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Stand-Alone Microgrid with 100% Renewable Energy: A Case Study with Hybrid Solar PV-Battery-Hydrogen

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Abstract: A 100% renewable energy-based stand-alone microgrid system can be developed by robust energy storage systems to stabilize the variable and intermittent renewable energy resources. Hydrogen as an energy carrier and energy storage medium has gained enormous interest globally in recent years. Its use in stand-alone or off-grid microgrids for both the urban and rural communities has commenced recently in some locations. Therefore, this research evaluates the techno-economic feasibility of renewable energy-based systems using hydrogen as energy storage for a stand-alone/off-grid microgrid. Three case scenarios in a microgrid environment were identified and investigated in order to select an optimum solution for a remote community by considering the energy balance and techno-economic optimization. The "HOMER Pro" energy modelling and simulating software was used to compare the energy balance, economics and environmental impact amongst the proposed scenarios. The simulation results showed that the hydrogen-battery hybrid energy storage system is the most cost-effective scenario, though all developed scenarios are technically possible and economically comparable in the long run, while each has different merits and challenges. It has been shown that the proposed hybrid energy systems have significant potentialities in electrifying remote communities with low energy generation costs, as well as a contribution to the reduction of their carbon footprint and to ameliorating the energy crisis to achieve a sustainable future.

Keywords: hydrogen; renewable energy; power to hydrogen to power; hybrid battery-hydrogen storage RE storage; stand-alone microgrid

1. Introduction

Renewable energy (RE) generation has become a national target for all countries towards global sustainable development and greener future [1–3] e.g., solar, wind, wave, bioenergy, etc. The main challenge in the integration of the RE into conventional energy systems is the vital necessity for large-scale energy storage systems to overcome the variability of renewable resources [4,5]. The curtailed renewable power and the fact of its intermittency is the biggest barrier delaying the transition towards 100% of renewable power penetration into the power systems [6]. The storage systems will need to store and shift the RE generated power on different time scales, i.e., hourly, daily and seasonally [7,8]. The conventional energy storage systems like batteries, pumped-hydro, mechanical, etc. have their own merits [5]. However, they all have technical challenges and limitations [5,9]. These limitations raise the necessity for a new approach to store energy in an environmentally friendly way, large-scale capacity and longer discharge duration [9–11]. Hence, the innovative idea of storing RE in an energy carrier such as hydrogen, which is storable, transportable and utilizable has encouraged interest worldwide recently [7]. Robust energy storage technology with an intelligent and integrated control system is an urgent requirement today to increase the penetration of RE into the energy mix.

A modern microgrid is an integrated energy system consisting of localised grouping of distributed electricity generation with storage and multiple electrical loads [11,12]. It can be controlled as one entity or grid, either standalone, completely separate from, or connected to, the existing utility grid [13]. The development of the microgrid has been largely dominated by energy demand-side management, RE penetration and its integration into the utility grid [14,15]. In cases where it is not possible to connect the microgrid to the utility grid for any reason such as the remote or isolated location, a stand-alone microgrid (SAM) is an answer to the power supply challenges [16]. The authors of this research envisioned that the SAM is a good starting point to transit from the classic trend of fossil-fuelled powered systems to 100% RE powered systems.

The SAM is a low-voltage power system that supplies a specific localised area [17]. It comprises local power generation systems with load demands, that can operate in islanded mode or off-grid [18,19]. In the transition to a 100% RE SAM system, hybrid distributed (decentralized) or centralized energy generation and storage systems are used to meet the energy need [18]. The SAM is presented as a viable and effective solution to the utilisation of renewable energy resources (RER), by minimizing the problems associated with variability and intermittency of the renewables [16]. The main challenge in a SAM system is the optimal sizing of the system components to make the system secure and reliable while minimizing the capital and running costs [18]. Implementation of an optimal energy management strategy is essential to optimize the techno-economic performance of the holistic hybrid systems [16]. The development of artificial intelligence (AI) provides worthy optimization for modern SAM operations, without relying on extensive long-term weather data and forecasts [20]. Renewable energy storage systems (RESS) play a crucial role in maximizing the RER contribution to the SAM energy balance. Such RESS solutions can be a hybrid combination of more than one technology working together in a synergistic way [7,21]. However, the classic trend is to use a conventional diesel generator (DG) as a backup or to meet the peak load in combination with RESS for the optimal energy system component sizing to minimize capital cost [16,17,21–24].

From the available researches, it is evident that SAM with a high percentage of RE penetration and hybrid RESS can be reliable, cost-effective and more sustainable compared to a 100% fossil-fuel-based SAM [25]. Many countries around the world such as Australia, Bangladesh, India and South Africa are currently doing in-depth research to deploy microgrid-based energy-efficient and reliable power systems for rural or island communities [26–28]. Furthermore, hydrogen for electricity from fuel cells (FC) has been established as viable in remote specialist applications, e.g., by Ballard in Canada [29,30], and green hydrogen supplementation to fossil gas networks as a transition to low carbon gas is underway, e.g., by ATCO Gas in Western Australia [31–33].

Hydrogen as an energy carrier introduces a new approach to store the excess RE in SAM/RESS, with the merits of longer storage periods and ease of storage capacity expansion [16,34,35]. This system is called power to hydrogen to X (X means different applications depending on the hydrogen utilising pathway or end-use) [5,16,18,35–39]. The novel concept of power to hydrogen to power (P2H2P) is a promising option for storing intermittent renewables and regenerating power when needed [7].

