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Draft 2024 ISP

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 and detailed modelling that assesses the cost of potential green hydrogen and green ammonia value chains in Queensland (Fletcher et al (2023A) and Fletcher et al (2023B)). This submission to the *Draft 2024 ISP Consultation* is informed by this research. A submission was made to the *2024 Forecasting Assumptions Update Consultation* on 9 February 2024 which is referred to in this submission and is appended.

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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Executive Summary

We welcome the opportunity to provide feedback on AEMO's draft 2024 ISP published on 17 December 2023. The ISP, its supporting models and documents are highly complex and AEMO's transparency in providing this detailed information is valued. We believe that AEMO's consultation process and commitment to engage closely with stakeholders is a key strength of the ISP that provides the potential for emerging learnings from industry and research to be integrated into system planning.

The AEMO ISP's primary objective is to "optimise value to end consumers by designing the lowest cost, secure and reliable energy system capable of meeting any emissions trajectory determined by policy makers at an acceptable level of risk." Within our submission we highlight areas where AEMO could improve input assumptions and modelling methodologies to increase alignment with least-cost decarbonisation.

Our submission is focussed on future industrial decarbonisation load including hydrogen. The bulk of this new load is not forecast within this decade and thus is unlikely to impact on anticipated and actionable projects. However, now is an appropriate time to put focus on improving the knowledge base and modelling on demand side flexibility for industrial decarbonisation load, including electrification and green hydrogen. The research on which this submission is largely based was released in November 2023 (Fletcher et al (2023A) and Fletcher et al (2023B)). Prior to the release of the research, we were pleased to have the opportunity to present and test the research with AEMO energy system modelling experts and discuss how green hydrogen and green ammonia were modelled in the ISP.

As the energy system moves away from fossil fuels, sector coupling between energy supply and end uses may become increasingly important to efficiently integrate variable renewable energy. We believe that the ISP modelling methodology could better reflect the potential coupling between electricity, hydrogen, hydrogen derivatives and high embodied energy products. This key statement in the Draft 2024 ISP indicates its strong focus on supply: *"With coal retiring, renewable energy connected with transmission, firmed with storage and backed up by gas-powered generation is the lowest cost way to supply electricity to homes and businesses throughout Australia's transition to a net zero economy."*

We acknowledge that the integration of demand side flexibility in the modelling is highly complex and the incidence or predictability of future loads and associated demand-side flexibility of those loads is highly uncertain. However substantial industrial decarbonisation loads are included in the ISP and assumptions around the degree of flexibility or inflexibility of these loads could materially impact their implied decarbonisation cost. Thus, realistic flexibility assumptions are important. This submission presents the case for the value of improved integration of industrial decarbonisation load flexibility and insights from work conducted so far.

Appropriate models and data inputs for sector coupling of industrial decarbonisation load need to be developed

Sector coupling in the ISP heavily focuses on the residential consumer side, with highly detailed modelling of electric vehicle (EV) charging, and customer energy resources (CER). However, significant uncertainties remain and we welcome AEMO's commitment to provide a sensitivity for reduced CER orchestration in the Final ISP.

On the other hand, sector coupling involving industrial load has been comparatively underdeveloped. Industrial decarbonisation load grows to 20% of NEM demand by 2050. Improving the modelling of industrial decarbonisation load in the ISP requires an understanding of the flexibility of electricity-intensive industrial processes and their intermediate and end-product storages. Fletcher et al. (2023a) and Fletcher et al. (2023b) provide relevant data to support the modelling of green hydrogen and green ammonia. Electrification incorporating thermal energy storage is an alternative to hydrogen for industrial heat that warrants further investigation, particularly given the significant scale of Queensland's existing industrial energy demand.

Methodological issues with input models could be driving an overestimate of green hydrogen demand

Except green ammonia and green methanol, most hydrogen use cases require a constant supply of hydrogen. Thus, to achieve a fair comparison between green hydrogen versus alternatives, the cost of firming the variable hydrogen supply should be considered. The ISP input models that provide hydrogen demand and electrolyser capex projections lack the time-sequential detail to undertake an accurate assessment of the cost competitiveness of firmed green hydrogen. The models appear to be based on load duration curves, which may have been appropriate for modelling of fossil fuel dominated energy systems, but are less well-suited to variable renewable dominated systems. Because wind and solar PV generation is intermittent and subject to seasonality, time sequential modelling is preferred to capture these characteristics.

The lack of time-sequential modelling in ISP input models may:

- Underestimate the cost of hydrogen storage and the cost of firmed green hydrogen;
- Overestimate hydrogen competitiveness against alternatives, overestimating demand; and
- Overstate electrolyser capex reductions.

Many levelised cost of hydrogen (LCOH) projections have the potential to materially underestimate the cost of firmed green hydrogen as they:

- Use hydrogen production estimates that do not include storage costs, known as “farm gate” estimates (CSIRO, 2018; Deloitte, 2023; McKinsey & Company, 2022; Wood, Reeves, & Yan, 2023);
- Have modelling methodologies with coarse temporal resolution (ARUP, 2023); and/or
- Make broad assumptions around required storage (Clean Energy Finance Corporation & Advisian, 2021).

The AusTIMES model, used in the CSIRO Climateworks Centre Multi-Sector Energy model (ISP input model) and in other prominent reports, should be independently reviewed to aid CSIRO and Climateworks in addressing the issues identified and to strengthen confidence in this modelling. This is important for the ISP and more broadly to aid understanding of the cost of green hydrogen as a decarbonisation option.

Analysis of Draft 2024 ISP model indicates potential to improve hydrogen modelling

The ISP model assumes flexible electrolyser operation is balanced across the month to meet monthly production targets. Assuming that underlying hydrogen demand is constant, this implies a significant volume of ‘free’ hydrogen storage. To the authors’ best knowledge, there is no evidence base supporting the monthly balancing assumption.

As a consequence, the authors have conducted additional analysis using AEMO’s ISP Plexos model as a basis, finding that by 2050:

- For Queensland flexible electrolyser capacity is forecast to have grown to 6GW with load factors declining over time to around 35%. With existing assumptions, electrolysers become a solar soak, as well as providing inter-week demand response, flattening the operational demand profile and reducing required dispatchable generation.
- The hydrogen storage implied in the ISP reaches ~200GWh ($10 billion capex) in Central Queensland alone, compared with ~642GWh of power system storage (including CER) in the NEM (AEMO, 2024). For context, Central Queensland represents ~40% of NEM 2050 hydrogen demand.
- Assuming monthly balancing:
    - LCOH excluding storage declines over time, reaching $2.60/kg H2.
    - LCOH including storage only decreases slightly over time to around $6/kg H2, with storage contributing up to 70% of the cost stack.
- As the optimal electrolyser load factors, hydrogen storage and the electricity system cannot be accurately co-optimised using standard PLEXOS modules, a daily balancing scenario can instead be tested. This scenario has an LCOH of $3.70/kg H_2, a more reasonable outcome.

Due to the uncertainty around hydrogen demand given issues raised in this submission, sensitivities incorporating more techno-economically plausible hydrogen scenarios such as no grid-connected hydrogen demand or daily hydrogen balancing combined with lower orchestration of CER are recommended.

The benefits of integrating green ammonia value chain demand response for 2026 AEMO ISP

Green ammonia could play a pivotal role in decarbonising fertilisers and explosives, that are critical inputs into Australia's agriculture and resource sectors respectively. Industry consensus has emerged in Australia that ammonia is one of the 'no-regrets' clean hydrogen use cases where no real alternatives exist (Liebreich Associates, 2023) and where hydrogen policy support should be prioritised (Australian Energy Council, 2023A; Climateworks Centre, 2023; Institute for Energy Economics and Financial Analysis, 2023).

Modelling of green ammonia in Draft 2024 ISP does not fully reflect potential sector coupling benefits, including the potential for seasonal load shifting. Our research demonstrates that the predicted flexibility of new-build green ammonia plants combined with low-cost ammonia storage not only reduces the cost premium of meeting a fixed demand profile, but also offers the potential for demand response to the electricity system. Our modelling suggests that in the future, green ammonia value chain load shifting and load curtailment may be capable of competing with firming technologies such as batteries and gas peakers from cycling intervals as low as daily and up to inter-annual. Furthermore, while future costs are uncertain, our analysis suggests that this may occur at levelised costs of less than half of that of gas peaking generation. This demand response is distinct from using green ammonia as a fuel in peaking generation, which could be more than double the levelised cost of gas peakers.

Green ammonia demand response has the potential to contribute to addressing dunkelflaute and the renewable energy deficit in winter. In addition to reduced gas generation volumes, system benefits could include lower firming generation build requirements and lower CO_2e emissions. In the short to medium term OCGT in combination with power system storage (PHES and BESS) is expected to play a critical role, firming renewables to meet existing electricity load, where there may be limited potential for demand response (Australian Energy Council, 2023B).

There are emerging examples of hydrogen derivative projects incorporating demand response. Two green hydrogen derivative projects are currently proposed in New Zealand that incorporate demand response, including to mitigate the impacts of dry years for New Zealand's conventional hydropower dominated electricity system. More recent discussions with proponents of Australian green ammonia projects revealed they are investigating incorporating demand response into project design.

A key challenge with integrating a green ammonia value chain into power system modelling is that it requires the optimisation of three layers of storage (power system, hydrogen and ammonia). The Draft 2024 ISP only optimises power system storage. Cesaro et al. (2023) shows that sector coupling of green hydrogen and ammonia with a future renewable energy dominated Indian electricity system significantly reduces system costs. Given there is an emerging body of research supporting the more detailed integration of the green ammonia value chain, investigating a similar co-optimisation approach for the NEM in the 2026 ISP is recommended.

Summary of Recommendations

Draft 2024 ISP

1. Step change sensitivity 1 – no domestic hydrogen load
2. Step change sensitivity 2 – combined sensitivity of no domestic hydrogen and low CER and EV orchestration
3. Step change sensitivity 3 – daily demand balancing period for hydrogen
4. Step change sensitivity 4 – combined sensitivity of daily demand balancing period for hydrogen and low CER and EV orchestration

5. More granular hydrogen demand traces should be provided including a split of domestic demand between industry (including ammonia vs other) and transport.

2026 ISP

1. Independent review of CSIRO Climateworks Centre multi-sector energy modelling
2. Investigate modelling options for more accurately integrating green ammonia value chain demand response. This should include investigating co-optimisation modelling with greater definition of green ammonia value chains including hydrogen storage, ammonia plants and ammonia storage.
3. Develop appropriate models and data inputs for sector coupling of other industrial decarbonisation and in particular electrification incorporating thermal energy storage to inform how these loads could be modelled more accurately

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1. Appropriate models and data inputs for industrial sector coupling need to be developed

Sector coupling refers to the increased integration of energy end-use and supply sectors (Figure 1) which can provide benefits such as improving flexibility and reliability of energy system, allowing greater penetration of renewable energy and reducing the cost of decarbonisation (Van Nuffel, 2018). 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 and end-product storages is required. Linkages with international markets for high embodied energy products should also be considered as they may facilitate load curtailment.

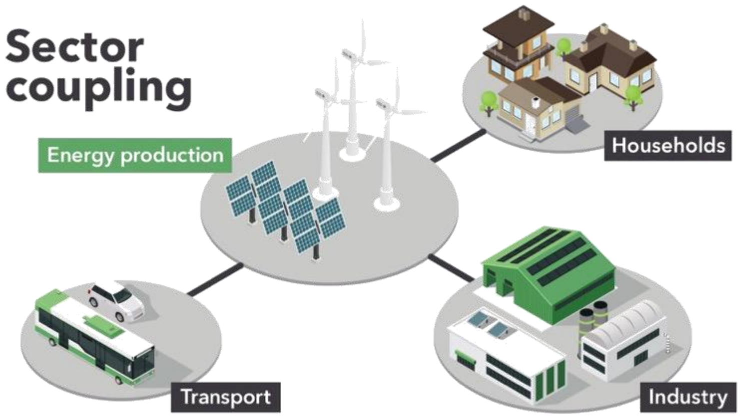

Figure 1: Sector Coupling, Source: https://www.nproxx.com/sector-coupling-an-integrated-approach-to-emissions-reduction/

In the short to medium term gas is expected to play a critical role in combining with power system storage to firm renewables to meet existing electricity load, where there may be limited potential for demand response (Australian Energy Council, 2023B).

However, in the future, EV, hydrogen and industrial electrification are key drivers of load growth in the AEMO ISP and may present significant potential for sector coupling (Figure 2). This 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 (BESS and PHES):

- Electric vehicles: Load shifting and vehicle-to-X (V2X) are integrated into the ISP with significant detail around EV projections and charging behaviours (CSIRO, 2023). We welcome AEMO's commitment to model a sensitivity with lower levels of EV charging and CER orchestration for the final 2024 ISP. A sensitivity is appropriate given significant uncertainty around uptake trajectory and orchestration level of EV and CER BESS.

- Industrial decarbonisation: Hydrogen and electrification compete, particularly for industrial heat and thus should be grouped together. The models and data inputs for industrial decarbonisation need to be developed to inform AEMO ISP modelling. The appended *2024 Forecasting Assumptions Update Consultation* submission recommends including technologies relevant to industrial decarbonisation such as ammonia storage and thermal energy storage.
    - Hydrogen: Our understanding is the key domestic hydrogen demand in Queensland in the Step Change scenario is industrial heat and transport (CSIRO/Climateworks Centre, 2022). To the authors'

best knowledge, there is no evidence supporting assumed flexibility of hydrogen demand, i.e., balancing of electrolyser operation to meet monthly production targets.

- Hydrogen derivatives: Fletcher et al. (2023A&B) provides relevant data and modelling for green hydrogen and green ammonia. The ammonia plant flexibility characteristics identified in this research are consistent with the *2023 Aurecon Cost and Technical Parameter Review*. The partial flexibility of green ammonia value chain is currently partially integrated into ISP modelling for export hydrogen.

- Industrial electrification: Thermal energy storage as a supporting technology to enable flexible electrified load is not considered in the electrification of industrial heat.

