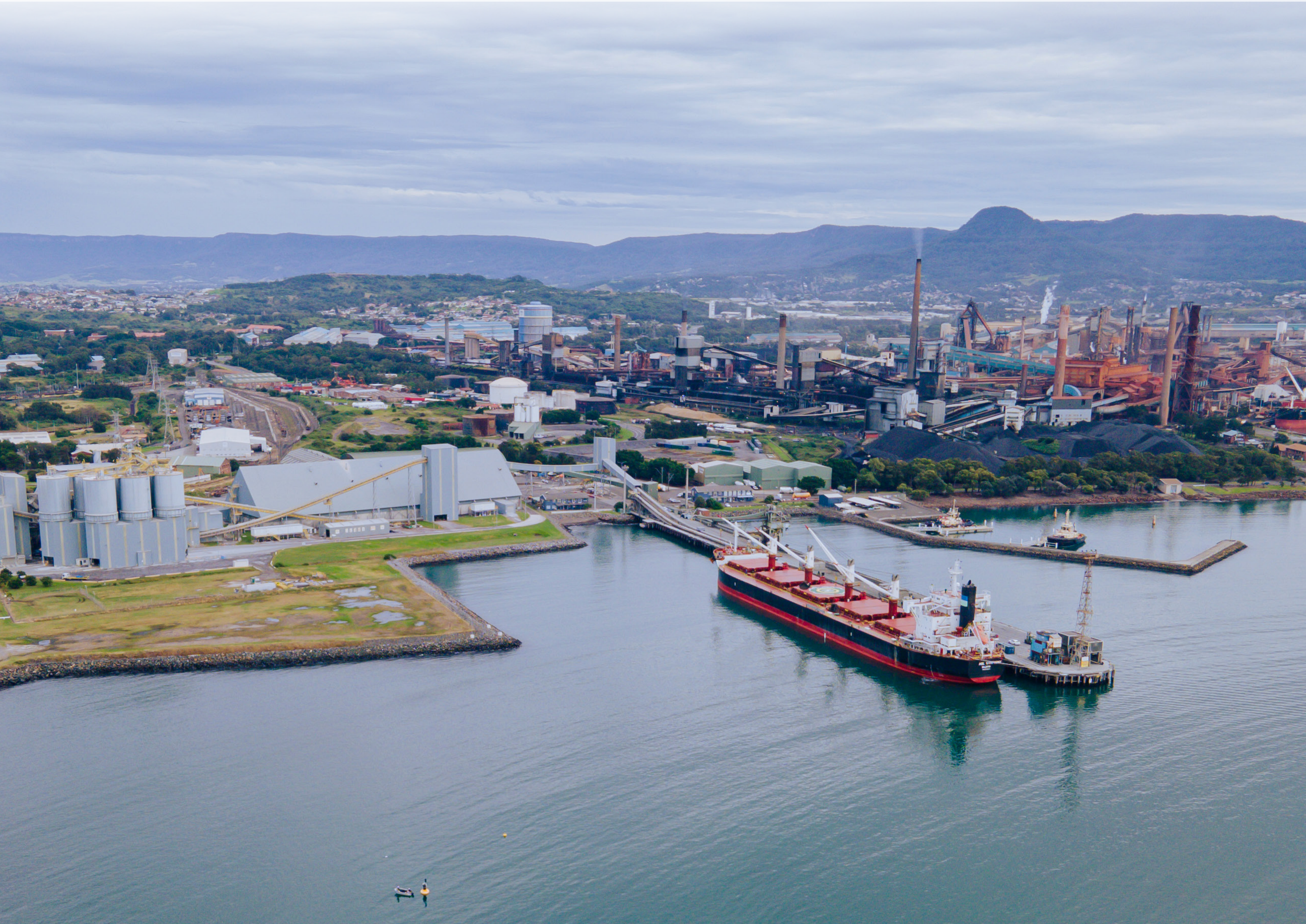
Australia's National Science Agency

The State of Energy Transition Technologies

Levelised cost analysis

TECHNICAL APPENDIX

December 2025



Citation and authorship

CSIRO (2025) The State of Energy Transition Technologies: Australian research, development and demonstration (RD&D) opportunities. CSIRO, Canberra.

This report was authored by Vivek Srinivasan, Melissa Craig, Erin McClure, Philippa Clegg, Monica Jovanov, Angus Grant, Rosie Dollman, Doug Palfreyman, Katie Shumilova.

CSIRO Futures

At CSIRO Futures we bring together science, technology, and economics to help governments and businesses develop transformative strategies that tackle their biggest challenges. As the strategic and economic advisory arm of Australia's national science agency, we are uniquely positioned to transform complexity into clarity, uncertainty into opportunity, and insights into action.

Acknowledgement

CSIRO acknowledges the Traditional Owners of the land, sea, and waters, of the area that we live and work on across Australia. We acknowledge their continuing connection to their culture, and we pay our respects to their Elders past and present.

CSIRO and the authors are grateful to individuals or organisations that generously gave their time to provide input to this project through Steering Committee meetings, consultations, reviews and feedback as well as scientists and researchers from CSIRO. We would also like to thank the Australian Council of Learned Academies (ACOLA) for their input and support. This is a CSIRO report and should not be taken as representing the views or policies of individuals or organisations consulted.

We would like to thank the Steering Committee, Peter Mayfield, Dietmar Tourbier, Helen Brinkman, Stephen Craig, Stuart Whitten, James Deverell, Ben Creagh, Lukas Young and Sandra Oliver, and the Energy Economics team at CSIRO, Paul Graham, Jenny Hayward, Luke Reedman and James Foster, for their input. We would also like to specifically thank Dominic Banfield, Andrew Beath, Brian Clennell, Stephen Craig, Jason Czapla, Claudia Echeverria Encina, Sarb Giddey, Peter Grubnic, Adrien Guiraud, Chad Hargrave, Patrick Hartley, Andrew Higgins, Allison Hortle, Tara Hosseini, Nikolai Kinaev, Chris Knight, Daniel Lane, Jim Patel, Fiona Scholes, Vahid Shadravan, Max Temminghoff for their advice and feedback.

Contents

1 Methodology

Levelised cost analysis was conducted for all use cases to provide a relative comparison of the long-term feasibility of technology options and identify *Primary technologies*. Given the difference in methodology, assumptions and uncertainties across sources for different technologies, the levelised cost results should be used to gauge the relative cost of technologies under the set of assumptions used in this report, rather than represent the absolute cost of a particular technology. This section outlines the cost analysis methodology for each use case. Projected costs in 2025 and 2050 are used to capture a technology's potential to be a short-term or long-term solution, respectively.

Technologies that progressed through the LC analysis were classified as *Primary technologies*. Technologies that did not progress through the framework are not precluded from playing a role in the transition, as continued development may improve their future competitiveness and viability.

1.1 Levelised cost methodology

Each of the cost models determines the levelised cost of output for each of its proposed technologies. The levelised cost of output is defined as the Net Present Value (NPV) of all costs of the asset per unit of output over the asset's lifetime (Equation 1). Costs are annualised, adjusted to a common price year and then discounted to arrive at a present value of future cash flows.

Each unit of output is specific to the operational profile of the subsector and use case. The time series of annual output is discounted in line with the costs and used to calculate the cost per unit of output.

Equation 1: General levelised cost definition

$$Levelised\ cost\ (LC) = \frac{NPV\ of\ total\ asset\ costs\ over\ its\ lifetime}{NPV\ of\ asset\ output\ over\ its\ lifetime}$$

Equation 2: Levelised cost equation

$$LC\left[\frac{c}{Output_t}\right] = \frac{\sum_{t=1}^{n} \frac{Capital\ Cost_t + Fuel\ Cost_t + CO2\ Cost_t + Fixed\ OPEX_t + Variable\ OPEX_t}{(1+d)^t}}{\sum_{t=1}^{n} \frac{Output_t}{(1+d)^t}}$$

Where:

- *t* is the year of operation
- *Capital Cost* is the cost for any capital payments in year t, which may include interest charges
- *Fuel Cost* reflects the cost of fuel production, distribution and storage
- *CO_2 Cost* reflects a cost of CO_2 emissions consistent with the IEA NZE scenario in 2050 (this is assumed to be zero in 2025)
- *Variable opex* reflects operating costs which vary with output (other than Fuel and CO_2 costs)
- *Fixed opex* reflects operating costs that are not directly associated with output
- *Output* is a quantifiable service or product delivered (e.g., electricity generated, freight moved, goods produced), variable by use case.
- *n* is the economic life of system (years)
- *d* is the discount rate (% per annum).

