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Green Hydrogen Driven by Wind and Solar—An Australian Case Study

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Highlights:

1. The modelling shows that green hydrogen would be viable this decade, so it suggests that planning for green hydrogen should begin immediately.
2. The analysis shows that green hydrogen would contribute to electrical system reliability and stability.

Abstract: The energy transition to wind and solar opens up opportunities for green hydrogen as the wind and solar generation tends to bring electricity prices down to very low levels. This paper evaluates whether green hydrogen can integrate well with wind and solar PV to help with improved management of the South Australian electricity grid. Green hydrogen can use membrane electrolysis plants during surplus renewable energy periods. This hydrogen can then be electrified or used in industry. The green hydrogen system was analysed to understand the financial viability and technical impact of integrating green hydrogen. We also used systems engineering techniques to understand the system holistically, including the technical, social, environmental, and economic impacts. The results show opportunities for the system to provide seasonal storage, grid firming, and reliability services. Financially, it would need changes to electricity rules to be viable, but without those changes, our modelling suggested it would be financially viable within this decade.

Keywords: Australia; electrolysis; energy transition; hydrogen; solar; wind

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1. Introduction

This report assesses a green hydrogen plant's viability in integrating more solar and wind energy into the South Australian electricity system. The literature shows this is technically feasible, but there is no evidence of financial feasibility. This research is to figure out the level of financial viability.

Australia's transition to renewable energy accelerated in 2001 with new legislation to promote renewable generation infrastructure (Nelson et al., 2013). Since then, energy policymakers have utilised carbon pricing, renewable energy certificates, renewable energy targets, and framework initiatives to drive renewable energy investment (Byrnes et al., 2013). These policies resulted in Australia's total renewable share of total electricity generation increasing to 24% in 2019 (Clean Energy Council, 2020). The percent of electricity sourced from renewable sources must increase to around 85% by 2050 to achieve the Paris Agreement's sustainability targets, which Australia formally ratified in 2016 (Gielen et al., 2019).

South Australia leads the nation in implementing renewable technology (Parkinson, 2019b), and this article focuses on green hydrogen in South Australia. Due to the rapid nature of its energy transformation stemming from reduced dependence on fossil fuels, South Australia is a fascinating case, with its final coal plant closing in 2016 (Harmsen, 2016). However, the predominance of wind and solar PV in the South Australian energy mix has promoted concern for future energy supply reliability (Mikkola & Lund, 2016).

The primary issue created by a high reliance on solar and wind energy is the intermittency of output due to supply variability. From 2016 to the present, SA's electricity blackouts have occurred five times (Warren, 2017) at costs of up to $367 million per event (Harmsen, 2016). The worst outages disabled two transmission lines and caused local energy generation and supply to cease (Harmsen, 2019).

Green hydrogen can provide electricity supply during peak periods of demand and, at the same time, alleviate reliability issues by offering energy storage and production capacity while delivering on-demand, dispatchable electricity. Hydrogen production can use excess renewable energy, and then during a high electricity demand period, we burn the hydrogen to contribute to the network. This use of green hydrogen can reduce the frequency of blackouts and reduce costs to consumers. Green hydrogen would supply a flexible energy source option in the South Australian grid, including storing seasonal energy and offering demand response mechanisms. This research assesses the financial viability of green hydrogen.

The research aims to address three current shortcomings of South Australia's energy grid; these are:

- Increase the reliability of energy supply to the South Australian grid through added generation, seasonal storage, and dispatchable energy sources.
- Reduce variability of energy prices for South Australian consumers.
- Increase the energy grid's stability by supplying an additional opportunity to remove energy from the grid and store it locally.

The proposed solution aims to support South Australia in achieving these goals. However, clarity of the financial viability is paramount to promoting the proposed solution's implementation. Thus, this research utilises Net Present Value (NPV), Internal Rate of Return (IRR) and Levelised Cost of Electricity (LCOE) and has been undertaken from the perspective of a private entity rather than that of a government body or Departments of Industry, Science, Energy and Resources. Therefore, we have limited our focus to reflect a private investor's research needs (financial return, rather than economic return). However, this research also explores the impacts on the South Australian community, including stimulating the local economy and improving the electricity grid's reliability.

Despite observing the feasibility of green hydrogen projects from a private entity's perspective, with financial return as the primary focus, we acknowledge the importance of societal and environmental benefits. Port Augusta on the Spencer Gulf in South Australia contains ideal characteristics to house a green hydrogen project. These include its proximity to several renewable energy sources and access to fresh and saltwater. Furthermore, the site is proximate to the distribution network, which adds to the project's viability. Additionally, when the Northern Power Station closed in mid-2016 (Harmsen, 2016), several hundred workers lost employment. By supplying an opportunity to upskill these workers, the Port Augusta region could see significant economic rejuvenation by housing a green hydrogen plant, potentially reducing unemployment.

2. Literature Review

This review covers the current understanding of the energy transition and its relationship with the South Australian energy network, including the Australian and South Australian energy markets, existing renewable energy production sources, the Energy Transition and its effect on energy supply, and innovative solutions using dispatchable technology. The review concludes by examining hydrogen's use for storage and energy production and finding existing hydrogen models.

Fossil fuels have historically dominated the Australian energy generation market, accounting for 82.9% of Australia's energy mix (Environment and Energy, 2019). The market's fossil fuel utilisation is black coal (46.6%), brown coal (13.8%) and gas (20.6%), whereas renewables only have a market share of 17.1%, with the bulk contributed by hydro (6.1%), wind (5.8%) and solar (3.8%) (Environment and Energy, 2019).

Despite this, South Australia's electricity system differs from other states due to its higher renewable share of the total electricity supply of 51%. In South Australia, wind (40%) and solar (10%) are the main contributors, whilst natural gas accounts for the entire fossil fuel energy production (Environment and Energy, 2019). Currently, the demand on the South Australian grid is considered "peaky" due to the significant shifts in loads (Parkinson, 2019a), with the network averaging around 1,500MW but fluctuating between 500MW and 3000MW loads (Day, 2019).

South Australia's ability to achieve 50% renewable energy has been through wind and solar energy adoption over the past 15 years. The state shifted from zero renewable capacity to 2,675 MW

(Parkinson, 2019a). South Australia is a world-class region for wind and solar due to its location and natural resources (Day, 2019). South Australia's shift to renewable energy production has led to a pipeline of wind, solar and storage projects equaling 14,551 MW, or an investment of $21.5 billion (Day, 2019).

Inertia reflects the power of a spinning plant within an electricity system needed to maintain the electrical voltage and frequency within an acceptable range. As wind and solar generation do not provide any measurable amount of inertia, renewables of this kind are limited to 50% of total instantaneous generation (Finkel et al., 2017). Kharel and Shabani (15) support this need for added inertia. They describe renewable energy generation sources such as wind and solar as highly weather dependent and not useful for a continuous supply. Kharel and Shabani (2018) suggest that a suitable renewable storage system is the most viable, sustainable solution. ARENA (2018), in their economic comparison of dispatchable renewable electricity options, support this, adding that renewable storage solutions will experience cost reductions in correlation with their global growth in deployment.

The South Australian Energy market is undergoing a transition to renewables. Market reliance on fossil fuel sources, such as coal, is reducing (Environment and Energy, 2019), and the market is shifting to VRE generations (ARENA, 2018). This transition is exemplified in Figure 1, which shows that due to the nature of VRE, dispatchable sources are required to balance the relationship between supply and demand to provide system reliability (ARENA, 2018). ARENA (2018) describes dispatchable sources' requirements as flexibility (fast start-up) and guaranteed power output, ultimately limiting the number of available renewable technologies.

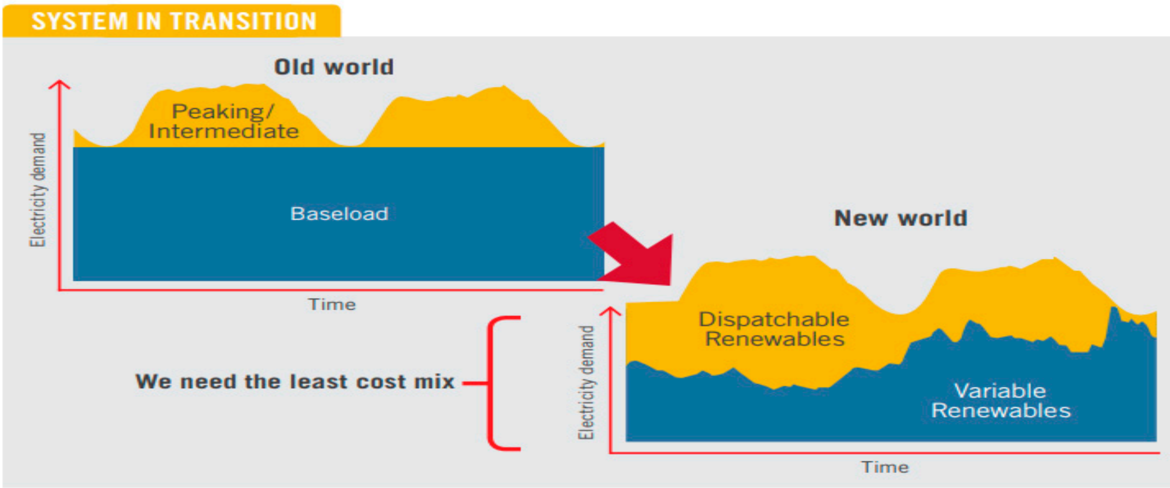

Figure 1. Energy Transition (ARENA, 2018).