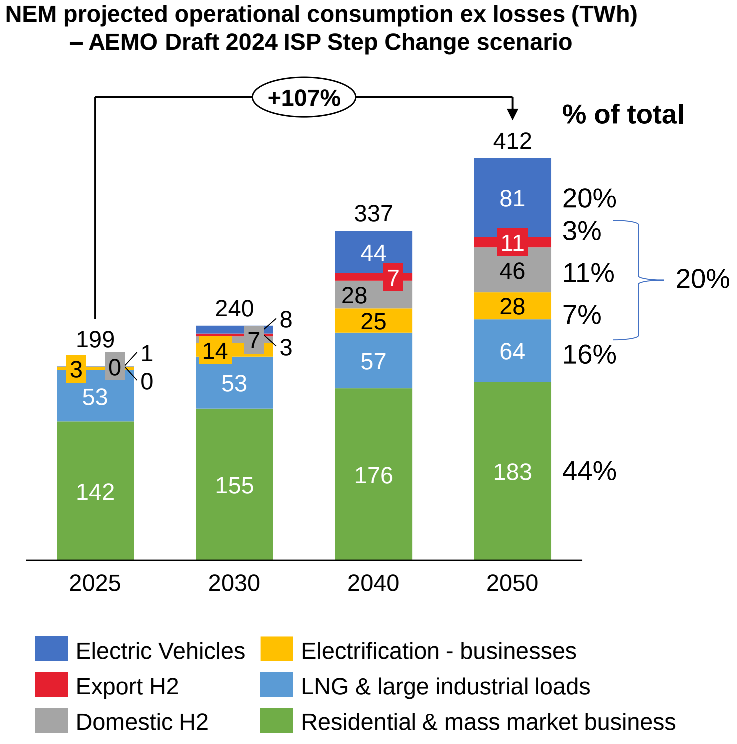

Figure 2: NEM projected operational demand excl losses (TWh) – Step Change scenario

Compared to the rest of the NEM, Queensland has a relatively high use of gas in energy intensive industries which means that energy system modelling outcomes are expected to be more sensitive to flexibility assumptions for industrial decarbonisation loads. Potential large Queensland decarbonisation loads include green ammonia and electrified industrial heat (alumina refining) (ARENA/Deloitte, 2022). The modelling within this submission is focussed on Queensland.

2. Methodological issues with input models could be driving an overestimate of green hydrogen demand

In the GenCost report, the Global and Local Learning Models for Electricity (GALLME) model projects the future electrolyser cost using experience curves (CSIRO, 2023). Technology cost reductions are achieved through ‘learning-by-doing’ and uptake. This requires forecast cumulative uptake of the technology, which is dependent on cost versus alternatives. The GALLME model solves this by simultaneously projecting both the cost and uptake with the aim to minimise the total system costs while meeting demand and all constraints. Based on hydrogen demand from the IEA, GALLME selects steam methane reforming (with or without CCS) or electrolysis to meet this demand.

This electrolyser capex projection is then used in the CSIRO/Climateworks multi-sector energy model (AusTIMES) to determine domestic hydrogen demand (CSIRO/Climateworks Centre, 2022). AusTIMES compares green hydrogen versus alternatives (electrification, fossil fuels, blue hydrogen) to meet energy demand in different sectors. Hydrogen demand from transport is sourced from FCEV projections in CSIRO Electric Vehicle Projections 2023 (CSIRO, 2023). Export hydrogen demand is an exogenous input (CSIRO/Climateworks Centre, 2022).

Except ammonia and methanol, most hydrogen use cases identified by Climateworks Centre and CSIRO, particularly 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 should be considered.

However, these three models (IEA, AusTIMES and GALLM) lack the time-sequential detail to address this issue. The AusTIMES model aggregates electricity demand into 16 load blocks (CSIRO/Climateworks Centre, 2022) and our analysis shows that this leads to a significant underestimate of high-cost hydrogen storage required for firming. Although hydrogen storage is lower cost than batteries (Figure 3), the cost is non-trivial and is unlikely to significantly decline over time since technological improvements are not anticipated, and the cost is driven by raw materials, land costs and labour.

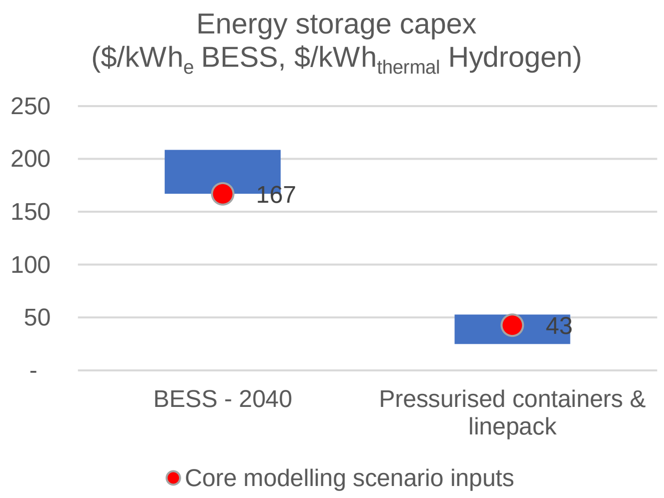

Figure 3: Energy storage capital cost per MWh (excludes power (MW)). Source: Fletcher et al. (2023B)

While using what appears to be a load duration curve in energy system modelling may have been appropriate for fossil fuel dominated systems, it is not considered best practice for variable renewable dominated systems. Because wind and solar PV generation is intermittent and subject to seasonality, time sequential modelling is preferred to capture these characteristics. This technical issue is appropriately managed in the ISP capacity outlooks models with time sequential modelling used in the Detailed Long-Term Model.

Figure 4 shows that the multi-sector model projected green hydrogen costs provided in *2024 Draft Inputs and Assumptions workbook* are closer to islanded farm gate cost than that of providing a constant green hydrogen supply in Fletcher et al (2023A), which sources input assumptions from similarly dated CSIRO GenCost (CSIRO, 2022). Section 4.4 contains the result of PLEXOS modelling for grid connected electrolysers using the Draft 2024 ISP model which confirms the large premium over farm gate costs for firmed hydrogen.

It is not clear whether the multi-sector model incorporated electricity network charges or connection costs into the LCOH projections. These extra costs may significantly increase the levelised cost of grid-connected hydrogen (Fletcher et al. (2023B)). The firming and connection costs can potentially have a negative impact on the prospects of a wide range of hydrogen use cases.

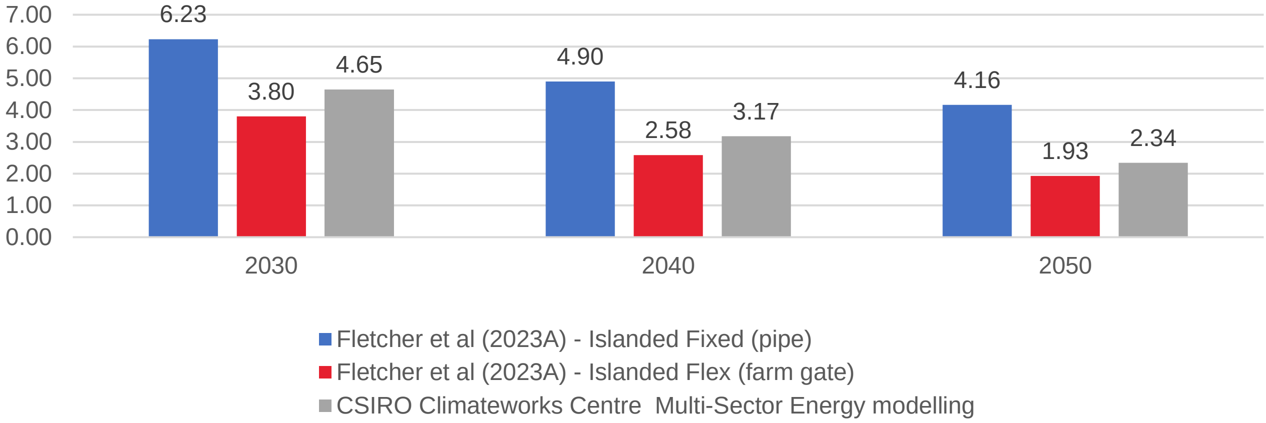

Figure 4: LCOH projections ($/kg H_2)

Figure 5 which was produced by the same authors as CSIRO GenCost shows that the farm gate cost of green hydrogen is similar to alternatives (Butler, Maxwell, Graham, & Hayward, 2021). This demonstrates that the inclusion of green hydrogen firming costs could impact on the AusTIMES decision to select green hydrogen or an alternative.

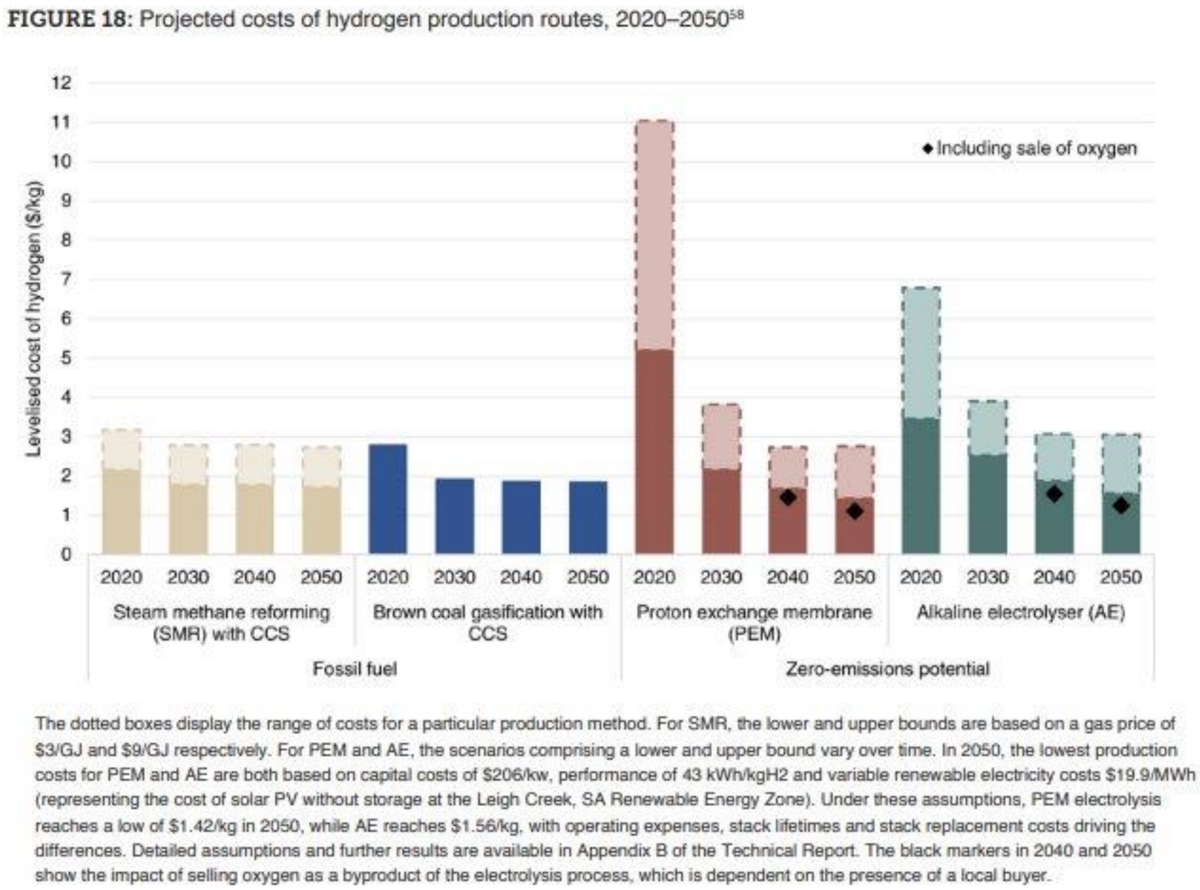

Figure 5: 2021 Internal LCOH projections from CSIRO (Butler, Maxwell, Graham, & Hayward, 2021)

In summary, the lack of time-sequential modelling in ISP input models may:

- Underestimate the cost of firmed green hydrogen and thus overestimate competitiveness (vs alternatives) artificially increasing demand; and
- Overestimate electrolyser capex reductions due to overstated demand projections.

In the appended *2024 Forecasting Assumptions Update Consultation* submission, section 3.2.1 of discusses GALLME and the circularity between artificially high demand and reduction in capex projections and sector 5 discusses issues around how hydrogen demand is forecast for FCEV in more detail.

Many LCOH projections in the literature underestimate the cost of firmed green hydrogen as they use farm gate hydrogen production estimates that do not include storage costs (CSIRO, 2018; Deloitte, 2023; McKinsey & Company, 2022; Wood, Reeves, & Yan, 2023), have modelling methodologies with coarse temporal resolution (ARUP, 2023); or make broad assumptions around required storage (Clean Energy Finance Corporation & Advisian, 2021).

We are supportive of the AEMO ISP continuing to use the multi-sector model and are thankful for the engagement we have had with CSIRO and Climateworks on the issue we have identified. There are limited parties who have the expertise to undertake this highly technical modelling and have their strong reputation and independence. To aid CSIRO and Climateworks in addressing the issues identified and to strengthen confidence in this modelling, an independent review of the AusTIMES model is recommended. This is important for not only the ISP, but given the context of the common use of potentially understated hydrogen cost projections, the wider Australian community to aid understanding of the cost of green hydrogen as a decarbonisation option. In addition, AusTIMES has been used as the basis for several recent prominent publications including:

- Industry Energy Transition Initiatives (2021-2023) (Industry Energy Transitions Initiatives, 2021-2023)
- Climateworks Centre Decarbonisation Scenarios 2023: Paris Agreement Alignment for Australia (Li, Croser, Murugesan, & Whelan, 2023)
- CSIRO Pathways to Net Zero Emissions – An Australian Perspective on Rapid Decarbonisation (CSIRO, 2023)

In the short term whether methodological changes can be made to address the issue within the model should be investigated. One potential solution 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. A similar process is already undertaken in the Multi-Sector Energy Model where energy storage is forced in.

3. ISP hydrogen modelling methodology does not optimise electrolyser capacities to provide firmed green hydrogen

The capacity outlook process consists of two stages: the Single-State Long-Term (SSLT) model which optimises the entire modelling horizon in a single stage and the Detailed Long-Term (DLT) model which divides the modelling horizon into multiple steps to be optimised sequentially (Figure 6).

Electrolyser capacity is determined in the SSLT model based on hydrogen demand from the AusTIMES model (AEMO, 2023). Understandably this computationally intensive SSLT model is not publicly released. As a result, hydrogen sensitivities undertaken in the publicly available DLT model in PLEXOS are limited as they are impacted by the hydrogen demand input assumptions from AusTIMES and the electrolyser capacities determined in the SSLT model. Within the DLT model, standard PLEXOS modules do not allow accurate co-optimisation of the electricity system, electrolyser capacity and hydrogen storage.

The capacity outlook models assume most of the hydrogen load is flexible, subject to monthly production targets. The next section will explore the implications of this assumption.

