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Hydrogen storage in depleted gas fields: A techno-economic case study of Moomba, South Australia

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Abstract
This study conducted a techno-economic analysis of green hydrogen production, focusing on evaluating the 'cost of delivering hydrogen to market', which includes storage and transportation. The analysis evaluates PEM electrolyser hydrogen production at Moomba (South Australia), comparing underground storage (UHS) in depleted gas fields and surface storage for techno-economic performance. Hydrogen transport to Port Bonython is assessed via 659 km of pipelines and 963 km of tube trailer road transport. Delivery capacities are based on ship export categories: small (1500-3000 m^3), medium (10,000-20,000 m^3) and large (40,000-50,000 m^3) carriers. They correspond to hydrogen capacities of 106.2 to 212.4 tonnes, 708 to 1,416 tonnes and 2,832 to 3,540 tonnes, respectively. The requirements correspond to hydrogen production rates of 305.86 tonnes/day and 632.10 tonnes/day for 1.27 GW and 2.54 GW electrolysers, respectively. Increasing electrolyser capacity slightly improves economic performance through economies of scale, reducing the levelized cost of hydrogen production from A$6.95–A$8.87 kg^{-1} H_2 (1.27 GW) to A$6.92–A$8.73 kg^{-1} H_2 (2.54 GW), but not a very significant reduction. UHS demonstrates lower costs (A$0.12–A$0.88 kg^{-1} H_2) compared to surface tanks (A$3.24–A$6.15 kg^{-1} H_2). Pipeline transport yields the lowest levelized cost of hydrogen transport of A$1.21–A$1.27 kg^{-1} H_2, while tube trailer shows higher costs for CGH_2 (A$3.45–A$7.79 kg^{-1} H_2) and LH_2 (A$6.35–A$13.67 kg^{-1} H_2). The integrated analysis shows a levelized cost of hydrogen delivered (LCOHD) of A$3.74–A$7.15 kg^{-1} H_2. Hydrogen price, electricity cost, discount rate and utilities are the primary economic drivers. The study recommends reducing renewable electricity costs, prioritising pipeline infrastructure and underground storage, and adopting effective integrated hydrogen supply chain planning.

Keywords: Green hydrogen production; Techno-economic analysis; Hydrogen supply chain integration; Levelized cost of hydrogen; Economic cost drivers.

1. Introduction
Hydrogen is recognised as a clean energy carrier due to its high energy density, zero-emission combustion and versatility (Amirthan, 2023). It can be produced from multiple sources and stored at various scales, offering a solution to the intermittency of renewable energy (Huang et al., 2025). Excess renewable electricity from wind or solar can be used to generate hydrogen via electrolysis, enabling zero-emission energy storage like natural gas (Taiwo et al., 2024).

This study evaluates the techno-economic viability of green hydrogen production using Proton Exchange Membrane (PEM) electrolysers, combined with underground hydrogen storage (UHS) in depleted gas fields and above-ground storage tanks (AGS), based on a case study of the Moomba gas field (South Australia). Hydrogen produced at Moomba is stored either underground or in surface storage systems, then retrieved and transported to the Port Bonython export hub via pipelines or tube-trailers for export.

Moomba gas hub has an existing production and processing facility for gas, condensate and oil from the Cooper Basin (EHS Support, 2023). Liquid products like propane are piped to Port Bonython, while gas is transported via pipeline to Australian domestic markets (Weidenbach, 2015). Port Bonython serves as an export hub for Cooper Basin products (Santos Ltd., 2019). Owned by the SACB JV and operated by Santos, the facility features a deep-water port, gas fractionation plant and storage infrastructure. The existing infrastructure offers a cost-effective opportunity for repurposing from hydrocarbon to hydrogen export (CSIRO, 2023).

The International Energy Agency (IEA) forecasts hydrogen demand to increase sixfold to 530 Mt by 2050 (Shahabuddin et al., 2023), necessitating safe and cost-effective storage and transport systems. UHS has been in use since the 1970s as a viable option, while pipeline transport remains the dominant mode for hydrogen delivery, playing a growing role in future energy systems (Uliasz-Misiak et al., 2025). Large-scale deployment of UHS in depleted gas fields enhances energy security, supports economic growth and provides techno-economic solutions to mitigate climate change while quantifying hydrogen's economic value (Quintos et al., 2023).

1.1. Objective of the paper

This paper evaluates the techno-economic 'cost of delivering hydrogen to market' by assessing hydrogen production, storage options (UHS and AGS) and transportation systems (pipelines and tube trailer) based on the Moomba gas field to Port Bonython case study. Shipping costs are assumed under a free-on-board (FOB) export arrangement.

Using literature-based data, organisational reports and Excel modelling, the study simulated system performance by analysing key techno-economic indicators of each infrastructure component. It also identifies economic trade-offs and key cost drivers affecting overall system viability by addressing a regional research gap of providing techno-economic data-driven insights into the cost of delivering hydrogen to market.

It seeks to identify the most efficient, cost-effective hydrogen storage and transportation mode with required supporting infrastructure by addressing the following key points:

- Evaluate key techno-economic parameters influencing hydrogen production, storage and transportation to market.
- Analyse techno-economic indicators such as the levelized cost of storage (LCOHS), levelized cost of transportation (LCOHT), levelized cost of production (LCOHP), levelized cost of hydrogen delivered (LCOHD), internal rate of return (IRR), revenue, net cash flow (NCF) and net present value (NPV) by exploring capital expenditures (CAPEX) and operational expenditures (OPEX) of each contributing infrastructure.
- Assess economic trade-offs and major cost drivers.
- Investigate integration aspects across the hydrogen value chain from production, storage and transportation to market.
- Examine market policy and regulatory factors that affect the commercial viability and investment readiness of UHS projects in terms of hydrogen price viability.
- Synthesise key knowledge gaps and future research directions in techno-economic modelling and system-level analysis of underground hydrogen storage transportation costs.

The results aim to inform policymakers and industry stakeholders as Australia and the Pacific region advance toward decarbonisation targets, ensuring both environmental integrity and economic resilience of its clean energy transition.

2. Literature review

This section reviews literature related to techno-economic factors influencing hydrogen (H_2) production, storage and transportation modelling. The review focuses only on onshore reservoirs, excluding environmental impact assessments but emphasising the key objective and supporting points.

2.1. Literature review methodology

A systematic literature review methodology was applied to ensure a comprehensive and targeted literature review (Higgin et al., 2019).

Boolean operators (AND, OR) were used to combine keywords across themes in database searches, including Scopus, Web of Science, ScienceDirect, Google Scholar, and the Victoria University of Wellington library, as well as organisational reports. This approach improved the breadth and precision of identifying relevant peer-reviewed studies and high-quality grey literature (Atkinson and Cipriani, 2018) "AND" logic was applied between themes, and "OR" logic was used within categories to broaden the search scope. The search query for the review process was adapted with additional cross-references from Atkinson and Cipriani (2018).

The major research question was, what are the main techno-economic parameters and economic cost drivers influencing the hydrogen value chain integration from production, storage and transportation to market? Search queries guided the process by structuring into three categories encompassing technical, economic and integration-focused terms across five thematic matrices: technical-economic feasibility, economic cost drivers, strategic outlook and knowledge gaps, market and policy viability and value chain integration.

The reviewed literature primarily covered Europe, North America and the Asia-Pacific region. However, studies from other regions were also examined to identify global trends, similarities and differences in the techno-economic viability of UHS in depleted gas fields.

2.2. Literature review process

The PRISMA system was used to identify, document, evaluate and synthesise the relevant study selection and screening process (Higgin et al., 2019). A modified PRISMA flow diagram, provided in the supplementary material, was adapted from Pidgeon et al. (2016) and Glass (1976).

A total of seven hundred and seventy-five records (n=775) were initially identified through database searches. During the filtering stage, fifty duplicate papers (n=50) were removed. They appeared across multiple databases containing similar geographical information classified as least relevant, meeting the exclusion criteria. An additional twelve papers (n=12) were excluded based on publication year, title ineligibility and insufficient quality of information. Following a detailed assessment of the remaining articles, a further six hundred records (n=600) were excluded for not meeting the thematic code categories of the search query. Consequently, the final number of eligible articles included in the study was one hundred and thirteen papers (n = 113).

Most of the inclusion criteria studies were peer-reviewed between 2021 to 2025 with a few before 2021 that were directly relevant for this study. Studies were excluded or regarded as less relevant when they focused solely on geological, technical studies or other themes without incorporating direct techno-economic studies, or if they lacked techno-economic integration relevance.

2.3. Key themes in the literature

The literature was based on the three categories and five thematic codes mentioned in section 2.1.

2.3.1. Underground hydrogen storage technoeconomic feasibility

Underground hydrogen storage (UHS) is a highly promising technological innovation in the hydrogen storage field, where significant amounts of hydrogen could potentially be stored in various geological formations. These formations include deep aquifers, dissolved salt caverns, underground mine workings and depleted hydrocarbon reservoirs (Taiwo et al., 2024). It represents a promising long-term, large-volume solution for hydrogen and hydrogen-methane blends, which is crucial for the anticipated "hydrogen economy" (Roy et al., 2024) that enhances economic outcomes (Chen et al., 2024).

2.3.2. Depleted gas field techno-economic viability

Depleted gas fields are former natural gas reservoirs no longer economically viable due to declining pressure, making them suitable for underground hydrogen storage (Taiwo et al., 2024). They can provide large-scale seasonal energy storage to balance generation and demand (Liu et al., 2025). However, an international review identified technical challenges for commercial deployment in porous reservoirs (Bo, 2024), including hydrogen containment, diffusion losses and well integrity issues (Talukdar et al., 2024).

2.3.3. Capital cost, operational cost and levelized cost

Rezaei et al. (2024) examined key techno-economic indicators, including capital expenditure (CAPEX), operational expenditure (OPEX), and the levelized cost of hydrogen in UHS and renewable hydrogen export systems, reporting projected hydrogen costs decreasing from about US$3.5 kg^{-1} in 2022 to US$2.3 kg^{-1} by 2030. Additionally, Shahabuddin et al. (2023) estimated Proton Exchange Membrane Electrolyser costs between US$1000–5000 kW^{-1} for production capacities of 1–760 $Nm^3\ h^{-1}$. Additionally, breakeven hydrogen prices are highly sensitive to reservoir architecture, with homogeneous geological formations providing more consistent economic baselines (Bo, 2024).

2.3.4. Technical and economic outlook and hydrogen supply chain

Ta et al. (2024) assessed Vietnam's large-scale hydrogen export potential to Asian markets using a techno-economic analysis of transport and energy carriers, including LH_2, NH_3, and LOHC, but did not consider hydrogen delivery costs using UHS.

Okunlola et al. (2022) emphasise that techno-economic optimisation of hydrogen supply chains, including production, storage, transport, liquefaction, shipping and reconversion are critical for international hydrogen trade (Gianni et al., 2024). Efficient system design must balance storage capacity with economic performance, such as net present value, while accounting for costs, energy use, safety, operating conditions and capacity factors (Pham et al, 2024).

2.3.5. Strategic outlook of UHS

Green hydrogen produced from excess renewable electricity will play a significant role in future zero-emissions energy systems (Nicol et al., 2022), and may be stored at relatively shallow depths (~100 m) (Bischoff et al., 2021). An example is a prospectivity analysis for UHS in the Taranaki Basin (Aotearoa New Zealand) using a multi-criteria decision-making approach that assessed the technical suitability of depleted hydrocarbon fields and a deep aquifer for seasonal hydrogen storage in porous media (Yates et al., 2021). This approach is considered a potential method for storing surplus renewable energy and balancing energy demand, although it remains largely untested at a large scale (Higgs et al., 2024).

2.3.6. Economic cost drivers

Around 40% of Asia–Pacific studies highlight key cost drivers for hydrogen supply chains, including proximity to demand centres, existing infrastructure and transport logistics. Southern Vietnam was identified as a promising UHS location due to abundant renewable resources, proximity to consumers, and export-capable harbours (Pham et al., 2024). Similarly, the Taranaki Basin in Aotearoa New Zealand is noted as favourable for UHS development because of its well-characterised geology, nearby hydrogen demand and existing oil, gas, and transport infrastructure (Nicol et al., 2022). These economic and logistical advantages can lower infrastructure and transport costs, enhancing the cost-effectiveness of large-scale hydrogen production and storage systems.

