industry up to a value higher than 60,000 ton per year.

Copper mining: Smelting process

Green hydrogen can be used in the smelting process of copper as a reduction agent itself or as an energy carrier for the production of an adequate reduction agent needed in this process to obtain a final copper product with the desired specifications and characteristics.

The process of producing high purity copper from copper sulphide ores requires of several complex stages. After extracting the mineral, the first process consist in reducing the rock by crushing and grinding processes until the rock becomes dust, this dust consequently is submerged in flotation cell pools where chemical reagents are used and air bubble are pumped, allowing the separation of mineral particles of interest from the minerals of the gangue when combining with the air bubbles that reaches the surface by buoyancy. This process produces a copper concentrate with almost 30% of purity that is dried and fed to the smelting process.

The smelting process consists in the exposure of the copper concentrate to high temperatures and chemical reactions in order to continue separating copper from other minerals and impurities. The process is divided in critical stages which are: fusion, conversion and refining. In the fusion process the copper concentrate is fed in to high temperature furnaces (Reverberatory or Modified Teniente Converter type) where it is melted by heating it at 1200 °C and as the copper concentrate changes to liquid state, the elements that compose it are naturally separated according to their weight and as copper is the heaviest element, it stays at the bottom. To remove sulfur, iron residues and other impurities from the copper obtained before in the fusion, a conversion process must be carried out that is divided in two stages: slag blowing and copper blowing. During slag blowing, iron sulphides (FeS) are oxidized, generating slag (Fe2SiO4–Fe3O4) and sulfur dioxide (SO_2). Copper blowing releases the copper contained in copper sulphide (Cu2S) by reacting with oxygen, forming sulfur dioxide and metallic copper. The output of this process is SO_2 gases, slag and blister copper which has +- 98.5% of purity. Finally, the blister copper still has some impurities like oxygen and sulfur and valuable elements such as silver, gold, or iron that need to be removed by a refining process. The main steps of this process are oxidation, where impurities are removed by the reaction of oxygen and later gasification of sulfur (SO_2) and reduction, where the excess of oxygen used before needs to be reduced in order to obtain a higher purity copper (99.6%), a suitable surface and physical properties material. The reduction is performed by introducing into the anodic furnace reduction agents such as solid, liquid or gas hydrocarburs like eucalyptus, liquid petroleum gas (LPG), kereosene, diesel or ammonia, which indirectly or directly supply the necessary H_2, CO and C for the success of the process (Cochilco, 2015).

The selection of a specific reducing agent depends on convenience, availability, cost and sulfur content. In this final reduction stage, the use of hydrogen renders the reduction more efficient, with a consequent decrease in the oxidation process time. As a result, the same anode or anode furnace can have higher production when using hydrogen as a reducing agent, which translates into an increase in productivity and therefore in an increase in the amount of copper that the furnace can process (Bozo, 2021). The potential demand of hydrogen in the refining of copper during the smelting process is hard to estimate as there is not many precise data of the specific fuel consumption in the reduction and oxidation process. Even thou, an approximation can be done in order to estimate the order of magnitude of the potential hydrogen demand in this process. Considering that in the smelter Altonorte, which has a smelting capacity of 1,160,000 ton of copper per year (Editec, 2019), the refinery-molding process consumed around 600 TJ of fuel in 2019 (Energy Ministry, 2019) which is equivalent to 5,000 ton of hydrogen if a low heating value (LHV) of 120 MJ/kg is considered.

The integration of green hydrogen as a reducing agent in the copper production is with no doubt and interesting technological opportunity to decarbonize copper mining in Chile, but the lack of evidence about the efficiency behavior when hydrogen is used as reducing agent or the insufficient experimentation in large scale copper mining motivates to perform further investigation in this subject to determine if it is actually technically and economically viable.

Copper mining: Open mine transportation

The other opportunity of introducing green hydrogen in the copper industry of Chile is in the sub sector of transportation. As already mentioned before, mining has a huge energy consumption, divided in electric (53%) and fuel (47%) consumption. From the total energy consumption, 39% is consumed in open pit processes and corresponds mainly to fuel consumption, which represents

94% of the total energy in open pit mines. The high fuel demand is mainly due to the transportation of the raw material in the open pit mines. Millions of tons of resource material need to be transported from the extraction points inside the mine to the next productive stage point where the material is crushed and grinded (Cochilco, 2019). The transportation is done by big mining extraction haul trucks (CAEX) with power engines of about 900 kW for capacities of 100 tones and up to 3,000 kW for capacities of 400 ton, they use internal combustion engines with a diesel fuel consumption between 2,500 to 4,000 liters per day and can work almost 24/7 (Corfo, 2017). With this information, it can be estimated that the annual diesel consumption of each CAEX truck is in the range of 912,500 – 1,460,000 liters. For reference, with the amount of daily diesel consumption of this trucks, an average car could drive between 25,000 – 40,000 kilometers or between 250 – 400 cars could drive around 100 kilometers each. In terms of energetic equivalence, hydrogen has around three times more energy density than diesel which means that a typical copper mine in Chile with a CAEX fleet of 50 units could have a potential hydrogen demand of 15,200 – 24,300 tons per year.

Considering the magnitude of the copper industry in Chile and that indirect emissions generated by electricity consumption can be reduced mainly by decarbonizing the energy grid with renewables, a first approximation clearly exposes the important opportunity of decarbonizing the open pit mines transportation sector as it consumes massive amounts of fuel and consequently, produces critical levels of direct GHG emissions in the country. This could be done by integrating low and zero emission technologies like hydrogen combustion engines (H_2ICE) and fuel cell vehicles (FCEV), technologies that will be discussed in the next chapters of this work in order to verify the viability of integrating green hydrogen in the material transportation subsector of the copper mining.

1.2. State of Art: Hydrogen as a fuel

As the world is immersed in an energetic transition towards a carbon-free future, the transportation sector has been one of the main targets to decarbonize as it accounts for one quarter of the world's CO_2 emissions were almost 75% is due to road transport (IEA, 2019). Under this context, multiples efforts have been made in the past decades on developing low emission technological solutions for this sector as car manufacturers have turned their attention to electric/hybrid vehicles and fuel cell vehicles.

1.2.1. CAEX mining haul trucks market in Chile

Before presenting and discussing the available technologies for integrating green hydrogen in heavy duty mining trucks it is necessary to briefly review the actual technology used for the transportation of extracted raw material in open pit mines.

Mining extraction trucks (CAEX) are a well-established technology in the mining industry around the world. The main companies that share the market of mining extraction trucks are Komatsu and Hitachi from Japan, Caterpillar from U.S.A, Belaz from Bielorussia and Liebherr from Germany. In Chile, Komatsu and Caterpillar dominate the market with more than 802 and 827 hauling trucks respectively, while Liehberr has a smaller participation with around 43 trucks (Editec, 2020).

This trucks can be mechanically driven or electrically driven depending of the power train or transmission design. The main difference between an electrical or mechanical drive power train is that an electrical transmission design don't use a common gearbox, instead it uses a dynamo or alternator to convert the mechanical force of the engine into electrical energy which is used to drive traction engines (electrical engine). This engines are usually induction engines in the case of Komatsu models and have two modes, propulsion and retard mode. In propulsion mode, the alternator generates AC current which passes through a control system where it is rectified (DC) and reconverted to AC by inverters in order to supply a controlled and three-phase current to the induction engines to move the truck forward or in reverse. The retard mode is activated when the truck moves down in inclined roads, the induction engine behaves as a generator producing AC current which is rectified and produces a movement opposite to the wheels rotation, hence, slowing down the truck. Some Komatsu models like the 830E uses a DC system instead of AC (Rojas, 2014). The electric drive system, in comparison with the mechanical drive, allows an efficient and cleaner movement and by excluding almost all mechanical structure elements, this system reduces scheduled maintenance intervals and corrective repairs, and therefore, reduces operating and maintenance costs while it increases the availability rate and production of the truck. Both type of systems use diesel Internal Combustion Engine (ICE).

The most common CAEX haul truck fleets in the copper mine in Chile are the Caterpillar's mechanical powertrain models 793F and 797F, Liehberr's electrical drive system models T264-284 and Komatsu's electrical drive system models 730E, 830E, 930E. Their typical fuel consumption ranges between 160-200 liters per hour.

Specifications	CAT 797F	Komatsu 930E-4
Engine model	C175-20 (20 cylinder-turbo 4 cycle)	SSDA16V160 (16 cylinder- 4 cycle)
Fuel	Diesel	Diesel
Net power	2,828 kW – 3,793 HP	2,495 kW – 3,346 HP
Load capacity [ton]	363 metric tones	290 metric tones
Max velocity [km/h]	67,6	64,5
Gross Weight [kg]	623,690	501,974
Cost [million USD]	3-5	4-5

Table 4: CAT 797F vs Komatsu 930E-4 general specification comparison. Own elaboration with data from producers.

1.2.2. Fuel Cell Vehicles (FCEV)

Fuel cell vehicles use a full electric propulsion system in which the energy used is produced by a fuel cell stack system supplied with pure hydrogen. In basic terms, fuel cells working principle is the opposite of electrolysis as hydrogen is now introduced in the anode, oxygen is introduced to the cathode and hydrogen molecules break apart into protons and electrons due to electrochemical reactions (oxidation-reduction) activated by a catalyst. Protons travel through the membrane to the cathode and electrons are forced to travel through an external circuit to perform work and hence provide power to the vehicle. The electrons finally recombine with the protons on the cathode and combine with oxygen molecules forming water molecules. The electricity produced by the fuel cells is used to power an electric motor and whenever extra power is needed in the vehicle it is provided by a battery which can be charged with the excess energy produced by the fuel cell and by the brake energy from the vehicle. FCEVs have some similarities to conventional internal combustion engines as they are fueled in less than 4 minutes and the fuel, in this case hydrogen, is stored in a tank on-board the vehicle. (DOE, 2021).

The tank-to-wheel efficiency of fuel cell vehicles is reported to be close to 50% and considering the conversion losses in producing hydrogen from electricity, the well-to-wheel efficiency drops to some 35% (Mckinsey, 2021). Nowadays the FCEV market is dominated by Hyundai and Toyota, but Hyundai historically has more expertise and experience developing this type of vehicles. In 2002 they launched a 75 kW fuel cell Santa Fe model with an autonomy of 230 km, 2004 a 80 kW Tucson, 2006 a 160 kW bus with an autonomy of 380 km, 2007 a 100 kW Tucson with an autonomy of 370 km, 2009 a 200 kW bus with an autonomy of 380 km and in 2013 they launched the first mass produced FCEV, the model ix35 with 100 kW power fuel cell, autonomy of 594 km, two storage tanks of 5.64 kg and 24 kW Li-ion battery. The model ix35 was discontinued but more recently Hyundai launched the model NEXO, a second generation FCEV with autonomy of 666 km and charging time of five minutes (Hyundai, 2021). Toyota produces the FCEV model Mirai which has power of 114 kW, autonomy of 550 km, two storage tanks of five kg at 700 bar and a battery with 1.2 kWh capacity (Toyota, 2021).

Not only light duty FCEV are being developed but also heavy-duty trucks as they are interesting car manufacturers due to the promising future potential market they have in the energetic transition. Hyzon Motors developed a 170 kW and 49 ton with an autonomy between 400 - 600 km and a maximum power of 500 kW (HyzonMotors, 2021). Nikola motors are developing different models of heavy duty trucks, one of them the Nikola Two, which are set to have a powertrain of 1,000 HP, range of 500 – 750 miles, battery package of 250 kWh and torque of 2,000 lb-ft (Fuelcelltrucks, 2021).

Finally, an illustrative demonstration made by the Rocky Mountain Institute showed the opportunity of integrating the FCEVs technology in a heavy duty mining truck. The analysis consisted in comparing the Nikola One truck with a typical an widely used mining haul truck CAT 785D. The Nikola One truck can generate up to 1,000 HP on a 18,000 - 21,000 lb truck frame with 300 kW fuel cell capacity, whereas the CAT 785D truck has a gross HP of 1,450 on 46,000 – 67,-000 lb vehicle. If scaled up, three Nikola One 320 kWh battery packs would weigh 9,000 – 12,000 lb and produce a torque of up to 6,000 lb-ft which can be positively compared with a CAT 3512C HD diesel engine that have a dry engine weight of 14,650 lb with a peak torque of 6,910 lb-ft (RMI, 2018). The analysis is purely illustrative as it also assumes a linear scaling of batteries which has to be further investigated. The scalability of FCEV technology is not trivial as it present some critical challenges regarding the availability and cost of components for matching the power and technical requirements of a standard mining haul truck considering also the weight of crucial components like fuel cells stacks, battery packs and storage tanks, which can be a major issue at the size level of this heavy duty trucks.

The challenge of integrating hydrogen fuel cell systems in the mining industry is already taken by several companies and promising achievements have been accomplished until now.

1.2.3. Hydrogen-fueled Internal Combustion Engine (H_2ICE)

Nowadays concern and pressure on decarbonizing the transport sector in order to reduce significantly the GHG emissions by reducing the dependency of transportation on fossil fuels, has activated the interest not only in electromobility and fuel cell systems solutions but also towards the use of hydrogen as a vehicular combustion fuel. Hydrogen as an energy carrier is the only fuel that is potentially free of hydrocarbon, carbon monoxide and carbon dioxide emissions. Some of hydrogen's properties that reinforce the idea of using it as a fuel for transportation is its high diffusivity, meaning that it disperses rapidly in case of leak which can avoid or minimize unsafe conditions, it has a very high combustion velocity in the engine combustion chamber, which contributes increases the engine efficiency and also hydrogen has a wide range of flammability, which allows it to burn in engines when mixed with air in a wide range of different proportions (Zbigniew, 2021). One of the technologies that can integrate hydrogen as a fuel are the already well-known internal combustion engines (ICE) which may work as a mono fuel and dual fuel hydrogen internal combustion engine (H_2ICE) without greater modifications of the standard ICE and using the same operational principles of them. Even though the technology is still in an early phase of development and hasn't reach a commercial level yet, several studies have been made in the past decade on the performance of adding hydrogen in this type of engines in terms of efficiency and the potential NOx emissions generated by the combustion with air, but there is still no general agreement as results founded may be contradictory.

In 1982, Gopal et al. obtained thermal efficiencies comparable with pure diesel operation while investigating a conventional single cylinder four-stroke diesel engine with hydrogen as inducted fuel (Gopal, 1982) and in 1992 no loss in the efficiency and power output was obtained when substituting up to 38% of diesel with hydrogen at full load in a 4 kW diesel engine (Mathur, 1992). Lambe et al. optimized the design of a engine for pilot diesel fuel engine and obtained a reduction of 70% of NOx and 80% of carbon dioxide and smoke (Lambe, 1993). Later, one of the first main projects that achieve concrete results in the investigation of this type of engines was the "HyICE" project in 2004 - 2007 which demonstrated that a gasoline-like hydrogen engine with spark ignition and direct fuel injection could have better performance than current gasoline engines in terms of power density and efficiency. Two concepts of mixture formation were developed, a direct injection at 10 - 200 bar and cryogenic port injection at – 200 °C and in both methods performance was doubled while consumption was reduced (Green Car Congress, 2007). Another similar project, "H2BVplus", developed a dedicated hydrogen combustion engine with diesel-like geometry and progressive H_2 high-pressure direct-injection technology that achieved an efficiency level of 42% (Green Car Congress, 2009). The BMW Hydrogen was a limited production H_2ICE vehicle powered by a modified 6L -V12 engine burning hydrogen injected at 300 bar and gasoline. Further improvements to this car, including hybrid PI-CI systems using diesel resulted in delivering peak efficiencies of about 42%, comparable to the best TDI diesel engines (BMW, 2009).

According to Alberto Boretti, dual fuel operation in H_2ICE is interesting from the point of view of hydrogen availability as the fact of adding a second fuel to the system secures the engine operation in case hydrogen is not available. But also this type of arrangement means that two fuels need to be stored on board and their management is more challenging. In addition to this, for the case of hydrogen direct injection some critical combustion phenomena must be considered, like the pre-ignition, auto-ignition and backfire problems. Boretti studied the performance of a 1.6L, four-cylinder turbo charged direct injection (TDI) engine with diesel and hydrogen direct injections. The main results of the study was that direct injection dual fuel H_2-diesel ICE can operate more efficiently and with increased power density than conventional diesel engine as they have similar top brake thermal efficiency (BTE) close to 40% and the dual fuel engine permits brake mean effective pressures (BMEP) over 35 bar from the less than 25 bar from diesel (Borretti, 2011). In other study, Boretti investigated four modes of injection in a diesel truck engine converted to hydrogen with a direct fuel injector of hydrogen and a jet injection (JI) pre-chamber or homogeneous charge compression ignition (HCCI) in case jet injection don't occur. The results showed better efficiencies than diesel engine at the same BMEP outputs covering the full range of speeds and loads (Boretti, 2011).

Antunes et al. described the development of an experimental setup for the testing of a four-stroke, single cylinder, air cooled diesel engine in the direct injection hydrogen-fueled mode found an efficiency advantage when using 80% hydrogen and 20% diesel compared to the conventional diesel-fueled mode. Better performance was found for hydrogen direct ignition mode and even better for pre-mixed hydrogen homogeneous charge compression ignition (HCCI) mode (Gomes Antunes, 2009). The results of this study are shown in the following table:

	Diesel DI	Diesel + H_2	H_2 HCCI	H_2 DI
Brake thermal efficiency [%]	27.9	33.9	48.0	42.8
Cooling System [%]	42.2	31.2	20.4	17.3
Exhaust gases [%]	35.3	34.9	31.6	39.9
Shaft Power [W]	9,000	8,950	7,076	10,280

Table 5: Experimental results for engine energy balance (Gomes Antunes, 2009).

In the study of a direct injection diesel 553 cc engine with dual diesel and hydrogen operation it was found that the efficiency increased in a full load operation with 6.76% hydrogen and 93.24% diesel without and with exhaust gas recirculation EGR (Saravanan, 2010). Roy et al. investigated the engine performance and emissions of a supercharged dual-fuel engine fueled by hydrogen and ignited by a pilot amount of diesel fuel and reported a thermal efficiency of 42% with a fuel-air ratio of 0.3, however the NOx emissions were high. But by introducing EGR in the hydrogen engine, the NOx emissions were reduced to the zero level (Roy, 2010).

More recently, a peak efficiency of 45.5% was obtained in an optimized DI combustion system with 5 hole nozzles and at part-load a brake thermal efficiency of 33.3%. The evaluation was performed in a range of 1000 to 3000 RPM and a load range from 1.7 to 14.3 bar BMEP and the injector configuration showed NOx improvements (Wallner, 2012). Finally, Boretti in a later study concluded that further improvements of H_2ICE could exploit waste recovery to deliver even better peak and cycle average fuel conversion efficiencies. H_2ICEs have the potential to deliver peak fuel conversion efficiency higher than 50% if coupled to hybrid powertrains, both in the dual fuel compression ignition (CI) and the positive ignition (PI) direct injection (DI) jet ignition (JI) design. Also Boretti considers that hydrogen PI ICEs may qualify as zero-emission vehicles, same as electric cars, as NOx emissions can be reduced in the after treatment (Boretti, 2013). At last, dual-fuel liquid hydrogen-diesel CI ICEs may deliver above 50% peak fuel conversion efficiency, better than diesel. (Boretti, 2020).

Other studies obtained less optimistic results regarding the performance and emissions of hydrogen internal combustion engines (H_2ICE). For example, Pana et al. carried out an experimental investigation in a diesel engine fuelled with diesel fuel and hydrogen at different rate between 11.2 L/min and 40.3 L/min and it was reported that the dual operation resulted in a decrease of almost 10% in terms of brake specific energetic consumption compared to standard engine diesel but also the NOx emissions decreased in 5.5% for a 3.9% percent of substitute ratio of diesel fuel by hydrogen (Pana, 2017). Karagoz et al. experimented with a single-cylinder, four stroke, water cooled, naturally aspirated diesel engine for different full load conditions and speeds and the results showed that with a 25% and 50% hydrogen addition the brake thermal efficiency (BTE) decreased by 3.3 - 8.1% and 8.2 - 15.5% compared to only diesel fuel respectively. Added to this, a dramatic rise of NOx emissions could not be prevented as they increased by 15.2% to 39.6% with 25% hydrogen addition and by 68.6% to 212.7% with 50% hydrogen addition compared to only diesel fuel (Karagoz, 2016).

In the work of Liu et al. a heavy duty diesel engine with hydrogen aspirated in the intake observed a reduction in brake thermal efficiency (BTE) and increase in NO2 emissions due to poor hydrogen combustion efficiency with the presence of unburnt hydrogen (Liu, 2011). Liew et al. used a Cummins ISM370 turbocharged diesel engine of 370HP to study the effect of hydrogen addition at different rates and it was reported that with a 15% addition a substantial deterioration of the premixed combustion occurred and with a 70% addition the combustion duration dramatically decreased. Finally, the addition of hydrogen had no positive effect in enhancing the combustion efficiency of diesel fuel (Liew, 2010). A more recent study, presented the results of a hydrogen-diesel co-combustion experiments carried in a light duty and heavy duty diesel engine. The indicated thermal efficiencies decreased in the light duty engine and especially in the heavy duty engine when the proportion of hydrogen increased. In terms of NOx emissions, the light duty engine had higher emissions as the hydrogen proportion increased but in contrast, the NOx emissions of the heavy duty engine stayed constant/reduced slightly with increasing levels of hydrogen (Talibi, 2018). A peak BTE of 45% in a hydrogen ICE was demonstrated at 2,000 rpm and a high load condition of 13.5 bar brake mean effective pressure BMEP (Yip, 2018).

The effect on engine efficiency with the integration of hydrogen in internal combustion engines is still not completely clear as different studies reported excellent and poor results of performance and NOx emissions. However, this is due to the different engines configurations and technical parameters that can be varied depending on the use of the system. This clearly gives the opportunity to exploit the engines characteristics and set the optimal engine configuration while adding emission reduction technologies and heat recoveries systems in order to achieve H_2ICEs with better or equal performances than standard diesel engines and with low-zero emissions.

1.2.4. H_2ICE v/s FCEV:

Both hydrogen fuel internal combustion engine vehicles (H_2ICE) and fuel cell vehicles (FCEV) have zero CO_2 emissions but in terms of air quality, H_2ICE can eventually produce critical quantities of NOx emissions if no aftertreatment technologies like selective catalytic reduction (SCR) or exhaust gas recirculation (EGR) are used depending in the engine configuration, compared to FCEVs that don't produce any kind of emissions. According to Mckinsey, the total cost of ownership (TCO) is an important parameter when comparing different technologies and can differ significantly by vehicle and use case considering that generally the best approach is to find the optimal trade-off between up-front capital costs and fuel consumption. In the case of FCEVs, the high capital expenditures (CAPEX) of fuel cells and batteries is a drawback and economical barrier for this technology compared to H_2ICEs which has similar CAPEX as diesel ICE but the cost of hydrogen tanks has to be considered too. The high CAPEX of fuel cells and batteries is mainly associated to the raw materials needed to manufacture them, specially platinum which is the most common catalyst used in FCEVs and cobalt, nickel, lithium and manganese used as main materials in the cathodes of Li-ion batteries. Both technologies have similar infrastructure costs regarding the hydrogen distribution costs and refueling stations that are required. Summed to this, the refueling time and uptime is similar for both technologies as they have relatively fast refueling depending on the tanks size. In terms of space constraints, both FCEVs and H_2ICEs required more space than a standard ICE vehicle, but FCEVs need much more space due to the integration of fuel cell stacks, hydrogen tanks and battery packs (Mckinsey, 2021).

According to Verhelst, the advantages of hydrogen ICE compared to the FC technology include a higher tolerance to fuel impurities, flexibility to switch between fuels, reduction of rare materials usage and a more straightforward transition from conventional vehicles (Verhelst, 2014). Another consideration to take account when comparing this two technologies is their powertrain performances under different loads and extreme operational conditions such as dust, hot and cold weather, altitude and vibrations. In this case, H_2ICEs have a clear advantage over FCEVs as ICEs vehicles have already met the high power requirements needed to operate under extreme conditions like in the heavy duty mining industry. The relatively good efficiencies achieved at high load plus the low CAPEX of ICEs and the decreasing hydrogen prices from renewables make H_2ICEs competitive with standard diesel ICEs. Finally, at first glance it seems that H_2ICEs are the most feasible and viable option for decarbonizing the mining haul trucks but it is crucial to make efforts in developing both type of technologies as H_2ICEs will help bringing down the costs of FCEVs and vice versa, making them complementary to each other could boost the decarbonization of the transport sector in general (Mckinsey, 2021).

