Techno-Economic Analysis of Green Hydrogen Production Through Solar in South Africa

Chad Langdon

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Student Number: 1391607

Supervisor: Dr H Roohani
Co-supervisor: Dr S Schekman

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ABSTRACT

Green hydrogen is set to become a part of South Africa's energy mix within the next decade, with multiple case studies already in place, and a planned adoption as early as 2030. The question is whether green hydrogen can financially compete with the likes of diesel, natural gas and alternative forms of energy. This research investigates the financial feasibility of green hydrogen production in South Africa using solar energy. Three scenarios are considered: utilising only solar power source; a grid tied solar system with clean energy wheeled through the grid; and a standalone solar system coupled with battery storage. Each scenario is evaluated for three electrolyser sizes (2.4 kW, 120 kW and 500 kW) using a levelized Cost-of-Hydrogen (LCOH) analysis. The study reveals that a grid tied system, with clean energy being wheeled through the grid, offers the most cost competitive pathway for green hydrogen production. This scenario can achieve an LCOH of 140.00 ZAR/kg at 100% electrolyser utilisation, approaching the cost of blue hydrogen (131.00 ZAR/kg). However, standalone solar-battery systems face challenges to the high cost of battery energy storage. The lowest LCOH achieved is 328.00 ZAR/kg for a 500 kW electrolyser. A sensitivity analysis identifies electrolyser efficiency, solar and electrolyser CAPEX, and the cost of capital as the three primary factors influencing the LCOH. This study underscores the need for further technological advances in green hydrogen production, as well as supportive policies aimed at reducing the cost of green hydrogen production in South Africa, to enhance its competitiveness against existing sources of energy.

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1. INTRODUCTION

1.1. Hydrogen uses in industry

The South African climate transparency report [1] states that South Africa needs to reduce its emissions by 34% by 2030 to be in line with limiting the global temperature rise to 1.5 degrees Celsius. One potential approach to meeting this target is for an increased adoption of Hydrogen in industry. Until relatively recently, hydrogen has predominantly been used in the petroleum-refining and fertilizer industries. With technological advances and a focus on clean energy, hydrogen has shown its application in powering heavy machinery, as a source of heat in metal refining, and in emerging markets as a fuel source for transportation, as shown in Figure 1. One of the key benefits to using hydrogen as an energy source is that it emits only water as a by-product.

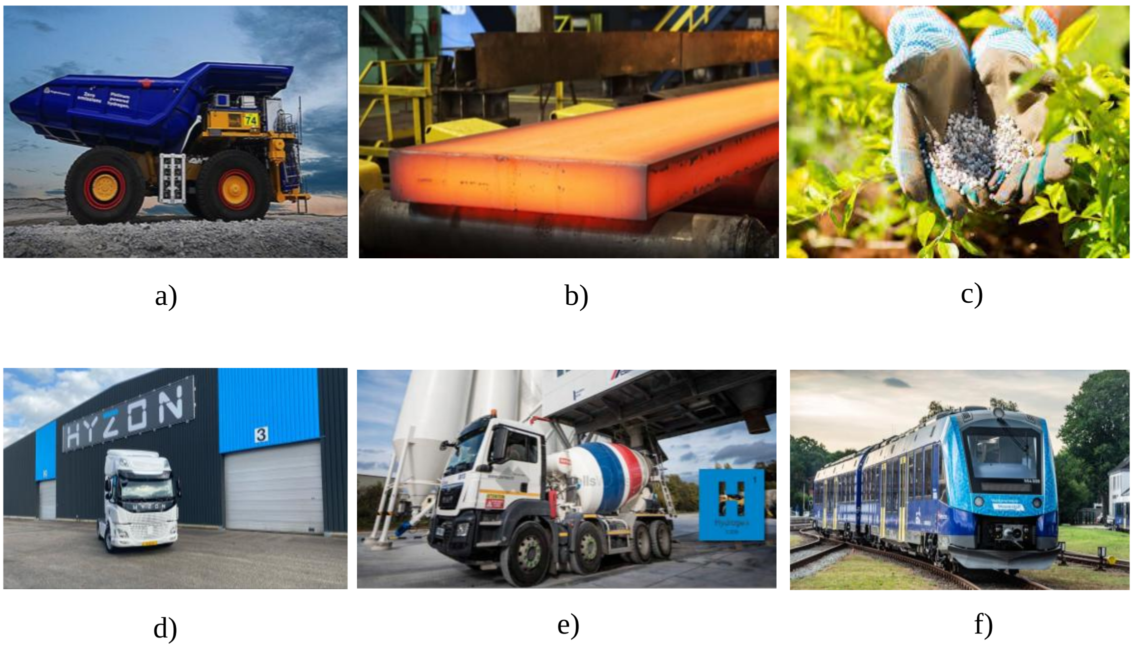


Figure 1 - Current examples of hydrogen use across multiple types of industries. (a) Anglo American Platinum have tested hydrogen powered mining trucks, (b) Green steel manufacturing, (c) Fertilisers, and (d – f) medium to long distance transportation

One of the limiting factors affecting the adoption of hydrogen in industry is its production. There are various methods for producing hydrogen but not all of them are considered clean. Specifically, it is the form of energy used to power the hydrogen production process that is the predominant factor in determining how eco-friendly the hydrogen is.

1.2. Different types of hydrogen and how they are defined

The way hydrogen is produced determines whether it is considered a clean source of energy. This gives rise to the commonly used, colour defined, naming convention for differentiating hydrogen based on how clean it is. White hydrogen occurs naturally in reservoirs underground. Pink hydrogen is produced when using nuclear powered electrolysis - method of producing hydrogen through splitting water into hydrogen and oxygen. Hydrogen produced using coal as the source of energy, is considered black (for black coal) or brown (when lignite is used). Grey hydrogen is any hydrogen produced through steam methane reforming of natural gas or methane. This is the most commonly used process in South Africa, to date. The process of steam methane reforming produces less carbon emissions hence it is called grey hydrogen, even when coal power plants are used. If the carbon dioxide from the Steam Methane Reforming is captured, then the hydrogen can be classified as blue. Hydrogen produced using a source of renewable energy is considered green hydrogen, as per the definition provided by the International Renewable Energy Agency [2]. Blue hydrogen is seen as the intermediary form of hydrogen until green hydrogen is cost competitive [3]. It is green hydrogen that should be targeted for South Africa's emission goals.

1.3. Global and local hydrogen production and consumption quantities

With the global increase in attention surrounding the use of clean energy and sustainability, many countries with a high demand for hydrogen have been sourcing green hydrogen from Europe, North America, Japan and parts of China [4], [5]. The expected global demand for green hydrogen by 2050 is expected to be 500 – 600 million tonnes per annum [2]. Based on South Africa's hydrogen roadmap, South Africa aims to provide at least 2%, or 12 million tonnes, of this green hydrogen [6]. By 2030, 2% of these 12 million tonnes is set to be used locally, while the rest is exported [6]. Various companies, either South African or based in South Africa, are in the process of developing hydrogen projects. Sasol BMG Group South Africa, and Anglo-American Platinum, are currently collaborating on a fleet of hydrogen powered vehicles. Their purpose is to demonstrate hydrogen project value chains and to advance the industry from mere policy to useful application in line with the South African hydrogen roadmap [7]. In the Eastern Cape, Hive Hydrogen is investing R105 billion in infrastructure powered through renewable sources of energy alone, including wind power in the Western Cape and solar power in the Northern Cape, near De Aar. Phase 1 of the project will require 3.6 GW of renewable energy with phases 2, 3 and 4 following with similar sizes [8]. For context, the predicted 12 million tonnes of green hydrogen from South Africa would require approximately 74 GW of installed renewable energy - assuming the energy would be available 24 hours a day for 365 days a year. Due to the variable nature of renewable energy, it is therefore realistic to predict that more than 74 GW will be required.

1.4. Hydrogen production in South Africa

Producing hydrogen requires on average 54 kWh per kilogram of hydrogen produced through the process of electrolysis [9]. One kilogram of hydrogen can produce 33.33 kWh based on its lower heating value (LHV), or 39.39 kWh based on its higher heating value (HHV) [10]. The heating value is the amount of heat released when a specific quantity of the product is combusted. It is an indication of how much energy one unit of a specific product contains. Based on the lower and higher heating value of hydrogen, the process of converting water to hydrogen through electrolysis has an efficiency of anywhere between 61.7% and 72.9%. This is before the hydrogen has been stored or distributed for use.

It is here proposed that the energy required for meeting South Africa's green hydrogen production goals is readily available in the form of solar alone. For comparison, South Africa's solar irradiance levels range between 1 600 and 2 200 kWh/m^2, whilst parts of Europe range between 1 000 and 1 500 kWh/m^2. Consequently, the area represented by Figure 2, which is less than 7% of the Karoo's surface area, is sufficient to power South Africa's entire green hydrogen revolution, with a presumed 12 million tonnes required per annum with an energy consumption of 54 kWh/kg. This implies that space is not the constraint when it comes to building new renewable energy plants.

Figure 2 – A visual representation of the surface area required in South Africa to power the green hydrogen revolution. The red square represents 7% of the Karoos surface area. Image from Britannica [11].

It is admitted, however, that building a solar plant in the Karoo, which is largely desert area, may not be feasible considering the necessary high voltage infrastructure required. Additionally, there is limited access to distribution networks, skilled labour and water. Currently, the renewable energy required for the green hydrogen revolution is distributed across South Africa and strategically located near industrial hubs. Nevertheless, the use of solar power is still seen as a viable power source for hydrogen production in South Africa.

1.5. Cost considerations in South Africa

Although South Africa has an abundance of renewable energy in the form of solar, the cost of that energy is a considerable concern. Research has shown that the cost of energy (in this case, rands per kilowatt hour of energy consumed) plays a significant role in the final cost of green hydrogen. For example, Martinez de Leon et al [12] have shown that at least 40% - 60% of the final cost of hydrogen produced through solar power is associated with the cost of energy, depending on the size of the plant. This is considered true for a fixed electrolyser utilisation factor of close to 100%. The cost of energy consumption may play a less significant role depending on how the electrolyser is used. Other important variables in the cost of green hydrogen production through electrolysis include capital expenditure, operations and maintenance costs, the cost of capital, and the operating parameters of the hydrogen production system. The capital expenditure costs include the upfront CAPEX required for the equipment needed for producing green hydrogen. This may include the hydrogen electrolyser, compressors, storage tank, solar inverters solar modules and cabling, to name a few. Operations and maintenance costs relate to an annual fee required to keep the plant running safely and at the optimal efficiency. This is typically considered as a percentage of the total capital expenditure. The cost of capital is the interest component that needs to be paid when borrowing money to fund these projects. The cost of capital is generally linked to the prime lending rate.

The cost of hydrogen is typically looked at from a levelized cost approach. That is, the cost of the hydrogen averaged over the hydrogen production plant's lifetime. The cost output from the levelized cost approach is one that will ensure the plant is profitable over the expected lifetime of the plant at a predetermined rate of return. Currently, blue hydrogen produced through Steam Methane Reforming with carbon capture, costs anywhere between 130.00 and 281.00 rand per kilogram (ZAR/kg) [2]. This is the international price, not specific to South Africa, which was converted at R18.20 to the dollar. Current green hydrogen costs are in the range of 416.00 and 1125.00 ZAR/kg [2]. For green hydrogen to be competitive in the future, the price must be at least comparable with that of blue hydrogen, as it is currently the cheapest and cleanest form of hydrogen available. This will ensure that green hydrogen gains a significant market share as a source of energy, which will allow for further developments and increased investor interest in the green hydrogen economy. The Organisation for Economic Cooperation and Development [13] notes that the following risks currently impact the high cost of hydrogen: uncertain market demand; a shortage of companies and people willing to use hydrogen as their primary source of energy; uncertainty around where the price of green hydrogen will end up; political risk, and insufficient infrastructure. These risks are further exacerbated by South Africa's grid instability and dependence on coal as a primary source of power.

1.6. South Africa's green hydrogen future

South Africa's ambitions for green hydrogen production, use and distribution are not far-fetched. There are, however, significant obstacles to overcome first. Although South Africa has access to high levels of renewable energy, the country is still the 14^{th} largest emitter of greenhouse gasses in the world, owing to its largely coal-based power plants. With increasing electricity tariffs and unreliable electrical infrastructure in South Africa, industries are looking for secure, clean, sustainable and cost-effective forms of energy to drive our economy forward. Hydrogen could play an important role in that transition. Before green hydrogen can become a reality in South Africa, it is important to understand exactly what determines the price of green hydrogen when coupled with renewable energy systems. Specifically, it is important to understand how all the variables associated with the cost of green hydrogen influence the final cost based on the plants operating parameters. Knowing this will allow policy makers, engineers and business owners to make informed decisions when selecting, sizing, costing and designing green hydrogen production pants.

2. RESEARCH QUESTION

Based on the use case identified for green hydrogen in South Africa and the potential obstacles for its production, the following research question is defined:

Is it economically feasible to produce green hydrogen in South Africa, and what are the key factors for reducing the cost of hydrogen production?

3. OBJECTIVES

Based on the research question and introduction, the following objectives have been identified:

- Determine the cost of solar energy in South Africa.
- Determine the cost of equipment for hydrogen production in South Africa.
- Determine the operating costs of a hydrogen production plant.
- Determine the final levelized cost of green hydrogen production in South Africa.

4. LITERATURE REVIEW

4.1. An overview of the hydrogen production process.

The hydrogen production process is summarised by Figure 3. Green hydrogen is produced when renewable energy is used to power electrolysers. The use of electrolysers is discussed in. The electrolyser produces hydrogen and oxygen – the process is discussed in further detail in section 4.2. The hydrogen is then stored for later distribution and consumption. Renewable energy can be such as solar and/or wind energy and either be provided by grid tied solutions or by a standalone renewable energy system. The standalone system would be coupled with a battery which typically stores excess energy during the day and then releases the energy for consumption at night.

Each of these methods of green hydrogen production has different cost implications. As previously mentioned, the cost of hydrogen production is typically measured by a metric known as the levelized cost of hydrogen (LCOH). This is the methodology of cost calculation to be used as part of the techno-economic assessment. This research paper considers the cost of green hydrogen at the output from the electrolyser, storage and distribution costs are not considered as part of this scope. In question is the production of green hydrogen whose production is based on the power source. The storage and distribution are independent of the type of hydrogen produced. Additionally, the ability for South Africa to store or transport the hydrogen, regardless of type, is thus seen as beyond the scope of this research.

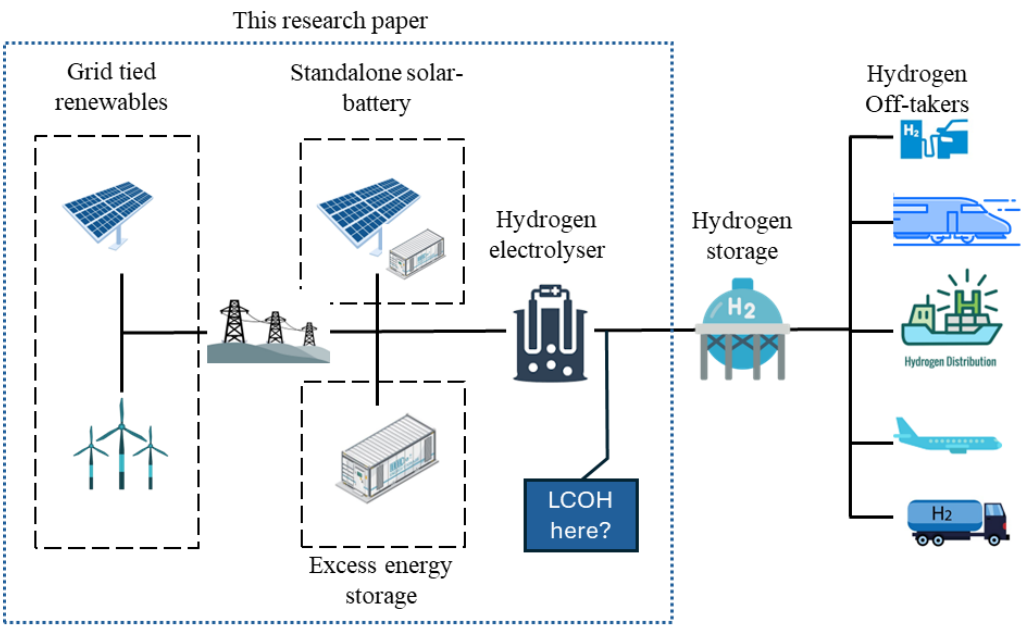


Figure 3 – An overview of the green hydrogen production process as may be adopted in South Africa

4.2. Hydrogen production through electrolysis

In the context of producing green hydrogen, an electrolyser is an electrochemical device that uses electricity to split water into its constituent elements, hydrogen and oxygen. An electrolyser generally contains two electrodes, the anode and the cathode, as well as a form of membrane. The cathode and anode materials are selected to catalyse the hydrogen production process. When current is applied to the electrolyser, positively charged hydrogen atoms are attracted towards the cathode and negatively charged oxygen atoms are attracted to the anode. A membrane is used to separate the oxygen and hydrogen compartments. This process is shown in Figure 4.

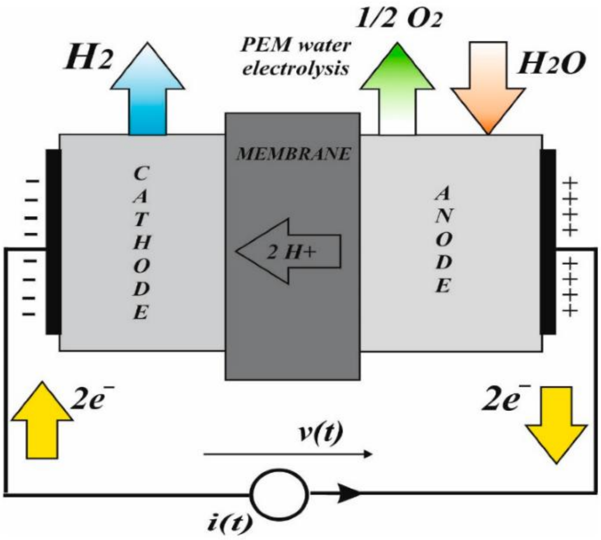


Figure 4 – A polymer electrolyte membrane electrolyser schematic, showing the separation of hydrogen and oxygen from water [14]

There are currently four main technologies for electrolysis. These technologies include solid oxide electrolysis (SOE), alkaline electrolysis (AEL), polymer electrolyte membrane (PEM) electrolysis, [15] and anion exchange membrane (AEM) electrolysis.

Solid Oxide Electrolysers are known for their high efficiencies; however, they operate at high temperatures (500 – 850 °C) [16] which lead to fast deterioration of the catalyst, requiring additional processing to produce pure hydrogen [16]. Based on this, the SOE technology will not be considered as viable for South Africa's production requirements.

Alkaline electrolysis is the most mature of the technologies listed above, and is therefore, the most widely used form of electrolysis. Alkaline electrolysers require lower capital costs at 4 970 ZAR/kW compared to 7 363 ZAR/kW for PEM. Alkaline electrolysers typically operate at fixed steady state conditions with a minimum load range of between 10 and 40% of the electrolyser's nominal capacity [17]. Renewable sources of energy are variable by nature and thus, at any given time, may not supply enough power to meet the electrolysers minimum load capacity. The minimum load range of AEL's thus means they are not suitable for coupling with renewable sources of energy. They will not be considered further.

Polymer electrolyte membrane (PEM) and anion exchange membrane (AEM) electrolysis technologies have a low minimum load range of 0% to 10% of the electrolyser's nominal capacity [18]. This means that a PEM or AEM electrolyser connected to a renewable source of energy can continue to produce hydrogen during low levels of energy supply. This characteristic is beneficial when considering the variability of solar energy in South Africa. This variability is shown by Figure 5. The data is taken from a solar production site situated in Pretoria.

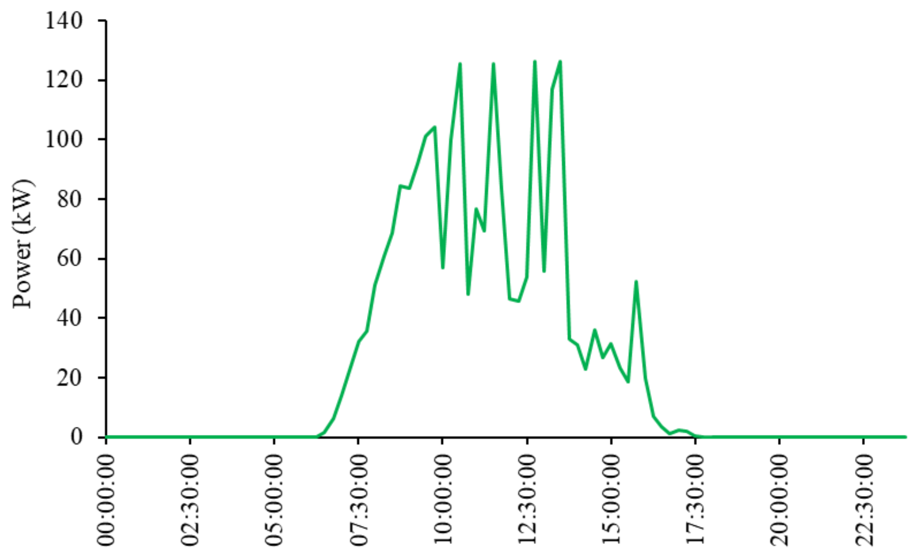


Figure 5 - Example of a solar system's power output fluctuation throughout the day. Data sourced from Sinani Energy (PTY) LTD online platform.

Figure 5 shows that at any given time during peak generation, the energy output from the solar system may go from maximum (approximately 130 kW) to half that (approximately 50 to 60 kW) in a short period of time. This is also true for seasonal variations. In winter, a solar system can produce half the amount of energy that is produced in summer. The PEM or AEM electrolyser will continue to produce hydrogen at these low solar production levels, whilst Alkaline electrolysers would need to shut down due to their minimum load range of 10% to 40%. Therefore, coupling either a PEM or AEM electrolyser with a renewable source of energy should allow for less down time and higher production volumes. PEM electrolysers, however, require rare earth metals, such a platinum or iridium as the catalyst, which makes them costly. AEM electrolysers require less expensive materials and have the same wide operating range as PEM electrolysers.

The critical components of a PEM or AEM electrolyser typically consists of the hydrogen and oxygen evolution reaction catalysts, the membrane, the bi-polar plate, the gas diffusion layer and the ionomer. The weighting of each of these components in the total cost of the electrolyser is shown in Figure 6. The primary cost for the AEM electrolyser comes from the membrane at 60%. In contrast the PEM electrolysers predominant cost is shared between the membrane and the oxygen evolution reaction (OER) catalyst at 28.5% and 32.29% respectively [19]. The membrane costs are significant in the AEM electrolyser due to current technical limits however, there is potential for this cost to be decreased as more stable membrane technologies are developed [19]. The OER catalyst in the PEM electrolyser is significantly more expensive due to the use of the platinum on carbon (Pt/C) catalyst. The material costs for PEM are therefore higher compared to alternative electrolysers. Cost reductions would primarily need to come from either reducing the amount of platinum needed or with market maturity and large-scale adoption of the technology.

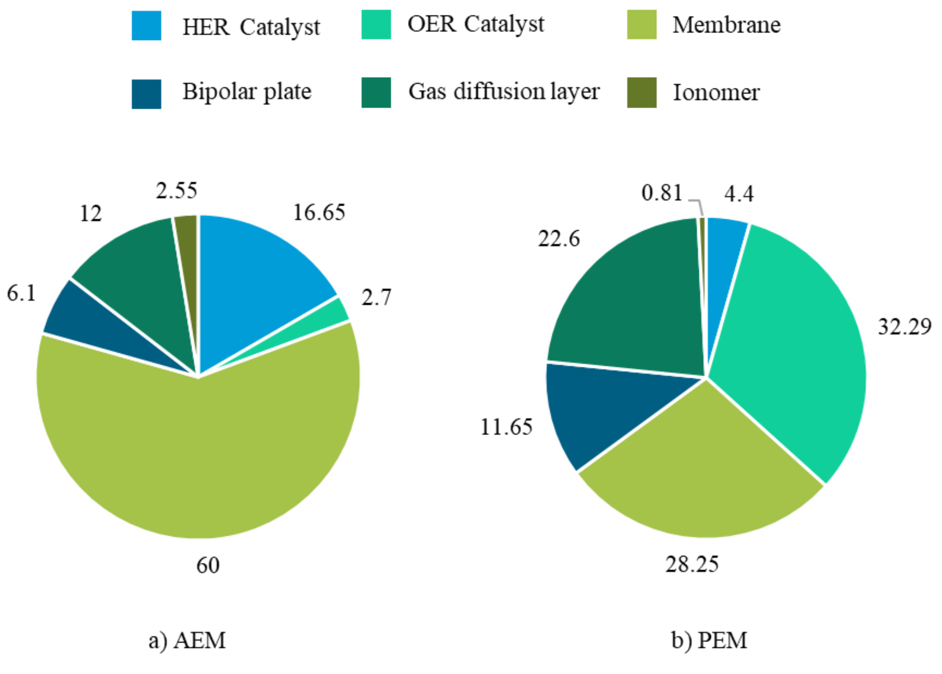


Figure 6 - Component cost breakdown for a) -AEM electrolyser and b) - PEM electrolyser. Adapted from Yang B et al [19].

Price predictions have been given by the International Renewable Energy Agency (IRENA). Capital investment costs for large stacks (greater than 1MW) in 2020 were as follows: Alkaline – 4 970.00 ZAR/kW, PEM – 7 363.00 ZAR/kW and AEM – 36 818.00 ZAR/kW. These were the price predictions for just the electrolyser stack as per the above mentioned in Figure 6, not all the equipment required to produce hydrogen. IRENA estimated in 2020 that the capital costs for the entire system would be in the range of 9 204.00 – 18 409.00 ZAR/kW for alkaline electrolysers and 12 886.00 – 25 772.00 ZAR/kW for PEM electrolysers. A detailed investigation into electrolyser costs by Christensen Adam compares the cost predictions from IRENA, IEA and Bloomburg with their own estimated electrolyser costs in America and Europe [20]. Alkaline electrolysers reach lows of 8 965.00 ZAR/kW in 2050, whilst current prices indicate 23 342.00 ZAR/kW. Current PEM electrolysers prices were found to be in the range of 7 087.00 ZAR/kW to 38 070.00 ZAR whilst prices dropped slightly to between 5 983.00 and 32 786.00 ZAR/kW in 2050. As of 2024 costing data was sourced for three of Enapter's AEM electrolysers for sizes 2.4 kW, 120 kW and 500 kW. Enapter does supply larger electrolysers however, data on these system costs was not available at the time the data was sourced. CAPEX values for these three electrolysers are shown in Figure 7. Figure 7 shows that the price per kilowatt for Enapters electrolysers reduces with increasing size. There is therefore a quantitative benefit in reducing the LCOH by increasing the electrolysers sizes. This is further quantified in section 6.

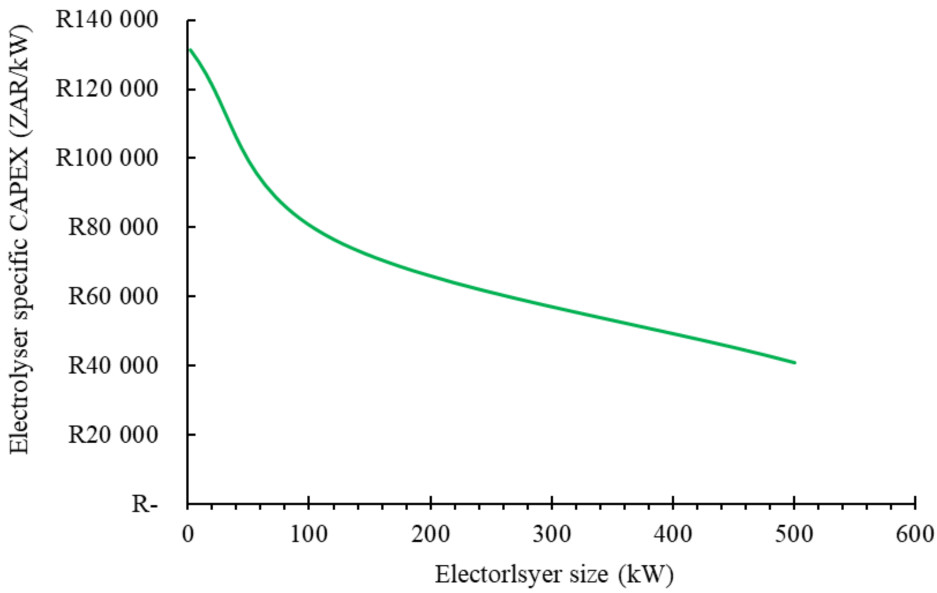


Figure 7 - The specific price (ZAR/kW) for three of Enapters AEM electrolysers as of 2024.

Based on the data presented above, the Enapter electrolyser pricing is to be used for the purpose of this research. This pricing encompasses the full system required for hydrogen production and is considered as the manufacturer most easily available on the market. Considering the variability of pricing shown above, using the higher pricing from Enapter means the final LCOH will be calculated based on a worst-case scenario. The variability in this case is taken as the difference between the actual pricing for Enapters 500kW electrolyser and the predicted pricing from IRENA. Based on the characteristics of the

AEM and PEM electrolyser, either may be suitable for the coupling with renewable energy sources for the purpose of green hydrogen production however, for the purpose of this research, the AEM electrolyser will be considered.