The effect of South Australia's transition to renewable energy has been observed by Macdonald-Smith (2015). It has been argued that the closure of Alinta's Power Station in Port Augusta directly led to the loss of 478 jobs (Macdonald-Smith, 2015). The area is expected to be impacted further as the local economy was strongly linked to the power station, contributing 14-16% ($160 million) to the local economy (Regional Development Australia, 2016). Reid (2017) further explored this closure's impacts, asserting that many of these workers cannot find new work within the power generation industry, with proposed renewable energy projects not progressing to their labour-intensive phase.

Table 1 shows potential dispatchable technologies and uses available literature to examine the suitability of each.

Table 1. Dispatchable energy technology comparison.

Dispatchable Technology	Strengths	Limitations
Battery Storage	Storage source provides grid stability, reduce energy costs and	Poor long-term storage (ARENA, 2018)

	integrates renewable sources into the grid (Toscano, 2019)	
Pumped Hydro Storage	Technically mature, widely used up to 97% of global storage (Kharel & Shabani, 2018)	Geographical requirements, water availability, and elevation requirements (Kharel & Shabani, 2018)
Hydrogen	Carbon-free emission, long-term storage (ARENA, 2018)	Technically immature, costs (ARENA, 2018)
Nuclear	Provide baseload capacity (Agency, 2012)	Slow start-up time (Agency, 2012). Legislation preventing the construction and operation of new plants (Agency, 2008)
Natural Gas	Prevalent in South Australia (Environment and Energy, 2019).	It is a fossil fuel and produces carbon emissions (Australian Gas Networks, 2020).
Interconnector	Improve energy security, lower energy prices and increase economic activity (Scopelianos, 2019)	Dependence on other states (Warren, 2017)
Bioenergy	Cost-Effective, produced from wastes (ARENA, 2020)	Availability of waste and low-cost feedstock (ARENA, 2020)

After considering the literature on the above options, we chose to analyse green hydrogen further.

2.1. Hydrogen Technology

The implementation of hydrogen systems includes hydrogen production, hydrogen storage and re-electrification.

There are five categories of hydrogen production technology:

3. Electrochemical or electrolysis uses electricity to split water into hydrogen and oxygen (CSIRO, 2018), and alkaline electrolysers (AE) and proton exchange membrane (PEM) electrolysers are the only commercially available technologies (IEEFA, 2020),
4. Thermochemical steam methane reforming (SMR) with and without carbon capture,
5. Coal or biomass gasification or pyrolysis,
6. Biological production, and
7. Emerging technologies (CSIRO, 2018).

Hydrogen storage can be achieved in large quantities and for extended periods. Hydrogen can fill the energy storage void currently experienced in the energy market (Andersson & Grönkvist, 2019; Gerwen et al., 2019). Hydrogen can be stored in, liquefied, pressurised, absorbed or in chemical forms (Andersson & Grönkvist, 2019).

Energy stored in the hydrogen can be converted back to electricity (e-electrification). This re-electrification can be done with a gas turbine (GE-Power, 2020) or fuel cells. The fuel cell process is a reversed electrolysis process (Gerwen et al., 2019) and boasts high efficiency, emission-free power generation, and fast start-up and shut down capabilities.

2.2. Hydrogen Implementation

The Institute for Energy Economics and Financial Analysis (IEEFA) has identified 50 current and viable large-scale hydrogen projects globally in its August 2020 report (IEEFA, 2020). The international projects combined have a total hydrogen capacity of 4 Mtpa, with a renewable power capacity of 50 GW. Australia is one of the leading countries in adopting hydrogen, with up to nine proposed large-scale projects, totaling a capacity of 1496 ktpa – more than any other region globally.

KPMG has developed the H2City assessment tool to model hydrogen implementation within communities across Australia (KPMG, 2019). The tool enables potential investors and communities to assess the locale's suitability and implementation methods, supplying an early screening method. Similarly, Location SA (2020) has developed an interactive map displaying infrastructure locations critical to developing hydrogen production systems. This tool enables investors to evaluate the potential locations of hydrogen plants.

The literature review showed a contemporary understanding of the energy transition and its relationship with the South Australian network. The gap this research fills is whether green hydrogen is viable in South Australia.

2.3. Summary

Renewable energy is a very current and relevant issue given the ever-deteriorating nature of the global climate. Green hydrogen supplies an opportunity to support renewable energy development. Its cost is set to fall by up to 64% by 2040 (Wood Mackenzie, 2020); this highlights that early research and implementation could help steer Australia to a more sustainable future. South Australia's renewable energy capacity provides an ideal location to evaluate the feasibility of using green hydrogen.

3. Method

3.1. Methodology

This research explores the potential integration of hydrogen within the South Australian electricity grid. This research includes many considerations and assessment criteria, limiting the accuracy of any potential modelling given the copious quantities of input parameters needed, meaning significant adjustments must be made before the model is appropriate for the South Australian context. Many models are available for public use online, although these models bias towards the developer's interests. Further, these models were difficult to validate, resulting in difficulty in critically analysing results.

Therefore, we decided that developing a new model would be needed to assess the hypothesis appropriately. Our modelling uses technical and financial assessment from a private entity's perspective would be most beneficial, given the opportunity to capitalise on electricity unreliability in the state. Hence, we developed a model to determine key investment factors using industry research and expert interviews.

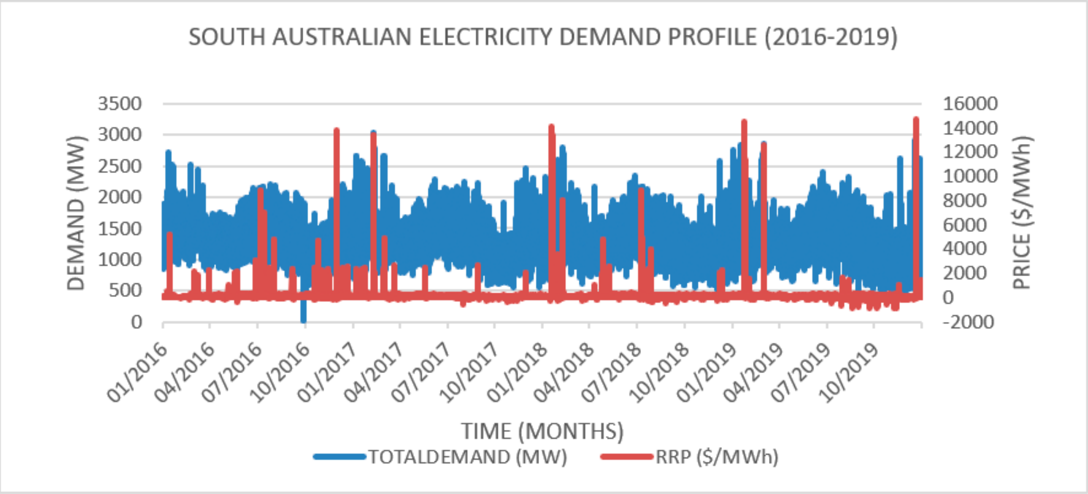

Figure 2. South Australian Electricity Demand Profile (2016 - 2019).

This report hypothesises that using an electrolyser to generate significant quantities of storable hydrogen will allow re-electrification as the network requires. Therefore, South Australia's electricity network's reliability is improved by harnessing the existing renewable infrastructure's natural variability. The method for hypothesis testing is outlined in Section 3.2.

3.2. Method Detail

Before implementing a hydrogen system, the owner would need significant research and validation. Hydrogen plants of this type are new to Australia; hence, there is a need to model and predict the expected learning rate, which will help figure out the investment case for a private entity.

Figure 3 shows the proposed hydrogen system to help improve the reliability of South Australia's electricity network. The significant capital investment includes the hydrogen electrolyser and a gas turbine that runs on 100% hydrogen gas.

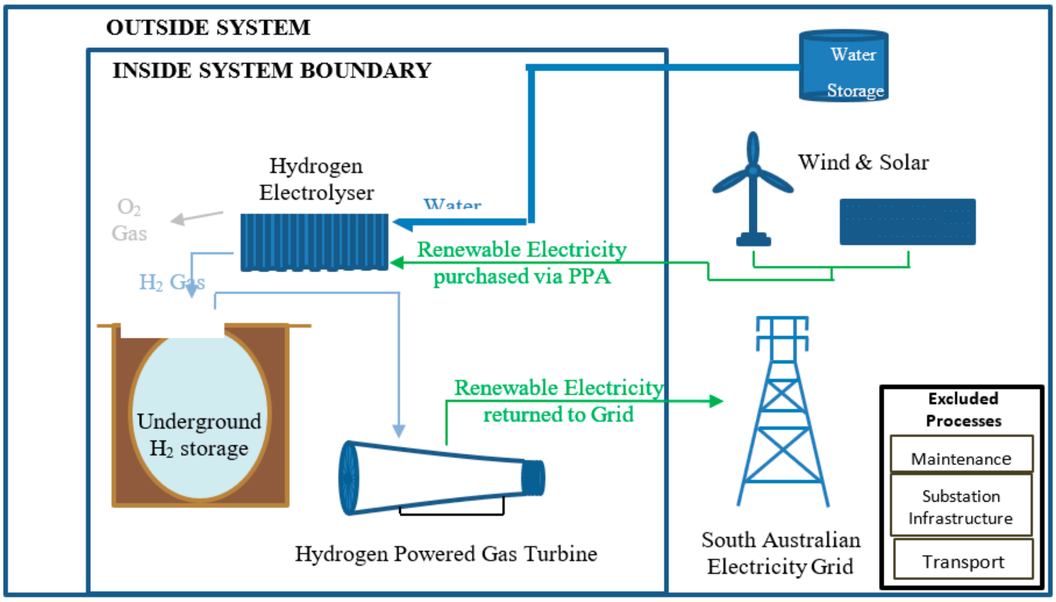

Figure 3. Proposed System of Green Hydrogen in South Australia.