1.2.5. Reference H_2ICE / FCEV projects

In this section, the most recent and promising projects regarding the use of hydrogen as a fuel in the mining industry are presented.

FCEV mining haul truck – Anglo American: South Africa

Anglo American is developing with Williams Advanced Engineering a hydrogen powered ultra-class electric mining hauling truck set to be tested in the platinum open pit mine Mogalakwena in South Africa. The project consists of replacing the current power system of a Komatsu 930E-4 truck model with hydrogen fuel cell and battery system. The fuel cell system is formed by 8 FCvelocity-HD cells modules of 100 kW and 280 kilogram each from Ballard Inc. and a battery pack with a capacity of 1,100 kWh, the whole system can provide a peak power of 2,100 kW. The hydrogen used in this new mining truck will be produced by a 3.5MW electrolyzer from Nel ASA and powered by a PV plant from Engie. The following figure shows some details of the fuel cell system developed in this project (International mining, 2021).

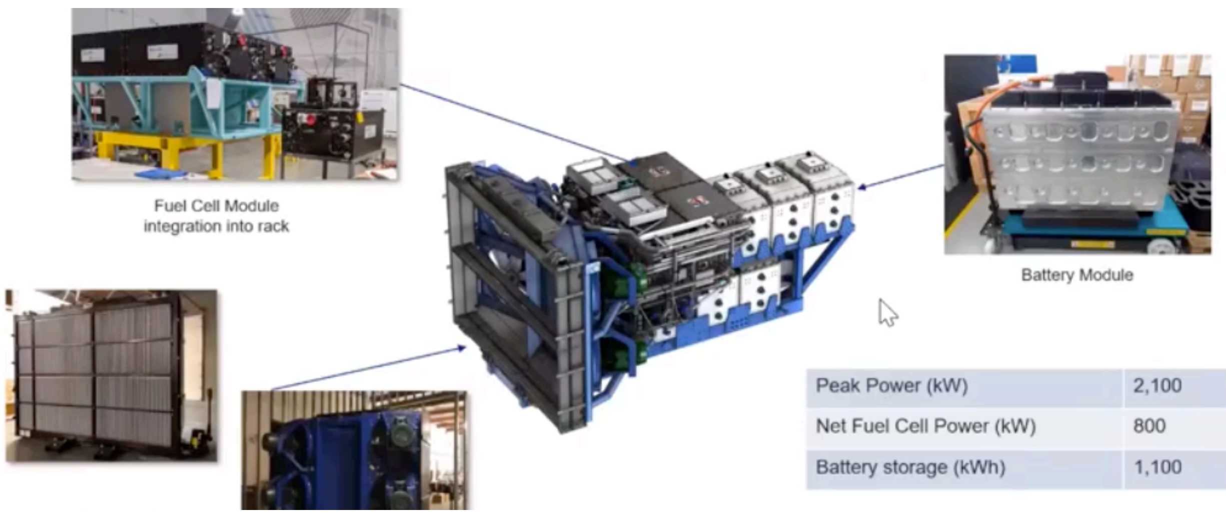

Figure 12: Fuel cell system developed in Anglo American's mining truck project. (Webinar Green Hydrogen USM, 2020)

FCEV mining haul truck - HYDRA project: Chile

Engie and Mining3 are the owners of the HYDRA project which considers the replacement of the internal combustion engine of a large capacity mining haul truck with a hybrid system of hydrogen fuel cells and batteries. Reborn Electric is the partner company in charge of the integration of a modular fuel cell of 100 – 200 kW and battery powertrain into a mining hauling truck of the constructor Liebherr. The project is currently in phase 2 testing a 60 kW fuel cell provided from Ballard with a 5 kilogram hydrogen storage provided from Hexagon fuels at 150 bar and a system of 4 Li-ion batteries of 140 kWh. The pilot test is set to held in March 2022 at Centinela mine from Antofagasta minerals. The phase 2 of this project also consist in the validation of the actual assumptions regarding the fuel consumption in high altitudes and the fuel cell system performance in extreme weather and dust conditions.

FCEV Load Haul Dump (LHD) - USM: Chile

The Technical University of Santa Maria, Fraunhofer Chile, Ballard, Spain National Hydrogen Center (CNH2) are the main members of a technological consortium in charge of the project of adapting a Load Haul Dump mining truck with fuel cells and battery pack for underground mine operations. One of the most crucial problems to be solved in underground operations is ventilation, dust and noxious gases must be removed in order to ensure a healthy working environment. This process needs fans and extractors that consume large amounts of energy up to 30% of the underground operations energy consumption, so the integration of low-carbon or carbon-free solutions in the material extraction processes is attractive for decarbonizing and improving the air quality of underground operations which consequently reduces the amount of power needed for ventilation and hence, reduces the operational costs in the mine.

The first results of the study held by the technological consortium showed that the replacement of the diesel internal combustion engine and fuel tank of a 11 ton capacity LHD with an electric engine, a fuel cell, hydrogen tanks and a electrochemical storage would require 25 kilograms of hydrogen to meet the requirements of a normal working shift of 8 hours. However, the whole new retrofitted system occupies 144% more space than the available volume in the truck. To solve this, the study suggests a design that can supply the energy requirements for 4 hours meaning that the LHD would need to refuel one time per shift (Araneda, 2019).

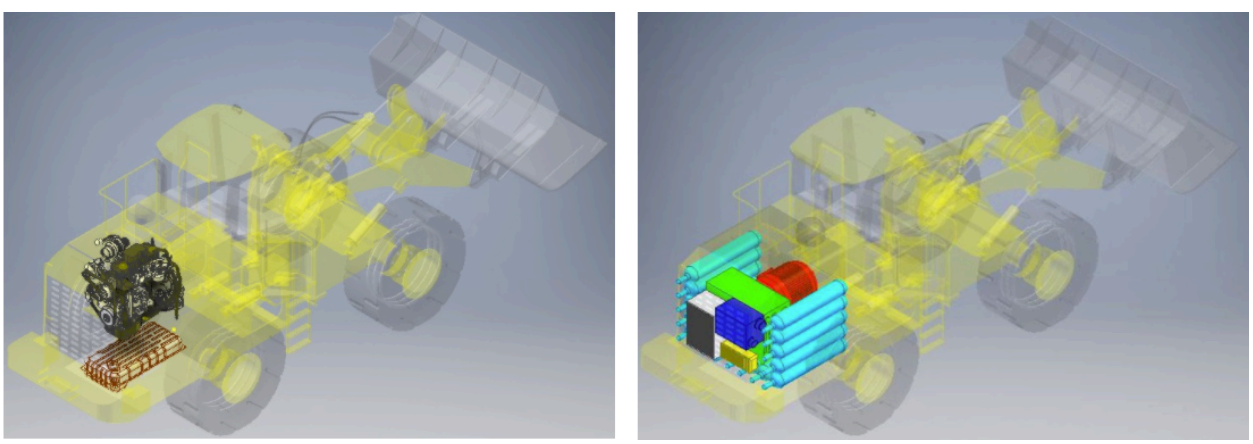

Figure 13: LHD retrofit design comparison with diesel ICE. (Araneda, 2019)

H_2ICE retrofitted CAEX – ALSET: Chile

As heavy duty trucks like long-range buses, transportation trucks or mining hauling trucks consume greater amounts of fuel and travel larger distances than standard light duty vehicles, they are being prioritized in the decarbonization pathways and energetic roadmaps of many countries. In the case of mining hauling trucks (CAEX), the fact of using their existing ICE engine to integrate hydrogen makes H_2ICE a very attractive technological solution to decarbonize mining operations in the world, considering the complexity and size of this trucks that makes other low emission technologies like fuel cells harder to integrate with the existing system components like cell modules or batteries.

For this reason, Chile's Production Promotion Corporation (CORFO) launched an international call for developing a project of mining trucks retrofitting to operate with dual fuel, hydrogen and diesel. It was finally awarded to an international consortium led by Alset Global and formed by Engie, Acciona, AngloAmerican, CAP, BHP billiton, NTT Data, Hydrogenics, Catholic University of Chile and University of Santiago with a total budget of 20MUS$. The main objectives of this project are the reduction of costs and the volatility of fuel, the reduction of emissions and operational reliability in case of one of the fuels is not available. The technological development consisted first in an engine programming with the manufacturer specifications using diesel which was then simulated and optimized iteratively with different hydrogen configurations. The optimal results are then evaluated in a testing bench using research engines and more iteration simulations are performed in order to obtain more reliable data of combustion and constraints. At last, the data is reevaluated in a multi cylinder research engine in order to integrate it later to the truck pilot.

The project has already achieved to simulate a first configuration with 60% hydrogen addition at full load and 97% at part load and a second optimized configuration was obtained with 80% at full load and 97% at part load. Finally, Alset Global reports that hydrogen could be added in a range between 60 - 97% depending on the mine characteristics. Now the project is in its innovation & strategy phase that will conclude with the test and improvement of the pilot truck in 2022 and in the period 2023-2026 the industrialization of the technology is aimed for series production by the industrial partner MAGNA STEYR and production would start in 2027. By 2040 a 100% hydrogen new CAEXs could be achieved according to the consortium considering the lifetime of 15 years of the trucks (ALSET, 2021). In the following figure, ALSET's emission reduction plan is shown:

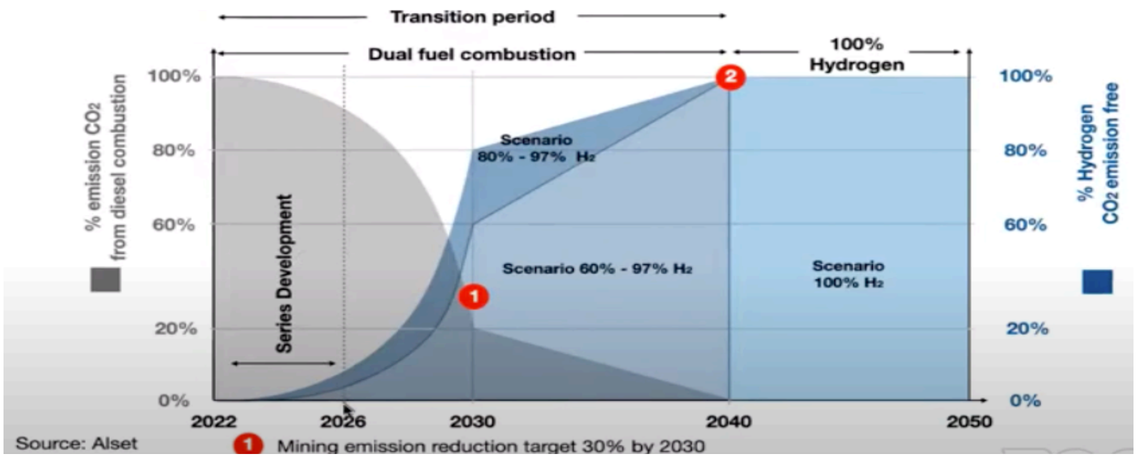

Figure 14: Emissions reduction plan. (Presentation of Alset in Sernageomin webinar of Green Hydrogen Guide Launch, 2021)

1.3. Green H_2 supply chain review

In this section, a review of the hydrogen supply chain is presented. After the hydrogen production, the delivery chain can vary depending if hydrogen is produced on-site or off-site (centralized production) and whether hydrogen is transported as gaseous hydrogen (GH_2) or liquid hydrogen (LH_2). The general components of a hydrogen supply chain includes compressors, liquefiers, storage vessels, transportation truck trailers, pipelines and hydrogen refueling stations (HRS). A general and simplified hydrogen supply chain is shown in the following figure:

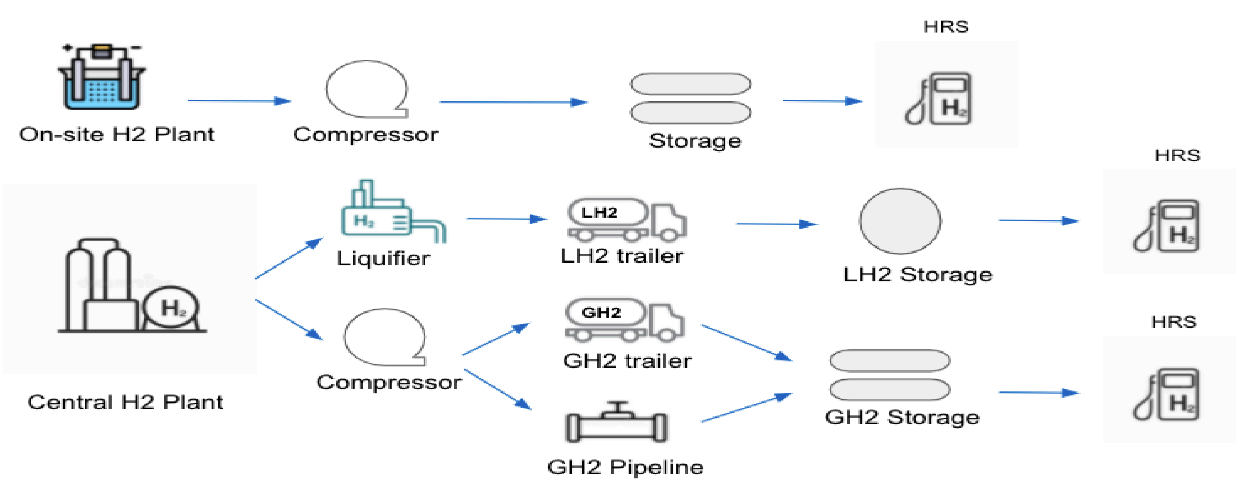

Figure 15: Simplified schematic diagram of the a typical hydrogen supply chain. Own elaboration.

H_2 pre-treatment: Liquefaction/Compression

The two typical ways to manage hydrogen after its production is as liquid hydrogen (LH_2) and compressed gaseous hydrogen (GH_2). LH_2 is preferred to GH_2 when large quantities of hydrogen must be transported and stored due to the low volumetric density of GH_2 as 1 kg of hydrogen gas occupies 11 m^3 of volume at room temperature and atmospheric pressure while liquified hydrogen only needs 0.014 m^3 to store 1 kg at 1 bar. In general, GH_2 storage is more expensive than LH_2 storage as it requires significantly high pressures to compress the gas while LH_2 trucks can transport more hydrogen per truck than GH_2 trucks. However, the highly energetic and complex processes needed to transform hydrogen in its gaseous form to the liquid state during the liquefaction process counterbalances the LH_2 advantages and storage cost over GH_2.

The process of hydrogen liquefaction basically consists in the cooling of the gas to temperatures below 21K or - 253 °C at 1 bar. The most simple liquefaction process, the Joule-Thompson expansion, firstly compresses the hydrogen gas at ambient temperature and then cools it using a heat exchanger. Later, the cooled and compressed gas passes through a throttling valve where an isenthalpic Joule-Thompson expansion takes place. The Joule-Thompson effect is the change of temperature while a gas is expanded without producing work or heat transfer, basically all real gases cool down when expanded at room temperature with the exception of neon, helium and hydrogen that have the opposite behavior, they warm at room temperature when they are expanded. This is why hydrogen must be pre cooled to its inversion temperature (-73 °C at 1 bar) in order to cool it when expanding (Aziz, 2021). This cooling problem during throttling process and the extreme low boiling point at - 253 °C are the fundamental reasons that explain why the liquefaction process of hydrogen requires substantial amounts of energy which signifies higher cost expenditures. Some modern hydrogen liquefaction plants have a specific energy demand of approximately 10 kWh/kg, but values below 6 kWh/kg can be achieved in larger plants by improving some processes. But even thou the energy consumption of the liquefaction process can be reduced, the capital investment of the liquefaction plant dominates the overall cost of liquefaction and it can even represent up to 50% of the total liquefaction cost of a plant with 100 ton per day capacity (Andersson, 2018).

As reference, the liquefaction technology from Linde can be used due that this company is a global leader in hydrogen production, processing, storage and distribution of hydrogen. Figure 16 shows a medium scale liquefier developed by Linde with a hydrogen refrigeration Claude cycle, a capacity range between 2 to 50 ton per day, a specific energy consumption between 7.5 - 12 kWh per kilogram, feed pressure between 10 – 25 bar, a pre-cooling system with liquid nitrogen LN2, a piston compression system and a Joule-Thompson valve as main specifications (Cardella, 2019).

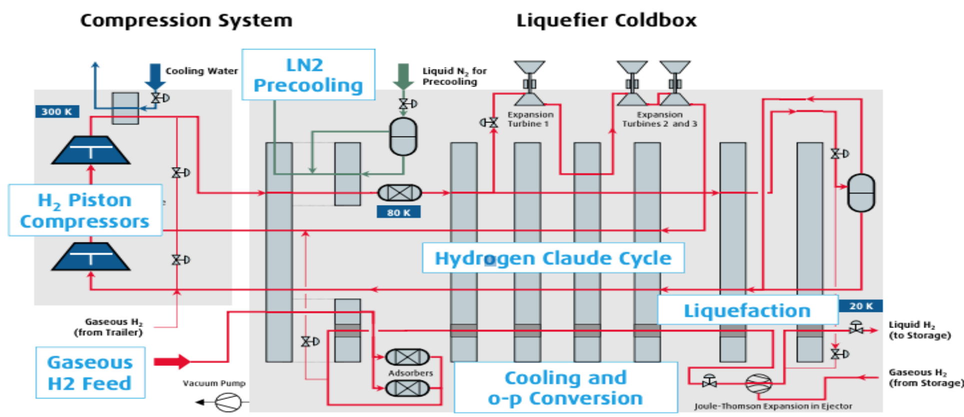

Figure 16: Medium scale hydrogen liquefier plant by Linde.

If hydrogen is delivered as GH_2, it has to be compressed up to high pressures in order to store it for further transportation (if needed), refueling (for mobility solutions) or for on-site clients. According to the U.S DOE, the theoretical energy needed to compress hydrogen isothermally from 20 bar to 350 bar is 1.05 kWh/kg and only 1.36 kWh/kg for 700 bar (DOE, 2009) while other studies consider that the compression of GH_2 from the production pressure (10 – 30 bar) to the storage pressures (200 – 700 bar) requires an electrical consumption in the range of 0.7 and 1.0 kWh/ kg of hydrogen (Yang, 2007) while another study presented a compressor energy consumption of 2 – 4 kWh/kg from 20 to 350 bar (Richardson, 2015). Finally, hydrogen compression is typically done with reciprocating (positive displacement) and centrifugal type compressors.

LH_2/GH_2 storage terminal

After hydrogen is produced and liquified or compressed it must be stored before passing to the next step in the supply value chain. Several storage method includes cryogenic tanks for LH_2, I-II-III-IV type tanks, salt caverns and liquid organic hydrogen carriers (LOHC) for GH_2. The storage of LH_2 is challenging as its extreme low temperature requires of very well thermal insulated vessels usually referred as cryogenic tanks. Usually cryogenic tanks are made of an inner vessel made of stainless steel or composite materials and an outer vessel made of carbon steel, with vacuum insulation between the vessels. LH_2 is stored at pressures lower than 10 bar and this type of storage allows using large bulk storage systems with high energy densities. However, any heat transfer to LH_2 causes some fraction of hydrogen to evaporate, which causes boil-off losses.

The storage of GH_2 is also challenging due that hydrogen in its gaseous state needs to be compressed at high pressures in order to be stored in large quantities and even at high pressures its volumetric density is low, so larger volumes are needed and higher pressure vessels have consequently high investment costs. This is mainly due to the increase of thickness with the increase of pressure required in the tanks, which increases the tank mass and higher strength materials are needed. The typical high pressure vessels for storing hydrogen are classified as Type I, II, III and IV. The cheapest and most widespread are type I which are mainly used for large-scale storage at pressures between 150 to 300 bar while type II are commonly used for only higher pressures and for stationary applications. Type III and IV are preferred for transport applications and composite materials with carbon-fiber are used as weight savings are essential. However this vessels are much expensive than typical aluminum/steel vessels type I - II and are not economically viable for large scale storage applications (Tashie-Lewis, 2021).

A potential solution for storing large volumes of GH_2 is using underground salt caverns which are able to store hundreds and even thousands tons of hydrogen at 60 - 180 bar (Portarapillo, 2021). However, this type of storage depends on geographical conditions and can take several years to construct considering exploration phases. At last, another method for storing is using LOHC which consists in liquid oil that can chemically store hydrogen at high densities and ambient conditions.

Even thou LOHC and salt caverns are promising methods for storing hydrogen and competitive with compressed and liquified hydrogen storage, they will not be considered further in this study.

Hydrogen transport

After its production, green hydrogen requires a viable infrastructure to be able to be delivered to a specific end user, such as industry, power generators, households, shipping or fueling stations. For this, a brief review of the most common transportation solutions is done in order to select the most suitable for the specific end users considered in this study, the copper mines. The types of transport includes trailer trucks or pipelines, which depends on the final use, demand and distance from the production site.

Cryogenic LH_2 Trucks

As the process of liquefaction increases the volumetric density of hydrogen, the transportation of LH_2 is usually suitable for delivering relatively high flows of hydrogen over long distances. LH_2 is transported by super-insulated cryogenic tank trucks with capacities between 3,000 – 4,500 kilograms. For example, the company Linde offers two types of truck systems one using a typical trailer trucks with vessels of 13.7 meter of length and capacity of 4,000 kilograms with loading and unloading times of four hours and one hour respectively, and a container truck of 3.000 kilograms capacity, loading time of three hours and low unloading time of half an hour by swapping the new container with an old one and with liquid nitrogen (LIN) shield between the inner and outer vessels to ensure low heat exchange with the LH_2 (Decker, 2019).

Figure 17: Linde's LH_2 trailer trucks systems. (sintef.no / linde-engineering.com)

Compressed Gas GH_2 Trucks

Current GH_2 transportation consists in large semi-trucks carrying tube trailers with hydrogen at high pressures in the range of 180 to 250 bar, which is the limit in the U.S. However, higher pressure trailers up to the range 400 - 500 bar have been built and received special certification. As hydrogen in its gaseous form needs large volumes in order to be stored, typical trailer tube trucks can carry small amounts of hydrogen around 380 kilograms, but recently composite storage vessels have been developed with higher capacities in the range of 560 - 900 kilogram (HFTO, 2021) and even up to 1,150 kilograms but with significant capital costs above 1 MUSD (Reddi, 2016).

Pipeline GH_2

Pipelines can be used to transport large volumes of gaseous hydrogen similarly as natural gas transportation nowadays. Hydrogen has to be compressed previously and it can be transported through pipelines at maximum pressures around 70 bar. Pipelines have high initial investments costs, not only because of materials like steel, but installation costs, miscellaneous and right of way (ROW) costs, this last one can be in some cases very costly and administratively challenging. However, hydrogen pipelines have low operational costs and are still a relatively low cost option for transporting large quantities of hydrogen and over large distances, especially for large scale industries. Hydrogen flows almost three times as fast as natural gas at the same pressure and pipe diameter, so if hydrogen compressors are operated to meet similar pressure requirements as natural gas compressors, hydrogen pipelines diameters would have similar diameters as natural gas pipelines, up to 48 inches (1,220 mm). However, hydrogen pipelines depend on the demand and the pressures achievable. Historically, stainless steel or carbon steel has been used to deliver hydrogen through pipelines but the use of higher strength steels are not recommended as they are more susceptible to hydrogen embrittlement, so the use of low strength and thicker steels usually are required but this can increase the cost of the pipeline (Argonne, 2008). Potential solutions to this problem include using fiber reinforced polymer (FRP) pipelines that are able to withstand higher strains as its composite structure increases tensile and compression strength, improves burst and collapse pressure ratings and better load carrying capacity. The use of multiple and small diameter FRP pipelines for hydrogen transmission is practically and economically feasible according to a study carried out by U.S DOE (Smith, 2005) and globally the installation costs for FRP pipelines are 20% less than pipelines (HFCTO, 2021).

