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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.

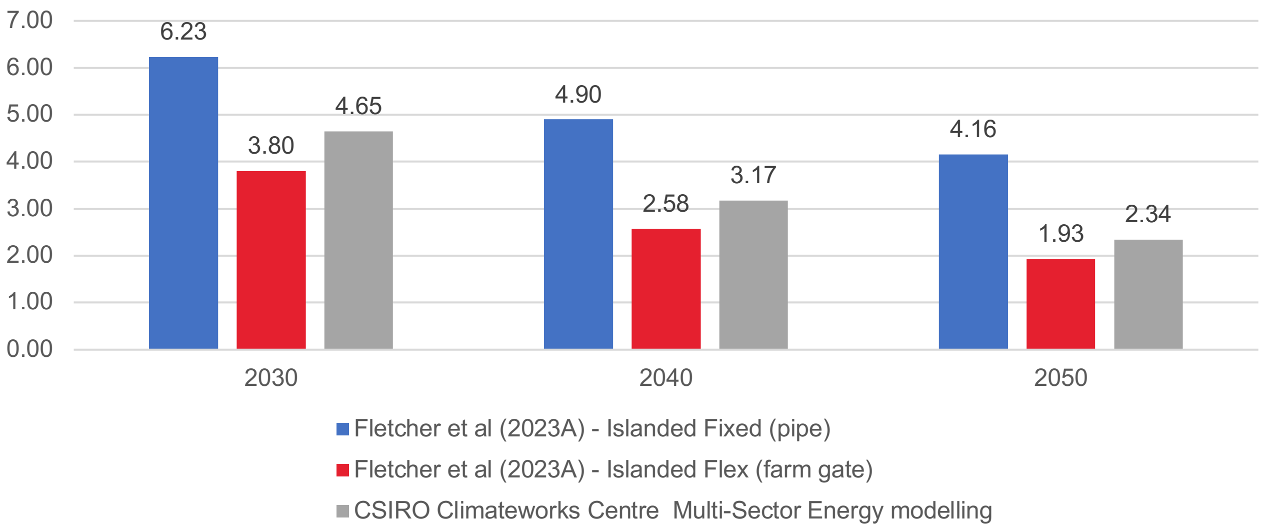

Figure 1 – Levelised cost of hydrogen ($/kg H_2) projections

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.

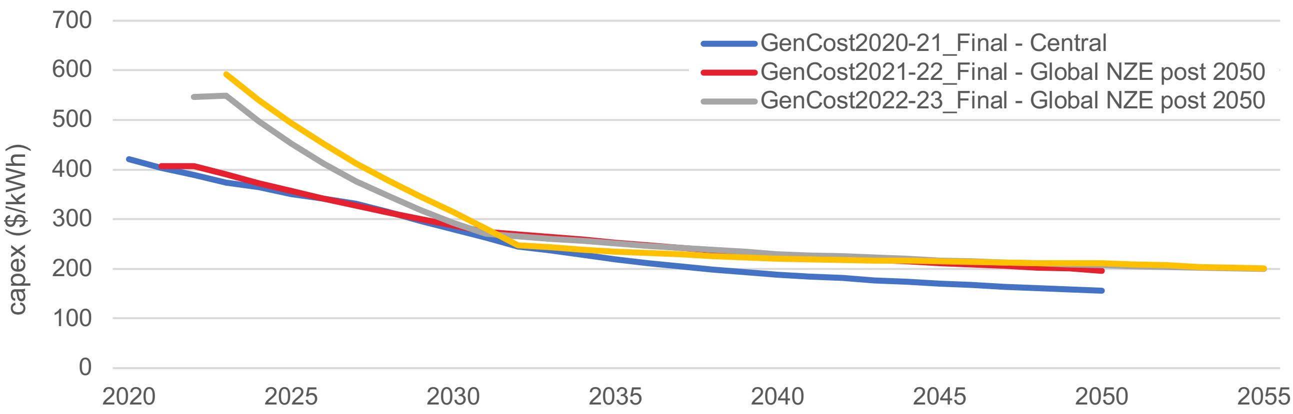

Figure 2: CSIRO GENCOST 4 hr BESS capex (Step Change)

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.

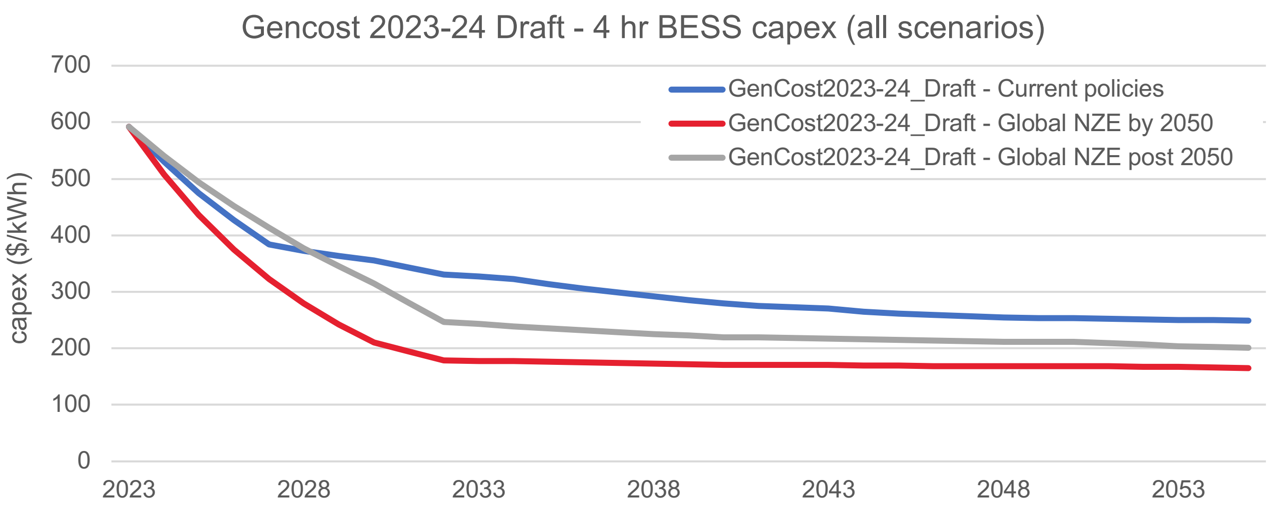

Figure 3: CSIRO Gencost 2023-24 Draft - 4 hr BESS capex (all scenarios)

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.

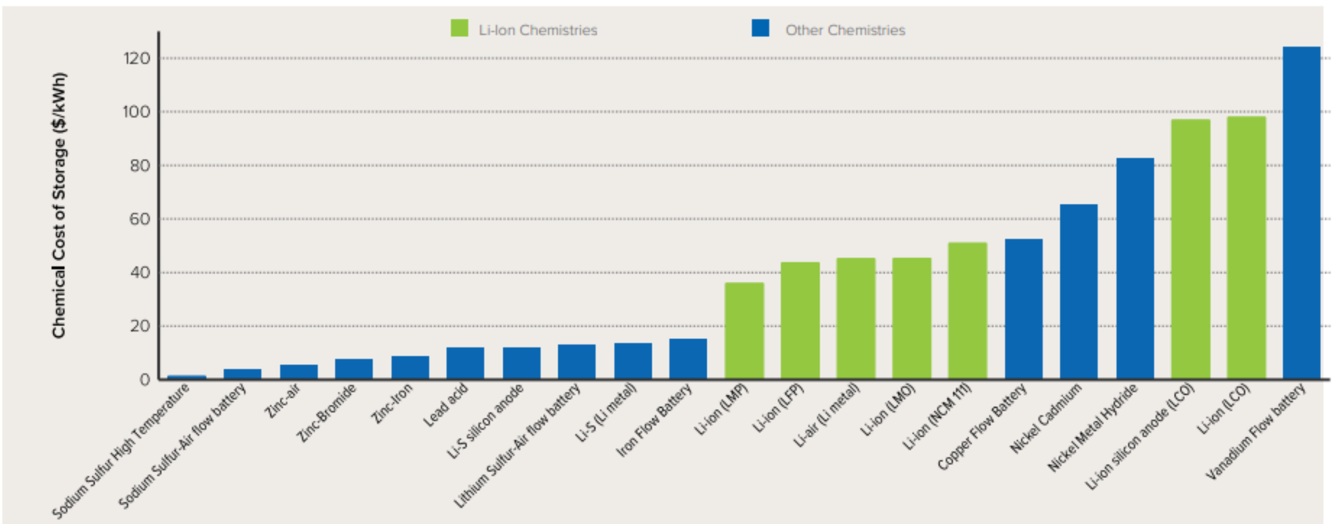

Figure 4 - Estimated Cost of Raw Materials for Different Battery Chemistries. Source: Tyson and Bloch (2019)

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)).

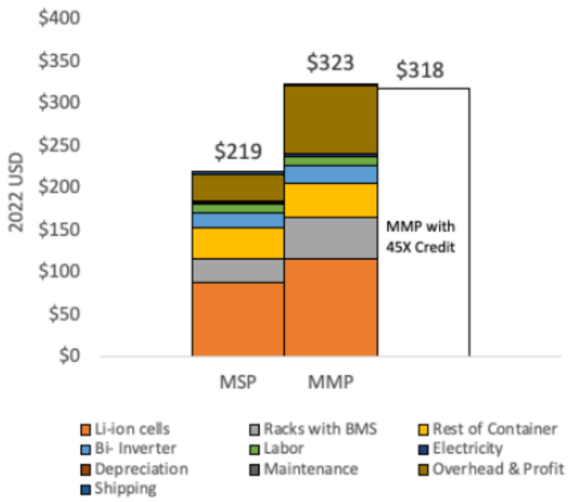

Figure 5 – US Utility ESS cost US$/KWh Q1 2023, Minimum Sustainable price & modelled market price. Source – NREL (2023)

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.

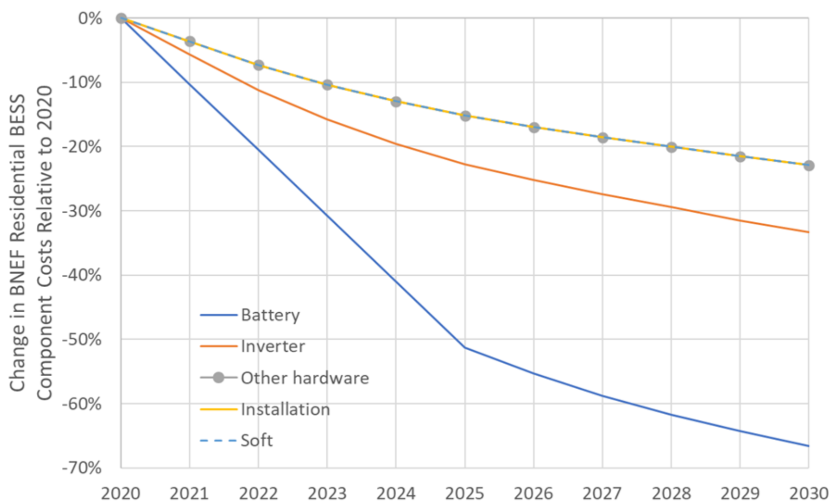

Figure 6 - Changes in projected component costs for residential BESS. Source – NREL (2024A) - BNEF. “Energy Storage System Costs Survey 2019.” BloombergNEF, October 14, 2019.

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.

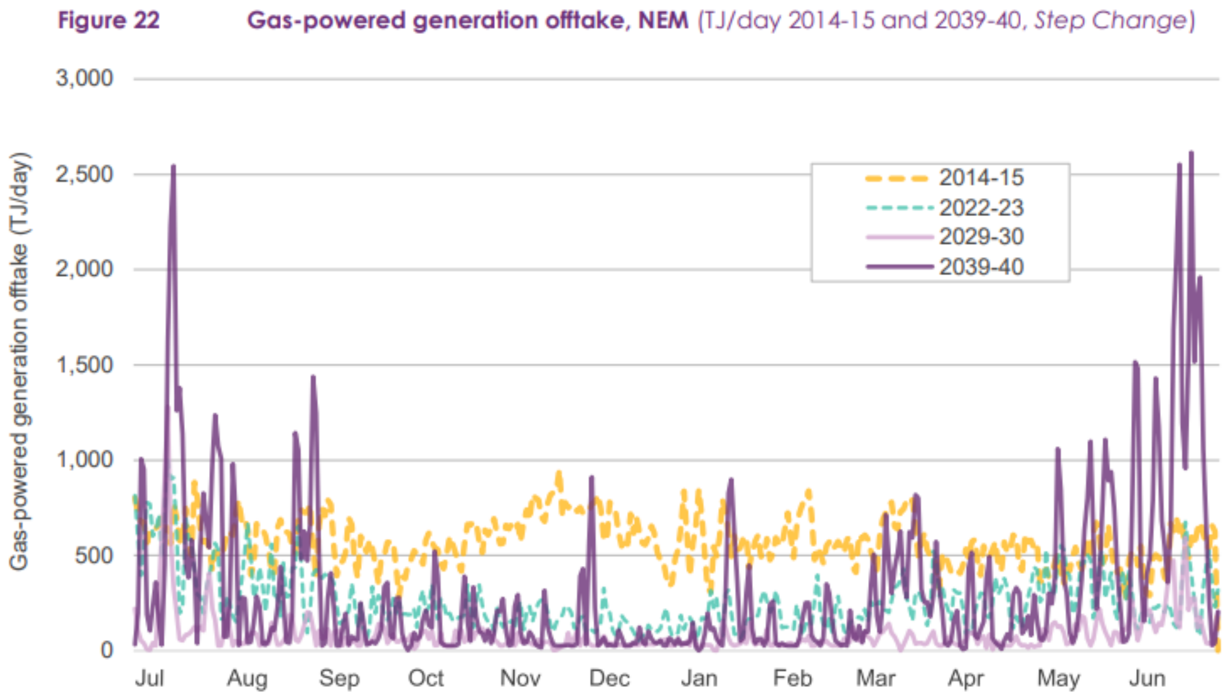

Figure 7 – gas powered generation offtake NEM (TJ/day 2014-15 and 2039-40, Step Change). Source DRAFT 2024 ISP

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)

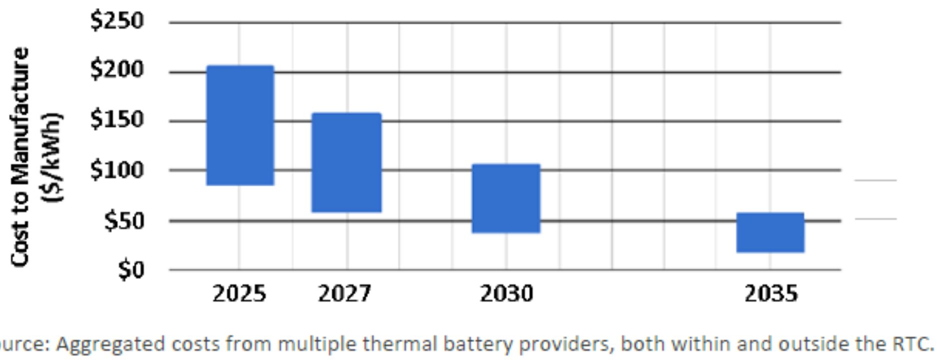

Figure 8: Thermal battery companies' projected total manufacturing costs: Source - Spees et al(2023)

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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Queensland green ammonia value chain:

Decarbonising hard-to-abate sectors and the NEM

Main Report

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Nancy Spencer[3], Phillip Wild[3] and Rene Bañares-Alcántara[2]

Abstract

Fossil fuel-based ammonia production currently accounts for around 1% of global greenhouse gas emissions. Ammonia is one of the few hydrogen use cases where no real alternatives exist. Green ammonia could play a pivotal role in decarbonising fertilisers and explosives, that are critical inputs into Australia's agriculture and resources sectors respectively.

This report assesses the design of infrastructure required for a world-scale Queensland green ammonia industry (multiple 1mtpa NH_3 capacity plants) with value chain costs estimated for supplying (a) green hydrogen and (b) green ammonia, to meet variable and fixed customer demand profiles.

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.

In contrast, the predicted partial-flexibility of new-build Haber Bosch green ammonia plants and the low cost of ammonia storage reduces the cost of meeting a fixed customer demand profile. These characteristics could also enable sector coupling benefits through the provision of demand response services to the electricity system. Future levelised costs of green ammonia value chain load shifting and load curtailment could be less than half of that of gas peaking generation, providing the potential to further decarbonise the electricity system, beyond ~90-95% renewables. To maximise sector coupling benefits a hybrid green ammonia value chain is proposed with co-located renewables (primarily solar) and electrolysers connected to the electricity grid to provide demand response services, with electrolysers connected to a hydrogen pipeline for transport to a separately located ammonia plant, that is grid connected.

Key words: green ammonia, green hydrogen, sector coupling, demand response.

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1 Introduction

This report documents the findings of the second phase of the study into Infrastructure Investment for Green Hydrogen and Ammonia in Queensland conducted by Griffith and Oxford universities. The report explores two main contributions of green hydrogen and green ammonia:

1. The decarbonisation of hard-to-abate sectors. Green ammonia could play a pivotal role in decarbonising fertilisers and explosives, that are critical inputs into Australia's agriculture and resources sectors respectively; and
2. Deeper decarbonisation of the electricity system via sector coupling.

The study considers potential production locations for green hydrogen and green ammonia in Queensland and explores the key drivers for value chain cost competitiveness. The techno-economic assessment of potential value chains, including production, storage and transport, is undertaken with a high level of detail with key potential common user infrastructure identified that has the potential to increase cost competitiveness. Analysis is undertaken based on a world-scale ammonia, plant producing 1mpta of ammonia (180,000t H_2 by mass).

Decarbonisation of industry will lead to significant electricity load growth, including green hydrogen and ammonia. The value of integrating these industrial loads with the electricity system could increase as the energy system decarbonises, with potential benefits including lower costs and carbon emissions. This report explores potential sector coupling benefits, in particular outlining the demand response services that a green ammonia value chain could provide and its cost competitiveness with other forms of firming technology.

Based on the research findings and building on the Queensland Energy and Jobs Plan, a high-level vision for the infrastructure required for the phased development of development of Queensland into a green ammonia exporter and then a diversified green energy exporter is outlined.

The report should be read in conjunction with the Information Sheets compiled for Phase 1 of the Study, which describe each functional component of the green hydrogen and green hydrogen derivatives value chain.

2 Context

2.1 Decarbonisation of hard-to-abate sectors

2.1.1 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. Unlike other hydrogen derivatives (e.g., methanol) a key advantage of ammonia is that it does not require a carbon source as a feedstock. 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).

The use of green ammonia as a zero-carbon fuel, particularly in shipping, provides potential upside. However there is not industry consensus, with competition in maritime shipping from alternatives including methanol and biofuels and a range of economic, safety, environmental and emissions issues for ammonia to overcome (Machaj, et al., 2022; DNV GL & Norwegian Maritime Authority, 2022).

Other emerging use cases for hydrogen such as alumina, ironmaking and steel are still nascent and the timing of widespread adoption and costs are uncertain (Devlin, Kossen, Goldie-Jones, & et al, 2023; ARENA, 2023).

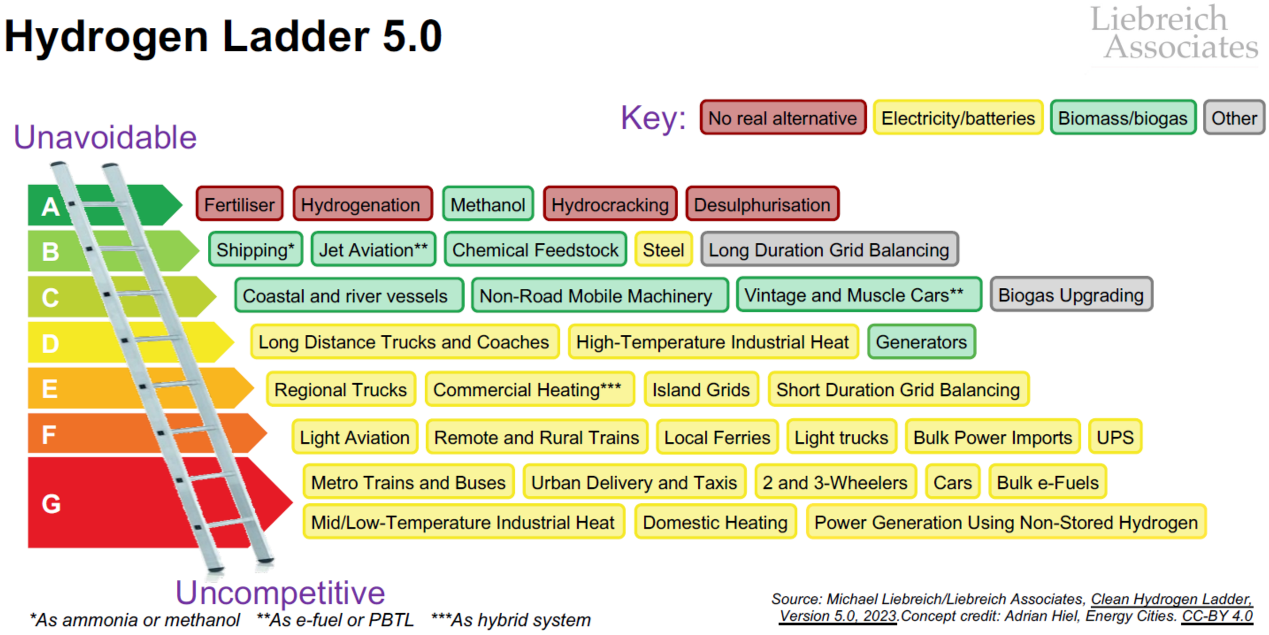


Figure 1: Hydrogen Ladder Version 5.0 | *Source: (Liebreich Associates, 2023)*

Much of the literature on hydrogen and its uses has adopted the notion that comparing the farm gate cost of green hydrogen to production costs for a fossil fuel alternative is an 'apples for apples' comparison (Australian Government - Department of Industry, Science, Energy and Resources, 2020; ARENA, 2020; Fowler, 2020; McKinsey & Company, 2022). Farm gate hydrogen production cost estimates are based on renewable energy generation and have variable output. However, customers may require a consistent and reliable supply of green hydrogen (firmed hydrogen) and this requirement can significantly increase cost. Hydrogen storage and transport has high capital costs (power system storage is higher cost), driven by hydrogen's low volumetric energy density (refer to Hydrogen Storage and Transport information sheets for details). These extra costs might reduce hydrogen's competitiveness in use cases that require a consistent and reliable supply. This report includes cost estimates for the full value chain required to meet such a demand profile for export scale industrial customers and further strengthens the case for green ammonia due to its production process flexibility.

2.1.2 Global context – current hydrogen and ammonia demand and emissions

Currently the world produces around 95 million tonnes of hydrogen per annum (around 43% of which is used in oil refineries and around 33% used as an input for ammonia production) (International Energy Agency, 2023A) and 176 million tonnes of ammonia per annum (The Royal Society, 2021). Ammonia production is currently dominated by fossil fuels, with 70% of the hydrogen used in ammonia production sourced via natural gas steam reforming, with most of the remainder sourced from coal gasification (International Energy Agency, 2021). Hydrogen production accounts for greater than 900 million tonnes of CO_2 emissions per year (International Energy Agency, 2023A), around 2% of annual global greenhouse gas (GHG) emissions (The Royal Society, 2021). Ammonia production accounts for around 450 million tonnes of CO_2 emissions per year (International Energy Agency, 2021)and is one of the most emissions-intensive commodities produced by heavy industry (The Royal Society, 2021).

As the world progresses towards its goal of net-zero, green hydrogen and green ammonia will become increasingly important renewable energy vectors. These renewable energy vectors can allow the movement of renewable energy to the time, place, and end-use to which it is best suited.

2.1.3 Australia and Queensland context – current ammonia demand and emissions

The majority of east coast domestic ammonia production and imports are used in the production of ammonium nitrate explosives for the resource sector and does not require a carbon feedstock. This contrasts with the production of urea fertiliser, that represents the most common nitrogen-based fertiliser, and synthetic hydrocarbons such as methanol which require a carbon feedstock (Refer to Hydrogen Conversion Process Information Sheet for further details). The domestic green ammonia market opportunity includes conversion of grey ammonia production (~2mtpa) and displacing ammonia imports (~0.3mtpa). Following completion of the Perdaman urea project in Western Australia, Australian urea production will roughly meet domestic demand. Decarbonising existing global ammonia production (176mtpa) presents a larger opportunity, with use of ammonia as fuel providing potential upside. For scale context, Queensland's has proposed green ammonia projects with a total capacity exceeding 2.5mtpa.

Green ammonia market opportunity excluding energy use cases (mtpa NH_3 equivalent)

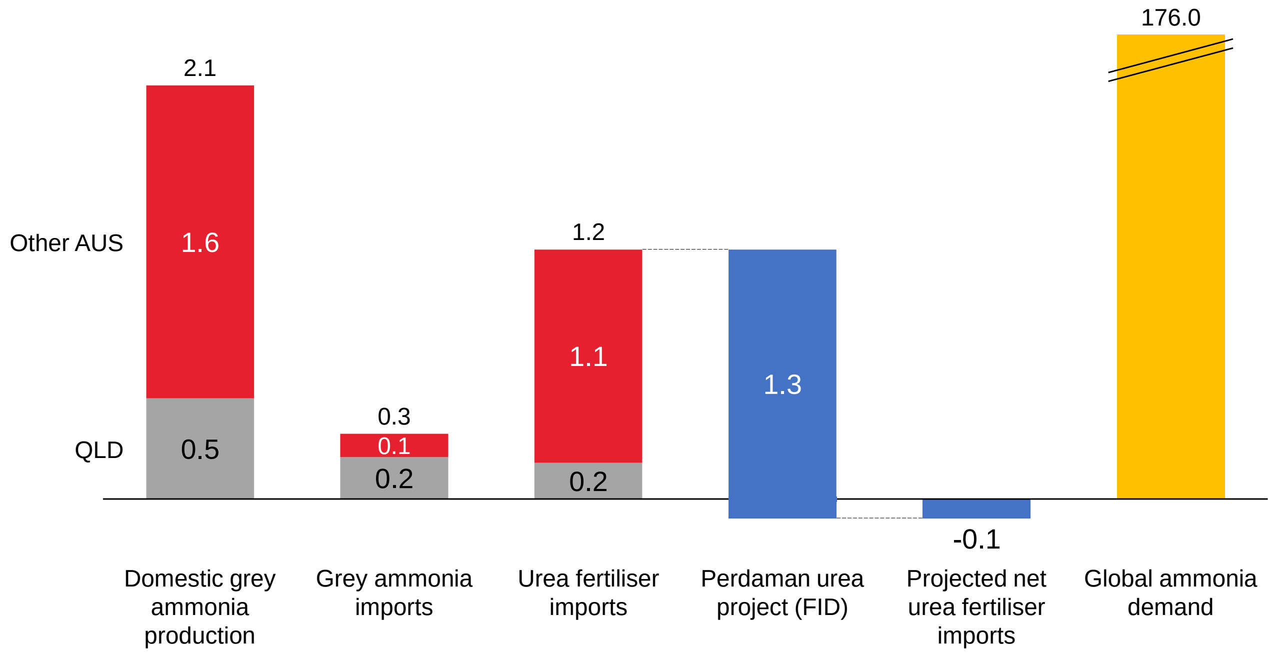


Figure 2: Green ammonia market opportunity excluding energy use cases

Source: (Gladstone Ports Corporation, 2023; Port of Newcastle, 2023; Australian Government - Department of Industry, Science, Energy and Resources, 2021; Australian Trade and Investment Commission, 2023; Clean Energy Finance Corporation & Advisian, 2021; Incitec Pivot, 2023A; Incitec Pivot, 2023B; Incitec Pivot, 2023C; Orica, 2023A; Orica, 2023B).

For the 5 years to 2021 Scope 1 emissions from ammonia production averaged 0.7mtpa CO_2e for Queensland and 2.2mtpa CO_2e for Australia. Domestic ammonia production emissions accounted for 0.4% of greenhouse gas emissions over the period (Australian Government - Department of Climate Change, Energy, Environment & Water, 2022). However, once imports of ammonia and fertilisers are considered emissions increase by 150% for Queensland to 1.7mtpa CO_2e and by 170% for Australia to 6.1 mtpa CO_2e[4].

[4] *Due to data limitations fertiliser imports (Australian Government - Department of Agriculture, Fisheries & Forestry, 2022) are based on urea, which requires 0.58t NH_3 per tonne of urea, which may lead to an underestimate of fertiliser imports. Ammonia production is assumed to have lifecycle emissions of 2.6t CO_2/t NH_3 which includes natural gas supply chain leakage (Liu, Elgowainy, & Wang, 2020; Mayer, et al., 2023).*

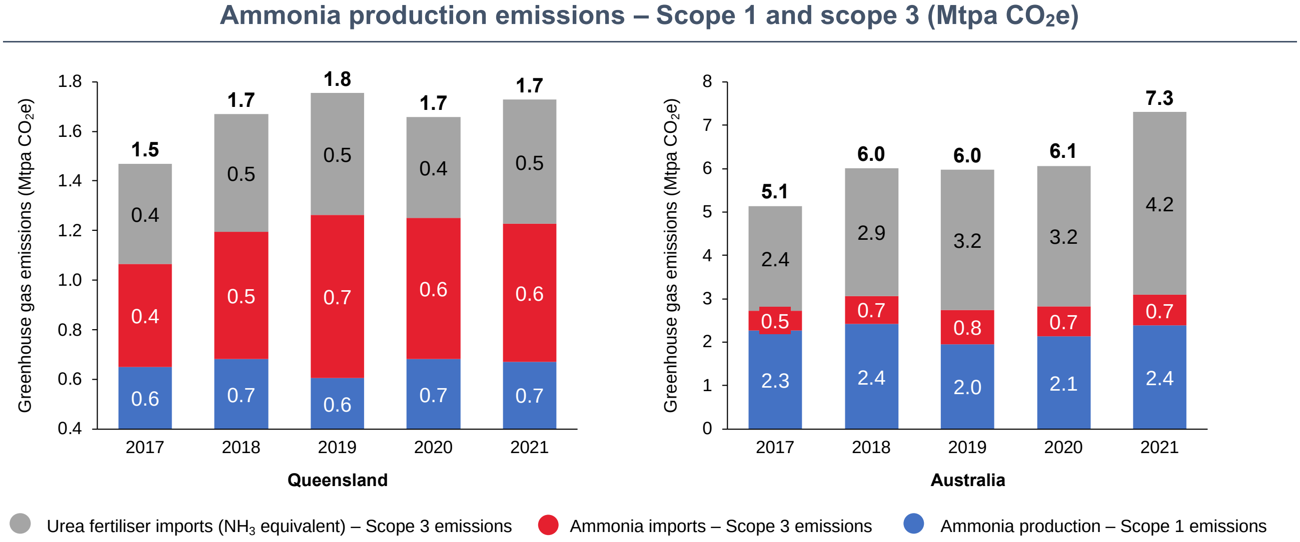


Figure 3: Emissions from ammonia and fertilisers in Queensland and Australia

Source: (Australian Government - Department of Climate Change, Energy, Environment & Water, 2022; Gladstone Ports Corporation, 2023; Port of Newcastle, 2023; Australian Government - Department of Agriculture, Fisheries & Forestry, 2022)

The detailed modelling of plant design to achieve least cost hydrogen and ammonia production is covered in Section 3 - Detailed optimisation modelling.

2.2 Further decarbonisation of the electricity sector via sector coupling

The Queensland Energy and Jobs Plan (QEJP) released in September 2022 includes:

- a new renewable energy target of 70% by 2032 and 80% by 2035;
- a commitment to convert all of Queensland's publicly-owned coal-fired power stations into clean energy hubs by 2035;
- a commitment to progress two new long duration (24 hours) pumped hydro projects by 2035—Borumba (2,000MW) and Pioneer-Burdekin (up to 5,000MW); and

a pathway to build the new Queensland SuperGrid (including 500kV backbone), which will connect solar, wind, battery and hydrogen projects across the state and unlock new capacity and storage (Queensland Government - Department of Energy and Public Works, 2022).

Despite these commitments standard National Energy Market modelling scenarios find that 5-10% of Queensland's electricity is generated by gas in 2040 (Ernst & Young, 2022). In a renewable energy dominated NEM, gas generation is typically required to address two key problems:

1. Renewable energy droughts, which are a result of renewable energy intermittency; and
2. Seasonal energy imbalances (the 'winter problem').

Sector coupling between the ammonia value chain and the electricity network could contribute to addressing these problems, reducing electricity system costs and carbon emissions. This could be critical for not only the electricity system, but sectors that are relying on electrification for decarbonisation. These potential benefits are analysed in detailed in Section 4 - Electricity system integration.

2.2.1 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. Figure 4 depicts a typical energy market modelling outcome within in the range of 5-10% gas generation in 2040. Gas generation is highly seasonal, with the 'winter problem' more acute in southern NEM states, with key drivers being higher seasonality in solar generation and larger winter heating loads. The magnitude of the 'winter problem' in southern states would be larger than shown in Figure 4, if not for the greater renewables overbuild in these states, that leads to more renewable energy spill which is highly seasonal.

NEM and Queensland monthly gas-fired generation volume – Orderly Transition (2040)

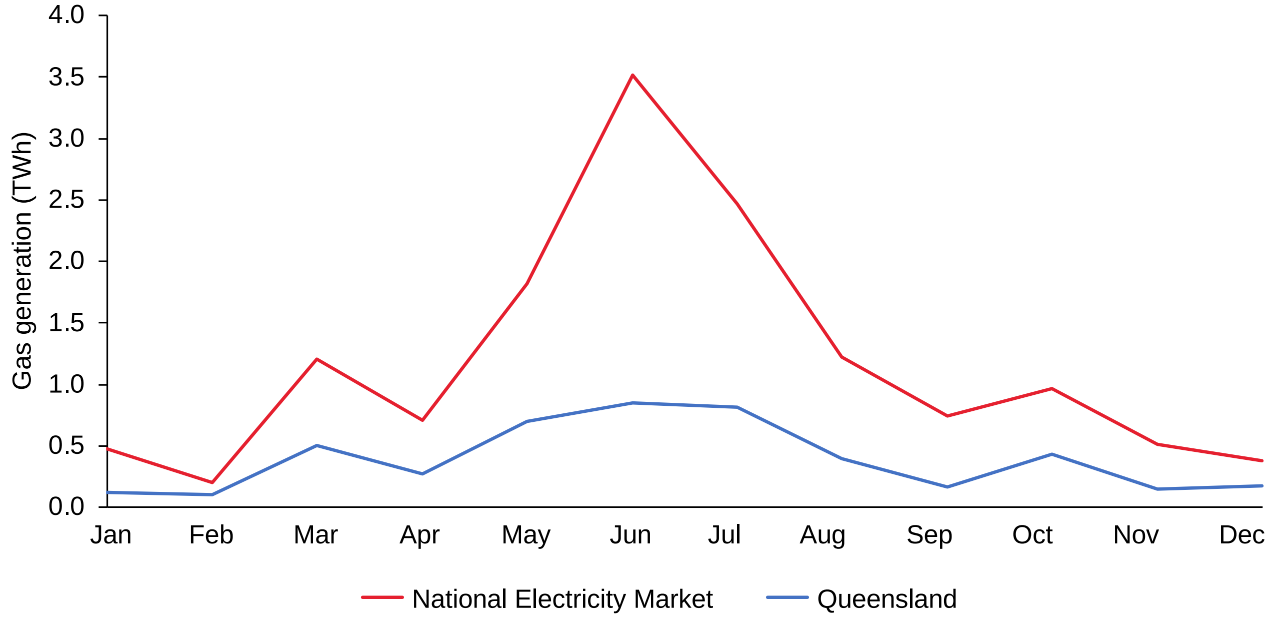


Figure 4: NEM and Queensland monthly gas generation volume (2040) | *Source: March 2023 Price Projection – Orderly Transition (Endgame Economics, 2023)*

Queensland's renewable resources are well suited to addressing the 'winter problem'. Queensland solar PV generation has less seasonality than southern NEM states (Figure 5), due to longer winter daylight hours and sunny weather (Australian Government - Bureau of Meteorology, 2023A).

Monthly solar capacity factors

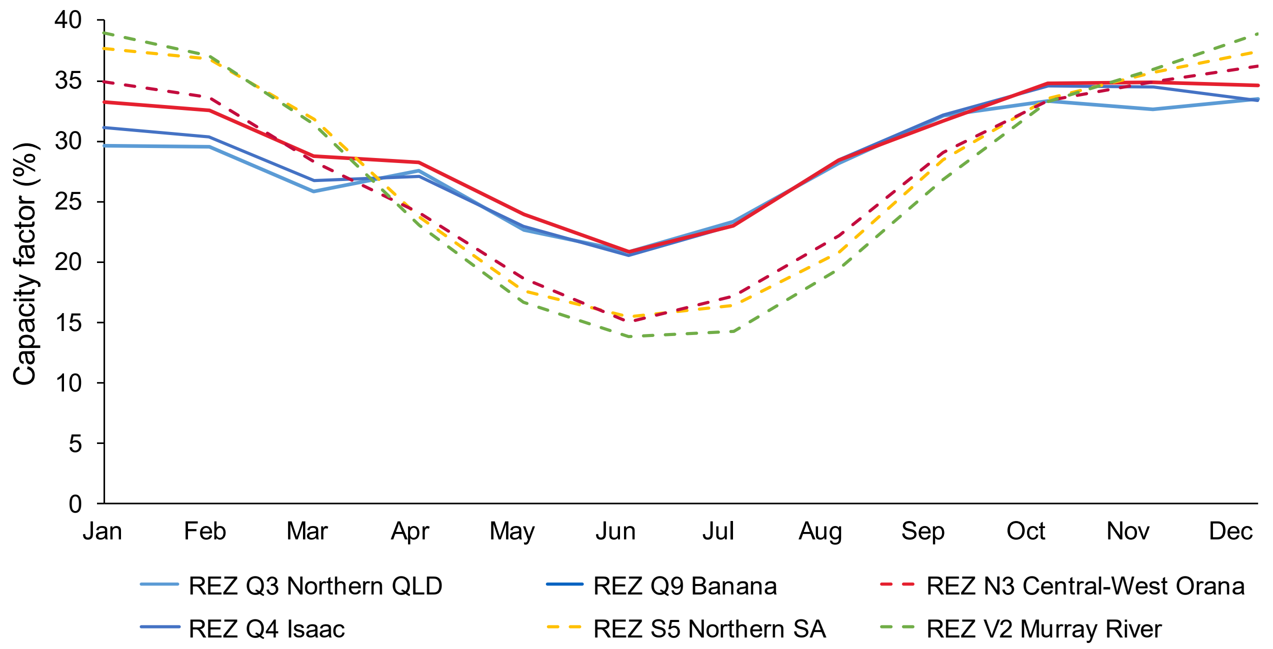


Figure 5: Monthly solar capacity factors in different NEM states | *Source: (Australian Energy Market Operator, 2022c)*

A key driver of seasonality in Queensland wind generation is the movement of the sub-tropical ridge (Australian Government - Bureau of Meteorology, 2023B). A clear pattern is observable in Queensland between the relative strength of winter wind generation increasing as latitude decreases, i.e., the further north, the higher relative winter generation (Australian Energy Market Operator, 2022c).

