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# Forecasting assumptions update

The Griffith University Centre for Applied Energy Economics and Policy Research (griffith.edu.au) (CAEEPR) is an industry partner-funded collaboration between Griffith Business School and a diverse group of energy sector partners including: Powerlink Queensland, CS Energy, Stanwell Energy, Clean Co, Iberdola Australia, Tilt Renewables, Queensland Treasury Corporation and King and Wood Mallesons.

CAEEPR aims to provide and publish independent, sophisticated energy policy advice and thought leadership for industry and government and contribute to inclusive, sustainable, and prosperous businesses and communities. Through its world class economic and policy research CAEEPR aspires to underpin a successful transition to electrification and green hydrogen with a less carbon-intrusive power generation and transmission system.

CAEEPR recently finalised techno-economic research that assesses the cost of Queensland green hydrogen and green ammonia energy infrastructure options in collaboration with the University of Oxford's Oxford Green Ammonia Technology research group (specifically Nicholas Salmon and Professor René Bañares-Alcántara). The research includes Information Sheets which describe each functional component of the green hydrogen and green hydrogen derivatives value chain (Fletcher et al (2023B)) and detailed modelling that assesses the cost of potential green hydrogen and green ammonia value chains (Fletcher et al (2023A)). This submission to the *2024 Forecasting Assumptions Update Consultation* is informed by this research, which is included as an attachment. A further submission will be made to the *Draft 2024 ISP Consultation* that includes detailed analysis of the Draft 2024 ISP model and provides further evidence regarding some of the issues raised in this submission.

This submission has been prepared by Andrew Fletcher and Huyen Nguyen, who are Industry Adjunct Research Fellows at Centre for Applied Energy Economics and Policy Research (CAEEPR). The views expressed in this submission are entirely the authors' and are not reflective of CAEEPR.

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# Introduction

This submission highlights opportunities to improve:

- The suite of CSIRO models (GALLME – GenCost, CSIRO Climateworks Multi Sector Energy Modelling and Electric Vehicle Projections) that underpin hydrogen demand and technology capital cost projections for the AEMO ISP; and
- The level of detail and transparency of projections for wind, solar PV, BESS and electrolysers.

The recommendations to improve the suite of input assumptions to better model efficient development of the NEM are:

- Inclusion of most recent Draft GenCost data in Final 2024 ISP
- Incorporating REZ locational cost factors
- For wind, solar PV, BESS and electrolysers improving detail and disclosure of capex cost estimates and projections to be in line with best practice (e.g. NREL (2023), IEA (2023) and IRENA (2020)), by including a breakdown of capex stack into different components with different learning rates
- Introducing other technologies such as fixed plate PV, ammonia storage and thermal energy storage
- Reviewing FCEV forecasts to ensure that the full cost of green hydrogen including storage and transport are incorporated in determining uptake of FCEV trucks

## 1. Gencost version for Final 2024 ISP

It is recommended that *Aurecon Cost and Technical Parameters Review (Dec 2023)* and *CSIRO GenCosts 2023-2024 Consultation* be used as inputs in the 2024 Final ISP.

## 2. REZ Locational cost Factors - Aurecon 2023 Cost and Technical Parameters Review

The *Aurecon 2023 Cost and Technical Parameters Review* includes locational cost factors by REZ which show a wide range, with remoteness appearing to be a key cost driver, with a maximum of 180%. This compares to the less granular low, medium and high zonal locational factors in the *2023 Inputs, Assumptions and Scenario Report* and the *2024 Draft Inputs and Assumptions workbook* which have a maximum of 131%.

The Aurecon REZ locational cost factors are more granular and for some REZ are materially different from those listed in the IASR. Aurecon's estimates and the higher precision data Aurecon provide is welcomed. Some of the REZ with the largest differences have large capacities of renewables built in the Draft 2024 ISP Step Change scenario and the Green Energy Exports scenario, and could be materially impacted by the REZ locational cost factors.

It is recommended that AEMO could consider either incorporating the Aurecon REZ locational cost factors in the Final 2024 ISP (and future ISPs) or including a sensitivity.

## 3. Detailed capex and land estimates and projections for key technologies

Wind, Solar PV and lithium ion BESS are the key technologies that underpin the decarbonisation of the energy system and whose capex is projected to decline over time due to learning benefits from significant growth in deployment. Capex estimates and projections for these technologies are critical AEMO ISP inputs that drive modelling outcomes. For most technologies CSIRO applies global learning rates and local learning rates in its projections, though doesn't provide this breakdown in its results. Detail and disclosure of capex estimates and projections should be improved to be in line with, or set a new benchmark for, quality of input assumptions to support efficient NEM development (e.g. NREL (2023), IEA (2023) and IRENA (2020)). In particular a breakdown of technology capex stack into different components with different learning rates and disclosing this detail in projections. This will provide better clarity and build more confidence around CSIRO Gencost capex projections.

The remainder of this section provides more details around each of these key technologies.

## 3.1 Land cost projections

It is recommended that land cost projections be calculated based on current land cost escalated by a real land cost index and for land costs to be broken out for wind, solar PV, battery energy storage and electrolysers. If there is projected to be reduction in project land footprint due to technology improvements these assumptions should be documented.