Hydrogen Refueling Stations (HRS)

Fueling stations are the end point of the supply chain for hydrogen mobility applications and can have different configurations depending on the hydrogen supply mode and the type of vehicle that needs to refuel. Fueling stations can be divided in to LH_2 stations and GH_2 stations, this last type of station can differ in terms of compressor energy consumption and hydrogen storage depending if the hydrogen is supplied from pipelines or by tube trailer trucks.

LH_2 station

Figure 18 shows the fueling station general configuration for LH_2 considered in the HDRSAM model developed by the Argonne National Laboratory of the U.S. Once the liquid hydrogen supplied from the LH_2 trucks arrive to the fueling station it must be stored in large cryogenic tanks before moving to the next process. LH_2 can be converted into low-pressure GH_2 by passing through a heat exchanger before being compressed up to 950 – 1000 bar or it can be directly compressed and transformed to its gaseous state by using a high pressure cryogenic pump and evaporator. After the compression, hydrogen is stored in high pressure buffer storage tanks in order to deliver the required pressure to the vehicle. In the heat exchanger – compressor path, an additional cooling system is needed to cool down gas hydrogen to - 40 °C in order to prevent expansion and overheating while the hydrogen is fueled in the vehicles tank. By the other hand, the cryogenic pump process takes full advantage of the LH_2 cooling capacity and doesn't need additional cooling during fueling and it can eventually dispense directly at 350 bar without passing through the evaporator and high pressure storage, which reduces the investment costs. At last, the direct LH_2 compression by the cryogenic pump reduces significantly the energy consumption compared to the conventional compressor path, thus, operational costs are much lower (Argonne, 2017).

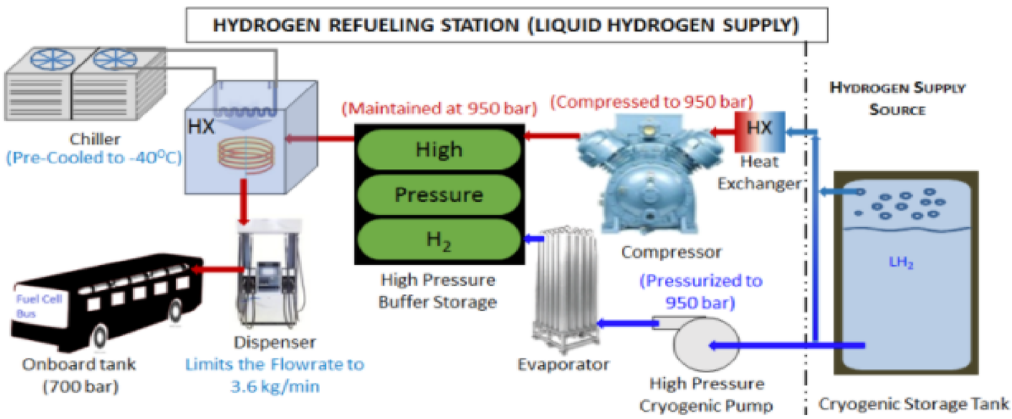

Figure 18: LH_2 refueling station configurations scheme. (Argonne, 2017)

GH_2 station

Fueling stations based on GH_2 delivery work similarly as LH_2 stations but are simpler because there is no need of a heat exchanger for converting the hydrogen supply in to another hydrogen physical state before compressing it. A second compressor can be integrated to deliver hydrogen at different pressures with the same dispenser module. The following Figure 19 shows a basic schematic of a typical GH_2 station configuration.

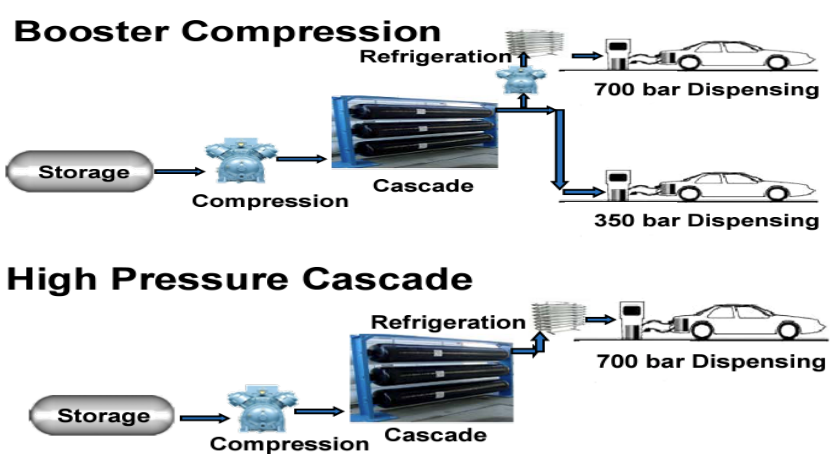

Figure 19: GH_2 refueling station configurations scheme. (Argonne, 2017)

GH_2 stations may vary in the storage configuration depending if the hydrogen is supplied by pipelines, by tube trailers or with on-site hydrogen production. Pipelines supply hydrogen at lower pressures (20 bar – 80 bar) so larger pressure storage is needed compared to trailer trucks supply as the same tube trailers may be dropped off and used as storage.

In general, there are two types of hydrogen storage pressure vessels in HRS's: cascade storage and buffer storage. The first one consists in three stage vessels with tanks with low, medium and high pressures and the filling process is made in sequence starting with the lower pressure tank and finishing with the high pressure tank. During the process, when the station reservoirs are discharging, the compressor is automatically switched on to fill the high-pressure reservoir and then medium and the low-pressure reservoirs respectively. This technique ensures that the reservoirs are kept at a certain pressure, the refueling is continuous and less compressor capacity is needed (Sadi, 2019). By the other hand, the buffer storage vessel has only one high-pressure hydrogen tank, it always maintain the same pressure fluctuation and generally can achieve lower filling times than the cascade storage system (Tian, 2022).

2. GENERAL AND SPECIFIC OBJECTIVES

The main objective of this investigation thesis is estimating the potential demand required for replacing diesel fuel in the Chilean open pit copper mines extraction operations done by CAEX trucks based on the integration of dual hydrogen-diesel combustion engines (H_2ICE) or fuel cell (FCEV) technology and assessing a future hydrogen supply chain for a specific case of study.

The specific objectives are:

-Contextualizing Chile's energetic matrix, economy, and industry for understanding the potential of producing green hydrogen in Chile and identifying the technological opportunities of integrating hydrogen in the major industrial sectors.

-Analyzing and justifying the copper mining sector as the industry with the foremost potential for decarbonizing with the integration of green hydrogen.

-Analyzing and discussing the state of art and technical parameters of the current technological solutions that implement hydrogen as a fuel in the transportation sector.

-Estimating the potential hydrogen demand of the major copper mines in Chile in future scenarios and determine a specific case of study.

-Calculating and discussing the levelized cost of hydrogen (LCOH) production and the sensitivity of its components in a specific and future hydrogen economic pole considering projected scenarios with different renewable plant configurations and costs.

-Determining the viability of replacing diesel with green hydrogen in CAEX trucks and estimating the cost of green hydrogen needed to be more competitive than diesel.

-Assessing and designing a potential hydrogen value supply chain for a specific case of study from the production step to the final end-user delivery via hydrogen refueling stations (HRS) considering the cheapest production configuration possible.

-Evaluating an optimum hydrogen on-board storage system that could fit in CAEX trucks considering its payload capacity, available space, filling rate and similar operational performance than the normal diesel trucks.

3. METHODOLOGY

After analyzing the Chilean industry it was identified that the copper mining sector has the best potential to lead the integration of green hydrogen in the country. The processes of the copper industry that can have a bigger impact if decarbonized in terms of direct greenhouse emissions, are the open pit operations, specifically the transportation of raw material by the mining haul trucks CAEX since they consume significant amounts of diesel. Consequently, in this section of this work, the integration of green hydrogen in the Chilean copper mining industry by retrofitting

CAEX mining haul trucks is assumed, considering a conservative replacement of 60% of diesel with hydrogen using the H_2ICE technology developed by ALSET and the reconversion of CAEX trucks as FCEVs following the recent projects developed by Anglo American and Hydra project in Chile. For this, a deep investigation of the main copper mines parameters is performed, such as identifying the specific fleet of mining hauling trucks CAEX and their diesel consumption to estimate the hydrogen consumption of each mine. In addition to this, every mine was mapped in order to define areas of interest with the potential of becoming green hydrogen poles by designing and installing major green hydrogen plants with the optimal renewable energy feedstock configuration to produce the lowest and competitive hydrogen possible.

As the H_2ICE – FCEV technology and green hydrogen production is still in an early stage in Chile, it will be assumed that the implementation in the copper mines will be gradually and starting from 2030, so the baseline data collected will be linearly projected using official energetic projections of the copper industry provided by the Energy Ministry. However, as copper mines have a limited lifetime depending on their copper reserves and copper concentration, the analysis must consider the projections of each mine for future scenarios in which the copper mines are still operating. In order to project a potential demand in longer term scenarios like 2050, a general and simplified estimation of the hydrogen demand will be performed by projecting the whole copper industry diesel consumption. The levelized cost of producing hydrogen will be calculated considering two types of configurations and a sensitivity analysis will be performed in order to determine if the replacement of diesel is economically viable based on future diesel projections. A hydrogen supply chain will be designed for a particular case of study considering the selected renewable plant and electrolyzer capacity while the supply chain components will depend on the specific configuration suitable for the case of study. Finally, an analysis of the possible on-board storage configuration will be performed considering today's HRS standards, vessels tanks market and normal performance of diesel CAEX trucks.

3.1. Diesel consumption in copper mining

According to the Chilean Copper Commission (Cochilco), the total energy consumption increased from 175,577 TJ in 2019 to 180,249 TJ in 2020, in which 85,807 TJ corresponded to fuel consumption in 2019 and 84,300 TJ in 2020. The open pit mines processes consumed 79.6% of the total fuel consumption in copper mining in 2019 and 78% in 2020, where the main processes are the transportation and extraction of materials by different kind of heavy duty trucks like extraction shovels, bulldozers, auxiliary trucks but especially by CAEX hauling trucks that dominates in terms of fuel consumption. In general, almost 90% of the total fuel consumption is diesel in the copper mining industry but in the open pit processes diesel consumption it accounts for almost 98 - 99% of the total fuel consumption (Cochilco, 2016). Diesel's energetic content is between 35.87 MJ/L (LHV) and 38.66 MJ/L (HHV) according to the Transportation Energy Data Book (Staffell, 2011) but a reference energetic content value of 36 MJ/L is assumed for calculations in this work. Considering this value and using equation (1) it can be estimated that open pit mine operations needed roughly 1,899 million liters of diesel in 2019 which is equivalent to approximately 570,000 tones of H_2 by using Equation (2).

$$\text{Diesel demand [L]} = \frac{\text{Diesel energetic demand [TJ]}}{\text{Diesel Energetic content } \left[\frac{\text{MJ}}{\text{L}}\right] * \frac{1}{1000000} \left[\frac{\text{TJ}}{\text{MJ}}\right]} \tag{1}$$

$$\text{H}_2 \text{ demand [Ton]} = \frac{\text{Diesel energetic demand [TJ]}}{\text{H}_2 \text{ energetic content} \left[\frac{\text{MJ}}{\text{kg}}\right] * \frac{1}{1000000} \left[\frac{\text{TJ}}{\text{MJ}}\right] * 1000 \left[\frac{\text{kg}}{\text{Ton}}\right]} \tag{2}$$

3.2. Baseline estimations for CODELCO's and private copper mines

In this section, the main copper mines of Chile are identified with their respective copper production, fuel consumption in open pits, location and number of CAEX trucks. With this general information, an overview of the main copper areas in Chile is identified and an estimation of the equivalent hydrogen demand for replacing diesel consumption in the open pit mine transport operations is performed.

First, the state copper mining company CODELCO (National Copper Corporation) is analyzed, which is the biggest mining company in the world with a total production of 1,727 kTon of fine copper in 2020 which represents 30% of the Chile's total production. CODELCO owns totally six mines and has some participation in two other mines in Chile, in the following table general information of this mines is presented:

Mines	2019 Annual production [kTon Cu][1]	2019 Total Fuel consumption [TJ][2]	# CAEX trucks
Chuquicamata	385.3	5,960	95[3]
Andina	170.3	1,830	10[4]
Teniente	459.7	1,760	18[5]
Gabriela Mistral	104.1	1,620	18[6]
Radomiro Tomic	266.4	6,580	98[4]
Ministro Hales	151.8	3,470	39[7]
Salvador	50.6	1,020	18[8]

Table 6: Annual copper production, fuel consumption and CAEX fleet of CODELCO's mines.

The values of fuel represent the total fuel consumption of each mine, including open pit and underground mine operations, smash and grinding, LX/SX/EW processes, services and smelting or refinery in the case of mines that have this operations in their site like Chuquicamata, El Salvador and El Teniente (just smelting). Data from CODELCO between 2014 - 2017 was used to estimate the participation of fuel consumption in open pit mines and for simplification, it is assumed that all the fuel corresponds to diesel and consumed only by CAEX trucks because other heavy duty machinery fuel consumption is negligible compared to CAEX's considerable consumption or are simple driven by electro-mechanical systems. Table 7 shows the estimated diesel consumption of each mine of the company CODELCO and the equivalent H_2 consumption considering 100% replacement and by using Equations (1) and (2) with the respective LHV values of diesel and H_2 mentioned in section 5.1.

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1 Cochilco. Yearbook of copper and other metal statistics 2001-2020.

2 Codelco. Reporte avance del convenio de cooperación entre ministerio de energía y consejo minero. 2020.

3 Córdova, Gustavo. Mejoramiento de prácticas operacionales para el aumento de horas efectivas camiones de extracción gerencia mina, división ministro Hales Codelco chile. Universdiad de Chile, 2017

4 Mujica, Andrés. Factibilidad de implementación de camiones autónomos en división Radomiro Tomic, Codelco. Universidad de Chile, 2019.

5 Villaroel, Cristian. Aplicación de lean managment en una mina rajo abierto división el teniente. Universidad de chile, 2015.

6 https://www.litoralpress.cl/sitio/Prensa_Texto.cshtml?LPKey=VHEJ46N4OSVE6GDS4VFYH72VKHSSKVBYVFLSF6UA7AV6R7UG2HXQ

7 ttps://www.codelco.com/cgi-bin/prontus_imprimir.cgi?_URL=http%3A//www.codelco.com/prontus_codelco/site/artic/20110421/pags/20110421111840.html

8 https://energiminas.com/belaz-logra-colocar-sus-primeros-18-camiones-mineros-en-una-operacion-extractiva-en-chile/

CODELCO mines	Open pit diesel participation [%]	2019 CAEX fuel consumption [L]	H_2 equivalent [ton]
Chuquicamata	64	105,955,556	31,787
Andina	34	18,874,417	5,662
Teniente	96	5,866,667	1,760
Gabriela Mistral	79	34,200,000	10,260
Radomiro Tomic	76	169,983,333	50,995
Ministro Hales	36	92,533,333	27,760
El Salvador	12	10,200,000	3,060

Table 7: Diesel consumption and H_2 equivalent in CODELCO's open pit mines.

The same analysis is done for the other 70% of Chile's production, where the most important mines are considered like Escondida mine, property of BHP Hilton which produced 20% of the copper in Chile in 2019 with 1,187.3 kTon of fine copper and is the biggest copper mine in the world. In this part the information is more precise because each data was taken from the specific mine energetic reports developed by the Ministry of Energy and the Chilean Copper Commission COCHILCO. In most of the reports, the specific CAEX total diesel consumption in open pit mine operations is precised and the reports where no specific information is presented, calculations are made assuming 24/7 operation and consumption of 3,300 liters of diesel per day per CAEX truck.

Private Mines	2019 Annual production [kTon Cu]	2019 CAEX Fuel consumption [L]	H_2 equivalent [ton]	# CAEX trucks
Escondida	1,187	295,360,000	88,608	168
Bronces	324	86,883,000	26,064	69
Pelambres	372	71,691,000	21,507	56
Collahuasi	565	168,000,000	50,400	118
Soldado	54	10,114,020	3,034	6
Centinela	276	24,081,000	29,451	72
Zaldivar	97	32,535,000	9,760	30
Sierra Gorda	114	88,749,119	26,625	58

Caserones	145	37,087,200	11,126	27
Candelaria	111	40,880,000	12,264	35
Antucoya	72	16,591,000	4,977	16
Lomas Bayas	79	31,566,739	9,480	26

Table 8: Diesel consumption and H_2 equivalent in private's open pit mines (Reporte Avance Convenio Cooperación entre Ministerio de Energía y Consejo Minero)

3.3. Scenario 2030-2050 estimations

The final demand of H_2 for each mine should consider the requirement of dual combustion engines under development by the technological consortium led by ALSET, in which a 60% H_2 and 40% diesel internal combustion engine is proposed and considering the complete replacement of the diesel engine system with a fuel cell system following the recent projects of FCEV trucks from Anglo American and Hydra project. Another aspect to be considered is the fact that this new technology is still in pilot phase and it will advance gradually while it is developed, so it cannot be assumed that all the CAEX trucks fleet will integrate dual internal combustion engines at some point in the short or mid-term. For the short term, it will be assumed a conservative and low hydrogen market penetration of 10% in Chilean copper mines in 2030 which is also aligned with CORFO's proposal (Gomez, 2020). For 2050, it is assumed a 37% implementation according to the Determined Contribution at National Level (NDC) report (Energy Ministry, 2020). With all this information, it is possible to estimate the amount of CAEX trucks that can be retrofitted into H_2ICE and FCEV.

In order to estimate the diesel consumption and the hydrogen demand of each mine in 2030/2050, the projection of the copper mining industry energy demand in the Long Term Energetic Planification (PELP) of the Energy Ministry is used. However, this methodology is not the most accurate since it doesn't differentiate the fuel consumption from the electric consumption and it assumes a relatively optimistic copper production until 2050 while some considerations have to be paid attention for the future of copper mining in Chile. Firstly, since 2003 the copper concentration or "copper law" has decreased from 1.13% to 0.67% in 2019 (Cochilco, 2019) meaning that more material need to be extracted to be processed which makes more attractive for copper mines to prioritize the final production of copper concentrates rather than copper cathodes. Consequently, the use of the crushing-grinding process increases and the fact that this process is by far the more intensive in terms of electric and water consumption in the copper industry, the global electric consumption is expected to increase through the years but not only by the crushing-grinding process itself, also because of the increasing desalinated water consumption that requires large amounts of electricity, especially for pumping water to the mining sites.

Secondly, the decrease of copper concentration signifies that it is also necessary to extract material deeper inside the open pit mines, which has a direct repercussion in the amount of fuel consumed by the CAEX mining trucks and the their fleet size as more distances traveled require more fuel and more material extractions requires to increase the number of CAEX in each mine. However, at a certain point it is not economically viable to go deeper in an open pit mine and the transition to underground mines is explored by mining companies. So in conclusion, the continuously and increasing production of copper either by maintaining current mine operations, expanding old mines or by new mining projects, will signify in an increase of the electric and fuel consumption in this industry in the long term. Thus, even thou assuming the PELP energy projections is not the most accurate methodology, it can give a reasonable estimation of the fuel consumption in the future.

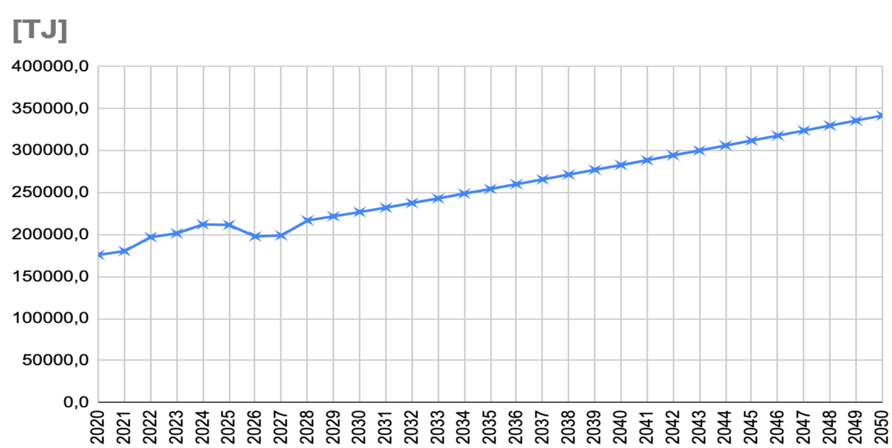


Figure 20: PELP Energy demand projection of the copper mining industry. Own elaboration.

A critical consideration for the future projections of the copper mines identified in this work is that in order to be consistent with the copper mines long term planification and give a more accurate analysis of the specific integration of green hydrogen in each mine, the lifetime of the mines should be considered in order to correctly select the ones that are planned to operate in the long term.

Mine	Lifetime deadline	Considered in the study
Chuquicamata*	2050 **	Yes
Ramorio Tomic	2030	No
Ministro Hales	2030	No
Andina	2050	Yes
Teniente*	2050 **	No
Salvador	2050 **	Yes
Gabriela Mistral	2028	No
Escondida	2040	Yes
Bronces	2036	Yes
Pelambres	2035	Yes
Collahuasi	2040	Yes
Soldado	2027	No
Centinela	2042	Yes
Zaldivar	2030	No
Sierra Gorda	2035	Yes
Spence	2050 **	Yes
Caserones	2040	Yes
Candelaria	2030	No
El Abra	2050 **	Yes
Antucoya	2035	Yes
Lomas Boyas	2040	Yes

Table 9: Lifetime of copper mines identified in this study

**Underground mine / ** Lifetime projected further than 2050*

Table 9 shows the estimated lifetime of each mine identified in this study considering potential extensions planned by the owners and globally the criteria for selecting the mines considered in this study consists in discarding those mines that are not expected to operate beyond 2030. Some copper mines have the potential of becoming underground mines after their lifetime, but this type of mines are not considered in this study as they use different and smaller mining trucks like LHD, with the exception of Chuquicamata, one of the most emblematic open pit mine in the world and that is currently in the transition of operating just as an underground mine since the open pit is in the last cycle of its lifetime and is planned to operate gradually until 2028-2029. Hence, for 2030 scenario the analysis of Chuquicamata mine will consider a potential hydrogen demand from the LHD trucks in order to set a baseline for a further investigation in the integration of fuel cells in underground operations. The calculations for this specific case are based on direct information given by shift operators of the mine regarding the actual copper production and LHD models and fleet size.

Finally, for longer term projections beyond 2050 the potential hydrogen demand is estimated for the whole copper mining industry considering the production projections and targets for 2050 due to the lack of information and uncertainty related to the future of mining projects. For this, one alternative is exploiting equations (1) and (2) considering the total fuel consumption (TJ) in 2020, the open pit participation in the total fuel consumption and the PELP energy projections. An alternative analysis can be performed considering the total CAEX fleet in Chile reported by Editec in 2020, the PELP energy projection and assuming 24/7 operation with an average CAEX diesel consumption of 3,300 liters per day.

3.4. CO_2 emissions and water consumption

With the results that will be obtained with the previous methodology it is possible to estimate how much CO_2 emissions will be produced by every fleet of CAEX trucks in each mine considering green hydrogen implementation for the projected scenarios of 2030 and 2050 and considering business as usual with no green hydrogen integration in the copper mines. The calculation is based in the following equation:

$$CO_2\ emissions\ [Ton] = Energy\ consumption\ [TJ] * EF\ \left[\frac{Ton}{TJ}\right] \tag{3}$$

Where EF is the emission factor of diesel and its value is 74 Ton/TJ (Cochilco, 2021). The saved emissions are calculated considering the energy replaced from diesel with hydrogen:

$$CO_2\ saved\ emissions\ [Ton] = Energy\ consumpt.[TJ] - H2\ replaced\ [TJ] * EF\ \left[\frac{Ton}{TJ}\right] \tag{4}$$

A similar analysis is done for estimating the potential water consumption of hydrogen production in the future scenarios based on the following equation:

$$Water\ consumption\ [L] = H_2\ production\ [Ton] *\ WC\left[\frac{L}{Ton}\right] \tag{5}$$

where WC is the specific water consumption of producing 1 kilogram of hydrogen which from a stoichiometric perspective corresponds to 9 liters of water per kilogram of hydrogen (IRENA, 2021). Some manufacturers like Plug Power specified a water consumption of around 11.5 liters per kilogram of hydrogen in their 5 MW GenFuel electrolyzer model while Siemens reported a water consumption of 10 liters per kilogram of hydrogen in their Silyzer 300 model. However, taking into account some inefficiencies in the whole process and considering the process of demineralization, the water consumption can range between 18 to 24 kilogram of water per kilogram of hydrogen (IRENA, 2020). A study held in Australia estimated that the water consumption for green hydrogen produced from solar PV and the grid was of 40 L/kg and 130 L/kg respectively (Shi, 2020). Finally, the water consumption will be estimated considering the theoretical consumption, and average water consumption considering demineralization and consumption with a PV and grid configuration.

