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Techno-economic feasibility of underground hydrogen storage at the Ahuroa gas field with combined cycle gas turbine integration in the Taranaki region of Aotearoa New Zealand

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Abstract
This study assesses the technical and economic feasibility of converting the Ahuroa depleted gas field in Taranaki, Aotearoa New Zealand into an underground hydrogen storage facility integrated with an existing combined cycle gas turbine power station for dispatchable green electricity generation. Underground hydrogen storage in depleted gas reservoirs offers a pathway for seasonal-scale energy storage that batteries and pumped hydro cannot provide, making it particularly relevant to the country's goal of achieving one hundred percent renewable electricity. Using site-specific operational data and internationally sourced cost parameters, the study calculates the Levelised Cost of Hydrogen across three scenarios and extends this to a full Levelised Cost of Electricity comparison against natural gas generation. The results show that Ahuroa is technically suitable for hydrogen storage conversion, with confirmed reservoir geology, existing infrastructure, and a direct pipeline connection to the power station. However, the economic analysis reveals that green hydrogen electricity is significantly more expensive than natural gas electricity under current market conditions, with the cost gap driven primarily by energy conversion losses in the hydrogen production and electricity generation chain rather than by the storage infrastructure itself. Carbon pricing at current New Zealand levels contributes negligibly to closing the competitiveness gap, and commercial viability requires a combination of low-cost renewable electricity, rising natural gas prices, capacity payments, and direct production support. Ahuroa is best understood not as a standalone commercial hydrogen project but as a technically credible long-duration storage asset that becomes increasingly relevant as the country's gas supply declines and the energy transition deepens.

Keywords: Underground hydrogen storage; LCOH; LCOE; CCGT integration.

1. Introduction
Aotearoa New Zealand aims to achieve 100% renewable electricity by 2030, following the Climate Change Response (Zero Carbon) Amendment Act 2019. The country relies mostly on hydropower, which supplies about 57% of its annual electricity. However, this is sensitive to dry years with low rainfall (Higgs et al., 2024). As more wind and solar energy is added to the system, the need for long-duration energy storage becomes more crucial. This type of storage can balance energy supply and demand over weeks and months instead of just hours. Batteries can store energy for hours but cannot provide the seasonal storage that the country needs to manage long periods of low renewable generation or dry years. The Onslow pumped hydro scheme is one solution to this challenge, but current estimates are in the order of $9 billion with consenting complexities(RNZ-NZ News, 2026).

Hydrogen is emerging as an important solution in the global shift toward low-emissions energy. It is a clean, flexible energy carrier used in transport, industry, and electricity generation. When produced with renewable electricity, hydrogen can have a very low carbon footprint (Muhammed et al., 2023). One of hydrogen's main benefits is its ability to be stored for long periods and used when renewable electricity is not available, something batteries struggle with at large scale. However, safely and affordably storing hydrogen in large amounts is a significant challenge for a hydrogen economy. Hydrogen has low density as a gas or liquid and must be kept under high pressure (Muhammed et al., 2023). Above-ground storage requires many cryogenic tanks or deep shafts, raising concerns about high costs, safety, and land use (Nicol et al., 2022).

Using depleted gas fields for underground hydrogen storage (UHS) is a practical and cost-effective alternative. Depleted reservoirs are appealing because they have shown they can hold buoyant fluids over geological time and usually come with detailed subsurface information (Nicol et al., 2022). These fields already have essential infrastructure like wells, pipelines, and geological data, cutting down on the need for new investment. They are often close to existing energy infrastructure, making it easier and more economical to connect to the energy system. Reusing existing assets allows for the growth of hydrogen storage as demand increases, without needing to construct new facilities.

The Taranaki region of Aotearoa New Zealand shows strong technical potential for UHS, especially in its depleted oil and gas reservoirs. Taranaki also has the country's most developed gas infrastructure, including several depleted gas fields that have been extensively studied through decades of production and storage activities. The Ahuroa field, located in the South Taranaki Basin about 25 kilometres east of Stratford, has operated as a natural gas peak-shaving storage facility since the 1990s by Contact Energy. It holds a confirmed cushion gas volume of 6,000 TJ, has a working pipeline connection to the Taranaki Combined Cycle (TCC) power station 14 km away (Taranaki Regional Council, 2022), and has reservoir parameters confirmed as suitable for hydrogen storage (Liu et al., (2025).

Despite the technical suitability of the Taranaki region and the Ahuroa field specifically, no published study has quantified the full economics of hydrogen storage at this site or assessed the cost implications of hydrogen-fuelled generation at the TCC power station. Existing international UHS techno-economic studies provide methodological frameworks and cost benchmarks but do not address specific conditions including Aotearoa New Zealand electricity prices, its gas market dynamics, or the operational characteristics of the Ahuroa reservoir. This study addresses that gap by developing a site-specific Levelised Cost of Hydrogen model for Ahuroa using actual operational data, extending it to a full Levelised Cost of Electricity analysis for hydrogen-fuelled electricity generation at TCC, and identifying the policy conditions required for commercial viability.

1.1. Objective of the paper

This paper assesses the techno-economic feasibility of converting the Ahuroa gas field into an underground hydrogen storage facility integrated with the TCC power station. The specific objectives are:

- To evaluate the economic viability of underground hydrogen storage (UHS) in Taranaki's depleted gas field to support grid-scale electricity generation via Combined Cycle Gas Turbines (CCGTs).
- To quantify the impact of UHS on the Levelized Cost of Hydrogen (LCOH) under various storage and production scenarios.
- To analyse the sensitivity of LCOH to fluctuations in parameters, which directly affect the cost of green hydrogen production.
- To determine the conditions under which hydrogen becomes cost-competitive with natural gas for use in CCGTs in terms of Levelised Cost of Electricity (LCOE).

- To provide policy-relevant insights that support infrastructure planning, investment decisions, and regulatory frameworks for hydrogen storage and dispatchable power generation in Aotearoa New Zealand.

2. Literature review

This section reviews the technical and economic literature on underground hydrogen storage in depleted gas reservoirs, green hydrogen production costs, and CCGT integration with hydrogen fuel, with emphasis on studies directly applicable to the Ahuroa context.