2.3.7. Value chain integration

Strategies for integrating hydrogen into national economies must consider technological costs, efficiency, decarbonisation potential, social acceptance and export readiness (Wen et al., 2025). The study also highlights South Australia's advantageous geographic location and complementary seasonal energy patterns as potential strengths for exporting hydrogen to Asia.

2.3.8. Gaps in current modelling practice

Despite the growing body of research, several limitations remain that require further investigation and the development of more tailored regulatory frameworks for subsurface energy projects. Existing studies have not comprehensively assessed the full hydrogen supply chain, including production, storage and transportation costs to market under large-scale operational scenarios. Furthermore, there is limited research evaluating the role of UHS in enhancing grid storage under real-world conditions or its economic viability at plant scale within real-time electricity markets (Chen et al., 2024). Although experience from UHS provides useful insights, the safe and economically viable operation of UHS in porous reservoirs remains uncertain (Bo, 2024).

3. Research methods

The study adopted basic applied, quantitative and descriptive research approaches (Patel, 2019). The research process followed stages from problem formulation, literature review, hypothesis development, research design, data collection, modelling, data and sensitivity analysis and interpretation-based framework (Howell, 2022) adopted from Feather (2012). It utilised data from government, literature and private sources targeting PEM electrolyser systems, compression and storage, and compared transportation options via pipelines, tube trailers and shipping. Storage options were evaluated by comparing underground hydrogen storage with surface pressurised tanks and assessing the techno-economic performance across the integrated hydrogen supply chain.

3.1. Research design approach

The study employed an Excel simulation-based research design, a case study and mixed methods with multiple phases of data collection and analysis. It integrated quantitative, qualitative, descriptive and explanatory methods. The deductive approach was associated with the quantitative method, and the inductive approach with the qualitative method (Technological University Dublin Library, 2025).

The deductive approach assessed whether real-world system performance aligns with expected theoretical outcomes. It began with the techno-economic theory on how the costs of hydrogen production, storage and transportation are influenced by factors such as energy input, system scale and transport distance (Creswell, 2018; Saunders et al., 2023). These theoretical relationships provide the basis for developing the hypotheses on operational constraints, economic cost drivers and potential optimisation strategies (Technological University Dublin Library, 2025), which were subsequently tested using Excel simulation models and cost analysis.

Elements of the inductive approach were incorporated when analysing qualitative patterns and contextual data from case studies. Observational data from simulation results, storage modelling and transport costs analysis were examined to identify recurring trends and relationships. These patterns were interpreted to generate insights and refine the understanding of system behaviour, culminating in recommendations and conceptual models that integrate the observed data with the theoretical principle (Creswell, 2014). Inductive reasoning complemented the deductive approach by providing a deeper understanding of the hypothesis that emerged from the data itself (Bryman, 2016).

3.2. Research details (Moomba-Port Bonython case study)

The Moomba Gas Field to Port Bonython case study evaluates the techno-economic performance of hydrogen production (PEM electrolysers), underground and surface storage, and transportation scenarios. Financial viability was assessed through economic indicators incorporating each scenario to determine the overall system efficiency and economic feasibility using CAPEX and OPEX parameters on a 60-year project horizon.

3.2.1. Moomba gas field and Port Bonython

Moomba Gas Field is a best-case site for underground hydrogen storage (UHS) due to its existing infrastructure such as pipelines, compressors, production facilities and wells that support conversion to hydrogen. Port Bonython acts as an export hub, offering deep-water access and storage facilities, enabling cost-effective transportation of hydrogen from the Cooper Basin (Santos Ltd., 2019).

3.3. Hydrogen production strategy and modelling approach

The detailed modelling approach is presented in sections 3.4 and 3.5, conducted in the following order:

- Hydrogen export ship volume requirements were determined.
- Electrolyser capacity was calculated to meet target export volumes based on ship demand.
- Daily and annual hydrogen production by the electrolyser system was calculated.
- Suitable Moomba gas field wells were selected for underground storage to match production and withdrawal needs.
- Hydrogen transport modes to Port Bonython were identified.
- CAPEX and OPEX for hydrogen production, storage (UHS and surface tanks) and transport (pipeline and tube trailer) were estimated.
- Techno-economic financial indicators were modelled, including revenue, net cash flow (NCF), NPV, IRR, and levelized costs (LCOHP, LCOHS, LCOHT, LCOHD).

The techno-economic model adopts a 60-year project lifetime to accurately reflect the long-term nature of hydrogen infrastructure systems, particularly those involving subsurface storage in depleted gas fields. While key components such as electrolysers, compressors, pipelines and fuel cells have shorter operational lifespans and require periodic replacement, the primary asset, namely the geological storage reservoir and associated infrastructure can remain operational for several decades. A 60-year horizon therefore enables the model to capture multiple equipment replacement cycles, long-term operational dynamics and the full utilisation of the storage resource. This extended timeframe also ensures that high upfront capital costs are appropriately amortised, resulting in more representative estimates of Levelized Cost of Hydrogen (LCOH), net present value (NPV) and overall project viability. Furthermore, it aligns with long-term energy transition pathways and decarbonisation targets, providing a robust basis for assessing the economic performance of large-scale hydrogen systems over their realistic operational life.

3.4. System parameters

3.4.1. Ship loading volume and hydrogen loading mass

The ship capacities determined were small liquid hydrogen (LH_2) carriers at 1,500–3,000 m^3, medium carriers at 10,000–20,000 m^3 and future large vessels at 40,000–50,000 m^3 (Aditiya et al., 2025; Meca et al., 2022). The mass of hydrogen transported per vessel was calculated by converting the ship's cargo volume into mass using the thermophysical density of LH_2 at its normal boiling point (−252.87 °C, 20 K), and at near-atmospheric pressure (Desai, 2022). LH_2 has a density of approximately 70.8 kg·m^{-3} (Leachman et al., 2009; Chan, 2025). Using this density value, the hydrogen mass per shipment (M_{H_2}) was determined as a product of the corresponding cargo volume (V_{ship}) and the density of liquid hydrogen (ρ_{LH_2}) as:

$$M_{H_2} = V_{Ship} \times \rho_{LH_2} \tag{1}$$

Table 1 presents the ship loading volume and hydrogen mass required.

Table 1. Hydrogen ship loading volume and hydrogen mass

Ship Type	Volume (m^3)	Mass of H_2 (tonnes)
Small LH_2 carriers	1,500–3,000	106–212
Medium LH_2 carriers	10,000–20,000	708–1,416
Large future carriers (under development)	40,000–50,000	2,832–3,540

3.4.2. Ship loading rate

Loading rates of 300–600 m^3 per hour were adopted from manufacturer specifications for cryogenic pumps and industrial LH_2 handling equipment (Jungwoo Energy Systems Co., Ltd., 2022), aligning with typical centrifugal cryogenic pump performance in bulk hydrogen transfer (see Table 2).

Table 2. Liquid hydrogen (LH_2) loading rate

LH_2 pump parameter	Loading rate	
	Low rate	High rate
Pump Rate (m^3/hr)	300	600

3.4.3. Ship turnaround time

Loading turnaround time ($TAT_{loading}$) was calculated as a ratio of the vessel's cargo capacity (V_{ship}) (see Table 1) and volumetric loading rate of LH_2 (see Table 2) as:

$$TAT_{loading}(hr) = \frac{V_{ship}\ (m^3)}{Loading\ rate\ (m^3/hr)} \tag{2}$$

$$TAT_{loading}(day) = \frac{TAT_{loading}(hr)}{24\ (\mathrm{hrs}/day)} \tag{3}$$

The ship's TAT were calculated to be between 2.5 hours and 7 days (168 hours), depending on vessel type and operational conditions (see Table 3).

Table 3. Ship loading volume, hydrogen capacity and turnaround time

Ship Type	Volume (m³)	Mass of H_2 (tones)	Loading time (hrs)		Loading time (days)	
			Low rate	High rate	Low rate	High rate
Small LH_2 carriers	1,500–3,000	106.2–212.4	5.00–10.00	2.50–5.00	0.21–0.42	0.10–0.21
Medium LH_2 carriers	10,000–20,000	708–1,416	33.33–66.67	16.67–33.33	1.39–2.78	0.69–1.39
Large future carriers (under development)	40,000–50,000	2,832–3,540	133.33–166.67	66.67–83.33	5.56–6.94	2.78–3.47

3.4.4. Hydrogen mass flow rate

The required hydrogen mass flow rate ($m_{req.flowrate\ (H_2)}$) during loading is the ratio of hydrogen cargo mass per ship ($M_{ship\ (H_2)}$) and loading turnaround time ($TAT_{loading}$), simplified as:

$$m_{req.flowrate\ (H_2)}(tonne/hr) = \frac{M_{ship\ (H_2)}\ (tonnes)}{TAT_{loading}(hr)} \tag{4}$$

This equation determines the instantaneous hydrogen supply rate necessary to fully load a vessel within the allowed turnaround window. The required hydrogen mass flow rate during loading was determined to be 21.24 to 42.48 tonnes per hour based on thevalues in Tables 1 and 2.

3.4.5. Electrolyser capacity

The electrolyser capacities were reverse calculated from hydrogen export ship loading requirements. LH_2 ship capacities of 106 to 3,540 tonnes (see Table 1) were combined with allowable turnaround times of 2.5 hours to 168 hours (7 days), and hydrogen mass flow rate (21.24- 42.48 tonnes/hour) during loading to determine the required hydrogen mass flow rates. The electrolyser power demand, (P_{el}) was then calculated as a product of the specific energy consumption (SEC) of 60 kWh per kg H_2 (IREA, 2018) and hydrogen production rate (m_{el}) as:

$$P_{el} = m_{el} \times SEC \tag{5}$$

Table 4. Electrolyser specific energy and density data

Electrolyser specific energy	
Modern PEM / alkaline systems	55 – 70 kWh/kg
Energy used in production	60 kWh/kg
Liquid hydrogen density, LH_2 (ρ) at −253°C	70.8 kg/m³

(Source: IREA, 2018)

Using equation 5 and Table 4 data, the required PEM electrolyser capacities to effectively supply the range of ship loading volumes were determined as 1.27 GW and 2.54 GW scale, respectively (see Table 5).

Table 5. PEM Electrolyser capacities and hydrogen loading flow rate

Loading (m^3/hr)	H_2 Flow (tonnes/hr)	PEM Electrolyser (GW)	PEM Electrolyser (MW)
300	21.24	1.2744	1274.4
600	42.48	2.5488	2548.8

3.4.6. Moomba gas wells storage capacity

Four gas wells were selected to store the hydrogen produced in the Moomba gas field. Geological data were obtained from the Australian Department for Energy and Mining (2025). Storage capacities were estimated based on reservoir pressure conditions of 4-48 MPa and temperatures 100-240 °C (Santos Ltd, 2021), assuming a 40% working gas to 60% cushion gas ratio (Heinemann et al., 2021). The hydrogen mass stored was calculated in two stages by incorporating the compressibility factor (Z) at the corresponding temperature and pressure conditions (H_2Tools, 2025). Initially, the hydrogen gas pore volume of the rocks (PV) was determined using the 'volumetric gas-in-place equation 6' (Ezekwe, 2021), as a product of area (A), net thickness of the well bore (h), porosity of the reservoir (ϕ) and gas saturation space (S_g) as:

$$PV = A \times h \times \phi \times S_g \tag{6}$$

Then the final mass of H_2 (m_{H_2}) for storage was calculated with the 'real gas mass equation 7' (H_2Tools, 2025), as a ratio of the product of pressure (P) and storage volume (V), corrected by the compressibility factor (Z), universal gas constant (R=8.314J/mol.K or 4124 J/kg.K), temperature (T), and multiplied by the molar mass of hydrogen $\left(M_{H_2}\right)$ as:

$$m_{H_2} = \frac{P \times PV}{Z \times R \times T} M_{H_2} \tag{7}$$

The calculated storage capacities of the selected Moomba gas wells are shown in Table 6.