3.5. Copper mines mapping

Every mine was located by using the tool of Google Earth (Annex 1). It is evident that the most dense mining area is the northern part of Chile, specifically the Antofagasta region where several major copper mines can be identified. Among this mines, the bigger ones are Escondida, the biggest copper mine in the world located 170 kilometers at the southeast of Antofagasta city, Collaguasi mine which is located in Tarapacá region but close to the limit with Antofagasta region and Chuquicamata, Radomiro Tomic and Ministro Hales property of CODELCO located in Calama city. But as mentioned before in this study, only Chuquicamata mine is considered due that the other CODELCO's mines are planned to operate until 2030. Other smaller but not less important mines such as Spence, Sierra Gorda, Centinela, Lomas Bayas, Antucoya and El Abra are located in this zone. The whole mining area identified contributed to around 60% of the total copper production of Chile in 2020. The next interesting mining area is in the surroundings of the city of Copiapó in the Atacama region, and the mines that distinguish the most are El Salvador, Caserones and Candelaria, but this last one is also in its last lifetime cycle and is not considered. Finally, in the central zone of Chile several mines can be identified such as Andina and Los Bronces that are located near the capital Santiago de Chile, Pelambres and the underground mine El Teniente that is not considered in the study. Each mining area will be referred as Zone 1, Zone 2 and Zone 3 respectively, from north to south and they are shown with more detail in Annex 2, Annex 3, Annex 4.

Due that Zone 1, in a first approach is by far the most interesting mining area for what concerns green hydrogen demand and renewable energy sources, only this zone will be studied while the other zones will be left for further study, especially the central zone (Zone 3) that has the best copper mining potential in the country since it has the largest copper reserve in the area of Rio Blanco-Los Bronces which has an estimated reserve of 200 million tons of copper and higher than Chuquicamata's and Escondida's reserve of 135 and 144 million tons respectively according to different projections (Valor Minero, 2017).

3.6. Green H_2 supply chain design

In this section, the design of the hydrogen supply chain required for Zone 1 is performed. The design must include the sizing of the production plant with the integration of a renewable plant and considering water and electrical consumption, a liquefaction plant or compressors, storage, transportation and refueling station.

3.6.1. Case of study: Zone 1 - Calama city

The city of Calama is located at 2,260 meters above the sea level in Antofagasta region and in the middle of the Atacama desert, the driest desert of the world. It may be considered as the mining capital of Chile due to the heavy presence of copper mines around the city, in fact, the closest open pit mine is less than five kilometers close from the urbanization of Calama. Three of the four biggest mines of the state company CODELCO, Chuquicamata, Ministro Hales and Radomiro Tomic mining divisions are near the city while other private mines such as Spence, Sierra Gorda and Centinela are less nearer at around 50 kilometers from the city. But this city not only is characterized for the copper industry, it is also becoming one of the hotspots for the development of renewable energy projects as the area of Calama has one of the best solar radiations in the world and strong winds from the Cordillera de los Andes. Multiple solar and wind energy projects of 50-230 MW are installed in the surroundings of Calama, including a concentrated solar power (CSP) plant of 110 MW and geothermal power plant of 48 MW. The whole region of Antofagasta is considered the energetic capital of Chile as it generates one fourth of the energy (still with major participation of fossil fuels) of the National Electric System (SEN) with an installed capacity of 6,354 MW and currently 26 new renewable projects are under construction that will contribute with an additional 2,680 MW to the energetic matrix (Energy Ministry, 2021).

Figure 21 shows with detail the case of study selected which consists in a sub-area of Zone 1 excluding Collaguasi and Escondida mines that are located much further to the north and south of Calama respectively but have the biggest hydrogen demands from the copper mines considered in this study, so they should be further analyzed separately. The map of the case of study also shows multiple renewable plants in the area and the Port of Mejillones, which is a major port with the potential of exporting green hydrogen to other countries.

Figure 21: Calama city case of study map. Source: Own elaboration using Google Earth Pro

3.6.2. H_2 - RES plants configurations

The analysis of the hydrogen production in the different mining areas will be done considering two types of configurations with Renewable Energy Source (RES) plants: (1) Direct connection with off-grid PV or Wind plant and (2) Indirect on-grid connection to PV/Wind/CSP plant through Power Purchase Agreements (PPA). The objective of this analysis is to estimate the potential best option to produce hydrogen based on the levelized cost of hydrogen (LCOH) and comparing it with the equivalent cost of diesel to determine if the hydrogen integration in copper mining is economically viable or not. For simplification, the hydrogen demand required by the CAEX mining trucks is considered to be constant due that mining operations are 24/7.

The first configuration consists in an off grid PV or onshore Wind plant integrated directly to the PEM electrolyzer, meaning that the electrolysis process will be influenced by the intermittent operation of the PV or Wind plant, hence, the capacity factor of the hydrogen plant will be the same as the PV/Wind plant. For this case, as the PV/Wind system is integrated to the production of hydrogen, the capital (CAPEX) and operational (OPEX) expenditures are considered in the specific cost of producing hydrogen. The objective of this configuration is to analyze the trade-off between reducing the electricity cost to zero (by using own generated electricity), not having extra cost related to grid connection and the increase of the total cost of the integrated on-site system.

This type of configuration allows the oversizing of the PV plant in order to increase the capacity factor of the H_2 plant, this give the advantage of increasing the available energy for producing more hydrogen but always limited to the maximum hydrogen production possible determined by the electrolyzer efficiency and considering that a potential large part of the PV production could be wasted. This increase of hydrogen production generates an interesting trade-off with the increase of CAPEX and OPEX of the oversized PV plant. The oversizing of an on-shore wind plant is less suitable due to its higher capital costs and its less availability in the zone of study compared to solar energy. Globally, the hydrogen production may be affected with the off-grid configuration as it is limited to the available solar hours so the daily hydrogen demand could be certainly not be matched in some cases and it could not be suitable for the intensive demand of hydrogen required by the CAEX mining trucks operations which are usually 24/7. So it is compulsory to include an optimum hydrogen storage system capable of accumulating the excess hydrogen produced in peak solar production days for meeting the demand when the solar availability is low and is not able to meet the demand. The oversizing of the solar PV plant lowers the risk of not achieving the hydrogen demand in case of meteorological phenomena and the excess electricity could be stored in batteries in order to produce hydrogen as back-up or supply energy to other processes.

The second configuration considers the indirect supply of electricity via PPA's from Solar, Wind or CSP plants. A PPA consists in a bilateral financial energy contract between a generator and a client or consumer available in the Chilean electricity market. This mechanism allows industrial companies with highly intensive energy demands like mining (regulated clients with power contract higher than 5 MW) to negotiate freely their energy supply with a producer at a convenient price for both parties. The advantage of this type of contracts is that the consumer will have a constant supply at the agreed nominal power during the solar hours block between 8am to 18pm. Hence, a H_2 plant supplied with a solar PPA would increase the overall efficiency of the system as higher operating hours, the lower the cost of producing hydrogen mainly due to the electrolyzer size reduction. However PPAs are in general more expensive than the levelized cost of energy (LCOE) of a specific PV plant or electricity prices from public auctions for regulated clients (power demand lower than 5 MW) and the constant baseload of this contracts reduces the flexibility of the power system.

A summary of the different scenarios is shown next:

1) Direct connection with Off-grid PV plant
2) Direct connection with Off-grid oversized PV plant
3) Direct connection with Off-grid Onshore Wind plant
4) Indirect connection with On-grid PV plant via PPA
5) Indirect connection with On-grid Onshore Wind plant via PPA
6) Indirect connection with On-grid CSP + TES plant via PPA

The electrolysis plants considered in this study are based on the PEM technology manufactured by NEL ASA. The hydrogen production process designed by NEL consists in a Proton Exchange Membrane (PEM) electrolyzer feeded with water and with electricity from a voltage supply, the hydrogen generated from the electrolyzer passes through a hydrogen/water separator that removes liquid water from the high pressure hydrogen and recycles it to the water tank, the hydrogen is then dried in multiple beds filled with desiccant in order to absorb water and reach the optimal dew point. The whole process is able to deliver hydrogen with a high purity of 99,9998% to the next process of the supply chain.

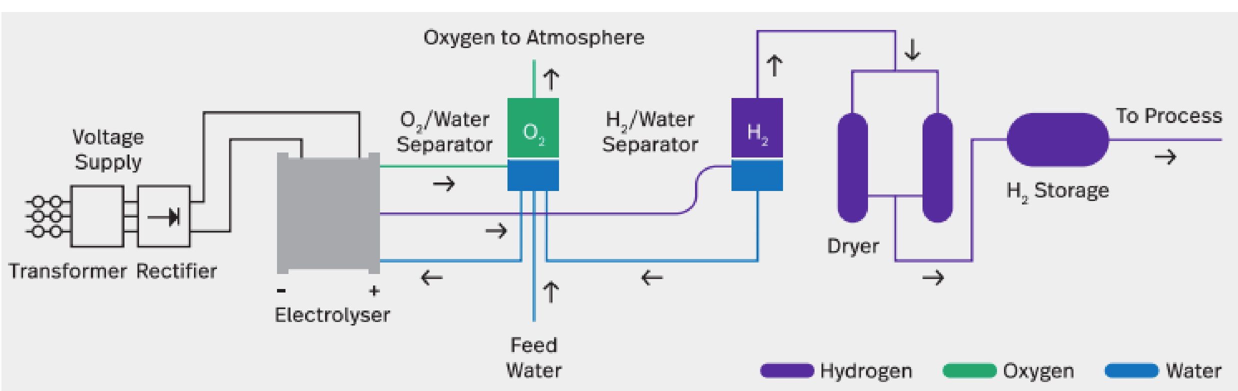


Figure 22: PEM electrolysis hydrogen production process (NEL ASA, 2021).

The electrolyzer selected for this study is the containerized M series model M400 suitable for harsh outdoor conditions like the mining industry and flexible operation for renewable energy feedstock as it has fast response times and a dynamic production range (10 - 100%). The specific parameters of this electrolyzer model are shown in the following table.

Parameters	Value	Unit
Net production rate	413	[Nm^3/h]
Stack power consumption	4.53	[kWh/Nm^3]
Delivery pressure	30	[bar]
Feed water consumption	0.9	[L/Nm^3]
Electrolyzer container W x D x H	12.2 x 2.5 x 3	[m]

Table 10: Main parameters of the PEM electrolyzer M400 (NEL ASA, 2021)

The manufacturer specifies that the total stack power consumption will be higher and depend of the system configuration. For this study, a conservative stack efficiency of 60% LHV will be considered and hence the specific energy consumption of the cells stack assumed will be 5 kWh/Nm^3 or 55.5 kWh/kg. For future scenarios, stack efficiencies between 66% and 70% could be expected (Peterson, 2019).

3.6.3. Electrolyzer sizing

For direct connected off – grid PV plant, the PV – electrolyzer direct coupling configuration is assumed, which is the most basic way of producing hydrogen from solar energy as only few controls form part of the power electronic system and considers just a switch that disconnects the system in case the current fed to the electrolyzer is lower than the safety limit. This basic system has the advantage that it has no cost associated to DC/AC inverter systems which consequently lowers the total capital costs of the whole system (Shiriyan, 2020). The same approach is contemplated for the onshore Wind – electrolyzer system with the difference that wind power generation produces AC current so inverters are required in order to feed the electrolyzer.

The sizing of the electrolyzer is performed using a general methodology and numerical/analytical methodologies are left for further investigation since the objective of this study is to asses a potential supply chain for copper mining industry rather than the analysis of the performance and dynamic behaviour of electrolyzers coupled with intermittent renewable energies (e.g. I-V curves, MPP optimization, irradiance and temperature variations, inefficiencies, etc).

The equation used for determining the size capacity of the electrolyzers P_{H_2} in kilowatt is given as it follows:

$$P_{H_2} = \frac{EL_{H2}}{h * CF} \tag{6}$$

where EL_{H_2} is the annual hydrogen load energy consumption in kilowatt-hour, h is the hours in a whole year and CF is the capacity factor. In the case of off-grid configurations, it is assumed that the electrolyzers capacity factor is the same as the renewable plant. EL_{H_2} depends on the annual hydrogen demand M_{H_2} in kilograms and the electrolyzer stack specific energy consumption C_{El} in kilowatt-hour per kilogram of hydrogen:

$$EL_{H_2} = M_{H_2} * C_{El} \tag{7}$$

For example, the minimum electrolyzer capacity needed to meet an hydrogen demand of 1,000 ton considering a PV – H_2 plant, a CF of 32% in Calama and the stack specific energy consumption of NEL electrolyzer is:

$$19{,}798\ [kW] = \frac{1{,}000{,}000 \left[\frac{kg}{year}\right] * \ 55.5 \left[\frac{kWh}{kg}\right]}{8{,}760 \left[\frac{h}{year}\right] * 0.32}$$

3.6.4. Solar/Wind plant sizing

One of the main constraints of integrating intermittent renewable energies for producing hydrogen is that load fluctuations affect the performance of the electrolyzer and their start-up/switch-off times can reduce the hydrogen production. So for technical and safety reasons, electrolyzers are designed to operate with a minimum load. PEM electrolyzers can handle better load changes than

Alkalyne electrolyzers as their minimum load lies between 0% to 10% while Alkaline only achieves 20% - 40% (Smolinka, 2011).

As in this study no numerical/analytical optimization is performed, the dynamic behaviour and responses of the electrolyzer is not further investigated. However, a general methodology can be performed considering a minimum PEM load so that the sizing of the off grid solar/wind plants can be more reliable and close to reality. For this, the solar and wind explorers developed by the Energy Ministry of Chile are used. This tools provide meteorological data bases of the majority of the Chilean territory and can estimate solar and wind generation for different type of configurations, generators models and technical inputs for each technology. The tool gives as output the annual solar or wind profile of a specific location and with a simple model using as constraint a minimum PEM load of 10%, a sizing coefficient S_{EL} can be obtained. The coefficient is calculated by the following equation:

$$S_{EL} = \frac{EL_{real}}{EL_{H_2}} \tag{8}$$

where EL_{real} is the real annual hydrogen load energy consumption considering that the electrolyzer only produces hydrogen when the hourly energy production of the solar/wind plant profile is higher than 10% of the electrolyzer capacity P_{H2}. With this, the size capacity of the solar/wind plant is obtained as it follows

$$P_{solar/wind} = \frac{EL_{H_2}}{h*CF} * S_{EL} \tag{9}$$

In the case of hydrogen production based in on-grid indirect connection via PPA, a similar calculation is made by just modifying Equation (9) into:

$$P_{RES\_PPA} = \frac{EL_{H_2}}{h*CF} \tag{10}$$

As it is considered that PPA contracts are able to secure constant supply at the agreed nominal power, the hydrogen plant connection is not linked or affected to instantaneous variations of the RES plants, hence, the electrolyzer minimum load issue is not considered for this configurations.

3.6.5. Storage, compression and HRS sizing

In order to ensure that the supply chain can meet the refueling requirements of the mining trucks for the material extraction operations, it is necessary to reasonable size the storage, compression, transportation of hydrogen and the HRS capacity. Some of this components can vary depending if the supply chain configuration considers a centralized production where large scale hydrogen plants produce for different copper mines or decentralized production where each mine has on-site hydrogen production .

Low-pressure storage

The storage capacity of hydrogen after production is a crucial design parameter in order to ensure reliability in the supply chain of hydrogen and this can be done using low-pressure tanks (< 200 bar) which its main function is to operate as surge buffer. The storage system must be able to store at least the average daily CAEX trucks demand considering 24/7 operation. However, the intermittency of the renewable energy supply to the hydrogen plant may provoke that the hydrogen production is higher than the daily demand, meaning that if the storage system is not oversized, the excess of hydrogen production will be lost. For this, it can be assumed that the low pressure storage needs to be capable of storing a quantity of hydrogen equal to the mining site daily average demand of 3 days. With this assumption, the storage system can safely secure the supply of hydrogen to the CAEX trucks against unplanned interruptions of the plant, the variability of the renewable energy plant and peak demands depending on the daily roadmap and operation planning of the CAEX trucks. The following equation is used to calculate the low-pressure storage capacity C_{LPS} :

$$C_{LPS} = D_{H_2\_avg} * SF \tag{11}$$

Where $D_{H_2\_avg}$ is the daily average hydrogen demand in the copper mine and SF is the safety factor assumed to be equal to 3 days of storage. In case of centralized hydrogen production, an extra low-pressure storage system must be included upstream in the hydrogen supply chain and will depend on the total hydrogen demand it needs to supply, so a higher SF is recommended. In case the supply chain is based on GH_2 or LH_2, the estimation of the volumetric size of the storage must consider the volumetric densities of GH_2 and LH_2.

Compressor

An general method for sizing the compressor capacity needed to take the hydrogen production pressures (20 – 30 bar) up to higher pressures (200 – 900 bar) is assuming an adiabatic compression process (Li, 2009).

$$W_c = C_c * \frac{T_1}{\eta_c}\left(\left(\frac{P_2}{P_1}\right)^{\frac{r-1}{r}} - 1\right) * m_c \qquad (12)$$

Where C_c is the specific heat of hydrogen at constant pressure (14,304 KJ/kgK), η_c is the compressor mechanical efficiency (70%), T_1 is the hydrogen temperature at the compressor inlet (293 K), P_1 and P_2 are the compressors input and output pressures, r is the specific heat ratio (1.4) and m_c is the hydrogen mass flow rate through the compressor (kg/h). The minimum hydrogen mass flow rate needed corresponds to the HRS capacity divided in each hour of the day, however the compressors must be designed to meet the hydrogen demand during the CAEX trucks filling process which occurs generally two times a day after each shift of 12 hours.

Transportation

In case hydrogen needs to be distributed from a centralized hydrogen production plant to the mining copper HRS, the transportation capacity is crucial for delivering the required hydrogen demand. For road transportation through trailer trucks, the following equations can be used to estimate the size of the fleet of trucks N_{trucks} required:

$$N_{trucks} = \frac{C_{LPS}}{T_c * UF * f_{truck}} \tag{13}$$

Where D_{HRS} is the final daily hydrogen demand needed in the HRS (kg/day), T_c is the truck capacity (kg), UF is the utilization factor (%) based on the availability of the trucks and f_{truck} is the daily frequency in which each truck can deliver during a day based on the distance covered d, truck velocity v and loading/unloading times l_{truck} and u_{truck} respectively:

$$f_{truck} = \frac{24[h]}{\frac{d}{v}[h] + l_{truck}[h] + u_{truck}[h]} \tag{14}$$

It must to be noticed that in case of CH_2 transportation, the low-pressure storage at the HRS can be replaced by the same storage tanks transported by tube trailer trucks.

Hydrogen Refueling Station (HRS)

The capacity of the HRS of each mine is defined by the daily average hydrogen demand D_{H2_avg} and the number of dispensers will depend on the CAEX fleet and hydrogen tank capacity, filling time and dispatch/control plannings of each mine. On average, CAEX trucks need to refill every shift of 12 hours considering that the maximum fuel level until CAEX trucks can operate is 20% of its tank capacity. As mining operations are 24/7, the optimum amount of dispensers and hoses should be further investigated with analytical/optimization queuing models in addition to a fast hydrogen market expansion for enabling economies of scale and upgrading technological advances regarding the refueling of heavy duty vehicle (HDV) with larger tank capacities.

High pressure vessel

For calculating the capacity of the high pressure storage vessels, it is assumed that the optimum capacity is about 15% of the daily hydrogen refueling demand of the HRS based on the H2A simulation model developed by DOE (Tian, 2022).

On-board CAEX high pressure vessel

With the hydrogen demand projections results obtained from the methodology in 3.3 it can be estimated the daily amount of hydrogen that the CAEX trucks would need to operate. With this data known, it is possible to estimate different on-board storage capacities and HRS filling times with specific tank vessel models, different HRS filling rates and considering similar amounts of fuel filings per day than the normal diesel CAEX in order to ensure a similar operational performance.

The storage vessels considered are type-IV tanks of 9.8 kg – 18.4 kg at 700 bar and 4.7 kg – 8.4 kg at 350 bar from the manufacturer Hexagon Porous. Table 11 shows the specific parameters of this tanks.

Tank model	Diameter [mm]	Length [mm]	Weigh [kg]	Volume [L]
Type IV – N – 9.8 kg	530	2,154	188	244
Type IV – O – 18.4 kg	705	2,078	272	457
Type IV – H – 4.7 kg	430	2,110	67	193
Type IV – I – 8.4 kg	509	2,342	112	350

Table 11: Hexagon Porous tank IV specifications (Hexagon Porous datasheet, 2022)

The HRS filling rates considered are derived from the existent global refueling standard SAE JS2601 protocol for light duty vehicles refiling at 350 - 700 bar for maximum tank capacities of 10 kg and SAE JS2601/2 for heavy duty vehicles at 350 bar. The filling rates are 1.8, 3.6 and 7.2 kg/min (Elgowainy, 2017).

3.7. Economic parameters

The levelized cost of hydrogen (LCOH) is a measure of the net average cost of hydrogen taking into account all the capital and operating costs of producing hydrogen during the lifetime of the specific system. The same methodology can be used to estimate the levelized cost of the whole hydrogen supply chain for different pathways. The next formula shows how the LCOH is calculated in this study:

$$\text{LCOH} = \frac{\sum_{n=0}^{N} TOTAL\ COST * (1-r)^n}{\sum_{n=0}^{N} M_{H2} * (1-r)^n} \tag{15}$$

The calculation is done by determining the total discounted costs ($TOTAL\ COST$) for the life of the system divided by the total discounted hydrogen production (M_{H_2}). The $TOTAL\ COST$ corresponds to the whole system cost in the year n including capital expenditures (CAPEX), operational expenditures (OPEX), equipment replacement, electricity and water cost until the whole lifetime (N) of the system. Finally, the discount rate (r) for this economic evaluation will be assumed to be equal to the weighted average cost of capital (WACC) which is calculated with the following formula:

$$\text{WACC} = \mathrm{K_D} * (1 - T_C) * \frac{D}{E+D} + K_E * \frac{E}{E+D} \tag{16}$$

Where $\mathrm{K_D}$ and K_E are the cost of debt and equity, T_C is the corporate tax rate, and the components E - D represent the percentage of equity and debt. The lifetime (N) and discount rate or WACC will be assumed to be the same for every case of study and equal to 20 and 7% respectively. This last one is calculated by using the following assumption based on Aswath Damodaran cost of equity and capital for the Green & Renewable Energy industry in the U.S (Damodoran, 2021).

$\mathrm{K_D}$	5,93%	WACC	7,3%
K_E	8,24%		
T_C	1,43%		
E	60%		
D	40%		

Table 12: WACC parameters (Damodoran, 2022)

This value of WACC is in accordance with other studies based on projects developed in Chile like the work done by Armijo et al (2019).

3.7.1. Electrolyzers cost: CAPEX – OPEX

The precise cost of electrolyzers remains challenging to estimate as a wide range of costs can be found in past and recent studies, especially regarding PEM electrolyzers which may be considered to be still in an early stage of development compared to the widely recognized and mature technology of Alkalyne electrolyzers. But with today's increasing efforts on producing green hydrogen, PEM technology is gaining more attention than Alkalyne electrolysis due to its shorter time response that make them more suitable to react against the intermittent fluctuations of renewable energies like wind or solar. Even thou, according to IRENA, there is no a single electrolyzer technology that performs better in every technical aspect, both alkaline and PEM could be suitable to follow wind or solar fluctuations and the flexibility of this systems is limited mostly by the balance of plant (BoP) rather than the stack system itself (IRENA, 2020).