2.1. Underground hydrogen storage: Technical and economic background

Underground hydrogen storage (UHS) uses subsurface geological formations to store large volumes of hydrogen for later use. The main storage types studied in the literature are salt caverns, depleted oil and gas reservoirs, and saline aquifers (Gianni et al., 2024, Muhammed et al., 2023). Salt caverns are the most commercially proven option with operational sites in the United States and United Kingdom since the 1980s, but they are geographically limited in Aotearoa New Zealand (WSP New Zealand Limited, 2022). Depleted gas reservoirs are considered the next most attractive option because they already have proven containment, existing wells and pipelines, and detailed geological data from decades of hydrocarbon production (Nicol et al., 2022, Yousefi et al., 2023). These features reduce development costs compared to new sites. As of 2023 there were fifty eight UHS projects globally with only five operational, confirming the technology is still in early deployment stages (Shahriar et al., 2024). The geological parameters that determine site suitability include reservoir depth, porosity, permeability, caprock integrity, and structural closure. A key operational requirement is cushion gas; a permanent volume of gas left in the reservoir to maintain pressure and enable efficient withdrawal of working gas. In depleted reservoirs, residual natural gas can serve as cushion gas, reducing costs compared to injecting new gas (Muhammed et al., 2023). Two technical risks are relevant to this study. Hydrogen embrittlement of steel wellbore casing, pipeline steels, and packers is a primary concern for existing infrastructure conversion (Deng et al., 2025). Microbial activity from sulphate-reducing bacteria in reservoir fluids can consume hydrogen and reduce storage efficiency (Gianni et al., 2024). Hydrogen diffusion losses through the cap rock are a further consideration, incorporated into the economic model as an annual loss rate (Pan et al., 2021).

The Taranaki Basin is Aotearoa New Zealand's only commercial petroleum basin and is recognised as having the most suitable geological conditions for underground energy storage in the country (Rendel et al., 2025). A 2018 screening of eighteen Taranaki fields identified several onshore sites as suitable for UHS conversion based on field size, reservoir quality, depth, and existing well infrastructure (Nicol et al., 2022). Higgs et al. (2024) identify Ahuroa and Maui A as the top candidates for technical suitability using a multi-criteria decision-making approach. Many Taranaki fields are expected to cease production between 2030 and 2050, making them prime candidates for repurposing into energy storage facilities. The existing petroleum infrastructure in Taranaki, combined with growing renewable electricity resources, positions the region as a potential hydrogen hub for the country (Higgs et al., 2024, Nicol et al., 2022).

Aotearoa New Zealand's electricity generation is dominated by renewables but seasonal shortfalls are currently met by natural gas and coal (Higgs et al., 2024). As wind and solar capacity increases, the need for long-duration dispatchable backup generation becomes increasingly important. Harrison (2024) finds that large-scale electrolysis can help smooth peak demand and compensate for the loss of fossil fuel generation. Nicol et al. (2022) project that the country's 2050 energy demand could include a significant hydrogen component generated from renewable electricity surplus for industrial users and peak power generation. The H_2 Taranaki Roadmap specifically supports development of a hydrogen supply pipeline connecting large-scale renewable generation with industrial complexes in Taranaki (Venture Taranaki, 2019). These findings support the strategic case for Ahuroa UHS as a long-duration grid balancing asset. Despite this, most local studies focus on geological feasibility rather than economics. Nicol et al. (2022) and Higgs et al. (2024) identify suitable reservoirs but do not assess whether UHS is cost-competitive in the electricity market. The feasibility study of WSP New Zealand Limited (2022) for the NZ Battery Project dismissed underground hydrogen storage as too immature without assessing any specific site. This study addresses that gap.

2.2. Levelised Cost of Hydrogen: Modelling methods and key drivers

Levelised Cost of Hydrogen (LCOH) is the primary metric used to assess the economic viability of hydrogen production and storage. It represents the total lifecycle cost per kilogram of hydrogen delivered and is calculated by dividing the sum of annualised capital costs, operating costs, and energy costs by the effective annual hydrogen output (Lord et al., 2014, Yousefi et al., 2023). The standard LCOH formula uses the Capital Recovery Factor to annualise upfront capital costs over the project lifetime at a given discount rate, an approach adopted consistently across the UHS techno-economic literature and used in this study.

Lord et al. (2014) established foundational parameters widely used in UHS economic modelling, a 30-year project lifetime, compression energy of 2.2 kWh/kg for hydrogen injection, and a storage-only LCOH for a US depleted gas reservoir including a pipeline. These values have been adopted in subsequent studies and are used directly in this study. Yousefi et al. (2023) provide the most directly comparable study to Ahuroa, assessing a Dutch depleted gas field and reporting a storage-only LCOH base case of EUR 0.79/kg with a sensitivity range of EUR 0.58–1.04/kg. The Dutch study's methodology – separating storage CAPEX, storage OPEX, and compression energy into distinct cost components – is consistent with the approach used in this study and provides the primary international benchmark for the storage-only component of Ahuroa's LCOH.

Deng et al. (2025) provide the most comprehensive published cost framework for converting existing underground gas storage to hydrogen storage. The paper distinguishes between the CUGS route, Converting Utilised Gas Storage, which reuses existing infrastructure and applies a residual asset value credit, and the CDGR route, Converting Depleted Gas Reservoir, which requires more extensive infrastructure work at higher cost. Unit costs for all major CAPEX and OPEX components are provided in Table 2 and Table 3 of (Deng et al., 2025) and are adopted as the primary cost basis in this study, normalised to Aotearoa New Zealand conditions through labour replacement and volume scaling adjustments. This framework is chosen because it is a published study that provides a comprehensive, component-level economic model for UHS conversion of existing gas storage infrastructure with explicit CAPEX and OPEX breakdowns.

Electrolyser costs are sourced from the International Energy Agency (2024) Assumptions Annex, which provides the most authoritative current global benchmarks - CAPEX of USD 2,160/kWe, efficiency of 66% LHV, and annual OPEX of 3% of CAPEX inclusive of stack replacement. The IEA NZE 2030 projection of USD 960/kW_{el} is used for the optimistic scenario, reflecting projected manufacturing scale-up.

The Ministry of Business and Employment (2022) estimates near-term green hydrogen production costs of NZD 6–10/kg covering electrolyser capital, operating, and electricity costs but not storage. Energy Efficiency and Conservation Authority (2024) reports a current indicative price of NZD 8/kg with a 2050 target of NZD 2/kg. Both are production-only benchmarks.

