RESOURCES, SYSTEMS AND TECHNOLOGIES

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H2LCA.org: An online tool for life cycle assessment of green hydrogen and ammonia production

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Hydrogen and ammonia are essential chemicals for modern society. However, climate mitigation targets will necessitate their production using low-emission technologies, especially renewable energy. In addition to techno-economic assessment, it is critical that the life cycle environmental impacts of conventional and green production are assessed. We present an online assessment tool that assesses life cycle emissions, including emissions embodied in the plant and equipment, and Scope 2 emissions associated with grid electricity. The tool combines an electricity system simulation model, a life-cycle assessment model, a techno-economic model, and a sensitivity-optimisation model. When combined with techno-economic assessment, life cycle assessment provides an important evaluation of the costs and benefits of green chemical production under different scenarios. The tool can be readily configured to test for configurations for off-grid and grid-connected plant. We present results for three case studies using the tool. We find that greenhouse gas emissions are highly sensitive to the selection of plant and equipment, mode of operation, and emission profile of the electricity grid. The life-cycle greenhouse intensity of off-grid green hydrogen production is 2 to 3 kg CO2/kg H2 under optimal conditions. With grid buffering of renewable supply, the greenhouse intensity can increase markedly, to 20 kg CO2/kg H2 or higher. These results can be compared with a baseline intensity of 10 to 12 kg CO2/kg H2 with production using natural gas. With respect to cost, the production cost of green hydrogen ranges from $8 to $22 /kg H2, which can be compared with a baseline cost of $2.27 to $2.77 in 2019 using natural gas. The tool is evolving and further functionality is being incorporated. Anticipated additions include a wider range of green products and processes, such as green steel, and the Allam cycle, and a wider range of life cycle options.

Comparing the economics and emissions of grid-connected vs. off-grid hydrogen production

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This paper provides a comparative analysis of three hydrogen production models: large-scale off-grid green hydrogen hubs, small-scale grid-connected hydrogen projects, and dedicated renewable energy systems with grid buffering. The viability of these models depends heavily on the local configuration of the electricity supply.

The present analysis began by identifying high-potential locations for off-grid hydrogen hubs across Australia based on renewable resource quality and infrastructure availability. A mixed-integer programming model was then used to conduct a detailed techno-economic optimisation of system configurations and operations for the identified hub locations. The model optimised key design decisions including electrolyser capacity, battery and hydrogen storage, and an ideal mix of wind and solar generation for each location to meet the production target. For dedicated off-grid projects, optimisation results show well-balanced combinations of wind and solar resources can reduce storage needs and costs while increasing electrolyser utilisation rates and lowering production costs.

For grid-connected projects, the interplay between electricity tariffs and emissions profiles was modelled using historical data from the Victorian and South Australian grids as contrasting case studies. The optimisation tool simulated hourly hydrogen production and scope II emissions under two strategies: minimising total electricity bills and minimising indirect grid emissions. Key insights revealed that the current retail tariff structures mute wholesale market price and emission signals. Minimising total electricity bills led to more night-time electrolyser operation (when time-varying tariffs are lower, but carbon-intensive coal generation is higher), increasing emissions. Conversely, choosing to minimise emissions increased daytime hydrogen production coinciding with higher solar availability but at higher network tariffs.

Off-grid hydrogen production requires high capital expenditures on renewable plants and batteries for energy storage, while grid-connected systems incur usage tariffs and network fees. In addition, operators using grid electricity for buffering or participating directly in real-time wholesale markets must balance economic and environmental factors. This study found that hydrogen production relying solely on grid electricity with high fossil fuel penetration results in high emissions and costs due to elevated network and demand charges. Network-connected projects with dedicated renewable sources that use the grid for buffering are currently the most economical option. Nevertheless, off-grid hydrogen systems running on dedicated renewables are projected to become increasingly competitive as renewable energy and storage costs continue to fall. The findings of this study provide valuable insights for hydrogen developers and policymakers in evaluating optimal electricity supply configurations and retail tariff designs.

Cost-competitiveness implications of misalignment in hydrogen certifications: a case study of exports from Australia to the EU

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Certification systems for emissions embodied in hydrogen will be necessary to ensure that this energy carrier can contribute to mitigating climate change. These certification systems are rapidly developing worldwide, but as yet there is no recognised and consistent international standard.

One potential area of misalignment between regional standards relates to the definition of 'renewables based' electricity. We consider the case of Australian hydrogen exports to the EU to describe potential alignment and misalignment between treatment of grid electricity in the hydrogen certification systems emerging in both jurisdictions. This is followed by a modelling exercise exploring how demand for Australian hydrogen is likely to emerge under two scenarios with differing costs of electrolysed hydrogen: 1) when only Australian off-grid hydrogen is recognised as renewables-based, and 2) when Australian certification successfully underpins EU recognition of grid-based electrolysis as renewables-based.

We use an analytical framework linking a linear optimisation model for estimating the levelised cost of hydrogen with a system dynamics model to capture the interaction between the demand and landed cost of hydrogen, and perform sensitivity analyses to consider the cost-competitiveness of on-grid vs. off-grid hydrogen under scenarios for high and low electricity costs, among other sources of variation in cost of hydrogen production. The models consider hydrogen product costs specific to several states and territories in Australia that are considering developing hydrogen export industries. Findings indicate that grid-connected hydrogen production could be more cost-effective than off-grid production in the near-term (2025) under optimistic electricity cost scenarios, achieving levelised costs of 3.05 USD/kg H2 in Tasmania. However, potential international cost-competitiveness of this hydrogen would only be useful for export markets if Australian certification aligns with importer requirements (and if long-distance export is technologically feasible). In the longer-term (2030 and 2040), off-grid hydrogen production in all states is projected to be comparable to or cheaper than on-grid production across the envelope of modelled costs.