The example of electrolyser capex projections is used to highlight the issue with the current land cost projection method. *Aurecon 2023 Cost and Technical Parameters Review* includes current land cost of $23.2m ($232/kW) and $24.0m ($240/kW) for 100MW PEM and alkaline electrolysers respectively. This compares to a 2049-2050 projection for electrolyser capex for both PEM and Alkaline of $361/kW for the Step Change Scenario and $193/kW for Green Energy Exports, with the former lower than current land cost. These figures demonstrate a methodological issue with how land costs are projected in *CSIRO GenCosts 2023-2024 Consultation Draft*. Land costs appears to be assumed to be a constant proportion of the capex cost stack. For technologies where there are positive learning rates and in particular electrolysers, capex is projected to reduce significantly over time and thus land should become a higher proportion of capex.

## 3.2 Electrolyser capex estimates and projections

### 3.2.1 Green hydrogen demand

Electrolyser capex projections are produced by the GALLME model:

*In GenCost projections prior to 2022-23, hydrogen demand was imposed together with the type of production process used to supply hydrogen. In our current model, GALLME determines which process to use – steam methane reforming with or without CCS or electrolysers. This choice of deployment also allows the model to determine changes in capital cost of CCS and in electrolysers.*

Within GALLME global hydrogen demand is assumed based on IEA forecasts. As this assumed demand does not have any explicit firmed hydrogen requirement, the key driver of electrolyser deployment and thus capex projections is the cost of green hydrogen vs blue hydrogen. The 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.

However, except ammonia and methanol, most hydrogen use cases as identified by Climateworks Centre and CSIRO (2023) such as industrial heat require a constant supply of hydrogen. Thus, to achieve a fair comparison between green vs blue hydrogen, the cost of firming the variable hydrogen supply must be considered[1]. Fletcher et al (2023A) finds 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."*

GALLME is a 13 regional model of the world and does not involve time sequential energy modelling. Assessment of the cost of a constant supply of green hydrogen vs blue hydrogen requires time sequential

[1] It is noted blending in natural gas pipelines could provide some flexibility, though this is not costless and is unlikely to be sustainable as gas demand reduces and hydrogen demand increases. AEMO (2023) states that: *However, the assumption for the majority of the industrial sector was that 100% hydrogen could be supplied directly if new supply infrastructure were established. The average for the industrial sector could therefore exceed 10% by volume depending on the relative proportion of supply from existing/new pipelines. The assumption is supported by the detailed results of the Multisector Modelling, which estimated an optimal industrial sector average in the range of 40-80%.*

modelling. *CSIRO Climateworks Centre Multi-Sector Energy Modelling*, which aggregates electricity demand into 16 load blocks, provides an example of the impacts of not using time sequential modelling for green hydrogen modelling. **Error! Reference source not found.** shows that *CSIRO Climateworks Centre Multi-Sector modelling* projected green hydrogen costs provided in *2024 Draft Inputs and Assumptions workbook* are closer to islanded farm gate green hydrogen costs from Fletcher et al (2023A) than the cost of providing a constant green hydrogen supply from the same study. Both models source input assumptions from similarly dated CSIRO GenCosts. It is not clear whether CSIRO Climateworks Centre have incorporated electricity network charges or connection costs into their LCOH projections. These extra costs may significantly increase the levelised cost of grid-connected hydrogen.

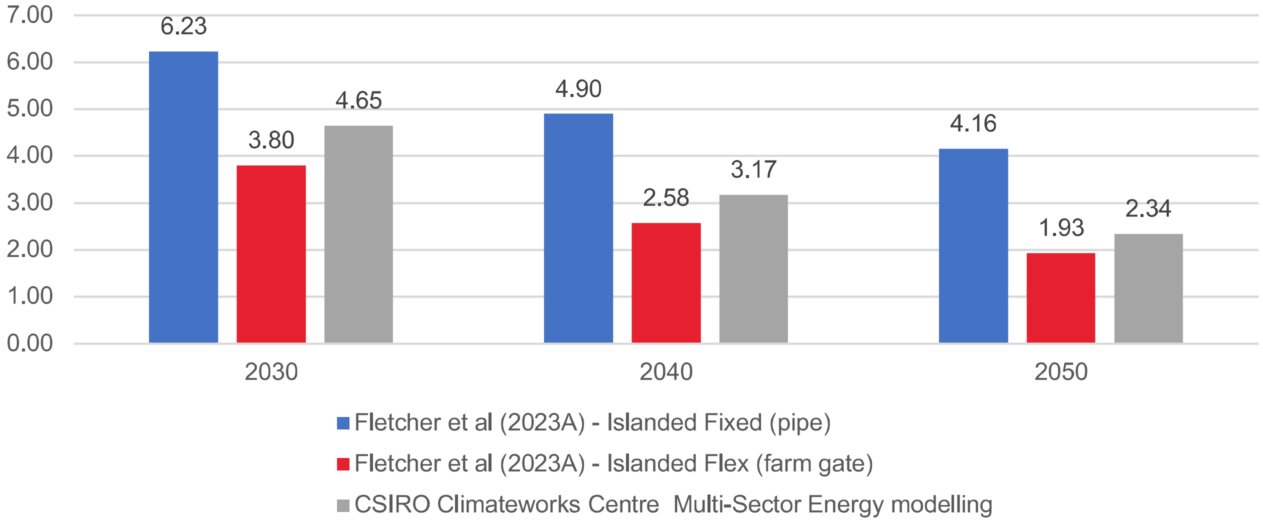


Figure 1 – Levelised cost of hydrogen ($/kg $H_2$) projections

This methodological issue could underestimate green hydrogen cost, overestimate its competitiveness against blue hydrogen and lead 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 be compounded, over-estimating green hydrogen demand and materially underestimating electrolyser capex.

