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2024-2025 GenCost Consultation Submission

Submission to CSIRO and AEMO, 11 February 2025

The Centre for Applied Energy Economics and Policy Research (CAEEPR) is a collaborative partnership between Griffith Business School and energy sector participants in Australia's National Electricity Market.

CAEEPR aim to maximise the energy sector's potential to achieve emission reductions and contribute to inclusive, sustainable, and prosperous businesses and communities while building capacity in electricity economics. CAEEPR uses a national electricity market model to develop and analyse different scenarios to assess different policy positions for generator dispatch and transmission efficiency.

CAEEPR's sub aims/objectives that are most relevant to this submission:

- Supporting the transition to more sustainable and less carbon-intensive power generation and transmission system and address the accompanying policy, economic, technical and political challenges within the industry.
- Provide thought leadership and industry engagement strategies that our members can design and deliver best practice energy services with reduced emissions.
- Create and uphold advanced Electricity Market models for analysing wholesale spot and future markets, power system reliability, integration of dispatchable and intermittent resources, and network capacity adequacy.

This submission has been prepared by Andrew Fletcher who is an Industry Adjunct Research Fellow at CAEEPR. While aspects of this submission has drawn on the market knowledge and expertise of CAEEPR members, the views expressed in this submission are entirely the author's and are not reflective of CAEEPR.

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Executive Summary

I welcome the opportunity to provide feedback to CSIRO and AEMO on the CSIRO GenCost 2024-25 Consultation Draft and the Aurecon 2024 Energy Technology Cost and Parameter Review, both released in December 2024. As these reports are intrinsically linked this submission also forms an integral part of the author's Draft 2025 IASR Stage 1 Consultation Submission, which includes consultation on Aurecon's report. As there are multiple cross references between the two submissions, they should be considered as attachments to each other.

CSIRO GenCost is the is the source of critical build cost projections for generation technologies and electrolysers for the AEMO ISP, with these projections also used as input in a range of modelling undertaken by researchers, industry and policy makers. This submission includes recommendation for the modelling of key technologies which underpin the transition to net zero and are selected in the 2024 AEMO ISP's optimal development path including onshore wind, OCGT, utility scale BESS, rooftop solar PV and electrolysers which are included via consultant modelling reports (CER and multi-sector respectively). While GenCost has a robust methodology and proven theoretical underpinnings in learning-by-doing, there is the opportunity to improve GenCost, including by:

- Increasing transparency of inputs and methodology and outputs, by providing a breakdown of build cost projections into components and providing greater detail on drivers of changes in projections for utility scale BESS.
- Rooftop Solar PV
  - Modelling rooftop solar PV separately from utility scale solar PV as the break-down of build cost into components is materially different, particularly for inverters.
  - Applying lower learning rates than utility scale solar PV for Balance-of-System, consistent with literature and lower rates for inverters, consistent with historical data
  - Reducing installation/Balance of System learning as average system size growth declines, in recognition that increasing system size has been a key driver of decreasing rooftop solar PV build costs.
- Electrolysers
  - Incorporating current build cost estimates from detailed studies on actual Australian projects for electrolysers and a more accurate breakdowns into components.
  - Adding a cost premium for firming variable green hydrogen to allow an unbiased assessment of green and blue hydrogen and providing transparency on capacity of generation built by technology in GALLME.
  - Incorporating contemporary research which considers a technology's complexity and degree of design customisation as drivers of learning rates.
- Onshore wind
  - Equipment costs should experience only a partial reversion towards GALLME modelled costs
  - Partially reverting wind equipment toward GALLME modelled costs due to maritime shipping costs being materially higher than historical levels, while considering that decarbonised shipping will be higher cost than historical levels.
  - Not reverting installation/balance-of-plant back to historical level as engineering construction escalation has historically exceeded CPI and this is forecast to continue.

- Varying local learning rates for installation / Balance of Plant by scenario to reflect uncertainty around the level of further turbine scaling.

- OCGT
    - Retaining OCGT as a candidate technology given limited design and cost differential vs 'hydrogen ready' turbines and techno-economic challenges with hydrogen fuelled turbines, including the need for geological hydrogen storage and hydrogen transmission pipeline infrastructure.
    - Partially reverting OCGT equipment costs toward historical levels due to evidence of rising OEM profit margins, while increasing Balance of Plant/ installation cost at construction escalation.

Additionally, the modelling of the technical parameters of utility scale BESS, which is relevant for Aurecon and AEMO, could be improved by:

- Varying degradation with duration, reflecting lower degradation on longer duration BESS due to lower C-rates and less cycling.
- Incorporating round trip efficiency degradation.

Consultation submission review guide

To aid in the review of this consultation submission recommendations are listed at x.1 of each section with each individual recommendation aligning with a sub section.

While we encourage AEMO to review the entire document as well as the author's Draft 2025 IASR Stage 1 Consultation Submission, the following table outlines in green the sections most relevant for each of CSIRO, Aurecon and AEMO.

Subject	Section number	CSIRO	Aurecon	AEMO
Transparency	1.2			
Electrolyser build costs	2.2-2.3			
Electrolyser build costs	2.4			
Electrolyser build costs	2.5			
Electrolyser build costs	2.6			
Rooftop solar PV	3.			
Onshore wind	4.2			
Onshore wind	4.3-4.6			
Open Cycle gas turbines	5.2-5.3			
Open Cycle gas turbines	5.4-5.5			
Utility scale BESS	6.			

Table 1: Consultation submission review guide

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1. Transparency

1.1 Recommendations

The following recommendation are made which align with submission sections:

Section 1.3 The source and date of build cost input assumptions and breakdown into components should be disclosed for each technology

Section 1.4 The source of learning rates assumptions, including data source and time-period of calculation should be disclosed for each technology

Section 1.5 CSIRO's modelled build cost breakdown by component should be disclosed for historical and current modelled period for key technologies

Section 1.6 CSIRO's Build Cost projections should be disclosed by component for key technologies

Section 1.7 Time-periods for learning rate 1 and learning rates 2 periods should be disclosed

Section 1.8 2050 global generation mix by capacity should be disclosed

Section 1.9 Greater transparency should be provided around drivers of the increase in battery build cost projections

1.2 Background

CSIRO GenCost is the source of build cost projections for generation technologies and electrolysers for the AEMO ISP. (Australian Energy Regulator, 2023) states that:

"*The AER's forecasting guidelines require AEMO's forecasting practices and processes to have regard to the following principles:*

- *forecasts should be as accurate as possible, based on comprehensive information and prepared in an unbiased manner;*
- *the basic inputs, assumptions and methodology that underpin forecasts should be disclosed; and*
- *stakeholders should have as much opportunity to engage as is practicable, through effective consultation and access to documents and information."*

Consistent with these principles the author's 2023-24 GenCost consultation submission (Fletcher & Nguyen, 2024) called for greater transparency of build cost projections disclosing the breakdown of capital cost projections for key technologies, including wind, utility scale solar PV and electrolysers. Providing greater transparency will provide stakeholders a greater opportunity to engage with and appraise the build cost projections. Build cost, particularly as the impact of global and local cost pressures on build cost projects is matter of significant interest to stakeholders as seen through previous detailed CSIRO GenCost consultation submissions (2024 ISP Consumer Panel, 2023)

Through email, the authors of CSIRO GenCost have shared more details and responses to some queries regarding the inputs, assumptions and methodology that underpin build cost projections.

Of particular relevance to Section 0 is the following description of wind and utility scale solar PV build cost projections provided by Paul Graham on 18 November 2024, with aligns with information provided on the GenCost webinar on 5 February 2025.

"The model starts in 2006 and begins with the split in costs that occurred in 2006 for modules, BOP and the inverter. The data for this was from the IEA. Each of these different components has its own learning rate, where the modules are global and the BOP is local. The inverters just have a constant cost reduction as we could not include a learning rate or it would make the model non-linear.

We include what has been built up until and including 2023 by region in the model, so that the costs of the module and BOP reduce in cost separately. We combine the module, BOP and inverter costs in the output.

We use the same approach for wind but we model the equipment (turbine) which has a global learning rate and the installation, which has a separate local learning rate.

We have calculated our own learning rates in the past using IEA and/or IRENA data."

1.3 The source and date of build cost input assumptions and breakdown into components should be disclosed for each technology

The author's experience is that stakeholder perception is that capital cost input assumptions and their breakdown into components, is sourced from the Aurecon Energy Technology and Technical Parameter Review of the same date. However, for utility scale solar PV and rooftop solar PV projections inverter capex is sourced from 2006 IEA data and Aurecon does not provide current capex estimates for inverters in its report. Section 3.4.5 discusses this issue in relation to electrolysers.

1.4 The source of learning rates assumptions, including data source and time-period of calculation should be disclosed for each technology

The author's experience is that stakeholder perception is that the references contained in the learning rates summary table are the sources of learning rates assumptions. However, this isn't always the case, for instance see discussion in Section 2.4 regarding the source of Balance of System/ local learning rates for rooftop solar PV.

We recommend disclosing the data source, geographic scope and time-period for learning rates calculations, consistent with the learning rate literature review contained in the supplemental information spreadsheet of (Malhotra & Schmidt, 2020). For instance, wind learning rates appear to have been estimated based on global data from IEA's 2000-2009 Wind Annual Report (Hayward & Graham, 2013).

We recognise that in some cases learning rates may have been estimated using other methods, including where a degree of professional judgment has been applied. This is particularly the case where CSIRO has assumed different learning rates to align with scenario descriptions, a practice which we are supportive of given uncertainty around learning rates.

1.5 CSIRO's modelled build cost breakdown by component should be disclosed for historical and current modelled period for key technologies

Given for several technologies CSIRO's projections start in 2006 using global figures, there is the potential that the build cost breakdowns could be materially different from actual, including due to actual Global and Local learning rates diverging from assumed. Disclosing this information would inform the materiality of any divergences and whether any changes are required to realign CSIRO modelled build cost breakdowns with Aurecon's current build cost breakdowns estimates. Key technologies are considered those selected in AEMO's optimal development path such as utility scale solar PV, onshore wind, utility scale Batteries and open cycle gas turbine, plus rooftop solar PV which is included in consultant CER projection reports.

This potential for divergence is heightened as in recent years Australian energy project build costs have been materially impacted by:

- Global supply chain issues impacting equipment cost.
- Balance of plant being impacted by energy infrastructure project cost escalation exceeding CPI.

See Section 4 for discussion and analysis of this issue in relation to onshore wind.

1.6 CSIRO's Build Cost projections should be disclosed by component for key technologies

Except for utility scale batteries CSIRO does not disclose the breakdown of build cost into equipment and Balance of Plant. Consistent with our submission to 2023-24 GenCost (Fletcher & Nguyen, 2024) we recommend that transparency be provided for the breakdown of build cost into component including equipment, Balance of System, inverter (where relevant) and Land and Development for key technologies.

1.7 Time-periods for learning rate 1 and learning rates 2 periods should be disclosed

CSIRO assume up to two learning rates time periods per technology, with LR1 representing the initial learning rate during the early phases of deployment and LR2, a lower learning rate, that occurs during the more mature phase of technology deployment. This could entail disclosure in the Appendix C1 and C2 tables and where relevant, discussion of changes.

1.8 2050 global generation mix by capacity should be disclosed

Section 3.5.1 discusses that the GALLME model which underlies CSIRO GenCost is not a time sequential model and doesn't estimate the cost of supplying a constant supply of green hydrogen. This issue could also apply more generally to the GALLME model which may not capture the full cost of providing a constant supply of green electricity. In addition to 2050 global generation mix by generation (TWh), disclosing 2050 global generation mix by capacity (TW) would allow stakeholders to assess alignment with results from time sequential energy system modelling.

1.9 Greater transparency should be provided around drivers of the increase in battery build cost projections

Figure 1 shows Aurecon's breakdown of utility scale BESS cost into power and energy components for its 2024-25 draft and 2023-24 final report. The reduction in energy cost components has been the key driver of cost reductions and Aurecon states that:

"It is Aurecon's opinion that this decrease was substantially brought about by the reduction in lithium carbonate price. By July 2024 this price had fallen.to approximately 30% of the July 2023 price. The 2024 costs (nominal) are nearly back to the 2021 costs."

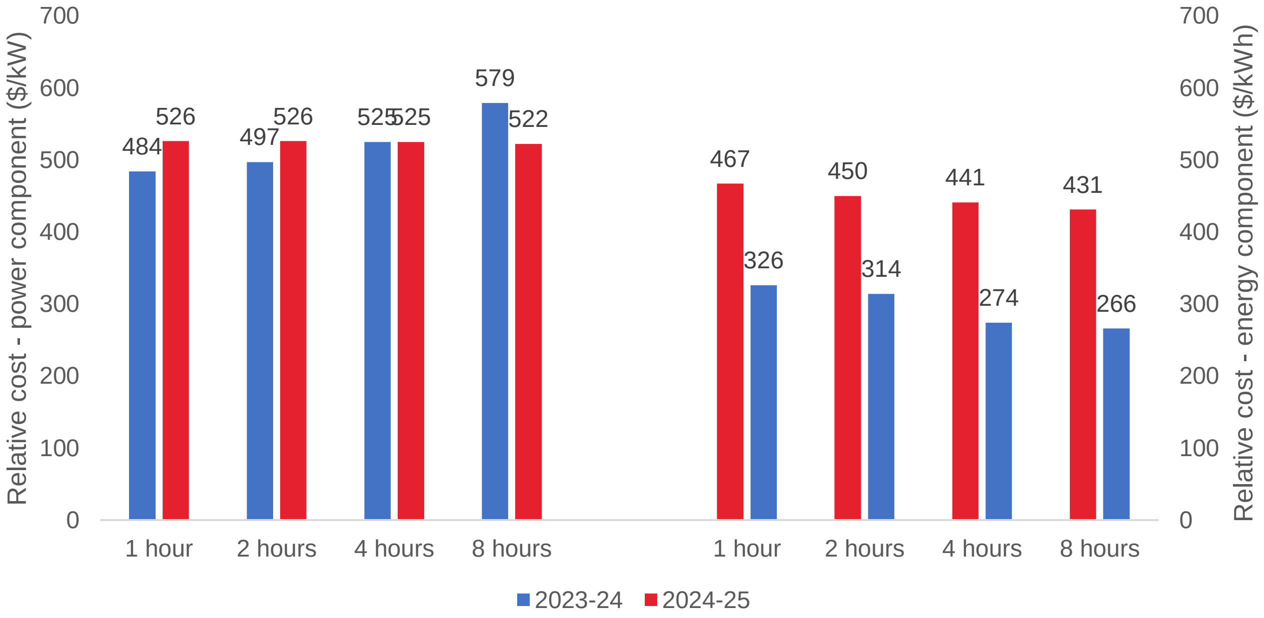

Figure 1: Aurecon utility scale BESS relative cost of power and energy components by publication year | Source: (Aurecon, 2024A) (Aurecon, 2024B)

Figure 2 shows CSIRO GenCost battery build cost projections by components for 4hr BESS for the Global NZE post 2050 scenario (Step Change). For both power and energy components long term projected costs have increased by more than 10% for the 2024-25 Draft, including after accounting for inflation. The change is greater than the learning rate assumption of 10% local and 10% global, which is the same for all three projections, which implies a material change in BESS installation. An explanation is sought as to what is driving the increased cost projections.

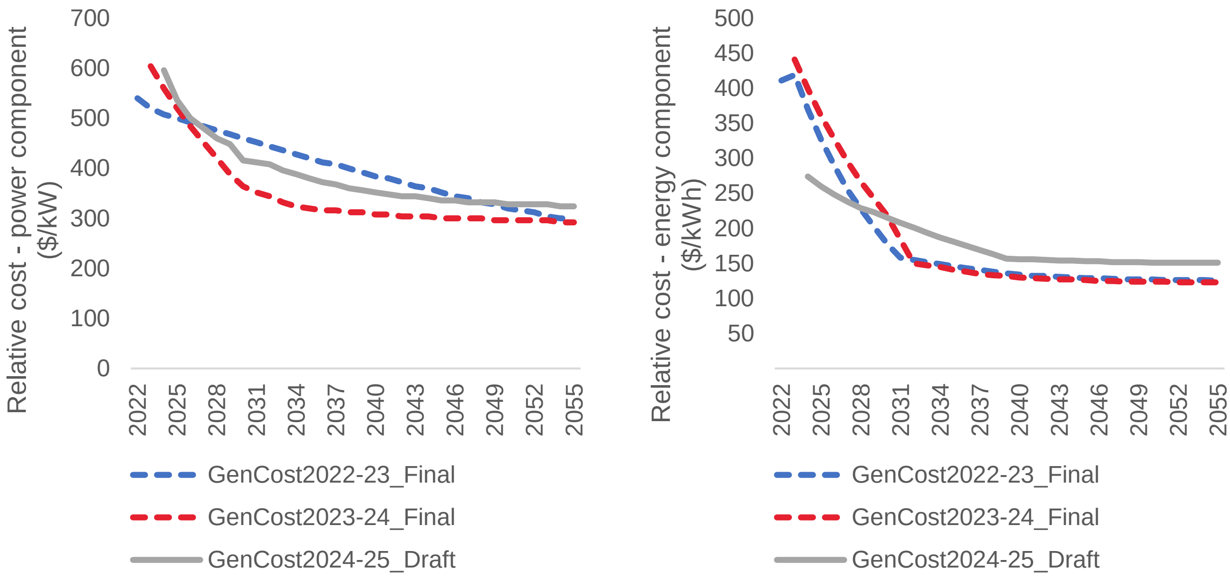

Figure 2: CSIRO GenCost NZE post 2050 4hr battery build cost projections by power (left) and energy component (right) | Source: (CSIRO, 2024A) (CSIRO, 2024B) (CSIRO, 2023) (CSIRO, 2022)

2. Rooftop solar PV

2.1 Recommendations

The following recommendations are made which align with submission sections:

Section 2.2 Rooftop solar PV and utility scale solar PV should be modelled separately

Section 2.3 Learning rate should be estimated for rooftop solar PV inverter

Section 2.4 Balance of System learning rates for rooftop solar PV should be reduced

Section 2.5 Balance of System learning rates for rooftop PV should reduce as system size growth declines

2.2 Rooftop solar PV and Utility scale solar PV should be modelled separately

Although utility scale solar PV and rooftop solar PV could benefit from co-learning on solar PV modules, the break-down of their build cost into components is materially different, as could be learning rates on Balance of System and inverters. CSIRO's current methodology for rooftop solar PV projections is:

"Solar photovoltaics is listed as one technology with global and local components however there are two separate PV plant technologies in GALLME. Rooftop PV includes solar photovoltaic modules, and the local learning component is the balance of plant (BOP). Large-scale PV also include modules and BOP. However, a discount of 25% is given to the BOP to take into account economies of scale in building a large-scale versus

rooftop PV plant. Inverters are not given a learning rate instead they are given a constant cost reduction, which is based on historical data."

To the best of the author's knowledge a full current Australian rooftop solar PV build cost breakdown data is not publicly available. To achieve CSIRO's projected $724/kW DC reduction in build cost by 2050 a large reduction in balance of system (eg. racking, cabling) and labour costs is implied, which could be optimistic. Discussions with Australian residential and C&I solar experts suggests that due to cost reductions, hardware now represents a relatively small portion of build cost with:

- Wholesale prices for solar modules currently A$200/kW DC.
- Australian residential inverter costs varying by brand, with the cost of a 5kW SMA inverter in the range of $340/kW AC to $400/kW AC, with Chinese brands around half this cost (Solar Choice, 2025A)

Figure 3 compares Q1 2023 United States build cost for residential and utility scale solar PV. Including due to higher US Soft Costs and import tariffs, the total residential solar PV build costs are materially higher than Australian figures (Calhoun & Crofton, 2024), however the relative hardware component costs of utility scale and residential scale solar may still be instructive. Residential inverter (string inverter) capex of US$314/kWh is 6.5x utility scale inverter (central inverter) capex of US$48/kWh. Economies of scale could be a factor in this differential with (Aurecon, 2024A) stating that:

"Currently, inverters used for utility-scale sites are typically "central" inverters, rated at 4-10 MW each and supplied on a skid or platform with the MV power transformer, isolation and switching, communications and auxiliary power integrated by the inverter manufacturer."

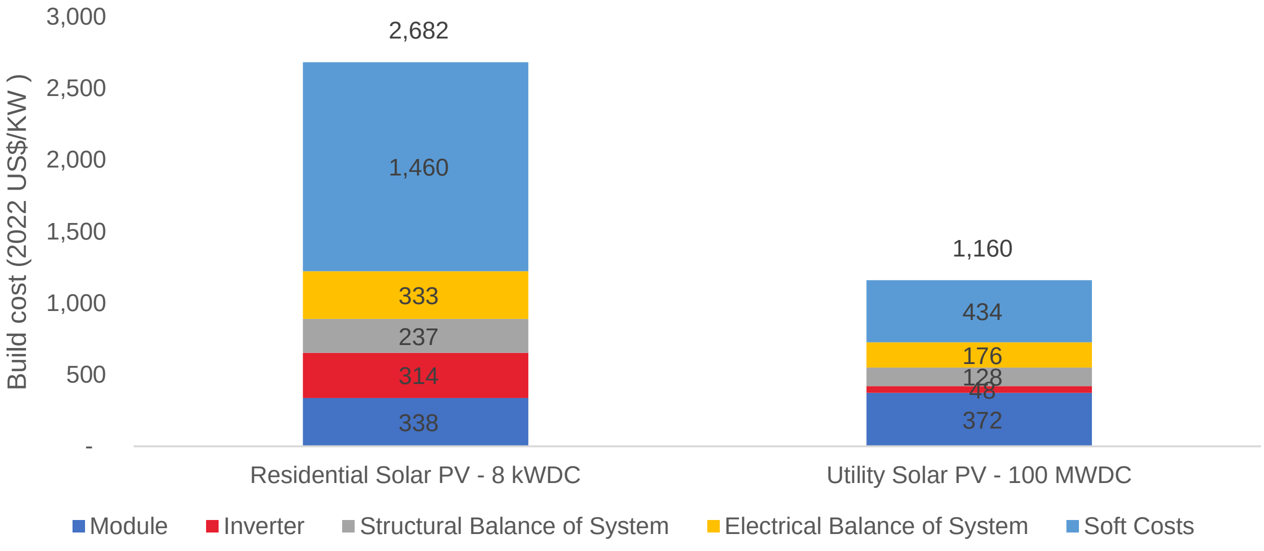

Figure 3: NREL Q1 2023 US Modelled Market Price cost benchmarks (USD 2022) | Source: (NREL, 2023B)

2.3 Learning rate should be estimated for rooftop solar PV inverter

Figure 4 shows that since 2010 residential inverters (string inverters) have experienced a 43% reduction in cost while utility scale inverters (central inverters) have experienced an 85% reduction in cost. Deployment growth does not appear to be an explanatory factor with IEA data shows that from 2015 to 2022 residential solar PV capacity grew by 400%, while the aggregate of utility scale and commercial and industrial grew by 403% (International Energy Agency, 2025).

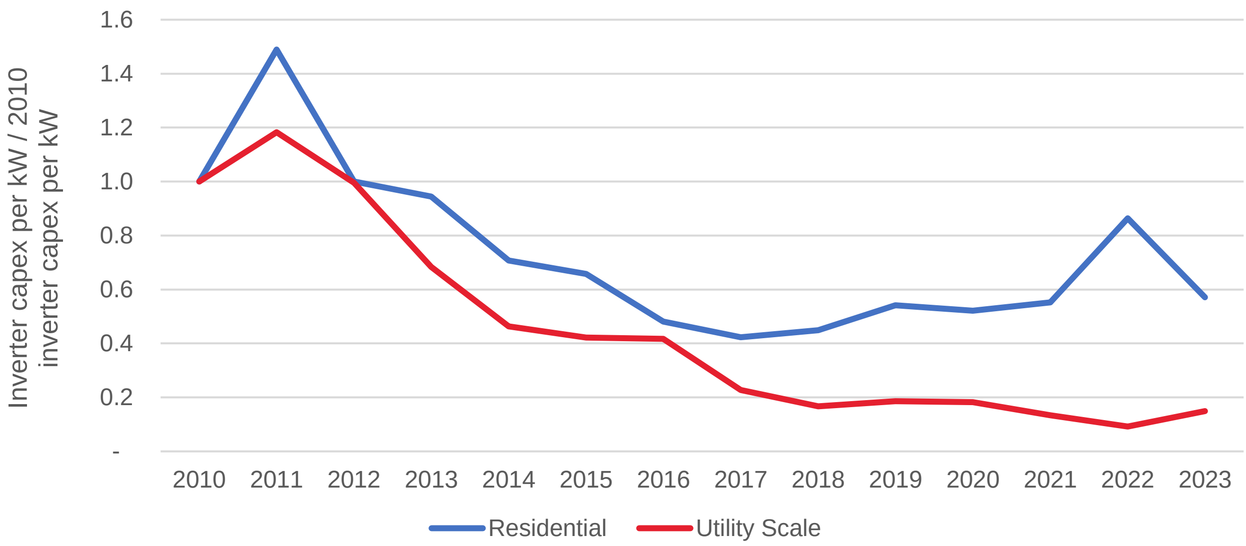

Figure 4: US Utility and residential inverter cost reduction (real) since 2010 | Source: (NREL, 2025)

2.4 Balance of System learning rates for rooftop solar PV should be reduced

Table 2 shows that CSIRO applies a 17% learning rate for Balance of Plant for utility scale solar PV and rooftop solar PV, across all scenarios. This is materially higher than (Elshurafa, Albardi, Bigerna, & Bollina, 2018), who estimate the learning curve of solar PV balance of system for over 20 countries and finds a global learning rate of 11% and an Australian learning rates of 12% for the period 1992-2015. None of CSIRO's references shown in Table 2 includes learning rates for Balance of System, while (Fraunhofer ISE, 2015) contains 2050 cost projections scenarios for Balance of System cost based on component-based analysis.

