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# Economics of renewable hydrogen production using wind and solar energy: a case study for Queensland, Australia

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*Abstract*

*This study presents a technoeconomic analysis of renewables-based hydrogen production in Queensland, Australia under Optimistic, Reference and Pessimistic scenarios to address uncertainty in cost predictions. The goal of the work was to ascertain if the target fam-gate cost of AUD 3/kg (approx. USD 2/kg) could be reached. Economies of scale and the learning rate concept were factored into the economic model to account for the effect of scale-up and cost reductions as electrolyser manufacturing capacity grows. The model assumes that small-scale to large-scale wind turbine (WT)-based and photovoltaic (PV)-based power generation plants are directly coupled with an electrolyser array and utilises hourly generation data for the Gladstone hydrogen-hub region. Employing first a commonly used simplified approach, the electrolyser array was sized based on the maximum hourly power available for hydrogen production. The initial results indicated that scale-up is very beneficial: the levelised cost of green hydrogen (LCOH) could decrease by 49% from $6.1/kg to $3.1/kg when scaling PV-based plant from 10 MW to 1 GW, and for WT-based plant by 36% from $5.8/kg to $3.7/kg. Then, impacts on the LCOH of incorporating curtailment of ineffective peak power and electrolyser overload capacity were investigated and shown to be significant. Also significant was the beneficial effect of recognising that electrolyser efficiency depends on input power. The latter two factors have mostly been overlooked in the literature. Incorporating in the model the influence on the LCOH of real-world electrolyser operational characteristics overcomes a shortcoming of the simplified sizing method, namely that a large portion of electrolyser capacity is under-utilised, leading to unnecessarily high values of the LCOH. It was found that AUD 3/kg is achievable if the electrolyser array is properly sized, which should help to incentivise large-scale renewable hydrogen projects in Australia and elsewhere.*

*Keywords: hydrogen; economic analysis; economies of scale; peak power shaving; dynamic efficiency; overload capacity.*

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## 1. Introduction

According to the International Renewable Energy Agency (IRENA) and the International Energy Agency (IEA), renewable-based hydrogen is needed to reach the goal of deep decarbonisation, especially in hard-to-abate carbon-intensive sectors (IEA, 2019; IRENA, 2019), in line with Goals 7 and 13 of the UN 2030 Agenda for Sustainable Development (United Nations, 2015). Recognising the critical role of green hydrogen, governments have developed national roadmaps and strategies to integrate it into their economies to help meet their commitments to achieving net-zero carbon emissions target by 2050 (IEA, 2021). Based on the latest IRENA report (IRENA, 2022), 8% of final energy demand in 2050 is expected to be met by 400 million tonnes of green hydrogen; according to BloombergNEF the figures are respectively 22% and 800 million tonnes (BloombergNEF, 2021). These projections indicate the importance of green hydrogen in the 2050 energy market. However, the cost-competitiveness of hydrogen remains a critical issue, particularly since costs of environmental damage are rarely internalised in the production costs of dirty technologies. Presently, about 95% of global hydrogen production is “grey”, produced from fossil fuels without sequestration of the carbon-dioxide by-product (IRENA, 2020a). Despite technological, financial and socio-political challenges delaying development of a hydrogen economy (IRENA, 2018; IRENA, 2020a), IRENA and the Hydrogen Council believe that cost-competitive hydrogen is achievable in the coming years through technological advancement, market creation, introduction of appropriate policies and regulations, and scale-up (IRENA, 2020b; Hydrogen Council, 2020).

The cost of producing green hydrogen from renewables is normally the main contributor to the final hydrogen cost in its supply chain, driven by the required capital investment (CAPEX) in electrolyser plant (Ishimoto et al., 2020) and the cost of renewable electricity (Schnuelle et al., 2020). Location of production is therefore one of the main determinants of final cost, since this sets the capacity factor of the plant capturing renewable energy. Preliminary assessments show that Australia is among the countries with the highest potential for green hydrogen production (IRENA, 2022), given the abundant wind and solar resources across the country. For example, a recent study estimates that the practically available offshore wind resource around Australia’s coastline exceeds 2 TW (Briggs et al., 2021). Australia aims to produce green hydrogen for transport, electrification of remote areas, industrial feedstock, heat generation, grid stability, and, especially, export (Bruce et al., 2018; Australia’s National Hydrogen Strategy, 2019). Both domestic and overseas market penetration of Australian green hydrogen are heavily dependent on its price. The target cost of green hydrogen production, the so-called “farm-gate cost” (excluding storage and distribution), has been set at a challenging AUD 2–3/kg in Australia’s National Hydrogen Roadmap report (Australia’s National Hydrogen Strategy, 2019). An in-depth cost estimate for green hydrogen production related to proposed locations is therefore essential.

Cost projections imply uncertainty, so factors influencing the predictions, for example cost of finance and electrolyser efficiency, should be considered carefully (Rezaei et al., 2022). Such factors are difficult to project because unforeseen developments may occur at any time, so ultimately reasonable assumptions have to be made. Two important assumptions are incorporated here, one on the supply side and one on the demand side. On the supply side, the unit production cost of a technology, especially a new technology such as proton-exchange membrane (PEM) electrolysis, tends to decline over time as cumulative production capacity grows, through "learning-by-doing" (Grübler et al., 1999). In general, economies of scale lower the initial investment cost per unit of production as production is scaled up, also resulting in decreased unit cost of the final product (Haldi and Whitcomb, 1967). On the demand side, the scaling concept captures the cost savings and competitive advantages of large-scale projects over smaller ones. Here, economies of scale are accounted for on the demand side only, since electrolysers are built to order rather than mass produced. The importance of these two factors was illustrated in a report on the cost of hydrogen refuelling stations (Melaina and Penev, 2013), where it was highlighted that considering these factors is essential for developing a comprehensive and reliable understanding of the initial investment costs. Therefore, learning-rate and scaling models are incorporated in our economic modelling. The approach taken is summarised in Fig. 1.

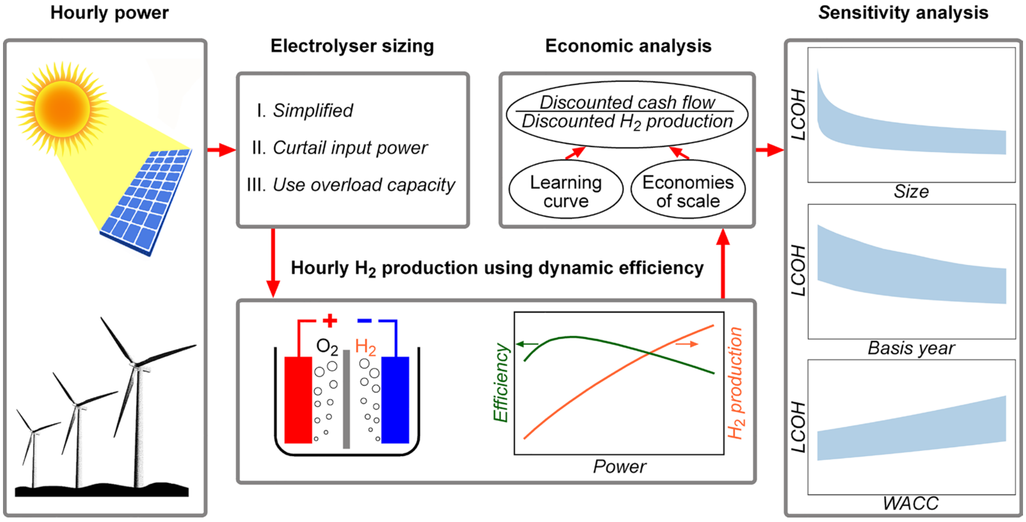


**Fig. 1.** Economic modelling approach. Wind turbine image: Flaticon.com.

Presently, electrolysis technologies range in their development from mature (alkaline; AEL) to rapid commercial development (proton-exchange membrane; PEM) to not fully commercial (solid-oxide electrolyte; SOE). To date, AEL is the most cost-effective option due to its maturity, accounting for the highest share of installed capacity in 2020 (IEA, 2021). However, it has been predicted that PEM will dominate by 2030 (Schmidt et al., 2017), offering the lowest cost compared to other major technologies, as depicted in Fig. 2(a). Fig. 2(b) shows a comparison of the projected cost evolution for AEL and PEM technologies up to 2030. Therefore, the selection of a specific technology also impacts the results of an economic analysis. The primary reason for our choice of PEM is its suitability for direct connection to a renewable energy source, owing to its wider range of operating power relative to nameplate capacity (turndown) compared to AEL.