An independent review of this model is recommended. Whether methodological changes can be made to address the issue within GALLM should be investigated. One solution that should be investigated it is to force an additional green hydrogen firming premium into the model. To calculate this premium separate detailed modelling of the cost of providing a constant supply of green and blue hydrogen and electrification alternatives could be undertaken using time sequential modelling. CSIRO Climateworks Centre follow a similar process in *CSIRO Climateworks Centre Multi-Sector Energy Modelling* where energy storage is forced in.

### 3.2.2 Capex estimates and projections – breakdown into electrolyser stack and BOP

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. IEA (2023) and IRENA (2020) electrolyser capex projections are split into stack and BOP components with different learning rates applied.

It is recommended that capital cost estimates and projections for electrolysers are split into stack and balance-of-plant components and projections disclosed in line with practice from leading international energy agencies, industry and academia. It would be preferable if installation cost was also able to be separately split out as this is driven by local factors such as labour costs.

### 3.2.3 Capex projections – breakdown into equipment and installation/BOP

*CSIRO GenCosts 2023-2024 Consultation Draft* Global NZE post 2050 scenario (Step Change) projects that wind capex will decline from $3,038/kW for 2023 to $2,518/kW by 2026 to $1,989/kW by 2030, a more than third reduction. The project capital cost includes wind projects that have Commercial Operations Dates of 2026 or later. This trend is inconsistent with Fletcher et al (2023B) that finds:

*Feedback from various industry sources is that capital cost estimates for a number wind projects currently under development are significantly higher than those in GenCost 2022-23. Project capital costs could be higher for a number of reasons including:*

- *Environmental offsets costs;*
- *Community/stakeholder engagement and offset costs;*
- *Cost impact of more stringent industrial relations and local contents requirements, including as part of requirements for various state government renewable energy support mechanisms;*
- *The quality of wind sites reducing as the best sites have already been developed. E.g. challenging terrain and/or geotechnical conditions leading to higher construction, land, environmental and community offset costs; and*
- *Higher connection costs (relevant for grid connected projects) as best located sites already developed E.g. longer distance from transmission network and locations with higher system strength requirements.*

Given Aurecon's extensive expert market knowledge of renewable energy project developments it is recommended that its feedback is sought as to whether CSIRO GenCosts short term capital cost projections (e.g. 2026) are consistent with projects which are currently being developed and/or contracted for the same Commercial Operation Dates.

In addition to increased freight and raw material costs (e.g. lithium carbonate for BESS) construction costs have been a key driver of increased energy project capex as well construction project capex across other sectors of the economy. The increase in civil construction costs can be seen in wind farm installation cost (balance-of-plant) increasing by ~41% from $510/kW (30% of total EPC) in the *Aurecon 2021 Cost and Technical Parameters Review* to $719/kW in the *Aurecon 2023 Cost and Technical Parameters Review* (25% of total EPC).

Although wind farm equipment may benefit from learning rates it is difficult to build a case that the same level of local learning will occur for balance-of-plant, which is primarily driven by labour and material costs whose costs are driven by domestic economic conditions. This is particularly the case when the quality of wind sites may decline over time as the best sites have already been taken. There is a large pipeline of energy and non-energy projects in Australia which is putting upward pressure on civil construction cost. Given these factors CSIRO's assumed local learning rate of 11.3% for onshore wind appears highly optimistic. CSIRO should consider this local learning rate, taking into consideration these factors.

It is noted that capex projections for wind projects are split between equipment and installation (balance -of-plant) and different learning rates applied reflecting different cost drivers for these capex components. Disclosure of this split in capex projections is recommended.

Lastly, in some cases the REZ locational cost factors provided in *Aurecon 2023 Cost and Technical Parameters Review* could contribute to closing the gap between industry estimates and CSIRO GenCosts capital cost estimates, while connection costs are also provided separately in *2024 Draft Inputs and Assumptions workbook.*

To provide clarity to stakeholders, it is recommended that a worked example for a wind farm be provided for the capex build up, including application of locational cost factors and connection costs. Although this would typically be included in the IASR, it would be of benefit to include this worked example in CSIRO GenCosts, as it is used as a standalone reference document by a range of stakeholders.

### 3.2.4 Capex estimates and projections for utility scale solar PV capex- breakdown into modules, other equipment and installation

The technical parameters and capital cost estimates, including installation cost for utility scale solar PV in the *2023 Cost and Technical Parameters Review* are the same as the *2022 Cost and Technical Parameters Review.* It would be valuable to for Aurecon to confirm this. In a period of high inflation and rising construction costs this result seems unlikely.

*Aurecon 2023 Cost and Technical Parameters Review* assumes that $/W EPC cost is $1.20/W (DC) with equipment representing 60% of EPC cost and installation cost 40% of EPC cost. NREL (2023) shows that for a utility scale system, module may only represent 32% of total solar PV capex. Solar PV module costs per watt are often reported in the press and module cost reductions have been a key driver of historical reductions in utility scale solar farm capex. However, a large portion of installation cost is labour. In the future while higher module efficiency may lead to lower installation cost per watt, *Aurecon 2023 Cost and Technical Parameters Review* finds that module size is reaching practical limits for handling and wind loading. More material reductions in labour costs could require significant automation, which is uncertain.