Monthly wind capacity factors indexed to 1 – QLD vs other NEM states

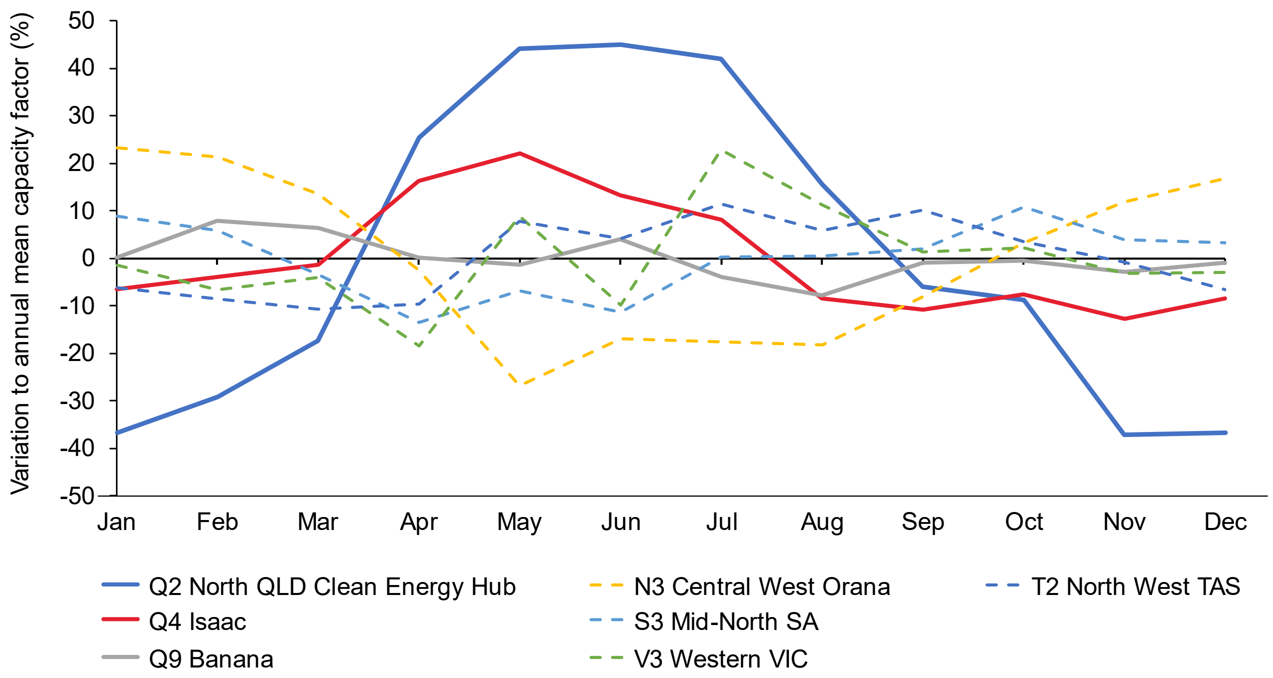


Figure 6: Monthly wind capacity factors indexed to 1 - QLD vs. other NEM states | *Source: (Australian Energy Market Operator, 2022c)*

2.2.2 Sector coupling

Sector coupling refers to the increased integration of energy end-use and supply sectors 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 (European Parliament - Policy Department for Economic, Scientific and Quality of Life Policies, 2018). Household and transport sector coupling has been a key focus of Australian energy system modelling such as the AEMO ISP.

Potential sector coupling benefits from flexible industrial loads may increase as energy system and industry decarbonises and price signals become stronger. For instance, the daily price shape may become more pronounced and price volatility may increase, while industrial load may grow due to electrification. Green hydrogen and green ammonia production is electricity intensive and the flexibility of these processes could allow sector coupling benefits driven by demand response (Australian Energy Market Commission, 2022A; Australian Energy Market Commission, 2023; ARENA, 2022).

To date standard Australian market modelling of potential flexible industrials load, such as green hydrogen and ammonia has typically been limited. For instance, flexible load and/or industrial demand response may be treated as an exogenous variable. Alternatively modelling methodologies are used that simplify the industrial loads for modeling ease and in doing so risks not accurately capturing their techno-economic characteristics.

Within the literature and industry there is a number of examples emerging of energy system modelling that more thoroughly integrates flexible industrial loads with the electricity system (see Section 4.7.2). These models are able to more accurately depict demand response capability and thus identify sector coupling benefits that may not be apparent in standard energy system models.

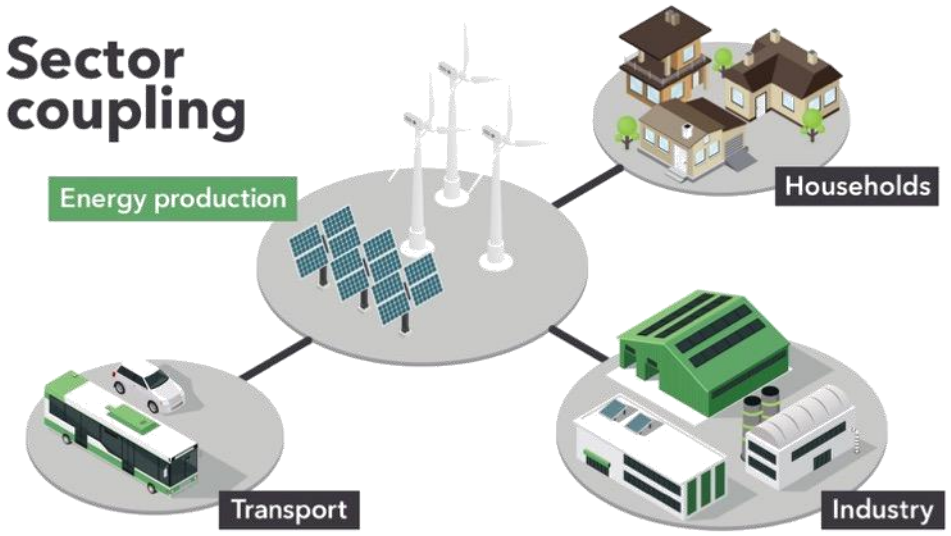


Figure 7: Sector coupling diagram | Source: *https://www.nproxx.com/sector-coupling-an-integrated-approach-to-emissions-reduction/*

2.2.3 Demand response

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.

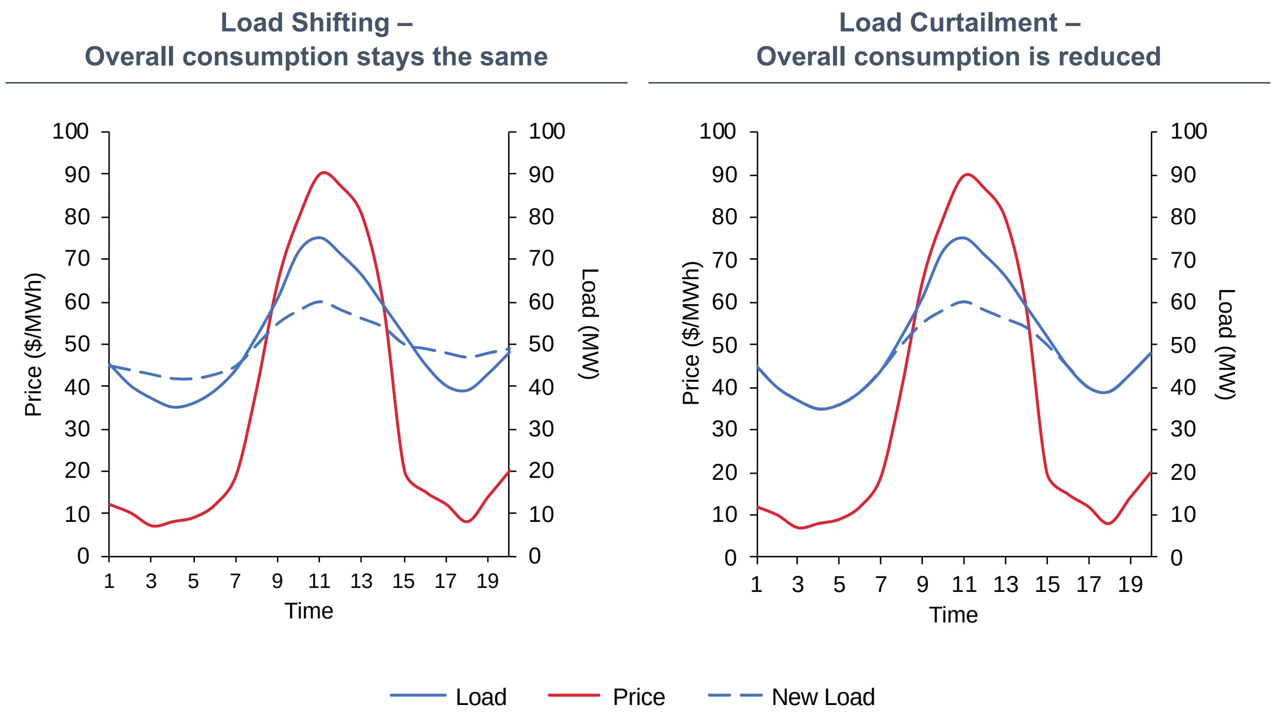
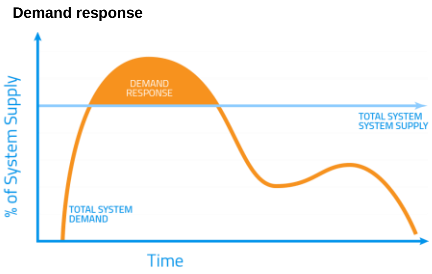


Figure 8: Demand response services

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

Load flexibility	Low-cost storage	Grid connection
• Future green ammonia value chain is predicted to be highly flexible • Flexibility allows load to match renewables and to be reduced to allow renewable exports to the grid when prices are high	• Geological hydrogen storage and ammonia tank storage are mega scale and have low capex	• Hydrogen pipelines preferred over electricity transmission for transport due to lower cost and social licence risk • Electricity network connection required to enable potential sector coupling benefits



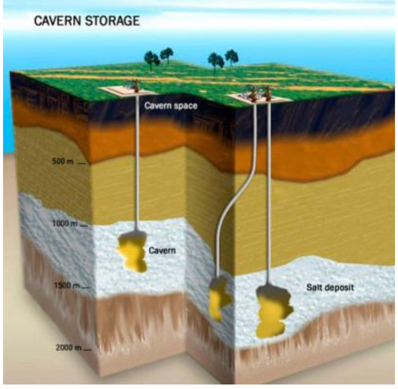


Figure 9: Demand response – three pillars

Source: *https://encorp.com/demand-response/, https://www.linkedin.com/pulse/salt-caverns-promising-solution-large-scale-hydrogen-leal-duarte/ 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.

In order to realise the full potential benefits from sector coupling, the plant owner will have to adopt the mindset of an energy trader, leveraging process flexibility and storage to optimise profit and risk rather than maximising production (Hirschorn, Wilkinson, & Brijs, 2022)[5]. Plant owners who do not adopt such a mindset face the risk of being less profitable, having higher production costs than their competitors.

A more thorough exploration of demand response, including the three pillars is contained in Section 4 Electricity system integration.

2.3 Queensland – favourable location for green ammonia investment

Green ammonia represents a significant potential investment opportunity for Queensland as:

- Queensland has surplus renewable resources, that could enable the development of green ammonia projects;
- In addition to the opportunity to meet domestic demand, Queensland is located close to potential demand hubs in Asia and has a number of potentially suitable ports for export; and
- The seasonal generation profiles and diversity of Queensland's renewable resources are favourable characteristics for producing ammonia cost competitively and also for providing electricity system demand response services, including to southern NEM states.

2.3.1 Surplus renewable energy resources

Queensland has abundant high quality solar resources available for green ammonia production, with solar PV resources build limits for Queensland REZ contained in the 2022 AEMO ISP not reflective of Queensland's full potential resource (Refer to Queensland Renewable Energy Information Sheet for more detail).

Queensland has surplus wind resources in the north of the state. Assuming domestic energy customers and existing energy intensive export industries are preferred in the allocation of wind resources, except for the inland Barcaldine REZ, there could be limited to no wind resources available in central and southern

[5] Hirschorn P., Wilkonson, O. and Brijs, T. (2022), *What CEOs Can Learn from Energy Traders,* covers this topic in significant detail.

Queensland for export hydrogen derivatives (Advisian, 2022). The 2022 AEMO ISP step change scenario finds that domestic load growth results in the wind build limits for southern and central Queensland REZ being reached and in the case of Wide Bay and Darling Downs significantly exceeded (Australian Energy Market Operator, 2022a; Australian Energy Market Operator, 2022b). AEMO's modelling approach of allowing the breaching of build limits by applying an additional cost penalty per MW is considered optimistic and is not a standard approach taken by industry. (Refer to Queensland Renewable Energy Information Sheet for more detail).

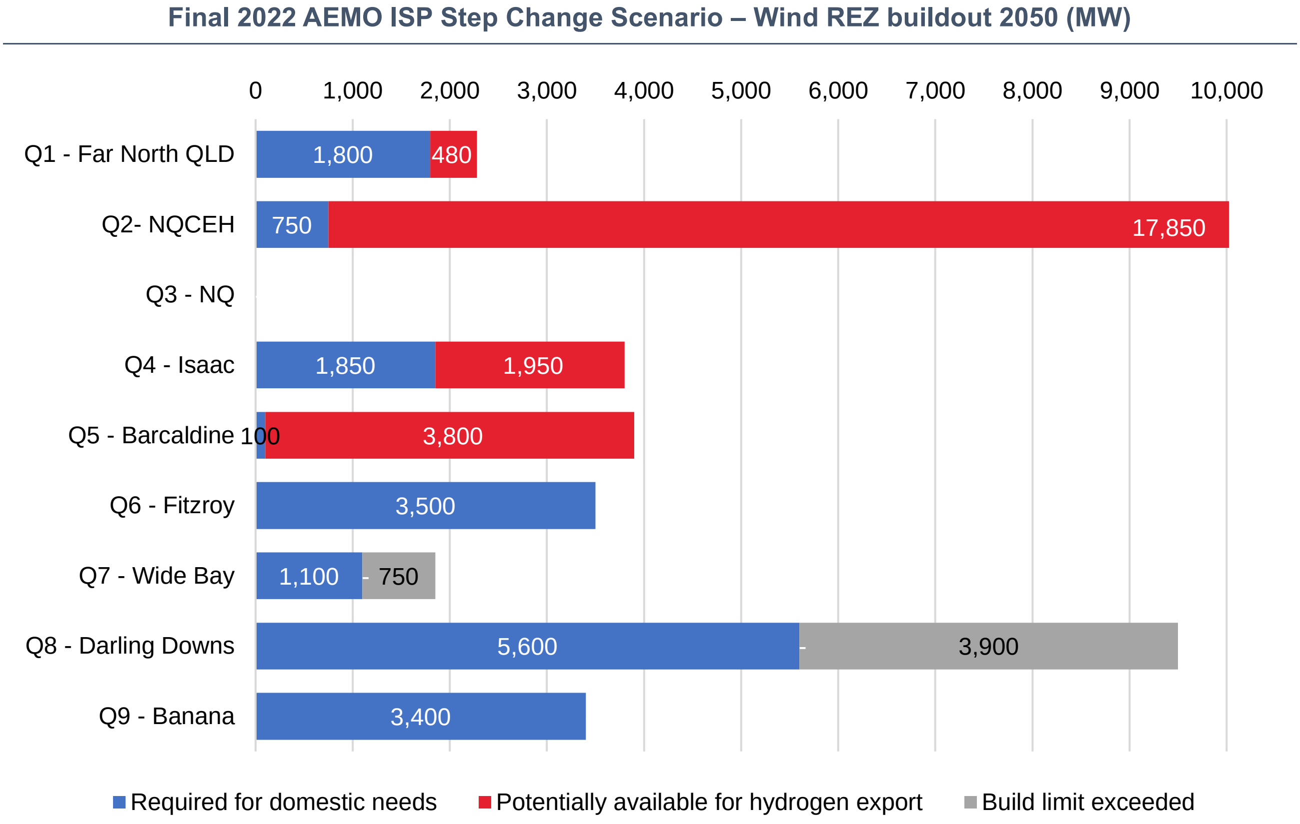


Figure 10: Final 2022 AEMO ISP Wind REZ buildout 2050 (MW of build limit) | *Source: (Australian Energy Market Operator, 2022b)*

2.3.2 Favourable renewable generation profiles and electricity infrastructure

The limited seasonality of Queensland's solar PV generation and its seasonal anti-correlation with north Queensland wind resources could be favourable for maintaining electrolyser and ammonia plant load factors over winter, increasing cost competitiveness.

The value of potential demand response services that a green ammonia value chain could provide to a renewable energy dominated electricity system is dependent on several factors, which Queensland is positively aligned with including:

- A mild 'winter problem', with renewable resources having relatively strong winter generation and limited electricity system heating load. A severe 'winter problem' may result in there being limited solar generation to export or even produce the hydrogen feedstock and electricity required to operate the green ammonia plant at minimum load;
- Diversified renewable energy resources. Unlike other NEM states, Queensland benefits from significant intra-state wind diversity as demonstrated by low or negative correlations of daily wind generation between Queensland REZ . This diversity means that a demand response service incorporating wind is more likely to have a higher value. For example, electricity prices may be high when wind farms in southern Queensland REZ are not generating, with low or negative correlation meaning that wind farms in north Queensland that are part of a green ammonia value chain are more likely to be generating strongly,

providing the opportunity to turn down hydrogen and ammonia production and export this wind generation to the grid. When the southern Queensland wind REZ are generating strongly there may be spilled electricity, green ammonia value chains in north Queensland REZ could import this electricity to increase hydrogen and ammonia production.

- Valuable demand response to southern states: Queensland wind REZ have low or negative correlation with southern NEM states' wind REZ, potentially increasing value;
- Transmission network with substantial electricity load, transmission capacity and interconnection. Queensland has significant grid connected load and transmission network capacity will increase with the Queensland SuperGrid (including 500kV backbone) which is part of the QEJP (Queensland Government - Department of Energy and Public Works, 2022);
- Lack of competing clean firming technologies on seasonal and inter-annual timescales. Ammonia value chain demand response has the potential to compete with power system storage of all durations. However, it is especially valuable on longer timescales as Queensland has limited conventional hydropower generation that can provide a response over these longer timeframes.

		QLD				NSW			SA			TAS			VIC		
		Q2	Q4	Q8	Q9	N2	N3	N5	S1	S3	S6	T1	T2	T3	V3	V4	V5
QLD	Q2	1.00	0.53	-0.50	0.06	-0.24	-0.58	-0.30	-0.18	-0.35	-0.38	0.17	0.29	0.36	0.10	0.20	0.18
	Q4	0.53	1.00	-0.05	0.33	-0.13	-0.15	-0.19	-0.17	-0.18	-0.03	0.00	0.04	0.18	-0.06	-0.05	-0.08
	Q8	-0.50	-0.05	1.00	0.53	0.43	0.56	0.18	0.07	0.24	0.37	-0.20	-0.25	-0.20	-0.09	-0.18	-0.25
	Q9	0.06	0.33	0.53	1.00	0.32	0.15	0.02	-0.11	-0.02	0.13	-0.06	-0.04	0.03	-0.04	-0.09	-0.13
NSW	N2	-0.24	-0.13	0.43	0.32	1.00	0.47	0.20	0.10	0.11	0.20	-0.14	-0.13	-0.23	0.05	-0.07	-0.09
	N3	-0.58	-0.15	0.56	0.15	0.47	1.00	0.31	0.15	0.38	0.50	-0.30	-0.27	-0.35	-0.05	-0.24	-0.30
	N5	-0.30	-0.19	0.18	0.02	0.20	0.31	1.00	0.57	0.50	0.25	0.17	0.13	0.00	0.52	0.31	0.26
SA	S1	-0.18	-0.17	0.07	-0.11	0.10	0.15	0.57	1.00	0.44	0.11	0.14	0.17	0.04	0.65	0.53	0.31
	S3	-0.35	-0.18	0.24	-0.02	0.11	0.38	0.50	0.44	1.00	0.68	-0.05	-0.04	-0.15	0.20	0.07	-0.04
	S6	-0.38	-0.03	0.37	0.13	0.20	0.50	0.25	0.11	0.68	1.00	-0.20	-0.18	-0.24	-0.08	-0.20	-0.30
TAS	T1	0.17	0.00	-0.20	-0.06	-0.14	-0.30	0.17	0.14	-0.05	-0.20	1.00	0.60	0.58	0.38	0.39	0.58
	T2	0.29	0.04	-0.25	-0.04	-0.13	-0.27	0.13	0.17	-0.04	-0.18	0.60	1.00	0.60	0.39	0.37	0.59
	T3	0.36	0.18	-0.20	0.03	-0.23	-0.35	0.00	0.04	-0.15	-0.24	0.58	0.60	1.00	0.32	0.39	0.47
VIC	V3	0.10	-0.06	-0.09	-0.04	0.05	-0.05	0.52	0.65	0.20	-0.08	0.38	0.39	0.32	1.00	0.72	0.59
	V4	0.20	-0.05	-0.18	-0.09	-0.07	-0.24	0.31	0.53	0.07	-0.20	0.39	0.37	0.39	0.72	1.00	0.53
	V5	0.18	-0.08	-0.25	-0.13	-0.09	-0.30	0.26	0.31	-0.04	-0.30	0.58	0.59	0.47	0.59	0.53	1.00

Figure 11: Selected ISP Wind REZ daily generation correlation | *Source: (Australian Energy Market Operator, 2022c)*

3 Detailed optimisation modelling

3.1 Methodology

3.1.1 Islanded plant design

In each of the case studies, using the ten years of variable renewable energy generation data, the optimal plant design is identified which will meet the specified hydrogen and ammonia demand at the minimum cost (least cost modelling). An islanded hydrogen production system is shown in Figure 12 and ammonia in Figure 13.

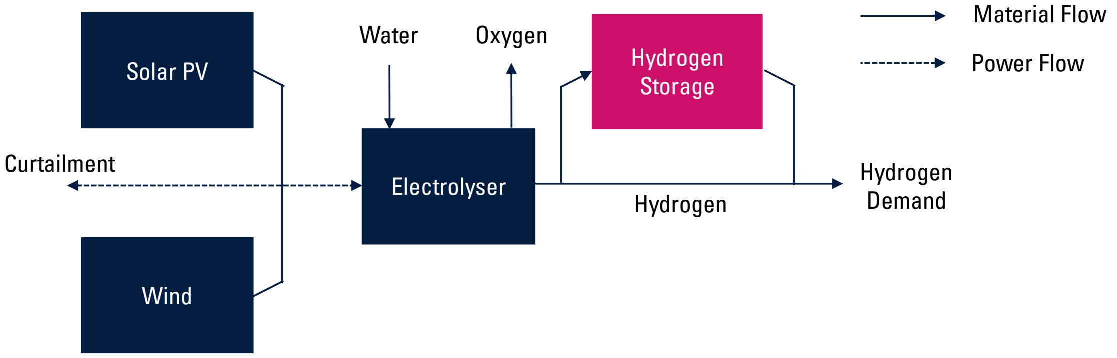


Figure 12: Schematic of hydrogen plant design

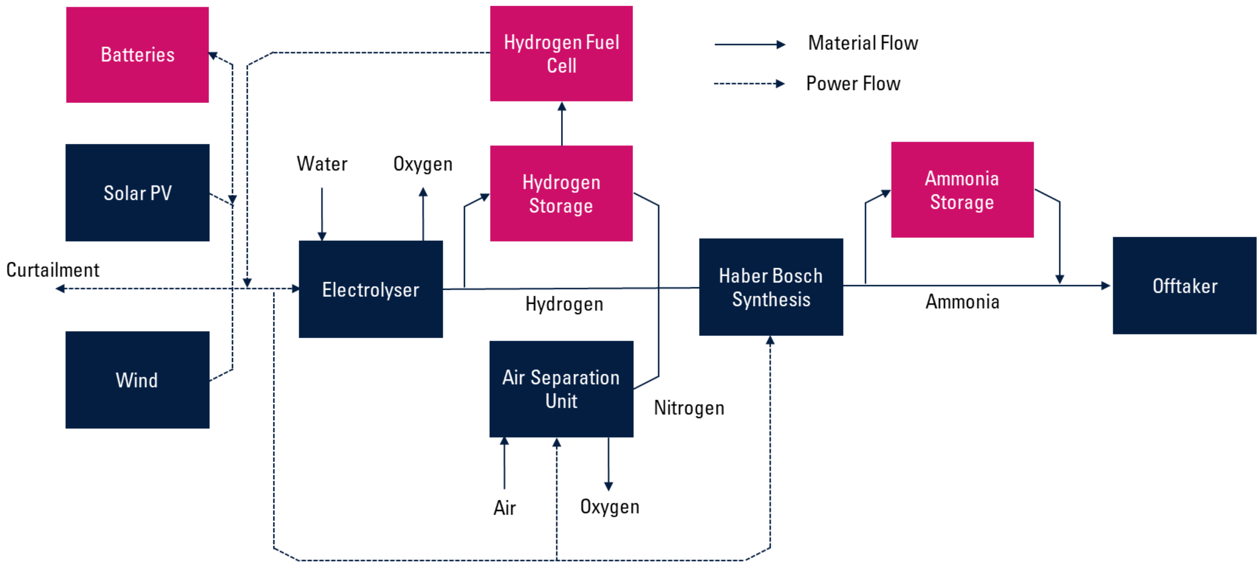


Figure 13: Schematic of ammonia plant design

3.1.2 Optimisation methodology

This report uses optimisation modelling to determine the lowest cost plant design (value chain/infrastructure) for green hydrogen and ammonia in Queensland. A series of case studies are conducted to determine how the presence of specific technologies, hydrogen demand profiles, and infrastructure developments, impacts on the cost of green hydrogen and ammonia.

The model is a Mixed Integer Linear Program (MILP) which identifies the best design without being limited by pre-conceptions of how the optimum system will look or be operated. Each unit in the value chain carries associated information which informs how the model will solve. Some of this information applies to the unit when it is purchased – for instance, all units have an associated capital cost, fixed and marginal operating cost. The hydrogen electrolyser and the ammonia plant have an efficiency with which they convert inputs into the end product. However, most of the information provided to the model relates to how the unit is operated. Most importantly, the solar PV and wind turbine inputs include renewable energy generation output at each time-step considered by the model.

3.1.3 Data sources

Seven potential production locations are considered in Queensland, corresponding to the Renewable energy zones identified in AEMO's 2022 Integrated System Plan (ISP) for the National Electricity Market (NEM): North Queensland Clean Energy Hub (Q2), Northern Queensland (Q3), Isaac (Q4), Barcaldine (Q5), Fitzroy (Q6), Darling Downs (Q8) and Banana (Q9) (Australian Energy Market Operator, 2022b).

Only solar PV was modelled for Northern Queensland (Q3) as the AEMO ISP wind build limit is zero and Fitzroy (Q6) and Darling Downs (Q8) where scarce wind resources are assumed to be allocated to domestic decarbonisation, particularly due to the proximity of these REZ to major load centres. The appendix (Section 6.7 and Section 6.8) contains modelling results where wind is assumed to be available in these REZ. Banana (Q9) has the same issue with scarce wind resource availability as Fitzroy (Q6) and Darling Downs (Q8), however results with wind available are included in the main report due to stakeholder interest and uncertainty around wind buildouts in the AEMO ISP. Wind traces for medium-quality wind (Australian Energy Market Operator, 2022f) are used for all relevant REZ as high-quality wind is assumed to be required for domestic decarbonisation.

Far North Queensland (Q1) and Wide Bay (Q7) were not considered due to the limited scale of wind resources, most if not all of which is assumed to be allocated to domestic decarbonisaton and the lower quality of solar PV resources relative to the other Queensland REZ. For further details see Queensland Renewable Energy Information Sheet.

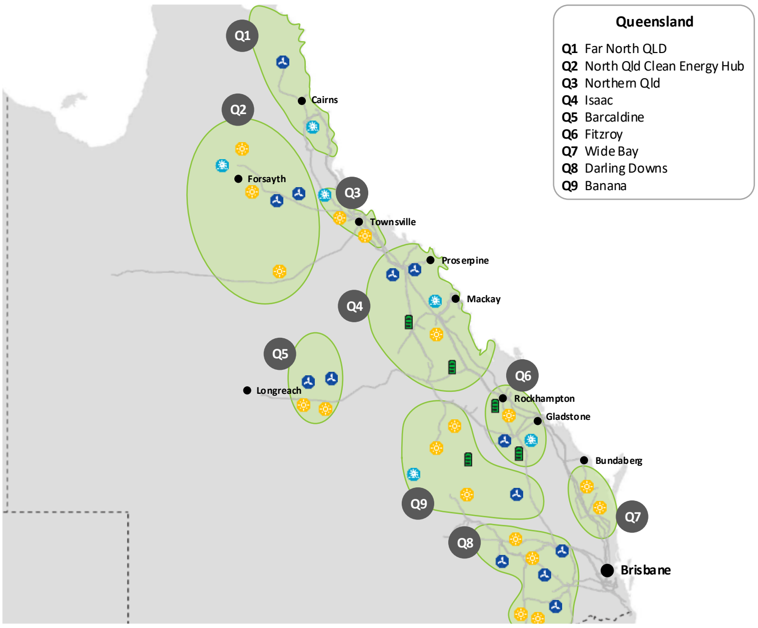
REZ	Main Report	Appendix
Far North Queensland (Q1)	n/a	n/a
NQCEH (Q2)	Hybrid	Hybrid
Northern Queensland (Q3)	Solar	Solar
Isaac (Q4)	Hybrid	Hybrid
Barcaldine (Q5)	Hybrid	Hybrid
Fitzroy (Q6)	Solar	Solar, Hybrid
Wide Bay (Q7)	n/a	n/a
Darling Downs (Q8)	Solar	Solar, Hybrid
Banana (Q9)	Hybrid	Hybrid

Table 1: REZ and renewable resources modelled

Ten years of variable renewable energy generation (wind and solar PV) data in half hourly time intervals (provided by the ISP) are considered to design a system which will produce hydrogen and ammonia at the least cost (Australian Energy Market Operator, 2022c). Because of the modelling complexity associated with these very large amounts of data, they are aggregated together for runs which consider the production of ammonia into four-hourly time steps. Prior research using these models has shown that this introduces a small error of around 3% but enables a far larger amount of data to be considered. For runs considering the production of hydrogen, which is a less complex optimisation, there is no aggregation of the data.

Where available cost assumptions are sourced from the CSIRO GenCost Consultation Draft 2022-23 released in December 2022 (AEMO ISP technology input cost assumptions) (CSIRO, 2022A), with key assumptions provided in the Appendix (Section 6.9). Each case is considered using data for 2030, 2040 and 2050. Sections 3.2.1.5 and 3.2.2.6 outlines key limitations regarding input assumption and modelling methodology, with further detail contained in the Information Sheets.

QLD AEMO ISP REZ Map



Source: (Australian Energy Market Operator, 2022b)

3.1.4 Transport options

The basis of the optimisation is an islanded system where the renewables, electrolysers, energy storage and ammonia plant (where applicable) are all in the same location. However, many of these renewable energy zones are not located near potential sites of hydrogen/ammonia demand. The report explores routes for energy transport to determine advantages and disadvantages of different forms of transport. Transport elements are added to the model as post-processing adjustment instead of being co-optimised with the plant. Thus LCOH and LCOA are likely to be overestimated, though as transport is found to represent a small percentage of the cost stack, this is immaterial to LCOH and LCOA.

Two modes of energy transport are considered: transport by electricity wires (i.e., electrons) and transport by hydrogen pipeline (as a gas). Salt cavern hydrogen storage is considered with the hydrogen pipeline (as a gas) transport mode.

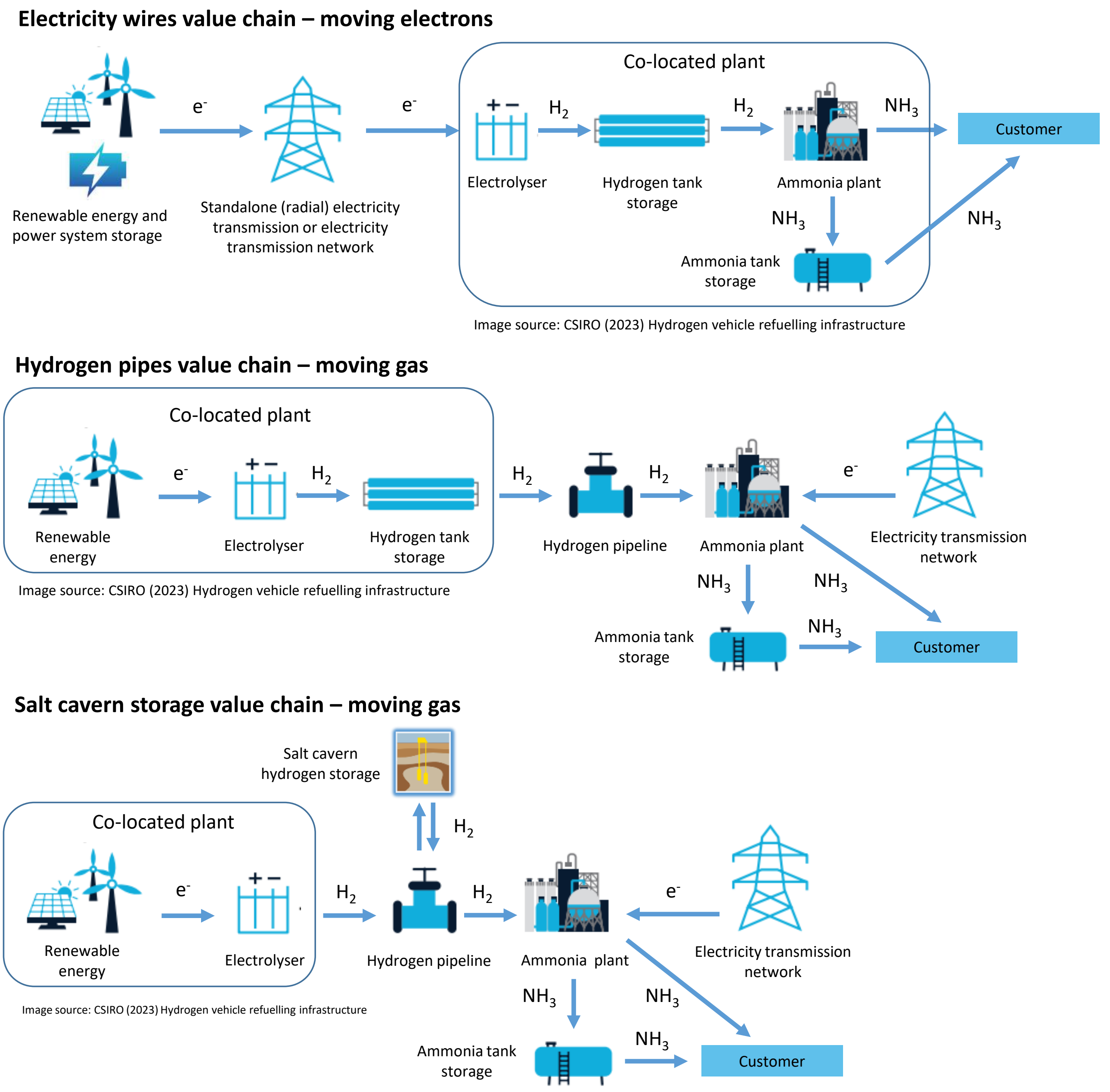


Figure 14: Modelled green ammonia value chains

Transport by ammonia pipeline (as a liquid) is considered in the appendix (section 6.5) as it is assumed that there would be value in transporting hydrogen to a range of different users. Industry feedback is that there is significant social license risk associated with ammonia pipelines in Queensland due to environmental and safety concerns.

Four ports are selected as potential demand locations, based on Queensland's priority ports (Abbott Point/ Mackay consolidated with Abbott Point given proximity) and Brisbane. REZ locations and potential salt cavern storage location is selected on based on recent Geoscience Australia 3D modelling, with the Rosebank 1 well location assumed (Paterson, Feitz, Wang, Rees, & Keetley, 2022).

Transport distances from the REZ to the closest port and to potential salt cavern storage in the Adavale Basin are shown below. As the Adavale Basin is located west of all REZ, transport routes for value chains incorporating salt caverns would run from the Adavale Basin to the REZ to the port at the coast, with distance provided for this route.

	REZ	Closest port	Distance to port (km)	Distance to salt cavern (km)	Distance – salt cavern to REZ to port (km)
Hybrid	NQCEH (Q2)	Townsville	299	667	967
	Isaac (Q4)	Abbot Point	77	676	753
	Barcaldine (Q5)	Abbot Point	499	295	794
	Banana (Q9)	Gladstone	151	494	645
Solar	North Queensland (Q3)	Townsville	20	768	788
	Fitzroy (Q6)	Gladstone	17	627	644
	Darling Downs (Q8)	Brisbane	304	480	784

Table 2: Transport distances by REZ

3.2 Results

3.2.1 Islanded hydrogen

3.2.1.1 Levelised cost of hydrogen (LCOH)

The three scenarios for hydrogen storage based on two customer demand profiles are described below:

Scenario Name	Description	Hydrogen storage cost (AUD/kg)
Fixed – Tank	The plant design must deliver one tonne of hydrogen each hour to an end customer. This hydrogen could be provided directly from the electrolyser or could come from the hydrogen storage. Hydrogen tank storage (e.g. buried pipe storage or pressurised containers), which has a similar cost to linepack is available.	1428
Fixed – Salt Cavern	As for the Fixed – Tank case, hydrogen must be delivered to the customer at a fixed rate. Salt-cavern hydrogen storage is the available storage option, which is lower cost than hydrogen tanks.	50
Flexible	The plant design must deliver the same total amount of hydrogen over its lifetime as in the fixed case; however, the customer can accept hydrogen which is produced at a variable rate.	N/A

Table 3: Three scenarios for hydrogen modelling

The Fixed and Flexible cases represent two book ends of the potential demand profile. The difference between costs in the Fixed – Tank and Flexible case is large in the order of 2 AUD/kg at hybrid sites and in the order of 4 AUD/kg at solar PV only sites (Figure 15).

The absolute cost premium for providing fixed hydrogen deliveries to customers is relatively constant over time, as shown by Figure 15. Thus, its proportional impact on the LCOH (optimised cost of hydrogen) increases over time. This is because compressed hydrogen storage cost is 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 and labour. Meanwhile, solar PV, wind and electrolysis costs are expected to fall significantly; the AEMO ISP, in particular, shows the cost of solar PV falling by more than 40% in 2050 compared to 2030 (CSIRO, 2022A).

The implication of this finding is that hydrogen use cases that require consistent reliable deliveries of hydrogen (firmed hydrogen), such as transport will likely pay a significant price premium to farm gate hydrogen costs. This is likely to have a significant negative impact on the prospects of a wide range of hydrogen use cases. This finding provides further evidence supporting the classification of hydrogen use cases in the Hydrogen Ladder Version 5.0 (Liebreich Associates, 2023).

It is worth highlighting that many LCOH projections in the literature use farm gate hydrogen production estimates that don't include storage costs (CSIRO, 2018; Deloitte, 2023; McKinsey & Company, 2022), have modelling methodologies with coarse temporal resolution (ARUP, 2023); or make broad assumptions around required storage (Clean Energy Finance Corporation & Advisian, 2021). All these LCOH projections have the potential to materially underestimate the cost of firmed hydrogen.

Hydrogen storage costs are clearly a strong determinant of LCOH where a fixed demand profile must be met. One solution which may reduce these costs is to use salt caverns, rather than above ground tanks or buried pipelines. Alternative forms of hydrogen of storage are described in the Energy Storage Information Sheet, with salt caverns allowing hydrogen storage at a significantly reduced capital cost, in the order of 50 AUD/kg of stored hydrogen. Salt caverns bring down the LCOH ~30-50% compared to hydrogen tanks, with the largest cost reduction for a solar PV only renewable energy portfolio (Figure 15). The cost premium associated with supplying a fixed demand profile using salt cavern storage is around 0.8 AUD/kg – compared to between 3 and 5 AUD/kg if tank storage is used. Although hydrogen salt cavern storage could reduce the cost of firmed hydrogen, suitable geology is location specific and not present in many jurisdictions (Blanco & Faaij, 2018).