The cost components included are a combination of capital expenditures (‘capex’) and operating expenditures (‘opex’) and are dependent on the sector, use case and technology.

Capex is calculated using a financing approach, to account for the cost of capital. The capital cost component includes the NPV of the stream of annual repayments (principal and interest) accrued over the duration of the loan, as well as the residual value of the technology at the end of the appraisal period. The approach used for the aviation sub-sector uses available industry data on annual depreciation and leasing charges.

Opex account for all fixed and variable costs required to maintain the asset over its lifetime. For example, for road transport assets, fixed costs include insurance and registration costs, and variable costs include maintenance and tyres. As the objective of the cost analysis is to demonstrate relative costs of each technology within a use category, this analysis prioritised the inclusion of costs that vary depending on the technology.

2 Levelised cost model key assumptions and sources

2.1 Core assumptions

Across all cost models:

- All prices presented in this appendix are in 2024 AUD, unless otherwise noted.
- The CO_2 cost is adapted from IEA forecasts to achieve net zero for advanced economies, adjusted to a 2024 price year.
- Hydrogen feedstock assumptions are consistent with the levelised cost of hydrogen calculated for alkaline electrolysis / proton exchange membrane electrolysis, except where otherwise specified.

For all demand-side technologies:

- A structured approach has been developed to define input electricity cost assumptions, which are summarised in Table 2 and Table 3. These assumptions are designed to capture the potential variation in electricity costs across different end uses.

Table 1: Core assumptions across all models

Assumption		
Discount rate	7.0%	
Price year	2024	
USD to AUD currency conversion	0.66	
Euro to AUD currency conversion	0.61	
GBP to AUD currency conversion	0.54	
Carbon emission cost[1]	2025	2050
	$0 / t CO2	$435 / t CO2

Table 2: Demand-side technologies - input electricity cost assumptions

		2025		2050	
Assumption		Electricity cost ($/kWh)	Rationale	Electricity cost ($/kWh)	Rationale
Wholesale electricity cost	*Fully firmed*	0.108	Aligned to 2024-25 DMO6 CL1 wholesale cost, averaged across distributors.	0.097	Based on CSIRO STABLE modelling of firmed renewable electricity wholesale cost in 2050.
	Partially firmed	n/a		0.072	Based on STABLE modelling of partially firmed renewable electricity to minimise levelised cost of hydrogen production. The modelled utilisation of electrolysers is also sourced from this STABLE modelling.

[1] The CO2 emission cost is applied to each tonne of emissions produced by a particular technology and contributes to the levelised cost of that technology in the long-term. As it serves as a proxy for government intervention, no CO2 emission cost has been assumed for the short-term. The costs are adapted from IEA to align with CSIRO modelling specifications in <https://www.iea.org/reports/world-energy-outlook-2023>.

Retail electricity cost	0.215	Assumed to cover costs in addition to wholesale electricity cost, such as network, environmental, retail and retail margin.	0.195	Assumed to cover costs in addition to wholesale electricity cost, such as network, environmental, retail and retail margin.
Levelised cost of charging infrastructure	-	Varies based on infrastructure output power and utilisation	-	Varies based on infrastructure output power and utilisation

Table 3: Demand-side technologies – input electricity cost component(s)

Sub-sector	Input electricity cost component(s)			Rationale
	Wholesale electricity cost	Retail electricity cost	Levelised cost of charging infrastructure	
Electricity generation	n/a	n/a	n/a	
Electricity storage	n/a	n/a	n/a	All electricity storage fuel assumptions are directly sourced from the CSIRO (2023) Renewable Energy Storage Roadmap, see Table 7.
Hydrogen production	✓			2050 wholesale electricity costs are based on STABLE modelling of partially firmed renewable electricity to minimise levelised cost of hydrogen production. The modelled utilisation of electrolysers is also sourced from this STABLE modelling.
Hydrogen storage		✓		
Road		✓	✓	
Aviation, Rail, Shipping		✓	✓	
Iron and steelmaking	✓			
Medium-temperature process steam	✓			
Mining heavy haulage		✓	✓	

2.2 Electricity

2.2.1 Key assumptions

Table 4: Electricity generation – Technologies[2]

ASSUMPTION	ELECTRICITY GENERATION			
	Capacity factor (%)[3]	Efficiency (%)	Economic life (years)	Construction (years)
Gas with CCS	71%	44%	25	2.0
Hydrogen reciprocating	20%	32%	25	1.0
Black coal with CCS	71%	30%	30	2.0
Biomass (small scale)	71%	29%	30	1.3
Biomass with CCS (large-scale)[4]	71%	25%	30	2.0
Nuclear (SMR)	71%	33%	30	4.4
Nuclear large-scale	71%	33%	30	5.8
Concentrated solar power (CSP)	64%	100%	30	1.8
Large-scale solar PV	26%	100%	30	0.5
Wind (onshore)	39%	100%	25	1.0
Wind (offshore, fixed)	2025: 46%, 2050: 50.5%	100%	25	3.0
Hydroelectricity	34%	100%	35[5]	5.0
Wave[4]	30%	100%	20	1.0

Table 5: Electricity generation – Fuels[6]

ASSUMPTION	ELECTRICITY GENERATION	
	2025	2050
Fuel price		
Black coal	$3.81 / GJ	$3.76 / GJ
Brown coal	$0.64 / GJ	$0.73 / GJ
Natural gas[7]	$16.1 / GJ	$14.1 / GJ
Hydrogen[8]	$61.0 / GJ	$32.9 / GJ

[2] Assumptions have been designed to broadly align with the 2024 ISP IASR Step Change scenario. They have been sourced from GenCost 2024-25 except where indicated: Graham P, Hayward J, Foster J (2025) GenCost 2024-25: Final report. CSIRO, Australia. When sourced from GenCost, alignment with the Step Change scenario is achieved by taking the midpoint of the GenCost Low and High assumptions.

[3] The midpoint of the GenCost capacity factor assumptions has been used. Refer to GenCost for a discussion on the choice of average capacity factors, noting in reality these will be influenced by site specific factors and market conditions.

[4] Levelised costs not supplied in GenCost, assumptions sourced from Costs 2023 Costs and Technical Parameter Review (Aurecon).

[5] 35-year economic life has been assumed for hydroelectricity generation. Capital costs are repaid in full over this period in line with the GenCost methodology. To recognise the potential for continued operation beyond this economic life, the residual value at the end of year 35 has been calculated and subtracted from the total operating cost in this year. The residual value is calculated using straight line depreciation over an 80-year asset life.

[6] Assumptions have been designed to broadly align with the 2024 ISP IASR Step Change scenario. Except where indicated, they have been sourced from Graham P, Hayward J, Foster J (2025) GenCost 2024-25: Final report. CSIRO, Australia.

[7] Natural gas price derived from AEMO's 2024 ISP Inputs and Assumptions Workbook as the average gas price in the Step Change scenario for new CCGT and OCGT generating stations: AEMO (2024) 2024 Integrated System Plan (ISP): Current Inputs, Assumptions and Scenarios. <https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios> (accessed 3 January 2025).

[8] Sourced from levelised cost of hydrogen production analysis, refer to the *Low Carbon Fuels* technical appendix.