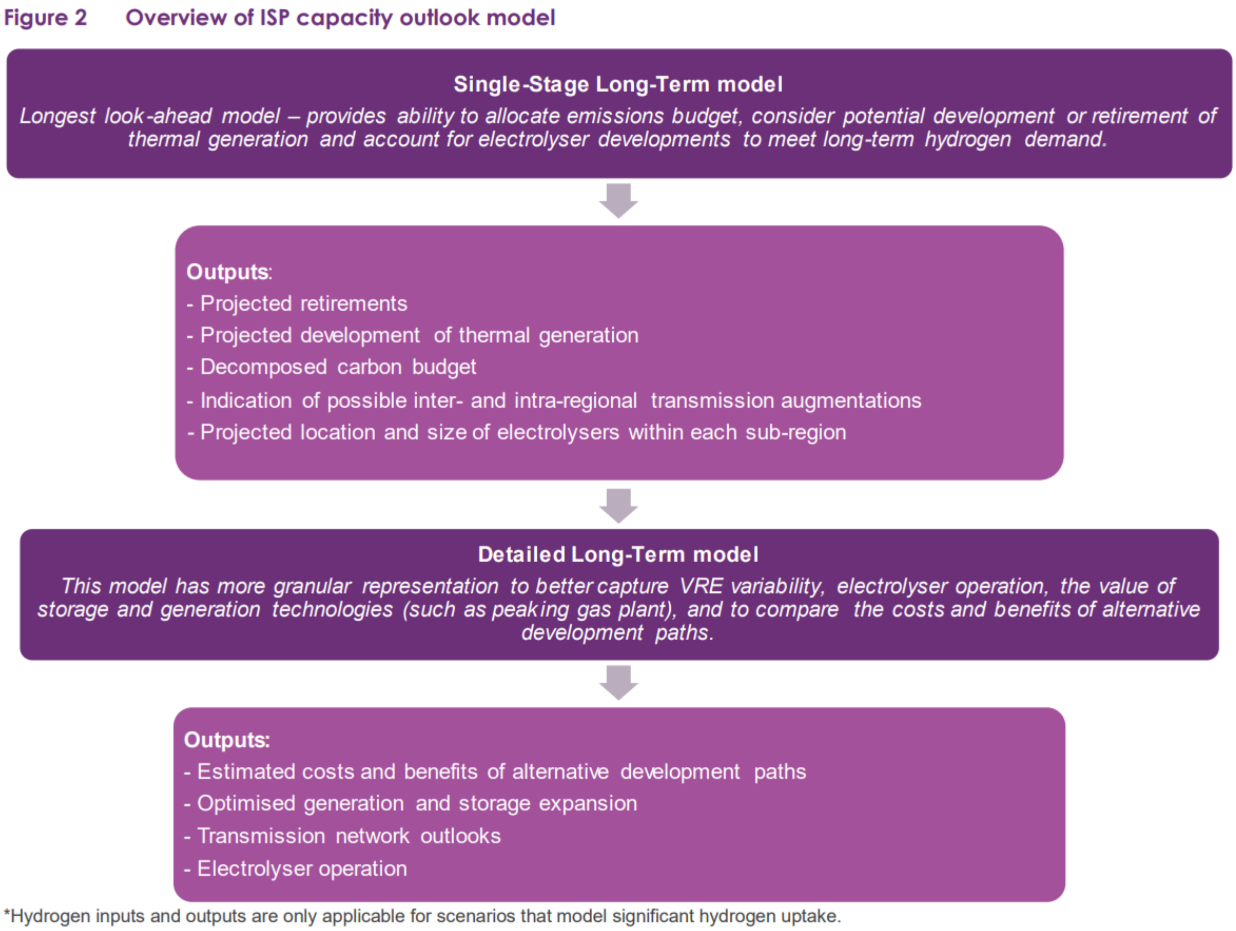

Figure 6: ISP capacity outlook model

4. Analysis of Draft 2024 ISP model indicates potential to improve hydrogen modelling

Different scenarios were tested using the publicly released Draft 2024 ISP DLT model in PLEXOS. Time resolution was decreased from half-hourly to two-hourly time blocks to reduce runtime. These two settings were benchmarked using the base case to confirm that the two settings result in nearly identical buildouts. Queensland was the focus of the analysis, but hydrogen assumption changes were extended to other states. Prices are those generated from the long-term model (capacity expansion) not the short-term model (dispatch).

4.1 Significant volume and capacity of flexible hydrogen load forecast for Queensland

The Step Change scenario forecasts substantial hydrogen load growth with a large portion of this in Queensland. In 2050 Queensland is forecast to have 6GW of flexible electrolyser load and ~230MW of inflexible electrolyser load (Figure 7). Our understanding is the majority of Queensland hydrogen demand in the Step Change scenario is expected to be for industrial heat (e.g. alumina refining) and transport (fuel cell trucks) whose demand for hydrogen is expected to be inflexible. The ISP assumes export hydrogen is green ammonia, a production process predicted to have a high degree of partial flexibility (see section 5 for more details).

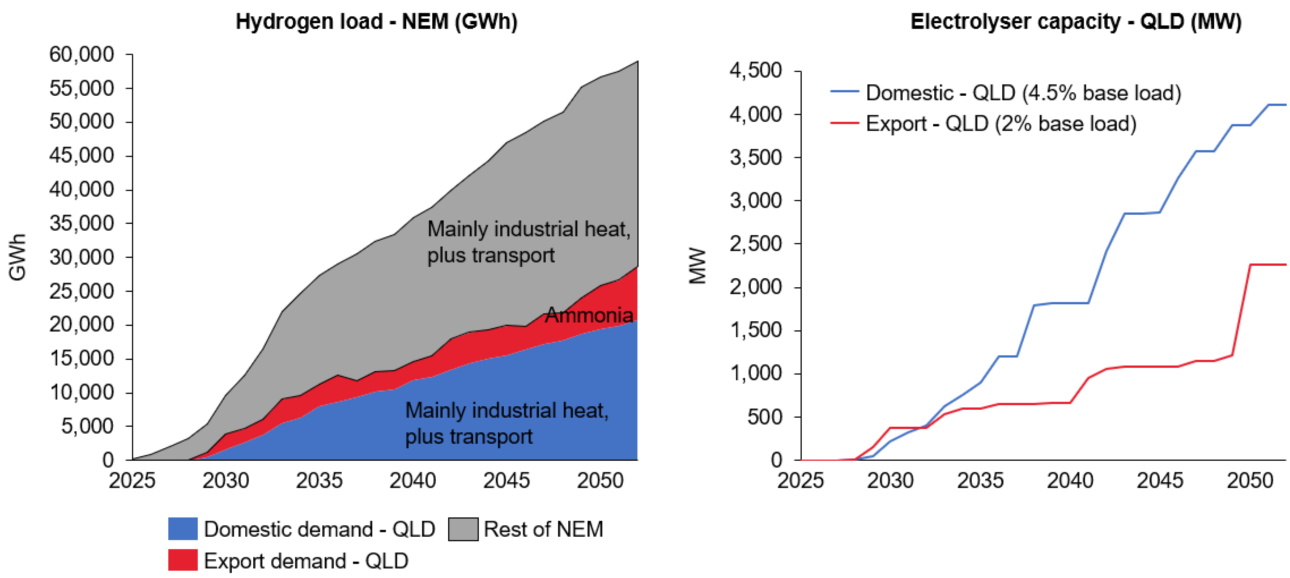

Figure 7: Hydrogen load and electrolyser in the ISP

4.2 Seasonal and interannual electrolyser load profiles are counterintuitive

Domestic flexible hydrogen production has a seasonal profile where demand is highest in July, the month with the largest energy imbalance due to low solar PV output. Export hydrogen targets are highly volatile over the forecast period. The rationale for these patterns appears not to have been explained in AEMO documentation and clarification around these patterns and their drivers is sought.

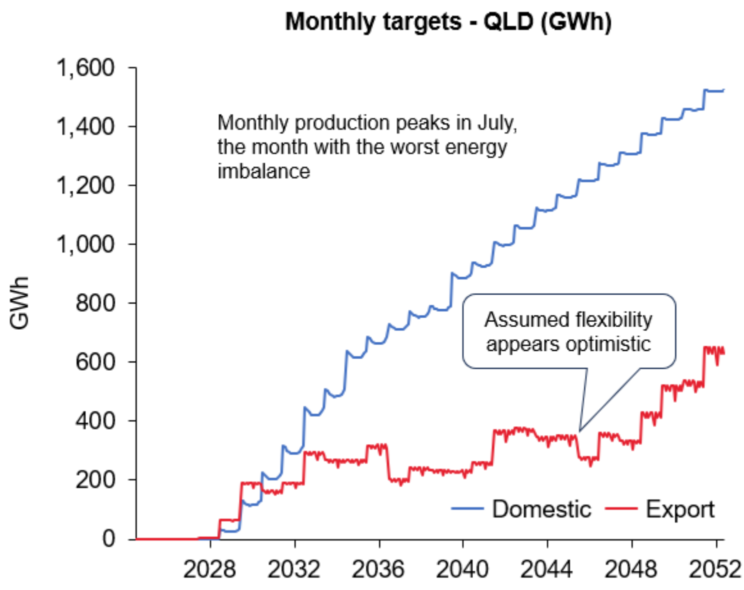

Figure 8: Monthly targets of flexible hydrogen load in Queensland

~~4.3~~ Electrolyser load factors are assumed to decline over time and become a solar soak, while also providing inter-week demand response

Load factors were calculated based on the provided electrolyser capacities and energy demand in the model. Load factors decline over time and this result is intuitively appealing given declining electrolyser capex and a widening gap between wind and solar LCOEs (AEMO, 2023).

These load factors should be treated with a degree of caution as they have been determined by the SSLT model that does not explicitly consider hydrogen storage and instead assumes a generous balancing period. Co-optimisation incorporating the cost of hydrogen storage may lead to a different outcome.

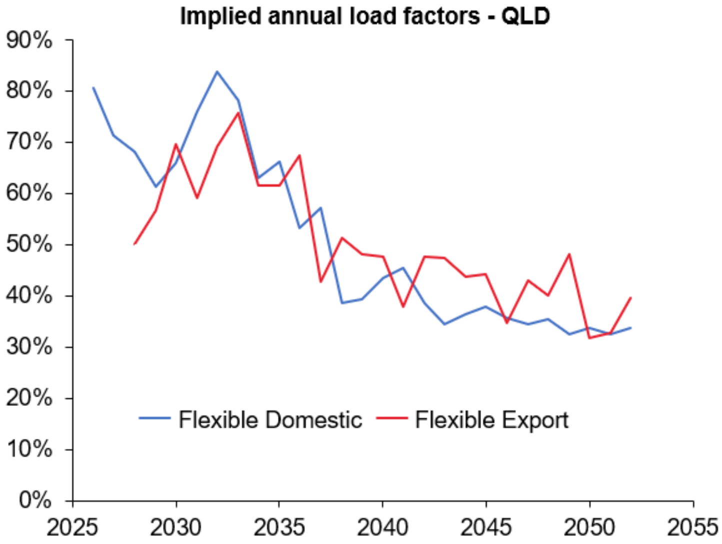

Figure 9: Load factors of flexible hydrogen loads in Queensland

The monthly balancing assumption allows the electrolyser to provide load shifting from time horizon up to inter-week, undercutting dispatchable generation (Figure 10). This becomes more pronounced over time as electrolyser load factors decline. The electrolyser turns off infrequently in 2030, while in 2040 it ramps up and down more frequently and daily production becomes much more variable.

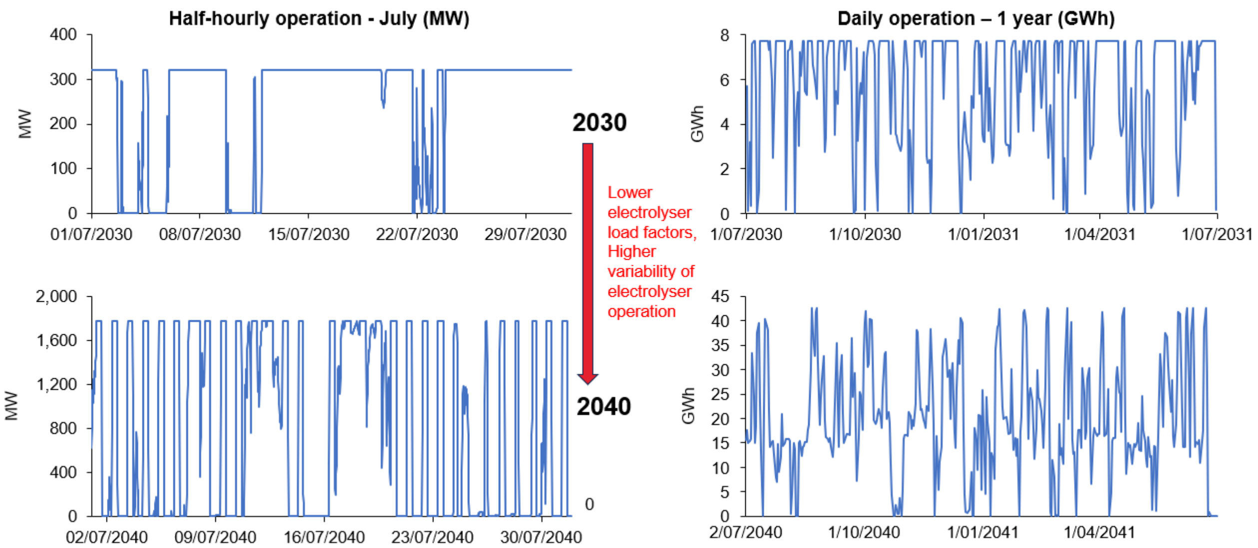

Figure 10: Half-hourly and daily operation of CQ hydrogen load in 2030 and 2040 from Plexos outputs

In addition to EV charging and CER, electrolyser load is a 'solar soaker' that further flattens the operational demand profile (Figure 11). Due to the uncertainty around hydrogen demand given issues raised in this submission, sensitivities incorporating more techno-economically plausible hydrogen scenarios such as no grid-connected hydrogen demand or daily hydrogen balancing combined with lower orchestration of CER are recommended. A scenario incorporating no hydrogen load is appropriate as there is a high degree of uncertainty around the competitiveness of green hydrogen and the cost of grid connection could be significant. For instance, (CSIRO, 2023) assumes that gas continues to be used for alumna calcination (high temperature heat).

with limited hydrogen substitution.