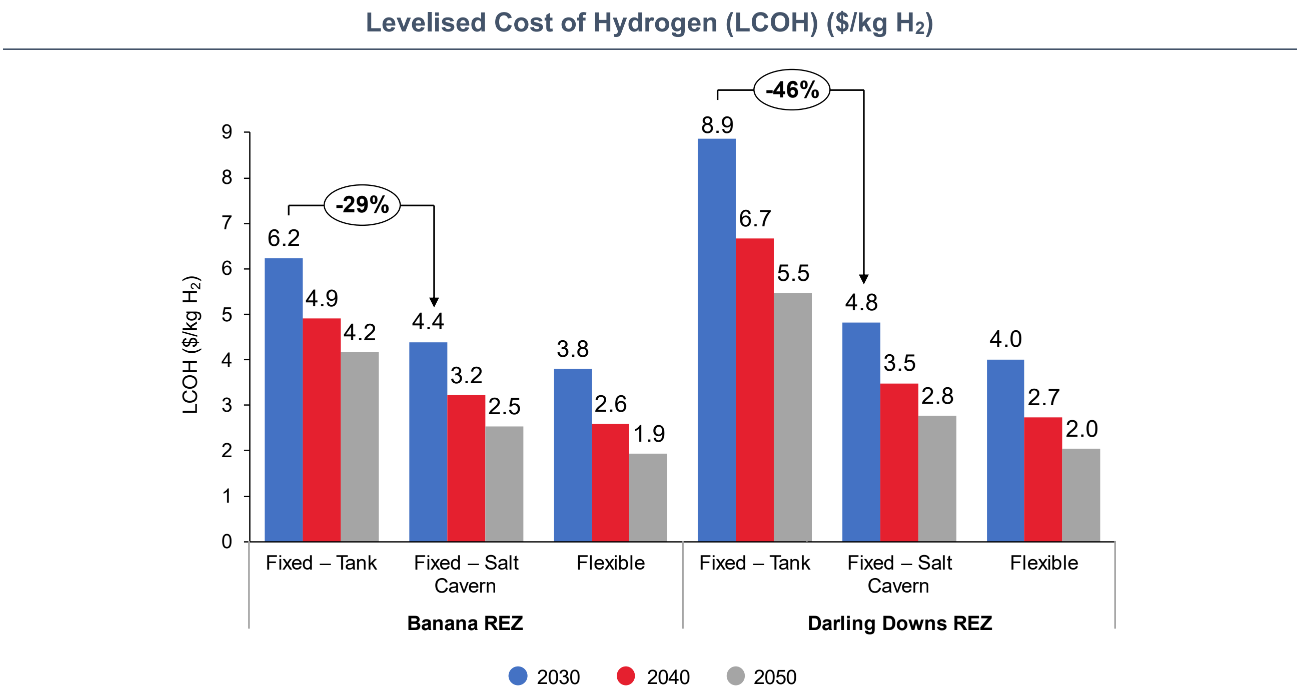


Figure 15: Levelised Cost of Hydrogen (LCOH) under different scenarios in different years in Banana and Darling Downs (solar PV only).

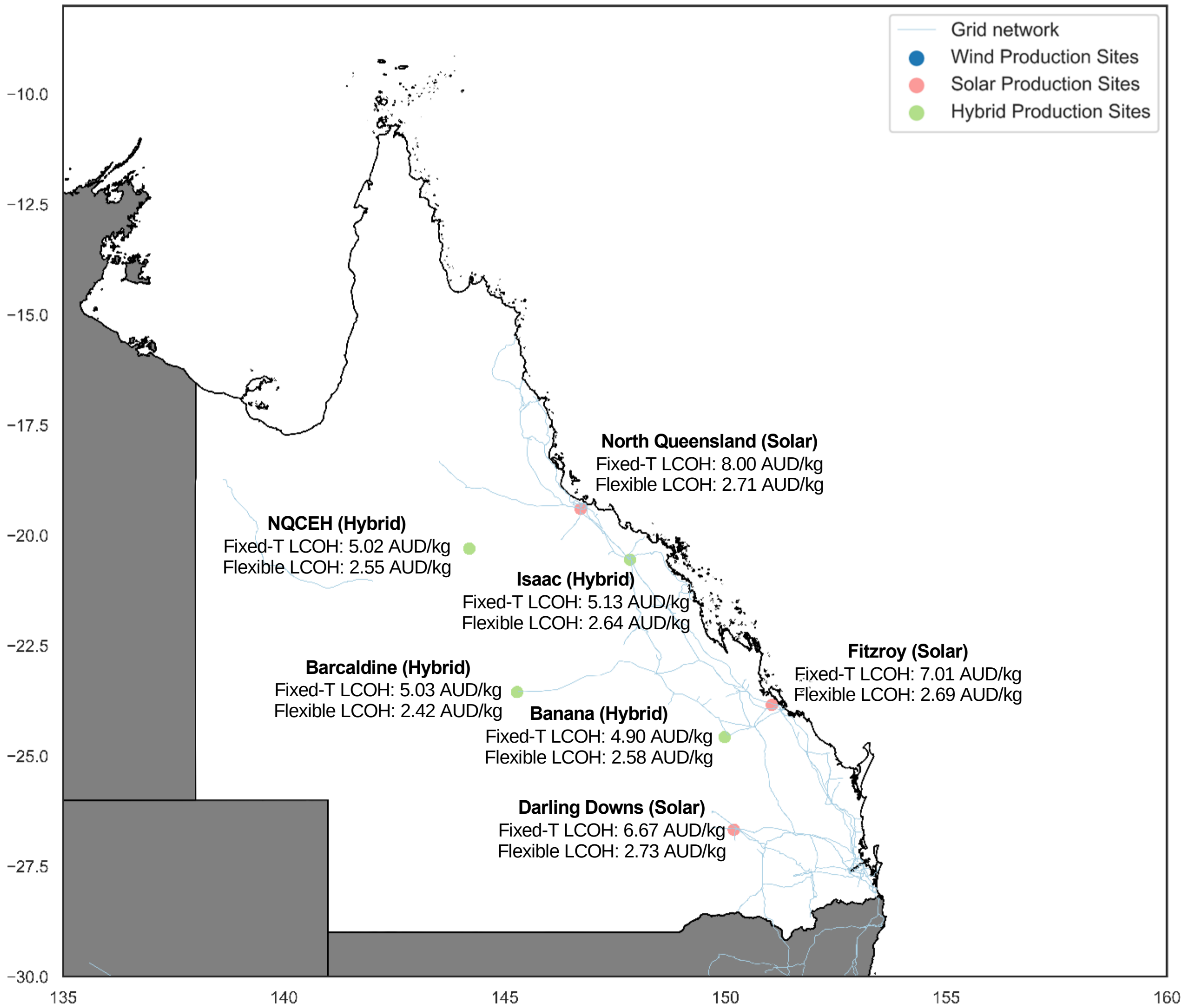


Figure 16: Map showing 2040 levelised costs of hydrogen ($/kg H_2) in the Fixed – Tank and Flexible scenarios

2030	Hybrid				Solar		
	NQCEH (Q2)	Isaac (Q4)	Barcaldine (Q5)	Banana (Q9)	North Qld (Q3)	Fitzroy (Q6)	Darling Downs (Q8)
Fixed – Tank	6.29	6.36	6.30	6.23	9.87	9.07	8.86
Fixed – Salt Cavern	4.12	4.41	4.18	4.39	4.76	4.67	4.81
Flexible	3.66	3.87	3.57	3.80	3.98	3.94	4.01

2040	Hybrid				Solar		
	NQCEH (Q2)	Isaac (Q4)	Barcaldine (Q5)	Banana (Q9)	North Qld (Q3)	Fitzroy (Q6)	Darling Downs (Q8)
Fixed – Tank	5.02	5.13	5.03	4.90	8.00	7.01	6.67
Fixed – Salt Cavern	3.02	3.26	3.09	3.23	3.43	3.36	3.48
Flexible	2.55	2.64	2.42	2.58	2.71	2.69	2.73

2050	Hybrid				Solar		
	NQCEH (Q2)	Isaac (Q4)	Barcaldine (Q5)	Banana (Q9)	North Qld (Q3)	Fitzroy (Q6)	Darling Downs (Q8)
Fixed – Tank	4.31	4.44	4.22	4.16	6.99	5.89	5.47
Fixed – Salt Cavern	2.35	2.59	2.44	2.54	2.69	2.66	2.77
Flexible	1.91	1.98	1.81	1.93	2.03	2.01	2.05

Table 4: Levelised cost of hydrogen (\$/kg H_2) under different scenarios in different years all REZ.

3.2.1.2 Optimal capacity build

Beyond the levelised cost of hydrogen, the changing demand profile also necessitates a significant adjustment in plant design. The model determines an optimal plant design based on producing on average one tonne H_2 per hour (8,760 tonnes H_2 pa) which is scaled by a factor of 20.55 to achieve 180,000 tonnes pa, the mass of hydrogen in one million tonnes of ammonia (NH_3).

The benefit of the increasing gap between the levelised cost of energy (LcoE) of solar PV (lower cost) and wind (higher cost) can overwhelm the benefit from higher electrolyser load factors that adding wind to the renewable portfolio may bring. A key driver of this result is also that electrolyser capex is projected to reduce to $1,028/kW by 2030 and $400/kW by 2050, with electrolyser efficiency also increasing. Where hydrogen demand is flexible, typically only solar PV is built. If there is a requirement for constant hydrogen deliveries to the customer, wind resources might be selected by the model when it is lower cost than increasing solar, electrolyser and storage capacities. This is not the case from 2040 onwards in some REZs where for the scenario incorporating salt cavern storge (Fixed – Salt Cavern) the model only selects solar PV (Figure 17). Battery is never selected to firm hydrogen production because it is significantly higher cost than hydrogen storage (For further analysis see Energy Storage Information Sheet).

Electrolyser capacity is only slightly lower than renewable capacity for the flexible deliveries scenario. Renewable generation capacity is oversized relative to electrolyser capacity in the scenarios where constant deliveries of hydrogen are required, with the overbuild highest in the Fixed – Tank case.

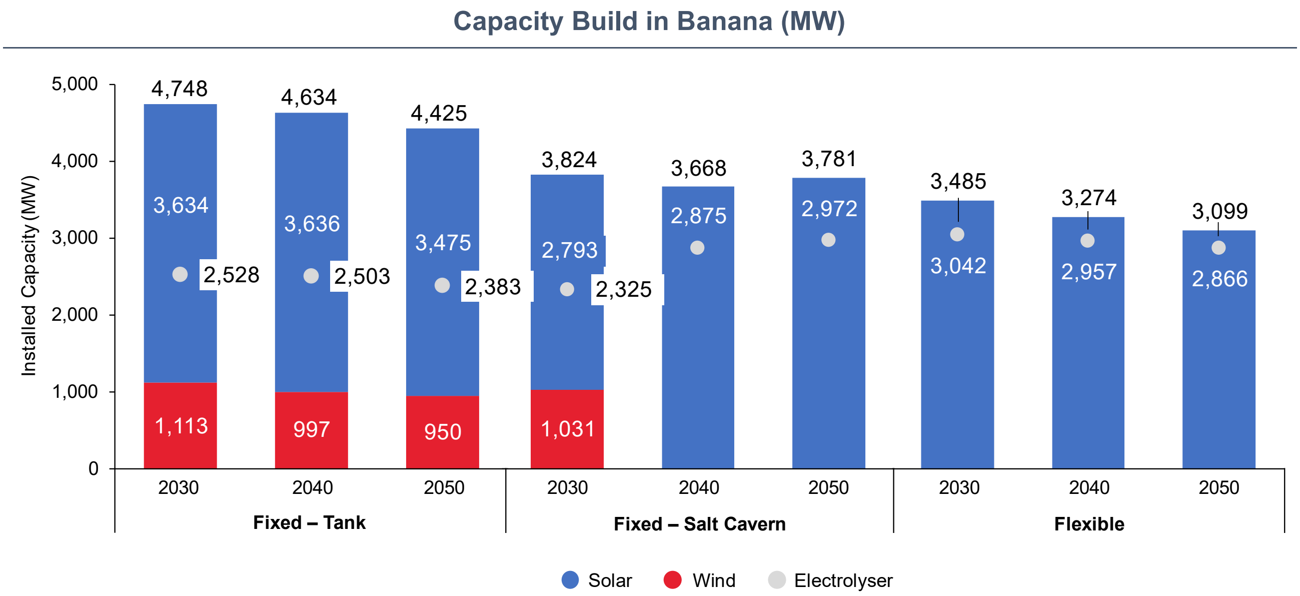


Figure 17: Hydrogen – capacity mix (MW) in different scenarios for different years for Banana

When only solar PV is allowed in the system, the Fixed – Tank case requires significant overbuild of electrolysers and the highest solar PV build of all scenarios (Figure 18). Due to the high cost of hydrogen tank storage, this oversizing of production (solar PV and electrolyser capacity) is cheaper than building more storage. In contrast, using lower cost salt cavern storage result in much less renewable overbuild, with the solar PV build for Fixed – Salt Cavern only around ~10% higher than the flexible case.

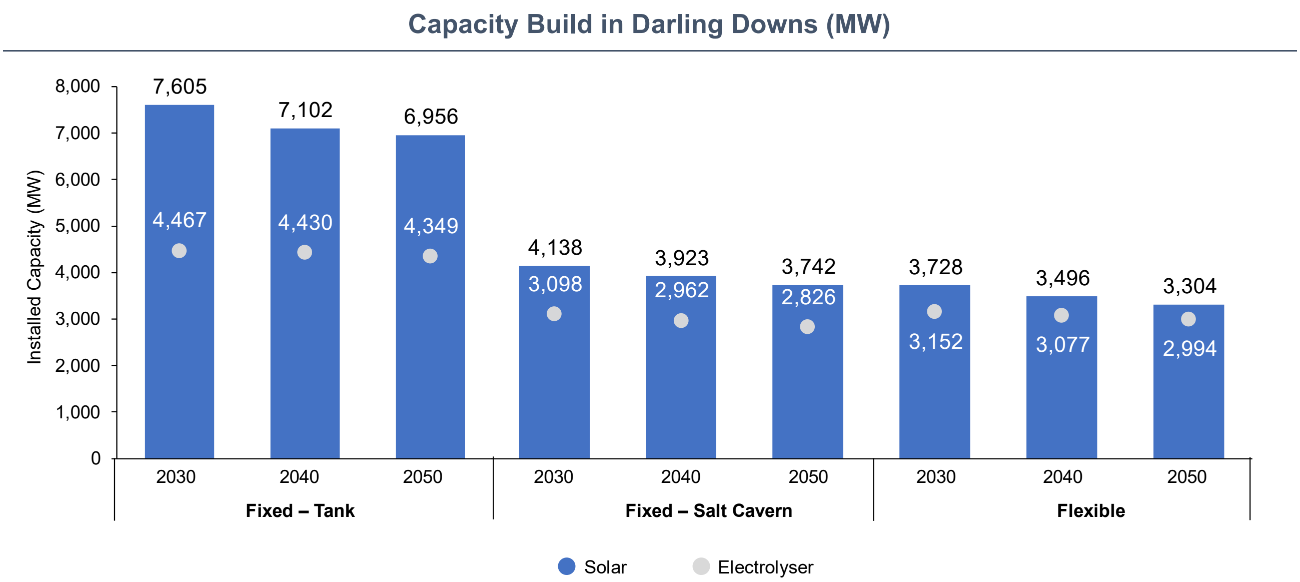


Figure 18: Hydrogen – capacity build in different scenarios for different years for Banana

			Levelised cost of hydrogen (LCOH) ($/kg H_2)			Solar portfolio weighting			Capacity factor of curtailed renewable energy			Electrolyser load factor		
			Fixed – Tank	Fixed – Salt Cavern	Flexible	Fixed – Tank	Fixed – Salt Cavern	Flexible	Fixed – Tank	Fixed – Salt Cavern	Flexible	Fixed – Tank	Fixed – Salt Cavern	Flexible
2030	**Hybrid**	NQCEH (Q2)	6.29	4.12	3.66	82%	72%	58%	7%	2%	1%	36%	44%	53%
		Isaac (Q4)	6.36	4.41	3.87	69%	64%	100%	7%	2%	0%	42%	48%	33%
		Barcaldine (Q5)	6.30	4.18	3.57	65%	63%	100%	8%	2%	1%	46%	49%	34%
		Banana (Q9)	6.23	4.39	3.80	77%	73%	100%	8%	2%	1%	40%	43%	33%
	Solar	North Qld (Q3)	9.87	4.76	3.98	100%	100%	100%	11%	3%	1%	24%	31%	31%
		Fitzroy (Q6)	9.07	4.67	3.94	100%	100%	100%	13%	3%	1%	22%	33%	32%
		Darling Downs (Q8)	8.86	4.81	4.01	100%	100%	100%	15%	3%	1%	23%	33%	32%
2040	**Hybrid**	NQCEH (Q2)	5.02	3.02	2.55	83%	88%	100%	8%	3%	1%	37%	35%	32%
		Isaac (Q4)	5.13	3.26	2.64	69%	91%	100%	7%	3%	1%	41%	36%	32%
		Barcaldine (Q5)	5.03	3.09	2.42	83%	100%	100%	10%	3%	1%	33%	35%	34%
		Banana (Q9)	4.90	3.23	2.58	78%	100%	100%	8%	3%	1%	38%	33%	32%
	Solar	North Qld (Q2)	8.00	3.43	2.71	100%	100%	100%	11%	2%	1%	23%	31%	31%
		Fitzroy (Q6)	7.01	3.36	2.69	100%	100%	100%	13%	3%	1%	21%	33%	32%
		Darling Downs (Q2)	6.67	3.48	2.73	100%	100%	100%	14%	3%	1%	22%	32%	31%
2050	**Hybrid**	NQCEH (Q2)	4.31	2.35	1.91	85%	93%	100%	9%	4%	0%	34%	33%	32%
		Isaac (Q4)	4.44	2.59	1.98	71%	100%	100%	7%	5%	1%	40%	31%	32%
		Barcaldine (Q5)	4.22	2.44	1.81	82%	100%	100%	12%	5%	1%	31%	32%	33%
		Banana (Q9)	4.16	2.54	1.93	79%	100%	100%	8%	5%	1%	38%	31%	32%
	Solar	North Qld (Q2)	6.99	2.69	2.03	100%	100%	100%	11%	4%	0%	23%	28%	30%
		Fitzroy (Q6)	5.89	2.66	2.01	100%	100%	100%	13%	5%	1%	21%	30%	31%
		Darling Downs (Q2)	5.47	2.77	2.05	100%	100%	100%	15%	3%	1%	21%	32%	30%

Table 5: Hydrogen – LCOH and operating metrics summary for all scenarios, years and REZ

3.2.1.3 Cost breakdown

Plant cost stacks are shown in Figure 19 on an LCOH (\$/kg H_2) basis and Figure 20 on a capex basis (\$m). As electrolysers experience the largest reduction in capital cost per MW across the modelling period the proportion of the cost stack that they represent reduces the most of any value chain element. Renewable energy also experiences capital cost reductions, with cost declines larger for solar than wind. As no cost reductions are assumed for storage, it becomes an increasing proportion of the cost stack for Fixed – Tank and Fixed – Salt Cavern.

In relation to the scenarios, broadly speaking, the plant design in the Fixed – Salt Cavern case largely follows the plant design in the Flexible case. In order to meet customer demand on an hour-by-hour basis the key three plant design differences for the Fixed – Salt Cavern case are (i) a higher renewable build, (ii) the addition of low-cost storage, and (iii) the use of wind in 2030. The change from a wind and solar portfolio in 2030 to solar only in 2040 for Fixed-Salt Cavern results in a hydrogen storage requirement.

By contrast, the Fixed – Tank case which uses hydrogen tank storage is entirely differently designed from the Flexible case: there is a materially higher renewable energy build incorporating wind and lower electrolyser capacity, reducing the need for storage. Even with this smaller storage, the high cost of tank storage means the total contribution of storage to the cost is still large (Figure 20).

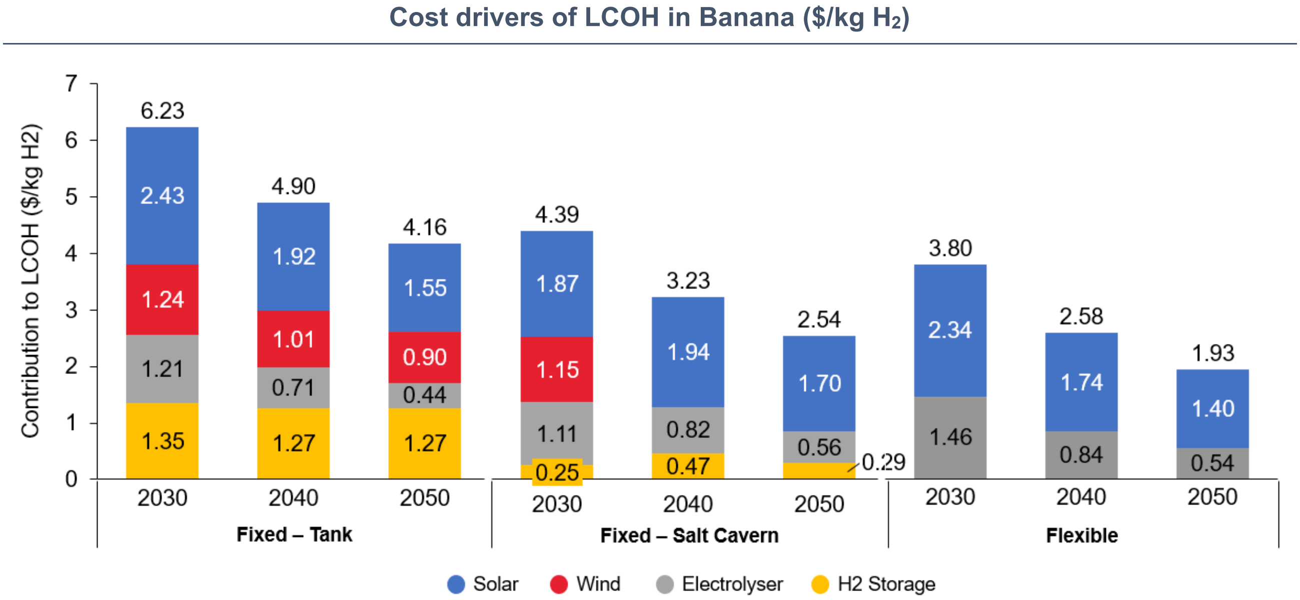


Figure 19: Hydrogen – Cost drivers of LCOH for different scenarios for different years for Banana

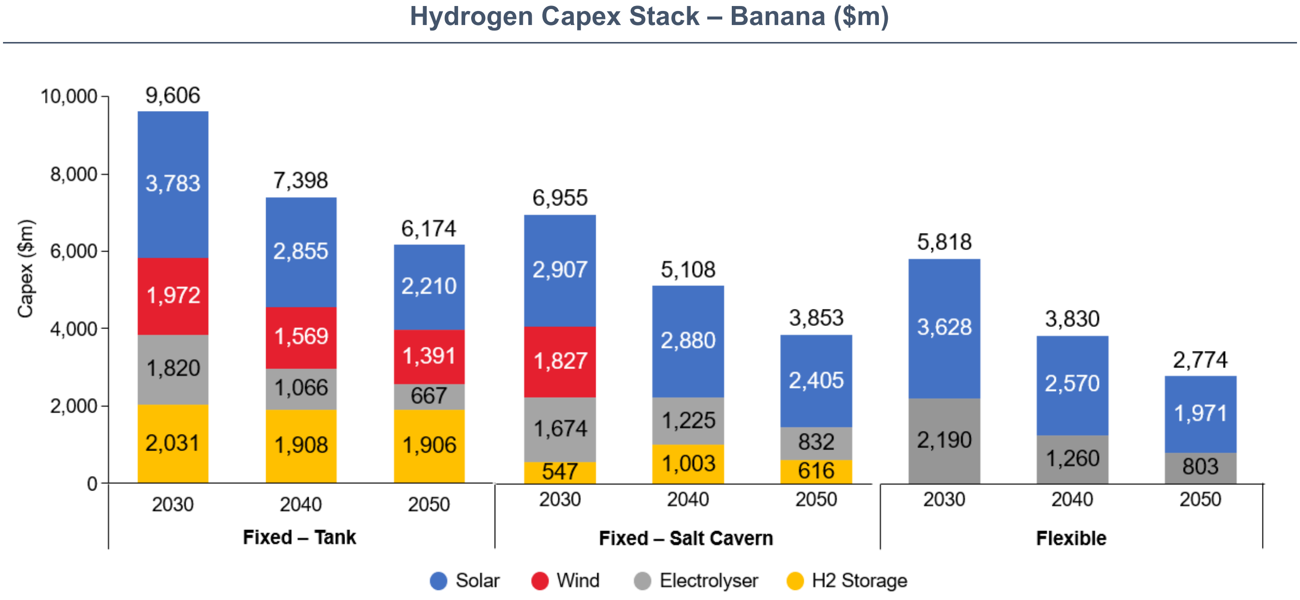


Figure 20: Hydrogen – capex stack for different scenarios for different years for Banana

3.2.1.4 Seasonal plant behaviour

In the Fixed – Tank case, the electrolyser's load factor shows limited variation throughout the year as the plant is required to deliver a consistent output and storage does not play a meaningful role in managing seasonality. Wind capacity factor is strongest in winter when solar output is at its weakest. In contrast, solar has the highest curtailment in summer, with curtailment reaching as high as a third of output (Figure 21). Hydrogen tanks cycle rapidly and at certain times can nearly empty within a week. Tank storage cycles (fills and empties) multiple times a year and there is no clear seasonal pattern (Figure 22).

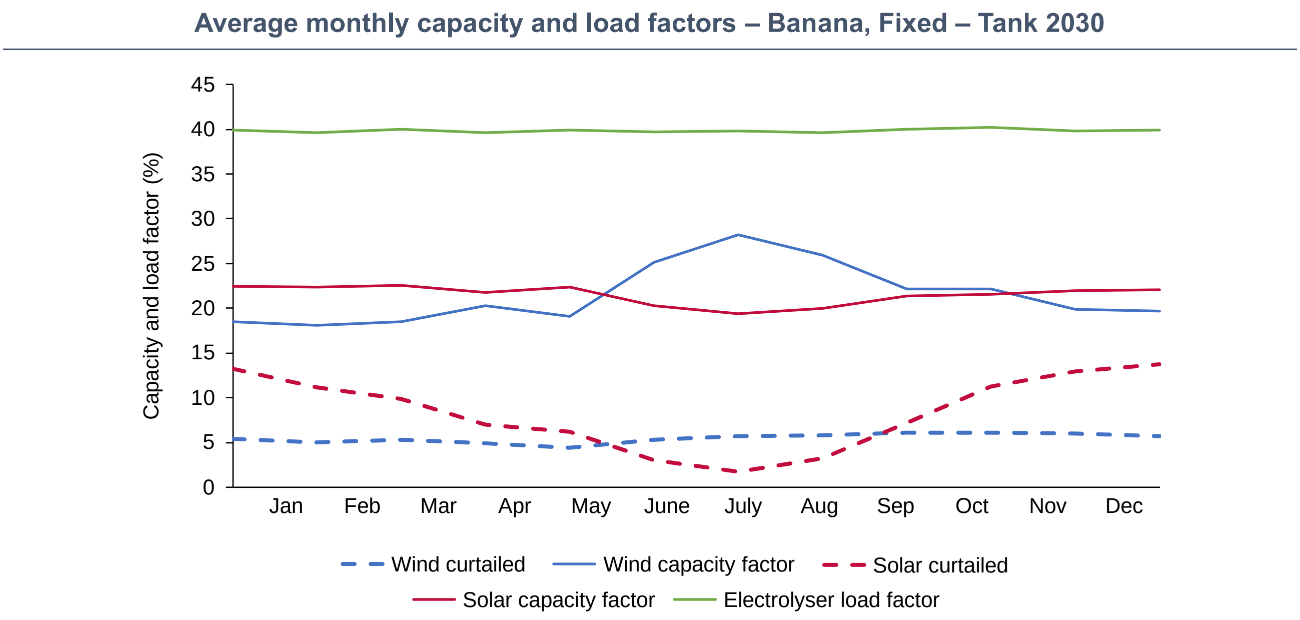


Figure 21: Hydrogen – Average monthly capacity factors and curtailment in Banana (Fixed – Tank) over 10 years (2030-2040)

Hydrogen Tank Storage Level 1 year – Banana, Fixed – Tank 2030

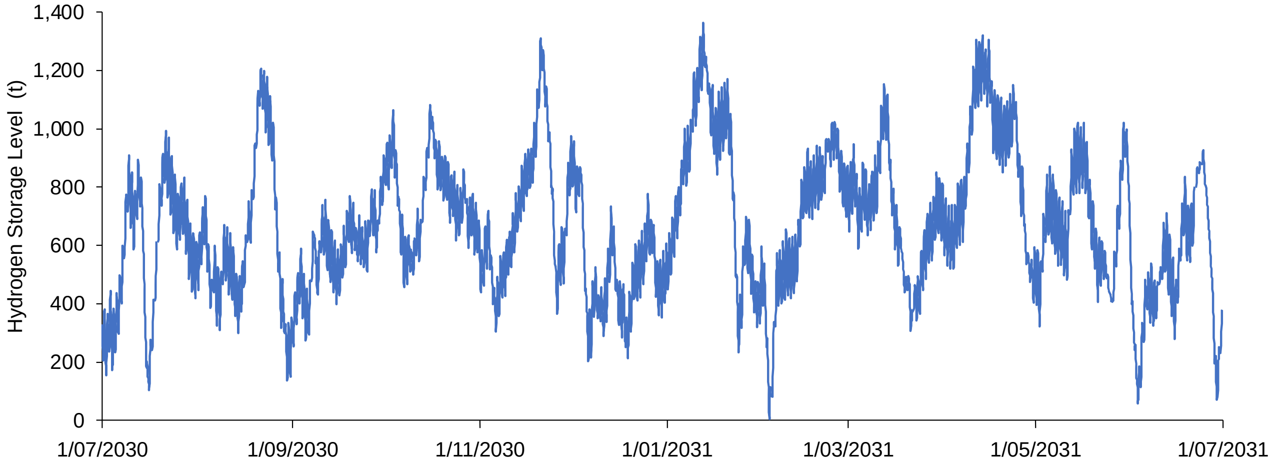


Figure 22: Hydrogen – level of hydrogen storage in hydrogen tanks over one year at Banana (Fixed – Tank) 2030

In the Fixed – Salt Cavern case, the electrolyser and storage's behaviours are much more seasonal. The electrolyser's load factors are lowest in winter months when solar output is weak while this is partially compensated by higher wind output. Renewable curtailment is negligible throughout the whole year (Figure 23). The salt cavern storage level displays a clear seasonal pattern with the salt cavern filling over summer and emptying over winter (Figure 24). There are also sub-annual variations due to fluctuations in renewable generation which can be seen in both Fixed cases.

Average monthly capacity and load factors – Banana, Fixed – Salt Cavern 2030

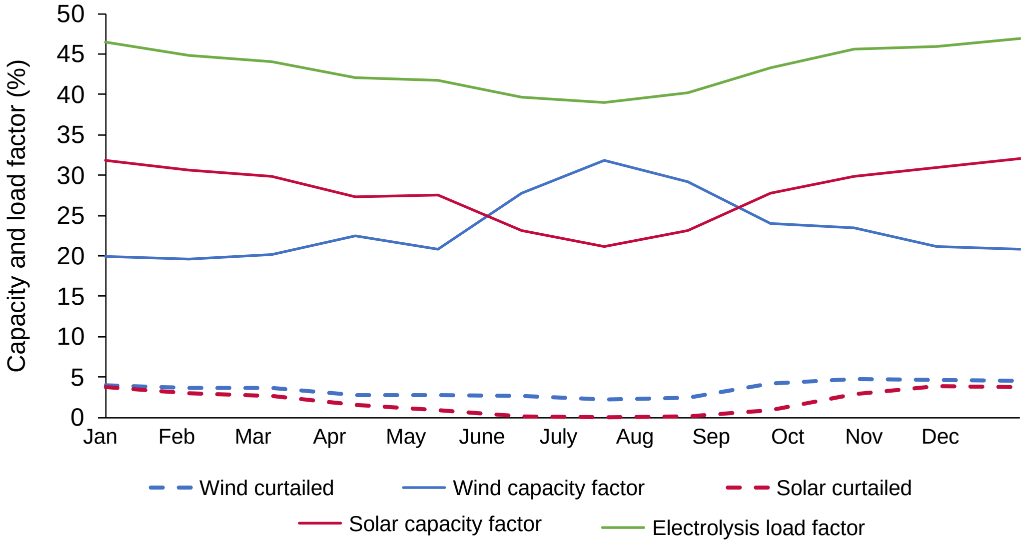


Figure 23: Hydrogen – average monthly capacity factors in Banana (Fixed – Salt Cavern) over 10 years (2030-2040)

Salt Cavern Hydrogen Storage Level 10 years – Banana, Fixed – Salt Cavern 2030

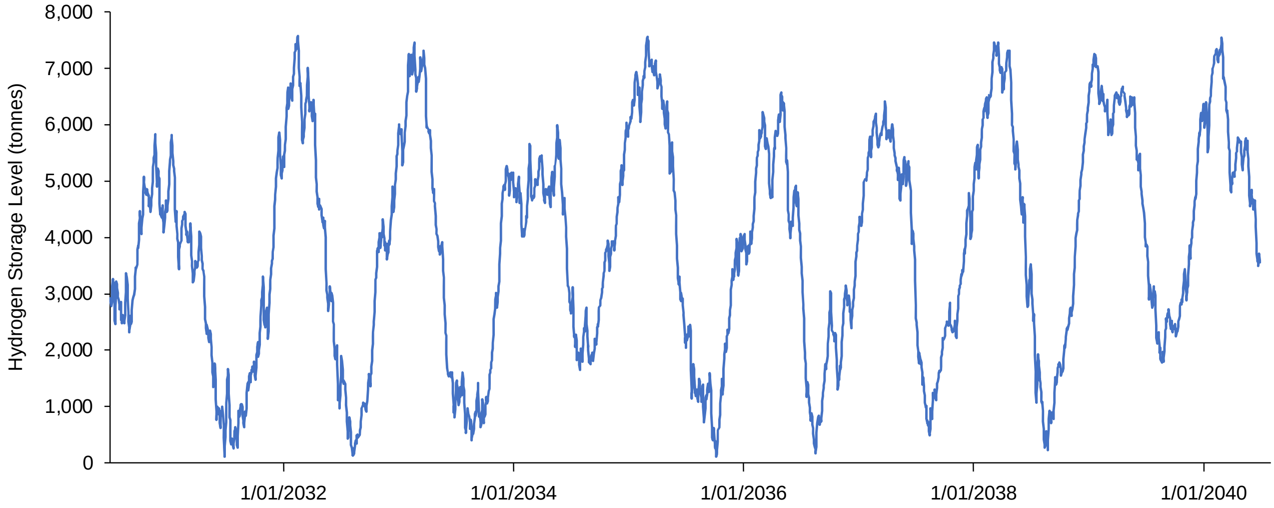


Figure 24: Hydrogen – level of hydrogen storage in Fixed – Salt Cavern case over 10 years (2030-2040) at Banana

In the Flexible case, the electrolyser's load factor tracks solar output closely and the seasonal pattern is even more distinct (Figure 25).

Average monthly capacity factors in Banana- Flexible 2030

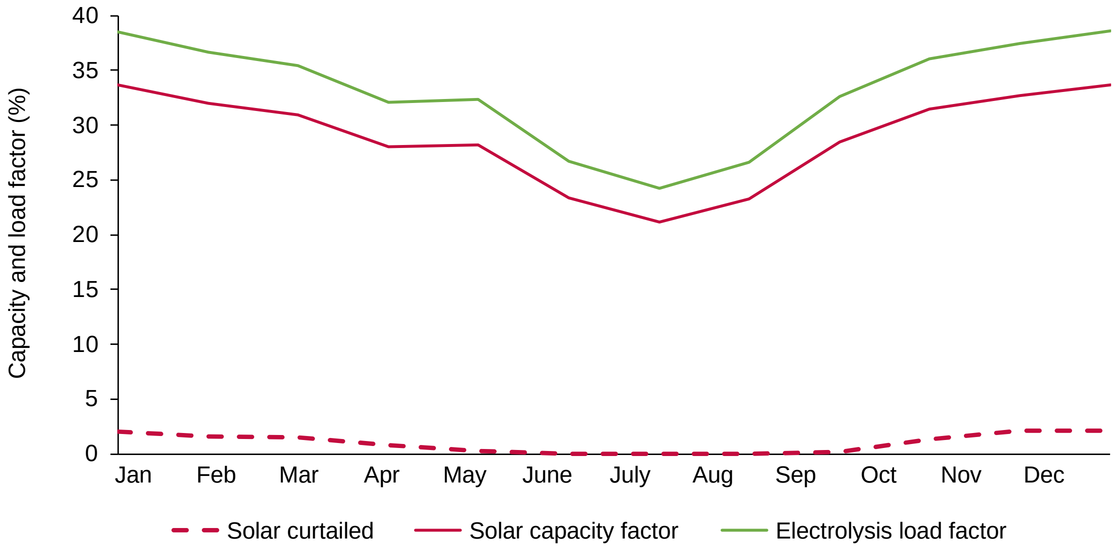


Figure 25: Hydrogen – average monthly capacity factors and curtailment in Banana (Flexible case) over 10 years (2030-2040)

3.2.1.5 Limitations and constraints

3.2.1.5.1 Input assumptions – renewable energy

GenCost 2022-23 Final Report (CSIRO, 2023) was released in July 2023 and shows the projected cost gap between wind and solar has increased materially versus GenCost 2022-23: Consultation Draft (2022) released in December 2022, which are key modelling inputs for this research (CSIRO, 2022A; Australian Energy Market Operator, 2022d). Feedback from various industry sources is that capital cost estimates for a number of wind projects currently under development are significantly higher than those in the GenCost 2022-23 Final Report (CSIRO, 2023A).

Although findings around seasonal generation profiles and correlation benefits are supported by different weather reanalysis data sets and wind project site measurements, there is uncertainty around the magnitude of patterns, including due to a lack of generation data from operating wind farms. Refer to Queensland Renewable Energy Information Sheet for further detail.

3.2.1.5.2 Input assumptions – electrolysers

Feedback from some industry sources indicates that capital cost projections may be optimistic as a reasonable portion of capital cost relates to balance-of-plant, which is a common, mature technology that may not experience material cost reductions (Martin, 2022). Refer to Electrolyser Information Sheet for further detail.

The aim of this study is to explore the key drivers of future value chain cost competitiveness, particularly location, renewable mix, storage and transport infrastructure. No explicit sensitivities are undertaken for electrolyser capex, which is projected to decrease to $1,028/kW in 2030 to $400/kW in 2050, contributing to declining LCOH. Higher electrolyser capex is likely to result in a higher renewable portfolio weighting for wind than modeled, however this could be countered by using more recent higher wind capital cost projections (Refer to 3.2.1.5.1).

Electrolysers are assumed to operate at nameplate efficiency, with any potential benefits from higher efficiency at part-load operation or temporarily operating above nameplate capacity not captured (Siemens, 2021).

3.2.1.5.3 Land requirements

An explicit assessment of land requirements is not undertaken, though details on renewable energy project land requirements are contained in the Renewable Energy Information Sheet. Renewable resource constraints for wind are considered by only allowing wind in REZ where there is wind resources that are surplus to domestic decarbonisation needs (See Section 2.3.1 and Section 3.1.3).

3.2.1.5.4 Water infrastructure

Modelling of specific water infrastructure, including pipelines is not included. Desalination is one option for reliable water supply, which typically adds between 1 and 2 cents to the cost of hydrogen per kilogram. Refer to Electrolyser Information Sheet for further details.

3.2.1.5.5 Geological hydrogen storage – location and cycling constraints

Geological hydrogen storage is location specific and the salt deposits of the Adavale Basin in southwest Queensland have geological properties that are favourable for the development of hydrogen salt cavern storage. Although only six wells have intersected the Boree Salt, a recent model of the salt developed by Geoscience Australia using seismic data suggests that the shallowest depth is approximately 1200m. These characteristics suggest that the Boree Salt could be suitable for salt cavern construction.

