AN EXAMINATION OF THE TECHNICAL-ECONOMIC FEASIBILITY OF GREEN HYDROGEN PRODUCTION FROM SOLAR CLIPPING LOSSES IN NORTHERN CHILE

by

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EXECUTIVE SUMMARY

Interest in green hydrogen has skyrocketed over the past several years as the world looks for decarbonization solutions, particularly within heavy industry. Chile, in particular, has an aggressive national strategy to become the cheapest producer and leading exporter of green hydrogen in the world (Ministry of Energy with McKinsey, 2020).

This project was completed as a part of Duke University's Fuqua Client Consulting Practicum (FCCP) in the spring of 2021. The client is confidential (hereafter referred to as "Company"). Company owns and operates a 13 MWac solar project in the Copiapó region of northern Chile. The project falls under the Pequeño Medio de Generación Distribuido (PMGD) tariff category in Chile, which sets an injection limit of 9 MWac and results in solar clipping losses. This project analyzes the technical-economic feasibility of green hydrogen production from those solar clipping losses.

We first analyzed the potential supply of green hydrogen available from the pilot project. To do so, we evaluated the solar resource using Chile's Ministry of Energy's Solar Explorer tool, which provided us with global horizontal irradiation (GHI) levels at the project site. We used this information to model the electricity produced on site using the trial version of PVsyst. We modeled the 13 MWac solar plant in PVsyst to obtain an 8760 timeseries of hourly electricity production, which we used to isolate the solar clipping losses in hours with a production of greater than 9 MWac. We found that, in a typical year, solar clipping losses are 3,123 MWh. Also on the supply side, Company provided us with five electrolyzer quotes received from various manufacturers. Based on the small size and cost sensitivity of the pilot project, we selected two alkaline electrolyzers to use in our financial model. Given the hydrogen production rates (kg/MWh) of these electrolyzers, we estimated that the pilot project could generate between 47 – 57 metric tons of green hydrogen per year.

The next step in our research was to identify target markets for the sale of the green hydrogen produced by the pilot project. We developed both quantitative and qualitative criteria for industry attractiveness that enabled us to rank industries and identify the top two markets for us to analyze further. Based on the ranking system and input from Company, we selected mining companies and gas utilities. We then estimated the volume of demand in each market over the short, medium, and long-term. We estimate the volume of demand for green hydrogen as fuel for mining trucks to be between 63.35MM kg/year in the short term and 295.61MM kg/year in the long term. For green hydrogen for blending with natural gas, we estimate the volume of demand to be 60.76MM kg/year in the short term and 1,231.33MM kg/year in the long term. We then estimated each industry's willingness to pay (WTP) for green hydrogen. Based on current fuel prices, the availability of alternatives, and carbon prices, we estimate the average WTP for green hydrogen for mining companies and gas utilities to be $2.23/kg and $1.65/kg, respectively. Taking the volume of demand together with the WTP, we estimate the addressable green hydrogen market size for mining companies and gas utilities in the long term to be $955MM and $1,798MM, respectively.

We incorporated all of this information into a financial model to evaluate the financial viability of the pilot project. Our analysis indicates that the solar clipping losses business model does not produce enough hydrogen to offset the initial CAPEX investment based on the estimated prevailing green hydrogen prices in Chile. We recommend that Company analyze a second iteration of the pilot project where more electricity is drawn to the electrolyzer based on hourly electricity costs. If producing and selling green hydrogen is more profitable than selling electricity to the grid, then this could be a way to increase the electrolyzer utilization factor, generate higher revenues, and justify the CAPEX investment.

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CLIENT BACKGROUND & CONFIDENTIALITY

This project was completed as part of the Duke University Fuqua Client Consulting Practicum (FCCP) in Spring 2021. The client has requested to remain confidential and shall hereafter be referred to as "Company." As background, Company develops, constructs, and operates energy and industrial infrastructure assets across the investment-grade Americas.

INTRODUCTION

Interest in green hydrogen has skyrocketed over the past several years as the world looks for decarbonization solutions, particularly within heavy industry. Green hydrogen is hydrogen that is produced via renewable energy powering electrolysis, making it emissions-free (Clifford, 2022). Several countries around the world have compiled national green hydrogen strategies to prepare for what seems to be a burgeoning new industry. One such country is Chile.

Chile has a promising green hydrogen market for several reasons. First, Chile has strong renewable natural resources which have high potential to be used in the production of electricity. In fact, Chile has the renewable energy potential to install up to 70x the current electricity capacity (Ministry of Energy with McKinsey, 2020). Second, Chile has a national strategic plan where the Chilean government aims to be the cheapest producer and leading exporter of green hydrogen in the world (Ministry of Energy with McKinsey, 2020). Finally, there is growing momentum for green hydrogen in Chile. At the time of our project, over 40 companies in the country were looking to seize and participate in the green hydrogen market opportunity (Electricidad, 2021).

This project aims to evaluate the financial and technical feasibility of producing green hydrogen with excess solar electricity produced in northern Chile. Company owns and operates a solar power plant that, due to local law (Ministry of Energy, 2020), has solar clipping losses that

they would like to potentially harness for green hydrogen production. The business model that Company had in mind is illustrated in Figure 1 below:

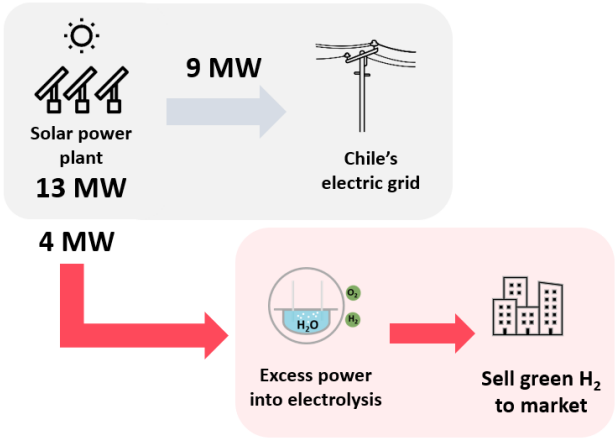

Figure 1: Proposed Company Green Hydrogen Business Model

This business proposition sparked the impetus for our project, driven by three main questions. First, how would green hydrogen be produced at the solar facility? Second, what is the market, in terms of both the volume of demand and the price, for green hydrogen in Chile? Third, is this opportunity financially viable? These questions motivated our research and will be addressed in the following sections of this paper.

THE ISSUE

Company owns a solar farm in northern Chile with a capacity of 13 MWac. However, the project is only able to dispatch a maximum of 9 MWac because the tariff with which the project operates falls within the *Pequeño Medio de Generación Distribuido* (PMGD) category (Ministry of Energy, 2020). The project consequently operates as seen in Figure 2 below.

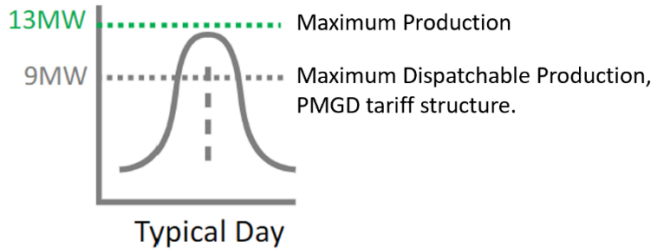

Figure 2: Project Operation Under the PMGD Tariff Structure

As a result, the project is losing some of its capacity, leading to inefficiencies and lost revenue. To extract the maximum amount of value from the project, our team was asked to estimate the volume of solar clipping losses and evaluate the feasibility of utilizing the clipping losses for green hydrogen production.

SUPPLY ESTIMATION

Solar Energy Available from Clipping Losses

To estimate the electricity available for hydrogen production, we first had to assess the site-specific solar irradiation at our target location in northern Chile. We obtained these values from the publicly available Solar Explorer tool from the Chilean Ministry of Energy (Ministry of Energy, n.d.). This tool enables users to derive all of the required solar irradiation components used to estimate the long-term electricity production at a given site.

The site of our pilot project is located in the region of Copiapó, Chile. We used the global horizontal irradiance (GHI) in kWh/m^2/day for 2016 to estimate a typical year (Habte, Lopez, Sengupta, & Wilcox, 2014) of electricity production using industry standards (Monje, 2017). Figure 3 below shows the summary site conditions derived from Solar Explorer.

Figure 3: Solar Explorer GHI Results *(Ministry of Energy, n.d.)*

The map depicts the GHI level scales, where red indicates the highest values. Copiapó is towards the bottom of the map, identified using a red marker. This location has one of the highest irradiation levels in the world per SolarGIS maps (SolarGIS, 2022).

Once we identified the GHI levels from Solar Explorer, we used the trial version of PVsyst to model the electricity produced on site. PVsyst is one of the leading software for electricity production simulation based on solar GHI and other relevant variables (PVsyst Home, 2022). To calculate the excess solar energy available for green hydrogen production, we modeled a 13 MWac solar power plant in PVsyst to obtain an annual 8760 timeseries that shows the power plant's hourly electricity production in every hour of a typical year. In hours where electricity production exceeded 9 MWac, we capped the timeseries to isolate the solar clipping losses. For instance, if hourly production was 8 MWac, then there were no clipping losses in that hour. If electricity production was 10.5 MWac, then there were 1.5 MWac of clipping losses in that hour. The solar clipping losses were summed over the course of the year, with the result shown in Figure 4.

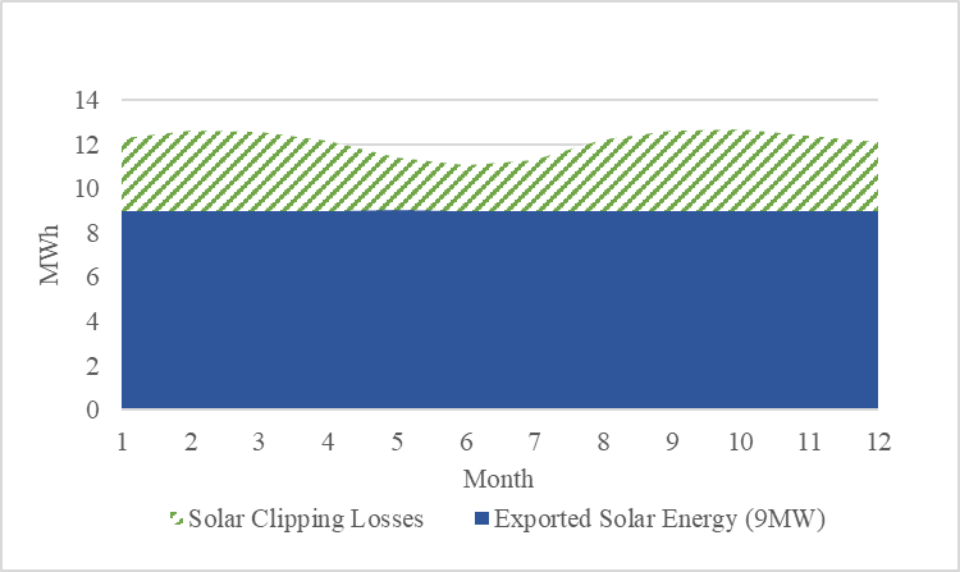

Figure 4: Hourly Maximum Electricity Generation per Month

The solar farm has a total capacity of 13.7 MWdc and 13 MWac. Figure 5 contains the details that were used in the PVsyst trial version simulation.

Capacity	13.7 MWdc
Panels	42,200
Inverters	13 MW
Irradiation	Solar Explorer, Chile
Panels per string	20
# of strings	2097

Figure 5: Solar Farm Specifications

The PVsyst simulation modeled JAM6(K) solar panels from JA Solar (JA Solar JAM6(K), 2016) and the TBEA Centralized Inverter (TBEA, 2022). The solar panels and inverter models were selected to simulate the conditions of the existing solar plant in the north of Chile.

The hourly time series results from the solar clipping losses calculation is summarized in the figure below.

Variable	Quantity	Unit
Max	3.67	MWh
Mean	1.78	MWh
Sum	3,123	MWh/yr
Count	8,760	hr

Figure 6: Energy Production Results Summary

In a typical year, there are 3,123 MWh in solar clipping losses which might be available for green hydrogen production. The resulting PVsyst 8760 was incorporated into our financial model to estimate the pilot project's annual green hydrogen production.

Green Hydrogen Production

There are two main types of electrolyzers: alkaline and polymer electrolyte membrane (PEM). Alkaline electrolyzers are a mature technology, provide long-term stability, and are much more cost-effective than PEM electrolyzers. However, alkaline electrolyzers have a slow-startup time, more corrosion, and complicated maintenance. They also produce hydrogen with less gas purity, which can be important in certain applications. PEM electrolyzers are a newer technology that have a fast start-up time, low corrosion, and simple maintenance. They also produce hydrogen with high gas purity. However, PEM electrolyzers are less durable and are much more expensive than alkaline electrolyzers (Ruth, Mayyas, & Mann, 2017).