Source	Progressive Change (Current policies)	Step Change (Global NZE post 2050)	Green Exports (Global NZE by 2050)	References
Global Learning Rate 1	30%	30%	30%	(International Energy Agency, 2021A) (International Renewable Energy Agency, 2022) (Fraunhofer ISE, 2015)
Global Learning Rate 2	13%	23%	23%	
Local Learning Rate 1	-	-	-	
Local Learning Rate 2	17%	17%	17%	
Inverter	Straight line – not disclosed	Straight line – not disclosed	Straight line – not disclosed	

Table 2: CSIRO GenCost 2024-25 Consultation Draft Photovoltaics learning rates and cost reduction | Source: (CSIRO, 2024A)

2.5 Balance of System learning rates for rooftop PV should reduce as system size growth declines

While decreasing module costs has been the key driver of rooftop solar PV build cost reductions, increasing system size has been also played an important role. Figure 5 (left) shows that nominal rooftop solar cost per kw (net of small-scale Technology Certificates (STC)) for a 6kW system is unchanged from June 2019 to January 2025, as reductions in STCs has largely balanced reduction in gross installation cost. Figure 5 (right) shows that driven by increasing system size, costs of the average system size, fell by 12.4%.

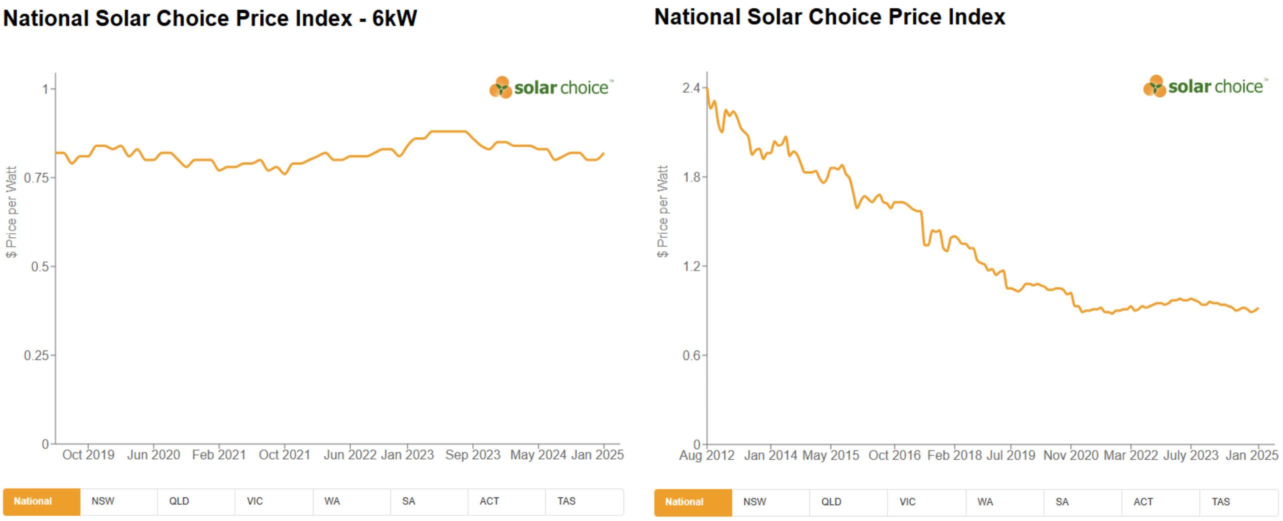

Figure 5: National Solar Price Index - net of small-scale Technology Certificates: (Left- 6kw) (Right -Average system size) | Source: (Solar Choice, 2025B)

Figure 6 (left) shows that rooftop solar PV system size has grown from 4kW in 2015 to 8.6kW for 2024, with CSIRO forecasting this to increase to 9.3kW and 10.6kW respectively for Progressive Change and Step Change, in the mid-2030s (CSIRO, 2024C). Thus, a key driver of Balance of System cost reductions is no longer available and learning rates for Balance of System should be reduced.

Figure 6 (right) shows that build cost per kW excluding STCs starts to decline more rapidly in the mid-2030s for Global NZE Post 2050 (Step Change) and Global NZE by 2050 (Green Energy), with timing roughly aligning with average system size plateauing. This further supports the recommendation that rooftop solar PV and utility scale solar PV should be modelled separately, as the result lacks intuitive appeal given that:

- Increasing system size is no longer a cost reduction driver.
- There isn't a rapid increase in rooftop solar PV installs in the mid to late 2030s.

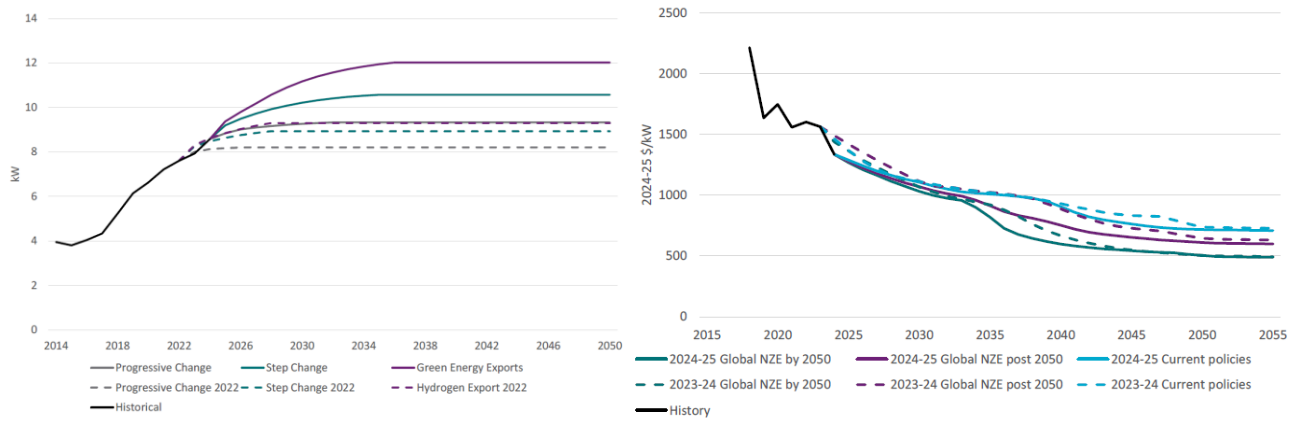

Figure 6: (Left - Historical and assumed future size of new residential solar systems) (Right - Projected capital costs for rooftop solar PV excluding STCs by scenario compared to 2023-24 projections) | Source: (CSIRO, 2024C) (CSIRO, 2024A)

3. Electrolysers

3.1 Recommendations

The following recommendation are made which align with submission sections:

Section 3.4.1 Current electrolyser build cost estimates should be increased to be in line with recent estimates based on detailed studies of Australian hydrogen projects

Section 3.4.2 Compression costs should be included in electrolyser build cost estimates

Section 3.4.3 Balance of Plant and Construction capex estimate should be disaggregated

Section 3.4.4 Portion of capex relating to electrolyser stacks should be reduced from 40% to 30% of capex (ex-land and development) for PEM electrolysers

Section 3.4.5 CSIRO's and Aurecon's current build costs assumptions and breakdown into components should align

Section 3.5.1 A cost premium for firming green hydrogen should be included in CSIRO's projection model (GALLME)

Section 3.5.2 Non-equipment learning rates should be decreased to recognise complexity and customisation of electrolyser projects

Section 3.5.3 Methodology for projecting land and development costs should be changed to reflect zero or very low learning rates

3.2 Literature Review Summary

Public generic estimates of electrolyser project build cost have been materially underestimated, with a key driver the insufficient appreciation of full scope of system costs (BNEF, 2024A). Generic build cost estimates have focussed on direct costs such as electrolyser stacks and balance of plant and not properly accounted for or neglected other costs such as offsites & utilities, civil costs and construction indirects (Ramboll, 2023). As a result, capex estimates based on detailed studies for actual projects have been materially higher.

In 2024 a number of electrolyser project build cost estimates were released based on detailed studies for electrolyser projects in the Netherlands (TNO, 2024) and also Australia (APA Group, 2024) (Fortescue, 2024). While in 2024 high profile generic electrolyser build cost estimates and projections were increased by IEA and BNEF (International Energy Agency, 2024B) (BNEF, 2024A). (Siekkinen, 2024) provides a useful discussion of the history of electrolyser capex estimates and the influence of optimistic capex estimates and projections from (International Renewable Energy Agency, 2020) on researchers and policymakers.

The lack of appreciation of the full scope of electrolyser system costs has led to learning rates like those achieved for solar PV modules, being applied to a disproportionate portion of electrolyser capex or even the entire capex stack (International Energy Agency, 2021B). While it is reasonable to apply learning rates like solar PV modules for the electrolyser stack, the balance of plant and other capex components are expected to have lower learning rates due to their complexity and requirements for design customisation to the specific site (Ramboll, 2023). While this reasoning is beginning to be reflected in electrolyser capex projections, from IEA and BNEF, they use current capex estimates that are materially lower than detailed studies (International Energy Agency, 2024A) (BNEF, 2024B) and as such capex projections are likely to be materially underestimated.

Of the major Australian hydrogen projects that have publicly released FEED study summaries, many have been abandoned or shelved by project sponsors such as:

- Feb 2025: H2Kwinana – Hydrogen and biofuel plant both shelved (Milne, 2025).
- Feb 2025: CQH2 – Queensland State Government has withdrawn further funding (McKenna, 2025).
- Nov 2024: Fortescue Gibson Island – project officially abandoned and site sold (PV Magazine, 2024A).

Consistent with global trends there have been high profile exits from Australian green hydrogen project development including:

- Oct 2024: Origin Energy's announced that it was exiting the Hunter Valley Hydrogen Hub development project and all hydrogen development activities (Origin Energy, 2024)

- Sep 2024: Woodside announced it was shelving the 1.7GW H2Tas green hydrogen and renewable ammonia project and the 600MW Southern Green Hydrogen project in New Zealand (PV Magaznie, 2024B).
- July 2024: Fortescue announcing it was slashing 700 jobs, merging its mining and energy divisions and putting on hold plans to produce 15mtpa of renewable hydrogen by 2030 (WA today, 2024).

Please refer to Section 3.6 for a detailed literature review that support the analysis and recommendations in the following sections.

3.3 Comparison to other public estimates and projections

Figure 7 and Figure 8 shows recent build cost estimates based on detailed studies on actual projects as well as how current generic electrolyser build cost estimates and projections have changed over time for CSIRO, BNEF and IEA. Build cost estimates from detailed studies on actual projects are 60-80% higher than CSIRO GenCost (Aurecon) generic build cost estimates, with the same issue apparent for IEA and BNEF (For further detail refer to Section 3.4.1). Given that current build cost input assumptions for projections models are materially lower than for detailed studies, projected values are likely materially underestimated. Even so, CSIRO's projections are optimistic vs other high-profile electrolyser build cost projections:

- For Step Change Scenario:
  - CSIRO's 2050 projections for Alkaline are 27% lower than IEA and are less than half of BNEF's.
  - CSIRO's 2050 projections for PEM are 19% higher than IEA and 24% lower than BNEF.
- For Green Energy Scenario:
  - CSIRO's 2050 projections for Alkaline are 62% lower than IEA and 77% lower than BNEF's.
  - CSIRO's 2050 projections for PEM are 29% lower than IEA and 57% lower than BNEF's.

CSIRO's projections have increased in 2024 driven by lower local learning rates assumptions (balance of system). The difference in CSIRO's projections between Alkaline and PEM is notable and per discussion in Section could be driven by assumptions that non-electrolyser stack capex represents a higher proportion of build cost for Alkaline than PEM. Section 3.4.3 shows that a range of data sources point to this proportion not being materially different between Alkaline and PEM.

IEA's projections increased in both 2023 and 2024, driven by higher current capex, a recognition that electrolyser stacks represented a smaller portion of build cost and by reduced learning rate assumptions for non-electrolyser stack cost components as outlined in Section 3.6.4.

While CSIRO and IEA's projections are based on learning rate models with the low-emission hydrogen demand forecast from the World Energy Outlooks, BNEF's projections are based on detailed bottom-up estimates. BNEF's 2050 projection is 112% and 55% higher than IEA and CSIRO's Alkaline estimates respectively for the Step Change scenario.

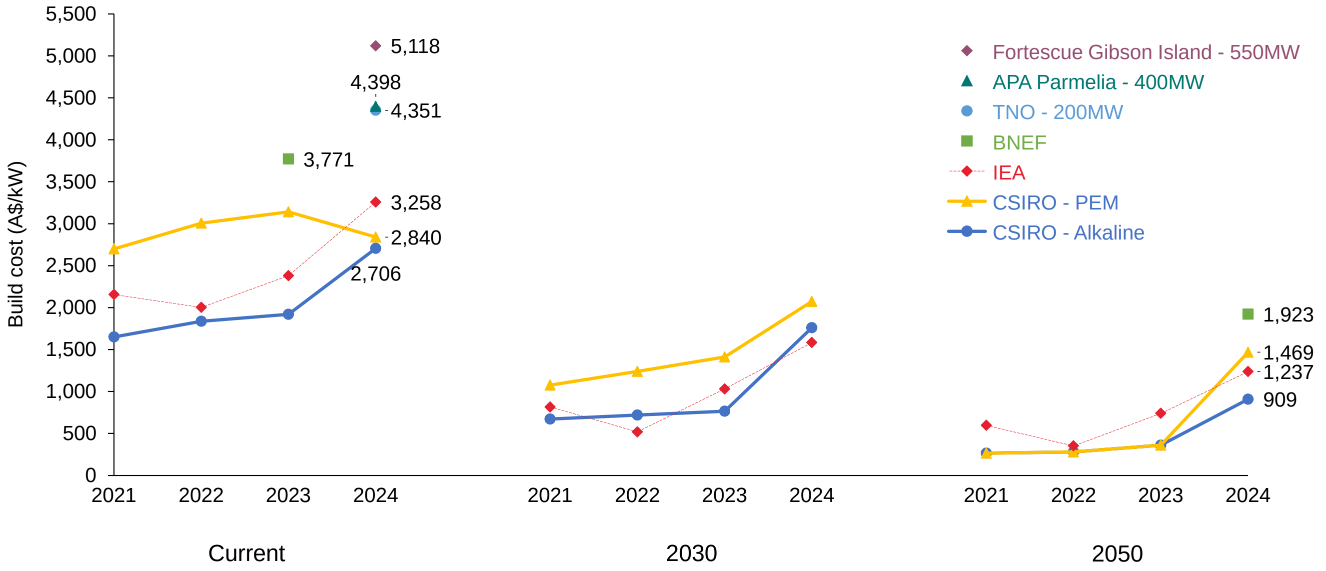

Figure 7: Step Change electrolyser projections for CSIRO (NZE post 2050) and IEA (Announced Pledges) compared to BNEF and project capex estimates based on detailed studies

Source: (CSIRO, 2024A) (CSIRO, 2024B) (CSIRO, 2023) (CSIRO, 2022) (International Energy Agency, 2024A) (International Energy Agency, 2023A) (International Energy Agency, 2022A) (International Energy Agency, 2021A) (Department of Energy - United States of America, 2024) (Tengler, 2024) (TNO, 2024) (APA Group, 2024) (Fortescue, 2024)

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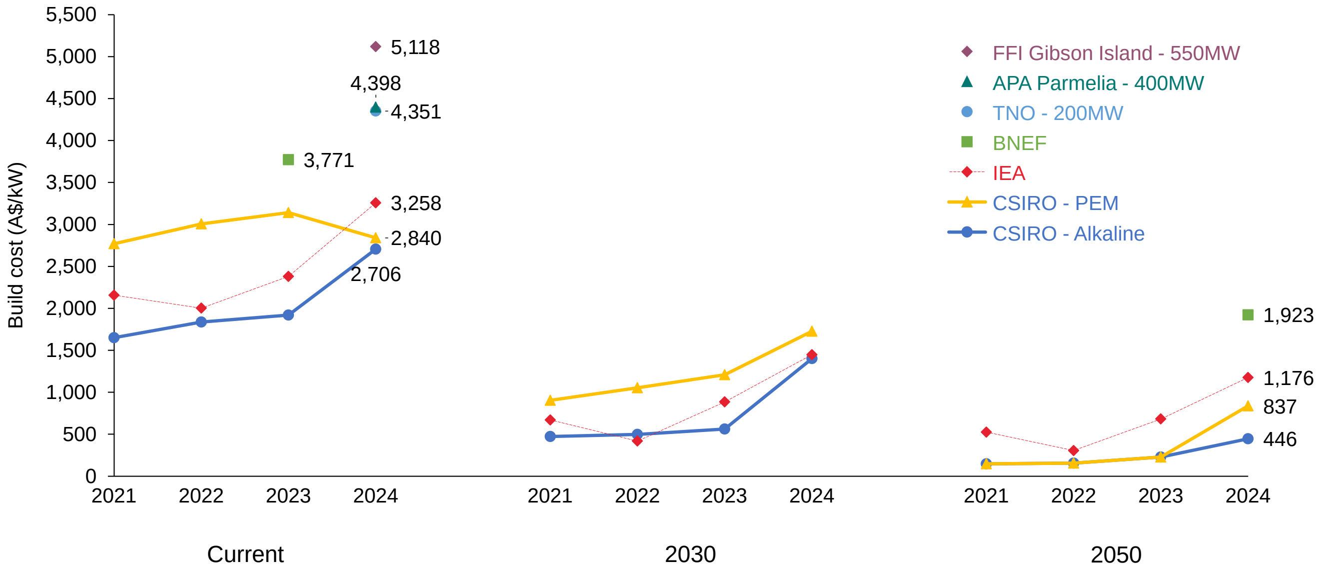


Figure 8: Green Energy electrolyser projections for CSIRO (NZE by 2050) and IEA (Net Zero Emissions) compared to BNEF and project capex estimates based on detailed studies

Source: (CSIRO, 2024A) (CSIRO, 2024B) (CSIRO, 2023) (CSIRO, 2022) (International Energy Agency, 2024A) (International Energy Agency, 2023A) (International Energy Agency, 2022A) (International Energy Agency, 2021A) (Department of Energy - United States of America, 2024) (TNO, 2024; Tengler, 2024) (APA Group, 2024) (Fortescue, 2024)

Notes:

- Current figures are nominal $, while projections are real $2024
- AUD/USD exchange rate: 2024 – 0.65, 2023 - 0.663, 2022 - 0.689, 2021 – 0.752, 2020 -0.6863 USDE/EUR exchange rate: 2024 - 0.93
- 2024 WEO estimates were released in 2024 and are includes as 2024 in the chart, however they contain 2023 estimates. Hence the 2023 AUD/USD exchange rates is applied to them.

- BNEF and IEA do not have separate Alkaline and PEM projections. APA Parmelia is Alkaline, Fortescue Gibson Island PEM and TNO do not have separate Alkaline and PEM.

3.4 Current electrolyser build costs

3.4.1 Current electrolyser build cost estimates should be increased to be in line with recent estimates based on detailed studies of Australian hydrogen projects

Figure 9 shows that estimated electrolyser build cost for the 400MW option for APA Group's Parmelia Green Hydrogen Project, which is based on alkaline technology, is 63% higher than Aurecon's 500MW alkaline electrolyser build cost estimate (APA Group, 2024). Build costs estimates are 86% and 52% higher than Aurecon for 200MW and 900MW project options respectively (APA Group, 2024). Fortescue's build cost estimate for the 550MW PEM electrolyser associated with its green ammonia project is 80% higher than Aurecon's PEM build cost estimate (Fortescue, 2024)

TNO's cost estimates which are based on detailed studies of actual projects are 86% and 61% higher than Aurecon's Alkaline electrolyser build cost estimates for a 100MW and 200MW project respectively.

Aurecon's estimates are similar to 2023 studies for H2Kwinana and Port of Newcastle Hydrogen Hub, both of which were Class 5 estimates, also known as rough order of magnitude estimates, that have the lowest maturity of project definition with typical accuracy range of -50% to +100%. The author does not consider these estimates to be based on detailed studies.

Aurecon's estimate is also lower than international generic build cost estimates, with Aurecon's alkaline estimate 19% lower than IEA and 26% lower than BNEF's 2023 estimates, both of which were released in 2024.

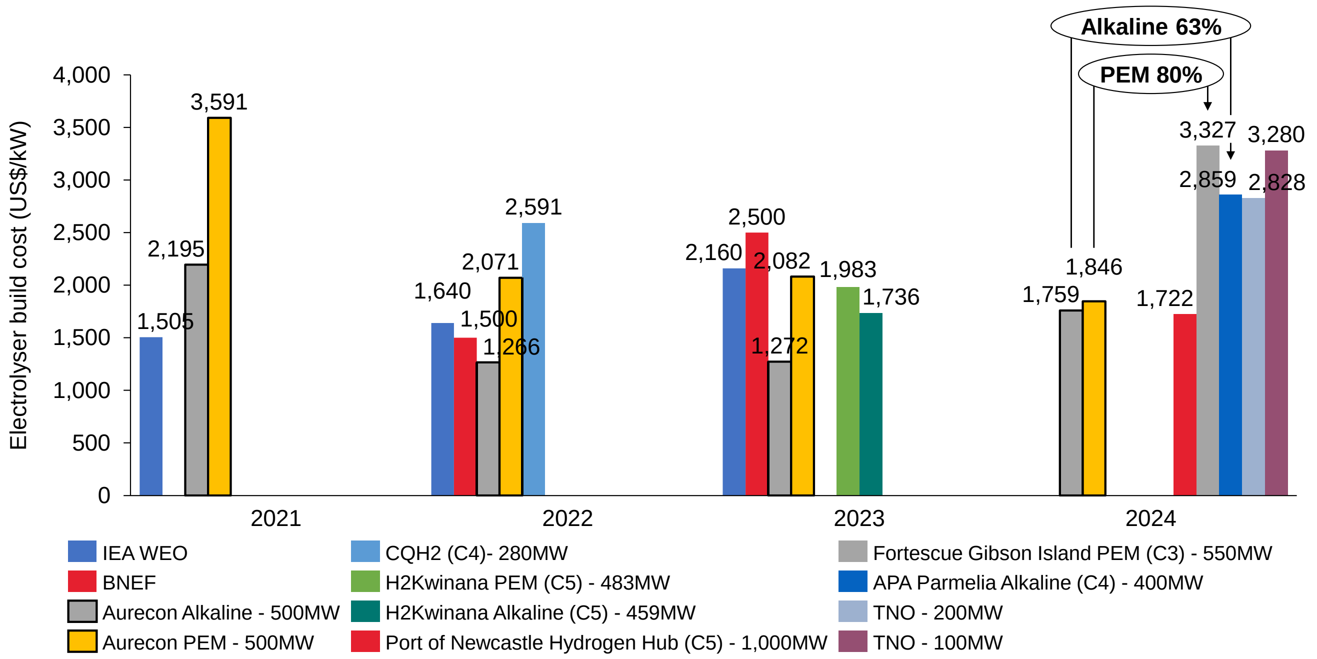


Figure 9: Electrolyser build cost estimates by year - excluding China (US$/kW)

Source: (International Energy Agency, 2024A) (International Energy Agency, 2023A) (International Energy Agency, 2022A) (International Energy Agency, 2021A) (CSIRO, 2024A) (CSIRO, 2024B) (CSIRO, 2023) (CSIRO, 2022) (Department of Energy - United States of America, 2024) (Stanwell Corporation Limited, 2022) (BP Australia Pty Ltd and Macquarie Corporate Holdings, 2023) (Port of Newcastle and Macquarie Asset Management Green Investments, 2023) (Fortescue, 2024) (APA Group, 2024) (TNO, 2024)

Notes:

- All figures are nominal US$
- AUD/USD exchange rate: 2024 – 0.65, 2023 - 0.663, 2022 - 0.689, 2021 – 0.752. USDE/EUR exchange rate: 2024 - 0.93
- IEA 2024 WEO and BNEF estimates were released in 2024, however estimates were for 2023
- Electrolyser technology not specified in IEA, BNEF, CQH2 and TNO estimates. APA Parmelia is Alkaline, Fortescue Gibson Island PEM.

- APA Parmelia Green Hydrogen Project Feasibility Study (APA Group, 2024) is dated October 2024, however it provides Class 4 estimates which are in $ real (2022), which have been inflated by CPI of 10.03% from June 2022 to June 2024. Hydrogen storage costs is assumed to be $2,000kg/$H_2$ for APA Parmelia, based on analysis of (Australian Pipelines and Gas Association - GPA Engineering, 2021). Refer to the author's Draft 2025 IASR Stage 1 Consultation Submission for further details.
- Fortescue Gibson Island build cost is based on Class 3 estimates and an assumed 8% contingency for project is allocated across consistently across all project components. Insufficient detail was provided on hydrogen storage volumes in the Gibson Island feasibility study summary to estimate its contribution to project capex. Site space constraints meant that pipeline storage was infeasible and the preferred option was pressure vessel. Hydrogen storage capex could be an explanatory factor as to why Gibson Island's other costs are higher than other hydrogen projects.
- CQH2 is Class 4 estimate
- H2 Kwinana and Port of Newcastle Hydrogen Hub are Class 5 estimates. Insufficient information were provided on hydrogen storage in relevant reports to deduct it from the estimate.
- Where transmission connection cost has not been itemised an estimate is deducted based on a cost of 110.5/kw consistent with the value for CQ in the 2025 IASR (Australian Energy Market Operator, 2024)
- Storage and compression are included in BNEF's 2025 capex estimate, but account for less than ~US$300/kw.