Figure 3 defines the system boundary of the hydrogen hypothesis. At the beginning of the system, renewable electricity is sourced from South Australia's existing renewable infrastructure, including wind and solar farms. This electricity is then purchased through a Renewable Power Purchase Agreement (PPA) when the spot price of electricity drops below $50/MWh and is used to power a PEM Electrolyser, which, in conjunction with water, produces hydrogen. This hydrogen is stored in underground storage. It will remain stored until the spot price for electricity reaches $240/MWh. The re-electrification process occurs via a gas turbine, thus creating green electricity. This electricity is then distributed back into the South Australian grid, representing the end boundary of the system in this research.

Further, the electrolyser's fast ramp rate for hydrogen generation allows the system to take electricity out of the grid when its frequency exceeds the regional standard. Conversely, when the grid frequency is below the regional standard, the re-electrification peaking system's fast ramp rate can distribute electricity back into the grid, bolstering the supply's overall stability.

Statistical supply and demand modelling predicted the state's energy requirements and assessed the hydrogen system's effect on the energy deficit while verifying the financial viability. The modelling used South Australian 30-minute aggregated historical price and demand data for the calendar years 2016-2019 to forecast the levels of Hydrogen the system could generate, store and re-electrify (AEMO, 2020c). The modelling found the intense volatility of the cost of electricity, which, when coupled with storage mechanisms, highlighted an opportunity to use arbitrage methods to generate revenue. Figure 4 emphasises the operating technique to realise this strategy, indicating when electricity is purchased, stored, and sold. Figure 4 highlights that the system purchases electricity for 1,900 hours per year and sells only 200 hours yearly, complemented by long storage periods.

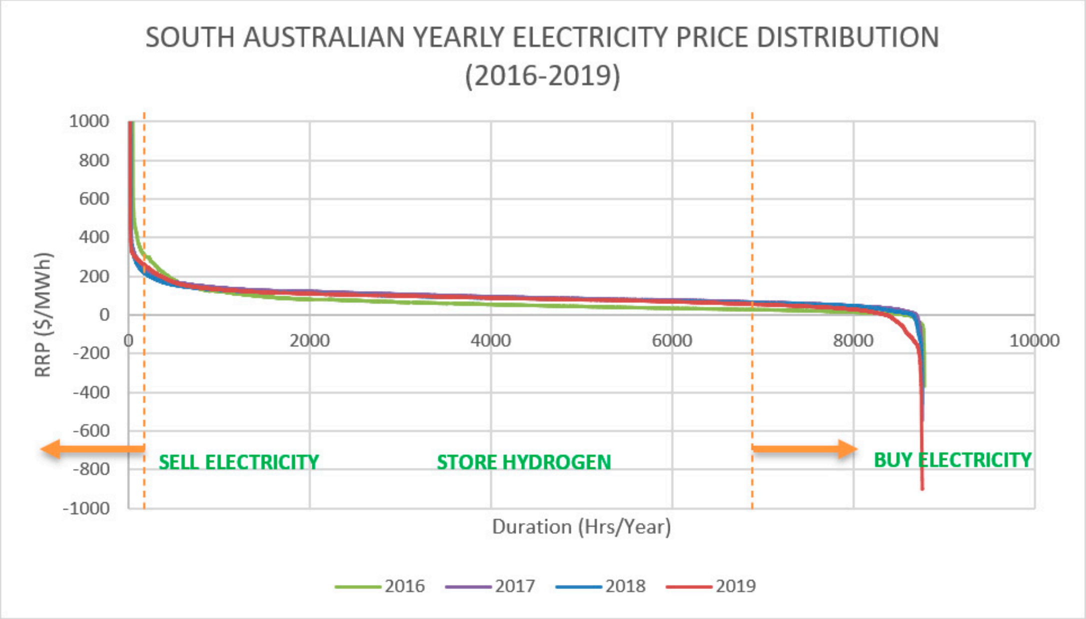

Figure 4. South Australian Electricity Price Distribution (2016-2019).

Electricity would be bought during the day when the electricity demand is low (and the electricity spot price is low), as shown in Figure 5. The phenomenon shown in Figure 5 is due to surplus PV electricity during the day, leading to low electricity prices.

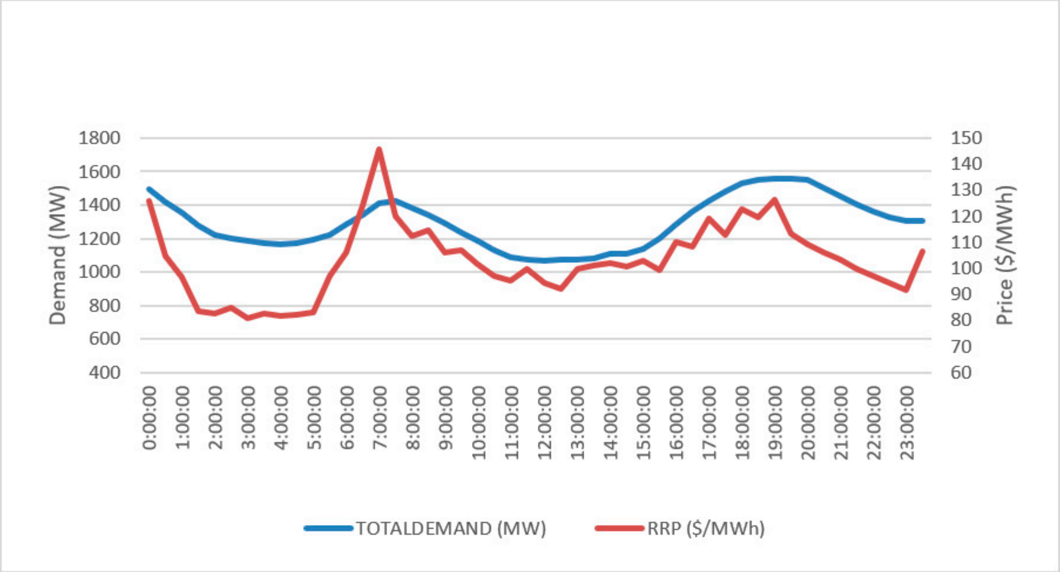

Figure 5. Average Intraday Electricity Price and Demand Fluctuations (Duck Curve).

Figures 6 and 7 show the system operating strategy. Figure 6 shows when hydrogen is produced, and Figure 7 shows when hydrogen will be burnt to power the gas turbine and generate dispatchable electricity for the South Australian grid.

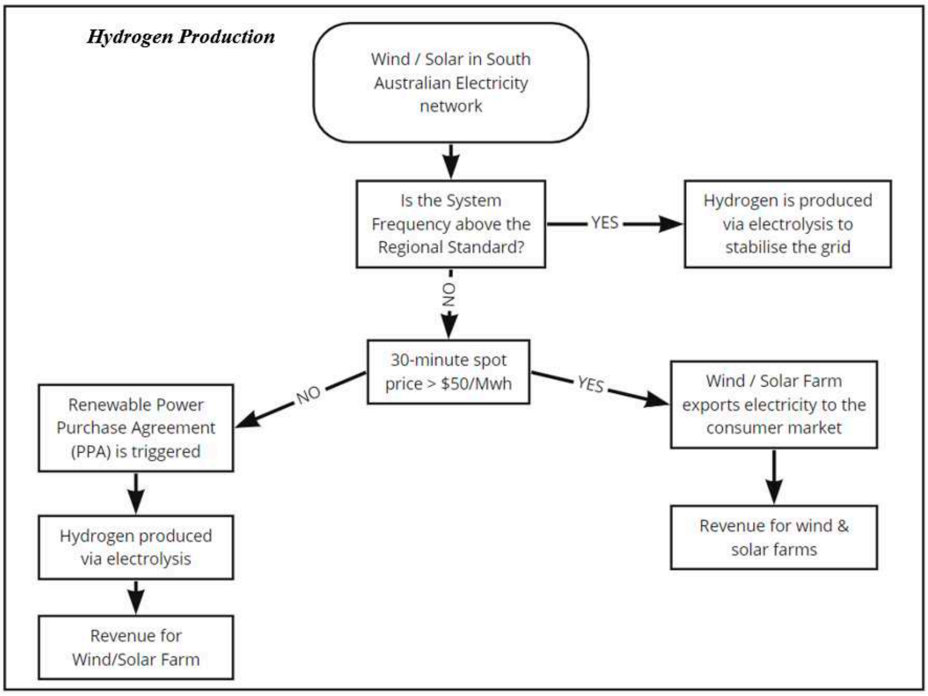

Figure 6. Hydrogen Production Flow Chart.