In this research, a remote community SAM has been proposed to identify the techno-economic viability of a 100% RE-based system with hydrogen-battery energy storage. In Western Australia (WA), there are dozens of remote stand-alone electricity grids that are beyond the State's main utility grid, the South West Interconnected System (SWIS) [40,41]. Currently, the typical arrangement of remote towns and mining energy supply depends on fossil fuel (mainly diesel) energy resources, which contributes to the significant levels of CO_2 and other Greenhouse Gas (GHGs) in our atmosphere. Additionally, the cost of diesel fuel is high and keeps increasing due to transport and storage costs. Thus, decarbonisation of the energy supply by utilising locally generated, clean and sustainable renewable energy is essential for future energy cleanness and sustainability as well as energy security and economic development. Hence, as a case study this research considers a remote location in the regional North-West of WA.

2. Previous Works

In recent years, many research studies on P2H2P systems have dealt with the energy management systems, controller functions, technical challenges of RESS components, and economic analysis. Studies such as Giorgio Caua et al. 2014 [19], L. Valverde et al. 2016 [20], Mauricio Higuita Cano 2017 [21] and Yanfeng Liu et al. 2018 [11] examined the optimal scheduling of the RESS components to maximize the benefit of the RE and minimize the investment cost. These research studies have concluded that an energy management strategy is essential for the optimal utilisation of the P2H2P systems as well as the optimization of the RESS. Mario Petrollese et al. 2016 [42] developed an intelligent control strategy for the efficient management of microgrids with higher penetration of RER and different energy storage systems including hydrogen. The key aspect was the design and development of the SAM system's controllers to execute the proposed energy management strategies, utilising a statistical approach, to take into account weather and load forecasting uncertainties. Another research project was carried out by Jianwei Li et al. 2017 [17] to design and test a hybrid energy storage system for primary frequency control in SAM systems using a dynamic droop method. Many of the research projects in the field of control of the SAM systems have focused on frequency and voltage control. The recent paper by Kwang Woo Joung et al. 2018 [22] dealt with the lack of inertia in the SAM systems and proposed a new decoupled frequency and voltage controller for DG, which can keep the grid frequency and voltage magnitude constant. Yanfeng Liu et al. 2014 [43], have introduced a genetic algorithm-based method for optimal components sizing and life-cycle considerations in SAM systems. The SAM systems have been investigated for both developing and developed countries as well as for sub-tropical, tropical and hot-arid climatic conditions to identify the techno-economic viability [27,44].

GM Shafiullah et al. [44] developed a SAM with solar photovoltaic (PV)/diesel/battery for a small town called Cue in the Mid-West region of Western Australia, from which it is evident that the integration of PV and battery storage with the existing diesel generators can play a significant role in reducing energy generation costs, fuel consumption, and generators' operating time. A percentage of RE penetration (wind-PV) with a diesel backup hybrid power system in Saudi Arabia has been investigated by Rehman et al. [45]. It has been seen that the system, with 35% renewable energy contributions and 65% diesel power contribution, was the most cost-effective power system compared to a diesel-only system [45]. Yashwant Sawle et al. 2018 [46] have evaluated various hybrid system configurations using PSO, as compared to HOMER Pro software for the optimal cost of energy (COE). However, the proposed scenarios did not include any P2H systems.

Subodh Kharel et al. 2018 [47] developed a large-scale long-term grid-connected hybrid battery-hydrogen system for the South Australia grid, which found the hydrogen-based system to be cost-competitive compared to battery-only energy storage systems.

From the literature, it is evident that the SAM with DER plays a key role in managing energy demand, future load growth, reducing energy costs and global warming. However, the prospects of such systems mostly depend on geographical location, climatic conditions, availability of resources, socio-economic factors, and economic and population growth of the community.
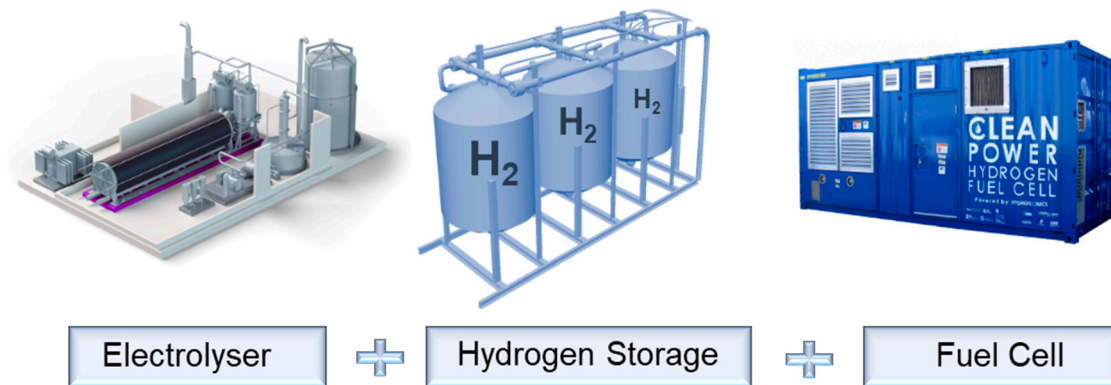
Despite a large amount of research in the literature regarding the techno-economic evaluation of hybrid P2H2P, there is no research available to compare a 100% RE-P2H2P-battery hybrid RESS systems with DG SAM systems. Therefore, this current research aims to investigate the potentialities of a 100% RE-based SAM with hybrid energy storage systems for remote/rural areas, considering cost-economic and environmental benefits using the HOMER Pro Microgrid Analysis Tool [24]. The aim is to evaluate and compare hydrogen-based RESS scenarios with conventional DG powered microgrid and battery-based RESS, for SAM to identify an optimum solution for a remote community.

Outcomes of this research will be a useful tool for power utilities and government bodies in their planning for deployment of SAM with hybrid energy storage for rural communities to supply power to the community, as well as to identify a hydrogen utilisation pathway. The proposed research method can be used in any remote area or any islands to identify the techno-economic aspects for

the deployment of a SAM considering indigenous parameters such as renewable energy resources potential, community load profile, and cost of equipment for the individual areas.