ASSUMPTION	ELECTRICITY GENERATION	
	2025	2050
Biomass	$11.4 / GJ	$11.4 / GJ
Uranium	$1.21 / GJ	$0.6 / GJ

Table 6: Electricity storage – Technologies[9]

ASSUMPTION		ELECTRICITY STORAGE									
Technology	Technology type modelled	Power capital costs ($/kW installed)		Energy capital costs ($/kWh installed)		Efficiency (%)		Total cycles		Economic life (years)	
		2025	2050	2025	2050	2025	2050	2025	2050	2025	2050
Metal-ion batteries	Lithium-ion battery	604	351	259	170	81%	90%	6,000	7,300	20	20
Flow batteries	Vanadium redox flow battery	3,043	1,797	396	232	66%	72%	18,000	18,000	20	20
PHES		3,529	3,089	71	62	75%	81%	30,000	50,000	35[10]	35[1010]
CAES	Adiabatic system	2,462	2,078	131	65	60%	65%	30,000	50,000	30	30
Compressed hydrogen tank	350 bar	3,292	2,349	12	11	31%	37%	15,000	20,000	30	30
Underground hydrogen storage	Salt cavern; 100 bar	3,292	2,349	2	2	31%	37%	15,000	20,000	30	30
hTESe		2,162	1,125	56	29	42%	42%	30,000	30,000	30	30
eTESe		2,162	1,125	5	29	42%	42%	30,000	30,000	30	30

Table 7: Electricity storage – Fuels[11]

ASSUMPTION	ELECTRICITY STORAGE	
	2025	2050
Fuel price		
Electricity	$0.06 / kWh	$0.04 / kWh
Thermal energy	$0.05 / kWh_{th}	$0.02 / kWh_{th}

[9] Lithium-ion battery capital and operational costs have been sourced from: Graham P, Hayward J, Foster J (2025) GenCost 2024-25: Final report. CSIRO, Australia. PHES capital and operational costs have been directly sourced from: Graham P, Hayward J, Foster J (2024) GenCost 2023-24: Final report. CSIRO, Australia. All other assumptions are directly sourced from the CSRIO (2023) Renewable Energy Storage Roadmap: CSIRO (2023) Renewable Energy Storage Roadmap. <https://www.csiro.au/en/work-with-us/services/consultancy-strategic-advice-services/CSIRO-futures/Energy/Renewable-Energy-Storage-Roadmap>.

[10] 35-year economic life has been assumed for hydroelectricity generation. Capital costs are repaid in full over this period. To recognise the potential for continued operation beyond this economic life, the residual value at the end of year 35 has been calculated and subtracted from the total operating cost in this year. The residual value is calculated using straight line depreciation over an 80-year asset life.

[11] All electricity storage fuel assumptions are directly sourced from the CSIRO (2023) Renewable Energy Storage Roadmap: CSIRO (2023) Renewable Energy Storage Roadmap. <https://www.csiro.au/en/work-with-us/services/consultancy-strategic-advice-services/CSIRO-futures/Energy/Renewable-Energy-Storage-Roadmap> (accessed 12 December 2024).

2.2.2 Cost model components and sources

Electricity generation

USE CASE(S)	• Large-scale electricity generation (GenCost 2024-25)	
Costed component	**Notes**	**Base source(s)**
• Fuel costs, including the price of production, processing (if relevant), and transportation of feedstocks. • Fixed Opex, including scheduled maintenance and repairs, tax and insurances, labour costs, permits and licensing fees, and other miscellaneous fixed charges. • Variable Opex, including material replacement costs. • Capex, including equipment, construction and set-up costs. • CO_2 cost in 2050, applied to non-zero emission pathways such as coal and gas with CCS. CO_2 storage costs are included for CCS pathways. • Integration costs in 2025 for VRE technologies (i.e., CSP, solar PV, onshore and offshore wind).	• Capacity factors were calculated as the midpoint between low and high assumptions in GenCost 2024-25. • Integration costs were included for 2025, sourced from GenCost's 2024-25 modelled case on preparing for 90% VRE adoption and calculated as the midpoint of the integration costs for the Low and High scenarios. They were excluded for 2050 on the assumption that, if variable renewable generation technologies are widely adopted, the majority of renewable integration resources will already be established. • BECCS analysis does not include any credits for the net removal of CO_2 that this process could deliver as a co-benefit.	Base assumptions have been adapted from: • Graham et al. (2024) GenCost 2024-25. CSIRO.

Electricity storage

USE CASE(S)	- Short duration: 2 hours of electricity storage (394 annual cycles) - Medium duration: 12 hours of electricity storage (234 annual cycles) - Long duration: 48 hours of electricity storage (68 annual cycles)	
Costed component	**Notes**	**Base source(s)**
• Energy Capex, including cost of storage containment infrastructure and/or medium (mechanical, thermal or chemical storage), or battery cells and stacks (electrical storage). • Power Capex, including conversion equipment such as compressors, turbines, inverters or pumps. • Fixed Opex, see cost examples in *Electricity Generation* above. • Charging costs, based on electricity and thermal energy prices.	• Electricity prices are assumed to be lower than average wholesale prices, reflecting the likelihood that electricity will only be stored when generation exceeds demand. • A gas peaker plant has been modelled with a carbon price included in 2050, assuming its operation for an equivalent number of hours as the storage technologies in each use case • Round-trip efficiency assumptions capture the charging cost for converting the input energy into the required storage medium and then into the electricity output.	Base assumptions have been sourced from the CSIRO (2023) Renewable Energy Storage Roadmap unless otherwise noted.

2.3 Low Carbon Fuels

2.3.1 Key assumptions

Table 8: Hydrogen production – Technologies[12]

Assumption	Hydrogen production						
	Capacity factor (%)		Nameplate Capacity (t/day)		Economic life (years)	Construction time (years)	CO_2 captured (%)
Year	2025	2050	2025	2050			
AE	80%	60%	4.7t/day at 10MW	56t/day at 100MW	25	1	N/A
PEM	80%	60%	4.3t/day at 10MW	56t/day at 100MW	25	1	N/A
SMR with CCS	95%	95%	210t/day	500t/day	30	3	72%
Biomass with CCS[13]	96%	96%	120t/day	240t/day	30	3	87%
Natural hydrogen[14]	96%	96%	38t/day	77t/day	30	3	100%[15]
CST thermochemical[16]	90%	90%	100t/day	200t/day	30	3	N/A

Table 9: Hydrogen production – Fuels

Assumption	Hydrogen production	
	2025	2050
Fuel price		
Electricity[17]	$0.108 / kWh	$0.072 / kWh
Natural gas[18]	$16.1 / GJ	$14.1 / GJ
Biomass $100/t	$0.1 / kg	$0.1 / kg
Biomass $200/t	$0.2 / kg	$0.2 / kg

[12] Unless otherwise indicated, all hydrogen production cost assumptions are aligned with the NZE Post 2050 scenario and are directly sourced from: Graham P, Hayward J, Foster J (2024) GenCost 2023-24: Final report. CSIRO, Australia.

[13] Biomass with CCS cost assumptions are derived from Wu N, Lan K, Yao Y (2023) An integrated techno-economic and environmental assessment for carbon capture in hydrogen production by biomass gasification. Resources, Conservation and Recycling 188, 106693. https://doi.org/10.1016/j.resconrec.2022.106693

[14] Natural hydrogen cost assumptions are derived from Musa M, Hosseini T, Sander R, Frery E, Sayyafzadeh M, Haque N, Kinaev N (2024) Techno-economic Assessment of Natural Hydrogen Produced from Subsurface Geologic Accumulations. International Journal of Hydrogen Energy. doi.org/10.1016/j.ijhydene.2024.11.009

[15] CO_2 capture in the natural hydrogen pathway is assumed to occur as part of the process of purifying the extracted hydrogen. This differs from the CO_2 capture from syngas and/or flue gas used in the SMR and biomass pathways. Capture efficiency for the natural hydrogen pathway will depend on the purity of the natural hydrogen resource.

[16] CST thermochemical cost assumptions are derived from NREL (2020) Future central hydrogen production from solar thermo-chemical ferrite cycle version Oct 2020 model. <https://www.nrel.gov/hydrogen/h2a-production-models.html> (accessed 14 January 2025).