3.4.2 Compression costs should be included in electrolyser build cost estimates

AER's forecasting guidelines principals include that, *"forecasts should be as accurate as possible, based on comprehensive information and prepared in an unbiased manner"* (Australian Energy Regulator, 2023). Hydrogen storage is a standard feature of hydrogen projects, with all three Australian projects listed in Figure 9 including hydrogen storage, necessitating compression. The ISP Methodology also assumes flexibility of electrolyser loads, while noting potential hydrogen use case partial-flexibility, this implies some level of hydrogen storage. Aurecon estimates of compression capex equate to $49/kW for PEM and $189/kW for Alkaline, with lower cost for PEM driven by an assumed ~30 bar electrolyser output pressure. While Aurecon's response to this matter on the GenCost webinar on 5 Feb 2025 that compression design will be project specific is acknowledged, assuming zero cost is not consistent with AER forecasting guideline principals.

Figure 10 compares 2024 electrolyser project build cost estimate breakdowns for detailed studies and Aurecon, with connection cost and hydrogen storage excluded for consistency. Aurecon's estimates are materially lower than detailed studies across all project build cost components. Project build cost for detailed studies includes compression capex, however where possible transmission connection and hydrogen storage capex have been removed or adjusted, for consistency.

Australian detailed project capex estimates include other costs ranging from $1,030/kW to $1,806/kW, with economies of scale relating to electrolyser capacity observed. In addition to compressions the boundary of Aurecon's cost estimates could exclude other costs which aren't accounted for in generic project estimates (TNO, 2024) as discussed in Section 3.6.2. There is also some ambiguity around the inclusion of contingencies in Aurecon's report, which appear to be included in wind EPC capex, while the financial assumptions assume no contingency for all technologies. Contingencies aren't material enough to explain the gap between Aurecon and other estimates, representing 8% of build cost for Fortescue Gibson Island and 17% for TNO.

Other potential costs not captured by Aurecon include infrastructure upgrade cost outside of the project boundary. The National Hydrogen Infrastructure Assessment Final Report identifies that as well as electricity transmission and hydrogen pipelines, water and port infrastructure upgrades may be being required to support hydrogen production (ARUP, 2023)

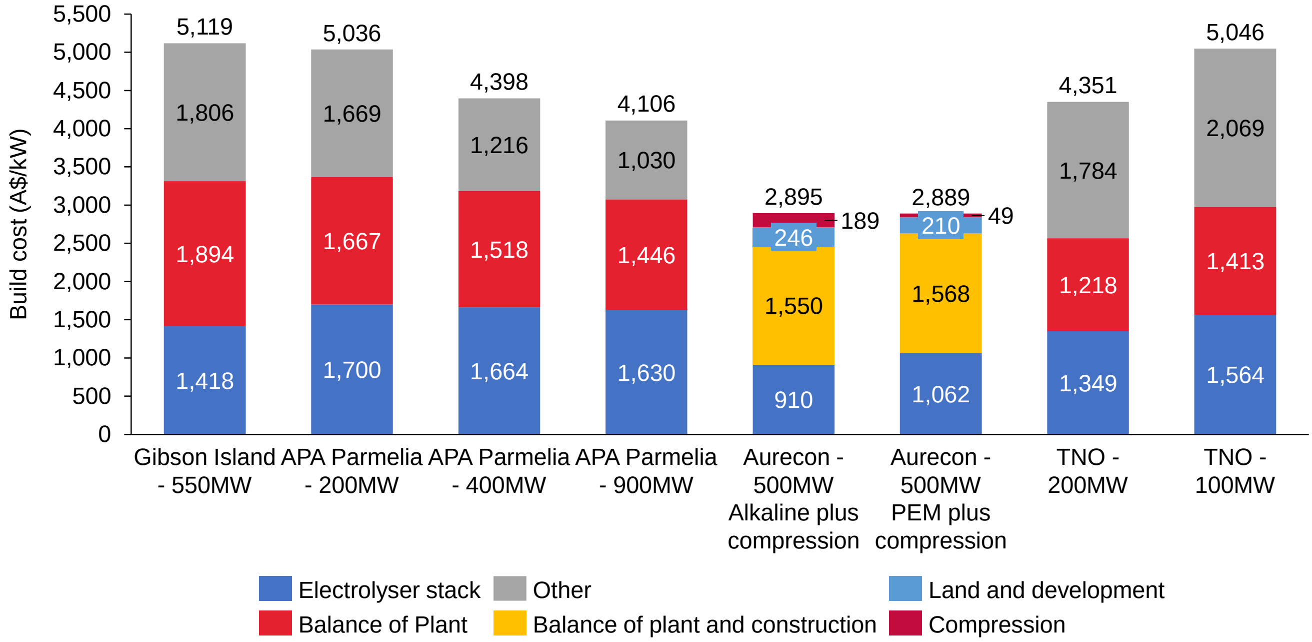


Figure 10: 2024 Electrolyser project capex estimates breakdown for detailed studies and Aurecon estimates, excluding connection cost and hydrogen storage (A$/kW)

Source: (Stanwell Corporation Limited, 2022) (Fortescue, 2024) (APA Group, 2024) (Aurecon, 2024A) (Fortescue, 2024) (TNO, 2024)

Notes:

- All figures are real A$ 2024
- See also Figure 9 notes

3.4.3 Balance of Plant and Construction capex estimate should be disaggregated

The literature has developed to recognise that the disaggregation of Balance of Plant and construction costs (including construction indirect) is important as these capex components have materially different learning rates (Refer to Section 3.6.1). Figure 11 shows that excluding Aurecon the other capex category (typically installation, construction indirects, offsites and utilities and civil works) is usually similar to or larger than the Balance of Plant category. Aurecon's build cost breakdown is materially different from other sources with Balance of Plant and construction representing 57% and 56% of build cost for Alkaline and PEM electrolysers respectively.

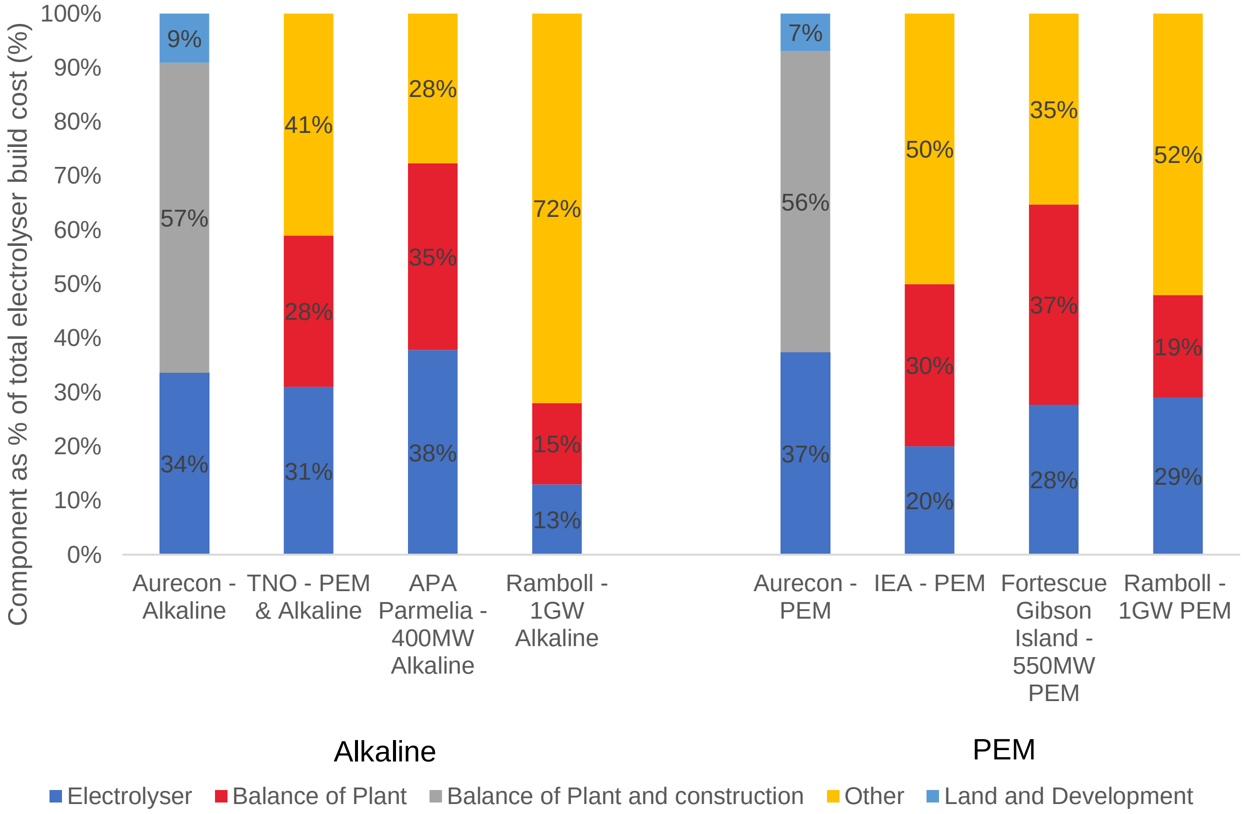


Figure 11: Electrolyser build estimates – breakdown into components

Source: (Aurecon, 2024A) (TNO, 2024) (APA Group, 2024) (Ramboll, 2023) (International Energy Agency, 2024B) (Fortescue, 2024)

3.4.4 Portion of capex relating to electrolyser stacks should be reduced from 40% to 30% of capex (ex-land and development) for PEM electrolysers

For its 2020 to 2023 reports, Aurecon assumed that the electrolyser stack accounted for 70% of electrolyser capex (ex-land and development), while in its 2024 draft report this decreased to 37% and 40% for Alkaline and PEM respectively. Figure 12 Shows that Aurecon's assumption is 8-17% higher than assumptions based on detailed studies.

The material difference between build cost estimates for detailed studies and Aurecon's build cost assumptions and the substantial change in electrolyser stack proportion of capex is concerning. Aurecon is named numerous times in the Public FEED Summary Report for Fortescue Gibson Island Green Hydrogen and Ammonia projects, as preparing various technical studies and plans (Fortescue, 2024). Clarity is sought as to what data sources are being used by Aurecon to produce its cost estimates and in particular how it is considering its internal database of projects (eg. Fortescue Gibson Island), public FEED summary reports and public and subscription research, such as BNEF, which it refers to in its commentary.

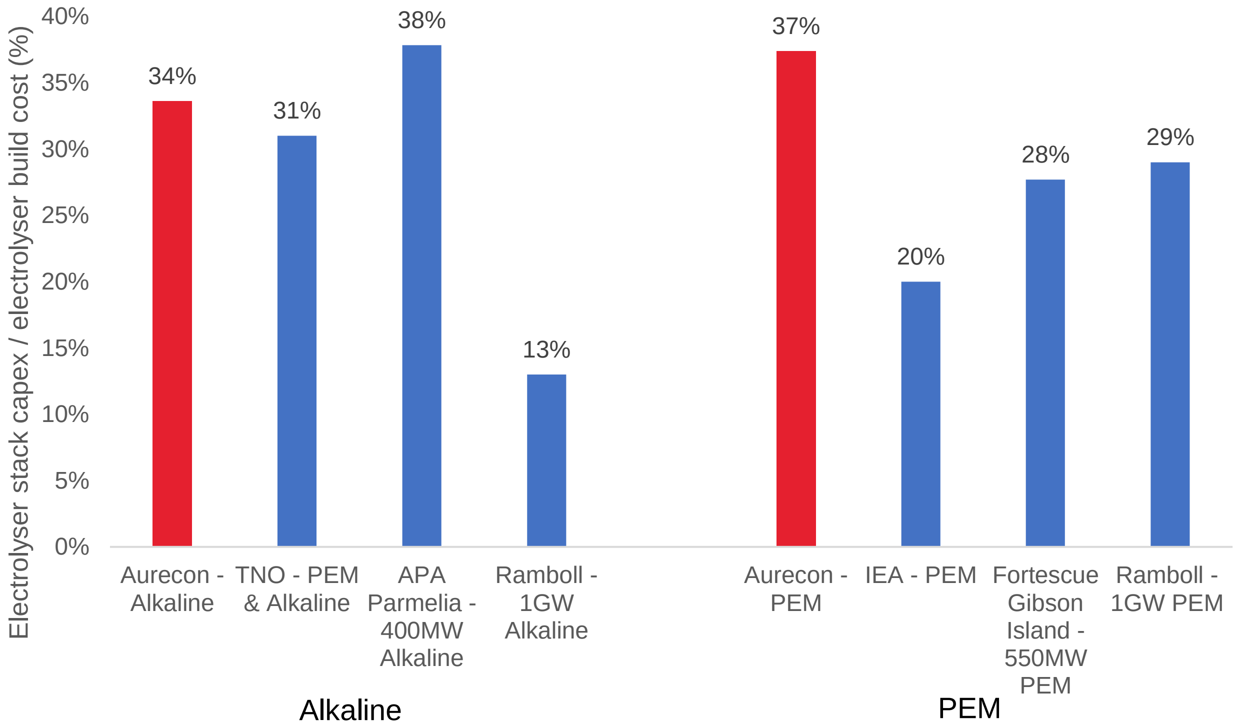


Figure 12: Electrolyser stack as a proportion of electrolyser build cost for detailed studies, plus IEA and Aurecon

Source: (Aurecon, 2024A) (TNO, 2024) (APA Group, 2024) (Ramboll, 2023) (International Energy Agency, 2024B) (Fortescue, 2024)

3.4.5 CSIRO's and Aurecon's current build costs assumptions and breakdown into components should align

(CSIRO, 2024A) states that:

"updated projections provide separate cost paths for the two technologies (Alkaline and PEM) based on their differences in balance of plant. Updated analysis of balance of plant costs has also assisted in providing a more divergent cost range which better reflect future uncertainty."

However, Figure 12 shows that Aurecon's electrolyser capex assumption for Alkaline (34%) and PEM (36%) are not materially different and CSIRO assumes that learning rates for Alkaline and PEM are equivalent. On the GenCost webinar on 5 Feb 2025, CSIRO advised slightly different figures.

Per Section 1.3 CSIRO should improve transparency regarding the source of build cost inputs and their breakdown into components.

3.5 Electrolyser capex projections

3.5.1 A cost premium for firming green hydrogen should be included in CSIRO's projection model (GALLME)

AER's forecasting guidelines principals include that, *"forecasts should be as accurate as possible, based on comprehensive information and prepared in an unbiased manner"* (Australian Energy Regulator, 2023). The GALLME model which underlies CSIRO GenCost is not a time sequential model and doesn't estimate the cost of supplying a constant supply of green hydrogen.

A time sequential model is required to accurately estimate the cost of supplying a constant supply of green hydrogen, which is needed for use cases such as green iron. Additionally for hydrogen use cases that can accept a degree of variability of hydrogen supply, such as ammonia production, additional infrastructure oversizing and potentially ammonia storage costs may be required versus a constant hydrogen supply. Though not disclosed by CSIRO we understand that GALLME is not a time sequential model and that *"GALLME is not temporally detailed enough to determine preferences between"* Alkaline and PEM electrolysers. Given divergent projections are provided for Alkaline and PEM electrolysers, we encourage CSIRO to included further discussion around how these two technologies are modelled in GALLME.

Global hydrogen demand is assumed based on IEA World Energy Outlook forecasts, with allocation of hydrogen supply between production pathways (green, grey and blue) technologies and hydrogen production technology capex projections determined by GALLME model. Figure 13 shows that CSIRO modelling finds that green hydrogen will dominate in the future, thus driving down the cost of electrolysers, which further lowers the cost of green hydrogen. For a further discussion of potential input and methodology biases with IEA green hydrogen modelling see the author's Draft 2025 IASR Stage 1 Consultation Submission.

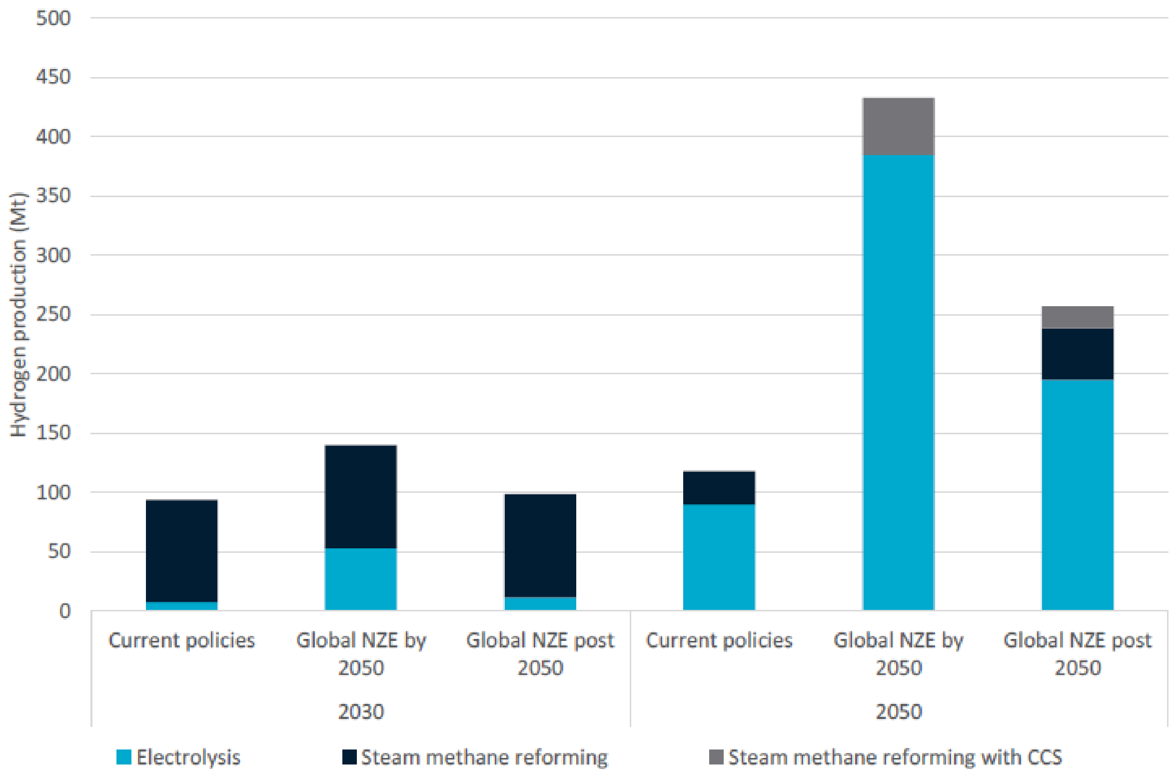


Figure 13: Global hydrogen production by technology and scenario, Mt | Source: (CSIRO, 2024A)

Figure 14 shows that the cost of providing a constant supply of green hydrogen could be almost double that of a variable supply ('farm gate'), which is likely to have a significant negative impact on the prospects of a wide range of hydrogen use cases (Fletcher A. , et al., 2023A). In addition, Figure 14 shows green hydrogen cost estimates from CSIRO Climateworks Centre Multi-Sector Energy Modelling Report (CSIROCC) (CSIRO & Climateworks Centre, 2022), which aggregates electricity demand into 16 load blocks (not time sequential). Figure 14 shows that CSIROCC green hydrogen cost estimates are closer to islanded farm gate green hydrogen costs from than the cost of providing a constant green hydrogen supply. Both models source input assumptions from similarly dated CSIRO GenCost.

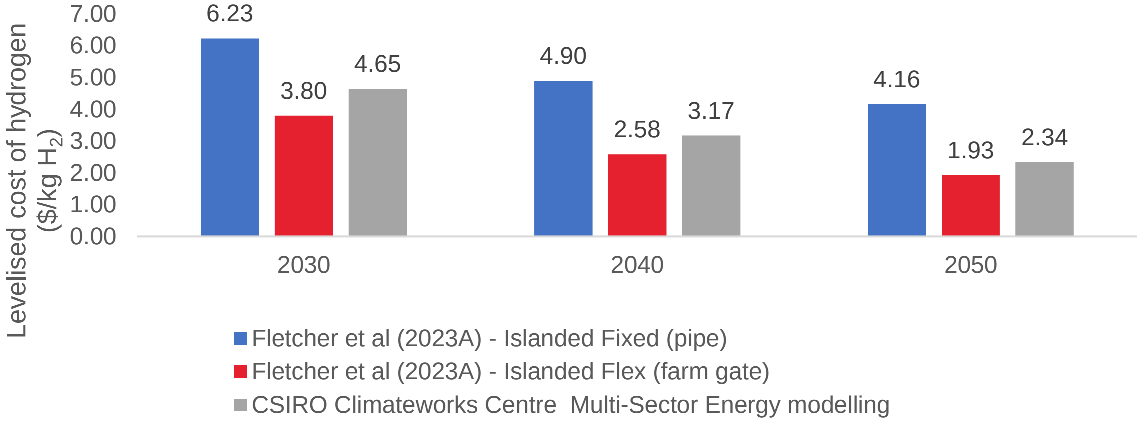


Figure 14: Levelised cost of hydrogen projections ($/kg H_2) | Source: (Fletcher A. , et al., 2023A)

GALLME could be underestimating green hydrogen cost, overestimating its competitiveness against blue hydrogen, leading to earlier uptake and greater deployment of electrolysers. As capex projections are based on a learning model, with deployment the key driver of electrolyser capex, the model bias/error has the potential to create a positive feedback loop, leading to green hydrogen demand being over-estimated and electrolyser build cost being materially underestimated.

While in our previous submission to GenCost 2023-24 (Fletcher & Nguyen, 2024) we recommended investigating whether methodological changes can be made within GALLME to address the issue, improving the modelling by adding a green hydrogen firming premium into GALLME is a simpler approach. AEMO is proposing to implement a similar approach to address this issue with green hydrogen modelling in CSIRO Climateworks Centre Multi Sector Modelling (ACIL ALLEN, 2024). We recommend CSIRO leverage off the same approach and outputs from ACIL ALLEN to ensure transparency and internal consistency between the models which serve as inputs to the AEMO ISP, while noting the author has recommended several improvements to AEMO's proposed approach in his Draft 2025 IASR Stage 1 Consultation Submission.

3.5.2 Non-equipment learning rates should be decreased to recognise complexity and customisation of electrolyser projects

The 2020 paper *Accelerating low-carbon innovation* (Malhotra & Schmidt, 2020), classify technologies into three different types depending on their complexity and need for customisation and demonstrate that learning rates differ between these different technology types (See Section 3.6.1 for further detail).

Per section 3.4.3 other capex category (typically installation, construction indirects, offsites and utilities and civil work) is usually similar to or larger than the Balance of Plant category. While an 8% learning rate is reasonable for Balance of Plant, (Ramboll, 2023) classifies other capex (installation, construction indirect) as Type 3 technology, where the median learning rate is 4% (Malhotra & Schmidt, 2020).Similarly (Martin, 2022) discusses scaling electrolysers and presents the view that balance of plant will not be subject to significant cost reductions due to the commonality and maturity of the relevant equipment.

We note that CSIRO's 8% Local Learning Rate aligns with IEA's EPC and installation cost learning rate assumption from its 2024 Global Hydrogen Review (which is listed as a reference), however IEA has not provided a source for this assumption (International Energy Agency, 2024A). Section 3.6.4 provides further details on IEA's electrolyser projections and learning rates and reasons why they should be treated with caution.

Source	Progressive Change (Current policies)	Step Change (Global NZE post 2050)	Green Exports (Global NZE by 2050)	References
Global Learning Rate 1	10%	10%	18%	(International Energy Agency, 2024B) (Schmidt,
Global Learning Rate 2	5%	5%	9%	
Local Learning Rate 1	-	-	-	

Local Learning Rate 2	8%	8%	8%	Hawkes, Gambhir, & Staffell, 2017)

Table 3: CSIRO GenCost 2024-25 Consultation Draft Electrolyser learning rates | Source: (CSIRO, 2024A)

3.5.3 Methodology for projecting land and development costs should be changed to reflect zero or very low learning rates

While this issue was highlighted in our previous submission to GenCost 2023-24 (Fletcher & Nguyen, 2024) we recommended that land and development cost for electrolyser projections be calculated based on either of the following methods):

- Current land cost escalated by a real land cost index (56% increase by 2050).
- Current land cost escalated by a real land cost index and applying a 4% learning rates consistent with the median learning rate for Type 3 technology (Malhotra & Schmidt, 2020)

(Aurecon, 2024A) states that:

“The development and land costs for a generation or storage project typically include the following components:

- *Legal and technical advisory costs*
- *Financing and insurance (no interest during construction considered)*
- *Project administration, grid connection studies, and agreements*
- *Permits and licences, approvals (development, environmental, etc)*
- *Land procurement and applications.”*

Aurecon assume that land accounts for 9.1% and 7.0% of build cost for Alkaline and PEM electrolysers respectively and our understanding is that this grows to 14.2% and 10.9% of build cost respectively by 2050 due to the application of a 56% real land cost inflator.

CSIRO project that electrolyser build cost will reduce by 48% and 66% for PEM and Alkaline respectively by 2050 and thus its methodology results in the same savings in land and development. This implies that land and development costs will have a learning rate equivalent to electrolyser capex (electrolyser stack and Balance of Plant), which given the makeup of land and development cost is highly optimistic. Except legal and technical advisory, the potential for significant land and development cost reduction appears limited. Legal and technical advisory cost reduction could be limited by the complexity and customisation of electrolyser projects, driving requirement for technical advisory services.