3. Power to Hydrogen to Power System

The P2H2P system can act as an energy storage system similar to batteries but, using hydrogen as an energy carrier that functions as the storage medium in the batteries [29,48,49]. The P2H2P systems comprise three main components; the electrolyser, hydrogen storage and fuel cell (FC), as illustrated in Figure 1.

Figure 1. Power to hydrogen to power (P2H2P) system components. Pictures credit: https://nelhydrogen.com/product/electrolysers/ https://www.3dcadbrowser.com/download.aspx?3dmodel=55633 https://www.energy.gov/eere/success-stories/articles/eere-success-story-fuel-cell-generators-prove-they-can-save-energy-and.

The round-trip efficiency (η) of P2H2P systems is described in Equation (1).

$$\eta_{Round\text{-}trip} = \eta_{Electrolyser} * \eta_{Storage} * \eta_{FC} \tag{1}$$

The energy management strategy, i.e., the controller's operating algorithm, has an enormous effect on the optimal utilisation of the P2H/P2H2P systems, i.e., electrolysers and fuel cells operating hours, the number of starts/stops cycles and the components' degrading rate [50,51].

Further, dealing with hydrogen can bring some new hazards which must be dealt with [52–54]. Hydrogen, like all fuels, is a flammable gas with relatively low ignition temperature, with higher gravimetric energy content than most of traditional fuels, which at 298o K is 120–141.8 MJ/kg compared to 44 MJ/kg for gasoline [7,11]. Additionally, hydrogen has the ability to escape through materials, as well as having a destructive capability (i.e., hydrogen embrittlement), which requires additional engineering controls to ensure safe utilisation [7,52]. However, the hydrogen handling, risk assessment, regulations and policies these days have brought lots of attention in the literature [52–57]. The safety and handling practices, codes and regulations are beyond the scope of this research study.

3.1. Water Electrolysis

Water electrolysis is defined as a process of splitting water into oxygen and hydrogen gas due to the passage of a direct electric current (DC) [58–60]. Renewable (green) hydrogen can be produced by utilising RE resources via a water electrolysis pathway [58–60].

The electrolysis process is expressed in Equation (2) [61].

$$H_2O \rightarrow 2H_2 + O_2 \quad \Delta H° = 286 \text{ kJ/mole (at 25 °C, 1 bar)} \tag{2}$$
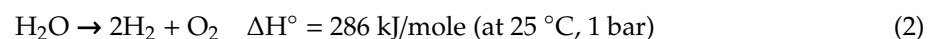
The three water electrolysis technologies most mentioned in the literature are [35,48,62]:

- Alkaline water electrolysis (AWE),
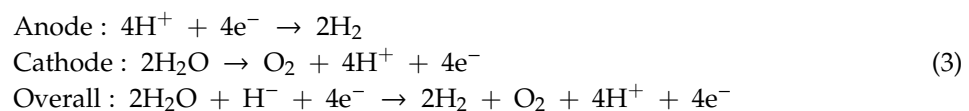- Proton exchange membrane (PEM),
- Solid oxide electrolyte (SOE).

The PEM technology electrolyser was used in this research study for its merits of maturity and suitability for the acceptable efficiency in partial and full load performing, as well as the fast response to the input/output power fluctuation [35,48,63]. However, there are some challenges in utilising and sizing the electrolyser, such as the H_2 production capacity, excess energy availability and the number of start/stop cycles (up to 10,000 cycles before ultimate degradation [50]). Moreover, the maturity in electrolysis technologies (electrolysers), has made the P2H systems a promising gateway towards the hydrogen economy era [5,10,39,48,64–67].

3.2. Hydrogen Storage

There is a wide range of approaches for hydrogen storage liquified hydrogen, compressed gas or material-based storage systems. In this research study, the physical-based compressed gas (i.e., 350 bar) technology in durable tanks was proposed [68,69]. The literature reveals that this technology is the most mature and economically viable hydrogen storage technology, as well as being suitable for the scale and the purpose of the proposed scenarios [67,69].

3.3. Fuel Cells

Fuel cells are one of the most attractive and promising hydrogen utilising technologies, where hydrogen combines with oxygen without combustion in an electrochemical reaction (reverse of electrolysis) and produces electricity, i.e., red-ox reaction is occurring [70], as illustrated in equation set 3, below:

$$
\begin{aligned}
&\text{Anode}: 4H^+ + 4e^- \rightarrow 2H_2 \\
&\text{Cathode}: 2H_2O \rightarrow O_2 + 4H^+ + 4e^- \\
&\text{Overall}: 2H_2O + H^- + 4e^- \rightarrow 2H_2 + O_2 + 4H^+ + 4e^-
\end{aligned}
\tag{3}
$$

4. Methodology

This study proposes the development of 100% renewable energy-based SAM systems with hybrid energy storage for a remote community. The proposed system analyses the characteristics of P2H2P systems, as well as the techno-economic potentialities of a P2H2P hybrid RESS. In this study conventional DG and three 100% RE-based scenarios have been modelled, simulated and evaluated using "HOMER Pro", and their performances compared, based on performance metrics such as net present cost (NPC), capital costs (CAPEX), operational costs (OPEX) and cost of energy (COE) to identify the most optimum solutions for a remote community.

In order to upgrade this DG-SAM, a 100% RE system has been introduced in the form of conventional solar PV farms and different types of energy storage systems.

Li-ion Battery and P2H2P systems were considered as energy storage systems, that not only provide power in the absence of PV, but also help to overcome the problem of variability and intermittency of renewable resources. The base case comprising two full capacity DGs was compared to the following three scenarios:

- Scenario 1 (S1): 100% solar PV-battery system.
- Scenario 2 (S2): 100% solar PV-P2H2P system.
- Scenario 3 (S3): 100% solar PV and hybrid battery-P2H2P system.