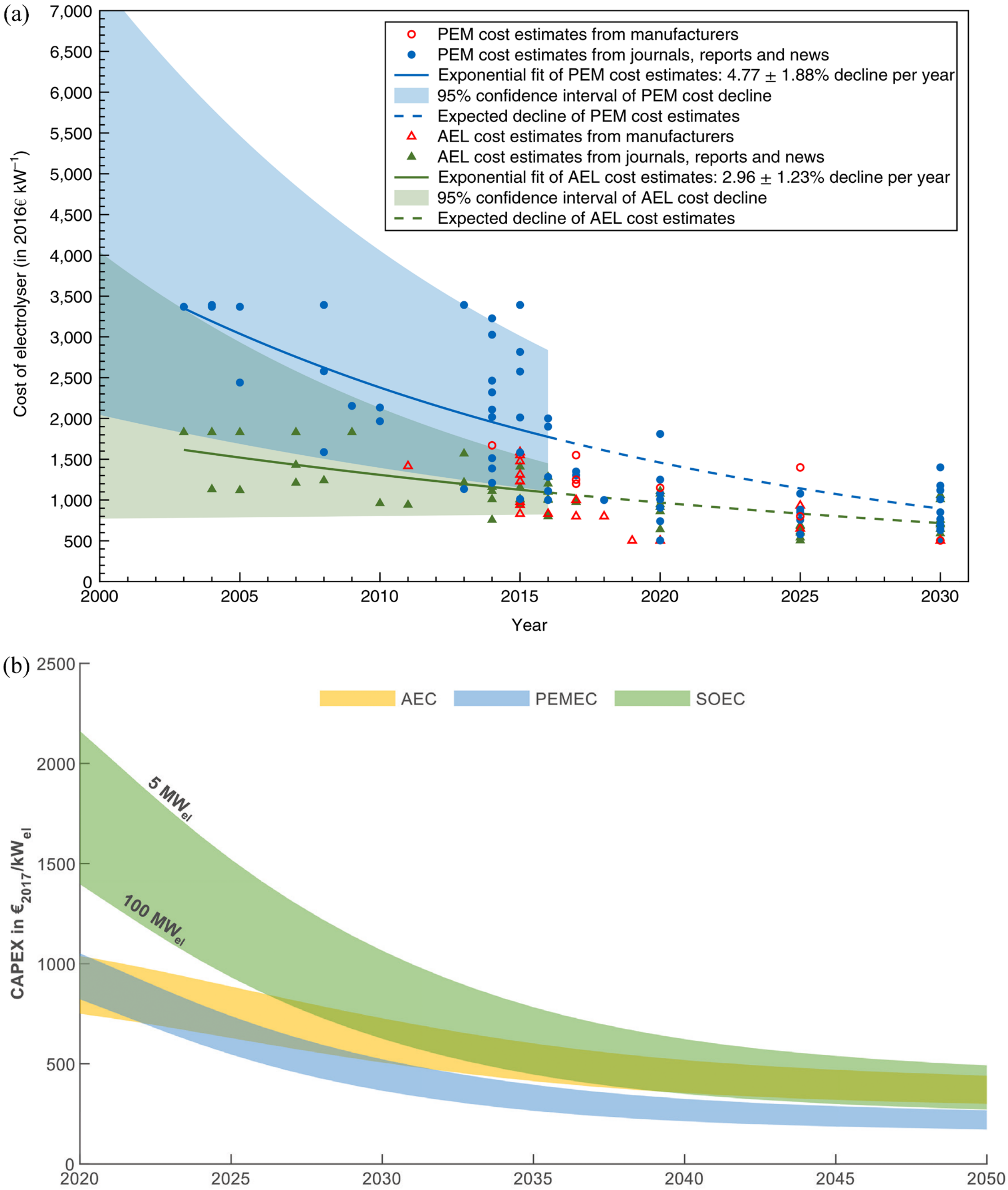


**Fig. 2.** Projected cost evolution of major electrolysis technologies. (a) Predictions by the European Union (STORE&GO, 2020). (b) Predictions by (Glenk and Reichelstein, 2019).

This study investigates the economics of renewable hydrogen production from solar and wind energy in Gladstone, Queensland, Australia, although the methodology is applicable to any solar and/or wind installation. The reason behind our selection is that the Australian and Queensland Governments recently announced Gladstone as the location of a hydrogen hub (State of Hydrogen, 2022). Based on good resources of wind and solar energy in the region, here solar-based and wind-based hydrogen production prospects are assessed. To evaluate the levelised farm-gate cost of hydrogen (LCOH) as accurately as possible, the cost of land and water are accounted for.

A fundamental problem of green hydrogen production by electrolysis is that power from photovoltaic (PV) and land-based wind turbine (WT) arrays inherently changes in a wide range, leading to ineffective peaks in power, where ineffective peak power refers to that portion of PV and WT output power which if accommodated within the nameplate capacity of the electrolyser would cause a significant increase in electrolyser CAPEX for only a small increase in hydrogen production. Accordingly, peaks in output power are sometimes intentionally shaved (curtailed) to avoid oversizing the electrolyser (Park et al., 2023). By curtailing ineffective power generation, the capacity of the electrolyser can be better utilised, resulting in a higher hydrogen production share relative to the overall power output. The impact of this reality on the LCOH is often overlooked, or it is accommodated by adding expensive storage capacity to smooth the power flow (Mongird et al., 2020).

One goal of this work is to test the viability of green hydrogen production relative to the target farm-gate cost without storage. To do this, the techno-economic model is first run using the common approach for sizing the electrolyser capacity, then re-run with a modified energy input profile in which ineffective PV and WT peak power is curtailed. Another rarely explored parameter in techno-economic modelling of hydrogen production systems, electrolyser overload capacity, is also factored into the modelling. According to recent reports (Patonia and Poudineh, 2022), PEM electrolysers can operate for short periods at around 120% of nameplate capacity, with significant variations between manufacturers and models, and this factor is expected to increase as the technology matures. Taking advantage of the overload capacity decreases the CAPEX and LCOH. Therefore, the techno-economic model is also re-run while accounting for electrolyser overload capacity at a nominal level of 150% to explore its effect on the LCOH.

Table 1 summarises the distinctions between the current study and the existing literature.

Table 1. Comparison between some of the most recent papers in the literature regarding four critical factors with significant impacts on the LCOH.

| Reference | Economies of scale for large-scale projects | Learning-by-doing model for cost projection | Electrolyser efficiency | Overload |
|---|---|---|---|---|
| (Akdağ, 2023; Cheng and Hughes, 2023; Henry et al., 2022; Juárez-Casildo et al., 2022) | – | – | Fixed | – |
| (Henry et al., 2023; Sadiq et al., 2023; Sako et al., 2021) | ✓ | – | Fixed | – |
| (Zhen et al., 2023) | – | ✓ | Fixed | – |
| (Park et al., 2023) | – | – | Fixed | ✓ |
| (Böhm et al., 2020; Yates et al., 2020) | ✓ | ✓ | Fixed | – |
| (Ginsberg et al., 2023; Gu et al., 2023; Liu et al., 2023; Shin et al., 2023; Zhang and Yuan, 2022) | – | – | Generic dynamic | – |
| (Khan et al., 2022) | ✓ | ✓ | Generic dynamic | – |
| This study | ✓ | ✓ | Actual dynamic | ✓ |

The dash indicates that the respective factor was either not mentioned/considered or was not applicable to that particular study.

This paper is divided into eight sections. Section 2 outlines modelling and approaches for sizing the electrolyser array. In section 3, we present the assumptions and scenarios considered. PEM cost projections are discussed in Section 4, followed by the analysis presented in Section 5. Section 6 covers the sensitivity assessment and subsequent discussion, followed by Section 7 discussing the limitations. Lastly, Section 8 provides a summary and conclusions.

## 2. Methodology

### *2.1. Economic modelling*

It is assumed that PV-based and WT-based power generation plants ranging from small to large scale are DC-connected to a PEM electrolyser array. This approach is expected to decrease the initial investment cost, system complexity, and consequent power losses by eliminating entirely the need for DC-DC converters for PV (Phan Van et al., 2023) and minimising the need for power converters for WT. Hourly solar and wind power profiles for the selected location, which were calculated respectively based on (Pfenninger and Staffell, 2016) and (Staffell and Pfenninger, 2016), were imported into our model from (www.renewables.ninja). Having hourly power profiles, the maximum power available at the input of the electrolyser is first ascertained. Then the electrolyser array is sized to utilise the maximum available hourly PV or WT power. This simplified method avoids peak power curtailment on time scales longer than one hour. Where available, finer-grained data would obviously make this and the following estimates more accurate. The hourly hydrogen production can be calculated by:

$$m_{H2}^{t} = \frac{E_{out}^{t}}{SEC^{t}} \quad (1)$$

in which $m_{H2}^{t}$ is the hydrogen produced at hour $t$, $E_{out}^{t}$ denotes the hourly power generated by PV or WT that is available at the input of the electrolyser at hour $t$, and $SEC^{t}$ is the specific energy consumption of the electrolyser, which is inversely proportional to efficiency, at hour $t$. Often, this parameter is simplistically assumed in the literature to be independent of the input power (e.g., (He et al., 2023; Moran et al., 2023; Park et al., 2023; Yang et al., 2023)). In reality, the overall electrolyser efficiency is low at low stack power because of roughly constant balance-of-plant consumption, and decreases at high power because of resistive losses in the stack. For a more realistic estimation of the hourly hydrogen production, we adopt the approach of a recent study by (Hofrichter et al., 2023), where the efficiency of the electrolyser is correlated with the input power. They proposed a dual function to evaluate the efficiency for every operating hour based on the real operating characteristics of the Mainz Energy Park in Germany using empirical data from the project (Kopp et al., 2017). According to the model, the electrolyser efficiency is estimated by Eq. (2) for input powers below 15% of the electrolyser nominal capacity and by Eq. (3) for 15% up to the maximum available power. To capture the expected improvement in efficiency of PEM technology relative to its 2020 level, a rate = 0.25% was included in the model following (Hofrichter et al., 2023) adopted from (Kopp et al., 2017; Zauner et al., 2019).

$$\begin{aligned}\eta^{t} = (&0.00005 \times U^{5} - 0.0061 \times U^{4} + 0.2372 \times U^{3} - 4.2014 \times U^{2} \\ &+ 36.675 \times U - 62.87) \times 1.0025^{Basis\ year-2020}\end{aligned} \quad (2)$$

$$\eta^{t} = (-0.149 \times U + 74.977) \times 1.0025^{Basis\ year-2020} \quad (3)$$

in which $\eta^{t}$ is the PEM efficiency at hour $t$ and $U$ refers to the utilisation of electrolyser capacity. The hourly values calculated here are used in Eq. (1) to estimate hourly hydrogen production.