Figure 15 compares CSIRO GenCost 2050 projections to alternative projections where no improvement in land and development cost, with the 56% real land cost inflator applied to both projections. Given higher land and development costs and larger projected build cost declines, assuming no land improvement has the largest impact on 2050 projections for Alkaline, with Global Net Zero by 2050 (Green Energy) 72% higher. For this projection land and development cost represent more than half of build cost.

The quantum of this issue could be magnified if current build cost is increased in line with recommendations in Section 3.4.1. While for other technologies the same methodological issue applies, build cost represent a much lower portion of current build costs: 4% for solar and 2.5% for wind (Aurecon, 2024A).

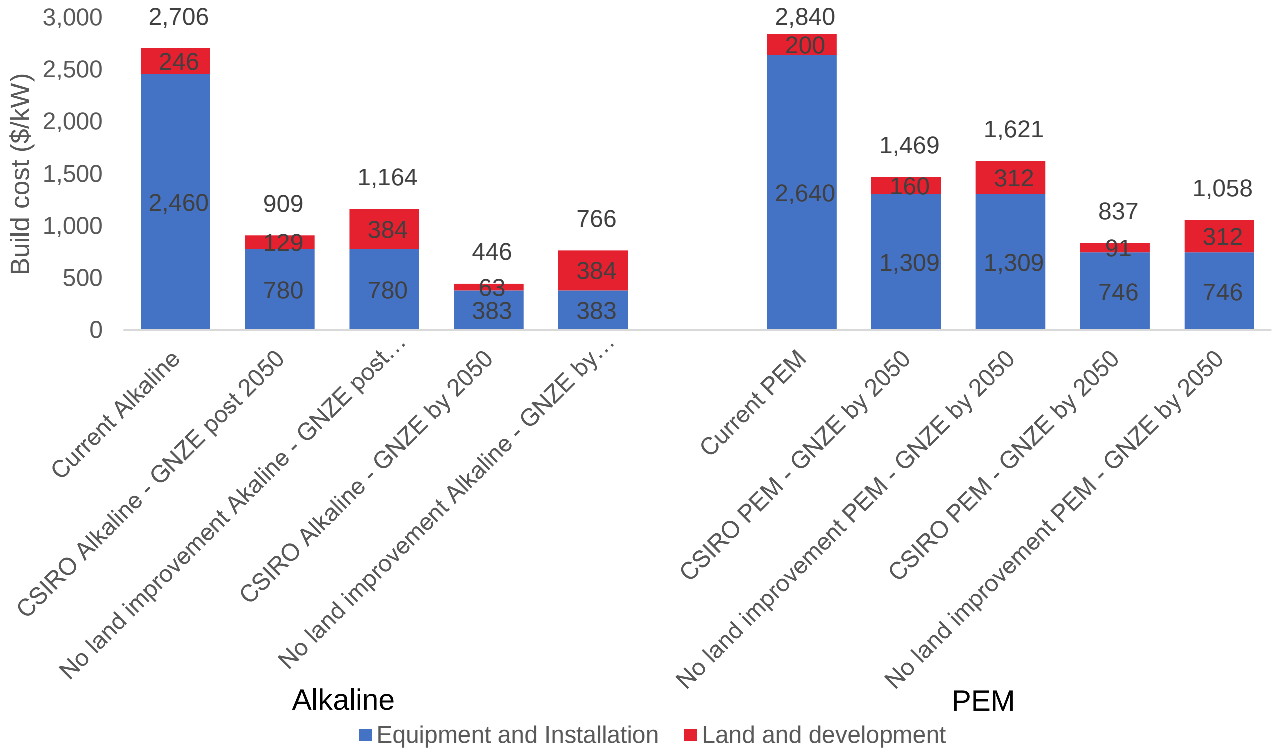


Figure 15: CSIRO GenCost 2050 Electrolyser build cost projections – impact of land and development cost methodology

Source: (CSIRO, 2024A)

3.6 Literature review

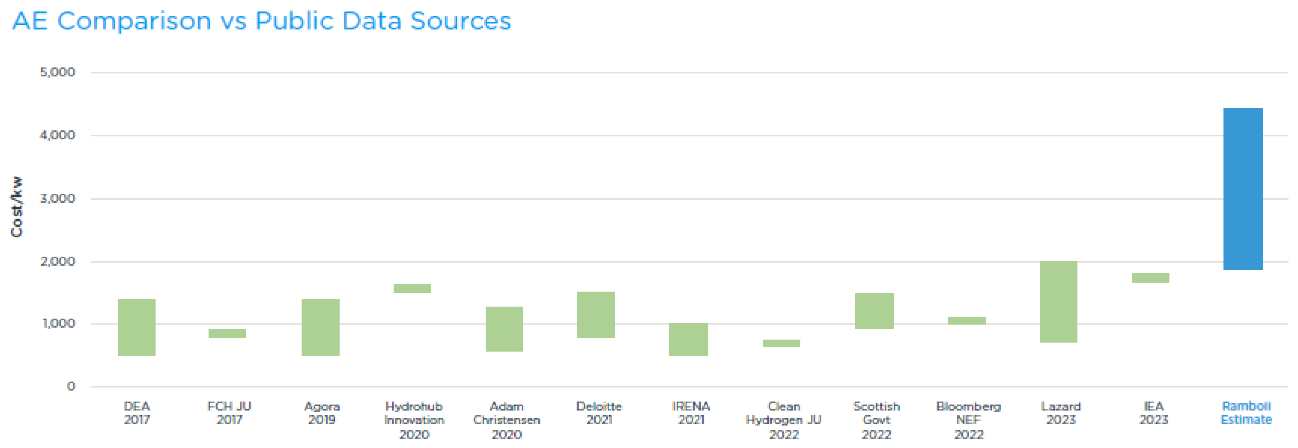
3.6.1 Ramboll Whitepaper

Current electrolyser capex estimates

In November 2023 Ramboll, a global engineering firm, that has worked on more than 30 power-to-X projects across the US and EU, released a whitepaper (Ramboll, 2023) that showed that public estimates of hydrogen projects capex were materially lower than detailed project cost estimates from Ramboll (see Figure 16). Ramboll states that differences:

- *“can accumulate to 1.3-3.3x the CAPEX estimates promulgated in often-cited public reports on a $/kW basis.”*
- *“These increases are likely attributed to a basis of design differentiation between Ramboll and the public sources, such as inclusion of compression and/or electrical infrastructure for a high up-time facility.”*

Ramboll estimates exclude storage and contingency for consistency with public sources.



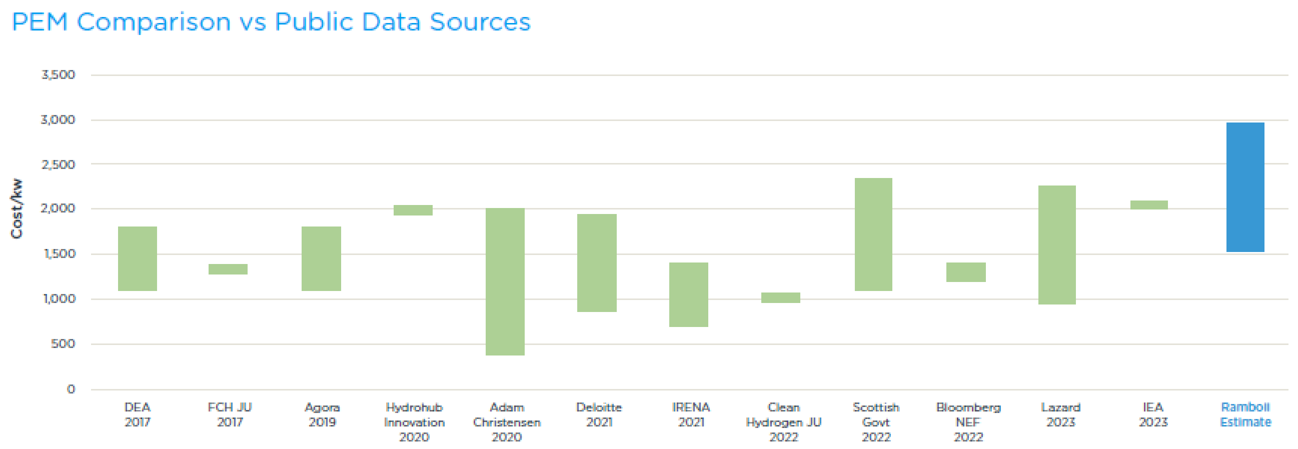


Figure 16: Ramboll estimates for electrolysers hydrogen production plant CAPEX from estimates of system sizes 10MW - 1GW (Top – Alkaline, Bottom – PEM) | Source: (Ramboll, 2023)

Notes:

- Ramboll estimates are ranges that assume low-saline water input, ample electrical at the battery limit, and compression to 50 bar.
- The higher range includes electrolyser buildings with mechanical ventilation and safety systems, and electrical infrastructure such as gas-insulated switchgears (GIS).
- The lower range assumes an outdoor weather rated installation of the equipment, and electrical infrastructure such as air-insulated switchgears (AIS).

Ramboll find that electrolyser stacks represent a small portion of hydrogen project costs, with other components such as BoP, offsites & utilities and construction indirect representing a larger portion of capex. Noting that public estimates are a fraction of Ramboll's, Ramboll find that:

"public estimates over-estimate certain cost categories, such as engineering, procurement, and construction (EPC) costs as a proportion of large project budgets (typically 15-30% of top-line CAPEX), while de-scoping other cost categories, such as buildings, electrical, indirects, and contingency"

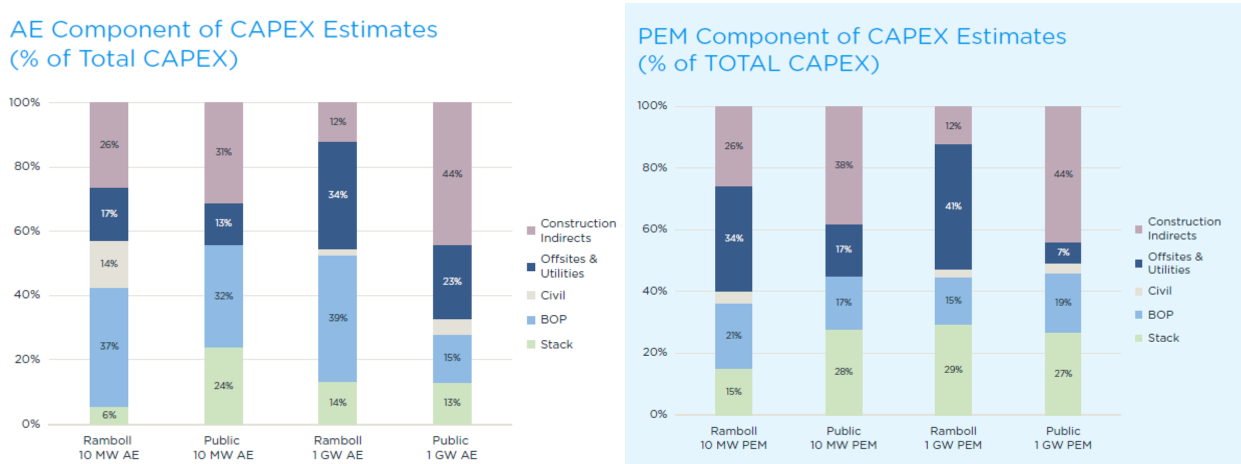


Figure 17: Ramboll vs public estimates of System Components at scale – non-pressurized system (Left – Alkaline, Right– PEM)

Source: (Ramboll, 2023)

Electrolyser learning rates

The 2020 paper *Accelerating low-carbon innovation* (Malhotra & Schmidt, 2020), classify technologies into three different types depending on their complexity and need for customisation per Figure 18. Type 1 (e.g.: LEDs, solar PV modules) is the easiest to achieve cost reduction while Type 3 (e.g. nuclear power plants, CCS) is the hardest/slowest. They provide data for a range of energy generation and other technologies demonstrating that learning rates differ between these different technology types as seen in Figure 18.

As well as being relevant for electrolysers this framework is a relevant contemporary reference document when considering learning rates for other technologies. (Ramboll, 2023) consider utility scale solar PV, onshore wind and rooftop solar PV all to be classified as type 2 reflecting that in addition to equipment the installation involves a degree of design complexity and/or need for customisation. In discussing the example of utility scale solar PV (Ramboll, 2023) note the that the proportion of the utility scale solar PV capex represented by solar PV modules fell from 50% in 2010 to 25% in 2020.

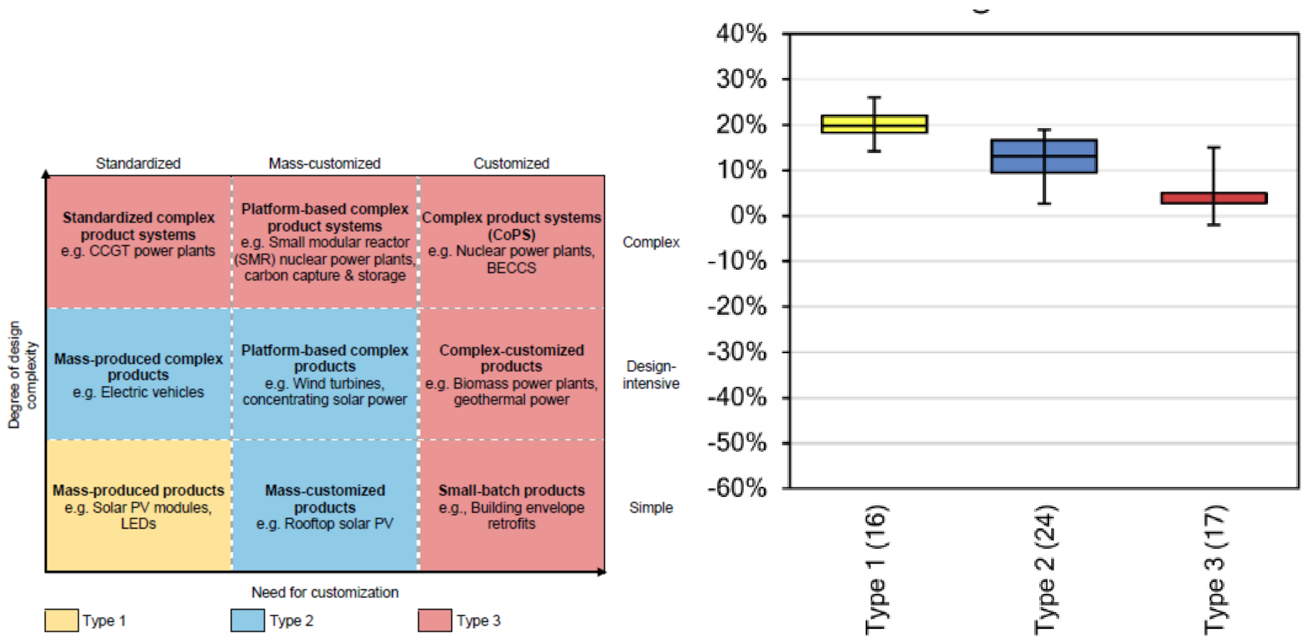


Figure 18: Left: Schematic Characterization of Different Energy Technologies Based on Their Design Complexity and Need for Customization
Right: Global Experience Rates and Box Plots for Different Technology Types and Technologies
Notes:

- The technologies are grouped into three types, each requiring different roles of national and international innovation and deployment policy

Source: (Malhotra & Schmidt, 2020)

- For Type 1 technologies (no shading), access to large and increasing global markets induces innovation.
- Type 2 technologies (blue) provide opportunities for national green industrial policies fostering local industry, technological adaptation, and participation in global value chains.
- Type 3 technologies (red) require a combination of national green industrial policies and measures to promote international coordination for inter-project and inter-context learning at a regional or global scale. The need for international coordination increases as one moves towards the top-right of the figure.

Ramboll assert that hydrogen production plants are complex and their design is customised to their surroundings. Figure 19 shows a unti level analysis of a hydrogen production plant. The plant consists of the electrolyser unit, electrolyser system, as well as the balance of plant and multiple process loops that connect with the outside environment: such as the water, electrical, and gas streams. Ramboll argues that these external interfaces make the plants highly customised to their specific location and thus reduce the impact of learning and scale. They also ask the reader to consider the large number of design factors in converting green electricity and water into an industrial stream of hydrogen or e-fuels in a hydrogen production plant, compared to utility scale solar PV project.

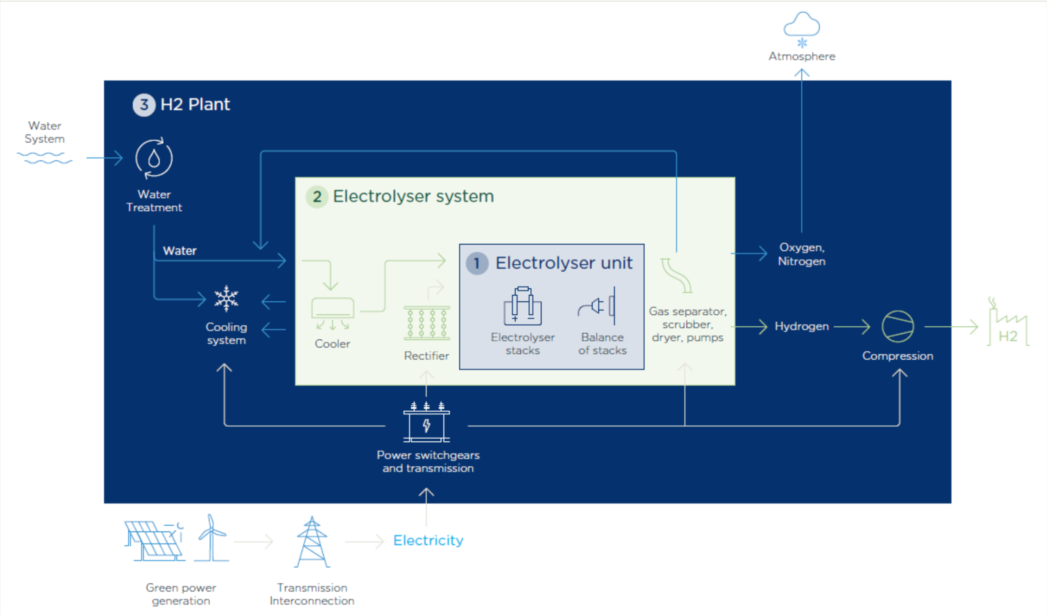


Figure 19: Visualising the interconnectivity of a H2 plant. | Source: (Ramboll, 2023)

Ramboll's white paper applies the framework in (Malhotra & Schmidt, 2020) to electrolysers and makes the case that that hydrogen production plants are a combination of type 1, 2 and 3 technologies, as depicted in Figure 20. Ramboll promote applying the (Malhotra & Schmidt, 2020) framework in estimating learning rates for green hydrogen production plants. Per Figure 17 electrolyser stacks represent a small portion of hydrogen project capex, and other components could experience lower learning rates due to high complexity and design customisation. Similarly (Martin, 2022) discusses scaling electrolysers and presents the view that balance of plant will not be subject to significant cost reductions due to the commonality and maturity of the relevant equipment.

Ramboll argues (Ramboll, 2023) that many studies conducted by policymakers (including (International Energy Agency, 2021B)), trade groups, and industry participants assign learning curves from the solar industry to predict the potential cost declines in green hydrogen electrolysers based on the assumption green hydrogen electrolysers are a Type 1 technology. This implies that these projections (including IEA) could be materially underestimating electrolyser capex projections and therefore the cost of green hydrogen.

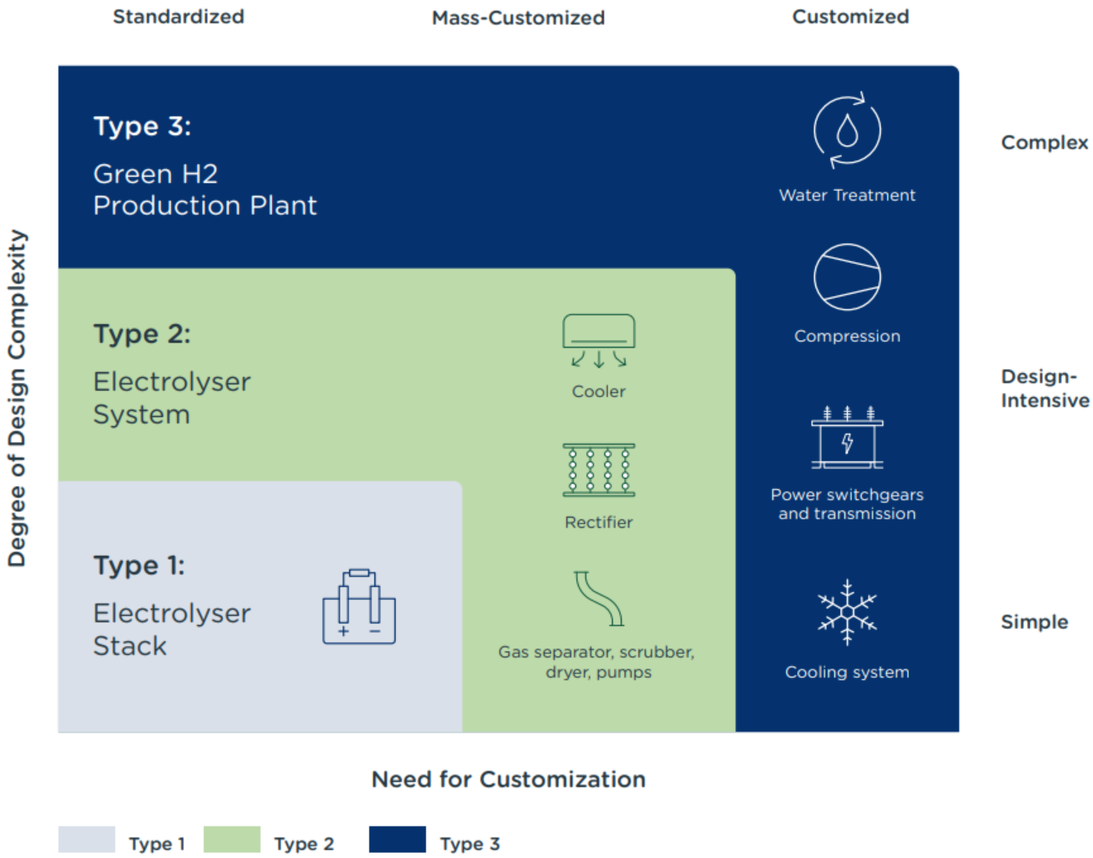


Figure 20: Hydrogen production plants are a complex, customized system of products that are built off of mass-customized and simpler, more standardized products.

Source: (Ramboll, 2023)

3.6.2 TNO

(TNO, 2024) conducted a study for the Energy Transition Studies research programme (OPETS) of the Climate Directorate of the Ministry of Economic Affairs and Climate Policy (Netherlands) with the aim of providing as realistic as possible overview of the cost components of green hydrogen production.

Project developers were asked to reflect on the estimates of electrolysis data from the market consultation (held in 2022) for the main Dutch support scheme (SDE++ or Sustainable Energy Transition Incentive Scheme), and to provide cost data of their 100MW to 200MW electrolyser projects. In total eleven parties provided data sets for fourteen projects. Based on the data provided electrolyser project capex was estimated as €3,050/kW and €2,630/kW for a 100MW and 200MW project respectively.

The €3,050/kW cost estimate for a 100MW electrolyser project was 38% higher than the €2,200/kW capex from the penultimate market consultation SDE++ undertaken in 2023 (TNO, 2024). The market consultation included the subsidy intensity per ton of CO_2 by applying the technology and this was an important criterion in this subsidy instrument, which could have incentivised lower cost being put forward (TNO, 2024). See (Fkyvbjerg & Rasnussen, 2021) for a discussion of the top ten behavioural biases in project management that includes: strategic misrepresentation, optimism bias and overconfidence bias.

The data in Figure 21 is sourced from (TNO, 2024) and shows that project capex estimates were far higher than generic public estimates and the previous TNO study . Generic estimates are not based on detailed design and cost studies. Such estimates are often mainly based on direct costs estimates and cost factors, such as indirect costs, owner costs and contingency costs, are often insufficiently included or not considered because they are location-specific and can also depend on the development phase of a project (TNO, 2024).

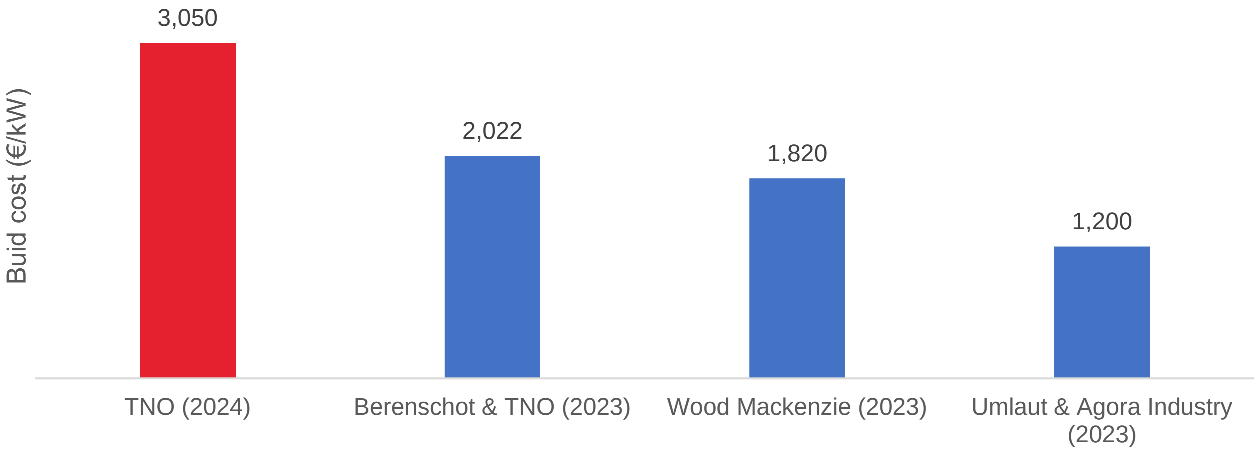


Figure 21: Electrolyser build cost for TNO and public generic estimates based on 2023 reference year | Source: (TNO, 2024) (Berenschot & TNO, 2023) (Wood Mackenzie, 2023) (Umlaut & Agora Industry, 2023)

Figure 22 Shows the breakdown in of green hydrogen production facility build cost into constituent parts. Indirect cost includes, among others, management cost of engineering, procurement and construction (EPC contractor), temporary housing facilities and temporary site services and facilities. Owner costs in general are the non-EPC costs, e.g. engineering and project management, and land cost and site development outside of project boundaries.