Table 6. Storage capacity of four selected gas wells at Moomba gas field

Gas wells	H_2 storage capacity (tonnes)		Working gas (tonnes)		Cushion gas (tonnes)	
	Low	High	Low	High	Low	High
Aroona 2	8,893	173,598	5,336	104,159	3,557	69,439
Alwyne 8	16,809	1,303,069	10,085	781,842	6,724	521,228
BigLake 149	2,044,696	39,914,227	1,226,818	23,948,536	817,878	15,965,691
BROMPTON_1	510,831	18,848,356	306,499	11,309,014	204,333	7,539,343

The hydrogen storage dynamics for each well per square kilometre of reservoir was calculated at varying temperatures and pressures using standard compressibility factors (Z) (H2Tools, 2025; Lemmon, 2007) (see Figure 1).

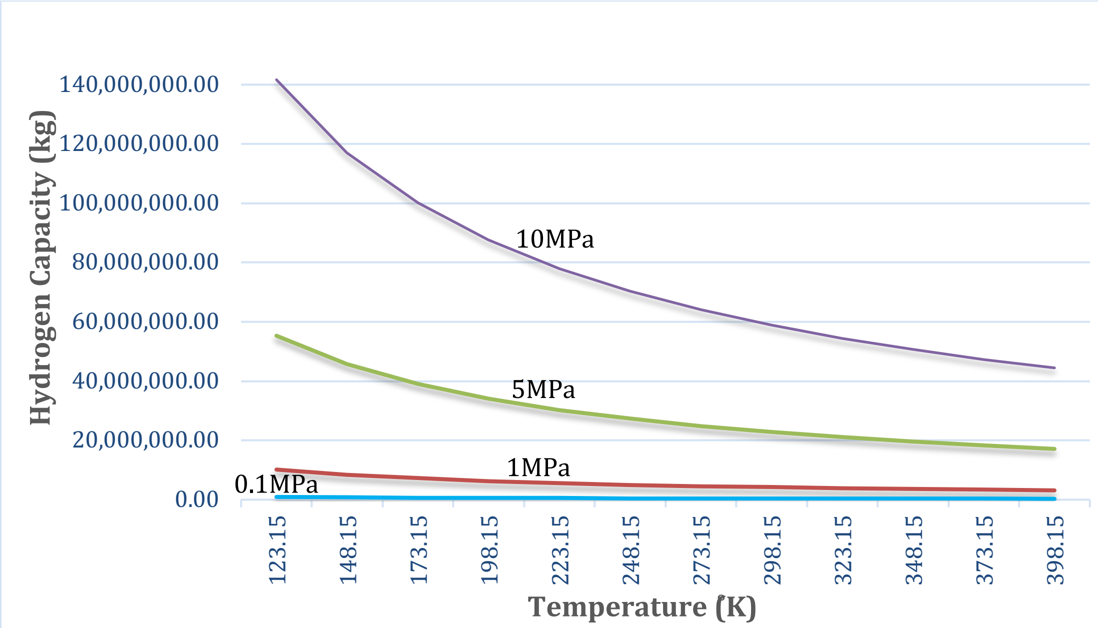

Figure 1. Hydrogen storage dynamics of each well per square kilometre

3.4.7. Moomba to Port Bonython pipeline system

The Moomba to Adelaide pipeline system (MAPS), owned and operated by Epic Energy Pty Ltd, is a transmission network spanning a distance of 659 km (SAAEMC, 2022). This distance is used throughout all relevant modelling calculations.

3.4.8. Port Bonython hydrogen hub

The State Government aims to develop a large-scale hydrogen export hub at Port Bonython, leveraging existing infrastructure and resources (CSIRO, 2023) (see Table 7).

Table 7. Hydrogen Hub – Port Bonython

Project Name	Location	Energy Source	Production Method	Electrolyser Size (MW)	H_2 Production (t/year)	Status	Expected Start Date
Port Bonython Hydrogen Hub	Port Bonython	2.12MW solar farm (Santos)	PEM Electrolyser	60	1.8 million tonnes by 2030	Hub	n/a

(Source: CSIRO, 2023)

Santos installed a 2.12 MW solar farm at Port Bonython, complementing renewable energy systems to the Port Bonython processing facility (Santos Ltd., 2025).

3.5. Cost data and input parameters

The CAPEX and OPEX input parameters were compiled for hydrogen production (electrolysis), storage (UHS and AGS) and transportation (pipeline, tube trailer, and shipping under FOB conditions).

The OPEX is divided into fixed operating costs (utilities, electricity, infrastructure conversion, stack and equipment replacement and maintenance) and variable compression-related costs driven by electricity consumption. All cost inputs were defined using lower- and upper-bound ranges to capture uncertainty and improve estimate accuracy (IREA, 2018).

3.5.1. PEM Electrolyser cost input parameters

The PEM electrolyser costs were based on the two electrolyser capacities determined in Table 3 (1.27 GW and 2.27 GW). Published techno-economic studies estimate the capital expenditure (CAPEX) of ALK and PEM electrolyser systems between A$700 and A$1,500 per kW (IREA, 2018). Commercial packages, including rectifiers, water treatment and gas purification, range from A$1,000 to A$3,000 per kW for small-scale systems (<1 MW) (AHRN, 2023). Current PEM electrolyser estimated CAPEX is at A$1,640–A$2,700 per kW, with long-term projections of A$300–1,340 per kW (PwC Australia, 2020).

Fixed operational expenditure (OPEX) includes water tariffs of A$3.365 per kL for 2025–2026 (SA Water, 2025) and electricity costs of A$104.31 per MWh (A$0.10 per kWh) (AEMO, 2022).

A PEM stack has an estimated lifetime of 11 years at a replacement cost of £240 kW-1 installed (A$398 kW-1) (Vives et al, 2023). The analysis applied a discount rate of 6.98% (7%) (Oxford Economics Australia, 2024). Table 8 presents the technical input parameter assumptions for hydrogen production technoeconomic modelling.

Table 8. Hydrogen production techno-economic input parameters

Technology	Unit	Value
Efficiency	kWh /kg H_2	52
Efficiency (LHV) (2025)	%	64
Lifetime Stack	Operating hours	80,000
PEM stack lifetime	Years	11
CAPEX–PEM Electrolysis	A$ / kW	700 -1500
OPEX–PEM Electrolysis	A$ / kW / year	14 -28
PEM stack replacement cost	A$ / kW	398
Compression (450 bar) CAPEX	A$ / kg	0.01 – 0.03
Compression (450 bar) – OPEX	% CAPEX	1 - 4
Energy required for compression	kWh / kg	0.10 – 0.30
Discount rate	%	6.98

(Source: IREA, 2018; Vives et al., 2023)

3.5.2. Pipeline repurposing input cost parameters

The existing pipeline infrastructure, extending 659 km from the Moomba Gas Field to Port Bonython, was originally constructed in the 1980s for A$1.4 billion (Australian Department for Energy and Mining, 2025).

Pipeline repurposing CAPEX is estimated at A$0.715–A$1.716 million per km (10–35% of new-build cost) based on broader hydrogen infrastructure studies rather than project-specific data for the Moomba to Port Bonython pipeline (Epic Energy, 2002). For comparison, new onshore pipelines cost £1.2–£1.6 million per km, and large offshore pipelines up to £5 million per km, depending on diameter (EU Hydrogen Backbone Initiative, 2022; Kerle et al., 2024).

A UK review of hydrogen infrastructure cost shows fixed OPEX for new or repurposed hydrogen pipelines and related infrastructure at around 1.25% of CAPEX. This is a commonly cited range in industry planning (Kerle et al., 2024). These figures were used for H2 pipeline repurposing technoeconomic modelling (see Table 9).

Table 9. Hydrogen pipeline repurposing techno-economic input parameters

Pipeline Data	Value
Pipeline length (Moomba to Port Bonython)	659 km
Original construction cost (1980s)	A$1.4 billion
Public cost estimate for hydrogen pipeline conversion	A$0.715 -1.716 million/km
Hydrogen hub funding (government)	A$70 million
Fixed OPEX	1.25% of CAPEX

3.5.3. Underground hydrogen storage cost parameters (UHS)

The hydrogen injection and withdrawal costs are based on the retrofitting of existing wells, compression systems and ongoing monitoring.

Well retrofitting CAPEX input parameter

Retrofitting the four selected wells (see Table 6) is estimated at USD 0.29 million (A$0.41 million) per well (NETL, 2017), while new well drilling costs are USD 1.28 million (A$1.83 million) per well, within typical onshore gas well ranges (EIA, 2023). Compression CAPEX is approximately USD10 million (A$14.59 million) per unit, consistent with large-scale hydrogen compression benchmarks (U.S. DOE, 2023; IRENA, 2022) (see Table 10).

Table 10. Well retrofitting CAPEX input parameters

Item	Cost per well	Notes
New well CAPEX	A$1,830,400.00	Per well for a depleted gas field well
Retrofitting an existing well CAPEX	A$ 414,700.00	Per well
Compressor unit CAPEX	A$14,586,000.00	Per compressor (designed for 2 000 kg H_2/hr)

UHS compression (OPEX) parameter

Compression energy costs range from A$1.05–A$8.06 kg^{-1} H_2 (2–8 $kWh.kg^{-1}$) depending on storage pressure and efficiency (U.S. DOE, 2023; NETL, 2019). Annual fixed OPEX, covering monitoring, safety, maintenance and compressor servicing, totals A$0.72–2.86 million. A single compressor train with 1,500–3,000 kg H_2 per hour capacity was assumed, consistent with industrial-scale hydrogen storage (NETL, 2019). These input parameters support UHS technoeconomic modelling (see Table 11).

UHS withdrawal cycle

Hydrogen production was modelled over a 7 to 30 days export cycle periodic ship loading (see Table 3), following international supply chain approaches (EIA, 2019; IRENA, 2022). Each cycle assumed 0.10 days for loading, yielding net production periods of 6.90 days. This corresponds to steady-state hydrogen production of 305.9 tonnes per day (111,637 tonnes/year) for the 1.27 GW electrolyser and 632.1 tonnes per day (230,717 tonnes/year) for the 2.25 GW electrolyser system (see Table 5).

Annual hydrogen volumes delivered to storage and exported, accounting for <0.1% leakage losses (Frazer-Nash Consultancy, 2022), are shown in Table 12. The batch-export framework follows established hydrogen logistics modelling used in global market and infrastructure assessments (Hydrogen Council, 2021).

Table 11. UHS techno-economic input parameters

Parameters	Value	
	Low range	High range
Annual H_2 production (tonnes/day)	305.86	632.10
Storage cycles per year	2	4
Electricity cost (A$/kWh)	0.10	0.35
Compression energy (kWh/kg H_2)	0.8	1.5
Compression energy (A$/kg H_2)	1.05	8.60
OPEX (% of storage CAPEX)	1.50%	3.00%
1 compressor train (kg H_2/hour)	1,500	3000
Ongoing monitoring per year (OPEX)	A$715,000	A$2,860,000
Compressor CAPEX	35 units × 10 M USD/unit	
No. of wells retrofitted	4	
Cushion gas	60%	
Working gas	40%	

Note: All compression OPEX costs parameters also apply to pipeline transportation OPEX costs modelling.

3.5.4. Surface hydrogen storage cost parameters (high-pressure tanks)

Above-ground hydrogen storage was assumed at a design pressure of 350 bar, consistent with industrial gaseous hydrogen storage systems used in large-scale energy applications (IEA, 2019).

Hydrogen loading frequency

The ship loading frequency was determined using the turnaround time data (see Table 3 and Table 12) to calculate the corresponding hydrogen transport capacity.

Table 12. Surface storage hydrogen loading parameters

Ship type	Turnaround loading time (days)	Shipping cycle frequency (days)	Hydrogen storage duration (days)	Hydrogen storage capacity (tonnes)
Small	0.10 - 0.42	7	6.58 - 6.90	2,122.3 - 2,026.8
Medium	0.69 - 2.78	14	11.22 - 13.31	3,444.2 - 4,080.8
Large	2.78 - 6.94	30	23.06 - 27.22	7,059.9 - 8,333.0

Surface storage CAPEX and OPEX input parameter

Surface storage tank costs were calculated based on hydrogen storage requirements and ship loading capacity (see Table 12). CAPEX ranges from A$800–1,500 kg-1 H_2, reflecting variations in materials, pressure ratings and project scale, consistent with international hydrogen infrastructure benchmarks (IREA, 2020; DOE, 2023).