$LCOH,$ as an economic metric that accounts for all the costs occurring over the project lifetime, including both capital and operating costs of renewable electricity production, is estimated by:

$$LCOH = \frac{CAPEX \times CRF + OPEX + \sum(\frac{REPEX}{(1+d)^{y}} \times CRF)}{\sum m_{H2}^{t} \times CF_{ele}} \quad (4)$$

where $CAPEX$ denotes the initial investment of the installed equipment that is ready to operate, $OPEX$ refers to the yearly fixed cost which is supposedly incurred evenly for operating and maintaining the hydrogen production system and the renewable electricity production components, $REPEX$ is the variable cost incurred after the lifetime of any component, e.g., the electrolyser stacks, ending at year $y$, $d$ is the discount rate to value future dollars in the basis year, $CF_{ele}$ is the electrolyser capacity factor, and $CRF$ is the capital recovery factor, which is calculated by:

$$CRF = \frac{d \times (1+d)^n}{(1+d)^n - 1} \quad (5)$$

in which $n$ is the project lifetime in years and $d$ is normally equal to the weighted average cost of capital (WACC). Post-tax $WACC$ is calculated by:

$$WACC = E \times R_e + D \times R_d \times (1 - TR) \quad (6)$$

where $E$ is the share of equity and $D$ is that of debt in capital structure, $R_e$ denotes the cost of equity, $R_d$ represents the cost of debt and $TR$ is the corporate tax rate.

### *2.2. Learning rate*

To predict the cost of electrolyser stacks at the time when the current stacks will be replaced, the learning-rate concept is applied. This approach, which was discussed by (Grübler et al., 1999) relates the unit cost of a technology to its cumulative production in order to price it in the future, following Wright's Law (Wright, 1936). Actual data for the costs of various technologies indicate that there exists a falling power-law relationship between unit cost and cumulative units produced as shown by Eq. (7):

$$\frac{C_F}{C_P} = N^{-\beta} \quad (7)$$

in which $C_F$ refers to the unknown unit cost of a technology in the future when the cumulative production has reached $N$ units. $C_P$ is the cost at present and $\beta$ is the power-law index which is calculated by:

$$\beta = -log_2(10) \times log_{10}(1 - LR) \quad (8)$$

where $LR$ is the learning rate and depends on the maturity of the technology, ranging from 15–20% when the technology is still in the research and development stage, to 0–5% (when the technology is mature). This approach does not involve time directly. Hence, the production growth over time should be known to be able to price stacks over the ensuing years. Here, the learning-rate concept is applied to units of hydrogen production (or electrolyser capacity), since electrolyser stack sizes are escalating rapidly. The prediction by the IEA (IEA, 2020c) is taken into account, according to which total electrolyser hydrogen production capacity is almost being doubled each year.

### *2.3. Economies of scale*

Economies of scale usually refer to the cost advantages that large-scale projects gain when the project scales up (Silberston, 1972). Regardless of the type of goods/services as the output of the project/manufacturing process, this trend has been observed in various fields. For example, the latest empirical data from the wind-energy industry showed that unit cost of wind turbines tends to decline with increase in project capacity following a non-linear relationship (NREL, 2022), and this trend has also been observed for hydrogen stations (Melaina and Penev, 2013). Moreover, data from commercial projects (Felgenhauer and Hamacher, 2015) showed that the CAPEX of both PEM and alkaline electrolyser technologies follows the rule of economies of scale. Economies of scale are discussed in other fields such as biogas production (Skovsgaard and Jacobsen, 2017), wind-based renewable electricity (Dismukes and Upton, 2015), power storage technologies (Mauler et al., 2021), PV panels (Pillai, 2015), and shipping (Ros Chaos et al., 2021).

To estimate the CAPEX associated with different scales, Eq. (9), which is employed in chemical engineering (Ulrich, 1984), is applied:

$$CAPEX_S = CAPEX_{Base} \times (\frac{Capacity_S}{Capacity_{Base}})^{SF} \quad (9)$$

where $CAPEX_S$ is the required initial investment cost after scaling up to $Capacity_S$. $CAPEX_{Base}$ denotes the initial investment when the size of the plant is $Capacity_{Base}$, here 10-MW. $SF$ is scaling factor or scaling exponent.

The extent of cost reduction through economies of scale, which is determined by $SF$, may vary case by case as benefits of economies of scale are captured differently by manufacturers/project managers, and this leads to different values of $SF$ (Moreno-Benito et al., 2017; Morgan et al., 2013; Snyder and Kaiser, 2009). For this reason, along with a lack of empirical data from large-scale renewable-powered PEM electrolysis projects, there is no unique scaling exponent and so different values are proposed in the literature (e.g., (Gerloff, 2021; Parra and Patel, 2016; Zauner et al., 2019)). It should also be mentioned that each process/component/material involved in PEM technology manufacturing is very likely to have different scaling exponents (as mentioned for wind turbines (Blanco, 2009)), making detailed incorporation of economies of scale into modelling complicated, as with the learning rate model. Therefore, the simplified model expressed by Eq. (9) is applied here to make the model tractable, and we conduct a sensitivity analysis to account for uncertainty in $SF$.

To ascertain the impact of scaling on $LCOH$, different sizes from small-scale to large-scale are studied. First, 10-MW PV- and WT-powered hydrogen production plants on which the cost components are based are analysed. Then, 100-MW, 500-MW and 1-GW plants are evaluated.

### *2.4. Power curtailment and overload capacity of electrolyser*

As mentioned, the electrolyser array is first sized so as to utilise maximum power at the output of the power generation plant, which is calculated based on hourly data. This approach is mainly effective for the cases when maximum power occurs frequently or deviation from maximum power is low. However, if the peak power does not occur frequently, then it leads to under-utilised electrolyser capacity and consequently higher *CAPEX* values. This issue can be dealt with by shaving (curtailing) ineffective peak power. To study how power shaving affects $LCOH$, the electrolyser array is resized based on the modified power profile after curtailment. To do this, a certain percentage of the peak available power is adopted as the maximum acceptable continuous power, $E_{acc}$, for the electrolyser. Then, hourly power with values within the range $E_{acc}$ and $E_{peak}$ is shaved, leading to more effective utilisation of the electrolyser capacity. The modified power profile can be calculated by Eq. (10):

$$E_{sh}^{t} = \begin{cases} E_{out}^{t} & if \;\; E_{out}^{t} \leq E_{acc} \\ E_{acc} & if \;\; E_{out}^{t} > E_{acc} \end{cases} \qquad (10)$$

where $E_{sh}^{t}$ refers to the hourly shaved power profile which is sent to the electrolyser. Then the process is iterated to find the minimum $LCOH$ and corresponding optimum curtailment point.

On the other hand, PEM electrolysers can utilise input power above the nameplate capacity, denoted the overload capacity, for a limited time (Patonia and Poudineh, 2022). Here, as the third method of sizing, the model is re-run again on a scheme analogous to that just outlined to ascertain the impact of brief, infrequent overloads on *LCOH*. As there is no universal overload capacity or duration, reasonable assumptions were made, as detailed in the next section.

## 3. Assumptions and scenarios

Solar-based and wind-based power generation plants with 10-MW, 100-MW, 500-MW and 1-GW installed capacity were studied. Fixed-tilt PV panel systems with no solar tracking technology and wind turbines with a hub height of 100 meters, both with typical performance specifications, were adopted. An efficiency penalty of 5% is included, based on (Paul and Andrews, 2008), because the maximum power point (MPP) of the PV system's current-voltage (*I*-*V*) curve may not align perfectly with the polarisation curve of the electrolyser.[4] The same factor is applied to the WT case to allow for imperfect MPP tracking over a wide range of turbine rotation speed. The 10-MW size is adopted as the base capacity, $Capacity_{Base}$, for scaling up. For the other sizes, the impact of economies of scale is incorporated based on a 10-fold increase in

[4] To mitigate this efficiency penalty, a detailed study (Phan Van et al., 2023) was performed on how to optimally match the $I-V$ curve of the electrolyser with the maximum power points line of the PV system.

size, following (Yates et al., 2020). Due to the paucity of data on actual large-scale renewable hydrogen production by PEM technology, there is no unique scaling exponent in the literature, and the utilised value of $SF$ varies significantly (Böhm et al., 2020), for example, 0.70 (Parra and Patel, 2016) and 0.90 (Yates et al., 2020). Here, the mid-point of values found in the literature ($SF$ = 0.80) is assumed. Then, a sensitivity analysis is performed to estimate the consequent uncertainty in $LCOH$. The assumed scaling factors for WT and PV systems are respectively 0.95 and 0.90, based on (Superchi et al., 2023) and (Yates et al., 2020). Regarding the learning-by-doing model, $LR = 13\%$ is proposed for PEM technology in the Hydrogen Council report (Hydrogen Council, 2020) under the current situation. Given the basis year of this study, 2030, by which time PEM technology will be more mature, we assume $LR = 10\%$ to estimate the future electrolyser stack replacement cost, with cumulative capacity doubling each year based on the IEA's prediction (IEA, 2020c). Here all the cost assumptions are based on a collaborative report between Australia's Commonwealth Scientific and Industrial Research Organisation (CSIRO) and the Australian Energy Market Operator (AEMO) (Graham et al., 2022). This report sets out installed/ready-to-operate CAPEX of components which includes cost of equipment, engineering and design, construction and supporting facilities, labour, etc. The basis year's *CAPEX* values are derived from the published 2021 values under different scenarios considering prospective uncertainty and possible variations in learning rates, leading to different *CAPEX* values. We categorise the scenarios as Optimistic (lowest costs), Reference (most likely costs) and Pessimistic (highest costs), as set out in Table 2. To estimate *WACC* for discounting cash flow, financial parameters of the Merchant scenario from a very recent publication for the Australian National Energy Market (NEM) (Gohdes et al., 2022) are adopted. The parameters include gearing = 40.75%, corporate tax rate = 30%, the cost of debt = 6.6%, the cost of equity = 14.75% and the inflation rate = 2.5%.