Company provided us with five electrolyzer quotes that were incorporated into the pilot project financial model. The specifications are summarized in the table below, but the manufacturer names have been removed for confidentiality reasons.

	Alkaline Electrolyzers		PEM Electrolyzers		
	Alk. 1	Alk. 2	PEM 1	PEM 2	PEM 3
Electrolyzer Size (MW)	1.84	1.50	1.25	2.50	1.00
H_2 Production Capacity (kg/MWh)	19.54	26.96	17.69	17.69	17.98
Total CAPEX Cost ($MM)	**1.06**	**1.38**	**2.28**	**4.55**	**1.82**
Total CAPEX Cost ($MM/MW)	**0.58**	**0.92**	**1.82**	**1.82**	**1.82**

Figure 7: Electrolyzer Quote Specifications

The alkaline electrolyzer quotes were significantly less expensive on a $MM/MW basis. Given the small size and cost sensitivity of the pilot project, the alkaline electrolyzers were the preferred technology.

We used the hydrogen production capacity (kg/MWh) from the quotes to estimate the amount of hydrogen produced by the project over the course of the year based on the solar clipping losses calculated in the previous section. In a typical year, the annual hydrogen production from the pilot project was 46,421 kg.

DEMAND ESTIMATION

Industry Selection

In order to understand the financial viability of the pilot project, we needed to estimate green hydrogen market demand. According to Chile's National Green Hydrogen Strategy, domestic green hydrogen demand in Chile until 2030 will be mainly driven by five industries: heavy duty trucks/buses, iron and steel production, oil refineries, blending into gas grids, and ammonia.

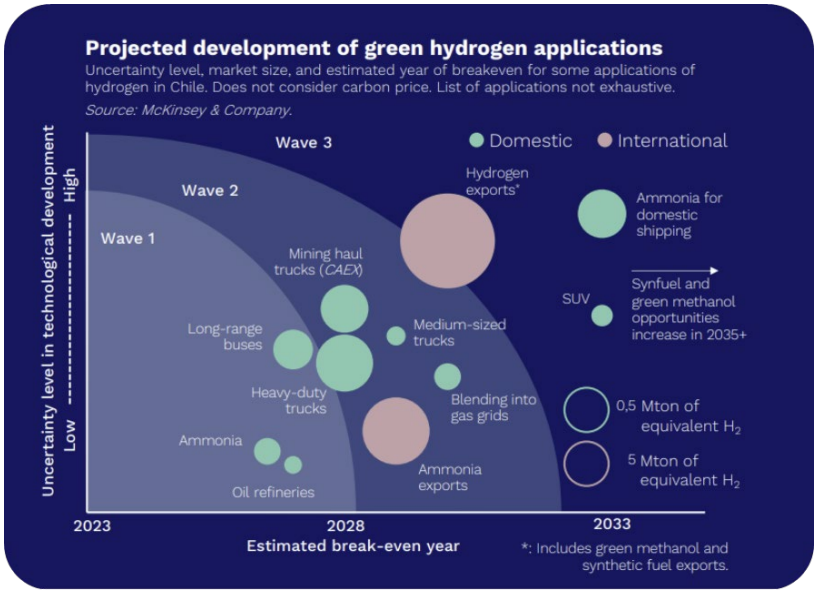

Figure 8: Projected Development of Green Hydrogen Applications in Chile (Ministry of Energy with McKinsey, 2020)

For the purposes of this project, we needed to select two industries to analyze. To prioritize these industries and choose two for our study, we developed seven metrics for analysis:

Figure 9: Seven Industry Prioritization Metrics

These metrics provided us with a framework to understand the attractiveness of each industry as potential buyers of green hydrogen from the pilot project. We were consequently able to rank the industries (Figure 10). A detailed breakdown of the specific estimations can be found in the Appendix.

Industry Ranking (#)		Volume Demand (H_2 tons annually)	Number of Clients (#)	Client quality (1 high – 5 low)	Competition level (1 low– 5 high)
1	Mining trucks	63,345	5	1	4
2	Blending Gas	60,765	6	3	1
3	Iron & Steel	65,000	2	1	2
4	Oil Refineries	46,000	1	1	5
5	Ammonia	32,000	1	1	5

Figure 10: Industry Ranking

We also considered qualitative criteria to select the two industries. A breakdown of these qualitative factors is below:

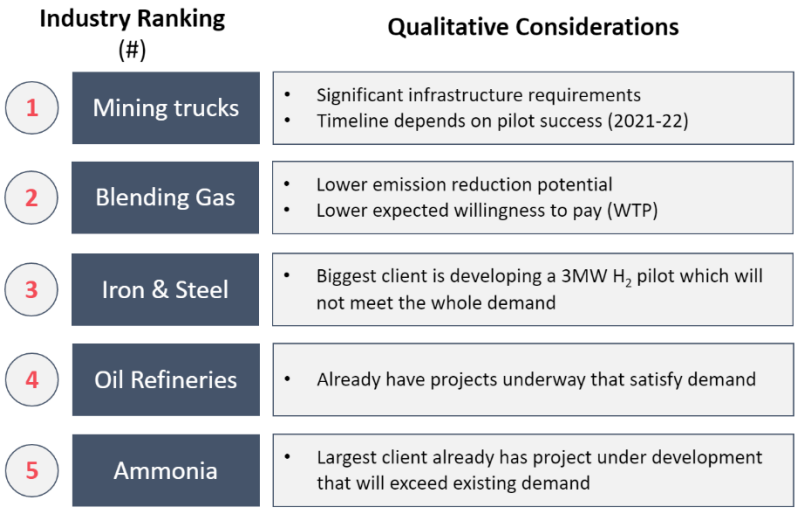

Figure 11: Qualitative Considerations, by Industry

Given these factors, Company decided to focus our analysis on the mining trucks industry and the blending gas industry.

Volume of Demand

Following industry selection, we then calculated the projected demand for the two target industries (blending gas and mining trucks) by researching green hydrogen blend limits in each of the applications. Step one entailed calculating the current demand for diesel or natural gas within the target industry. Step two was to calculate growth projections for fuel demand within the industry in the short (present – 2030), medium (~2040), and long-term (~2050). Finally, step three was to research green hydrogen blend limits with existing infrastructure and in the future with infrastructure upgrades.

Blending Gas: In the short-term, we assumed a 5% hydrogen blend into natural gas pipelines. At present, the limits for hydrogen blending into natural gas networks has been kept very low (between 0.2 - 6%) (Pellegrini, Guzzini, & Saccani, 2020).

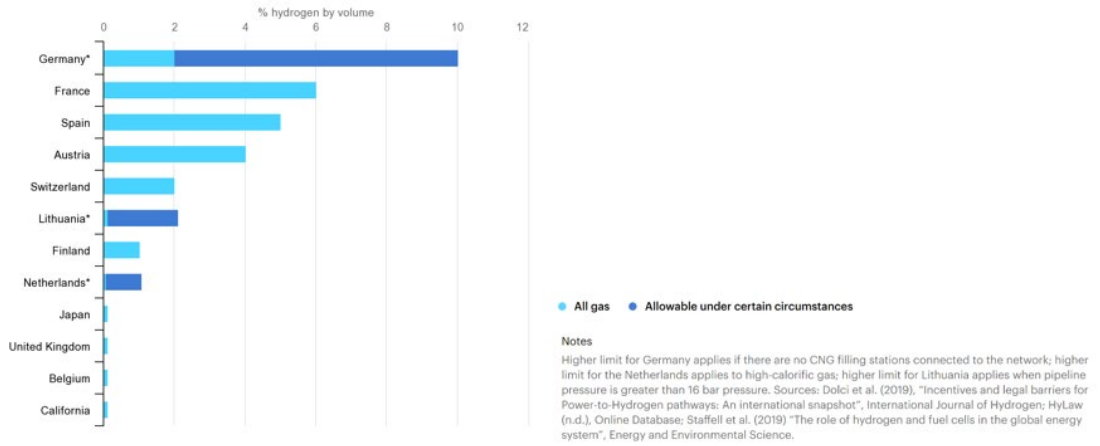

Figure 12: Limits on Hydrogen Blending in Natural Gas Networks, 2018 *(IEA, 2020)*

For the medium-term, we assumed a 20% hydrogen blend into natural gas pipelines with some minor infrastructure modifications. Based on current research, a 20% blend of hydrogen into natural gas pipelines is the maximum blend percentage without requiring major modifications to infrastructure (IRENA, 2019).

Long-term, we assumed a range of between 70 – 100% hydrogen blend, with major modifications or a complete conversion to hydrogen pipelines required. There are various considerations for this. First, given the lower energy density of hydrogen, current pipeline sizes cannot supply the same energy demand as natural gas (Noussan, Raimondi, Scita, & Hafner, 2021). Second, while converting to 100% hydrogen is technically feasible, it is unknown whether the Chilean government has that long-term goal (hence the 70-100% range). Third, there is varying impact on different infrastructure components, and varying impact for distribution vs. transmission systems which might impact the blend percentage (Melaina, Antonia, & Penev, 2013).

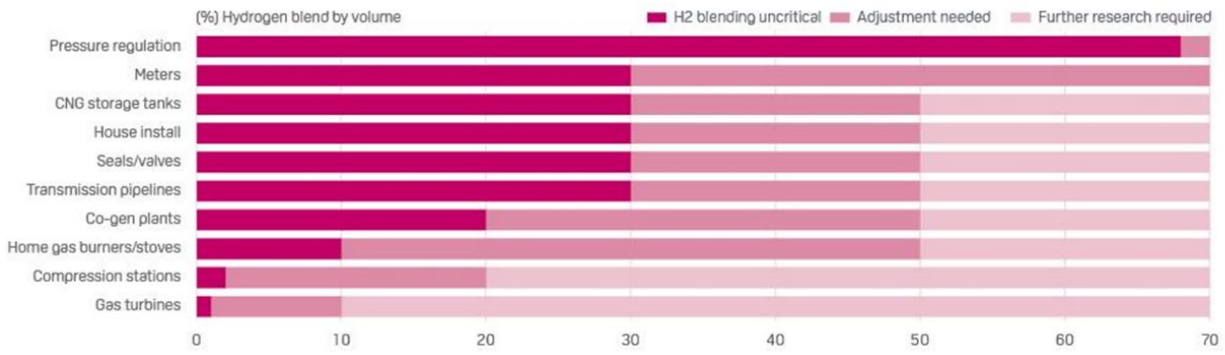

Figure 13: Hydrogen Blending Limits in Natural Gas Grid by Volume *(McDonald, 2020)*

Finally, hydrogen pipelines have higher rates of leakage than methane, which pose both a safety and economic consideration (Melaina, Antonia, & Penev, 2013). Important for this application, hydrogen is also a very small molecule and more prone to leakage from natural gas-grade pipelines.

Given the short, medium, and long-term blending percentage assumptions outlined above, we calculated the potential demand:

Natural Gas Consumption, Cubic Meters (2019)	1,578,307,796	• *Open Energy, National Energy Commission of Chile, 2020.*	**Gas consumption in Chile has grown at a CAGR of 1.2% over the past decade**
2040 Projection: Natural Gas Consumption, Cubic Meters	2,027,600,848		
2050 Projection: Natural Gas Consumption, Cubic Meters	2,284,481,204		

	Short Term (Present-2030)	Medium Term (2040)	Long Term - Low (2050)	Long Term - High (2050)
H_2 Blend Volume	5%	20%	70%	100%
Cubic Meters of NG to Replace	78,915,390	405,520,170	1,599,136,843	2,284,481,204
H_2 required (Tons)	60,765	312,251	1,231,335	1,759,051
Chile's installed renewable energy capacity was 6,639 MW as of January 2021. To meet the long term green H_2 demand, it would need to increase by:*			3.5x	5.1x

*Assuming an average NCF of 30% (in Jan 2021, the NCF was 36.3% so we assumed a slightly lower annual NCF due to seasonality) and a production rate of 19.76 kg/MWh.

Figure 14: Blending Gas Industry Potential Green Hydrogen Market Demand in Northern Chile

Gas consumption in Chile has grown at a compound annual growth rate (CAGR) or 1.2% over the past decade (CEIC, 2020). To meet this long-term growth, Chile's installed renewable energy capacity (Djunisic, 2021) would have to increase by between 3.5 - 5.1x.

Mining Trucks: For mining trucks, we estimated the hydrogen-diesel dual fuel blending percentage. In the short term, we assume a 15% hydrogen blend into diesel engines without major engine modifications. Most academic papers agree that 15% is the maximum optimal blend percentage under current engine conditions ((Akal, Oztuna, & Buyukakin, 2020); (Barrios, Dominguez-Saez, & Hormigo, 2017); (Cernat, et al., 2020); (Dimitriou & Tsujimura, 2017); (El Hannach, Ahmadi, Guzman, & Pickup, 2019); (Yip, et al., 2019)). For the medium and long-term, we assume a range of between 40 – 70% hydrogen diesel blend in the dual engine. Alta Ley, a spinoff of CORFO (the Chilean Economic Development Agency), has partnered with Alset to develop a dual fuel hydrogen/diesel engine. The aim was to produce a functional mining prototype by the end of 2021 ((Alta Ley, 2020); (Casey, 2020); (Mission Innovation, 2021)).