Compression energy for 350 bar storage was estimated at 2–2.5 kWh/kg H_2, corresponding to A$0.20–0.25 kg^{-1} H_2 (DOE, 2023; NETL, 2019), based on an electricity price of A$0.10 kWh^{-1} (AEMO, 2025). Fixed O&M costs for surface tanks were 2–3% of CAPEX annually (IRENA, 2020; NETL, 2019). These inputs ensure that LCOHS captures all storage-specific costs (see Table 13).

Table 13. Surface storage infrastructure techno-economic input parameters

Parameters	Value
Tank pressure (bar)	350
Electricity price (A$/kWh)	0.10
CAPEX cost (A$/kg H_2)	800 - 1500
Compression energy (kWh/kg H_2)	2.0 - 2.5
Compression OPEX cost (A$/kg H_2/year)	0.20 - 0.25
Fixt tank O&M cost	2% - 3% of CAPEX

Tube trailer transport cost input parameters

The main hydrogen truck transport modes are compressed gas hydrogen (CGH_2) and liquid hydrogen (LH_2) tube trailers (ANZ, 2024). Tecno-economic input data include cost of one vehicle (CAPEX), OPEX, vehicle replacement costs and transport distance for each mode.

CGH_2 and LH_2 trailers cost parameters

High-capacity CGH_2 tube trailers cost approximately A$960,000 each and carry 700 kg H_2 per load (IEA, 2019; DOE, 2022; ANZ, 2024). Operating costs are estimated at A$1.05 per kg H_2 per 50 km, including fuel, labour, maintenance and handling. LH_2 trailers carry about 4,400 kg H_2 per load (IEA, 2019), with a CAPEX of A$1.39 million (IEA, 2019; DOE, 2022; ANZ, 2024). Higher OPEX of A$5.95 per kg per 50 km reflects additional liquefaction and cryogenic storage costs, compared with CGH_2 for medium to long-distance transport.

Vehicle replacement CAPEX (10-year life) cost parameters

Assuming a 10-year economic lifetime for each H_2 transport vehicle, the replacement duration annualised cost is determined by:

$$Annualise\ replacement\ CAPEX\ (A\$) = \frac{CAPEX\ purchase\ cost\ (A\$)}{10\ years} \quad (8)$$

The annualised capital replacement costs is approximately A$96,000 per year for CGH_2 trailers and A$139,000 per year for LH_2 trailers, reflecting typical heavy-vehicle depreciation and fleet renewal practices (IEA, 2019) (ANZ Report, 2024) (see Table 14).

Table 14. Hydrogen tube trailers techno-economic costs parameters

Trailer type	Truck Cost (A$)	Capacity (kg H_2 /load)	OPEX (A$/ kg per 50km)	Replacement cost (A$/Year)
CGH_2	960,000	700	1.05	96,000
LH_2	139,0000	4,400	5.59	139,000

Moomba to Adelaide Road distance and travel parameters

The 963 km road distance between Moomba, Adelaide, and Port Bonython (Fromto.Travel, 2025) corresponds to a one-way travel time of about 12 hours at 80 $km.hr^{-1}$, or 24 hours for a return trip. These estimates align with standard heavy-vehicle logistics assumptions and are used for transport cost modelling (Fromto.Travel, 2025; DriveBestWay, 2025) (see Table 15).

Table 15. Tube trailers road transport parameters

Data	Value	Comment
Moomba → Adelaide	963 km	One-way trip
	1926 km	Two-way trip
Project life	60 years	Production duration
Trailer replacement life	10 years	
Hydrogen production	305,856.00 kg/day	1.27 GW
	632,102.40 kg/day	2.54 GW
Driving speed	80.00 km/hr	
Driving time	12.04 hours	One-way trip
	24.08	Two-way trip

4. Results

This section presents the results based on system input parameters and modelling approach. It covers the techno-economic performance of the hydrogen production supply chain integration for PEM electrolysers (1.27 GW and 2.54 GW), underground storage (UHS), above-ground storage (AGS) and transportation via pipeline or tube trailers from the Moomba production site to Port Bonython. It evaluates capital (CAPEX) and operations (OPEX) costs, levelized costs (LCOHP, LCOHS, LCOHT, LCOHD), net cash flow (NCF), return on investment (ROI), net present value (NPV) and internal rate of return (IRR).

4.1. PEM electrolyser (1.27 GW and 2.54 GW) production cost modelling

The key financial metrics were modelled at low and high hydrogen price ranges.

4.1.1. Total CAPEX and OPEX cost

The total electrolyser CAPEX was calculated at an input cost of A$700–1,500 per kW (see Table 8) based on system capacity using equation 9. Fixed OPEX at 2–4% of CAPEX, compression OPEX at A$14–A$80 per kW per year, electricity price of A$0.10 per kWh and water costs at A$0.05 per kg H_2 (see Table 16).

$$Total\ CAPEX\ (A\$) = CAPEX\ input\ \ (A\$/kW)\ \times Electrolyser\ capacity\ (kW) \qquad (9)$$

Table 16. Total CAPEX and OPEX for electrolyser hydrogen production

Electrolyser Capacity	Range	Total CAPEX (A$)	Fixed OPEX (A$)	Compression OPEX (A$)
1.27 GW	Low range	892.08 million	17.84 million	1.91 million
	High range	2.57 billion	101.95 million	11. 48 million
2.54 GW	Low range	1.78 billion	35.68 million	1.91 million
	High range	5.10 billion	203. 90 million	19.12 million

4.1.2. Hydrogen production capacity and levelized cost of hydrogen production (LCOHP)

Hydrogen production capacity

The two electrolyser systems were modelled at 60% conversion efficiency (IRENA, 2018). Hydrogen production was modelled based on the relationship between electrolyser capacity (C_{elect}), operating time (t = 8760 hours), efficiency (η = 60%) and specific energy consumption (E_{spec} = 60 kWh/kg) as:

$$Hydrogen\ production\ (kg/year) = \frac{C_{elect} \times t \times n}{E_{spec}} \quad (10)$$

Equation 10 yields a hydrogen production rate of 305,856 kg.day^{-1} (111,637 tonnes/year) for the 1.27 GW system and 632,102 kg.day^{-1} (230,717 tonnes/year) for the 2.54 GW system, demonstrating strong scale effects in capital-intensive electrolysis (see Table 17).

Table 17. PEM electrolyser hydrogen production capacity

Electrolyser capacities	Hydrogen production (tonnes/day)	Hydrogen production (tonnes/year)	Hydrogen production (tonnes/60 years)
1.27 GW	305.86	111,637.44	6,698,246.40
2.54 GW	632.10	230,717.38	13,843,042.56

Levelized cost of hydrogen production (LCOHP)
The levelized cost of hydrogen production ($LCOHP$) is the ratio of the total discounted (r =7%) annualised lifecycle production costs (CP_t) to the total discounted annual hydrogen production (H_t) at year t, simplified in accordance with established methodologies (IEA, 2019; IRENA, 2020) as:

$$LCOHP\ (A\$/kg) = \frac{\sum_{t=0}^{n=60} \frac{CP_t}{(1+r)^t}}{\sum_{t=1}^{n=60} \frac{H_t}{(1+r)^t}} \quad (11)$$

The term $(1+r)^t$ reduces future cash flows to their present-day equivalent. The LCOHP was determined as A\$6.95–A\$8.87 per kg H_2 for the 1.27 GW electrolyser and A\$6.92–A\$8.73 per kg H_2 for the 2.54 GW system. (see Figure 2).

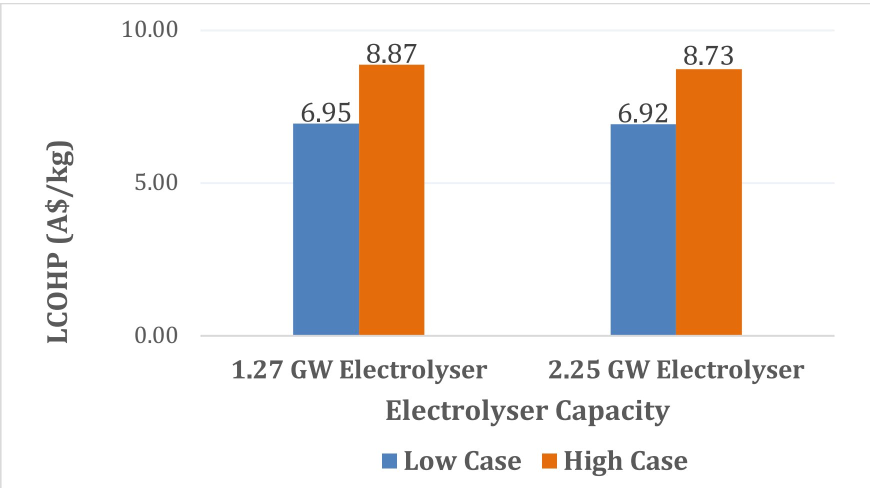

Figure 2. Levelized cost of hydrogen production (LCOHP)

4.1.3. Hydrogen price sensitivity and learning curve

Green hydrogen prices are projected to decline from A\$5.35–A\$16.73 per kg to A\$2.28–A\$7.28 per kg by 2050 (BloombergNEF, 2024). Wright's Law (Wright, 1936) was applied to estimate future costs under large-scale deployment based on the relationship:

$$C_n = C_1 \left(\frac{Q_n}{Q_1}\right)^{log_2(b)} \quad (12)$$

where, C_n is the cost after cumulative production (Q_n). C_1 is the initial cost at baseline production (Q_1). b is the learning factor. Future hydrogen prices over the production lifetime ($n = 60\ years$) were estimated using three learning factors (b = 0.80, 0.85, 0.89). For every doubling of cumulative production, costs decreased by a constant percentage defined by the learning rate of 20%, 15%, and 10% (see equation 13, Table 18 and Figure 3).

$$Learning\ rate, r = 1 - b \tag{13}$$

Table 18. Hydrogen learning price

Current H_2 price range	Learning factor and H_2 prices in 60 years		
	0.80	0.85	0.90
AUD 5.35 / kg	AUD 1.43/kg	AUD 2.05/kg	AUD 2.87/kg
AUD 16.73 / kg	AUD 4.48/kg	AUD 6.41/kg	AUD 8.98/kg