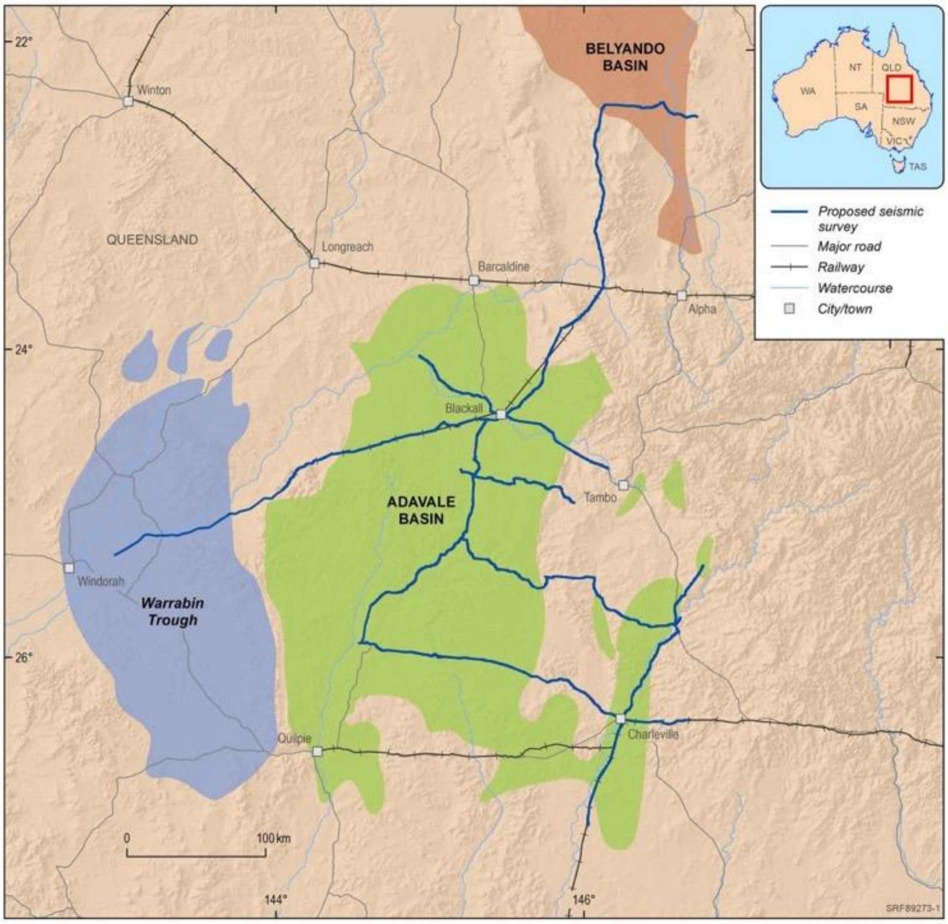


Figure 26: Adavale Basin map – Geoscience Australia (2023) Seismic acquisition survey

Salt caverns are used in the United States and United Kingdom for grey hydrogen storage, although they are not typically required to fill and empty with high frequency. More frequent cycling is expected to be required for green hydrogen production in order to convert variable green hydrogen production into fixed hydrogen deliveries to customers.

In this study, in order to reflect salt cavern pressure change constraints different maximum hydrogen storage injection and withdrawal rates were imposed across a number of optimisations. Based on interpreting these modelling results, cycling constraints may impact LCOH in isolated cases, but not materially. For more detailed analysis, see Appendix (Section.6.1 Hydrogen - Salt cavern hydrogen storage cycling constraints)

3.2.1.5.6 Model operation – single hydrogen storage type

The model does not allow for different hydrogen storages to be selected in an optimisation and LCOH could potentially be lowered if the model allowed this. Hydrogen tank storage could potentially be used to manage potential hydrogen salt cavern cycling constraints. There is also the potential that LCOH could be further reduced by introducing other forms of geologic hydrogen storage into a hydrogen storage portfolio, though additional cost reductions for the case where salt caverns are used is limited by the small contribution salt caverns make to LCOH. It is noted however that other potential forms of geologic hydrogen storage, such as depleted gas fields, have a range of technical issues (for further detail, please refer to Hydrogen Storage Information Sheet).

3.2.2 Islanded ammonia

3.2.2.1 Levelised cost of ammonia (LCOA)

The Haber Bosch (HB) process, the main industrial process for producing ammonia, is a high temperature, high pressure, catalytic synthesis process. The Haber Bosch process has high partial flexibility enabling the hydrogen production rate to be more flexible, while ammonia storage is a fraction of the cost of non-geologic hydrogen storage such as tanks (please refer to section 4.1.2 and the Storage Information Sheet for details). The ammonia plant is assumed to be able to turn down to 30% of nameplate capacity, for both hydrogen throughput and electricity requirement.

The same cases are considered for ammonia as for hydrogen: Fixed – Tank, Fixed – Salt Cavern and Flexible.

Case	Hydrogen storage	Ammonia Storage
Fixed – Tank	Tanks	Tanks
Fixed – Salt Cavern	Salt Cavern	Tanks
Flexible	Tanks	None

The cost of ammonia storage tanks is not well described in the literature, and potential values range from 1500 AUD/t to 6000 AUD/t NH_3. A value of 3000 AUD/t is assumed in this study.

The cost differential between the Fixed – Tank and Flexible case for ammonia is around 3% (Figure 27), which contrasts sharply with the ~$2/kg H_2 differential for hydrogen. This is for two reasons:

- The cost of ammonia storage is much lower than non-geologic hydrogen storage (tanks) and can act as a buffer between variable ammonia production and fixed ammonia demand.
- Even in the Flexible case, there is a small continuous demand for hydrogen because the ammonia plant cannot turn down to zero (minimum load 30%) without completely shutting down for an extended period.

The Fixed – Salt Cavern case has a levelised cost of ammonia (LCOA) that is 6% lower than the Fixed – Tank case for Banana for 2030, which is a significantly lower cost differential than for hydrogen. There is still a benefit from low-cost hydrogen storage, but this benefit is limited due to the availability of low-cost ammonia storage.

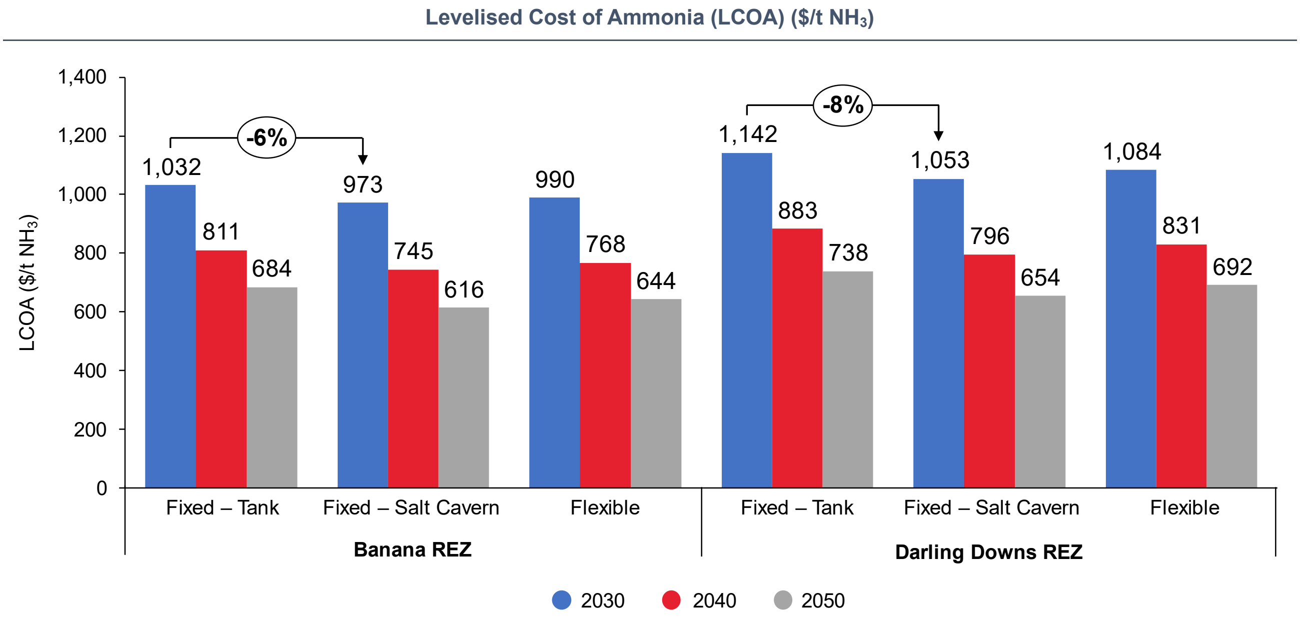


Figure 27: Levelised Cost of Ammonia (LCOA) in different scenarios in different year in Banana and Darling Downs (solar PV only).

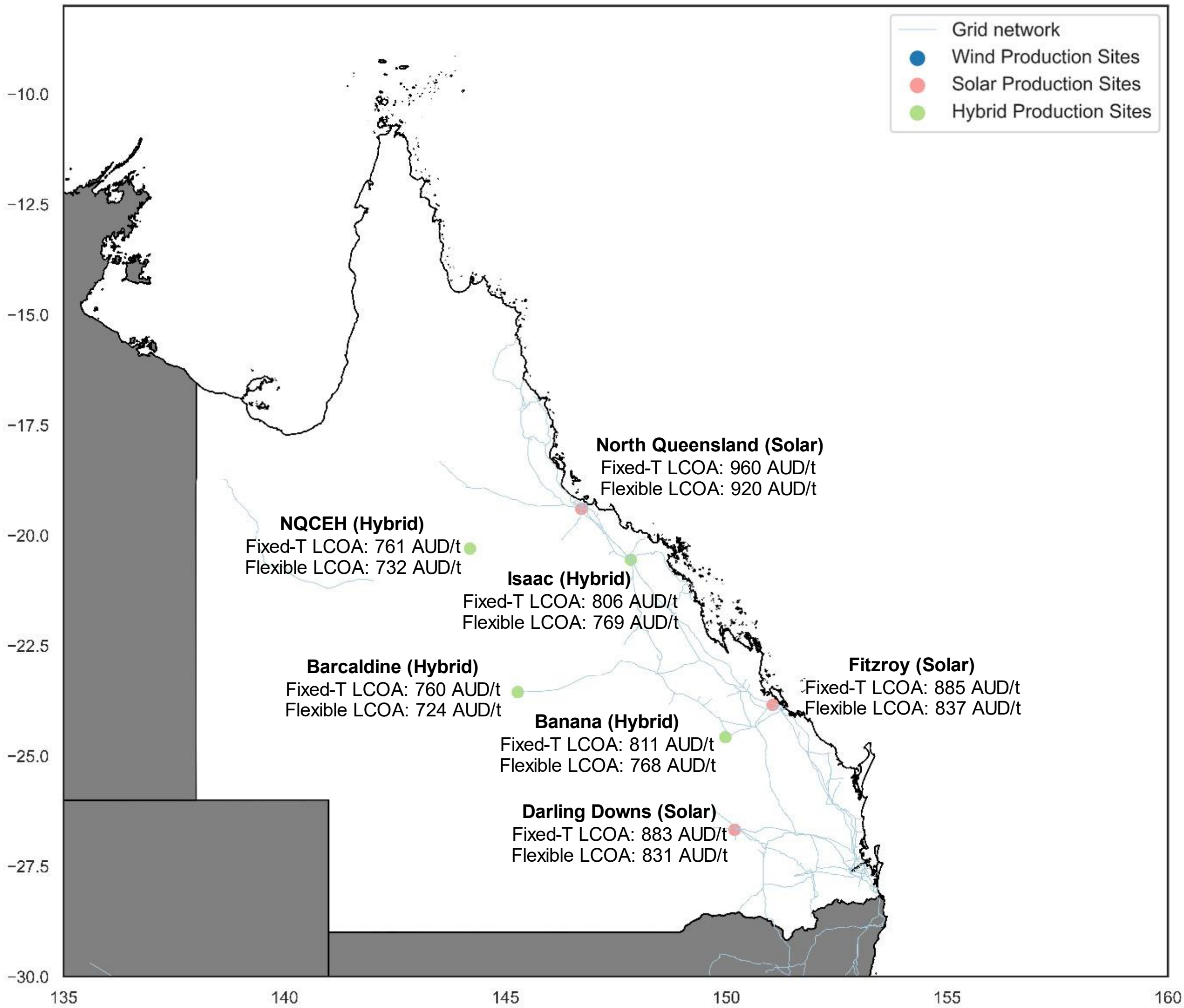


Figure 28: Map showing 2040 levelised costs of ammonia ($/tonne NH_3) in the Fixed and flexible scenarios

2030	Hybrid				Solar		
	NQCEH (Q2)	Isaac (Q4)	Barcaldine (Q5)	Banana (Q9)	North Qld (Q3)	Fitzroy (Q6)	Darling Downs (Q8)
Fixed – Tank	958	1,013	965	1,032	1,220	1,139	1,142
Fixed – Salt Cavern	906	963	915	973	1,037	1,032	1,053
Flexible	927	977	931	990	1,174	1,087	1,084

2040	Hybrid				Solar		
	NQCEH (Q2)	Isaac (Q4)	Barcaldine (Q5)	Banana (Q9)	North Qld (Q3)	Fitzroy (Q6)	Darling Downs (Q8)
Fixed – Tank	761	806	760	811	960	885	883
Fixed – Salt Cavern	707	750	700	745	779	779	796
Flexible	732	769	724	768	920	837	831

2050	Hybrid				Solar		
	NQCEH (Q2)	Isaac (Q4)	Barcaldine (Q5)	Banana (Q9)	North Qld (Q3)	Fitzroy (Q6)	Darling Downs (Q8)
Fixed – Tank	646	687	641	684	817	744	738
Fixed – Salt Cavern	591	625	581	616	640	640	654
Flexible	618	650	606	644	781	699	692

Table 6: Levelised cost of ammonia ($/t NH_3) under different scenarios in different years all REZ.

3.2.2.2 Optimal capacity build

Because of the continuous requirement for hydrogen feedstock and electricity supply for the ammonia plant (turndown to 30% of nameplate capacity assumed), all of the ammonia production cases incorporate wind generation where available, even if they can produce ammonia at a flexible rate (Figure 29). In addition, a small amount of battery storage is built (~100MW, 400MWh) to ensure that minimum power requirements for the ammonia plant are not breached. Battery storage is required when there is insufficient wind generation to keep the ammonia plant running overnight. Hydrogen fuel cells are not selected by the model due to their high cost. Compared to hydrogen the difference in build between the three scenarios is limited. Fixed – Salt Cavern has the highest solar portfolio weighing of all scenarios.

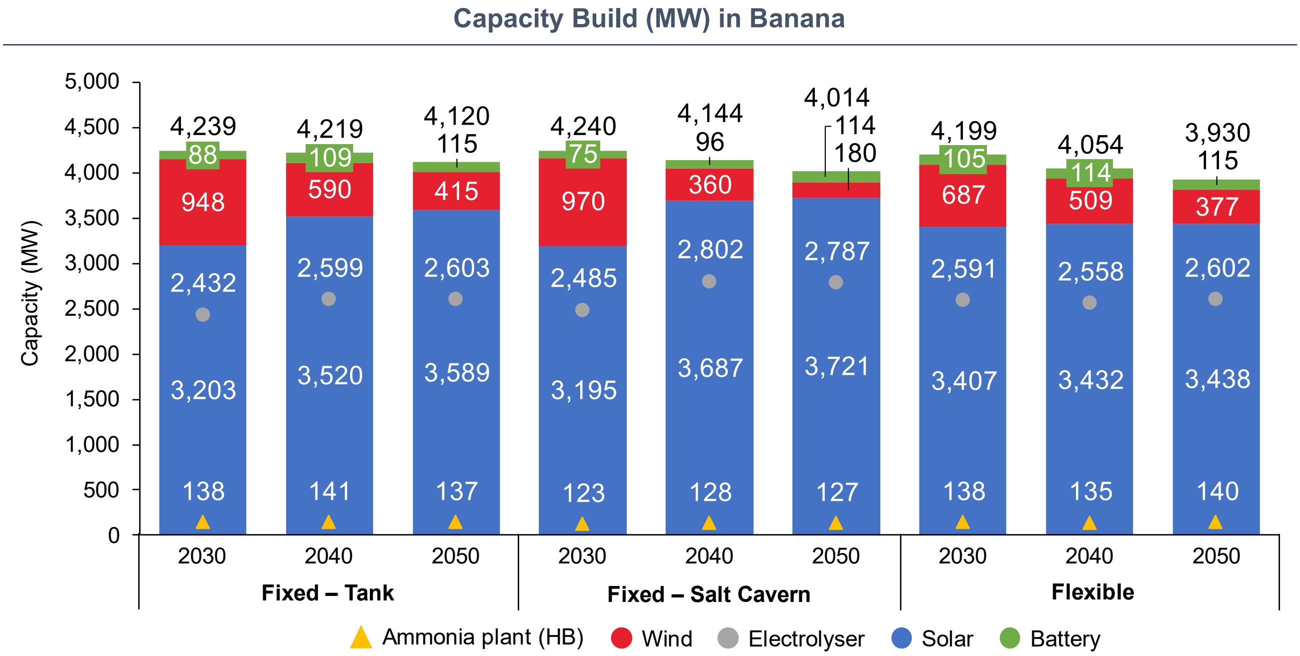


Figure 29: Ammonia – capacity build (MW) in different scenarios for different years for Banana

Due to the lower cost of ammonia storage and the ammonia plant's high partial flexibility, ammonia storage dominates the installed capacity in GWh for the Fixed – Tank case (but not the project cost). More storage is required in REZs where only solar is allowed (Darling Downs, Fitzroy and North Queensland) to smooth out greater variability in production. No ammonia storage is required for the Flexible scenario. Battery storage is immaterial on an energy basis (GWh) and is not shown.

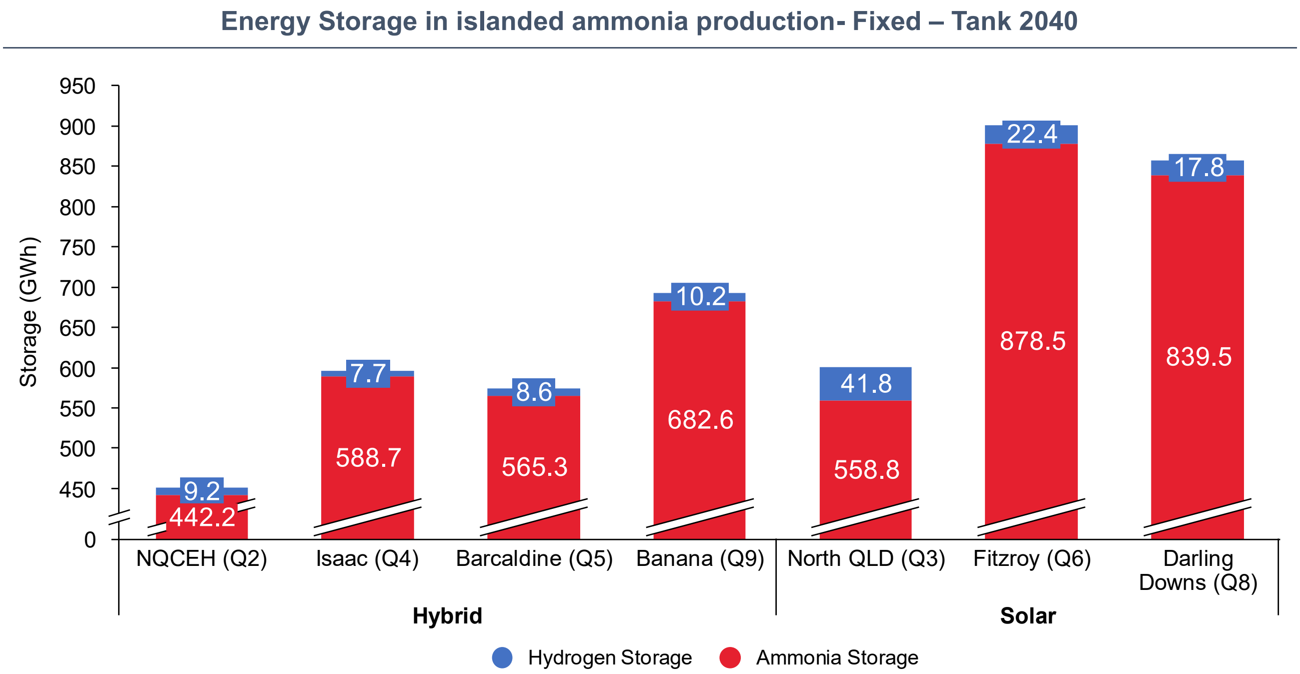


Figure 30: Ammonia – Energy storage in islanded ammonia production, Fixed – Tank 2040

Detailed analysis regarding hydrogen and ammonia storage builds and the impact of different capital costs for the Fixed – Salt Cavern case are contained in the Appendix (Section 6.3 Ammonia – Energy storage capex).

			Levelised cost of ammonia (LCOA)			Solar portfolio weighting			Percentage or renewable energy curtailed			Electrolyser load factor		
			Fixed – Tank	Fixed - Salt Cavern	Flexible	Fixed – Tank	Fixed – Salt Cavern	Flexible	Fixed – Tank	Fixed – Salt Cavern	Flexible	Fixed – Tank	Fixed – Salt Cavern	Flexible
2030	**Hybrid**	NQCEH (Q2)	958	906	927	71%	67%	64%	6%	4%	5%	46%	48%	50%
		Isaac (Q4)	1,013	963	977	70%	73%	70%	6%	5%	5%	45%	43%	45%
		Barcaldine (Q5)	965	915	931	71%	79%	76%	6%	6%	5%	46%	41%	43%
		Banana (Q9)	1,032	973	990	77%	77%	83%	6%	7%	6%	41%	41%	39%
	Solar	North Qld (Q3)	1,220	1,037	1,174	100%	100%	100%	12%	9%	9%	32%	31%	33%
		Fitzroy (Q6)	1,139	1,032	1,087	100%	100%	100%	11%	8%	9%	33%	33%	34%
		Darling Downs (Q8)	1,142	1,053	1,084	100%	100%	100%	11%	9%	8%	33%	33%	33%
2040	**Hybrid**	NQCEH (Q2)	761	707	732	77%	84%	80%	7%	6%	5%	42%	38%	40%
		Isaac (Q4)	806	750	769	76%	84%	78%	7%	7%	6%	42%	37%	41%
		Barcaldine (Q5)	760	700	724	87%	93%	90%	9%	7%	6%	38%	36%	37%
		Banana (Q9)	811	745	768	86%	91%	87%	10%	9%	6%	37%	34%	37%
	Solar	North Qld (Q2)	960	779	920	100%	100%	100%	13%	9%	10%	31%	31%	32%
		Fitzroy (Q6)	885	779	837	100%	100%	100%	12%	9%	10%	33%	32%	33%
		Darling Downs (Q2)	883	796	831	100%	100%	100%	13%	11%	9%	32%	31%	32%
2050	**Hybrid**	NQCEH (Q2)	646	591	618	84%	88%	85%	8%	6%	6%	39%	36%	38%
		Isaac (Q4)	687	625	650	81%	93%	85%	9%	8%	7%	39%	33%	37%
		Barcaldine (Q5)	641	581	606	93%	96%	94%	11%	8%	7%	36%	35%	36%
		Banana (Q9)	684	616	644	90%	95%	90%	12%	10%	7%	35%	33%	36%
	Solar	North Qld (Q2)	817	640	781	100%	100%	100%	16%	9%	12%	31%	30%	31%
		Fitzroy (Q6)	744	640	699	100%	100%	100%	16%	9%	12%	31%	31%	32%
		Darling Downs (Q2)	738	654	692	100%	100%	100%	15%	12%	10%	31%	31%	32%

Table 7: Ammonia– LCOA and operating metrics summary for all scenarios, years and REZ page 1

			Ammonia plant (Haber-Bosch) load factor			Ammonia plant (HB) capacity / renewable energy capacity			Hydrogen storage (GWh)			Ammonia storage (GWh)		
			Fixed – Tank	Fixed – Salt Cavern	Flexible	Fixed – Tank	Fixed – Salt Cavern	Flexible	Fixed – Tank	Fixed – Salt Cavern	Flexible	Fixed – Tank	Fixed – Salt Cavern	Flexible
2030	**Hybrid**	NQCEH (Q2)	84%	90%	84%	4%	3%	4%	9.2	52.9	9.7	442	464	0
		Isaac (Q4)	81%	90%	81%	3%	3%	4%	7.7	47.4	7.8	589	483	0
		Barcaldine (Q5)	85%	91%	83%	4%	3%	4%	8.6	62.1	9.0	565	442	0
		Banana (Q9)	83%	93%	81%	3%	3%	3%	10.2	57.8	11.0	683	445	0
	Solar	North Qld (Q3)	89%	89%	87%	3%	3%	3%	41.8	81.8	43.8	559	519	0
		Fitzroy (Q6)	87%	89%	85%	3%	3%	3%	22.4	75.7	24.1	878	788	0
		Darling Downs (Q8)	82%	87%	80%	3%	3%	3%	17.8	84.2	18.9	839	760	0
2040	**Hybrid**	NQCEH (Q2)	85%	90%	84%	4%	3%	4%	8.8	71.2	9.1	406	312	0
		Isaac (Q4)	83%	87%	83%	3%	3%	4%	8.7	58.0	9.7	510	411	0
		Barcaldine (Q5)	85%	90%	84%	4%	3%	4%	10.1	62.4	11.3	461	484	0
		Banana (Q9)	81%	89%	83%	3%	3%	3%	10.9	81.7	11.6	347	374	0
	Solar	North Qld (Q2)	90%	88%	89%	3%	3%	3%	40.8	70.4	42.0	531	527	0
		Fitzroy (Q6)	88%	89%	87%	3%	3%	3%	21.3	73.0	22.6	832	538	0
		Darling Downs (Q2)	84%	88%	82%	3%	3%	3%	17.1	85.1	18.1	783	527	0
2050	**Hybrid**	NQCEH (Q2)	84%	91%	84%	4%	3%	4%	9.2	78.8	9.5	353	279	0
		Isaac (Q4)	84%	88%	85%	3%	3%	4%	9.8	70.0	11.3	425	441	0
		Barcaldine (Q5)	86%	90%	85%	4%	4%	4%	10.9	58.1	11.7	459	494	0
		Banana (Q9)	83%	90%	84%	3%	3%	4%	11.7	82.7	12.2	344	379	0
	Solar	North Qld (Q2)	91%	89%	91%	3%	3%	3%	39.1	75.1	40.6	506	512	0
		Fitzroy (Q6)	88%	89%	88%	3%	3%	3%	20.5	72.1	21.6	520	544	0
		Darling Downs (Q2)	84%	90%	83%	3%	3%	3%	16.8	84.3	17.7	483	503	0

Table 8: Ammonia– LCOA and operating metrics summary for all scenarios, years and REZ page 2

3.2.2.3 Cost breakdown

Plant cost stacks are shown for Banana on an LCOA basis (Figure 31) and on a capex basis (Figure 32). As for hydrogen the proportion of the cost stack that electrolyser represents reduces the most of any value chain element, while renewable energy and batteries also experience capital cost reductions. Ammonia plants, hydrogen and ammonia storage are mature technology, with no reduction in capex projected, resulting in these value chain elements becoming an increasing proportion of the cost stack for all scenarios.

There is little discernible difference between the cost stacks for the three scenarios, apart from the lower storage cost for the Fixed – Salt Cavern Scenario and that Flexible has no ammonia storage.

Cost drivers of LCOA – Banana

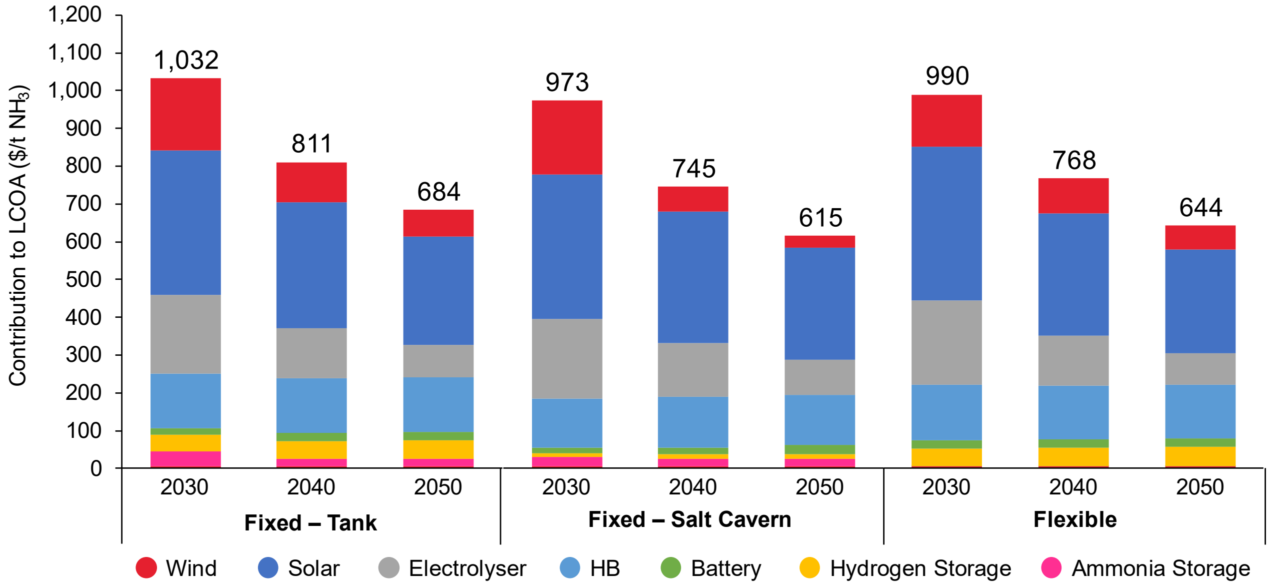


Figure 31: Ammonia – cost drivers of LCOA for Banana for different scenarios for different years

Ammonia Capex Stack – Banana

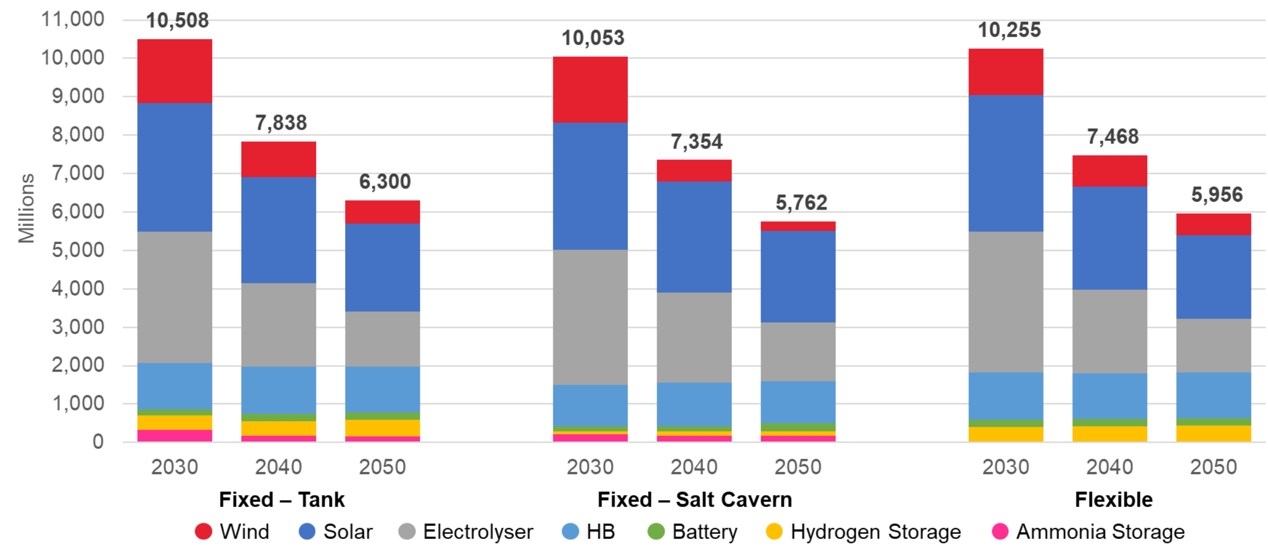


Figure 32: Ammonia – capex stack for Banana for different scenarios for different years

3.2.2.4 Seasonal plant behaviour

The capacity factors of wind, solar and the electrolyser are similar in the three cases (Figure 34; Figure 35). However, the HB plant has the highest capacity factors in the Fixed – Salt Cavern case because the large volume of hydrogen storage allows the plant to run more consistently (Figure 34; Figure 35).

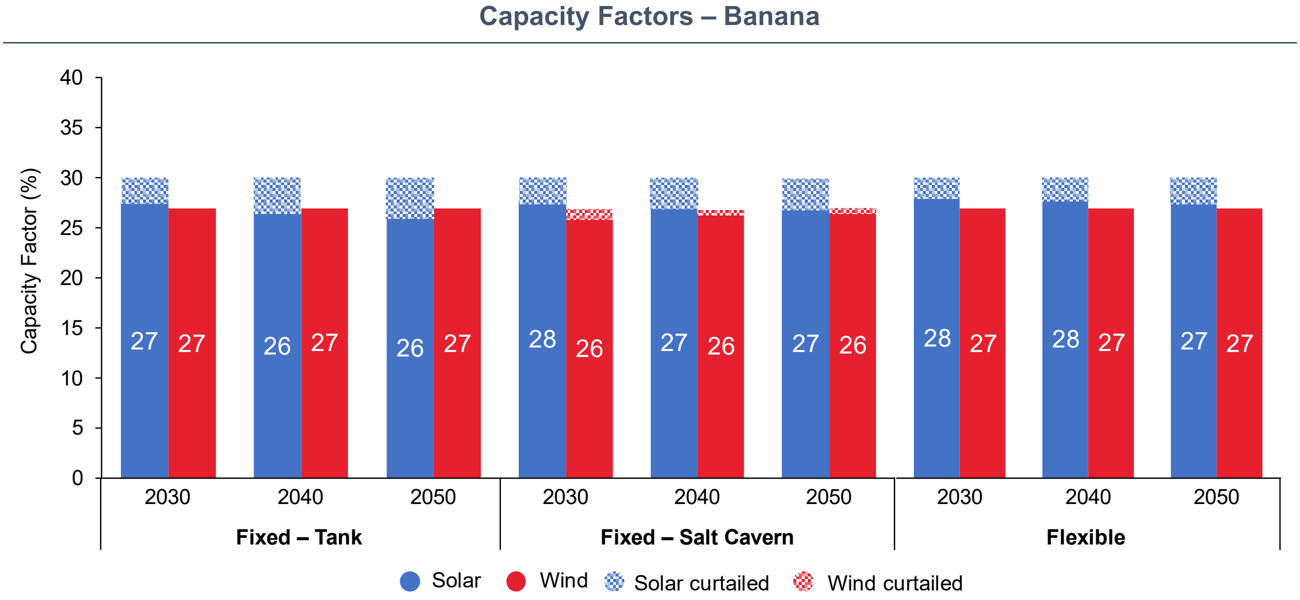


Figure 33: Ammonia – average annual capacity factors and curtailment for Banana for different scenarios and years

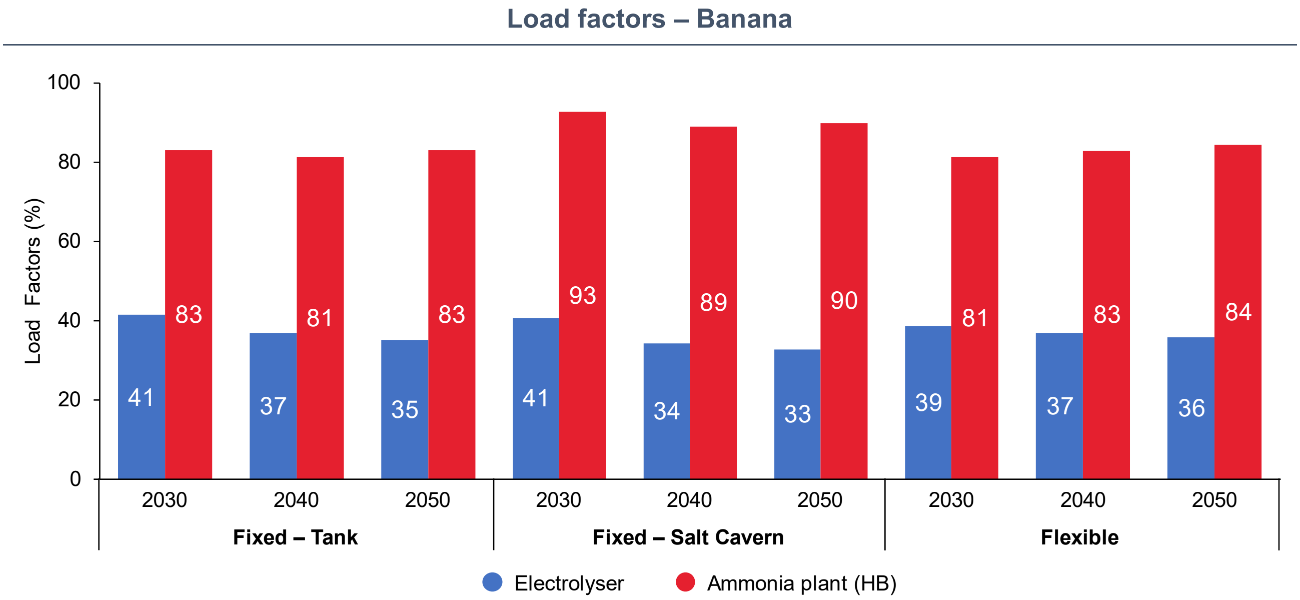


Figure 34: Ammonia – Average annual load factors for Banana for different scenarios and years

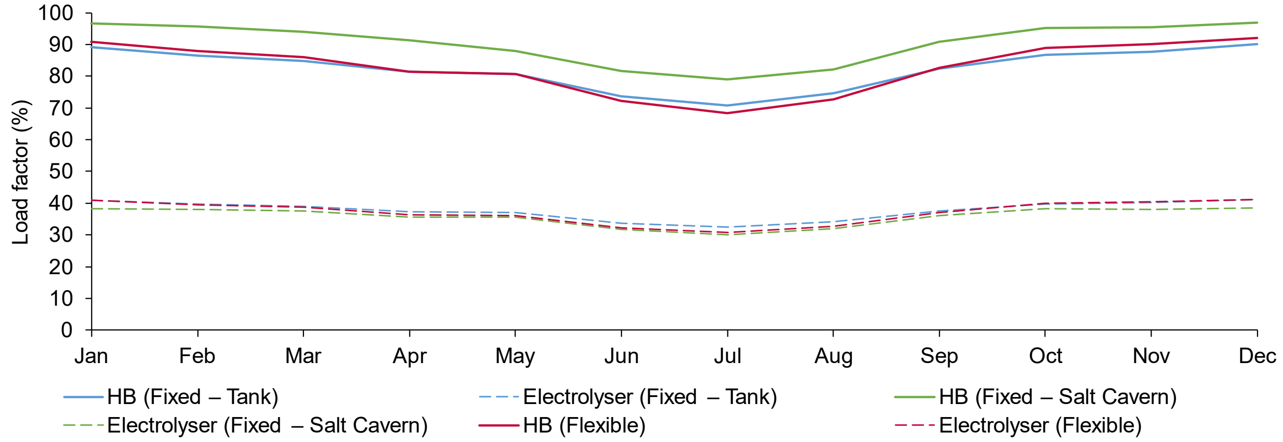


Figure 35: Ammonia – average monthly ammonia plant and electrolyser load factors for three scenarios in Banana

Ammonia storage shows a clear seasonal pattern while hydrogen storage fluctuates on a smaller timescale to store hydrogen during the day and provide hydrogen to the ammonia plant at night. Unlike salt caverns in the Fixed – Salt Cavern hydrogen case, ammonia storage rarely becomes depleted (Figure 36).

Ammonia storage behaves similarly in the Fixed cases displaying clear seasonal variations (Figure 36, Figure 37). In contrast, hydrogen tanks in Fixed – Tank cycle very rapidly a few hundred times a year (Figure 38).