Considering the methodology developed by the National Renewable Energy Laboratory in 2015, the capital costs of an electrolyzer (CAPEX) includes the costs of the stacks, installation, BoP and indirect costs such as profit margins, marketing, administration and other costs than can add up to 50% of the total cost of the stack and BoP. The breakdown cost of the stack system is composed mainly by the manufacturing and materials costs of the Catalyst-Coated Membrane (CCM), Bipolar and End Plates, Porous Transport Layer (PTL), Membrane Electrode Assembly (MEA), Frame/Seal, and the stack assembly. The BoP consists in the sub-systems and equipments that allow the functioning of the stack like heat exchangers, pipes, pumps, valves and tanks for the cooling, hydrogen processing, deionized water circulation and power supply, DC voltage/current transducers for the whole power supplies system. Finally, the installation costs can reach values up to 30% of the total system cost (Mayyas, 2019).

One of the key factors for reducing the total cost of electrolyzers is achieving economies of scale by increasing stack production with larger scale automated manufacturing facilities. According to the methodology developed by NREL, the production rate of 1MW electrolyzers was in the order of magnitude of 10 units per year at the time of the study and in order to reach economies of scale, a target of 1,000 units per year should be attained. The following Figure 23 shows the total system cost breakdown for a system of 100 kW and 1 MW related to the annual production rate and it clearly exposes the significant cost reduction that can be reached if economies of scale are produced.

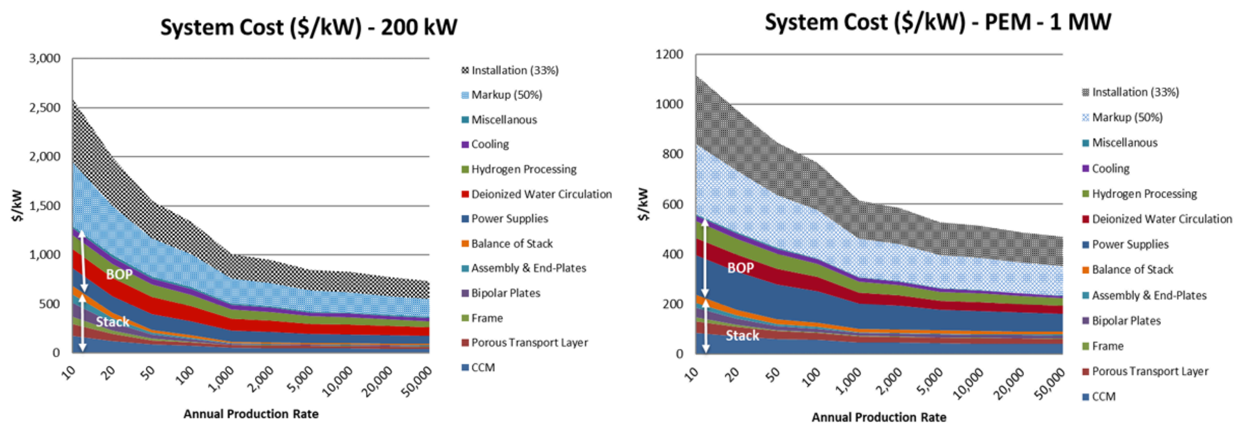


Figure 23: Installed system cost for a 200 kW and 1 MW PEM system respect to an annual production rate (Mayyas, 2019)

Other relevant studies reported similar ranges for the PEM system costs, like the work done by Tractabel where they selected CAPEX values of 1500, 1300 and 1200 €/kg for PEM systems of 1, 5 and 20 MW respectively for 2017 case of studies and 1000, 900 and 700 €/kg for the same capacities but for 2025 case of studies (Tractabel, 2017). Values of 700 €/kg in 2030 and 385 €/kg in 2050 for 15 MW PEM systems where considered by the report Power to Gas Roadmap for Flanders (Thomas, 2016). A more recent study elaborated by Deloitte reported values between 800 – 1800 €/kg for 2020 and estimated cost reductions to 600 – 1400 €/kg for 2030 with the possibility of reaching a lower level between 400 – 600 €/kg if R&D initiatives and scalability is successfully done (Deloitte, 2021). More optimistic studies elaborated by Mckinsey for the Hydrogen Council, the IEA and IRENA considered lower CAPEX values of electrolysis systems between 200 – 250 $/kg by 2030 (Mckinsey, 2021) , 269 $/kW by 2050 (IEA, 2020) and 100 – 200 $/kW by 2050 (IRENA, 2020). Finally, Saba et al. studied more deeply the state-of-art of electrolyzer's CAPEX and the reported values are shown in the following Figure 24:

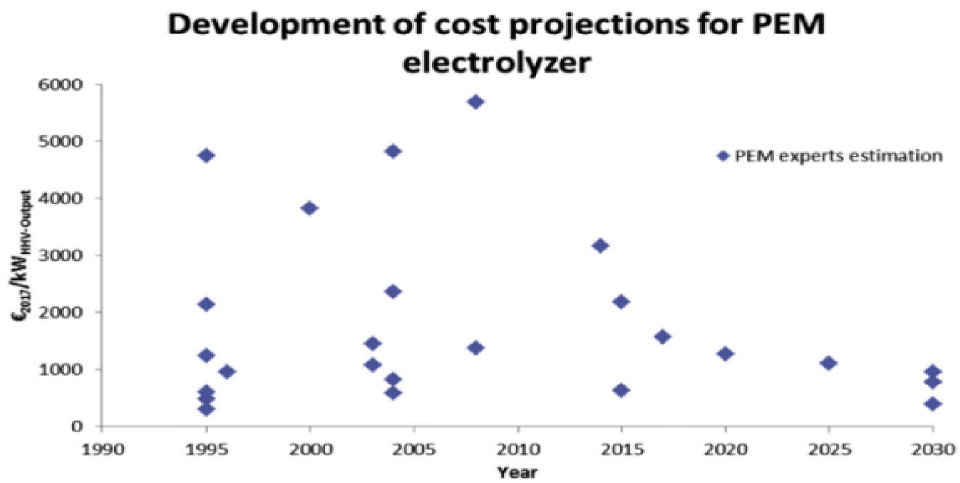


Figure 24: Compilation PEM plant from Joris Proost (2018) cost based on Saba et al. (Saba, 2017)

Based on the studies mentioned before, a CAPEX value of 1,200 $/kg is considered for actual base scenarios, and more conservatives values of 900 $/kg for 2030 and 500 $/kg for 2050. The operational expenditures (OPEX) includes operation costs, planned and unplanned maintenances and replacements of auxiliary components like pumps, filters, etc. It is generally assumed as a percentage of the total CAPEX cost and typical values range between 1 to 4 % according to the main literature reviewed before. For example, the Tractabel report considered for its business cases specific OPEX of 4%, 3% and 2% for 2020, 2030 and 2050 respectively while Deloitte's study reported values ranging between 2 to 4% for 2020 and 2030. Another study considered low, nominal and high values of OPEX of 17 $/kW, 13.6 $/kW and 20.5 $/kW (Yates, 2020). According to a report made by E4TECH, operational costs are very sensitive to the location (labour costs) and size, for example, for a 1 MW and 1.000 MW plant the values of OPEX can reduce from 5% to 1.5% (Bertuccioli, 2014). For this study, the OPEX values considered will be 3% for base scenarios, 2% for 2030 and 1% for 2050.

Economical Parameters	2022	2030	2050
CAPEX [$/kW]	1,200	900	500
OPEX [% of CAPEX]	3	2	1
Stack efficiency [% LHV]	60	65	70
Stack electrical usage [kWh/kg]	55.5	51.2	47.6
Stack replacement [% CAPEX]	40	35	30

Stack lifetime [hours]	80,000	100,000	120,000
Water consumption [L/kg]	9	9	9

Table 13: Economical parameters chosen in this study.

3.7.2. Other costs: Stack replacement, electricity and water cost

Stack replacement

The cell stacks of a PEM electrolyzer can have a specific lifetime of 50,000 to 80,000 hours and the targets for 2050 are stack lifetimes between 100,000 to 120,000 hours (IRENA, 2020). The operating hours of an electrolyzer will depend on the specific plant configuration and the overall capacity factor and this will determine if the stack system needs to be replaced at a certain point. For example, a system with a lifetime of 80,000 hours and 8,000 operating hours per year, means that a stack replacement would be needed after 10 years of operation. The stack replacement cost is usually reported as a percentage of the total CAPEX and typical values ranges between 30% to 45% (IRENA, 2020).

Water

In terms of water consumption, as already mentioned before, this study will consider desalinized water due to the fact that the main copper mines in Chile are located in areas of water scarcity and the installation of water desalination plants in the north of Chile is growing rapidly. Providing desalinated water to the copper mining industry in chile is challenging from the point of view of the high investments costs and electricity consumption from the process of desalination itself, but particularly the engineering challenge of pumping water to distances above 150km and altitudes higher than 2,000 meters above the sea level. Because of this, a higher desalinated cost of water of 5 $/L (Colegio de Ingenieros A.G, 2021) is assumed in this work in addition to the theoretical water consumption of 9 liters per kilogram of hydrogen (IRENA, 2021).

Electricity

Some indicators of the Chilean electric system can give hints of what is the cost of electricity in the country, for example in terms of marginal costs, which are the variable costs of the most expensive generation unit operating at a certain time, the average cost in 2020 reported in Crucero (Calama) substation was of 39 $/MWh (Generadoras, 2021). Also, the average market price (PPM) which is determined by the costs of the contracts informed by the generators to the CNE, in June-Septmeber of 2021 the PPM was 74.8 $/MWh (CNE, 2021). But since the electricity required for producing green hydrogen needs to be produced from renewable energies and the energetic matrix of Chile has still a considerable share of fossil fuels, the cost of solar and wind energy must be analyzed. For this, the public energy auctions for regulated clients can be used to estimate the range of prices of renewable energies in Chile, since the PPA mechanism for non-regulated or free clients is not public.

In Chile, the public electric auctions held in 2015 for regulated clients awarded an average price in the solar block 8h - 18h of 42 $/MWh with a minimum offered price of 29 $/MWh while the average price of wind project was 40.6 $/MWh to be supplied in 2021 (CNE, 2015). In the latest auction, the minimum solar price awarded was 13.2 $/MWh and the highest price was 26.8 $/MWh with an average of 22.8 $/MWh while the wind price awarded was of 25.2 $/MWh, all this awarded energy are supposed to start to supply in 2026 (CNE, 2021). This prices are consistent with the cost of energy reported by IRENA as the global weighted average LCOE of utility-scale PV plants declined from 38.1 $/MWh in 2010 to 57 $/MWh in 2020 and recent wind auctions and PPAs results reported prices falling to the range of 5 – 10 $/MWh. (IRENA, 2021). Another important technology starting to develop in the north of Chile is the Concentrated Solar Power (CSP) with Thermal Energy Storage (TES) which has already been successfully installed in the region of Antofagasta with Cerro Dominador project. Different studies based on this plant CSP + TES plant reported an optimal LCOE of 65.6 $/MWh for 2018 and 48.1 $/kW for 2030 (Gallardo, 2018) and 55.5 $/kWh for 2019 (Benitez, 2019) respectively. In the latest energy auction, a record 34 $/MWh CSP price was offered by Likana Solar to supply energy in 2026, but surprisingly the offer wasn`t awarded due that the auction design mechanism assigns no value to storage from renewable energy. CSP-PPA contracts could supply energy during 24 hours depending on the TES capacity, like Cerro Dominador project which has a TES storage of 17.5 hours trough molten salts. However, in this study a electrolyzer capacity factor of 90% will be assumed for hydrogen production for a CSP configuration.

Regarding PPA contracts, according to Verdejo in Calama non-regulated clients like the copper mining companies, pay around 56 $/MWh and this price could reduce up to 40 $/MWh in future contracts due to the penetration of renewable energies in the area (Verdejo, 2019). The energy company ENEL reported and average PPA in Chile of 68 $/MWh with an average duration of 10 years. (ENEL, 2021). For simplifications, conservative values are selected between the public auction prices and the few reported values of PPA prices.

Finally, for future scenarios, IRENA estimates that solar LCOE will be around 20 $/MWh in 2030 and in the range of 5 – 14 $/MWh in 2050, similar to the 20 $/MWh target in 2030 set by U.S Energy Department (DOE, 2021), while on-shore wind LCOE will reach 5 – 9 $/MWh in 2030 and 3 – 7 $/MWh in 2050 (IRENA, 2019). In Table 14, the summary of the LCOE and PPA costs assumed in this study is shown.

Parameter	Technology	2022 (baseline)	2030	2050
PPA [$/kWh]	Solar	0.035	0.030	0.015
	Wind	0.045	0.40	0.025
	CSP + TES	0.075	0.050	0.020

Table 14: PPA prices projections used in this study.

3.7.3. PV plant costs: CAPEX - OPEX

According to the last study of Renewable Power Generation costs in 2020 developed by IRENA the global weighted average total installed cost of utility-scale PV fell by 12% in 2020 to just 883 $/kW. India, China, Germany and Spain had even lower costs, specifically 596 $/kW, 651 $/kW, 700 $/kW and 761 $/kW respectively and Chile had an installed cost of 1,047 $/kW (IRENA, 2021). Even thou this value concerning PV investment cost in Chile reported by IRENA is far above countries like India and China, a study helded by INODU reported cost of installation between 669 – 742 $/kW for utility-scale PV of 50 – 100 MW based on information given by manufacturers that have PV projects in Chile (CNE, 2020). The cost breakdown of utility-scale solar PV total installed cost is mainly dominated by the PV modules costs (200 – 400 $/kW), racking and mounting, grid connection, mechanical and electrical installation and margin soft costs. (IRENA, 2021). Regarding O&M costs, studies reported OPEX costs of 2.3% of the total CAPEX cost for utility-scale PV with one-axis tracking (Tsiropoulos, 2017) and 1.7% for one-axis tracking PV in the north of Chile (Armijo, 2020).

For future scenarios, the Future of Solar Photovoltaic report of IRENA estimated that the total installed cost of PV projects would fall in the range of 340 – 834 $/kW in 2030 and continue to decrease until a range of 165 – 481 $/kW in 2050 (IRENA, 2019). The Department of Energy (DOE) of the U.S assumed total installed costs for 100 MW utility-scale PV systems between 550 - 750 $/kW in 2030 to achieve the new LCOE targets (DOE, 2021). Finally, Wood Mackinsey estimates values of PV cost investment around 600 $/kW for the world average and 700$/kW for Chile in 2030 (CNE, 2021)

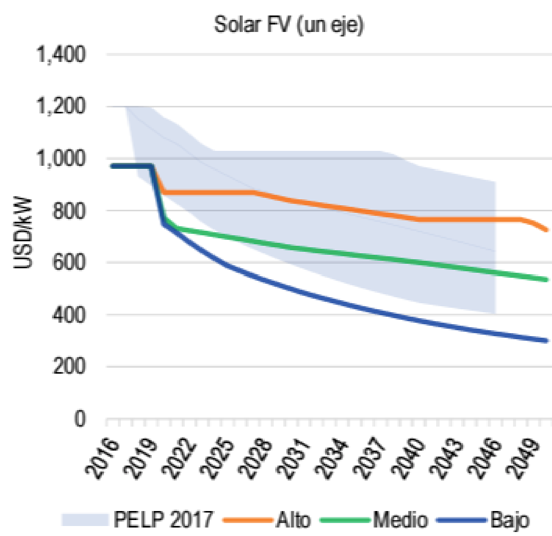


Figure 25: PV investment costs projections in Chile. (PELP, 2022)

Table 15, shows the one axis trackers PV total installed costs projections scenarios reported in the Long Term Energetic Planification (PELP) elaborated by the Chilean Energy Ministry in 2019. The results are consistent with the studies mentioned before as the costs considered in the scenarios of the report ranged between 800 – 1000 $/kW in the past few years, for 2030 in the range 500 – 900 $/kW and for 2050 between 300 – 700 $/kW considering a high, medium and low scenarios.

In this study, the baseline PV installed cost assumed will be of 750 $/kW and conservative values between the medium (green line) and low (blue line) scenarios presented in Chile's 2019 PELP will be assumed. For 2030 and 2050. At last, for simplifications and due to the harsh desertic conditions (dust, high temperatures and strong winds) that face the PV projects installed in the north of chile where the main copper mines are located, a fix OPEX will be considered for every scenario. The following table resumes the CAPEX and OPEX parameters considered in this study:

Parameter	2022 (Baseline)	2030	2050
CAPEX [$/kW]	750	650	400
OPEX [% Capex]	2	2	2

Table 15: Solar PV cost parameters assumed in this study.

3.7.4. Wind: CAPEX - OPEX

IRENA reported that by 2030 offshore wind installed cost could decline to the range 800 – 1,350 $/kW in 2030 and 650 – 1,000 $/kW in 2050. Even thou, lower costs has been reported around the world, for example the NREL reported an installed cost for a 2.6 MW land-based wind turbine of 1,436 $/kW (Stelhy, 2019) and Armijo reported CAPEX's of 1,300 $/kW and 1,200 $/kW for a 2 MW Vestas 90 class II and 3.3 MW Nordex N100 class 1 turbine models respectively (Armijo, 2019).

The study held by INODU reported wind installed costs between 1,448 and 1,492 $/kW for capacities in the range 100 – 250 MW in Chile (CNE, 2020). The PELP elaborated by the Chilean CNE estimated installed cost slightly lower than 1,400 $/kW for 2022, for future scenarios between 1,000 – 1,200 $/kW for 2030 and 850 – 1,100 $/kW for 2050. According to Wiser et al. , for installed offshore wind projects between 2015 and 2018, the O&M costs ranged between 33 – 59 $/kW (Wiser, 2020).

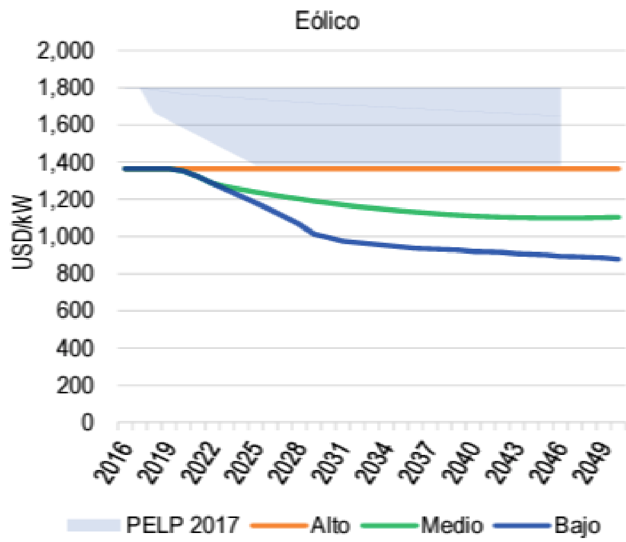


Figure 26: Onshore wind investment costs projections in Chile. (PELP, 2022)

Using the wind explorer tool of the Energy Ministry of Chile, two interesting windy zones can be found at the latitude of Taltal near the cities of Balmaceda and Calera and the Valley of Calama. In the first one, capacity factors between 38 – 51% can be achieved with a 122 meter high 3 MW class III turbine model from Alstom while in the Calama Valley capacity factors between 40 – 46% can be achieved using the same turbine model. At last, IRENA reported that the weighted average capacity factor for onshore wind has increased from 35% in 2010 to 43% in 2020 and future projects could achieve capacity factors up to 55% and 58% in 2030 and 2050 (IRENA, 2019).

Finally, with the information mentioned before, the parameters assumed in this study for onshore wind are shown in the following table.

Parameter	2022 (Baseline)	2030	2050
CAPEX [$/kW]	1,400	1,100	950
OPEX [% capex]	2.5	2.5	2.5
Calama CF [%]	40	45	50

Table 16: Onshore wind cost parameters assumed in this study.

3.8. Green hydrogen competitiveness with diesel

In order to incentive mining companies to replace diesel fuel with green hydrogen, it's evident that the price of this last one has to be competitive with the price of diesel, on the contrary, it will not be attractive for mining companies to enable a transition towards green hydrogen integration in their extraction operations due that price fluctuations can signify millions of dollars saved or extra in their annual cash flows.

A first approach for determining if replacing diesel with green hydrogen is economically viable is comparing the LCOH and diesel price considering the following energetic equivalence:

$$Diesel\ equivalent\ price\ \left[\frac{\$}{kg\ H_2}\right] = 3.33\ \left[\frac{L}{kg\ H_2}\right] * Diesel\ price\ \left[\frac{\$}{L}\right]$$

Where 3.33 coefficient is obtained by exploiting the lower heating values (LHV) of hydrogen (120 MJ/kg) and diesel (36 MJ/L) considered in this study. For future scenarios, the U.S diesel price ($/gallon) projections from the annual energy outlook are considered:

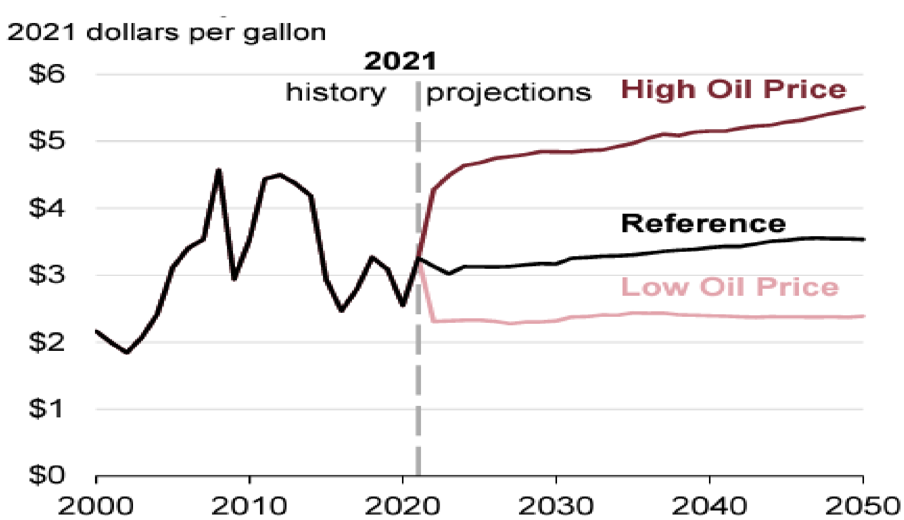


Figure 27: Diesel prices projections in $/gallon. (Annual Energy Outlook, 2022)

The following Table 17 and Table 18 show an approximation of the projections presented in Figure 27 considering that 1 U.S gallon is equivalent to 3.78 liters of diesel and that 1 kilogram of hydrogen is energetical equivalent to 3.33 liters of diesel respectively:

AEO 2021	2020 [$/L]	2030 [$/L]	2040 [$/L]	2050 [$/L]
High	0.66	1.24	1.37	1.48
Reference	0.66	0.84	0.95	1.00
Low	0.66	0.63	0.66	0.68

Table 17: Diesel prices projections based on Figure 27. (Annual Energy Outlook. 2021)

AEO 2021	2020 [$/kg]	2030 [$/kg]	2040 [$/kg]	2050 [$/kg]
High	2.20	4.13	4.56	4.93
Reference	2.20	2.80	3.16	3.33
Low	2.20	2.10	2.20	2.26

Table 18: Diesel equivalent price based on Figure 27.

Finally, it can be seen that the levelized cost of hydrogen (LCOH) should be at least in the range of 2.10 – 4.13 $ by 2030 in order to be competitive with diesel.

4. RESULTS AND DISCUSSION

4.1. Hydrogen demand projections and retrofitted CAEX's

For simplifications, the same trend based on PELP projections for estimating fuel consumption was applied to the CAEX fleet in each copper mine. Table 19 and Table 20 shows the projections of the 2030 scenario using all the assumptions and considerations mentioned in the methodology for CODELCO's mines and the rest of the private mines identified in this work.

CODELCO mines	**2030 Diesel consumption [L]**	**2030-H_2-CAEX consumption [ton]**	**#CAEX 2030**
Chuquicamata	30,000,000	9,009 (LHD)	46(LHD)
Andina	26,295,206	7,889	14

El Salvador	14,210,299	4,260	25

Table 19: Diesel and H_2 projections in CODELCO's open pit mines for 2030 scenario.