Table 2. Assumptions of values of installed *CAPEX*, *OPEX* (Graham et al., 2022) and *REPEX* (IRENA, 2020b).

| **Component** | **Installed *CAPEX* (AUD/kW) in 2030 derived from real 2021 dollars** | | | ***OPEX*** | ***REPEX*** |
|---|---|---|---|---|---|
| | **Optimistic** | **Reference** | **Pessimistic** | | |
| PV panel | 513 | 796 | 968 | 4% of CAPEX | _ |
| WT system | 1848 | 1871.5* | 1895 | 2% of CAPEX | _ |
| PEM electrolyser | 700 | 919 | 1269 | 3% of CAPEX | 45% of CAPEX |

* Since there are only two values for installed CAPEX of WT systems, here we assume a midpoint for its CAPEX under the reference scenario.

Since curtailment of ineffective peak power is reasonably expected to lead to financial benefits through avoiding under-utilised electrolyser capacity, we first assume a range for peak power shaving. Here, a range between [0−50%] of peak power available at the output of the PV/WT system is assumed to be shaved and then the model is rerun to determine at which point the lowest value of $LCOH$ occurs. This point shows the optimal peak power shaving. Moreover, to be more realistic, a minimum useable power for the electrolyser should be considered (Hofrichter et al., 2023). Accordingly, here a minimum of 5% is assumed and factored into the modelling based on (Schnuelle et al., 2020) and (Patonia and Poudineh, 2022). This means if the input power to the electrolyser falls below 5% of its nominal capacity, the electrolyser stops operating.

Incorporation of overload capacity also changes the optimum electrolyser size. Under this scenario, the electrolyser is sized to utilise input power exceeding its nameplate capacity infrequently for a short period, to avoid decreasing the stack lifetime. There is no specific value for this parameter. For example, in 2023, Elogen's PEM technology has been reported to be capable of operating at peak capacity of 130% compared to its nominal capacity (Krause, March 2023), while according to (Patonia and Poudineh, 2022) 120% overload capability has been found for PEM technology, with further developments aiming at an overload capacity of 300%. To ascertain the impact on $LCOH$ of incorporating overload capacity, a value of 150% (considering likely improvements until 2030) is assumed for a short period of time, based on (Park et al., 2023). It should be noted that operating the electrolyser continuously in overload increases ohmic losses and is very likely to negatively impact the lifetime of the system, with consequent increases in operating and maintenance costs respectively (Tjarks et al., 2016). For this, the model is forced to return to normal operation at nominal capacity for a duration of 1 h after a maximum of 1 h of overload, and overload is assumed to be allowed for a maximum of 20% of the total operating time per year. Once this threshold is reached, the electrolyser is not permitted to operate in overload. This restriction is supposed to also mitigate potential pressure-related problems for the stacks. The assumption is derived from observations of the Mainz Energy Park, Germany, where the duration of overload was 15 minutes, followed by a mandatory 15-min cooling period. In our study, we base our assumption on a 1 h duration due to the hourly data collection. In cases where the electrolyser operates under overload for 1 h and the subsequent hourly generated power surpasses its nameplate capacity, the excess amount is curtailed as depicted by Eq. (10). Furthermore, to accommodate the probable, yet not clear, increased costs associated with overload operation, we assume a reduction in stack lifetime equal to the ratio of overload to total operation duration. For instance, if overload occurs for 10% of operating time, the stack durability is assumed to decrease by 10%.

Land requirements for a PV power generation plant and a wind farm are in accordance with the Queensland Solar Farm Guidelines report and the actual wind farms operating in Australia (Queensland solar farm guidelines, www.epw.qld.gov.au; ldcinfrastructure.com.au). Regarding the cost of water, an under-operation large-scale water desalination plant in Queensland has led to a levelised cost of water around \$2.02/m$^3$ according to (Desalination in Australia, www.advisian.com), which makes a negligible contribution to the final LCOH in the light of uncertainties arising in other factors. It has been reported that cost of water contributes as little as 2% to the final LCOH (Bruce et al., 2018). The main concern about the water requirement for hydrogen production is scarcity, which should not be an issue for the case study here as it is carried out for a coastal area. It is necessary to further purify even potable water for electrolysis. Here we assume a purified water requirement of 10 l/kg of produced hydrogen at \$10/m$^3$ cost. The reasons for assuming this high value are that first, the extra purification is typically done by reverse osmosis, requiring around 25 l/kg $H_2$ of potable feedwater and second, an inverse impact of economy of scale is expected relative to large desalination plants for providing drinking water.

## 4. Model validation

### *4.1 PEM cost projection*

Since the results of technoeconomic analysis rely absolutely on robust cost projections, the cost prediction model employed here was benchmarked against values from CSIRO (Graham et al., 2022), as well as those from the studies by the European Union (STORE&GO, 2020) and (Glenk and Reichelstein, 2019) shown in Fig. 2. Fig. 3 depicts the predicted cost evolution of PEM electrolysers from our previous study (Rezaei et al., 2022), derived from values in (Shaner et al., 2016) and the model developed in this study, using the base values provided by CSIRO (Graham et al., 2022). The figures fall within the range predicted by CSIRO; the variation difference among the ranges is attributed to the underlying assumptions. Expected PEM cost in 2030, shown by the blue dashed line in Fig. 2(a), aligns with the upper bound of our prediction, corresponding to the Pessimistic cost scenario. However, the range of PEM cost in 2050 depicted in Fig. 2(b) aligns well with the optimistic side of CSIRO's projections and our current model.

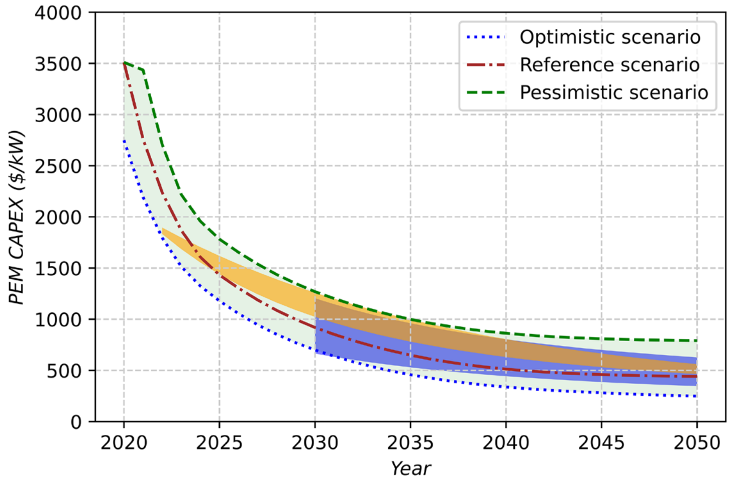


**Fig. 3.** Cost development of PEM electrolysis technology. The blue-shaded area starting from 2030 is derived from values presented by CSIRO and developed using our model. The orange-shaded area is generated from the base values in (Shaner et al., 2016) and developed considering likely learning rates employed in our previous study (Rezaei et al., 2022).

### *4.2 Curtailment model*

To validate our approach to finding the minimum LCOH by shaving peak power, we compared it with the model developed by (Hofrichter et al., 2023). For this, two cases in their study were replicated: first, a global location with high PV full-load hours[5] (FLH) in Tibet (2250 FLHs equivalent to 26% annual capacity

[5] Full load hours are calculated by dividing annual energy production of the plant (kWh) by its nominal capacity (kW).

factor) and second, a global location with high wind FLHs in Patagonia, Chile (6500 FLHs equivalent to 74% annual capacity factor). As mentioned, their model was developed based on the real operating characteristics of a PEM electrolyser array in the Mainz Energy Park project in Germany, to ascertain the optimal ratio between the PEM size and the PV or WT size (similar to the approach applied by (Gallardo et al., 2022) to minimise $LCOH$). Using the same source for hourly data, the results of our model for sizing the electrolyser to reach the minimum $LCOH$ perfectly match their findings.

## 5. Analysis

An important finding of our study is that incorporating a realistic power-dependant efficiency of the electrolyser has a significant impact on $LCOH$, particularly when the electrolyser is solely powered by renewable resources. Comparing $LCOH$ obtained from the commonly employed approach, for which $SEC =$ 55 kWh/kg was assumed (representing a fixed efficiency of 72% based on the higher heating value of 39.4 kWh/kg as described in (Park et al., 2023)), and employing the simple sizing method, it was found that making $SEC$ independent of input power would increase the calculated $LCOH$ by up to 12% for the WT-based model and 10% for the PV-based model. The overestimation in $LCOH$ caused by assuming a fixed $SEC$ significantly increases with an increase in the assumed $SEC$ value, i.e., with decreasing efficiency. For example, assuming $SEC =$ 62.5 kWh/kg (Henry et al., 2023) increased $LCOH$ by approx. 22% and 20% for WT and PV, respectively. It was strongly suggested that future studies should consider the efficiency–power curve for the electrolyser. Our finding is strongly supported by a recent publication by (Zhang et al., 2023), indicating that the final cost of hydrogen production is significantly influenced by fluctuations in wind energy, which directly affects the electrolyser efficiency. Consequently, estimating $LCOH$ based solely on average annual values, such as the average capacity factor commonly used in the literature, is unlikely to yield an accurate representation. Additionally, a recent study by (Ginsberg et al., 2023) emphasises the importance of integrating dynamic operation of the electrolyser into techno-economic modelling to obtain reliable, realistic projections.