All scenarios were simulated for optimal system component capacities and COE over the project lifetime of 25 years in comparison to the conventional diesel generator scenario. The proposed system model for all scenarios is illustrated in Figure 2. The environmental impacts (emissions) were compared to show the reduction in the amount of emission, whilst all scenarios were developed to reliably and

sufficiently deliver the energy demand, with the least cost of energy in each scenario. A hypothetical case study has been used to develop, model and simulate energy balance in different proposed scenarios (excluding the microgrid civil infrastructure development), as they are assumed to be the same in all scenarios. Finally, selected simulation results have been presented for comparison and to demonstrate the possibilities of these different scenarios.
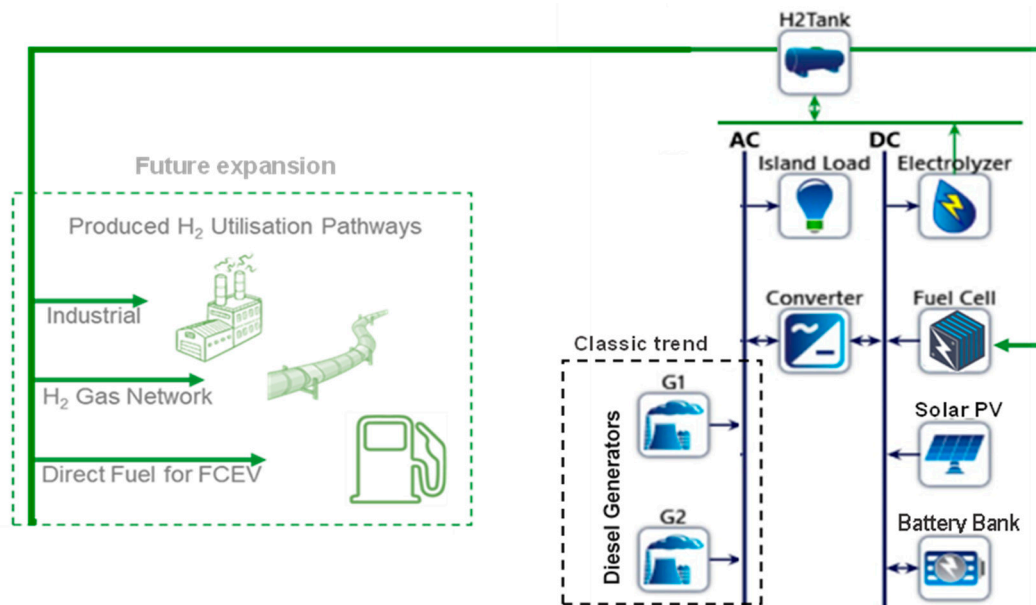
Figure 2. The proposed 100% hybrid PV–battery–hydrogen model.

4.1. Case Study; Hypothesis

A hypothetical remote community settlement in the North-West of Western Australia, comprising 100 dwellings (400 dwellers) and a few small commercial buildings and factories. A semi-residential load profile, with a daily AC load of 2 MWh has been proposed. The residents get their fuel supply by fuel tanker trucks which adds an extra cost to the diesel cost for the electricity generators. The diesel fuel is assumed to cost two US Dollars per litre after adding the transport and storage cost [71]. The remote community settlement location, solar irradiance, temperature and weather data were imported from NASA global data [72] into the Homer Pro software, as shown in Figure 3.
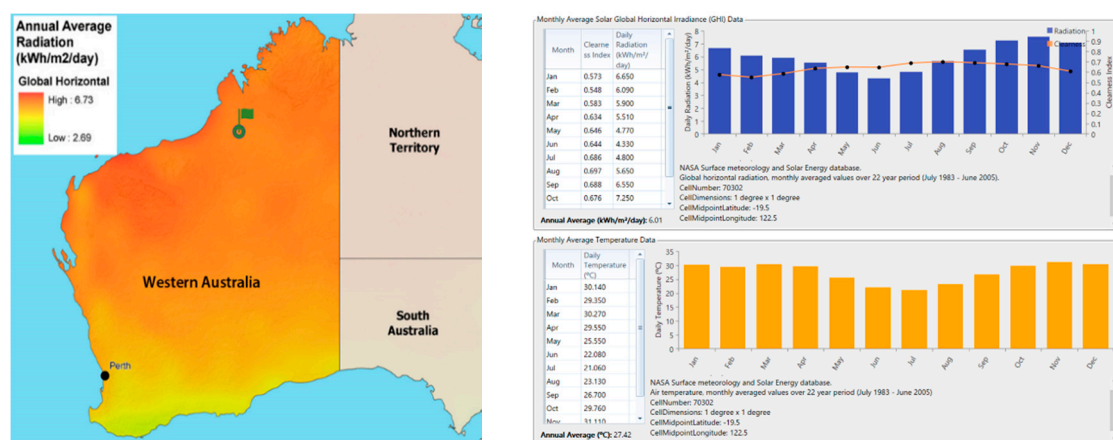
Figure 3. The proposed remote community settlement location (18°11′43.0″ S 125°33′55.5″ E), solar irradiance, temperature and the weather data, imported from NASA global data [72]. Map credit: https://greenpowerlabs.com/western-australia-solar-map/.

A stand-alone 100% RE microgrid has been proposed, which comprises solar PV farm and RESS scenarios to deliver the energy requirements reliably. The RESS scenarios have been modelled and simulated using input parameters and price assumptions available in Homer Pro [73]. The simulation results were tabulated for a detailed comparison of capital costs (CAPEX), operation costs (OPEX), cost of energy (COE) and emission reductions for all possible studied scenarios.