The developed model allows a threshold electricity spot-price input, selected at $50/MWh. The electrolyser will run and produce storable hydrogen when the spot price lies below this point. Prices below this are during low demand and surplus renewable energy; conversely, prices above are typical when high demand and supply of renewable energy meet demand (Wagner, 2016). A renewable PPA provides favourable benefits to renewable energy developers who require a PPA to reduce their risk of losing revenue opportunities due to excess supply compared to demand. A renewable PPA is also beneficial for producing hydrogen, as electricity costs can be low and sometimes negative (Rai & Nunn, 2020).

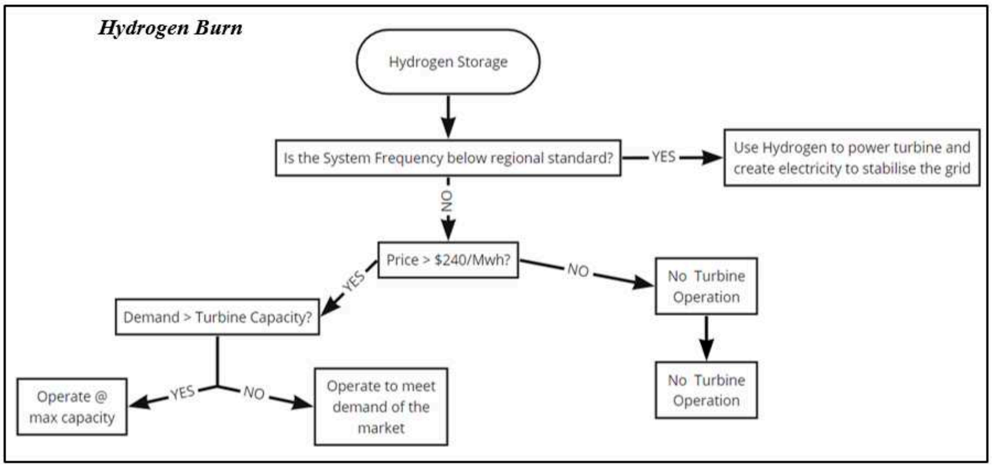

Figure 7. Hydrogen Burn Flow Chart.

Likewise, the spot price to sell electricity can be input into the model, and the impact analysed. When electricity prices rise above the $240/MWh on the market, the hydrogen-powered gas turbine will run at the market-required capacity.

The purpose-built model provides insight into the system's financial viability and is coupled with finding enhancements to electricity supply reliability and price stability. A hydrogen gas turbine's technical characteristic is utilised alongside the existing AEMO 30-minute data to dynamically determine the required electrolyser size. Hydrogen flows into and out of the storage vessel (kgH_2 vs. time) were modelled as though the system had been used throughout the previous four calendar years, aiming to demonstrate the feasibility of green hydrogen.

The model was created to analyse energy price fluctuations and their correspondence with the available energy supply from a financial perspective. This also shows a hydrogen electrolyser's optimal operating capacity and functioning time for maximum profit. The model also uses a series of expenditures and income assumptions to calculate the system's Net Present Value (NPV) and derive a Levelized Cost of Electricity (LCOE), thus allowing the payback duration and system reliability to be found.

3.3. Summary

Many methodologies are available to investigate the hydrogen hypothesis, although while many models already exist, they require significant alterations to assess the proposed solution and are challenging to validate. We hypothesise that we can reduce electricity prices and stabilise the South Australian grid using a hydrogen electrolyser producing storable hydrogen, which is then burnt in a gas turbine for dispatchable electricity,

The proposed system boundary highlights the factors that will require procurement and the areas a potential investor will control. The proposed model allows price input to buy electricity through a PPA and sell electricity produced through the hydrogen system. The operating strategy is key to the project's success. This operating strategy includes several factors controlling how the system would work, including when it will produce and store hydrogen, burn hydrogen, and sell electricity. Tests of the model's effectiveness and implications for the South Australian grid are in Section 4.

4. Results

4.1. Location Assessment

Location assessment selects an area that will support a hydrogen system's needs whilst helping the local community. Location choice requires several key considerations – proximity to water and power infrastructure, logistical considerations relating to storage and transport, and impact on local communities.

The creation of hydrogen via electrolysis requires two principal inputs – electricity and water. Figure 8 shows South Australia's existing energy infrastructure. Our goal was to find a location with connectivity to existing infrastructure and resources to reduce capital costs; this involved assessing transmission line routes, water accessibility and connectivity with other South Australian regions. Traditionally, freshwater has been required to produce hydrogen; however, technological improvements have meant that hydrogen production from seawater is possible during water scarcity, providing a perpetual alternative to freshwater (Abdel-Aal et al., 2010) and encouraging seafront positioning.

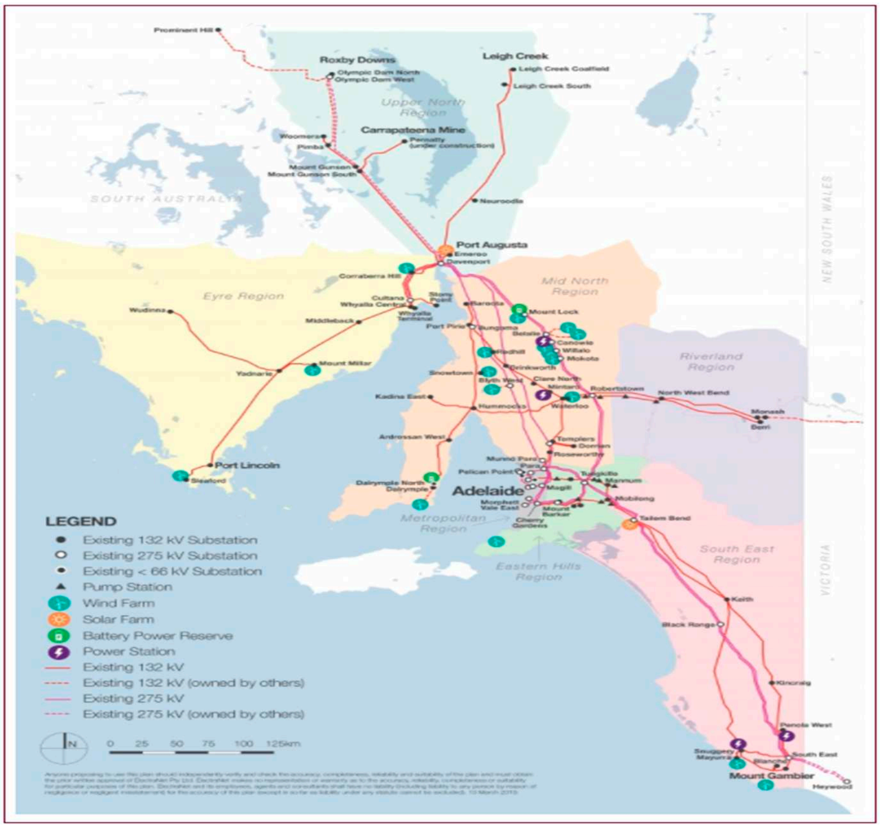

Figure 8. South Australian Network Map (ElectraNet, 2019).

The Port Augusta region is within a defined Renewable Energy Zone (REZ), with over 1,100MW of new generation infrastructure proposed (AEMO, 2020b). Port Augusta is an ideal location for large-scale hydrogen generation due to its location in a REZ, its water mains access from the Murray River, its adjacent seawater, local existing energy infrastructure with several substations and transmission lines feeding through the city (Figure 8) which would allow the hydrogen system direct access to the energy grid with connectivity between South Australia's Eyre, upper north and mid-north regions, an opportunity to source renewable energy from local energy generation such as the planned 252 MW Lincoln Gap Wind Farm Stage 2 (NEXIF, 2019) and 375MW Port Augusta Renewable Energy Park (DP Energy2020), and the existing 126MW Lincoln Gap Stage 1 Wind Farm, local aquifers have been nominated as the preferred option for green hydrogen storage due to fewer cost implications than a manufactured storage vessel and decreased risk of contamination compared with depleted hydrocarbon fields (Letcher, 2016). The South Australian Gulf, including Port Augusta, houses local aquifers of varying sizes (BOM, 2012), and available skilled local labour due to an unemployment rate of 11.2%, partly due to the Northern Power Station closing (Macdonald-Smith, 2015).

The location of Port Augusta, South Australia, has connectivity to supporting infrastructure. However, the financial viability of implementation is unclear and is the focus of this research.

4.2. Capital and Operating Expenses of the Hydrogen System

Factors that affect the financial viability of hydrogen technologies can be separated into the following categories: Capital costs (CAPEX), operation and maintenance costs (OPEX), plant size, capacity factor, efficiency, asset life, replacement costs, technology learning curve (based on technology maturity), electricity procurement strategies and financial parameters including risk, Weighted Average Cost of Capital (WACC) and real discount rates (CSIRO, 2018).

Hydrogen production through PEM electrolysis is the first process within the plant system boundary. PEM electrolysis inputs are water and electricity, with electricity having the highest fiscal impact (43). Therefore, the level of contribution depends heavily on electricity procurement methods.

Four methods of obtaining electricity for PEM electrolysis were considered: grid electricity, dedicated renewables, renewable power purchase agreement (PPA), and curtailed renewables. Table 2 supplies a comparison of the different electricity procurement options.

