GEOTHERMAL AND HYDROGEN: COULD HYDROGEN MAKE SOME GEOTHERMAL PROJECTS VIABLE?

Abbie Dean[1], Greg Ussher[1], Walter Gerardi[1], Liam Schwartz[1], Alex Batten[1], Aaron Hochwimmer[1], and Scott Henderson[1]

[1]Jacobs 11-16 Nicholls Lane, Parnell, Auckland, New Zealand

Abbie.Dean@jacobs.com

Keywords: *Geothermal, Green Hydrogen, Carbon Emissions, Stranded Geothermal, Baseload*

ABSTRACT

The production of hydrogen via geothermal has seen a growing interest worldwide in recent times, and for a good reason. There is much potential for geothermal to act as a source of energy in the production of hydrogen. Hydrogen from geothermal could displace a significant amount of emitted carbon, especially in countries struggling to reduce their carbon footprint or in countries abundant in geothermal resources that can produce hydrogen for export. The economics, the desire and the timing must be right, however. This paper presents a comparison of hydrogen generation from a dedicated geothermal plant with that produced from solar and solar plus battery storage. This is to test and illustrate the value of baseload generation that is achievable from geothermal in comparison with alternative renewables that are normally considered 'lower cost'.

1. OVERVIEW

1.1 Introduction

Much of today's hydrogen is produced using steam methane reforming (SMR) equipment, which uses natural gas for a hydrogen source (Mayyas et al., 2019). This is clearly a carbon emissions-intensive approach. Production of hydrogen via electrolysis (where water molecules are split) is a maturing technology with Alkaline and Proton Exchange Membrane (PEM) water electrolysers, both emerging as alternative options to SMR. In order to reduce the carbon footprint of this technology, the electrolysers need to be fuelled by renewable energy sources. Those renewable energy sources include solar (with or without battery storage), wind, hydro or geothermal energy.

1.2 Geothermally Produced Hydrogen

While different classifications of hydrogen as a fuel source are produced and classified differently (e.g. black, blue, brown, pink), the New Zealand Government reports classifying green hydrogen as "low carbon derived" and is produced "using renewable electricity to power an electrolyser" (MBIE, 2019).

Since the 1950s, geothermal has been mostly used for electricity production (with some traditional, direct use such as hot pools etc.). Particularly, geothermal's ability to act as 'base load' generation in an electricity market has been a valued attribute to stabilise energy supply to a country's electricity grid. A renewed surge in innovation in geothermal has been evident in the past few years globally because of the increasingly intensive scrutiny on carbon emissions and climate change globally. This includes the reinjection of geothermally produced carbon dioxide, investigations into producing geothermal energy from supercritical (hotter and deeper) geothermal resources, a renewed interest in precious metal extraction from geothermal fluids for sale as low carbon metals on the commodities market, and more recently, the production of hydrogen using geothermal as a stable, low-carbon emitting source of energy. Groups, both from the public and private sector, have shown interest internationally in using geothermal resources, along with other renewable energy resources, to produce green hydrogen from regions such as Asia, South America, East Africa and The Pacific (FFI, 2021; Obayashi, 2021; Kata Data 2021). New Zealand is one of a number of countries that have signed agreements with international partners or expressed interest to export green hydrogen produced locally to countries such as Singapore, Japan and South Korea (MBIE 2018, MFAT 2019, MBIE 2021).

But do the economics really stack up? Is geothermal really the best source of renewable energy to be used in green hydrogen production? This paper investigates these questions.

2. MODELLING GEOTHERMAL HYDROGEN POTENTIAL

In this paper, we have developed a Levelized Cost of Hydrogen (LCOH2) model, similar to a Levelized Cost of Energy (LCOE) model traditionally used in renewable energy production, to evaluate financial return on investment. It is important to note that it is the view of the authors that an LCOH2 model does not factor in the financing, which could substantially alter project economics, and that making investment decisions should not simply be based on financial considerations alone. Further considerations are also noted in the sections below.