4.2.1. Modelling the electrolysis process

Electrolysers have a specific response time depending on the operating environment. There are currently three primary methods of modelling hydrogen production through electrolysis. This includes static models based on semi-empirical equations, static models based on empirical equations, and more recently, dynamic models. The static semi-empirical equations use Faraday's law to directly relate the current and hydrogen production rates [21]. The empirical models focus on defining various characteristics of the electrolysis process through experimentation, such as the reversible potential, activation over-potential and ohmic over potential [21]. More details on static and semi-empirical modelling are detailed by Hernandez-Gomez et al [21], Olivier et al [22] and Abdin et al [23]. Figure 8 compares a static model with a dynamic model and an experimental model.

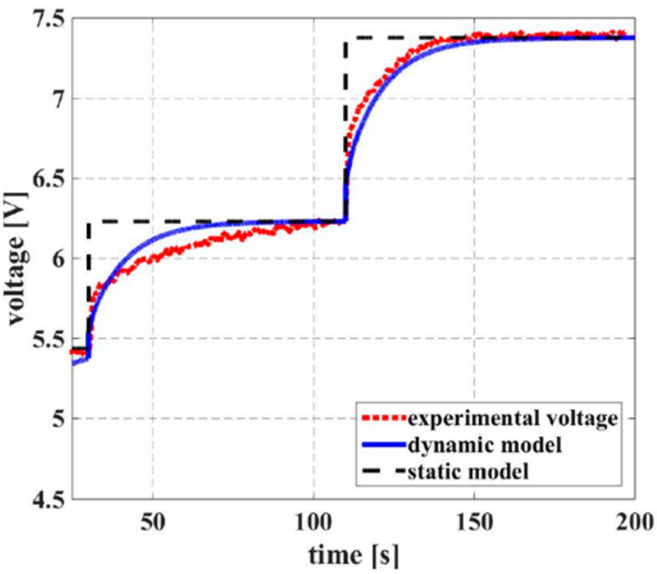


Figure 8 - Schematic of a dynamically modelled PEM electrolyser showing the discrepancy between a static and dynamic model, as demonstrated by Guilbert et al [14]

An important characteristic of an electrolyser is its ability to start up and operate under varying load cycles. Dynamic modelling considers the ability of the electrolyser to react to variations in input energy, whereas the static models previously mentioned do not consider this. Guilbert and Vitale [24] show that dynamic modelling more accurately represents the true electrolyser reaction to varying input currents. The study shows that the maximum error between the experimental data and their dynamic model is

4%, compared to 15% for the static model. This concept is shown in Figure 8. The dotted line represents that of a static model. The static model assumes an instantaneous increase in electrolyser voltage. As the electrolysers increase in voltage, hydrogen production increases, as shown by the red line in Figure 8. An example of an AEM electrolyser which can react instantaneously to rapid changes in the operating environment is shown in Figure 9 below, from Enapter. One of their key selling traits is their electrolysers' "rapid reaction time to intermittent renewables" [25]. The rapid reaction times from the AEM electrolyser mean that when the electrolyser is powered through variable power sources such as solar, less energy is wasted in transitioning between operating points.

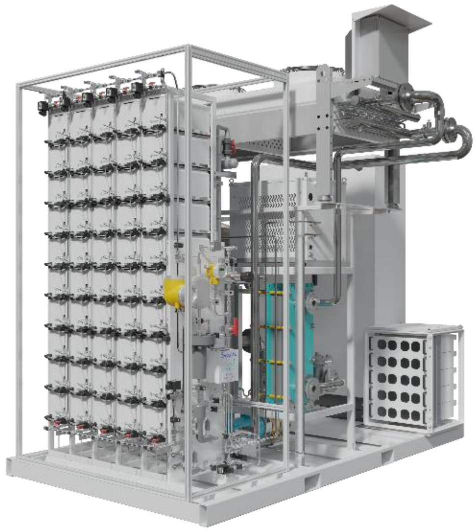


Figure 9 - Example of a 120kW AEM electrolyser from Enapter [25]

Table 1 defines the key characteristics of the 120 kW AEM electrolyser range offered by Enapter. These characteristics play an important role in the system design and modelling. Each of the values in Table 1 were used throughout the process of determining hydrogen production quantities as well as the LCOH of hydrogen at various electrolyser utilisation factors. Key considerations from Table 1 include the electrolysers operational flexibility and specific power consumption. An operational flexibility of 12% – 100% means that the 120 kW electrolyser will only start up once 14.4 kW of power is available. The most significant variable considered is that of the specific power consumption (electrolyser's efficiency). The Enapter electrolysers requires 53.3 kWh/kg$_{H2}$, as shown in Table 1, however, this number could vary between 42.2 and 65.6 kWh/kg depending on the type and brand of electrolyser used [26].

Table 1 - AEM electrolyser characteristics by Enapter

	Units	**Value**
Electrolyser size	kW	120
Hydrogen production flow rate	kg/24h	53.9
Hydrogen purity as standard	%	99.95
Hydrogen outlet temperature	Degree C	5-55
Oxygen production flow rate	Kg/24h	26.95
Nominal power consumption	kW	120
Water consumption	L/h	23
Operational flexibility	%	12-100
Hot start up time (0-100%)	s	100
Cold start up time (0-100%)	min	20
Specific power consumption (Electrolyser efficiency)	kWh/kg_{H2}	53.3

An investigation done by Virah-Sawmy et al, has shown that assuming a constant electrolyser efficiency can result in an overestimate in hydrogen production by between 5 and 25% [19]. Considering the lower heating value of hydrogen at 33.33 kWh/kg, the process of producing hydrogen through electrolysis results in a system efficiency of 62.53% at a specific energy consumption of 53.3 kWh/kg. This system efficiency is then used to determine how much green hydrogen could be produced from the energy supplied by the solar system, as shown in equation 1:

$$kg_{H2} = \frac{kWh\ supplied}{53.3\,\frac{kWh}{kg}} \qquad [1]$$

This simplified equation assumes a static model, and therefore, the system's hydrogen production variance must be considered. Additional considerations in variation include the CAPEX for the hydrogen system, which is covered in section 4.2. The balance of power required to run additional compressors, cooling fans and lighting system must also be considered. The balance of power considers any energy used for the ancillary items which will reduce the amount of hydrogen that can be produced. Electrolysers also require periodic O&M and this value quantified, is usually between 2% and 3% of the system CAPEX per annum. [27], [28], [29].

Furthermore, the stack lifetime of a hydrogen electrolyser must be considered. Depending on how often the electrolyser is used, it would need to be replaced. Typical stack lifetimes for AEM electrolysers range between 35 000 and 50 000 operating hours [28]. Therefore, at 50% utilisation, an electrolyser would typically need to be replaced every 8 to 11 years. The stack lifetime varies depending on the type of electrolyser used. For example, the PEM electrolyser may have a longer lifespan of between 50 000 and 80 000 hours [30]. The cost of the stack replacement is included in the operating and maintenance costs of the system. The cost of replacing the electrolyser stack ranges between 10% and 43% of the system CAPEX depending on the type of electrolyser used [31]. This cost is typically included in the annual O&M allowance for the project. O&M costs for hydrogen systems are usually accounted for as 1.5% of the system CAPEX per annum [32]. Including the cost of the stack replacement this would increase to 2% on the low end and 5% on the high end. This is calculated based on the CAPEX of a 500 kW electrolyser at 42 000.00 ZAR/kW assuming the stack needs to be replaced every ten years.

4.3. Solar irradiance and modelling

Irradiance is a measure of the rate at which energy is produced by the sun. Irradiance is the single most important variable when calculating the energy output from a solar system. The initial step required when modelling solar systems is to calculate the irradiance on the Global Horizontal Plane, known as GHI (Global Horizontal Irradiance). The irradiation is calculated from climate data which is typically supplied by a third-party company, such as Meteonorm, who use a combination of ground based and satellite measurements to provide a data set. These data sets are known as a Typical Meteorological Year (TMY) and are visualised in the format shown in Figure 10. These are typically measured in kilowatt hours per square meter (kWh/m^2) watts per square meter (W/m^2).

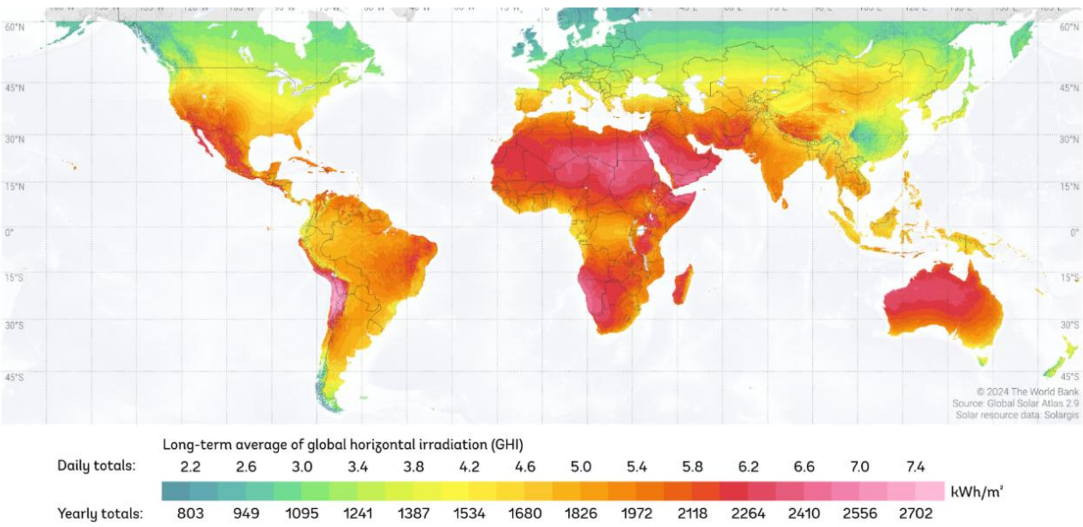


Figure 10 – A global irradiance graphic showing the total kilowatt hours of irradiance received per square meter [33].

4.3.1. Typical Meteorological Years (TMY)

A Typical Meteorological Year (TMY) data set provides designers with hourly meteorological values that would typify irradiance levels at a specific location over a longer period, such as 20 years [34]. The quality of this data has been investigated by Mabasa et al. [35] in South Africa. Mabasa et al. [35], have shown that out of the data sets investigated, a mean absolute error of between 9% and 11% can be expected [35]. This means that when calculating the amount of energy that a solar system can produce over the course of a year, a 9% to 11% correction factor must be considered.

Using the TMY data set, a series of steps are followed to calculate the hourly energy output from the system over the course of a year. The precise method of calculation depends on the software being used. Typical software includes the likes of PVSol, PVSyst, Homer and SolarEdge, to name a few. The general process is as follows: For a specified location, the sun's position is calculated using latitude, longitude and elevation angle. The angle of the sun relative to the modules is used for calculating the angle at which the sun will hit the modules, and therefore, either be absorbed, reflected or refracted. The global radiation from the TMY data set is divided into direct and diffuse radiation. This is calculated using the Hoffman model [36]. Whether the sun is above or below the horizon line is also considered for every increment of the model. This is known as horizontal shading, where a hilly terrain may cause shading on the modules. The total irradiance on the inclined plane is then calculated using the Perez model [37]. Finally, ground reflection, depending on the surface's Albedo, and extra-terrestrial radiation are considered before calculating the final hourly energy output over the course of a year. Figure 11 summarises the above-mentioned approach.

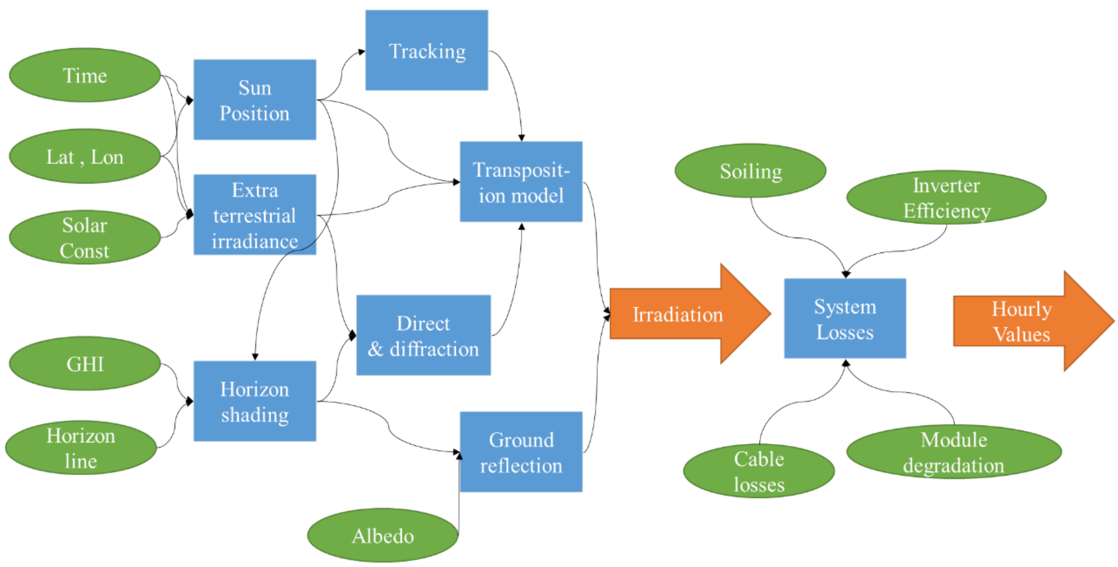


Figure 11 - A graphic representation of the process followed, and inputs considered, when calculating the energy output from a solar system based on the solar irradiance as an input.

4.3.2. Solar system losses and gains

After calculating the final hourly energy output, additional system parameters must be considered. These parameters are dependent on the system design specification and operating environment. Figure 12 is a waterfall graph showing which factors affect solar energy production and to what extent. From Figure 12, the largest contributor includes the module efficiency. This is the modules' ability to convert the energy available from the sun into usable DC and then AC power. Other factors include soiling (dust build up on the modules), module reflection, that is dependent on the module construction, cables losses and other equipment specific losses.

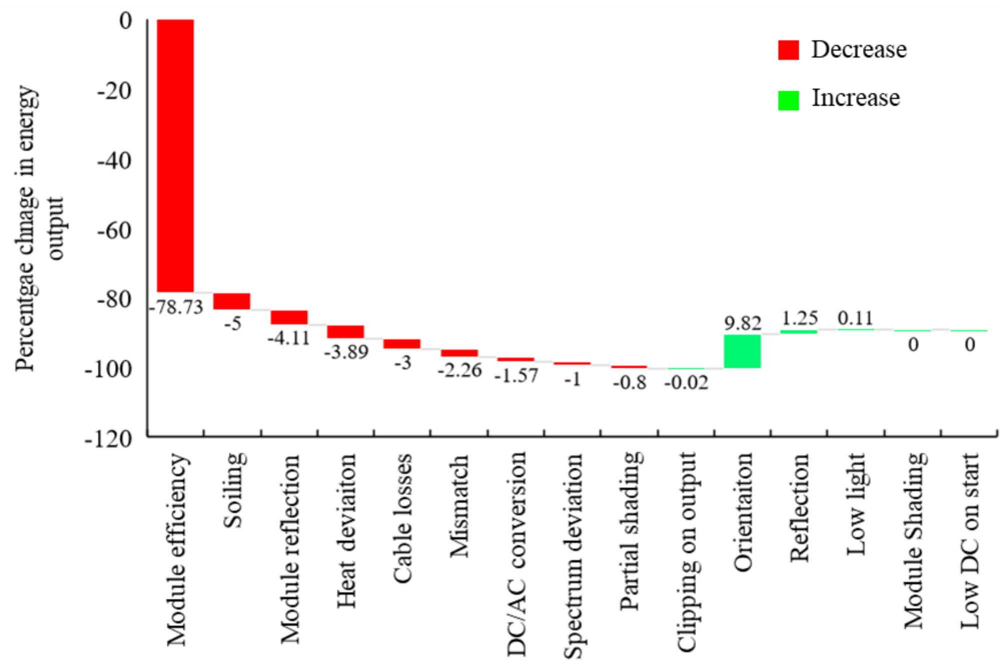


Figure 12 - Waterfall graph showing the losses and gains incurred by a solar system, acting as the benchmark.

The final output is the graph shown in Figure 13. Most typical solar systems would see a significant reduction in production output in winter. This is seen during the South Africa winter months (from March to August) for a 0º module tilt as represented in green in Figure 13. However, when the tilt of the modules is set to match that of the latitude at which the system is built, the graph becomes flatter and more consistent in production, as shown in blue. Aligning the modules' tilt with the latitude in this scenario improved the overall output of the system by 10%. Further improvements would be realised if a solar system which tracked the sun were installed. With tracking capabilities, the energy output from the solar system may improve by an additional 20 to 30% [38].

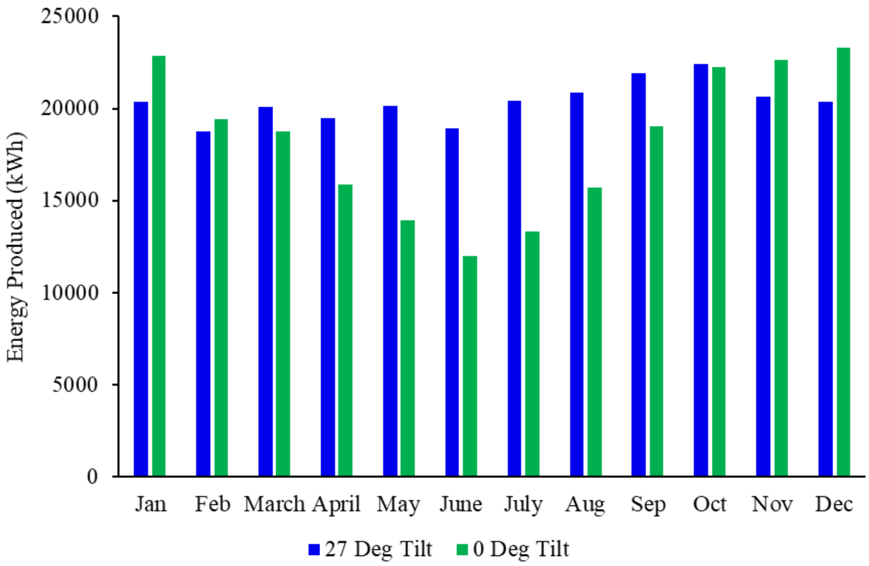


Figure 13 – A comparison of the annual energy production between two solar systems that have been designed with different levels of modular tilt.

4.3.3. Solar system sizing and throttling

Accounting for differences in energy production in summer and winter, solar systems are typically oversized on the direct current (DC) size compared to the alternating current (AC) size. This is known as the DC to AC ratio. Depending on a system's location a DC/AC ratio of between 1.1 and 1.25 is typical. When a solar system is oversized compared to the load, the system will experience throttling, which is the response of limiting its output based on the demand. This is explained using Figure 14.

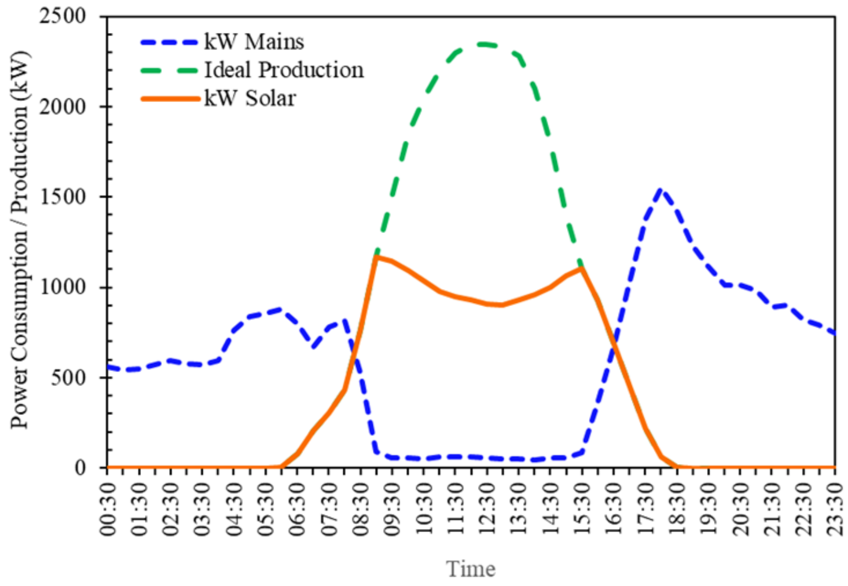


Figure 14 - A graphical representation of a solar system that is being throttled.

Figure 14 shows the kilowatt-hours consumed from the grid in blue, the actual amount of solar energy produced in orange, and the ideal solar system production in green. In this scenario, the solar system production is limited by the grid consumption. From 09:00 to 15:30, the consumption from the grid reaches zero as the solar system is producing more energy than required. This results in the solar system production being limited, as shown by the orange line in that same time frame. Summing the orange line and blue line at any time tells us the systems actual total load. At 12:30 the client's total load is approximately 1000 kW. However, from the green line it is shown that the solar system has been sized to be able to produce almost 2400 kW at its peak production. All the available solar energy, that is, energy between the green and orange line, is essentially throttled by the system and therefore wasted. Oversized systems are useful when coupling the solar system with a battery. This is further discussed in section 5.

4.3.4. Solar irradiance uncertainties

There are uncertainties associated with each input in the modelling process. Meteonorm has shown that there is between a 2 and 10% uncertainty in the irradiance data that they use, depending on the location and vicinity to existing ground-based measurement devices [39]. Other factors such as soiling, (build-up of contaminants on the surface of the solar modules) and cable losses (voltage drop over long cable runs) are determined by the engineer designing the system and are often left up to interpretation. Soiling losses can vary between 3 and 8% or between 0.4 and 1.2% per week depending on the location of the modules, the tilt, the weather and how often the system is cleaned. Cabling losses are dependent on the length, size and type of cabling being used. These calculations are subject to inputs such as ambient temperatures, method of installation and amount of current the cable can carry. These typically vary between 1% and 5%.

4.3.5. PVSol solar modelling validation

The software used to investigate solar energy production for this research paper is PVSol. PVSol completes the above-mentioned process to estimate the annual energy production from a solar system. The complex model is validated using the below simplified equations, which can be split into the irradiance independent equation and irradiance dependent equations as follows:

Equation 2 – Irradiance independent energy output

$$E_{E2} = (I_{GHI} - (S_D + S_R - S_{GR} - S_O)) \times A_M \qquad [2]$$

Where E_{E2} – is the energy output based on equation 2 in kWh, I_{GHI} – is the global horizontal irradiance in W/m^2, S_D – is the losses due to spectrum deviation in %, S_R – is the reflection losses in %, S_{GR} is the ground reflection gains in %, S_O – is the orientation of the modules in % and A_M – is the module area in m^2.

Equation 3 - Irradiance dependent energy output

$$E_{E3} = E_{E2} - E_{E2}(S_S + S_T + S_M + S_{Cl} + S_C + S_{CBL}) \qquad [3]$$

Where E_{E3} – is the energy produced in kWh from equation 3, S_S – is the losses due to soiling in %, S_T – is the losses due to temperature deviation of the modules in %, S_M – is the losses to the voltage mismatch in %, S_{CL} – is the losses due to clipping in %, S_C – is the losses due to the DC/AC conversion process in % and S_{CBL} – is the losses in the cables as a %^.

Equations 2 and 3 are used together with the TMY data set that was input into the modelling software. The result is Figure 15. The light blue bar graph shows the modelled as expected, representative of a solar system with a tilt equal to that of the solar system's longitude. The darker blue bar graphs represent the system modelled with the simplified equations above.

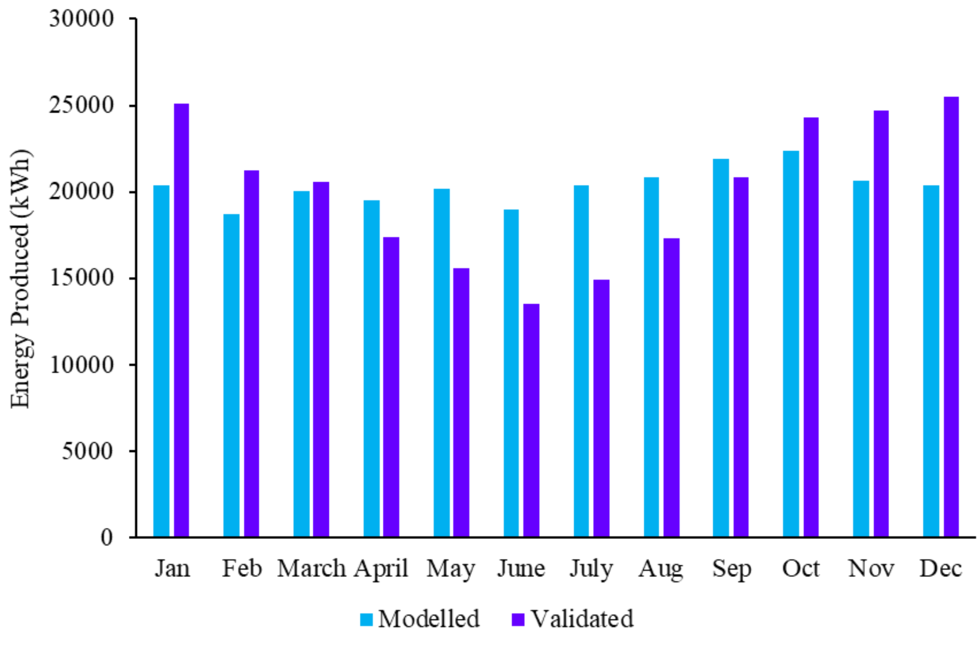


Figure 15 - A comparison between the modelled energy output and calculated energy output of a solar system based on simplified equations 3 and 4.

The graphs do not perfectly align on a month-to-month basis, however, over the period of one year there is a 1.4% difference between the calculated energy yield. The shape of the validated data set strongly matches the graph shown in 14 which suggests that there is a component related to the tilt of the modules which is being neglected in the validation equations. This may be true, as additional parameters such as diffuse irradiation was not considered. Furthermore, there are additional factors which the computational model considers, such as the ambient temperature. High ambient temperature in summer leads to lower system performance which could explain the results of the blue graph being lower than that of the darker blue graph in the summer months. In winter, when the ambient temperature is lower, the overall efficiency of the system improves. This, together with the tilt favouring the lower sun position, allows the modelled system to outperform the validated system. Considering that the data for the levelized cost analysis is based on annual energy production, the model is therefore considered to be validated.

4.3.6. Solar system components and costs

There are a variety of types of solar systems, each with a different system component breakdown. These may include ground mount, roof mount - long rail, roof mount - ballasted, carport type systems, tracking solar systems, building integrated and floating solar to name a few. For this research ground mount and roof mount – long rail systems are the most likely to be used due to their simplicity and ease of construction. The components for each solar system are similar however may constitute a different proportion of the total system cost depending on the type of system being built. This is shown in Figure 16. Costly components include the modules, mounting structure, distribution boards and labour. In this case labour is inclusive of design and engineering.

The primary cost and design difference between the various solar systems is that of the mounting structure. For example, the mounting structure in the ground mount solution (Figure 16 (a)) constitutes 14% of the total cost, while the mounting structure for the roof mount solution (Figure 16 (b)) drops to 7%. This factor, along with various design nuances which may be project specific create the variability in the solar system cost. Typical commercial sized solar systems (100kW and larger) vary between 10.00 and 15.00 rand per watt (ZAR/W), with roof mounted solar systems on the lower end and ground mounts towards the middle and upper limit of this range. There is economy with scale for solar PV systems. Typically benefits can be seen when approaching sizes such as 1 megawatt. For this report, it is assumed that there is no reduction in the price per watt peak for system sizes of 100 kW to 500 kW AC.

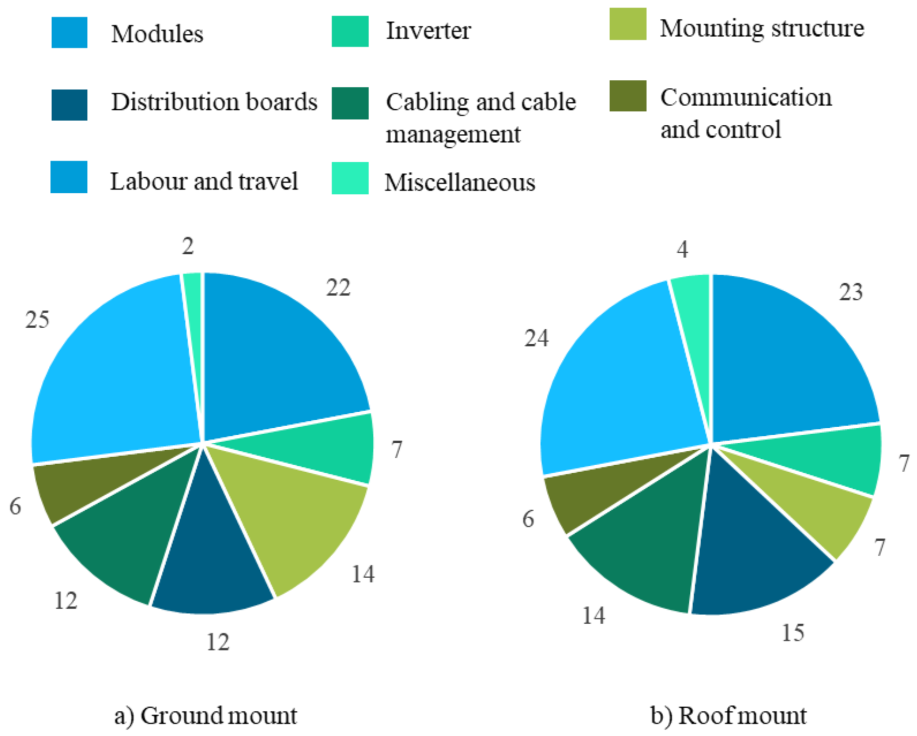


Figure 16 - Solar PV system component proportions of the total cost for a) ground mount systems and b) roof mount systems.