Table 2. Electricity Procurement Options Comparison.

	Grid Electricity	**Dedicated Renewables**	**Renewable PPA**	**Curtailed Renewables**
Description	Source electricity directly through a grid connection and pay retail electricity prices. Supply grid firming services by running when demand is low and ramping down when demand is high.	Build renewable energy projects "behind the meter" and feed electricity directly into the electrolyser.	Source renewable grid electricity to offset emissions. Supply grid firming services by running when demand is low and ramping down when demand is high.	Build renewable energy projects connected to the grid, and when surplus renewable electricity is available, use this to feed the electrolyser.
Emissions Intensity (kgCO$_2$ per kgH$_2$)	10	0	0	0
Revenue Streams	Arbitrage, FCAS, grid firming services and cap contracts.	Large-scale generation certificates, FCAS and grid firming services.	Arbitrage, large-scale generation certificates, FCAS and grid firming services.	Large-scale generation certificates, FCAS and grid firming services.

The model assumes a PPA with a renewable energy developer will be adopted to procure electricity; this ensures the process is green (Dincer, 2012). Therefore, the modelling does not consider capital and operating costs associated with renewable energy development; we consider electricity purchase costs (Gorre et al., 2019). The renewable PPA costs fluctuated with the South Australian 30-minute aggregated historical price and demand data (AEMO, 2020c).

PEM electrolysis is well understood, and its economics and overall viability at a large scale are straightforward (Shiva Kumar & Himabindu, 2019). This article's modelling of PEM electrolysis uses currently available commercial electrolysers (Parra & Patel, 2016). Residual uncertainty is reflected by the variance in CAPEX and OPEX's cost estimates for PEM electrolysis, as shown in Table 3.

Table 3. Electrolyser CAPEX and OPEX based on different plant capacities.

Electrolyser Size (MW)	CAPEX ($/kW)	OPEX (% of CAPEX/year)	Source
0.025	3970	2%	(Parra & Patel, 2016)
0.95	2600	5%	(CSIRO, 2018)
1	3496	2%	(CSIRO, 2018)
1	1315	2%	(Parra & Patel, 2016)
10	918	2%	(Parra & Patel, 2016)
100	720	2%	(Parra & Patel, 2016)
100	690	1%	(Nguyen et al., 2019)
1000	620	2%	(Parra & Patel, 2016)

This article assumes a relationship between electrolyser CAPEX and electrolyser size as follows:

$$\boldsymbol{Electrolyser\ CAPEX\ (\$/kW) = 1937.3 \cdot Electrolyser\ Size\ (MW)^{-0.195}} \quad (1)$$

The required electrolyser size directly depends on the system's capacity factor and load requirements (Wanjiku et al., 2011). Thus, the required electrolyser size is calculated as follows:

$$\boldsymbol{Electrolyser\ Size\ (MW)} = \frac{\boldsymbol{Required\ H_2\ Output * Electrolyser\ Efficiency}}{\boldsymbol{CF_{Electrolyser}}} \tag{2}$$

The capacity factor (CF) in energy systems is the percentage of actual output compared to an asset's total possible output. The characteristics that impact the CF of an electrolyser vary significantly, however, they are primarily based on the electricity procurement strategy. Our research assumed that electricity procurement would be sourced through a renewable PPA, where electricity is bought when the spot price is below $A50/MWh. The assumption that we would use a renewable PPA at a spot price below $A50/MWh formed the basis of the electrolyser capacity factor using the following formula:

$$\boldsymbol{CF_{Electrolyser}} = \frac{\boldsymbol{Hours\ where\ price < \$50/MWh}}{\boldsymbol{Hour\ per\ year}} * \boldsymbol{100} \tag{3}$$

Table 4 shows the CAPEX and OPEX costs of the various storage technologies and indicates from a financial perspective that underground natural storage mechanisms are the most feasible option. However, underground storage may not be applicable for each case based on geological requirements. We have modelled this article using an underground aquifer to store the hydrogen. There are aquifers in the Port Augusta area, though this would require further research (42).

Table 4. Hydrogen Storage Technologies CAPEX (for equipment only, not system).

Physical Form	Storage Mechanism	CAPEX ($/kgH$_2$)	Source
Pressurised	Aboveground Vessel	612	(Kharel & Shabani, 2018)
Pressurised	Belowground vessel	612	(Kharel & Shabani, 2018)
Pressurised	Carbon Fibre Vessel	1460	(Gerwen et al., 2019)
Pressurised	Salt cavern	35	(Gerwen et al., 2019)
Pressurised	Depleted gas field	6	(Gerwen et al., 2019)
Pressurised	Aquifer	14	(Gerwen et al., 2019)
Liquefied	Cryogenic vessel	257	(Gerwen et al., 2019)

Finally, hydrogen re-electrification is considered. Hydrogen-fuelled gas turbines represent an opportunity in that traditional gas turbines can be moderately re-designed to run on 100% Hydrogen (Chiesa et al., 2005). The CAPEX and OPEX costs of the technology are shown in Table 5.

Table 5. Hydrogen Re-electrification Technologies CAPEX and OPEX.

Technology	CAPEX ($/kW)	OPEX (% of CAPEX/year)	Efficiency as per Higher Heating Value (HHV)	Source
Hydrogen fuelled gas turbine	820	3%	38%	(Gerwen et al., 2019)

Learning curves relate production costs to accumulating experience with each new technology. Therefore, mature technologies usually have smaller learning rates, while emerging technologies are subject to more considerable cost reductions. Hydrogen is the most abundant chemical globally, but hydrogen production via PEM electrolysis is novel (Shiva Kumar & Himabindu, 2019). Furthermore, associated infrastructure, including storage technologies and hydrogen-fuelled gas turbines, will likely be subject to learning rates (Schoots et al., 2008), bringing their prices down. Table 6 summarises 30-year learning rates for hydrogen technologies.

Table 6. Expected Annualised Learning Rates for Hydrogen Technology (Advisian, 2017).

	2020	2025	2030	2040	2050
CAPEX – PEM Electrolysis	4%	4%	2%	2%	2%
OPEX – PEM Electrolysis	3%	3%	1.5%	1.5%	1.5%
CAPEX – Storage Technologies	2%	2%	0.2%	0.2%	0.2%

OPEX – Storage Technologies	1.5%	1.5%	0.2%	0.2%	0.2%
CAPEX – Hydrogen Fuelled Turbine	4%	4%	2%	2%	2%
OPEX – Hydrogen Fuelled Turbine	3%	3%	1.5%	1.5%	1.5%

4.3. Operational Strategy & System Size

Revenue provides the only mechanism that positively impacts the NPV, so revenue is a critical input to the model. Table 2 indicates various revenue streams for the renewable PPA option, including an opportunity to participate in Frequency Control and Ancillary Services (FCAS). Therefore, the modelling includes FCAS as a secondary revenue stream and arbitrage. Arbitrage exploits the spot-price difference between the cost of producing hydrogen during low electricity prices and re-electrifying during high electricity prices (Figure 4). When the system produces electricity, arbitrage revenue in $/MWh is calculated using Equation 4.

$$\boldsymbol{Arbitrage\ Revenue} = \boldsymbol{Spot\ price} * \mathbf{min}\ (\boldsymbol{generation\ capacity}, \boldsymbol{market\ demand}) \tag{4}$$

The Australian National Electricity Market (NEM) operates two regulation FCAS markets and six markets for contingency circumstances. However, forecasting revenues from these markets is complex and highly dependent on varying circumstances. Therefore, the modelling simplifies the estimate for FCAS by assuming it as a percentage of arbitrage revenue. Anderson and Leach (2004) found that FCAS revenues account for 15-18% of arbitrage revenue, depending on the storage technology, and we used this in the modelling to calculate FCAS revenues (Equation 5).

$$\boldsymbol{FCAS\ Revenue} = \mathbf{15\%} * \boldsymbol{Arbitrage\ Revenue} \tag{5}$$

Multiple operating strategies were tested involving trialling various price indicators for purchasing and selling electricity, and the optimal results are shown in Table 7.

Table 7. Modelled Operational Strategy and System Size Parameters.

	Value	**Unit**
Electricity spot-price indicator for buying	50	$/MWh
Electricity spot-price indicator for selling	240	$/MWh
Electrolyser Capacity Factor	21.68%	
Electrolyser Size	870	MW
H2 Production	13,650	tonnes H2/year
Aquifer Size	5,000	tonnes H2
Aquifer Cycles	2.48	per Year
H2 Turbine Capacity Factor	2.42%	
H2 Turbine Size	800	MW
H2 Burn	12,400	tonnes H2/year

4.4. Financial Modelling Results

Figure 8 shows the financial modelling of NPV over the project life, IRR, expected payback period and LCOE.

Table 8. Financial Modelling Results (CI 90%).