Given these blending percentages, we estimated the potential green hydrogen market demand for mining trucks:

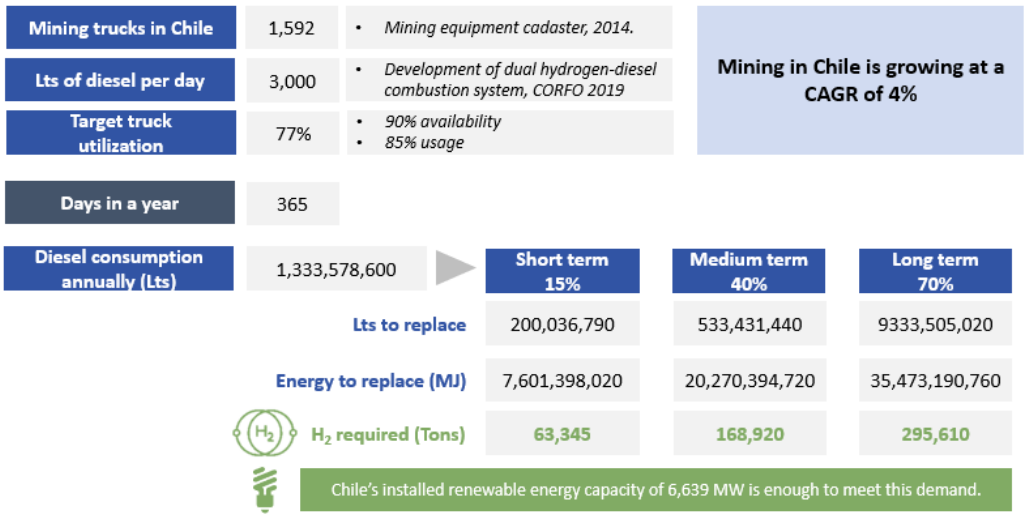

Figure 15: Mining Trucks Industry Potential Green Hydrogen Market Demand in Northern Chile

While the Chilean mining industry grew at a CAGR of 0.8% between 2015 – 2019, it is projected to grow at a CAGR of 5.4% over the next five years (Research and Markets, 2021). Company

therefore requested that we use a CAGR of 4% in our analysis. Even with this long-term growth, Chile's installed renewable energy capacity is enough to meet this demand.

Willingness to Pay Estimation

For the price analysis, we estimated the willingness to pay (WTP) for green hydrogen as well as the cost of other alternatives such as carbon offsets. We developed four scenarios, summarized in the figure below:

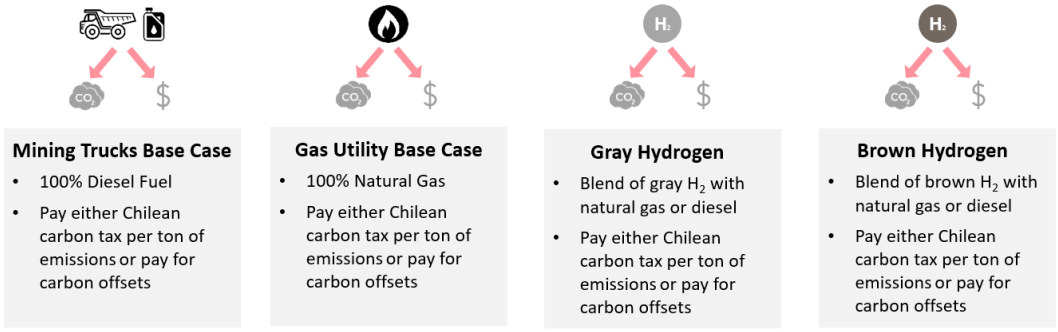

Figure 16: Willingness to Pay for Green Hydrogen Estimation Scenarios

Gray hydrogen is the most common form of hydrogen production today and is created from natural gas using steam methane reformation (National Grid, 2022). Brown hydrogen uses lignite coal in the production of hydrogen (National Grid, 2022).

In addition to the fuel costs, we sought to understand the emissions cost to companies. To do so, we analyzed the price of carbon offsets and a carbon tax in Chile of $5/mt CO2e. The carbon tax in Chile does not currently cover mining and gas companies, but it is expected to from 2025 onwards (International Carbon Action Partnership, 2021). Carbon offsets vary from $1.4/mt CO2e to $4.3/mt CO2e, with an average price of $2.8/mt CO2e (S&P Global, 2020).

Offset Source	Average Price ($/mt CO2e)
Renewable Energy	1.4
Forestry and Land Use	4.3
Waste Disposal	2.5
Household Devices	3.8
Chemical Processes/Industrial Manufacturing	1.9
Energy Efficiency/Fuel Switching	3.9
Transportation	1.7
Average	**2.8**

Figure 17: Average Price of Carbon Offsets by Source

We also conducted interviews with various Chilean company executives to understand their current WTP for green hydrogen. Key takeaways are summarized below.

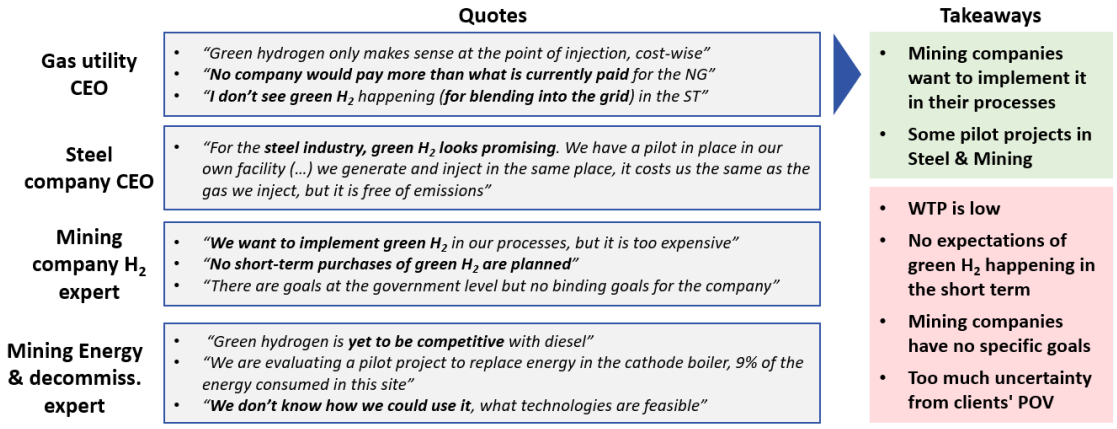

Figure 18: Key Willingness to Pay for Green Hydrogen Takeaways from Industry Interviews

From those interviews, it is clear that there is only a WTP for green hydrogen at prevailing commodity price rates for the alternatives that companies are currently using.

Therefore, we calculated the WTP for each industry without any additional green premium for green hydrogen. Our results are summarized in the table below, with additional details in the Appendix.

Mining Company Willingness to Pay		
	($/kg)	($/MMBtu)
Average	**2.23**	**16.54**
Minimum	1.18	8.73
Maximum	3.23	23.90

Gas Utility Willingness to Pay		
	($/kg)	($/MMBtu)
Average	**1.65**	**12.20**
Minimum	1.18	8.73
Maximum	1.46	10.81

Figure 19: Willingness to Pay for Green Hydrogen, by Industry

Addressable Market Size

Putting the demand and willingness to pay estimations together, we estimated the addressable market size for each use case to be as follows:

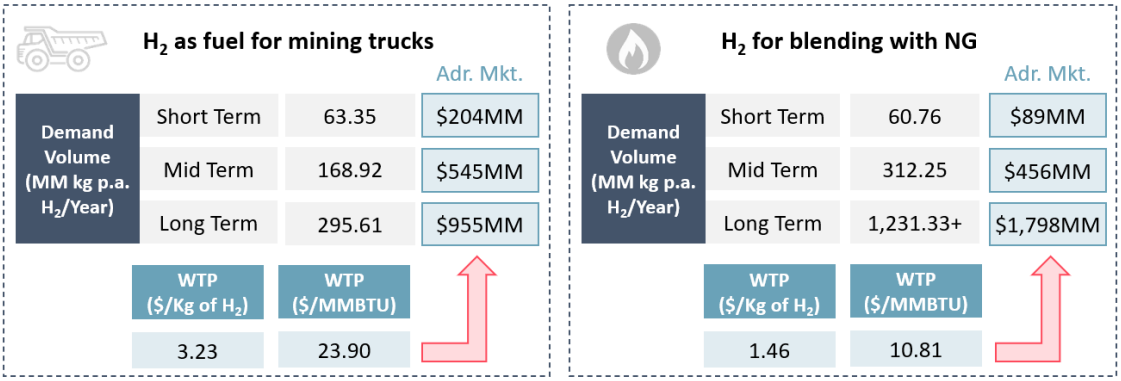

Figure 20: Addressable Market Size for Green Hydrogen in Chile, by Industry

Note that we used the maximum willingness to pay for each industry in these calculations, as momentum for green hydrogen is rising in Chile.

FINANCIAL MODEL

We incorporated the inputs described above into a financial model to understand the economic feasibility of the green hydrogen pilot project. The financial results are summarized in the figure below.

Financial Results		
	Mining Trucks	Blending Gas
WTP* ($/kg)	3.23	1.46
WTP ($/MMBtu)	23.90	10.81
NPV ($MM)	(1.25)	(1.74)
MOIC	0.86x	0.02x
BE Price**	7.73 $/kg (57.20 $/MMBtu)	

*Willingness to Pay
**Break-even hydrogen price (NPV = 0 at 15% discount rate)

Figure 21: Financial Model Results, by Industry

The project Net Present Value (NPV) is negative for both use case scenarios. The break-even hydrogen price at a 15% IRR for the project is $7.73/kg ($57.20/MMBtu), which is well above the estimated WTP for both industries. The pilot project break-even green hydrogen price at a 0% IRR is $26.10/MMBtu, which is still above each industry's WTP.

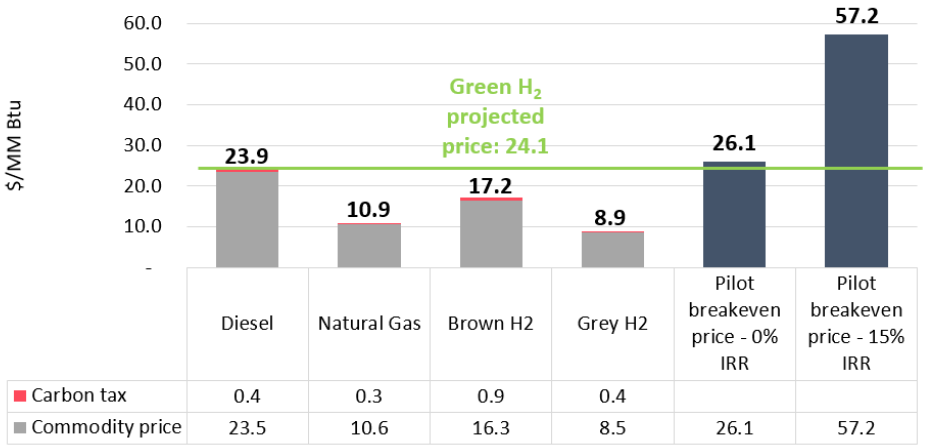

Figure 22: Comparison of Industry WTP by Alternative Fuel Source and Pilot Break-Even Green Hydrogen Prices

Details on the financial model assumptions, project costs, and cash flow results can be found in the Appendix.

RESULTS

The green hydrogen pilot project has a negative NPV and does not yield economic benefits. This can be explained by two main factors. First, the amount of hydrogen production derived from

clipping losses is between 47 – 57 metric tons per year, which leads to an electrolyzer utilization factor of only ~15% (see Appendix for details). This asset utilization does not yield economies of scale. Second, the willingness to pay for green hydrogen within Chile is currently low, despite efforts across the industries to reduce carbon emissions. From the industry interviews, there is only a WTP for green hydrogen at prevailing commodity price rates for the alternatives that they are currently using. This low WTP does not provide Company with the price point needed for the pilot project to be economic.