### *5.1 Simple sizing scheme*

First, our analysis was performed with the simplified sizing method (without curtailment and overload) considering the Optimistic, Reference and Pessimistic scenarios for $CAPEX$.

The WT-based $LCOH$ value for the small-scale plant is slightly less than for the PV-based one under the Reference scenario, even though the WT-based levelised cost of electricity (LCOE) is much higher. This implies that higher wind capacity factor effectively offsets the higher CAPEX of WT systems for small-scale plants. However, it is observed that the WT-based LCOH becomes less favourable compared to the PV-based case as the size of the plant increases. This occurs because, with equal increases in the size of both PV and WT systems, $CAPEX$ of PV decreases at a higher rate due to better economies of scale. As the error bars indicate, PV-based $LCOH$ comes with higher uncertainty arising in the wide range of cost projections by CSIRO. For 10-MW size, for example, the PV-based $LCOH$ = $7.9/kg under the Pessimistic scenario, while for WT it is $6.7/kg. Similarly, the PV-based $LCOH =$ $4.3/kg under the Optimistic scenario, while for WT it is $5.2/kg. For the PV-based case, scaling up from 10 MW to 500 MW or to 1 GW almost halved $LCOH$, with an expected small difference between the 500-MW and 1-GW scales. The extent of reduction in $LCOH$ is significant after scale-up for the WT-based case, but less than that for PV. This is again due to a lower impact from economies of scale in wind technology. Under the Reference scenario, $LCOH$ for PV-based plant decreases from $6.1/kg to $3.1/kg, a reduction of 49%, when scaling up from 10 MW to 1 GW. For the WT-based plant, the decrease is 36%, from $5.8/kg to $3.7/kg, as depicted in Fig. 4.

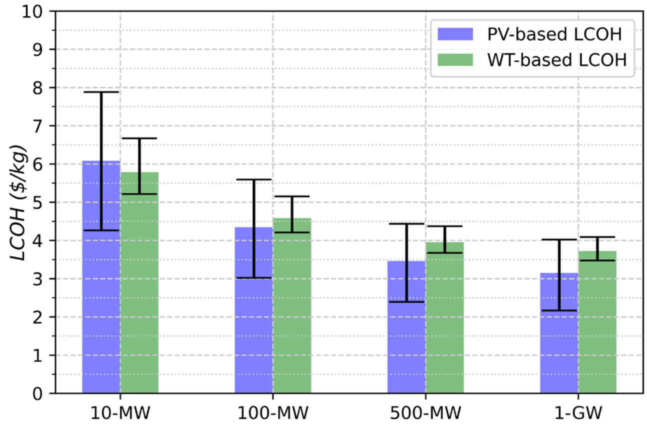


**Fig. 4.** PV-based and WT-based $LCOH$ in Gladstone under the Reference scenario with error bars indicating the Optimistic and Pessimistic scenarios.

### *5.2. Incorporation of power curtailment*

Curtailment of ineffective power was done by decreasing the electrolyser capacity from the value calculated using the simple sizing method. This aligns with the concept of increasing the ratio of renewable energy capacity to electrolyser capacity, as explored in (Hofrichter et al., 2023). A curtailment range of [0 – 50%] of the maximum power available across the year was explored with 1% step size, until the minimum $LCOH$ value, corresponding to optimal peak power shaving, was found. Fig. 5(a) indicates that the lowest PV-based $LCOH$, corresponding to a saving of 4%, occurs when shaving almost 15% of the peak PV power, while only 3% of total produced hydrogen is lost. This means that under the simplified approach of electrolyser sizing for the 10-MW PV plant, 15% of an 8.2-MW electrolyser was responsible for only 3% of total produced hydrogen.[6] Similarly, Fig. 5(b) shows that the optimal curtailment for the WT-based plant is almost 20%, with a consequent 4% reduction in yearly hydrogen production and 3.6% decrease in $LCOH$. Fig. 5 shows that the extent of reduction in $LCOH$ decreases as the size of the plant increases. This indicates that the negative impact of not curtailing ineffective peak power can be partially offset by economies of scale. Therefore, curtailment is more important for small-scale to medium-scale plants. Fig.

[6] The extent of reduction in $LCOH$ through curtailment relies solely on weather data. Hence, the optimal curtailment level varies based on different locations.

6 depicts modified power profiles of the 10-MW PV and WT plants after curtailment. More curtailment is required in the WT model to reach minimum $LCOH$, owing to greater variability in the available power compared to PV.

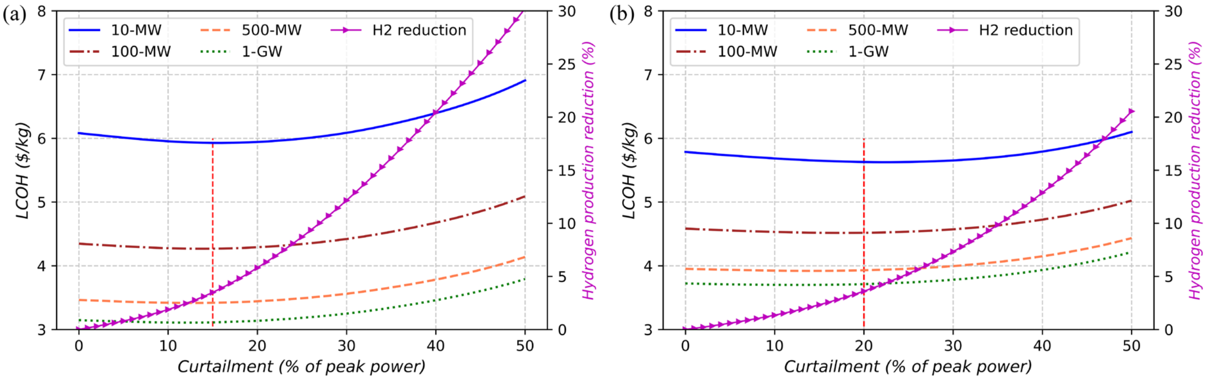


**Fig. 5.** The impact of peak power curtailment on $LCOH$ and yearly hydrogen production for (a) PV-based and (b) WT-based models. Vertical dashed lines indicate the curtailment percentage for minimum $LCOH$.

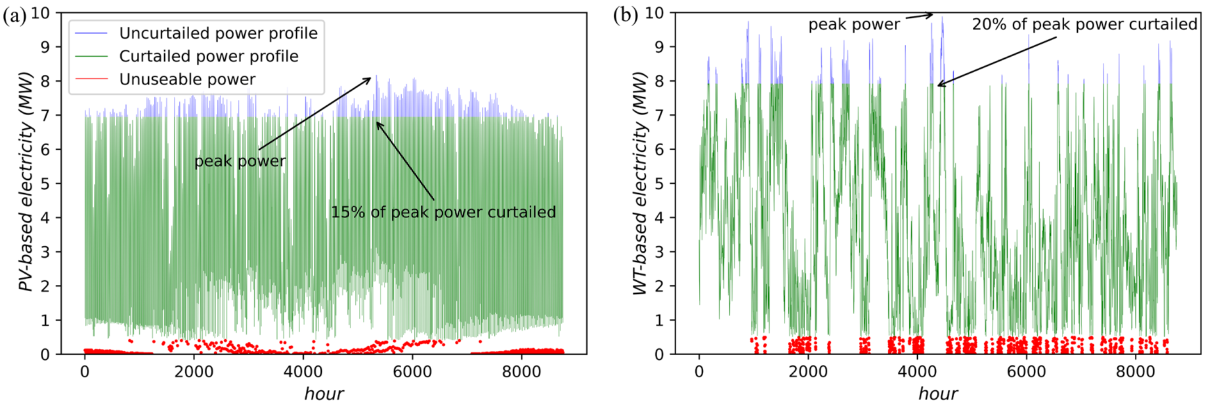


**Fig. 6.** Peak-power curtailment for 10-MW plants: (a) PV; (b) WT.

Fig. 7 depicts the cumulative probability of hourly PV and WT output power throughout the year, using a cumulative probability density function. The visualisation reveals a substantial distinction between the two energy sources. Specifically, the probability of PV output dropping below the minimum acceptable load is notably higher (54$^{th}$ percentile) compared to WT output (13$^{th}$ percentile). However, it is noteworthy that after curtailment, both PV and WT reach similar percentiles (93$^{rd}$ percentile) for their respective peak outputs of 7 MW and 7.9 MW.

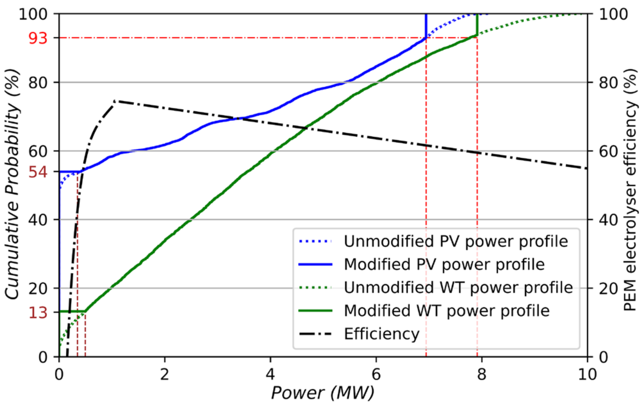


**Fig. 7.** Cumulative probability of 10-MW PV and WT power. The vertical, red-dashed lines indicate the peak power after optimal curtailment, while the vertical brown-dashed lines represent the minimum acceptable power, below which power is referred to as unusable in Fig. 6. The unmodified profiles refer to hourly power profiles before curtailment and elimination of unusable power).