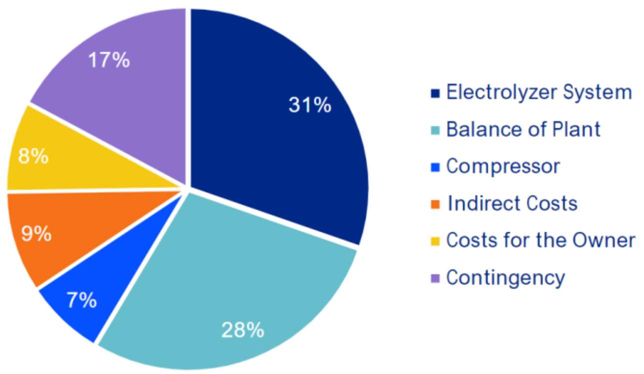


Figure 22: Breakdown of electrolyser build cost into constituent parts | Source: (TNO, 2024)

3.6.3 BNEF

In March 2024, BNEF increased its 2023 electrolyser system cost estimate to US$2,500/kw (Hydrogen Insight, 2024) (BNEF, 2024A) (Department of Energy - United States of America, 2024) . BNEF acknowledge that many public estimates, including their own had underestimated capex by 50-70% (BNEF, 2024A). The key root causes identified by BNEF were:

- Developers underestimating indirect costs (infrastructure, storage, compression, contingencies etc). Storage and compression accounted for less than ~US$300/kw of BNEF's capex estimate and we are of the view that hydrogen storage should be modelled separately.
- Electrolyser manufacturing capacity exists only on paper and is mostly in China. Combined with inadequate workforce, suppliers of stack subcomponents such as catalysts and membranes aren't expanding as quickly as makers of the stacks themselves, restricting effective manufacturing capacity
- Utilities and labour costs are higher for Western manufacturers.

In September 2024 BNEF's released "*Electrolysis System Cost Forecast 2050: Higher for Longer"* which contains a detailed bottom-up analysis of electrolysis system costs (Tengler, 2024) (BNEF, 2024B). Key findings were:

- Electrolysis capex could fall by about one half from today to 2050 assuming continued government support and free trade.
- The new 2050 capex forecast is significantly higher than what BNEF anticipated in its 2022 analysis.
- Strict trade barriers could lower the cost reduction to just 28% in Western markets and limit the industry's growth.
- Not all components of an electrolysis system are likely to fall in cost at the same rate. While stacks can get significantly cheaper, the costs of more established technologies like transformers are unlikely to decline as rapidly.

3.6.4 IEA

Figure 23 shows the how the International Energy Agency's current electrolyser build cost and projected electrolyser build cost for the Announced Pledges and Net Zero Emissions Scenario have changed over the past four World Energy Outlooks.

In October 2024 the 2024 Global Hydrogen Review (International Energy Agency, 2024B) revised previous 2023 electrolyser capex estimates (International Energy Agency, 2023B) by ~20% and 2030 capex projection upward. For the 2023 figure the increase was, "based on newly available data from more advanced projects and to include contingency costs, resulting in an increase of about 20% ((BNEF, 2024A), (TNO, 2024))". BNEF's build cost estimate is 16% higher than IEA's and TNO's 42% and 22% for 100MW and 200MW respectively.

IEA typically doesn't source its current electrolyser capex estimates from independent sources and thus should be treated with caution. The key data source for its Global Hydrogen Review's current capex and projections being McKinsey & Company and the Hydrogen Council (International Energy Agency, 2024B) (International Energy Agency, 2023B) (International Energy Agency, 2022B) (International Energy Agency, 2021B). The Hydrogen Council is the peak lobby group for the Hydrogen industry and McKinsey & Company produces a significant volume of promotional reports and analysis for the Hydrogen Council (Hydrogen Council, 2024). For a discussion regarding the role of lobbyists in promoting the hydrogen industry in Europe refer to (Liebreich, 2024).

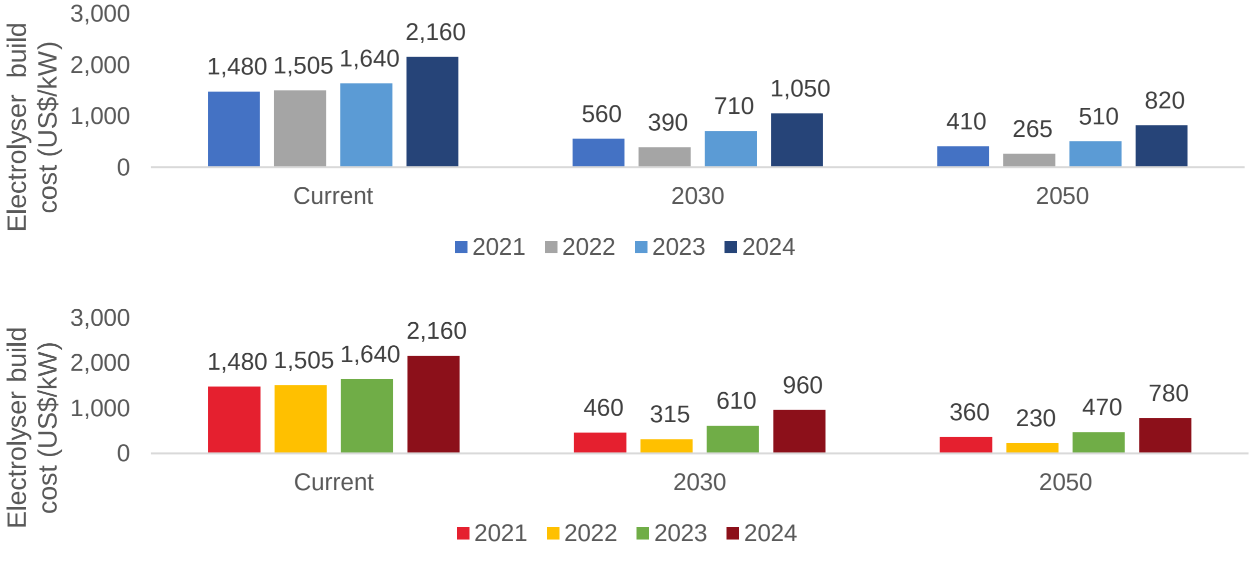


Figure 23: IEA World Energy Outlook electrolyser build cost estimates and projections (Top – Announced Pledges scenario, Bottom – Net Zero Emissions scenario)

Source: (International Energy Agency, 2024A) (International Energy Agency, 2023A) (International Energy Agency, 2023A) (International Energy Agency, 2021A)

While on a whole low-emission hydrogen demand projections have remained similar between IEA World Energy Outlooks 2050 electrolyser build cost projections have increased driven by higher current capex and lower assumed learning rates on non-electrolyser stack components per Table 4. IEA has progressively reduced learning rates over time for non-electrolyser stack components, though it has provided no source for non-electrolyser stack learning rates. In the 2024 Global Hydrogen Review the IEA reported that for PEM, electrolyser stack represented 20% of capex vs previous version of the report where it reported that it represented 50%. The IEA also reported that EPC and installation represented 50% of PEM capex and introduced a learning rate for this component. The large changes and lack of sources for learning rates is further evidence as to why IEA's projections should be treated with caution.

The 2021 Global Hydrogen Review selected a learning rate of 15% for the electrolyser stack, which takes account of learning rates for fuel cells that rely on the same electrochemical processes (International Energy Agency, 2021B). The source of the learning rate was a literature review.

The 2022 Global Hydrogen Review assumed a learning rate of 18% for the electrolyser stack, based on fuel cell learning rates from (Store&Go, 2019), while for the other components, that IEA stated represented almost half of electrolyser capex, the assumed learning rate varies between 7-13% (International Energy Agency, 2022B). It's not clear why IEA have used fuel cell learning rates of 18% from (Store&Go, 2019) for the electrolyser stack when the literature review of this report finds that based on three studies electrolyser stack the mean learning rates is 9.6% and a standard deviation of 5.5%. No sources are provided for the other learning rate assumptions.

The 2023 Global Hydrogen Review reduced learning rates on other components to 5-12% (International Energy Agency, 2023B). No sources are provided for the other learning rate assumptions, that that IEA stated represented about half of electrolyser capex.

The 2024 Global Hydrogen Review split other capex into two components: Balance of Plant with a 2-10% learning rate and EPC and installation with an 8% learning rate (International Energy Agency, 2024B). No sources are provided for these learning rate assumptions. The report also contains Figure 24 which shows that the electrolyser stack for a PEM electrolyser represents 20% of capex, compared to the almost half of capex claimed in 2022.

IEA Global Hydrogen Review	Electrolyser stack	Other	Balance of plant	EPC and installation cost
2021	15%			
2022	18%	7-13%		
2023	18%	5-12%		
2024	18%		2-10%	8%

Table 4: IEA Global Hydrogen Review learning rates by electrolyser component

Source: (International Energy Agency, 2024B) (International Energy Agency, 2023B) (International Energy Agency, 2022B) (International Energy Agency, 2021B)

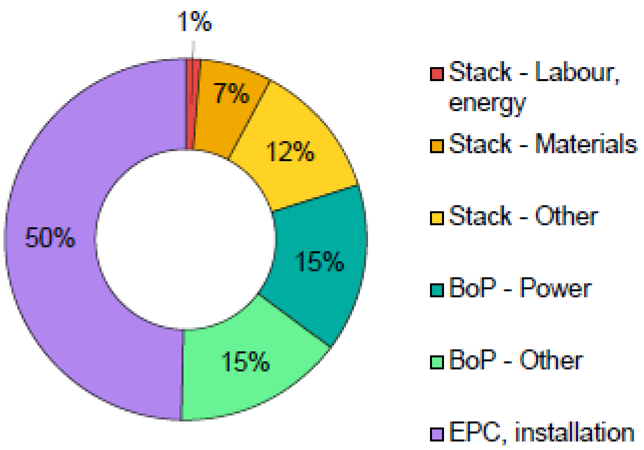


Figure 24: 2024 IEA Global Hydrogen Review – PEM electrolyser capex by component

Source: (International Energy Agency, 2024B)

4. Onshore wind

4.1 Recommendations

The following recommendations are made which align with submission sections:

Section 4.2 Proportion of build cost relating to installation should be increased and align with activities rather than contractual structures

Section 4.3 Installation costs should be projected based on learning rates, rather than reverting to modelled levels

Section 4.4 Local learning rates for installation should vary by scenario to reflect uncertainty around the level of further turbine scaling

Section 4.5 Equipment costs should experience only a partial reversion towards GALLME modelled costs

Section 4.6 Current GenCost build cost should align with Aurecon's estimate

4.2 Proportion of build cost relating to installation should be increased and align with activities rather than contractual structures

4.2.1 Aurecon's cost estimates don't appear to have adequately captured the trend of rising installation costs over the past 5 years

(Aurecon, 2024A) states that construction costs are up more than 25% over the past five years (to June 2024) vs 21.2% for CPI and has applied nominal cost escalation of 5-7.5% to 2023 estimates, except gas turbines where it has applied 10% cost escalation.

However, while Figure 25 shows that real wind build costs have grown by 36% over the past 5 years, installation cost has reduced. This result may be driven by Aurecon's installation cost estimates being somewhat rudimentary, with installation costs falling from 40% of EPC capex in 2019 to 30% in 2020, 20 to 25% in 2022 onward.

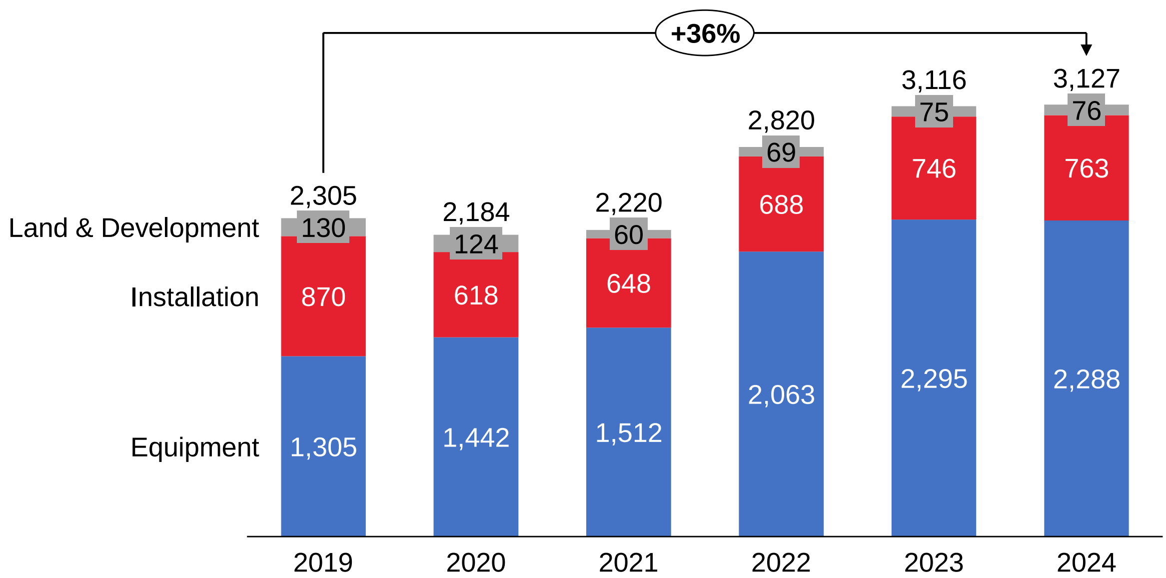


Figure 25: Aurecon Wind Farm build cost estimate by year - $/kW ($A 2024)

Source: (Aurecon, 2024A) (Aurecon, 2024B) (Aurecon, 2022) (Aurecon, 2021A) (Aurecon, 2021B) (Aurecon, 2019)

Figure 26 (left) shows while Aurecon wind build cost estimates have been closely aligned with US build cost estimates, (right) shows that Aurecon's aggregate estimates of Balance of System and Soft Costs has not increased at the same rate as US estimates from NREL (NREL, 2024A) . NREL's 2023 Balance of Plant and Soft Cost estimates are 66% above Aurecon's estimate. Note "United States – Adjusted" excludes wind turbine transport and wind turbine warranty (2yrs), which were included for the first time in 2022. This data series is included so trends in costs can be observed.

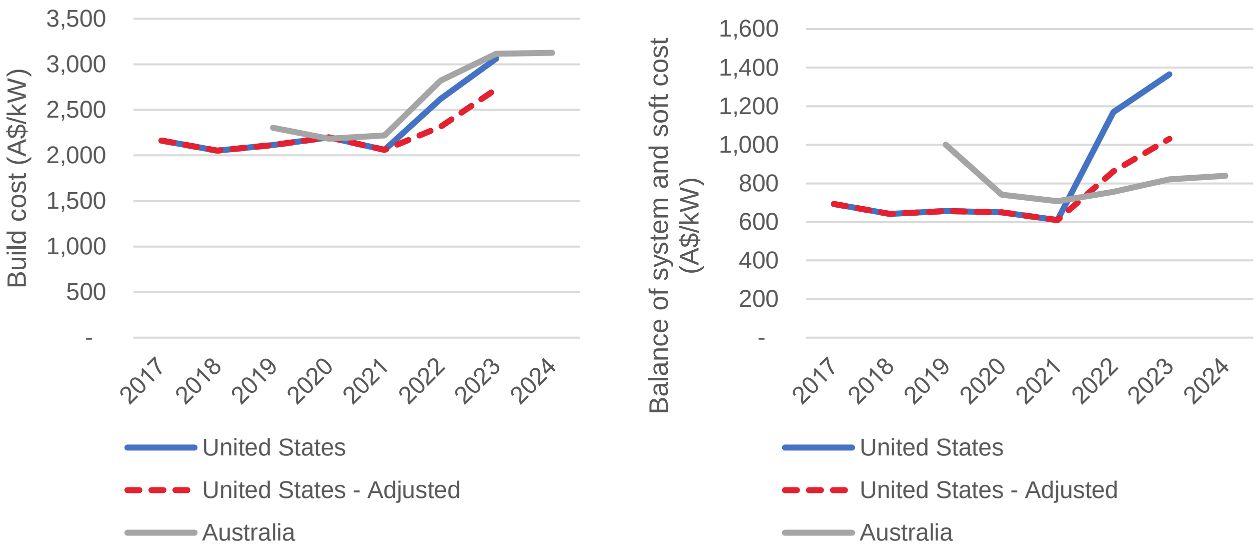


Figure 26: United States and Australia onshore wind farm build cost (left) and Balance of System and Soft Cost by year ($A 2024)

Source: (NREL, 2024A) (NREL, 2023A) (NREL, 2022) (NREL, 2021) (NREL, 2020) (NREL, 2019) (NREL, 2018) (Aurecon, 2024A) (Aurecon, 2024B) (Aurecon, 2022) (Aurecon, 2021A) (Aurecon, 2021B) (Aurecon, 2019)

Aligning with Figure 25 (CSIRO, 2024A) states that in relation to onshore wind:

"Costs have risen around 36% since the beginning of the pandemic. Equipment costs appear to account for around 40% of that increase with the remainder reflecting other factors such as local installation (based on analysis of Vestas average selling price adjusted for Australian dollars)"

CSIRO's statement implies that Aurecon's 2024 equipment, land and development cost is underestimated by $654/kW (78%) consistent with Figure 27.

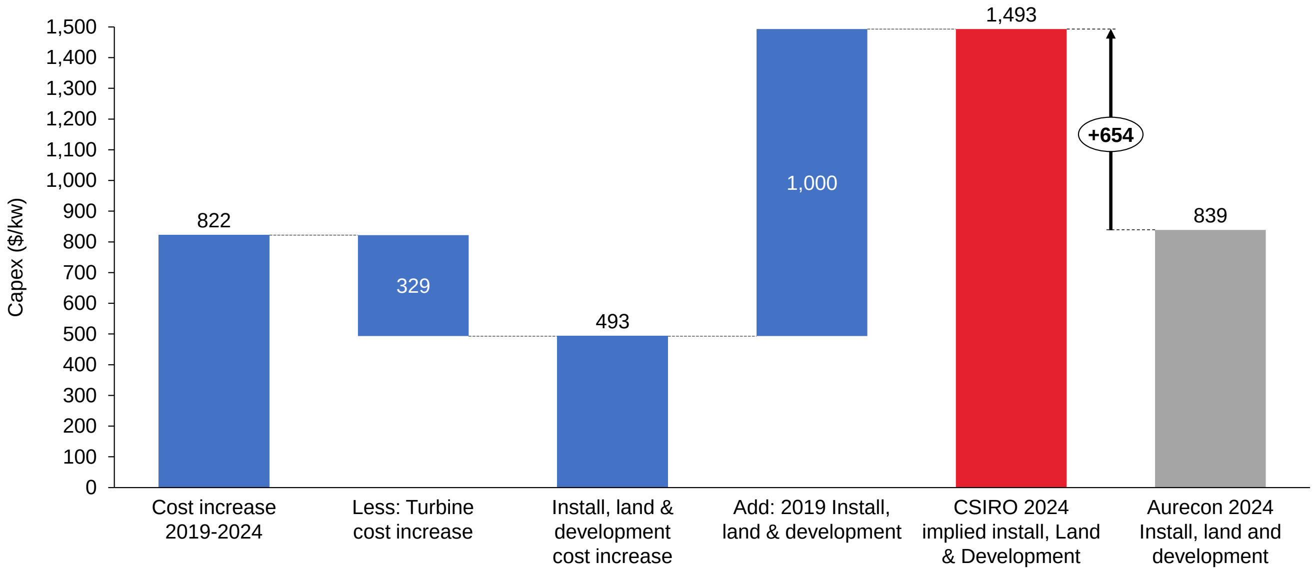


Figure 27: CSIRO implied 2024 onshore wind install, land & development capex ($A 2024)

Source: (Aurecon, 2024A) (Aurecon, 2019)

4.2.2 Installation, land and development represent a lower proportion of build costs for Aurecon than other benchmarks, including NEM wind projects

Aurecon is encouraged to be clearer around its current delineation of equipment and installation cost within its report and to include an additional estimate of installation that aligns with underlying activities (including domestic turbine transport and installation).

Aurecon's delineation of equipment cost and installation/balance of plant could be clearer in its report. Aurecon provided feedback on the GenCost webinar on 5 Feb 2025 that its aligned with a split EPC contract.

Figure 28 compares Aurecon's estimates to US NREL data and to two NEM wind farms, based off confidential data provided by a CAEEPR member. Electrical sub-stations are within the boundary of the two NEM wind farms capex estimates, while for Aurecon's estimates this infrastructure is not included, though this does not materially impact the analysis. Wind farm development fees/development costs were excluded from the analysis.

The red columns in Figure 28 represent estimates of Balance of Plant and land and development cost based on a spilt EPC contract, where the turbine Supply and Install contract includes wind turbine transport, assembly and installation. The Balance of Plant and land & development component of the two NEM wind farms are 14%-19% higher than Aurecon and a further 4% higher than NREL.

The blue columns in Figure 28 represents the 22% increase in Balance of Plant and land and development cost from moving from a spilt EPC contract aligned definition to NREL's definition. NREL's definition may be better aligned with underlying activities and if applied to NEM wind farm estimates could increase Balance of Plant and land and development to over 50% of build costs.

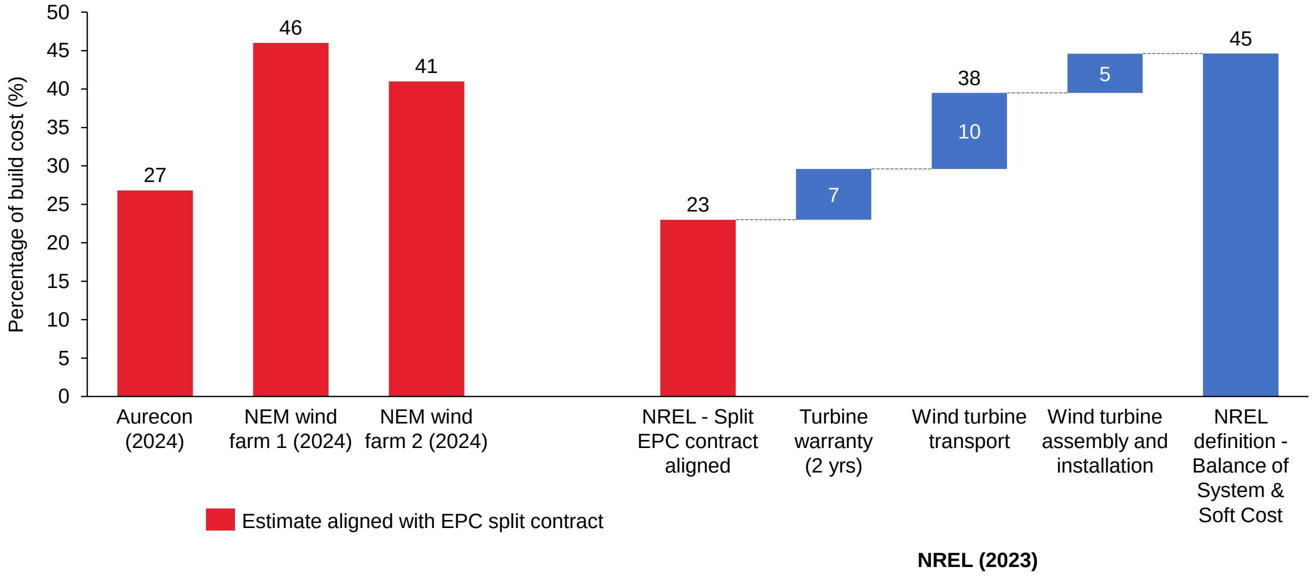


Figure 28: US and Australia - Balance of Plant and land & development capex as percentage of build cost

Source: (Aurecon, 2024A) (NREL, 2024A) Confidential CAEEPR member project data

4.3 Installation costs should be projected based on learning rates, rather than reverting to modelled levels

A key part of CSIRO rationale for reverting wind build cost to their modelled path by 2035 is that:

"In recent years, the cost of a range of technologies including electricity generation, storage and hydrogen technologies has increased rapidly driven by two key factors: increased freight and raw materials costs."

However, it is not appropriate to model a reversion in installation cost towards modelled levels as cost escalation on major Australian construction projects is forecast to continue to exceed CPI. Instead, installation costs should be projected based on learning rates.