4.4. Types of batteries used for commercial solar systems

Commercial solar systems typically comprise batteries to store excess solar power produced and provide power in low light or nighttime conditions. The two common battery types are lead-acid (PbA) and Lithium-ion. Lead acid batteries are relatively cheap, require low maintenance, and can withstand harsh conditions. These batteries, however, have a short life span with a study by Saha et al [40] found that a PbA test battery had a capacity degradation of 8.62% after 2000 cycles. Lithium-ion batteries, on the other hand, have captured the commercial solar market due to their deep discharge capability, longer lifespan, and lower self-discharge losses compared to lead-acid batteries. Saha et al [40] found that that after 2000 cycle the lithium-ion battery had a capacity degradation of just 3%. Based on these advantages, Lithium-Ion batteries are more commonly used in residential and commercial solar systems. Further, these types of batteries are commonly used by various suppliers such as Freedom Won, ATESS, Blue Nova, Energenic, Hubble, Jinko, Sungrow and solar MD to name a few, all of which can be found in South Africa. The positive electrode is a metal oxide or phosphate including lithium, the negative electrode is graphite, and the electrolyte is a lithium salt. There are several types of lithium-ion batteries, including Lithium-Iron Phosphate (LFP), Nickel Manganese Cobalt Oxide (NMC): These batteries are also common in commercial solar batteries, adopted by manufacturers such as LG Chem and Samsung. Alternative lithium compound batteries include Lithium-Cobalt Oxide (LCO), Lithium-Manganese Oxide (LMO), Lithium-Nickel Cobalt Aluminium Oxide (NCA), and Lithium Titanate (LTO), though these are not as commonly used.

The performance of these batteries is evaluated based on factors including the number of complete cycles, voltage deviation during discharge, discharge capacity, energy output, and round-trip efficiency. These factors are important when considering which battery to select for coupling with solar energy systems. For example, a higher discharge capacity means a smaller battery can be used for the same amount of energy output. Batteries are typically sized based on the load that they need to operate at and the amount of time they are expected to operate at this load for. When coupling a battery system with a solar system the amount of energy the solar system can produce compared to the amount of energy the battery can store becomes important. The purpose of a battery in a solar coupled system, is to store cheaper energy (compared to grid supplied energy from suppliers such as Eskom) produced during the day for use during load shedding or arbitrage. This is termed as arbitrage - the practice of taking advantage of the cheaper energy produce by the sun storing it and using it when electricity prices are higher or when the sun is not available.

The price of the battery has a large influence on the cost of energy output from the hybrid battery solar system. Several battery types in South Africa were compared by *mybroadband* as a cost comparison [41]. Looking at the more popular battery specific pricing in the rage of 10 to 20 kWh's of storage: Sunsynk – 6 333.00 ZAR/kWh, Hubble – 6 950.00 ZAR/kWh, Freedom Won – 7 048.00 ZAR/kwh, Huawei – 13 933.00 ZAR/kWh, Tesla powerwall – 16 741.00 ZAR/kWh. The batteries considered are typically a smaller scale than what would be considered for commercial solar systems. For commercial sized solar systems (50 kWh and greater) two suppliers, a local South African battery supplier, Freedom Won, compared to battery manufacturer and supplier ATESS, based in China, are compared in Figure 17. The CAPEX value of each battery is shown on the left y-axis in green and blue, while the specific price (ZAR/kWh) of each battery is shown on the right y-axis in red and purple. It can be seen that the local supplier Freedom Won is competitive with the Chinese supplier at lower energy storage values of between 100 kWh and 300 kWh, as represented by the blue dots and green triangles. As the battery energy storage requirement increases towards 800 kWh, the price difference between Freedom Won and ATESS diverges.

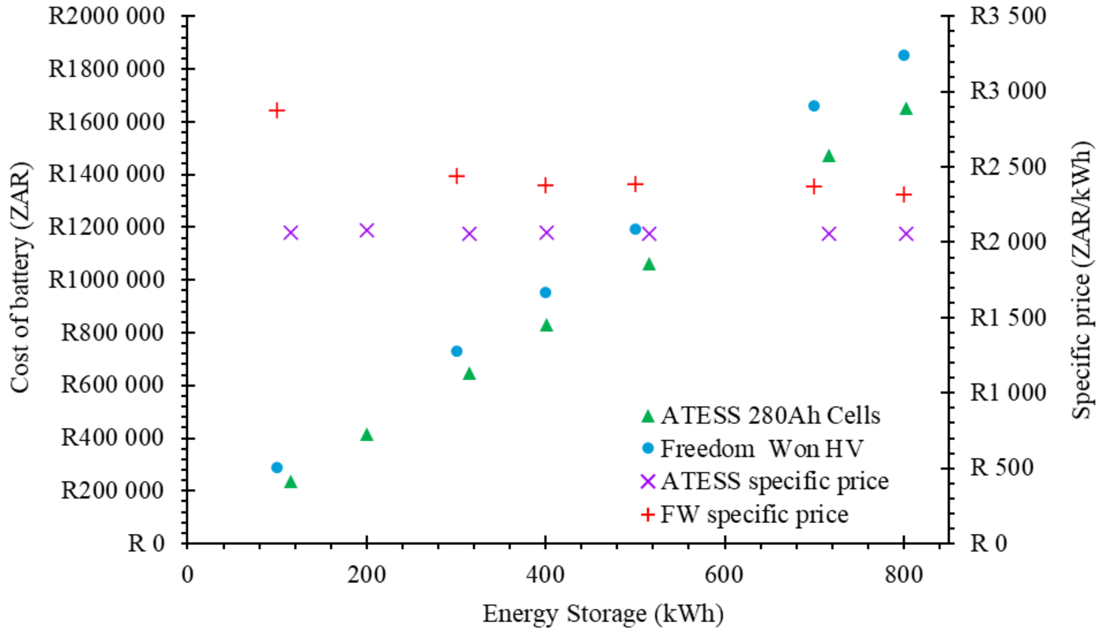


Figure 17 - ATESS and Freedom Won commercial battery pricing comparison by CAPEX values on the left y-axis and specific price on the right y-axis.

An important consideration is that of the specific price of the batteries (considering ZAR/kWh instead of just ZAR). The ATESS battery maintains a consistent specific price of 2 056.00 ZAR/kWh, dropping very slightly as the energy storage requirements increase as shown by the purple x marks. The Freedom Won battery starts at a higher specific price of 2 873.00 ZAR/kWh and decreases with increasing energy storage to 2 315.00 ZAR/kWh for an 800 kWh battery. Note that the above shown pricing is only for the battery. The pricing excludes the additional items required to make the battery system work such as additional inverters, transformers, containers, cabling, engineering design, installation labour, commissioning and transport to name a few. Based on industry experience the typical specific price for a completed installation will vary between 5 700.00 and 9 000.00 ZAR/kWh excluding the solar system.

4.5. Hydrogen storage

Although storage costs are not considered as part of this technoeconomic assessment, various hydrogen storage options are discussed to understand how the hydrogen may be stored for the purpose of future expansion on this research. Depending on the method of storage selected, the LCOH for green hydrogen would increase. This approximate cost increase is considered below for reference.

Hydrogen can be potentially stored as compressed hydrogen, liquid hydrogen and ammonia. Less common forms include absorption storage and metal hydrides. All these technologies often require pre-compression of the gas or other preparation methods of the hydrogen or storage vessel. In this case a storage vessel can be a pressurised container, or a liquid or metal capable of storing hydrogen under certain conditions. The storage technologies are elaborated on below.

Hydrogen can easily be stored in the form of a compressed gas. The process of producing hydrogen with an AEM electrolyser results in gas outlet pressures of at least 30 bar. High pressure electrolysis means less energy is required to further compress the gas to a pressure fit for long- or short-term storage, usually ranging from 200 to 700 bar [42]. A multistage intercooled compressor was considered by Gallardo [43]. Multistage compression allows for cooling of the gas between stages and therefore, can reduce the amount of energy required to compress the gas to its final pressure. The inlet pressure to the multistage compression train is equal to the electrolyser outlet pressure, which can typically vary between 30 to 200 bar, depending on the method of electrolysis [44]. This additional process of compression can require up to 4 kWh/kg of hydrogen stored in additional energy [45]. This additional energy increase would result in a 7.5% increase in the LCOH for hydrogen system powered by solar.

Storing hydrogen stored in liquid form is known as the process of liquefaction. Liquefaction allows for hydrogen to be stored at a much higher density at standard atmospheric pressure [46]. The liquefaction of hydrogen can be beneficial when transporting the hydrogen over long distances, due to its high energy density. However, keeping the hydrogen at low enough temperatures to remain liquid requires a lot of energy. The liquefaction of hydrogen is based on data of the IDEALHY project by Stolzenburg et al. [47]. The capacity studied in the IDEALHY project is 50 tonnes of hydrogen per day resulting in a specific energy consumption of 6.76 kWh/kg$_{H2}$. The precompression of hydrogen to 30 bar reduces this value to 6.4 kWh/kgh$_2$. These values are in line with the 6.1 kWh projected by the international energy agency (IEA) [48]. This form of storage may increase the LCOH by around 12%.

Storing hydrogen in the form of Ammonia results in a chemical hydride. This form of storage has significant advantages in terms of the mass content of hydrogen. Liquid ammonia at 25 degrees Celsius and at 10 - 20 bars has a mass density of around 680 kg/m^3. The hydrogen mass content in ammonia is 18% [49] , resulting in an equivalent hydrogen density of 122.4 kg/m^3 which is 70% higher than the density of liquid hydrogen at 71.4 kg/m^3 [50]. However, the additional cost and complexity of ammonia synthesis and the fact the hydrogen may need to be recovered from the ammonia, if the ammonia cannot be used directly, adds costs and complexity. The process of combining hydrogen and nitrogen to form ammonia requires an additional 7 - 10 kWh/kg of ammonia produced [51]. If green hydrogen were to be stored in this form, the cost would increase by 13 - 18 %.

Alternative forms of hydrogen storage include absorption, liquid organic hydrogen carriers (LOHC's) and metal hydrides. Absorption storage makes use of van der Waal's principle of bonding between molecular hydrogen and materials with large surface areas. For example, liquid nitrogen may be used at a pressure between 10 and 100 bar as the absorbent for the hydrogen [52]. Absorption has typically only been used at a laboratory scale and is therefore not considered a suitable option for this research.

LOHCs includes any material that can be characterized by its dehydrogenation and hydrogenation ability in liquid form. This means that in liquid form, they are capable of absorbing and releasing hydrogen through a chemical reaction. LOHCs typically require a noble catalyst, pressures in the range of 10 – 50 bar, and temperatures up to 200 degrees Celsius. LOHCs have more recently emerged as a potential storage solution for large scale hydrogen storage. This is because the process typically has lower energy requirements compared to ammonia production. LOHCs may be considered for the storage of hydrogen for this research project depending on the method's cost competitiveness. Lastly, metal hydrides involve the chemical bonding during the absorption of hydrogen as opposed to van de Waal's forces in absorption storage. The result is a much stronger bond that allows more hydrogen to be stored at ambient conditions. For example, metal hydrides typically require less energy to store hydrogen compared to ammonia. This being said, there is potential for metal hydrides to be used in the storage of green hydrogen, depending on their economic feasibility, which is considered in detail by Amica et al [53]. Storing hydrogen in the LOHC format requires an additional 10.616 kWh/kg of hydrogen, therefore, resulting in an 18.5% increase in final LCOH.

4.6. Techno-economic assessment

To compare the cost of green hydrogen in South Africa to other parts of the world, a technoeconomic assessment will be undertaken. A technoeconomic assessment is a method of research used to determine the economic performance of a process or product [54]. In this case, the process is the production of green hydrogen through solar energy. A technoeconomic assessment will consider various inputs into the model such as capital costs, operating costs, and any technical or financial parameters which may influence the performance of the process. These may include, electrolyser sizing and modelling, solar system sizing and modelling, capital costs, and operating costs of the equipment and hydrogen production processes.

4.6.1. Current research on the techno-economics of green hydrogen production

Previous studies on the technoeconomic assessment of hydrogen production through renewable sources of energy typically follow the same method. First, the location is considered. The location is determined based on access to renewable energy, existing infrastructure for distribution, and expected demands. Once the location is determined, solar data is required. Solar data is either used from existing solar production plants or is based on satellite data. The solar data is used as an input into the hydrogen production model. The hydrogen production model varies based on the authors' objectives. Typically, models look at two scenarios, the first being, standalone solar PV systems connected to PEM or alkaline electrolysers, which may or may not include battery storage. Scenario 2 involves grid tied solar PV systems, in which power is supplied by the grid in circumstances where solar cannot provide power. In the case of a grid tied solar system, the energy from the grid must come from a renewable resource to be considered green. If the energy powering the electrolyser comes from a coal power station for example, the hydrogen cannot be considered green.

Gallardo et al. [43] have investigated the production of green hydrogen by solar in Chile, which has solar irradiance levels like that of South Africa. The locations were based on existing solar production plants, and the energy data from these plants was used as an input into the hydrogen production model. The method of electrolysis determined the system-specific energy consumption. For the polymer electrolyte membrane (PEM) electrolysers used in this study, an energy consumption value of 54 kWh/kg of hydrogen was used. The hydrogen demand was then determined based on the ability to export hydrogen to meet Japan's demand of 300 kilotons per year. The levelized cost of hydrogen was calculated based on the production method, after which the additional cost for the distribution and supply was considered. The results show that for a PEM electrolyser connected to a solar PV system, the levelized cost in 2018 was 508.00 ZAR/GJ excluding distribution. The levelized cost of hydrogen dropped to 338.00 ZAR/GJ by 2025 [43]. This is 1.2 times the current cost of blue hydrogen in South Africa, showing that green hydrogen costs could become competitive with blue hydrogen soon, given the high levels of solar irradiance in South Africa.

Morocco is identified as an ideal location for hydrogen production based on the large requirement for hydrogen in the fertilizer industry, and the cost of green hydrogen production has been evaluated by Berrada et al [55]. A demand of at least 260 000 kg of green hydrogen could be developed if the cost of green hydrogen production is competitive with current grey hydrogen production in Morocco. According to Berrada et al, this cost must be less than 766 ZAR/GJ of green hydrogen. Berrada et al [55] use solar data from Meteonorm and the system is modelled as a 20MW single axis solar PV system. The electrolyser is also selected as a 20MW system. The solar and electrolyser model are created from first principles and evaluated in a Simulink/Matlab environment. The electrolyser model focuses particularly on using a static model for hydrogen production. According to the Berrada et al, a 20MW solar system coupled with a 20MW electrolyser will produce on average 900 000 kg of green hydrogen in Morocco, at a cost of 887.00 ZAR/GJ or 106.48 ZAR/kg, like the cost of current blue hydrogen.

Bhandari et al. [56] calculates green hydrogen production costs in Germany, however on a smaller scale of 8 000 kg of hydrogen per annum, or between 2.6 and 3 MW of power. Although a smaller scale is considered, the methodology remains the same. Bhandari et al, selects the green hydrogen production location based on the proximity to industries which produce and consume hydrogen, as well as the expected demand of 8 000 kg per annum. The demand is then used to size the electrolyser. Bhanderi et al [56] then assumes that the electricity demand required by the electrolyser is supplied by Solar PV. The solar PV data is taken from Meteonorm; however, it is not clear if the solar PV system is sized based on the kW peak of the electrolyser, or the amount of kWh required to produce the required amount of hydrogen. The levelized cost of hydrogen is then calculated based on the initial investment, annual operating costs, a discount rate of 4%, and a system lifetime of 20 years. Of the various scenarios investigated by Bhanderi et al, the off-grid PV and PEM electrolyser is of relevance to this research based on the scenarios that will be investigated. In this configuration, the expected hydrogen production cost is 1 092 ZAR/kg.

The above-mentioned methodologies provide the framework for the methodology adopted in this research. However, as part of this research, more focus is given to the design of the solar system and the variability in the output from the solar plant. Furthermore, as opposed to the above-mentioned methodologies, this research considers alternative scenarios to hydrogen produced by solar alone. These additional scenarios include grid connected systems, where clean energy is bought through power purchase agreements (PPA's) and battery connected systems, where solar systems are oversized, and excess energy production is stored for later use. This research also looks at the variability in the electrolyser's utilisation and the associated change in the LCOH.

4.7. Calculating the Levelized Cost of Energy (LCOE)

The levelized cost of energy (LCOE) is an economic metric which is used to compare alternative methods of energy production. In this case it represents the energy costs involved in green hydrogen production. It can be thought of as the average total cost of building and operating the green hydrogen production plant per unit (in GJ) of green hydrogen produced. The LCOE is calculated as shown in Equation 4 below. The denominator in this equation represents the hydrogen production quantities in kilograms. The numerator of this equation represents all the capital and operating costs associated with green hydrogen production.

Equation 4 - The levelized cost of energy equation

$$LCOE = \frac{I \; + \; \sum_{t=1}^{n} \frac{A_t}{(1+i)^t}}{\sum_{t=1}^{n} \frac{H_t}{(1+i)^t}} \qquad [4]$$

Where I is the initial investment in ZAR, A_t is the annual costs including operation and maintenance, H_t is the hydrogen produced in GJ, n is the system lifespan in years, t –is the time span in years and i

– is the discount rate [56]. Equation 4 is expanded to take into consideration all the fixed and operating costs of a green hydrogen production system as shown in Equation 5.

Equation 5 - The levelized cost equation expanded for a solar and hydrogen combination system resulting in the levelised cost of hydrogen (LCOH)

$$LCOH = \frac{\left(C_s + C_E + C_W + C_B + \frac{\sum_{t=1}^{n}(O_E + O_{O\&M} + O_W)}{(1+i)^t}\right)}{\sum_{t=1}^{n}\frac{(E_S \times \eta_S \times \eta_E) \times \mu_F}{(1+i)^t}} \quad [5]$$

Where the variables are defined as follows; C_s is the capital cost of the solar system. C_E is the capital cost of the electrolyser. C_W is the capital cost of the water system. C_B is the capital cost of the battery system. O_E are the operating expenses due to energy. $O_{O\&M}$ is the operating expense associated with annual maintenance. O_W is the operating expense associated with running the water filtration plant. E_S is the amount of solar energy that can be produced in a year from a given solar system. η_S is the efficiency of the solar system with degradation and additional losses taken into consideration. η_E is the efficiency of the electrolyser. μ_F is the utilisation factor of the electrolyser. The utilisation factor is defined as a percentage of electrolyser utilisation compared to the maximum potential that the electrolyser could operate at. The time frame t is considered as 20 years and a normal discount rate in South Africa is linked to the prime lending rate at 11%. A study done by Glenn Jenkins and Chun-Yan Kou on the economic cost of capital in South Africa found that the cost of capital ranges between 10.7% and 11.87% with a real rate of 11%. The costs associated with design and commissioning are considered as being built into the upfront CAPEX of the project.

On the operations side of a hydrogen production plant, factors taken into consideration, when looking at the levelized cost of hydrogen, include the cost of energy and energy escalation. The cost of energy becomes relevant if energy needs to be used directly from the grid. Energy directly from the grid in South Africa cannot be used to produce green hydrogen, as the grid is primarily powered by coal. A concept known as "wheeling", therefore, becomes important. Wheeling of clean energy is the process where clean energy is produced in one part of the country and consumed and paid for in another location. Essentially this process allows energy consumers to connect to any point in the national grid and consume clean energy that is not produced onsite. Figure 18 below shows how the price of electricity from the grid has continually increased over the last two decades. This is an important consideration when opting for wheeling through the grid. Although the price of the electricity through wheeling is linked to the cost of solar, there are grid administration fees which must still be taken into consideration. When a power purchase agreement (PPA) is signed, the set price of the energy purchased is often linked to Eskom's tariff changes. The commercial sector shows that the Eskom tariff has increased, on average, 12.62% per year since 2003, with the most recent increase being 12.75% in 2025.

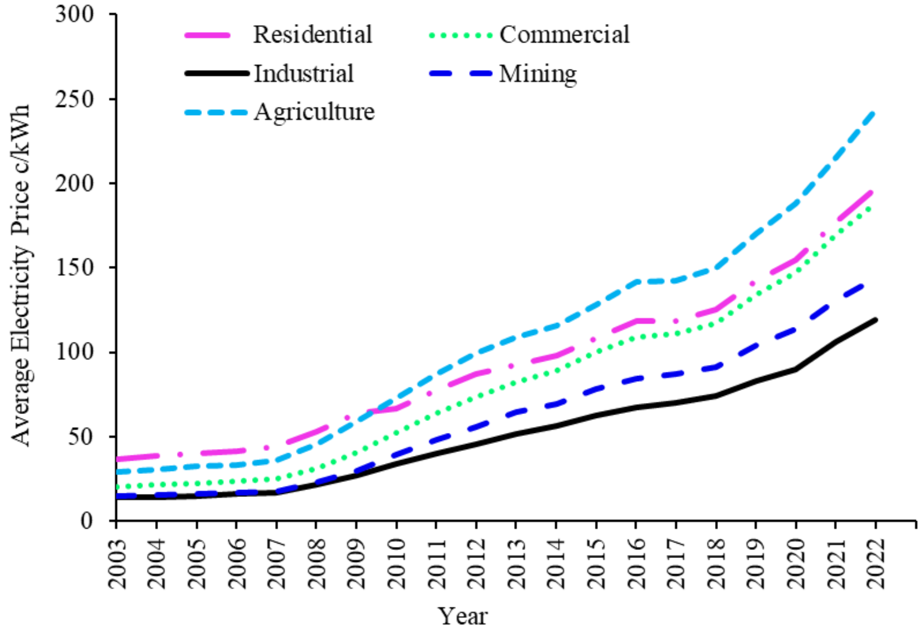


Figure 18 - The average price for electricity supplied by Eskom in c/kWh from 2003 to 2022, showing the increase in electricity cost across various sectors [57].

Less significant factors, such as operations and maintenance costs, are usually linked to a percentage of the CAPEX for the project. This typically varies between 1% and 5% depending on the conditions of the project, such as location and guarantees. This was discussed in detail in section 4.2.1. For hydrogen production projects, the cost of the stack replacement is considered part of the O&M. The discount rate is dependent on the facility that the project is being financed with.

4.8. Sources of water

At least 9 litres of water are required to produce one kilogram of green hydrogen [58]. It is therefore important to consider the source of water to ensure that the process is sustainable. South Africa is inherently a water scarce country. The water supply is therefore considered via reverse osmosis of sea water, which is considered an abundant source. In South Africa there is currently little research into the desalination of water, primarily due to its relatively high cost compared to surface water supply sources. However, with the increasing risks of drought associated with harsh climatic conditions, various municipalities have considered desalination a viable solution. The city of Cape Town released a report on desalination to provide sustainable water in March of 2020 [59]. Various cities in South Africa currently use small desalination plants such as in Mossel Bay, Knysna, Sedgefield and

Plettenburg Bay, to name a few. A study done by Du Plessis et al [60], presents a step-by-step approach to calculating the capital and operating costs of a desalination plant. The main parameters for these cost calculations include: the plant capacity, the required membrane area, and the feed water pressures. Du Plesis et al suggest that the primary operating costs consist of the energy costs. For green hydrogen, this energy must be supplied by a renewable energy source.

For comparison, a summary on international sea water desalination by Karagiannis and Soldatos (2008) is considered [60]. Based on over 100 studies on desalination costs, and for a plant capacity of 100 million litres per day, an estimate of 9.84 per ZAR/m^3 (2008) was calculated. This is equivalent to approximately 20.00 ZAR/m^3 today (2023), with an average of 5.13% inflation per year. The cost of desalinized water in Chile is reported as 50.98 ZAR /m^3, in line with the reported costs by Gallardo [9] and Campero [61].

The water produced at the desalination plant will need to be transported to the electrolysis plant. Ideally the desalination and electrolysis plants are situated near each other to minimise the additional cost associated with pumping the water. Zhou et al [62], have completed an extensive literature review on the costs associated with pumping water. It has been shown that the costs associated with transporting the water is minimal. To move water 100m vertically it would cost less than 1 ZAR/m^3, whilst moving the water horizontally costs less than 1.10 ZAR/m^3 over 100 km. In summary, the cost of desalinating and transporting water would increase the cost of green hydrogen by less than 2% [63], or less than 1.00 ZAR/kg of hydrogen [64] currency conversion of R 18.36 to the dollar.

5. METHODOLOGY

The purpose of this research is to understand the coupling of a hydrogen production system with solar systems to produce green hydrogen. The study's objectives are to:

- Determine the cost of solar energy in South Africa.
- Determine the cost of the equipment required for producing hydrogen in South Africa.
- Determine the operating costs of a hydrogen production plant.
- Determine the final levelized cost of green hydrogen production in South Africa.

With solar power as the primary focus for the source of energy, it is important to understand how much energy could be produced from solar alone, and how this affects the operating parameters of the hydrogen system. Considering that solar cannot provide energy 24/7, alternative options for a hybrid solar and hydrogen production system are considered. These include a battery connected, and a grid connected hydrogen production system. The three scenarios for green hydrogen production are detailed below in section 5.1 and analysed as follows in section 5.2.

5.1. Hydrogen production scenarios considered

5.1.1. Scenario 1

The coupling of a green hydrogen production system with a grid tied solar system, where hydrogen can only be produced when solar energy is available, is shown in Figure 19.

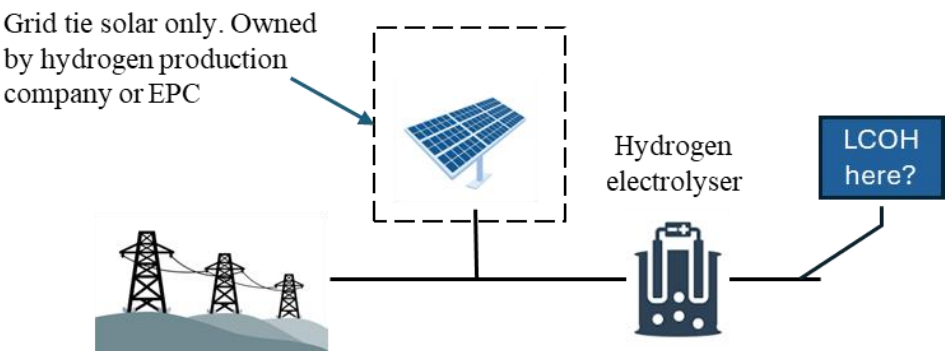


Figure 19 – Schematic representation of production Scenario 1, hydrogen production through solar alone

In this scenario the electrolyser can only be powered when the sun is shining. This means the electrolyser will not produce energy at night and will have reduced production with cloudy weather. In this scenario, the solar energy may be provided by a third-party EPC, where the hydrogen producer buys energy at an agreed rate. Alternatively, the hydrogen production may own the solar system as an asset. This is the most likely scenario, as the energy produced by the solar system is generally less expensive.

5.1.2. Scenario 2

A grid tied hydrogen production system coupled with a solar system, where any additional energy required is wheeled through the grid is shown in Figure 20.

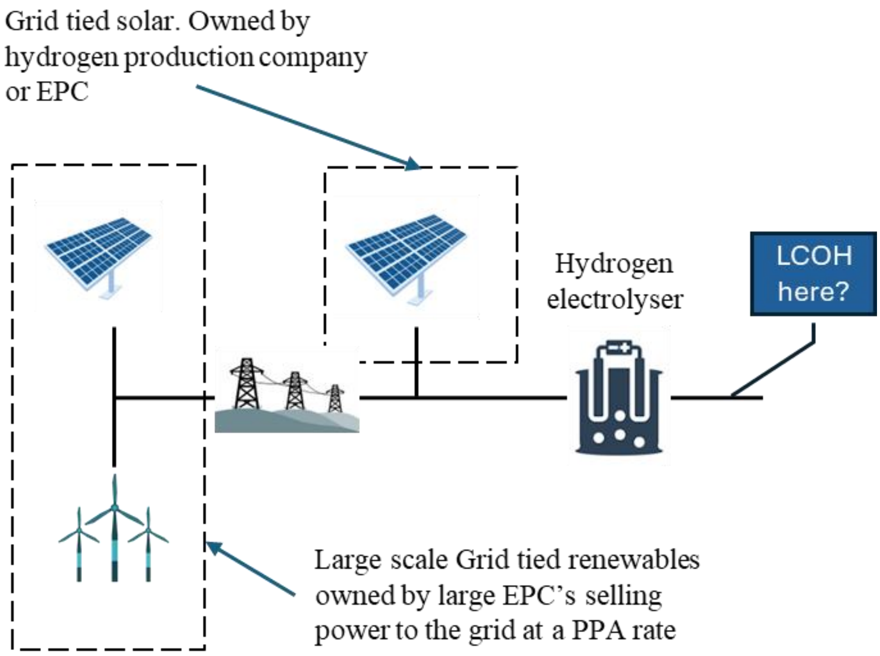


Figure 20 - Schematic representation of production Scenario 2, a grid tied hydrogen production system where wheeling clean energy through the grid is utilised.