[17] Refer Tables 2 and 3.

[18] Refer Table 5.

Table 10: Hydrogen storage – Technologies

Assumption	Hydrogen storage					
	Efficiency (%)		Electricity consumption (kWh/GJ)		Fill rate (GJ/day)	
Year	2025	2050	2025	2050	2025	2050
Compressed hydrogen tank[19]	100%	100%	12.72	11.93	19,413	32,355
Underground hydrogen storage[20]	100%	100%	7.89	7.39	19,413	32,355
Capped pipe storage[21]	100%	100%	1.65	1.55	19,413	32,355
Cryogenic spheres[22]	100%	100%	0.01	0.01	19,413	32,355
e-ammonia tank[23]	90%	90%	2.03	2.03	19,413	32,355
e-methanol tank[24]	100%	100%	-	-	19,413	32,355

Table 11: Hydrogen storage – Fuels

Assumption	Hydrogen storage	
	2025	2050
Fuel price		
Hydrogen (Gaseous)[25]	$61.1 / GJ	$32.9 / GJ
Hydrogen (Liquid)[25]	$87.7 / GJ	$53.1 / GJ
Electricity[26]	$0.215 / kWh	$0.195 / kWh
e-ammonia[27]	$104 / GJ	$71.6 / GJ
e-methanol[28]	$200 / GJ	$84.9 / GJ

[19] Compressed hydrogen tank is modelled with 350 bar pressure. Cost assumptions are derived from Bruce S, Temminghoff M, Hayward J, Schmidt E, Munnings C, Palfreyman D, Hartley P (2018) National Hydrogen Roadmap. CSIRO, Australia. < https://www.csiro.au/en/research/environmental-impacts/fuels/hydrogen/hydrogen-roadmap> (accessed 14 January 2025); the Argonne National Laboratory (n.d.) Hydrogen Delivery Scenario Analysis Model (HDSAM). < https://hdsam.es.anl.gov/index.php?content=hdsam> (accessed 14 January 2025) ; Turton R (2021) Analysis, Synthesis, and Design of Chemical Processes, 5th ed. West Virginia University. <https://richardturton.faculty.wvu.edu/publications/analysis-synthesis-and-design-of-chemical-processes-5th-edition> (accessed 14 January 2025).

[20] Underground hydrogen storage is modelled as a salt cavern with 100 bar pressure.

[21] Hydrogen pipe storage is modelled with 30 bar pressure.

[22] Cost assumptions on cryogenic spheres are derived from Bruce S, Temminghoff M, Hayward J, Schmidt E, Munnings C, Palfreyman D, Hartley P (2018) National Hydrogen Roadmap. CSIRO, Australia. < https://www.csiro.au/en/research/environmental-impacts/fuels/hydrogen/hydrogen-roadmap> (accessed 14 January 2025); Turton R (2021) Analysis, Synthesis, and Design of Chemical Processes, 5th ed. West Virginia University. <https://richardturton.faculty.wvu.edu/publications/analysis-synthesis-and-design-of-chemical-processes-5th-edition> (accessed 14 January 2025).

[23] Cost assumptions on e-ammonia tanks are adapted from Methanol Institute (2020) Techno-economic assessment of zero-carbon fuels. <https://www.methanol.org/wp-content/uploads/2020/04/Techno_economic_assessment_of_zero_carbon_fuels.pdf> (accessed 13 January 2025).

[24] Cost assumptions on e-methanol tanks are adapted from Methanol Institute (2020) Techno-economic assessment of zero-carbon fuels. <https://www.methanol.org/wp-content/uploads/2020/04/Techno_economic_assessment_of_zero_carbon_fuels.pdf> (accessed 13 January 2025).

[25] Sourced from levelised cost of hydrogen production analysis, refer to the *Low Carbon Fuels* technical appendix.

[26] Refer Tables 2 and 3.

[27] Cost assumptions on ammonia cracking are derived from Restelli F, Spatolisano E, Pellegrini LA, de Angelis AR, Cattaneo S, Roccaro E (2024) Detailed techno-economic assessment of ammonia as green H2 carrier. Int. J. Hydrogen Energy 52A: 532–547. https://doi.org/10.1016/j.ijhydene.2023.06.206

[28] Cost assumptions on steam reforming are derived from Lee JS, Cherif A, Yoon HJ, Seo SK, Bae JE, Shin HJ, Lee C, Kwon H, Lee CJ (2022) Large-scale overseas transportation of hydrogen: Comparative techno-economic and environmental investigation. Renewable and Sustainable Energy Reviews 165:112556. https://doi.org/10.1016/j.rser.2022.112556; Rahatade SS, Mali NA (2023) Techno-economic assessment of hydrogen production via dimethyl ether steam reforming and methanol steam reforming. Chemical Engineering & Process Development Division, CSIR-National Chemical Laboratory, Pune, India; Academy of Scientific and Innovative Research (AcSIR), Ghaziabad, India.

2.3.2 Cost model components and sources

Hydrogen production

USE CASE(S)	• Large-scale (>50t/day) hydrogen production	
Costed component	**Notes**	**Base source(s)**
• Feedstock costs. These are technology-dependent and may include electricity, natural gas, biomass, water inputs, and heat. • Fixed Opex, see cost examples in *Electricity Generation* above. • Variable Opex, see cost examples in *Electricity Generation* above. • Capex, including equipment costs, site approvals and preparation costs, and return payment to investors. • CO_2 cost in 2050, applied to non-zero emission pathways such as SMR and biomass and waste conversion with CCS. CO_2 storage costs are included for CCS pathways.	• The modelled levelised cost of hydrogen production via biomass gasification does not include any credits for the net removal of carbon dioxide that this process could deliver as a co-benefit.	Base assumptions have been adapted from: • Biomass: Wu N, Lan K, Yao Y (2023) An integrated techno-economic and environmental assessment for carbon capture in hydrogen production by biomass gasification. doi.org/10.1016/j.resconrec.2022.106693. • Natural hydrogen production: Musa et al. (2024) Techno-economic assessment of natural hydrogen produced from subsurface geologic accumulations. doi.org/10.1016/j.ijhydene.2024.11.009 • Electrolysis: Graham et al. (2024) GenCost 2024-25. CSIRO. • CST thermochemical water splitting: Channel M, Lewandowski A, Weimer A (2018) Future central ferrite solar thermochemical hydrogen production ($NiFe_2O_4$ on ZrO_2). NREL.

Hydrogen storage

USE CASE(S)	- Short duration: 12hrs of energy storage, discharged 365 times per year; - Medium duration: 7 days of energy storage, discharged 12 times per year; - Long duration: 28 days of energy storage, discharged 3 times per year.	
Costed component	**Notes**	**Base source(s)**
- Feedstock costs, being the cost of hydrogen, as well as conversion into derivative carriers. - Energy Capex, including the costs for storage infrastructure or containment system. - Power Capex, including equipment for compression, liquefaction, reconversion etc. - Fixed Opex, see cost examples in *Electricity Generation* above. - Electricity costs, including the power consumption required for compression, refrigeration, and the retrieval of hydrogen.	As this analysis considers ammonia and methanol as hydrogen carriers, it considers the cost of producing, storing and reconverting the carrier to hydrogen for use.	Base assumptions have been adapted from: - Compressed hydrogen tank, cryogenic sphere: Graham et al. (2024) GenCost 2024-25. CSIRO. Pearson; Bruce et al. (2018) National Hydrogen Roadmap. CSIRO; Argonne National Lab (n.d.) Hydrogen delivery scenario analysis model (HDSAM). <https://hdsam.es.anl.gov/index.php?content=hdsam>. - Capped pipe storage: Turton et al. (2018) Analysis, synthesis, and design of chemical processes. Pearson. - Ammonia tank: Restelli et al. (2024) Detailed techno-economic assessment of ammonia as green H_2 carrier. doi.org/10.1016/j.ijhydene.2023.06.206. - Methanol tank: Rahatade SS and Mali NA (2022) Techno-economic assessment of hydrogen production via dimethylether steam reforming and methanol steam reforming. doi.org/10.1080/00194506.2022.2162450. - Underground hydrogen storage: Graham et al. (2024) GenCost 2024-25. CSIRO.