It is recommended that for *Aurecon 2023 Cost and Technical Parameters Review* and *CSIRO GenCosts* solar PV capex estimates are broken down into at least module, other equipment cost and installation cost, with different learning rates applied. NREL (2023) provides an example of breakdowns into US utility scale PV capex. To test the reasonableness of the installation cost projections an implied FTE jobs figure should be provided.

### 3.2.5 Capex estimates and projections for BESS - breakdown into chemical materials, battery cells, other equipment and installation

GenCost BESS capex projections change significantly with different GenCost versions and by scenario, without any link to detailed bottom-up analysis of battery technology. The link to chemical material costs (e.g. lithium carbonate price for lithium-ion BESS) and other readily available battery cost data such as EV battery cell packs is also not clear, creating confusion with stakeholders.

Figure 2 shows how capex projections for 4hr BESS have changed for the Step Change and equivalent scenario over time, while learnings rate assumptions have remained the same. It is notable that:

- short term capex projections have increased significantly in the two most recent GenCosts driven by higher current project capex provided by Aurecon, but return to the same value in 2030; and
- despite projected global BESS deployment likely increasing due to global emission polices, 2050 BESS capex in the 2023-24 GenCost draft is 35% higher than the 2020-21 final draft.

Figure 2 also demonstrates that one issue with learning rate models that do not consider the breakdown of capex for BESS is that transitory issues such as higher lithium carbonate prices that impact current capex persist in the projections in perpetuity, even though these higher prices may only last for a year.

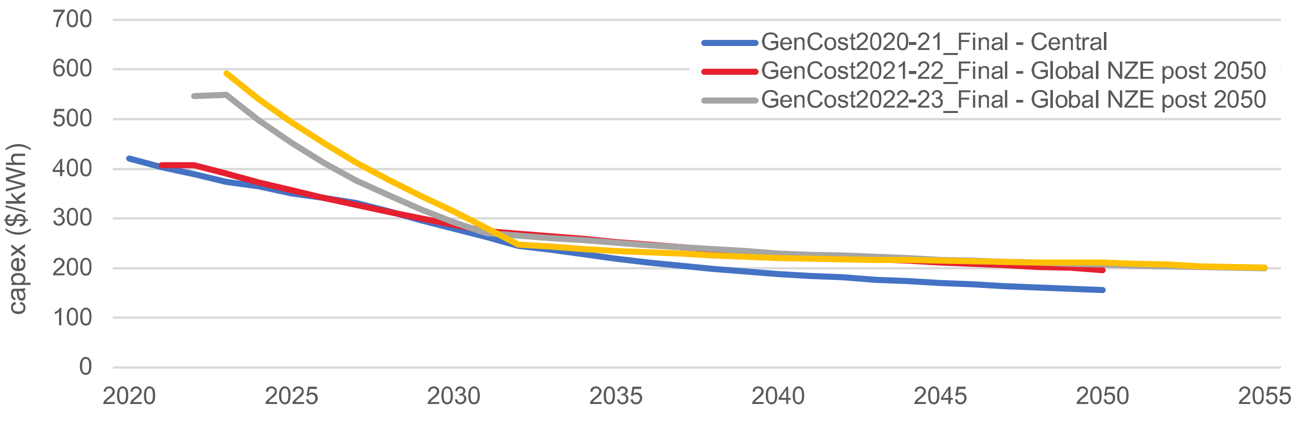


Figure 2: CSIRO GENCOST 4 hr BESS capex (Step Change)

Figure 3 demonstrates the impact that different deployment and assumed learning rates have on capex for 4hr BESS. The 2050 capex for 4hr BESS for the Current Polices scenario is 50% higher than the Global NZE post 2050 scenario. This is a substantial difference, which is inconsistent with the scenario spread seen in other modelling (e.g. IEA (2023)). There is no capital cost breakdown to assess the reasonableness of these projections.