4.2. Scenarios Description

The community load profile imported from Homer Pro software was used, as shown in Figure 4, and has been scaled up to a daily AC load of 2 MWh and a peak load of 192 kW, which is assumed to supply 100 dwellings. The capital and operating costs (CAPEX and OPEX) in US Dollars of all systems' components and there specifications were imported from the Homer Pro library [11,73] and modified according to the authors' best knowledge. The CAPEX and OPEX of the system component were adjusted to the near-real costs in the literature reviewed and the market. A Homer Pro simulator was used to calculate optimal component sizes, to achieve the minimum COE in each scenario, to cover the daily load and three days of autonomy. The studies scenarios (base case and three 100% RE) are described below;

Figure 4. Modelling inputs (load profile, components, parameters and costs) have been imported from the Homer-Pro software library [73].

Base Case Scenario (BCS): The base case scenario is the classic trend for a stand-alone microgrid which comprises two diesel generators (DG) (200kW each); one to follow the daily load profile and a

second for full capacity back up DG. Hence, power is generated from the direct consumption of diesel fuel only. The diesel generator parameters are summarised in Figure 4.

Scenario 1 (S1): A 100% RE system comprises solar PV and Li-ion battery bank with Cycle Charging (CC) dispatch strategy. The simulation constraints were set to meet the load requirement for more than 99.9% and to have a minimum of two hours of autonomy. This scenario model has been simulated to the optimal COE, and system components size to the minimum NPC, using the same simulator input parameters as shown in Figure 4. In reality, the system must provide sufficient hours of autonomy, which require higher CAPEX and OPEX.

Scenario 2 (S2): A 100% RE-P2H2P system comprises a solar PV, electrolyser, hydrogen tank and FC (proposed in lieu of a battery bank). The same simulation constraints of S1 were used. This model is simulated to the optimal COE and electrolyser size, to convert the maximum amount of the excess renewable energy into hydrogen. Additionally, the size of the hydrogen storage tank is optimized to handle the daily generated hydrogen, plus three days of autonomy. The fuel cell size is optimized to cover the full peak load of 192 kW. The specification and parameters of the P2H2P system components are summarised in Figure 4.

Scenario 3 (S3): A 100% RE system comprises solar PV generation and a hybrid storage system, which comprises P2H2P and a smaller capacity Li-ion battery bank. In this hybrid model, the size of the battery is optimized to handle the peak load for a short period of time, while the P2H2P system will act like a baseload generator with the optimal size to utilise the maximum excess energy in the stand-alone microgrid system. The hybrid system is simulated and optimized for the least COE and component sizes and optimal energy balance in the microgrid. The simulation constraints were the same as in S1 over S2, while the same input parameters are shown in Figure 4, fed into the Homer Pro simulator.

5. Results and Analysis

Optimal system performance and sensitivity analyses have been carried out with HOMER Pro to evaluate the performances of a SAM with PV/battery, PV/P2H2P and PV/P2H2P/battery systems. Table 1 shows selected simulation results to give an outlook of all the proposed scenarios for upgrading a classic Diesel Generator (DG) stand-alone microgrid to a 100% RE hybrid stand-alone microgrid. The options are to integrate the 100% solar PV generation with battery RESS and/or the P2H2P system to reduce COE and eliminate emissions.

Possible feasible combinations are identified, based on the given constraints and inputs, and based on their CAPEX, OPEX, NPC and COE, whereby all scenarios have been analysed and revealed the following;

The techno-economic comparison of all scenarios in Table 1 revealed that the BCS is the lowest in capital investment, but the highest in NPC over the project lifetime. However, it is the highest COE in the long run for the project life of 25 years, as shown in Table 1. Moreover, this BCS results in the highest pollution (610 metric tons CO_2 per year), due to the diesel fuel and absence of renewable energy (0% renewable fraction) in the energy generation system, as shown in Table 1.

In Scenario 1 (S1), a model of 100% renewable energy (solar PV) and a battery bank were simulated, and the results are tabulated in Table 1 to compare it to all other scenarios. The simulation results showed that eliminating the emissions and diesel fuel supply requires higher CAPEX, but lower COE (48.6% diminish) over the 25 years of the project lifetime. COE for this scenario is US $0.394, compared to US $0.665 in the BCS.

Table 1. Simulation selected results for all scenarios.

	Results/Scenarios	Base Case Scenario (BCS)	S1	S2	S3
System Component	Optimised Solar PV—direct electric current (DC) Bus (kW)	X	1708	1047	953
	DG1 Capacity(kW)	200	X	X	X
	DG2 Capacity (kW)	200	X	X	X
	Li-ion Battery Capacity (kWh)	X	1700	X	300
	Fuel Cell (FC) Capacity (kW)	X	X	200	100
	Electrolyser Capacity (kW)	X	X	250	250
	H_2 Tank Capacity (kg)	X	X	300	200
	Converter Capacity (kW)	X	200	200	200
Economics	Net Present Cost (NPC) (millions of $)	6.27	3.74	4.47	3.23
	Simple Payback Vs BCS (yr)	BCS	6.26	6.7	4.94
	Discounted Payback Vs BCS (yr)	BCS	7.91	8.39	6.01
	Cost of Energy (COE) (lifetime of 25 years) ($)	0.665	0.394	0.474	0.342
	Capital Costs (CAPEX) (millions of $)	0.20	2.96	2.53	2.30
	Operational Costs (OPEX) ($/yr)	469,741	58,841	149,880	72,032
RE	Renewable Energy (RE) Frac (%)	0.0	100.0	100.0	100.0
	System Cap. Short (%)	0.00	0.099	0.045	0.052
	Excess Elec (%)	5	74.9	35.2	33
	Excess Elec (kWh/yr)	39,000	2,394,702	803,313	696,087
DG 1	DG1 Operating (hours/yr)	8760	X	X	X
	DG1 Fuel	231,186	X	X	X
	DG1 O&M Cost ($/yr)	262.8	X	X	X
	DG1 Fuel Cost ($/yr)	462,373	X	X	X
Hydrogen	FC Operating (hours/yr)	X	X	8757	4282
	FC Prod. (kWh/yr)	X	X	322,991	325,479
	FC H_2 Fuel (kg/yr)	X	X	14,200	12,839
	FC O&M Cost ($/yr)	X	X	35,028	8564
	H_2 Tank Autonomy (kg)	X	X	277	177
	H_2 Tank Autonomy [1] (hr)	X	X	120	80
Battery	Battery Autonomy (hr)	X	16.3	X	2.88
	Battery Nominal Capacity (kWh)	X	1700	X	300
	Battery Usable Capacity (kWh)	X	1360	X	240
GHGs	Emissions CO_2 kg /yr	610,004	0	0	0
	Emissions NOx /yr	6066	0	0	0
	Emissions SO_2 kg /yr	1517	0	0	0