Our sensitivity modelling, and subsequent discussion, emphasizes the role of uncertainty in development of hydrogen industry. While off-grid electricity costs are dependent on the downward trajectories of solar and wind costs, on-grid electricity costs are also dependent on evolution of renewable energy certificates, potential changes in electricity markets, and necessary grid storage and transmission costs with as-yet uncertain allocation. The ability of hydrogen producers to use grid-connected electricity for electrolysis is especially dependent on development of transmission in close proximity to hydrogen production while avoiding grid congestion – particularly since EU import requirements will necessitate geographical correlation between hydrogen production and the renewable electricity that feeds it. In this context, certainty regarding certification alignment could remove one source of variation affecting hydrogen industry development.

Modelling sustainable hydrogen supply chain paths

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Hydrogen derived from renewable powered electrolysis is a promising energy storage technology for future decarbonised energy systems. However, the inherent nature of intermittent renewable energy means such systems will generate a fluctuating hydrogen output unless suitable storage or backup strategies are implemented. In this work, we have conducted location-specific, temporal modelling of variable renewable powered electrolysis systems with a focus on ensuring a stable hydrogen supply. Five industrial precinct locations across Australia with a clear focus on transitioning from fossil fuel production to clean energy were chosen for analysis. The modelling methodology incorporates local temporal weather data over the past decade (at an hour resolution) and subsequently models the anticipated solar and wind power profiles across a typical metrological year (TMY) for a given location. These are then used to derive the hydrogen output from an electrolyser. An optimisation algorithm is then used to determine the optimum combination of batteries, local grid usage and open-cycle gas turbines (OCGT) to minimise the levelized cost of hydrogen (LCOH) whilst also ensuring a constant supply of hydrogen.

The base scenarios relying purely on renewable energy demonstrate that electrolytic hydrogen can be generated at reasonable cost (LCOH: \$3.89/kg – \$5.72/kg, depending on location in Australia). However, these scenarios of course generate hydrogen at highly variable production rates, which is often impractical for downstream applications. OCGP or grid backup can achieve stable hydrogen generation within emissions thresholds (e.g. CertifHy: 4.37 kg-CO_2e/kg-H_2). It is difficult however to justify installing an OCGT with such a small capacity factor design, whilst the price of grid electricity is likely to limits it usage to only the final 5-10% of power generation. Introducing a capacity factor requirement on renewable only systems enables the systems designs to be oversized in order to achieve a consistent hydrogen supply, albeit at a higher LCOH. However, even systems designed to achieve very high capacity factors (e.g. ≥ 95%) can be unreliable during periods of poorer weather (e.g. Winter). This was illustrated by modelling the likelihood of achieving a given daily capacity over ten years of weather data. Such modelling helps to understand and quantify the trade-off which exists between system cost and reliability. For inflexible downstream applications which require a stable hydrogen supply, the most suitable system design is suggested to be one where the typical process capacity factor (e.g. 95%) is achieved in a TMY using renewable energy, however a grid backup is provided to support the system for periods of particularly poor weather. Such a system is capable of generating a stable supply of hydrogen which is predominantly produced from renewable energy, with system reliability ensured by using the small degree of grid backup. This gives a true cost of reliable electrolytic hydrogen production (LCOH) which is only ~15% more expensive than that of intermittent generation. As a conclusion the algorithm is shown applied to the power requirements of a remote WA mine site.

Export-domestic energy integration via industrial hydrogen storage

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Australia has set a vision for a world-leading hydrogen industry to support the ambition to become a renewable energy superpower. Large-scale development of hydrogen industries will reshape our current electricity network and creates opportunities for strategically operating hydrogen facilities to add significant flexibility to the electricity grids, supporting a zero-carbon energy transition. Renewable energy resources are weather-dependent, and hence are variable and uncertain in nature. Large-scale solar and wind energy integration brings significant challenges to energy security, while the variability spans over multiple timescales ranging from seconds to seasons. Therefore, cost-efficient storage methods are key to addressing the variability issues associated with large-scale renewable energy integration on a full timescale. Industrial hydrogen storage is an emerging energy storage approach, which can be a game changer for Australia's energy markets. Industrial hydrogen storage has a high storage efficiency of 92% (compressed gas). The storage cost is relatively low, ranging from US$3/kWh (salt cavern) to US$30/kWh (storage tank), which is one to two orders of magnitude cheaper than electricity storage. Therefore, industrial hydrogen storage is ideally positioned for large-scale stationery energy storage applications over multiple timescales. Coupling hydrogen storage with electrolysers in the industries (e.g. green steel production) will create new industrial load centres that are interruptible, dispatchable, and responsive on timescales ranging from seconds to seasons. This research investigates how hydrogen storage coupled with industrial electrolysers can support Australia's zero-carbon energy transition, including the potential for industrial hydrogen storage to: (i) address the variability issues related to large-scale renewable energy integration; and (ii) enhance the resilience of zero-carbon electricity grids under extreme weather events. The research findings contribute to a new paradigm for integrating Australia's hydrogen export industry with domestic energy sector to facilitate an affordable and reliable transition to net-zero energy futures.