In Scenario 2, clean energy is always available. The assumption made here is that at any given time, there will either be wind, solar or an alternative renewable energy source, like hydropower, available to supply the electrolyser. This energy would be procured through the grid, by an agreement with the energy provider. This is known as a wheeling agreement. The energy would be bought through a power purchase agreement (PPA), where the off taker would pay a pre-determined rate to the energy provider. This system would be more beneficial when large quantities of hydrogen are required.

5.1.3. Scenario 3

A stand-alone hydrogen production system coupled with an oversized battery and solar system, capable of supplying all the energy required for up to 100% utilisation is shown in Figure 21 below.

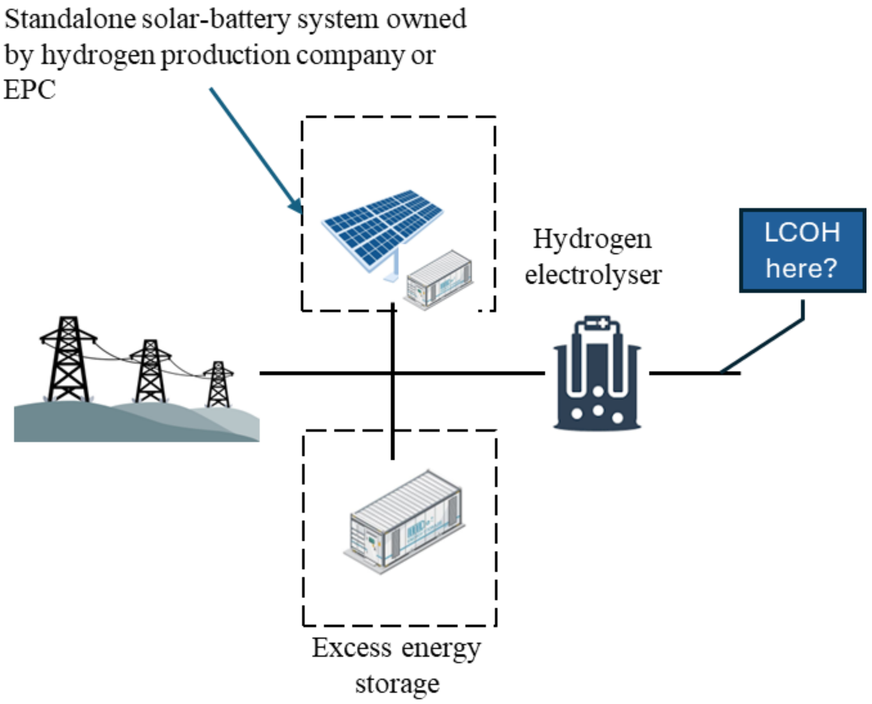


Figure 21 - Schematic representation of production Scenario 3, a standalone hydrogen production system powered by a solar and battery coupled system.

In this scenario, the solar system is oversized so that excess solar energy produced during the day is stored in the battery system. The battery then releases the stored energy when required, to ensure the electrolyser can operate for up to 100% utilisation. This solution would typically be required in remote areas, where access to wheeled energy through the grid is difficult to access. Wheeling energy through the grid for this example would require new grid infrastructure to be built and thus potentially increase the cost of the energy.

5.2. Analysis of the three green hydrogen production scenarios.

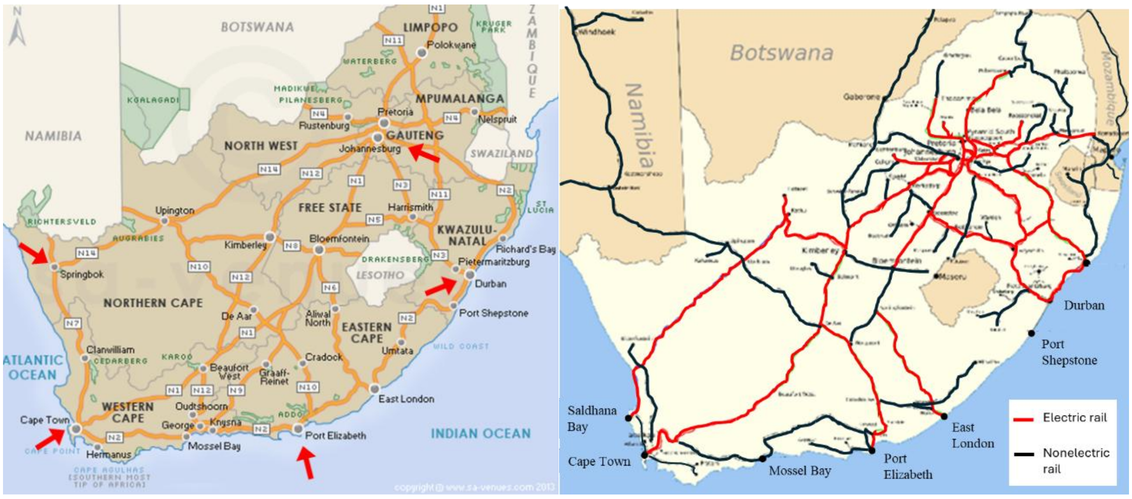
The limitations of Scenario 1, lead to the requirement for additional scenarios. In Scenario 1, hydrogen can only be produced when solar energy is available. This means that the utilisation factor for the electrolyser is very low at 18%, matching the energy availability from solar in South Africa. This is further expanded on in section 5.3.

To improve the electrolyser utilisation and therefore drive the cost of hydrogen down, Scenario 2 is established. In this scenario, the hydrogen electrolyser is connected to an existing solar system which feeds energy into the electrolyser when the energy is available. When solar energy is not available, additional green energy is wheeled through the grid from alternative renewable energy plant such as wind, geothermal, hydro or even battery storage. It is important that this energy is still green and therefore must be from a renewable energy source.

It is not always easy to register for grid wheeling projects and therefore a 3rd option is required, scenario three. Scenario 3 investigates using a hybrid solar and battery system. This system would use an oversized solar system, where the excess energy produced is stored in the battery and then used as needed for up to 100% electrolyser utilisation. During the day, when solar is available, some of the solar energy produced will feed directly into the electrolyser, whilst the remaining energy is stored in the battery onsite. The battery is then be used outside of the hours where energy is available from the sun. At various instances, the solar and battery energy system supplies energy simultaneously to meet the energy needs of the electrolyser.

5.3. Considerations for determining the location of a hydrogen production plant

To understand the levelized cost of green hydrogen production across South Africa, five locations were chosen across the country as suitable for building a solar and hydrogen production plant. The locations chosen are based on access to water along the coastlines and distribution routes such as shipping, trains and road. These locations were selected to represent the whole of South Africa in the modelling of green hydrogen production. In Figure 22(a), the red arrows indicate the five hydrogen hubs selected which include Durban, Gauteng, Port Elizabeth, Saldanha Bay and Springbok. Gauteng was chosen as the only inland location due to its access to potential distribution infrastructure, however it is assumed that water is readily available.



a) b)

Figure 22 – South African Geography being considered. a) Primary Road transport routes in South Africa [65] and b) Primary railroad routes in South Africa [66].

Figure 22 (b) shows that those selected locations are also linked through rail. This infrastructure has the potential to make it easier, cheaper and faster to distribute hydrogen across South Africa. It is most likely that hydrogen produced at the coast would be transported inland due to the need for water in the hydrogen production process through electrolysis.

At the coast, water would typically be used from the ocean and put through a desalination and reverse osmosis process. The primary differentiating factors between the locations is the level of solar irradiance and therefore the energy output from the solar system. Less irradiance means less energy which in turn means less hydrogen. Five benchmark solar energy models were done, one for each location. This was done to determine the potential energy output from each location, and then the average across South Africa. Although location is important for determining the LCOH due to varying irradiance conditions, the cost of storage and distribution of hydrogen across South Africa is not considered part of this research. The cost considered as part of this research is at the output of the electrolyser.

5.4. Benchmark solar system and modelling

The benchmark solar system is required to understand the potential energy output in each location. The benchmark system is then scaled to suit the size of the hydrogen system being investigated. It was assumed that the benchmark solar system used in this study would be designed as a ground mounted system with an ideal module tilt equal to that of the system latitude (ranging from 26 degrees South in Gauteng to 34 degrees South in Cape Town). The system is North facing, and it is assumed that the modules will not cause any shading on each other. This system setup is shown in Figure 23. Furthermore, it was assumed that there is a soiling factor of 5%.

Figure 23 - Example of a ground mounted solar system. Image from Sinani Energy PTY (LTD).

Over the course of the 20-year period the Canadian solar, 545 Wp modules selected will experience a 1st year degradation of 2% and no more than 0.55% per annum thereafter as shown in Appendix A – Canadian solar modules data sheet [67]. A 100 kW AC solar system was selected as a benchmark, with Sungrow being the preferred supplier. The 100 kW solar system was ideally designed with a DC ratio of 1.25 times the AC size of the system. A DC ratio of 1.25 typically allows the system to operate efficiently in summer and winter, without underperforming in the winter months, whilst also not needing to waste energy in summer through throttling. Throttling occurs when there is more power available from the solar modules then can be consumed or produced by the inverter, as discussed in section 4.3.3. Therefore, for a 100 kW AC solar system, 125 kWp of solar panels were required. This benchmark system was modelled in Johannesburg, Durban, Port Elizabeth, Springbok and Saldanha Bay. The benchmark solar system was modelled in the above five locations in PVSol, whilst the TMY dataset was supplied by Meteonorm. The monthly output of these models is shown in Figure 24.

Figure 24 shows the expected energy production in kilowatt-hours for each location selected. More details on the modelling process followed in PVSol can be found in Appendix C – Step by step process for simulating solar models in PVSol. From Figure 24, Port Elizabeth (black) and Durban (dark purple) have the lowest energy outputs over a year followed by Cape Town (light pink) with the 3rd highest. Gauteng (light green) has the second highest energy output at 244,358 kWh per year and Springbok (light blue) in the Northwest producing the highest amount of energy at 252,687 kWh per annum. The average energy output from the above mentioned five systems was then taken as the input into the hydrogen model. This is shown in Figure 25, where the average was determined as 228,275 kWh per annum with an 11% difference from the maximum production in Springbok and a 14% difference from the minimum in PE.

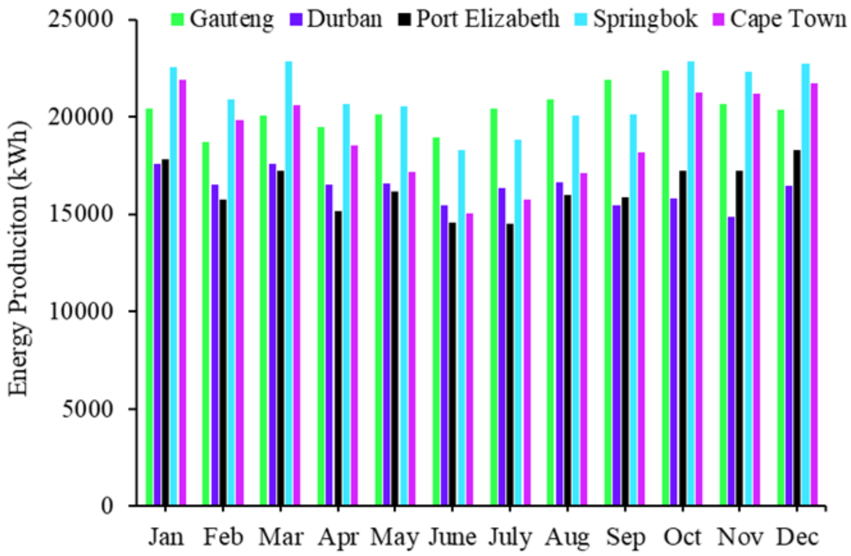


Figure 24 – A monthly energy production comparison for the benchmark solar system modelled across five different locations in South Africa.

Solar engineering companies will typically only guarantee 90% of this value due to uncertainties and variations in the modelled data, as discussed in section 4.5. Therefore, the annual energy considered as the first-year input into the hydrogen model is 201,020 kWh per annum (based on a 90% guarantee) shown in Figure 25.

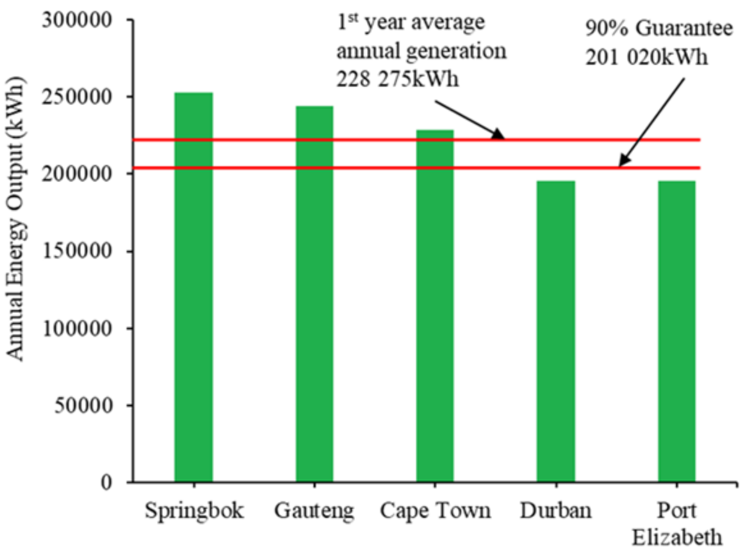


Figure 25 – The average energy production for the benchmark solar model across South Africa.

The guaranteed yield of 201,020 kWh of energy production from the solar system is true for the first year of operation only. Considering the levelized cost is calculated over 20 years, the system degradation with time must be considered.

The reduction of the annual energy output from the benchmark solar system is shown in Figure 26. As previously discussed, the system will have a first-year degradation of 2% and no more than 0.55% per annum thereafter based on the module degradation over a 20-year period (Appendix A). From Figure 26, the average energy output from the solar system over 20 years is 190 516 kWh. This, as a percentage of the total number of available hours in a year, means that on average, a solar system in South Africa will have a utilisation of just over 18%. A utilisation of between 18% and 35% is considered as an achievable operating range on certain days where the irradiance is between 2 900 and 3 300 kWh/m$_2$ or, in scenarios where the system design has been improved with the use of single or dual axis tracking systems s discussed in section 4.3.2.

System Sizing	
System Size kW AC	*100.00*
System Size kW DC	*125.00*

Year	**Year 1**	**Year 5**	**Year 10**	**Year 15**	**Year 20**
January	20 055	19 614	19 062	18 511	17 959
February	18 345	17 942	17 437	16 933	16 428
March	19 668	19 235	18 694	18 153	17 612
April	18 052	17 655	17 158	16 662	16 166
May	18 127	17 728	17 230	16 731	16 233
June	16 443	16 082	15 629	15 177	14 725
July	17 168	16 790	16 318	15 846	15 374
August	18 142	17 743	17 244	16 745	16 246
September	18 311	17 908	17 405	16 901	16 398
October	19 901	19 463	18 916	18 368	17 821
November	19 238	18 815	18 286	17 757	17 228
December	19 905	19 467	18 920	18 372	17 825
Annual Degradation (%)	2.00%	0.55%	0.55%	0.55%	0.55%
Total Annual Output (kWh/year)	223 355	218 441	212 299	206 157	200 015
Annual Specefic Yield (kWh/kWp)	1786.8416	1747.531085	1698.392941	1649.254797	1600.116653
Annual Yield Gaurantee (kWh/year)	201 020	196 597	191 069	185 541	180 013

Committed P50 Yield Guarantee (%)	90.00%

Average energy production over 20 years (kWH)	190 516
Percentage of total hours in a year (%)	18.12

Figure 26 – The benchmark solar system (100 kW AC, 125 kW DC) annual energy output and degradation over 20 years, considering typically guaranteed yields.

5.5. Hydrogen system and modelling

Different methods of electrolysis have been considered here. The electrolysis types considered include alkaline electrolysis, polymer electrolyte membrane electrolysis, solid oxide electrolysers and anion exchange membrane electrolysis, which are covered in more detail in section 4.2. AEM electrolysers were selected as the most suitable for being coupled with renewable energy systems due to their ability to start up at lower input currents, as well as their flexibility in terms of operating range. The AEM electrolyser is suited to an environment where the power source is not constant, which is predominantly expected in Scenarios 1 and 3. Furthermore, although alkaline electrolysers are currently the cheapest due to their larger market share, AEM electrolysers are becoming more popular due to their fast reaction times to intermittent renewable, use of non-noble metals, high energy density, no need for a corrosive electrolyte as with alkaline electrolysers and an increase in manufacturing capacity.

With the method of electrolysis selected data was sourced that explained the operating parameters of the electrolysers. Various suppliers were considered such as Siemens, Cummins, Nel Hydrogen, SinoHy Energy, Linde, Hydrox Holdings, Enapter and Sungrow. Enapter was selected as the supplier of choice due to the amount of information available on the equipment as well as the flexibility Enapter provides in terms of system sizing**.** This supplier is selected for the purpose of this research however, alternative suppliers may be selected in South Africa based on real world applications and equipment availability at the time of the project.

Enapter uses a modular approach where any electrolyser sizes can be built by combing their EL4.1 hydrogen electrolyser. These 2.4 kW units can be used as building blocks to form any size electrolyser required. Three different hydrogen electrolyser sizes were then investigated, including a 2.4 kW electrolyser, a 120kW electrolyser and a 500kW electrolyser. The 500 kW electrolyser was considered as the upper limit for the purpose of this investigation. This is primarily due to the technical and financial information available on these size electrolysers. The amount of hydrogen produced from an electrolyser is calculated using equation 1, repeated below for reference.

$$kg_{H2} = \frac{kWh\ supplied}{53.3\,\frac{kWh}{kg}} \qquad [1]$$

The kWh supplied is the output from the solar system model. The denominator is the efficiency of the electrolyser, which for the Enapter electrolyser is 53.3 kWh per kg of hydrogen produced. The process followed for calculating hydrogen output in kilograms described by Table 2 below. More details on the Enapter electrolysers can be found in Appendix D.

From Table 2, step 1 is selecting the electrolyser size. In this example the electrolyser is 500kW. From the Enapter data sheets (Appendix D), the efficiency of that electrolyser is taken as 53.3 kWh/kg of hydrogen as shown in line 2. The assumed electrolyser capacity in this scenario as shown in line 3 is 50%. This means the electrolyser will run for 50% of the 8760 hours in a year (a total of 4380 hours). The next step is to calculate the amount of energy required for a 500kW electrolyser to run at 50% utilisation for one year. This is calculated by multiplying line 1 by line 3 and then multiplying by the number of hours in a year. In this scenario, 2190MWh of energy are required to run a 500kW electrolyser at 50% utilisation for one year. Lines 5 and 6 are for information and show the efficiency of the process based on the heating value of hydrogen used. Line 7 is calculated using equation 1 above. The total amount of solar energy divided by the electrolyser efficiency results in the number of kilograms of hydrogen that can be produced. In this case, 41,088.2kg of hydrogen will be produced in one year as shown in line 7. Line 8 and 9 show different metrics of hydrogen production quantity, including kilograms per day and kilowatt hours per day.

Table 2 **-** A step by step breakdown for calculating hydrogen production quantities in kilograms and the associated energy requirements.

	Electrolyser Specifications		
1.	Electrolyser capacity	500.00	kW
2.	Electricity required per kg H_2 produced (Efficiency – energy required per kg of H_2)	53.30	kWh per kgH_2
3.	Utilisation Factor (UF)	50%	Average annual capacity utilisation
4.	Annual electricity required (supplied from solar)	2 190.00	MWh
5.	Electrolysis efficiency, stack (HHV)	73.92%	(HHV: 1 kgH2 = 39.4 kWh)
6.	Electrolysis efficiency, stack (LHV)	62.48%	(LHV: 1 kgH2 = 33.3 kWh)
	Hydrogen output calculation		
7.	Hydrogen production in kilograms per year	41 088.20	kgH_2 / year
8.	Hydrogen production in kilograms per day	112.60	kgH_2 / day
9.	Energy available from produced hydrogen per day	3 748.60	kWh per day (LHV)
10.	Balance of system (BoS) load	10.0%	% of total system load to losses

11.	Connection capacity	550.0	kWac – minimum AC power required
12.	Annual electricity consumed by system	2 409 000.00	kWh
13.	Electricity required per kg H2 (system)	59.20	kWh per kgH_2
14.	Electrolysis efficiency, system (HHV)	66.53%	(HHV: 1 kgH_2 = 39.4 kWh)
15.	Electrolysis efficiency, system (LHV)	56.23%	(LHV: 1 kgH_2 = 33.3 kWh)
	Electricity required renewable power capacity:		
16.	Capacity of renewable power required	1 264.00	kW_{DC}

Next, the size of the renewable energy system required to produce the necessary amount of hydrogen is calculated. In line 10, the balance of system power is considered, which allows for additional loads such as pumps, fans, compressors and any additional loads required to run the system. The loads typically account for up to 10% of the electrolyser size. Therefore, the total connection capacity is calculated as 550 kW as shown in line 11 and the annual energy consumption is calculated in line 12 as 2 409 000 kWh. From the benchmark calculations in section 5.4 it is known that a standard 100 kW solar system can reliably produce 190 516 kWh per annum. Therefore, a 1264.45 kW solar system is required to meet the electrolysers energy demands. It is important to note that if the electrolyser was to be run at a load factor close to a solar system current availability factor (18-35%), then the solar system size required would equal the size of the electrolyser. The above method was followed for utilisation factors ranging from 0% – 100% for all three scenarios being investigated. The below summarises the key steps considered:

1. Select the electrolyser side that needs to be investigated
2. Based on the electrolyser size and utilisation factor being investigated, calculate the energy requirements.
3. Calculate the amount of hydrogen produced per annum for the selected electrolyser size at the specified utilisation factor.
4. Account for the systems balance of power energy consumption.
5. Size the renewable energy system required based on the known benchmark solar system design and annual energy output.

Following the process of calculating the hydrogen production quantity and sizing the solar system required, the LCOH can be calculated as follows in section 5.6.

5.6. Calculating the Levelized Cost of Hydrogen (LCOH)

The levelized cost of hydrogen is an economic metric which is used to calculate the selling price of hydrogen that is required to ensure the stakeholders minimum percentage return on investment is realised. In this case it represents the cost of the energy that the green hydrogen can provide once it has been produced. It can be thought of as the average total cost of building and operating the green hydrogen production plant per unit (in GJ) of green hydrogen produced. The LCOH is calculated using equation 5, repeated below for reference. This equation is explained in detail in section 4.7.

$$LCOH = \frac{\left(C_s + C_E + C_W + C_B + \frac{\sum_{t=1}^{n}(O_E + O_{O\&M} + O_W)}{(1+i)^t}\right)}{\sum_{t=1}^{n}\frac{(E_S \times \eta_S \times \eta_E) \times \mu_F}{(1+i)^t}} \quad [5]$$

To investigate the levelized cost the capital and operating costs for the full system must be understood. Therefore, an in-depth study into the equipment and operational costs of a solar and hydrogen system were conducted, as discussed in sections 4.2, 4.3.6, 4.4 and 4.8. Equipment suppliers from the solar industry such as Sungrow, Huawei, SMA and SolarEdge were investigated for local availability and cost. The same process was followed for electrolyser suppliers such as Siemens, Cummins, Nel Hydrogen, SinoHy Energy, Linde, Hydrox Holdings, Enapter and Sungrow however limited data was available on electrolyser CAPEX costs from suppliers. CAPEX costs were found for the Enapter electrolysers of 2.4 kW, 120 kW and 500 kW. This data was used as the primary CAPEX input. These costs were compared to existing research on electrolyser CAPEX costs. The full range of costs was then considered as part of the uncertainty analysis in section 6.6.1. Costing data from these suppliers were then amalgamated and reduced to a rand per kilowatt value (ZAR/kW). It was assumed that water was readily available and therefore the CAPEX associated with water (C_W) is considered as 0. With the solar availability and costing parameters defined, the variables which affect the levelized cost of hydrogen were then investigated. These benchmark variables for a 500 kW electrolyser are summarised in Table 3 below.

Table 3 - List of variables considered in the LCOH calculations for a solar hybrid hydrogen production system.

Variables	**Quantity**	**Units**
Electrolyser System CAPEX - $\mathbf{C_E}$	42 000.00	ZAR/kW
Solar System CAPEX - $\mathbf{C_S}$	12 500.00	ZAR/kW_p
Battery system CAPEX - $\mathbf{C_B}$	7 500.00	ZAR/kWh
Water system CAPEX - $\mathbf{C_W}$	0.00	ZAR/L
Solar system energy production - $\mathbf{E_S}$	190 516.00	kWh

Solar System Annual Degradation - $\boldsymbol{\eta_S}$	0.55	%
Electrolyser Annual Degradation - $\boldsymbol{\eta_E}$	0.15	%
Energy Cost - $\mathbf{O_E}$	2.00	R/kWh
Annual Energy Escalation	7.00	%
O&M Cost - $\mathbf{O_{O\&M}}$	1.00	%
O&M escalation	7.00	%
Water Usage	25.00	L/kg_{H2}
Water cost - $\mathbf{O_W}$	44.00	R/m^3
Cost of Capital - **i**	11.00	%
Stack Lifetime	80 000.00	Full Load Hours
Plant Life – **t**	20.00	Years
Utilisation factor - $\boldsymbol{\mu_F}$	0-100	%

These variables were used to investigate the levelized cost of the three scenarios described in section 5.1. Each scenario was tested with a 2.4 kW, 120 kW and 500 kW electrolyser for an electrolyser utilisation range of 0 to 100%. The specific scenarios are discussed in further detail in sections 5.6.1 to 5.6.3.

5.6.1. LCOH for Scenario 1

In Scenario 1, a solar system is directly coupled with an electrolyser, meaning the electrolyser can only produce hydrogen when the solar system is operating. Equation 5 is therefore modified as follows, with the CAPEX for the battery system (C_B) and the operating expenses associated with energy use from the grid (O_E) removed, resulting in equation 6 below.

$$LCOH = \frac{\left(C_s + C_E + C_W + \frac{\sum_{t=1}^{n}(O_{O\&M} + O_W)}{(1+i)^t}\right)}{\sum_{t=1}^{n} \frac{(E_S \times \eta_S \times \eta_E) \times \mu_F}{(1+i)^t}} \qquad [6]$$

The levelized cost of hydrogen is then calculated over a 20-year period. With each increment in year the O&M costs are increased by 7% and the solar system and hydrogen system degradation is incorporated by decreasing η_S and η_E by 0.55% and 0.15% respectively. The utilisation factor μ_F, is varied from 0 – 100% to understand how the levelized cost varies with electrolyser utilisation. Based on the electrolyser size, the electrolyser CAPEX is determined. The solar system size required is determined based on the electrolyser utilisation as discussed in section 5.5. The output of this scenario is the levelized cost of hydrogen for an electrolyser utilisation range of between 0 and 18%, with a possible extension to 35% utilisation if the solar system designs were improved on as discussed in section 5.4 (based on the benchmark system) and section 4.3.2.

5.6.2. LCOH for Scenario 2

Scenario 2, focuses on a hydrogen system powered by a solar system and the grid. The CAPEX of the battery is therefore removed from equation 5, resulting in the below modified equation 7. The cost of energy O_E is now included.

$$LCOH = \frac{\left(C_s + C_E + C_W + \frac{\sum_{t=1}^{n}(O_E + O_{O\&M} + O_W)}{(1+i)^t}\right)}{\sum_{t=1}^{n} \frac{(E_S \times \eta_S \times \eta_E) \times \mu_F}{(1+i)^t}} \qquad [7]$$

Scenario 2 looks at the combination of a solar system and a hydrogen electrolyser that are also connected to the grid. Because this research focuses on green hydrogen specifically, it is assumed that clean energy can be wheeled through the grid to supply energy to the electrolyser. This green energy is typically supplied by wind or energy stored in batteries. Using the same methodology as in Scenario 1, three different electrolyser sizes are investigated with the required solar system size. Whilst the electrolyser runs off solar during the day the cost of energy is a function of the CAPEX and OPEX of the system whilst when the solar power is not available the cost of energy is determined by what is supplied through the grid. Grid electricity costs of 1.00 to R2.50 ZAR/kWh were investigated. where 2.50 ZAR/kWh is on the higher end of the current cost of electricity as shown in section 4.7. Wheeling clean energy through the grid is typically considered cheaper, with rates between 1.00 and 1.40 ZAR/kWh to be expected. Various graphs were then plotted showing the overall system levelized cost against the utilisation of the system.