To illustrate this point, we conducted a sensitivity analysis on the IRR and resulting break-even green hydrogen prices to better understand the profitability of the pilot project:

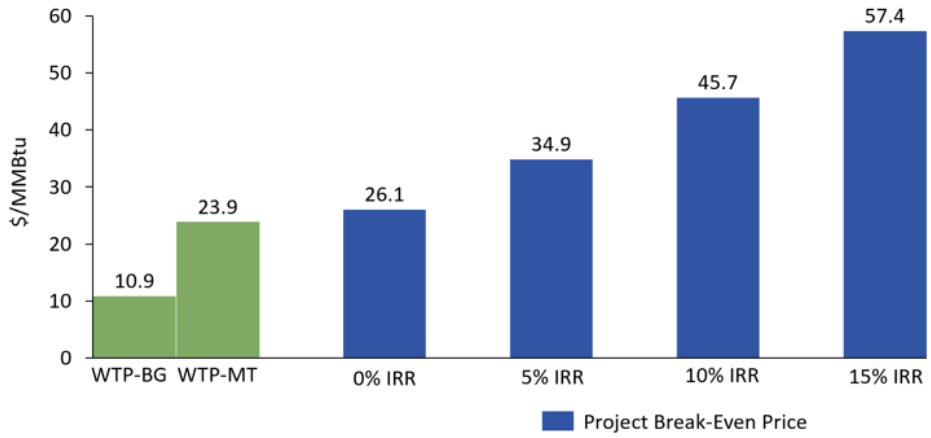

Figure 23: Pilot Project IRR and Resulting Break-Even Green Hydrogen Price Sensitivity

At the pilot project's rate of hydrogen production, it would realistically need the WTP of gas utilities and mining companies to be at least $45/MMBtu in order to be a feasible investment.

DISCUSSION

The clipping losses model is not sustainable for the green hydrogen pilot project. The low, variable amount of electricity throughout the day and year do not allow for a constant utilization of the electrolyzers. Consequently, the electrolyzers cannot produce enough green hydrogen to

send to market and offset the initial CAPEX investment. This phenomenon is further exacerbated by the low willingness to pay for green hydrogen that currently exists in the Chilean gas utility and mining industries.

At the point of this project, there were several potential national and regional grants that could make the green hydrogen pilot project more economical. The objective of these grants was to better understand the performance, supply chain, and challenges of green hydrogen development within Chile. According to a Company Executive, CRDP-GORE grants a maximum of $350,000 USD in regional grants for any project that qualifies. The application process for such a grant focuses on the technical, economical, and carbon impact of the project, including innovation. Under the grant, CRDP received the funds and manages them with the company. Additionally, a CORFO grant of $50MM USD is available to allocate between projects with a size of greater than or equal to 10 MW (Benitez, Cruzat, & Moran, 2021). While these grants would help the project economics, the pilot project would still need a large percentage of its CAPEX to be covered by the grant in order to break even or achieve a positive IRR.

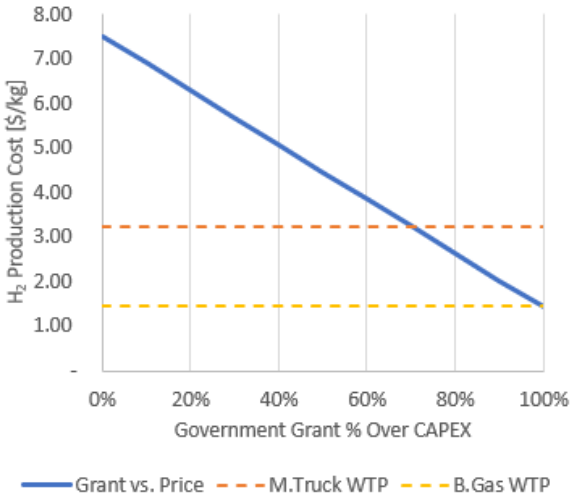

Figure 24: Hydrogen Production Costs vs. Government Grant % Over CAPEX Sensitivity

To better understand the technical and economic forces impacting the project, we also ran a sensitivity analysis on various inputs to the financial model.

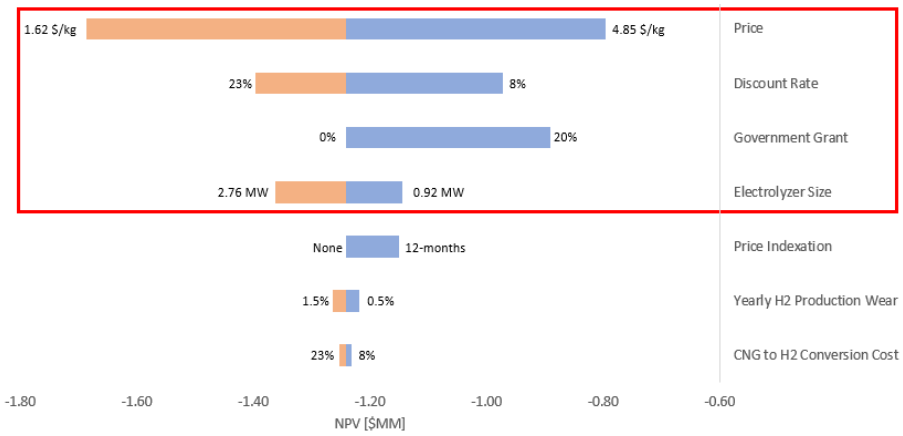

Figure 25: Sensitivity Analysis: +/- 50% From Base Case

The four factors that move the needle the most on project NPV are the price (companies' WTP for green hydrogen), discount rate, potential grants from the Chilean government, and the electrolyzer size.

For a more holistic understanding of the project economics, it is important to consider both the hydrogen storage and transportation costs. While an analysis of the storage and transportation costs was outside of the scope of our project, we did briefly examine these factors. In the case of this pilot project, given the low amounts of daily hydrogen production, storage would have been necessary to achieve sufficient scale to fill up the hydrogen tube trailer trucks for transport to market. However, both the storage and transport solutions were too expensive and not justifiable for the small quantity of hydrogen produced by the project. Client conversion requires a much larger quantity of green hydrogen to be delivered; thus, customers will not buy green hydrogen until the price is competitive and the supply is both sufficient and stable.

Another interesting factor for green hydrogen in Chile is regulation. At the time of the project, there were not many regulations in place to oversee green hydrogen production and use.

There are certainly intentions to regulate hydrogen within Chile, but as the industry evolves the regulations must as well. Since hydrogen is considered a hazardous material, and dangerous in liquid and gaseous states, it will likely require special permits. An in-depth look at hydrogen policy and regulation within Chile was outside of the scope of our research, but it is important to note that it will have a significant impact on the feasibility of green hydrogen projects moving forward. Therefore, Company should keep a close eye on any future green hydrogen policy or regulatory developments in Chile.

CONCLUSION

Chile has an attractive green hydrogen market given its aggressive national strategy and plentiful renewable energy capacity. However, we do not recommend that Company move forward with the proposed green hydrogen pilot project. The solar clipping losses business model does not allocate enough electricity for hydrogen production. The low hydrogen production rates of between 47 – 57 metric tons per year do not provide enough hydrogen for sale to offset the initial CAPEX investment.

We recommend that Company analyze a second iteration of the pilot project where more electricity is drawn to the electrolyzer based on hourly electricity costs. If producing and selling green hydrogen is more profitable than selling electricity to the grid, then this could be a way to increase the electrolyzer utilization factor, generate higher revenues, and justify the CAPEX investment.

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APPENDIX

Market Demand Estimations:

Mining Trucks

There are pilot projects underway to create dual fuel engines that run on a blend of hydrogen and diesel fuel in the mining industry. We therefore estimated that, if successful, the addressable market size would be 63,345 tons of hydrogen annually in Chile with 7,091 tons of this specifically in the Atacama region. This assumes a replacement of 15% diesel fuel with hydrogen.

Figure 26: Mining Trucks Industry Analysis

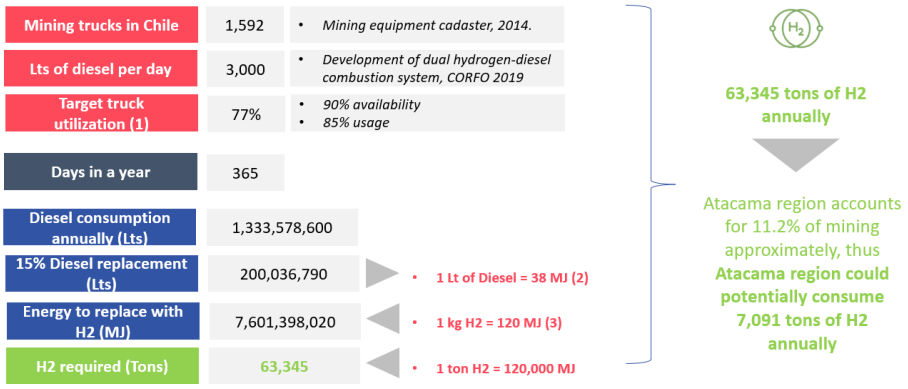


Figure 27: Hydrogen Requirements for Diesel Replacement in Mining Trucks

Sources:

- Number of mining trucks in Chile in 2013-14: (Mineria Chilena, 2014)
- Liters used by truck per day: (CORFO , 2017)
- Energy content per kg of H2 in MJ: (The Physics Factbook, 2005)
- Energy content per Lt of diesel in MJ: (Cambridge Regional College, n.d.)

Iron & Steel

Iron and steel production processes are expected to evolve into using hydrogen to reduce emissions and improve efficiency. Given the two largest steel producers in Chile that operate in the northern region, we estimated the addressable market size to be 65,000 tons of green hydrogen per year.

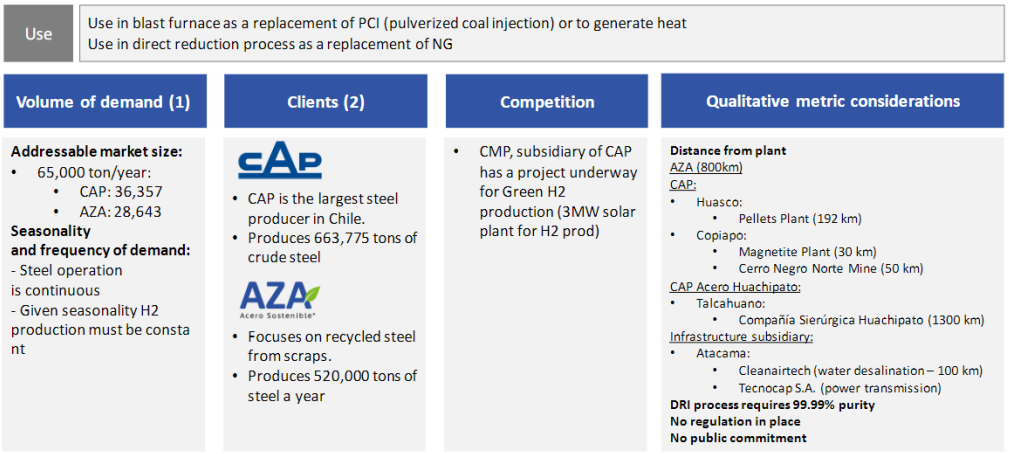


Figure 28: Iron & Steel Production Industry Analysis

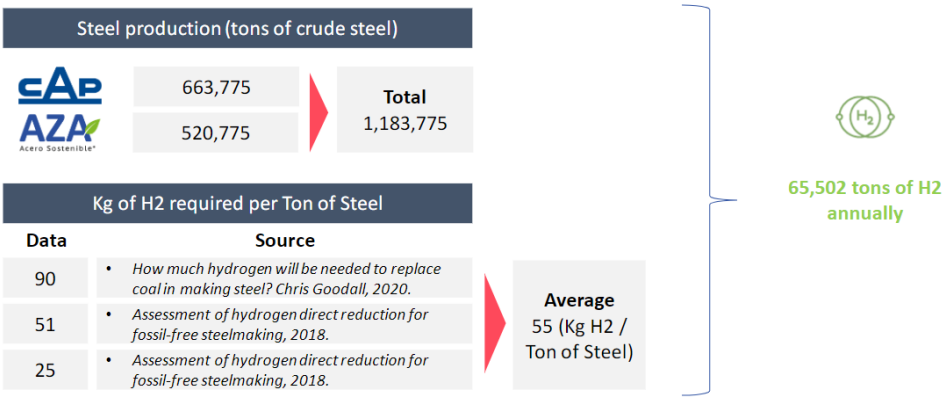


Figure 29: Hydrogen Requirements for Steel Production

Sources:

- Quantity of H2 required per ton of steel:
  - (Goodall, 2020)
  - (Vogl, Ahman, & Nilsson, 2018)
  - (Hoffmann, Van Hoey, & Zeumer, 2020)

Fuel Blend with Natural Gas

Hydrogen can be blended into the natural gas system and used by existing consumers for power and heat needs. Based on pilot projects elsewhere, we estimate a 5% hydrogen blend into Chile's natural gas network as feasible, which results in an addressable market size of 60,765 tons of green hydrogen.