2.4 Transport

2.4.1 Key assumptions

Table 12: Transport – Fuels

Assumption	Transport			
Year	**2025**		**2050**	
Fuel price[29]				
Petrol	$2.05 / L	$0.06 / MJ	$2.05 / L	$0.06 / MJ
Diesel[30]	$2.05 / L	$0.06 / MJ	$2.05 / L	$0.06 / MJ
Renewable diesel[31]	$3.37 / L	$0.09 / MJ	$2.8 / L	$0.08 / MJ
Biomethane[32]	$4.19 / kg	$0.08 / MJ	$2.78 / kg	$0.06 / MJ
Jet A1	$0.88 / L	$0.03 / MJ	$0.88 / L	$0.03 / MJ
FT SAF – Fischer-Tropsch (from biomass)	$2.22 / L	$0.06 / MJ	$1.52 / L	$0.04 / MJ
HEFA SAF - Hydroprocessed esters and fatty acids (from veg oil)	$1.54 / L	$0.04 / MJ	$1.36 / L	$0.04 / MJ
ATJ SAF – Alcohol-to-jet (from ethanol)	$2.83 / L	$0.08 / MJ	$1.36 / L	$0.04 / MJ
PtL SAF – Power-to-liquids	$11.8 / L	$0.33 / MJ	$3.89 / L	$0.11 / MJ
MGO[33]	$0.69 / L	$0.02 / MJ	$0.62 / L	$0.02 / MJ
Methanol[34]	$3.14 / L	$0.2 / MJ	$1.34 / L	$0.08 / MJ
Ammonia[35]	$1.94 / kg	$0.1 / MJ	$1.34 / kg	$0.07 / MJ
Electricity price[36]				
Battery electric	$0.58 / kWh	$0.16 / MJ	$0.44 / kWh	$0.12 / MJ
Catenary electric	$0.22 / kWh	$0.06 / MJ	$0.19 / kWh	$0.05 / MJ
Gaseous hydrogen price[37]	$13.7 / kg	$0.11 / MJ	$6.96 / kg	$0.06 / MJ
Production	$7.32 / kg		$3.95 / kg	

[29] Jet A1, AtJ, FT diesel, HEFA and PtL prices derived from: https://www.csiro.au/en/research/technology-space/energy/sustainable-aviation-fuel.

[30] For rail and mining heavy haulage cost analysis, the excise tax component of the diesel price is removed. This component is assumed to be $0.50 per litre, the average excise rate in 2024 from: < https://data.gov.au/data/dataset/excise-data/resource/b9227cdf-4c04-492d-bd84-65031adc408e> (accessed 31 October 2025).

[31] Adapted from Ou L, Li S, Tao L, Phillips S, Hawkins T, Singh A, Snowden-Swan L, Cai H (2022) Techno-economic Analysis and Life-Cycle Analysis of Renewable Diesel Fuels Produced with Waste Feedstocks. ACS Sustainable Chemistry and Engineering 10, 382. doi:10.1021/acssuschemeng.1c06561

[32] Adapted from: <https://exchange.iseesystems.com/public/sam-culley/biomethane-viability-tool/index.html#page1> (accessed 23 July 2024). Assumptions used for 2025 fuel price: 29.2kt/year of cereal straw at $100/t delivered cost (including feedstock cost); plant output set at 2,000 NM3/hour; 50% utilisation. Assumptions used for 2050 fuel price: 292kt/year of cereal straw at $100/t delivered cost (including feedstock cost); plant output set at 10,000 NM3/hour.

[33] Adapted from CME Group, Singapore FOB Marine Fuel 0.5% (Platts) Futures Quotes. <https://www.cmegroup.com/markets/energy/refined-products/singapore-fob-marine-fuel-05-platts.quotes.html#venue=globex> (accessed 9 May 2024)

[34] Methanol formulation process uses carbon dioxide removal. Adapted from <https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2021/Jan/IRENA_Innovation_Renewable_Methanol_2021.pdf>; CSIRO modelling.

[35] CSIRO modelling.

[36] Refer Tables 2 and 3.

[37] CSIRO modelling, refer to the *Low Carbon Fuels* technical appendix.

Assumption	Transport			
Year	**2025**		**2050**	
Distribution	$6.41 / kg		$3.01 / kg	
Liquid hydrogen price[38]	$16.9 / kg	$0.14 / MJ	$9.37 / kg	$0.08 / MJ
Production	$7.32 / kg		$3.95 / kg	
Distribution	$6.41 / kg		$3.01 / kg	
Liquefaction	$3.19 / kg		$2.42 / kg	

Table 13: Road

Assumptions	Road transport		
Use case	**Light-duty**	**Medium-duty**	**Heavy-duty**
Annual distance travelled (km)[39,40]	11,124	39,193	148,837
Asset lifetime (years)[41]	12	12	12
Effective capacity[42]	1.7 pax	4.7t (4.1t BEV)	12t (10t BEV)

Table 14: Aviation

Assumptions	Aviation
Use case	**Medium range: 2-hour flight with 180 passengers**
Specification	Boeing 737-800
Daily distance travelled (km)	6,806
Asset lifetime (years)	15
Passengers	180 (2x 90 H_2)
Load factor	83%
Use case	**Short range: 1-hour flight with 18 passengers**
Specification	Beechcraft 1900D
Daily distance travelled (km)	2,700
Asset lifetime (years)	25
Passengers	18 (2x 9 Battery Electric)
Load factor	83%

[38] CSIRO modelling, refer to the *Low Carbon Fuels* technical appendix.

[39] The annual kilometres travelled assumption for a light-duty vehicle is the national average distance travelled by a light-duty vehicle sourced from the Australian Bureau of Statistics, Survey of Motor Vehicle Use, Australia (2020). Australian Bureau of Statistics, Survey of Motor Vehicle Use, Australia (2020).

[40] The annual kilometres travelled assumption for a medium-duty and heavy-duty vehicle is calculated as the average annual kilometres travelled over the asset life of a new rigid / articulated truck, respectively, and accounts for the typical variation in annual kilometres travelled over this asset life. These figures have been derived from Australian Bureau of Statistics, Survey of Motor Vehicle Use, Australia (2020); Bureau of Infrastructure and Transport Research Economics, Australian Infrastructure and Transport Statistics Yearbook 2023, Road Statistics, <https://www.bitre.gov.au/publications/2023/australian-infrastructure-and-transport-statistics-yearbook-2023> (accessed 04 March 2024).

[41] Vehicles are assumed to be sold at the end of this asset lifetime. This is accounted for in the calculation of levelised cost of transport, with the vehicle's depreciated value is used as the sale price.

[42] Maximum vehicle capacity is adjusted to an effective capacity to account for real world factors typical for each end use. In the light-duty end use this adjustment accounts for vehicle occupancy. In the medium-duty and heavy-duty end uses it accounts for the assumed proportion of backhauling (25% of return legs assumed to carry freight) and the reduced maximum payload capacity of BEV vehicles due to battery weight.