5.6.3. LCOH for Scenario 3

Scenario 3 looks at the combination of a solar system, a hydrogen electrolyser and a battery energy storage system. Equation 5 is therefore modified to include the CAPEX costs of the battery, whilst the cost of energy is now removed, resulting in equation 8 below.

$$LCOH = \frac{\left(C_s + C_E + C_W + C_B + \frac{\sum_{t=1}^{n}(O_E + O_{O\&M} + O_W - O_{OXY})}{(1+i)^t}\right)}{\sum_{t=1}^{n} \frac{(E_S \times \eta_S \times \eta_E) \times \mu_F}{(1+i)^t}} \qquad [8]$$

In this scenario, the solar system is sized to provide the hydrogen electrolyser with energy 24/7. Therefore, the solar system is oversized compared to the size of the electrolyser and the battery is sized to store all the excess energy production from the solar system during the day. The battery will then discharge when solar power is not available, allowing the hydrogen electrolyser to continuously produce hydrogen. Using the same methodology as in the previous scenarios, three different electrolyser sizes were considered, whilst the solar system size and battery size were varied based on the required utilisation of the electrolyser. Lower utilisation requirements mean smaller solar systems and batteries. The CAPEX of the battery system was considered as a rate per kWh of energy storage required, similarly to the solar and hydrogen systems.

5.7. Scenario summary

The levelized cost of energy from green hydrogen production is determined for each of the three scenarios mentioned above. The LCOH is determined using equation 5 in its modified format for each scenario. Inputs into the levelized cost include capital costs, operation and maintenance costs and resources costs as previously discussed. These costs are calculated for each scenario and are compiled into a single cost measured in ZAR/GJ or ZAR/kg of hydrogen produced. This levelized cost is then critically evaluated as discussed in section 6. For all three scenarios mentioned above an uncertainty analysis was then conducted based on the variable ranges identified in the literature review. These are summarised in Table 4 of section 6.6.1. A sensitivity analysis was then conducted to determine which variables in the levelized cost calculations have the greatest influence on the final levelized cost as discussed in section 6.6.2. This was done to understand where the most impact could be made in driving the cost of hydrogen down.

6. RESULTS AND DISCUSSION

This research is focused on understanding the financial feasibility of coupling hydrogen electrolysers with solar energy, for the purpose of producing green hydrogen. The primary metric being investigated is the levelized cost of the hydrogen (LCOH). Three scenarios for three electrolyser sizes have been considered with distinct energy sources.

6.1. Characteristic LCOH

Before considering the three proposed scenarios, it is considered useful to first consider a characteristic LCOH. When considering how the LCOH varies with an electrolyser's utilisation, a characteristic curve is developed, as shown in Figure 27. The utilisation of the electrolyser is measured as a percentage of the total potential operating hours in one year, where 100% utilisation would be 24 hours a day for seven days a week for 365 days a year (8760 hours). There are two fundamental contributors to the LCOH shown in Figure 27. The first is the capital expenditure, shown in green. This is the expenditure required to design, procure, build and commission the plant. The second contributor is the cost of energy, shown in purple. This is considered an operating cost of the plant and is a function of the type of energy used to power the plant. For example, energy supplied from the grid may be more expensive than energy supplied through a power purchase agreement from a renewable energy provider. A power purchase agreement is a contract setup between a client and a solar company, where the client agrees to buy solar energy from the solar company at a set or linked price. The linked price is linked to the tariff set by Eskom and will increase by the same percentage as the Eskom tariff increase. This would typically happen because the rates set by Eskom, and their predominantly coal based energy system, cannot compete with the cost of solar energy. The client would recognise significant saving on their energy bill by buying energy from a solar plant. The same is true for powering a hydrogen electrolyser. Lower energy costs result in lower hydrogen costs. The cost of energy has a varying effect on the hydrogen cost, depending on how the electrolyser is being utilised. As shown in Figure 27, it is generally understood that at lower electrolyser utilisation levels the capital expenditure is the dominant factor in determining the LCOH, as shown in green. When the hydrogen demand from the plant is increased and the electrolyser utilisation increases, CAPEX plays less of a role and the cost of energy becomes a more significant factor, as shown in purple. At low utilisation levels, the electrolyser consumes less energy and therefore the LCOH is made up of predominantly CAPEX related costs. At higher utilisation levels, more energy is consumed, therefore the initial CAPEX gets shared between more kilograms of hydrogen and the cost of energy becomes a predominant factor in the LCOH.

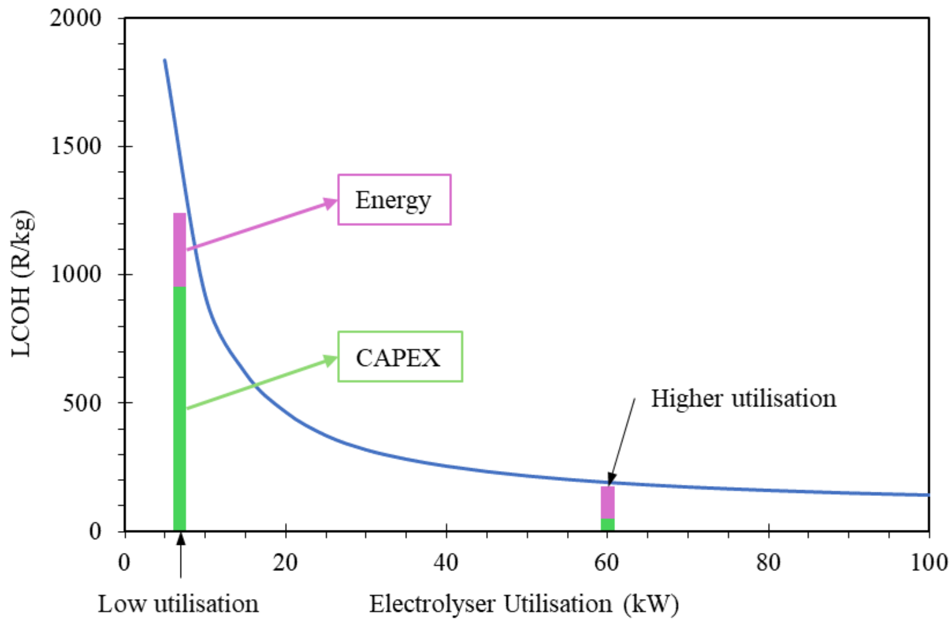


Figure 27 - The characteristic levelized cost of hydrogen curve for an electrolyser, indicating high CAPEX costs and low energy costs at low utilisation, in contrast to high utilisation.

6.2. Results and discussion of Scenario 1

The effect of coupling a solar system with an electrolyser as in Scenario 1 is shown in Figure 28. Figure 28 follows the characteristic curve as shown in Figure 27, with high LCOH at low utilisation levels and decreasing LCOH with increasing electrolyser utilisation. Figure 28 describes the LCOH for varying utilisation levels of a 500 kW electrolyser only, with a focus on utilisation levels between 5% and 35%. The lower limit of 5% is dependent on the electrolyser selected. Specifically, the Enapter electrolyser has a minimum startup load of 5% utilisation as shown in Appendix D – Enapter electrolyser data sheet. A utilisation of between 5% and 18% is considered as the most likely operating range for the AEM electrolyser powered by solar alone with 18% being the upper limit for an average solar system in South Africa, as discussed in section Benchmark solar system and modelling5.4. A utilisation of between 18% and 35% is considered as an achievable operating range on certain days where the irradiance is between 2 900 and 3 300 kWh/m^2 or, in scenarios where the system design has been improved with the use of single or dual axis tracking systems. Improved designs were discussed in section 4.3.2 with the limitations of the solar system size.

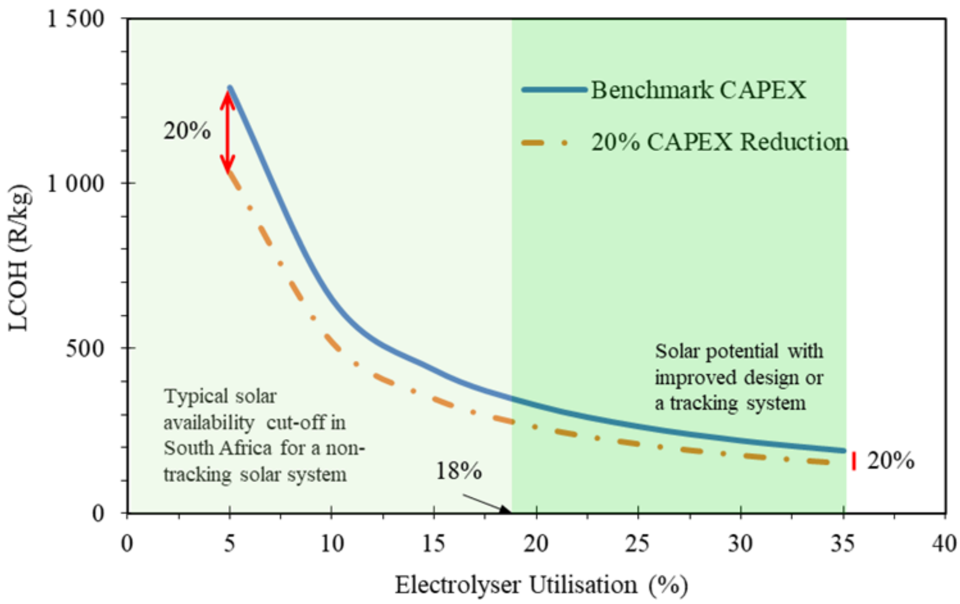


Figure 28 - Hydrogen electrolyser utilisation when coupled with a solar system only

Based on the benchmark solar system model, the solar system is sized for the electrolysers load and therefore the electrolyser utilisation is capped at a maximum of 35% to avoid throttling. Throttling is further discussed in section 4.3.2. In scenario one, the electrolyser only runs when the solar is available and the output of the electrolyser is dependent on the time of day. At 18% utilisation the lowest LCOH achievable is 387.02 ZAR/kg of hydrogen produced. If the solar system design was improved with, for example, a tracking system, or the system experienced high levels of irradiation, yields from the solar energy could be as high as 35% - depicted as the darker green section in Figure 28. The LCOH then decreases to 189.77 ZAR/kg. This 60% reduction in LCOH can only be realised if the initial CAPEX of the system remains the same and the overall performance of the system improved due to higher irradiance levels. If the designs were upgraded to incorporate tracking of the sun, the CAPEX would increase and the reduction in LCOH would not be as high.

Additional improvements to the LCOH could be realised if the initial CAPEX was reduced. A report on renewable energy costs by the International Renewable Energy Agency (IRENA) has shown that cost of solar modules has fallen 80% since 2010 and learning rates of between 18 to 22%. The learning rate is defined by IRENA as the percentage reduction in cost for every doubling of cumulative capacity installed [68]. Wood Mackenzie estimate that the global installed solar capacity will at least triple over the next 10 years [69]. CAPEX costs for electrolysers are still considered on the high end of the scale at the time of writing however (2024). In the short-term IRENA suggest that a 40% reduction could be expected and up to an 80% reduction in the long term.

Based on the above mentioned, it is more than likely that the CAPEX for hydrogen production systems could be reduced by 20% within the next 10 to 30 years. The effect of this is represented by the orange dotted line in Figure 28. With this decrease in CAPEX, the LCOH for the entire system would drop by the same 20%. At 18% utilisation the price would drop from 387.02 ZAR/kg to 296.00 ZAR/kg at 35% utilisation, the LCOH would drop from 189.77 to 152.05 ZAR/kg. This is a characteristic indicative of an electrolyser powered by solar alone. The cost of hydrogen produced by electrolysis at low utilisation levels, depends heavily on the CAPEX spent on the system. Considering the solar alone is the source of energy, the reduction in energy costs at higher utilisation levels is directly linked to the initial CAPEX spent on the system.

The effect of improving the energy output efficiency of the solar plant has a large influence on the LCOH. Figure 29 shows the relationship between the electrolyser size and the LCOH, for improving solar energy availability factors. The effect of improving the solar systems energy efficiency was investigated for three electrolysers sizes, including a 2.4 kW, 120 kW and 500 kW electrolyser. The available energy from the solar system was then varied from 18% (the average in South Africa) to 25% as a midpoint and 35% as the maximum. As previously discussed, these higher energy availability factors may be reached with improved plant design or in locations where the irradiance factors are higher, like in the Northwest.

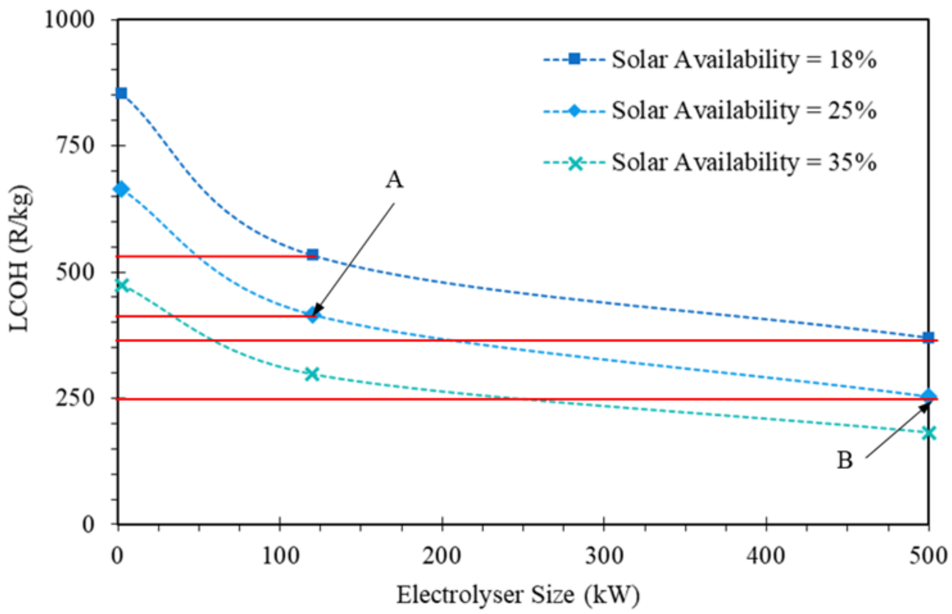


Figure 29 - The effect of increasing solar availability from 18% to 35% on the LCOH for an electrolyser powered by solar alone.

From Figure 29, detail A shows that a 120 kW solar system would see a 22% reduction in LCOH due to a 7% improvement in the solar system energy output. This is a reduction from 534.00 ZAR/kg to 416.00 ZAR/kg. For the same 7% improvement in solar energy output, a 500kW electrolyser would realise a 32% reduction in LCOH, a reduction from 370.00 ZAR/kg to 250.00 ZAR/kg as shown by detail B. Figure 29 shows that a lower LCOH can be achieved with an increased solar energy efficiency and, that the benefit is greater for larger electrolyser plants.

Figure 29 shows that to achieve the target cost of current blue hydrogen in South Africa, at 131 ZAR/kg, electrolysers larger than 500 kW will be required, or the electrolyser utilisation level must be improved. Larger electrolysers were not investigated as part of this study due to the limited amount of data available on pricing and availability. However, extrapolating from Figure 29, at the current cost of solar, at least a 1 800 kW electrolyser system would be required to match the cost of blue hydrogen. This is based on a logarithmic trend with an R^2 value of 0.98. Alternatively, the electrolyser utilisation can be improved by considering a grid connected electrolyser system, where clean energy is wheeled through the grid, as per scenario two.

6.3. Results and discussion of Scenario 2

Scenario 2 focuses on improving the electrolyser utilisation by connecting the system to the grid. Energy through the grid must be bought from a renewable energy supplier through a power purchase agreement (PPA), to ensure the hydrogen remains green. Energy may also be bought or used from solar systems that are installed but are throttling. Throttling was previously described by Figure 14.

In this scenario the solar system would be allowed to feed all its excess energy into the grid. This excess energy would then be used to convert electricity into hydrogen which can be stored for later use, instead of the energy being wasted or not utilised. The alternative option is to buy the energy through a PPA from independent renewable energy suppliers, such as from wind farms or large solar and battery storage systems. As shown in Figure 27, the cost of energy has a greater impact on the cost of green hydrogen at higher utilisation levels. To improve the utilisation factor of the electrolyser and thus reduce the LCOH, it is important to find a source of cheap reliable and clean energy to produce green hydrogen.

Figure 30 shows how the LCOH varies for different electrolyser sizes connected to a solar plant and the grid. The energy from the grid will be required when the solar cannot provide enough energy to sustain hydrogen production at higher utilisation levels. The limit of solar production is considered as 18% considering the benchmark solar system. It is assumed the solar system has not been modified for improved output. The electorlsyers performace at higher utilisation levels is expanded on in Figure 31 based on the price of electricty consumed.

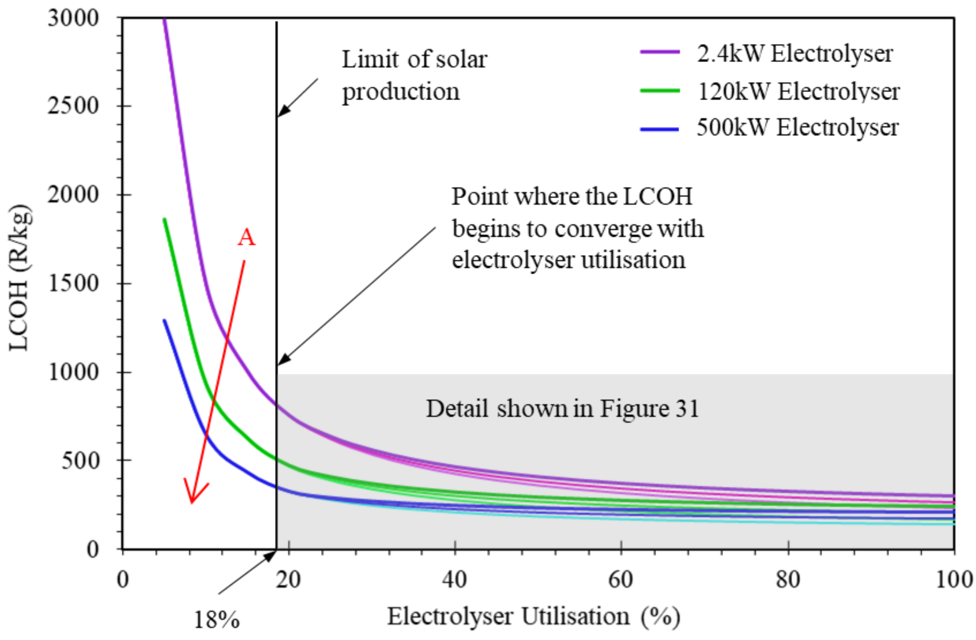


Figure 30 – Figure showing the effect of increasing the electrolyser size on the LCOH

Referring to detail A in Figure 30, increasing the electrolyser size has a positive impact on reducing the LCOH, however this benefit is reduced at higher utilisation levels. It is shown that as the grid takes over from the solar, the LCOH of the different electrolyser sizes begin to converge. This occurs because it is assumed that the cost of energy from the grid does not change based on the utilisation factor. This assumption is made based on the typical structure of PPA models. Typically, a PPA rate is agreed upon at a constant rate per kilowatt-hour of energy consumed. More details on PPA's and pricing models are explained by the World Business Council for Sustainable Development [70]. The lines converge as the cost of energy becomes the more prominent factor in determining the cost of the hydrogen. Figure 31 shows a more detailed view of the grid powered portion of the electrolyser, with the effect of reducing the cost of energy.

Figure 31 compares three different electrolyser sizes with three different costing scenarios, with energy costs of 1.00, 1.50 and 2.00 ZAR/kWh, based on the grid energy prices described in section 4.7. These are the likely rates that energy could be bought at however, renewable energy is often cheaper and rates as low as 1.00 ZAR/kWh may be realised. The general trend is that the larger the electrolyser the lower the LCOH with increasing electrolyser utilisation. Furthermore, the lower the cost of energy the lower the LCOH with increasing electrolyser utilisation.

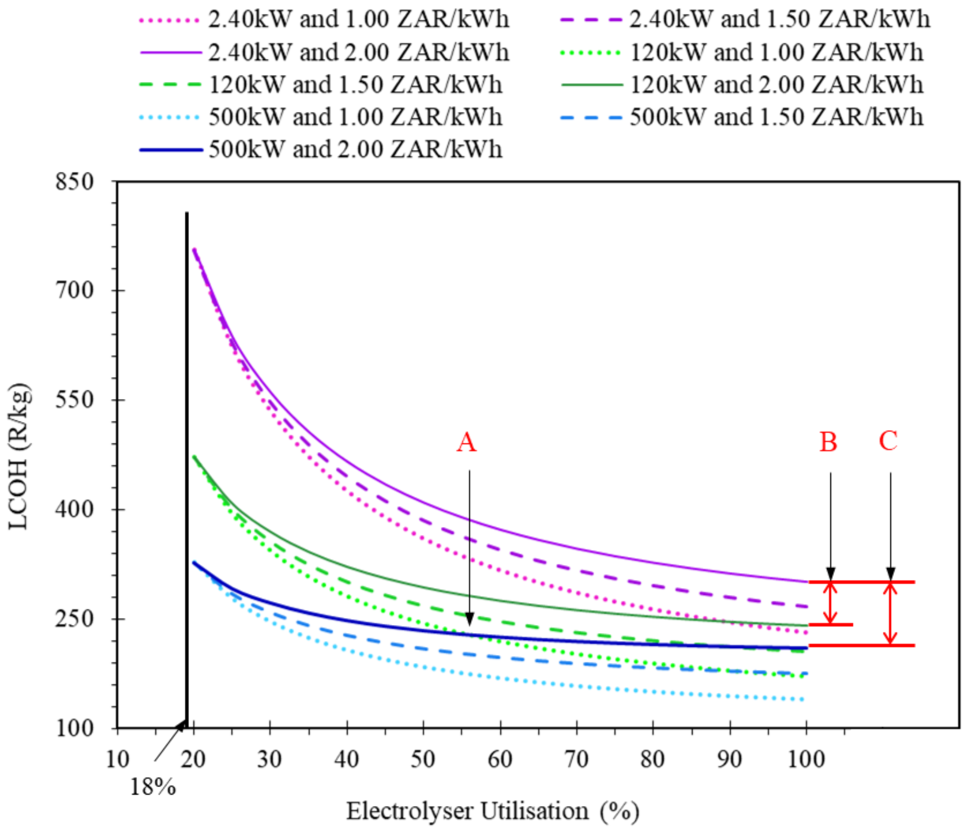


Figure 31 - A detailed view of the grid powered section of an electrolyser, showing the effect of a reduction in energy costs from 2.00 ZAR/kWh to 1.00 ZAR/kWh.

Detail A in Figure 31 shows that a 120 kW electrolyser could be used to produce hydrogen at the same LCOH as a 500 kW electrolyser given that the cost of energy was reduced from 2.00 ZAR/kWh to 1.00 ZAR/kWh. At this intersection point labelled A in Figure 31, the LCOH is 230.00 ZAR/kg at 55% utilisation. Although a lower initial CAPEX may be realised by reducing the size of the electrolyser, it must be taken into consideration that a 12 0kW electrolyser running at 56% utilisation will not produce the same quantity of hydrogen as a 500 kW electrolyser running at 56% utilisation. Therefore, a hydrogen production system must always first be sized based on the hydrogen demand. Detail B shows that for an energy cost of 2.00 ZAR/kWh, the LCOH drops by 60.00 ZAR/kg when the electrolyser size increases from 2.4 kW to 120 kW at 100% utilisation. For the same energy cost at 2.00 ZAR/kWh, further increasing the electrolyser size from 120 kW to 500 kW results in a 30.00 ZAR/kg reduction in LCOH for a final LCOH of 210.00 ZAR/kg at an energy cost of 2.00 R/kWh. Therefore, a 316% increase in electrolyser size, from 120 kW to 500 kW resulted in a 13% overall reduction in LCOH. Looking in more detail into the effect of decreasing energy costs, Figure 31 is focused on for a utilisation range of 30 to 100% as shown in Figure 32.

Figure 32 below focuses on two things. One, increasing the size of the electrolyser reduces the LCOH but the effectiveness in reducing the LCOH converge with increasing electrolyser utilisation. This is shown by the solid purple, green and blue lines converging with increasing utilisation. This further indicates that the CAPEX of the hydrogen production system becomes less important with increased utilisation.

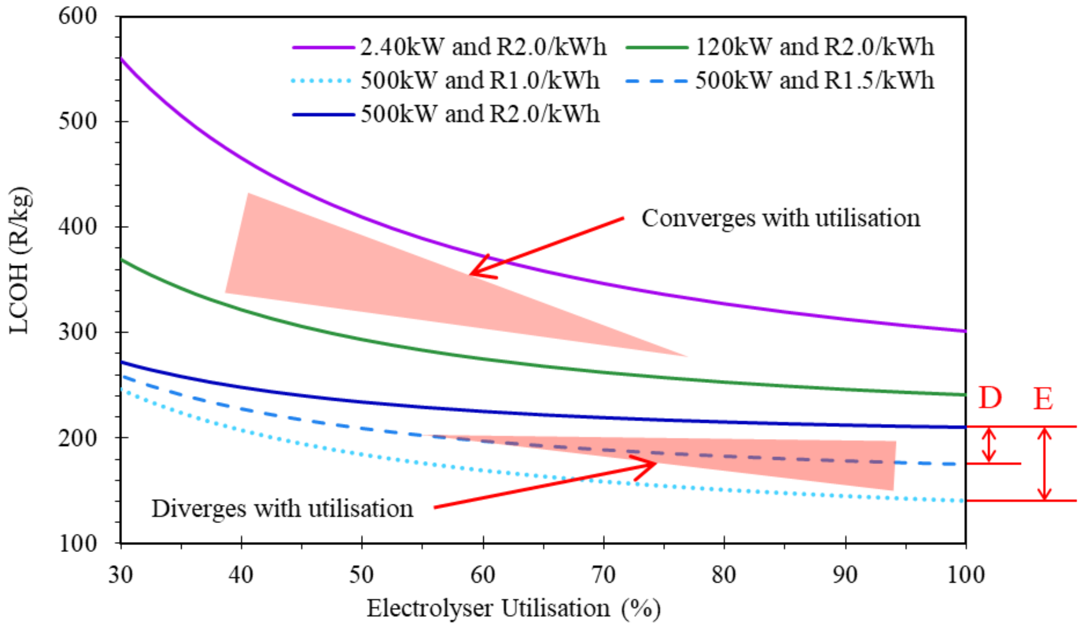


Figure 32 – A detailed view of the 30% to 100% electrolyser utilisation of the grid connected hydrogen system.

Looking at detail D in Figure 32, reducing the cost of energy by 25%, from 2.00 ZAR/kWh to 1.50 ZAR/kWh, results in a decrease in the LCOH of 16.6%. Detail E shows that reducing the energy cost by 50%, from 2.00 ZAR/kWh to 1.00 ZAR/kWh, results in a decrease in the LCOH by 33.3%. The minimum LCOH achieved in this scenario is 140 ZAR/kg by the 500kW electrolyser at an energy tariff of 1.00 ZAR/kWh. From the blue lines in Figure 32, as the cost of energy decreases from 2.00 ZAR/kWh to 1 ZAR/kWh, the resulting LCOH diverges with increasing utilisation. Therefore, at high utilisation levels, the most important factor for reducing the LCOH is the cost of energy. Scenario 2 has shown that the cost of energy is one of the most important factors in determining the LCOH at higher utilisation levels, and not necessarily the size of the system. Furthermore, a hydrogen production system should always be sized based on the hydrogen demand first, and not on the best-case cost scenario.

6.4. Results and discussion of Scenario 3

In certain cases, it is not possible to use the grid as an additional source of energy. This may occur when there are no wheeling agreements in place, the grid is not stable, or the grid is only powered by coal or alternative non-renewable sources of energy. In this case it would be useful to investigate the coupling of hydrogen production system with a stand-alone solar system connected to a battery system. The solar system is then oversized compared to the electrolyser so that the additional energy produced is stored in the battery. The electrolyser then runs off the battery when the sun is not available. This process of oversizing the solar system is also described by Figure 14. In this case, instead of throttling the system is allowed to produce energy, and all the energy between the orange and green line is then stored by the battery. Figure 33 shows the effect of connecting the hydrogen electrolyser to a combined solar and battery grid.

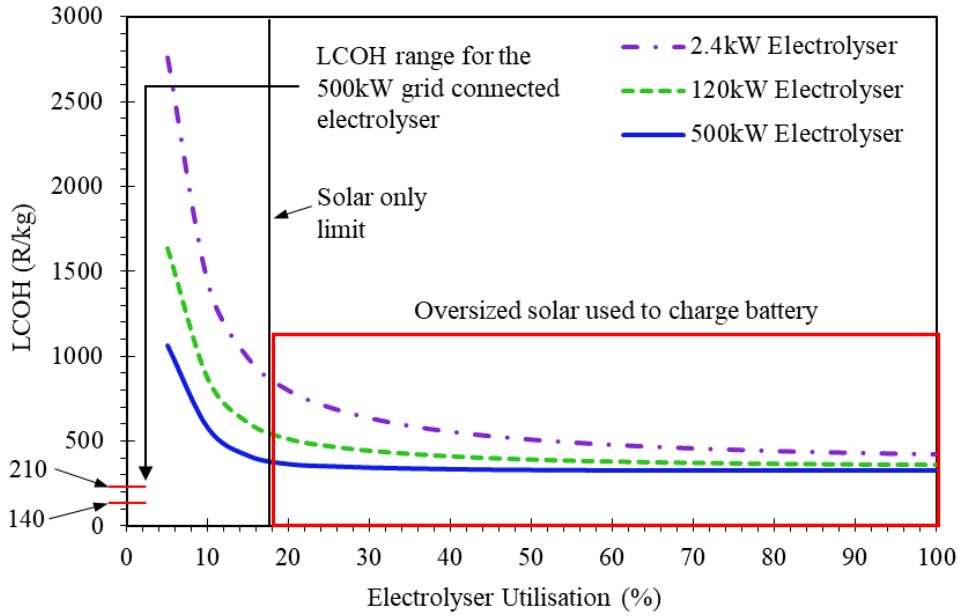


Figure 33 – The variation in LCOH for a standalone hybrid battery and solar electrolyser system for electrolyser utilisation ranging between 0% and 100%.