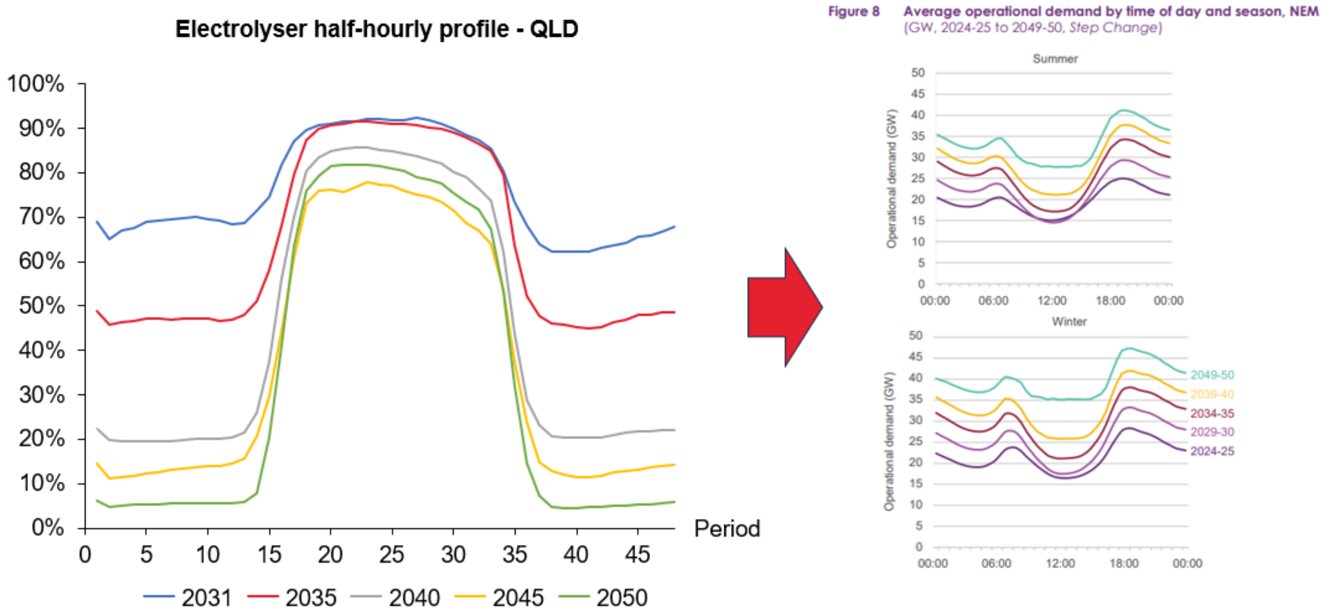

Figure 11: half-hourly CQ electrolyser profile from PLEXOS outputs

4.4 Including hydrogen storage significantly increases LCOH and system cost

Except ammonia and methanol, most hydrogen use cases require a constant supply of hydrogen and hydrogen storage is required to firm this variable supply. We estimate the size of the hydrogen storage as follows: the equivalent electrolyser monthly flat load (MW) is derived from the monthly electrolyser load (MWh) divided by the numbers of hours in a month. Hydrogen is injected into storage when the instantaneous electrolyser load exceeds this average flat load and withdrawn when the opposite happens (Figure 12). The storage size is the difference between the maximum and minimum storage levels. Energy usage from compression losses that would increase LCOH and would increase as electrolyser load factors decline are not considered.

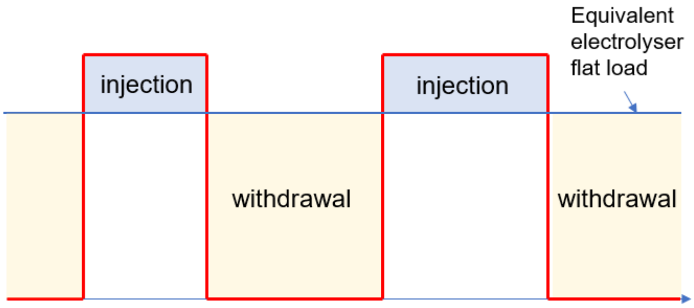

Figure 12: Behaviour of a flexible electrolyser including hydrogen storage

Assuming a hydrogen storage capex cost of $1,428/kg H_2 ($US1,000/kgH_2) assuming hydrogen pressure vessels or linepack, electrolyser capex cost provided in the IASR and the electricity cost from the PLEXOS output, the LCOH with and without hydrogen storage were estimated. LCOH excluding storage declines over time, consistent with islanded modelling. LCOH including storage only decreases slightly over time to around $6/kg H_2, with storage contributing up to 70% of the cost stack (Figure 13). The benefit from declining electrolyser capex cost and utilising cheaper electricity prices during solar hours is almost cancelled out by the higher hydrogen storage requirement. It is worth noting that these LCOH figures are likely to be underestimated as compression losses, O&M, grid connection and network charges are excluded. Given the cost of hydrogen storage a more suitable balancing period could be daily, which reduces implied hydrogen storage.

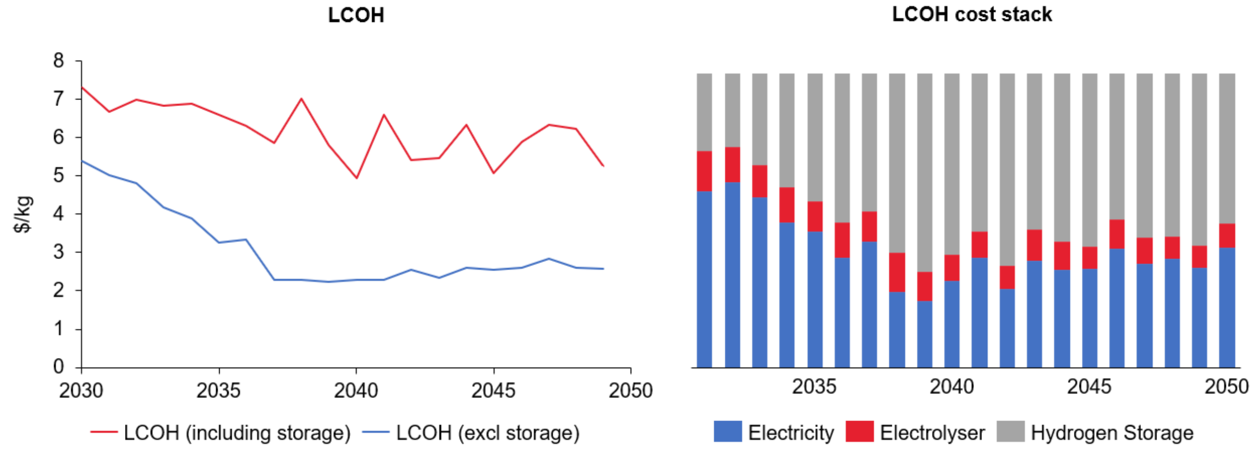

Figure 13: Left: LCOH excluding and including storage. Right: LCOH cost stack of firmed hydrogen.

Monthly balancing implies multiple days of hydrogen buffer storage, which varies significantly by year and within year (Figure 14). This variation implies that electrolyser load shifting could be playing a significant role in managing acute intra-month energy imbalances including renewable energy droughts. By 2050, the hydrogen storage implied in the ISP reaches ~200GWh ($10 billion capex) in Central Queensland alone, compared with ~642GWh of power system storage (including CER) in the NEM (AEMO, 2024). For context, Central Queensland represents ~40% of NEM 2050 hydrogen demand. While geological hydrogen storage such as depleted gas fields and salt caverns could theoretically provide the required scale at lower cost, cycling and location constraints greatly reduce their practicality (Fletcher et al. (2023B)).

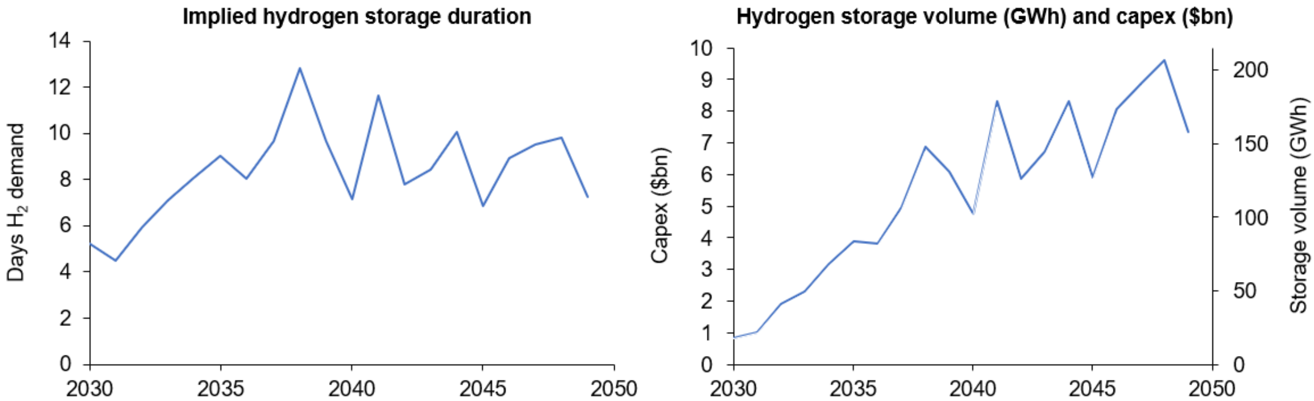

Figure 14: Left: Implied hydrogen storage duration. Right: Implied hydrogen storage volume (GWh) and capex ($bn).

Fletcher et al (2023B) demonstrates that for islanded hydrogen production, oversizing and running electrolysers at lower load factors and utilising hydrogen storage is a lower cost option than firming renewable energy using BESS to run electrolysers as a flat load. Whether these findings and the rate of decline in electrolyser load factors observed in islanded modelling are applicable to grid connected electolysers are uncertain. This uncertainty is compounded by policy and CER uptake assumptions that drive renewable energy and power system storage supply.

As optimal electrolyser load factors (hence, capacity), hydrogen storage and the electricity system cannot be accurately co-optimised using standard PLEXOS modules, a flat electrolyser load scenario is provided as a bookend. Figure 15 demonstrates that monthly balancing delivers the highest LCOH due to high implied hydrogen storage cost.

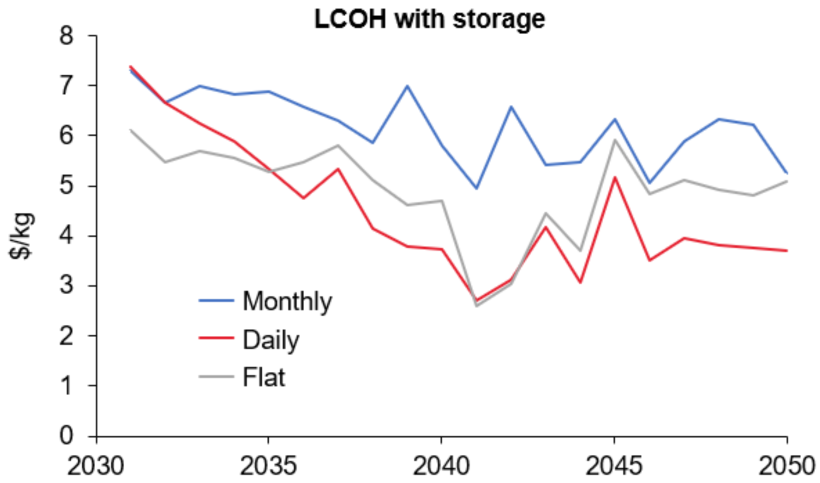

Figure 15: LCOH (including storage) using different balancing periods

Daily balancing results in slightly more utility scale BESS and gas (Figure 16) an a largely unchanged total system cost (Figure 17). This analysis highlights that changing from monthly balancing to daily balancing had limited impact on the ISP model while delivering a more reasonable LCOH outcome. In contrast, a flat hydrogen load requires significantly more BESS and results in a much higher system cost.

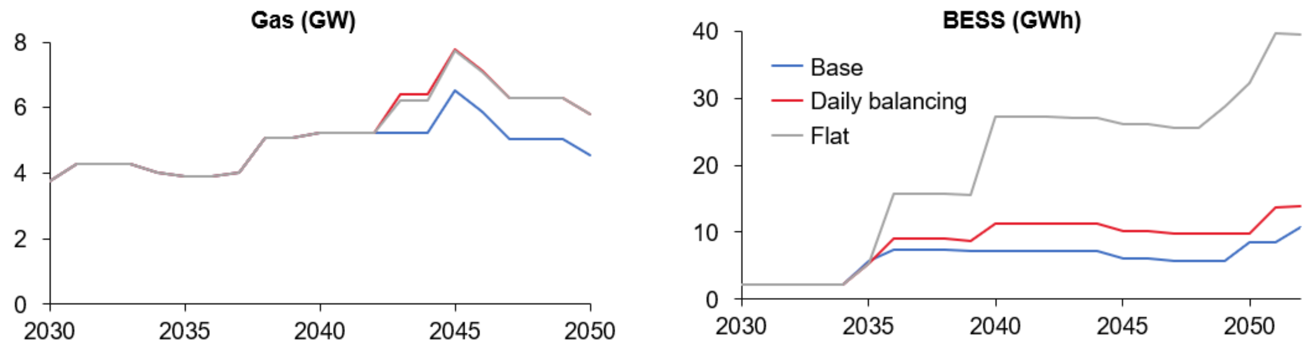

Figure 16: Impact of balancing period on BESS build in Queensland

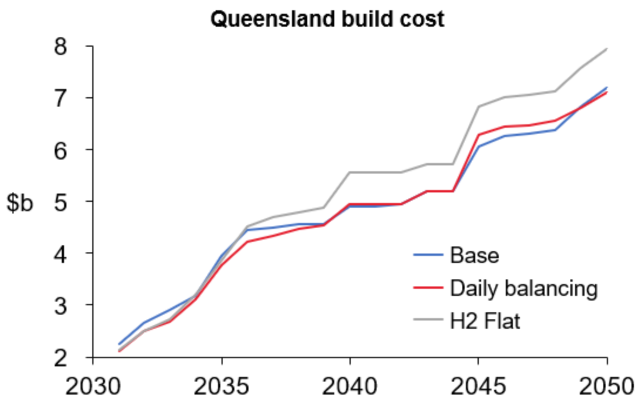

Figure 17: Impact of balancing period on system build cost ($bn)

The impact on the BESS requirement is even more pronounced when the CER assumptions (aggregated distributed storage and V2G modelled as storage) are removed. Daily balancing of hydrogen can require up to 10GWh and a flat hydrogen load require up to 30GWh of additional storage (Figure 18).

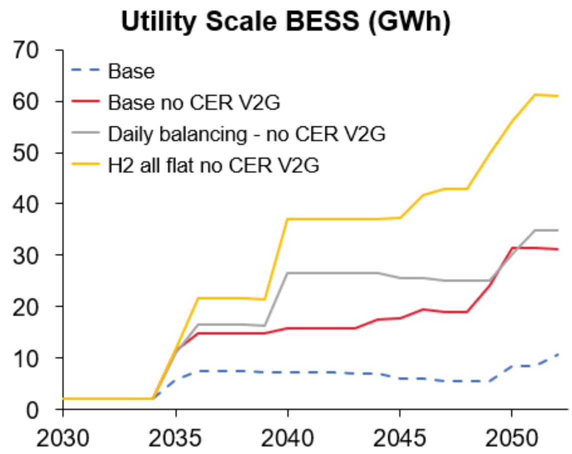

Figure 18: Impact of balancing period on Queensland BESS build with aggregated distributed storage and V2G removed

While interpreting the modelling results, it is worth nothing that policy constraints (e.g., carbon budget, renewable and storage targets) and assumed CER uptake might be confounding the results. Further analysis is required to fully dissect the impacts of these different factors.