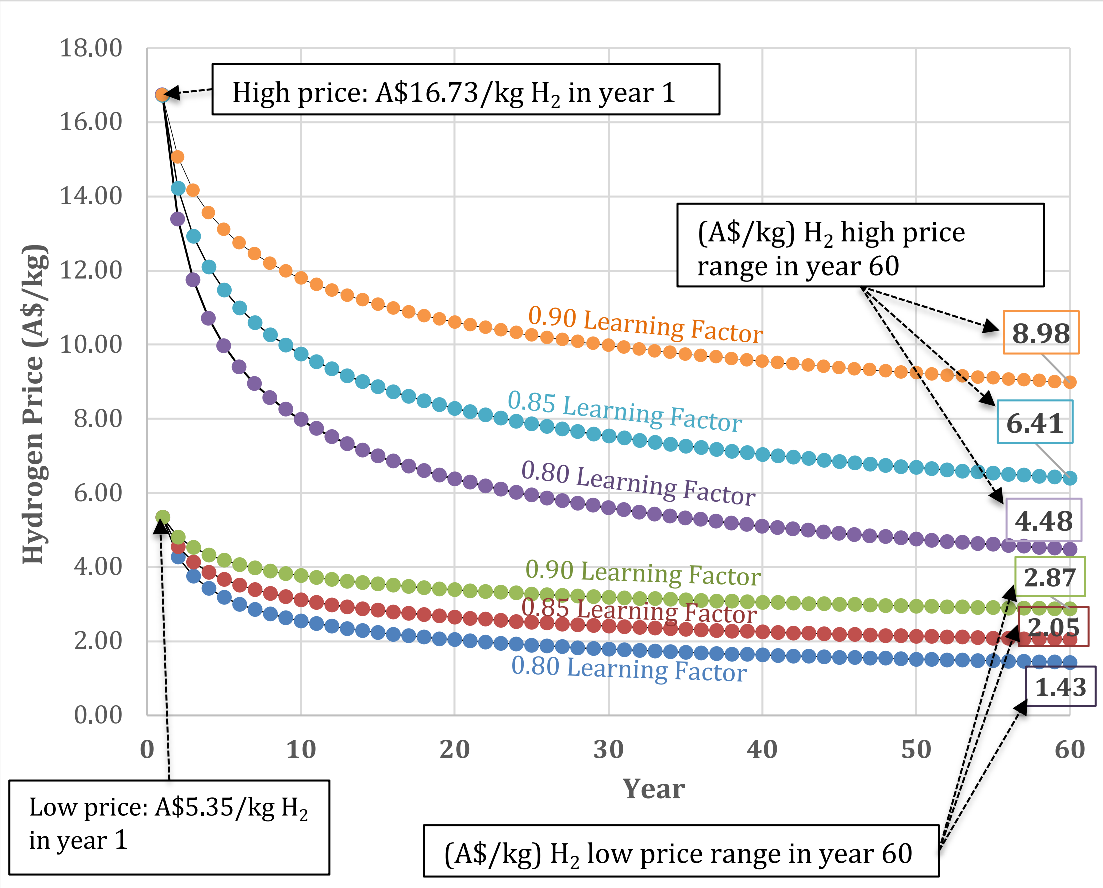

Figure 3. Hydrogen learning price curve in 60 years

4.1.4. Hydrogen production revenue

The revenue ($Hydrogen\ revenue_{,t}$) is the product of the hydrogen selling prices in year t ($P_{H_2,t}$) and the total annual hydrogen production ($Q_{H_2 t}$) for a given year, t of operation. It is simplified as:

$$Hydrogen\ revenue_{,t}\ (A\$/year) = P_{H_2,t}\left(\frac{A\$}{kg}\right) \times Q_{H_2 t}\left(\frac{kg}{year}\right) \tag{14}$$

Figures 4 and 5 represent the hydrogen revenue trend for the 1.27 GW and 2.54 GW electrolysers, respectively, modelled on the price ranges based on the learning rate. The revenue did not take operations and maintenance (O&M) costs into account at this stage.

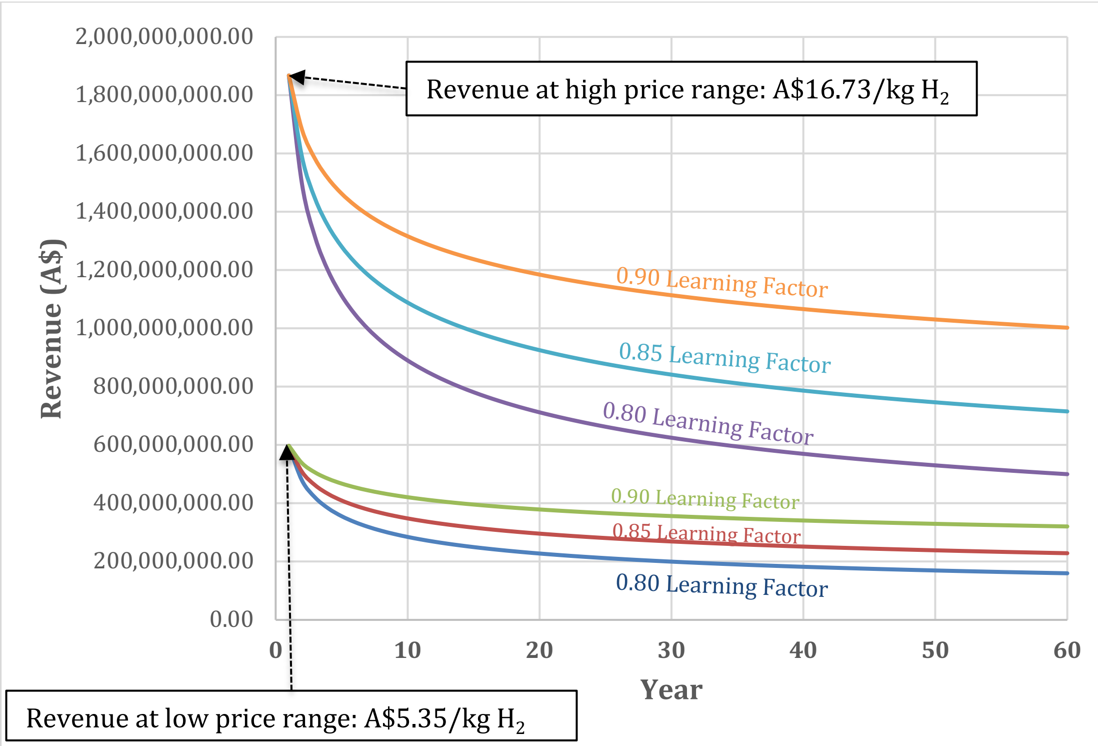

Figure 4. Hydrogen revenue learning curve (1.27 GW scale)

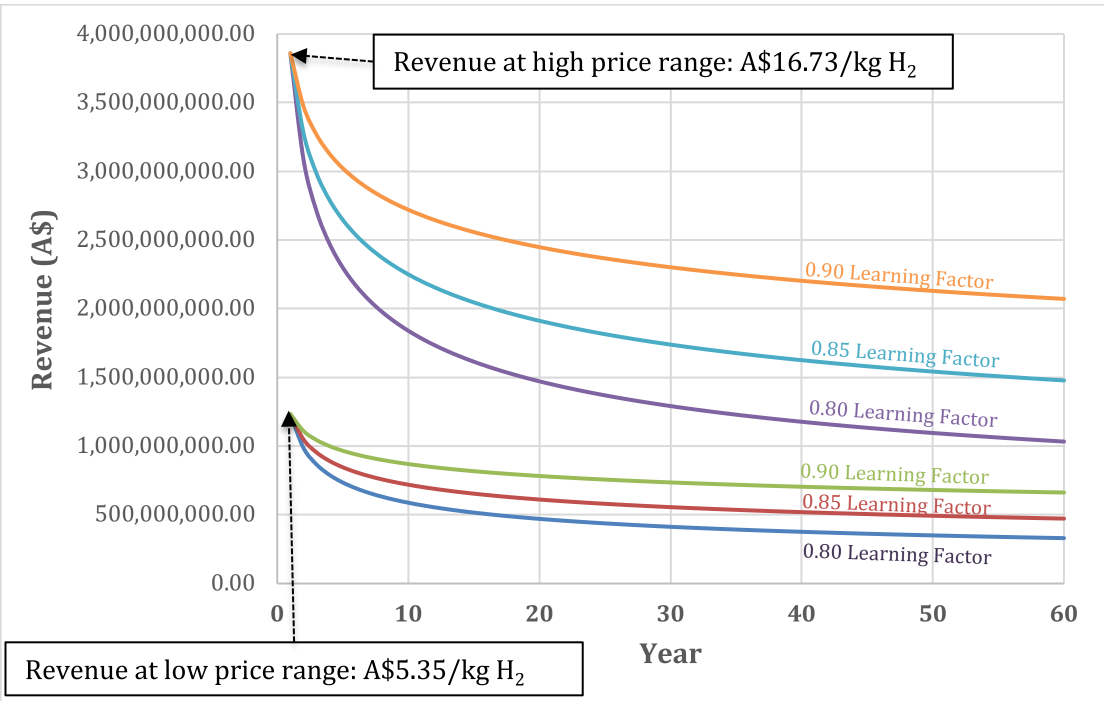

Figure 5. Hydrogen revenue learning curve (2.54 GW scale)

4.1.5. Net cash flow (NCF)

The net cash flow (NCF) was calculated by subtracting the total O&M costs ($OPEX_t$) from the revenue ($P_{H_2,t} \times Q_{H_2t}$) in year, t per equation 15. Figures 6 and 7 show the resulting NCF for both electrolyser systems, respectively.

$$NCF_t = \left(P_{H_2,t} \times Q_{H_2t}\right) - OPEX_t \tag{15}$$

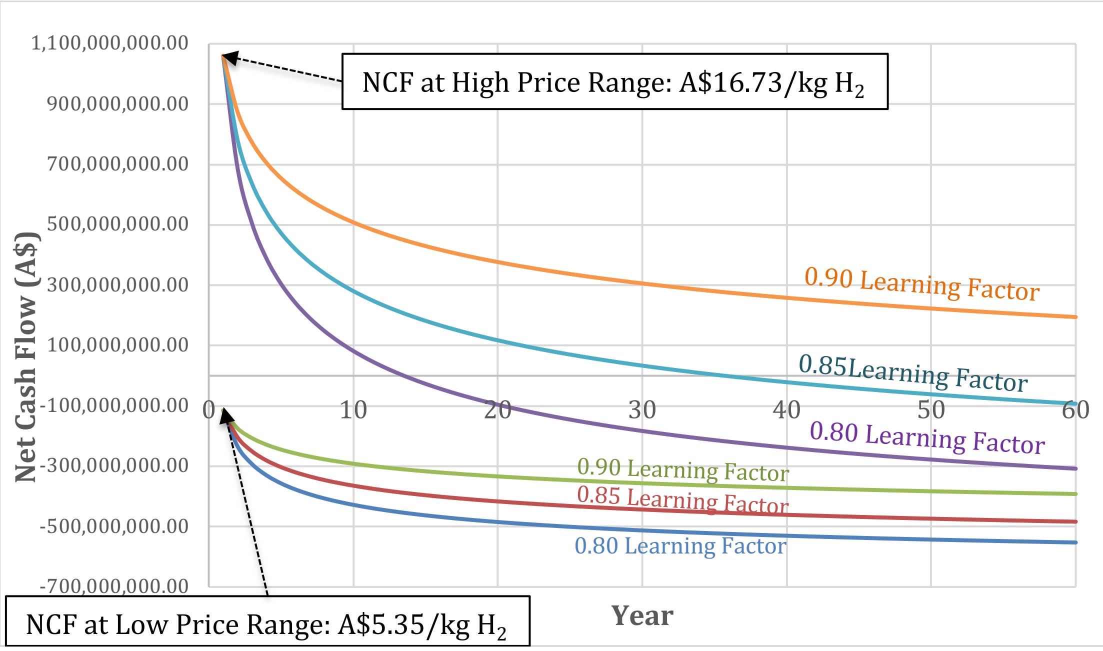

Figure 6. Hydrogen net cash flow learning curve model in 60 years (1.27 GW scale)

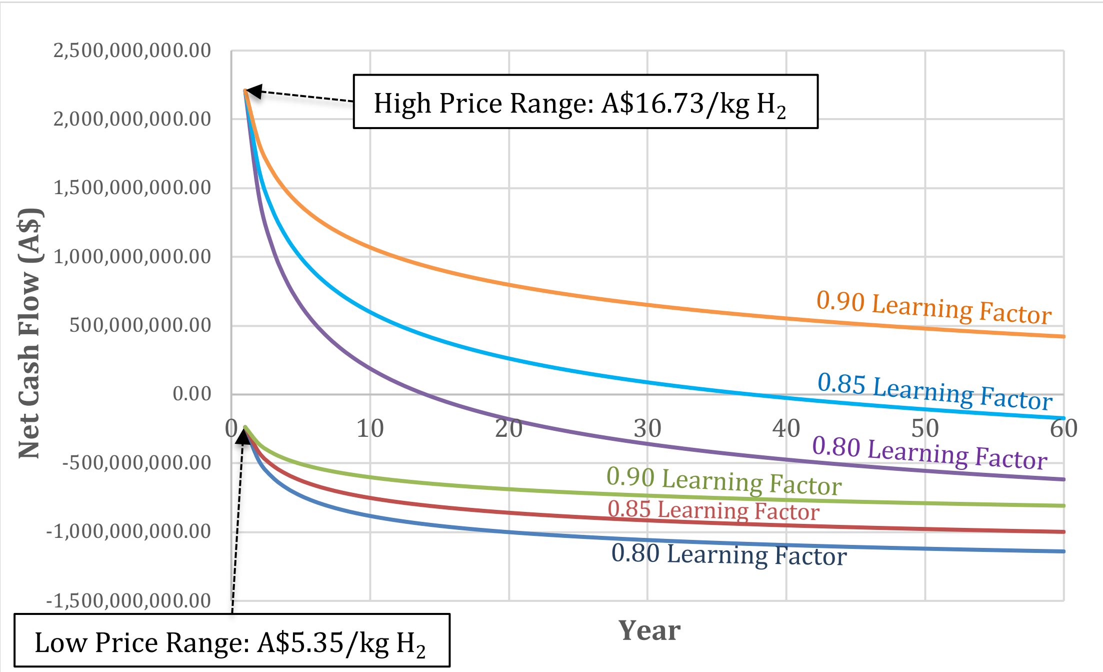

Figure 7. Hydrogen net cash flow learning curve model in 60 years (2.54 GW scale)

4.1.6. Return on investment (ROI) and net present value (NPV)

The return on investment (ROI) and net present value (NPV) is used to evaluate the profitability and overall financial viability by accounting for the time value of money of the electrolyser systems over the project lifetime.