The correlation between power curtailment and $LCOH$ is initially inverse[7] due to decreasing PEM $CAPEX$. Past the minimum in $LCOH$, the correlation turns direct because decreased PEM capacity cannot compensate for increasing $LCOE$ (because PV or WT $CAPEX$ is fixed despite decreased total electricity use). Although the percentage of reduction in $LCOH$ after power curtailment is greatest for small-scale PV- and WT-based plant, depending on the location it can still be very worthwhile for the largest plant sizes because of their much higher production volume.

### *5.3. Incorporation of overload capacity*

Taking overload capacity into consideration (without curtailment), it was found that $LCOH$ would decrease by a meaningful amount, as shown by Fig. 8. Similar to the trend of $LCOH$ considering ineffective peak power curtailment, the extent of $LCOH$ reduction after accounting for electrolyser overload capacity decreases with increasing plant size. However, when comparing the PV and WT plant, incorporation of electrolyser overload capacity into the PV-based plant is more beneficial since higher reduction in $LCOH$ is observed (Fig. 8), which contrasts with the peak power shaving case. For example, the PV-based $LCOH$, initially at \$6.1/kg without considering overload, would decrease by 16.4% to \$5.1/kg when overload is factored in for the 10-MW plant. This reduction diminishes to 7.4% for the 1-GW plant. Similarly, for the 10-MW and 1-GW wind plants, the reductions are 9.5% and 4.3%, respectively. In consequence of the restrictions placed on overload frequency and duration, the proportion of overload hours when the electrolyser array is connected to the PV plant is around 17% versus 8% for the WT case.

[7] The correlation between power curtailment and $LCOE$ is certainly direct as some power is wasted while expenditure is fixed.

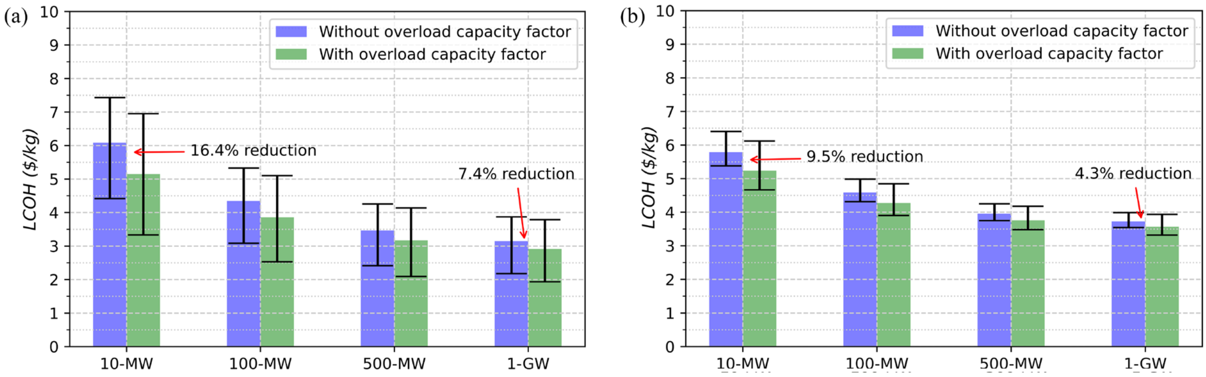


**Fig. 8.** $LCOH$ reduction after incorporating overload capacity into the model for (a) PV-based and (b) WT-based plant under the Reference scenario with error bars indicating the Optimistic and Pessimistic scenarios.

Curtailment and occasional overload are alternatives in practice for two reasons. First, peak shaving to the nameplate electrolyser capacity implies that too much time is spent at nameplate to satisfy the conditions adopted for employing overload. Second, overload operation is likely to hasten degradation, with a consequent increase in operating and maintenance costs. Nevertheless, if the increased cost of overload operation is acceptable, and if curtailment is not workable, overload operation can bring a worthwhile decrease in $LCOH$.

## 6. Sensitivity analysis and discussion

The analysis shows that the scale of the plant has a significant impact on $LCOH$ and in effect determines whether the project can reach the target value of \$3/kg $H_2$. To better understand the possibilities, $LCOH$ is calculated as a function of the power plant capacity, to ascertain the threshold size at which the target $LCOH$ value can be reached under different cost scenarios for 2030 (Fig. 9). For this, in addition to the base-case PV scaling factor = 0.90 (Yates et al., 2020) and WT scaling factor = 0.95 (Superchi et al., 2023), a small improvement in scaling factors respectively leading to 0.85 and 0.90 is also assessed, based on (Yates et al., 2020).

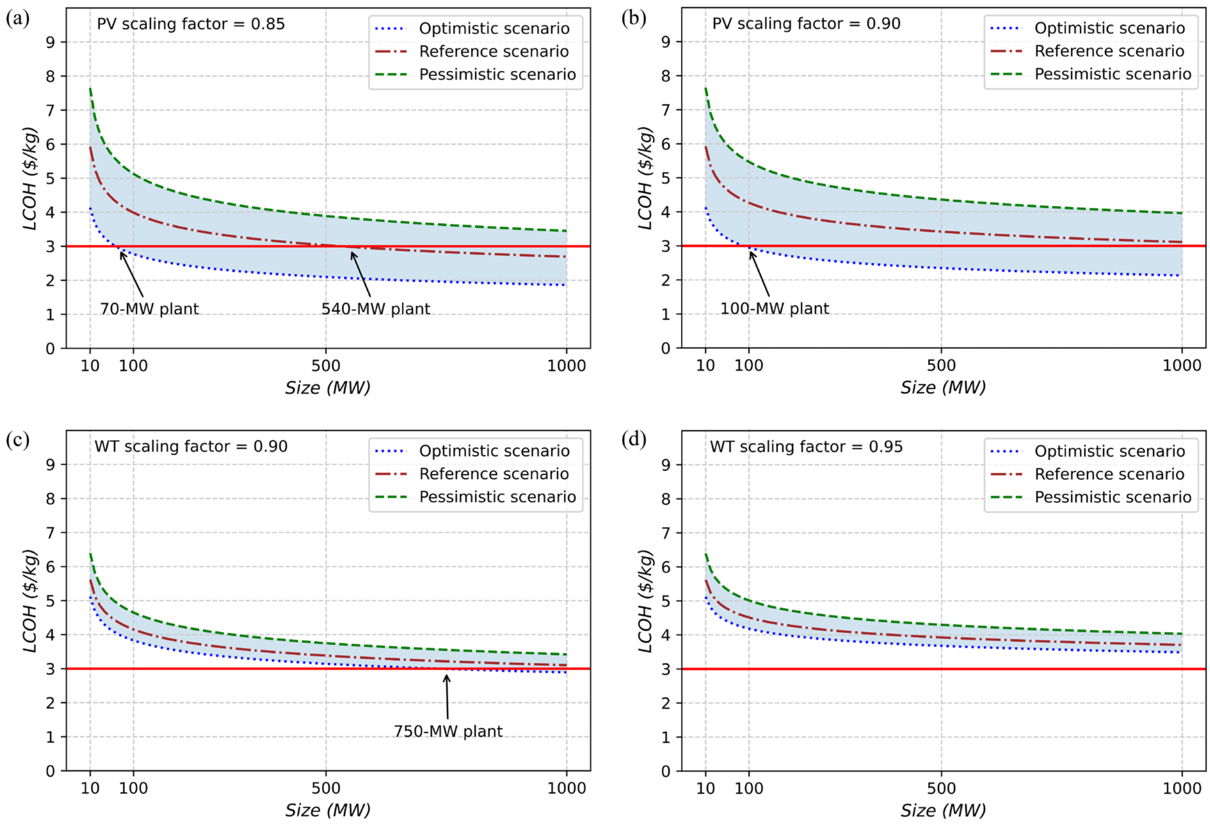


**Fig. 9.** Evolution of $LCOH$ as a function of size for (a) PV scaling factor = 0.85, (b) PV scaling factor = 0.90, (c) WT scaling factor = 0.90 and (d) WT scaling factor = 0.95.

With PV scaling factor = 0.85, \$3/kg $H_2$ is within reach for a 70-MW PV plant under the Optimistic scenario and for a 540-MW PV plant under the Reference scenario. With PV scaling factor = 0.90, the target value can be reached by a 100-MW PV plant under the Optimistic scenario. For any $CAPEX$ values ≥ those of the Reference scenario, however, only GW-scale projects will reach the target, although improvements in other technical and/or financial factors (e.g. lower $WACC$, higher electrolysis efficiency and green subsidy (Rezaei et al., 2022)) will unquestionably drive $LCOH$ down.

With the base-case scaling factor for WT set at 0.95, it is evident that even under the Optimistic scenario, large-scale plants are unable to reach the target value. However, WT plant sizes ≥ 750-MW have the potential to achieve \$3/kg if the scaling factor improves to 0.90 under the Optimistic scenario. We remark that the situation would likely improve for offshore WT installations.

Next, the trend of $LCOH$ as a function of basis year (with constant 20-year project lifetime and ongoing expected increase in the PEM electrolysis efficiency based on (Hofrichter et al., 2023)) was evaluated. Fig. 10(a) indicates that with improvement of the PV $CAPEX$ scaling factor to 0.85, the target value of $LCOH$ could be reached by 2035, even under the Pessimistic cost scenario, for PV plant sizes ≥ 500 MW. With the base-case scaling factor = 0.90 (Fig. 10(b)), the time required to reach the target will be delayed by 5 years.

With the current scaling factor of 0.95 for WT $CAPEX$, it is expected that the target value will be achievable by 2040 for the 1-GW plant, and by 2050 for 500 MW. A small improvement in this factor, to e.g., 0.90, would significantly shorten the time to reach the target.