From Figure 33, coupling the hydrogen electrolyser with a battery system (scenario 3) cannot achieve the same low LCOH as when coupled with the grid (scenario 2). Whilst the grid connected system could achieve an LCOH ranging between 140.00 and 210.00 ZAR/kg, the battery coupled system achieved a minimum LCOH of 328.00 ZAR/kg for the 500 kW electrolyser, as shown by the solid blue line. The reason for this is that now instead of purchasing energy at a rate between 1.00 and 2.00 ZAR/kWh, the CAPEX required for the oversized solar system and battery system means that the cost of energy when being deployed from the battery is now closer to 3.00 ZAR/kWh, or 50% higher.

Focusing on the battery powered section of the electrolyser in Figure 34, the LCOH converges as utilisation increases as indicated by the red arrows. For example, looking at detail A, a 33% reduction in LCOH is realised at 25% utilisation. Looking at detail B, a 28% reduction in LCOH is realised at 35% utilisation. The benefit of increasing the electrolyser utilisation decreases as the LCOH becomes more dependent on the cost of the stored energy in the battery. As previously mentioned, the cost of energy stored in the battery is 50% higher compared to energy procured from the grid.

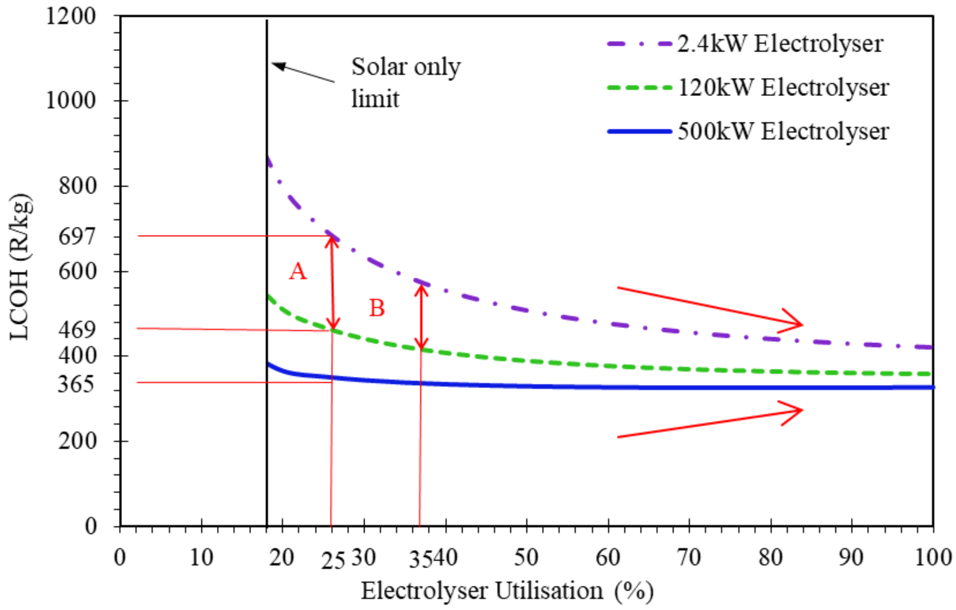


Figure 34 - The LCOH for a battery powered electrolyser with a utilisation factor greater than 18%.

If a battery system is required for the hydrogen production system, it is important to reduce the initial CAPEX of the system as much as possible. This scenario is shown in Figure 35, focusing on the 500 kW electrolyser only. The CAPEX of the battery only, is reduced by 13% and 26% arbitrarily, from 7 700.00 ZAR/kWh to 6 700.00 and 5 700.00 ZAR/kWh respectively. This price range reflects the current costs of battery systems in South Africa. Recently however, significant gains have been realised in the battery manufacturing industry. Manufacturing costs as low as 1 000.00 ZAR/kWh have been reached in China. If batteries could reach and maintain this price point for commercial sale, the price of green hydrogen could reach as low as 167.00 ZAR/kWh at 100% utilisation, as shown by the green line in Figure 35.

Figure 35 shows that there will not be any benefit in the reduction of the battery CAPEX when the solar system is supplying all the energy required (between 5% and 18% utilisation). After which, the LCOH begins to decrease with increasing electrolyser utilisation. For a 13% and 26% reduction in battery

CAPEX, the LCOH reduces by 7.3% and 14.6% at 100% utilisation respectively. The lowest LCOH achievable for battery costs of 5 700.00 ZAR/kWh is 280 ZAR/kg.

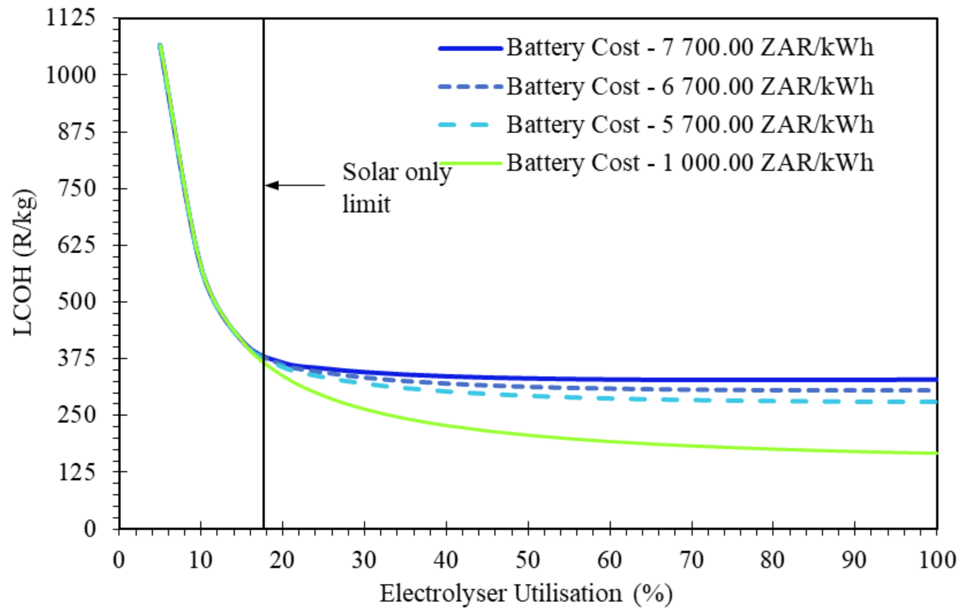


Figure 35 - The effect of reducing the battery CAPEX on the LCOH

With all three scenarios investigated, a cost comparison with existing sources of energy such as diesel, natural gas and blue hydrogen is conducted. This is done to understand whether the cost of green hydrogen produced on a scale between 2.4 kW and 500 kW, is feasible in South Africa. This investigation is done in section 6.5 below, where the two best performing scenarios are compared with the cost of energy in terms of Rands per megajoule.

6.5. Green hydrogen cost comparison with existing sources of energy

To understand the feasibility of green hydrogen production from the above discussed methods, a comparison is made with alternative sources of energy such as diesel and natural gas as shown in Figure 36. This figure shows that green hydrogen production is feasible when compared to the current cost of blue hydrogen, measured as R/MJ however only for a hydrogen production system that can be connected to the national grid and where wheeling clean energy through the grid 24 hours a day 365 days a year is possible. In this configuration, green hydrogen may be produced at an LCOH just 6% more than blue hydrogen. For scenarios where electrolysers are powered by green energy stored in batteries, the LCOH will be 134% more than blue hydrogen at the present-day cost of battery integrated systems. However, it has been shown in Figure 35, that reducing the CAPEX of the battery integrated system may make green hydrogen more feasible in the future.

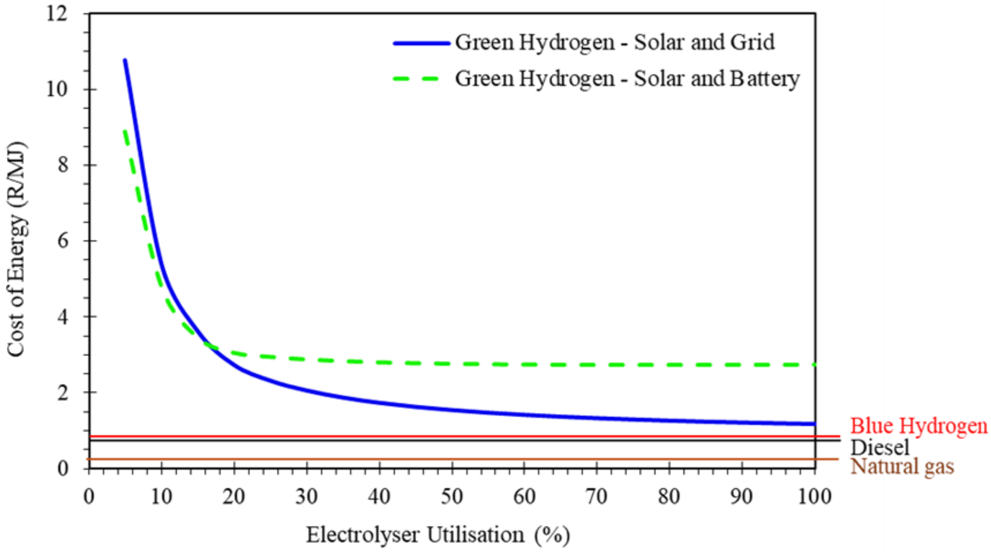


Figure 36 - A comparison of the cost of green hydrogen with existing sources of fuel, most notably, blue hydrogen.

As with any maturing market there are a wide variety of options when it comes to designing hydrogen production systems powered by renewables. There is also not a lot of published or easily accessible data for equipment pricing. Therefore, an investigation into the range of expected green hydrogen production costs in South Africa is detailed in section 6.6.1. Furthermore, a detailed investigation into how the LCOH may be decreased to become more competitive with the likes of blue hydrogen and diesel is detailed in section 6.6.2 This section highlights which aspects of the green hydrogen production process would have the largest impact on reducing the LCOH in the future.

6.6. Uncertainty and sensitivity analysis of the levelized cost of green hydrogen in South Africa

For the purpose of this research the uncertainty analysis and sensitivity analysis are differentiated as follows:

1. Uncertainty analysis – The uncertainty of the LCOH is calculated by considering the maximum and minimum values for each variable considered in the LCOH calculations. The variables ranges are shown in Table 4. The uncertainty is calculated by inputting the maximum and minimum values into equations 6, 7 and 8 and plotting the resulting line in comparison to the benchmark LCOH values.
2. Sensitivity analysis – The sensitivity analysis aims to understand which variables in the LCOH equations 6, 7 and 8 have the most significant impact on determining the cost of hydrogen. This is done by adjusting each variable by a known quantity, in this case 10%, and assessing how much the LCOH changes.

Based on the above definitions, the uncertainty and sensitivity analysis are completed in sections 6.6.1 and 6.6.2 respectively.

6.6.1. Uncertainty Analysis in the levelised cost of green hydrogen

A consideration on the uncertainty regarding the LCOH was conducted considering that there are several variables across the hydrogen production chain. These variables are dependent on the solar, hydrogen, battery and grid system selection and designs and are shown in Table 4 below. The variables are shown with the benchmark values that were used in this study, as well as their range of values, defined as maximum and minimum. The maximum values are defined as the values that would give the highest LCOH, whilst the minimum values would give the lowest LCOH. The source of these values and their ranges are discussed further in section 4.

Table 4 - Benchmark variables used in calculating the LCOH with their minimum and maximum ranges.

	Benchmark Price	**Maximum Price**	**Minimum Price**
Solar system cost (ZAR/kWp)	12 500.00	15 000.00	10 000
Electrolyser system cost (ZAR/kW)	42 000.00	47 812.00	36 818.00
Battery system cost (ZAR/kWh)	7 700.00	9 000.00	5 700.00
Solar energy output (kWh)	190 516.00	220 998.00	169 559.00
Soiling (%)	8.00	11.00	5.00
Cables losses (%)	3.00	5.00	1.00
Electrolyser efficiency (kWh/kg_{H2})	53.30	42.20	66.10
Operations and maintenance (% of CAPEX)	1.00	5.00	1.00
O&M escalation (% per annum)	7.00	8.60	0.00
Cost of capital (%)	11.00	11.87	10.70
Energy cost (ZAR/kWh)	2.00	2.50	1.00

The uncertainty analysis was analysed for the 500 kW electrolyser across the three scenarios, repeated below for reference:

1. The coupling of hydrogen electrolysers with a grid tied solar system only.
2. Hydrogen electrolysers coupled with a solar system, where any additional energy required is wheeled through the grid.

3. Electrolysers coupled with a stand-alone hydrogen production system, powered by a hybrid solar and battery system.

The results are shown in Figures 37 and 38. In Scenario 1, the LCOH ranges from a low of 772.00 ZAR/kg to a high of 2 630.00 ZAR/kg at an electrolyser utilisation of 5%. This is a range of 1 858.00 ZAR/kg. The range decreases to 469.00 ZAR/kg at 20% utilisation and further decreases to 271.20 ZAR/kg at 35% utilisation. At 35% utilisation the minimum LCOH achievable is 114.00 ZAR/kg whilst the maximum expected LCOH is 271.00 ZAR/kg. The increased uncertainty at lower utilisation levels is due to the low hydrogen production levels and the influence of large capital costs. As utilisation increases the upfront capital costs get amortised and the operating costs become more prominent. This is further shown by Figure 38, where the operating range of the electrolyser is increased to 100%. From Figure 38(a), the uncertainty analysis for Scenario 2 shows that the minimum LCOH achieved at a 35% utilisation is 426.00 ZAR/kg while the maximum LCOH is 566.00 ZAR/kg with an uncertainty range of 426.00 ZAR/kg. At 100% utilisation the minimum LCOH achievable is 86.00 ZAR/kg whilst the maximum is 447.00 ZAR/kg with an uncertainty band of 361.00 ZAR/kg. The uncertainty band does not decrease as much as in Scenario 1, as the cost of energy from the grid becomes fixed from 18% utilisation up to 100% utilisation.

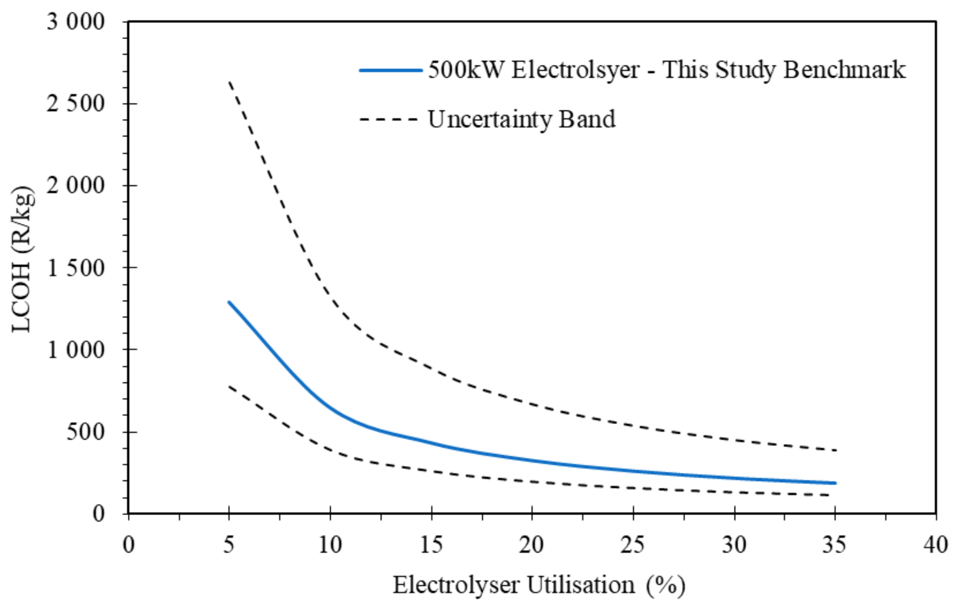


Figure 37 - Uncertainty analysis for Scenario 1, green hydrogen production through solar only.

A similar effect is experienced with the battery connected system as shown by Figure 38(b). The minimum LCOH achieved for the battery connected at 100% utilisation is 176.00 ZAR/kg and the maximum possible LCOH is 722.00 ZAR/kg, with an uncertainty range of 546.00 ZAR/kg. From Figure

38 it is shown that the battery connected system has a larger range of uncertainty compared to the grid connected system however, both show more uncertainty at higher LCOH values. This is primarily related to the CAPEX associated with the battery systems.

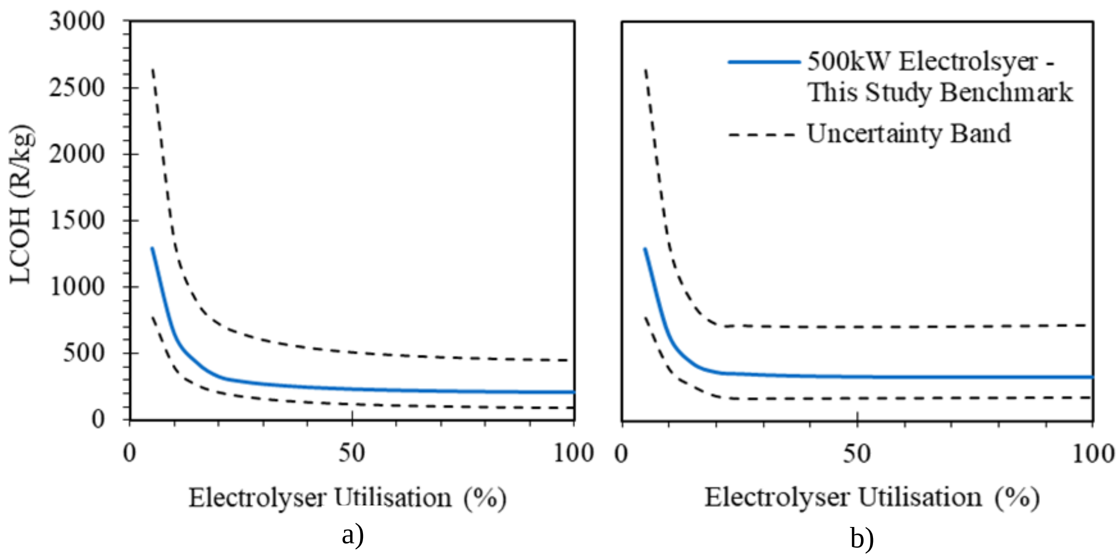


Figure 38 - Uncertainty analysis for a) – Scenario 2, a grid tied solar system power a hydrogen electrolyser and b) – Scenario 3, a hybrid solar and battery connected hydrogen electrolyser.

Overall, the uncertainty analysis shows that there is a wide range of uncertainty in the LCOH. In Scenario 1, the LCOH showed a significant range, decreasing as electrolyser utilisation increased due to the amortization of capital costs. Scenario 2 displayed less reduction in uncertainty at higher utilisation levels because grid energy costs remained fixed beyond 18% utilisation. Scenario 3, involving battery systems, demonstrated a larger range of uncertainty around the cost of electrolyser equipment and the efficiency of the equipment selected. Electrolysers currently have a broad range of specifications, and the system performance will be mainly dependant on the design of the system. With the range of uncertainty associated with the three scenarios investigated, a sensitivity analysis is now conducted to determine which variables have the greatest impact on reducing the LCOH.

6.6.2. Sensitivity analysis of the variables affecting green hydrogen production.

These different scenarios were investigated to understand the levelized cost of green hydrogen (LCOH) over a 20-year period. The outcome shows that green hydrogen production through solar and battery connected system at a scale of between 2.4 kW and 500 kW is not yet feasible. However, for a grid connected system where cheap clean energy can be bought through the grid, it is possible to produce green hydrogen at an LCOH competitive with grey hydrogen and approaching the cost of diesel. To further understand how the cost of hydrogen may be decreased, the following sensitivity analysis was completed. This was done by taking each variable considered in determining the cost of green hydrogen and decreasing it by 10%. The change in overall LCOH was then recorded and represented in Figure 39.

A 10% reduction in the overall cost of green hydrogen is feasible as the International Energy Agency (IEA) expects a 30% reduction by 2030 [71] . Moreover, the like of quantitative research done by Frieden and Leker has shown the cost of hydrogen reducing 17% by 2030 and another 39% by 2050 [72] In this way, it was determined what the most effective method would be to reduce the LCOH of the system. Figure 39, shows the variables listed from least effective to most effective in reducing the cost of hydrogen.

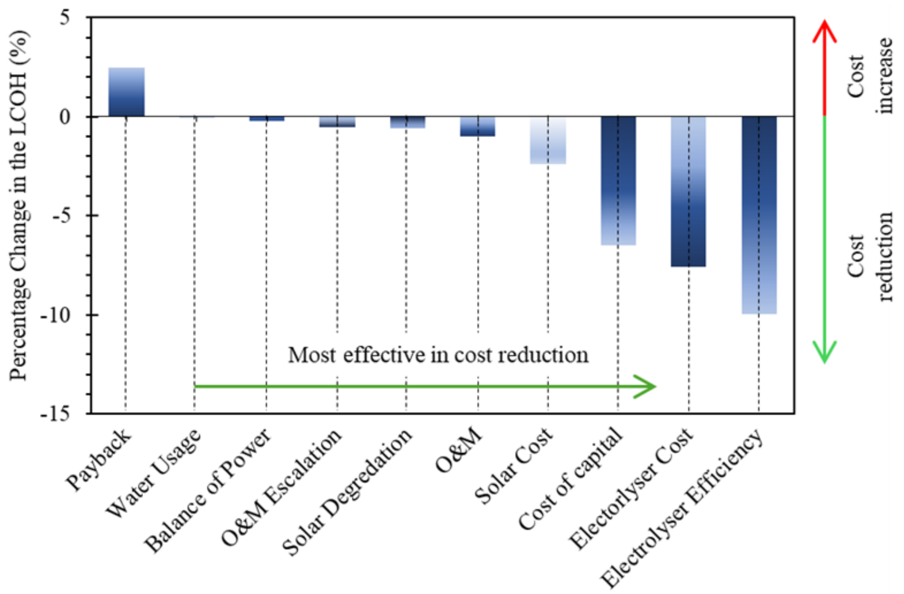


Figure 39 - A sensitivity analysis of the variables affecting the LCOH, ordered from least to most effective in reducing the LCOH.

It is shown that decreasing the payback period has a negative effect on the LCOH whilst all other variables cause a reduction in LCOH. Decreasing the payback period means that the same return is required in a shorter amount of time, therefore driving the cost of hydrogen up. The variables with the biggest impact in reducing the LCOH include the cost of solar, the electrolyser cost, the cost of capital and the electrolyser efficiency, ranging between a 2.4% and 9.95% reduction. Electrolyser efficiency has the most weight in reducing the overall LCOH at 9.95% however, if both the CAPEX of the solar system and electrolyser were reduced these collectively would have the same impact and might be a more achievable target in the short term. If a favourable agreement between the Engineering Procurement and Construction (EPC) company could be reached with the borrowing facility, the cost of hydrogen could further be reduced by 6.5% based on the cost of capital. The cost of capital is heavily dependent on the lending facility. Something to consider is that the lending rate will always be more than what could be achieved in a standard savings or investment account. Generally, projects of this nature, carry high levels of financial risk and therefore the lending rate can typically be 11% and up.

Although there is potential for reducing the cost of hydrogen for a standalone solar and hydrogen system as previously shown, a hydrogen system connected to solar alone could not produce at a utilisation factor higher than 18%. Therefore, the benefit of cheaper hydrogen at higher utilisation rates is not achievable. The lowest achievable price on average would be 387.02 ZAR/kg, which is still 22.5% higher than grey hydrogen and 92% higher than diesel. A grid connected hydrogen production system, where wheeling of clean energy through the grid is possible, levelized costs as low as 140 ZAR/kg can be realised at a 100% utilisation rate. This is close to the current cost of blue hydrogen at 131 ZAR/kg however, to achieve even lower hydrogen costs, competitive with natural gas further analysis of the variables affecting green hydrogens LCOH is required, at the full range of electrolyser utilisation. Figures 40 to 42 show how reducing the cost variables by 10% would affect the LCOH over the full electrolyser range. The figures are ordered from most effective to least effective in reducing the LCOH.

Figure 40 shows that once again the electrolyser efficiency is most important when trying to reduce the LCOH for both grid and battery connected systems, and it is true for the full electrolyser utilisation range. The reduction in LCOH is also linearly linked to the efficiency improvement. If the efficiency of the electrolyser improved by 10% the LCOH reduces by 10%, shown by the solid blue lines in Figure 40(a) and 40(b)b. For the grid connected system shown by Figure 40(a), at lower utilisation levels, reducing the electrolyser cost (light blue dashed line) and cost of capital (light pink dotted line) is more beneficial in reducing the LCOH. At utilisation levels lower than 40% the cost of capital and of the electrolyser play a larger role in reducing the LCOH as shown by the light blue and pink dashed and dotted lines. Initially reducing the electrolyser cost by 10% may reduce the LCOH by 7.6% however reducing to 2.1% at 100% utilisation. Approaching higher utilisation levels, the cost of energy (dark green solid line) and energy escalation (light green dashed line) becomes more important for reducing the LCOH. Both the electrolyser cost and cost of capital approach lower LCOH reduction at 100% utilisation, whilst both the cost of energy and energy escalation show improved cost reduction with increasing utilisation. At a utilisation of 40%, a crossover between the electrolyser cost and the energy cost occurs. At this point reducing the cost of energy will have a larger impact on reducing the overall LCOH. At 100% utilisation a reduction of 7.2% may be achieved by reducing the cost of energy by 10%. The contrast between the effect of the energy cost and cost of the electrolyser is indicative of the characteristic curve defined in Figure 27. As expected, with higher utilisation levels the energy cost has a larger influence on the outcome of the LCOH whilst the CAPEX of the electrolyser has a diminishing effect with increasing utilisation

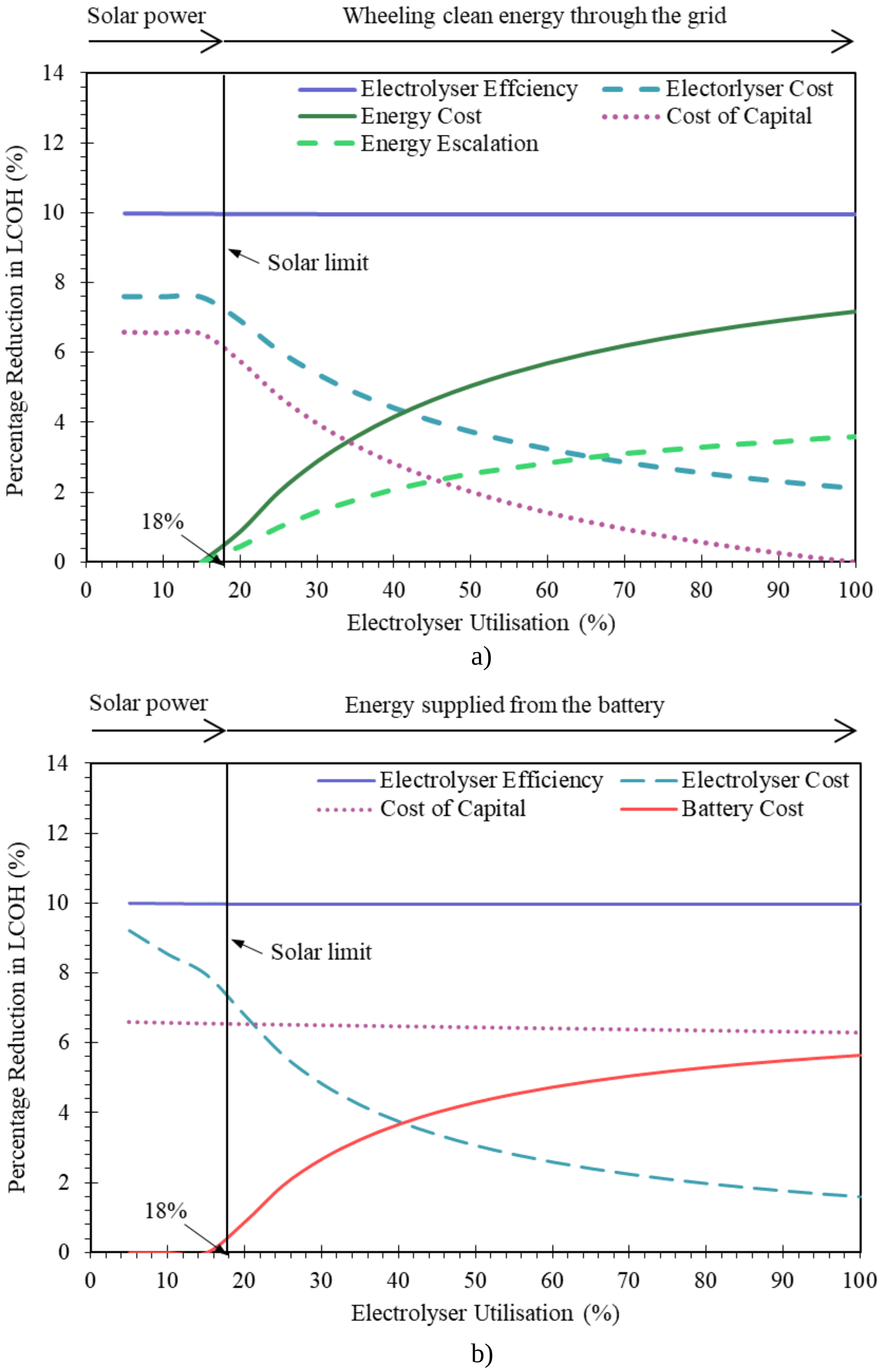


Figure 40 - Variables which have the greatest effect on changing LCOH through varying utilisation levels. a) – when wheeling clean energy through the grid and b) – when using a hybrid solar and battery connected system.