The ROI is the difference between the present value of future NCF in year t (NCF_t), and the initial CAPEX over the project lifetime (n=60 years). It is simplified as:

$$ROI\ (\%) = \frac{\sum_{t=1}^{n=60} NCF_t - CAPEX}{CAPEX} \times 100 \tag{16}$$

The NPV represent the difference between the present value of future discounted (r=7%) NCF in year t (NCF_t) and the initial CAPEX. It includes revenues from hydrogen sales minus operating costs, simplified as:

$$NPV\ (A\$) = \sum_{t=1}^{n=60} \frac{NCF_t}{(1+r)^t} - CAPEX \tag{17}$$

Table 19 presents the ROI and NPV of the 1.27 GW and 2.54 GW production scales, respectively. In the cost values, '*B*' indicates billion and '*M*' is million.

Table 19. ROI and NPV modelled results (1.27 GW and 2.54 GW electrolyser)

Electrolyser Capacity	CAPEX (A$)	OPEX A$ /year	H_2 Price A$/kg H_2	Learning Factor	[1]ROI (%)	NPV (A$)
1.27 GW	893.57 million	735.37M- 820.09 M	5.73	0.80, 0.85, 0.90	-3796 to -2171	-7.90B to -4.84B
		735.37M- 820.09 M	16.73	0.80, 0.85, 0.90	98 to 3172	2.72B to 8.08B
	2.56 billion	735.37M- 820.09 M	5.73	0.80, 0.85, 0.90	-1266 to -696	-9.56 B to -6.50B
		735.37M- 820.09 M	16.73	0.80, 0.85, 0.90	99 to 1177	1.06B to 6.43B
2.54 GW	1.79 billion	1.47B to 2.56 billion	5.73	0.80, 0.85, 0.90	-3262 to -2245	-13.48B to -9.94B
		1.47B to 2.56 billion	16.73	0.80, 0.85, 0.90	102 to 3281	5.69B to 16.78B
	5.12 billion	1.47B to 2.56 billion	5.73	0.80, 0.85, 0.90	-1289 to -722	-19.32B to -13.25B
		1.47B to 2.56 billion	16.73	0.80, 0.85, 0.90	101 to 1214	2.38B to 13.47B

4.1.7. Internal rate of return (IRR)

The IRR (%) represents the effective annual discount rate of return generated by the project at which the present value of all future cash inflows equals the initial investment (when NPV = 0). It is calculated as:

$$0 = \sum_{t=1}^{n=60} \frac{NCF_t}{(1+IRR)^t} - CAPEX \tag{18}$$

$$IRR\ (\%) = IRR\ (NCF_0, NCF_1 \ldots, NCF_{60}) \tag{19}$$

The IRR results for 1.27 GW and 2.54 GW electrolysis scales are presented in Table 20. In the cost values, 'B' indicates billion and 'M' is million. A positive IRR was achieved only at the high hydrogen price of A$16.73 kg-1. No returns were observed at the lower price range.

[1] ROI (%) is calculated as (NPV÷CAPEX) ×100. The wide range, including large negative and positive values, reflects the sensitivity of ROI to NPV over the 60-year modelling horizon. Values may appear exaggerated and should be interpreted alongside NPV and LCOH.

Table 20. IRR modelled results (1.27 GW and 2.54 GW electrolyser)

Electrolyser Capacity	CAPEX (A$)	OPEX A$ /year	H_2 Price A$/kg H_2	Learning Factor	[2]IRR (%)
1.27 GW	893.57M	735.37M- 820.09M	16.73	0.80, 0.85, 0.90	87-116
	2.56 B	735.37M- 820.09M	16.73	0.80, 0.85, 0.90	9-35
2.54 GW	1.79 B	1.47B to 2.56B	16.73	0.80, 0.85, 0.90	102-120
	5.12 B	1.47B to 2.56B	16.73	0.80, 0.85, 0.90	8-105

4.1.8. Hydrogen storage (UHS and AGS) cost parameters

Hydrogen storage costs accounted for underground (UHS) and above-ground (AGS) hydrogen storage, representing the average cost per kg H_2 for storage infrastructure. UHS costs include cushion gas, well conversion, surface facilities, monitoring, maintenance, and compression energy, while AGS costs comprise tank CAPEX, compression, O&M and periodic tank replacement.

The final UHS CAPEX and OPEX results are presented in Tables 21 and 22.

Table 21. Underground storage (UHS) CAPEX and OPEX costs

Parameter	Value
CAPEX (A$)	11.29 million – 19.53 million
OPEX (A$/year)	11.79 million – 16.120 million

Table 22. Surface storage tanks CAPEX and OPEX

Ship volume	CAPEX (A$)	OPEX (A$/year)
Small Ship	1.66 billion - 3.11 billion	34.99 million - 57.08 million
Medium ship	3.01 billion - 5.64 billion	57.52 million - 95.87 million
Large ship	6.16 billion - 11.54 billion	108.19 million - 186.33 million

The levelized cost of storage ($LCOHS$) was determined by equations 20 and 21:

$$LCOHS\left(\frac{A\$}{kg}\right) = \frac{Annualised\ storage\ CAPEX\ \left(\frac{A\$}{yr}\right) + Storage\ O\&M\ \left(\frac{A\$}{yr}\right) + Compression\ OPEX\ \left(\frac{A\$}{yr}\right)}{Hydrogen\ withdrawn\ \left(\frac{kg}{yr}\right)} \tag{20}$$

$$LCOHS\ \left(\frac{A\$}{kg}\right) = \frac{\sum_{t=0}^{n=60} \frac{SC_t}{(1+r)^t}}{\sum_{t=1}^{n=60} \frac{EH_t}{(1+r)^t}} \tag{21}$$

The $LCOHS$ is the ratio of the total discounted (r =7%) annualised lifecycle storage costs (SC_t) to the total discounted energy (hydrogen) discharged from storage in year t (EH_t), for the project lifetime (n=60 years).

UHS resulted in lower LCOHS of A$0.11–0.88 per kg H_2, compared with A$1.55–10.29 per kg H_2 for above-ground tanks (AGS), especially at higher ship loading volumes (see Table 23).

[2] IRR (%) is the discount rate at which NPV equals zero. High values are influenced by the 60-year modelling horizon and strong long-term cash flows relative to initial investment, and should be interpreted alongside NPV and LCOH.

Table 23. LCOHS for UHS and surface H_2 storage

	LCOHS (A$/kg H_2)	
Production target per ship loading capacity	**Depleted gas field (UHS)**	**Above-ground tanks (surface H_2 storage)**
High rate (small ship)	0.11 - 0.88	1.55 - 3.01
Medium ship	0.12 - 0.88	2.75 - 5.14
Large ship	0.12 - 0.88	5.42 -10.29

Pipeline total cost

Based on the hydrogen pipeline repurposing techno-economic input parameters (see Table 9), the total repurposing CAPEX was calculated using equation 22, and compression (A$1.05-8.6kg H_2) (see Table 11) and fixed OPEX (2.5% of CAPEX) for the 659 km Moomba to Port Bonython route (see Table 24).

$$Total\ CAPEX\ (A\$) = CAPEX\ input\ \ (A\$/km)\ \times Total\ distance\ (km) \qquad (22)$$

Table 24. Total pipeline CAPEX and OPEX cost

Total Pipeline Costs	Value
CAPEX (A$)	471.19 million -1.13 billion
OPEX (A$/year)	5.89 million - 14.14 million

Tube trailer total cost

Tube trailer LCOHT was determined for CGH_2 and LH_2 trailers with 300, 700 and 1,400 kg H_2 capacities (ANZ, 2024). The number of trailers per day was determined from the hydrogen volumes required for each ship size. The total CAPEX comprises the cost of each trailer and replacement CAPEX (see equation 8). The OPEX was based on the input cost per 50 km with respect to the total distance travelled and mass of hydrogen (m_{H_2}) (see equation 7) transported (see Table 14).

$$CAPEX_{truck}\ (A\$) = \left[Cost_{per\ truck}\ (A\$) \times No.of\ trucks\right] + Replacement\ CAPEX\ (A\$) \qquad (23)$$

$$OPEX_{truck}\ \left(\frac{A\$}{year}\right) = OPEX_{input}\left(\frac{\frac{A\$}{kg}}{50km}\right) \times m_{H_2}(kg) \times \frac{Distance_{total}(km)}{50km/year} \qquad (24)$$

Results are shown in Tables 25 and 26. Cost values '*B*' indicates billion and '*M*' is million.

Table 25. Total CAPEX range for tube trailer (LH_2 and CGH_2)

Ship volume type	LH_2 & CGH_2 total CAPEX (A$)		
	300 kg H_2/load	**700 kg H_2/load**	**1400 kg H_2/load**
Small LH_2 carriers	885.88M-2.83B	379.66M-1.22B	60.40M-193.2M
Medium LH_2 carriers	5.91B-18.89B	2.53B-8.09B	402.68M-1.289B
Large future carriers	23.62B-47.25B	10.12B-20.24B	1.61B-3.22B

Table 26. Total OPEX range of LH_2 and CGH_2 tube trailers

Ship volume type	Tube Trailer OPEX	
	CGH_2 (A$ million/yr)	LH_2 (A$ million/yr)
Small LH_2 carriers	2.14 -4.29	11.43 - 22.86
Medium LH_2 carriers	14.31 - 28.64	76.22 -152.45
Large future carriers	57.27 -71.59	304.90 -381.12

Levelized cost of hydrogen transport (LCOHT)

The LCOHT represents the average cost per kilogram of hydrogen quantity transported over the project lifetime. All costs were discounted (r=7%) to present value as a ratio of the total annualised transport-related costs (TC_t) to transport hydrogen quantities in a year (Q_t). This metric enables comparison of pipelines vs tube trailer transport, while accounting for port infrastructure costs. It was performed as follows:

$$LCOHT\ \left(\frac{A\$}{kg}\right) = \frac{Annualised\ transport\ CAPEX\ \left(\frac{A\$}{yr}\right) + Fix\ O\&M\ \left(\frac{A\$}{yr}\right) + Compression\ OPEX\ \left(\frac{A\$}{yr}\right)}{Hydrogen\ quantity\ transported\ \left(\frac{kg}{yr}\right)} \tag{25}$$

$$LCOHT\ \left(\frac{A\$}{kg}\right) = \frac{\sum_{t=0}^{n=60} \frac{TC_t}{(1+r)^t}}{\sum_{t=1}^{n=60} \frac{Q_t}{(1+r)^t}} \tag{26}$$

Pipeline resulted in lower LCOHT compared to tube trailers (see Tables 27 and 28). The average LCOHT for tube trailer types is shown in Figure 8.