The analysis of Chuquicamata underground mine is included and the estimation of diesel consumption of the LHD trucks is performed considering that currently the mine is extracting 40,000 ton per day with 11 LHD of 21 ton capacity and 2 LHD of 15 ton according to the information given by a chief of shift in the mine. The target of the mine is extracting 140,000 tons per day for an annual production of 360,000 of copper which should be accomplished during the ramp-up period after the gradual transition from the open pit is completed. The fuel estimation is based in this information and considering the 21 ton LHD Sandvik LH621 model of 352 kW of power, fuel tank capacity of 740 liter, average fuel consumption at 50% load of 45 liter per hour (Sandvik, 2021), the need of refueling in each shift of work (8 hours each) and a conservative annual availability of 80% per LHD.

Private Mines	**2030 Diesel fuel consumption [L]**	**2030-H_2-CAEX consumption [ton]**	**#CAEX 2030**
Escondida	411,485,678	123,446	234
Bronces	121,042,491	36,313	96
Pelambres	99,877,504	29,963	78
Collahuasi	234,051,983	70,216	164
Centinela	136,768,555	41,031	100
Sierra gorda	123,642,306	37,093	81
Spence	65,088,742	19,527	38
Caserones	51,668,647	15,501	49
El Abra	30,379,892	9,114	20
Antucoya	23,114,027	6,934	16
Lomas Bayas	43,977,725	13,193	26
TOTAL	1,343,131,573	403,343	902

Table 20: Diesel and H_2 projections in private open pit mines for 2030 scenario

Green hydrogen will be implemented gradually up to a level of 10%, so the integration of the H_2ICE and FCEV technology assumes that 10% of the total diesel consumption in each mine will be replaced in retrofitted CAEXs with 60% H_2 and 40% diesel (with the exception of Chuquicamata mine where fuel cell LHDs are considered). In this way, only a percentage of each

CAEX fleet will be retrofitted with the new technology and the rest of the fleet will stay operating as usual with only diesel. Considering the results from Table 19 and Table 20, the results of this estimations are shown in the following tables.

10% H_2 – scenario 2030 – H_2ICE							
Mines	**H_2ICE – 60% H_2**		**H_2ICE – 40% Diesel**		**Retrofit**	**No Retrofit**	
CODELCOs	H_2 [TJ]	H_2 [ton]	Diesel [TJ]	Diesel [L]	# CAEX	Diesel [L]	# CAEX
Andina	94.7	789	63.1	1,753,014	2	21,912,672	12
El Salvador	371.3	3,094	247.5	6,875,432	9	85,942,898	45
TOTAL	**466**	**3,883**	**310.6**	**8,628,446**	**11**	**107,855,570**	**57**

Table 21: Estimations for H_2ICE retrofit in CODELCO's open pit mines for 2030 scenario.

10% H_2 – scenario 2030 – H_2ICE							
Mines	**H_2ICE – 60% H_2**		**H_2ICE – 40% Diesel**		**Retrofit**	**No Retrofit**	
Private mines	H_2 [TJ]	H_2 [ton]	Diesel [TJ]	Diesel [L]	# CAEX	Diesel [L]	# CAEX
Escondida	1,481.3	12,345	987.6	27,432,379	39	342,904,731	195
Bronces	435.8	3,631	290.5	8,069,499	16	100,868,742	80
Pelambres	359.6	2,996	239.7	6,658,500	13	83,231,254	65
Collahuasi	842.6	7,022	561.7	15,603,466	27	195,043,320	137
Centinela	492.4	4,103	328.2	9,117,904	17	113,973,796	83
Sierra G.	445.1	3,709	296.7	8,242,820	14	103,035,255	67
Spence	234.3	1,953	156.2	4,339,249	9	54,240,618	46
Caserones	186.0	1,550	124.0	3,444,576	6	43,057,206	31
El Abra	109.4	911	72,9	2,025,326	5	25,316,576	23
Antucoya	83.2	693	55.5	1,540,935	4	19,261,689	19
Lomas B.	158.3	1.319	105.5	2,931,848	6	36,648,105	30
TOTAL	**4,828**	**40,232**	**3,219**	**89,406,502**	**156**	**773,019,465**	**776**

Table 22: Estimations for H_2ICE retrofit in private's open pit mines for 2030 scenario.

10% H_2 – scenario 2030 - FCEV			
Mines	**FCEV 100% H_2**	**Retrofit**	**No Retrofit**

CODELCOs	H_2 [TJ]	H_2 [ton]	# CAEX	Diesel [L]	#CAEX
Andina	94,7	789	1	23,665,686	13
El Salvador	51,2	426	3	12,789,269	22
Chuquicamata	108.1	901	5 (LHD)	-	41 (LHD)
TOTAL	**268**	**2,116**	**9**	**36,454,955**	**76**

Table 23: Estimations for FCEV retrofit in CODELCO's open pit mines for 2030 scenario.

10% H_2 – scenario 2030 - FCEV					
Mines	**FCEV 100% H_2**		**Retrofit**	**No Retrofit**	
Private mines	H_2 [TJ]	H_2 [ton]	# CAEX	Diesel [L]	#CAEX
Escondida	1,481.3	12,345	23	370,337,110	211
Bronces	435.8	3,631	10	108,938,242	86
Pelambres	359.6	2,996	8	89,889,754	70
Collahuasi	842.6	7,022	16	210,646,785	148
Centinela	492.4	4,103	10	123,091,700	90
Sierra gorda	445.1	3,709	8	111,278,075	73
Spence	234.3	1,953	6	60,410,489	50
Caserones	186.0	1,550	4	46,501,782	34
El Abra	109.4	911,4	3	27,341,903	25
Antucoya	83.2	693	2	20,802,624	20
Lomas Bayas	158.3	1,319	4	39,579,953	32

Table 24: Estimations for FCEV retrofit in private's open pit mines for 2030 scenario.

The potential hydrogen demand of the CAEX trucks in the copper mining industry in 2050 is calculated with the methodology proposed 3.3:

$$Diesel\ demand\ [L] = \frac{159{,}812\ [TJ]}{36\left[\frac{MJ}{L}\right] * \frac{1}{1000000}\left[\frac{TJ}{MJ}\right]} * 78\% = 3{,}462{,}596{,}000\ [L]$$

$$H_2\ demand\ [Ton] = \frac{159{,}812\ [TJ]}{120\left[\frac{MJ}{kg}\right] * \frac{1}{1000000}\left[\frac{TJ}{MJ}\right] * \frac{1000}{1}\left[\frac{kg}{Ton}\right]} * 78\% = 1{,}038{,}778\ [Ton]$$

The results of the alternative method are the following:

$$Diesel\ demand\ [L] = 3{,}170\ [CAEX] * 3{,}300\ \left[\frac{L}{day}\right] * 365 = 3{,}818{,}265{,}000\ [L]$$

$$H2\ demand\ [Ton] = \frac{3{,}818{,}265{,}000\ [L]}{120\ \left[\frac{MJ}{kg}\right] * \frac{1}{36}\left[\frac{L}{MJ}\right] * \frac{1000}{1}\ \left[\frac{kg}{Ton}\right]} = 1{,}146{,}626\ [Ton]$$

Similar results can be obtained with the two alternatives and the slight difference can be explained by different reasons. For example, the total CAEX fleet reported by Editec considers the whole mining industry, not only the copper mining industry so a smaller share could be represented by the iron mining mainly and eventually the lithium and gold mining. Other reasons are the assumptions that consider 24/7 operation and a daily average consumption of 3,300 liters. Even thou the copper industry operates during the day and night, the CAEX trucks don't have a 100% annual availability, several interruptions due to refueling, drivers break, accidents, planned and unplanned maintenances, technical failures and rainy days among others can reduce significantly the effective hours of operation along a year. Finally, the daily consumption can differ depending on the CAEX truck model and the specific daily roadmap.

The final potential hydrogen demand in 2050 considering a 37% market penetration would be:

$$2050\ H_2\ demand\ [Ton] = 1{,}146{,}626 * 37\% = 424{,}252\ [Ton]$$

4.2. Zone 1 case of study results summary

In Table 25, the summary of the copper mines studied in Zone 1 is presented with the specific retrofitted CAEX's fleet and daily hydrogen demand for H_2ICE and FCEV technology.

				H_2ICE		**FCEV**	
Mine	H_2 annual demand [ton]	H_2 daily demand [kg]	H_2 hourly demand [kg]	# retrofitted CAEX	H_2 daily CAEX demand [kg]	# retrofitted CAEX	H_2 daily CAEX demand [kg]
Centinela	4,103	11,241	468	17	661	10	1,124

Sierra G.	3,709	10,162	423	14	726	8	1,270
Spence	2,014	5,517	230	9	613	6	919.5
Lomas B.	1,319	3,615	150	6	602	4	903.7
El Abra	911	2,497	104	5	500	3	832.3
Antucoya	693	1,900	79	4	475	2	950
Chuqui.	901	2,468	103	-	-	5 (LHD)	493.6

Table 25: H_2 main inputs of the case of study.

It can be seen that the average daily hydrogen demand per truck for the H_2ICE CAEX's is around 600 kg/day and for FCEV CAEX's is around 1,000 kg/day.

4.3. CO_2 emissions saved and water consumption

The following table resumes the total CO_2 emissions emitted by the CAEX trucks in the cooper mines selected in this study and the emissions saved if green hydrogen is integrated gradually through the retrofit of the trucks with H_2ICE and FCEV in 2030:

	Business as usual	**Business as usual**	**10% H_2 scenario with H_2ICE - FCEV**
Mines	**2019 emissions [ton]**	**2030 emissions [ton]**	**2030 emissions saved [ton]**
Chuquicamata	-	79,920	7,992
Andina	50,281	70,050	7,005
Salvador	27,173	37,856	3,786
Escondida	786,839	1,096,198	109,620
Bronces	231,456	322,457	32,246
Pelambres	190,985	266,074	26,607
Collahuasi	447,552	623,514	62,351
Centinela	261,528	364,351	36,435
Sierra gorda	236,428	329,383	32,938
Spence	124,462	173,396	17,340
Caserones	98,800	137,645	13,765
Candelaria	108,904	151,722	15,172
Antucoya	44,198	61,576	6,158

El Abra	58,092	80,932	8,093
Lomas Bayas	84,094	117,157	11,716
TOTAL	**2,754,682**	**3,912,251**	**391,225**

Table 26: CO_2 estimations without H_2 integration and with H2ICE for 2030 scenarios.

For the 2050 scenario, the global CO_2 emission that can be saved with green hydrogen in the whole copper industry are shown in the next table:

	Business as usual	**37% scenario**
Mines	**2050 emissions [ton]**	**2050 emissions saved [ton]**
Total copper mining 2050	10,171,818	3,763,573

Table 27: CO_2 estimations without H_2 integration and considering H_2ICE for 2030-2050 scenarios.

Finally, the 2030 scenario could save 0,45% of Chile's total GHG emissions by replacing 10% of the diesel fuel in open pit copper extractions and around 1.7% in 2050 with 37% replacement.

In terms of water consumption, the following Table shows the potential water consumption for the copper mines in Zone 1 according to the methodology in section 3.4:

		Theoretical 0.009 m^3/kg	**Desalinated 0.021 m^3/kg**	**PV 0.040 m^3/kg**	**Grid 0.13 m^3/kg**
Private mines	H_2 [ton]	m^3	m^3	m^3	m^3
Escondida	12,345	111,105	259,245	493,800	1,604,850
Bronces	3,631	32,679	76,252	145,240	472,030
Pelambres	2,996	26,964	62,916	119,840	389,480
Collahuasi	7,022	63,198	147,462	280,880	912,860
Centinela	4,103	36,927	86,163	164,120	533,390
Sierra gorda	3,709	33,381	77,889	148,360	482,170
Spence	1,953	17,577	41,013	78,120	253,890
Caserones	1,550	13,950	32,550	62,000	201,500
El Abra	911	8,199	19,131	36,440	118,430
Antucoya	693	6,237	14,553	27,720	90,090

Lomas Bayas	1,319	11,871	27,699	52,760	171,470
TOTAL	**40,232**	**362,088**	**844,872**	**1,609,280**	**5,230,160**

Table 28 :Water consumption for copper mines in Zone 1 in 2030.

According to a recent report about the water consumption projections from 2020 to 2031 in the copper mining, the water consumption would increase from 18.38 m^3/s in 2021 to 23.21 m^3/s in 2030 (Cochilco, 2020). The total water consumption in the copper mines of Zone 1 considering a 10% market penetration in 2030 would be theoretically of 0.011 m^3/s, about 0.027 m^3/s considering desalinated water, 0.051 m^3/s and 0.16 m^3/s for hydrogen production from solar PV and grid respectively. Comparing to the total copper mining water consumption, hydrogen production would represent only between 0.047 to 0.69% which is significantly low and even more insignificant if compared to other industries like agriculture that represent 72% of the total national water consumption while mining accounts for just 4% (Cochilco, 2020). Even if hypothetically in 2030 the whole copper mining diesel used in open pit operations is replaced by green hydrogen, the water consumption could represent between 0.86% to 12% of the total mining consumption in the worst case.

4.4. LCOH results and sensitivity analysis

Based on the technical and economical parameters presented in the previous sections in Table 12 to Table 16, the LCOH's for the different configurations and scenarios assumed in the case of study of this work are summarized in the next table while the detail of the LCOH calculation is shown in Annex 5:

Parameter	Technology	2022	2030	2050
Off – grid LCOH [$/kg]	Solar	5.32	3.63	1.85
	Wind	5.51	3.34	1.89
	Oversized Solar	4.47	3.11	1.60
On – grid/ PPA LCOH [$/kg]	Solar	5.70	3.91	1.84
	Wind	5.53	3.85	1.94
	CSP + TES	5.48	3.48	1.44

Table 29: LCOH results for the different configurations and RES plants.

It can be seen from Table 29 that the LCOH of the off-grid configuration is lower than the on-grid configuration with PPA for hydrogen production with solar and wind plants in all the scenarios. In 2030, the wind renewable connection results in a slight lower LCOH than the solar configuration for both off-grid and on-grid which can be explained by the much higher capacity factor increase that this technology can achieve compared to solar energy which is more challenging in the near term. However, solar energy can off-set this by 2050 as solar capital costs are expected to decrease more than on-shore wind, resulting in lower LCOH than wind. It can also be seen that a PPA connection with a CSP + TES plant could achieve lower hydrogen production costs compared to PPAs with solar and wind plants from 2030 to 2050. Globally, the difference of LCOH between all the technologies and configurations is not significant, 3.34 – 3.91 $/kg in 2030 and 1.44 – 1.94 $/kg in 2050, meaning that the three types of renewable technologies are attractive for this zone of Chile.

If the off-grid plant is oversized (Figure 28), the optimum oversize factor for the case of study in Calama city is 1.39, which means that if the solar plant capacity is increased to a capacity 1.39 times the electrolyzer size, the optimum trade-off is reached between the increase of the solar plant costs, the increase of the capacity factor and hydrogen production. This configuration would produce 33% more hydrogen than the normal layout considering the hourly limit capacity of the electrolyzer. If the solar plant is 2.5 bigger than the electrolyzer, the LCOH starts to be higher than the base configuration and the oversizing is no longer convenient. This configuration is the cheaper option among the different configurations between 2022 and 2030 with a LCOH of 4.47 $/kg and 3.11 $/kg while for 2050 scenario the CSP + TES is the cheapest option with a LCOH of 1.44 $/kg. It must be take into account that this configuration would certainly need more storage capacity as it produces more hydrogen than required for the copper mining demand, which consequently would increase the supply chain cost. However, the excess of hydrogen could be sold to other minor end-users and this could eventually off-set the extra storage costs. Finally, the oversize solar plant could be also exploited to supply electricity for other processes like compression, liquefaction or powering the HRS.

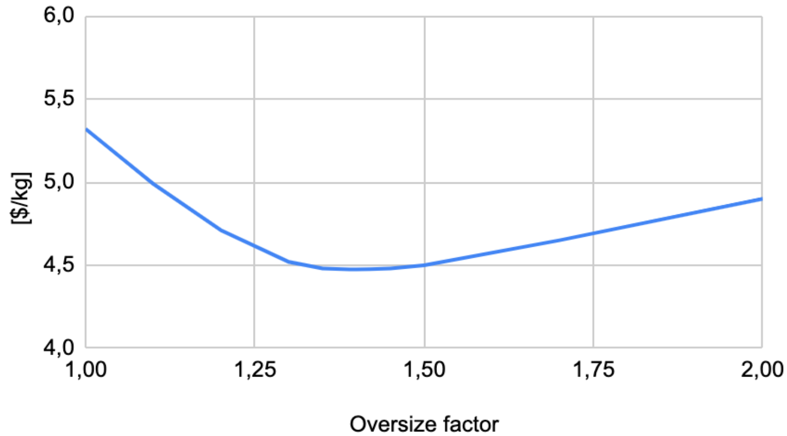


Figure 28: Solar plant oversizing optimization. 2022 scenario.

The specific LCOH cost breakdown for the off-grid configurations and on-grid configurations with PPA are shown in Figure 29 and Figure 30. For the baseline scenario, it can be seen that the electrolyzer system is the most expensive component as it contributes around 69% of the LCOH for solar off-grid considering capital investment (39%), stack replacement (16%) and operational expenditures (14%) while for the off-grid onshore wind the major component are the wind CAPEX with 35% and the electrolyzer with 30%. Globally, the LCOH is reduced for the off-grid configurations by reducing the RES and electrolyzer CAPEX which consequently reduces the operational expenditures. It has to be noticed that for the 2050 scenario the wind CAPEX contributes for almost half of the LCOH so if wind initial investments can achieve lower costs, the LCOH of onshore wind could be much more cheaper since it has better capacity factor than solar energy. Finally, the water cost can be negligible as it contributes with just 0.046 $/kg in every scenario.

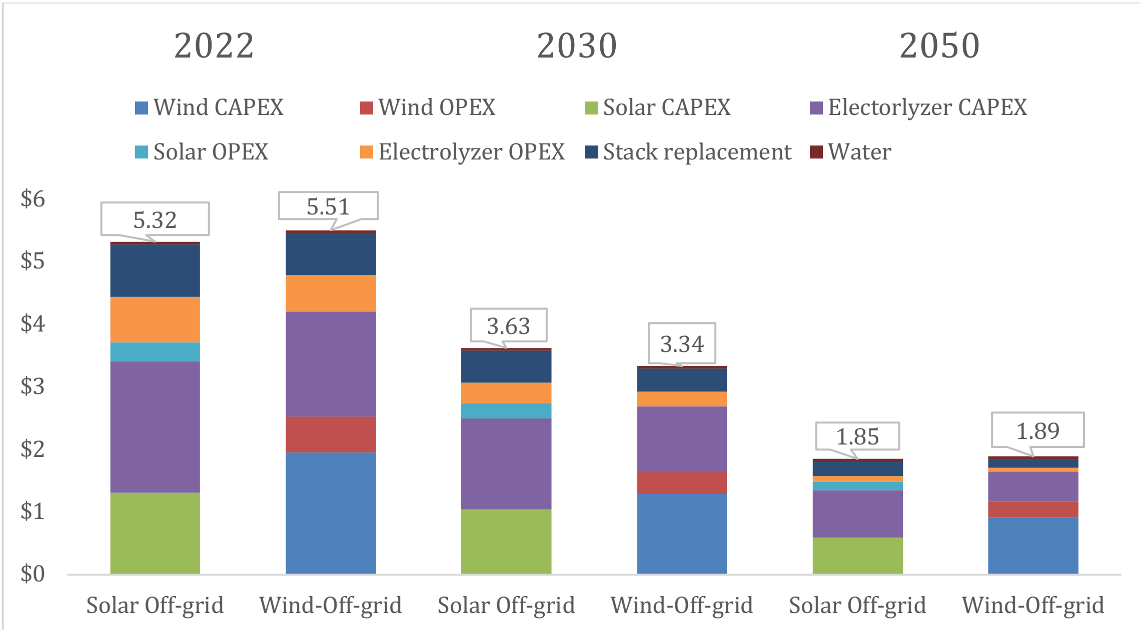


Figure 29: LCOH results breakdown for the Off-grid configurations

From Figure 30, it can be noticed that the electricity cost is a major component in the LCOH for wind and CSP - PPA as it contributes with 2.55 $/kg and 3.98 $/kg respectively while in the case of solar PPA it has a similar contribution than the electrolyzer's CAPEX with 1.99 $/kg and 2.1 $/kg. The trend shows clearly that for future scenarios the reduction of the PPA prices will be key for achieving a low and competitive LCOH.

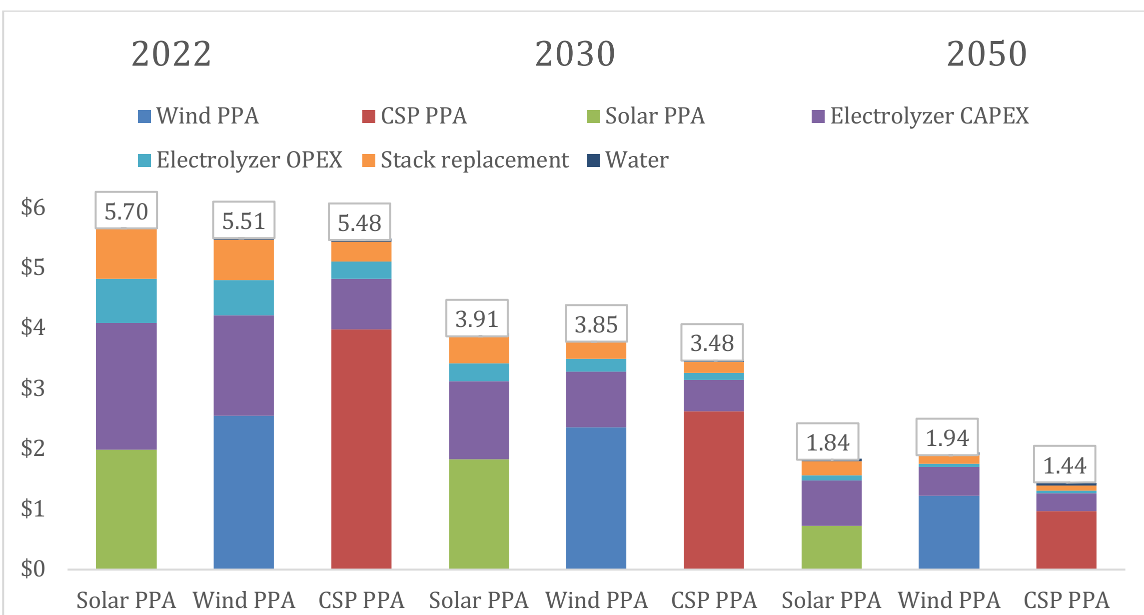


Figure 30: LCOH results breakdown for the On-grid / PPA configuration

In order to evaluate if the LCOH obtained in this study will be competitive with diesel by 2030, it is necessary to compare the results shown in Table 29 with the diesel equivalent price projections based on Table 18. It can be seen that the whole range of LCOH from 3.11 to 3.91 $/kg for the different configurations assumed in this work fits inside the diesel price range between the high and reference price projections of 2.80 and 4.13 $/kg. However, the projections of diesel are not trivial since its price is very exposed to global crisis like COVID-19 or geopolitical conflicts like the recent war in Ukraine. In fact, diesel price has considerably increased during the development of this work and have reached values around 1.4 $/L on average in the U.S, which is equivalent to 4.66 $/kg in terms of H_2 while in Chile the recent diesel price in February was of 1.1 $/L in Calama city which is equivalent to 3.66 $/kg of H_2. Considering this last value, both solar and wind off-grid connections could produce competitive green hydrogen by 2030 in Chile according to the LCOH results of this work while the CSP configuration through PPA would also produce competitive green hydrogen. However, a more pessimistic scenario for green hydrogen is considered in order to push and accelerate the development of green hydrogen and the reference projection from the AEO is assumed with diesel prices lower than 0.84 $/L or 2.80 $/kg H_2. Considering this, not even the lowest LCOH of 3.11 $/kg obtained with the optimized/oversized solar off-grid configuration would be competitive with diesel in 2030.