[1] FC consume 0.0391 kg of hydrogen per kWh (as per Homer Pro simulator [73]).

The optimization towards the minimal COE and battery size, as well as to ensure the system stability and reliability, required a large solar PV generation capacity of 1.708 MW, which leaves over 74.9% of excess electricity. Additionally, the RESS autonomy is 16.3 hours, which needs more investment in the battery capacity, to reduce the wasted excess energy, and increase storage autonomy.

The idea of storing RE in the form of hydrogen was evaluated via two scenarios, to compare the pros and cons of utilising hydrogen energy towards the rapidly emerging hydrogen economy era. Thus, Scenario 2 (S2), as a combination of the solar PV and P2H2P system, was modelled and simulated in comparison to BCS and S1. The simulation of P2H2P RESS revealed that full-size hydrogen-based RESS is not the most cost-effective solution when compared to S1. However, storing RE in the form of hydrogen is more effective than the battery system (S1) in reducing curtailed excess RE by (56%), due to a bigger hydrogen production capacity (electrolyser). Therefore, less solar PV capacity is required for the similar energy balance of the stand-alone microgrid, as shown in Table 1 (S1 and S2). Additionally, P2H2P systems have more energy autonomy in the form of stored excess compressed hydrogen in the tank, which can be increased significantly by increasing the production and storage capacities, i.e., the electrolyser and H_2 tank. The COE in both scenarios (S1 and S2) are still diminished significantly in comparison with BCS and emissions are completely eliminated.

Whilst hydrogen-based RESS is a promising innovative approach, there are some techno-economic challenges, such as the high capital of the system components and partial full load inappropriateness. Additionally, using the FC as an inertia keeper in a stand-alone microgrid will need the FC to be kept in hot mode, i.e., the FC will provide only a small fraction of the energy supply but will do so continuously.

Due to the results of S1 and S2, a hybrid battery-hydrogen RESS was proposed, modelled and simulated to evaluate its techno-economic viability. Scenario 3 (S3) comprises a smaller capacity battery and a P2H2P. The evaluation of S3 showed that it is the most cost-effective system for 100% RE-based SAM. Moreover, this hybrid battery-hydrogen RESS model (S3) shows a very promising discounted payback period of 6.01 years and COE reduction of 48.6% vis a vis the BCS, compared to a reduction of 40.8% when only battery RESS was used, as shown in Table 1. Furthermore, the 100% RE-based SAM in S3 curtails only 33% of the RE generation, compared to 74.9% in the S1. The system autonomy in S3 is 80 hours in the form of stored hydrogen (177 kg H_2) as shown in Figure 5, compared to 16.3 hours only, in the case of S1.

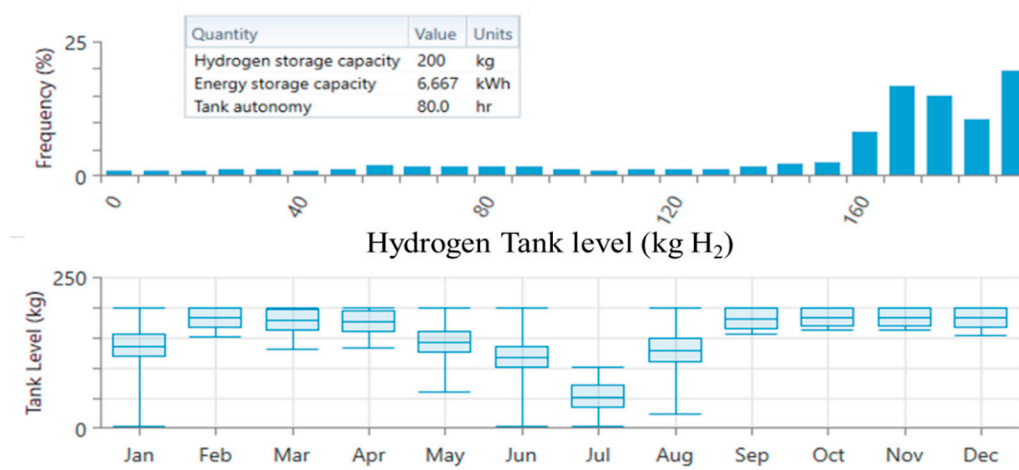
Figure 5. The hydrogen monthly tank level and frequency of occurrence.