5. More accurately integrating green ammonia value chain demand response should be investigated for 2026 AEMO ISP

This section provides:

- A description of how green ammonia is currently modelled in the Draft 2024 ISP and recommendations for the Draft 2024 ISP and 2026 ISP; and
- Excerpts from Fletcher et al (2023A) that presents the benefits of integrating green ammonia value chain demand response into the 2026 ISP.

5.1 Modelling of green ammonia in Draft 2024 ISP does not fully reflect potential sector coupling benefits

The Draft 2024 ISP only assumes conversion of hydrogen to ammonia for export. Clarification is sought as to whether the Draft 2024 ISP includes any green hydrogen demand from domestic green ammonia and in particular the potential conversion of domestic grey ammonia production. Domestic hydrogen demand projections for green ammonia and other hydrogen use cases should be split out due to different requirements for the firmness of hydrogen supply.

Energy demand for green ammonia for export is modelled as two components:

- Hydrogen load is modelled in the same fashion as other hydrogen use cases (i.e. monthly balancing). Given the predicted flexibility of green ammonia plant hydrogen throughput and low cost of green ammonia storage, hydrogen demand for this use case should be modelled differently than others. The current modelling methodology where hydrogen demand is balanced over a defined period is unable to accurately represent operating constraints of ammonia plant hydrogen throughput. Furthermore, monthly hydrogen targets ignore potenital sector coupling benefits from green ammonia seasonal demand response. A key challenge with integrating a green ammonia value chain into power system modelling is that it requires the optimisation of three layers of storage (power system, hydrogen and ammonia). The Draft 2024 ISP only optimises power system storage.

- Electricity load for ammonia plant is considered inflexible. Although there may be the potential to make electricity load more flexible, this conservative assumption is supported given the limited deployment of green ammonia plants. It however should be revisited in the future as deployment increases.

For the Draft 2024 ISP hydrogen demand for ammonia should be modelled consistently with other hydrogen use cases, for which our recommendation is daily balancing. More granular hydrogen demand traces should be providing including a split of domestic demand between industry (including ammonia vs other) and transport.

For the 2026 AEMO ISP more accurately integrating green ammonia value chain demand response should be investigated. This should include investigating co-optimisation modelling with greater definition of value chains including hydrogen storage, ammonia plants and ammonia storage.

5.2 An emerging body of research supports the more detailed integration of the green ammonia value chain into 2026 ISP

5.2.1 Green ammonia is one of the few no-regrets clean hydrogen use cases

Hydrogen has generated enormous interest over the last few years as a decarbonisation option, particularly for the replacement of hydrocarbons. However, for many use cases hydrogen competes with electrification, with hydrogen's competitiveness impacted by a number of considerations, but particularly its low energy efficiency versus electrification (IRENA, 2020).

Green ammonia could play a pivotal role in decarbonising fertilisers and explosives, that are critical inputs into the agriculture and resources sectors respectively. Industry consensus has emerged in Australia that ammonia is one of the few no-regrets clean hydrogen use cases where no real alternatives exist (Liebreich Associates, 2023) and where hydrogen policy support should be prioritised (Australian Energy Council, 2023A; Climateworks Centre, 2023; Institute for Energy Economics and Financial Analysis, 2023). Green ammonia also offers relatively unique sector coupling benefits that will be explored in the next section.

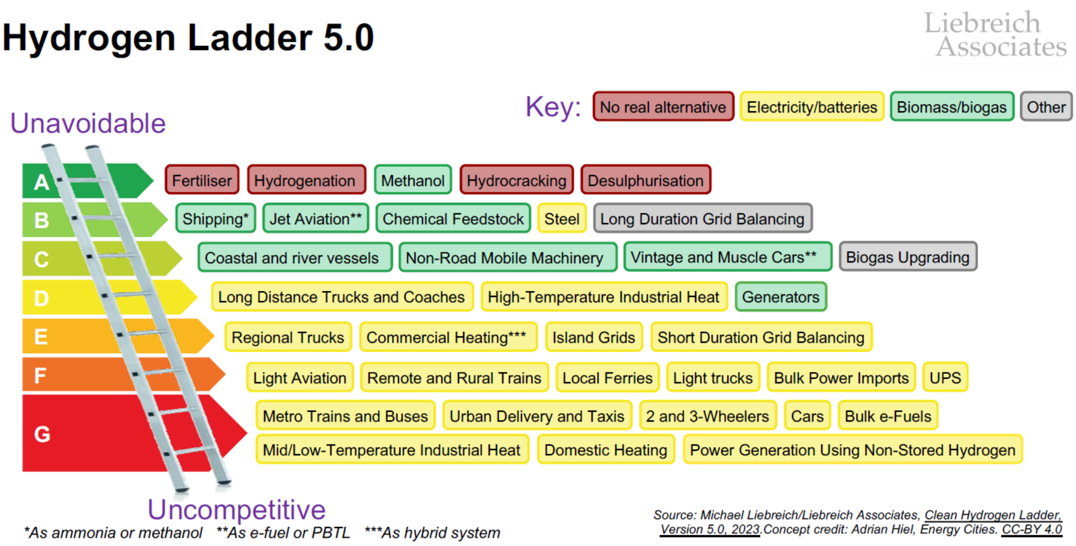

Figure 19: Hydrogen Ladder 5.0. Source: Liebreich Associates (2023)

5.2.2 Sector coupling benefits from green ammonia value chain demand response rely on three pillars

Demand response refers to balancing the demand on power grids by encouraging customers to reduce or shift electricity demand to times when electricity is more plentiful or other demand is lower, typically through prices or monetary incentives (International Energy Agency, 2023; Australian Renewable Energy Agency, 2023). There are two forms of demand response: load curtailment where overall consumption is reduced and load shifting where overall consumption remains the same.

Sector coupling benefits from green ammonia value chain demand response rely on three pillars:

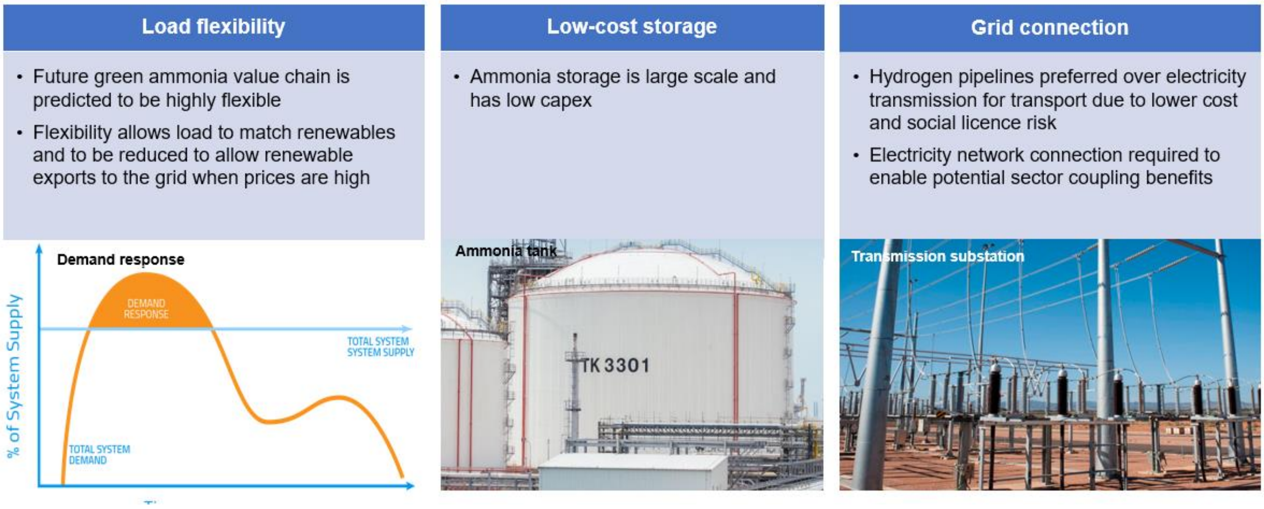

Figure 20: Three pillars of ammonia value chain demand response.

Source: https://encorp.com/demand-response/, https://www.ammoniaenergy.org/articles/vopak-explores-new-ammonia-infrastructure-in-singapore-the-netherlands/ , .https://www.electranet.com.au/our-approach/safety/transmission-substations/

Another important factor is that ammonia is a tradable commodity such that if production is reduced, alternative supplies and/or downstream products such as fertilisers and explosives can be sourced from domestic or global markets, providing the potential to mitigate financial risk for the producer. The details of the three pillars are provided in the Appendix.

5.2.3 Green ammonia value chain demand response has the potential to reduce the required capacity and alter the mix of firming technology

In order to provide a high-level comparison of firming technologies a range of levelised cost measures are calculated in Fletcher et al (2023A), including new measures for demand response. The broad approach draws on standard methods to calculate LCOE (Schmidt, Melchior, Hawkes, & Staffell, 2019) and is consistent with the approach taken in the CSIRO Renewable Energy Storage Roadmap (CSIRO, 2023B).

Figure 21: Levelised cost of different firming technologies by cycling interval ($/MWh) shows relevant levelised cost metrics across a range of firming technologies. These cost measures provide some guidance as to what impact these technologies could have on detailed energy system modelling that integrates a green ammonia hybrid value chain with the electricity system. However, the measures are not directly comparable as they:

- Provide different services with different reliability;
- Have different technology readiness levels; and
- Have different deliverability risk (including cost and timeframes).

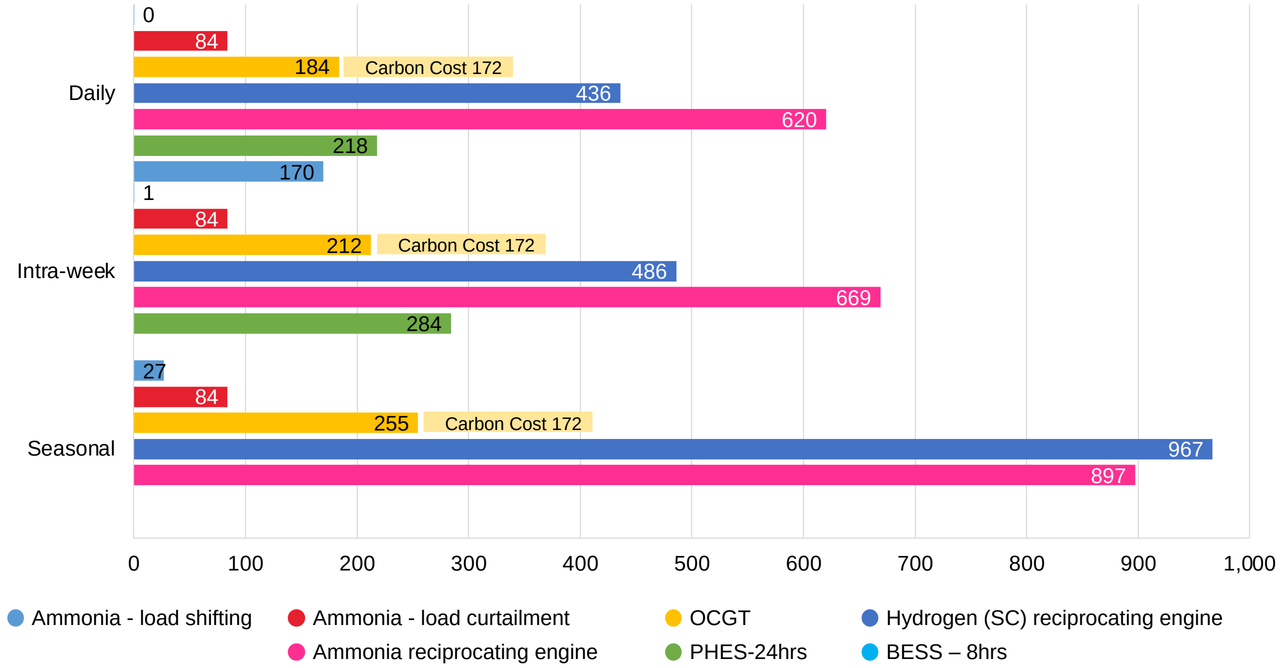

Figure 21: Levelised cost of different firming technologies by cycling interval ($/MWh)

While future costs are uncertain, our modelling indicates that ammonia demand response services (load shifting and load curtailment) may be lower cost than alternatives across all cycling intervals, though its reliability is dependent on several factors including behind-the-meter renewables, hydrogen storage levels and plant turndown capability. As ammonia storage is the only cost associated with load shifting, LCoLS reduces as cycling rate increases, to an immaterial value for intraweek and daily cycling. LCoLC is calculated based off an assumed LCOA of $800/t NH3 divided by 9.54MWh/t NH3, resulting in a levelised cost of $84/MWh, that is unrelated to cycling frequency.

OCGT is higher cost than ammonia demand response services and has the highest reliability of all technologies.

Though reliability is potentially high, hydrogen (salt cavern) and ammonia reciprocating engine have relatively high LCoS driven by the low round-trip-efficiency involved in producing and storing hydrogen or ammonia then using it as fuel in an engine to produce electricity. Low-cost geological hydrogen storage is required for hydrogen engines to provide a similar level of reliability to ammonia engines or OCGT at a reasonable cost and thus options with hydrogen tank storage are not provided. LCoS is inversely related with cycling rate. At daily and intraweek cycling intervals, hydrogen is lower cost than ammonia driven by its lower fuel cost. However, for seasonal cycling, ammonia is lower cost than hydrogen, reflecting its lower assumed storage cost.

Power system storage's reliability is dependent on renewable energy surpluses, with the additional potential to use gas peaking generation to charge. LCoS is favourable at high cycling rates but prohibitively expensive for seasonal cycling.

5.2.4 Green ammonia value chain demand response could be key resource that could contribute to addressing the 'winter problem'

Although ammonia value chain demand response may be valuable over the entire year, its greatest potential may be in contributing to addressing the 'winter problem'. In a renewable energy dominated NEM, the 'winter problem' is the energy deficit caused by high demand from electrified heating coinciding with low solar PV generation. To estimate the demand response potential in winter, a scenario was run in which the ammonia plant is turned down to its minimum load of 30% over winter (June, July, August). The capacity build is the same as the islanded fixed case[1]. NQCEH and Isaac (2030) are both located in northern Queensland and have seasonal generation profiles that are favourable for winter. Based on a sample year (2030) ammonia production could be reduced by 18% and 13% for NQCEH and Isaac respectively and 1.8TWh and 1.3TWh respectively of renewable generation could potentially be exported to the grid (Figure 21). The demand response potential could be greater if:

- load curtailment is used throughout the year; and
- Salt cavern storage was part of the value chain, such that hydrogen feedstock requirement could be sourced solely from storage allowing electrolyser to be turned off for extended periods.