Electricity cost is the most important single driver of green hydrogen production costs (International Energy Agency, 2024). No published studies prior to this one have examined LCOH sensitivity to electricity price in the Aotearoa New Zealand context. The NZ Treasury Circular 2024/15 specifies the social opportunity cost discount rate of 8% used in the capital recovery factor calculation, with the social rate of time preference of 2% used as a mandatory lower-bound sensitivity (NZ Treasury, 2024). The natural gas price of NZD 20/GJ is taken from the Regional Energy Transition Accelerator Auckland Report (RETA, 2025), which provides the most current available industrial gas price data based on MBIE Q1–Q4 2024 retail prices for non-feedstock industrial users.

2.3. CCGT integration with hydrogen: Technical feasibility and cost implications

Combined cycle gas turbines play an important role in a hydrogen economy as a means of converting stored hydrogen back to dispatchable electricity (Garcia and Guédez, 2025). A CCGT operates on the Brayton-Rankine thermodynamic cycle, combining a gas turbine and steam turbine to achieve thermal efficiencies of 55–60% LHV for modern plants. The thermal efficiency of a CCGT is determined primarily by the turbine inlet temperature and pressure ratio, properties of the plant cycle rather than the fuel, meaning that switching from natural gas to hydrogen does not significantly change efficiency for modern turbine designs (Garcia and Guédez, 2025).

Garcia and Guédez (2025) model the techno-economics of a retrofitted European CCGT for hydrogen operation, reporting thermal efficiencies on hydrogen comparable to natural gas for modern combined cycle plants. Their study provides fixed O&M costs of EUR 13.4/kW/year and variable O&M costs of EUR 2.42/MWh, and a CCGT upgrade cost of EUR 50/kW_{el} for hydrogen blends above 30% by volume. These values are adopted directly in this study given that Garcia and Guédez (2025) model a 400 MW_{el} plant, comparable in scale to TCC at 383 MW, making direct parameter transfer methodologically appropriate. The CO_2 emissions factor of 0.35 tCO_2/MWh for natural gas CCGTs (Garcia and Guédez, 2025) is used in the carbon price breakeven analysis. Generating electricity from hydrogen in CCGTs is currently costly and becomes more economic only if hydrogen production costs fall significantly or market electricity prices increase (Garcia and Guédez, 2025).

3. Research methods

The research methodology consists of three sequential quantitative modules:

- LCOH modelling for green hydrogen production and underground storage at Ahuroa gas field;
- CCGT integration analysis producing LCOE for hydrogen-fuelled generation at TCC; and
- Cost competitiveness analysis including carbon price sensitivity. All costs are expressed in 2025 New Zealand dollars unless otherwise stated.

The LCOH module calculates the cost of producing and storing hydrogen at Ahuroa. This cost is then used as the fuel cost input for the CCGT integration module, which converts it into a cost per megawatt-hour of electricity. The carbon price analysis then uses the electricity cost gap between hydrogen and natural gas to determine what carbon price would be needed to make hydrogen competitive. All three modules use the same three scenarios – conservative, base case, and optimistic – ensuring that results are comparable across the full analysis.

3.1. Data sources

Site-specific data for Ahuroa were drawn from two primary sources. Reservoir parameters – depth (2,000 m), temperature (65°C), operating pressure range (16-24 MPa), porosity (14%), horizontal permeability (40 mD), and gas-water contact at 2,260 m – were taken from Liu et al. (2025). Operational injection and withdrawal data were taken from Contact Energy Limited (2023), a dataset of 2,246 daily records covering 2020-2023, providing daily opening balance, change in storage, closing balance, and cushion gas volume in terajoules.

TCC plant parameters were sourced from the 2016 Monitoring Report (Contact Energy Limited, 2016) filed with New Zealand regulatory authorities, reporting an upgraded installed capacity of 383 MW and a thermal efficiency of 56.7% LHV. Annual generation of 1,071,000 MWh/year is from the Power Technology (2025) plant profile. The Taranaki Regional Council compliance report (2022) confirms the operational pipeline connection between Ahuroa and TCC. Storage conversion costs were derive from Deng et al. (2025). Electrolyser parameters are from International Energy Agency (2024) Assumptions Annex. CCGT O&M and retrofit costs are from Garcia and Guédez (2025). The NZ natural gas price of NZD 20/GJ is the mid-point assumption for non-feedstock industrial users from RETA (2025), citing MBIE Q1-Q4 2024 retail price data. The discount rate of 8% is the social opportunity cost rate from NZ Treasury Circular 2024/15(NZ Treasury, 2024). The TCC power station, also referred to as the Stratford Power Station, originally had a capacity of 354 MW and was subsequently upgraded to 383 MW. TCC was selected as the integration target for this study because it is the direct downstream user of Ahuroa gas. The existing gas supply relationship, shared pipeline, and compatible turbine design make TCC the only power station in Aotearoa New Zealand for which an Ahuroa hydrogen integration study is immediately technically coherent. The base case electricity price of NZD 100/MWh is taken from the MBIE Hydrogen Economic Modelling Report(Ministry of Business and Employment, 2023), which reports this as a representative NZ wholesale electricity market price. The base case natural gas price of NZD 20/GJ represents the mid-point assumption for non-feedstock industrial users in the North Island, based on MBIE Q1-Q4 2024 retail price data reported in RETA (2025).

3.2. LCOH modelling and scenario definitions

The LCOH is calculated using the standard discounted cost formulation consistent with Lord et al. (2014) and Yousefi et al. (2023). The LCOH is given by the equation:

$$LCOH = \frac{(CAPEX_{stor} + CAPEX_{elec}) \times CRF + OPEX_{stor} + OPEX_{elec} + C_{energy}}{M_{H2effective}} \quad (1)$$

Where $CAPEX_{stor}$ is the net storage conversion capital cost in NZD millions after residual value credit, $CAPEX_{elec}$ is the electrolyser capital cost in NZD millions, CRF is the capital recovery factor that converts upfront capital into an equivalent annual cost, $OPEX_{stor}$ is the annual storage operating cost in NZD millions per year, $OPEX_{elec}$ is the total annual electrolyser operating cost including both maintenance and electricity in NZD millions per year, C_{energy} is the annual compression electricity cost for injecting hydrogen into the reservoir in NZD millions per year, and MH2effective is the annual effective hydrogen output in kilograms after accounting for withdrawal losses and diffusion.