Three theoretical scenarios are used. In all scenarios, several assumptions are made and used and are important to highlight. These assumptions may be modified and evolve as the probability of using renewable energy options to produce hydrogen for either local and/or export use becomes clearer. General assumptions are stated in further detail in Section 2.2

2.1 Modelled Scenarios & Specific Assumptions

Modelled scenario 1 - Geothermal

Scenario 1 uses electricity produced via geothermal, as well as a clean water source, to provide power to an electrolyser to produce green hydrogen. Once produced, hydrogen can be used locally or exported to other countries. Transmission costs are omitted as in this scenario, the hydrogen and geothermal plants are co-located.

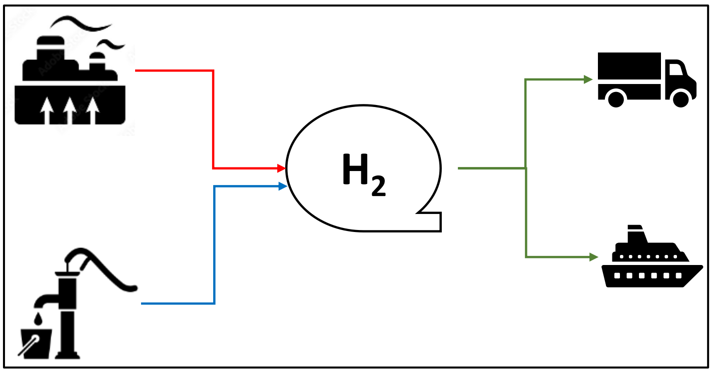

Figure 1: Scenario 1, where electricity to fuel a hydrogen plant is produced via geothermal.

Modelled Scenario 2 - Solar

Scenario 2 uses electricity produced via solar arrays, as well as a clean water source, to provide power to an electrolyser to produce green hydrogen. Transmission costs are again omitted as in this scenario, the hydrogen and solar plants are co-located.

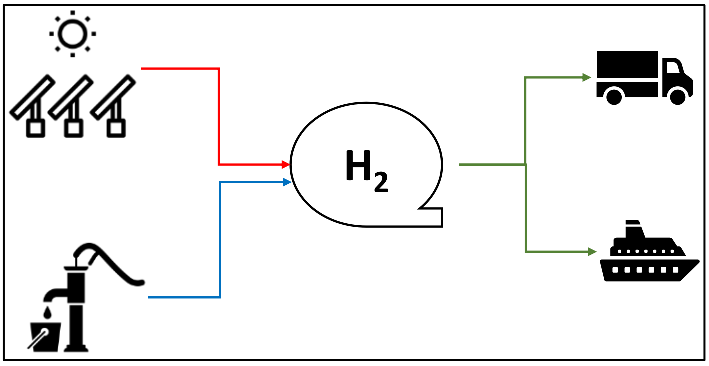

Figure 2: Scenario 2, where electricity to fuel a hydrogen plant is produced via solar arrays.

Modelled Scenario 2 – Solar + Battery Storage

Scenario 3 uses electricity produced via solar arrays combined with battery storage, as well as a clean water source, to fuel an electrolyser to produce green hydrogen. Transmission costs are again omitted as in this scenario, the hydrogen and solar plus battery plants are co-located.

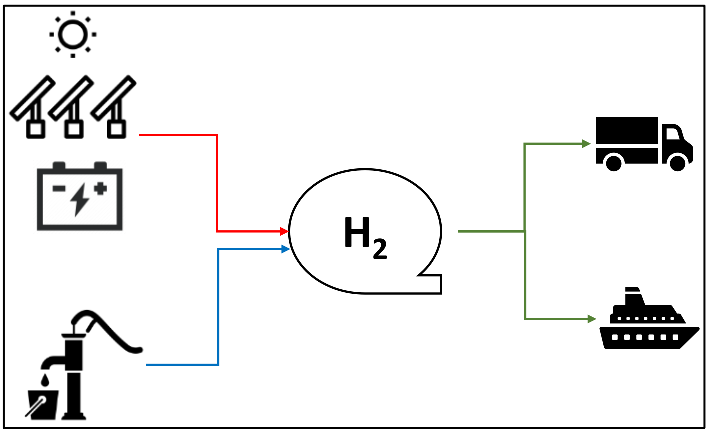

Figure 3: Scenario 3, where electricity to fuel a hydrogen plant is produced via solar arrays with batteries.