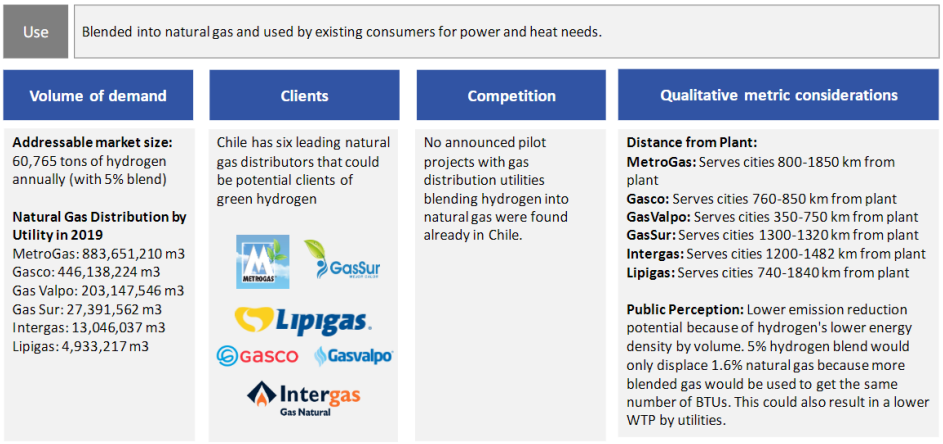


Figure 30: Fuel Blend with Natural Gas Industry Analysis

Sources:

- (Cortes-Simon, 2019)

Oil Refineries

Oil refineries can use hydrogen for several processes, as indicated below. Based on the potential client of ENAP, we estimate the addressable market size to be 46,000 tons of hydrogen per year.

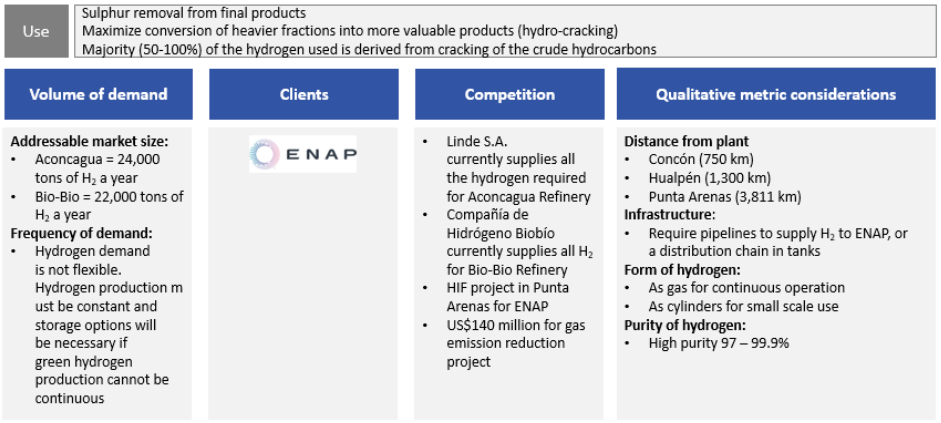


Figure 31: Oil Refineries Industry Analysis

Sources:

- (Dolci, 2018)
- (Saez & Ladislao, 2020)
- (Vasquez & Salinas, 2018)

Ammonia

Green hydrogen can be converted into ammonia to be used for mining explosives. We estimate the addressable market size based on the Enaex Prillex plant, which has a capacity of 850,000 tons of ammonium nitrate annually, which is equivalent to 32,000 tons of hydrogen annually.

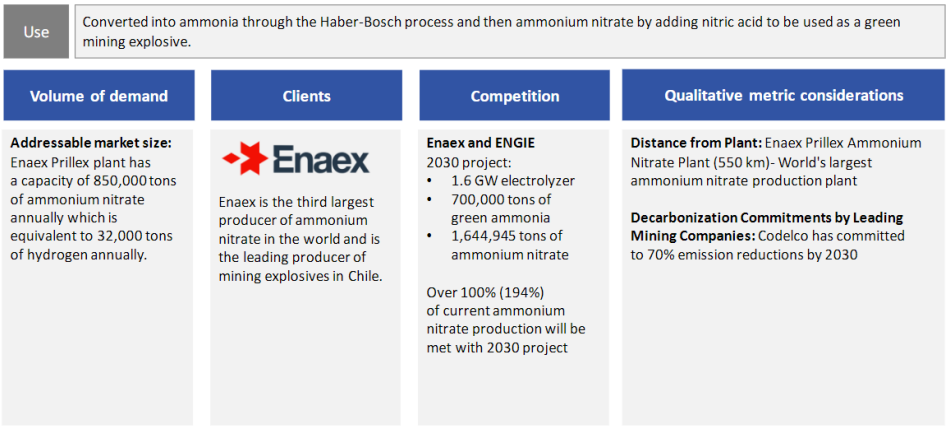


Figure 32: Ammonia Industry Analysis

Sources:

- (Enaex, 2022)

- (Jones, 2020)
- (Asher, 2020)

Willingness to Pay Estimations:

To calculate the willingness to pay, we took the fuel prices, fuel emission intensity, and emission costs to companies, summarized below.

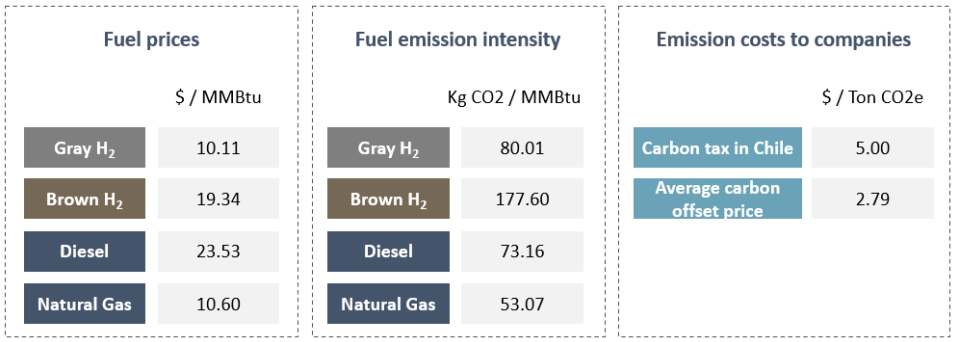
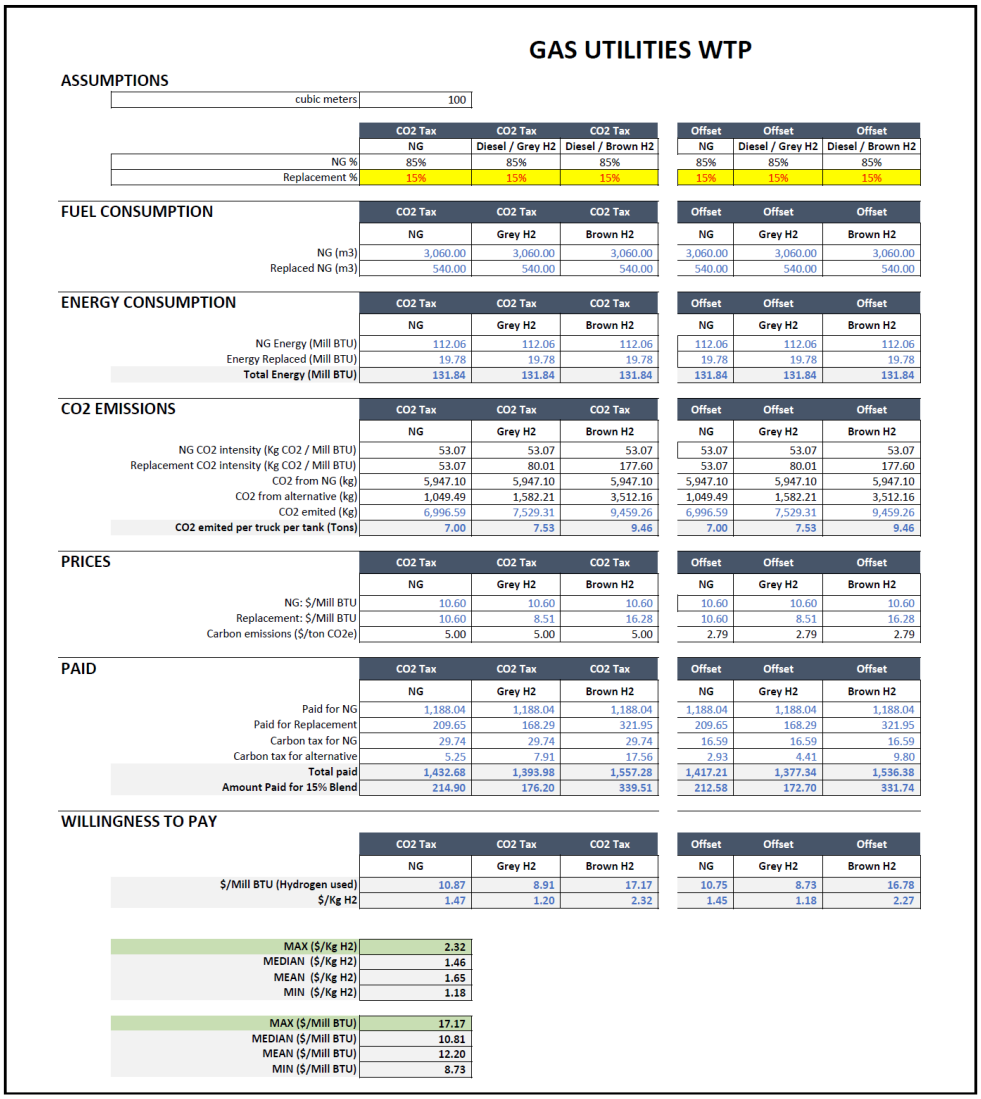


Figure 33: Willingness to Pay Estimation Components

The data listed above is from the following sources:

- Fuel prices
  - Gray and brown hydrogen: (IEA, 2020)
  - Diesel: (Global Petrol Prices, 2021) – previous version
  - Natural gas: (Global Petrol Prices, 2021) – previous version
- Fuel emission intensity
  - Gray and brown hydrogen: (IEA, 2020)
  - Diesel and natural gas: (US Energy Information Administration, 2021) – previous version
- Note: the carbon tax in Chile and carbon offset price are described in the main text

We utilized this data to calculate the gas utilities and mining companies' WTP for green hydrogen. Detailed analysis can be found below:



GAS UTILITIES WTP

ASSUMPTIONS

cubic meters	100

	CO2 Tax NG	CO2 Tax Diesel / Grey H2	CO2 Tax Diesel / Brown H2	Offset NG	Offset Diesel / Grey H2	Offset Diesel / Brown H2
NG %	85%	85%	85%	85%	85%	85%
Replacement %	15%	15%	15%	15%	15%	15%

FUEL CONSUMPTION

	CO2 Tax NG	CO2 Tax Grey H2	CO2 Tax Brown H2	Offset NG	Offset Grey H2	Offset Brown H2
NG (m3)	3,060.00	3,060.00	3,060.00	3,060.00	3,060.00	3,060.00
Replaced NG (m3)	540.00	540.00	540.00	540.00	540.00	540.00

ENERGY CONSUMPTION

	CO2 Tax NG	CO2 Tax Grey H2	CO2 Tax Brown H2	Offset NG	Offset Grey H2	Offset Brown H2
NG Energy (Mill BTU)	112.06	112.06	112.06	112.06	112.06	112.06
Energy Replaced (Mill BTU)	19.78	19.78	19.78	19.78	19.78	19.78
Total Energy (Mill BTU)	**131.84**	**131.84**	**131.84**	**131.84**	**131.84**	**131.84**

CO2 EMISSIONS

	CO2 Tax NG	CO2 Tax Grey H2	CO2 Tax Brown H2	Offset NG	Offset Grey H2	Offset Brown H2
NG CO2 intensity (Kg CO2 / Mill BTU)	53.07	53.07	53.07	53.07	53.07	53.07
Replacement CO2 intensity (Kg CO2 / Mill BTU)	53.07	80.01	177.60	53.07	80.01	177.60
CO2 from NG (kg)	5,947.10	5,947.10	5,947.10	5,947.10	5,947.10	5,947.10
CO2 from alternative (kg)	1,049.49	1,582.21	3,512.16	1,049.49	1,582.21	3,512.16
CO2 emited (Kg)	6,996.59	7,529.31	9,459.26	6,996.59	7,529.31	9,459.26
CO2 emited per truck per tank (Tons)	**7.00**	**7.53**	**9.46**	**7.00**	**7.53**	**9.46**

PRICES

	CO2 Tax NG	CO2 Tax Grey H2	CO2 Tax Brown H2	Offset NG	Offset Grey H2	Offset Brown H2
NG: $/Mill BTU	10.60	10.60	10.60	10.60	10.60	10.60
Replacement: $/Mill BTU	10.60	8.51	16.28	10.60	8.51	16.28
Carbon emissions ($/ton CO2e)	5.00	5.00	5.00	2.79	2.79	2.79

PAID

	CO2 Tax NG	CO2 Tax Grey H2	CO2 Tax Brown H2	Offset NG	Offset Grey H2	Offset Brown H2
Paid for NG	1,188.04	1,188.04	1,188.04	1,188.04	1,188.04	1,188.04
Paid for Replacement	209.65	168.29	321.95	209.65	168.29	321.95
Carbon tax for NG	29.74	29.74	29.74	16.59	16.59	16.59
Carbon tax for alternative	5.25	7.91	17.56	2.93	4.41	9.80
Total paid	**1,432.68**	**1,393.98**	**1,557.28**	**1,417.21**	**1,377.34**	**1,536.38**
Amount Paid for 15% Blend	**214.90**	**176.20**	**339.51**	**212.58**	**172.70**	**331.74**