The Capital Recovery Factor is calculated as follows:

$$CRF = i(1+i)^{\wedge}n \,/\, ((1+i)^{\wedge}n - 1) \qquad (2)$$

Where i is the discount rate expressed as a decimal and n is the project lifetime in years. At 8% over 30 years this gives CRF of 0.08883. A higher discount rate increases the CRF, which increases the annualised CAPEX burden and therefore raises the LCOH. This is why discount rate appears in the sensitivity analysis.

The effective hydrogen output is calculated as follows:

$$M_{H2effective} = M_{H2gross} \times 0.90 \times 0.99 \qquad (3)$$

Where 0.90 is withdrawal efficiency (Liu et al., 2025) and 0.99 reflects 1% annual diffusion loss (Pan et al., 2021). Compression energy cost is calculated as follows:

$$C_{energy} = M_{H2effective} \times 2.2 \frac{kWh}{kg} \times 0.10 \frac{NZD}{kWh} \qquad (4)$$

Where 2.2 kWh/kg is the energy needed to compress hydrogen for injection into the reservoir and 0.10 is the electricity price in NZD per kWh. Dividing by 1,000,000 converts the result from NZD to NZD millions for consistency with other cost terms.

The storage CAPEX covers all costs of converting Ahuroa from natural gas storage to hydrogen storage. This includes well maintenance, pipeline refurbishment, equipment upgrades for hydrogen compatibility, cushion gas procurement, and a 12% contingency allowance. A residual asset value credit is subtracted from the gross CAPEX to reflect the economic value of existing reusable infrastructure. The credit differs by scenario: 60% in the base case, 70% in the optimistic scenario, and 15% in the conservative scenario, reflecting different assumptions about infrastructure condition and reusability. The electrolyser is sized to match Ahuroa's physical injection rate rather than the theoretical reservoir working gas capacity. The injection rate of 0.60 MCM per day over 196 days per year gives a base case annual hydrogen production of 10,572,240 kg. The required electrolyser power is calculated from this production target divided by the hydrogen LHV of 33.3 kWh/kg and the electrolyser efficiency of 66%, giving 60.9 MW for the base case operating continuously on grid electricity. The annual electrolyser OPEX has two components: maintenance at 3% of CAPEX per year and electricity cost, which is calculated by dividing the energy needed to produce the annual hydrogen output by the electrolyser efficiency and multiplying by the electricity price. Storage OPEX covers four categories: production operations, facility management, depreciation, and indirect expenses. Chinese unit costs from Deng et al. (2025) are normalised to New Zealand by replacing labour rates with NZ engineering salaries of NZD 100,000 per person per year and scaling volume-dependent cost items from the reference injection volume of 300 MCM per year to Ahuroa's actual 90 MCM per year.

Storage conversion CAPEX is derived from Deng et al. (2025), with a 12% contingency and residual asset value credit. Equipment reusability differs by scenario: 60% base case (CUGS), 70% optimistic (CUGS), 15% conservative (CDGR-equivalent). Storage OPEX is adapted from Deng et al. (2025) Table 3, with domestic labour replacement at NZD 100,000/person/year and volume scaling at 0.30 from 300 MCM/year to 90 MCM/year; Ahuroa actual from (Contact Energy Limited, 2023).

Electrolyser capacity is sized to match Ahuroa's injection rate from Contact Energy Limited (2023):

$$M_{H2base} = 0.60\frac{MCM}{day} \times 196\frac{days}{yr} \times 89{,}900\frac{kg}{MCM} \quad (5)$$

$$Capacity\,(kW) = M_{H2} \times LHV \,/\, efficiency \,/\, operating\_hours \quad (6)$$

With LHV = 33.3 kWh/kg, efficiency = 0.66, and 8,760 hrs/yr, giving 60.9 MW base case. Electrolyser OPEX has two components: maintenance at 3% of CAPEX (International Energy Agency, 2024) and electricity cost:

$$OPEX_{elec_{electricity}} = M_{H2gross} \times LHV \,/\, efficiency \times P_{elec} \quad (7)$$

Three scenarios are defined with constant financial parameters across all. Table 1 summarises the scenario-specific inputs.

Table 1. Scenario definitions

Parameter	Conservative	Base Case	Optimistic
MH2 basis	Injection-constrained (Contact Energy Limited, 2023)	Injection-constrained (Contact Energy Limited, 2023)	Working gas 1.40 TWh
MH2 gross (kg/yr)	10,572,240	10,572,240	42,042,042
Equipment reusability	15% (CDGR)	60% (CUGS)	70% (CUGS)
Storage CAPEX net (NZD $M)	81.50	58.89	53.86
Electrolyser CAPEX rate (USD/kWe)	2,160	2,160	960
Electrolyser CAPEX (NZD $M)	285.80	223.60	395.18

3.3. CCGT integration, and LCOE and Carbon breakeven price calculations

The LCOE for hydrogen-fuelled electricity at TCC is calculated as follows:

$$LCOE_{H2} = \left(LCOH \times H_{2\,consumption}\right) + \frac{OM_{fixed}}{MWh} + OM_{variable} + \left(CAPEX_{retrofit} \times CRF\right) \quad (8)$$

Where LCOH is the hydrogen cost from the production and storage module in NZD per kg, $H_{2\,consumption}$ is the kilograms of hydrogen needed per MWh of electricity calculated from the CCGT efficiency and hydrogen LHV, OM_{fixed} is the annual fixed maintenance cost divided by annual electricity output to give a per-MWh cost, $OM_{variable}$ is the variable maintenance cost per MWh, and the product of $CAPEX_{retrofit}$ and CRF annualises the one-time cost of converting TCC for hydrogen combustion. Hydrogen consumption per MWh is 1,000 divided by the product of LHV and CCGT efficiency, giving 52.96 kg per MWh. This means each MWh of electricity from hydrogen fuel requires approximately 53 kg of hydrogen, a much larger fuel mass than natural gas requires for the same output, because hydrogen has lower volumetric energy density despite its high gravimetric energy content.

$$H_{2\,consumption} = 1{,}000 \,/\, (LHV \times CCGT_{efficiency}) \quad (9)$$

CCGT efficiency on hydrogen is assumed equal to 56.7% (MR2016), consistent with Garcia and Guedez (2025). Retrofit capital of NZD 35.43M is EUR 50/kW$_{el}$ (Garcia and Guedez, 2025, Table B1) annualised at 8% over 20 years. For natural gas the formula simplifies to:

$$LCOE_{NG} = Price_{NG} \times heatrate + OM_{fixed}/MWh + OM_{variable} \quad (10)$$

Where Price$_{NG}$ is the gas price in NZD per GJ and heat rate is 3.6 divided by the CCGT efficiency, giving 6.349 GJ per MWh. This is the energy that must be purchased as gas to generate one MWh of electricity. No retrofit term applies because TCC already runs on natural gas.