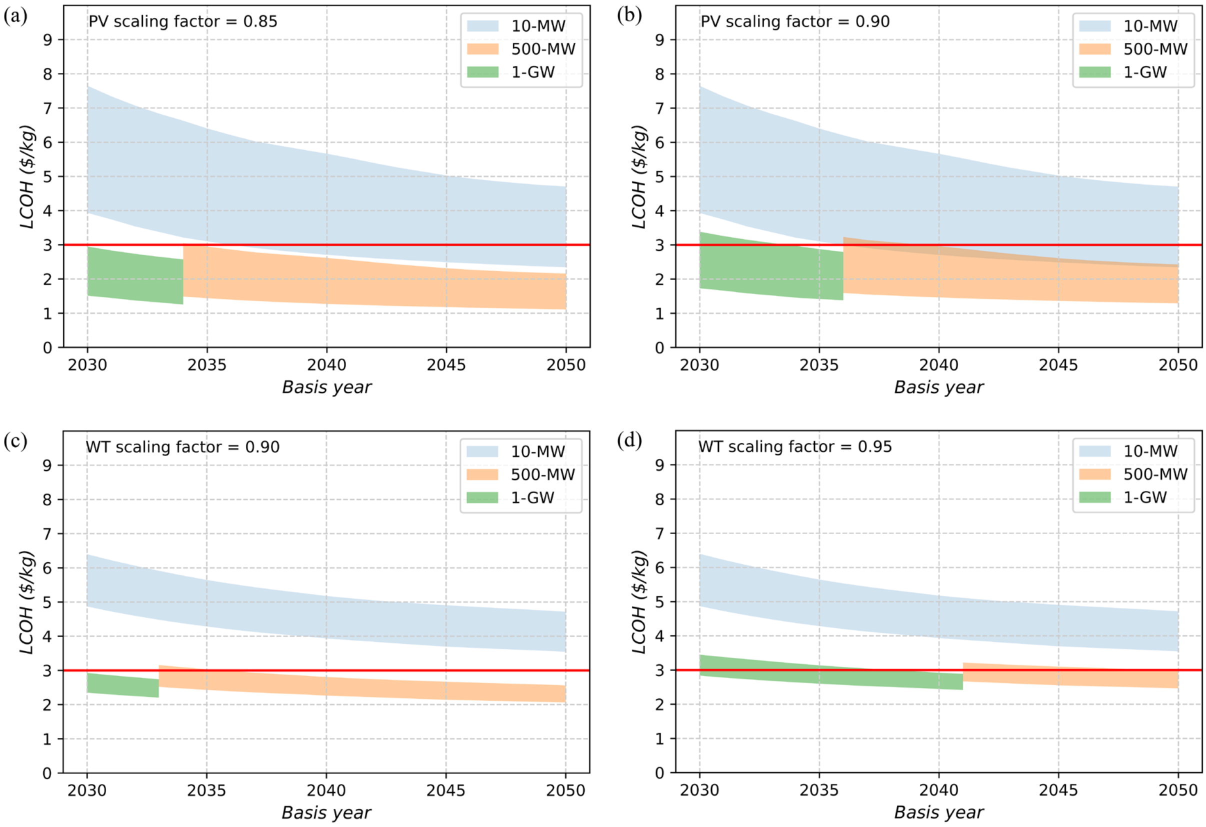


**Fig. 10.** Evolution of $LCOH$ as a function of basis year for (a) PV scaling factor = 0.85, (b) PV scaling factor = 0.90, (c) WT scaling factor = 0.90 and (d) WT scaling factor = 0.95. Shaded areas span Optimistic and Pessimistic scenarios. (To prevent overlapping of shaded areas, the 100-MW plants have been excluded).

These results underline the importance of economies of scale as the industry develops. Considering all the assumptions and the narrower range of predictions for WT $CAPEX$, benefits of economies of scale for WT systems should be captured better compared to the base-case value to reach the target of $3/kg under all scenarios for ≥ 500-MW plants.

Sensitivity of $LCOH$ to $LCOE$ was not studied, because the Optimistic and Pessimistic scenarios for $CAPEX$ capture uncertainty in $LCOE$. The sensitivities of $LCOH$ to the PEM $CAPEX$ scaling factor ($SF$) and $WACC$ were examined. As mentioned, values of $SF$ in the literature vary in a wide range, so a range between 0.70 and 0.90 was examined to cover the most likely values. To do so, 100-MW PV and WT plants (representing medium scale) and 1-GW plants (representing large scale) were modelled with curtailment incorporated. Fig. 11 and Fig. 12 respectively depict the individual impacts of variations in $SF$ and $WACC$ on $LCOH$.

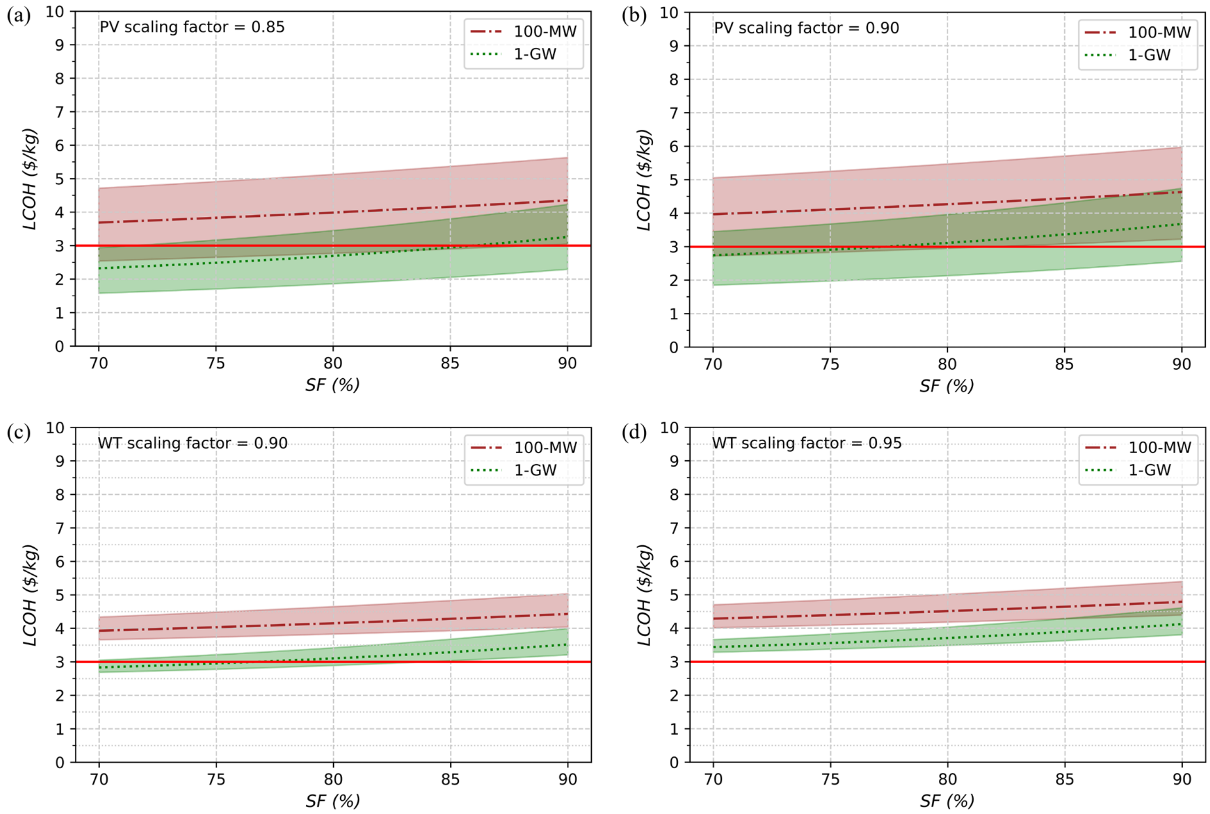


**Fig. 11.** Impacts of variations in $SF$ on PV-based $LCOH$ with PV scaling factor = (a) 0.85 and (b) 0.90 and on WT-based $LCOH$ with WT scaling factor = (c) 0.90 and (d) 0.95, with the other parameters held constant.