Table 27. Modelled pipeline LCOHT

Electrolyser Capacity	Pipeline LCOHT (A$ kg^{-1} H_2)
1.27 GW	1.21 - 1.27
2.54 GW	0.88 - 0.92

Table 28. Tube trailer (LH_2 and CGH_2) LCOHT

Tube trailer type	Tube trailer LCOHT (A$ kg^{-1} H_2)	
	1.27 GW Electrolyser	2.54 GW Electrolyser
CGH_2	3.45 – 7.79	1.67 - 3.77
LH_2	6.35 - 13.67	3.07 - 6.61

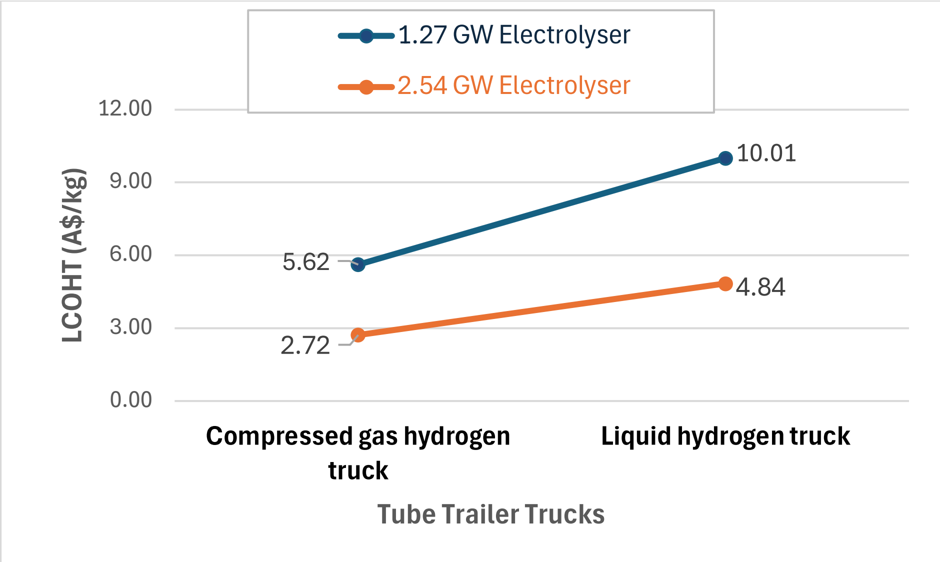

Figure 8. Tube trailer average LCOHT (CGH_2 and LH_2)

Levelized cost of hydrogen delivered (LCOHD)
Table 29 presents the LCOHD sensitivity results for the integrated hydrogen supply chain, evaluating 1.27 GW and 2.54 GW electrolysis across different production, storage and transport configurations.

Table 29. Levelized cost of hydrogen delivered (LCOHD)

Hydrogen production integrated parameters	Levelized cost of hydrogen delivered (LCOHD) for H_2 integration process (A$ kg^{-1} H_2)	
	1.27 GW Electrolyser	2.54 GW Electrolyser
H_2 Production, UHS, ship, pipeline, tube trailers	3.65 - 7.29	3.15 - 5.22
H_2 production, UHS, pipeline, port infrastructure, tube trailers	3.59 - 6.78	3.12 - 4.97
H_2 production, AGS, ship, pipeline, tube trailers	4.02 - 7.86	3.32 - 5.48
H_2 Production, AGS, Port Infrastructure, Pipeline, Tube Trailer	3.96 - 6.34	3.29 - 5.23
H_2 production, AGS, port infrastructure, pipeline transport	5.43 - 7.78	4.92 - 6.54
H_2 production, UHS, pipeline transport	4.79 - 6.85	4.61 - 6.09

4.2. Discussion

This section evaluates the techno-economic results, interpreting key cost drivers, economies of scale and system interactions. It assesses capital expenditures (CAPEX), operations and maintenance costs (OPEX) and levelized costs of hydrogen production, storage, transportation and value chain integration (LCOHP, LCOHS, LCOHT, LCOHD). Financial performance is analysed using hydrogen prices, revenue, net cash flow (NCF), net present value (NPV) and internal rate of return (IRR) to identify economically viable configurations under varying operational and sensitivity scenarios.

4.2.1. Hydrogen production and economic assessment

Doubling electrolyser capacity (1.27 GW to 2.54 GW) increases hydrogen production from 111,637 to 230,717 tonnes per year (see Table 17). Total CAPEX increases from A$892 million - 2.56 billion (1.27 GW) to A$1.78-5.10 billion (2.54 GW) (see Table 16), while the cost per unit of installed (LCOHP) of capacity decreases from A$6.95-A$8.87 per kg H_2 (1.27 GW) to A$6.92-8.73 per kg H_2 (2.54 GW) (see Figure 2). CAPEX and OPEX do not scale proportionally.

Increased electrolyser capacity improves economic performance, but benefits exhibit diminishing marginal returns. Further cost reductions are constrained by electricity prices, compression and utility requirements, and balance-of-plant costs, which remain the dominant contributors to hydrogen production costs. It aligns with Minutillo et al. (2021) on-site electrolysis costs ranging from €4.9 per kg (A$8.02) (renewable electricity) to €11.3 per kg (A$18.51) (grid electricity).

4.2.2. Return on investment (ROI), net present value (NPV), internal rate of return (IRR), net cash flow (NCF) analysis

ROI, NPV, IRR and NCF results are analysed across low (A$5.35 kg^{-1}) and high (A$16.73 kg^{-1}) hydrogen price range, incorporating learning rates (0.90–0.80) to capture cost reductions and scale effects (see Table 19, Table 20, Figure 6 and Figure 7). ROI, NPV, and NCF are evaluated with both price ranges, while IRR is only valid at high price (A$16.73 kg^{-1}) due to sustained negative cash flows and no break-even at low price (A$5.73 kg^{-1}).

ROI, NPV, IRR, NCF analysis at low hydrogen price (A$5.73 per kg H_2)

At A$5.73 per kg H_2, the 1.27 GW system shows consistent negative NCF, ROI (−3796% to −2171%) and NPV (−A$7.90 billion to −A$4.84 billion), with higher OPEX further degrading performance. For the 2.54 GW system, highly negative ROI (−3262% to −2245%) and NPV (−A$13.48 billion to −A$9.94 billion) indicate sustained value loss and inability to recover CAPEX and OPEX. Both scales show persistently negative NCF, ROI and NPV with no IRR, indicating failure to recover CAPEX and OPEX and overall economic infeasibility under these conditions (see Table 19 and Table 20).

ROI, NPV, IRR, NCF analysis at high hydrogen price (A$16.73 per kg H_2)

At A$16.73 per kg H_2, project viability improves significantly, but long-term positive cash flows depend on a high learning rate (0.90), with lower rates (0.80–0.85) undermining sustained economic performance over the 60-year lifetime (see Figure 6 and Figure 7). The low CAPEX (A$893.57 million) and OPEX case shows excellent technoeconomic viability; high ROI (98%–3172% and 102%–3288), and strong NPV (A$2.72–8.08 billion and A$5.69–16.78 billion), respectively, with robust IRR (>100%) for both 1.27 GW and 2.54 GW scale. At high CAPEX (A$2.56 billion), profitability weakens slightly; IRR drops to about 9–35% (1.27 GW) and 8-105% (2.54 GW), with a corresponding drop in NPV and ROI, though projects remain viable depending on OPEX and scale (see Table 19 and Table 20).

ROI, NPV, IRR, NCF analysis remark

The high CAPEX reduces capital efficiency, increasing upfront costs and delaying payback, which compresses IRR. Revenues are insufficient to offset the higher investment, making returns highly sensitive to OPEX and scale. Elevated hydrogen prices sustain strong returns and overall project viability. Higher learning rates reduce costs and improve economic performance, while the larger electrolyser capacity leverages economies of scale to increase output, revenue and extend positive NCF duration (18 and 39 years) compared to the smaller system (15 and 35 years). Profitability is primarily driven by hydrogen price, CAPEX and OPEX as secondary factors, and economic feasibility improves under higher prices or cost reductions from technological learning.

4.2.3. Hydrogen storage cost analysis (UHS, surface storage tanks)

UHS in depleted gas fields incurs lower CAPEX of A$11.28–19.53 million and annual OPEX of A$11.80–16.12 million (see Table 21), compared to surface hydrogen storage with higher investment CAPEX of A$1.66–11.54 billion and annual OPEX of A$35–186.33 million (see Table 22). Due to the use of existing subsurface formations in UHS, infrastructure requirements are significantly lower than those for high-pressure vessels, extensive safety systems and additional infrastructure to store large volumes of hydrogen above ground.

Levelized cost of hydrogen storage-LCOHS (UHS and surface storage)

UHS LCOHS are low and stable across production scales, ranging from A$0.11–0.88 kg^{-1} H_2 (see Table 23), consistent with Yousefi (2023) of $0.37–1.45 kg^{-1} H_2, Zhao et al. (2025) at $1.00 – $5.00 kg^{-1} H_2 in North America and $1.20 – $2.00 kg^{-1} H_2 for Asia (Roy et al., 2024). This demonstrates that repurposing depleted gas reservoirs provides a cost-efficient solution for large-scale hydrogen storage.

Surface storage tanks exhibit higher LCOHS of A$1.55–10.29 kg^{-1} H_2 depending on ship loading capacity. Costs rise sharply with larger storage requirements, exceeding A$10.00 kg^{-1} H_2 for high-volume ship loads, highlighting the economic challenge of scaling up above-ground storage. The average LCOHS across all volumes is A$3.24–6.15 kg^{-1} H_2 (see Figure 9).

UHS in depleted gas fields offers a substantially lower-cost solution compared with surface storage for large-scale hydrogen systems. It improves the economic feasibility of hydrogen supply chains by reducing storage costs and enabling large-volume hydrogen storage.

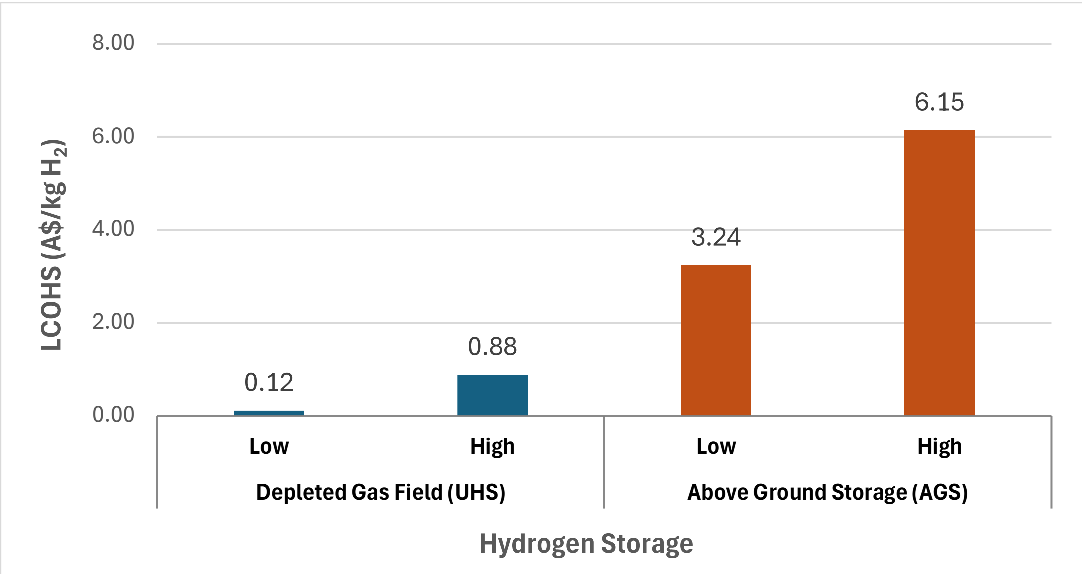

Figure 9. Levelized cost of hydrogen storage (LCOHS) for UHS and surface storage

4.2.4. Hydrogen transport cost analysis

This section presents the hydrogen transportation costs analysis via pipeline and tube trailers. It discusses the CAPEX, OPEX and levelized cost of hydrogen transport (LCOHT) for delivery from Moomba to Port Bonython, covering pipeline and tube trailer (CGH_2 and LH_2) transport options.

Pipeline costs and levelized cost of transport (LCOHT)
The pipeline CAPEX ranges from A$471 million -1.13 billion with annual OPEX of A$5.89-14.14 million (see Tables 24). This gives pipeline LCOHT of A$1.21–1.27 kg^{-1} H_2 (1.27 GW electrolyser) and A$0.88–0.92 kg^{-1} H_2 (2.54 GW system) (see Tables 27). The lower transport cost in combination with the larger system reflects that higher hydrogen volumes distribute infrastructure costs over greater throughput, consistent with Griñán et al. (2026) with LCOHT below €2 kg^{-1} across all distances.