The carbon price breakeven is calculated as:

$$Carbon\_price\_breakeven = \frac{(LCOE_{H2} - LCOE_{NG})}{CO_{2_{factorNG}}} \quad (11)$$

Where $CO_{2factorNG}$ is the carbon dioxide emitted per MWh of natural gas electricity at 0.35 tonnes per MWh. This formula tells how high the carbon price on natural gas emissions would need to be before the cost advantage of natural gas disappears and hydrogen becomes equally competitive. Hydrogen combustion produces no direct CO_2, so its LCOE is unaffected as carbon prices rise.

4. Results and discussion

The analysis (see the supplementary material) confirms that Ahuroa maintains a stable cushion gas volume of 6,000 TJ across all 2,246 daily records, confirming the structural integrity of the reservoir seal. The seasonal injection pattern is consistent: Injection occurs predominantly in spring and summer (September to February), with withdrawal during autumn and winter (March to August). The maximum observed working gas volume of 1,070 TJ is consistent with the 0.352 TWh base case injection-constrained capacity.

Ahuroa's physical injection infrastructure, not the theoretical reservoir working gas capacity, limits annual hydrogen production. At 0.60 MCM/day, the facility can inject a maximum of 117.6 MCM of hydrogen per year, equivalent to 10,572,240 kg (0.352 TWh H_2), substantially below the theoretical base case working gas capacity of 0.60 TWh.

This constraint is not unique to Ahuroa. Deng et al. (2025) note that injection and withdrawal rates in converted gas storage facilities are determined by existing compressor capacity and wellbore flow characteristics, and that infrastructure upgrades represent a distinct CAPEX category from basic conversion costs.

The operational data also confirms that the cushion gas volume of 6,000 TJ is stable year-round and does not vary with injection or withdrawal cycles. This stability is important for the economic model because it confirms that no additional cushion gas investment is needed for the hydrogen conversion, the existing natural gas cushion can serve this function, which is one of the cost advantages of converting Ahuroa over developing a new site.

Table 2. Summary of key modelling assumptions

Assumption	Value Adopted
Project lifetime	30 years
Discount rate	8%
USD to NZD exchange rate	1.70 NZD/USD
EUR to NZD exchange rate	1.85 NZD/EUR
H2 withdrawal efficiency	90%
H2 diffusion loss rate	1% per year
H2 LHV	33.3 kWh/kg
Compression energy	2.2 kWh/kg
Electrolyser efficiency	66% LHV
Electrolyser annual OPEX rate	3% of CAPEX/year
Electrolyser operating hours	8,760 hrs/year
Electrolyser project lifetime	30 years
NZ electricity price	NZD 100/MWh (base)
NZ natural gas price	NZD 20/GJ (base)
CCGT efficiency on hydrogen	56.7% LHV
CO_2 emissions factor - NG CCGT	0.35 tCO_2/MWh
CCGT remaining plant life	20 years
NZ ETS carbon price	NZD 68/tCO_2
Water and oxygen costs/revenues	Excluded

4.1. LCOH results and sensitivity analysis

Table 3 presents the full LCOH breakdown. The base case LCOH of NZD 10.70/kg is the most data-grounded result, using injection-constrained MH_2 from operational records, current IEA electrolyser costs and storage costs normalised to Aotearoa New Zealand conditions. The conservative LCOH of NZD 13.27/kg reflects lower equipment reusability and a larger electrolyser. The optimistic LCOH of NZD 7.65/kg reflects IEA NZE 2030 electrolyser cost reduction and full working gas utilisation.

The conservative scenario has a higher LCOH than the base case despite both using the same injection-constrained MH_2 denominator. The difference comes from the conservative scenario having a larger electrolyser sized for the 0.45 TWh working gas target, producing a higher CAPEX and a lower storage infrastructure reusability of 15% compared to 60% in the base case, resulting in a higher net storage CAPEX. This means the conservative scenario pays more in annualised capital costs while recovering the same amount of hydrogen, which pushes the LCOH up. The optimistic scenario achieves a lower LCOH partly through lower electrolyser unit costs under IEA 2030 projections and partly because the much larger hydrogen output of 42 million kg per year spreads both the storage and electrolyser fixed costs over a far greater denominator.

Table 3. LCOH results and cost component breakdown

Component	Conservative	Base Case	Optimistic
Annualised storage CAPEX (NZD \$M/yr)	7.24	5.23	4.78
Annualised electrolyser CAPEX (NZD \$M/yr)	25.39	19.86	35.10
Storage OPEX (NZD \$M/yr)	13.32	13.32	13.32
Electrolyser OPEX (NZD \$M/yr)	76.76	60.05	223.98
C_{energy} (NZD \$M/yr)	2.07	2.07	8.24
$M_{H2effective}$ (kg/yr)	9,419,866	9,419,866	37,459,459
LCOH (NZD/kg)	**13.27**	**10.70**	**7.65**
Storage-only LCOH (NZD/kg)	1.95	2.22	0.73

Electrolyser electricity cost accounts for NZD 53.34M/year (89%) of total electrolyser OPEX in the base case, confirming the International Energy Agency (2024) finding that electricity is the major LCOH driver for electrolytic hydrogen. Storage OPEX of NZD 13.32M/year is the second largest component. Annualised storage CAPEX of NZD 5.23M/year in the base case is a relatively minor cost once spread over 30 years, demonstrating that storage infrastructure conversion is not the primary economic barrier for Ahuroa UHS.