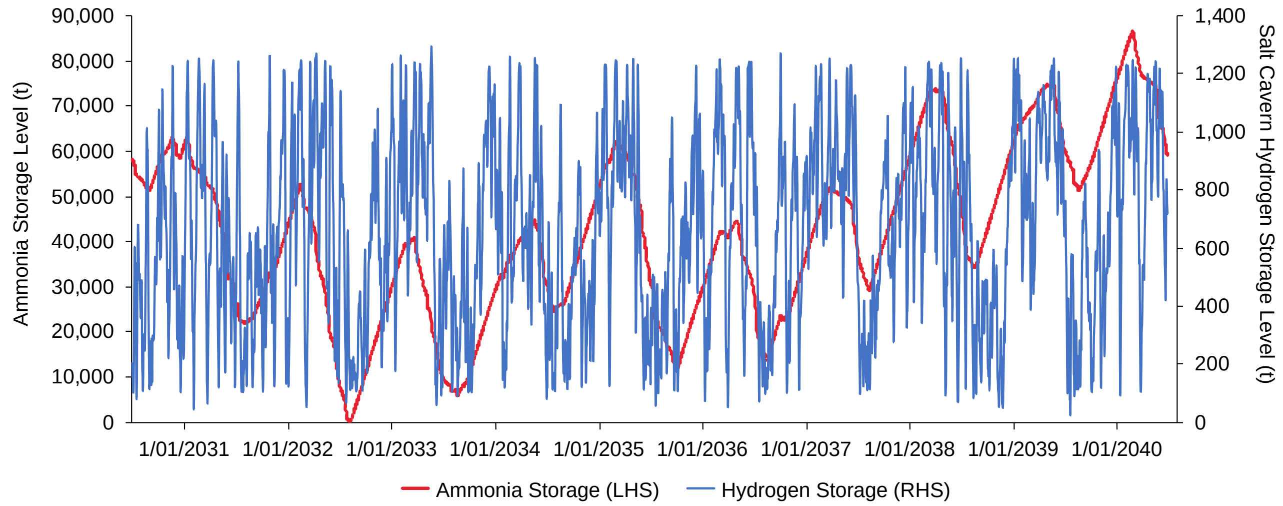


Figure 36: Ammonia Optimisation – salt cavern and ammonia storage level over 10 years in Banana

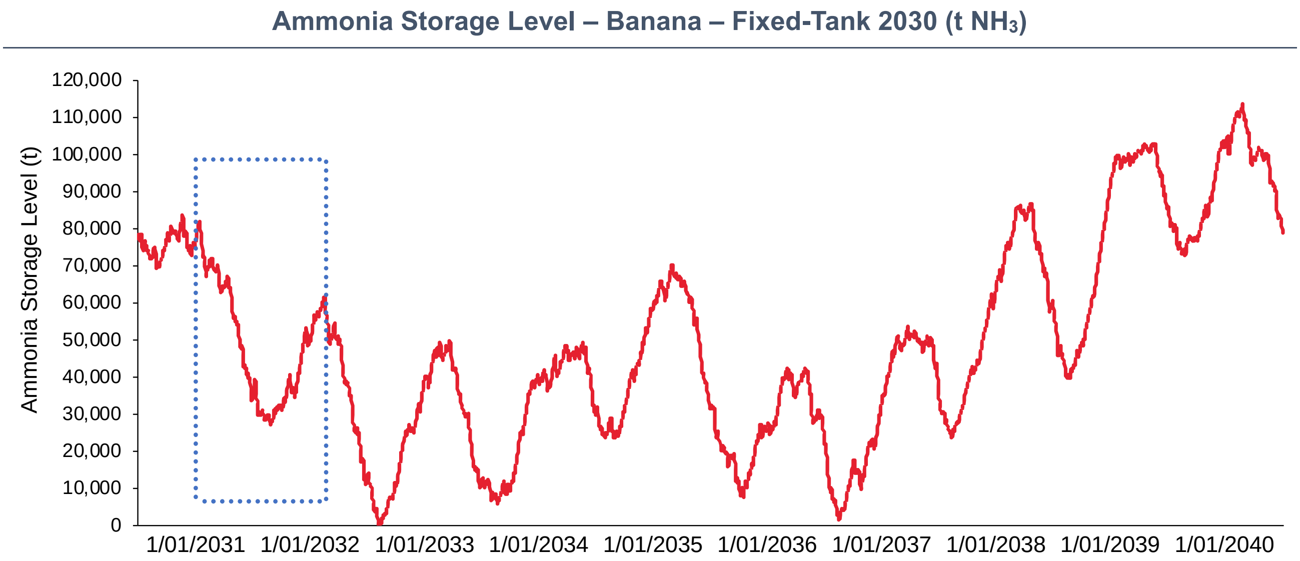


Figure 37: Ammonia Optimisation – Ammonia storage level over 10 years in Banana

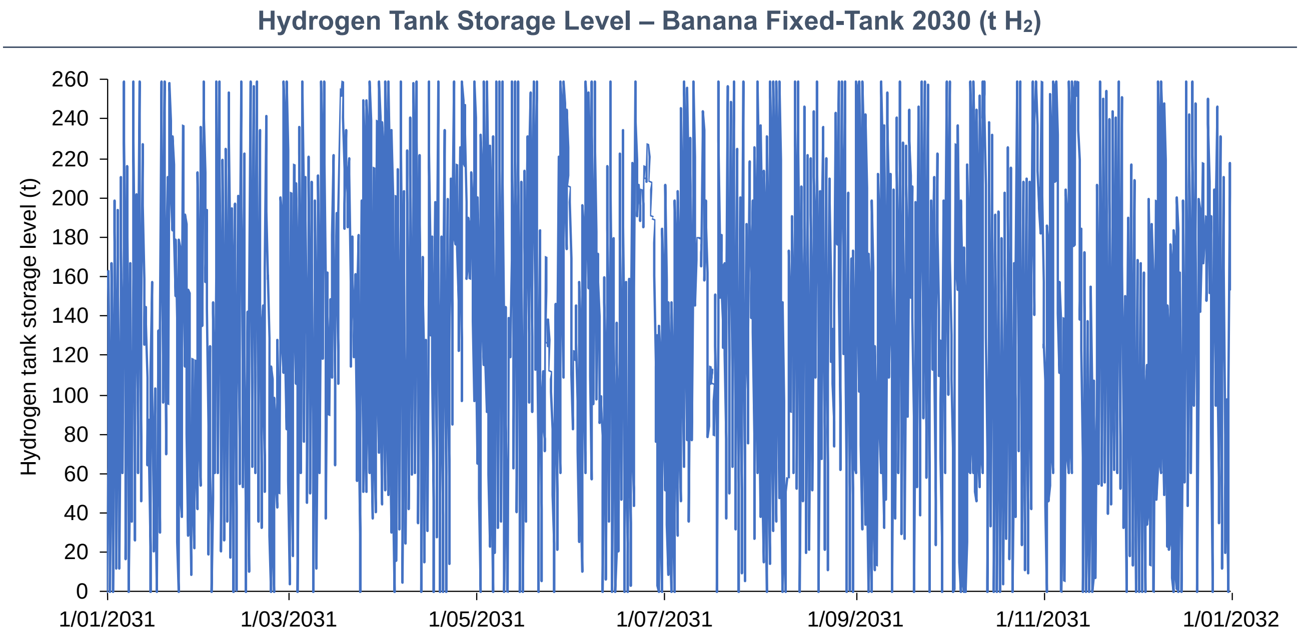


Figure 38: Ammonia Optimisation – hydrogen tank storage level over one year in Banana

3.2.2.5 Plant Operation – typical day

During the day, the electrolyser tends to run at close to its rated capacity. The hydrogen output is fed into the HB plant and also injected into storage. The battery is also charged during the day. Some solar and wind output might be curtailed if the generation exceeds the total power draw by the electrolyser, HB, battery and compressor (Figure 39). At night, if there is sufficient wind output, the electrolyser runs at reduced capacity, otherwise, the electrolyser is turned off while the HB plant draws power from wind (and/or battery) and hydrogen from storage to produce ammonia (Figure 40).

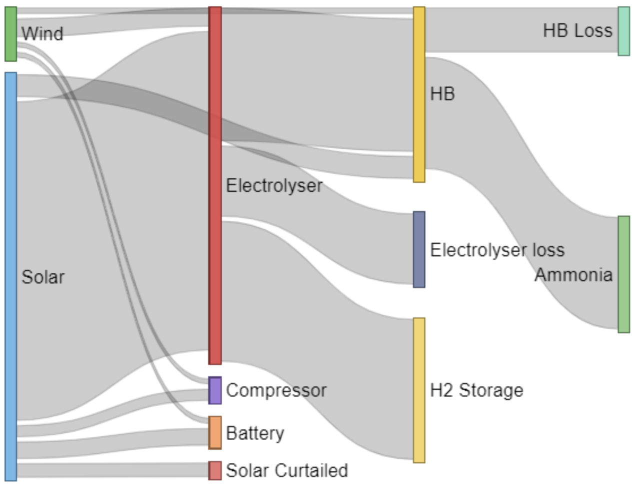


Figure 39: Ammonia – energy flow during typical daylight hours

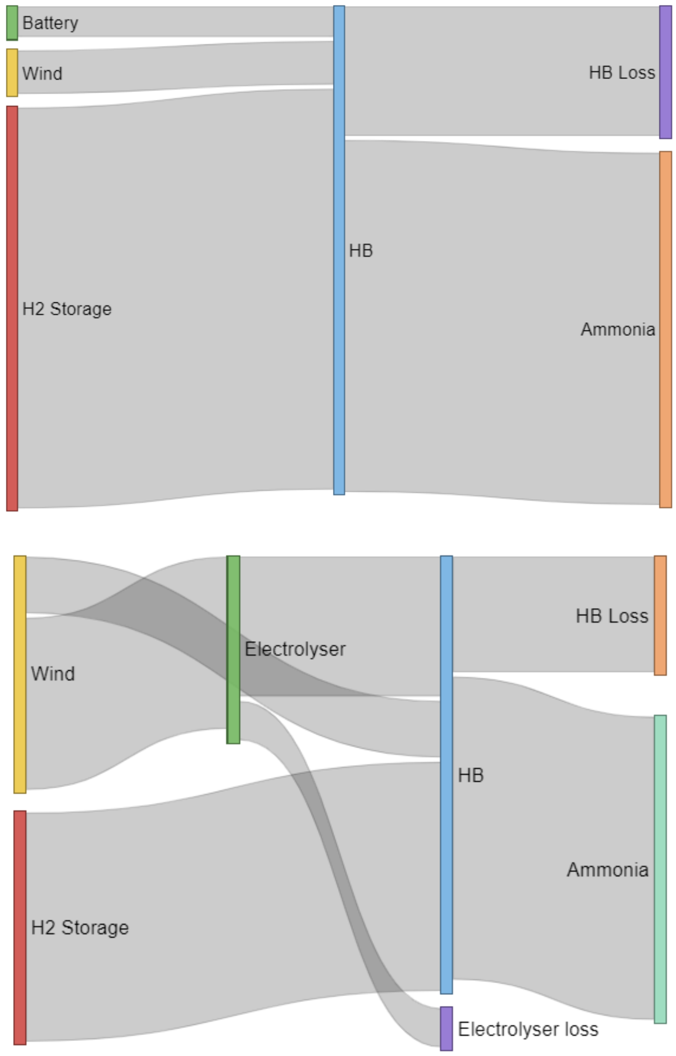


Figure 40: Ammonia Optimisation – energy flows during night (top chart HB only, bottom chart HB and electrolyser operating)

3.2.2.6 Limitations and constraints

This section outlines a number of challenges and constraints that apply to the modelling of ammonia that are in addition to those that apply to the modelling of hydrogen outlined in Section 3.2.1.5 that also apply to ammonia.

3.2.2.6.1 Input assumptions – ammonia plant flexibility

The modelling assumes that the firmed power requirement of the HB plant reduces in line with the reduction in hydrogen feed to a minimum of 30% of nameplate capacity. However, feedback from Australian industry sources suggests that it may not fall by the same amount as the hydrogen feed, to a minimum of around 50% and there may be some trade-offs between the capital cost of plants and turndown rates.

However, the ammonia plant represents a modest proportion of total green ammonia value chain capex, and Section 6.2 shows that reducing turndown rates for hydrogen feed to below 50% of nameplate capacity has limited impact on LCOA. However, the potential to reduce hydrogen feed to below 50% of nameplate capacity below may be highly valuable for providing demand response to the electricity system.

Assuming flexible operation, HB load factors are approximately 80%. Given the HB plant requirement is 10% of the total energy (Figure 49), the additional energy to run the HB plant without any power turndown would likely be around 2%. Additional renewable energy including wind and/or battery capacity may be required to meet this additional power requirement that may increase LCOA by more than 2%. Section 6.6 includes scenarios where the ammonia plant is grid connected at fixed electricity prices of $50MWh and $100MWh, resulting in ~6% increase in LCOA between these two scenarios. The sensitivity of LCOA to HB electricity price provides some indication of the impact of constraining HB power turndown capability.

3.2.2.6.2 Port infrastructure requirements including ammonia storage

Port infrastructure requirements are not considered, including additional ammonia tank storage required to ensure that ships are able to be filled quickly when they arrive at the port. Given the low cost of ammonia tank storage (See Energy Storage Information Sheet) and assuming 1mtpa ammonia production and ammonia tankers of 20,000t NH_3 capacity, the inclusion of 20,000t of additional NH_3 storage is unlikely to materially increase LCOA.

3.2.2.6.3 Geological hydrogen storage – cycling constraints

For the ammonia modelling salt caverns were not assumed to have any cycling constraints. As ammonia storage takes over the role of seasonal storage that salt caverns played in the hydrogen case, salt caverns are required to cycle more frequently than the typical maximum rate in the literature of 10-12 times per year (Figure 41).

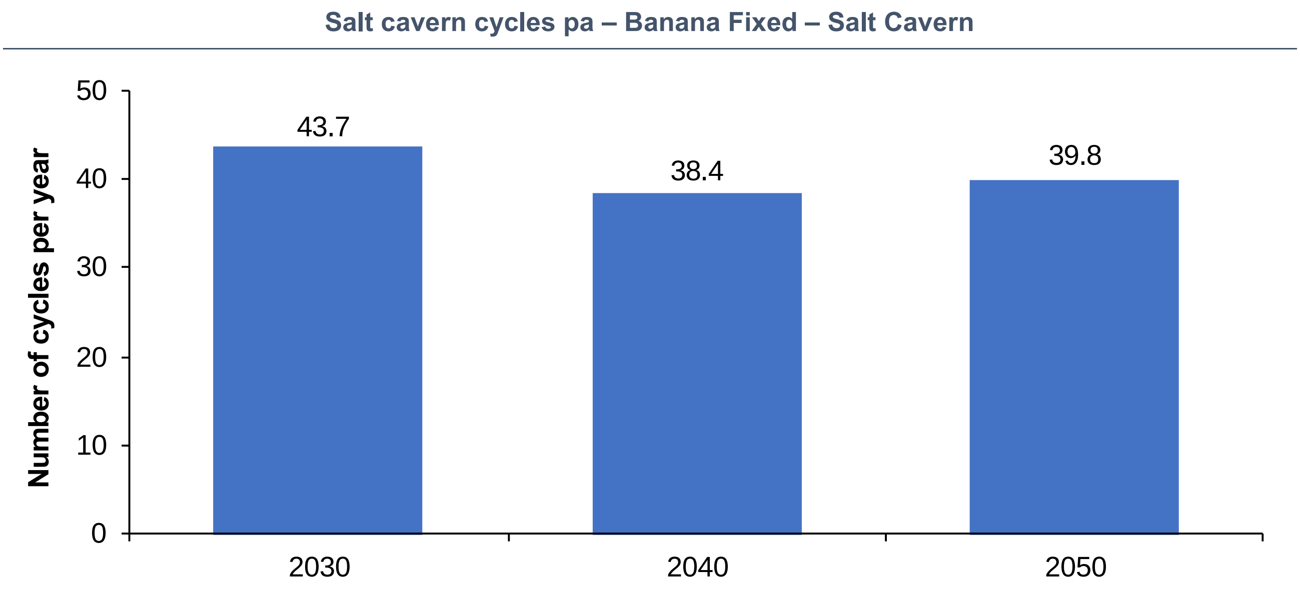


Figure 41: Ammonia – number of salt cavern cycles per year in Banana in Fixed – Salt Cavern case for different years

Constructing a larger storage capacity salt cavern is one way to mitigate this issue. As hydrogen storage volume is small relative to ammonia storage and salt cavern storage cost is only a small fraction of LCOA, imposing a stricter cycling constraint is not expected to materially impact LCOA. However, cycling constraints reduce the cost benefit of salt caverns to green ammonia production versus the alternative of hydrogen tanks. For more detailed analysis, see Section 6.1 Hydrogen - Salt cavern hydrogen storage cycling constraints.

3.2.2.6.4 End-product modelling – fertiliser and explosives

The modelling only considers the production of ammonia and not end-products such as urea fertiliser. Given the storage cost of this solid product may be lower than ammonia, there is the potential that urea could be produced with a seasonal profile matching that of ammonia, with urea stored seasonally rather than ammonia. The lower cost of urea storage could also potentially reduce the percentage cost gap between fixed and flexible customer demand profile versus ammonia. However, there are a range of practical considerations around end-product modelling and storage that should be considered including:

- Safety and environmental risks may impact on the potential scale and location of ammonia storage;
- Seasonal urea production requires additional plant capacity and in addition the CO2 feedstock may have limited flexibility;
- Domestic fertiliser demand is driven by rainfall and growing seasons as well as long term weather patterns, such as droughts;
- Ammonia, fertiliser and explosives are all globally traded products; and
- Storage of explosives is complicated from a security and safety standpoint.

3.2.2.6.5 Perfect foresight

The modelling assumes perfect foresight, meaning that the plant owner has absolute accuracy in renewable generation forecasting indefinitely, whereas real-life weather forecasts are inherently uncertain. When operated with imperfect foresight the plant will produce less ammonia (thus higher LCOA) than in the perfect foresight case, because it cannot manage its storage as effectively. In real life the plant would be operated more conservatively than in the perfect foresight case to ensure that forecasting errors would not result in plant operating constraints being breached, particularly the minimum HB load. Plant design could be adjusted to minimise the impact of imperfect foresight with key design changes likely to be focused on:

- Additional storage, which could encompass hydrogen and/or power system storage (BESS); and/or
- Selection of ammonia plant with higher turndown (lower minimum load) that may come at a higher capital cost.

Modelling undertaken by the University of Oxford Green Ammonia Technology research group in 2023 demonstrated that forecasting uncertainty could be managed cost-effectively by adjustments to plant design (Salmon & Banares-Alcantara, 2023). An islanded plant was designed based on an optimisation model with perfect foresight and an assumed HB minimum load, with the plant then operated in a different model with a 24-hour lookahead (rolling 24-hour forecast) and HB minimum load reduced by 20%. The modelling results showed that for a 30% minimum HB load, for a solar or hybrid (wind and solar) portfolio, imperfect foresight led to an up to a ~5% increase in LCOA. The exact amount of oversizing required at different levels of forecasting uncertainty requires further research.

The modelling results also showed that the LCOA premium for imperfect foresight increased significantly as plant flexibility decreased, while the imperfect foresight premium for wind was materially higher than for solar and hybrid (wind and solar) due to wind having higher variability and being more challenging to predict accurately. These results imply that cost estimates for inflexible hydrogen liquefaction project that assume perfect foresight, particularly those with high wind portfolio weightings, could materially underestimate actual costs.

3.2.3 Hydrogen with transport

Three scenarios were modelled that align with the value chain diagrams in Section 3.1.4:

- Fixed – Tank (wire): the electricity is delivered by transmission lines to the electrolyser co-located with tank storage;
- Fixed – Tank (pipe): the electrolyser is co-located with the renewable generation and tanks and the hydrogen is delivered in pipeline to the end customer (port); and
- Fixed – Salt Cavern (pipe): the electrolyser is co-located with the renewable generation and the hydrogen is delivered in pipeline to the salt cavern for storage and the customer (port).

In the Fixed – Tank (wire) case, the sizing of the transmission is determined by the capacity of the electrolyser and compression load. In the Fixed – Tank (pipe) case, the size of the pipeline is the fixed throughput rate of ~ 20.5t/h (hydrogen throughput required to produce 1mtpa ammonia). In the Fixed – Salt cavern case (Pipe), the pipeline is sized to accommodate the maximum possible flow into storage, which is calculated as the difference between the maximum hydrogen production rate and the demand rate.

Electricity transmission is costed on an N-basis, which is optimistic for this form of transport. N-basis is high risk, as a fault on one circuit of a double circuit transmission line, could result in up to a halving of transport capacity and the modelling does not incorporate this risk (refer to Transport Information Sheet for more detail). Wires are consistently more expensive than pipelines, making Fixed – Tank (wire) the most expensive option. Comparing the Fixed – Tank (pipe) and Fixed – Salt Cavern (pipe) cases, although the distance to the salt cavern is substantial and can significantly increase the cost of transport, the contribution of pipelines to the total cost stack is small, making Fixed – Salt Cavern (pipe) the most competitive option.

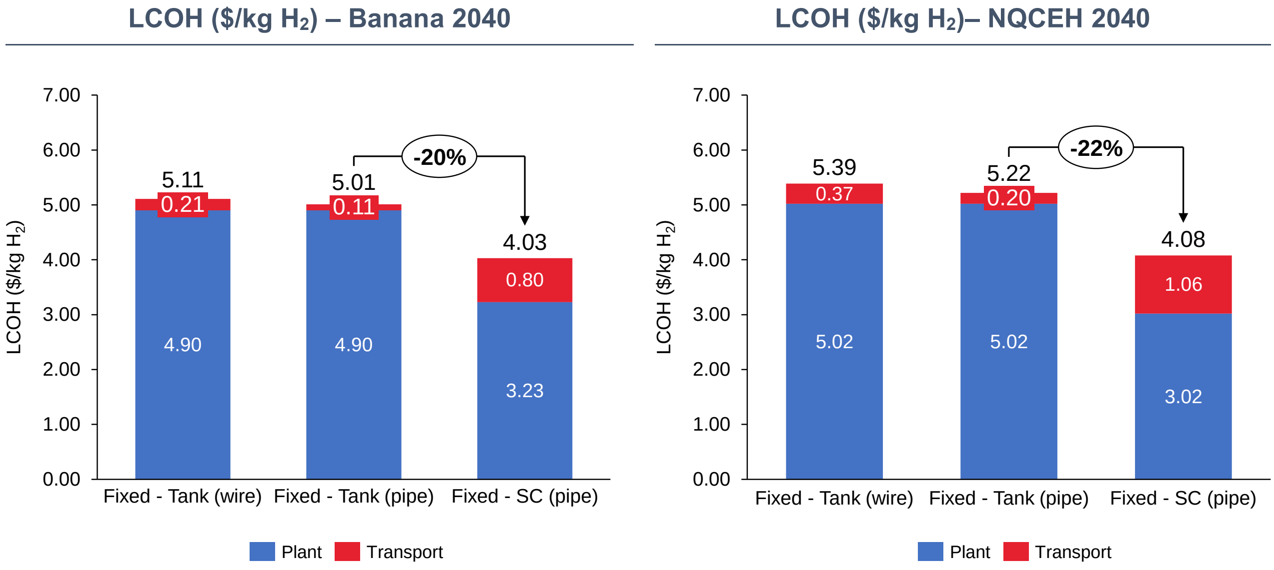


Figure 42: LCOH including transport in the different scenarios at Banana 2040 (left) and NQCEH 2040 (right)

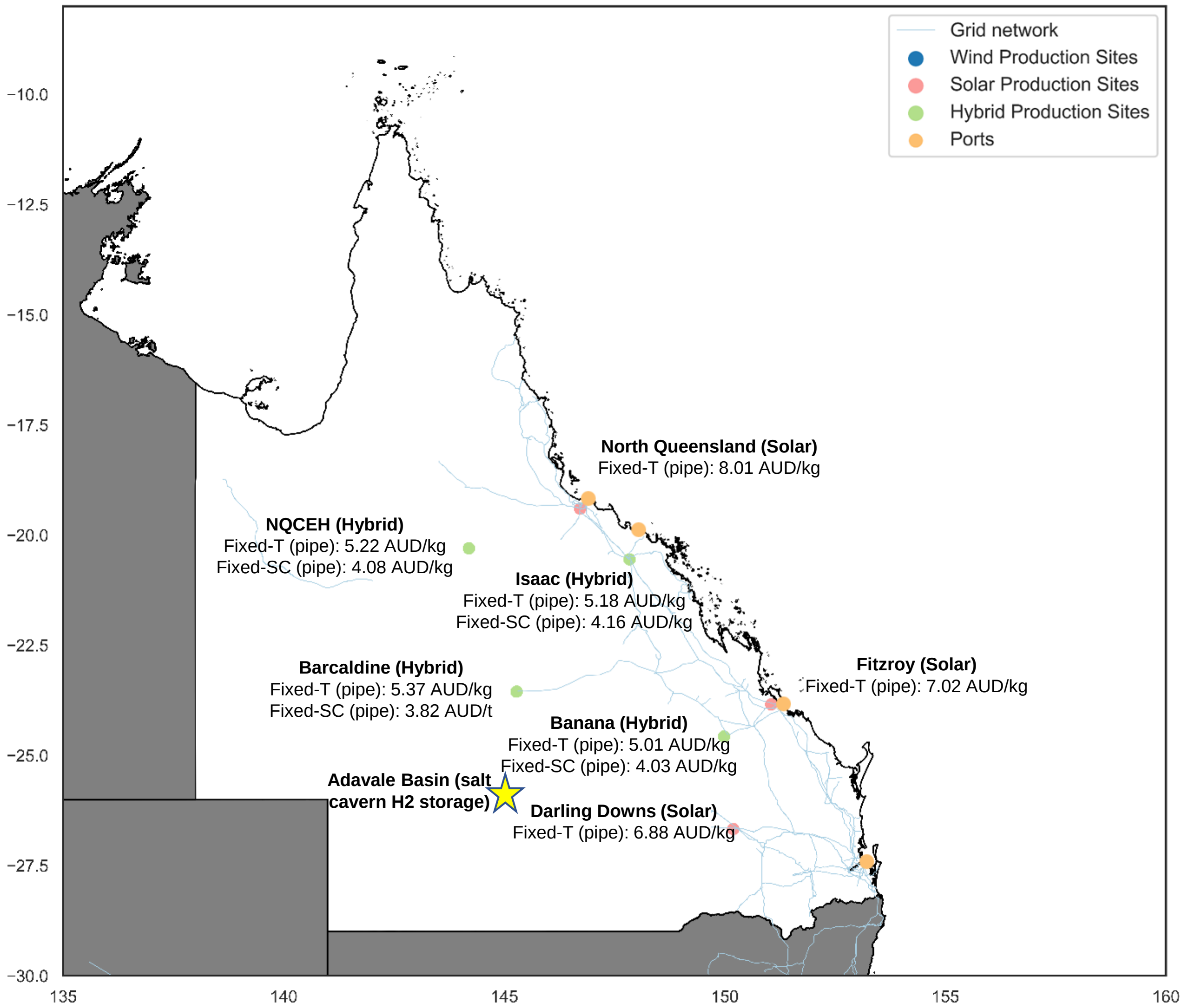


Figure 43: Map showing selected 2040 LCOH ($/kg H_2) including transport for selected scenarios

			Plant levelised cost of hydrogen (LCOH) ($/kg H_2)		Wires cost ($/kg H_2)	Pipes cost ($/kg H_2)		LCOH including transport ($/kg H_2)		
		REZ	Fixed – Tank	Fixed – Salt Cavern	Fixed – Tank	Fixed – Tank	Fixed -Salt Cavern	Fixed – Tank (wire)	Fixed – Tank (pipe)	Fixed – Salt Cavern (pipe)
2030	**Hybrid**	NQCEH (Q2)	6.29	4.12	0.43	0.21	0.79	6.72	6.50	4.91
		Isaac (Q4)	6.36	4.41	0.14	0.05	0.56	6.50	6.41	4.96
		Barcaldine (Q5)	6.30	4.18	0.52	0.35	0.56	6.83	6.65	4.74
		Banana (Q9)	6.23	4.39	0.23	0.11	0.56	6.46	6.33	4.95
	Solar	North Queensland (Q3)	9.87	4.76	0.15	0.01	1.21	10.02	9.88	5.97
		Fitzroy (Q6)	9.07	4.67	0.16	0.01	0.91	9.24	9.09	5.59
		Darling Downs (Q8)	8.86	4.81	0.70	0.21	0.91	9.56	9.08	5.72
2040	**Hybrid**	NQCEH (Q2)	5.02	3.02	0.37	0.21	1.06	5.38	5.22	4.08
		Isaac (Q4)	5.13	3.26	0.13	0.05	0.90	5.25	5.18	4.16
		Barcaldine (Q5)	5.03	3.09	0.63	0.35	0.73	5.65	5.37	3.82
		Banana (Q9)	4.90	3.23	0.21	0.11	0.80	5.11	5.01	4.03
	Solar	North Queensland (Q3)	8.00	3.43	0.14	0.01	1.23	8.13	8.01	4.65
		Fitzroy (Q6)	7.01	3.36	0.14	0.01	0.92	7.15	7.02	4.28
		Darling Downs (Q8)	6.67	3.48	0.63	0.21	0.91	7.30	6.88	4.40
2050	**Hybrid**	NQCEH (Q2)	4.31	2.35	0.37	0.21	1.14	4.68	4.52	3.49
		Isaac (Q4)	4.44	2.59	0.13	0.05	1.10	4.57	4.50	3.69
		Barcaldine (Q5)	4.22	2.44	0.63	0.35	0.78	4.85	4.57	3.22
		Banana (Q9)	4.16	2.54	0.20	0.11	0.88	4.36	4.27	3.42
	Solar	North Queensland (Q3)	6.99	2.69	0.13	0.01	1.36	7.12	7.01	4.05
		Fitzroy (Q6)	5.89	2.66	0.14	0.01	1.01	6.03	5.91	3.67
		Darling Downs (Q8)	5.47	2.77	0.62	0.21	0.91	6.09	5.68	3.69

Table 9: Hydrogen – LCOH including transport by scenario, all years and REZ

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3.2.4 Ammonia with transport

The scenarios are the same as in the hydrogen case, except the HB plant is located at the port and is grid connected, paying $100/MWh including network charges (e.g. TUOS). The scenarios align with the value chain diagrams in Section 3.1.4.

The cost of transport to the salt cavern overwhelms any value the low cost salt cavern hydrogen storage provides, making it a more expensive option than Fixed – Tank (pipe). The more coastal locations enjoy the lowest cost for ammonia production and transport due to lower cost of pipelines (Figure 44).

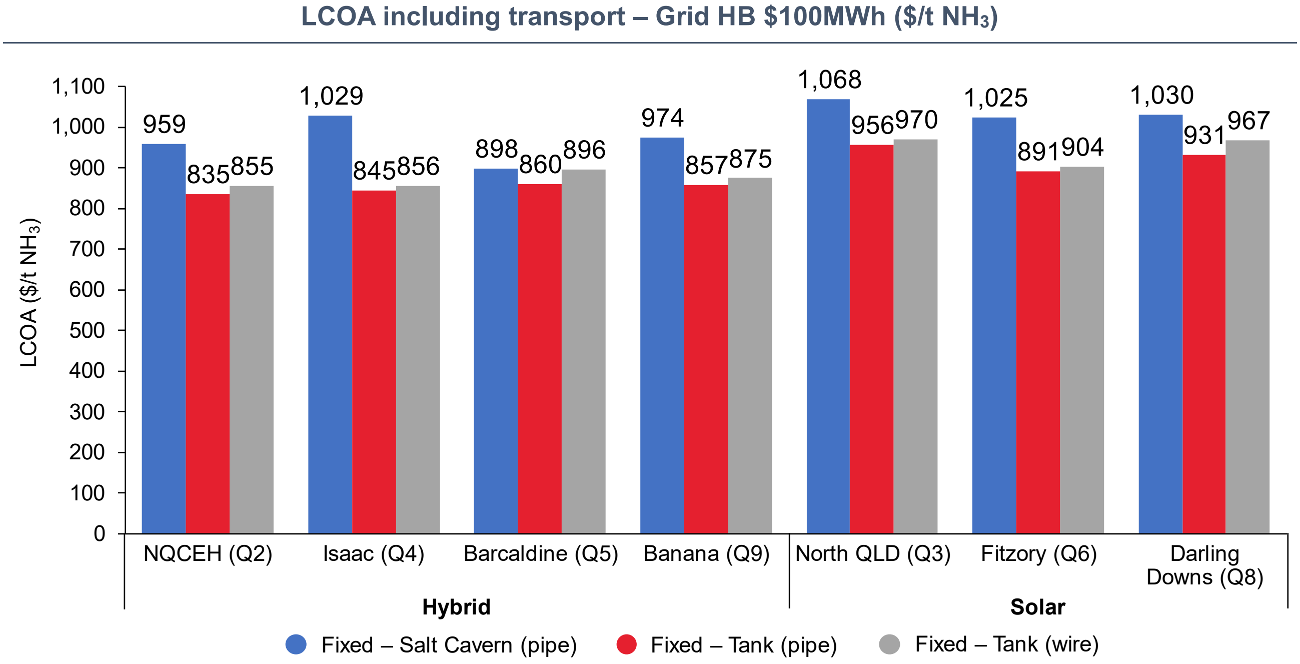


Figure 44: LCOA including transport – Grid connected HB paying $100MWh in different scenarios all REZ in 2040

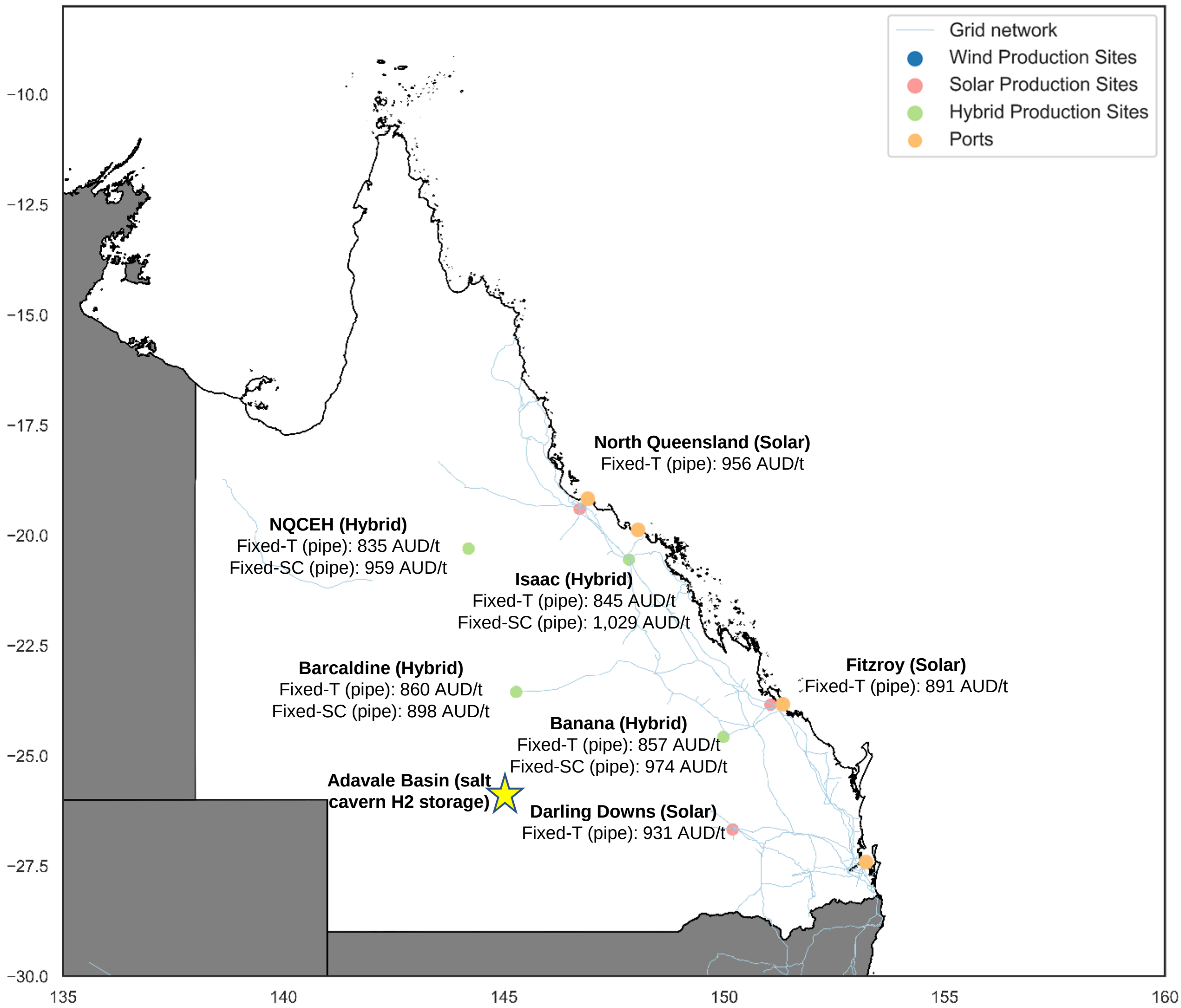


Figure 45: Map showing selected 2040 LCOA ($/t NH_3) including transport – Grid connected HB paying $100MWh for selected scenarios

		REZ	Plant levelised cost of ammonia – Grid HB $100MWh ($/t NH_3)		Wires cost ($/t NH_3)	Pipes cost ($/t NH_3)		LCOA including transport ($/t NH_3)		
			Fixed – Tank	Fixed – Salt Cavern	Fixed – Tank	Fixed – Tank	Fixed – Salt Cavern	Fixed – Tank (wire)	Fixed – Tank (pipe)	Fixed – Salt Cavern (pipe)
2030	**Hybrid**	NQCEH (Q2)	973	929	63	48	203	1,036	1,021	1,132
		Isaac (Q4)	1,025	979	25	16	170	1,049	1,041	1,149
		Barcaldine (Q5)	978	933	102	78	157	1,080	1,056	1,089
		Banana (Q9)	1,040	987	42	27	157	1,081	1,067	1,144
	Solar	North Queensland (Q3)	1,187	1,019	21	7	284	1,208	1,194	1,303
		Fitzroy (Q6)	1,117	1,017	19	7	233	1,136	1,123	1,250
		Darling Downs (Q8)	1,118	1,035	88	51	226	1,206	1,169	1,261
2040	**Hybrid**	NQCEH (Q2)	787	739	68	48	220	855	835	959
		Isaac (Q4)	829	774	27	16	256	856	845	1,029
		Barcaldine (Q5)	783	723	113	77	175	896	860	898
		Banana (Q9)	830	764	44	27	210	875	857	974
	Solar	North Queensland (Q3)	949	785	20	7	284	970	956	1,068
		Fitzroy (Q6)	884	784	19	7	241	904	891	1,025
		Darling Downs (Q8)	880	798	87	50	232	967	931	1,030
2050	**Hybrid**	NQCEH (Q2)	679	623	70	48	274	749	727	896
		Isaac (Q4)	716	651	28	16	261	744	731	911
		Barcaldine (Q5)	672	611	111	76	173	783	748	783
		Banana (Q9)	712	643	44	27	191	756	739	834
	Solar	North Queensland (Q3)	820	659	20	7	279	840	827	938
		Fitzroy (Q6)	884	659	19	7	243	904	891	902
		Darling Downs (Q8)	750	671	84	50	234	834	799	905

Table 10: LCOA including transport – Grid connected HB paying $100MWh by scenario and REZ all years

3.2.4.1 Green premium estimate

Grey ammonia is a derivative of natural gas and thus market prices are directly related to natural gas prices. Figure 46 shows that over the past 10 years, except for the 2021-2023 global energy crisis, ammonia has generally traded in the range of US$200-$550/t on global markets (A$286-A$786/t assuming 0.70 AUD/USD). The average over the ten-year period was US$430/t (A$614/t).

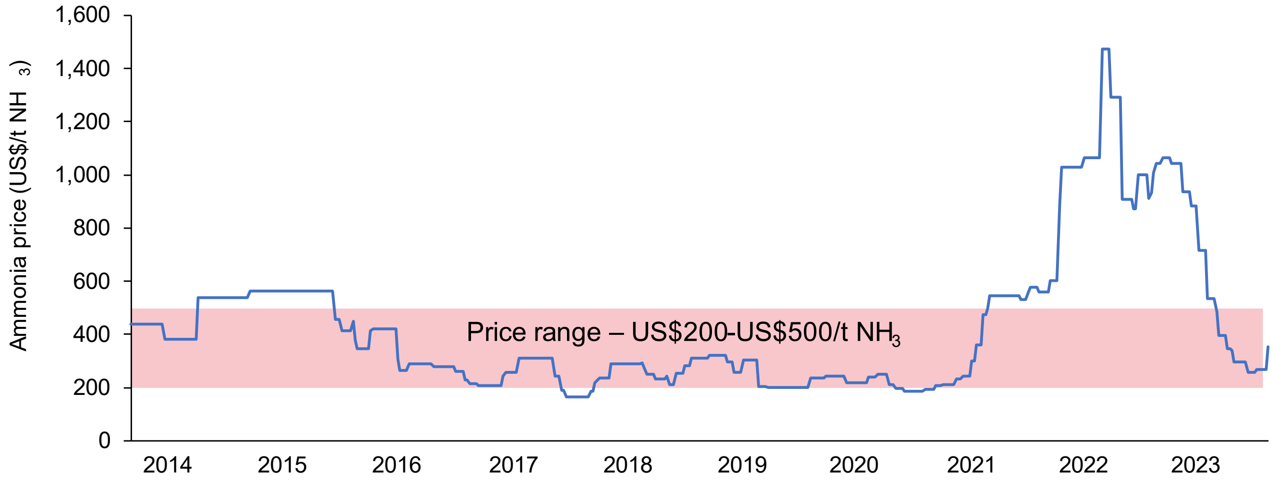


Figure 46: US Gulf NOLA Ammonia Spot Price 2014-23 (USD/t NH_3) | *Source: Bloomberg*

Based on the US$200-$550/t price range Figure 47 shows the significant green premium for Isaac green ammonia versus grey ammonia imports[6]. The green premium falls over time with declining green ammonia LCOA. However, for 2050 except for the top of the price range, the green premium is still positive. The green premium estimates are indicative and subject to the limitations and constraints discussed in Section 3.2.1.5 and Section 3.2.2.6.