2.2 Model Assumptions

We have established the models to generate approximately the same amount of hydrogen per year, essentially equivalent to that achievable from a 10 MW electrolyser operating at 100% capacity. The key differences between the scenarios are the installed capacity of generation (in MW), the achievable capacity factors, and the required size of the electrolyser plant necessary to generate the hydrogen from a variable energy source (particularly in the case of Scenario 2 – Solar).

Key parameters and assumptions for scenarios 1 through 3 are displayed in Table 1.

Key Assumptive Parameters	Unit	Geothermal	Solar	Solar + Battery
Hydrogen	T/yr	1486	1490	1486
Power Generation MW	MW	10.5	40	41.9
Power Generation Load Factor	%	95%	25%	25%
Power Generation Plant CAPEX	US$M	42	40	42
Makeup Drilling CAPEX	US$M	10		
Battery CAPEX	US$M			80
Electrolyser Plant MW	MW	10.5	40	10.5
Electrolyser Plant Load Factor	%	95%	25%	95%
Electrolyser Plant CAPEX	US$M	12	44	12
Total CAPEX	$	54	84	54
LCOE	$/MWh	68.99	47.81	123.69

Table 1: List of key parameters and assumptions per scenario. Note that LCOE for the power is estimated for reference only and has no specific meaning in this model.

While the costs of grid-scale geothermal, solar and battery are relatively well known, the cost of hydrogen production via electrolysers is less certain. The common theme amongst publicly published reports is that costs are currently high and are predicted to diminish over time. An IRENA report estimates capital expenditure brackets for Alkaline technology at USD$500 – 1,000 /KW and for PEM, USD$700 – 1,400 /$KW_a$ for a 'whole system' (plants under 10 MW). Others report prices up to USD$1,700 for a PEM plant (Noordende and Ripson, 2020). Figure 4 is taken from a report produced by NREL and is a good reflection of the varied components that make up the costs of producing hydrogen from a PEM electrolyser (based on a 1 MW plant; Mayyas et al., 2019).

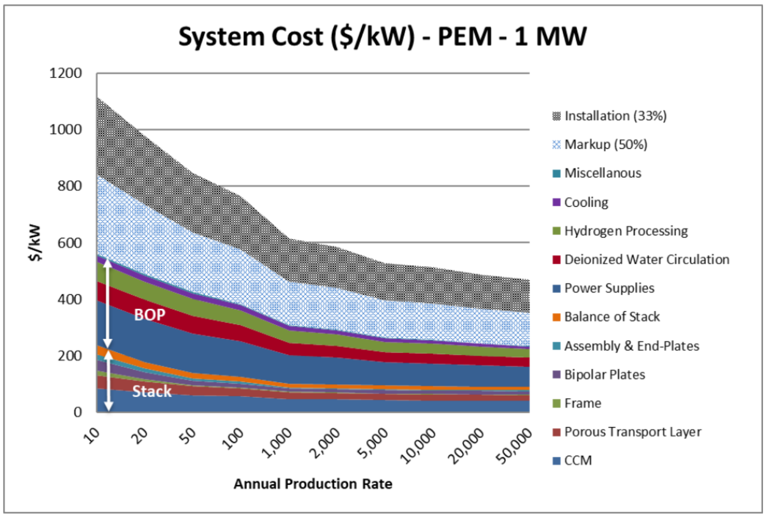

Figure 4: Costs of hydrogen Proton Exchange Membrane (PEM) Electrolyser including installation and manufacturer mark up. Note that Production Rate represents the volume of units being manufactured and represents cost reduction once these units are produced at volume in future—costs in USD (Mayyas et al., 2019).

Additional points to note are:

- No specific country is chosen in our scenarios. Location will have a bearing on further costing refinement and continued decisions, but it is assumed that generation would be sought in favourable locations for the respective energy source.
- The plant is assumed to be operational from 2023 and operate for 25 years.
- We have assumed plant sizing of a 10 MW scale. Of course, reducing or increasing plant capacity will have a bearing on LCOH, as indicated in Figure 4.
- A clean water source clean enough to be used in an electrolyser is assumed.

3. MODEL FINDINGS

A financial model incorporating factors affecting the initial capital costs to install, as well as some higher operational costs to maintain the plant, are factored into the LCOH2 model with results as presented in Figure and Figure .