1mtpa ammonia plant winter demand response potential – sample year

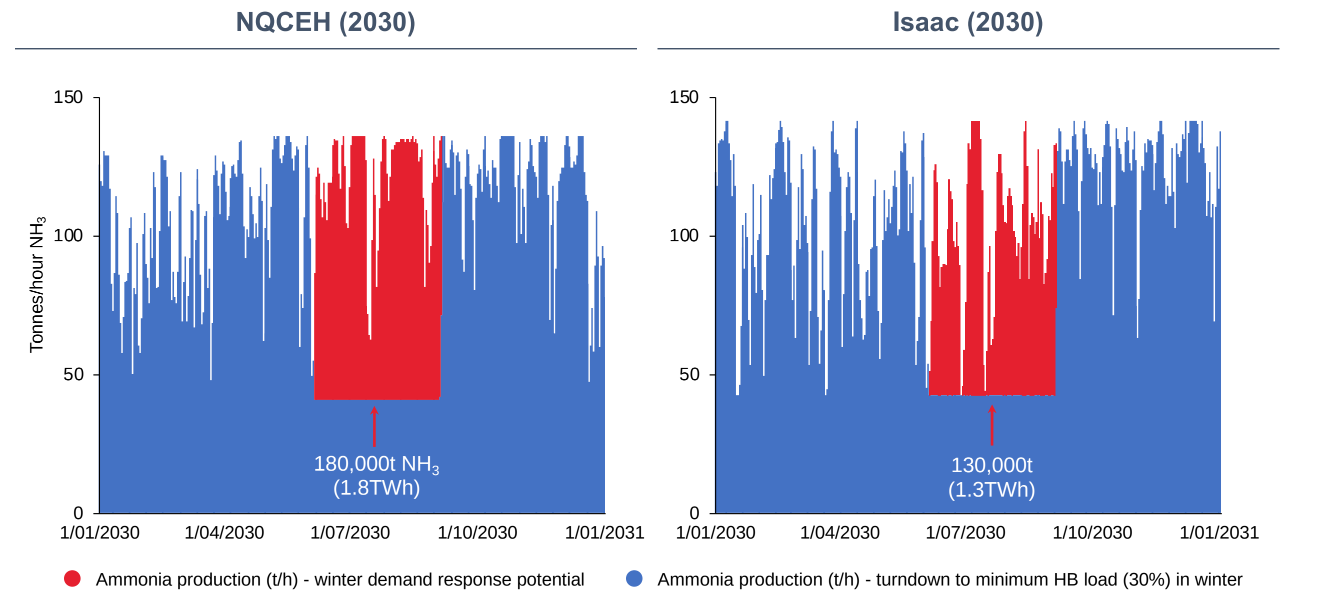

Figure 21: Daily ammonia production in the demand response case vs normal operation for NQCEH and Isaac in 2030

5.2.5 There are examples of energy system modelling that involves detailed co-optimisation of the electricity system with green ammonia value chains

Cesaro et al. shows that sector coupling of green hydrogen and ammonia with a future renewable energy dominated Indian electricity system significantly reduces system costs (Cesaro, Bramstoft, Ives, & Bañares-Alcántara, 2023). The research involves energy system modelling that integrates the ammonia value chain with a high degree of precision. The modelling shows that a green ammonia value chain could provide valuable short-duration and long-duration load-shifting services, including via seasonal ammonia production patterns (Cesaro, Bramstoft, Ives, & Bañares-Alcántara, 2023). System benefits included reduced system costs, LCOH and LCOA, reduced curtailment, increased system resilience and reduced requirement for firming capacity.

The research is the only known publicly released example of integration of the ammonia value chain into energy system modelling, which is challenging as it is a three-stage production process (renewables, hydrogen, ammonia) with three layers of energy storage (power system, hydrogen, ammonia), plus transport (Cesaro, Bramstoft, Ives, & Bañares-Alcántara, 2023). The authors of this submission have reviewed similar co-

[1] *The scenario assumed ammonia storage capital costs of $1,000/t NH_3 compared to core scenarios where $3,000/t NH_3 was assumed.*

optimisation modelling for a future Australian energy system produced by prominent researchers, which demonstrates the approach is replicable.

5.2.6 Emerging examples of hydrogen derivative projects incorporating demand response

Two green hydrogen derivative projects are currently proposed in New Zealand that incorporate demand response, including to mitigate the impacts of dry years for New Zealand's conventional hydropower dominated electricity system. Meridian and Woodside's proposed Southern Green Hydrogen project is targeting 500,000t NH_3 production pa as well as providing up to 40% of New Zealand's dry year flexibility needs to the electricity sector (Woodside Energy, 2022). Channel Infrastructure and Fortescue Future Industries' proposed Marsden Point synthetic sustainable aviation fuel project is targeting 60 million litres of eSAF production (Channel Infrastructure NZ, 2023). The pre-feasibility study is to include analysis on the potential provision of large-scale demand response and this underpinned New Zealand Government support for the pre-feasibility study.

More recent discussions with proponents of Australian green ammonia projects revealed they are investigating incorporating demand response into project design.

6. Electrification incorporating thermal energy storage is an alternative to hydrogen for industrial heat that warrants further investigation

6.1 Thermal energy storage

Electrification is a potential alternative to hydrogen for medium and high temperature industrial heat. Given the significant scale of Queensland's existing fossil-fuel based alumina refining, electrification of alumina digestion represents a large potential electrification load (ARENA/Deloitte, 2022). However, Figure 22 shows that firmed renewable electricity could be significantly higher cost than gas. Mechanical vapour recompression (increasing efficiency) and thermal energy storage offer the potential to lower the cost of electrified industrial heat. However, these technologies have limited adoption to date (ARENA/Deloitte, 2022).

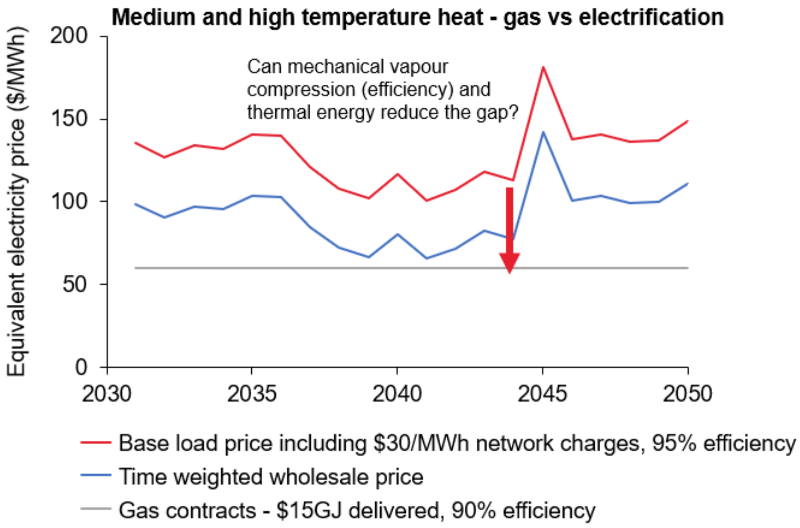

Figure 22: medium and high temperature heat - gas vs electrification

The appended *2024 Forecasting Assumptions Update Consultation* provides further detail on thermal energy storage and recommends that:

- Thermal energy storage is included in CSIRO GenCosts; and
- A more thorough investigation of the technology than would ordinarily be contained in the Aurecon Costs and Technical Parameters Review.

6.2 Production process flexibility

There is potentially significant value in introducing a degree of genuine process flexibility into electricity intensive industrial production processes, rather than utilising intermediate process storages such as hydrogen or thermal energy storage. Figure 23 shows that for islanded green ammonia production, partial load flexibility can have a material impact on levelised cost of ammonia (LCOA). Any investigation into electrified industrial heat should investigate the techno-economically viability of genuine process flexibility.

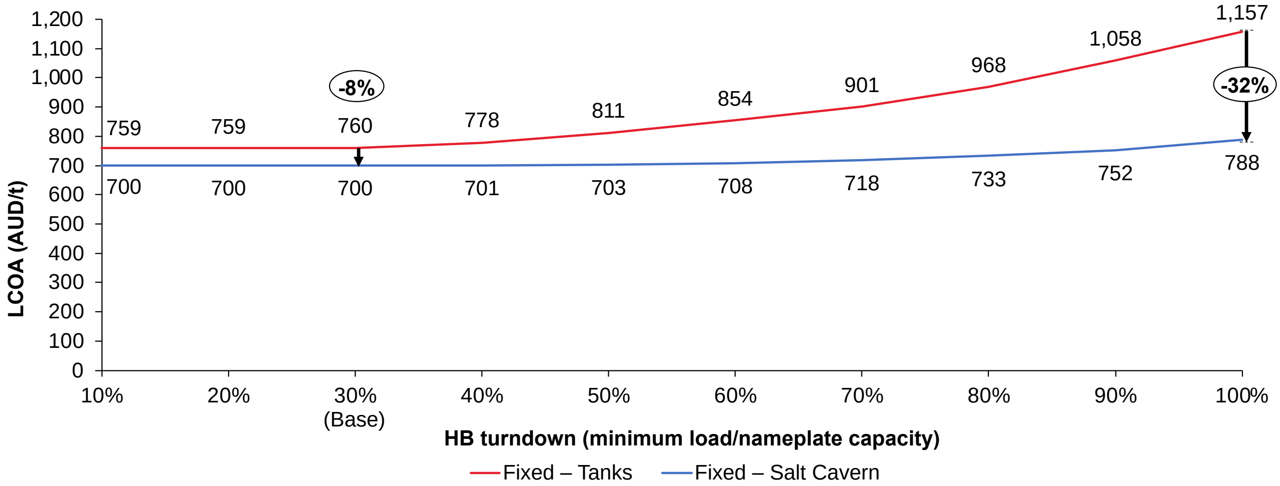

Figure 23: LCOA at different ammonia plant turndowns (Barcaldine 2040). Source: Fletcher et al (2023B)

7. Appendix

7.1 Pillar 1: Load flexibility

The green ammonia value chain has minimal firmed electricity requirements. Figure 24 shows that the rough rule of thumb for the electricity currently required to produce one tonne of ammonia is:

- 9-10MWh for electricity required to run electrolysers to produce hydrogen feedstock; and
- 1MWh electricity required to run the ammonia plant.

The ammonia produced has a higher heating value of 6.25MWh/t and a lower heating value of 5.2MWh/t. Key energy losses in the production process are through electrolyser inefficiencies and losses in the exothermic Haber Bosch ammonia production process (Refer to Hydrogen Conversion Process Information Sheet within Fletcher et al (2023B) for further details). As electrolyser efficiency is projected to increase over time total electricity required to produce one tonne of ammonia may fall below 10MWh/t NH_3 (International Energy Agency, 2022; Siemens, 2021).

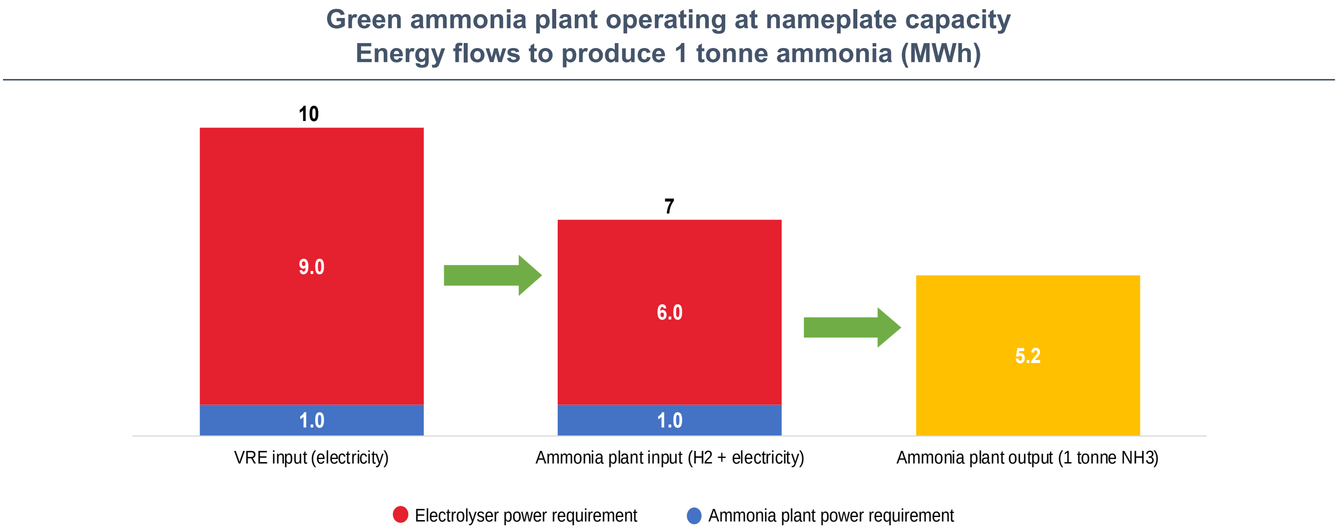

Figure 24: Green ammonia plant - simplified energy flows at nameplate capacity

While electrolysers are fully flexible, new build green ammonia plants are partially flexible, with turndowns predicted to be down to 10-40% of nameplate hydrogen throughput capacity (30% assumed in detailed optimisation modelling). Figure 25 shows that a green ammonia value chain operating at minimum capacity has a demand response potential equivalent to ~65% of nameplate capacity on an energy basis.

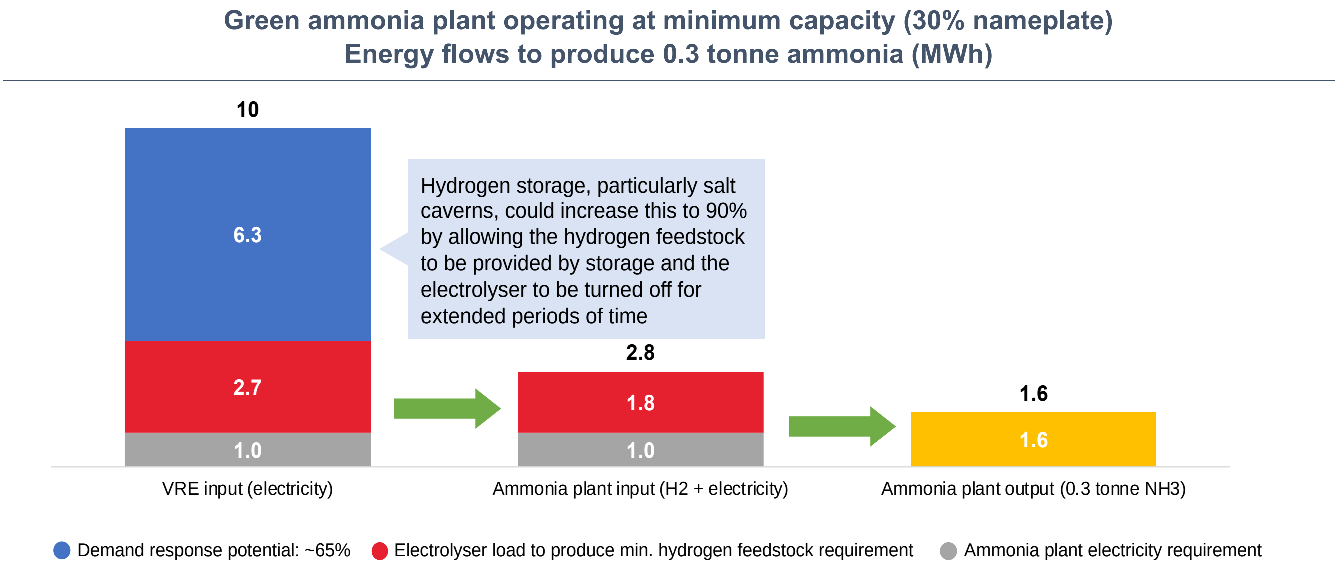

Figure 25: Green ammonia plant - simplified energy flows at minimum operating capacity

7.2 Pillar 2: Low-cost storage

Figure 26 shows the capital cost for the three forms of energy storage that are potentially part of hydrogen industry value chains:

- Power system storage – battery energy storage systems (BESS) and pump hydro energy storage (PHES);
- Hydrogen storage – geological and non-geological hydrogen storage; and
- Ammonia and liquid hydrogen.