Table 4 compares LCOH results against New Zealand and international benchmarks. The production-only benchmarks (MBIE, EECA) and combined production-plus-storage results (this study) must be carefully distinguished in interpretation.

The base case production component of the LCOH is NZD 8.48/kg, within the MBIE near-term range of NZD 6-10/kg. The full base case LCOH of NZD 10.70/kg exceeds this by NZD 2.22/kg, precisely the storage-only LCOH component. The storage-only LCOH of NZD 2.22/kg sits at the upper end of the Yousefi et al. (2023) range of NZD 1.07-1.92/kg, with the difference attributable to higher NZ construction costs and smaller facility scale.

Figure 1 shows that the electricity price is the dominant parameter in the sensitivity analysis with a total LCOH swing of NZD 10.59/kg, more than all other five parameters combined. At NZD 70/MWh the base case LCOH falls to NZD 8.91/kg, within the MBIE benchmark. The negligible impact of storage CAPEX (NZD 0.26/kg swing) and H2 loss rate (NZD 0.16/kg) confirms that storage geology and infrastructure parameters do not require further precision at pre-feasibility level.

Table 4. LCOH benchmark comparison

Benchmark	NZD/kg	Scope	Source
MBIE NZ near-term	6-10	Production only	(Ministry of Business and Employment, 2022)
EECA current indicative	8	Production only	(Energy Efficiency and Conservation Authority, 2024)
EECA 2050 target	2	Production only	(Energy Efficiency and Conservation Authority, 2024)
Lord et al. (2014)	3.23	Storage only	(Lord et al., 2014)
Yousefi et al. (2023) range	1.07-1.92	Storage only	(Yousefi et al., 2023)
This study - Conservative	**13.27**	**Production + Storage**	This study
This study - Base Case	**10.70**	**Production + Storage**	This study

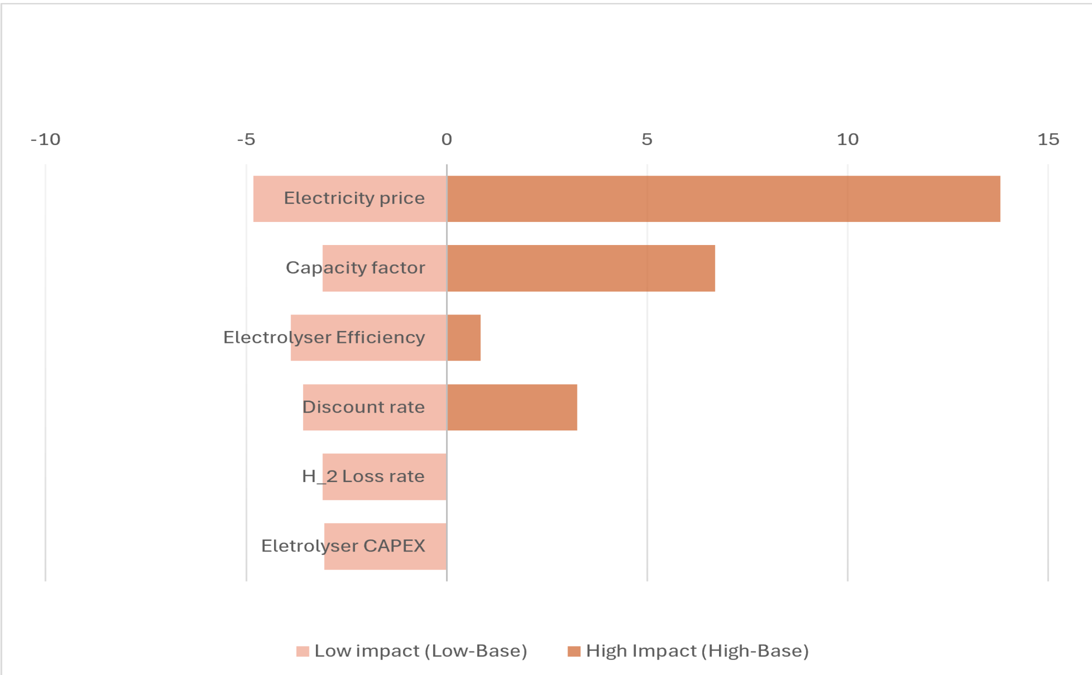

Figure 1. Tornado chart showing LCOH sensitivity to six parameters; electricity price dominates with a total swing of NZD 10.59/kg

The sensitivity results have a practical implication for where research and policy effort should focus. Electricity price and working gas capacity together account for over 80% of total LCOH variability across all parameters tested. This means that improving geological reservoir models or refining storage cost estimates, while academically useful, would not materially change the economics. The most impactful interventions are those that reduce the electricity price faced by the electrolyser or that increase the volume of hydrogen produced annually. Both are addressable through policy rather than further site characterisation.

4.2. CCGT integration and LCOE results

Table 5 presents the LCOE results. Hydrogen-fuelled electricity is 3 to 5 times more expensive than natural gas generation across the scenarios. Fuel cost accounts for 97% of hydrogen LCOE in the base case (see Figure 2). Retrofit cost contributes only NZD 3.37/MWh , less than 1% , confirming that CCGT plant modification is not a material barrier to hydrogen-fuelled generation.

Table 5. LCOE results and cost competitiveness

Metric	Natural Gas	Conservative	Base Case	Optimistic
Fuel cost (NZD/MWh)	127.0	702.8	566.6	405.2
Fixed O&M (NZD/MWh)	8.87	8.87	8.87	8.87
Variable O&M (NZD/MWh)	4.48	4.48	4.48	4.48
Retrofit CAPEX (NZD/MWh)	0	3.37	3.37	3.37
LCOE (NZD/MWh)	**140.3**	**719.5**	**583.4**	**421.9**
Cost gap vs NG (NZD/MWh)	—	579.2	443.1	281.6
Ahuroa supply of TCC demand (%)	—	16.6%	16.6%	66.0%