Plant Sizing and Capacity Factors

Scenario 1 designs a 10 MW geothermal plant at a 95% load factor to run a hydrogen electrolyser with a similar usage factor. Scenario 2 needs to use a 40MW solar plant at a 25% load factor as a result of the intermittent nature of solar. The electrolyser size and cost will have to increase by a factor of 4 in scenario 2 to match the solar capacity with peak daytime operation. Scenario 3 requires a 42 MW solar plant with batteries to provide a continuous 10 MW over 24 hours, reducing electrolyser size and take the load factor on the electrolyser up to 95%, similar to the geothermal model (Figure).

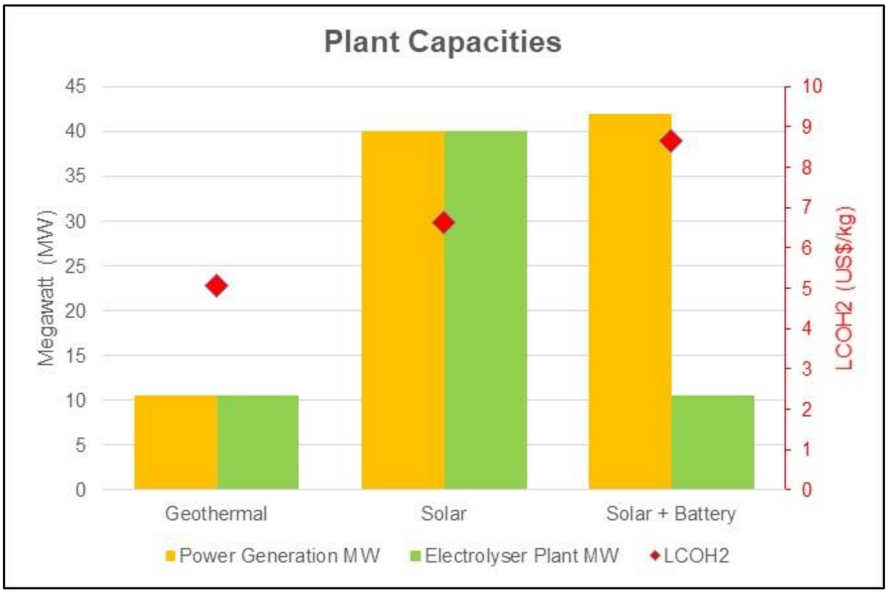

Figure 5: Plant capacities in megawatts (MW) for Scenarios 1 to 3 with a comparison to LCOH2. Electrolyser capital costs set at USD$1,100.

Capital Outcomes for Mid-Range Electrolyser Cost

In Scenario 1, our geothermally driven model also includes makeup well drilling over 25 years, and in scenario 3, our solar and battery storage model also includes battery capital costs which are substantial to provide 24-hour cover. The intermittent nature of solar means that a large amount of storage was required in order to reduce electrolyser size and run the electrolyser at 95% capacity.

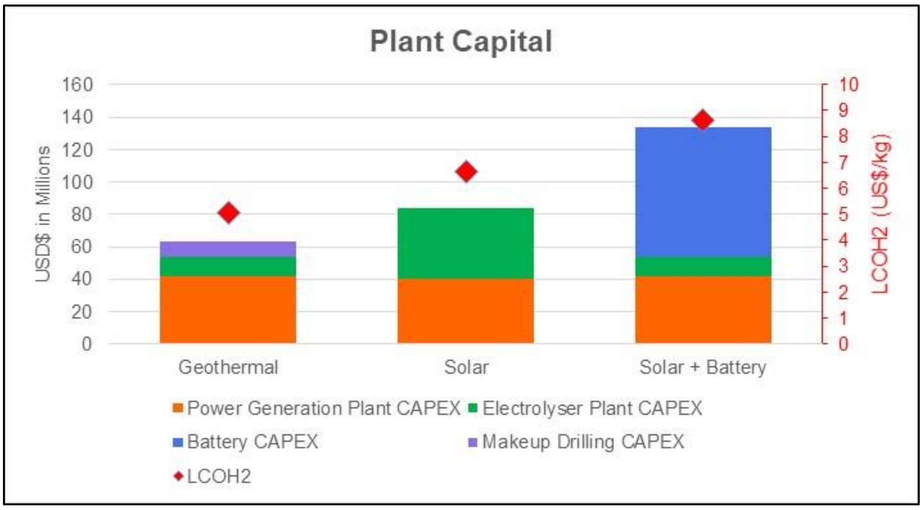

Figure 6: Plant capital in millions of US$ for Scenarios 1 to 3 with a comparison to LCOH2. Electrolyser capital costs set at USD$1,100.