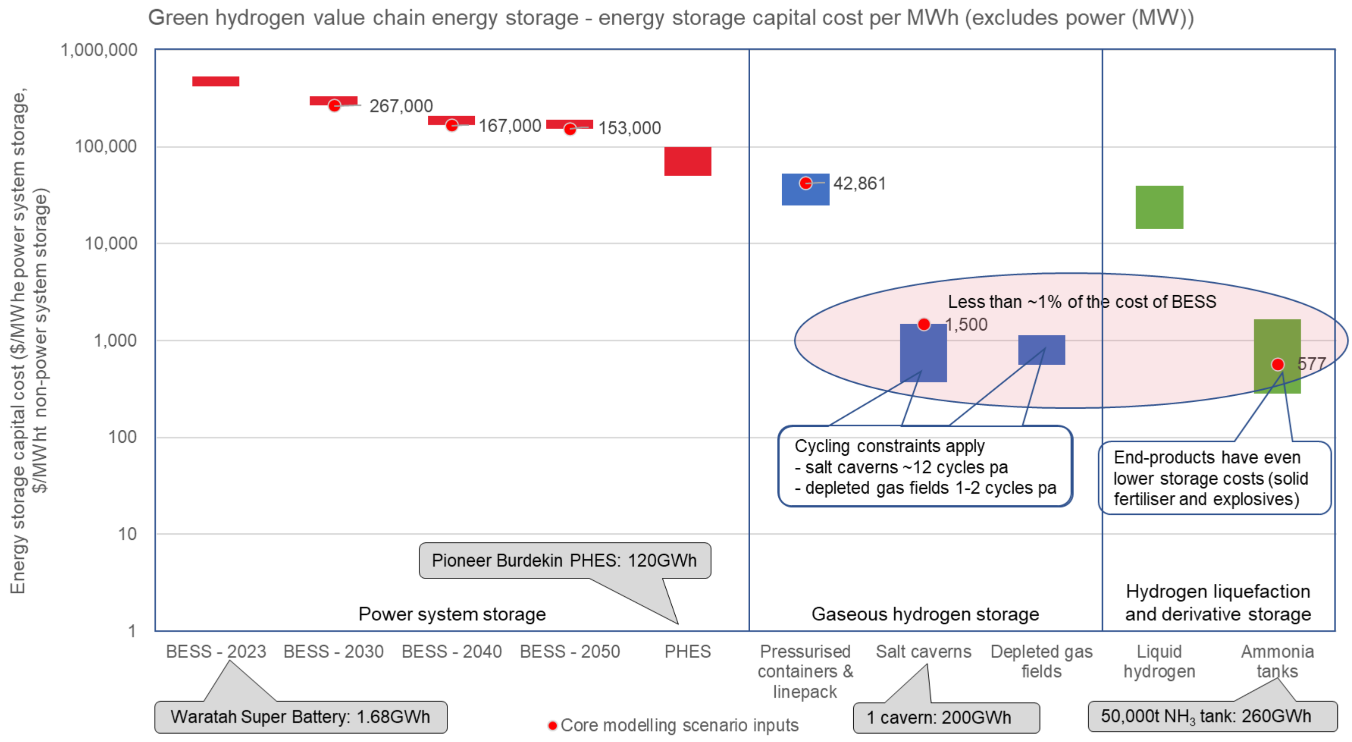

Figure 26: Energy storage capital cost per MWh (excluding power (MW)) in green hydrogen and ammonia value chain

Source: (Australian Energy Market Operator, 2022d), Fletcher (2023A). Assumptions: Lower heating value of hydrogen of 33.33kwh/kg and lower heating value of ammonia of 5.2MWh/tonne

Moving from left to right across Figure 26 is the energy storage potentially available in each step of the multi-stage production process of green ammonia and hydrogen liquefaction. The key use cases for green ammonia are fertilisers and explosives, which are valuable products in their own right, with potential future use as a fuel representing upside. Hence the capital costs are for energy storage only and excludes the cost of production and power generation. The capital cost for power system storage is based on MWh of electricity, while for non-power system storage (hydrogen and ammonia) it is based on MWh of thermal energy based on their lower heating values (LHV)[2]. Figure 26 does not consider the significant efficiency losses associated with using hydrogen and ammonia as a fuel to produce electricity, though this is incorporated in levelised cost of storage calculations in Section 4.4.

Power system storage is materially higher cost than liquid hydrogen storage and non-geological gaseous hydrogen storage, such as pressure vessels. Geological hydrogen storage and ammonia tank storage are less than 1% of the cost of BESS in 2050. Constraints on cycling of geological storage may limit their potential value and there are additional technical issues to overcome for depleted oil and gas fields (Refer to Energy Storage Information Sheet for more detail).

Geological hydrogen storage and hydrogen derivative storage are large scale with one salt cavern being able to store in the order of 200GWh and one 50,000t ammonia tank, 260GWh. This compares to the Waratah Super Battery at 1.68GWh and Pioneer Burdekin PHES at 120GWh. The large scale and low capital cost of salt caverns and ammonia tanks suggests that for the green ammonia value chain they are well-suited to providing seasonal storage and perhaps storage for more frequent cycling.

[2] *Green ammonia is a valuable product that requires 9-10MWh of renewable energy to produce, around double its LHV of 5.2MWh/t NH_3.*

7.3 Pillar 3: grid connection

For green ammonia value chain transport hydrogen pipelines are preferred over electricity transmission due to lower cost and lower social license risk. Figure 28 compares transport capex for standalone electricity transmission (e.g. transporting renewable energy to an electrolyser) and hydrogen pipelines (e.g. transporting hydrogen from co-located renewables and electrolysers to the customer) at various voltages and pipeline diameters respectively. The two alternatives are compared on an equivalent transport capacity, with hydrogen pipeline capex calculated based on MW of hydrogen higher heating value (HHV). Figure 27 demonstrates that hydrogen pipelines may be materially lower cost than standalone (radial) transmission at all capacities. Connection to the transmission network may be considerably higher cost than standalone alternatives, absent an operating model that allows network charges such as TUOS to be optimised.

Capex vs capacity for 250km transmission and one way hydrogen pipelines

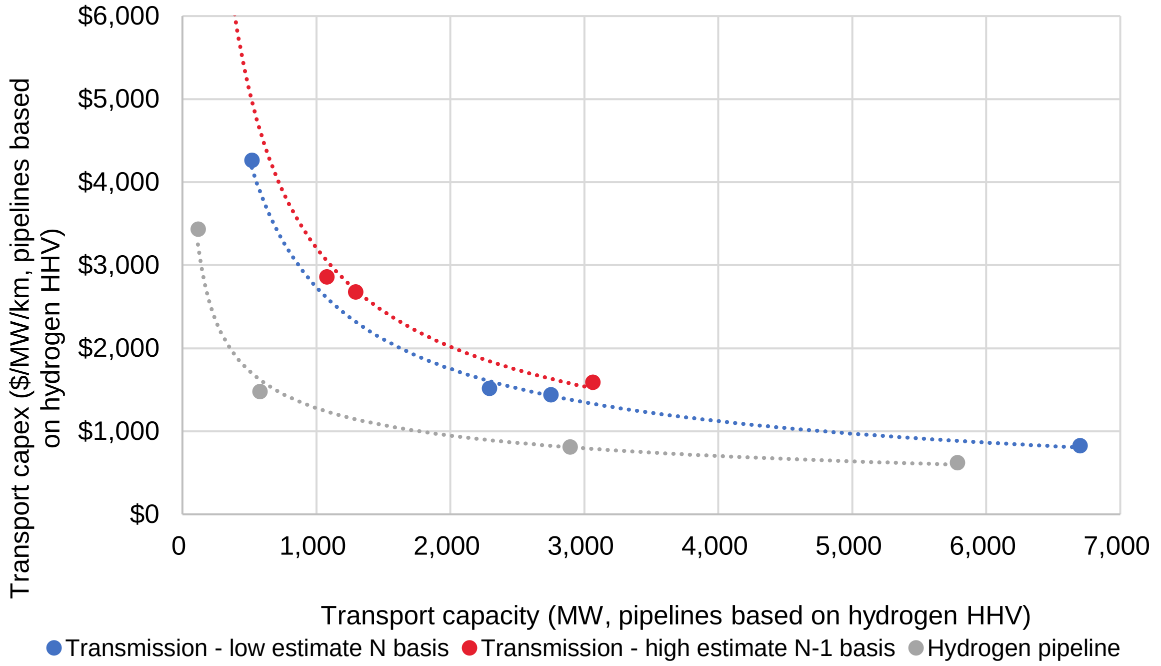

Figure 27: Capex vs capacity for 250km transmission and hydrogen pipeline

A hybrid value chain model where co-located renewables and electrolysers are connected to a hydrogen pipeline for transport (to an ammonia plant) and the electricity network to provide grid services enables potential sector coupling benefits (Figure 28). The grid connection allows the co-located renewables and electrolyser to provide demand response and frequency control ancillary services (FCAS). The ammonia plant is grid connected and is supplied with high load factor electricity supply from the electricity network. Hydrogen pipelines provide the potential to connect to low-cost geological storage such as salt caverns.

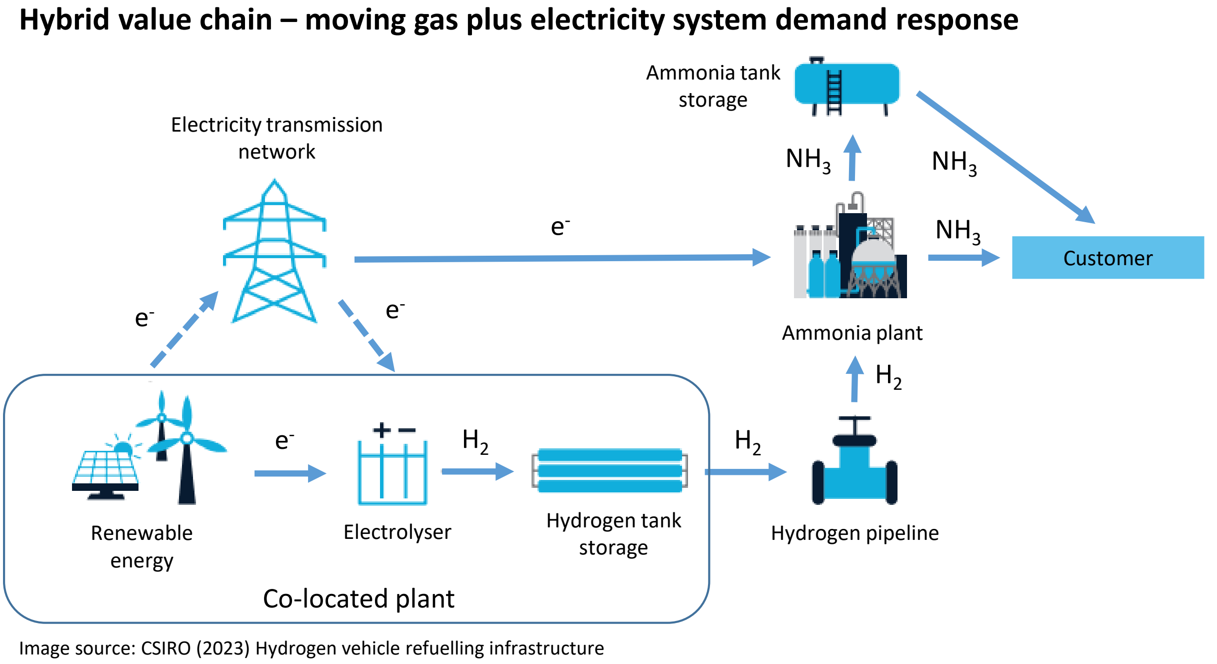

Figure 28: Hybrid value chain diagram

Transmission charges, such as TUOS, could potentially be limited provided that grid activity was contained to providing FCAS, utilising or load shifting renewable energy that would otherwise be spilled and load curtailment in times of high prices.

In addition to the capital cost of the transmission connection asset there may be further costs associated with maintaining power quality for a grid connected green ammonia value chain compared to islanded, though the quantum of any cost differential is uncertain. For instance, system strength is a key component of Generator Performance Standards (GPS) that applies to variable renewable energy and potentially inverter-based loads such as electrolysers (Australian Energy Market Operator, 2022E). For solar farms costs required to meet GPS could include the cost of oversizing inverters to up to 140% of network connection capacity. Inverters are currently estimated to represent 4% of the capital cost of US utility scale solar farms (National Renewable Energy Laboratory, 2023). Industry feedback is that the development of grid forming inverters (Australian Energy Market Commission, 2022B), could potentially reduce costs associated with maintaining power quality for inverter-based resources (variable renewable energy and electrolysers).

Dependent on project location potential benefits of the hybrid model may be materially impacted by transmission constraints and transmission losses.

Various changes to market rules and transmission charges may be required to allow the hybrid model, which are beyond the scope of this research.

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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.