Construction cost inflation (typically referred to as cost escalation) has normalised from exceptionally strong rates as transitory factors such as global supply chain bottlenecks have eased. However, going forward domestic demand for large construction projects, is expected to provide a sustained source of cost pressure that may drive cost escalation above CPI on a more persistent basis.

Based on ABS data (Oxford Economics Australia, 2024A) states that cost escalation:

"has historically outpaced growth in broader household-based inflation measures such as the Consumer Price Index (CPI)."

Growth in the ABS Engineering Construction Implicit Price Deflator (a broad measure of price growth in engineering construction work done) has exceeded CPI by:

- 0.3% since the mid-1980s, across the entire data series (3.4% Engineering Construction IPD vs 3.1% CPI)
- 0.9% since the 2000s, which captured the mining boom and post COVID-19 boom (3.7% Engineering Construction IPD vs 2.8% CPI)

Per Figure 29 (Oxford Economics Australia, 2024A) forecast that as early as FY2026:

"another 'decoupling' of construction cost escalation and the CPI, with engineering construction IPD potentially growing at more than 4%pa by FY2028 and pushing even higher towards the turn of the decade."

Rather than international factors, (Oxford Economics Australia, 2024A) see that domestic price pressures, driven by a strong pipeline of construction activity, is now increasing construction cost escalation. In particular (Oxford Economics Australia, 2024A) find that strong demand is driving stronger growth in construction wages and prices for inputs such as quarry materials, cement and concrete. Comparing Figure 29 and Figure 30, illustrates that the construciton IPD can still outpace CPI during periods with a relatively low construction pipeline, as it did in 2017-2020.

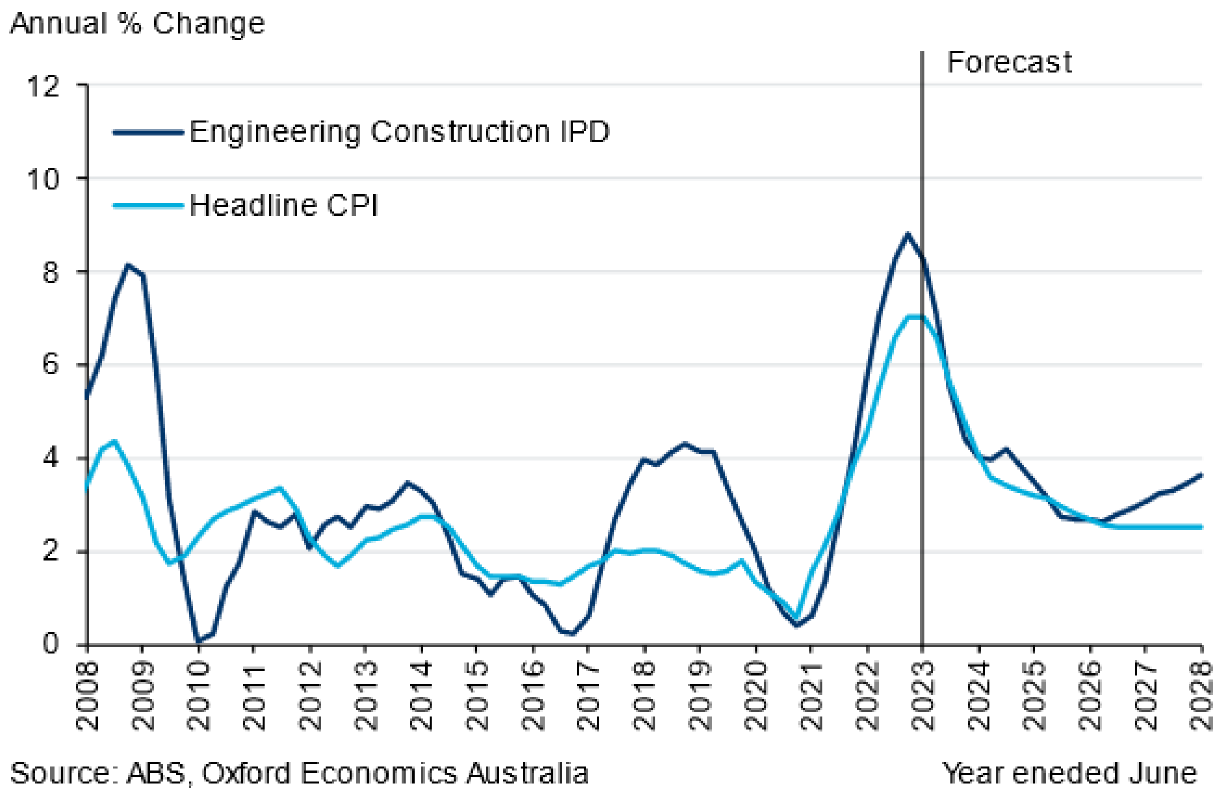


Figure 29: Engineering Construction Implicit Price Deflator and Headline CPI, 2008-2028 | Source: (Oxford Economics Australia, 2024A)

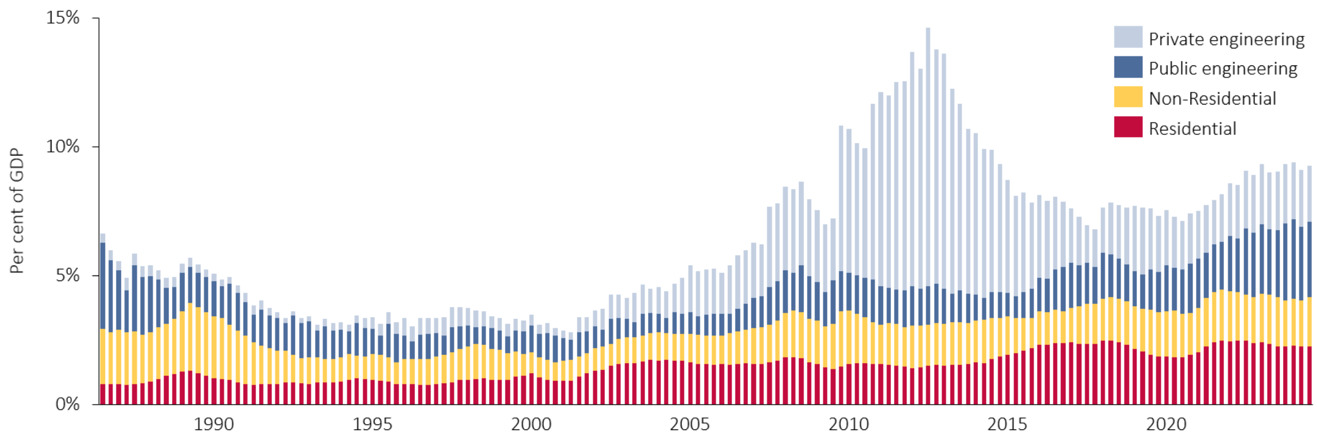


Figure 30: Australian Construction Pipeline as Per cent of GDP | Source: (Australian Bureau of Statistics, 2025A), (Australian Bureau of Statistics, 2025B), (Australian Bureau of Statistics, 2024)

Similarly per Figure 31 (Rider Levett Bucknall, 2024) forecast construction escalation for 2025 still being considerably higher than the RBA's 2—3% target range for CPI inflation, with this pattern persisting into the future. (Rider Levett Bucknall, 2024) identify persistent skilled labour shortages, material costs and supply chain issues as key issues impacting the outlook for construction activity. (Rider Levett Bucknall, 2024) identify that while some material costs have stabilised or fallen; others remain high due to ongoing supply chain disruptions.

	2024	2025 (F)	2026 (F)	2027 (F)	2028 (F)	2029 (F)
ADELAIDE	6.5	**5.0**	4.5	4.0	3.5	3.5
BRISBANE	7.2	**5.6**	5.1	5.1	5.1	5.1
CANBERRA	4.0	**3.75**	3.5	3.0	3.0	3.0
DARWIN	5.5	**5.0**	4.5	4.0	4.0	4.0
GOLD COAST	7.5	**5.0**	5.0	5.0	5.0	5.0
MELBOURNE	5.0	**4.0**	3.5	3.5	3.5	3.5
PERTH	5.2	**4.9**	4.5	4.0	3.7	3.7
SYDNEY	5.5	**4.5**	3.5	3.5	3.5	3.5
TOWNSVILLE	7.0	**6.0**	5.0	4.0	4.0	4.0

Figure 31: Annual Tender Price Index Uplift | Source: (Rider Levett Bucknall, 2024)

4.4 Local learning rates for installation should vary by scenario to reflect uncertainty around the level of further turbine scaling

Wind farm balance of plant consists of civil works such as access tracks, hard stands and turbine foundations, and electrical balance of plant such as main transformers and connection substation, underground electrical cable and overhead transmission lines (Canto & Hetherington, 2023). These balance of plant components are mature technologies, with designs customised to the specific site, including to conform with geotechnical conditions (Canto & Hetherington, 2023). Applying the framework in (Malhotra & Schmidt, 2020) suggests that balance of plant could be classified as Type 3 technology, implying lower learning rates. However, while cost reductions can be a result of a range of innovations, turbine scaling is a key driver of LCOE reduction for wind farms (NREL, 2016) and wind turbine balance of plant capex. (Bolinger, Wiser, & O'Shaughnessy, 2022) states that:

… "higher CapEx devoted to wind turbine scaling can reduce LCOE from multiple angles: by reducing balance-of-plant CapEx (e.g., fewer foundations and access road per MW), by reducing OpEx (e.g., fewer tower climbs per MW), and by boosting capacity factor (through taller towers accessing better winds, and via larger rotors relative to turbine capacity)."

However, there is uncertainty to the level and pace of further turbine scaling (hub height, rotor diameter, nameplate capacity) and cost benefits in Australia as:

- Table 5 shows committed NEM wind projects while Figure 32 shows data for US wind farm installations. The wind turbine hub height, rotor diameter and nameplate capacity NEM projects are materially higher than US projects installed in 2023. As similar finding is seen when comparing to global data from (Pelser, et al., 2024).
- Increasing turbine capacity may be of limited value as the marginal output will be at periods of high wind speed and as wind generation is highly correlated, dispatch weighted prices for this generation could be relatively low. This contrasts with increasing wind turbine hub height and rotor diameter which could result in higher generation over a range of wind speed conditions.
- Limiting factors to ongoing turbine sclaing include lifting capacity and maximum reach of the currently available cranes, with a present limit on hub height of 166m (Aurecon, 2024A). The requirement for large cranes to erect wind tower and turbine components at this hub height can increase civil balance of

plant cost for roads and hard stands (Williamson, Massive cranes on “tippy-toes:” Tricky sites might herald peak hub height for wind farms, 2023A), reducing the benefits of turbine scaling.

- Size and weight constraints on transport routes due to road class, corners, overpasses, etc. (Smith, Tracey, & Metherell, 2024) (Williamson, Massive cranes on “tippy-toes:” Tricky sites might herald peak hub height for wind farms, 2023A)
- Western turbine OEMs focussing on longer product cycles, focussing on existing models for longer (Reuters, 2024A) (Reuters, 2024B). (Aurecon, 2024A) states that further upscaling in onshore wind turbine capacity beyond 7-8MW is not expected in the short term.
- Vestas is the dominant onshore wind turbine supplier in Australia. A Vestas media release titled, *“It's time to slow down on turbines if we really want to scale up the offshore wind industry”* was released on 26 May 2023 (Vestas, 2023A). The media release stated that, *“Continuous rapid introduction of larger new models is hindering efforts to establish sustainable and robust supply chains”*. Vestas’ enVentus platform was introduced on 24 January 2019, with the largest variant the V162-5.6MW (Vestas, 2019). Over 5 year later, Vestas announced that a prototype V172-7.2MW was installed on 24th July 2024, the first in the enVentus range with a larger rotor diameter (REVE, 2024).

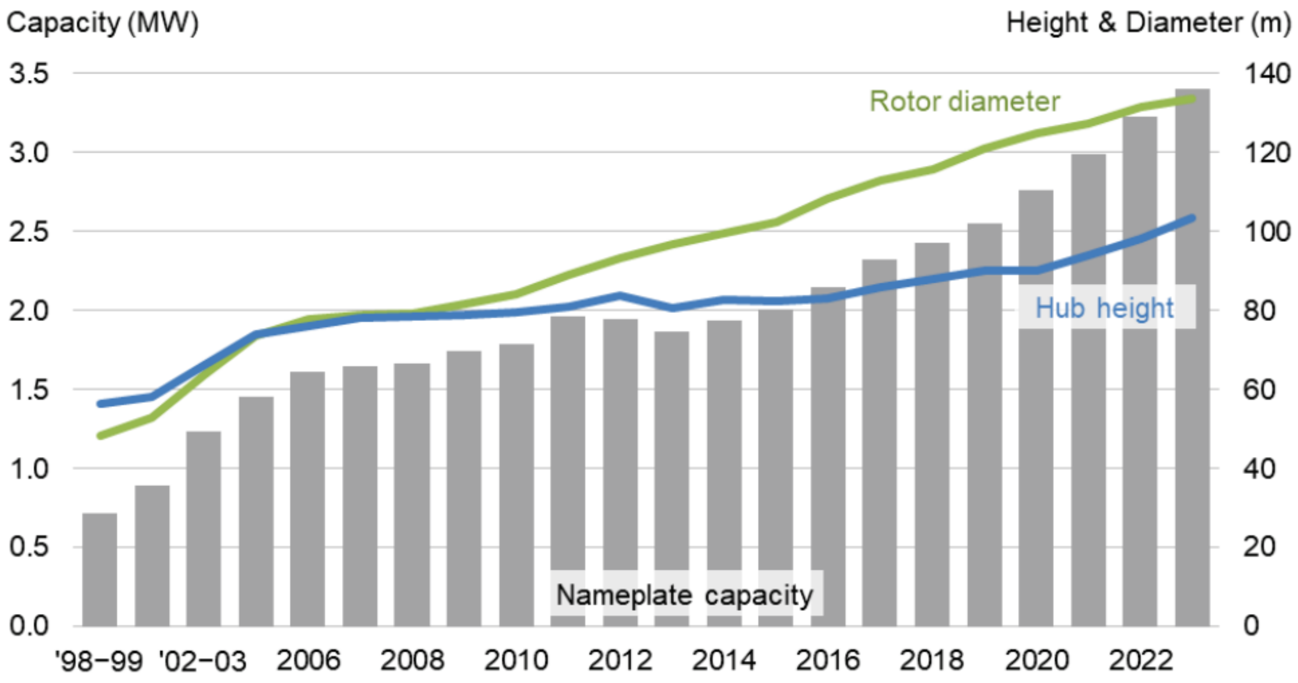


Figure 32: Unites States - Average turbine nameplate capacity, hub height, and rotor diameter for land-based wind projects | Source: (NREL, 2024B)

Project name	Wind farm capacity (MW)	Turbine nameplate capacity (MW)	Rotor diameter (m)	Hub height (m)	OEM
Clarke Creek Wind Farm	450	4.5	152	130	Goldwind
Golden Plains Wind Farm East	756	6.2	162	149	Vestas
Golden Plains Wind Farm West	577	6.2	162	149	Vestas
Lotus Creek Wind Farm	285	6.2	162	149	Vestas
MacIntyre Wind Farm	923	5.7	163	148	Nordex

Uungula Wind Farm	414	6	164	148 or 167	Vestas
Wambo Wind Farm (Stage 1)	260	6.2	162	166	Vestas
Capacity weighted average		**5.8**	**161**	**149**	

Table 5: NEM Committed onshore wind farms – wind farm capacity, turbine nameplate capacity, hub height, and rotor diameter | Source*:* (Australian Energy Market Operator, 2025)

Table 6 shows Global and Local Learning rates for onshore wind don't vary by scenario. Local learning rates should be considered in the context that, per Section 0, engineering construction cost escalation has exceeded CPI by 0.9% since the 2000's and construction cost escalation is forecast to exceed CPI in the future (Oxford Economics Australia, 2024A) (Rider Levett Bucknall, 2024). Given uncertainty around the level of future turbine scaling, Local Learning rates are recommended to be varied by scenario, with a learning rate of 4% for Current Policies (Progressive Change), aligning with average learning rates for Type 3 technologies from (Malhotra & Schmidt, 2020).

Source	All scenarios	References
Global Learning Rate 1	-	(International Energy Agency, 2021A) (Hayward & Graham, 2013)
Global Learning Rate 2	4.3%	
Local Learning Rate 1	-	
Local Learning Rate 2	9.8%	

Table 6: CSIRO GenCost 2024-25 Consultation Draft onshore wind learning rates | Source*:* (CSIRO, 2024A)

4.5 Equipment costs should experience only a partial reversion towards GALLME modelled costs

CSIRO provides the following rationale for reverting wind build cost to their modelled path by 2035:

"In recent years, the cost of a range of technologies including electricity generation, storage and hydrogen technologies has increased rapidly driven by two key factors: increased freight and raw materials costs. The most recent period where similar large electricity generation technology cost increases occurred was 2006 to 2009 with wind turbines and solar PV modules being most impacted. The cost drivers at that period of time were policies favouring renewable energy in Europe, which led to a large increase in demand for wind and solar. This coincided with a lack of supply due to insufficient manufacturing facilities of equipment and polysilicon in the case of PV and profiteering by wind turbine manufacturers.

…

In response to feedback, this report includes an exception which is that onshore wind costs do not return to their normal path until 2035. Of all the technologies that are currently in high demand, onshore wind capital costs were impacted the most and have demonstrated to be the slowest to recover. It is therefore appropriate to give onshore wind a separate pathway.

A consequence of this modelling approach is that all of the cost reductions to either 2027 or 2030 (or 2035 for onshore wind) mostly do not reflect learning. Rather, they are predominantly the slow unwinding of inflationary pressures that have temporarily placed costs above the underlying learning curve."

(NREL, 2016) analyses wind turbine price trends between 2001 to 2015 examining "endogenous" drivers largely within industries control, such as turbine scaling and learning and "exogenous" drivers fall largely outside of the industry's control. This Section provides similar analysis to (NREL, 2016) on a sub-set of the drivers, for the past 5-10 years, as well as consensus forecasts where data is readily available :

- "endogenous" variables – turbine prices, warranty provisions, profit margins and return on equity at turbine OEM.
- "exogenous" variables – wind turbine demand, steel, energy and shipping costs, global competition and barriers to entry

The analysis finds that current market conditions for wind turbine OEM, appear to be markedly different to those of 2006 to 2009. There doesn't appear to be evidence of rapidly rising demand for wind turbines ex China, or western wind turbine OEMs earning strong profits. In fact, turbine OEM are recovering from negative profitability, with the nadir in 2022, driven by lower wind turbine demand, cost escalation and poor product quality, leading to warranty claims.

- Growth in wind installations has been concentrated in China, with growth ex China relatively muted.
- There is limited evidence of enduring manufacturing capacity constraints.
- Western OEMs have increased turbine prices recently, though price cycles are not unusual for wind turbines.
- Warranty provisions have increased for western OEMs, however there are some signs of improvement
- Despite higher turbine prices OEM margins and return-on-equity have not yet recovered to pre COVID-19 levels.
- Material, shipping and energy costs are likely to be higher than historical levels in long term due to decarbonisation.
- Chinese OEMs are beginning to win market share in non-mature markets outside of China due to attractive pricing, which could put downward pressure on turbine prices.
- Barriers to entry could provide some protection to incumbent western OEM in mature markets.

The analysis suggests that a reversion to modelled costs from GALLME is not appropriate and wind farm build costs should instead be based on current build cost estimates from Aurecon, with learning rates applied. However, the analysis does identify that maritime shipping costs are materially higher than historical levels and some reversion of costs toward historical levels may be appropriate, while considering that decarbonised shipping will be higher cost than historical levels. As CSIRO identify increased freight and raw materials costs as being key drivers of onshore wind equipment escalation, further data on these cost drivers and rationale for future real cost reductions would be welcomed.

4.5.1 Growth in wind installations has been concentrated in China, with growth ex China relatively muted

The Global Wind Energy Council Reported that a record 116.5GW of wind capacity was installed in 2023 up 50% from 77.6GW in 2022 (Global Wind Energy Council, 2024), which compares to 2019 figures from IEA of 60.4GW (International Energy Agency, 2019). Installations tripled in China over this time, growing from 26GW to 75.6GW, while the rest of the world grew from 34.4GW to 40.9GW, a 6% CAGR. China is self-sufficient in wind turbine supply and in 2023 exported 1.7GW of wind turbines (BNEF, 2024C).

Compared to Pre-Covid, Figure 33 does not indicate that to date there has been a rapid increase in demand for major wind turbine OEM operating outside of China. Figure 33 shows wind turbine order intakes, for OEMs where this data is publicly available from 2018 to 2024 (9 months only). Wind turbine OEM order growth varied for 2023, with growth for Goldwind, Vestas, Nordex and Siemens Gamesa, -1%, 64%, 17% and -19% respectively. Order growth slowed somewhat in 2024, with Vestas and Siemens Gamesa (by revenue) recording, 2%, and -2% order growth respectively over the 9 months to Sep 2024, while Nordex recorded 13% growth in orders for 2024.

The Trump administration released a memo on 20 January 2025, that presents potential headwinds to onshore and offshore wind turbine demand in the Unites States (Greene, 2025). The memo has two major effects:

- It temporarily halts new leasing of federal waters for offshore wind.

- It directs all relevant agencies to pause approvals related to on- and offshore wind development, such as permits, until a comprehensive review has been completed.

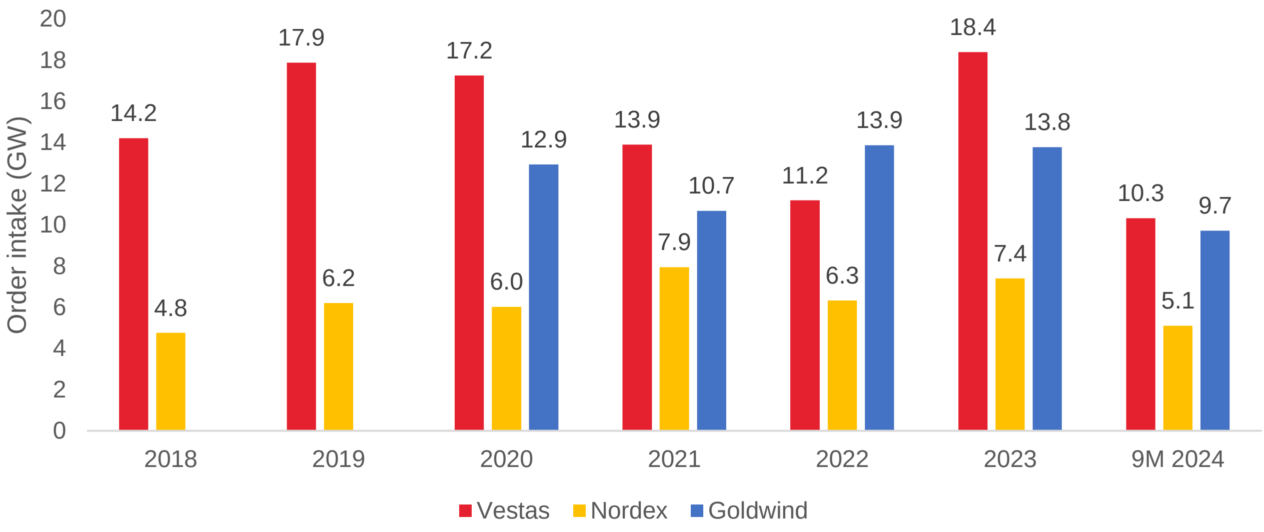


Figure 33: Selected turbine OEM – order intakes per year | Source: Bloomberg, Company annual and quarterly results presentations

4.5.2 There is limited evidence of enduring manufacturing capacity constraints

Some western wind turbine OEMs reduced manufacturing capacity in response lower demand in the early 2000s, with Vestas announcing the closure of three European factories in 2021 (Swagath, 2021), Nordex a German blade factory in 2022 (Ferris, 2022) and Siemens Gamesa mothballing two US factories (Reuters, 2023). More recently onshore wind turbine and component manufacturers have announced 15 expansions of U.S. factory capacity since the Biden administration's introduction of the Inflation Reduction Act (Reuters, 2024C). Investment announced by western OEMs in US manufacturing facilities include:

- GE Vernova - US$450 million in its existing U.S. manufacturing facilities in 2023 (GE Vernova, 2023).
- Vestas – US$40m in its existing two Colorado factories (Vestas, 2023B).
- Siemens Gamesa – reopening US blade manufacturing and nacelle assembly plants mothballed in 2022 (Reuters, 2023).
- Nordex – restarting production in mothballed Iowa factory (Nordex, 2024).

May 2023 IEA data on onshore wind equipment manufacturing capacity by region and component for 2022 and 2025, shows excess significant excess capacity for blades and nacelles in China, while the rest of the world shows regional variations (International Energy Agency, 2023C). Analysis by the Global Wind Energy Council and BCG (Global Wind Energy Council, 2024) find that based on an equivalent to a NZE by 2050 scenario:

"there is a risk of manufacturing bottlenecks before 2030 for multiple components at regional level, in particular gearboxes, generators, blades as well as offshore wind size compatible metal castings, towers and foundations."

Neither of these pieces of analysis considers the impact of announced and potential Trump administration policies that aren't consistent with a NZE by 2050 scenario and are likely to negatively impact onshore and offshore wind turbine demand in the Unites States (Greene, 2025).