The Levelized cost of hydrogen for each scenario is tabulated in Table 2.

Scenario	**Levelized cost USD$/ kg**
Scenario 1: Geothermal	5.07
Scenario 2: Solar	6.63
Scenario 3: Solar + Battery	8.65

Table 2: Estimated Levelized cost to produce a kilogram of hydrogen in scenarios 1 through 3.

Model Sensitivity to Electrolyser Costs

As electrolyser technology for hydrogen production is still a maturing technology, uncertainty exists on the costs associated with buying an 'off the shelf' electrolyser. Our research shows wide-ranging price estimates in common literature and in private communications. In the models above, a total of USD$1,100 per kWh/kg is used (which includes capital costs and balance of plant costs such as surrounding costs to install roading, administrative buildings etc.). This value was chosen as a median value between publicly stated literature values from reputable sources. However, prices as low as USD$400 per kWh/kg and as high as USD$2,100 per kWh/kg have been noted in other literature (Mayyas et al.,2019; Noordende and Ripson, 2020; IRENA, 2020). In part, some of this variability is a result of PEM generally being more expensive in upfront costings (as opposed to Alkaline plant CAPEX). Other possible factors include different cost additions (and exclusions) and different predictions for how and when the costs of electrolysers will reduce as the technology matures. The wide variability is ultimately a result of the maturing nature of technology. The variability in electrolyser costs can have a moderate bearing on modelled LCOH2 in scenarios 1 to 3. Figure and Figure 8 demonstrate this variability.

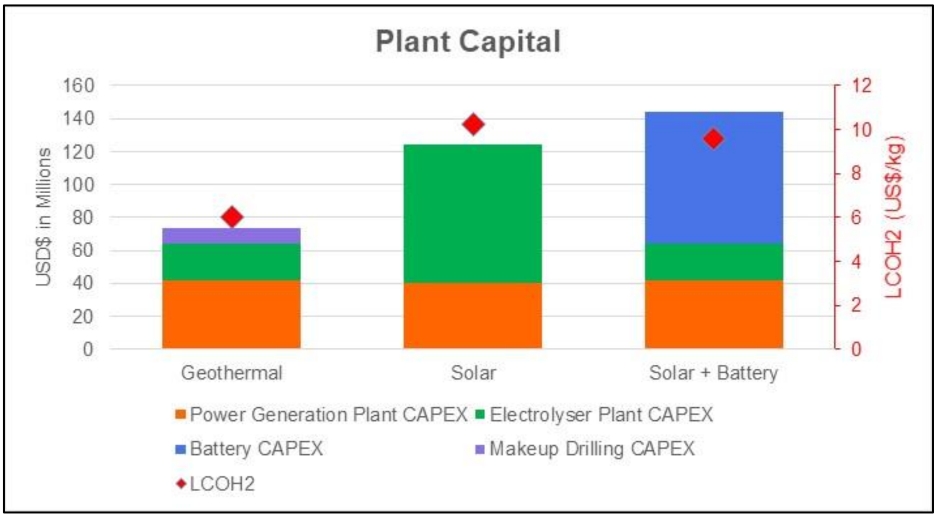

Figure 7: Plant capital in millions of US$ for Scenarios 1 to 3 with a comparison to LCOH2. Electrolyser capital costs set at USD$2,100.