[6] *NOLA ammonia spot price does not include costs of shipping to Australia, port costs, duties, etc. and thus it may underestimate grey ammonia import costs.*

Green ammonia green premium: Isaac – Fixed – Tank, Grid HB $100MWh, H_2 pipes transport (A$/t NH_3)

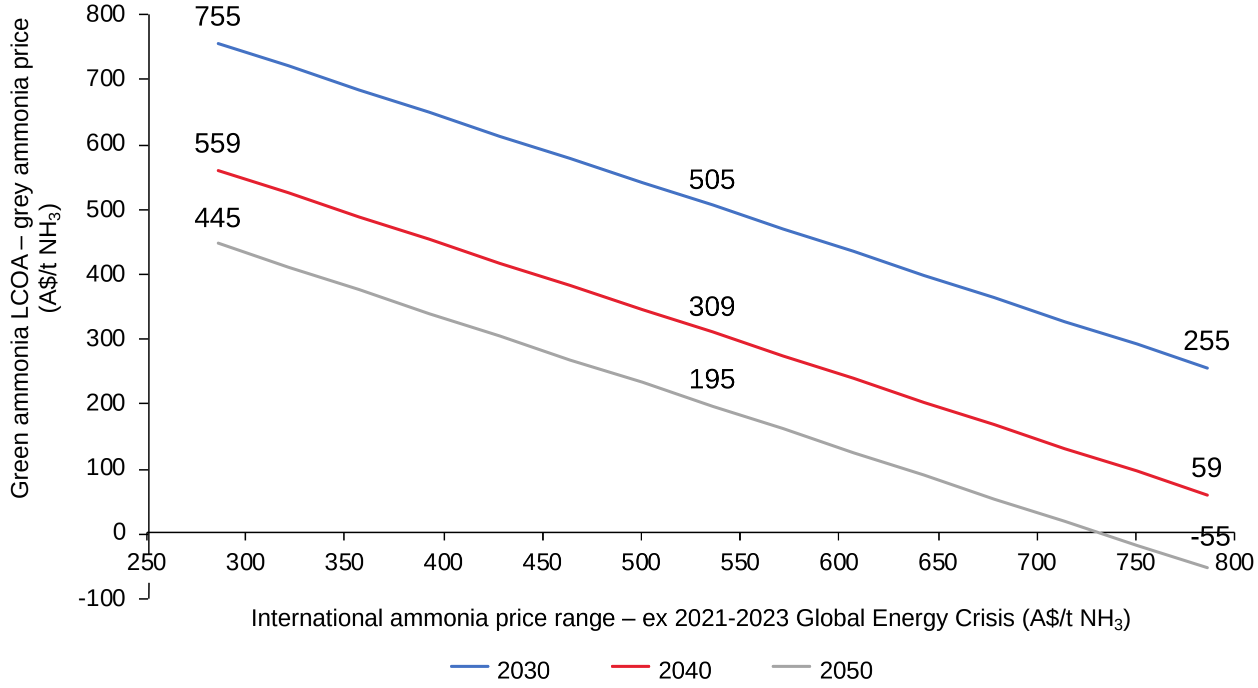


Figure 47: Green ammonia green premium: Isaac – Fixed – Tank, Grid connected HB at $100MWh, H_2 pipes transport (A$/t NH3)

Figure 48 shows that the implied carbon emissions abatement cost of Isaac green ammonia declines over time. The full lifecycle greenhouse emissions of grey ammonia production are assumed to be 2.6t CO_2e per tonne of ammonia production, which incorporates greenhouse gas emissions from production and natural gas supply chain leakage (Liu, Elgowainy, & Wang, 2020; Neininger, Kelly, Hacker, Lu, & Schwietzke, 2021; Mayer, et al., 2023).

At the midpoint of the range (A$535/t, below the 10-year average of A$614/t) in 2040 the implied CO_2e abatement cost of $119/t CO_2e. There is no marginal abatement cost curve to benchmark green ammonia against produced or made publicly available by State or Commonwealth Governments. Ammonia is a hard-to-abate industry and CO_2e abatement cost compares favourably with the future cost projections for direct air capture excluding storage of $A142-284/t CO_2 (US$100-200/t CO_2) (CSIRO, 2022B). There is significant risk around cost projections for direct air capture, as the technology is currently high cost and has not been deployed at scale (CSIRO, 2022B).

Green ammonia implied CO_2e abatement cost: Isaac – Fixed – Tank, Grid HB \$100MWh, H_2 pipes transport (A\$/t CO_2e)

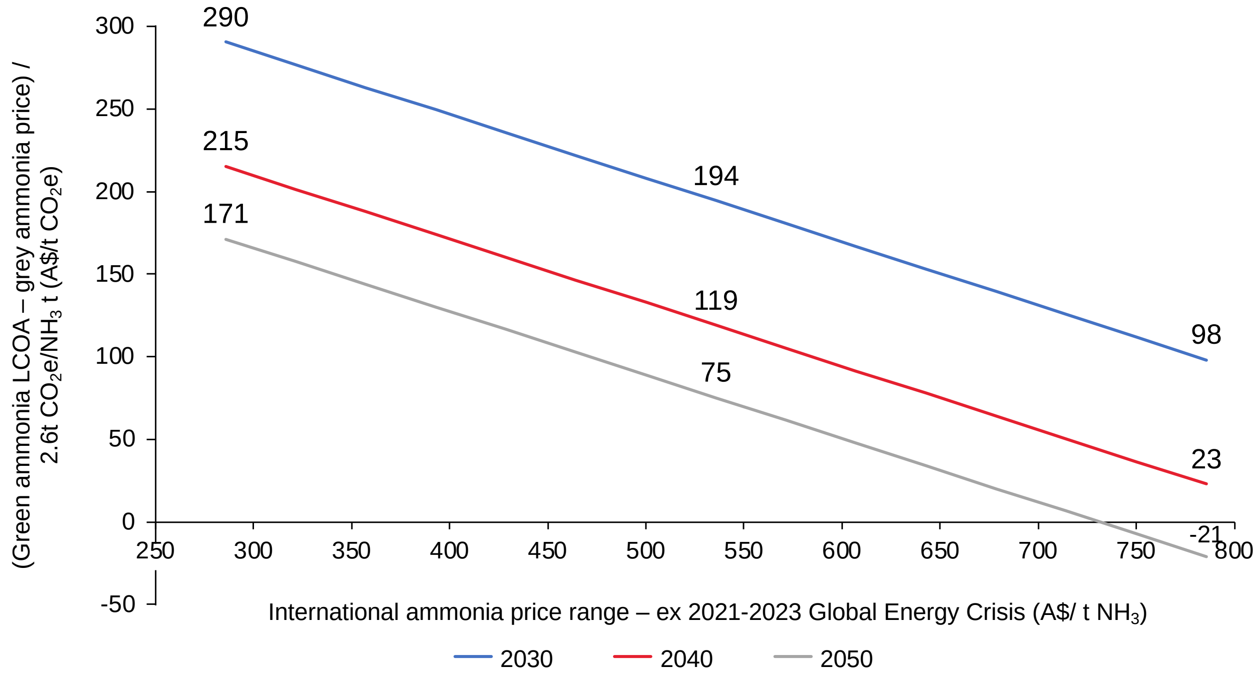


Figure 48: Green ammonia implied CO_2e abatement cost: Isaac – Fixed – Tank, Grid connected HB at \$100MWh, H_2 pipes transport (A\$/t CO_2e)

The analysis does not consider embodied emissions in the green ammonia value chain on the assumption that by 2040 that electricity supply for the manufacture of equipment utilises renewable energy, nor does it consider green ammonia value chain hydrogen leakage. The greenhouse gas potential of uncombusted hydrogen is around ten times that of carbon dioxide on a mass basis although this figure has a high degree of uncertainty (Warwick, et al., 2023).

The analysis does not consider blue ammonia, as policy support in Australia is focussed on green hydrogen (Australian Government - Department of Climate Change, Energy, the Environment and Water, 2023). As natural gas production costs are lower in some overseas jurisdictions than Queensland, imports may present the lowest cost blue ammonia alternative[7].

4 Electricity system integration

The optimisation modelling assumes off-grid (islanded) plant with dedicated renewables and does not incorporate an electricity network connection. This section presents the potential benefits that integrating the green ammonia value chain with the electricity system could provide, in particular via demand response.

4.1 Green ammonia value chain demand response – three pillars

4.1.1 Pillar 1: Load flexibility

The green ammonia value chain has minimal firmed electricity requirements. Figure 49 shows that the rough rule of thumb for the electricity currently required to produce 1 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

[7] *Refer to (Mayer, et al., 2023) for blue ammonia cost estimates.*

exothermic Haber Bosch ammonia production process (Refer to Hydrogen Conversion Process Information Sheet 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).

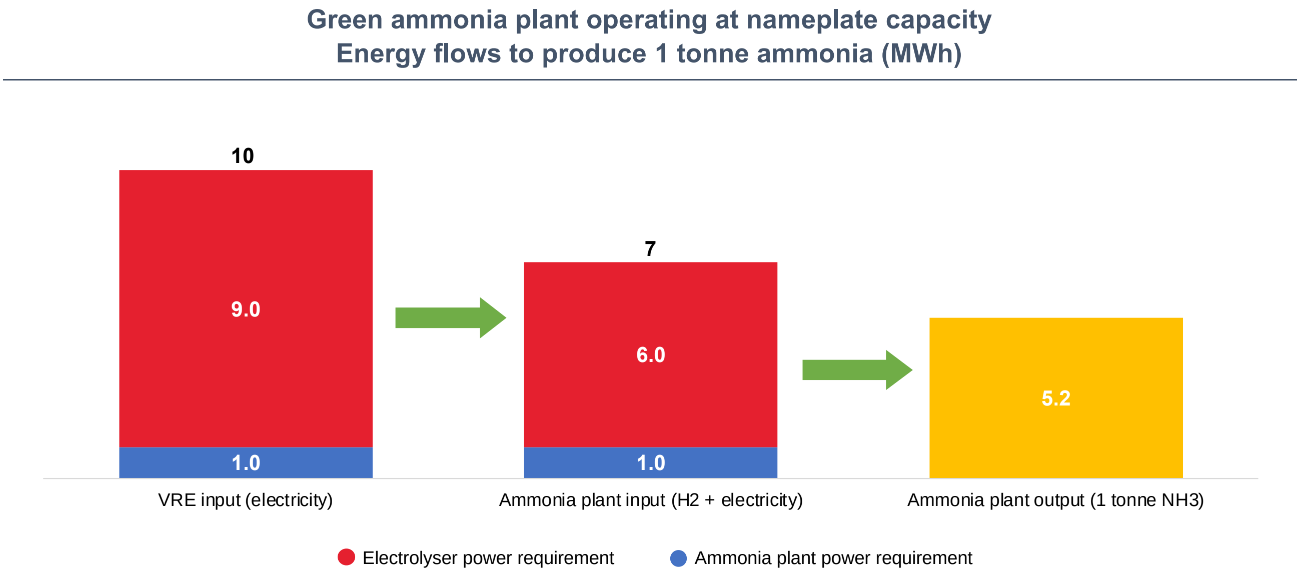


Figure 49: Green ammonia plant – simplified energy flows at nameplate capacity

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 50 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 50 is a conservative depiction as on a capacity basis demand response potential is 90% of nameplate capacity, as the minimum hydrogen feedstock requirement can be met by hydrogen storage, with electricity supply only required to operate the ammonia plant. Salt cavern hydrogen storage could provide sufficient storage capacity to deliver an ammonia plant's hydrogen feedstock requirements for extended periods, effectively leveraging the ammonia value chain's demand response capability. For simplicity Figure 50 does not include a turndown of electricity requirements for the ammonia plant (HB), which is also conservative.

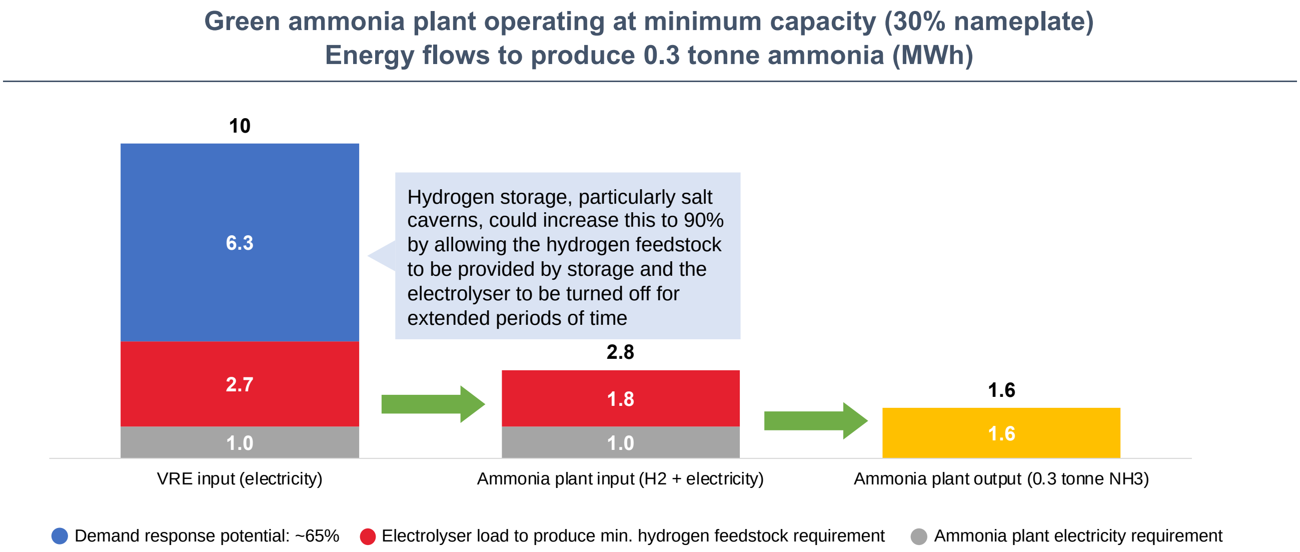


Figure 50: Green ammonia plant – simplified energy flows at minimum operating capacity

4.1.2 Pillar 2: Low-cost storage

Figure 51 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.

Moving from left to right across Figure 51 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)[8]. Figure 51 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 tanks 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.

[8] *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.*

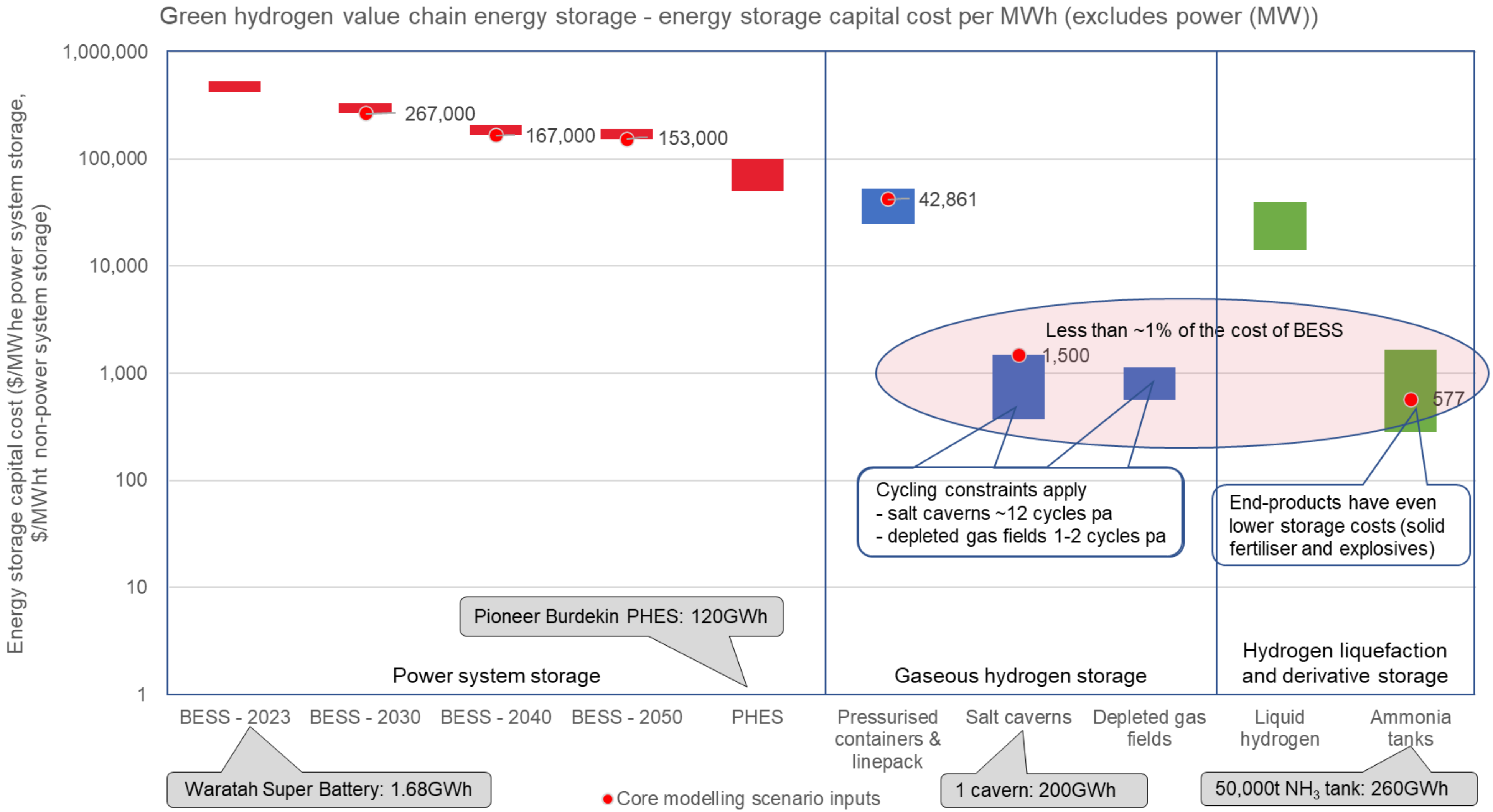


Figure 51: Green hydrogen and ammonia value chain energy storage – energy storage capital cost per MWh (excludes power (MW))

Source: (Australian Energy Market Operator, 2022d), other (refer to Section 4.3 of Energy Storage Information Sheet). Assumptions: Lower heating value of hydrogen of 33.33kwh/kg and lower heating value of ammonia of 5.2MWh/tonne,

4.1.3 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 52 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). For further detail refer to Transport Information Sheet. Figure 52 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.

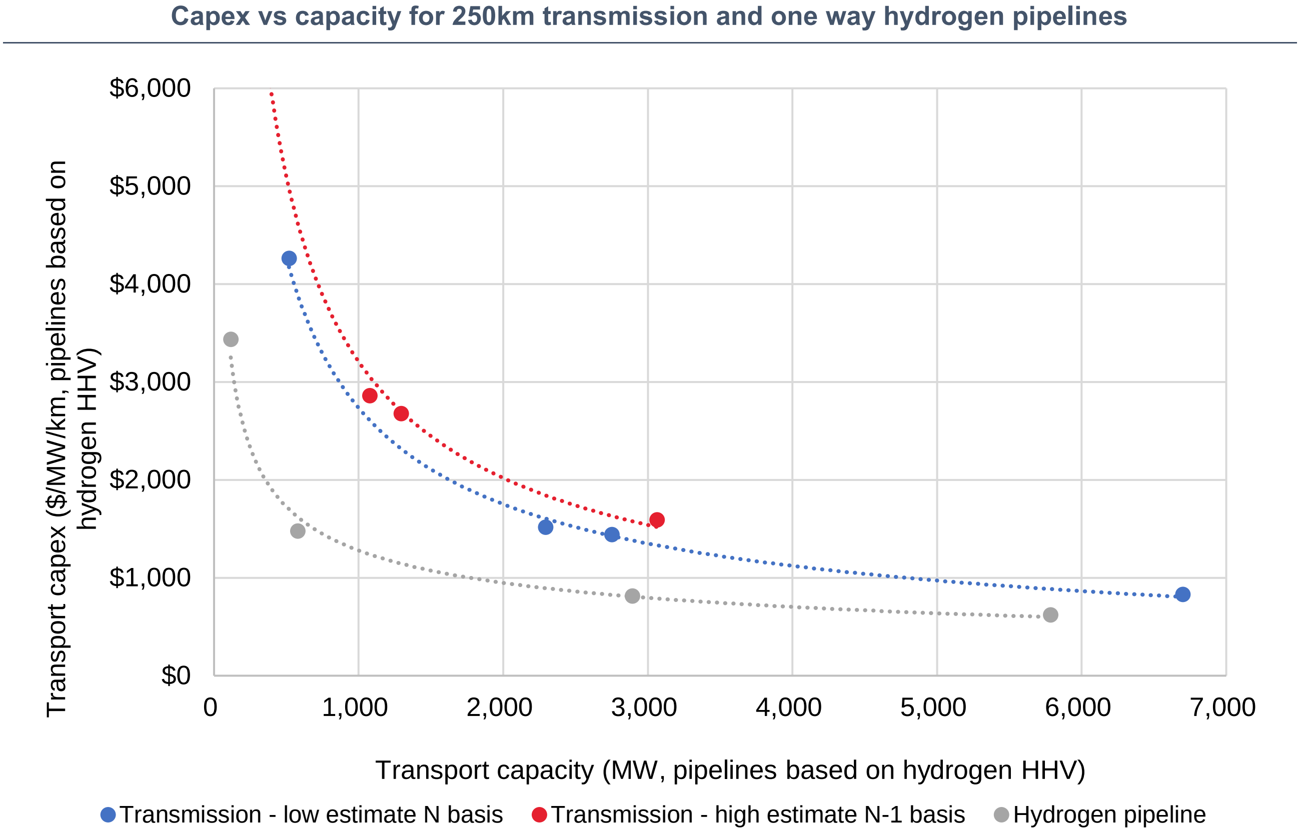


Figure 52: Capex vs. capacity for 250km transmission and one way hydrogen pipelines

Thus, a hybrid model that incorporates hydrogen pipelines for transport and an electricity transmission connection to enable the provision of demand response services is proposed. The grid connection links the flexible load, low-cost ammonia and/or hydrogen storage with the electricity system, maximising potential sector coupling benefits.

4.2 Hybrid green ammonia value chain model

4.2.1 Overview

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. 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.

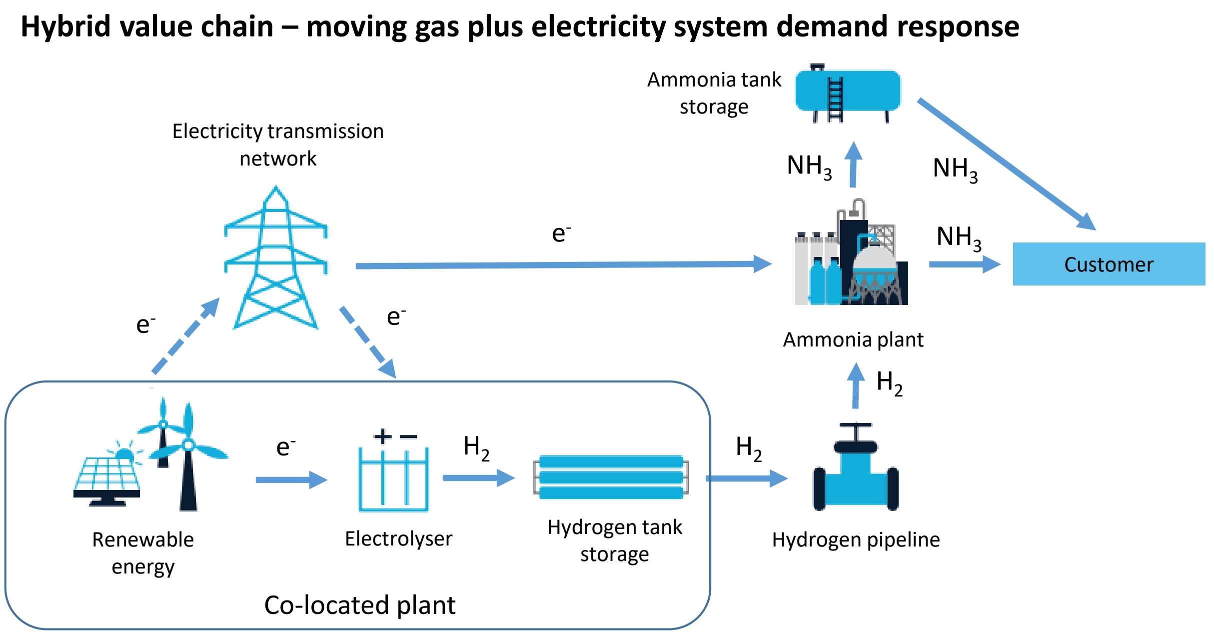


Image source: CSIRO (2023) Hydrogen vehicle refuelling infrastructure

Figure 53: 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.

4.2.2 Electricity network connection sizing considerations

The economic benefit and revenue from providing these services would need to be greater than the additional electricity network connection and other integration costs for the hybrid value chain model to be preferred to an islanded model. The electricity network connection cost is driven by its capacity and an optimal capacity could be significantly less than the renewable generation capacity as:

- Maximum import capacity is limited to the electrolyser capacity (load), which is significantly lower than renewable energy generation capacity. Electrolyser load at ammonia plant nameplate capacity is roughly half or less of electrolyser capacity;
- Renewable energy generation, particularly solar PV is highly correlated, thus in general post coal retirement when there is very high renewable generation from the hybrid facility there is also likely very high grid-based renewable generation, particularly solar PV generation and potentially spillage. i.e., when hybrid facility renewables are generating at or close to their nameplate capacity the market price could be

close to zero or potentially negative. This limits the potential value of a large network connection as there is likely to be declining marginal value of export capacity and its utilisation. This generalised finding may be impacted by the degree of correlation between the hybrid renewable generation and residual demand. Optimal connection capacity is likely to be positively related to correlation between hybrid renewable generation and residual demand; and

- The co-located renewables and electrolyser is assumed to be connected to a hydrogen pipeline and electricity network and provided the pipeline is connected to sufficient hydrogen storage (e.g., salt caverns) may present a suitable location for co-located hydrogen peaking generation. A hydrogen peaker is more likely to generate when there is low system and co-located renewable energy generation and all else being equal, this may allow a reduction in the size of the shared connection asset.

Illustrative network connection capacity range – Banana Fixed-Tank, Grid HB $100MWh, 2040

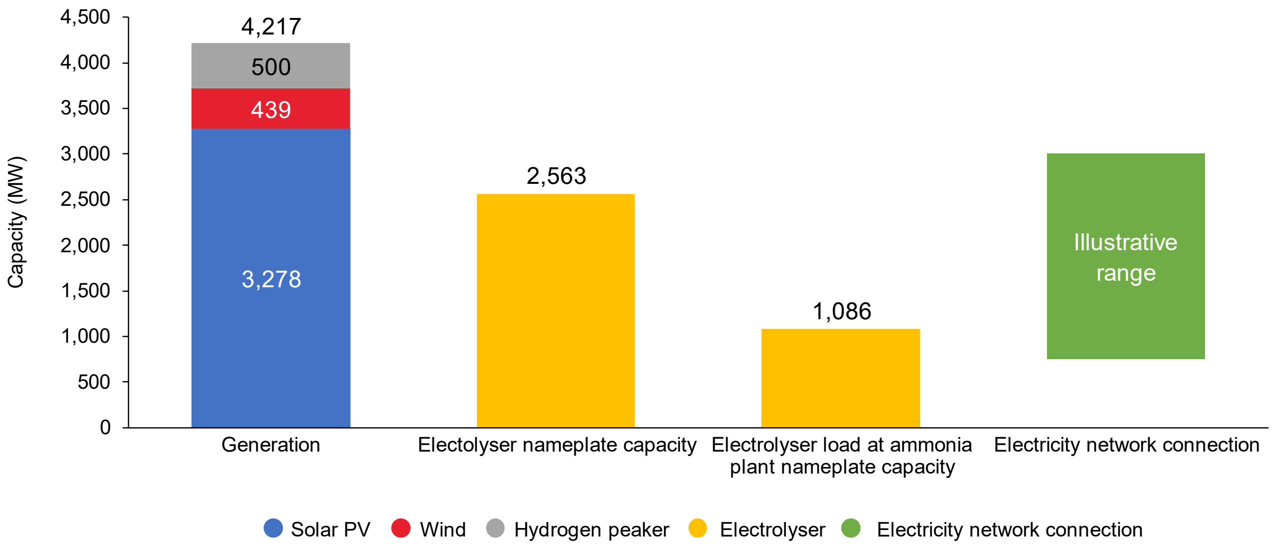


Figure 54: Hybrid value chain – Illustrative network capacity range – Banana Fixed-Tank, Grid connected HB at $100MWh 2040

4.3 Hybrid green ammonia value chain demand response services

4.3.1 Load curtailment

If an ammonia plant is co-located with renewable energy generation farm and electrolysers, but also has a grid connection, it could turn down hydrogen production and ammonia synthesis and instead sell electricity to the grid in times of high residual demand/ high prices. See section 4.2 for a description of a hybrid value chain model that also has the potential to provide demand response services.

Green ammonia value chain load curtailment could be a cost competitive form of demand response. Load curtailment is possible, provided alternative supplies of ammonia and downstream products such as fertiliser and explosives can be sourced from domestic or global markets, mitigating financial risk.

The total electricity currently required to produce one tonne of green ammonia in 2040 is 9.5MWh. If the production cost of green ammonia is in the order of 800 AUD/t for 2040, then the cost of one tonne of lost production from the ammonia plant could be recouped by selling the 9.5 MWh of electricity saved, provided the selling price was equal to 84 AUD/MWh. This breakeven cost represents the levelised cost of load curtailment. The cost may be increased by losses in efficiency and/or additional maintenance requirements from operating the plant flexibly, while the cost may also be lowered by the reduction in running hours deferring maintenance, including electrolyser membrane replacement.

Once a green ammonia plant is built the breakeven price of load curtailment may vary with domestic and international market conditions. Excluding shipping cost the breakeven price can be calculated as the ammonia price per tonne divided by the MWh of electricity required to produce green ammonia (9.5MWh in

2040). Contractual arrangements for renewable energy or ammonia sales means that plant owner behaviour may not conform with this parity pricing concept.

The linkage has parallels with natural gas where international gas prices are a key driver of domestic gas prices due to an LNG netback price (export parity price), where the profit from selling gas domestically or exporting is the same (Australian Competition & Consumer Commission, 2023). Gas is a key driver of electricity prices due its role as a marginal price setter and other generators shadow pricing gas generation, with the difference between the wholesale price of electricity and its cost of production using natural gas is referred to as the 'spark spread' (U.S. Energy Information Administration, 2013). In the future, green hydrogen derivatives could play a similar role to gas in setting electricity prices, however as a partially flexible marginal load rather a flexible generator. There may be a 'water/electrolyser split spread' with and/or green ammonia spreads, with market prices for these renewable energy vectors, becoming a key driver of electricity prices. A potential relationship with international prices could be diminished by Government policies, for example a domestic hydrogen and/or green ammonia reservation scheme.

4.3.2 Load shifting

The flexibility of the HB plant combined with electrolyser flexibility and the very low cost of ammonia storage allows load shifting to be provided on timescales from intraday to interannual, though at a minimum additional storage would be required to facilitate this service.

Seasonal load shifting could involve higher green hydrogen or green ammonia production in spring and summer being stored in salt caverns and ammonia tanks respectively and delivered to customers in winter. A future Queensland green ammonia value chain could contribute to addressing the 'winter problem' in both Queensland and southern NEM states via turning down to displace gas generation in Queensland and by exporting renewables south.

Interannual load shifting could involve higher green hydrogen or green ammonia production in El Nino years (higher solar PV generation) being stored in salt caverns and ammonia tanks respectively and delivered to customers in La Nina years (lower solar PV generation). The storage required to enable this service could act as a strategic energy reserve, as both a source of fuel for electricity generation via an ammonia engine or turbine or a source of electricity via load shifting (reducing green hydrogen or green ammonia production in order to export renewables to the grid).

The availability of load curtailment and load shifting from a green ammonia value chain would not be guaranteed, since it would also be subject to a number of factors, including the variability of behind-the-meter renewable generation, hydrogen storage levels and plant turndown constraints. This demand response is therefore not directly comparable to dispatchable generation such as gas peakers and as a result may not be useful in all instances, but in the future, it could be a valuable option as part of a portfolio of solutions for managing short, medium and longer-term renewable supply-demand imbalances, including renewable energy droughts and seasonal energy imbalances.

4.4 Levelised cost analysis

4.4.1 Methodology

4.4.1.1 Overview

In order to provide a high-level comparison of firming technologies a range of levelised cost measures are calculated, including new measures for demand response. The broad approach draws on (Schmidt, Melchior, Hawkes, & Staffell, 2019) and is consistent with the calculation approach taken in the CSIRO Renewable Energy Storage Roadmap (CSIRO, 2023B), which should be referred to for further details on methodology. Key input assumptions are sourced from CSIRO GenCost 2022-23: Consultation Draft (CSIRO, 2022A) and the 2022 Technical Cost and Technical Parameter Review (Aurecon, 2022), both of which are key inputs to the AEMO ISP. A 7% discount rate is assumed to apply to all technologies. Detailed levelised cost input assumptions and calculations can be found in the appendix (Section 6.10).

4.4.1.2 Levelised cost of Electricity (LCoE) - Open Cycle Gas Turbine (OCGT)

Small OCGT (Australian Energy Market Operator, 2022d) are assumed given the proposed development of aeroderivative turbine projects in Queensland (CS Energy, 2023; Quinbrook Infrastrucutre Partners, 2023), driven by faster start up times and greater redundancy from multiple units. LCoE is a simple calculation and tool for comparing the competitiveness of different electricity generation technologies, albeit noting intermittency. It is the total unit costs a generator must recover to meet all its costs including a return on investment when operating at practical output levels. It is calculated by dividing the net present value of the total cost of the asset, which includes the initial capital investment, operations and maintenance (O&M), and any fuel costs, by the total electricity generation over its lifetime.

A limitation of the LCoE methodology is that is does not explicitly consider fuel storage costs, particularly for a seasonal operating profile .There is limited literature regarding the capital cost of depleted gas field storage of natural gas, with what is available (Federal Energy Regulatory Commission, 2004) pointing to the capital cost per MWh of energy storage being immaterial. Industry feedback is that there is a typical $2-$4GJ seasonal gas price spread for the Iona Gas Storage Facility, located in Victoria and this represents a useful proxy for costs. Given the current existence of LNG export industry in Queensland, that can effectively provide demand response to the gas market by reducing export volumes, particularly seasonally and uncertainty around natural gas storage costs, no energy storage costs are included for OCGT.

Carbon emissions are assumed to be 0.54t CO_2e/MWh (Australian Energy Market Operator, 2022d), with Surat Basin natural gas supply chain methane leakage of 0.4% assumed with a global warming potential of 28 times CO_2 over 100 years increasing this figure to 0.60t CO_2e/MWh (Clean Energy Regulator, 2022; Neininger, Kelly, Hacker, Lu, & Schwietzke, 2021). Carbon costs are assumed to be to US$200/t CO_2e, based on future cost projections for direct air capture excluding storage of between US$100-200/t CO_2 ($A142-$A284/t CO_2) (CSIRO, 2022B). There is significant risk around cost projections for direct air capture, as the technology is currently high cost and has not been deployed at scale (CSIRO, 2022B)

4.4.1.3 Levelised cost of Storage (LCoS) – Power system storage, hydrogen and ammonia engines

Levelised cost of storage (LCoS) is relevant for power system storage and generation which uses green hydrogen and green ammonia as a fuel. LCoS can be defined as the sum of discounted costs per unit of delivered electricity over an investment's lifetime, which is equivalent to the average price that electricity can be sold at that results in a net present value of investment of zero. The approach uses separates renewable energy or fuel costs, energy storage costs and generation costs, so that cost drivers can be better understood. Generic cost estimates for PHES are sourced from the AEMO ISP (Australian Energy Market Operator, 2022d) rather than using cost estimates for the Borumba Pumped Hydro project that are double the AEMO ISP capex (Queensland Government, 2023).

LCoS for hydrogen (using salt cavern storage) and ammonia assumes the cost of firmed hydrogen and ammonia, based on the detailed optimisation modelling results. Hydrogen or ammonia is assumed to be produced and stored then used as a fuel in an engine to produce electricity, assuming a cost of $3.20/kg H_2 and $800/t NH_3, with the cost of additional hydrogen or ammonia storage added respectively to facilitate the assumed cycling interval. The use of firmed hydrogen/ammonia cost simulates a high level of reliability, similar to that of an OCGT.

As the capital cost input assumptions for hydrogen and ammonia storage are based on lower heating values, the cost of required storage needs to be grossed up to account for efficiency losses in engines. Assumed engine efficiency is 30.7% based of a conversion rate of 3.6=1MWh, divided by a heat rate of 11.7GJ/MWh. Thus storage capex is adjusted upward to account for the 30.7% efficiency from $1,500/MWh to $4,875/MWh for hydrogen and from $577/MWh to $1,875/MWh for ammonia.

No hydrogen value chain leakage is assumed or CO_2e emissions from the combustion of hydrogen and ammonia in engine.

4.4.1.4 *Levelised cost of load curtailment (LCoLC) and levelised cost of load shifting (LCoLS) – Ammonia load curtailment and ammonia load curtailment*

To the best of the author's knowledge levelised cost measures for demand response are not defined in the literature. The levelised cost of load curtailment (LCoLC) and levelised cost of load shifting (LCoLS) could be relevant for a range of different flexible industrial loads, however for the purpose of this report are estimated for a green ammonia hybrid value chain providing demand response services to the electricity system. From an electricity network perspective load curtailment involves the exporting of renewable energy into the grid when prices are high, while load shifting involves acting as load to capture renewables that would otherwise be spilled and exporting renewable energy to the grid when prices are high. The green ammonia value chain is already assumed to operate with a degree of flexibility to minimise islanded ammonia production cost and providing demand to the grid, within the constraints of plant operation, would be in addition to this (see Section 4.4.2 for analysis on potential volume of demand response)

LCoLS has the same broad definition as LCoS and is equivalent to the average price at which electricity can be sold such that the marginal investment required to facilitate the load shifting has a net present value of zero. The marginal investment is the additional ammonia storage required. To load shift one tonne of ammonia production (9.54MWh of input electricity in 2040), the one tonne of additional ammonia storage required has an assumed capital cost of \$3000/t NH_3, equivalent to \$315/ MWh of input electricity.

LCoLC has the same broad definition as LCoS and LCoLS and is equivalent to the average price at which electricity can be sold such that the net present value of the sum of the investment in the ammonia plant plus the electricity sold into the grid is unchanged. The key cost of load curtailment is the opportunity cost of foregoing revenue from ammonia production, with no marginal investment required.

In order to ensure consistency with levelised cost calculations for other technologies, grid connection and transport costs are not included for LCoLS and LCoLC. Cost of inefficiencies in electricity usage in ramping up and down the ammonia plant is not considered, though it is not expected to be material to levelised cost calculations.

4.4.1.5 *Key Divergences from CSIRO Renewable Energy Storage Roadmap*

Key divergences from the CSIRO methodology are:

- The inclusion of green ammonia;
- The inclusion of LCoLC and LCoLS measures;
- Levelised cost measures are calculated based on daily (365 cycles pa), intraweek (52 cycles pa) and seasonal cycling (1 cycle pa);
- The use of firmed hydrogen/ammonia cost is a more conservative approach than (CSIRO, 2023B) ;and
- For BESS LCoS energy storage capacity degradation is accounted for by adjusting energy storage capital cost per kW upward, while CSIRO's approach is to include a degradation assumption per storage cycle (CSIRO, 2023B). BESS round trip efficiency degradation is accounted for by using an average round trip efficiency over the economic life, while CSIRO does not incorporate it (CSIRO, 2023B).