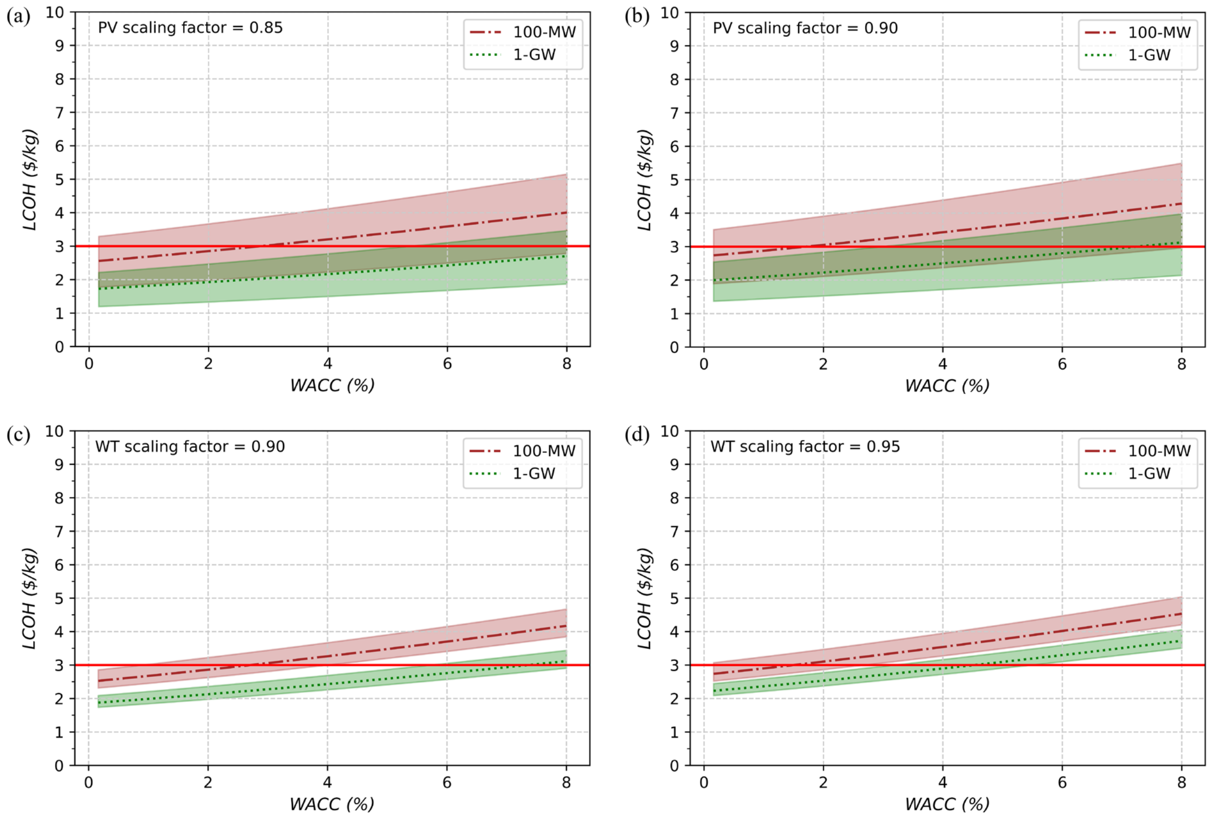


**Fig. 12.** Impacts of variations in $WACC$ on PV-based $LCOH$ with PV scaling factor = (a) 0.85 and (b) 0.90 and on WT-based $LCOH$ with WT scaling factor = (c) 0.90 and (d) 0.95, with the other parameters held constant.

Correlations between all variables and $LCOH$ are strong and direct, indicating that these should be considered carefully in the modelling. Regarding $WACC$, a modest improvement of < 3% in our assumed value (with other parameters held constant) would compensate for unfavourable values of PV and WT scaling factor. To reach the target with GW-scale plants having $CAPEX$ values ≤ the Pessimistic costs, improvement in the PV or WT scaling factor by 5% is an alternative to improvement in $WACC$ by 2%, regardless of energy source. However, a presently unforeseeable decrease in $WACC$ alone would be required for a 100-MW plant to reach the target under the Reference scenario, regardless of energy source. In terms of $SF$, if economies of scale with more favourable $SF$ values (e.g., 0.50 in (Superchi et al., 2023)) are able to be realised, then even the pessimistic scenario can result in $LCOH$ = \$3/kg, noting that PV plant would require lower $SF$ than WT because the scenarios span a wider range of $CAPEX$ values. $WACC$ is a determining variable that can offset the disadvantage of small- to medium-size plants to a great extent, suggesting a path to eventual scale-up by means of low-cost finance from government or international development sources. For example, according to a report by the Oxford Institute for Energy Studies (Craen, 2023), sources of low-cost debt suitable for green hydrogen export projects are concessional lenders such as JBIC, KfW or KDB and Export Credit Agencies (ECAs).

## 7. Limitations

Foremost among the limitations in our analysis is the scarcity of publicly available data, particularly concerning large-scale wind and solar farms, compounded by the non-existence at the time of writing of any operational large-scale renewable-based hydrogen production project. These constraints impact the depth and precision of our analysis in certain areas, necessitating reliance on model-based estimations and broad assumptions rather than concrete empirical data. Consequently, our findings might be subject to some degree of approximation due to the lack of direct, real-world data (such as learning rates and cumulative production capacity of PEM electrolysers). This limitation underscores the challenge of working in a domain where extensive operational data on renewable hydrogen production is not yet widely accessible. Despite the inherent limitations in conducting a technoeconomic analysis, we have employed rigorous modelling techniques and incorporated actual data from a 6-MW PEM-technology project in Germany to establish the most reliable model for estimating the LCOH.

## 8. Summary and conclusions

Production of green hydrogen from renewably sourced electricity is essential for decarbonisation of the global energy system. While the final cost in any country will depend on local factors such as the price placed on carbon, the farm-gate cost of production must be minimised by optimising controllable technical factors. To achieve this, a realistic financial scenario is needed to evaluate the viability of a project over its life. Here the levelised cost of hydrogen production was related to a model of CAPEX in which the decreasing cost over time of technology with cumulative production of that technology, and the decreasing unit cost with increasing project scale are both included. The goal of our study was to understand if and how a target farm-gate LCOH of AUD 3/kg H2 could be reached. In addition to simply sizing the electrolyser array to use the peak power available (from PV and wind in this case), scenarios were explored in which (i) curtailment (peak shaving) was employed to decrease the electrolyser nameplate capacity while foregoing only a very small percentage of annual hydrogen production; and (ii) advantage was taken of the intermittent overload capacity of the electrolyser to decrease the required nameplate capacity below the peak input power. The LCOH for solar-based and wind-based hydrogen production plants in the region of the planned Gladstone hydrogen hub, Queensland, Australia was evaluated within a range bounded by Optimistic and Pessimistic scenarios based on cost projections for PV and wind generation published by CSIRO and AEMO, for the base year 2030. While the absolute value of the modelled $LCOH$ depends on the acknowledged uncertainties in the input data, the model demonstrates clearly the potential for lower real $LCOH$ to be achieved by carefully sizing the electrolyser capacity relative to the maximum available electric power.

The main findings of our study are as follows:

- Capturing the benefits of economies of scale can significantly lower $LCOH$, to be at or close to the target value of \$3/kg $H_2$, regardless of energy source.
- The benefit of incorporating a power-dependent electrolyser efficiency is very significant, in the range 10–20% lower predicted $LCOH$.
- The simple sizing method for the electrolyser array (no curtailment and no electrolyser overload) indicates that only the PV-based $LCOH$ will come close to the target value of \$3/kg $H_2$ under the Reference (most likely) scenario for multi-GW projects.
- Under the Optimistic scenario, the target value is reached by PV plant at the scale of ≥ 100 MW with the base-case PV scaling factor, and by WT plant at several hundred MW only if the WT scaling factor improves.
- Applying curtailment of 15% for PV and 20% for WT achieves a useful reduction in $LCOH$ of around 4% for small-scale plants. Under the Reference scenario, the target $LCOH$ value will be within reach at 1 GW for PV-based plant. For GW-scale WT, improvement in other factors, e.g., WT scaling factor or the WACC, is required.
- Employing the assumed overload capability of the PEM electrolyser array (150% for a limited time) achieves a significant decrease in $LCOH$, such that the target value will be reachable under the Reference scenario for a PV plant size around 1 GW. For WT, this factor cannot push $LCOH$ down to the target value due to lesser economies of scale for wind turbines relative to PV systems.
- Curtailment and overload are effectively alternatives, since curtailment shaves the power peaks that could be utilised in overload.

- Under the Pessimistic scenario for WT, the target value would not be achievable even for a multi-GW project without improvement in some of the technical or financial factors, e.g., $SF$ decreases to 0.70 or $WACC$ decreases to 4%. The former requires more evidence from actual large-scale projects, but the latter might be accessible through international development financing sources.
- Under the Pessimistic scenario for 1-GW PV plant, the target value would be achievable with the current value of PV scaling factor only if $WACC$ decreased to almost 4%. With a small improvement in PV scaling factor, a $WACC = 6\%$ suffices. The real scaling factor thus plays a crucial role in achieving the target.
- The different in projections for PV- and WT-based projects arise substantially in the wider range of cost projections for PV.
- The target value of AUD 3/kg is within reach by 2040, even under the Pessimistic cost scenario, for PV projects at the 500-MW scale. For WT, an improvement in its scaling factor is required to reach the target sooner.

Our research has provided critical insights into the economic viability of green hydrogen production. Although tied necessarily to a location – in Australia in this instance – the methodology employed is generally applicable. Thus, our findings provide a practical roadmap for stakeholders, particularly policymakers, enabling them to develop strategies and incentive structures that promote the deployment of large-scale renewable hydrogen initiatives. Such insights are crucial in steering decision-making toward cost-effective and efficient renewable hydrogen solutions, thereby shaping the future landscape of the hydrogen energy sector.

## 9. Recommendations for further work

Our study revealed the substantial influence on project economics of appropriately sizing electrolysers by integrating their real-world operational characteristics into the modelling, in particular power-dependent efficiency and overload capability. These are fundamental as they directly affect the cost efficiency of green hydrogen production. By considering these elements, decision-makers can more reliably assess the financial feasibility of renewable hydrogen initiatives. Moreover, our study demonstrated the potential for a substantially lower LCOH achieved by scaling up renewable energy plants, bolstering the case for their widespread adoption.

In each instance, the mathematical model employed to quantify the economic consequences was notional to some degree: for the power-dependent efficiency model, data from a single PEM electrolyser were employed, based on a 2017 report that, in a field that is evolving very rapidly, is now out of date; for the scaling model, there is a dearth of information about the impacts of scale on real PV-plus-PEM systems; for the learning-by-doing model, 2015 data were employed, which in view of the rapid rise in production of PEM electrolysers in the intervening years is very out of date.

For future studies, it is strongly recommended to incorporate the power-dependent efficiency, overload capacity of the electrolyser and economies of scale in multi-objective optimization studies, as these factors distinctly impact both technical and economic objectives, but more up-to-date information is needed to decrease the uncertainty in the model outputs. Thus, it is also important for surveys to be conducted of real green hydrogen energy systems as a foundation for robust modelling.

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