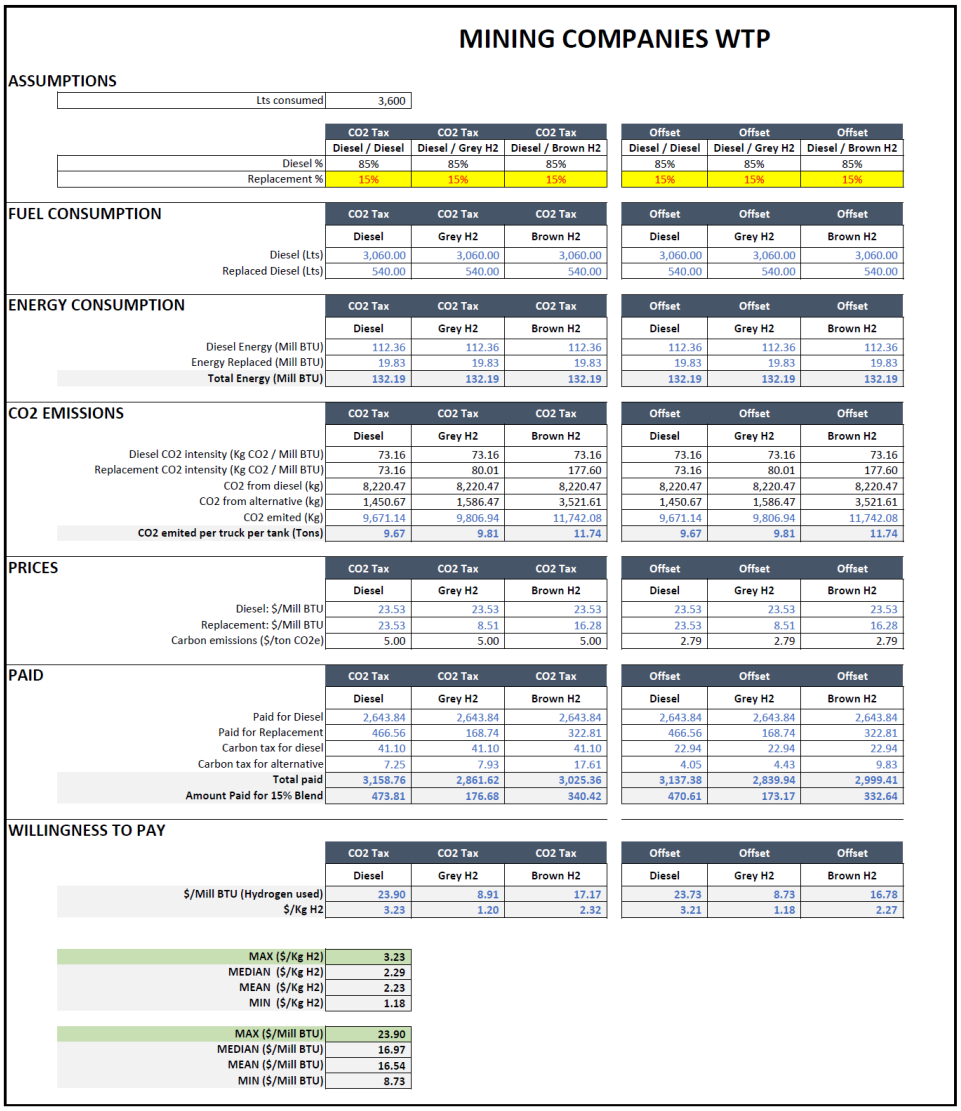
WILLINGNESS TO PAY

	CO2 Tax NG	CO2 Tax Grey H2	CO2 Tax Brown H2	Offset NG	Offset Grey H2	Offset Brown H2
$/Mill BTU (Hydrogen used)	**10.87**	**8.91**	**17.17**	**10.75**	**8.73**	**16.78**
$/Kg H2	**1.47**	**1.20**	**2.32**	**1.45**	**1.18**	**2.27**

MAX ($/Kg H2)	2.32
MEDIAN ($/Kg H2)	1.46
MEAN ($/Kg H2)	1.65
MIN ($/Kg H2)	1.18

MAX ($/Mill BTU)	17.17
MEDIAN ($/Mill BTU)	10.81
MEAN ($/Mill BTU)	12.20
MIN ($/Mill BTU)	8.73

Figure 34: Gas Utilities' WTP for Green Hydrogen Calculations



MINING COMPANIES WTP

ASSUMPTIONS

Lts consumed	3,600

	CO2 Tax Diesel / Diesel	CO2 Tax Diesel / Grey H2	CO2 Tax Diesel / Brown H2	Offset Diesel / Diesel	Offset Diesel / Grey H2	Offset Diesel / Brown H2
Diesel %	85%	85%	85%	85%	85%	85%
Replacement %	15%	15%	15%	15%	15%	15%

FUEL CONSUMPTION

	CO2 Tax Diesel	CO2 Tax Grey H2	CO2 Tax Brown H2	Offset Diesel	Offset Grey H2	Offset Brown H2
Diesel (Lts)	3,060.00	3,060.00	3,060.00	3,060.00	3,060.00	3,060.00
Replaced Diesel (Lts)	540.00	540.00	540.00	540.00	540.00	540.00

ENERGY CONSUMPTION

	CO2 Tax Diesel	CO2 Tax Grey H2	CO2 Tax Brown H2	Offset Diesel	Offset Grey H2	Offset Brown H2
Diesel Energy (Mill BTU)	112.36	112.36	112.36	112.36	112.36	112.36
Energy Replaced (Mill BTU)	19.83	19.83	19.83	19.83	19.83	19.83
Total Energy (Mill BTU)	**132.19**	**132.19**	**132.19**	**132.19**	**132.19**	**132.19**

CO2 EMISSIONS

	CO2 Tax Diesel	CO2 Tax Grey H2	CO2 Tax Brown H2	Offset Diesel	Offset Grey H2	Offset Brown H2
Diesel CO2 intensity (Kg CO2 / Mill BTU)	73.16	73.16	73.16	73.16	73.16	73.16
Replacement CO2 intensity (Kg CO2 / Mill BTU)	73.16	80.01	177.60	73.16	80.01	177.60
CO2 from diesel (kg)	8,220.47	8,220.47	8,220.47	8,220.47	8,220.47	8,220.47
CO2 from alternative (kg)	1,450.67	1,586.47	3,521.61	1,450.67	1,586.47	3,521.61
CO2 emited (Kg)	9,671.14	9,806.94	11,742.08	9,671.14	9,806.94	11,742.08
CO2 emited per truck per tank (Tons)	**9.67**	**9.81**	**11.74**	**9.67**	**9.81**	**11.74**

PRICES

	CO2 Tax Diesel	CO2 Tax Grey H2	CO2 Tax Brown H2	Offset Diesel	Offset Grey H2	Offset Brown H2
Diesel: $/Mill BTU	23.53	23.53	23.53	23.53	23.53	23.53
Replacement: $/Mill BTU	23.53	8.51	16.28	23.53	8.51	16.28
Carbon emissions ($/ton CO2e)	5.00	5.00	5.00	2.79	2.79	2.79

PAID

	CO2 Tax Diesel	CO2 Tax Grey H2	CO2 Tax Brown H2	Offset Diesel	Offset Grey H2	Offset Brown H2
Paid for Diesel	2,643.84	2,643.84	2,643.84	2,643.84	2,643.84	2,643.84
Paid for Replacement	466.56	168.74	322.81	466.56	168.74	322.81
Carbon tax for diesel	41.10	41.10	41.10	22.94	22.94	22.94
Carbon tax for alternative	7.25	7.93	17.61	4.05	4.43	9.83
Total paid	**3,158.76**	**2,861.62**	**3,025.36**	**3,137.38**	**2,839.94**	**2,999.41**
Amount Paid for 15% Blend	**473.81**	**176.68**	**340.42**	**470.61**	**173.17**	**332.64**

WILLINGNESS TO PAY

	CO2 Tax Diesel	CO2 Tax Grey H2	CO2 Tax Brown H2	Offset Diesel	Offset Grey H2	Offset Brown H2
$/Mill BTU (Hydrogen used)	**23.90**	**8.91**	**17.17**	**23.73**	**8.73**	**16.78**
$/Kg H2	**3.23**	**1.20**	**2.32**	**3.21**	**1.18**	**2.27**

MAX ($/Kg H2)	3.23
MEDIAN ($/Kg H2)	2.29
MEAN ($/Kg H2)	2.23
MIN ($/Kg H2)	1.18

MAX ($/Mill BTU)	23.90
MEDIAN ($/Mill BTU)	16.97
MEAN ($/Mill BTU)	16.54
MIN ($/Mill BTU)	8.73

Figure 35: Mining Companies' WTP for Green Hydrogen Calculations

Green and Blue Hydrogen Price Projections:

The following table contains green and blue hydrogen price projections from various sources, as well as the 2020, 2030, and 2050 price projections for diesel and natural gas. Note that ST = short-term, MT = medium-term, and LT = long-term.

Sources	Green H_2 ST		Blue H_2 ST		Green H_2 MT		Blue H_2 MT		Green H_2 LT		Blue H_2 LT	
	$/kg	$/MMBtu	$/kg	$/MMBtu	$/kg	$/MMBtu	$/kg	$/MMBtu	$/kg	$/MMBtu	$/kg	$/MMBtu
Bloomberg New Energy Finance[1]	2.70-4.70	19.98-34.78	1.90	14.06	1.15-2.00	8.51-14.80	2.10	15.54	.60-.63	4.44-4.66	2.20	16.28
IEA[2]	3.00	22.20	2.20	16.28	-	-	-	-	1.80	13.32	2.10	15.54
McKinsey[3]	2.00	14.80	1.50-3.00	11.10-22.20	1.40	10.36	1.50-3.00	11.10-22.20	0.80	5.92	1.50-3.00	11.10-22.20
S&P Global[4]	4.30	31.82	-	-	-	-	-	-	-	-	-	-
Average	**3.24**	**24.05**	**2.12**	**15.66**	**1.49**	**11.01**	**2.18**	**16.10**	**1.07**	**7.93**	**2.18**	**16.16**

	2020 Price ($/MMBtu)	2030 Price Projection ($/MMBtu)[7]	2050 Price Projection ($/MMBtu)[7]
Diesel	21.35	17.42	11.60
Natural Gas	10.60	14.30	16.11

Figure 36: Green and Blue Hydrogen Price Projections

The numbered sources are below:

1. (Snieckus, 2021)
2. (IEA, 2019)
3. (McKinsey & Company, 2020)
4. (S&P Global, 2020)
5. Diesel source: (Global Petrol Prices, 2021)
6. Metrogas source: (Metrogas, 2022) – previous version
7. Price growth projections: (US EIA, 2022) – previous version

The following chart summarizes these price projections. Green hydrogen is expected to be cheaper than diesel by 2026 and natural gas by 2028.

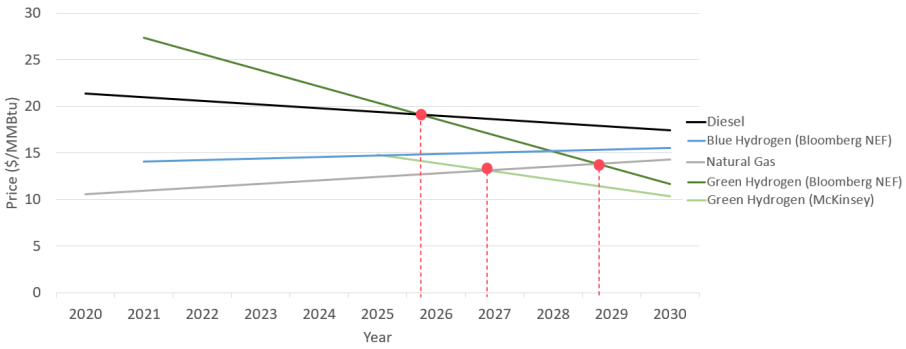


Figure 37: Fuel and Hydrogen Price Projections

Financial Model Details:

Financial Model Assumptions

The following table contains select financial model assumptions, with certain specifications redacted for confidentiality.

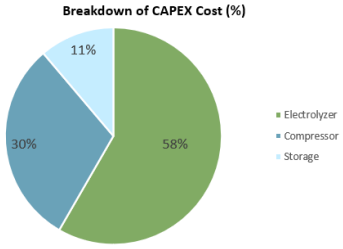
	Selected Value / Input	Notes
Electrolyzer Manufacturer	Confidential	Optimized for cost and MWh availability.
Electrolyzer Technology	Alkaline	Alkaline is more cost-effective than PEM.
Electrolyzer Size (MW)	1.84	From quote.
H_2 Production Capacity (kg/MWh)	19.54	From quote.
Compressor Quote	Confidential	Compressor capacity: 40 kg/hr; Power usage: 110 kW; Cost: $510k.
Storage Quote	Confidential	Optimized for two 450 kg tube trailers. Prime mover cost excluded.
Market Use Case	Mining Trucks & Blending Gas	Ran for both use cases. Base case involves short-term demand estimate and maximum WTP.
Discount Rate	15%	Base case is 15%. Ran sensitivity analysis.
Government Grant %	0%	Base case is 0%. Ran sensitivities to cover electrolyzer CAPEX.
Total CAPEX ($MM)	**1.77**	Figure includes electrolyzer, compressor, and storage.