Table 15: Rail

Assumptions	Rail
Use case	**Short range rail: 700km return journey**
Specification	Diesel – 4 diesel locomotives; Renewable diesel – 4 diesel locomotives; Diesel-electric hybrid – 2 diesel locomotives, 2 electric locomotives; Battery-electric – 4 electric locomotives, 1 battery tender; Hydrogen fuel cell – 4 electric locomotives, 1 hydrogen tender; Catenary electric – 4 electric locomotives
Annual distance travelled (km)	127,750 (700km return trip every second day)
Asset lifetime (years)	20
Train length (carriages)	2000m (142 carriages, including tenders)
Use case	**Long range rail: 2,800km return journey**
Specification	Diesel – 4 diesel locomotives; Diesel-electric hybrid – 2 diesel locomotives, 2 electric locomotives, 3 battery tenders; Battery-electric – 4 electric locomotives, 15 battery tenders; Hydrogen fuel cell – 4 electric locomotives, 5 hydrogen tenders; Catenary electric – 4 electric locomotives
Annual distance travelled (km)	255,500 (2,800km return trip every 4 days)
Asset lifetime (years)	20
Train length (m)	2000m (142 carriages, including tenders)

Table 16: Shipping

Assumptions	Shipping
Use case	**Deep sea: freight ship**
Specification	5,000 TEU container ship, based on a Panamax ship
Annual distance travelled (km)[43]	23 x 12,100km trips (278,400km)
Asset lifetime (years)	25
Use case	**Short sea: short-sea ferry**
Specification	Modelled off a Spirit of Tasmania I and II ro-pax ferry[44]
Annual distance travelled (km)[45]	40,000 (400 one-way trips, each 100km in length)
Asset lifetime (years)	25

[43] The ship is assumed to travel at design speed (25 knots) and with four days allowed in port between each trip.

[44] The purchase price of this end-use case's ro-pax ferry is derived from the purchase price of the Spirit of Tasmania I & II, adjusted to match the energy requirements of this specific end-use case, https://ferriesoftasmania.com/tt-line/. The Spirit of Tasmania I & II's ship power and fuel usage requirements were sourced from https://www.spiritoftasmania.com.au/media/802022/2252_ttlineannualreport2022-23_vfinal-digital-v2.pdf (accessed May 27 2024)https://web.archive.org/web/20190304183806/https:/www.spiritoftasmania.com.au/media/717328/2018-ship-facts.pdf.

[45] The number of annual trips conducted by one ship in this model is the total number of Spirit of Tasmania trips, divided by the Spirit of Tasmania fleet size. Sourced from https://www.spiritoftasmania.com.au/media/802022/2252_ttlineannualreport2022-23_vfinal-digital-v2.pdf (accessed 27 May 2024).

2.4.2 Cost model components and sources

Road transport

USE CASE(S)	
	• Light-duty vehicle: a passenger car travelling 11,120km per year, carrying an average 1.7 passengers; • Medium-duty vehicle: a rigid truck travelling 39,200km per year with an effective capacity of 4.7t, when accounting for backhauling; • Heavy-duty vehicle: an articulated truck travelling 148,800km per year and an effective capacity of 12t, when accounting for backhauling.

Costed component	Notes	Base source(s)
• Fuel costs, including fuel excise. • Capex, including the cost of the fuel cell/engine/battery, balance of plant, and chassis. • Fixed Opex, including registrations and insurances (as a percentage of new vehicles). • Variable Opex, including tires and maintenance and servicing costs on a weighted basis. • CO_2 cost in 2050, applied to ICE vehicles using diesel, e-methanol, renewable diesel, or biomethane.	• Some cost components (such as logistics costs) are not included as they are common across all technologies and do not affect the relative costs of each technology option. • Where battery charging is considered, the price of electricity includes wholesale cost, a retail margin and a fast-charging infrastructure and operating cost to reflect the need for dedicated fast charging infrastructure.	• ABS (2020) Survey of motor vehicle use, Australia. • RACQ (2023) Private vehicle expenses 2023. <https://www.racq.com.au/-/media/project/racqgroup/racq/pdf/articles/news/2023/9/2023-running-costs-racq-final.pdf?rev=61307c2d5e6a42888451ffb5abe101a4&hash=D3C38144A4D84E86C603FF76861ED4AF>. • CSIRO (n.d.) Transport logistics-TraNSIT. https://benchmark.transit.csiro.au/ • Freight Metrics (n.d.) Truck operating cost calculator trial. <https://freightmetrics.com.au/truck-operating-cost-calculator-trial/>. • Manheim (2020) Heavy vehicles <https://www.manheim.com.au/opalcmsassets/manheim/linkreports/Heavy-Vehicles-AU.pdf> • RACQ (2023) Private vehicle expenses 2023. <https://www.racq.com.au/-/media/project/racqgroup/racq/pdf/articles/news/2023/9/2023-running-costs-racq-final.pdf?rev=61307c2d5e6a42888451ffb5abe101a4&hash=D3C38144A4D84E86C603FF76861ED4AF>. • BITRE (2023) Road. <https://www.bitre.gov.au/publications/2023/australian-infrastructure-and-transport-statistics-yearbook-2023/road#dl-data> Use case study parameters, including range, occupancy and effective capacity draw on data from the ABS (2020) Survey of Motor Vehicle Use and BITRE (2023) Australian Infrastructure and Transport Statistics Yearbook. • Fuel economies sourced from Argonne National Lab (2025) R&D Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET) Model 2024 Rev1. < https://greet.anl.gov/>.

Aviation

USE CASE(S)

- Boeing 737-800 aircraft, operating at a typical frequency of 6,806km distance per day and load factor of 83%, and with an assumed asset lifetime of 15 years;
- Beechcraft 1900D, operating at a typical frequency of 2,700km distance per day and load factor of 83%, and with an assumed asset lifetime of 25 years.

Costed component	Notes	Base source(s)
• Fuel costs. • Capex, including the cost of the fuel cell/engine/battery, balance of plant, and balance of aircraft. • Fixed Opex, including registrations and insurances (as a percentage of new aircraft). This includes labour costs and admin. • Variable Opex, including consumables, maintenance and servicing costs on a weighted basis. • CO_2 cost in 2050, applied to conventional fossil-based fuels (including hybrid systems) and biofuels (including blends).	• This analysis does not capture the cost of establishing refuelling infrastructure. • Where battery charging is considered, the price of electricity includes wholesale cost, a retail margin and a fast-charging infrastructure and operating cost to reflect the need for dedicated fast charging infrastructure. • Where hydrogen is considered as a fuel, fuel costs include the cost of liquefaction. • For *Rail* and *Shipping* analysis, payload reductions were calculated, where additional fuel storage was added at the expense of cargo capacity.	• Vasigh B and Azadian F (2022) Aircraft valuation in volatile market conditions: guiding toward profitability and prosperity. Springer Cham. doi.org/10.1007/978-3-030-82450-1 • Simple Flying (2022) Airbus CEO: the A220 is still gaining altitude. <https://airinsight.com/wp-content/uploads/2022/02/Airbus-CEO-The-A220-Is-Still-Gaining-Altitude.pdf> • SAF fuel prices: CSIRO (2023) Sustainable Aviation Fuel Roadmap. • Cost of ownership: Finger et al. (2019) Cost estimation methods for hybrid-electric general aviation aircraft. Conference paper. <https://www.researchgate.net/publication/337757069_Cost_Estimation_Methods_for_Hybrid-Electric_General_Aviation_Aircraft>. • Project NAPKIN (2022) Making zero-carbon emission flight a reality in the UK final report <https://www.heathrow.com/content/dam/heathrow/web/common/documents/company/about/future-flight-challenge/NAPKIN%20Long%20Report%20221028.pdf> Short range flight use case also references: • Marksel M and Brdnik AP (2023) Comparative analysis of direct operating costs: conventional vs. hydrogen fuel cell 19-seat aircraft. doi.org/10.3390/su151411271.

Rail

USE CASE(S)	
	• Short-range (700km) train with a 2000m-length, an assumed average annual travel distance of 127,750km per year, and an asset lifetime of 20 years; • Long-range (2,800km) train with a 2000m-length, an assumed average annual travel distance of 255,500km per year, and an asset lifetime of 20 years.