	2020	2025	2030	2040	2050
CAPEX ($m)	$1,228	$1,007	$844	$699	$580
OPEX ($m/year)	$47	$38	$32	$27	$24
Revenue ($m/year)	$138	$138	$138	$138	$138
NPV ($m)	-$245	$22	$212	$376	$505.
IRR	3.72%	6.24%	8.60%	11.32%	14.30%
Payback period (Years)	N/A	23	16	12	9
LCOE ($/MWh)	$912	$744	$625	$523	$442

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Table 8 indicates that the system's capital costs will decrease significantly between 2020 and 2050, with an estimated reduction of 53%. This price decrease enables the system to be financially viable this decade and highlights an opportunity for immediate private investment without incentives. Table 8 also indicates the importance of achieving the learning rate, shown by the NPV remaining negative for investment between 2020 and 2024. Furthermore, these estimations include degrees of uncertainty that impose risk on the modelling. A sensitivity analysis of the modelled parameters assessed the level of risk.

4.5. Sensitivity Analysis

Sensitivity analysis provides insight into how financial parameters impact the system's viability. Further research would be needed on the electrical efficiency of the electrolyser. The sensitivity analysis result shows in Figure 9 that alterations in revenue have the most significant impact on the NPV, followed by CAPEX. Forecast revenue is a crucial risk, and there are opportunities from other revenue streams, as discussed in Section 5.5.

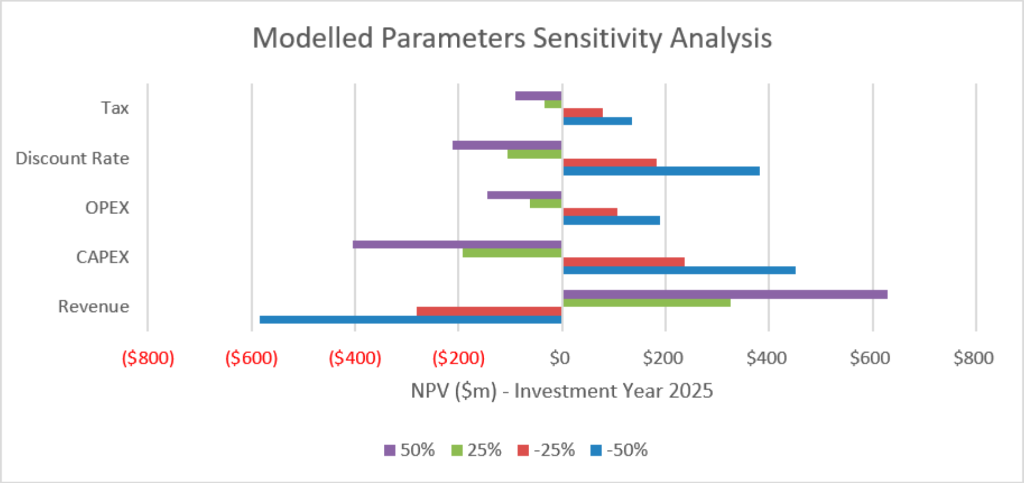

Figure 9. Sensitivity Analysis of Financial Parameters.

The sensitivity analysis identifies risks and opportunities from a financial perspective; however, private investors' risk appetite must also be determined.

4.6. Green Hydrogen Contribution to System Quality

The modelling provided insight into how the proposed system can support the South Australian grid's reliability during its 100% renewable energy transition. The modelling focussed on meeting the objectives outlined in Section 1: stability, reliability and price stability (leading to lower retail prices).

Grid stability refers to the resilience of the grid during unexpected events. The results show that the hydrogen system can support grid stability in multiple ways. Firstly, during periods of high renewable energy supply and low demand, the fast-start characteristic of electrolysers means the system can rapidly use surplus renewable energy. It can then generate electricity when demand outstrips supply. Therefore, the system provides grid-firming services from both supply and demand perspectives. Table 9 shows the modelled quantity of grid-firming electricity the plant uses and supplies.

Table 9. Grid Firming Services Provided by the Hydrogen System.

	2016	2017	2018	2019
Electricity used – during periods of high supply, low demand, and low prices (MWh)	1,066,960	588,519	570,352	722,948

Electricity used – the percentage of South Australia's average yearly demand	8.8%	4.8%	4.7%	5.9%
Electricity supplied – during periods of low supply, high demand, and high prices (MWh)	188,437	147,494	128,280	169,171
Electricity supplied – the percentage of South Australia's average yearly demand	1.6%	1.2%	1.1%	1.4%

The ability to harness surplus VRE is essential for energy supply stability. Green hydrogen can also be stored between seasons, leading to reliable, on-demand, green electricity.

Grid reliability means providing quality electricity to consumers on-demand, which is tricky as the energy supply transitions to renewable energy. The results show that the hydrogen system can supply seasonal storage of VRE, meaning the electricity supply is less reliant on intermittent and uncontrollable weather sources. Figure 10 highlights the modelled usage of stored electricity compared with demand from the South Australian grid. This exemplifies the system's ability to provide seasonal storage, indicated by the peaks in storage occurring during Autumn and Spring. In contrast, the troughs in storage occur during Summer and Winter. The cause of this can be attributed to demand surges during Summer and Winter for cooling and heating as opposed to the milder months (Cutler et al., 2011). Furthermore, the storage capacity is 5,000 TonnesH$_2$, equal to 63,840MWh, enough to power South Australia for three days.

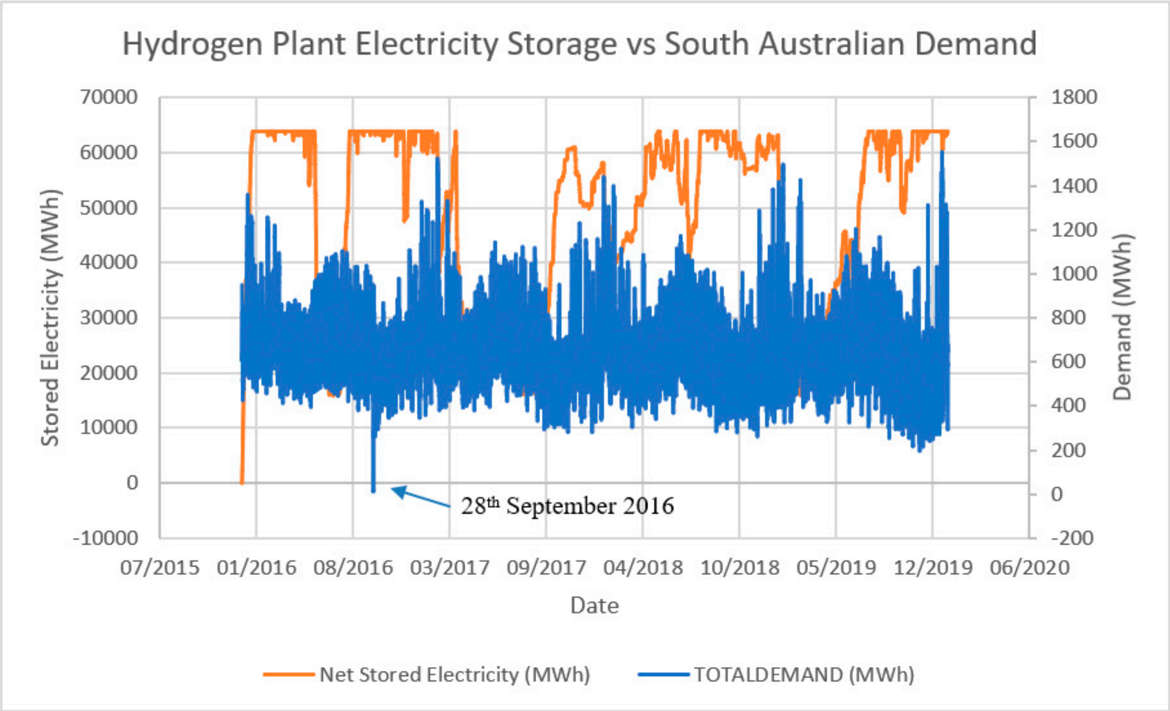

Figure 10. Hydrogen Plant Electricity Storage vs South Australian Demand.

The results show that the proposed hydrogen system can potentially increase South Australia's grid stability and reliability; however, this requires a decreased energy price variance for large-scale adoption.

Electricity spot-price stability has an impact on retail electricity prices. The spot price is the price energy retailers pay to procure electricity and sell it on the consumer market. The price dynamically reflects supply vs demand and is highly volatile (Figure 11), which presents a major risk for retailers, large-scale consumers and market participants (Kirschen, 2003). Furthermore, increased penetration of VRE is causing concern over price security and affordability. The modelling indicates that the hydrogen system would offer price cap guarantees to retailers and consumers who seek to mitigate spot-price volatility risk. However, to be financially viable, the average cap prices would need to be as per the LCOEs shown in Table 8: Financial Modelling Results. Figure 11 shows a price cap the hydrogen system could offer for each investment year relative to the spot price, which indicates an investment in 2050 could viably facilitate a cap price guarantee of $442.35/MWh, highlighting the ability to reduce variability.