Figure 38: Financial Model Assumptions

The financial model also incorporates the following project costs:

CAPEX:

	Cost ($MM)	Cost ($MM/MW)	Notes
Electrolyzer	1.06	0.58	Based on electrolyzer quote with 30% increase for Balance of Plant.
Compressor	0.51	0.28	From compressor quote.
Storage	0.19	0.10	Quote for two compressed H_2 tube trailers (450 kg each), FOB.
Total CAPEX	**1.77**	**0.96**	-



OPEX:

	Cost ($MM/yr)	Cost ($/MWh)	Notes
Water	0.01	3.08	From deionized water cost of $14.2/m^3.
Service & Maintenance	0.04	15.56	Estimate of $19/kW-year per academic source.[1]
Insurance	0.01	6.58	Assumed 0.01% per year per academic source.[2]
Total OPEX	**0.06**	**25.22**	-

*Note: OPEX electricity cost is assumed to be $0 due to internal clipping loss usage. No replacement cost is considered due to low electrolyzer utilization factor.

Figure 39: Financial Model Project Costs

Sources:

1. (Schnuelle, Wassermann, Fuhrlaender, & Zondervan, 2020)
2. (Peters, Timmerhaus, & West, 2002)
3. Company's actual cost.

Financial Model Results – Blending Gas

Alkaline electrolyzer w/ Blending Gas

IRR n/a

MOIC 0.02x

NPV (1.74)

			Up-Front	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	→	2041
1	Clipping Loses Available	*MWh*		3,123	3,123	3,123	3,123	3,123	3,123	3,123	3,123	3,123	3,123		3,123
2	Electrolyzer Size	*MW*		1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84		1.84
3	Clipping Loses Captured	*MWh*		2,382	2,382	2,382	2,382	2,382	2,382	2,382	2,382	2,382	2,382		2,382
4	Hydrogen Produced	*kg*		46,421	45,957	45,497	45,042	44,592	44,146	43,705	43,268	42,835	42,406	→	38,352
5	Hydrogen Sold	*kg*		46,421	45,957	45,497	45,042	44,592	44,146	43,705	43,268	42,835	42,406		38,352
6	Hydrogen Price	*$/kg*		1.47	1.47	1.47	1.47	1.47	1.47	1.47	1.47	1.47	1.47		1.47
7	Hydrogen Price	*$/MMBtu*		10.87	10.87	10.87	10.87	10.87	10.87	10.87	10.87	10.87	10.87		10.87
8	**Total Revenues**	*$*		**68,170**	**67,489**	**66,814**	**66,145**	**65,484**	**64,829**	**64,181**	**63,539**	**62,904**	**62,275**	→	**56,320**
9	Water	*$*	-	(7,334)	(7,334)	(7,334)	(7,334)	(7,334)	(7,334)	(7,334)	(7,334)	(7,334)	(7,334)		(7,334)
10	Service & Maintenance	*$*	-	(37,050)	(37,050)	(37,050)	(37,050)	(37,050)	(37,050)	(37,050)	(37,050)	(37,050)	(37,050)		(37,050)
11	Insurance	*$*	-	(15,681)	(15,681)	(15,681)	(15,681)	(15,681)	(15,681)	(15,681)	(15,681)	(15,681)	(15,681)		(15,681)
12	**Total Expenses****	*$*	**(1,767,570)**	**(60,065)**	**(60,065)**	**(60,065)**	**(60,065)**	**(60,065)**	**(60,065)**	**(60,065)**	**(60,065)**	**(60,065)**	**(60,065)**	→	**(60,065)**
13	**Pre-Tax Unlevered Cash Flow**	*$*	**(1,767,570)**	**8,105**	**7,423**	**6,749**	**6,080**	**5,419**	**4,764**	**4,116**	**3,474**	**2,839**	**2,210**	→	**(3,745)**
14	**CAPEX Investment**	*$*	**(1,767,570)**	-	-	-	-	-	-	-	-	-	-		-
15	Electrolyzer	*$*	(1,058,070)	-	-	-	-	-	-	-	-	-	-		-
16	Compressor	*$*	(510,000)	-	-	-	-	-	-	-	-	-	-		-
17	Storage & Transportation	*$*	(199,500)	-	-	-	-	-	-	-	-	-	-	→	-

*Discount rate of 15%, 13.3% government grant, 1% hydrogen production yearly wear, no price indexations, 20 years evaluation

**OPEX electricity cost is assumed to be $0 due to internal clipping loss usage. No replacement cost is considered due to low electrolyzer utilization factor.

Figure 40: Detailed Financial Model Results – Blending Gas

			Up-Front	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
1	Clipping Loses Available	*MWh*		318	315	338	216	113	86	139	243	355	364	346	290
2	Electrolyzer Size	*MW*		1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84
3	Clipping Loses Captured	*MWh*		243	225	235	169	108	85	136	202	253	250	247	229
4	Hydrogen Produced	*kg*		4,734	4,385	4,576	3,290	2,103	1,658	2,631	3,944	4,924	4,877	4,833	4,466
5	Hydrogen Sold	*kg*		4,734	4,385	4,576	3,290	2,103	1,658	2,631	3,944	4,924	4,877	4,833	4,466
6	Hydrogen Price	*$/kg*		1.47	1.47	1.47	1.47	1.47	1.47	1.47	1.47	1.47	1.47	1.47	1.47
7	Hydrogen Price	*$/mmBtu*		10.87	10.87	10.87	10.87	10.87	10.87	10.87	10.87	10.87	10.87	10.87	10.87
8	**Total Revenue**	*$*		**6,952**	**6,440**	**6,719**	**4,831**	**3,088**	**2,435**	**3,864**	**5,791**	**7,231**	**7,162**	**7,097**	**6,559**
9	**Electrolyzer OPEX**	*$*	-	**(4,543)**	**(4,488)**	**(4,518)**	**(4,315)**	**(4,127)**	**(4,057)**	**(4,211)**	**(4,418)**	**(4,573)**	**(4,566)**	**(4,559)**	**(4,501)**
10	Water	*$*		(748)	(693)	(723)	(520)	(332)	(262)	(416)	(623)	(778)	(771)	(764)	(706)
11	Electricity	*$*		-	-	-	-	-	-	-	-	-	-	-	-
12	Service & Maintenance	*$*		(2,913)	(2,913)	(2,913)	(2,913)	(2,913)	(2,913)	(2,913)	(2,913)	(2,913)	(2,913)	(2,913)	(2,913)
13	Insurance	*$*		(882)	(882)	(882)	(882)	(882)	(882)	(882)	(882)	(882)	(882)	(882)	(882)
14	Replacement	*$*		-	-	-	-	-	-	-	-	-	-	-	-
15	**Compressor OPEX**	*$*	-	**(638)**	**(622)**	**(631)**	**(573)**	**(520)**	**(500)**	**(543)**	**(603)**	**(647)**	**(645)**	**(643)**	**(626)**
16	Electricity	*$*		-	-	-	-	-	-	-	-	-	-	-	-
17	Service & Maintenance	*$*		(213)	(197)	(206)	(148)	(95)	(75)	(118)	(178)	(222)	(220)	(218)	(201)
18	Insurance	*$*		(425)	(425)	(425)	(425)	(425)	(425)	(425)	(425)	(425)	(425)	(425)	(425)
19	**Storage & Transportation OPEX**	*$*	-	-	-	-	-	-	-	-	-	-	-	-	-
20	**Total Expenses**	*$*	**(1,767,570)**	**(5,181)**	**(5,110)**	**(5,149)**	**(4,888)**	**(4,647)**	**(4,557)**	**(4,754)**	**(5,021)**	**(5,220)**	**(5,210)**	**(5,201)**	**(5,127)**
21	**Pre-Tax Unlevered Cash Flow**	*$*	**(1,767,570)**	**1,771**	**1,330**	**1,570**	**(57)**	**(1,559)**	**(2,121)**	**(890)**	**770**	**2,012**	**1,952**	**1,896**	**1,432**
22	**CAPEX Investment**	*$*	**(1,767,570)**	-	-	-	-	-	-	-	-	-	-	-	-
23	Electrolyzer CAPEX	*$*	(1,058,070)	-	-	-	-	-	-	-	-	-	-	-	-
24	Compressor CAPEX	*$*	(510,000)	-	-	-	-	-	-	-	-	-	-	-	-
25	Storage & Transportation CAPEX	*$*	(199,500)	-	-	-	-	-	-	-	-	-	-	-	-
			Average												
26	**Variable Hydrogen Production Cost**	*$/kg*	**(1.42)**	**(1.09)**	**(1.17)**	**(1.13)**	**(1.49)**	**(2.21)**	**(2.75)**	**(1.81)**	**(1.27)**	**(1.06)**	**(1.07)**	**(1.08)**	**(1.15)**
27	Water	*$/kg*	(0.17)	(0.16)	(0.16)	(0.16)	(0.16)	(0.16)	(0.16)	(0.16)	(0.16)	(0.16)	(0.16)	(0.16)	(0.16)
28	Electricity	*$/kg*	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Service & Maintenance	*$/kg*	(0.88)	(0.66)	(0.71)	(0.68)	(0.93)	(1.43)	(1.80)	(1.15)	(0.78)	(0.64)	(0.64)	(0.65)	(0.70)
30	Insurance	*$/kg*	(0.37)	(0.28)	(0.30)	(0.29)	(0.40)	(0.62)	(0.79)	(0.50)	(0.33)	(0.27)	(0.27)	(0.27)	(0.29)
31	Replacement	*$/kg*	-	-	-	-	-	-	-	-	-	-	-	-	-
32	Storage	*$/kg*	-	-	-	-	-	-	-	-	-	-	-	-	-
33	**Net Revenue**	*$/kg*	**0.05**	**0.37**	**0.30**	**0.34**	**(0.02)**	**(0.74)**	**(1.28)**	**(0.34)**	**0.20**	**0.41**	**0.40**	**0.39**	**0.32**
34	**Net Revenue**	*$/mmBtu*	**0.35**	**2.77**	**2.24**	**2.54**	**(0.13)**	**(5.49)**	**(9.47)**	**(2.50)**	**1.45**	**3.02**	**2.96**	**2.90**	**2.37**

Figure 41: Typical Year of Pre-Tax Unlevered Cash Flow – Blending Gas

Alkaline electrolyzer w/ Blending Gas + government grant

IRR n/a

-

MOIC 0.03x

+0.01x

NPV (1.50)

+0.14

			Up-Front	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	→	2041
1	Clipping Loses Available	MWh		3,123	3,123	3,123	3,123	3,123	3,123	3,123	3,123	3,123	3,123		3,123
2	Electrolyzer Size	MW		1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84		1.84
3	Clipping Loses Captured	MWh		2,382	2,382	2,382	2,382	2,382	2,382	2,382	2,382	2,382	2,382		2,382
4	Hydrogen Produced	kg		46,421	45,957	45,497	45,042	44,592	44,146	43,705	43,268	42,835	42,406	→	38,352
5	Hydrogen Sold	kg		46,421	45,957	45,497	45,042	44,592	44,146	43,705	43,268	42,835	42,406		38,352
6	Hydrogen Price	$/kg		1.47	1.47	1.47	1.47	1.47	1.47	1.47	1.47	1.47	1.47		1.47
		$/MMB													
7	Hydrogen Price	tu		10.87	10.87	10.87	10.87	10.87	10.87	10.87	10.87	10.87	10.87		10.87
8	**Total Revenues**	$		**68,170**	**67,489**	**66,814**	**66,145**	**65,484**	**64,829**	**64,181**	**63,539**	**62,904**	**62,275**	→	**56,320**
9	Water	$	-	(7,334)	(7,334)	(7,334)	(7,334)	(7,334)	(7,334)	(7,334)	(7,334)	(7,334)	(7,334)		(7,334)
10	Service & Maintenance	$	-	(37,050)	(37,050)	(37,050)	(37,050)	(37,050)	(37,050)	(37,050)	(37,050)	(37,050)	(37,050)		(37,050)
11	Insurance	$	-	(15,681)	(15,681)	(15,681)	(15,681)	(15,681)	(15,681)	(15,681)	(15,681)	(15,681)	(15,681)		(15,681)
12	**Total Expenses**	$	**(1,532,483)**	**(60,065)**	**(60,065)**	**(60,065)**	**(60,065)**	**(60,065)**	**(60,065)**	**(60,065)**	**(60,065)**	**(60,065)**	**(60,065)**	→	**(60,065)**
13	**Pre-Tax Unlevered Cash Flow**	$	**(1,532,483)**	**8,105**	**7,423**	**6,749**	**6,080**	**5,419**	**4,764**	**4,116**	**3,474**	**2,839**	**2,210**	→	**(3,745)**
14	**CAPEX Investment**	$	**(1,532,483)**	-	-	-	-	-	-	-	-	-	-		-
15	Electrolyzer	$	(917,347)	-	-	-	-	-	-	-	-	-	-		-
16	Compressor	$	(442,170)	-	-	-	-	-	-	-	-	-	-		-
17	Storage & Transportation	$	(172,967)	-	-	-	-	-	-	-	-	-	-	→	-