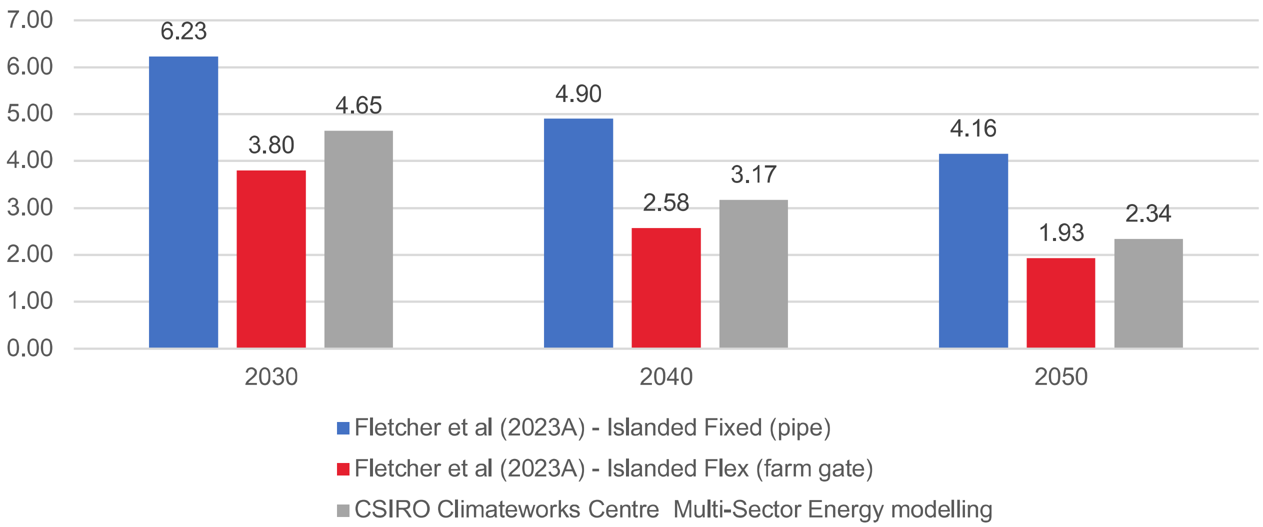

Figure 1 – Levelised cost of hydrogen ($/kg H_2) projections

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.

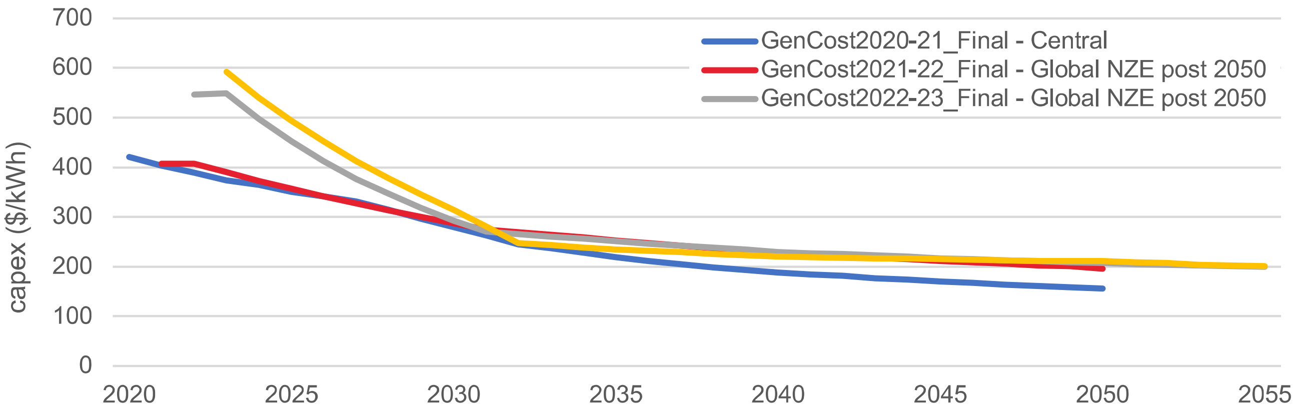

Figure 2: CSIRO GENCOST 4 hr BESS capex (Step Change)

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.

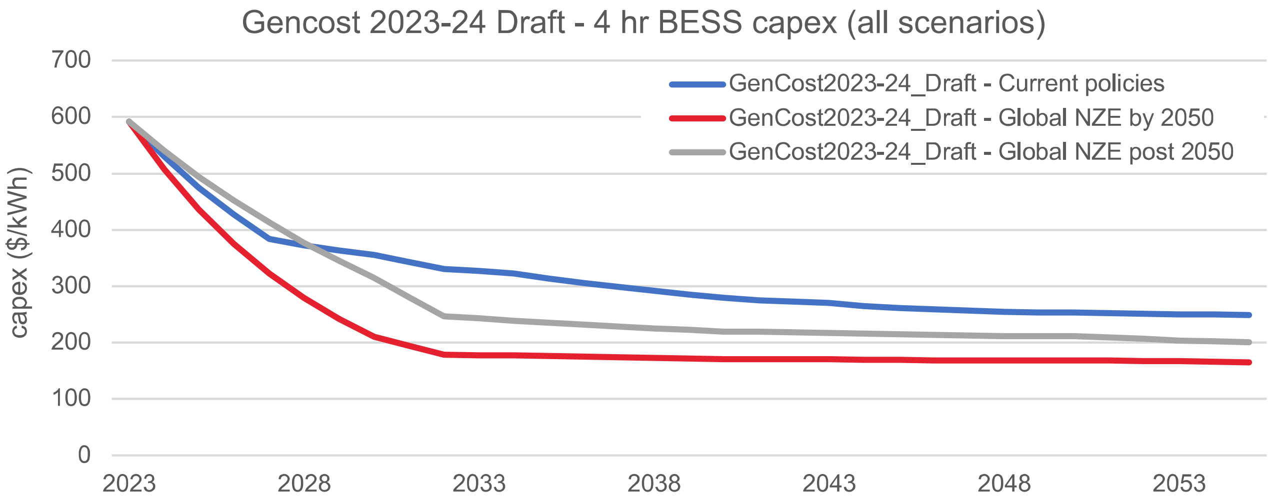

Figure 3: CSIRO Gencost 2023-24 Draft - 4 hr BESS capex (all scenarios)

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.

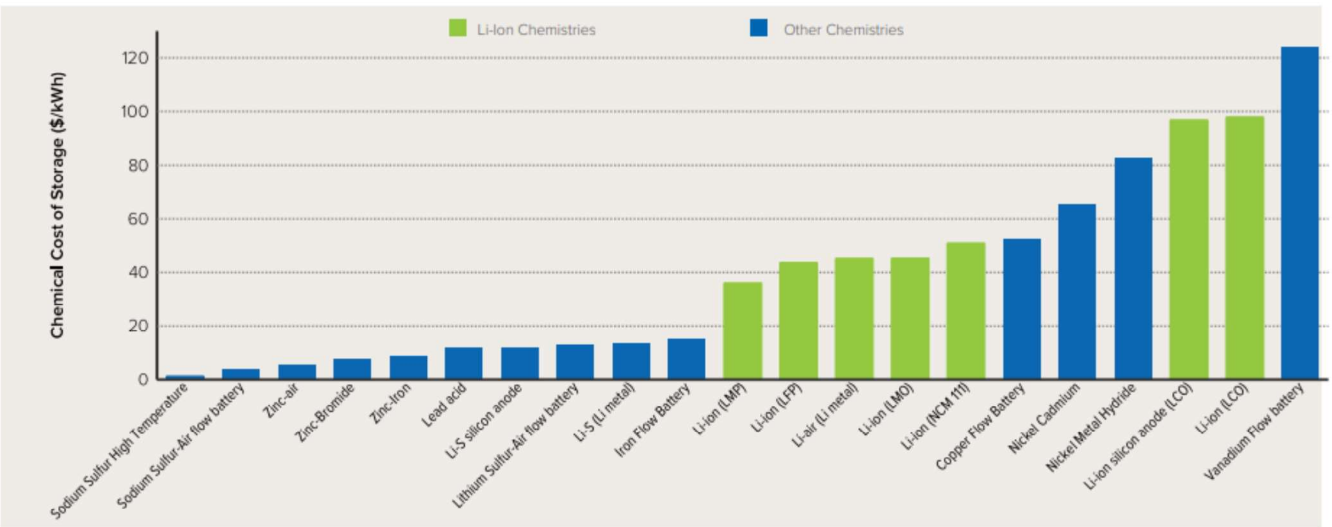

Figure 4 - Estimated Cost of Raw Materials for Different Battery Chemistries. Source: Tyson and Bloch (2019)

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)).

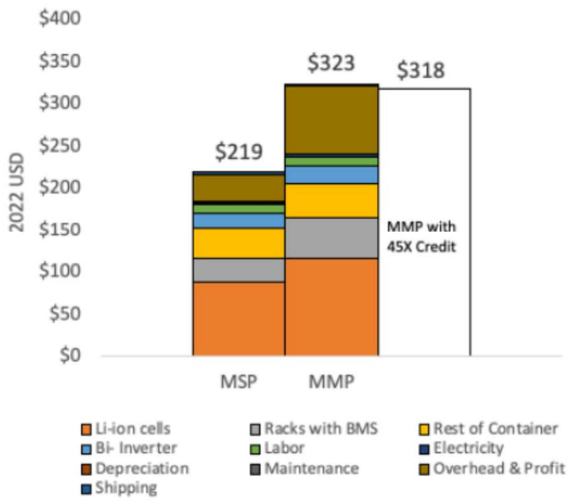

Figure 5 – US Utility ESS cost US$/KWh Q1 2023, Minimum Sustainable price & modelled market price. Source – NREL (2023)

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.

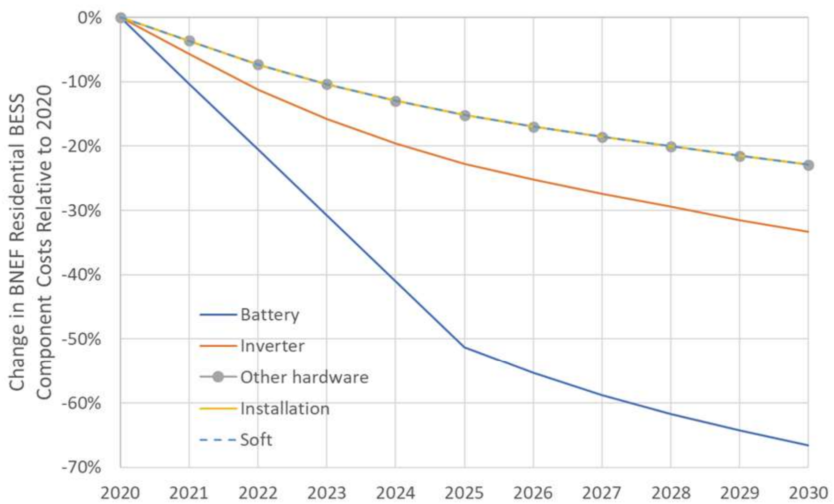

Figure 6 - Changes in projected component costs for residential BESS. Source – NREL (2024A) - BNEF. “Energy Storage System Costs Survey 2019.” BloombergNEF, October 14, 2019.

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.

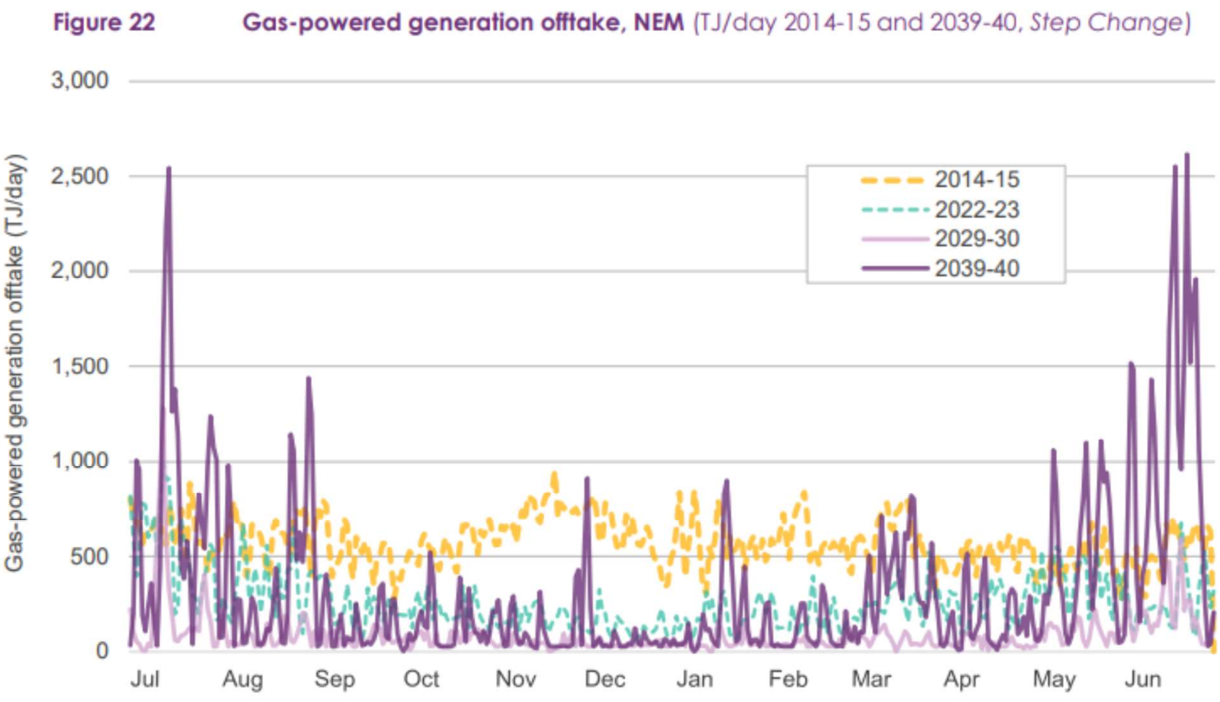

Figure 7 – gas powered generation offtake NEM (TJ/day 2014-15 and 2039-40, Step Change). Source DRAFT 2024 ISP

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)

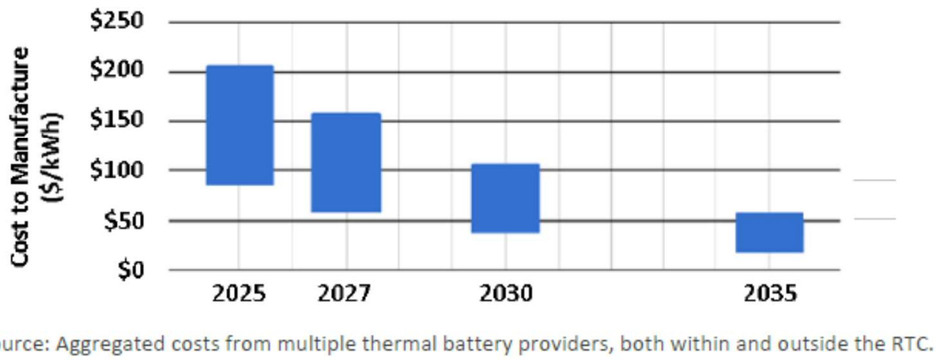

Figure 8: Thermal battery companies' projected total manufacturing costs: Source - Spees et al(2023)

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.

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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