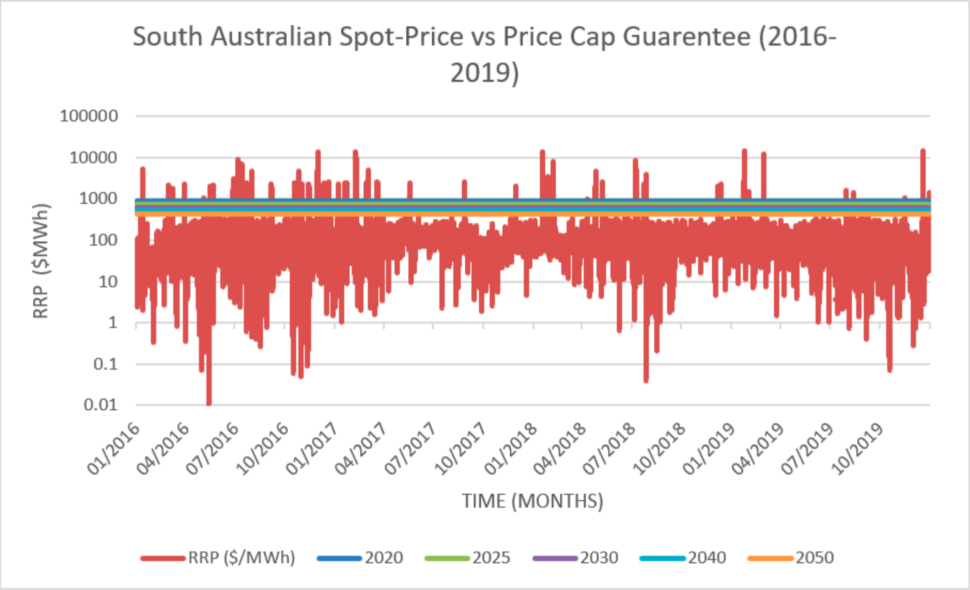

Figure 11. South Australian Spot-Price vs Potential Price Cap Guarantee (2016-2019).

4.7. Summary

Our model of the hydrogen system from a technical and financial perspective provides a starting point for a complete analysis needed for private investors and market operators to decide on the viability of integrating the system into the South Australian energy grid.

The system's vital technical characteristics include the dynamic and fast-start nature of the electrolyser and open-cycle hydrogen-powered turbine. These provide market benefits to supply and demand stability and ensure the grid can remain secure during unforeseen events, including severe weather. Further, the results indicate that hydrogen's properties enable seasonal storage of green electricity, thus, mitigating the reliance on intermittent VRE. This means that the energy supply is more reliable, decreasing the likelihood of unserved energy. The results show that the hydrogen system can minimise long-term spot-price volatility through grid stability and reliability. This will provide greater security for retailers, large-scale consumers, and market participants.

The results show that the system can be financially viable for investment this decade. The key influence on the viable investment year is when capital costs decrease for hydrogen technologies, specifically electrolysers, storage mechanisms and hydrogen-fuelled turbines. Furthermore, opportunities include other revenue streams for energy storage technologies, as revenue was the greatest impact on financial viability.

5. Discussion

We now discuss the requirements for the hydrogen system to become a commercial reality, the technology and regulatory requirements, a comparison against the cost and scale of other hydrogen projects, and evaluate other options to solve the research problem, model validation, and further research recommendations.

The results found that the hydrogen system provides technical benefits to grid stability and reliability. However, further analysis of the technologies is needed, including a deeper understanding of hydrogen production, storage, and re-electrification technologies.

Electrochemical and thermochemical technologies are viable options for producing hydrogen, demonstrated by each technology's commercial availability. However, the maturity level of PEM compared with other options indicates some uncertainty about the success of large-scale implementation (Holladay et al., 2009). Furthermore, PEM electrolysers' commercial availability remains on the Megawatt scale, which will need to increase to the Gigawatt scale for large-scale purposes to be practical (Thomas, 2019). This scale-up is expected to occur within five years (Thomas, 2019), and storage mechanisms that facilitate enormous hydrogen quantities will be developed.

The results indicate that the hydrogen system can provide seasonal renewable electricity storage, enhancing the energy supply's reliability. This ability is enabled because hydrogen has characteristics that allow it to be stored on large scales for lengthy periods, with few energy losses. Therefore, it provides an opportunity to fill the market's energy storage void (Andersson & Grönkvist, 2019). However, hydrogen storage is challenging, and the available technologies vary significantly. Four categories of hydrogen storage options—based on the elements' physical form—are: liquefied, pressurised, absorbed, and chemical. Due to PEM-electrolysis producing Hydrogen in gaseous form, pressurised storage is the preferred option; however, liquefied alternatives are also viable (Gerwen et al., 2019). Absorbed and chemical storage technologies were not considered due to their developing technical feasibility.

Pressurised underground natural storage mechanisms such as salt caverns, depleted gas fields and aquifers are the most suitable storage option for large-scale hydrogen storage. Furthermore, they benefit from low construction costs, low leakage rates, fast withdrawal and injection rates, low cushion gas requirements and low risk of hydrogen contamination (Kruck et al., 2013). However, these technologies are constrained, requiring favourable geological conditions (Kruck et al., 2013).

Our modelling has assumed an underground aquifer will be used for hydrogen storage. Although underground aquifers exist in the Port Augusta region, their viability for hydrogen storage was not determined as this would require geological exploration. Therefore, before commercialisation, private investors and developers must investigate local storage conditions to ensure the system is technically feasible.

Hydrogen re-electrification provides dispatchable green energy to the market. This process will generate the most revenue for the system. This electricity can be sold back into the retail market using arbitrage methods during low supply, high demand and high prices (Mayyas et al., 2020). Like hydrogen-producing technologies, electricity generation technologies are commercially available but require upscaling to support the hydrogen system.

Traditional gas turbines can be moderately re-designed to allow electricity generation from hydrogen (GE-Power, 2020). Open-cycle turbines can ramp faster than closed-cycle systems. Fast ramping is desirable for peaking systems, so the modelling has assumed an open-cycle turbine to re-electrify the stored hydrogen.

Hydrogen production requires careful consideration beyond just the CAPEX and OPEX of the technology used to create it. Key considerations in individual project viability include location selection for CCS and hydrogen storage, transportation methodology, and re-electrified hydrogen distribution. In principle, brown, grey, and blue hydrogen plants operate most effectively near depleted oil and gas fields, where CO2 can be captured and stored, ensuring that production is in line with global emission targets. Using these underground storage vessels for CCS, the opportunity for hydrogen storage is lost, and alternative methods, including fabricated storage vessels, become a requirement for mass production. Similarly, green hydrogen production via electrolysis requires a location with access to aquifers for a more financially viable option. The plant would also be ideally positioned near freshwater reserves, though saltwater is now an alternative (Abdel-Aal et al., 2010), and fed energy via a dedicated wind or solar plant. Hydrogen re-electrification would also happen near the energy grid for optimal energy efficiency, particularly if hydrogen is created for domestic end-use.

Finally, transportation methods for hydrogen are still developing. Australia has recently announced a $500 million 'Hydrogen Energy Supply Chain' demonstration project to utilise brown coal gasification to produce approximately three tons of hydrogen for transport to Japan via a world-first 'liquefied hydrogen carrier ship' (Joyce, 2020). Whether this is economically viable, is yet to be seen.

With an increasing focus on hydrogen as a long-term energy alternative, Australia is 'resource-rich'. It appears wise to adopt hydrogen production as a long-term energy source. Green hydrogen technology is the best option in transitioning from fossil fuels to renewable energy due to providing a stable, reliable alternative to the weather-reliant wind and solar farms currently adopted throughout South Australia.

5.1. Improving South Australia's Grid Reliability

The model aims to research and evaluate methods of enabling a safe, reliable, and affordable transition to 100% renewable energy in South Australia. The variability of wind and solar generation and their inability to efficiently store this form of electricity results in lost generated electricity. If we use a hydrogen electrolyser to convert this surplus renewable electrical energy into a storable gaseous form, this loss will not occur. Therefore, all three points of the trilemma are addressed.

While the system's LCOE is too high in the immediate future, the CAPEX costs of adolescent hydrogen technology will reduce significantly in the coming decades. As discussed in Section 4.0, this decrease in capital cost will ultimately result in a positive system NPV, meaning the LCOE will continue to fall as the research and technology development progresses. Policy reform and Government expenditure can carry hydrogen into the mainstream energy market and allow this LCOE to reduce to the point where it is financially viable. In the near term, the system can allow private entities to invest and generate revenue through consumer and FCAS markets. A guaranteed maximum price of $442.35/MWh is workable if the investment is made in 2050.

Energy system security defines a power system that can operate within defined technical limits, such as voltage and frequency, and withstand faults, even if an incident such as the loss of a major transmission line or large generator occurs (AEMC, 2020; Clean Energy Council, 2020). As shown in Figure 10, the hydrogen system could have mitigated the blackout event on 28th September 2016. This blackout event was caused by issues with the interconnector during a storm and shut down after a frequency fluctuation outside the system limits (AEMO, 2017). Had the hydrogen system been available then, it would have absorbed frequency, increasing the grid's stability.

Another element within the security envelope is energy system reliability, which defines the system's ability to ensure the network's capacity to supply customers with the energy they demand with high confidence (AEMC, 2020). As shown in Figure 10, the proposed hydrogen system improves this market aspect with a storage capacity of 64GWh, enough to power all homes in South Australia for three days. This storage capacity supplies a substantial dispatchable resource for the energy grid, which has no reliance on uncontrollable weather conditions to generate VRE and increases grid reliability without fossil fuel support.

5.2. Market Operators & Regulators

Market operators and regulators such as the Australian Energy Market Operator (AEMO) implement strategies and standards to ensure the grid is reliable and secure. This requirement is significant to enable the transition to 100% renewable energy. However, this transition is causing uncertainty and risk for market operators trying to provide a secure energy supply, leading to the energy trilemma, as discussed above. Our proposed hydrogen system can supply services that mitigate these risks and attract interest and favourable regulation. Such a hydrogen system would be enabled by technical characteristics that allow frequency control and energy storage systems into the grid. Our proposed hydrogen system can support South Australian market operators and regulators in pursuing reliable and green electricity.