*Discount rate of 15%, 13.3% government grant, 1% hydrogen production yearly wear, no price indexations, 20 years evaluation
**OPEX electricity cost is assumed to be $0 due to internal clipping loss usage. No replacement cost is considered due to low electrolyzer utilization factor

Figure 42: Detailed Financial Model Results – Blending Gas + Government Grant

Financial Model Results – Mining Trucks

Alkaline electrolyzer w/ Mining Trucks

IRR -1.42%

MOIC 0.86x

NPV (1.25)

			Up-Front	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	→	2041
1	Clipping Loses Available	MWh		3,123	3,123	3,123	3,123	3,123	3,123	3,123	3,123	3,123	3,123		3,123
2	Electrolyzer Size	MW		1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84		1.84
3	Clipping Loses Captured	MWh		2,382	2,382	2,382	2,382	2,382	2,382	2,382	2,382	2,382	2,382		2,382
4	Hydrogen Produced	kg		46,421	45,957	45,497	45,042	44,592	44,146	43,705	43,268	42,835	42,406	→	38,352
5	Hydrogen Sold	kg		46,421	45,957	45,497	45,042	44,592	44,146	43,705	43,268	42,835	42,406		38,352
6	Hydrogen Price	$/kg		3.23	3.23	3.23	3.23	3.23	3.23	3.23	3.23	3.23	3.23		3.23
7	Hydrogen Price	$/MMBtu		23.90	23.90	23.90	23.90	23.90	23.90	23.90	23.90	23.90	23.90		23.90
8	**Total Revenues**	$		**149,898**	**148,399**	**146,915**	**145,446**	**143,991**	**142,551**	**141,126**	**139,715**	**138,318**	**136,934**	→	**123,841**
9	Water	$	-	(7,334)	(7,334)	(7,334)	(7,334)	(7,334)	(7,334)	(7,334)	(7,334)	(7,334)	(7,334)		(7,334)
10	Service & Maintenance	$	-	(37,050)	(37,050)	(37,050)	(37,050)	(37,050)	(37,050)	(37,050)	(37,050)	(37,050)	(37,050)		(37,050)
11	Insurance	$	-	(15,681)	(15,681)	(15,681)	(15,681)	(15,681)	(15,681)	(15,681)	(15,681)	(15,681)	(15,681)		(15,681)
12	**Total Expenses****	$	**(1,767,570)**	**(60,065)**	**(60,065)**	**(60,065)**	**(60,065)**	**(60,065)**	**(60,065)**	**(60,065)**	**(60,065)**	**(60,065)**	**(60,065)**	→	**(60,065)**
13	**Pre-Tax Unlevered Cash Flow**	$	**(1,767,570)**	**89,833**	**88,334**	**86,850**	**85,381**	**83,926**	**82,486**	**81,061**	**79,650**	**78,252**	**76,869**	→	**63,776**
14	**CAPEX Investment**	$	**(1,767,570)**	-	-	-	-	-	-	-	-	-	-		-
15	Electrolyzer	$	(1,058,070)	-	-	-	-	-	-	-	-	-	-		-
16	Compressor	$	(510,000)	-	-	-	-	-	-	-	-	-	-		-
17	Storage & Transportation	$	(199,500)	-	-	-	-	-	-	-	-	-	-	→	-

*Discount rate of 15%, without government grant, 1% hydrogen production yearly wear, no price indexations, 20 years evaluation
**OPEX electricity cost is assumed to be $0 due to internal clipping loss usage. No replacement cost is considered due to low electrolyzer utilization factor.

Figure 43: Detailed Financial Model Results – Mining Trucks

			Up-Front	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
1	Clipping Loses Available	MWh		318	315	338	216	113	86	139	243	355	364	346	290
2	Electrolyzer Size	MW		1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84
3	Clipping Loses Captured	MWh		243	225	235	169	108	85	136	202	253	250	247	229
4	Hydrogen Produced	kg		4,734	4,385	4,576	3,290	2,103	1,658	2,631	3,944	4,924	4,877	4,833	4,466
5	Hydrogen Sold	kg		4,734	4,385	4,576	3,290	2,103	1,658	2,631	3,944	4,924	4,877	4,833	4,466
6	Hydrogen Price	$/kg		3.23	3.23	3.23	3.23	3.23	3.23	3.23	3.23	3.23	3.23	3.23	3.23
7	Hydrogen Price	$/mmBtu		23.90	23.90	23.90	23.90	23.90	23.90	23.90	23.90	23.90	23.90	23.90	23.90
8	**Total Revenue**	$		15,286	14,161	14,775	10,622	6,790	5,355	8,496	12,734	15,901	15,749	15,606	14,422
9	**Electrolyzer OPEX**	$	-	(4,543)	(4,488)	(4,518)	(4,315)	(4,127)	(4,057)	(4,211)	(4,418)	(4,573)	(4,566)	(4,559)	(4,501)
10	Water	$		(748)	(693)	(723)	(520)	(332)	(262)	(416)	(623)	(778)	(771)	(764)	(706)
11	Electricity	$		-	-	-	-	-	-	-	-	-	-	-	-
12	Service & Maintenance	$		(2,913)	(2,913)	(2,913)	(2,913)	(2,913)	(2,913)	(2,913)	(2,913)	(2,913)	(2,913)	(2,913)	(2,913)
13	Insurance	$		(882)	(882)	(882)	(882)	(882)	(882)	(882)	(882)	(882)	(882)	(882)	(882)
14	Replacement	$		-	-	-	-	-	-	-	-	-	-	-	-
15	**Compressor OPEX**	$	-	(638)	(622)	(631)	(573)	(520)	(500)	(543)	(603)	(647)	(645)	(643)	(626)
16	Electricity	$		-	-	-	-	-	-	-	-	-	-	-	-
17	Service & Maintenance	$		(213)	(197)	(206)	(148)	(95)	(75)	(118)	(178)	(222)	(220)	(218)	(201)
18	Insurance	$		(425)	(425)	(425)	(425)	(425)	(425)	(425)	(425)	(425)	(425)	(425)	(425)
19	**Storage & Transportation OPEX**	$	-	-	-	-	-	-	-	-	-	-	-	-	-
20	**Total Expenses**	$	(1,767,570)	(5,181)	(5,110)	(5,149)	(4,888)	(4,647)	(4,557)	(4,754)	(5,021)	(5,220)	(5,210)	(5,201)	(5,127)
21	**Pre-Tax Unlevered Cash Flow**	$	(1,767,570)	10,105	9,051	9,626	5,734	2,143	798	3,742	7,713	10,681	10,539	10,405	9,295
22	**CAPEX Investment**	$	(1,767,570)	-	-	-	-	-	-	-	-	-	-	-	-
23	Electrolyzer CAPEX	$	(1,058,070)	-	-	-	-	-	-	-	-	-	-	-	-
24	Compressor CAPEX	$	(510,000)	-	-	-	-	-	-	-	-	-	-	-	-
25	Storage & Transportation CAPEX	$	(199,500)	-	-	-	-	-	-	-	-	-	-	-	-
			Average												
	Variable Hydrogen Production														
26	**Cost**	$/kg	(1.42)	(1.09)	(1.17)	(1.13)	(1.49)	(2.21)	(2.75)	(1.81)	(1.27)	(1.06)	(1.07)	(1.08)	(1.15)
27	Water	$/kg	(0.17)	(0.16)	(0.16)	(0.16)	(0.16)	(0.16)	(0.16)	(0.16)	(0.16)	(0.16)	(0.16)	(0.16)	(0.16)
28	Electricity	$/kg	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Service & Maintenance	$/kg	(0.88)	(0.66)	(0.71)	(0.68)	(0.93)	(1.43)	(1.80)	(1.15)	(0.78)	(0.64)	(0.64)	(0.65)	(0.70)
30	Insurance	$/kg	(0.37)	(0.28)	(0.30)	(0.29)	(0.40)	(0.62)	(0.79)	(0.50)	(0.33)	(0.27)	(0.27)	(0.27)	(0.29)
31	Replacement	$/kg	-	-	-	-	-	-	-	-	-	-	-	-	-
32	Storage	$/kg	-	-	-	-	-	-	-	-	-	-	-	-	-
33	**Net Revenue**	$/kg	1.81	2.13	2.06	2.10	1.74	1.02	0.48	1.42	1.96	2.17	2.16	2.15	2.08
34	**Net Revenue**	$/mmBtu	13.38	15.80	15.27	15.57	12.90	7.54	3.56	10.52	14.47	16.05	15.99	15.93	15.40

Figure 44 Typical Year of Pre-Tax Unlevered Cash Flow – Mining Trucks

Alkaline electrolyzer w/ Mining Trucks + government grant

IRR -0.03%

+1.39b.p

MOIC 1.00x

+0.14

NPV (1.02)

+0.23

			Up-Front	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	→	2041
1	Clipping Loses Available	MWh		3,123	3,123	3,123	3,123	3,123	3,123	3,123	3,123	3,123	3,123		3,123
2	Electrolyzer Size	MW		1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84		1.84
3	Clipping Loses Captured	MWh		2,382	2,382	2,382	2,382	2,382	2,382	2,382	2,382	2,382	2,382	→	2,382
4	Hydrogen Produced	kg		46,421	45,957	45,497	45,042	44,592	44,146	43,705	43,268	42,835	42,406		38,352
5	Hydrogen Sold	kg		46,421	45,957	45,497	45,042	44,592	44,146	43,705	43,268	42,835	42,406		38,352
6	Hydrogen Price	$/kg		3.23	3.23	3.23	3.23	3.23	3.23	3.23	3.23	3.23	3.23		3.23
7	Hydrogen Price	$/MMBtu		23.90	23.90	23.90	23.90	23.90	23.90	23.90	23.90	23.90	23.90		23.90
8	**Total Revenues**	$		**149,898**	**148,399**	**146,915**	**145,446**	**143,991**	**142,551**	**141,126**	**139,715**	**138,318**	**136,934**	→	**123,841**
9	Water	$	-	(7,334)	(7,334)	(7,334)	(7,334)	(7,334)	(7,334)	(7,334)	(7,334)	(7,334)	(7,334)		(7,334)
10	Service & Maintenance	$	-	(37,050)	(37,050)	(37,050)	(37,050)	(37,050)	(37,050)	(37,050)	(37,050)	(37,050)	(37,050)		(37,050)
11	Insurance	$	-	(15,681)	(15,681)	(15,681)	(15,681)	(15,681)	(15,681)	(15,681)	(15,681)	(15,681)	(15,681)		(15,681)
12	**Total Expenses**	$	**(1,532,483)**	**(60,065)**	**(60,065)**	**(60,065)**	**(60,065)**	**(60,065)**	**(60,065)**	**(60,065)**	**(60,065)**	**(60,065)**	**(60,065)**	→	**(60,065)**
13	**Pre-Tax Unlevered Cash Flow**	$	**(1,532,483)**	**89,833**	**88,334**	**86,850**	**85,381**	**83,926**	**82,486**	**81,061**	**79,650**	**78,252**	**76,869**	→	**63,776**
14	**CAPEX Investment**	$	**(1,532,483)**	-	-	-	-	-	-	-	-	-	-		-
15	Electrolyzer	$	(917,347)	-	-	-	-	-	-	-	-	-	-		-
16	Compressor	$	(442,170)	-	-	-	-	-	-	-	-	-	-		-
17	Storage & Transportation	$	(172,967)	-	-	-	-	-	-	-	-	-	-	→	-

*Discount rate of 15%, 13.3% government grant, 1% hydrogen production yearly wear, no price indexations, 20 years evaluation

**OPEX electricity cost is assumed to be $0 due to internal clipping loss usage. No replacement cost is considered due to low electrolyzer utilization factor.

Figure 45: Detailed Financial Model Results – Mining Trucks + Government Grant

Electrolyzer Utilization Factor:

	Alkaline 1	PEM 1	Alkaline 2	PEM 2	PEM 3
Electrolyzer Capacity (MW)	1.84	2.5	1.5	1.25	1
Total Annual MWhs	16,118	21,900	13,140	10,950	8,760
H2 Production Capacity (kg/MWh)	19.54	17.69	26.96	17.69	17.98
Max Annual H2 Production (kg)	314,922	387,367	354,254	193,684	157,505
Current Annual H2 Production	46,421	50,486	55,026	31,167	26,296
Utilization Factor	14.74%	13.03%	15.53%	16.09%	16.70%

Figure 46: Electrolyzer Utilization Factor