For the battery connected system shown in Figure 40(b), the cost of the battery plays a similar role to the cost of energy in Figure 40(a). Reducing the cost of the battery is, in essence, reducing the cost of energy storage required for the system and therefore both lines follow a similar trend however to less effect for the battery connected system, with a maximum reduction in LCOH of 5.6% at 100% utilisation. For the battery connected system, reducing the electrolyser cost has the same effect as for a grid connected system however, the cost of capital displays a different characteristic. Instead of reducing with utilisation it remains constant, only reducing by 0.4% over the full utilisation range. This occurs since for a battery connected system to run at higher utilisation levels, a larger battery and solar system are always required. Therefore, more CAPEX is required, and the cost of that CAPEX increases as the system size increases.

Additional variables which have less impact on the reducing the LOCH are shown in Figure 41. Figure 41 shows the effect of reducing the balance of power, the cost of solar, solar system degradation, O&M cost, O&M escalation and water usage. The balance of power, shown by the pink dotted lines, is the power required for accessory items such as pumps, cooling fans and lighting. Reducing the amount of energy these items consume is linked to improving the efficiency of the electrolyser and therefore is beneficial over the full utilisation range, with greater effect for the grid connected system. Reducing the balance of power by 10% could lead to a LCOH reduction of up to 1.7% for a grid connected system and up to 0.86% for the battery connected system.

The cost of solar has the greatest impact for utilisation levels lower than 18% in a grid connected system, resulting in a LCOH reduction of 2.4% but reducing with increasing utilisation to just 0.7% at 100% utilisation. In contrast, reducing the cost of solar in a battery connected system reduces the LCOH over the full utilisation range, shown by the dark green line. This is since energy stored in the battery is a result of an oversized solar system. Therefore, if the CAPEX of the solar system is reduced the energy stored in the battery for later use also becomes cheaper. The O&M and O&M escalation show similar attributes. The LCOH reduction decreases with increasing utilisation for the grid connected system however, remaining constant for the battery connected system. For a grid connected system, the solid and dashed green lines show that O&M has a minimal impact on reducing the LCOH, especially at higher utilisation levels resulting in a less than 0.28% and 0.14% reduction respectively. For a battery connected system a reduction in O&M costs will reduce the LCOH for the full range of utilisation factors as the O&M is link to the CAPEX of the system. Reducing the solar degradation, in both scenarios means that more energy will be available from the solar system over the 20-year period and therefore has a constant improvement in the LCOH of 0.56%.

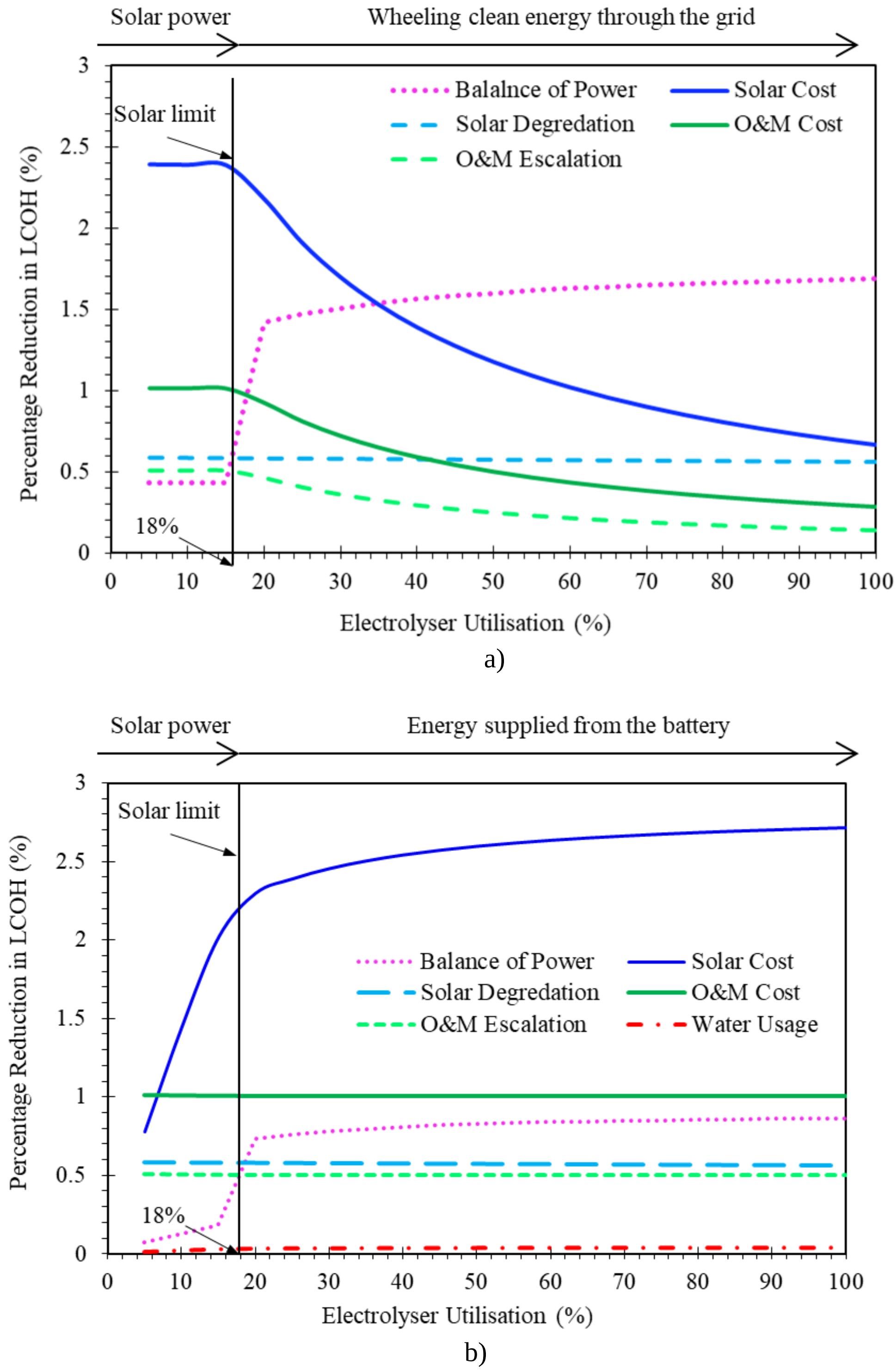
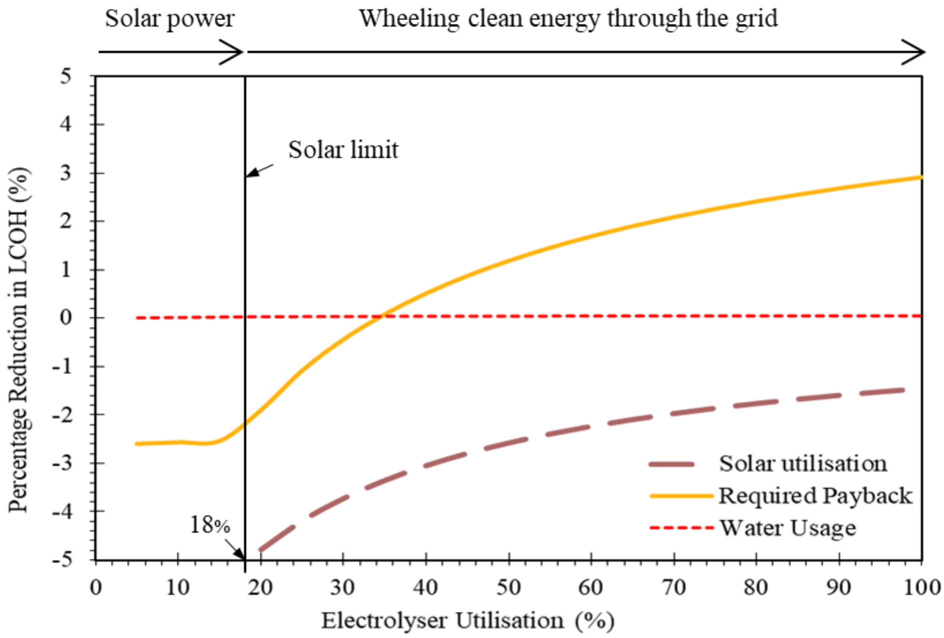
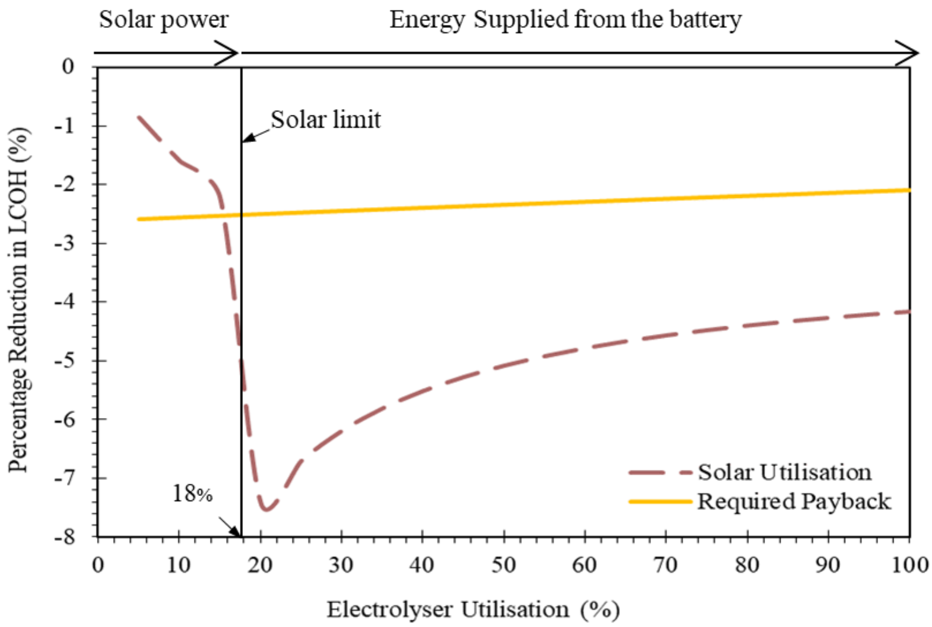


Figure 41 – Variables which have a minimal effect on LCOH through varying utilisation levels. a) – for a grid connected system and b) – for a solar battery hybrid connected system

Reducing some variables by 10% leads to an increase in the cost of the LCOH has shown in Figure 42



a)



b)

Figure 42 – Variables which have a negative effect on LCOH (LCOH increase) across varying utilisation factors for a) – a grid connected system and b) – a solar battery hybrid connected system.

For a grid connected system, reducing the solar utilisation increases the LCOH by 5% initially and increases towards a 1.5% increase at 100% utilisation. For a battery connected system the effect of reducing solar utilisation is worse and initially increases the LCOH by 7.5% dropping to a 4.2% increase as 100% utilisation. For a grid connected system, reducing the required payback times initially increase the LCOH by 2.5% but then increases towards a positive reduction in LCOH as utilisation increases to 100%. This occurs because the interest component of the cost of capital is reduced for a shorter payback period. With a shorter payback period and higher utilisation, the interest portion is less and therefore more kilograms of hydrogen are produced for less interest impact, reducing the LCOH in ZAR/kg. The same is true for a battery connected system, the LCOH initially increases by 2.5% and reduces to a 2% increase at 100% utilisation. The benefit of a reduced LCOH at higher utilisation levels is not realised because the CAPEX also continues to increase with utilisation and therefore so does the interest. From Figure 35 it can also be seen that cost of water in the system is negligible at less than 0.05%.

From the above a sensitivity analysis was performed to understand the levelized cost of green hydrogen (LCOH) over a 20-year period and which variables affected the LCOH outcome the most. It was determined that decreasing the payback period increases the LCOH, while other variables cause a reduction in LCOH. The variables with the biggest impact in reducing the LCOH include the cost of solar, the electrolyser cost, the cost of capital, and the electrolyser efficiency, ranging between a 2.4% and 9.95% reduction. It was noted that electrolyser efficiency has the most weight in reducing the overall LCOH at 9.95%. Electrolyser efficiency is most important when trying to reduce the LCOH for both grid and battery connected systems, across the full electrolyser utilization range. For a grid connected system, at lower utilisation levels, reducing the electrolyser cost and cost of capital is more beneficial in reducing the LCOH.

7. CONCLUSIONS AND RECOMMENDATIONS

7.1. Conclusions

This research has explored the economic feasibility of producing green hydrogen in South Africa by coupling electrolysers with solar and hybrid energy solutions. The economics have focused on the LCOH as the primary metric. Three scenarios were investigated for electrolyser sizes of 2,4 kW, 120 kW and 500 kW:

1. The coupling of a green hydrogen production system with a grid tied solar system, where hydrogen can only be produced when solar energy is available.
2. A grid tied hydrogen production system coupled with a solar system, where any additional energy required is wheeled through the grid.
3. A stand-alone hydrogen production system coupled with an oversized battery and solar system, capable of supplying all the energy required for up to 100% utilisation.

Each scenario was investigated based on the variables in Table 5. These variables changed based on electrolyser utilisation and operating principles. The key findings for each scenario are as follows:

For a standard solar coupled hydrogen electrolyser, where solar availability is not more than 18%, the lowest achievable LCOH for a 500 kW electrolyser is 370.00 ZAR/kg. When the system design can be improved such that the output from the solar plant reaches 35% of the total available hours in a year, the LCOH drops to 152.05 ZAR/kg. This is close to the current competitor, blue hydrogen, which currently costs 131.00 ZAR/kg. To reach an equivalent cost of blue hydrogen, larger system would be required, possibly greater than 1 megawatt and the solar system would need to be oversized to ensure that electrolyser can operate at the 35% utilisation. This scenario is highly influenced by capital expenditure and faces limitations in achieving utilisation rates as high as 35%.

The grid tied solar solution, coupled with wheeling clean energy through the grid, shows the most promising results. At 100% utilisation for a 500 kW electrolyser a LCOH of 140.00 ZAR/kg is achieved assuming an energy rate of 1.00 ZAR/kWh. This is competitive with the current costs of blue hydrogen in South Africa, at 131.00 ZAR/kg. This scenario benefits from high utilisation levels and sourcing clean energy through the grid by power purchase agreements with alternative renewable energy solution providers.

This electrolyser and hybrid solar and battery solution yields a minimum LCOH of 328.00 ZAR/kg for a 500 kW electrolyser. Currently, the cost of battery energy storage is too high to make this solution feasible. Significant reductions in the CAPEX of batteries will be required along with scaling of the system size from 500 kW to 5 MW and greater.

While green hydrogen production through a standalone battery and solar system is not yet achievable, a grid connected system with access to cheap clean energy through the grid competes with grey hydrogen and comes close to competing with blue hydrogen and diesel in South Africa. Key variables which must be addressed to bring down the cost of green hydrogen include, the electrolyser efficiency, solar, electrolyser and battery system CAPEX, the cost of capital and ultimately the cost of energy for systems with high utilisation factors.

The feasibility of green hydrogen production on a scale between 2.4 kW and 500 kW hinges on several factors. Standalone solar and battery systems currently face challenges in achieving cost competitiveness with grey and blue hydrogen as well as other forms of energy such as diesel and natural gas. Grid connected systems with access to low-cost clean energy through PPA's hold promise for producing green hydrogen at rates lower than currently produced grey hydrogen and at rates competitive with blue hydrogen and diesel. Furthermore, advancements in electrolyser efficiency, reductions in system CAPEX, and access to affordable clean energy sources will play a crucial role in driving down the cost of green hydrogen in the future.

Overall, there is currently potential for green hydrogen produced in South Africa to be competitive with existing forms of energy such as blue hydrogen and diesel. The most likely Scenario that could achieve these low costs is Scenario 2, a grid tied solar and hydrogen electrolyser system where clean energy can be wheeled through the grid. Achieving low green hydrogen costs is dependent on the system design, with focus on factors like capital expenditure and electrolyser efficiency. Furthermore, energy bought through wheeling agreements needs to cost less than 1.00 ZAR/kWh to ensure the green hydrogen remains cost competitive with the lies of blue hydrogen and diesel.

7.2. Recommendations

Based on the above research and conclusions, the following is recommended for further investigation:

1. Larger Electrolyser Plants: Hydrogen production plants larger than 500 kW should be investigated to confirm hypothesises towards achieving the target cost of blue hydrogen. The current research was limited by the technical and financial information available for larger systems.
2. Improved Plant Design: Improving plant designs to enhance solar energy availability factors, possibly through single or dual axis tracking systems. Future research could focus on the cost-benefit analysis of these designs in the South African context. Further improvements in pant design should also be investigated in terms of the electrolyser technology selected.
3. Electrolyser Efficiency: Given that electrolyser efficiency is a critical factor in reducing the levelized cost of hydrogen (LCOH), further research should focus on technological advancements that improve electrolyser efficiency.
4. CAPEX Reduction: Since the capital expenditure (CAPEX) of solar, electrolyser, and battery systems significantly impacts the LCOH, research should explore strategies for reducing these costs. This could include analysing different procurement strategies, alternative equipment specifications, technological innovations, or policy interventions.
5. Affordable Clean Energy: Access to affordable clean energy sources is crucial for reducing the LCOH. Future research could investigate various power purchase agreement (PPA) models and the potential for wheeling clean energy through the grid in South Africa. This research could focus on determining the actual cost at which clean energy is wheeled through the grid, based on existing large renewable energy projects.
6. Policy and Support: Since supportive policies can reduce the cost of green hydrogen production, research should explore which specific policies would be most effective in South Africa and how these policies should be implemented if not already.
7. Broader System Perspective: The current study considers the cost of green hydrogen at the output from the electrolyser. Storage and distribution costs are not considered as part of this scope. Future research should consider these additional costs, so that the LCOH is considered at the point of consumption.

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Appendix A – Canadian solar modules data sheet

The specifications of the Canadian Solar modules used in the benchmark model are shown below.

NEW

CanadianSolar

HiKu6 Mono PERC

530 W ~ 555 W

CS6W-530|535|540|545|550|555MS

MORE POWER

555 W

Module power up to 555 W
Module efficiency up to 21.6 %

Up to 4.5 % lower LCOE
Up to 5.6 % lower system cost

Comprehensive LID / LeTID mitigation technology, up to 50% lower degradation

Compatible with mainstream trackers, cost effective product for utility power plant

Better shading tolerance

MORE RELIABLE

Minimizes micro-crack impacts

Heavy snow load up to 5400 Pa, wind load up to 2400 Pa*

12 Years **Enhanced Product Warranty on Materials and Workmanship***

25 Years **Linear Power Performance Warranty***

1st year power degradation no more than 2%
Subsequent annual power degradation no more than 0.55%

*According to the applicable Canadian Solar Limited Warranty Statement.

MANAGEMENT SYSTEM CERTIFICATES*

ISO 9001:2015 / Quality management system
ISO 14001:2015 / Standards for environmental management system
ISO 45001: 2018 / International standards for occupational health & safety
IEC62941: 2019 / Photovoltaic module manufacturing quality system

PRODUCT CERTIFICATES*

IEC 61215 / IEC 61730 / CE / INMETRO / MCS / UKCA
CEC listed (US California) / FSEC (US Florida)
UL 61730 / IEC 61701 / IEC 62716 / IEC 60068-2-68
UNI 9177 Reaction to Fire: Class 1 / Take-e-way

* The specific certificates applicable to different module types and markets will vary, and therefore not all of the certifications listed herein will simultaneously apply to the products you order or use. Please contact your local Canadian Solar sales representative to confirm the specific certificates available for your Product and applicable in the regions in which the products will be used.

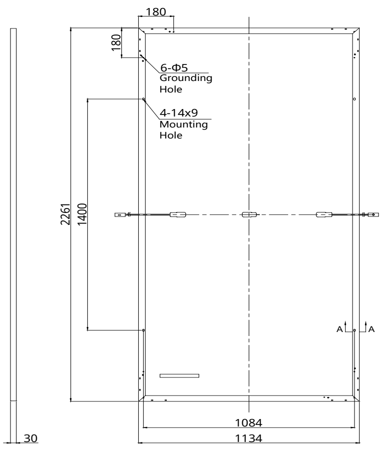
CSI Solar Co., Ltd. is committed to providing high quality solar photovoltaic modules, solar energy and battery storage solutions to customers. The company was recognized as the No. 1 module supplier for quality and performance/price ratio in the IHS Module Customer Insight Survey. Over the past 20 years, it has successfully delivered over 82 GW of premium-quality solar modules across the world.

* For detailed information, please refer to the Installation Manual.

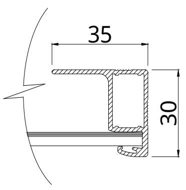
CSI Solar Co., Ltd.
199 Lushan Road, SND, Suzhou, Jiangsu, China, 215129, www.csisolar.com, support@csisolar.com

ENGINEERING DRAWING (mm)

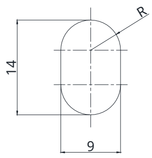
Rear View



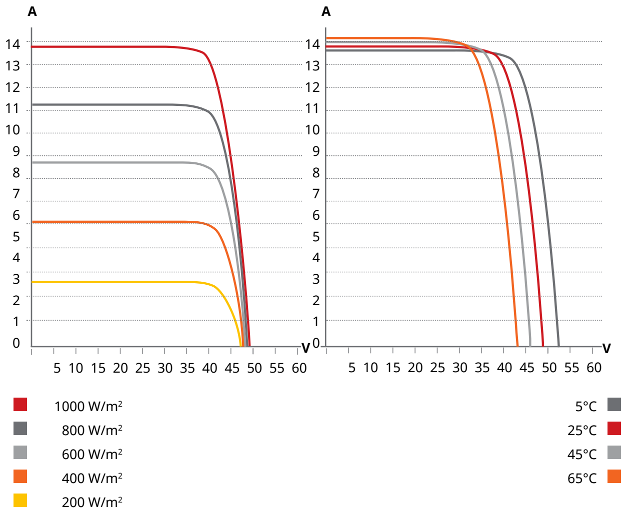
Frame Cross Section A-A



Mounting Hole



CS6W-530MS / I-V CURVES



ELECTRICAL DATA | STC*

CS6W	530MS	535MS	540MS	545MS	550MS	555MS
Nominal Max. Power (Pmax)	530 W	535 W	540 W	545 W	550 W	555 W
Opt. Operating Voltage (Vmp)	40.9 V	41.1 V	41.3 V	41.5 V	41.7 V	41.9 V
Opt. Operating Current (Imp)	12.96 A	13.02 A	13.08 A	13.14 A	13.20 A	13.25 A
Open Circuit Voltage (Voc)	48.8 V	49.0 V	49.2 V	49.4 V	49.6 V	49.8 V
Short Circuit Current (Isc)	13.80 A	13.85 A	13.90 A	13.95 A	14.00 A	14.05 A
Module Efficiency	20.7%	20.9%	21.1%	21.3%	21.5%	21.6%
Operating Temperature	-40°C ~ +85°C					
Max. System Voltage	1500V (IEC/UL) or 1000V (IEC/UL)					
Module Fire Performance	TYPE 1 (UL 61730 1500V) or TYPE 2 (UL 61730 1000V) or CLASS C (IEC 61730)					
Max. Series Fuse Rating	25 A					
Application Classification	Class A					
Power Tolerance	0 ~ + 10 W					

* Under Standard Test Conditions (STC) of irradiance of 1000 W/m², spectrum AM 1.5 and cell temperature of 25°C.

ELECTRICAL DATA | NMOT*

CS6W	530MS	535MS	540MS	545MS	550MS	555MS
Nominal Max. Power (Pmax)	397 W	401 W	405 W	409 W	412 W	416 W
Opt. Operating Voltage (Vmp)	38.3 V	38.5 V	38.7 V	38.9 V	39.1 V	39.3 V
Opt. Operating Current (Imp)	10.38 A	10.42 A	10.47 A	10.52 A	10.55 A	10.59 A
Open Circuit Voltage (Voc)	46.1 V	46.3 V	46.5 V	46.7 V	46.9 V	47.1 V
Short Circuit Current (Isc)	11.13 A	11.17 A	11.21 A	11.25 A	11.29 A	11.33 A

* Under Nominal Module Operating Temperature (NMOT), irradiance of 800 W/m², spectrum AM 1.5, ambient temperature 20°C, wind speed 1 m/s.

MECHANICAL DATA

Specification	Data
Cell Type	Mono-crystalline
Cell Arrangement	144 [2 x (12 x 6)]
Dimensions	2261 × 1134 × 30 mm (89.0 × 44.6 × 1.18 in)
Weight	27.6 kg (60.8 lbs)
Front Cover	3.2 mm tempered glass with anti-reflective coating
Frame	Anodized aluminium alloy
J-Box	IP68, 3 bypass diodes
Cable	4 mm² (IEC), 12 AWG (UL)
Cable Length (Including Connector)	410 mm (16.1 in) (+) / 290 mm (11.4 in) (-) or customized length*
Connector	T6 or MC4-EVO2 or MC4-EVO2A
Per Pallet	35 pieces
Per Container (40' HQ)	700 pieces or 630 pieces (only for US & Canada)

* For detailed information, please contact your local Canadian Solar sales and technical representatives.

TEMPERATURE CHARACTERISTICS

Specification	Data
Temperature Coefficient (Pmax)	-0.34 % / °C
Temperature Coefficient (Voc)	-0.26 % / °C
Temperature Coefficient (Isc)	0.05 % / °C
Nominal Module Operating Temperature	41 ± 3°C

PARTNER SECTION

* The specifications and key features contained in this datasheet may deviate slightly from our actual products due to the on-going innovation and product enhancement. CSI Solar Co., Ltd. reserves the right to make necessary adjustment to the information described herein at any time without further notice.
Please be kindly advised that PV modules should be handled and installed by qualified people who have professional skills and please carefully read the safety and installation instructions before using our PV modules.

CSI Solar Co., Ltd.
199 Lushan Road, SND, Suzhou, Jiangsu, China, 215129, www.csisolar.com, support@csisolar.com

Appendix B – Sungrow inverter data sheet

The specifications of the Sungrow inverter used in the benchmark model are shown below.

SG110CX New

SUNGROW
Clean power for all

Multi-MPPT String Inverter for 1000 Vdc System

HIGH YIELD

- 9 MPPTs with max. efficiency 98.7%
- Compatible with bifacial module
- Built-in PID recovery function

SMART O&M

- Touch free commissioning and remote firmware upgrade
- Online IV curve scan and diagnosis*
- Fuse free design with smart string current monitoring

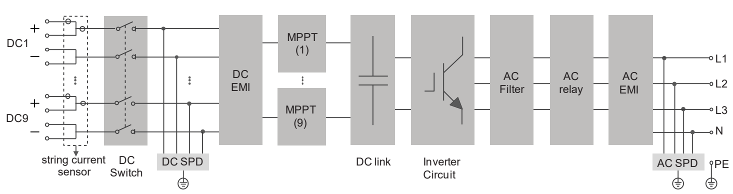
LOW COST

- Compatible with Al and Cu AC cables
- DC 2 in 1 connection enabled
- Q at night function

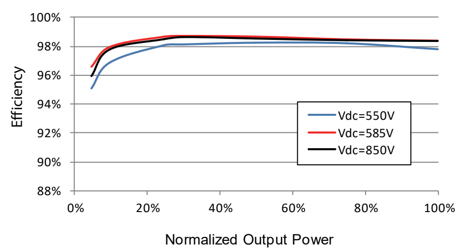
PROVEN SAFETY

- IP66 and C5 protection
- Type II SPD for both DC and AC
- Compliant with global safety and grid code

CIRCUIT DIAGRAM



EFFICIENCY CURVE



Type designation	SG110CX
Input (DC)	
Max. PV input voltage	1100 V
Min. PV input voltage / Startup input voltage	200 V / 250 V
Nominal PV input voltage	585 V
MPP voltage range	200 – 1000 V
MPP voltage range for nominal power	550V – 850 V
No. of independent MPP inputs	9
Max. number of PV strings per MPPT	2
Max. PV input current	26 A * 9
Max. DC short-circuit current	40 A * 9
Output (AC)	
AC output power	110 kVA @ 45 ℃ / 100 kVA @ 50 ℃
Max. AC output current	158.8 A
Nominal AC voltage	3 / N / PE, 400 V
AC voltage range	320 – 460 V
Nominal grid frequency / Grid frequency range	50 Hz / 45 – 55 Hz, 60 Hz / 55 – 65 Hz
THD	< 3 % (at nominal power)
DC current injection	< 0.5 % In
Power factor at nominal power / Adjustable power factor	> 0.99 / 0.8 leading – 0.8 lagging
Feed-in phases / connection phases	3 / 3
Efficiency	
Max. efficiency	98.7 %
Euro. efficiency	98.5 %
Protection	
DC reverse connection protection	Yes
AC short circuit protection	Yes
Leakage current protection	Yes
Grid monitoring	Yes
Ground fault monitoring	Yes
DC switch	Yes (not available for Australia)
AC switch	No
PV String current monitoring	Yes
PID recovery function	Yes
Overvoltage protection	DC Type II / AC Type II
General Data	
Dimensions (W*H*D)	1051*660*362.5 mm
Weight	89 kg
Isolation method	Transformerless
Ingress protection rating	IP66
Night power consumption	< 2W
Operating ambient temperature range	-30 to 60 ℃ (> 50 ℃ derating)
Allowable relative humidity range (non-condensing)	0 – 100 %
Cooling method	Smart forced air cooling
Max. operating altitude	4000 m (> 3000 m derating)
Display	LED, Bluetooth+APP
Communication	RS485 / Optional: Wi-Fi, Ethernet
DC connection type	MC4 (Max. 6 mm²)
AC connection type	OT / DT terminal (Max. 240 mm²)
Compliance	IEC 62109, IEC 61727, IEC 62116, IEC 60068, IEC 61683, VDE-AR-N 4110:2018, VDE-AR-N 4120:2018, IEC 61000-6-3, EN 50549, AS/NZS 4777.2:2015, CEI 0-21, VDE 0126-1-1/A1 VFR 2014, UTE C15-712-1:2013, DEWA
Grid Support	Q at night function, LVRT, HVRT,active & reactive power control and power ramp rate control

*: Only compatible with Sungrow logger and iSolarCloud

Appendix C – Step by step process for simulating solar models in PVSol.