The results highlight that the hydrogen system addresses the energy trilemma and aids market operators and regulators in transitioning to 100% renewable energy.

5.3. Further Model Validation

Our modelling used South Australian data from 2016-2019, a period of significant change in their electricity grid. This period included the closure of all coal generation, gas addition, and a transition to rooftop solar and battery storage (AEMO, 2019). Wind generation remained steady during this period, contributing 39.5% of energy generation (AEMO, 2019). Although coal is no longer present in the South Australian energy mix, the state still relies heavily on gas to support the network. This reliance is forecast to reduce by 75-80% over the next ten years, attributed to the retirement of Torrens Island A and Osborne power stations (AEMO, 2020d). We gathered forecast supply and demand data for a grid dependent on VRE to improve the modelling. Initial estimates indicate grid demand will steadily decrease in South Australia, dependent on a balance between the adoption of rooftop PV and the uptake of electric vehicles (AEMO, 2020a). Wholesale electricity prices are forecast to decrease; however, it is unclear to what degree retail consumers will benefit from these reductions due to the unpredictability of supply (Cludius et al., 2014).

5-minute settlement (5MS) periods were introduced in October 2021 in Australia. 5MS differs from the data used in the modelling for 30-minute settlement periods. This change will provide greater accuracy of price signals, benefiting fast response technologies such as electrolysers and peaking plants. 5MS can potentially increase revenues for these technologies by a factor of five due to its increased ability to harness spot-price volatility (MCCONNELL, 2016). Thus, factoring the shift to 5MS would improve the accuracy of our model

5.4. System Interaction

The black system event in South Australia in September 2016 could have been avoided if the hydrogen peaking plant had been available. However, as shown in Figure 3, the system boundary used in this research is discrete, focussing on hydrogen production, storage, and re-electrification. Therefore, we have not considered each component's intrinsic interactions within the electricity grid, including the interaction of government policy development, consumer choices, distribution networks, generators, substations, interconnectors, distribution lines, and associated infrastructure. These elements stay outside the research scope; however, further analysis or inclusion would help understand the system's viability. The model does not consider future markets' variable capacity but uses historical data to confirm the hypothesis. Holistic modelling would further understand how electricity generation instruments interact in the open market and the system operators' requirements to deliver reliable, secure, affordable, and environmentally friendly electricity to the consumer. Given South Australia's goal of being 100% renewable by 2030 (Parkinson, 2019b) and the ongoing reduced reliance upon natural gas, further modelling needs to be undertaken to predict the likely supply and demand requirements for the coming decades, as well as the consideration of how the energy transformation is expected to impact the state's electricity system

Our results cannot conclude that the hydrogen peaking plant would have evaded the black system entirely. Furthermore, an accurate calculation of a hydrogen plant's impact on overall system reliability would need complete grid data, which is beyond the scope of this report. We could use system reliability assessment software such as GE Energy's Multi-Area Reliability Simulation Software (68) or Homer to confirm the results. They could provide a detailed analysis of the grid's reaction following the integration of the plant.

5.5. Risk and Opportunity

Key risks and opportunities for the plant's financial viability revolve around revenue, highlighted in Figure 9, showing that this input significantly affects NPV. Conversely, this provides an opportunity as arbitrage was the sole revenue stream considered; however, the plant's technical characteristics indicate other sources of income exist (Genoese & Genoese, 2014). These stem from transmission system operators' requirement to maintain system frequency within regional standards by altering generation or demand to maintain the balance (AEMO, 2015). The hydrogen system's flexible characteristics enable quick-start and fast load change services, positioning it as a strong candidate for participation in FCAS markets (Kopp et al., 2017), another element that would benefit from 5MS data collection. Efficiency in this process can be achieved through Monte Carlo simulation software such as Oracle's Crystal-Ball (Gonzalez et al., 2005).

5.6. Model Limitations

A significant limitation is that the modelling used Microsoft Excel, meaning optimising system parameters was difficult. *Hydrogen in the Electricity Supply Chain* found an optimal capacity factor that minimises the hydrogen production costs due to a trade-off between capital and electricity procurement costs. The model assessed this trade-off by altering the assumed trigger price for purchasing electricity. The model was manually optimised, given time and cost restrictions on the project, meaning the results are limited in accuracy. The assumed trigger prices for activating the PPA when the spot price dropped below \$50/MWh and re-electrification when the spot price rises above \$240/MWh were based upon manual optimisation. Table 7 shows South Australia's electricity data from the previous four calendar years showing that the electrolyser threshold (capacity factor) will be 21.68%. The threshold for activation of the turbine falls at around 3% of the year, meaning an iterative optimisation approach could improve accuracy. Operating strategy optimisation is key for the system to be financially viable for the system operator, and this validation and optimisation process requires considerable time and financial investment.

One significant limitation of the research, which requires further investigation, is the storage part of the system. As shown in section 4.2, Underground aquifers were chosen to store gaseous hydrogen in our theoretical model. This assumption is based purely on cost implications (Table 4); however, further research could decide the vessel's implications on hydrogen purity and the hydrogen's impact on the local environment. Our investigation of this location shows it has ease of access to renewable energy sources, access to water, and distribution capacity. As discussed above, the ongoing development of hydrogen technology worldwide will decrease capital cost outlays for storage vessels. An opportunity lies within the market to develop a cost-effective storage mechanism for gaseous hydrogen.

This report faces limitations due to data availability constraints. As such, there are areas of research that require further investigation. Additionally, as hydrogen is new in the Australian electricity system, assumptions and data used in this report will vary with increasing time; thus, it should be monitored to ensure the model's validity and our established outcomes.

6. Conclusion

South Australia's strong reliance on weather conditions to generate a sizable part of its energy and its lack of significant storage capacity has exposed the state's energy system. This paper's techno-economic analysis suggests that PEM electrolysis technology can address these issues, enabling added generation and energy storage in times of low Wind and Solar PV availability. The energy for this would be during low wholesale price events. As of March 2023, the electricity prices are negative \$50 per MWhr in South Australia for 5-6 hours every day. The results, influenced by aggregated historical price and demand and industry estimates for system capital and operational costs, show that PEM electrolysis technology in a large-scale re-electrification peaking system in South Australia will reach financial viability soon. Further research we propose includes:

- Government policy,
- hydrogen storage at the proposed location and
- how fuel cells could further validate the re-electrification peaking system.

The South Australian government's Hydrogen Action Plan (2019) shows its interest in developing hydrogen. It aims to help investments, set up a world-class regulatory framework, deepen trade relationships, foster innovation, develop workforce skills capabilities, and integrate hydrogen into its energy system.

Further investigation is needed to understand the relationship between the proposed system and the government. There is the possibility of funding or tax cuts that can substantially affect the LCOE of hydrogen and the overall systems' CAPEX and OPEX.

A key assumption is the existence and availability of underground aquifers within reasonable proximity to the proposed Port Augusta location. These aquifers are assumed to be of suitable size and without the need for significant refurbishment. Though there are existing studies on aquifers in this region, time constraints prohibit an in-depth analysis of their viability. We recommended that further research be undertaken if this proposal is adopted.

Hydrogen Fuel Cells can produce electricity from hydrogen via reverse electrolysis. The technology boasts high efficiency, emission-free power generation, and fast start-up and shut-down, especially compared to turbines (Gerwen et al., 2019). We believe that fuel cells will have a significant role in the future viability and competitiveness of electricity production from hydrogen. We propose further research to prove the exact potential of the technology in terms of capital and operating costs and provide extra power to the grid.

As hydrogen technology develops and matures, there will be a reduction in capital and operating costs and an expansion in usability and capability. Section 4.2 shows the learning curve we expect to see for hydrogen. Industry experts suggest that solid global uptake of the developing PEM electrolysis technology will drive the technology's large-scale utilisation and consequent financial viability.

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Abbreviations:

AE	Alkaline Electrolysers
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
ARENA	The Australian Renewable Energy Agency
BCG	Brown Coal Gasification
CAPEX	Capital Expenditure
CCS	Carbon Capture and Storage
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CF	Capacity Factor
GHG	Greenhouse Gas
GW	1,000,000,000 watts – a unit of power
FCAS	Frequency Control Ancillary Services
IEA	International Energy Agency
IEEFA	Institute for Energy Economics and Financial Analysis
IRR	Internal Rate of Return
ktpa	kilo (1,000) tonnes per annum
kW	1,000 watts – a unit of power
LCOE	Levelised Cost of Electricity
Mtpa	Mega (1,000,000) tonnes per annum
MW	1,000,000 watts – a unit of power
MWh	1,000,000 watts per hour – a unit of energy
NPV	Net Present Value
OPEX	Operational Expenditure
PAREP	Port Augusta Renewable Energy Park
PEM	Proton Exchange Membrane
PHS	Pumped Hydro Storage
PPA	Power Purchase Agreement
REZ	Renewable Energy Zone

RRP	Recommended Retail Price
SMR	Steam Methane Reforming
VRE	Variable Renewable Energy
WACC	Weighted Average Cost of Capital

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