Costed component	Notes	Base source(s)
• Fuel costs, with the cost of fuel excise shown as a separate component. It is typically claimed back via a fuel tax credit for this use case. • Capex, including the cost of the fuel cell/engine/battery, balance of plant, and balance of vehicle. For Rail, this includes battery and fuel cell replacements for relevant systems. • Fixed Opex, including registrations and insurances (as a percentage of new locomotives). This includes labour costs and admin. • Variable Opex, including consumables, maintenance and servicing costs on a weighted basis. For Rail, this also includes Fixed Track Access Charges (FTAC) that contribute to maintenance of the track and associated infrastructure. • CO_2 cost in 2050, applied to conventional fossil-based fuels (including hybrid systems) and biofuels (including blends).	• This analysis does not capture the cost of establishing refuelling infrastructure, except in the case of the catenary electric train. • Where battery charging is considered, the price of electricity includes wholesale cost, a retail margin and a fast-charging infrastructure and operating cost to reflect the need for dedicated fast charging infrastructure. • Where hydrogen is considered as a fuel, fuel costs include the cost of liquefaction. • Payload reductions were calculated, where additional fuel storage was added at the expense of cargo capacity.	• Knibbe et al. (2022) Application and limitations of batteries and hydrogen in heavy haul rail using Australian case studies. doi.org/10.1016/j.est.2022.105813. • CSIRO (n.d.) Transport logistics-TraNSIT. <https://benchmark.transit.csiro.au/> • Queensland Rail (2024) Mount Isa Line Information Pack. <https://www.queenslandrail.com.au/forbusiness/the-regional-network/mount-isa-line-system> • Sahin et al. (2014) An approach for economic analysis of intermodal transportation. doi.org/10.1155/2014/630320. • Transport for NSW (2024) Transport for NSW economic parameter values.

Shipping

USE CASE(S)

- New single deep-sea 5,000 TEU freight vessel, using a low speed two stroke engine over a 12,100km distance, with an assumed to annual travel distance of 278,000km and four days allowed in port between each trip, and an asset lifetime of 25 years;
- Short-sea ferry, carrying 562 passengers on an 100km journey, with an assumed to annual travel distance of 40,000km and an asset lifetime of 25 years.

Costed component	Notes	Base source(s)
• Fuel costs. • Capex, including the cost of the fuel cell/engine/battery, balance of plant, and balance of vehicle. For Shipping, this includes battery and fuel cell replacements for relevant systems. • Fixed Opex, including registrations and insurances (as a percentage of new vessels). This includes labour costs, and admin and port fees. • Variable Opex, including consumables, maintenance and servicing costs on a weighted basis. • CO2 cost in 2050, applied to conventional fossil-based fuels (including hybrid systems) and biofuels (including blends).	• This analysis does not capture the cost of establishing refuelling infrastructure. • Where battery charging is considered, the price of electricity includes wholesale cost, a retail margin and a fast-charging infrastructure and operating cost to reflect the need for dedicated fast charging infrastructure. • Where hydrogen is considered as a fuel, fuel costs include the cost of liquefaction. • Payload reductions were calculated, where additional fuel storage was added at the expense of cargo capacity.	• Hydrogen Europe (2021) Techno-economic assessment of low-carbon hydrogen technologies for the decarbonisation of shipping. <https://hydrogeneurope.eu/wp-content/uploads/2023/11/Maritime-Technical-Paper_Final_HRreduced-vd3ygb.pdf>. • Kanchiralla et al. (2023) How do variations in ship operation impact the techno-economic feasibility and environmental performance of fossil-free fuels? A life cycle study. doi.org/10.1016/j.apenergy.2023.121773. • CSIRO (2023) Australia-Singapore Low-Emissions Technologies (ASLET) initiative for maritime and port operations. • European Maritime Safety Agency (2024) Potential use of nuclear power for shipping. <https://www.emsa.europa.eu/publications/item/5366-potential-use-of-nuclear-power-for-shipping.html>. • Murray W (n.d.) Economies of scale in container ship costs. United States Merchant Marine Academy. <https://www.usmma.edu/sites/usmma.dot.gov/files/docs/CMA%20Paper%20Murray%201%20%282%29.pdf>. • Graham et al. (2024) GenCost 2024-25. CSIRO. • Sørensen TA and Laursen R (2021) Total cost of ownership (TCO). Sustainable maritime fuels. <https://backend.orbit.dtu.dk/ws/portalfiles/portal/264043721/TCO_model_description_results_21.10.2021_clean.pdf>. • Solakivi T, Paimander A, Ojala L (2022) Cost competitiveness of alternative maritime fuels in the new regulatory framework. doi.org/10.1016/j.trd.2022.103500.

2.5 Industry

2.5.1 Key assumptions

Table 17: Operating assumptions, Iron and steelmaking[46]

ASSUMPTION	Capital cost ($M)	Capacity (tpa)	Economic life (years)	Construction (years)
BF-BOF	265	2,000,000	25	3
oxyBF-BOF + CCS	1240	2,000,000	25	3
oxyBF-BOF + partial biomass + CCS	1240	2,000,000	25	3
BF-BOF + partial H2	265	2,000,000	25	3
NG-DRI + EAF	1520	2,000,000	25	3
NG-DRI + EAF + CCS	1895	2,000,000	25	3
H-DRI + EAF	1420	2,000,000	25	3
H-DRI + EAF + biomass	1420	2,000,000	25	3

Table 18: Fuel assumptions, Iron and steelmaking

ASSUMPTION	Cost		
	Unit	2025	2050
Iron ore fines	$/t	165	165
Coking coal	$/t	345	345
Lump ore	$/t	205	205
BF grade pellets	$/t	220	220
DRI grade pellets	$/t	245	245
Limestone	$/t	45	45
PCI coal	$/t	300	300
Scrap (external)	$/t	460	460
Biochar	$/t	465	465
Electricity[47]	$/kWh	0.108	0.097
Natural gas[48]	$/GJ	16.1	14.1
Hydrogen[48]	$/kg	7.32	3.95

[46] Except where explicitly noted, cost assumptions have been derived from IEA (2024) IEAGHG Technical Report 2024-02 Clean Steel: an Environmental and Technoeconomic Outlook of a Disruptive Technology. IEA Greenhouse Gas R&D Programme. <https://ieaghg-publications.s3.eu-north-1.amazonaws.com/Technical+Reports/2024-02+Clean+Steel+An+environmental+and+technoeconomic+outlook+of+a+disruptive+technology.pdf> (accessed 17 January 2025).

[47] Refer Tables 2 and 3.

[48] Input costs aligned with electricity generation assumptions, refer Table 5.

Table 19: Operating assumptions, Medium-temperature steam

ASSUMPTION		
	Unit	Value
Boiler capacity	t/y	790,000
Pressure	bar	8
Temperature	°C	210

Table 20: Fuel assumptions, Medium-temperature steam

ASSUMPTION		Fuel	
	Unit	2025	2050
Gas boiler[49]	$/GJ	16.1	14.1
Biomass combustion[49]	$/kg	0.2	0.2
Electric boiler[50]	$/kWh	0.108	0.097
eTESh system[50]	$/kWh	0.108	0.072
Hydrogen boiler[49]	$/kg	7.32	3.95

Table 21: Technology assumptions, Medium-temperature steam[51]

ASSUMPTION	2025				2050			
	Capital cost		Efficiency (%) [52]	Lifetime (years)[53]	Capital cost		Efficiency (%)[57]	Lifetime (years)[58]
Gas boiler	115,000	$\$/MW_{th}$	90	25	94,000	$\$/MW_{th}$	90	25
Biomass combustion	1,304,000	$\$/MW_{th}$	90	25	1,127,000	$\$/MW_{th}$	90	25
Electric boiler	163,000	$\$/MW_{th}$	90	25	149,000	$\$/MW_{th}$	90	25
eTESh system	655,000	$\$/MW_{th}$	90	25	282,000	$\$/MW_{th}$	90	25
Hydrogen boiler	231,000	$\$/MW_{th}$	90	25	231,000	$\$/MW_{th}$	90	25

Table 22: Operating assumptions, Mining heavy haulage

ASSUMPTION		
	Unit	Value
Duty cycle time	s	876
Duty cycle distance	m	3,482
Ascent distance	m	1,005

[49] Input costs aligned with electricity generation assumptions, refer Table 5.

[50] Refer Tables 2 and 3.