PVSol is a 3D and 2D solar modelling software, which allows the user to specify the locations, the type of solar systems being installed, the specific equipment that must be used, the cable routing and to determine the financial return from the solar system, The output of the PVSol software is a set of data which can, on average, represent how much energy can be produced from the solar system designed in the software. A step-by-step process is followed when using the PVSol software. These can be broken down into eight steps a detailed below. To move between different steps the blue arrows in the top left of the page are used.

Step 1 – System type, climate and grid

Initially the systems connection type and location parameters are defined as shown in Figure 44. The type of system is selected as a 3D, grid tied system. Selecting 3D allows the user to sketch the area in 3D in the model space. This gives the added advantage of being able to accurately model shading from nearby obstructions. This is discussed in further detail in step 4. The time step of the simulation is selected as 1 hour. The 1-hour simulation is a faster, and aligns with typical measured data from energy meters, such as those used by Eskom. This allows the designer to compare the data easily with the data taken from grid usage studies. One-minute simulations can be used when more precise simulations are required. The climate data must then be specified. This is done by selecting the location where the solar system is going to be built. Highlighted by the red square in Figure 44, in brackets, next to the location, it is shown that the irradiance data set selected for modelling the scenario is being taken from Meteonorm. This is the standard data set used in PVSol. Additional data sets may be imported at an additional charge. The AC mains parameters are then defined based on the location grid code. In South Africa this is 230V, 3 phase and it is assumed the power factor from the solar system is 1.

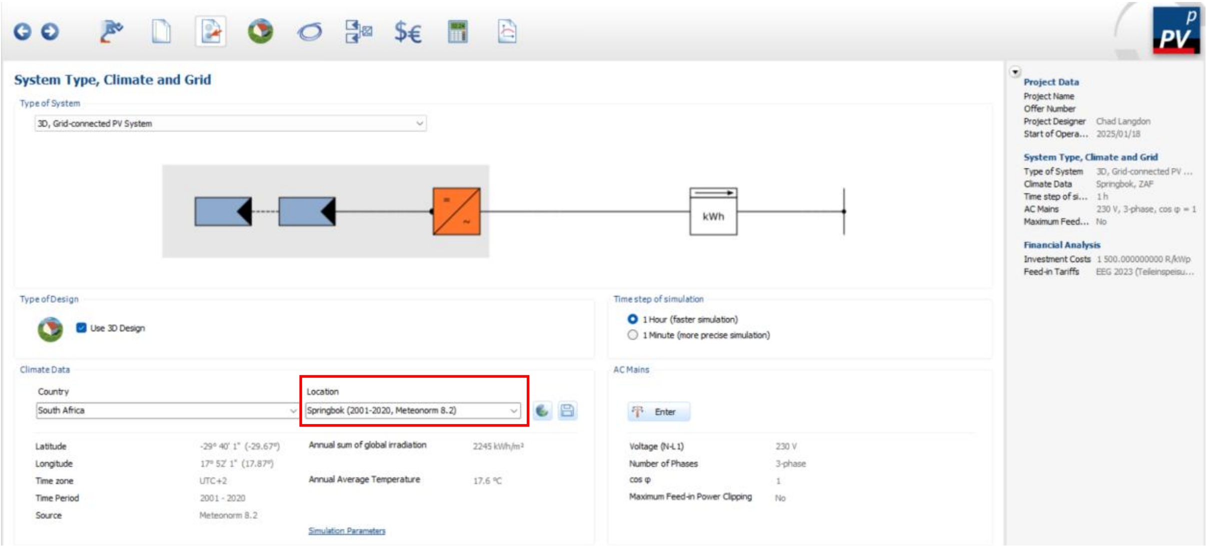


Figure 43 - PVSol modelling space step 1. Setting the initial parameters, location and model type.

Step 2 – 3D system design

Following the initial system and location specifications, the 3D map area must be defined. The 3D map area is selected by clicking on edit in Figure 45. At this stage basic system parameters can be confirmed on the right. The output of this is shown in Figure 46 and is elaborated on in Step 3.

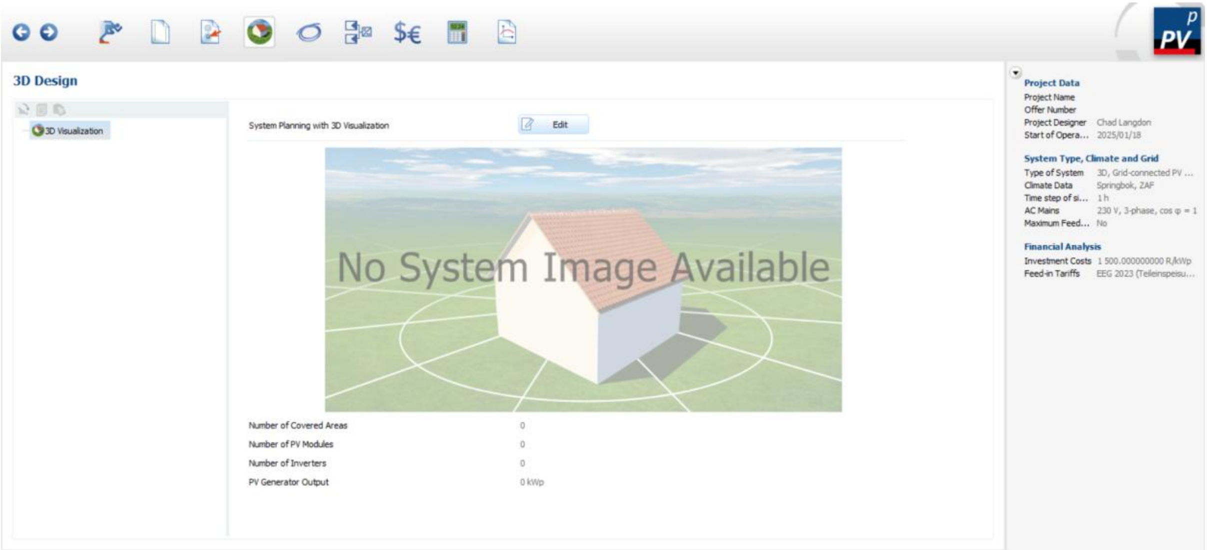


Figure 44 - Entering the 3D model space in PVSol confirming the system design parameters and proceeding to defining the model space.

Step 3 – Selecting the map area to be used in the 3D model.

Once entering the map area, a suitable location for the solar system must be selected. Generally, either roof space or ground space is allocated to the solar system. When selecting roof space, the roof should always be large enough for the desired system size, selecting roofs with minimal obstructions. For this research, a ground mount system was selected. For ground mounts, it is important to select locations away from large trees and buildings, as these will produce shading on the solar system when. The location should also not be in a valley and should be as flat as possible. The location is selected by zooming in and out of the map shown in Figure 46. Various map providers can be used, as shown on the right. This allows the designer to get the best image possible of the space available. Once the precise location is selected, the system specifications must be input, discussed further in Step 4.

Figure 45 - Map area selection in PVSol for the 3D modelling of a ground mount solar system.

Step 4 – System design, specification and assembly.

Step 4 is the process for designing the solar system in the 3D model space. The general process is defined by the tabs at the top, as shown in Figure 47 highlighted in green. The primary headings are as follows: Terrain view, object view, module coverage, module mounting, module configuration, cable plan. In terrain view, the horizon is defined. This allows the user to input any tall mountains near the solar system which may affect the low light performance of the system. Object view and module coverage are used when the solar system is being designed on a building and therefore is not relevant to this research. In module mounting the ground mount system is designed. In this research project, the system was designed as a 2V ground mounted system (2V being the number of modules in the vertical plane). The modules are titled at an angle equal to that of the system latitude (26 to 34 degrees). The specification of module used is first selected in first block shown in green in Figure 47. This allows the user to specify the module type and size that should be used for the project. The tilted ground mount system parameters are then defined by selecting the icon shown below in red. Once designed, the modules are deployed on the ground using the "fill area" button below. Clicking and dragging, allows the designer to deploy as many modules as required to suit the desired system size. In this case, three rows of 76 modules for a total of 228. 228 modules correlating to 124,26kW, as per the benchmark model.

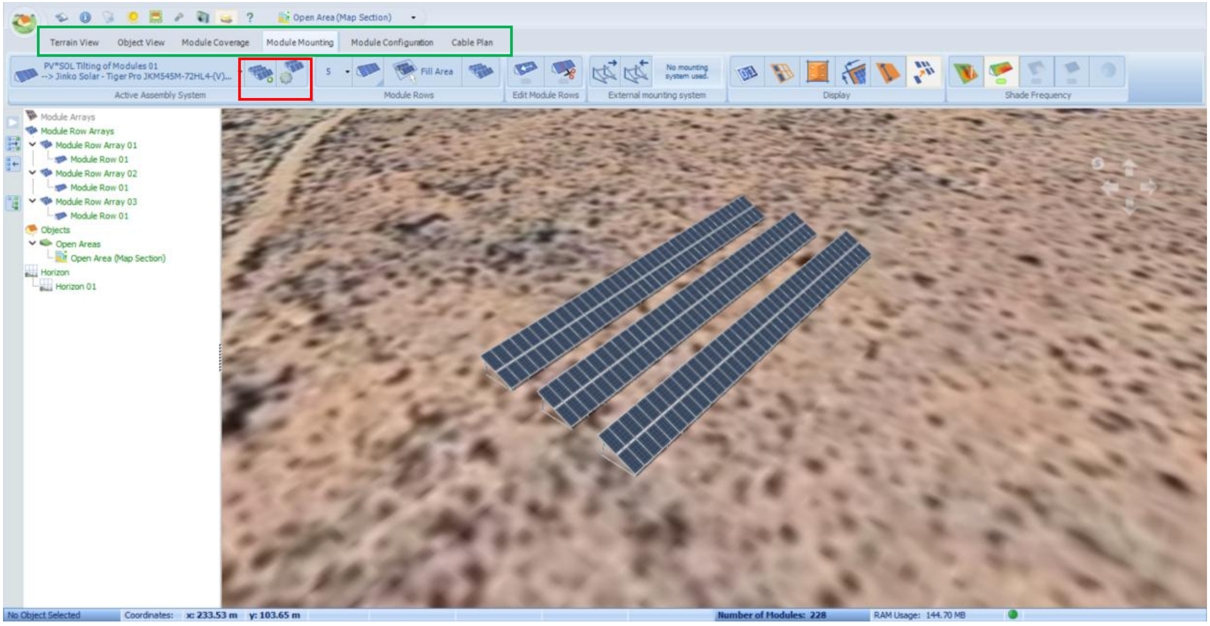


Figure 46 - 3D model space design for the benchmark ground mount solar system.

Step 5 – Setting the simulation parameters

Once the 3D model has been developed, and the necessary specifications have been defined, the simulation parameters must be set. This is done by selecting options and then simulation, as shown in Figure 48. The primary simulation changed depending on the site is soiling. For this research project it was selected as 5%.

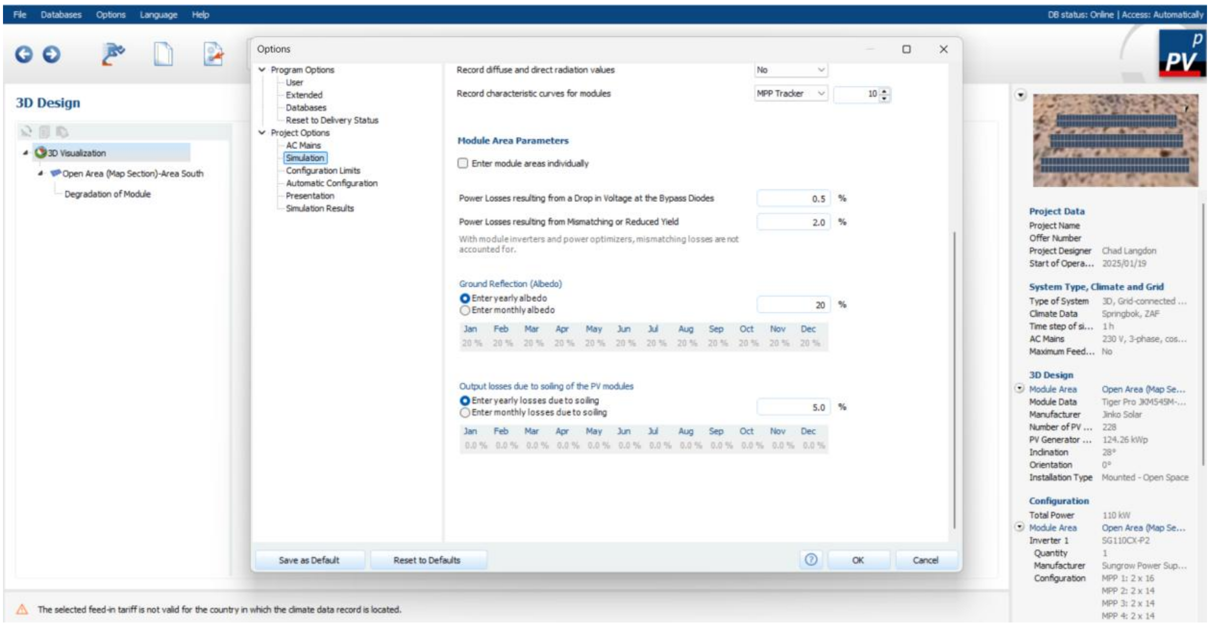


Figure 47 - Simulation parameter settings for the benchmark ground mount solar system model.

Step 6 – Specifying the cable losses and confirming the single line diagram.

Additional simulation parameters include defining the cables losses. This is done in the cable tab, as shown in Figure 49 below, highlighted in red. For small systems cable losses of approximately 3% are typical. Cables losses are calculated based on the voltage drop of the cable, which is dependent on the amount of current the cable is carrying, the length of the cable and the operating temperature.

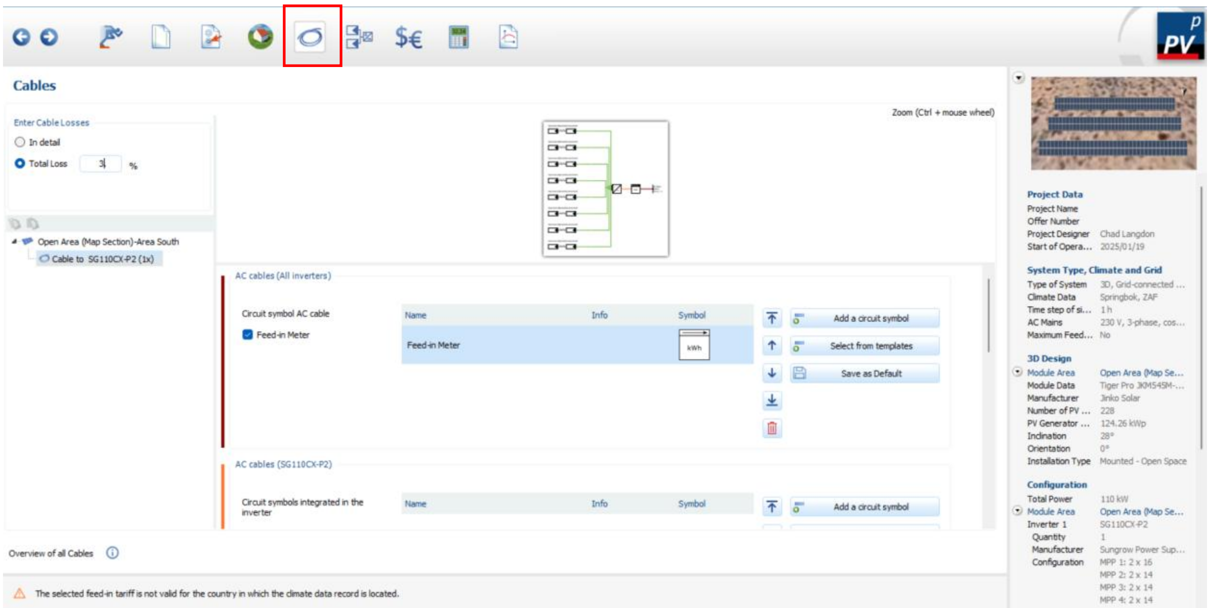


Figure 48 – Configuring the cable loss parameters in the benchmark solar system model.

Step 7 – Running the model and confirming the yields.

Moving from step 6 to step 7 automatically causes the simulation to run. The first output of the simulation running is the yield graph shown in Figure 50. Figure 50 shows the monthly expected yield from the solar system, as well as the total annual yield, In this case, 254 852 kWh/year, with a specific yield of 2 050 kWh/kWp. These two values are used an initial indication of the system performance. It is at the designer discretion to update the model to achieve the desired values. The second output of the system is detailed in step 8.

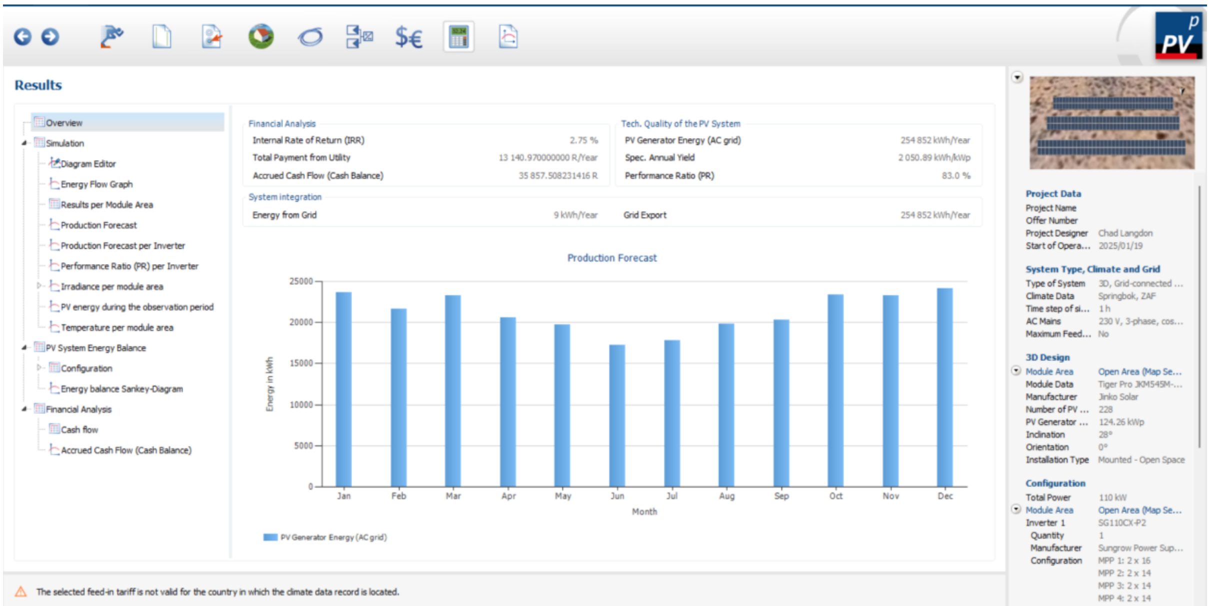


Figure 49 - Yield output and design interpretation of the benchmark solar system model.

Step 8 – Extracting the data and design report

The final step is to print out the design report and exporting the modelled data into a CSV file. The modelled data is exported in an hourly format for a full year. The hourly data can then be used in various models to assess the feasibility of the system compared to alternative sources of energy such as diesel, coal, wind etc… This is done in the presentation tab as shown in Figure 50

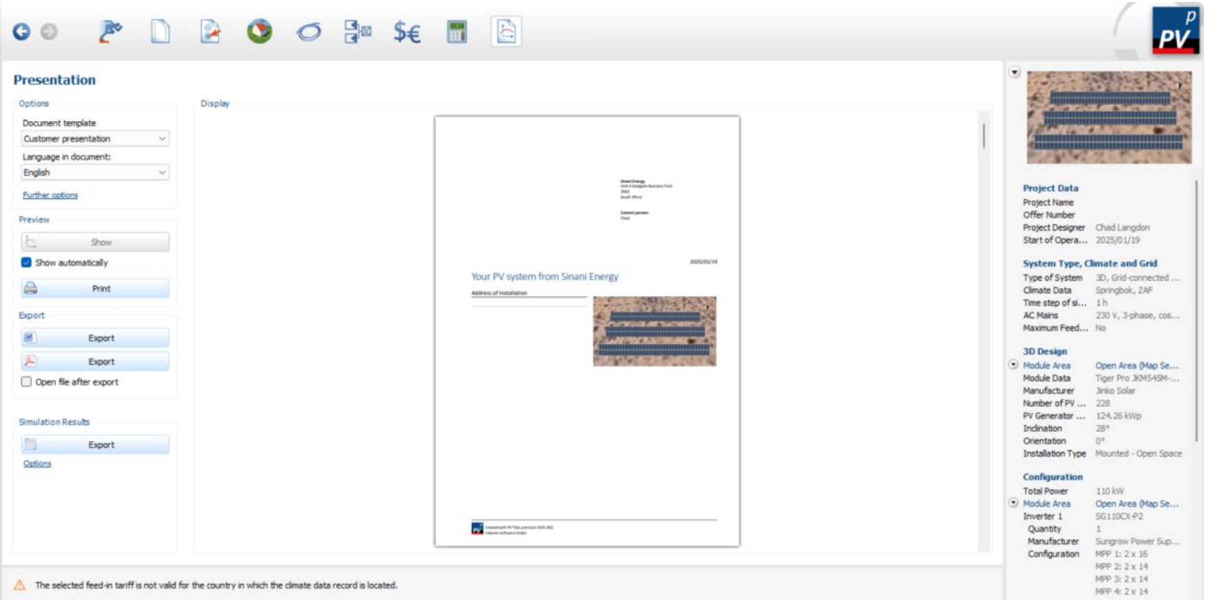


Figure 50 - Extracting data from the presentation tab for the benchmark solar system model.

Appendix D – Enapter electrolyser data sheet

The specifications of the Enapter electrolyser used in this research paper are shown below.

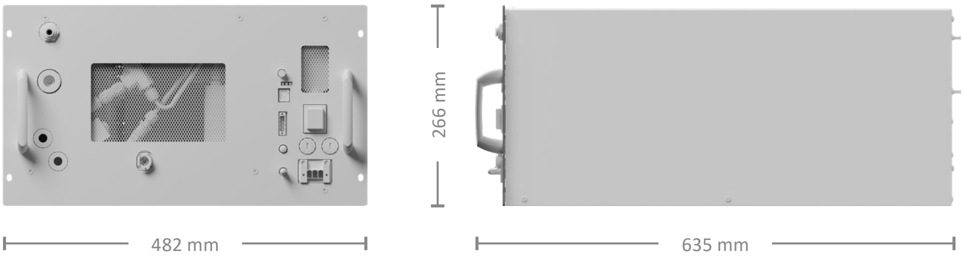
AEM Electrolyser
EL 4.1

Enapter's patented anion exchange membrane (AEM) electrolyser is a standardised, stackable and flexible system to produce on-site hydrogen. The modular design – paired with advanced software integration – allows set up in minutes and remote control and management. Stack this electrolyser to achieve the required hydrogen flowrate.

AEM Electrolyser EL 4.1
www.enapter.com/aem-electrolyser

Specifications

Enapter
AEM Electrolyser EL 4.1



Production rate	Up to 500 NL/h, up to 1.0785 kg/24 h
Hydrogen output purity	35 barg: 99.9% (< 1,000 ppm H_2O and < 5 ppm O_2) at 25 °C 8 barg: 98.8% (< 12,000 ppm H_2O and < 5 ppm O_2) at 25 °C
Output pressure	Up to 35 barg
Nominal power consumption per Nm³ of H_2 produced	4.8 kWh/Nm³, beginning of life
Operative power consumption	2.4 kW, beginning of life
Peak power consumption	3 kW
Heat dissipation **Max heat dissipation**	0.6 kW, beginning of life 0.9 kW, end of life
Standby power consumption[1]	0.3 kW
Power supply	220 – 240 V (AC), 50/60 Hz
Maximum water input conductivity	Minimum ASTM D1193-06 Type IV or recommended Type II or Type III[2]
Water consumption	~ 420 mL/h at 25 °C
Water input pressure range	1 – 4 barg
Ambient operative temperature range	5 °C – 45 °C
Ambient operative humidity range	Up to 90% humidity, non-condensing
IP rating	IP 20
Dimensions	W: 482 mm × D: 635 mm × H: 266 mm
Weight	42 kg
Space inside cabinet	6 U
Control and monitoring	Fully automatic with Enapter's EMS via 2.4 GHz Wi-Fi and Bluetooth, Modbus TCP over Ethernet
Conformity	CE mark according to the machine directive 2006/42/CE[3] UKCA mark according to Supply Machinery (Safety) Regulations 2008[4] CSA/ANSI B22734:2023 Ed.1 Hydrogen Generators Using Water Electrolysis - Industrial, Commercial, and Residential Applications[5]

[1] Standby refers to the condition in which no hydrogen is being produced and the auxiliary components are not powered.
[2] Please, check the Battery limits and the Owner's Manual for the complete requirements list
[3] The Electrolyser belongs to S.E.P. category according to Pressure Equipment Directive 2014/68/EU
[4] The Electrolyser belongs to S.E.P. category according to Pressure Equipment (Safety) Regulations 2016
[5] ETL recognized electrolyser versions only

Note: The product is under continuous improvement and the technical specifications might be subject to change. Please make sure to refer to our website for the most recent specifications.

AEM Electrolyser EL 4.1
www.enapter.com/aem-electrolyser

Enapter

Enapter

Assumptions (Enapter AEM Electrolysers)

CAPEX Values

Year	Year	Unit Cost
2022	AEM EL 4.0	€ 8,000
2023	AEM Multicore	€ 900,000
2025	Single-core electrolyser	€ 2,500
	AEM Multicore	€ 550,000

OPEX Values

	Value	Units
Electricity cost	0 - 0.05	€/kWh
Purified water cost	1.88	€/m^3
Insurance cost	1	% of CAPEX / annum
Insurance cost escalation	1	% / annum
Operations and maintenance (O&M)	1.5	% of CAPEX / annum
Discount rate	9.73	%

Technical Values

	AEM Multicore (2023)	AEM Multicore (2025)	AEM EL 4.0 (2022)	Single-core electrolyser (2025)
Power consumption	1008 kW		2.4 kW	
Production rate	210 Nm^3/h		0.5 Nm^3/h	
Nominal power consumption (beginning of life)	4.8 kWh/Nm^3			
System life	20 years			
Stack operating lifetime	>35,000 h	>50,000 h	>35,000 h	>50,000 h
Load factor	98%			
Water consumption	190 L/h	190 L/h	0.4 L/h	0.4 L/h

Grey & Blue Hydrogen Price Points

	Value
Grey & Blue hydrogen production cost range	1-4 EUR/kg [1]
Commercial price of grey hydrogen at refueling station	>9.85 EUR/kg [2]
Cost of hydrogen refuelling station infrastructure	5 EUR/kg [3]

[1] Min-Max range of values reported by IEA, IRENA, United States DOE, KPMG, Goldman Sachs

[2] Hydrogen refueling stations in Germany (9.85 EUR/kg), UK (16.55 EUR/kg) by S&P Global Commodity Insights

[3] Hydrogen refueling station capital and operation costs by the International Council of Clean Transportation (icct)