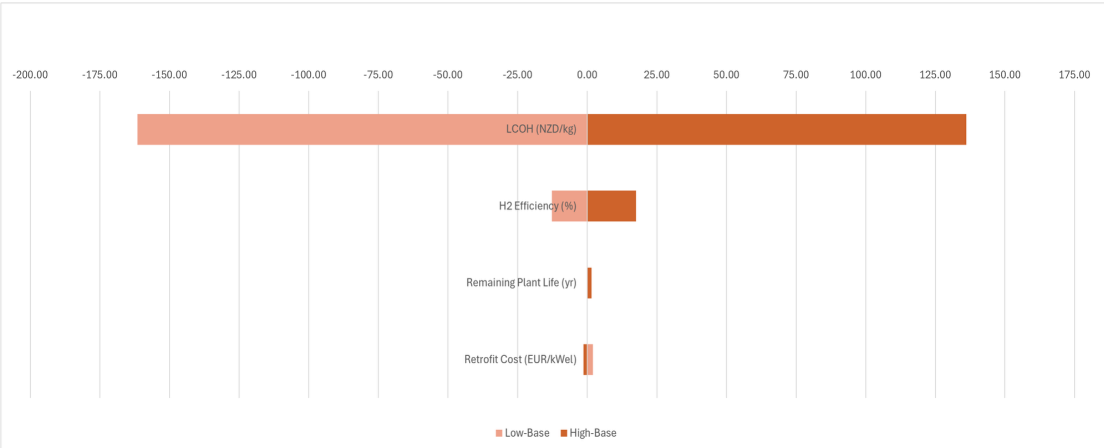

Figure 2. Tornado chart showing LCOE sensitivity to key parameters. LCOH, driven by electricity price is the dominant driver of hydrogen LCOE at TCC

It is important to note that the natural gas LCOE of NZD 140.3 per MWh is already above the current average wholesale electricity price of NZD 100 per MWh. This is because the natural gas LCOE includes the full cost of the fuel at NZD 20 per GJ plus fixed and variable O&M. The NZ wholesale electricity price of NZD 100 per MWh represents the market clearing price, not the cost of any specific generation technology. TCC sells electricity at the wholesale price, but its actual cost of generation depends on gas price and plant costs. The comparison between hydrogen LCOE and natural gas LCOE is therefore a comparison of generation costs, what it costs to produce one MWh from each fuel, rather than a comparison with the market price.

The fundamental driver of hydrogen's high fuel cost is round-trip energy conversion efficiency. The electrolyser-storage-CCGT pathway has a combined efficiency of 0.66 x 0.90 x 0.99 x 0.567 = 33.4%. At a flat electricity price of NZD 100/MWh, the project pays for input electricity and recovers only NZD 33.4/MWh in output value, a structural energy value loss that confirms the economic barrier is thermodynamic rather than a cost procurement problem. Ahuroa supplies only 16.6% of TCC's total hydrogen fuel demand in the base case, underscoring that Ahuroa is a partial contributor to a hydrogen fuel system rather than a complete solution for TCC decarbonisation.

This round-trip efficiency of 33.4% means Ahuroa UHS is best understood as a long-duration energy storage system rather than an energy arbitrage system. In an arbitrage system inexpensive energy is bought and sold when expensive, profiting from the price difference. Ahuroa cannot do this profitably at flat electricity prices because too much energy is lost in the conversion. To break even on energy value alone, the selling price of electricity would need to be at least three times the buying price, a price spread unlikely to be sustained in the wholesale market as renewable penetration increases. Its value is instead in providing energy that is available on demand regardless of weather or season, the same function as a reservoir behind a dam, which also loses energy through evaporation and flow losses but is valued for its dispatchability rather than its round-trip efficiency.

4.3. Carbon price analysis

Table 6 presents the carbon price breakeven analysis across scenarios and gas price assumptions.

Table 6. Carbon price breakeven across scenarios and gas price assumptions

Gas Price (NZD/GJ)	NG LCOE (NZD/MWh)	Breakeven Conservative	Breakeven Base	Breakeven Optimistic
9.31 (2023 MBIE wholesale)	72.5	1,849	1,460	998
20.0 (RETA 2025 base)	140.3	1,655	1,266	804
26.5 (MBIE 2024 commercial)	181.6	1,537	1,148	687
45.0 (RETA 2025 LNG scenario - 2035)	299.1	1,201	812	351

The carbon price breakeven table shows results for four different gas price assumptions because the gas price directly sets the baseline cost of natural gas electricity. As the gas price rises, natural gas LCOE rises and the gap that must be closed by carbon pricing narrows. This means the carbon price breakeven falls as gas prices rise, not because hydrogen becomes cheaper, but because natural gas becomes more expensive. The New Zealand gas market context is therefore directly relevant to the carbon price analysis. If gas prices continue rising toward the RETA 2035 LNG scenario, the required carbon price for competitiveness falls substantially even without any change in hydrogen costs or policy.

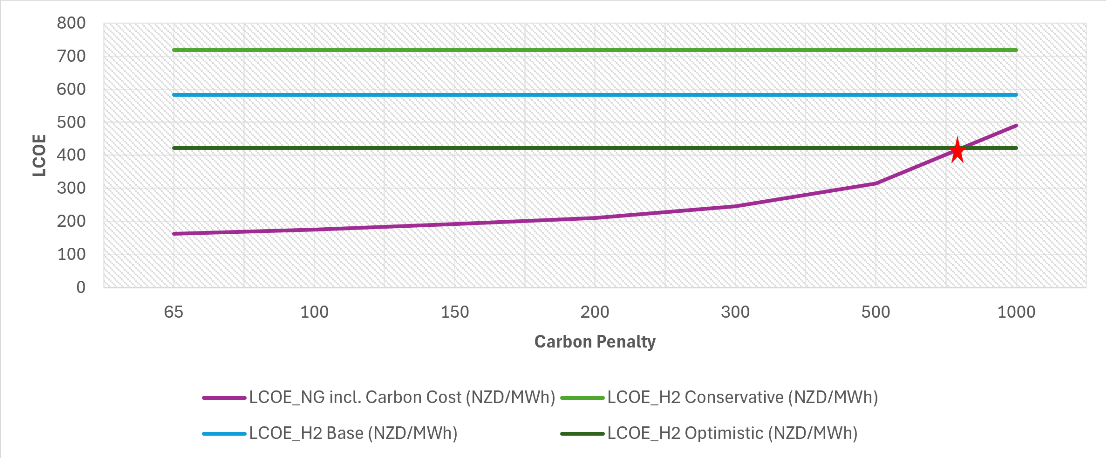

Figure 3. Effect of NZ ETS carbon price on natural gas LCOE relative to hydrogen LCOE across three scenarios. The red star marks the optimistic scenario intersection at approximately NZD 800/tCO_2

The current ETS price of NZD 68/tCO_2 (International Carbon Action Partnership, 2025) adds only NZD 23.8/MWh to the natural gas LCOE. This is negligible against the base case cost gap of NZD 443/MWh. Garcia and Guédez (2025) reach a similar conclusion in the European context, finding that even at EUR 80/tCO_2 EU ETS carbon pricing, hydrogen break-even requires electricity prices well below the grid average. ETS prices are currently approximately EUR 40/tCO_2 equivalent the New Zealand situation more challenging than the European reference.