By performing a sensitivity analysis for this particular configuration varying the two more dominant LCOH drivers according to Figure 29, it is possible to estimate the necessary solar plant and electrolyzer investment cost (CAPEX) by 2030 in order to achieve a LCOH more competitive than diesel. It can be seen in Table 30 that the solar CAPEX should be around at least around 450 – 500 $/kW considering the electrolyzer CAPEX assumed in this study of 900 $/kW and that for a solar CAPEX of 650 $/kW the electrolyzer costs should be at least near 700 $/kW.

2030 – Capacity factor 32%

		Solar CAPEX [$/kW]					
	$/kg	650	600	550	500	450	400
Electrolyzer CAPEX	900	3.11	3.00	2.90	2.80	**2.69**	**2.59**
	850	3.01	2.91	2.80	**2.70**	**2.60**	**2.49**
	800	2.92	2.81	**2.71**	**2.60**	**2.50**	**2.40**
	750	2.82	**2.72**	**2.61**	**2.51**	**2.40**	**2.30**

	700	**2.72**	**2.62**	**2.52**	**2.41**	**2.31**	**2.21**
	650	**2.63**	**2.52**	**2.42**	**2.32**	**2.21**	**2.11**
	600	**2.53**	**2.43**	**2.32**	**2.22**	**2.12**	**2.01**
	550	**2.44**	**2.33**	**2.23**	**2.13**	**2.02**	**1.92**
	500	**2.34**	**2.24**	**2.13**	**2.03**	**1.93**	**1.82**

Table 30: Sensitivity analysis for off-grid solar plant configuration by 2030.

In the case of the scenarios considering the hydrogen plant indirectly connected to RES plant via a PPA, it is interesting to analyze the behaviour of the LCOH with different PPA electricity prices, electrolyzer's CAPEX and capacity factors. First, for the 2030 scenario where an electrolyzer CAPEX of 900$/kW was assumed, it can be noticed from Table 31 that if the capacity factor of the electrolyzer plant is increased from 32% to 90%, the LCOH would decrease from 3.91 $/kg to 2.43 $/kg for a PPA price of 30 $/MWh, which is roughly a 62% decrease. This could be eventually achieved with PPA's from generators with a varied renewable mix that can could ensure the electricity supply during 24 hours, with the integration of large scale battery storage or thermal energy storage like the case of CSP plants. In general, this alternatives including storage would increase the price of the PPA contract so the optimum trade-off should be further investigated. In the case of a solar PPA, the only option for producing hydrogen at lower price than diesel in this study scenario is to reduce the electrolyzer's cost lower than 900$/kW or lowering the PPA price to minimum levels lower than 10 $/MWh considering a capacity factor of 32%. In the case of wind PPA configuration, the hydrogen production would be competitive at a PPA price of 15 $/MWh for a capacity factor of 40% and between 20 – 25 $/MWh for a wind capacity factor of 50%. At last, the price of the CSP + TES PPA should be between 35 – 40 $/MWh in order to be competitive with diesel considering a capacity factor of 90% and electrolyzer CAPEX of 900 $/kW.

2030 – Electrolyzer CAPEX 900 $/kW

		Capacity Factor [%]							
	$/kg	20%	30%	40%	50%	60%	70%	80%	90%
PPA [$/MWh]	10	4.24	3.02	**2.40**	**2.04**	**1.79**	**1.62**	**1.49**	**1.39**
	15	4.50	3.28	**2.67**	**2.30**	**2.05**	**1.88**	**1.75**	**1.65**
	20	4.76	3.54	2.93	**2.56**	**2.32**	**2.14**	**2.01**	**1.91**
	25	5.03	3.80	3.19	2.82	**2.58**	**2.40**	**2.27**	**2.17**
	30	5.29	4.06	3.45	3.09	2.84	**2.67**	**2.53**	**2.43**
	35	5.55	4.33	3.71	3.35	3.10	2.93	**2.80**	**2.69**

	40	5.81	4.59	3.98	3.61	3.36	3.19	3.06	2.96
	45	6.07	4.85	4.24	3.87	3.63	3.45	3.32	3.22
	50	6.33	5.11	4.50	4.13	3.89	3.71	3.58	3.48

Table 31: Sensitivity analysis for on-grid/PPA configuration for 2030 scenario with Elec. CAPEX = 900 $/kW

The same analysis can be done but this time fixing the capacity factor and varying the PPA price and the electrolyzer CAPEX. Table 32 shows this analysis for the case of a solar PPA with capacity factor of 32% and it can be seen that the electrolyzer CAPEX should be between 400 $/kW and 500 $/kW by 2030 if the solar PPA prices are around 30 $/MWh as it is assumed in this study. A more reasonable electrolyzer CAPEX of 600 $/kW by 2030 would require a solar PPA in the range of 20 – 25 $/MWh to be competitive with diesel or 15 $/MWh PPA with an electrolyzer CAPEX of 700 $/kW. At last, it can be seen that a low LCOH of 1.08 $/kg could be reached if the electrolyzer costs is reduced to 200 $/kW and the electricity cost to 10 $/MWh.

2030 – Capacity factor 32%

		Electrolyzer CAPEX [$/kW]					
	$/kg	1200	1000	800	600	400	200
PPA [$/kWh]	10	3.63	3.12	**2.61**	**2.10**	**1.59**	**1.08**
	15	3.89	3.38	**2.87**	**2.36**	**1.85**	**1.34**
	20	4.15	3.64	3.13	**2.62**	**2.11**	**1.60**
	25	4.41	3.90	3.39	**2.88**	**2.37**	**1.86**
	30	4.68	4.17	3.66	3.15	**2.64**	**2.13**
	35	4.94	4.43	3.92	3.41	2.90	**2.39**
	40	5.20	4.69	4.18	3.67	3.16	**2.65**
	45	5.46	4.95	4.44	3.93	3.42	2.91
	50	5.72	5.21	4.70	4.19	3.68	3.17

Table 32: Sensitivity analysis for on-grid/PPA configuration for 2030 scenario with CF=32%

Globally, the three renewable technologies considered in this study are attractive for producing low cost green hydrogen in Chile but it strongly depends on the rate of development of the electrolyzer technology and the time it would take to reach economies of scale, rather than the investments costs and electricity cost of solar or wind. In general, renewable energy prices in Chile are among the cheapest around the world as a low solar price of 13 $/MWh was already awarded in the latest energy auction, which is very similar to the lowest solar prices between 10.4 – 12.4 $/MWh reached in Saudi Arabia and 13 $/MWh in Portugal (Waever, 2020). On-shore wind reached prices around 25 \$/MWh while a record-breaking price of 34 \$/MWh was offered in the last energy auction in Chile for a CSP project. So even if Chile has the advantage of producing the cheapest renewable in the world, in order to meet the optimistic projections presented in the National Green Hydrogen Strategy (assessed by a study of Mckinsey & Company) for producing the most competitive green hydrogen in the world with a production price of 1.3 – 1.4 \$/kg by 2030 and 0.8 – 1.0 \$/kg by 2050 (Energy Ministry, 2020), the challenge remains in the electrolyzer's manufacturers to reduce significantly the capital investments costs of the technology (materials, bipolar plates, balance of plant, etc), reach economies of scale, increase the stacks efficiency and system lifetime among other crucial parameters. In parallel to this, Chile has to increase its efforts in terms of green hydrogen funding and attracting more financing schemes and investors in order to achieve the ambitious targets of 5 BUSD investments and 5 GW of electrolyzer installed and under construction by 2025, since Chile is set to attract 1 BUSD in the next few years according to CORFO (InvestChile, 2022) still far from the target and no electrolyzer plants have been finished.

If one of the three technologies considered in this study has to be selected for providing green hydrogen to the copper mines in Chile, this should be solar energy but not only due to the lower LCOH that it could be obtained by oversizing the solar plant but also because solar energy potential is everywhere in the case of study of this work and the price of solar energy in this zone should be lower than on-shore wind and CSP in 2030 when hydrogen integration in the copper mining trucks could be implemented.

4.5. Zone 1 hydrogen supply selection and design

Considering the massive amounts of energy and fuel consumed by the mining industry and the closeness of potential future centralized green hydrogen production plants to the main copper mining zones in the north of Chile, a first approach would be to transport hydrogen via LH_2 trucks to the mining site similarly to the actual intensive diesel supply to the large fuel bulk storage in mines via diesel tank trailer trucks. The selection is justified mainly because the daily hydrogen demand of the specific mining areas requires multiple trucks and round trips per delivery and in order to ensure supply reliability, large volumes of hydrogen must be stored on site to be dispensed in the trucks. Trailer GH_2 transport would need significantly more trucks to supply the same demand and larger volumes to store on site while pipelines are not attractive for relatively small distances (>100km) and in some cases high altitudes (< 4,000m) due to the high initial investments costs of pipelines, compressors capital costs and the electricity required to power them. However, the liquefaction process needed to produce LH_2 counterbalances the potential higher costs of transporting and dispensing GH_2. A further study must be done to analyze the trade-offs between this delivery options.

However a second approach, possibly the most suitable for Zone 1 case of study is to design a decentralized hydrogen production network with on-site electrolyzers in each copper mine. This configuration means more flexible and on-purpose production with low or no transportation costs compared to centralized hydrogen production that needs a more complex and expensive infrastructure for delivering hydrogen in a more mature hydrogen economy with a large scale network of industrial end-users and hydrogen refueling stations. Some of the arguments that justify this choice is the great renewable potential in the area with the presence of strong and reliable winds, high solar irradiance for PV and CSP generation and even geothermal energy. Additional to this, Zone 1 is characterized for having low population density and relatively flat geography as the majority of the area is located in a central depression in the middle of the Desert of Atacama. This characteristics gives the opportunity of installing very large scale projects proportional to the demands required by the copper mining due that the surface availability and footprint constraint is not a problem in general. The majority of the mines located in this Zone are easy to access and isolated from any rural-urban areas or major (but not less important) ecosystem, with the exception of Collaguasi that is located at 4,400 meters above the sea level and Chuquicamata which is located few kilometers from the city of Calama.

The supply chain configuration selected should include the following main components:

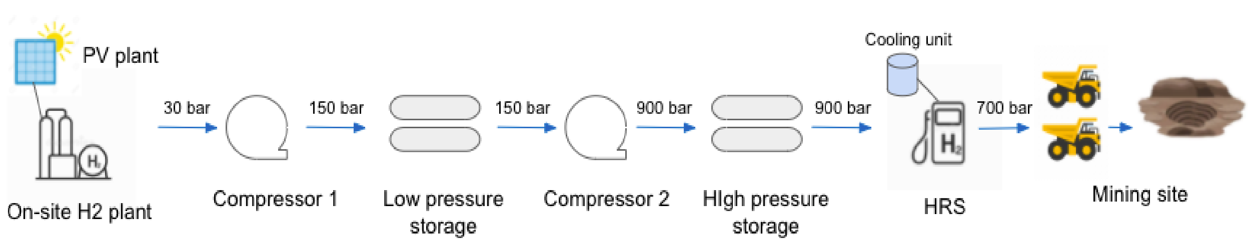


Figure 31: Hydrogen supply chain schematic for case of study.

The solar plant design methodology presented in 3.6.4 considered a minimum load of 10% for PEM electrolyzers. For the area of Calama, the solar profiles were based on the Solar explorer tool considering a tilted single axis tracker (TSAT) configuration, 14% of losses, 22 degrees of inclination, a temperature coefficient of -0.45 and capacity factor of 32%. It was found that for this area the sizing coefficient is practically negligible due to the excellent solar resource in Calama as nubosity is rare in this location and the solar profiles are quiet similar day by day during the year. For example, for Candelaria mine, an electrolyzer of 81.23 MW is required to meet the hydrogen demand and if a minimum electrolyzer load of 10% is assumed, the solar PV plant should be oversized to 81.47 MW which corresponds to an increase of just 0.36%. Even if a minimum load of 20% is considered, the solar PV of 81.96 would be needed. The following figure shows an example of rare solar intermittency in the area of Calama due to the meteorological phenomena of the "bolivian winter" that occurs usually in summer time and it can also be seen that the minimum electrolyzer load (orange line) is not met only few times and for short periods of time. Independently of the outcome of this analysis, as the H_2 plant configuration selected corresponds to the oversized off-grid solar PV plant connection analyzed in Figure 28, the problem of the electrolyzer minimum load is no longer an issue.

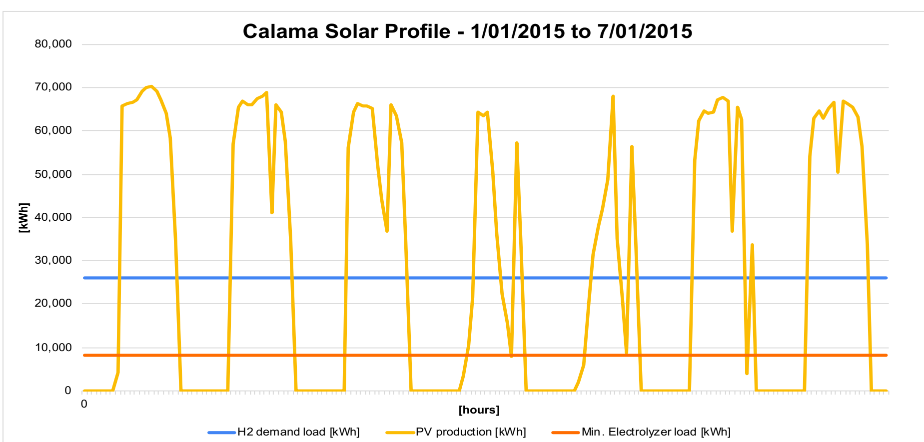


Figure 32: Solar profile for the area of Calama with CF=32%. Own elaboration based on solar explorer.

The hydrogen produced in the on-site H_2 plant need to be pre-compressed from 30 bar to 150 bar for being stored in the low-pressure storage system. Afterwards, the hydrogen is compressed from 150 bar to 900 bar and is stored in high-pressure vessels. In order to meet the requirements for the correct and safe refueling, hydrogen must be pre-cooled in a cooling unit before being dispensed into the truck on-board storage tank. The HRS needs a control unit to control the pressure difference between the dispenser and the vehicle's tank to prevent it from reaching a certain maximum pressure difference. This maximum allowable pressure difference is called Average Pressure Ramp Rate (APRR) and it is a function of the fill temperature and type of storage tank. In Table 33, the complete hydrogen supply chain design is presented for the copper mines of the case of study.

Mines	Centinela	Sierra G.	Spence	Lomas B.	El Abra	Antucoya	Chuqui.
Electrolyzer Capacity [MW]	81.2	73.4	39.9	26.1	18.0	13.7	17.8
PV Capacity [MW]	112.8	102.0	55.5	36.3	25.0	19.0	24.7
Compressor 1 [kW]	454.8	411.1	223.2	146.2	101.2	76.9	100
Low Pressure storage [kg]	33,724	30,487	16,551	10,844	7,491	5,699	7,405
Compressor 2 [kW]	520.8	470.8	255.6	167.4	115.7	88	114.4
High Pressure storage [kg]	1,686	1,524	828	542	374	285	370
HRS capacity [kg/day]	11,241	10,162	5,517	3,615	2,497	1,900	2,468

Table 33: H_2 supply chain design summary for case of study in 2030.

The size of the components estimated for the supply chain of each copper mine are just for reference and to give an order of magnitude for a further investigation and real implementation. The integration of H_2 plants and refueling stations in the Chilean copper mines for supplying green hydrogen to the CAEX mining trucks remains a challenge as nowadays the largest PEM plants are lower than 10 MW while the largest HRS in the world has a capacity of 5,000 kg/day (Air Liquide, 2021) but typical HRS capacities range between 200 to 1,500 kg/day, mainly for light duty vehicles, buses and heavy duty vehicles with storage tank capacities of 5 to 30 kilogram, which is far lower than typical CAEX mining trucks with diesel tanks above 3,000 liters and energetically equivalent to more than 900 kilogram of H_2. For copper mines with a fleet of 10, 50 and 100 CAEX considering a 10% hydrogen market penetration by 2030 and 37% by 2050 they would require hydrogen fueling stations with a capacity of 1,000, 5,000 and 10,000 kg/day in 2030 and 3,600, 18,000 and 36,000 kg/day in 2050 respectively.

According to Table 33, the minimum H_2 plant capacity for the case of study corresponds to Antucoya mine with 13.7 MW which is already larger than the biggest PEM H_2 plant in Europe, the REFHYNE project of 10 MW (FCH, 2021). In the case of Centinela and Sierra Gorda mines, the HRS needed would have to be at least 2 times today's largest HRS and 10 times an average HRS of 1,000 kg/day (Koleva, 2020) while significantly larger mines like Collaguasi or Escondida with daily demands of 19.237 kg/day and 33.821 kg/day respectively for CAEX truck fleets between 150 – 240 units (Table 22 / Table 24) would require HRS 20 and 30 times bigger than nowadays average's HRS, considering just a 10% diesel replacement by green hydrogen in each mine.

In terms of high pressure storage and compressor capacity, the design is complex and the optimal configuration will depend on the CAEX's on-board storage capacity, HRS filling rate and the daily operational planning of each mine. For example, if multiple back-to-back fillings are required after each shift, larger high pressure storage and compressor capacity would be needed in order to correctly refuel the CAEX fleet for starting operating in the following shift. In the case that every CAEX truck of the fleet is planned to start operating at similar times, the HRS would need to be capable of supplying larger hydrogen flow rates for this peak demands in a relatively short period of time (1 – 3 hours e.g) compared to the minimum hydrogen mass flow considering a constant flow during the day. Consequently, the compressors size would be bigger and more electrical energy will be consumed. Further investigation must be done in order to found optimal configurations between the number of dispensers, high pressure storage, compressor capacity and CAEX fleet operational planning.

4.6. CAEX on-board storage capacity and HRS filling time

Another challenge and major issue of retrofitting CAEX mining trucks is the optimization of the on-board storage capacity considering the maximum payload of the trucks and the HRS filling capacity in order to meet the intensive energy requirement demanded by the CAEX trucks. The integration of green hydrogen in this trucks not only has to be economically viable for mining companies in terms of fuel and retrofitting cost with H_2ICE or FCEV but also it has to achieve the same operational performance than the normal diesel CAEX trucks. For this, three major parameters has to be analyzed: storage volume, storage weight and filling rate. According to Table 25, the average daily hydrogen fuel consumption per CAEX is 600 and 1,000 kilogram for H_2ICE and FCEV retrofit respectively. The analysis of the different on-board configurations considering the potential daily consumption of hydrogen is shown in Table 34:

Storage capacity	Tank model	# tanks	Volume [m^3]	Total weight [kg]
1,000 [kg]	IV – 9.8 [kg]	102.0	24.90	20,183
	IV – 18.4 [kg]	54.3	24.84	15,782
800 [kg]	IV – 9.8 [kg]	81.6	19.92	16,146
	IV – 18.4 [kg]	43.5	19.87	12,626
600 [kg]	IV – 9.8 [kg]	61.2	14.94	12,110
	IV – 18.4 [kg]	32.6	14.90	9,469
300 [kg]	IV – 9.8 [kg]	30.6	7.47	6,055
	IV – 18.4 [kg]	16.3	7.45	4,734
150 [kg]	IV – 9.8 [kg]	15.3	3.73	3,027
	IV – 18.4 [kg]	8.2	3.72	2,367
75 [kg]	IV – 9.8 [kg]	7.7	1.87	1,513
	IV– 18.4 [kg]	4.1	1.86	1,183

Table 34: On-board storage main parameters with different storage tank models at 700 bar.

Storage capacity	Tank model	# tanks	Volume [m^3]	Total weight [kg]
1,000 [kg]	IV – 4.7 [kg]	212.8	41.0	15,255
	IV – 8.4 [kg]	119	41.6	14,333
800 [kg]	IV – 4.7 [kg]	170.2	32.8	12,204
	IV – 8.4 [kg]	95.2	33.3	11,466
600 [kg]	IV – 4.7 [kg]	127.7	24.6	9,153
	IV – 8.4 [kg]	71.4	25.0	5,385
300 [kg]	IV – 4.7 [kg]	63.8	12.3	4,576
	IV – 8.4 [kg]	35.7	12.5	4,300
150 [kg]	IV – 4.7 [kg]	31.9	6.2	2,288
	IV – 8.4 [kg]	17.9	6.3	2,150

75 [kg]	IV – 4.7 [kg]	16	3.0	1,144
	IV – 8.4 [kg]	8.9	3.1	1,075

Table 35: On-board storage main parameters with different storage tank models at 350 bar.

At first sight, it is evident that for FCEV trucks the integration of on-board storage systems of 1,000 kg and 800 kg at 700 and 350 bar is not possible due to the significant extra weight (12,000 – 20,000 kg) it would add to the truck and large space (19 – 41 m^3) it would require to integrate it. Even a storage capacity of 600 kg would be difficult to implement because the CAEX retrofitting into a FCEV must also consider the trade-off between the replacement of the diesel power engine with fuel cell modules and battery packs. If H_2ICE is integrated into the CAEX trucks, a 600 kg storage is also challenging especially at 300 bar due to the volume required for the tank system. Even thou some extra tons seem negligible compared to the significant weigh and payloads of this trucks like Caterpillar 797F model that has a truck weigh of 260 ton and payload of 363 ton, the extra weigh could affect the truck performance in terms of fuel consumption as more fuel would be needed or in terms of load capacity as the truck would eventually need to compensate the extra weigh by transporting fewer loads of material. Both situations would imply in higher operational costs for mining companies, especially for the ones that have important fleets of CAEX trucks.

	On-board storage capacity [kg]			
Filing rate [min/kg]	600	300	150	75
1.8	5.6 h	2.8 h	1.4 h	0.7 h
3.6	2.8 h	1.4 h	0.7 h	0.35 h
7.2	1.4 h	0.7 h	0.35 h	0.17 h
10	1.0 h	0.5 h	0.25 h	0.13 h

Table 36: Filing times comparison with different on-board storage configurations.

Before continuing with this analysis, it is necessary to also consider the relation between the HRS filling rate and the storage capacity in order to evaluate if it is possible to achieve similar performance compared to normal diesel trucks in terms of refueling stop times. Normally, CAEX trucks are filled once every shift of 12 hours or once per day depending on the diesel tank capacity and on-site diesel refueling stations (Annex 6) like in Candelaria mine (Zone 2) where it's diesel station can achieve filling rates of 150 L/min per hose according to information provided by a shift chief. Considering this filling rate and an average CAEX daily diesel consumption of 3,300 liters, it takes 22 minutes per day to refuel the CAEX trucks. Looking at Table 36, it can be seen that for H_2ICE trucks even if a single refill is achieved by integrating a storage tank of 600 kg, the minimum filling time possible with today's HRS standards (7.2 kg/min) would be of 82 minutes, roughly 4 times more than normal diesel CAEX trucks. If a 300 kg is considered, evidently the filling time would be reduced by halve but extra time will be needed to return to the HRS more than once, and even more extra time will be needed if the storage capacity continue to be decreased as more round-trips to the HRS are needed during the day.