4.4.2 Results

Figure 55 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).

Ammonia demand response services (load shifting and load curtailment) is 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 NH_3 divided by 9.54MWh/t NH_3, 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. Carbon costs represent almost half of OCGT LCoE. Gas storage costs are not considered and would further increase costs. The levelised cost analysis has a long-term focus (2040), however it is noted that in the short to medium term OCGT offers high reliability, high technology readiness level and low deliverability risk. OCGT is particularly important when 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).

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.

Further discussion of the results for seasonal cycling and other potential solutions to address the winter problem are contained in Section 4.7.4.

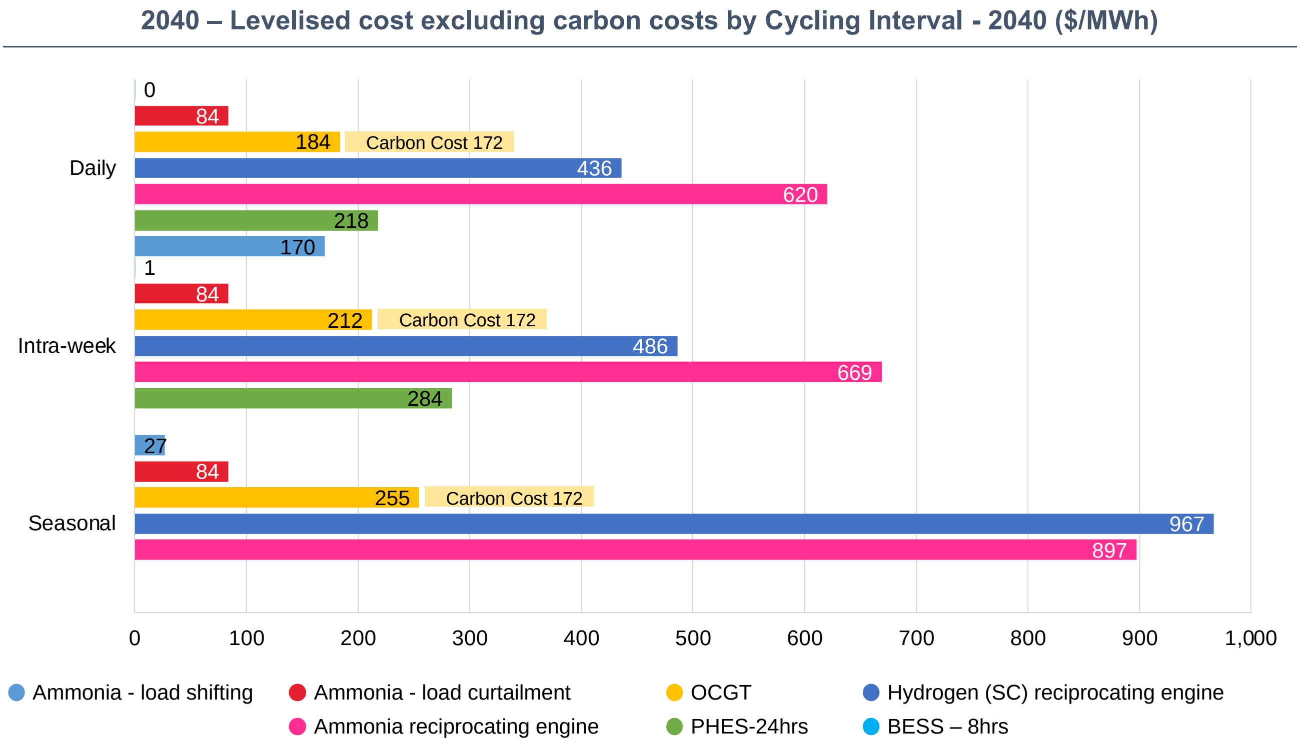


Figure 55: Levelised cost by cycling interval – 2040 ($/MWh)

2040		OCGT (small)	Ammonia - Load Curtailment	Ammonia - Load Shifting
Inputs				
Economic Life	Years	25	25	25
Power Capital Cost	$/kW	1,285	-	-
Energy Capital Cost	$/kWh	-	-	0.3
Short run marginal cost – ex carbon cost	$/MWh	113	-	-
Carbon cost	$/MWh	172	-	-
Daily				
Storage duration	hours	-	24	24
Capacity factor	%	20	20	20
Levelised cost of load curtailment	$/MWh	-	$84	-
Levelised cost of load shifting	$/MWh	-	-	$0.4
Levelised cost of electricity ex carbon cost (inc. carbon cost)	$/MWh	184 (356)	-	-
Intraweek				
Storage duration	hours	-	24	24
Capacity factor	%	14.2	14.2	14.2
Levelised cost of load curtailment	$/MWh	-	$84	-
Levelised cost of load shifting	$/MWh	-	-	$0.5
Levelised cost of electricity	$/MWh	212 (385)	-	-
Seasonal				
Storage duration	hours	-	438	438
Capacity factor	%	10	5	5
Levelised cost of load curtailment	$/MWh	-	$84	-
Levelised cost of load shifting	$/MWh	-	-	$27
Levelised cost of electricity	$/MWh	255 (427)	-	-

Table 11: Levelised cost of green ammonia hybrid value chain demand response and OCGT (small)- 2040 *Source: (Australian Energy Market Operator, 2022d)*

4.5 Hybrid green ammonia value chain – demand response potential

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'. To estimate the demand response potential in winter, a scenario was run in which the HB plant is turned down to its minimum load of 30% over winter (June, July, August) (Figure 56). The capacity build is the same as the islanded fixed case[9]. NQCEH and Isaac (2030) are both located in the 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

[9] *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.*

could potentially be exported to the grid. The modelling assumes the same turndown for hydrogen and electricity input to the ammonia plant. If no turndown of the electricity requirement was assumed this would reduce potential exports by ~10%. 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

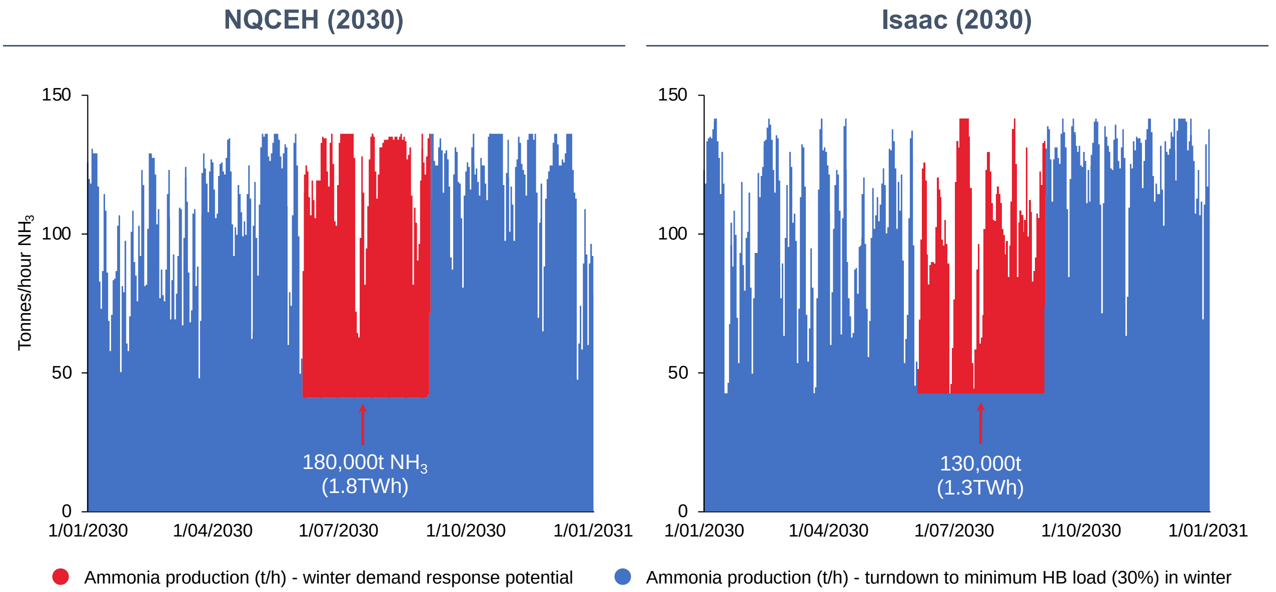


Figure 56: Daily ammonia production in the demand response case vs normal operation for NQCEH and Isaac for 1 year (2030).

Winter demand response potential is dependent on the seasonal profile of generation with REZ in the north of the state (NQCEH (Q2) – hybrid and North Queensland (Q3) – solar) having the highest demand response potential. Demand response potential for hybrid REZ is influenced by increasing solar portfolio weightings and the potential can vary between different REZ. In general demand response potential in GWh reduces over time due to increasing electrolyser efficiency lowering MWh/t requirement. However, breakeven cost of providing demand response decreases with LCOA due to lower capex cost.

			Levelised cost of ammonia (LCOA) ($/t NH_3)		Winter demand response based on 1mtpa production, Fixed – lower NH_3 storage cost			
		REZ	Fixed - Tank	Fixed – Tank, lower NH_3 storage cost	Potential (ktpa NH_3)	Potential (GWh pa)	Plant efficiency (MWh/t NH_3)	Breakeven cost ($/MWh)
2030	**Hybrid**	NQCEH (Q2)	958	940	173.2	1,722		94.6
		Isaac (Q4)	1,013	989	135.7	1,349		99.5
		Barcaldine (Q5)	965	943	137.6	1,368		94.8
		Banana (Q9)	1,032	1,004	138.6	1,378	9.9	101.1
	Solar	North Queensland (Q3)	1,220	1,190	147.3	1,464		119.8
		Fitzroy (Q6)	1,139	1,105	132.2	1,314		111.2
		Darling Downs (Q8)	1,142	1,105	116.2	1,155		111.2
2040	**Hybrid**	NQCEH (Q2)	761	743	164.9	1,573		77.9
		Isaac (Q4)	806	782	138.2	1,319		82.0
		Barcaldine (Q5)	760	737	136.7	1,304		77.3
		Banana (Q9)	811	783	137.9	1,315	9.5	82.1
	Solar	North Queensland (Q3)	960	935	152.4	1,454		98.0
		Fitzroy (Q6)	885	853	138.8	1,325		89.4
		Darling Downs (Q8)	883	851	122.5	1,168		89.2
2050	**Hybrid**	NQCEH (Q2)	646	630	161.1	1,476		68.7
		Isaac (Q4)	687	664	141.0	1,292		72.4
		Barcaldine (Q5)	641	619	138.5	1,269		67.5
		Banana (Q9)	684	660	140.3	1,286	9.2	72.0
	Solar	North Queensland (Q3)	817	794	155.3	1,424		86.7
		Fitzroy (Q6)	744	715	142.6	1,306		78.0
		Darling Downs (Q8)	738	711	127.0	1,164		77.6

Table 12: LCOA and demand response potential for 1mtpa ammonia plant for fixed scenario by REZ

In order for green ammonia value chain demand response to be of value to the electricity system, in particular by reducing gas generation, renewable energy exports from the plant must occur at time when there is either:

- Positive residual demand (demand is greater than renewable generation); or
- Negative residual demand (surplus renewable generation), but excess power system storage to time-shift exported renewables to future time periods, to displace gas generation.

Detailed modelling is required to assess potential value, however a key value driver that can be explored is correlation with the market renewable energy portfolio. Given the quality of the renewable resources and proximity to the Southeast Queensland (SEQ) load centre, a large capacity of solar and wind is built in Darling Downs REZ in the 2022 AEMO ISP. In addition, the majority of Queensland's rooftop PV is in SEQ, which is reasonably close to Darling Downs REZ. Thus, ignoring any potential transmission constraints, the utilisation and thus value of demand response could be inversely related to the correlation of demand response availability and Darling Downs renewable generation.

As the ammonia plant renewable portfolios are dominated by solar, demand response potential has higher correlation with Darling Downs solar than wind (Table 13). Not all of the demand response potential is useful due to renewable resources correlation. However, there is likely to be some benefit to demand response potential from having hybrid green ammonia value chains, particularly that incorporate wind, in a number of locations across the state.

	Darling Downs Solar Generation	Darling Downs Wind Generation
NQCEH demand response	51%	-10%
Barcaldine demand response	67%	10%
Banana demand response	37%	19%

Table 13: Correlation of winter daily demand response potential of different REZs with Darling Down renewable generation

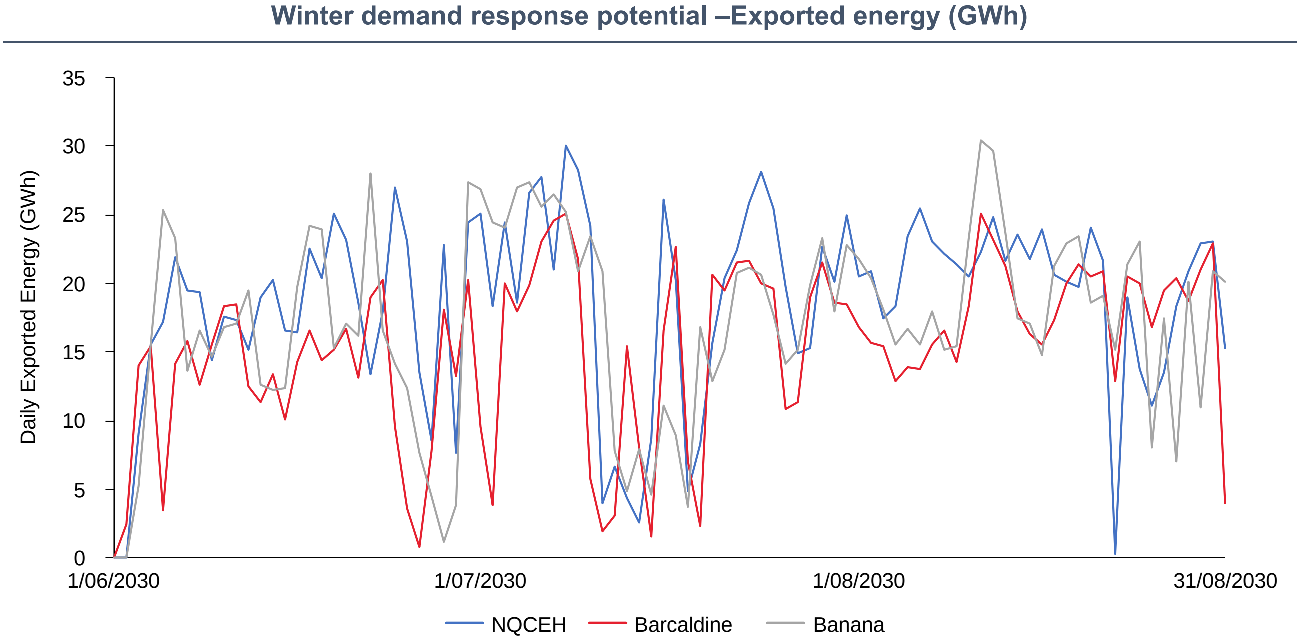


Figure 57: Energy available for export into grid (GWh) of 1mtpa ammonia plant Fixed -Tank, Grid HB $100MWh, 2030

Given the low cost of green ammonia value chain demand response (Refer to Section 4.4.2) co-optimising the ammonia value chain and the energy system could potentially lead to higher winter demand response potential from a higher proportion of wind in the ammonia plant's renewable portfolio. Such a co-optimisation should also consider the impact of transmission constraints and losses.

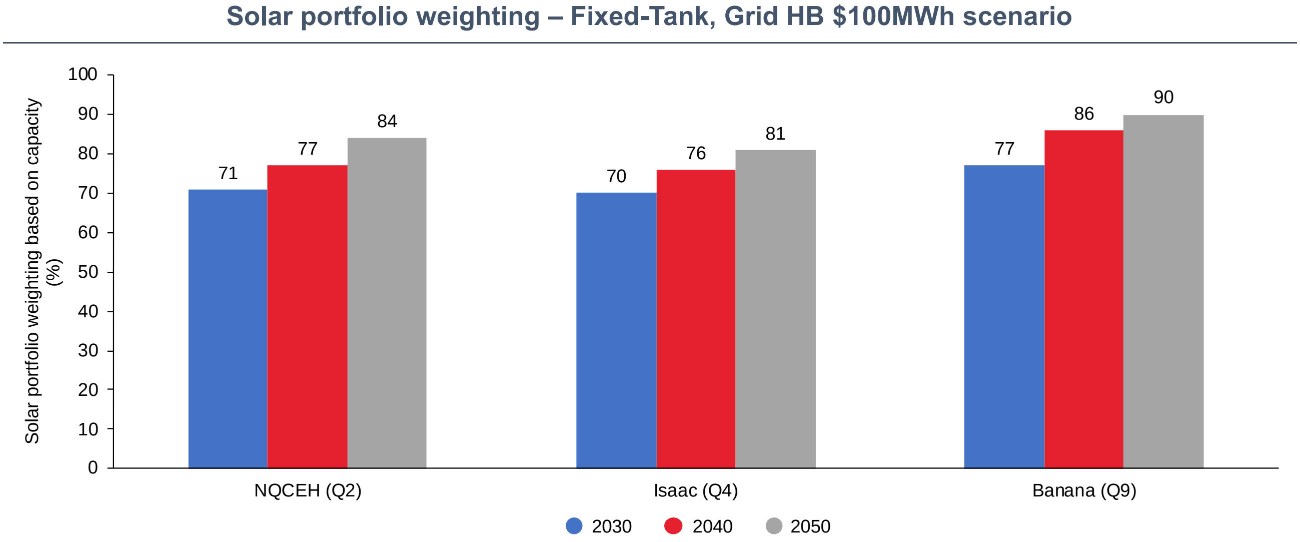


Figure 58: Solar portfolio weighting – Fixed – Tank, grid HB $100MWh, scenario selected REZ (%)

Figure 59 provides an example of the potential value, as represented by a reduction in LCOA vs an islanded plant, for green ammonia hybrid value chain demand response in 2040, assuming load curtailment of 5% and 10% of annual ammonia production. The potential value of load curtailment is directly related to utilisation and OCGT short run marginal cost (SRMC) whose major components are fuel cost and carbon cost, which is represented by direct air capture costs (DAC). Potential cost reductions increase over time as the levelised cost of load curtailment decreases with LCOA, while no change in OCGT SRMC is assumed. Islanded LCOA is based on a 1mtpa islanded ammonia plant, with the impact of a $1/t reduction in LCOA from demand response roughly equal to $1m adjusted for the decrease in annual production.

Load shifting does not result in reduction in ammonia production and thus should provide additional benefits versus load curtailment. However, the gap between the OCGT SRMC and the LCoLC or LCoLS is the key driver of value for demand response.

Connection cost is assumed to be $0.1m/MW with connection capacity assumed to be 1.84x the electrolyser load at ammonia plant nameplate capacity (refer to 4.2.2 for more details). Based on a 20-year economic life and 7% discount rate, this increases the cost of load curtailment by $43/MWh assuming 5% load curtailment and $22/MWh assuming 10% load curtailment. No network charges are assumed given the hybrid value chain model.

Demand response impact on LCOA: Isaac – Fixed-Tank, Grid HB $100Mwh, H_2 pipes transport (A$/t NH_3)

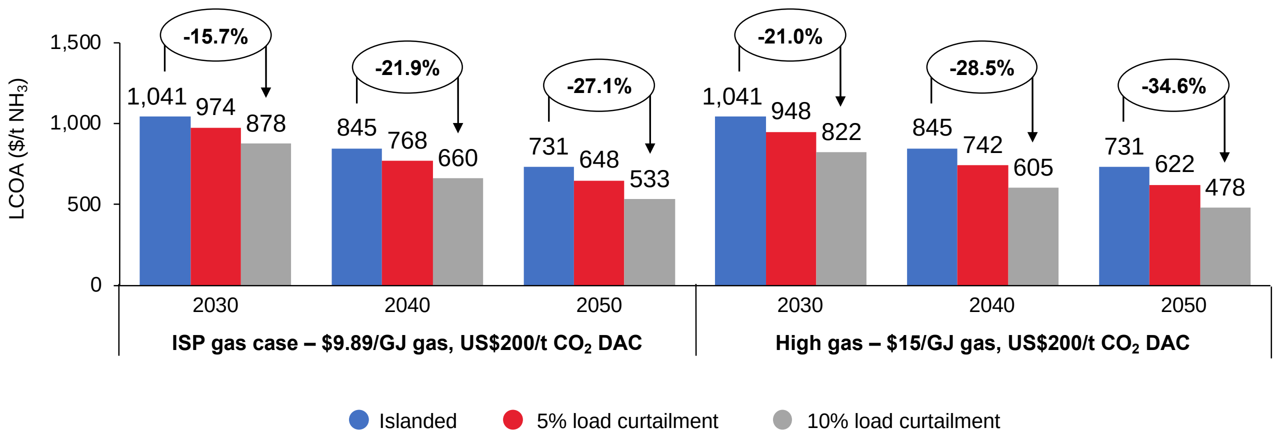


Figure 59: Demand response impact on LCOA: Isaac – Fixed, H2 pipes transport (A$/t NH_3)

Figure 60 demonstrates the impact of the load curtailment load factor, gas prices and carbon abatement costs on LCOA. The carbon cost assumption is a key driver of OCGT SRMC and thus a key driver of demand response value.

LCOA including load curtailment: Isaac 2040 – Fixed-Tank, Grid HB $100MWh, H_2 pipes transport (A$/t NH_3)

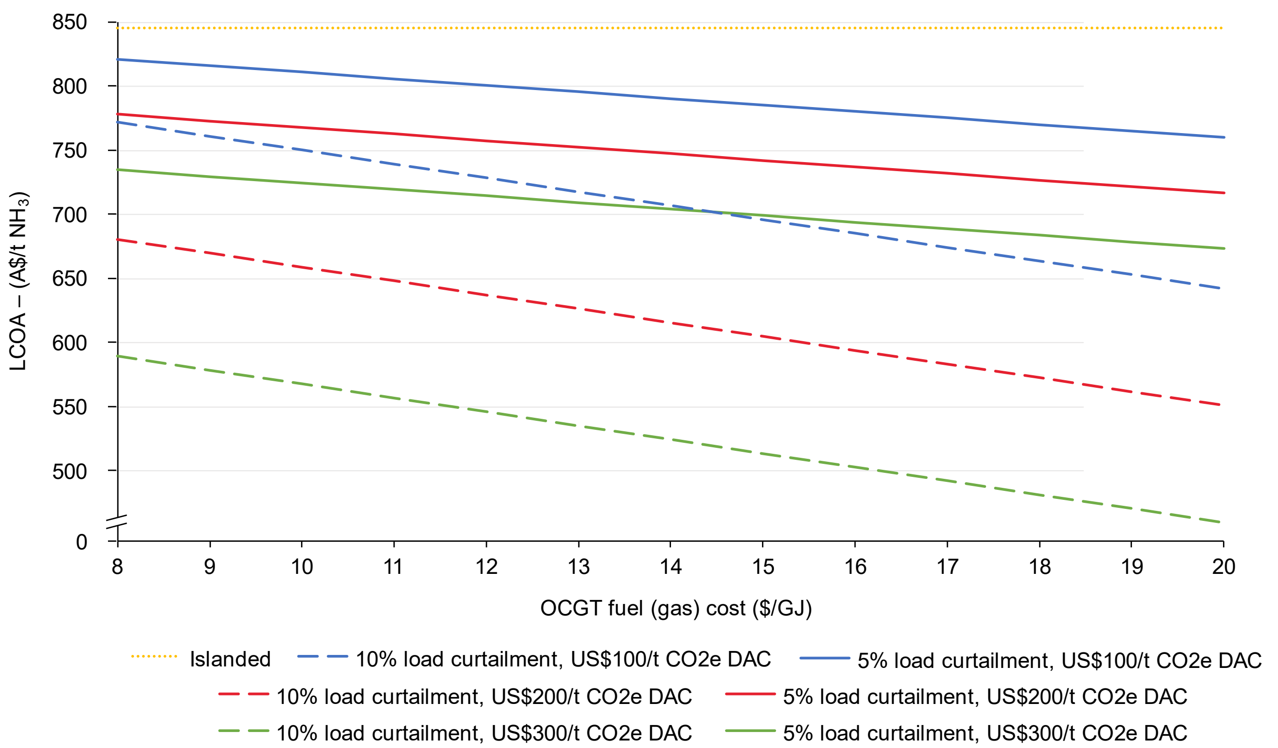


Figure 60: LCOA including load curtailment: Isaac – Fixed-Tank, grid connected HB at $100Mwh, H2 pipes transport (A$/t NH_3)

Figure 61 shows the system cost benefits of load curtailment versus an islanded plant for a 1mtpa green ammonia hybrid value chain. Pre-adjustment for lower ammonia production, a 1$/t NH_3 reduction in LCOA is equal to $1m pa of savings or an NPV of $10.6m assuming a 20-year economic life and 7% discount rate. Depending on assumption there is the potential for multibillion dollar system cost benefits, noting that 2040 plant and transport capex is estimated to be $6bn, excluding grid power supply for the ammonia plant. The estimate only considers marginal fuel and carbon abatement cost savings and not potential benefits from a reduction in firming generation.

System cost benefit of load curtailment: Isaac 2040 – Fixed-Tank, Grid HB $100MWh, H_2 pipes transport (A$/t NH_3)

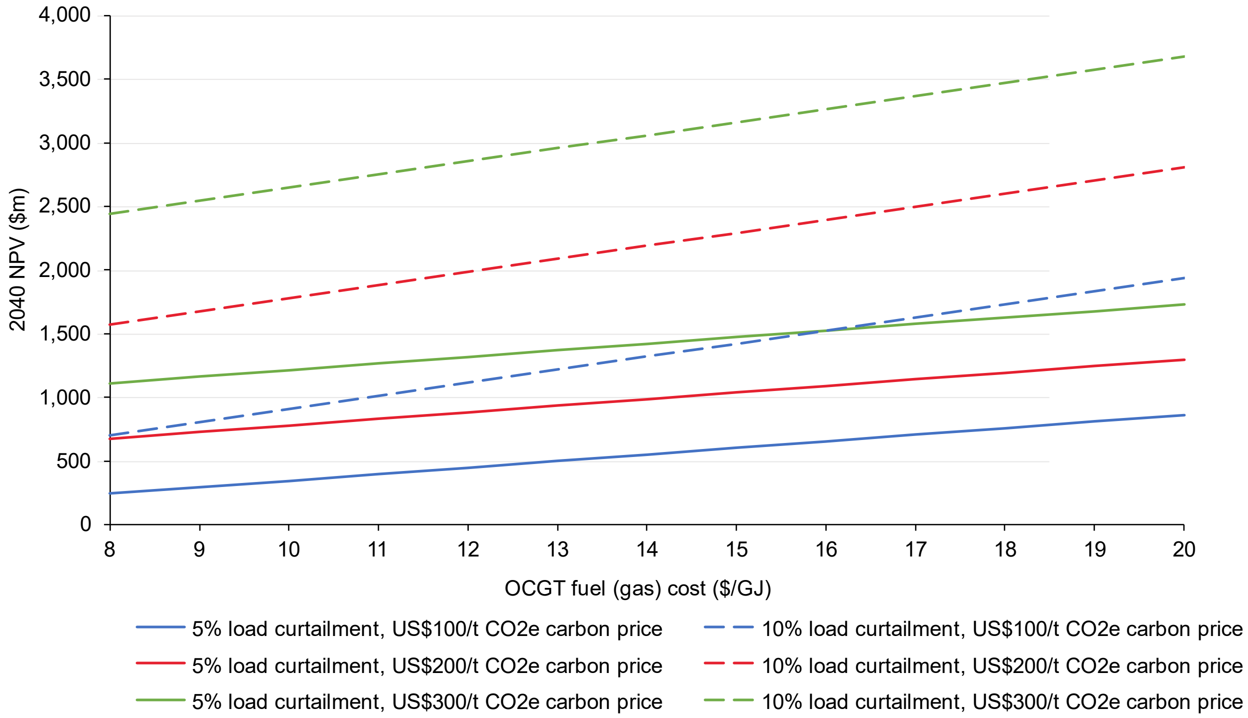
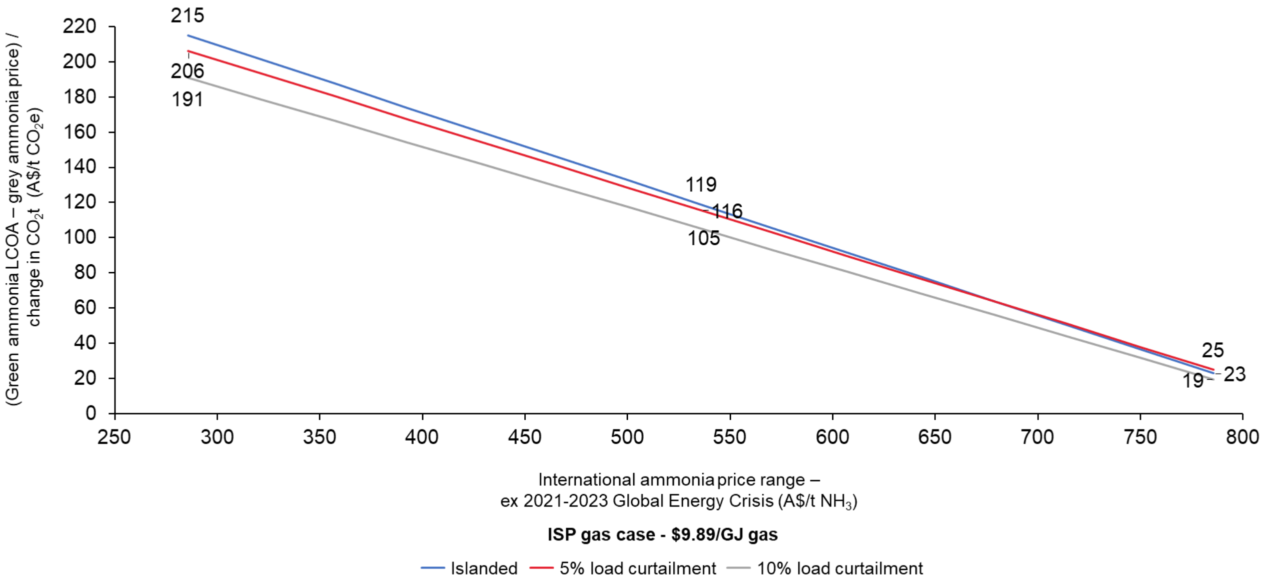


Figure 61: System cost benefit of load curtailment: Isaac 2040 – Fixed-Tank, Grid connected HB at $100MWh, H_2 pipes transport (A$/t NH_3)

Once load curtailment is incorporated the implied CO_2e abatement cost of green ammonia versus grey ammonia imports reduces. While the production of one tonne of green ammonia may abate 2.6t CO_2e[10] versus grey ammonia imports, one tonne of load curtailment is assumed to reduce OCGT generation by 9.5MWh, resulting in a 5.7t CO_2e reduction (0.6t $CO2_e$/MWh). The calculations assumes that green ammonia is able to be sourced from the market to compensate for curtailed production, with no emissions impact.

[10] *Ammonia production is assumed to have lifecycle emissions of 2.6t CO_2/t NH_3 which includes natural gas supply chain leakage (Liu, Elgowainy, & Wang, 2020; Mayer, et al., 2023).*

Demand response impact on implied CO_2e abatement cost: Isaac 2040 – Fixed-Tank, Grid HB \$100MWh, H_2 pipes transport (A\$/t NH_3)



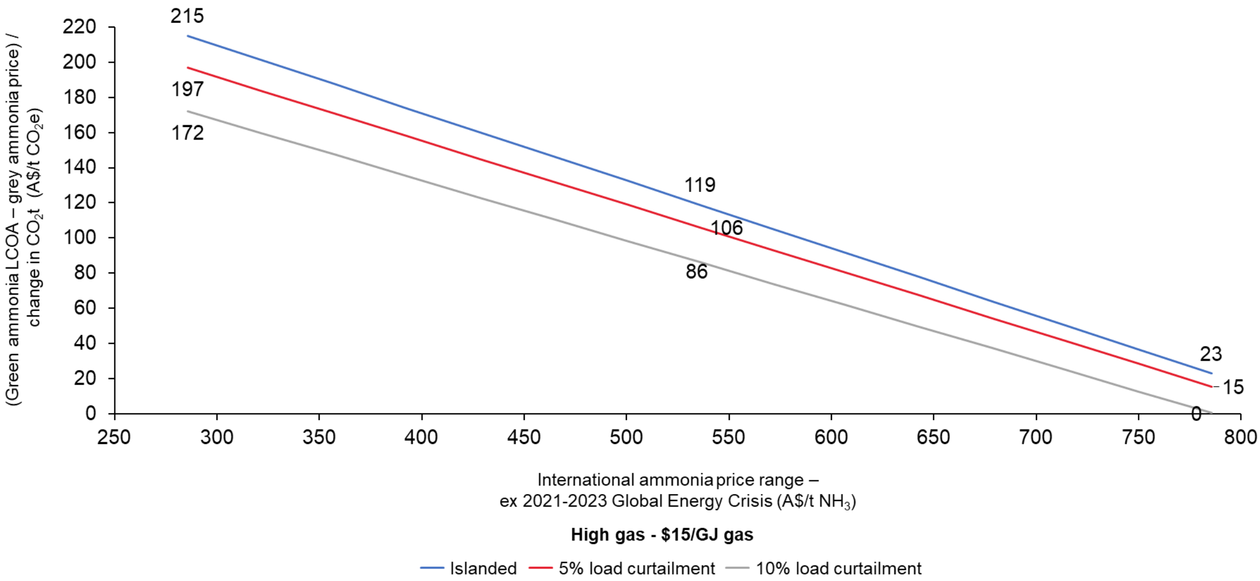


Figure 62: Demand response impact on implied CO_2e abatement cost: Isaac – Fixed-Tank, grid connected HB at \$100MWh, H_2 pipes transport (A\$/t NH_3)

4.6 Vision for green hydrogen infrastructure development

4.6.1 Phase 1 – Green ammonia exporter

Phase 1 of Queensland green hydrogen industry development focuses on green ammonia production as there is consensus that ammonia is a no-regrets clean hydrogen use case. This report shows that absent hydrogen salt cavern storage, the cost of hydrogen for uses cases that have a fixed demand profile is considerably higher than the farm gate hydrogen cost estimates widely quoted in the literature. Green ammonia does not have this issue and in fact the partial-flexibility of Haber Bosch ammonia synthesis and low-cost ammonia storage could allow potential sector coupling benefits, via green ammonia providing demand response services to the electricity system. These attributes could also apply to synthetic hydrocarbon production including green methanol, however ammonia production has the advantage of not requiring a carbon feedstock.

Timeframes for green hydrogen industry development will be impacted by various constraints including the availability of equipment, construction contractors and skilled labour. This is particularly the case, as green hydrogen may be competing for these resources with electricity systems attempting to decarbonise globally and within Australia. The high cost of green hydrogen and green ammonia will also impact timeframes with section 3.2.4.1 and Section 4.5 including estimates of significant green premiums and marginal CO_2e abatement costs for transitioning from grey to green ammonia production. As a result, a realistic timeframe for the development of multiple world scale ammonia plants (1mtpa NH_3) in Queensland could be the 2040s.

A hybrid green ammonia value is the preferred model as outlined in Section 4.2, with co-located renewables (primarily solar) and electrolysers connected to a hydrogen pipeline for transport to ammonia plants at demand centres (e.g. ports). The co-located renewables and electrolysers would have a partial connection to the electricity network to provide demand response services, while the ammonia plant would also be grid connected.

In order to enable the development of multiple world scale ammonia plants, a hydrogen pipeline following the 500kV electricity network outlined in the Queensland Energy and Jobs Plan (QEJP) is proposed as key common user infrastructure. The hydrogen pipeline may provide hydrogen transport at lower cost and lower social license risk than the alternative of building electricity transmission, that would likely be in addition to transmission proposed in the QEJP. Hydrogen pipelines have potential advantages as common user infrastructure as they can provide both transport and storage. This could reduce the risk involved in oversizing hydrogen pipelines for future potential users as the pipeline could also be used for storage for anchor pipeline users.

The location of the green ammonia value chain close to the coast where there are existing water assets and the potential for desalination, may also be more favourable location for water infrastructure costs. A substantial volume of Queensland water resources is currently allocated to carbon intensive uses such as coal fired power stations, coal mining (The University of Adelaide - The Centre for Global Food and Resources, 2020) and grey ammonia production. These water resources may become available as the global and Queensland economy transitions.

Phase 1 H_2 infrastructure development (2040) – Green ammonia exporter

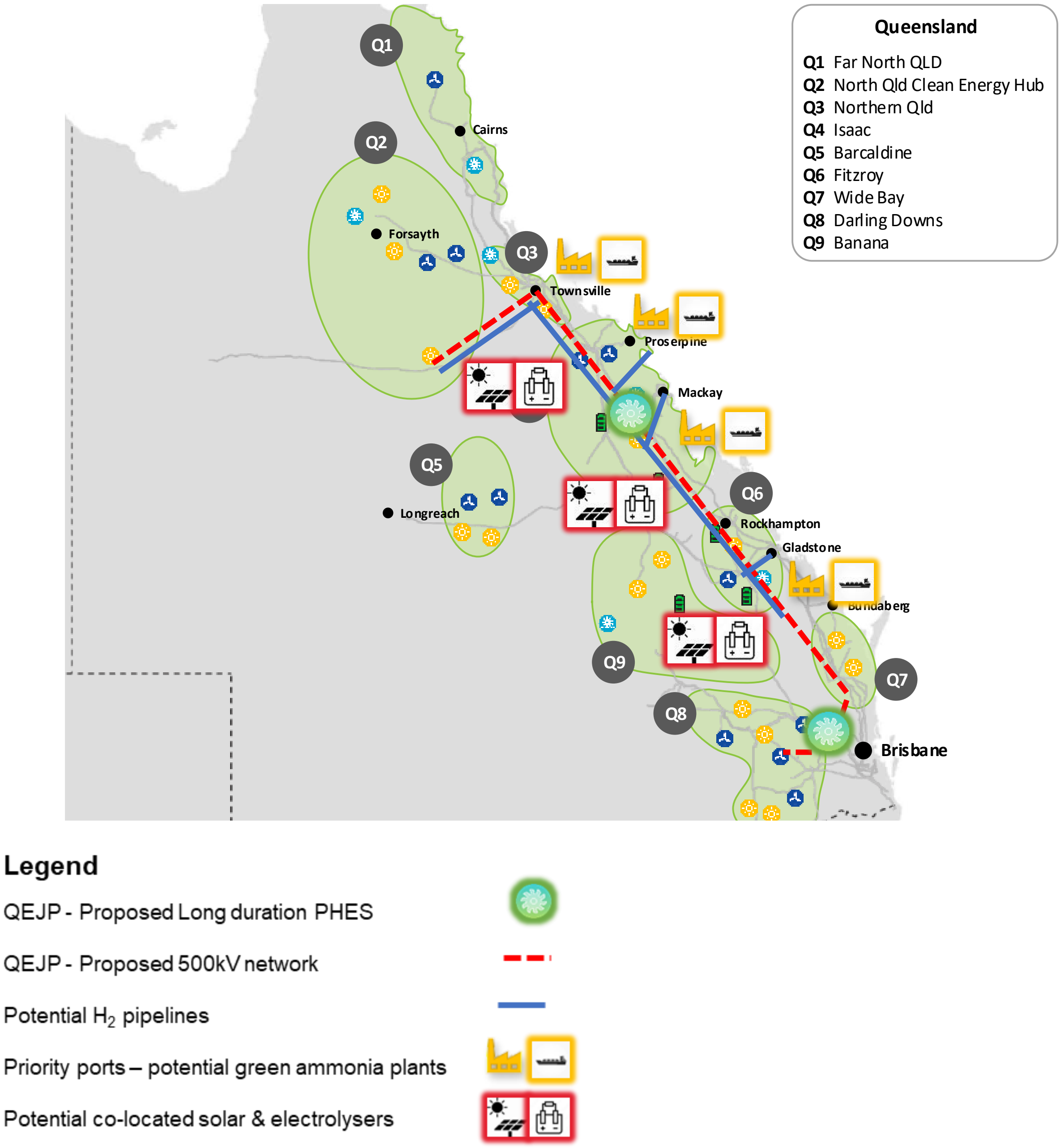


Figure 63: Phase 1 hydrogen infrastructure development (2040) – Green ammonia exporter

4.6.2 Phase 2 – Watching brief: diversified green energy exporter

Future Queensland demand for large scale hydrogen use cases that have fixed demand profiles is highly uncertain. Thus, proposed phase 2 infrastructure that could increase the competitiveness of supplying firmed hydrogen, is considered speculative and a watching brief may be appropriate.