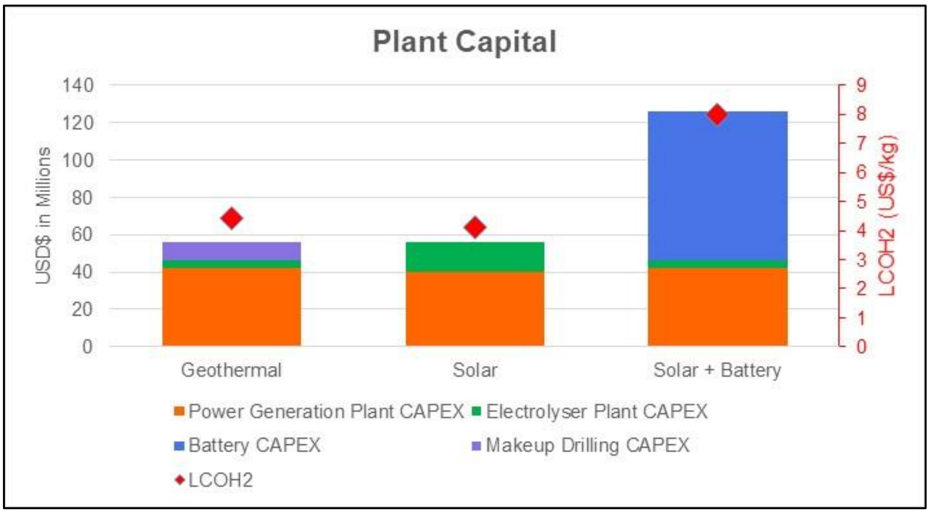

Figure 8: Plant capital in millions of US$ for Scenarios 1 to 3 with a comparison to LCOH. Electrolyser capital costs set at USD$400.

4. DEVELOPMENT IMPLICATIONS & FUTURE IMPROVEMENTS

4.1 Development Implications

The aim of this paper is to spark further thought on the possibility of using high quality, but stranded, geothermal resources where there is no market for the power and little option exists other than to develop the resource to produce green hydrogen via electrolysis for use close by (nationally) or for export internationally.

It is clear that geothermal's baseload advantage (giving a 95% load factor) overrides the high initial capital cost for geothermal generation that is a barrier in the traditional power sales market. The baseload value lies in minimising electrolyser plant size or the cost of having load levelling technology such as batteries that would be needed for solar. The need to oversize the generation component in the solar only model and the intermittent nature of the plant producing a 25% load factor is in addition to the need for an extra-large 40MW electrolyser plant. The addition of batteries with solar only serves to exacerbate costs despite bringing down electrolyser size and cost.

While this is reflected in the LCOH2 figures, there is also a stark contrast in raw capital required. The geothermal option has lower overall capital deployed, and so depending on the cost of capital, this may play out differently in a full financial model with different actual hydrogen costs. But fundamentally, capital is also a resource and needs to be deployed beneficially, and it seems that geothermal has the advantage here. The capital cost we have assumed for geothermal are mid-range for what we see globally but could be considerably lower for projects that target high-quality resources. This would further improve the favourability of the geothermal case. The downside of geothermal can be the exploration risk to prove the resource capacity, but the cost differential provides an incentive for good exploration effort.

Implications of these models are also beneficial for geothermal plants currently operating where perhaps additional capacity has been or could be built, but traditional demand has not warranted adding energy plant. This may benefit developing nations to displace local use of carbon-intensive products such as vehicle, plane or sea transport fuel. Further implications also exist for geothermal plants that may not be easily accessible or located close to a source use (which is most often associated with towns or cities). These resources could be used for green hydrogen production and exported to markets in need, making geothermal more of an exportable item. This may also make hotter and deeper geothermal resources more attractive as if demand for geothermal grows, more expensive drilling may be needed.

4.2 Future Improvements

Further work may be done to create models for other renewable energy sources, namely hydro and wind. These will be useful exercises to see how these renewable energy sources stack up against the attractive nature of geothermal's baseload (especially given hydro's load factor). Further parameters may also be added to further refine the general assumptions of the model and the scenarios used. For example, with the specific addition of a location, further refinements on cost components may be added to identify a better cost basis for decisions.

Most importantly, decisions to build a green hydrogen plant such as modelled here should not simply be made on a cost basis decision alone. Environmental, social and technical considerations should also be used in conjunction with financial factors. Each of these four factors may hold a different weighting, such as in Figure 9 a, b or c depending on the situation, motives for development and long-term legacy of projects.