[51] Climateworks Centre and CSIRO (2023); The Danish Energy Agency (2024) Technology Data for Industrial Process Heat <https://ens.dk/en/analyses-and-statistics/technology-data-industrial-process-heat> (accessed 17 January 2025).

[52] Efficiency is measured battery to wheel for batteries and % lower heating value of Hydrogen for fuel cells. Efficiency range reflects beginning and end of fuel cell life.

[53] Lifetime is measured to 80% of original capacity.

ASSUMPTION		
	Unit	Value
Ascent grade	%	10
Ascent speed	km/hr	12
Annual operating hours	hrs/year	6000

Table 23: Fuel assumptions, Mining heavy haulage[54]

ASSUMPTION	Fuel price		
	Unit	2025	2050
Diesel	$/L	1.54	1.54
Renewable diesel	$/L	3.37	2.28
Liquid hydrogen	$/kg	16.9	9.37
Electricity[55]	$/kWh	0.30	0.28

Table 24: Powertrain assumptions, Mining heavy haulage[56]

ASSUMPTION	2025						2050					
	Capital cost		Efficiency[57]		Lifetime[58]		Capital cost		Efficiency[57]		Lifetime[58]	
Diesel	404	$/kW	20.3	%	20,000	hours	404	$/kW	20.3	%	20,000	hours
Battery	244	$/kWh	85	%	5,841[59]	hours	125	$/kWh	85	%	11,682[60]	hours
Fuel cell	1,099	$/kW	38.3-33.7	%	30,000	hours	256	$/kW	38.3-33.7	%	30,000	hours

[54] Refer to Table 12 for fuel costs, and Tables 2 and 3 for electricity costs.

[55] The levelised cost of fast charging infrastructure is modelled using the Argonne National Laboratory (2023) Hevisam model. <https://hdsam.es.anl.gov/index.php?content=hevisam> (accessed 17 January 2025). Battery electric haul trucks are assumed to swap batteries every 6 haul cycles. Refuelling/recharging assumptions are based on the recharging model, not the battery swap.

[56] Note FCEHTs incorporate both fuel cells and batteries in their power train. Ahluwalia et al (2023) Performance and Total Cost of Ownership of a Fuel Cell Hybrid Mining Truck. Argonne National Laboratory https://www.osti.gov/pages/servlets/purl/1973413; Star et al (2022) Performance and cost of fuel cells for off-road heavy-duty vehicles. Argonne National Laboratory. https://doi.org/10.1016/j.ijhydene.2022.01.144.

[57] Efficiency is measured battery input to wheel for batteries and % lower heating value of Hydrogen for fuel cells. Efficiency range reflects beginning and end of fuel cell life.

[58] Lifetime is measured to 80% of original capacity.

[59] The equivalent of 4,000 discharge cycles.

[60] The equivalent of 8,000 discharge cycles.

2.5.2 Cost model components and sources

Iron and steelmaking

USE CASE(S)		
• Brownfield pathway: A 2Mt/year brownfield blast furnace-basic oxygen furnace (BF-BOF) steel mill is reaching the end of its blast furnace life. The BF is relined and the BF-BOF process is fitted with low emissions technologies to allow for low emissions steel production. • Greenfield pathway: A 2Mt/year brownfield BF-BOF steel mill is reaching the end of its blast furnace life. Rather than relining the BF, the furnace is retired, and alternative low emissions technologies are implemented.		
Costed component	**Notes**	**Base source(s)**
• Fuel costs. • Raw material costs, incl. the cost of iron ore fines, coking coal, lump ore, pellets, limestone, PCI coal, scrap and biochar. • Energy and reductant costs, which are carbon (coke) (conventional BF-BOF steel mill). • Capex, which reflect the estimated cost faced by an existing integrated steel mill with a blast furnace reaching the end of its economic life. • Fixed Opex, including costs for labour, insurances, asset depreciation, licensing and regulatory fees. • Variable Opex, including scheduled maintenance, energy consumption for additional components (i.e., condenser), parts replacement, and waste disposal. • CO_2 cost in 2050. CO_2 storage costs are included for CCS pathways.	• This cost model is representative of European steel mill operations and may not resemble the operating model of integrated Australian steel mill operations. • Pellets were assumed to be purchased by the steelmaking facility, with associated emissions occurring upstream at the mine site. • Connection costs to utilities such as hydrogen or electricity have not been included in this analysis. • As steelmaking pathways consume and produce electricity at different stages of production, some electricity is assumed to be re-circulated to other process units in the configuration. An external source of electricity was included in DR-based pathways due to a deficit of electricity within the system.	• IEAGHG (2024) Clean steel: an environmental and technoeconomic outlook of a disruptive technology. • IEAGHG (2013) Iron and steel CCS study (techno-economics integrated steel mill). • Elias et al. (2022) Biochar carbon credit market analysis: examining the potential for coupled biochar and carbon credit production from wildfire fuel reduction projects in the Western U.S. Blue Forest Conservation. • Wood T, Dundas G and Ha J (2020) Start with steel. Grattan Institute.

Medium-temperature steam

USE CASE(S)	• Lower-temperature alumina digestion, including a boiler operating to produce a steam temperature of 210°C at a pressure of 8 bar	
Costed component	**Notes**	**Base source(s)**
• Fuel costs. • Capex, including the cost of the burner and boiler system or other equipment (i.e., storage system for eTESh), as well as other associated plant equipment, construction and set-up costs. • Fixed Opex, including costs for labour, insurances, asset depreciation, licensing and regulatory fees. • Variable Opex, including scheduled maintenance, energy consumption for additional components (i.e., condenser), parts replacement, and waste disposal. • CO_2 cost in 2050, applied to gas boiler.	• This analysis assumes a purchase and full ownership of the equipment, hence no lease payments. The costs for software and control systems are not considered in this assumption.	• Climateworks Centre and CSIRO (2023) Pathways to industrial decarbonisation: phase 3 technical report. Australian Industry Energy Transitions Initiative, Climateworks Centre. • Danish Energy Agency (2024) Industrial process heat. Technology descriptions and projections for long-term energy system planning. <https://ens.dk/en/analyses-and-statistics/technology-data-industrial-process-heat>.

Mining heavy haulage

USE CASE(S)	• Mining haulage truck operating on a deep surface level mine, assumed to shift 7,380,464 tonnes per year across 6000 hours of annual usage	
Costed component	**Notes**	**Base source(s)**
• Fuel costs with the cost of fuel excise shown as a separate component. It is typically claimed back via a fuel tax credit for this use case. • Capex, including the cost of the fuel cell/engine/battery, balance of plant, and chassis. • Replacement Capex, including the replacement of fuel cell/engine/battery at end of lifetime. • Variable Opex, including maintenance and servicing costs. • CO_2 cost in 2050, applied to conventional diesel trucks. For renewable diesel trucks, tailpipe emissions were assumed to be completely offset by biogenic sequestration earlier in the carbon cycle.	• All alternatives have the same Gross Vehicle Weight (GVW) and payload during the haul cycle.	• FCEHT: Ahluwalia et al. (2023) Performance and total cost of ownership of a fuel cell hybrid mining truck. doi.org/10.3390/en16010286; Ahluwalia et al. (2022) Performance and cost of fuel cells for off-road heavy-duty vehicles. doi.org/10.1016/j.ijhydene.2022.01.144. • BEHT: Bao et al. (2024) Energy consumption and battery size of battery trolley electric trucks in surface mines. doi.org/10.3390/en17061494; Ahluwalia et al. (2023) Performance and total cost of ownership of a fuel cell hybrid mining truck. doi.org/10.3390/en16010286.

As Australia's national science agency, CSIRO is solving the greatest challenges through innovative science and technology.

CSIRO. Creating a better future for everyone.

Contact us

1300 363 400
+61 3 9545 2176
csiro.au/contact
csiro.au

For further information

CSIRO Futures
Melissa Craig
melissa.craig1@csiro.au

CSIRO Futures
Vivek Srinivasan
vivek.srinivasan@csiro.au