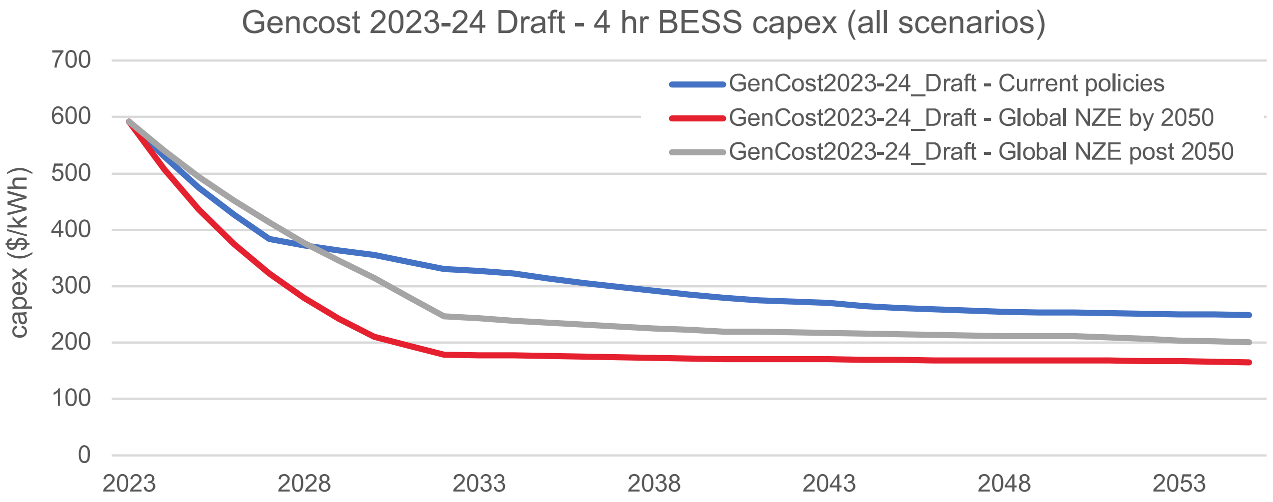


Figure 3: CSIRO Gencost 2023-24 Draft - 4 hr BESS capex (all scenarios)

The addition of flow batteries into Aurecon Cost and Technical Parameters Review is noted. Flow batteries and different cell battery chemistries have a range of advantages and disadvantages. The cost of chemical materials is an important cost driver that impacts on commercial deployment of battery technologies and can vary widely (Tyson and Bloch (2019)).

It is recommended that chemical material costs are split out for all BESS within Aurecon Cost and Technical Parameters Review and CSIRO GenCost, which will provide an important baseline for BESS cost projections.

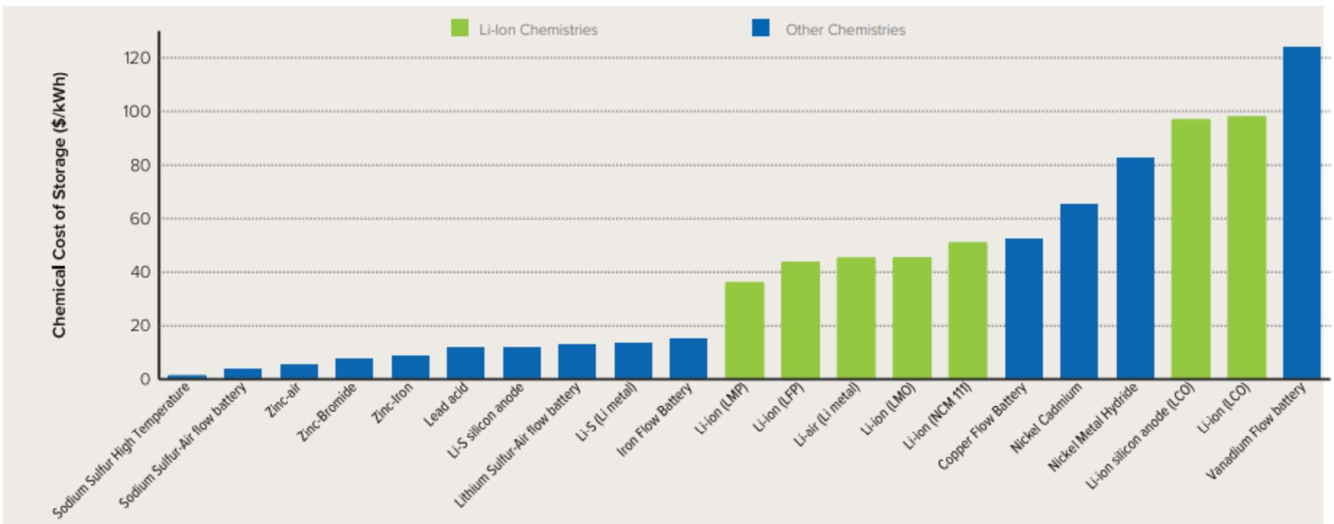


Figure 4 - Estimated Cost of Raw Materials for Different Battery Chemistries. Source: Tyson and Bloch (2019)

The cost of lithium-Ion battery packs is often quoted in industry press articles, e.g. BNEF (2023) and has the potential to cause confusion with stakeholders as battery cells represent only a portion of utility scale BESS (NREL (2023)).

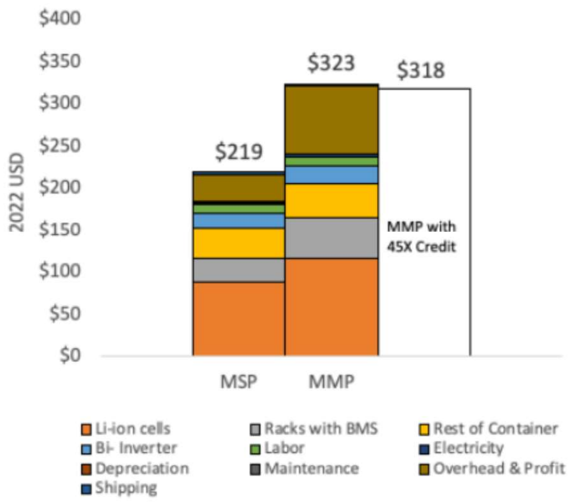


Figure 5 – US Utility ESS cost US$/KWh Q1 2023, Minimum Sustainable price & modelled market price. Source – NREL (2023)

Within the Aurecon Cost and Technical Parameters Review and CSIRO GenCost BESS EPC projection, a breakdown of EPC capex into at least cells (further split into materials component), other equipment and installation cost would help stakeholders assess, and potentially inform as required, the validity of capex projections. Different learning rates should be applied for these components within CSIRO GenCosts, consistent with global best practice (e.g. IEA (2023)).