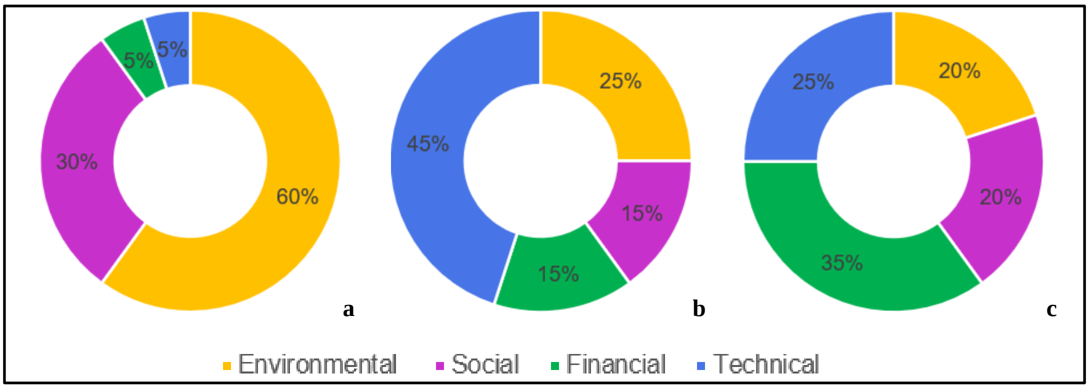

Figure 9: Examples of possible factors and possible weighting in making holistic decisions in conjunction with financial factors such as LCOH2.

ACKNOWLEDGEMENTS

The authors and Jacobs would like to acknowledge the collaboration, research, and modelling by past and present colleagues as well as those that support such work throughout the business. We would also like to thank the authors whose references have been re-presented here to help illustrate the potential uses of these combined technologies.

REFERENCESS

FFI (2021), *Supplying Green Energy Globally*, https://gggi.org/site/assets/uploads/2021/06/FFI-Presentation.pdf, Fortescue Future Industries Presentation.

IRENA (2020), *Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5ºc Climate Goal*, International Renewable Energy Agency, Abu Dhabi.

Kata Data (2021), *Pertamina Geothermal Berambisi Kembangkan Bahan Bakar Hidrogen Hijau*, https://katadata.co.id/happyfajrian/ekonomi-hijau/60a7ad1f0641b/pertamina-geothermal-berambisi-kembangkan-bahan-bakar-hidrogen-hijau?utm_source=Social&utm_medium=Twitter&utm_campaign=Energi_NFA,

Mayyas. A, Ruth. M, Pivovar. B, Bender. G and Wipke. K, (2020), *Manufacturing Cost Analysis for Proton Exchange Membrane Water Electrolysers*. Technical Report NREL/TP-6A20-72740, National Renewable Energy Laboratory.

MBIE (2018), *New Zealand Signs Hydrogen Agreement with Japan*, https://www.beehive.govt.nz/release/new-zealand-signs-hydrogen-agreement-japan, Press Release 23 October 2018, Ministry of Business, innovation and Employment,

MBIE (2019), *A Vision for Hydrogen in New Zealand: Green Paper,* Report ISBN 978 199 000415 5, Ministry of Business, Innovation & Employment.

MBIE (2021), *Hydrogen Arrangement Signed with Singapore*, https://www.beehive.govt.nz/release/hydrogen-arrangement-signed-singapore, Press Release 15 July 2021, Ministry of Business, Innovation and Employment.

MFAT (2019), *Trade, Business and Investment Focus for Visit to South Korea*, *https://www.beehive.govt.nz/release/trade-business-and-investment-focus-visit-south-korea*, Press Release 23 November 2019, Ministry of Foreign Affairs and Trade.

Noordende, Hans van ‘t., Ripson, Peter., (2020), *Baseline Design and Total installed Costs or a GW Green Hydrogen Plant*, Public Report, Hydrohub Innovation Program, Institute for Sustainable Process Technology.

Obayashi (2021) *Obayashi and Hydrogen & CCUS Technologies. Some Approaches for Decarbonization*, *http://www.env.go.jp/earth/Speech%2013.pdf/Speech%2013.pdf*, Obayashi Corporation Presentation.

ISSN 2703-4275