The interaction between rising gas prices and carbon pricing creates a more nuanced picture. At a gas price of NZD 45/GJ (RETA(2025) LNG import scenario for 2035), the natural gas LCOE reaches NZD 299/MWh and the optimistic scenario carbon breakeven falls to NZD 351/tCO_2. While still above any near-term NZ ETS price, this represents a plausible longer-term trajectory. Combining the RETA 2035 gas price with IEA NZE 2030 electrolyser costs and renewable PPA electricity access at NZD 70/MWh, the optimistic scenario approaches a carbon breakeven of approximately NZD 300/tCO_2, still a significant policy gap but one that falls within the range of ambitious longer-term carbon pricing scenarios discussed internationally.

The base case LCOH of NZD 10.70/kg would require support of NZD 2-8/kg H_2 to reach the MBIE benchmark of NZD 6-10/kg, substantially larger than the US IRA production tax credit of USD 3/kg (approximately NZD 5.10/kg). This confirms that an Aotearoa New Zealand hydrogen support scheme corresponding to or larger than the US equivalent would be required to make Ahuroa economically viable in the near term, and that carbon pricing alone is insufficient regardless of its trajectory.

5. Conclusion

This study presents the first site-specific techno-economic assessment of underground hydrogen storage at the Ahuroa depleted gas field in the Taranaki region of Aotearoa New Zealand, integrated with the Taranaki combined cycle power station.

Ahuroa satisfies the physical prerequisites for UHS conversion, with confirmed reservoir parameters, stable cushion gas, and an operational pipeline to TCC. The central original finding is that the physical injection rate of 0.60 MCM/day, identified from 2,246 daily operational records, is the binding constraint on hydrogen production, limiting base case output to 10,572,240 kg/year. The base case LCOH of NZD 10.70/kg is consistent with international early-stage green hydrogen benchmarks, and the storage-only component of NZD 2.22/kg is consistent with Lord et al. (2014) and within the range of Yousefi et al. (2023). The project is not commercially viable on wholesale electricity market terms under current conditions. It tells that market or policy conditions are needed to make Ahuroa viable, and it demonstrates that the storage infrastructure itself is not the barrier. The barrier is the energy transformation cost and addressing that barrier requires either access to inexpensive electricity, a mechanism that pays for grid security value, or direct production support. Hydrogen LCOE ranges from NZD 422 to NZD 720/MWh against NZD 140/MWh for natural gas, with round-trip conversion efficiency of 33.4% the fundamental barrier. The NZ ETS at NZD 68/tCO_2 adds only NZD 23.8/MWh to natural gas cost negligible against the cost gap, confirming that carbon pricing alone is insufficient. Commercial viability requires a combination of low-cost renewable electricity, rising gas prices, direct production support, and capacity payments that recognise the grid security value of seasonal storage.

5.1. Recommendations for policy-makers

The following recommendations are made for Aotearoa New Zealand energy policy:

- The best way to lower the LCOH at Ahuroa is to decrease the electricity price paid by the electrolyser. Access to off-peak renewable electricity through a dedicated Power Purchase Agreement at around NZD 70/MWh would bring the base case LCOH below the MBIE production benchmark without any other changes. The Electricity Authority should investigate whether current market rules support this type of deal for hydrogen producers.
- The wholesale electricity market currently does not recognize the value of having months' worth of dispatchable backup generation available during dry years or long periods of low wind. Ahuroa can provide this type of seasonal storage that batteries and pumped hydro cannot. A capacity payment for this grid security role would improve the project's economics and should be considered by the Electricity Authority.
- NZGIF currently supports clean energy projects in Aotearoa New Zealand. Including UHS conversion projects as eligible would allow Ahuroa to access concessional financing at a lower interest rate than commercial debt, which directly lowers the annualized capital cost.
- Aotearoa New Zealand lacks a green hydrogen production incentive similar to those in the United States or Europe. Without some form of production support, the economics shown in this study make it unlikely that a project like Ahuroa would move forward commercially in the near term. MBIE should consider a limited-time production incentive to support first-of-a-kind projects and generate real cost data for NZ-specific hydrogen policy.
- The injection infrastructure at Ahuroa is the main constraint on how much hydrogen the facility can produce each year. Upgrading the injection compressors to allow higher flow rates would significantly boost annual hydrogen output and improve the project's economics.

5.2. Study limitations and recommendations for further research

Several limitations apply to this study. Storage CAPEX and OPEX unit costs are derived from a Chinese reference facility (Deng et al., 2025) and converted to Aotearoa New Zealand conditions using exchange rates and normalisation adjustments; actual procurement and contractor costs may be higher given the country's remote location and lack of domestic hydrogen infrastructure manufacturing. The IEA electrolyser CAPEX is a global average reflecting predominantly Chinese supply chains and may understate import and installation costs. The LCOE analysis uses average annual electricity and gas prices rather than a dynamic dispatch model, meaning the option value of hydrogen storage during peak scarcity events is not captured and the economics are likely understated for grid security purposes. Microbial hydrogen consumption in reservoir fluids is not explicitly modelled, with the 1% loss rate from Pan et al. (2021) covering diffusion only; actual losses could be higher. Finally, a direct economic comparison between Ahuroa underground hydrogen storage and the above-ground ammonia storage proposed by WSP (2022) was not conducted in this study and is recommended for future work.

The study also does not model the time-varying value of hydrogen storage. In reality, hydrogen stored during low-demand periods and released during high-demand or low-renewable periods has a higher effective value than the average wholesale electricity price suggests. A dynamic dispatch model incorporating electricity price distributions and dry-year probability would likely show more favourable economics than the static annual average analysis presented here. This is identified as the most important area for future work.

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