4.5.3 Western OEMs have increased turbine prices recently, though price cycles are not unusual for wind turbines

Figure 34 shows average selling turbine price for Vestas (onshore and offshore) and Nordex (onshore) in real €m (Q3-2024), with a material increase seen in Vestas average selling price in recent years, with more muted increases from Nordex. While some of the change is driven by price increases to restore margins and profitability, Vestas' average selling price has also been impacted by a rising proportion of offshore wind turbine orders. At Dec 2020 Vestas has installed 5.8GW of offshore wind turbines vs 129GW of onshore. While offshore wind turbines, whose equipment is materially higher cost (Aurecon, 2024A), represented 22% of orders in 2023 and 17% for the 9 months to Sep 2024.

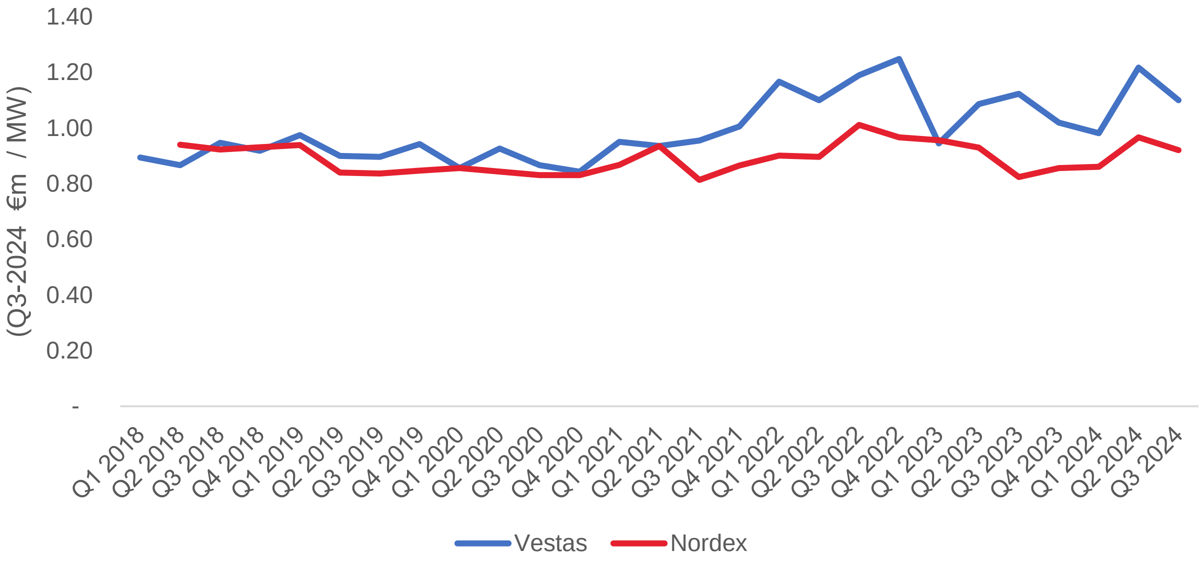


Figure 34: Vestas and Nordex – Turbine average selling price (Real € Q3-2024)	Source: Vestas Quarterly Investor Presentation Reports (2018-2024), Nordex Quarterly Analyst and Investor Call Presentation (2018-2024)

Figure 35 shows a historical time series of turbine prices for 1999 to 2023 on a real (USD 2023) basis, including for multiple turbine OEMs. Figure 35 confirms that that driven by supply-chain pressures and elevated commodity prices (NREL, 2024B), real-turbines prices have increased in recent years, though the level of this increase is not consistent between data sources. note that have driven given this trend.

Figure 35 also reveals some that turbine has been subject to long term trends in pricing:

- 2000 to 2008: wind turbines prices roughly doubled from an ~US$1,000/kW to ~$2,000/kW. (NREL, 2016) identify several factors driving this increase, including a declining USD/EUR exchange rate; increased materials, energy, and labour input prices; an increase in turbine IEM profitability; and increased turbine OEM warranty provisions.
- 2008 to 2019: wind turbine prices declined by more than 50%. In part reflecting a reversal of cost trends from this period as well as significant cost-cutting measures by turbine OEMs and component suppliers (NREL, 2016).

While wind turbines prices are one driver of changes in the levelized cost of energy (LCoE) of wind farms, it is noted there are a range of other innovations including turbine scaling, that have driven onshore wind LCoE reductions (Bolinger, Wiser, & O'Shaughnessy, 2022).

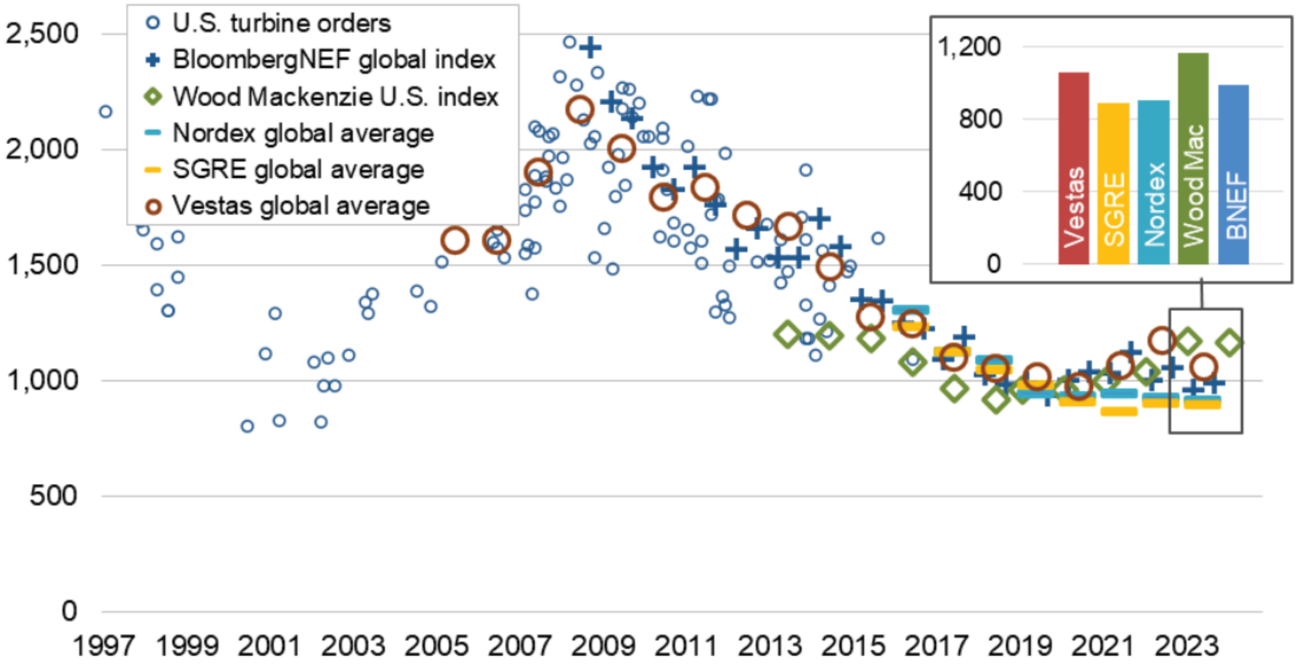


Figure 35: Historical turbine prices 1997-2023 (2023 US$/kW) | Source: (NREL, 2024B)

4.5.4 Warranty provisions have increased for western OEMs, however there are some signs of improvement

Figure 36 shows warranty provisions accruals as a percentage of revenue for wind turbine OEM where data is available. Siemens Gamesa is not included, as it warranty provisions have exceeded 10% in recent years, contributing to its bailout by the German Government (Financial Times, 2023).

In recent years warranty provision accruals have increased for western OEMs from 2% or lower in the 2010s to around 5% for Vestas (onshore and offshore) and around 3% for Nordex (onshore) currently. Consensus forecast for Vestas show that warranty provision accruals as a percentage of revenue may have peaked at 6.4% in 2022, with 4.8% recorded for 2024 and a forecast to decline to 3.5% for 2026 and below 3% by 2029. Nordex provision for the 9 months ended Sep 2024 were 3.7% of revenue, up from 3.2% in 2023.

Warranty claims for western OEM have typically been driven by product quality issues relating to new models and turbine (Williamson, 2023B). In order to increase product quality and profitability western turbine OEMs are focussing on longer product cycles, focussing on existing models for longer (Reuters, 2024A) (Reuters, 2024B).

Warranty provision accruals for Goldwind (onshore and offshore) have historically been materially higher than western OEM, ranging from 4-7% and were 4.7% for 2023.

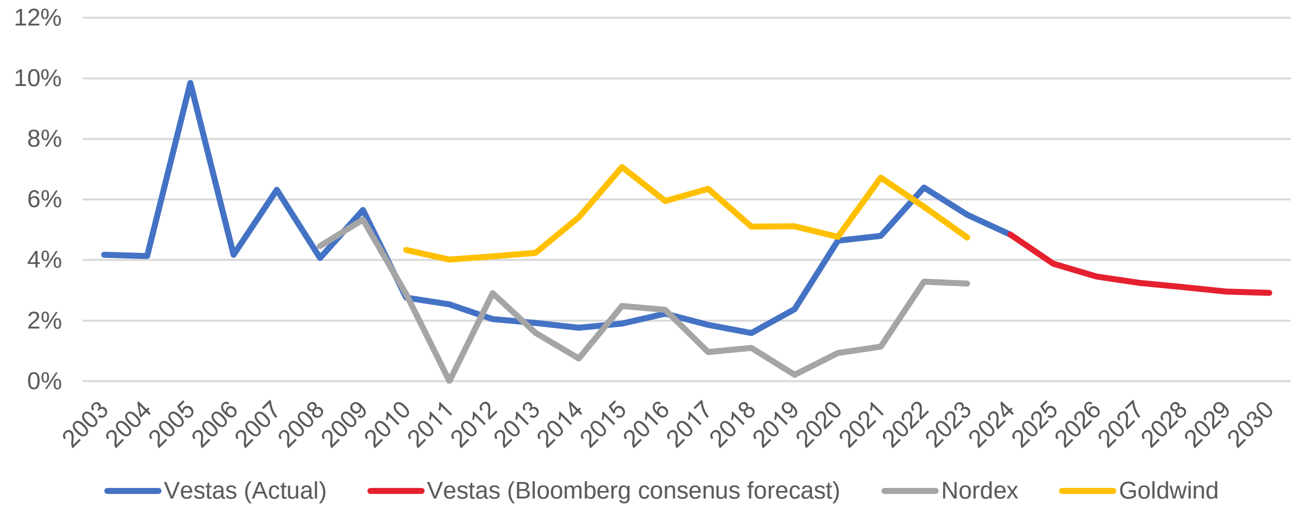


Figure 36: Selected wind turbine OEM - warranty provision added as a % of revenue

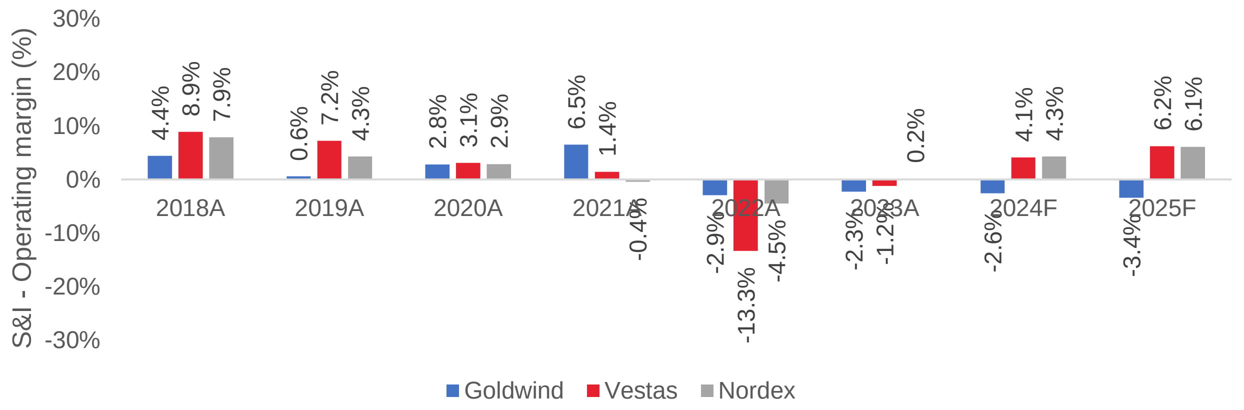
Source: Company accounts and investor presentations

4.5.5 Despite higher turbine prices OEM margins and return on equity have not yet recovered to pre COVID-19 levels

Wind OEMs typically split their operations into turbine sales and installation, and servicing divisions. Figure 37 shows operating margin for three OEMs (Goldwind Vestas and Nordex) where this breakdown is available, while Figure 43 shows total operating margin for these OEM plus GE Vernova and Siemens Gamesa, where performance has been materially worse.

Turbines sales and installation is typically lower margin, arguably acting as a loss leader to secure long term contracts for the higher margin servicing division. The servicing division represents 10%, 30% and 44% of 2024F EBIT for Goldwind, Vestas and Nordex respectively.

While margins for servicing have been relatively resilient, sales and installation margins deteriorated significantly and were negative for all turbine OEMs in 2022, however margins are now recovering. A range of factors have impacted OEM sales and installation operating margins in recent years including reducing demand in the early 2020s, cost escalation and product quality issues leading to warranty claims.



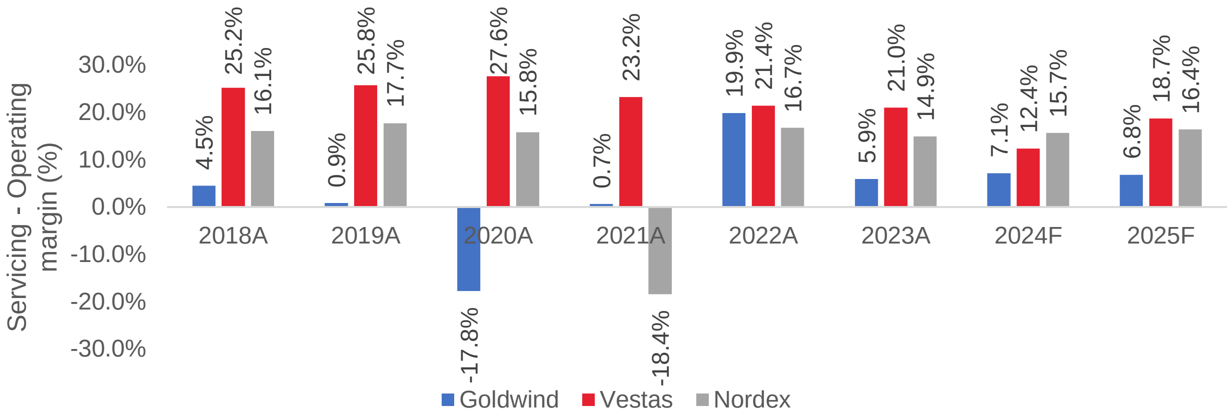


Figure 37: Top - Turbine OEM sale and installation division operating margin (%)
Bottom - Turbine OEM servicing division operating margin (%) | Source: Bloomberg

Return on equity is improving for turbine OEMs and consensus forecast is that return on equity for Vestas will return to pre-COVID levels in 2025. Nordex has historically been loss making, though consensus forecast is that it will return to profitability in 2024, with further improvement in 2025. Goldwind's return on equity is significantly impacted by its wind farm development division, which represented 127% of 2024F EBIT and involves significant capital investment. Over time Goldwind's return on equity has typically been significanlty lower than the 15% expected equity return for an Australian onshore wind farm (Oxford Economics Australia, 2024B).

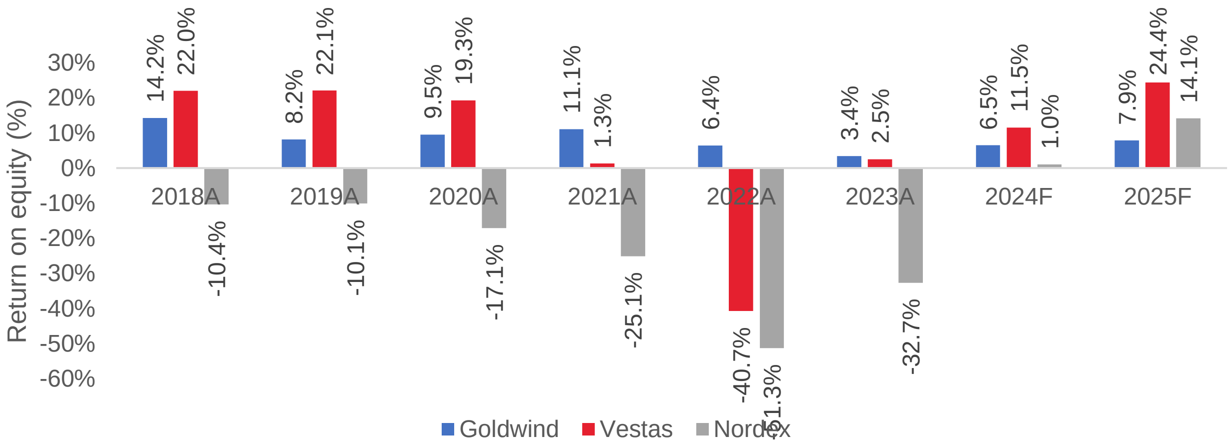


Figure 38: Wind turbine OEM return on equity (%) | Source: Bloomberg

4.5.6 Material, shipping and energy costs are likely to be higher than historical levels in long term due to the decarbonisation

Steel

While (NREL, 2016) showed that steel per MW on onshore wind turbine capacity turbine decreased from ~120t/MW in 2001 to 100t/MW in 2015, modern onshore wind turbines require around 120 tonnes of steel per MW of capacity (Wind Europe, 2023), suggesting that turbine scaling does not lead to steel material cost savings. Steel and iron constitute 80-90% of a wind turbine's material mass, and approximately 50% of a turbine's total lifecycle emissions (Vestas, 2024).

Figure 39 shows steel prices over the past 10 years, with a peak of US$1,945/t in Aug 2021 and current price of US$755/t in Feb 2022. The peak to current price reduction of US$1,118/t is equivalent to a US$0.14/MW steel material cost per turbine. Lower steel price are already contributing to improving margins for turbine OEMs and are captured in consensus forecast earnings.

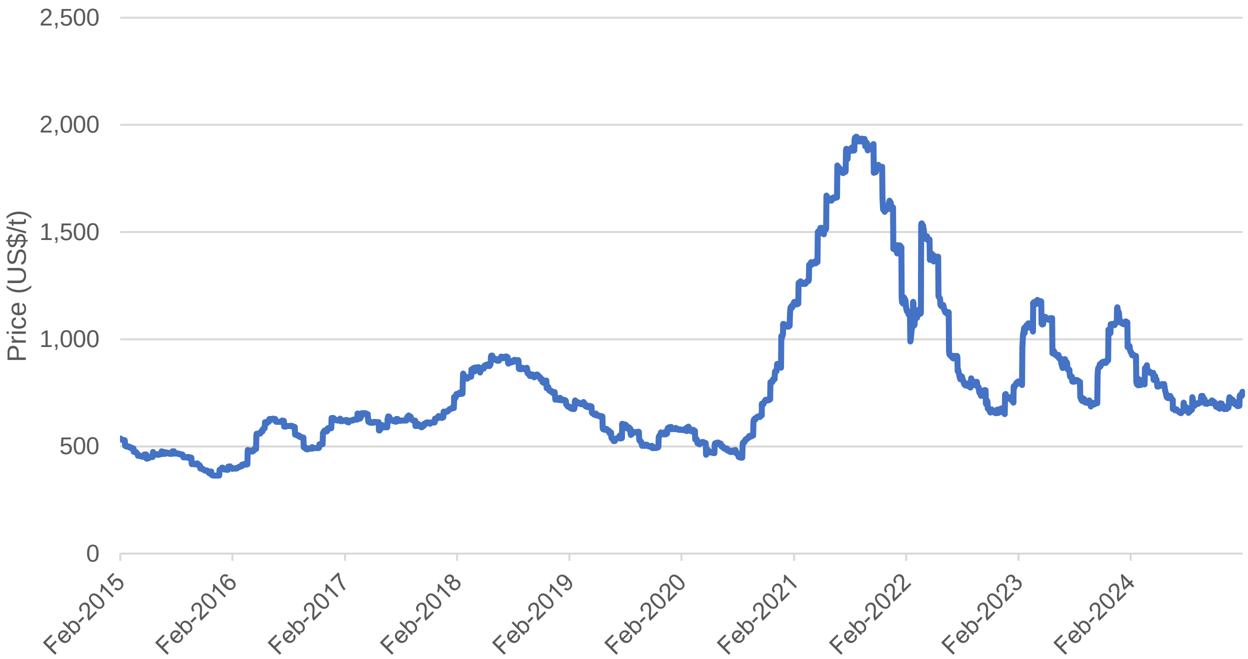


Figure 39: US Mid-West domestic hot rolled coil steel index - Chicago Mercantile Exchange | Source: Bloomberg

Table 7 showed that levelized cost of steel production for conventional and innovative iron-based steel production. Levelised cost of production includes estimated iron ore prices, carbon prices and fuel subsidies differentiated by region and scenario, and are weighted by regional deployment. Conventional routes are blast furnace-basic oxygen furnace (BF-BOF) and direct reduced iron-electric arc furnace (DRI-EAF). The innovative routes are BF-BOFs with carbon capture, utilisation and storage (CCUS), DRI-EAF with CCUS, and 100% electrolytic hydrogen-based (green hydrogen) DRI-EAF.

The current levelized cost of conventional iron-based steel production is in the range of US$510-US$610/t, below current prices of US$755/t, suggesting a reversion to pre-COVID steel prices is possible. However, the Upper range of innovative iron-based steel production is US$820-US$850 depending on scenario, above the current price of US$755/t. However, IEA's forecasts should be treated with caution as per Section 2 they use current electrolyser capex estimates that is materially lower than detailed studies and as such electrolyser capex projections are likely to be materially underestimated. The author's Draft 2025 IASR Stage 1 Consultation Submission discusses further reasons as to why IEA's green hydrogen costs projections, which is relevant for green hydrogen DRI-EAF, could be optimistic.

		Stated Policies			Announced Pledges			NZE BY 2050		
	2023	2030	2035	2050	2030	2035	2050	2030	2035	2050
Conventional										
Lower range	510	470	470	470	500	530	590	550	600	730
Upper range	630	560	560	560	690	730	770	750	770	850
Innovative										
Lower range	n.a	650	660	650	680	700	650	730	670	680
Upper range	n.a	840	880	850	960	880	820	910	760	830

Table 7: Levelised cost of iron-based steel production costs (USD/t) | Source*:* (International Energy Agency, 2024A)

Maritime shipping

Figure 40 shows the containerized freight index for the past 10 years. Prices rose from ~US$1,000 in the last 2010s to a peak of over US$5,000 in 2022. Price have been volatile since, but are currently ~US1,900 almost double historical levels of US$1,000.

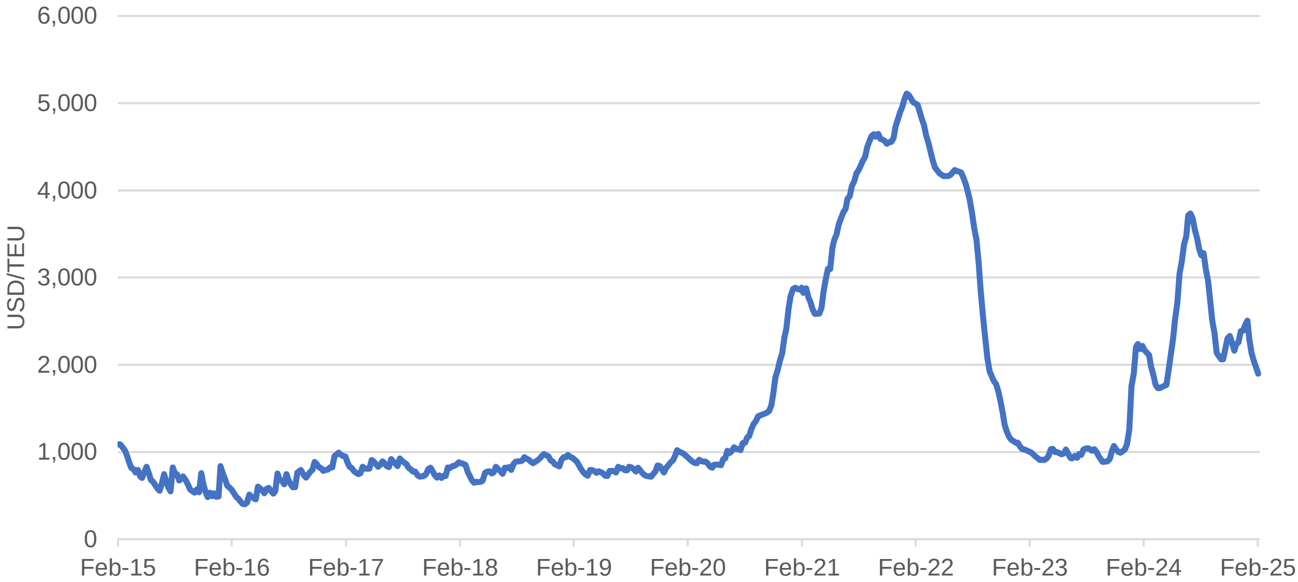


Figure 40: Containerised Freight index – USD/ twenty-foot equivalent unit (TEU)

Source: Shanghai Export Containerized Freight Index – Bloomberg & Shanghai Shipping Exchange

Transitioning maritime fuel to low carbon alternatives such as green ammonia or green methanol could lead to a material increase in wind turbine internation shipping cost compared to historical levels. (Fletcher A. , et al., 2023A) found for a 1mtpa islanded green ammonia plant located in Queensland that levelized cost of ammonia (LCOA) including transport could be $1,000-$1,200 including transport in 2030, compared to a typical global historical price range of $US200-$500 for ammonia. The green ammonia LCOA is likely optimistic as CSIRO GenCost was the source of electrolyser and onshore wind build cost estimates (Fletcher A. , et al., 2023A).