Hence, the discounted payback period for S3 is 6.01 years, which is 22.8 months shorter than the S1 discounted payback period. The S3 hybrid system payback periods in comparison to the BCS with cost sensitivity of the hydrogen system components (Electrolyser and FC), as well as the diesel cost, are plotted in Figure 6.
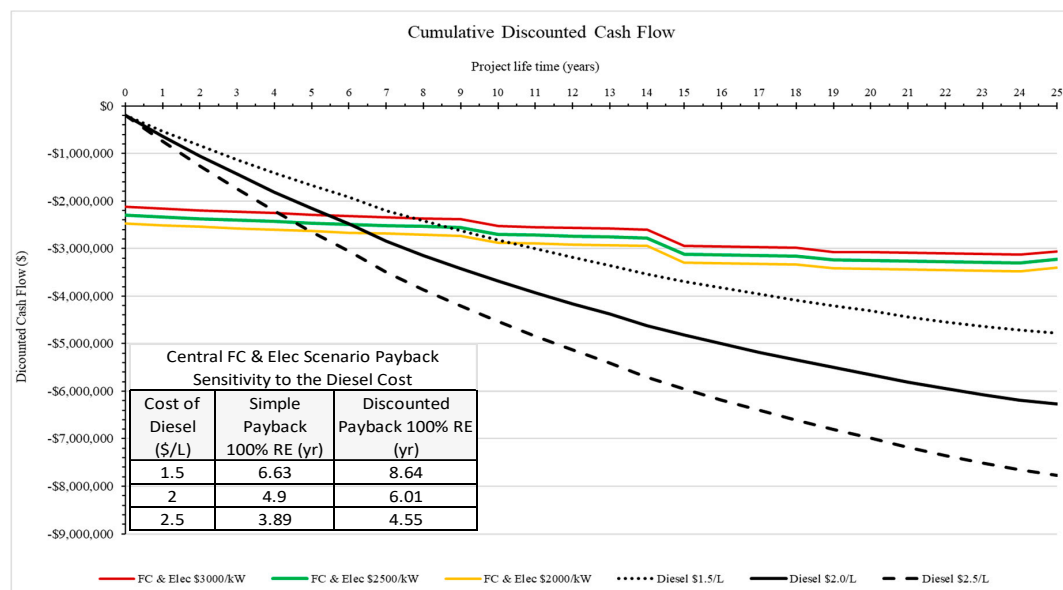
Figure 6. S3 payback periods with FC, electrolyser capital and diesel cost sensitivity.

Moreover, the battery bank with the DC-AC converter in the proposed S3 hybrid system can be used to ensure the SAM power quality, i.e., the frequency and voltage control [12,74].

Figure 7 is an example of a few days' plot during December of the SAM system components simulator integration and operation of the S3 hybrid system. The hourly simulation shows that the combination of the solar PV, battery discharge and the fuel cell output power can always meet the peak load (>99.9%). The graph demonstrates the contribution of the hydrogen fuel cell in the power supply for long hours, during the daily cycle of the S3 model for the proposed SAM system. The accumulation of the stored hydrogen level in the tank is at a high level and increasing (around 200 kg H_2), as December is the highest solar daily radiation month of the year, with 8.3 kWh/m^2/day [72] in the N-W of WA, as shown in Figure 3.

Figure 7. The stand-alone microgrid (SAM) system components' operations of S3 hybrid system (December).

The accumulated hydrogen in the storage tank shifts the excess RE seasonally to the low daily radiation periods, which is June in the N-W of WA. This is the main advantage of using hydrogen to store excess RE energy for longer periods than batteries only, as shown in Figure 8.
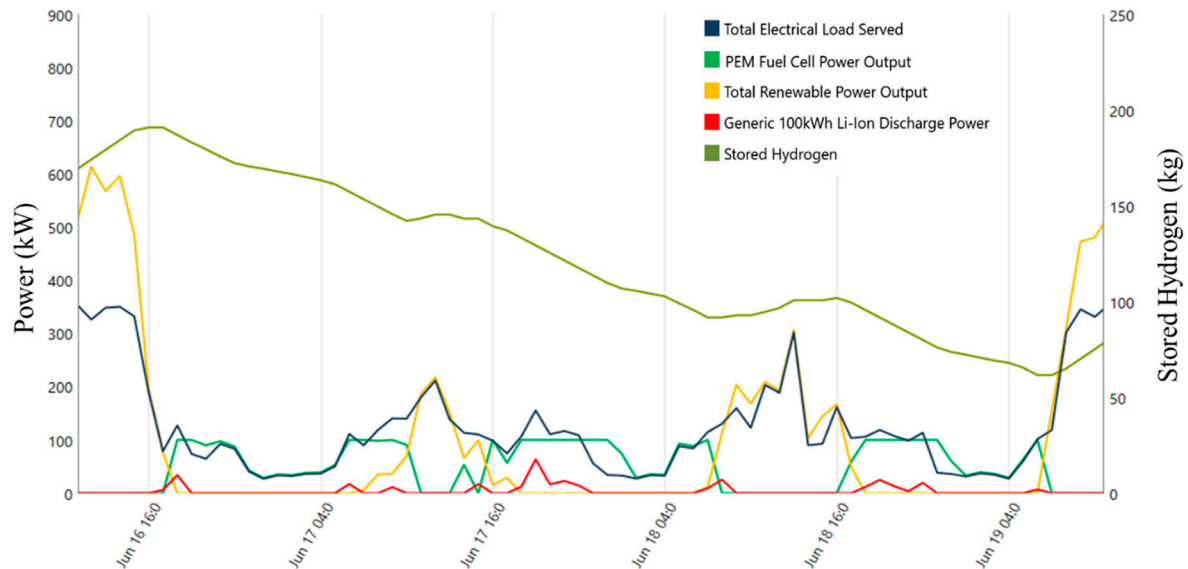

Figure 8. The SAM system components' operations of S3 hybrid system (June).

During the low solar radiation month, i.e., June, in this case shown in Figure 3, the average solar daily radiation falls to 4.08 kWh/m^2/day [72] in the region. The worst-case scenario is plotted in Figure 8, which shows that the average of the lower hydrogen level in the tank varies between 60–80 kg H$_2$ (also shown in Figure 5), which is around 18–24 hours' system autonomy (0.0391 kg H$_2$ per kWh). However, the yearly simulation of the proposed model shows an average of 177 kg H$_2$, which provides around 80 hours of autonomy, as shown in Table 1.