### 3.2.6 Green Energy Markets – residential BESS capex projections

A key driver of Green Energy Markets residential battery projections is an assumption that the capex premium over utility scale BESS declines from roughly 100% currently to 17% in 2032, consistent with the premium for distributed solar PV over utility scale. The modular nature of batteries and straightforward and relatively quick installation are the justification for this assumption.

NREL (2023) demonstrates that the capex stack for residential batteries is substantially different from utility scale batteries, including equipment. A comparison of capex forecasts for residential batteries in NREL (2024A) vs utility scale batteries in NREL (2024B) shows that a significant cost premium for residential batteries remains over time.

NREL (2024A) contains details of their residential battery capex assumptions and projection methodology, including the application of different learning rates per component. The absolute level and % capex reduction in NREL (2024A) residential BESS capex projections across all scenarios are materially lower than those provided by Green Energy Markets for the Step Change scenario.

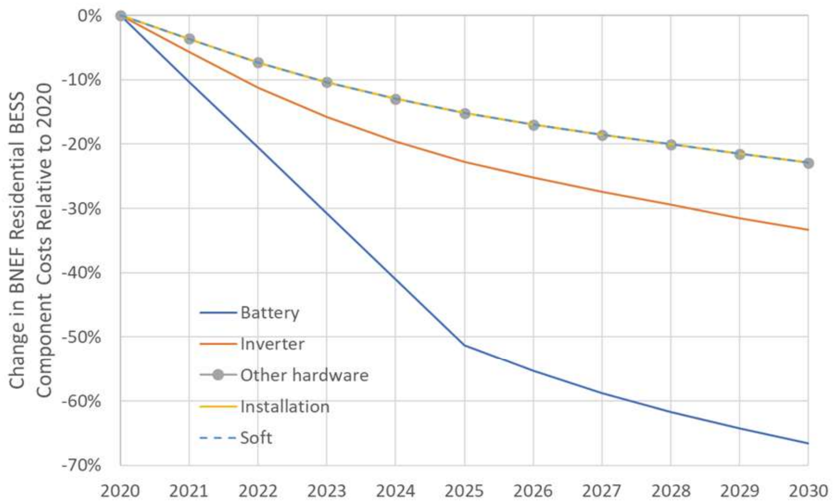


Figure 6 - Changes in projected component costs for residential BESS. Source – NREL (2024A) - BNEF. “Energy Storage System Costs Survey 2019.” BloombergNEF, October 14, 2019.

Although Green Energy Market's viewpoint that the cost premium for residential batteries will decline from ~100% to 17% consistent with solar PV has some intuitive appeal, these are different technologies and the viewpoint is not supported by detailed analysis, particularly a breakdown of capex projections. Its viewpoint is not consistent with residential BESS capex projections from CSIRO and global leading researchers (NREL 2024A and 2024B).

Green Energy Markets should provide better justification of its viewpoint including a detailed capex projection breakdown into major components, including installation cost. Absent relevant justification no reduction in residential premium should be assumed.

# 4. Inclusion of other technologies in Aurecon Cost and Technical Parameters Review and CSIRO GenCosts

## 4.1 Fixed-plate solar PV

Fixed-plate solar PV is not currently a candidate technology in the AEMO ISP as in recent years single-axis trackers have dominated the utility scale solar PV market in Australia. *Aurecon 2023 Cost and Technical Parameters Review* identifies that single-axis tracker systems *"generally have a lower LCOE, as they produce more energy throughout the day and align better with higher generation pricing periods – i.e. increased energy generation over fixed-tilt systems in the early morning and late afternoon generally have a lower LCOE, as they produce more energy throughout the day and align better with higher generation pricing periods – i.e. increased energy generation over fixed-tilt systems in the early morning and late afternoon."*

In the short to medium term Aurecon's perspective is sound, however the ISP is a long-term modelling exercise. In a renewables-dominated NEM, a key driver of high price periods could be renewable energy deficits, driven by renewable droughts and lower solar output in winter. This is when gas peaking generation is modelled to be required and high price periods are more likely. Figure 722 from the Draft 2024 ISP highlights the high use of gas in winter in 2039-40 in the Step Change Scenario.