This is before considering the relative price per GJ of ammonia and heavy fuel oil and lower energy density of ammonia, which will increase costs.

Energy

(Elia, Taylor, Gallachóir, & Rogan, 2020) shows that energy costs represent an immaterial portion of wind turbine equipment cost, falling from US$8/kw in 2005 to US$5/kw in 2017.

4.5.7 Chinese OEMs are beginning to win market share in non-mature markets outside of China due to attractive pricing, which could put downward pressure on turbine prices

Chinese turbine OEM are beginning to gain market share outside of China with a 7GW overseas order backlog at the end of 2023, of which 4.7 GW related to Goldwind (S&P Global, 2024).. Market share is been gained in less mature makets like Saudi Arabia, Kazakhstan and Uzbekistan due to attractive pricing compared to western OEMs and are also establishing manufacturing plants in Brazil and India (S&P Global, 2024). While Goldwind has more than 2GW of wind projects operating, under construction or under development in Australia, the vast majority of these projects have been developed by its subsidiary GoldWind Australia, rather than third parties (Goldwind Australia, 2025).

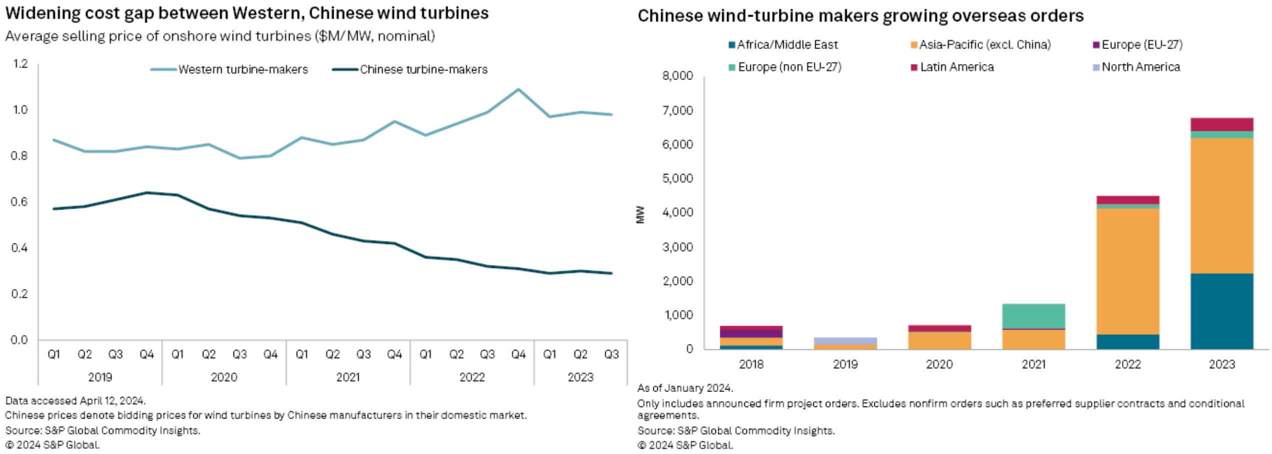


Figure 41: Left – Western vs China OEM wind turbine prices
Right – Chinese wind turbine overseas order book

Source: (S&P Global, 2024)

4.5.8 Barriers to entry could provide some protection to incumbent western OEM in mature markets

While Chinese OEMs are winning market share in less mature markets, there are potential barriers to entry in more mature markets including:

- Western OEMs have strong footholds and long track records (S&P Global, 2024), with bankability of Chinese turbines questioned due to lack of transparency in data regarding product quality, fabrication, and performance from Chinese suppliers (Rabobank, 2024). Warranty provision data for Goldwind shown in Section 4.5.4 supports this notion.
- Challenges in bringing new turbine models to the NEM including meeting and modelling of Generator Performance Standards.
- Weight-to-value ratios and resultant transportation costs reduce the attractiveness of international wind trade (van Wyk, 2023)
- Trade barriers and geopolitical risk:
    - Unites States: The Biden administration introduced tariffs on Chinese EVs (100%), lithium-ion batteries (25%) and solar PV cells (50%) in September 2024 (Utility Dive, 2024), while the Trump Administration has announced 10% tariffs on Chinese goods.
    - Europe: The European Commission open its first ex-officio investigation under the EU Foreign Subsidies Regulation, targeting Chinese wind turbines (Hogan Lovells, 2024). The European Commission's European Wind Power Action Plan includes a commitment to *"protect the internal market against trade distortions and threat to security and public order."* (European Commission, 2023)

Figure 42 summarises modelling undertaken by Global Wind Energy Council and BCG examining the impact of four global scenarios with different macroeconomic conditions, energy transition and trade policies on the wind supply chain (Global Wind Energy Council, 2024). Modelling outputs were additional wind market growth compared to a business-as-usual trajectory, supply chain actor margins and cost of wind power in LCOE terms. The scenarios demonstrate the impact of trade policy (barriers) with a reduction in LCOE vs BAU for the Open Door Scenario, higher LCOE under the Increased Barriers and Global Escalation scenario and limited impact on LCOE in the Economic Downturn scenario.

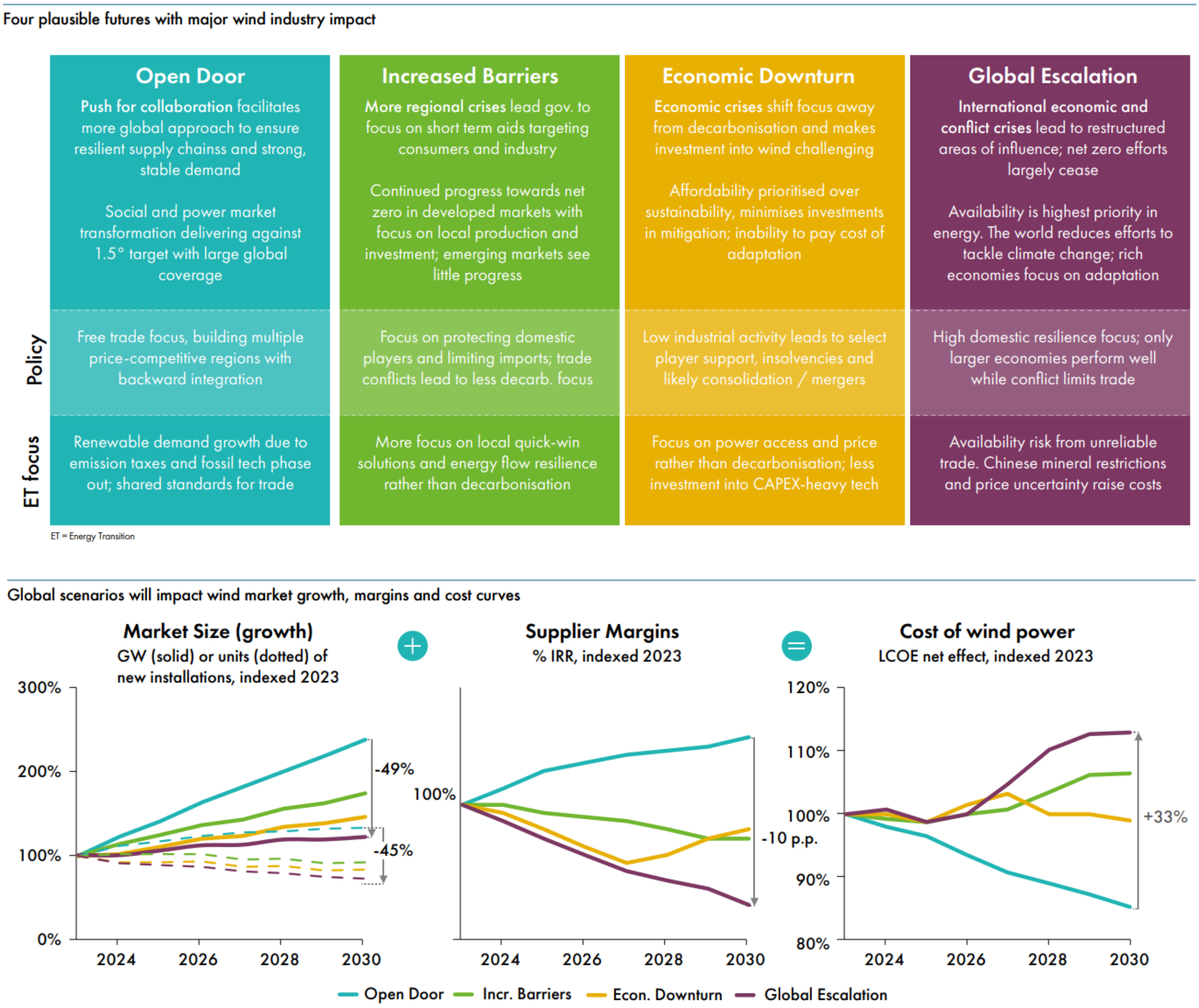


Figure 42: Impact of four global scenarios with different macroeconomic conditions, energy transition and trade policies on Wind market growth, supplier margin and cost curves

Source: Global Wind Energy Council and BCG, Mission Critical: Building the Global Wind Energy Supply Chain for a 1.5C World, 2023. (Global Wind Energy Council, 2024)

4.6 Current GenCost build cost should align with Aurecon's estimate

Aurecon's estimate of onshore wind build cost is $3,126/kW, while for CSIRO it is $3,223/kW, which flows through into the Draft 2025 Stage 1 Inputs and Assumptions Workbook (Australian Energy Market Operator, 2024).

5. Open cycle gas turbine

5.1 Recommendations

The following recommendations are made which align with submission sections:

Section 5.2 Open cycle gas turbines without hydrogen blending capability should be included as a candidate technology

Section 5.3 'Hydrogen ready' turbines and open cycle gas turbines should be compared to previous estimates as design and cost differences are limited

Section 5.4 Equipment costs should experience a partial reversion towards historical costs over time

Section 5.5 Real construction escalation should be applied to installation costs

5.2 Open cycle gas turbines without hydrogen blending capability should be included as a candidate technology

5.2.1 There is limited difference in build costs between OCGT and hydrogen ready gas turbines

There are limited design differences between open cycle gas turbines and hydrogen ready gas turbines. While increases in acceptable hydrogen blend above starting rated values may result in additional costs, Table 8 shows that based on the 2023 Aurecon Cost and Technical Parameters review (Aurecon, 2024B) that hydrogen readiness increases small OCGT build cost by $0.43m, while there is no additional cost for Large OCGT. Griffith CAEEPR members, who are actively developing small OCGT in Queensland have advised that the cost premium for hydrogen ready small OCGT is materially lower than shown in Table 8.

	Small OCGT	Hydrogen Ready Small OCGT	Large OCGT	Hydrogen Ready Large OCGT
Make model	LM 600 PF SPRINT	LM2500 (GE)	GE 9F.03	GE 9F.03
Gaseous hydrogen readiness by volume		35%		5-10%
Build cost ($M/MW)	$1.545	$1.975	$1.040	$1.040

Table 8: Gas turbine build cost – 2023 Aurecon Cost and Technical Parameters Review | Source: (Aurecon, 2024B)

5.2.2 Heat rates are higher for small 'hydrogen ready' small OCGT

Turbine efficiency reduced with hydrogen blending, with the heat rate of a hydrogen ready small OCGT around 0.5GJ/MWh (5%) higher when using a 35% hydrogen blend by volume.

	Small OCGT	Hydrogen Ready Small OCGT	Large OCGT	Hydrogen Ready Large OCGT
Make model	LM 600 PF SPRINT	LM2500 (GE)	GE 9F.03	GE 9F.03
Gaseous hydrogen readiness by volume		35%		5-10%
Heat rate at maximum operation (GJ/MWh) HHV net	10.017	10.489	10.811	10.811

Table 9: Gas turbine heat rate – 2023 Aurecon Cost and Technical Parameters Review | Source: (Aurecon, 2024B)

5.2.3 Requirements for geological hydrogen storage and transmission pipelines makes possibility of commercial utilisation of 'hydrogen readiness' capability remote

(Aurecon, 2024A) states that:

"All new gas turbine projects are expected to include provision/capability for hydrogen blending and eventual conversion to hydrogen firing when hydrogen supply becomes more readily available."

While the prospects for green hydrogen use in industry is challenging due to techno-economic issues discussed in Section 2 and the authors Draft 2025 IASR Stage 1 Consultation Submission, the prospects for hydrogen fuelled generation is materially worse. The dispatch of peaking generation such as 'hydrogen ready' turbines is expected to be focussed on periods of residual demand, including peak demand periods, dunkeflaute and winter when there is a seasonal energy imbalance. To manage the intermittency of green hydrogen production and peaking generation dispatch profiles, substantial geological hydrogen storage and transmission pipeline capacity would be required. Several studies find that the cost and uncertainty around the development of this infrastructure severely limits the potential for hydrogen powered generation including:

- *Hydrogen in the Power Sector: Limited Prospects in a Decarbonized Electric Grid*. Clean Air Taskforce. (Whakim & Kasparas, 2024)
- *Hydrogen: Not a solution for gas-fired turbines*. The Institute for Energy Economics and Financial Analysis. (Wamsted, 2024)

(Aurecon, 2024A) also states that:

"Hydrogen supply would be either via gas network as a blend or could be via dedicated renewable hydrogen supply from an electrolyser plant. Given the current status of hydrogen blending in gas networks planned in Australia based on current projects under development is likely to lead to open cycle gas turbine plants using a blend of hydrogen with natural gas."

It is not clear what planned hydrogen transmission pipelines Aurecon is referring to as there appears to be limited planning of hydrogen pipelines or pipeline conversions by pipeline operators. While APA Group has undertaken a technical feasibility study on converting a 43km section of the Parmelia gas pipeline (APA Group, 2025), it can be inferred from the Parmelia Green Hydrogen Project Feasibility Study Summary (APA Group, 2024) supplying this pipeline with green hydrogen could be prohibitively expensive (Refer to Section 2 for further detail).

5.2.4 Utilizing co-located hydrogen production and non-geological hydrogen storage is likely to be prohibitively expensive

(Aurecon, 2024A) states that:

"Alternatively, a hydrogen ready gas turbine plant could be supplied from a dedicated electrolyser plant using renewable energy supply and blended with a natural gas pipeline supply to the site. In this case, OCGT plant capacity would be based on hydrogen production from a suitable sized electrolyser plant and operated in peaking duty using hydrogen supply with storage to meet the hydrogen demand"

The commercially viability of this option is challenged by the high cost of non-geological hydrogen storage, as discussed in the authors Draft 2025 IASR Stage 1 Consultation Submission. Further, Snowy Hydro's Hunter Power Project, APA Group's Submission Report for the Kurri Kurri Lateral Pipeline Project (Umwelt on behalf of APA Group, 2022) states that:

"Snowy Hydro has advised that the level of capital expenditure required to construct the storage pipeline for it to be capable of storing a hydrogen blended fuel is not economic at this stage. Consequently, the storage pipeline will not be built to specifications which would enable it to store hydrogen.

Based on the evidence and investigations to-date, Snowy Hydro has advised that it does not agree that storage of a hydrogen blended fuel within the storage pipeline is commercially or technically viable."

Feedback has been provided from a number of CAEPR members who have gas and hydrogen pipelines expertise, that thicker steel is required for hydrogen pipeline linepack storage than previously understood and even with thicker steel pipeline life is constrained by a number of storage cycles.

5.2.5 'Hydrogen ready' component of example projects listed by Aurecon are driven by policy requirements

Of the five 'hydrogen ready' turbines listed by Aurecon, which are shown in Table 10, four are either directly owned by Government or by Government Owned Corporations.

Tallawara B is owned by the private sector and has received $83m of subsides for hydrogen readiness and hydrogen fuel use (CSIRO, 2024D).

Project	Capacity (MW)	Developer	Owner	Project Status	Subsidies received for hydrogen readiness and use

Brigalow	400	CS Energy	QLD Government	Publicly Announced	
Swanbank Clean Energy Hub	140	CleanCo Queensland	QLD Government	n/a	
Hunter Power Project	660	Snowy Hydro	Australian Government	Committed	
Hydrogen Power SA	200	South Australia Government	South Australia Government	Anticipated	
Tallawara B	320	Energy Australia	Private sector	Operating	$83m

Table 10: 'Hydrogen ready' gas turbine projects | Source: (Aurecon, 2024A) (CSIRO, 2024D) (Australian Energy Market Operator, 2025)

5.3 'Hydrogen ready' turbines and open cycle gas turbines should be compared to previous estimates as design and cost differences are limited

(CSIRO, 2024A) states that:

"Detail of previous costs are not included because the technology design has changed, impacting the costs. That is, all new gas turbine projects are expected to include the capability for hydrogen blending and eventual conversion to hydrogen firing when hydrogen supply becomes more readily available."

Per Section 5.2.1 there is limited design differences between open cycle gas turbines and hydrogen ready gas turbines. The GE 9F.03 turbine is used as the basis for Aurecon's hypothetical project cost estimates for 'hydrogen ready' gas peakers in Aurecon's 2024-25 Aurecon report and in the 2023-24 report for OCGT and 'hydrogen ready' gas turbines.

5.4 Equipment costs should experience a partial reversion towards historical costs over time

CSIRO reversion of wind turbines to historical costs, while maintaining gas turbines at elevated cost levels, is inconsistent and not supported by an analysis of OEM profit margins. Many western wind turbine OEMs are loss making or earning low margins, while gas turbine OEMs are experiencing strong order and revenue growth and profit margin expansion. That OCGT are a 'mature' onshore wind is subject to learning rates is not sufficient justification for their differential treatment.

Higher profit margins in gas turbines OEMs may not be sustainable, as they could trigger the entrance of new manufacturing capacity, putting downward pressure on equipment prices. What portion of cost increases to gas turbine equipment is transitory is uncertain and a partial reversion of equipment costs towards historical cost over time is recommended. Factors such as global energy, materials and labour costs, as well as OEM profitability could be considered in determining the level and speed of cost reversion.

Gas and wind turbine OEM's generate earnings from servicing as well as the sale and installation of new turbines.

Globally demand for gas turbines has increased, leading to revenue and margin growth with:

- Mitsubishi Power expecting total global gas turbine orders of 60GW from 2024 to 2026 up from an average of 40GW between 2021 and 2023 (BNN Bloomberg, 2024).
- Siemens Energy's Gas Services division increased orders by 27% in year ended Sep-2024. EBIT margin has increased from 5.4% for FY22 to 9.5% for FY23 and FY24, with FY25 and FY26 guidance of 9-11%. Compared to Siemen Energy's loss making wind division (Siemens Gamesa) which achieved a -50.4% EBIT margin for FY23, -18.4% for FY24, and FY25 and FY26 guidance of 7-12%.
- GE Vernova power division (gas and hydro power) increased orders by 28% in CY2024 (GE Vernova, 2025). EBIT margin has grown from 9.9% for CY2023 to 12.5% for CY2024 with guidance of 14% provided for CY2025 (GE Vernova, 2025). Compared to GE Vernova's loss making wind division which achieved a -13.1% EBIT margin for FY23, -6.1% for FY24.

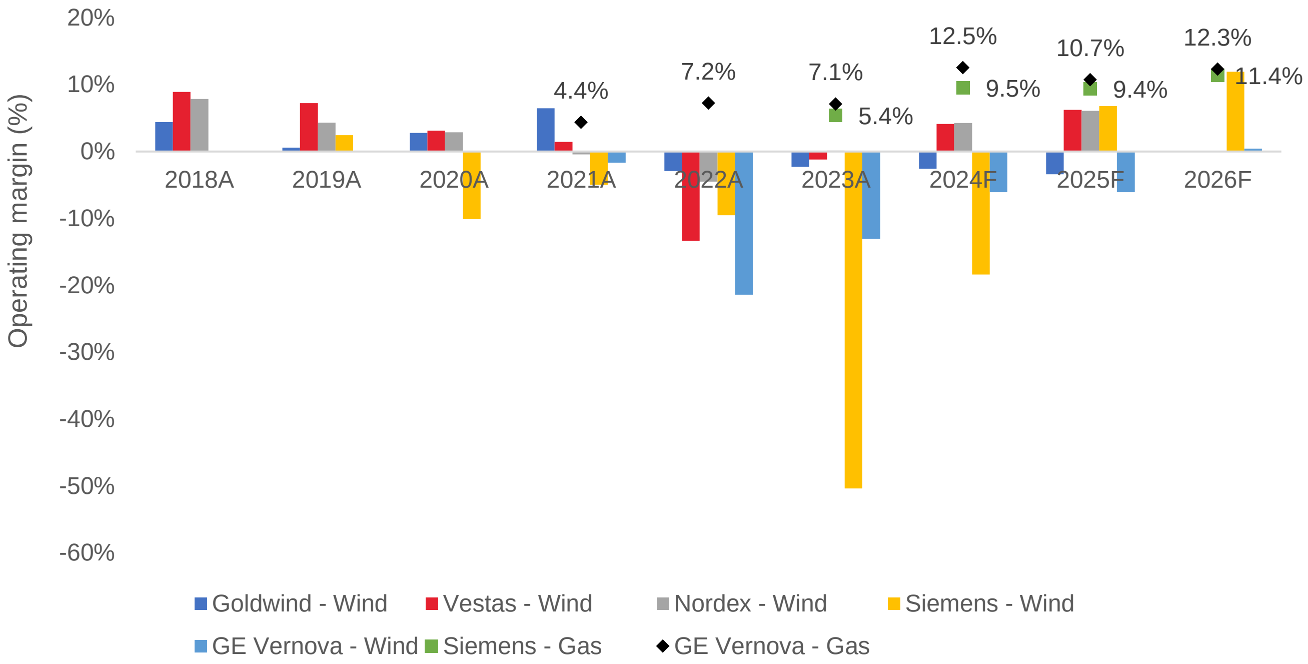


Figure 43: Wind and gas turbine OEM operating margins (%) | Source: Bloomberg, company results presentations

5.5 Real construction escalation should be applied to installation costs

Real cost escalation of 0.9% pa, consistent with the difference between Engineering Construction IPD (3.7%) and CPI (2.8%) since the 2000s is recommended (Oxford Economics Australia, 2024A).

(Aurecon, 2024A) estimate that installation represents 30% of OCGT EPC and 27% of OCGT build cost. Gas turbine equipment cost have increased significantly in recent years, with Aurecon applying 10% nominal cost escalation to their 2023 cost estimates for gas turbine, "*due to market conditions and supply chain issues"* higher than the 5-7.5% used for other technologies and higher than CPI inflation of 3.8% (Aurecon, 2024A). Section 0 outlines that energy infrastructure construction cost escalation is forecast to continue to exceed CPI.

Applying CSIRO's mature *"basket of costs"* method for OCGT installation cost is not recommended as the breakdown of components is materially different in (Bureau of Resources and Energy Economics, 2012) and the -0.35% appears to be an average across all technologies. (Bureau of Resources and Energy Economics, 2012) estimate that installation of $138/kW ($2022) represented 21% of OCGT EPC and 19% of OCGT build cost. Aurecon's 2024 estimate for large OCGT installation is $357/kW, 89% higher than (Bureau of Resources and Energy Economics, 2012) inflated estimate of $189/kW ($2024), providing further evidence that energy infrastructure cost escalation has exceeded CPI.

6. Utility scale BESS technical parameters

6.1 Recommendations

The following recommendations are made which align with submission sections:

Section 6.2 Battery degradation assumptions should vary with battery duration

Section 6.3 Round trip efficiency (RTE) degradation should be factored into RTE

6.2 Battery degradation assumptions should vary with battery duration

The Draft IASR degrades battery energy storage capacity by 16% regardless of duration, based on 1.8% annual degradation, a 20-year battery life and estimated operating levels.

A batteries C-Rate is the rate at which it charges or discharges relative to its energy storage capacity, with a one-hour battery having a C-rate of 1 and an 8hr-battery having a C-rate of 1/8. A number of academic studies have shown a direct relationship between C-rate and rate of battery degradation (Qu, Jiang, & Zhang, 2022) (Gao, et al., 2022) (Yüksek & Alkaya, 2023). OEM battery warranted degradation curves are commercially sensitive and are not publicly available. Griffith CAEEPR members who are actively developing and off taking batteries in Queensland, have advised that there is an inverse relationship between battery storage duration and warranted degradation curves, which Aurecon confirmed for 4hr BESS on the CSIRO GenCost webinar on 5Feb25.

In addition to lower C-rates, 8hr batteries are typically cycled materially less than once cycle per day, further supporting varying battery degradation assumptions with battery duration. Based off the 2024 Final ISP modelling, 8hr batteries typically have capacity factors of ~20% (4.8hrs generation per day), which is equivalent to cycling 71% of degraded energy storage capacity (8hrs x 84% = 6.72hrs) per day.

6.3 Round trip efficiency (RTE) degradation should be factored into RTE

While most generation technologies experience some level of efficiency degradation it is more pronounced for batteries. (Aurecon, 2024A) provides an indicative average annual RTE degradation figure of 0.2% pa, resulting in total of 4% reduction in RTE over a batteries' 20-year project life. This RTE is not incorporated into the Draft IASR and if AMEO applied the same multiple as is applied for annual battery degradation, average RTE would be reduced by ~2%. The Final 2024 ISP Step Change scenario (CDP3) find that storage charging is 88TWh in 2049-2050 thus incorporating ~2% RTE degradation losses may result in increased renewable and dispatchable generation requirements.

7. References

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