The PEM electrolyser feed water (demineralised) consumption is reported at 10 litres per kg H$_2$ according to the product datasheet by the manufacturer "Nel hydrogen" [75]. Therefore, the proposed system requires 356.3 litres of pure water per day. The PEM electrolysers typically require a higher water purity than alkaline electrolysers [76]. The water purification process consumes 3–5% of the energy stored in the produced hydrogen [77]. Hence, water purification can utilise the excess RE, which can be done when it is available and stored in a pure water tank.

The energy balance and components' working hours have been optimised using the Homer Pro software. However, the stable and constant power supply can be controlled by a case-specific designed energy management system and the battery to optimize electrolyser and FC working hours, to reduce the operating cost and enhance its lifetime. The major cost of S3 CAPEX was incurred by the P2H2P components, the COE to the electrolyser and FC cost, hence, a sensitivity analysis has been conducted. From Figure 9, it can be seen that COE increases with the increase of FC and electrolyser capital cost.
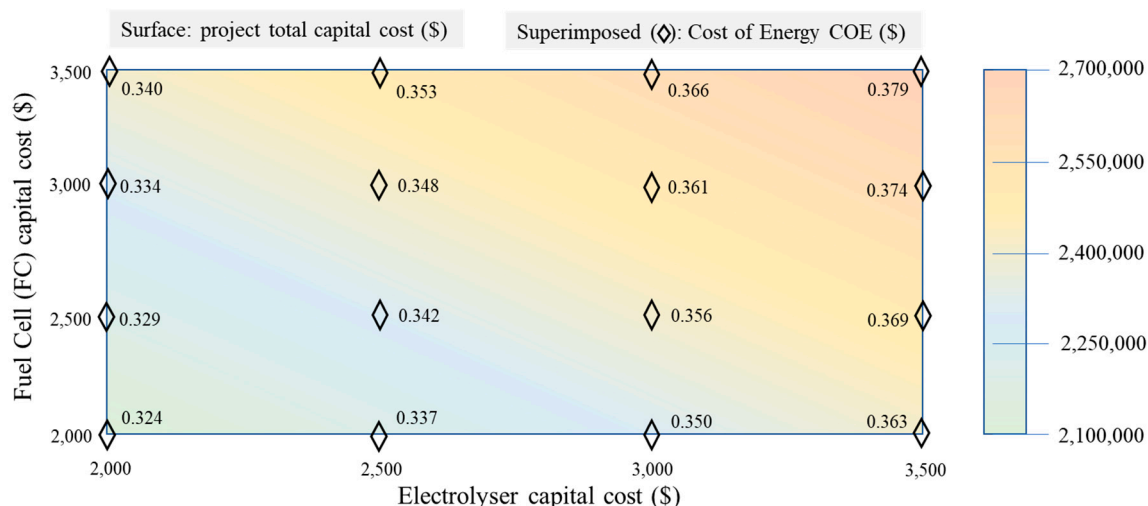
Figure 9. The COE and CAPEX to the electrolyser and FC initial costs sensitivity.

However, the classic trend of cost reduction of the hybrid battery-hydrogen RESS component increases the cost-effectiveness of such hybrid systems as a promising pathway towards 100% RE stand-alone microgrid systems. Additionally, having the energy stored in the form of hydrogen makes the system more resilient and introduces more possibilities to utilise stored hydrogen in other forms of energy, i.e., town gas supply and e-mobility sector.

This hypothetical case study has been conducted relying on actual RE resources available in the proposed region of North-West WA, Australia and near-real capital costs of the system components. The community daily load profile has been imported from the Homer-Pro library, assuming it is a near-real profile in the remote communities in WA. However, any change in the average daily load profile will have a minor effect compared to the immense effect of any change in the peak load period and amplitude. Hence, this case study model can be replicated within a similar load and peak load profile in the region. Changing the region or the daily load profile can use the same proposed model, but needs to re-simulate the model according to the new input parameters.

6. Conclusions

In this research, a set of 100% renewable energy (RE)-based scenarios were defined, modelled and simulated for a proposed stand-alone microgrid (SAM) system. A battery-based, a hydrogen-based and a hybrid combination of battery-hydrogen-based Renewable Energy Storage Systems (RESS) were evaluated and compared with the conventional DG-based SAM system. The evaluation of all proposed scenarios demonstrated that the hybrid battery-hydrogen-based RESS system (S3) is a promising innovative approach for 100% renewable energy-based SAM systems. The simulation of this hybrid system revealed that it has the least NPC and COE along the project lifetime of 25 years. Additionally, it curtails less excess energy in comparison with the battery-based storage system, as well as extending the system autonomy in the form of stored hydrogen. The promising discounted payback period of six years makes this system a highly prospective and cost-effective option for the transition towards 100% RE SAM systems. The proposed and evaluated model can be replicated within a similar load profile and RE resources available, but it needs re-simulation according to any change in the input data. More evaluation is required for optimal utilisation of excess RE and the possibility of utilising the stored hydrogen in an energy-water-waste nexus way of thinking, e.g., using the excess RE for drinkable water by reverse osmosis and using some of the stored hydrogen as direct fuel for heating, cooking and transport.

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Abbreviations

RE	Renewable Energy	AWE	Alkaline Water Electrolysis
SAHM	Stand-Alone Hybrid Microgrids	PEM	Proton Exchange Membrane
RER	Renewable Energy Resources	SOE	Solid Oxide Electrolyte
RESS	Renewable Energy Storage System	η	Efficiency
P2G	Power to Gas	CAPAX	Capital Cost
P2H	Power to Hydrogen	OPEX	Operating Cost
P2H2P	Power to Hydrogen to Power	NPC	Net Present Cost
DER	Distributed Energy Resources	Ren Frac	Renewable Fraction
COE	Cost of Energy	BCS	Base Case Scenario
FC	Fuel Cell	S#	Scenario Number #

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