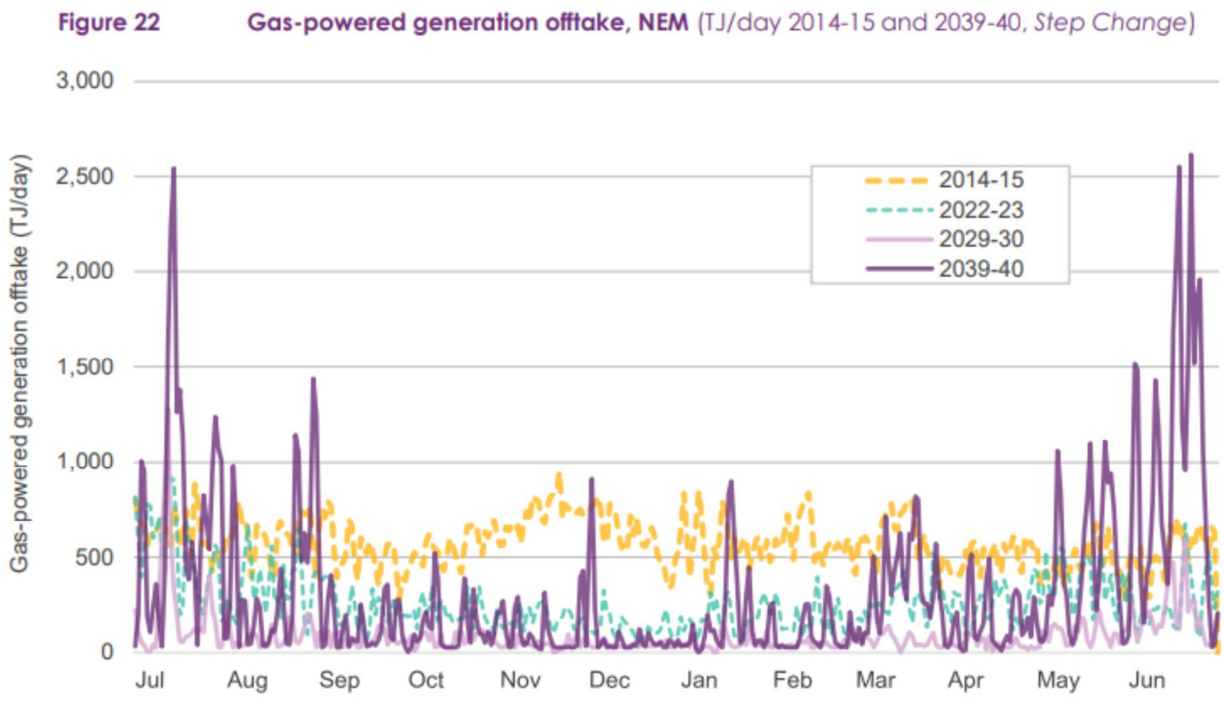


Figure 7 – gas powered generation offtake NEM (TJ/day 2014-15 and 2039-40, Step Change). Source DRAFT 2024 ISP

Fletcher et al (2023) demonstrates that the levelized cost of typical dispatchable generation options that could address the 'winter problem' such as OCGT and hydrogen peakers could be high cost. North facing solar PV warrants further investigation as a potential candidate technology as it has less seasonality in generation output than single-axis tracker, particularly in southern NEM states, which could contribute to addressing the winter problem (Gilmore, Nelson, & Nolan, 2022). Research into a future German energy system has also identified benefits from different solar PV orientations (Reker, Schneider, & Gerhards, 2022).

In southern NEM states (all NEM states except QLD) although north solar facing PV may have lower LCOEs than east-west facing single-axis tracker solar PV, the system cost benefit/value of electricity produced could be higher due to stronger winter generation volumes. North facing solar PV could be fixed-tilt systems or single-axis tracker systems that do not utilise their full tracker operating range.

In order to test north facing fixed-plate solar PV as a candidate in southern states it is recommended that capital cost estimates for the technology and solar PV traces are provided.

## 4.2 Non-geological hydrogen storage, green ammonia and thermal energy storage

In the future integrated energy system, other storage technologies could play an important role and should be considered. Fletcher et al (2023A) finds that:

*The key problem that energy system modelling for a renewable energy dominated system should be attempting to solve is how economic outcomes can be maximised by shifting renewable energy through time and space to meet demand for electricity, heat, hydrogen, hydrogen derivatives and high embodied energy products for an economy. To address this problem an improved understanding of the flexibility of electricity intensive industrial processes and their intermediate storages (e.g. hydrogen storage, thermal energy storage) and end-product storages (e.g. ammonia storage, alumina storage) is required.*

*The vast majority of Queensland's decarbonisation load has the potential for at least a portion of its firming to be provided by alternative energy storages that could have lower capital costs than utility scale power system storage. For instance electric vehicles allow load shifting and the potential for vehicle-to-home and vehicle-to-grid, green ammonia value chain could incorporate hydrogen and ammonia storage and green alumina value chain could incorporate thermal energy storage. Industrial production process flexibility offers another potential alternative to power system firming. Standard energy system modelling that does not explicitly consider these industrial demand response alternatives may overestimate gas generation volumes and overbuild firming generation such as gas peakers and power system storage. It is however noted that in the short to medium term OCGT is expected to play a critical role in combining with power system storage (PHES and BESS) to firm renewables to meet existing electricity load, where there may be limited potential for demand response (Australian Energy Council, 2023B).*

*Energy system modelling, such as the AEMO Integrated System Plan, should more accurately integrate potential green ammonia value chains. Investigation of the demand response potential of other industrial process loads is required, particularly industrial heat, with decarbonisation of alumina representing a sizable potential load for Queensland. Persisting with standard market modelling practices which have a narrow focus on electricity system costs may be to the detriment of least cost decarbonisation.*

For more integrated hydrogen, green ammonia and industrial heat modelling to be possible within the ISP, an evidence base covering input assumptions is required.

Fletcher et al (2023B) provides an independent evidence base around hydrogen storage and ammonia storage which has been tested with various industry experts. It would be valuable if Aurecon considered this research in the inclusion of costs estimates within the *Aurecon Cost and Technical Parameters Review* for:

- Green ammonia storage for export facilities as well as for other purposes, such as on farm ammonia storage, which could be lower cost; and
- Hydrogen storage in pressure vessels, buried pipe and/or hydrogen pipeline linepack.