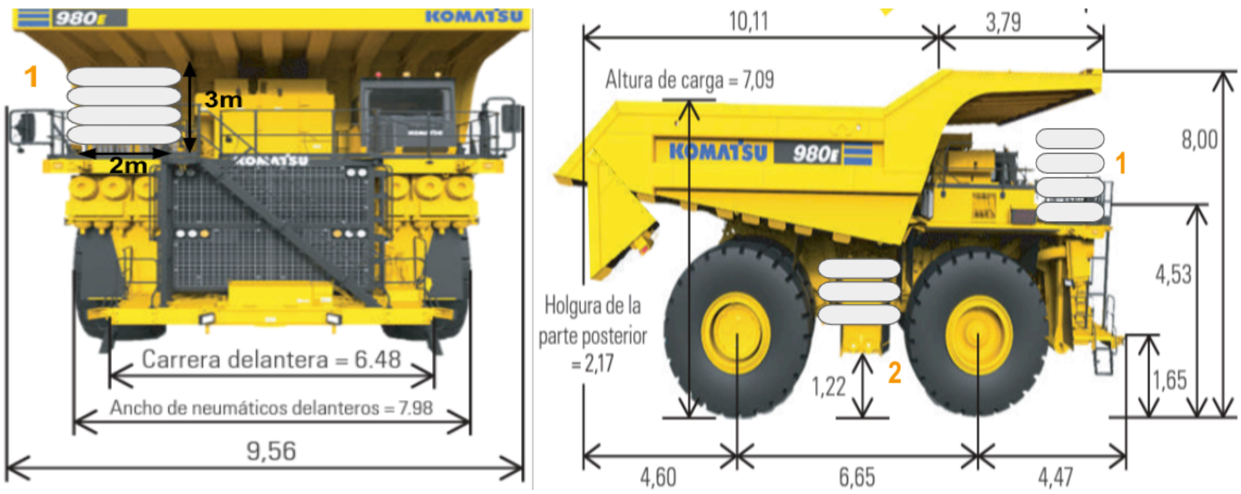


Figure 33: Possible available space for installing a hydrogen storage on-board. (Komatsu, 2022)

Regarding space availability, Figure 33 shows some possible options for installing the storage tanks system in the truck. One of them consists at the opposite level of the drivers cabin (1) where a volume in the range of 8 - 12 m^3 could be used but taking into account the possibility of interfering the drivers visibility by obstructing the lateral view mirror and obstructing the engine access point which in some truck models is located in this area. The drivers visibility problem would not be a problem in the case of autonomous trucks, which have been integrated recently in several copper mines around the world. Another logical option (2) is using the same space where the diesel tank is installed, in which a volume of 3 – 5 m^3 can be available in the case the truck is retrofitted as a FCEV as the diesel tank is no longer necessary and can be replaced. In the case the truck is retrofitted as a H_2ICE truck, the diesel tank is still needed or it can be reduced in order to make room for fitting hydrogen tanks. In both type of trucks, another smaller space could be available in the opposite side of the diesel tank where the hydraulic tank is located. Finally, another potential space where hydrogen tanks can be added is in the interior of the truck where the diesel engine is located. However, this could only be done in the case of FCEV retrofit where the diesel engine is replaced with a fuel cell – battery – storage system.

Considering the analysis done before, a reasonable storage size for H_2ICE trucks could be around 300 kg using type IV tanks of 18.4 kg at 700 bar as this configuration would require a volume of 7.4 m^3 and would add roughly 4,700 extra kg to the truck, but this number reduces down to around 3,400 kg due that with this technology only 40% of diesel is used, equivalent to 1,300 liters for an average 3,300 liters consumption per day and to 1,100 kg considering a density of 850 kg/m^3 for diesel. A good weigh trade-off could be achieved with a storage tank system of 75 kg, as it would weigh around 1,183 kg. With an on-board tank of 300 kg, the filling time would be of 42 minutes per shift and the truck should be refilled two times per day. This could be reduced in the future if a filling rate of 10 kg/min is achieved, and the H_2ICE truck would take three times more time to refill (1 hour) per day than a normal diesel CAEX. However, the H_2ICE has the disadvantage that each truck would need to pass through two filling stages, one to refill with diesel and other with hydrogen which would increase the total refueling stop time considering possible lingering times and extra time due to safety protocols or operators instructions.

For FCEV trucks, the optimum storage configuration is more complex as it depends in the overall retrofit design considering the replacement of the diesel engine with fuel stacks and a battery package. As reference, the Komatsu 930E-4 truck that was retrofitted for Anglo American, its diesel engine that weights 9,608 kg was replaced with 8 FC-Velocity fuel cells of 100 kW each that globally weights 3,080 kg considering the air and coolant subsystems and a battery package of 1,100 kWh that could weight around 4,200 to 5,000 kg if lithium energy densities of 220 and 260 Wh/kg are considered. The whole new system could be 1,530 to 2,300 kg lighter without considering auxiliary systems, piping or control units so in a first approach, the addition of extra weight with hydrogen storage tanks could be justified.

Finally, it is clear that the storage of hydrogen in this type of trucks is not trivial and is difficult to find the optimum configuration that could achieve at least a similar daily performance during the extraction operations than normal diesel CAEX trucks considering nowadays HRS standards. The on-board storage capacity could eventually be exploited in the range of 75 to 300 kg per truck and assuming possible economic losses due to more fuel consumption, decrease of production due to less material transportation per round-trip or less truck availability with the increase of refueling stop times. This potential economic losses could be eventually compensated if much lower green hydrogen LCOH prices are achieved compared to diesel.

5. CONCLUSIONS

Today's energy transition is mainly lead by renewable energies in combination with energy efficiency but green hydrogen is rapidly becoming a key player for achieving the objectives set in the decarbonization pathways due to its remarkable attributes as an energy carrier. Countries with abundance of low-cost renewable energy, space and access to water like Chile could become important producers of green hydrogen in the next decades. Chile has a unique geography with the highest solar radiation in the world at the Atacama Desert providing an exceptional potential for producing electricity based on solar PV and CSP, strong winds in the Patagonia for installing large scale onshore wind projects with high capacity factors, geothermal sources in the Cordillera of the Andes and more than 4,000 kilometers of coastline for access to water. In addition to this, Chile contains a great mineral wealth and is the largest producer of copper in the world, second in lithium and molybdenum production and sixth in silver production. In fact, the mining sector is the largest industry in the country specifically copper mining as it contributes to 11.2% of Chile's GDP while it consumes around 14% of the country total energy consumption and emits 15% of Chile's GHG emissions.

Particularly, 39% of the copper mining energy consumption occurs in the open pit operations where the fuel consumption represents 78% of this total and is mainly due to the transportation of extracted materials by large CAEX hauling trucks capable of loading up to 360 tons of material with their diesel engines of 2,000 – 2,800 kW. Each of this mining trucks consumes almost 3,300 liters per day on average, so this intensive fuel consumption in the copper industry motivated the analysis of the opportunity of decarbonizing this industry with the integration of green hydrogen through the retrofit of the CAEX trucks with dual hydrogen diesel combustion engines (H_2ICE) or reconversion into fuel cell electric vehicles (FCEV). The technology of H_2ICE has the advantage that the truck retrofit don't require major changements as it uses the same diesel engine, it could potentially achieve better BTE efficiencies, ensures reliability in case one of the fuels is no available and can meet the performance requirements under harsh conditions like dust, extreme heat-cold, altitude and vibrations. However, special attention must be taken regarding the problem of additional NOx emissions due to the combustion of hydrogen with oxygen, problem that don't have FCEV's which only output is water. Globally, efforts have to be made for developing both technologies so that they can be complementary between each other and reduce their costs for decarbonizing the mining industry.

The main objective of this thesis after identifying copper mining as the industry with the best opportunity of integrating green hydrogen, was estimating the specific potential hydrogen demand in the major copper mines in Chile. For this, three main mining zones were identified and the methodology consisted in estimating the hydrogen demand based on diesel consumptions projected to 2030 and 2050 with hydrogen market penetration of 10% and 37% respectively, considering each copper mines lifetimes, CAEX trucks fleet size and hydrogen's energetic density of 33.3 kWh/kg. With this information, the retrofitted CAEX fleets of each mine were estimated for the implementation year of 2030 and considering 60% diesel replacement through H_2ICE technology and 100% replacement with FCEV technology. The estimated CO_2 emissions saved in 2030 are 391,225 tons for the copper mines considered in the study and 3,763,573 tons in 2050 for the whole copper mining industry. The water consumed for the production of the green hydrogen implemented in this trucks is negligible compared to the total copper mining consumption of 23.21 m^3/s by 2030 as only 0.011 – 0.16 m^3/s could be potentially consumed.

Once the specific demand was estimated, the next main objective was designing a supply chain from the production of green hydrogen to the final supply of the CAEX trucks through HRS's in the mining sites for a selected group of mines from Zone 1 presented as the case of study of this thesis. The mines chosen where Centinela, Sierra Gorda, Spence, Antucoya, Lomas Bayas, El Abra and the underground mine of Chuquicamata. This last one was considered in order to further investigate the reconversion of LHD underground trucks into FCEV's. The mine with the highest annual hydrogen demand was Centinela with 4,103 ton which is equivalent to the fuel needed for operating 17 H_2ICE trucks or 10 FCEV trucks while Antucoya has the lowest demand with only 693 ton for refueling 4 H_2ICE trucks or 2 FCEV trucks. The whole annual hydrogen demand of the case of study was 13,651 ton and if Collaguasi and Escondida mines are considered, the final demand increases to 33,017 tons. All this selected mines are located in the Antofagasta region in the surroundings of Calama city, which is a crucial geographic area in terms of copper production and renewable sources availability as multiple solar PV and onshore wind plants are present while one CSP project is already operating.

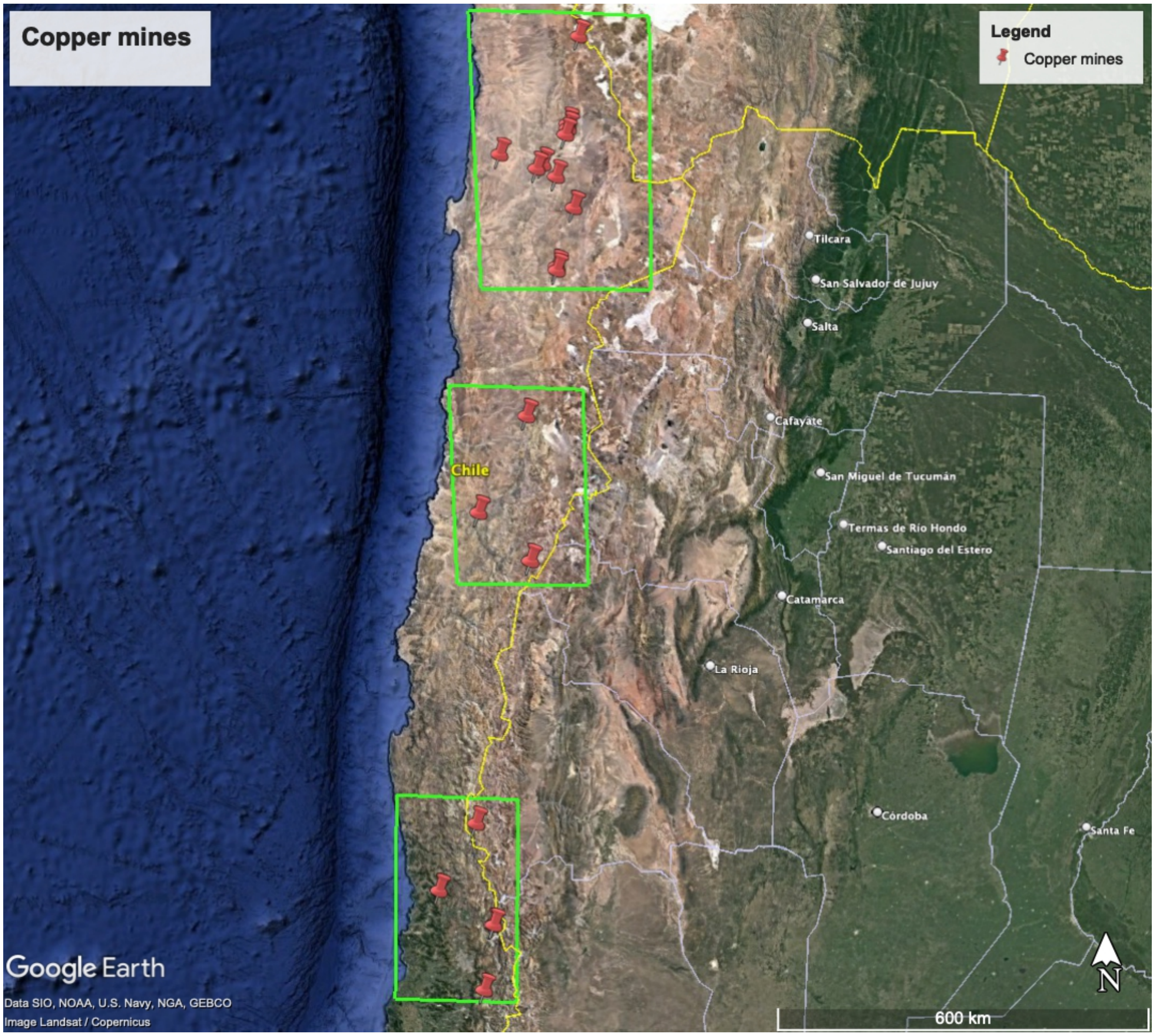
The first step for designing the hydrogen supply chain for this copper mines was calculating the LCOH for different H_2 plant configurations and future scenarios considering direct connection with off-grid solar PV and onshore wind plants and indirect connection through PPA's from solar PV, onshore wind and CSP plants. The goal of this step was finding the configuration that could produce the cheapest green hydrogen in 2030 and analyze if it would be competitive with possible future diesel prices. It was found that in general the solar/wind off-grid configurations achieved lower LCOH in 2022 (5.32 – 5.51 $/kg) and 2030 (3.34 – 3.63 $/kg) than solar/wind on-grid/PPA connections (5.53 – 5.73 $/kg and 3.85- 3.91 $/kg) but the LCOH of a PPA connection with CSP + TES plants have similar results than the off-grid plants in 2022 (5.48 $/kg) and 2030 (3.48 $/kg) while for a future 2050 scenario it achieved the lowest LCOH value of all configurations (1.44 $/kg). However, it was found that the lowest LCOH (3.11 $/kg) for the 2030 scenario could be achieved by exploiting the solar off-grid configuration through the oversizing of the PV plant as the trade-off between higher solar PV costs (but higher energy availability) with higher hydrogen production reached an optimum value at an oversizing factor of 1.39, considering the maximum daily production rate of the electrolyzers.

In terms of competitiveness with diesel, even if the LCOH prices estimated for 2030 (3.11 – 3.91 $/kg) fall in the range of future reference and high costs diesel price estimations (2.80 – 4.13 $/kg), in order to ensure that green hydrogen is more attractive than diesel for mining companies, its price should be lower than 2.80 $/kg, so economies of scale have to be achieved and electrolyzers capital investments costs have to be reduced at least down to the range of 600 – 700 $/kW in 2030 considering solar energy prices in the range of 15 – 25 $/MWh for being able to produce cheap and competitive solar green hydrogen in Chile. The renewable energy prices in Chile seems not to be a further barrier for accomplishing the national strategy goal of producing green hydrogen at prices around 1 $/kg in the future since very low offers have been offered already in recent public energy auctions. The main challenge remains in increasing the electrolyzers manufacture and learning rate in order to achieve rapidly economies of scale and lower the capital costs of H_2 plants.

The supply chain proposed in this work consisted in on-site H_2 production through oversized solar PV plants as this would be more suitable for an early stage of green hydrogen integration in copper mining due that it would not require a more complex and expensive transport infrastructure with liquefaction, delivery through trucks or long pipelines and the copper mines are located in an area with excellent solar resource with enough space for installing the large infrastructure needed for producing and supplying green hydrogen to the CAEX trucks. The PEM electrolysis plants capacity needed for the selected copper mines range between 13.7 - 81.2 MW, solar PV plant capacity between 19 - 113 MW, low pressure storage between 5,699 - 33,724 kg, high pressure storage between 370 - 1,686 kg, total compressor capacity between 165 - 976 kW and HRS capacity between 1,900 - 11,241 kg/day. Finally, the analysis of the potential design of the CAEX trucks on-board storage was performed and the proposed capacity range in which the integration of storage systems could be feasible in this trucks is between 75 - 300 kg.

Globally, the integration of green hydrogen in the copper mining sector is without doubt an excellent opportunity for decarbonizing this industry and boosting a green hydrogen economy in Chile due to the large amounts of hydrogen that could be required in the material transportation by CAEX trucks and the important impact of the copper industry in Chile's economy. However, the challenge remains quiet complex from a technical and engineering point of view due to magnitude of this industry in terms of infrastructure, energy consumption and intensive pressure of its non-stop high performing operations. It is compulsory to achieve lower costs of producing green hydrogen compared to diesel in order to incentive mining companies to be part of this energetic transition while HRS technology and standards have to achieve higher performances in order to rapidly integrate HDV like CAEX trucks in the value chain of hydrogen and R&D must be intensified regarding storage technologies so that H_2ICE or FCEV could achieve similar operational performances than diesel CAEX trucks. The challenge not only is complex from a technical and engineering perspective, but also in a financial, regulatory and market point of view. Chile's nowadays priority should be creating a green hydrogen framework and policy (which doesn't exist) in order to facilitate the development of green hydrogen projects without any kind of barrier and also more efforts have to be made in investing, financing and attracting green funds because with today's modest funding, Chile is still far of achieving its short term objectives set in its ambitious green hydrogen national strategy.

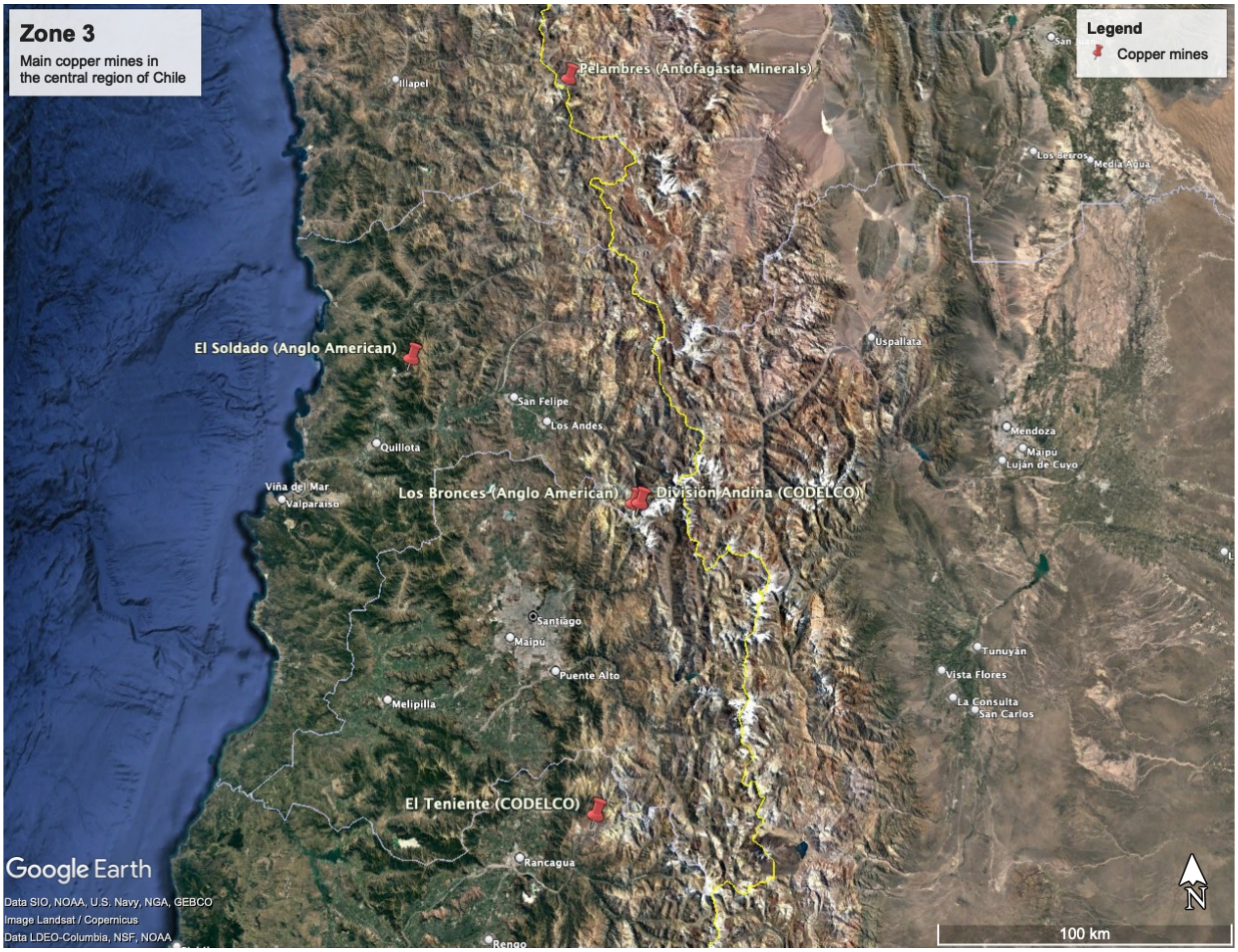
6. ANNEXES



Annex 1: Three major mining zones identified.

Annex 2: Zone 1 amplified image.

Annex 3: Zone 2 amplified image.

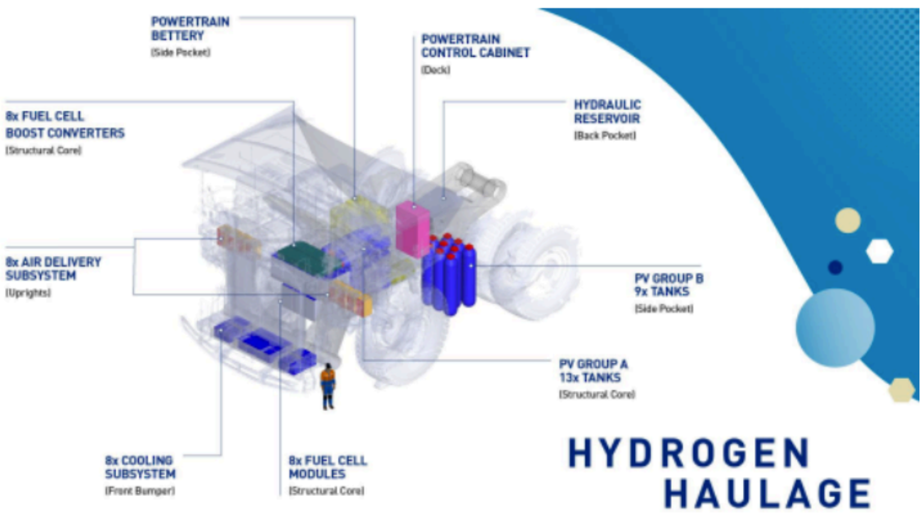


Annex 4: Zone 1 amplified image.

Year	stack hours [h]	EL CAPEX [$]	CAPEX stack [$]	EL OPEX [$]	Electricity cost [$/year]	Water cost [$/year]	Total cost [$/year]	H_2 production [kg H_2/year]
-	7,446	67,447,512	-	1,348,950	6,302,296	184,638	75,283,396	
1	14,892	-	-	1,260,701	5,889,996	172,558	7,323,255	4,103,057
2	22,338	-	-	1,178,225	5,504,669	161,270	6,844,164	3,834,633
3	29,784	-	-	1,101,145	5,144,550	150,719	6,396,415	3,583,769
4	37,230	-	-	1,029,108	4,807,991	140,859	5,977,958	3,349,317
5	44,676	-	-	961,783	4,493,450	131,644	5,586,877	3,130,203
6	52,122	-	-	898,863	4,199,486	123,032	5,221,380	2,925,423
7	59,568	-	-	840,058	3,924,753	114,983	4,879,794	2,734,040
8	67,014	-	-	785,101	3,667,993	107,461	4,560,555	2,555,178
9	74,460	-	-	733,740	3,428,031	100,431	4,262,201	2,388,017
10	81,906	-	23,606,629	685,738	3,203,767	93,860	27,589,995	2,231,791
11	89,352	-	-	640,877	2,994,175	87,720	3,722,772	2,085,786
12	96,798	-	-	598,950	2,798,295	81,981	3,479,226	1,949,333
13	104,244	-	-	559,766	2,615,229	76,618	3,251,613	1,821,806
14	111,690	-	-	523,146	2,444,139	71,606	3,038,891	1,702,623
15	119,136	-	-	488,922	2,284,242	66,921	2,840,085	1,591,236
16	126,582	-	-	456,936	2,134,806	62,543	2,654,285	1,487,137
17	134,028	-	-	427,043	1,995,145	58,452	2,480,640	1,389,847
18	141,474	-	-	399,106	1,864,622	54,628	2,318,355	1,298,923
19	148,920	-	-	372,996	1,742,637	51,054	2,166,687	1,213,947
20	156,366	-	-	348,594	1,628,633	47,714	2,024,941	1,134,529
TOTAL	-	67,447,512	23,606,629	15,639,748	73,068,904	2,140,691	181,903,485	46,510,593
LCOH [$/kg H2]	**-**	**1.45**	**0.51**	**0.34**	**1.57**	**0.05**	**3.91**	-

Annex 5: LCOH calculation detail for Centinela Mine, 2030, solar on-grid PPA configuration.

Annex 6: Diesel refueling station in Candelaria mine (Zone 2)



Annex 7: Anglo American FCEV truck design. Source: Greencarcongress.com

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