Tube trailer costs (CGH_2 and LH_2) and levelized cost of transport (LCOHT)
Hydrogen transport via tube trailers shows logistical constraints at low capacities. Small CGH_2 trailers (300 kg/load) require 354–11,800 trips per day, whereas high-capacity LH_2 trailers (4,400 kg/load) reduce this to 24–805 trips/day. This demonstrates that increasing trailer capacity substantially improves transport efficiency and scalability.

The CAPEX for CGH_2 and LH_2 trailer systems range from A$60.4 - A$2.83 billion (small export volumes) to A$23.6–47.3 billion (large-scale exports) when using low-capacity trailers due to high fleet requirements (see Table 25). Annual OPEX scales with volume, reaching A$2.14–381.12 million, highlighting the strong impact of transport capacity and system scale on overall costs (see Table 26).

Small CGH_2 trailers (300 kg capacity) yield a high LCOHT of A$0.58–31.42 per kg of H_2 due to the frequent trips required to meet large export volumes. Increasing trailer capacity to 1400 kg improves transport efficiency, reducing LCOHT to A$0.06–2.76 kg^{-1} H_2 for the 1.27 GW electrolyser system. Costs further decrease to A$0.03–1.33 kg^{-1} H_2 for the 2.54 GW system. These results highlight that higher vehicle capacity and improved logistics cost drivers, consistent with Griñán et al. (2026), on long-distance transport cost, strongly influenced by distance and subsystem costs, often exceeding €2 kg^{-1} H_2.

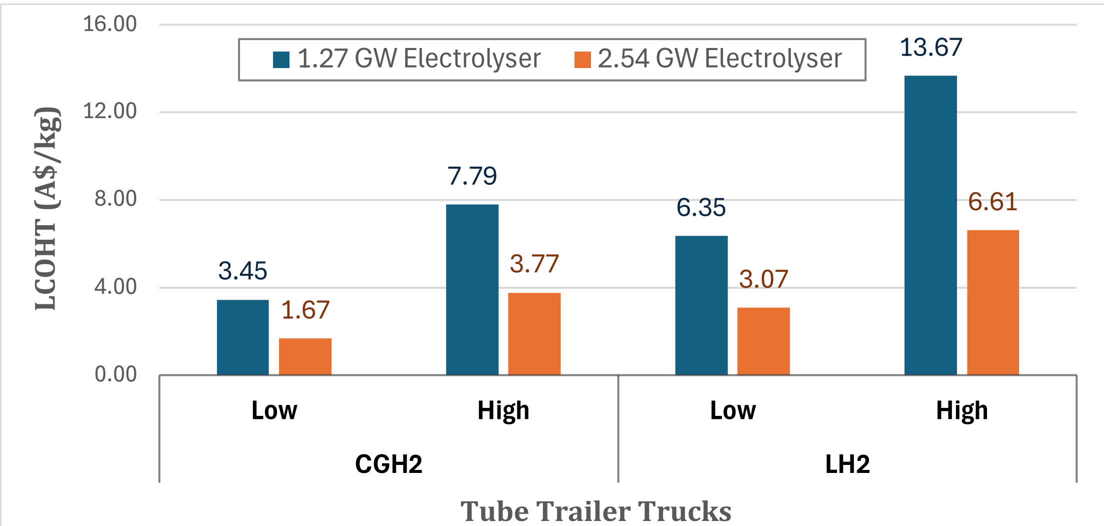

Figure 10. Average LCOHT for CGH_2 and LH_2 tube trailer configuration

The average LCOHT for tube trailer (CGH_2 and LH_2) costs decline on the 2.54 GW scale and CGH_2 trailer, indicating strong economies of scale (see Figure 10). It aligns with DESNZ (2023) that increasing CGH_2 trailer capacity reduces transport costs by 10–25%, confirming the techno-economic advantage of larger-capacity systems.

4.2.5. Levelized cost of hydrogen delivered (LCOHD) sensitivity analysis

The hydrogen value chain integration sensitivity analysis indicates that the levelized cost of hydrogen delivered (LCOHD) decreases with larger electrolyser scale and efficient storage and transport integration. It yields an average of A$5.18 kg^{-1} H_2 (A$3.59–A$6.78 kg^{-1} H_2) for the 1.27 GW system, while the 2.54 GW system reduces cost to an average of A$4.04 kg^{-1} H_2 (A$3.12–A$4.97 kg^{-1} H_2) (see Table 29). Figure 11 presents the average LCOHD across various hydrogen supply chain integration configurations.

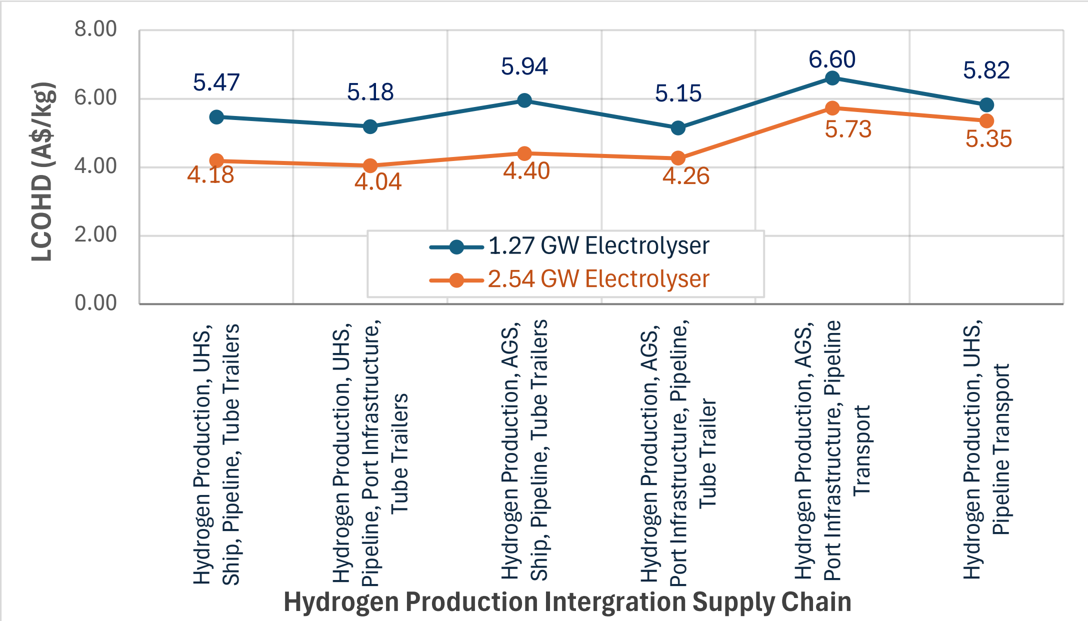

Figure 11. Average LCOHD for hydrogen supply chain integration configurations

The most cost-effective delivery uses UHS and pipelines, with LCOHD of A$4.79–A$6.85 kg^{-1} H_2 for the 1.27 GW system and A$4.61–A$6.09 kg^{-1} H_2 for the 2.54 GW system (see Table 29). Surface storage and tube trailers are costlier, while larger electrolyser capacity further lowers per-kg delivery costs. Lower UHS and pipeline costs reduce LCOHD compared with surface tanks and tube trailers due to lower CAPEX and the use of existing infrastructure.

4.2.6. Limitations

The techno-economic modelling relied mainly on secondary data and literature-based assumptions rather than field-validated data. Although results followed trends reported in previous hydrogen supply-chain studies (Staffell et al., 2019), the absence of practical operational data introduces uncertainty in cost estimates and system performance, requiring future validation using real-world monitoring and operational datasets.

The modelling tool used (Excel) is suitable for preliminary assessments but limited in dynamic modelling and optimisation. Advanced tools like MATLAB, Simulink, HOMER Pro (Glenk & Reichelstein, 2019), and Aspen Plus (Staffell et al., 2019) offer higher-accuracy simulations and integrated techno-economic analysis.

The analysis was limited to hydrogen production, storage, transport and delivery costs, and excluded environmental, land acquisition and other external economic factors.

5. Conclusion and recommendations

The study concludes that the levelized cost of hydrogen delivered (LCOHD) analysis identifies the most cost-efficient supply chain integration. Scaling electrolysers (1.27 GW to 2.54 GW) lowers unit CAPEX and OPEX via economies of scale, but does not significantly improve the overall economic performance. There was not much difference on the LCOH indicating that the CAPEX was not the main cost driver.

Hydrogen price was the main cost driver with electricity and utility costs as secondary factors. Low prices yield negative returns, while high prices enable strong positive NCF, ROI, NPV and IRR for both scales.

Underground storage (UHS) in depleted gas fields offers lower and more stable LCOHS across scales, while above-ground tanks incur higher CAPEX and significantly higher storage costs.

The transport analysis indicates pipelines offer stable, scale-efficient LCOHT, while tube trailers have variable costs reduced by larger capacities. LH_2 trailers are costlier due to liquefaction and cryogenic requirements.

5.1. Recommendations for policy and practice

The techno-economic findings suggest targeted actions to enable cost-competitive large-scale hydrogen production and export systems. The recommendations focus on enabling economic viability through cost reduction and market support measures.

5.1.1. Develop supportive hydrogen market policies and pricing mechanisms

Reduce the cost of renewable supply through PPAs, off-peak tariffs or direct generation access such as dedicated low-cost renewable energy zones. Provide policy support to regulate hydrogen prices between A$14.00–16.00 kg^{-1} and electricity costs below A$104/MWh to improve the overall project viability.

5.1.2. Support large-scale electrolyser deployment to capture economies of scale

Prioritise the rapid scaling and development of large-scale hydrogen production facilities, supported by investment incentives, infrastructure funding and streamlined regulatory approvals.

5.1.3. Prioritise underground hydrogen storage development

Support further research, regulatory frameworks and pilot projects for UHS to enable safe and efficient utilisation of existing geological formations for large-scale hydrogen storage.

5.1.4. Invest in hydrogen transport infrastructure

Strategic investment in hydrogen pipeline infrastructure should be prioritised. Expand pipeline utilisation, where geographically and economically feasible. This will play a critical role in minimising transport costs and enhancing the overall efficiency of large-scale hydrogen export systems.

5.1.5. Promote integrated hydrogen supply chain planning

Adopt an integrated infrastructure planning approach that optimises the entire hydrogen value chain rather than focusing on individual system components in isolation. Different infrastructure scenarios significantly influence the final LCOHD. Integrating large-scale production with cost-effective storage (particularly UHS) and efficient transport systems (especially pipelines and higher-capacity trailers) consistently produces lower delivered hydrogen costs compared with less optimised combinations.

5.2. Recommendations for further research

To build on this research, the following points are recommended.

5.2.1. Incorporate field-validated operational data

Future studies should include real-world performance data from operational hydrogen facilities, including electrolyser efficiency, storage behaviour and transport logistics to improve model accuracy and reduce uncertainty in cost estimates.

5.2.2. Comprehensive socio-economic and environmental assessment

Future work should expand the scope to incorporate environmental externalities, land acquisition costs, community engagement, regulatory impacts and policy frameworks to provide a more holistic evaluation of hydrogen project feasibility.

5.2.3. Use advanced energy system modelling tools

Subsequent research should integrate specialised simulation and optimisation platforms such as MATLAB, Simulink (MathWorks, 2024), HOMER Pro (HOMER Energy, 2024) or Aspen Plus (Aspen, 2024) to enable dynamic system modelling, sensitivity analysis and process-level optimisation beyond spreadsheet-based analysis.

5.2.4. Seasonal variability and domestic hydrogen integration

Incorporate seasonal weather and climate variability (winter, summer, autumn, spring) conditions to better capture fluctuations in renewable energy generation and hydrogen production. Future studies should explore opportunities for domestic hydrogen utilisation alongside export scenarios. This could include selling surplus hydrogen to local industrial markets or integrating hydrogen into the domestic energy system to enhance grid stability. Hydrogen can play a complementary role in supporting the electricity supply chain by providing renewable energy storage, backup generation and grid balancing services, especially to complement intermittent sources such as solar and wind power.

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