Projections are not required for these storage technologies as capital costs are not forecast to change significantly in the next three decades, since technological improvements are not anticipated, and the cost is driven by raw materials, land costs and labour (Fletcher, 2023B). Aurecon Technical Parameters Review provides capital cost estimates for a green ammonia production facility and capex projections are not necessary given the maturity of large-scale ammonia production facilities.

As medium and high industrial heat is a significant energy demand in Australia (ITP (2019)) and thermal energy storage (TES) is an important supporting technology for electrified heat, an evidence base for TES is required to inform the modelling of this electrification load. Many historical studies on TES have focussed on concentrated solar thermal, a technology that has experienced limited deployment and is locationally constrained. Standalone TES that could be relevant for medium and high temperature heat such as the Rondo Heat Battery (Rondo, 2024) should be the focus of investigation.

It is recommended that TES is included in CSIRO GenCosts as it may meet CSIRO's criteria for inclusion:

### Relevant to generation sector futures

TES is a competitor to power system storage (BESS, PHES) where there is electricity demand for medium and potentially high temperature heat. Potential benefits over BESS from a system cost perspective include:

- Potential for low cost of storage per MWh driven by lower material cost (Spees et al, 2023 and MIT (2022))
- High charge to discharge rate ratio, which can take advantage of lower cost solar PV including behind the meter, reducing energy and transmission costs. (Spees et al, 2023)
- High efficiency (90-98%) (Spees et al, 2023)

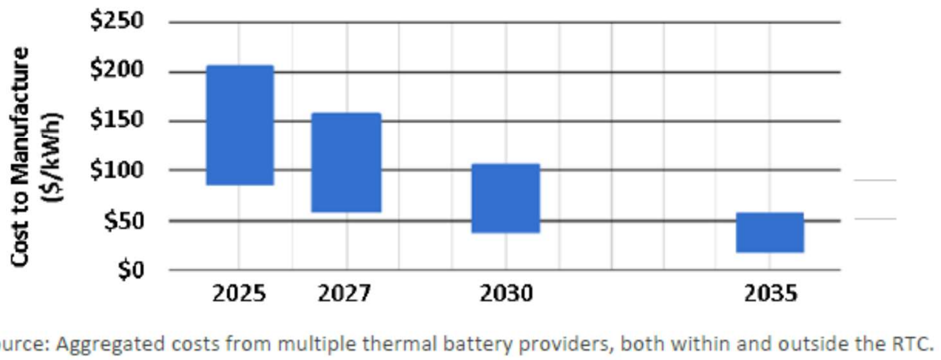


Figure 8: Thermal battery companies' projected total manufacturing costs: Source - Spees et al(2023)

### Transparent Australian data outputs are not available from other sources

To the best of the authors' knowledge no public cost or project data is available for Australia.

### Has the potential to be either globally or domestically significant

Industrial heat represents 22% of global final energy consumption in 2019 (McKinsey, (2022)). Industrial heat use in Australia was 730PJ was in 2016-2017 (ITP, (2019)). Electrification and hydrogen are competing technologies for decarbonising medium and potentially high-temperature industrial heat. Business electrification is forecast to be 28TWh and domestic hydrogen 46TWh by 2050 respectively (AEMO, (2024)). As issues have been raised in this submission around the modelling of hydrogen demand, business electrification load growth, which represents the target market for TES, could be understated.

### Input data quality level is reasonable

Input data quality is on the lower end of CSIRO's scale. Given the limited deployment of the technology, most cost projections are based on proponent estimates (e.g. Spees *et. al.* (2023)), where costs per MWh excluding installation are projected to be lower than lithium-ion BESS driven by low material costs. Thus building stakeholder confidence in TES capex projections is critical and a more thorough investigation of the technology than contained in the Aurecon Costs and Technical Parameters Review could be warranted.

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**Mindful of model size limits in technology specificity**

Thermal energy storage is relatively easy to introduce into energy market modelling as a storage candidate. Thermal energy storage's application is limited to medium and high temperature heat demand and thus deployment would need to be constrained to the decarbonisation of such demand.

## 5. CSIRO Electric Vehicle Projections 2023 – FCEV projections

Although there is more detail provided in *2022 CSIRO Electric Vehicle Projections* there is still insufficient detail to assess whether full value chain costs of FCEV have been assessed, including by undertaking time sequential modelling. This has the potential to bias model results in favour of green hydrogen compared to alternatives such as battery electric vehicles. CSIRO and GHD (2023) find that the cost of supplying hydrogen for FCEV could be as much as $15.60/kg $H_2$, highlighting the fuel cost challenges for FCEV.

A future role for hydrogen in road transport is heavily contested (Plotz, 2022). Per Fletcher et al (2023A) for the use of hydrogen FCEV in trucking it is recommended that:

*Hydrogen use case value chain costs should be compared against existing fossil fuel use and where relevant other decarbonisation alternatives. Synthetic hydrocarbons should be assessed as an alternative for transport use cases as firming costs could be relatively low and there is the potential to leverage existing value chain infrastructure and vehicles. Synthetic hydrocarbon production could have similar partial-flexibility to ammonia production and low-cost end-product storage, which may reduce required oversizing of value chain production capacity and storage costs.*

*To build stakeholder confidence around hydrogen demand projections used in the AEMO Integrated System Plan, a more detailed breakdown of projections should be provided, with separate detailed use case modelling undertaken on hydrogen vs alternatives using time sequential modelling.*

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