Synthetic hydrocarbon production processes such as methanol may have similar partial-flexibility to ammonia production and low-cost storage and thus development could leverage off the phase 1 infrastructure proposed for ammonia. Development of carbon feedstock value chains and/or reduced direct air capture costs could make Queensland more competitive at scale in the production of green fertiliser and synthetic hydrocarbons. However, given the current lack of investment in direct air capture (Azarabadi, et al., 2023) deployment at scale and the level of resultant cost reductions are uncertain and could take a number of decades to eventuate.

Green iron and green alumina are two potential large scale energy export industries that may require green hydrogen (Climateworks Centre, 2023) and particularly firmed green hydrogen. Green iron presents challenges as major iron ore resources have not been identified in Queensland. Alumina calcination, which uses high temperature heat is a potential large hydrogen use case for Queensland (Leitch, 2023), though electric calcination presents a potential alternative (Climateworks Centre, 2023; ARENA, 2022).The scale of Queensland's alumina industry warrants a detailed techno-economic assessment of alternatives for the provision of decarbonised heat to the digestion and calcination processes, including green hydrogen and electrification including the integration of thermal energy storage (ARENA, 2022).

Salt cavern hydrogen storage connected to the phase 1 coastal hydrogen pipeline network could facilitate low cost firmed green hydrogen supply for alumina calcination. It could also benefit the electricity system by allowing the demand response potential of green ammonia and synthetic hydrocarbon production to be leveraged, by increasing hydrogen buffer storage (Refer to Section 4.1.1).

Consistent with Phase 1 a hybrid green ammonia value chain (islanded with partial grid connection) is the preferred model as outlined in Section 4.2, with the addition of hydrogen salt cavern storage, while ammonia plants can be substituted for synthetic hydrocarbons plants and alumina refineries.

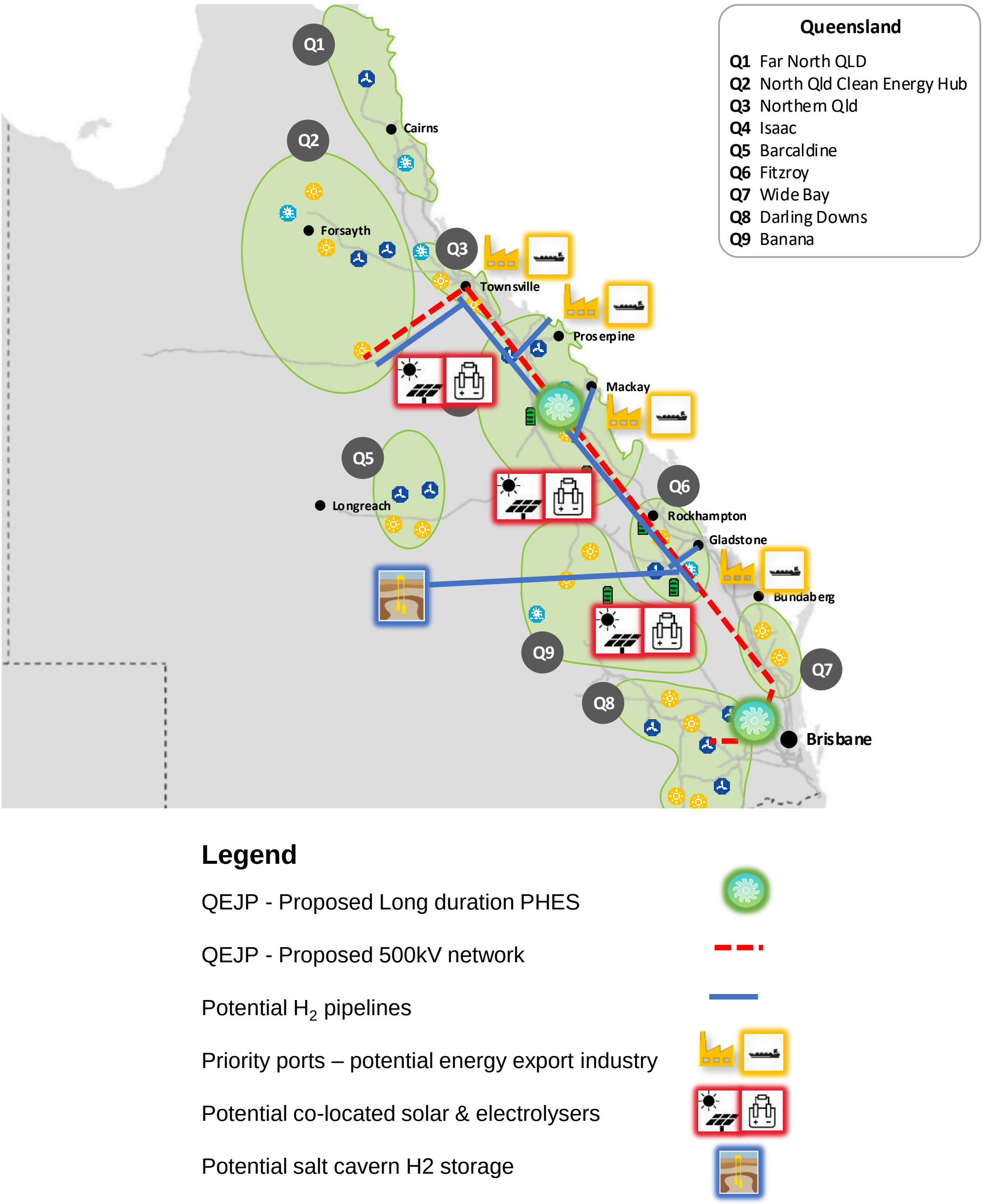


Figure 64: Phase 2 hydrogen infrastructure development (2050) – Diversified green energy exporter

4.7 Other considerations

4.7.1 International examples - 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.

4.7.2 Energy system modelling - integration of green ammonia value chain

The hybrid value chain model connects flexible and partially flexible load and low-cost ammonia and potentially geological hydrogen storage to the electricity system. (Cesaro, Bramstoft, Ives, & Bañares-Alcántara, 2023) shows that sector coupling of green hydrogen and ammonia with a future renewable energy dominated Indian electricity system significantly reduces system costs. The research involves energy system modelling that integrates the ammonia value chain with a high degree of precision, with a similar model specification to that contained in Section 3 Detailed optimisation modelling. 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 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). However, there is a growing number of examples of energy system modelling that integrates a future renewable energy dominated electricity system with hydrogen production, transport and storage. Examples include (The Royal Society, 2023) and (Aurora Energy Research, 2021) for the UK and Frontier Economics (not publicly available) for the Australian National Electricity Market.

A more accurate depiction of the flexibility and low-cost storage of the green ammonia value chain in the energy system modelling of the National Electricity Market could be highly disruptive to the typical finding of a large requirement for gas generation. In general, limited attention had been paid to accurately modelling potential future flexible industrial loads in Australian energy system modelling, which is typically focussed on the electricity system and only explicitly considers power system storage. In the current ISP methodology, ammonia production is modelled as inflexible load and hydrogen demands are modelled as flexible loads, subject to fixed monthly production requirements (Australian Energy Market Operator, 2023b). Thus, it may not fully capture the potential sector coupling benefits arising from the flexibility and low-cost storage that hydrogen and green ammonia value chains could provide, including intra-month energy shifting and load curtailment.

For Queensland and the NEM in addition to potentially reducing the quantity and mix of required dispatchable generation (storage and thermal peaking generation), the integration of green ammonia value chain, may impact the renewables mix, which could reduce requirements for enabling transmission. Thus, there could be additional benefits from reduced social licence risk and/or allowing scarce wind resources to be allocated to new energy intensive export industries, maximising economic benefits.

In addition to green ammonia, other electricity intensive industries have the potential to provide demand response services, particularly future potential electrification loads (Refer to Section 4.7.5). Thus ultimately 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 could facilitate load curtailment. Persisting with standard market modelling practices which have a narrow focus on electricity system costs may be to the detriment of least cost decarbonisation.

4.7.3 Hydrogen demand modelling

Hydrogen demand projections that are inputs into the AEMO ISP are an output from a multi-sector energy model (CSIRO and Climateworks Centre, 2022). The multi-sector energy model optimises the investment required to meet demand for energy in various sectors (e.g. transport, residential and commercial space heating), while achieving a carbon budget. The model considers various alternatives including hydrogen, electrification and incumbent fossil fuels. To make complex optimisation problems solvable within a reasonable time, simplifications are often required and this has the potential to introduce errors or bias into the results. Rather than use a time sequential modelling approach, which is best practice for variable renewable energy dominated energy system modelling, electricity demand is aggregated into 16 load blocks reflecting seasonal and time of day variation across the year (CSIRO and Climateworks Centre, 2022). This compares to 30 typical periods with 24 typical times slices used in modelling green hydrogen for the International Energy Agency's Global Energy and Climate Model (International Energy Agency, 2023B). As the approach taken in the multi-sector modelling (CSIRO and Climateworks Centre, 2022) may not capture full firming costs it could result in biased cost estimates for hydrogen and electrification, leading to biased demand estimates. In addition, asset-level assumptions are made for how alumina, steel and petroleum refining facilities are decarbonised, which are not detailed (CSIRO and Climateworks Centre, 2022).

Due to the aforementioned issues hydrogen demand projections from AEMO ISP Multi-sector energy modelling should be treated with caution. AEMO's approach could be enhanced by providing a more granular breakdown of hydrogen demand projections and separate detailed use case modelling for hydrogen vs alternatives using time sequential modelling.

4.7.4 Other potential options to address the winter problem

Except for ammonia demand response, the levelised cost for seasonal cycling of firming alternatives is high demonstrating the high cost of addressing the winter problem based on these firming options. Further investigation of these firming options is required as well as alternatives that could contribute to addressing the winter problem including:

- For OCGT, the potential for higher gas costs and the inclusion of the cost of infrastructure required to deliver a seasonal supply of gas, post future closure of LNG export industry and decarbonisation of ammonia and alumina industries. The AEMO 2023 Inputs Assumptions and Scenario Consultation (Australian Energy Market Operator, 2023C) has 2040 gas fuel cost projections of $12.98/GJ for 2040, $3.09/GJ higher than used in the LCoE analysis, that would result in a $31/MWh increase in LCoE. LCoE estimates for OCGT do not include the cost of gas storage and also implicitly leverage off a gas pipeline network where the other main Queensland gas users are ammonia and alumina industries. A $2 winter price premium for gas, based on an estimate of typical Iona seasonal gas price spread, would increase LCoE by $20/MWh;
- For industries where heat is decarbonised through electrification, retaining natural gas boilers to operate in times of high electricity prices, which on a system basis could result in ~65% reduction in gas usage vs an OCGT;
- For hydrogen engines an assessment of alternative hydrogen geological storage options, including depleted oil and gas fields. For a hydrogen engine the assumed hydrogen salt cavern storage capex of $50/kg H_2 is at the top of the capex estimate range in the literature and drives the high LCoS for seasonal cycling. Halving storage capex to $25/kg H_2 reduces the LCoS for seasonal cycling of a hydrogen engine by more than $200/MWh to $758/MWh, demonstrating the sensitivity to the cost of geological-hydrogen storage;
- Peaking generation fuelled by synthetic hydrocarbons, for instance methanol, that could potentially have lower storage capex than ammonia;
- Demand response from current (e.g. aluminium) and future potential electricity intensive industries (e.g. alumina). Refer to Section 4.7.5 for further detail;
- North facing solar PV generation that has less seasonality in generation output, particularly in southern NEM states (Gilmore, Nelson, & Nolan, 2022). Research into a future German energy system has also identified benefits from different solar PV orientations (Reker, Schneider, & Gerhards, 2022);

- Biomass generation, particularly fuelled by bagasse, which is produced from June to November as a waste product of the sugarcane crush (Australia Sugar Milling Council, 2022);
- Demand elasticity driven by price reflective tariffs; and
- Energy efficiency measures, for instance building standards for insulation and air conditioner efficiency standards.

4.7.5 Demand response potential from other industrial loads

A range of electricity intensive industries could potentially provide demand response services[11] (Hirschorn, Wilkinson, & Brijs, 2022). Green ammonia is of particular promise given the existing scale of domestic and international demand for explosives and fertilisers. Similar positive attributes may also apply to synthetic hydrocarbon production such as methanol, though they face the additional challenge of sourcing carbon feedstock.

This report has not focused on other industrial process loads, with the electrification of industrial heat loads representing another significant potential future source of demand response. Thermal energy storage may be a key enabler of the affordable electrification of industrial heat (International Renewable Energy Agency, 2020; Zefelippo, 2023; McKinsey & Company, 2022). Given the significant scale of Queensland's existing fossil-fuel based alumina refining, electrification of alumina refining, particularly alumina digestion, represents a large potential for demand response (Leitch, 2023).

Estimated electricity cost as a share of revenue (%)

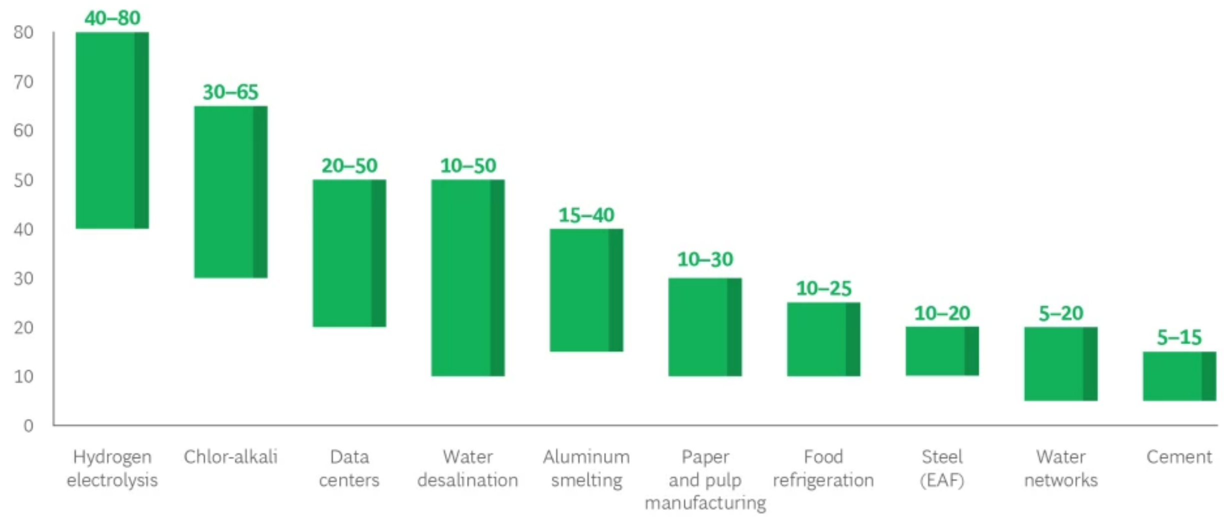


Figure 65: Estimated electricity cost as a share of revenue per energy intensive industry) | *Source: (Hirschorn, Wilkinson, & Brijs, 2022)*

4.7.6 Potentially distortionary subsidies including Hydrogen Headstart program

A potential distortion to the cost of green ammonia value chain demand response services is the imposition of a simple hydrogen production subsidy of \$2/kg H_2 as proposed under the Australian Government's Hydrogen Headstart program (Australian Government - Department of Climate Change, Energy, the Environment and Water, 2023). Similar to how uncontracted renewable energy projects often bid into the NEM at a price equal to negative the large-scale generation certificates (LGC) price, a green ammonia value chain could increase the price they would bid load curtailment into the NEM to account for the foregone hydrogen production subsidy. Assuming an electrolyser efficiency of 52.5kWh/kg H_2 a simple \$2/kg H_2 subsidy could result in a green ammonia producer increasing the cost it bids for load curtailment into the

[11] *It is noted that Figure 65 excludes alumina, where the electrification of alumina digestion, including the use of thermal energy storage presents a potential demand response opportunity as detailed in Leitch, D (2023) You see an alumina refinery, I see a very, very big battery. RenewEconomy. https://reneweconomy.com.au/you-see-alumina-refinery-i-see-a-very-big-battery/*

NEM by $38/MWh[12] to account for lost subsidy revenue. The magnitude of the impact of this distortion on potential sector coupling benefits is not clear.

Policy proposals such as extending the Renewable Energy Target (Clean Energy Council, 2023) could distort price signals for flexible demand by not placing a carbon cost on fossil fuel generation, such as gas peaking generation. The magnitude of any potential distortion and its impacts on industrial and other sector coupling benefits could be significant, particularly for potential future industrial electrification load where demand response has the potential to provide significant value (Refer to Section 4.5).

5 Conclusion and Implications for stakeholders

5.1 Discussion

Fossil-fuel based hydrogen production currently accounts for around 2% of annual global greenhouse gas (GHG) emissions (The Royal Society, 2021), with ammonia production accounting for around half of this (International Energy Agency, 2021). Green ammonia could play a pivotal role in decarbonising fertilisers and explosives, that are critical inputs into Australia's 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).

Whole-of-system considerations need to be incorporated into the design of infrastructure required for a world-scale green ammonia industry (multiple 1mtpa NH_3 capacity plants). This includes assessment of:

- Renewable energy resource availability and constraints;
- Hourly renewable generation profiles;
- Customer demand profiles including product molecule (i.e., hydrogen or ammonia);
- Hydrogen storage alternatives including salt caverns;
- Ammonia production process flexibility;
- Ammonia storage;
- Transport requirements such as pipelines and/or electricity transmission;
- Potential sector coupling benefits; and
- Water and port infrastructure (not assessed in this study).

Many of the same considerations are relevant for green hydrogen, however much of the literature on the techno-economic analysis of hydrogen that has adopted the notion that comparing the farm gate cost of green hydrogen to production costs for a fossil fuel alternative is an 'apples for apples' comparison (Australian Government - Department of Industry, Science, Energy and Resources, 2020; ARENA, 2020; Fowler, 2020; McKinsey & Company, 2022).

This report provides evidence for prioritising hydrogen industry policy support for green ammonia. It demonstrates that the predicted partial-flexibility of new-build Haber Bosch green ammonia plants and the low cost of ammonia storage, not only reduces the cost of meeting a fixed customer demand profile, but also offers the potential for sector coupling benefits through the provision of demand response services to the electricity system. In the future green ammonia value chain load shifting and load curtailment could compete with firming technologies such as batteries and gas peakers from cycling intervals as low as daily and up to inter annual, at levelised costs of less than half of that of gas peaking generation. Green ammonia value

[12] *The higher heating value of hydrogen is 39.4kWh/kg, implying an electrolyser efficiency of 75% at 52.5kWh/kg . This equates to 19kg of hydrogen production per MWh of electricity, which multiple by $2kg/$H_2$ equates to $38/MWh.*

chain demand response services are 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 '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. The 'winter problem' is the key driver of the 5-10% gas fuelled generation volume typically found in energy system modelling for a future renewable energy dominated NEM. In addition to reduced gas generation volumes, system benefits from green ammonia value chain demand response could include lower firming generation build requirements and lower CO_2e emissions. Despite these potential benefits, policy support is still required as green ammonia involves a significant green premium, even in 2040.

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).

To maximise sector coupling benefits a hybrid green ammonia value chain is proposed with co-located renewables (primarily solar) and electrolysers connected to a hydrogen pipeline for transport to a separately located ammonia plant, at a demand centre (e.g. Port). The co-located renewables and electrolysers would have a partial connection to the electricity network to provide demand response services, while the ammonia plant would also be grid connected. In order to enable the development of multiple world scale ammonia plants in Queensland a hydrogen pipeline following the 500kV electricity network outlined in the Queensland Energy and Jobs Plan (QEJP) (Queensland Government - Department of Energy and Public Works, 2022) is proposed as key common user infrastructure.

Compared to other NEM states Queensland is a favourable location for the development of a green ammonia industry. Queensland has abundant solar resources and surplus wind resources in the north of the state. The limited seasonality of Queensland's solar PV generation and its seasonal anti-correlation with north Queensland wind resources is favourable for maintaining electrolyser and ammonia plant load factors and/or providing demand response to the NEM to address the 'winter problem'.

In contrast to green ammonia, the cost of green hydrogen for use cases where the customer has a fixed demand profile could be almost double farm gate cost estimates, before transport costs. This is likely to have a significant negative impact on the prospects of a wide range of hydrogen use cases. This finding provides further evidence supporting the classification of hydrogen use cases in the Hydrogen Ladder Version 5.0 (Liebreich Associates, 2023).

The development of hydrogen salt cavern storage in the Adavale Basin in western Queensland and a hydrogen pipeline to the proposed hydrogen pipeline following the proposed QEJP 500kV network could meaningfully reduce costs for firmed hydrogen. However, future Queensland demand for large scale hydrogen use cases that have fixed demand profiles is highly uncertain as:

- Electrification may be a substitute for firmed green hydrogen supply. Green alumina is a potential large scale energy export industry that may be dependent on the supply of firmed green hydrogen. However, the alumina digestion process is expected to be electrified (ARENA, 2022), while electrification competes with hydrogen as an alternative for alumina calcination (ARENA, 2022; Climateworks Centre, 2023);
- Production processes requiring green hydrogen input may have flexible demand profiles rather than fixed. Synthetic hydrocarbon (including methanol) production processes may have similar partial-flexibility to ammonia production and low-cost storage. It is noted that to achieve development of this industry at scale carbon feedstock value chains and/or reduced direct air capture costs may be required.
- Likely use cases for green hydrogen may be less prospective in Queensland. Green iron may require firmed hydrogen, however major iron ore resources have not been identified in Queensland.

Given the significant scale of Queensland's existing fossil fuelled alumina refining (Leitch, 2023), decarbonisation of alumina refining represents a large potential for demand response that requires further investigation. This could include a techno-economic assessment of various alternatives for the provision of heat to the digestion and calcination processes including green hydrogen and electrification including the integration of thermal energy storage (ARENA, 2022).

5.2 Implications for policymakers and industry

5.2.1 Hydrogen policy support should be prioritised for green ammonia

This research reinforces industry consensus that hydrogen policy support should be prioritised for green ammonia (Climateworks Centre, 2023; Australian Energy Council, 2023A; Institute for Energy Economics and Financial Analysis, 2023) by bringing to light the significant sector coupling benefits that a green ammonia value chain could provide due to the predicted high partial flexibility of green ammonia production and low-cost ammonia storage.

5.2.2 Hydrogen demand and use cases analysis should consider full value chain costs

The prospects for a wide range of hydrogen use cases, is made even more challenging due to the high cost of providing firmed green hydrogen. Hydrogen demand and use case modelling should include all relevant value chain costs associated with meeting the required end customer demand profile (e.g. fixed customer demand profile for hydrogen, ammonia or alumina), that could include:

- Oversizing of production capacity for renewables, electrolysers and where relevant industrial production process; and
- Storage requirements for power system storage, hydrogen storage and where relevant end-product storage (e.g. ammonia or alumina).

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.

5.2.3 Energy system modelling should more accurately integrate industrial demand response

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.

5.2.4 Potential solutions for addressing the 'winter problem' should be assessed

For electricity intensive industries both the cost of renewables and their generation characteristics, including seasonal profiles, are important factors that drive energy portfolio optimisation and cost competitiveness. In a renewable energy dominated NEM Queensland will be a relatively favourable location for industrial load due to its mild 'winter problem', that could allow industrial load to operate relatively affordably at high load factors year-round. In southern NEM states the depth of the 'winter problem' could mean that it could be more profitable for electricity intensive industries to reduce production in winter to avoid high prices.

A range of alternatives to address the 'winter problem' should be assessed as options in energy system modelling including industrial demand response, retaining natural gas boilers where industrial heat is electrified to operate in high price periods, geologic natural gas and geologic hydrogen storage, synthetic hydrocarbons, north facing solar PV (Gilmore, Nelson, & Nolan, 2022), biomass, demand elasticity driven by price reflective tariffs and energy efficiency. In particular, the cost of infrastructure required to deliver a seasonal supply of gas, post future closure of LNG export industry and decarbonisation of ammonia and alumina industries should be investigated.

5.2.5 Industry needs to be guided and provided policy support to embrace demand response

Businesses in electricity intensive industries that have a trader mindset and pursue flexibility and storage in their production process have the potential to be more profitable than businesses that remain focussed on maximising production (Hirschorn, Wilkinson, & Brijs, 2022). If a trader mindset is not embraced the high cost of firmed renewable energy could result in forecast industrial electrification loads not eventuating. The potential system coupling benefits from a hybrid green ammonia value chain provides an example of value that can be unlocked from embracing a trader mindset.

Industry decarbonisation policy support, particularly that provided by ARENA, should consider supporting technology innovation that increases demand flexibility for current and electricity intensive industries, including both process flexibility and non-power system energy storage. Hydrogen Head Start program and future ARENA industry support programs should consider potential revenue and system benefits of demand response to a project's value stack.

5.2.6 Marginal abatement cost curve is required to inform policymakers and industry

Theoretically a least cost transition of the economy should involve an initial focus on decarbonisation options with low CO_2e abatement cost, with marginal CO_2e abatement costs increasing as the economy decarbonises. There is currently no accepted marginal abatement cost curve to compare estimated green ammonia premiums against. To inform policymakers and industry around the potential cost and ordering of decarbonisation options, marginal abatement cost curves should be produced for the economy with consistent input assumptions and methodologies used for energy decarbonisation options.

5.2.7 Preferred location for hydrogen projects will be impacted by wind resource scarcity

There is competition for scarce wind resources between domestic decarbonisation, decarbonisation of existing energy intensive export industries and export hydrogen projects. Assuming domestic energy customers and existing energy intensive export industries are preferred in the allocation of wind resources, except the inland Barcaldine REZ, there could be limited to no wind resources available in central and southern Queensland for export hydrogen derivatives (Advisian, 2022).

5.2.8 Potential distortionary impacts of decarbonisation support policies should be assessed

A least cost transition of the economy should include appropriate price signals for industrial demand response. Decarbonisation policy support mechanisms such as the Hydrogen Headstart program and proposals for an extension of the Renewable Energy Target (Clean Energy Council, 2023) could distort price signals for demand response. Gross margins from hybrid green ammonia value chain load shifting benefits from high costs for dispatchable generation, with carbon costs potentially a key cost driver for gas peaking generation, that do not apply for a Renewable Energy Target. In addition, Hydrogen Headstart could discourage flexible operation by incentivising production, increasing the price at which a grid connected hydrogen producer might provide load curtailment.

The economic impact of the potential distortion of price signals for industrial demand response from policy support mechanisms such as Hydrogen Headstart and the proposed extension of the Renewable Energy Target (Clean Energy Council, 2023) should be assessed.

5.2.9 Hydrogen pipelines should be key focus for common user infrastructure

Hydrogen pipelines have potential advantages as common user infrastructure as they can provide both transport and storage. This could enable the risk involved in oversizing hydrogen pipelines for future potential users to be reduced as the pipeline could also be used for storage for anchor pipeline users. A hydrogen pipeline following the 500kV electricity network outlined in the Queensland QEJP could be common user infrastructure that enabled the development of multiple world scale ammonia plants (1mtpa NH_3) at lower cost.

A watching brief may be appropriate for geologic hydrogen storage such as salt caverns and depleted oil and gas fields. For Queensland there is a high degree of uncertainty as to whether there will be viable large-scale hydrogen use cases that have a fixed demand profile for hydrogen and thus the need for geological hydrogen storage.

6 Appendix

6.1 Hydrogen - Salt cavern hydrogen storage cycling constraints

In this study, in order to reflect salt cavern pressure change constraints different maximum hydrogen storage injection/withdrawal rates were imposed across a number of optimisations. In order to explore the potential impact of cycling constraints, including to gain insights regarding alternative geological hydrogen storage that has more severe constraints, such as depleted gas fields, three values for annual cycle constraints were modelled: 2, 6 and 12 cycles per year. For base case optimisations the cycling rate is unconstrained.

A cycle involves the cumulative filling and emptying of the entire storage capacity and does not imply it is completely filled or emptied. An annual cycling constraint of ~12 cycles per year commonly referred to in industry and academic literature implies that the storage empties and fills completely every 30.4 days (730 hours with equal times for emptying and filling for simplicity). Thus, the hourly injection and withdrawal rate is constrained to be 1/365th of the storage capacity.

Post undertaking these optimisations expert industry feedback was received that supported the notion that an annual cycling constraint of 10-12 was reasonable. In addition, the absolute pressure change that applies over 24 hours, equally applies over 12 hours. This is important for green hydrogen production that is largely based on solar PV, as injection rates in daylight hours have the potential to be more than doubled from what was understood, while withdrawals overnight assisting in the management of cavern pressure change constraints.

Additional optimisations were undertaken for all REZ on to explore the impact of hydrogen salt cavern storage cycling constraints on LCOH and plant design. The cycling constraint significantly impacts LCOH. If only two cycles per year are possible (similar to a depleted gas field), the model must significantly oversize the hydrogen storage (Figure 67); in some locations, the cost associated with this storage installation is so large that it would be cheaper for the model to use aboveground tank storage rather than a salt cavern (Figure 66)

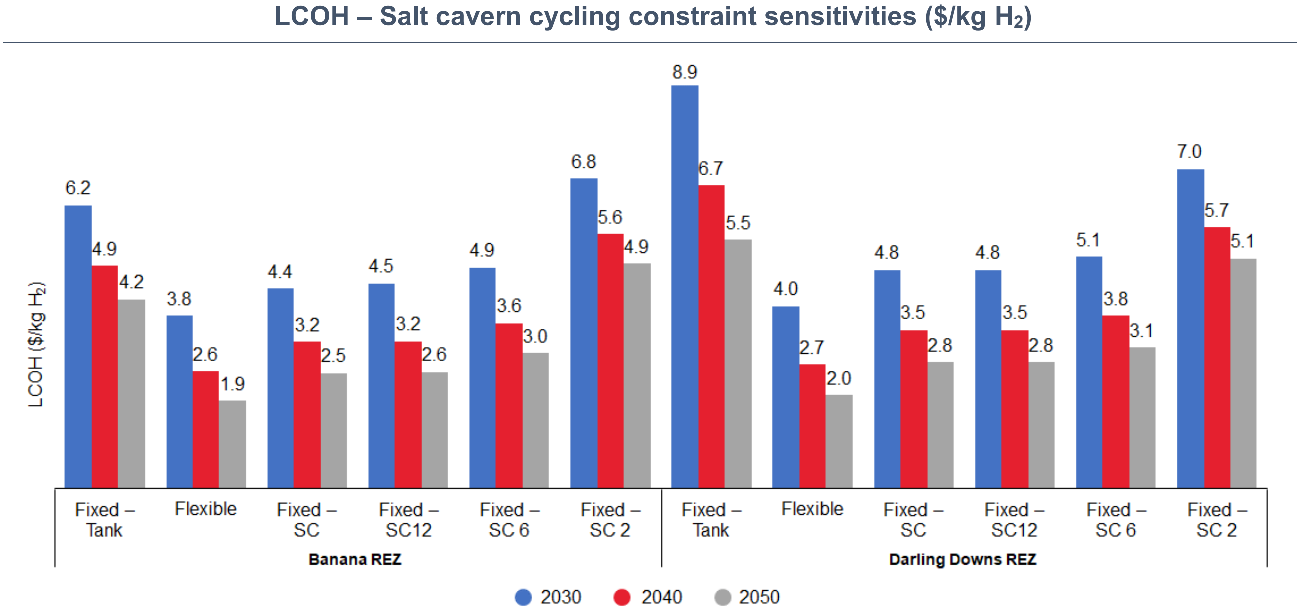


Figure 66: Impact of cycling constraint on LCOH ($/kg H_2) – Fixed – Salt Cavern case

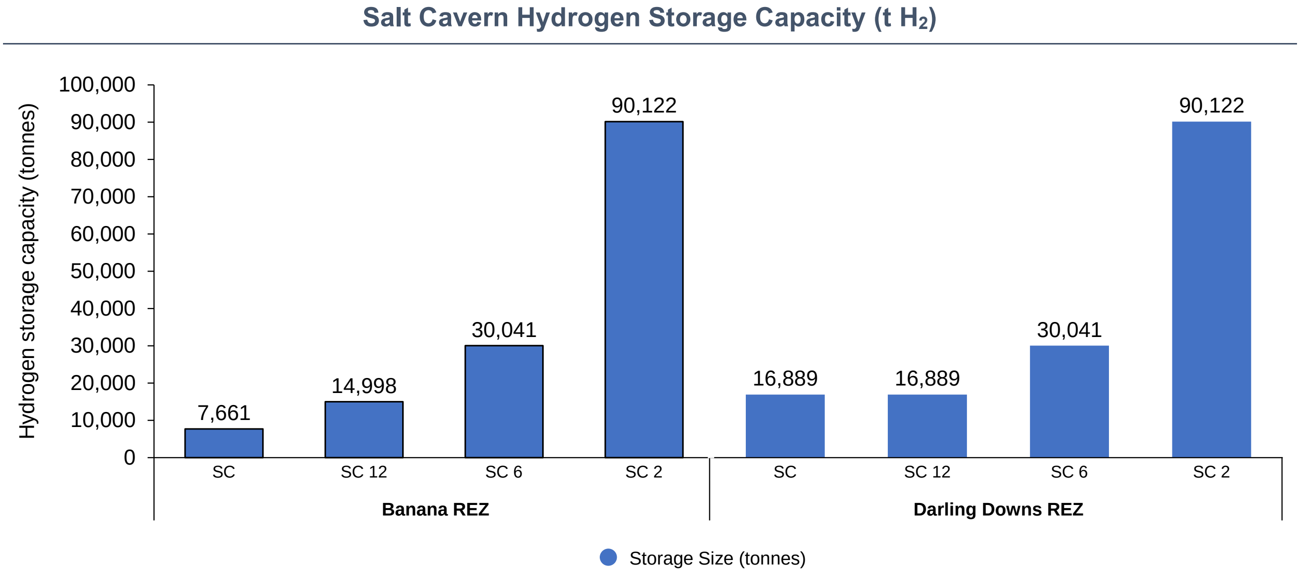


Figure 67: Storage (tonnes of hydrogen) required for different cycling constraints Fixed – Salt Cavern case

However, substantial value emerges if more cyclability is available; with 6 cycles per year, the impact of the cycling constraint is small (~0.3 AUD/kg) (Figure 66), and with 12 cycles per year the cycling constraint is not always active.

The cycling constraints modelled are conservative. Given the potential for higher injections over 12-hour periods and the high solar weightings in renewable portfolios the impacts of cycling constraints may be over-estimated. As the instantaneous rate of injection/withdrawal in each hour is limited, the actual number of cycles is much smaller than the annual cycling constraint – for the 12 cycles/year case, storage cycles on average between 5 and 7 times per year (Figure 68).

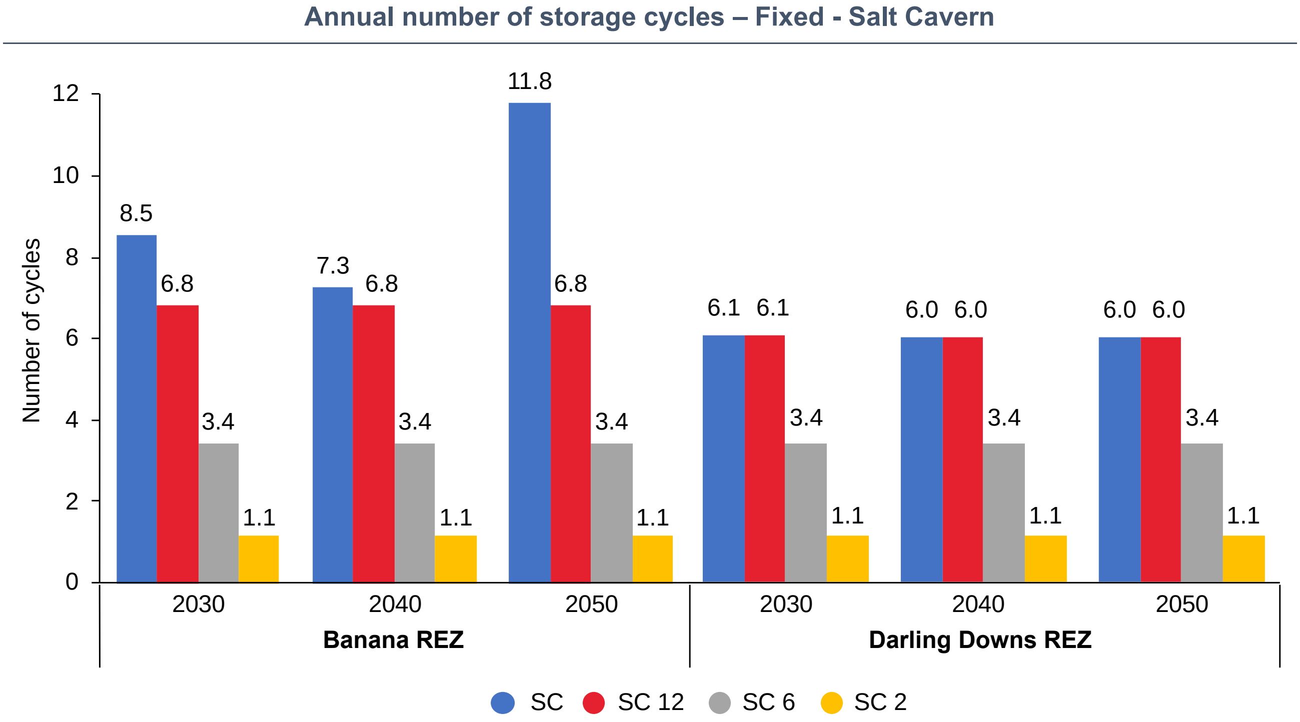


Figure 68: Number of cycles of salt cavern H_2 storage per year with different cycling constraints – Banana and Darling Downs Fixed – Salt Cavern case

For base case cycling (unconstrained), annual cycles only breaches the typical 10-12 cycles pa constraint for salt caverns in isolated cases, including NQCEH (Q2) for 2040 and 2050. The largest difference in LCOH between the base case (unconstrained) and 12 cycles is \$0.13/kg H_2 for NQCEH (Q2) in 2050. The storage is only cycled 6.92pa for the 12 cycles constraint scenario, which per previous discussion suggests that this LCOH gap may be overstated due to modelling methodology limitation in how the constraint is applied.

Sensitivities were not undertaken on ammonia. However, without the cycling constraints, the salt cavern has to cycle more much rapidly than in the hydrogen case (Figure 41). This cycling rate might breach the physical limits of the salt cavern and require a larger storage volume. However, as hydrogen storage volume is small relative to ammonia storage and salt cavern storage cost is only a small fraction of the total cost stack, imposing a more stringent cycling limit may not materially impact LCOA, though it may impact the cost benefit of salt cavern hydrogen storage for ammonia production. Refer to 6.3 Ammonia – Energy storage capex for further analysis.

			Levelised cost of hydrogen (LCOH)			Solar portfolio weighting			Hydrogen Storage (GWh)			Electrolyser load factor			Storage cycles pa		
			Base	12 cycles pa	6 cycles pa	Base	12 cycles pa	6 cycles pa	Base	12 cycles pa	6 cycles pa	Base	12 cycles pa	6 cycles pa	Base	12 cycles pa	6 cycles pa
2030	**Hybrid**	NQCEH (Q2)	4.12	4.20	4.67	72%	69%	57%	409	591	1,184	0	46%	54%	5.88	3.83	1.50
		Isaac (Q4)	4.41	4.49	4.91	64%	71%	98%	392	591	1,184	48%	45%	34%	5.26	4.12	3.29
		Barcaldine (Q5)	4.18	4.23	4.61	63%	90%	100%	342	591	1,184	49%	38%	34%	5.97	5.92	3.43
		Banana (Q9)	4.39	4.51	4.87	73%	100%	100%	302	591	1,184	43%	33%	34%	8.54	6.82	3.41
	Solar	North Qld (Q3)	4.76	4.76	5.07	100%	100%	100%	655	655	1,184	31%	31%	32%	6.30	6.30	3.50
		Fitzroy (Q6)	4.67	4.67	5.01	100%	100%	100%	589	591	1,184	33%	33%	33%	6.87	6.85	3.43
		Darling Downs (Q8)	4.81	4.81	5.09	100%	100%	100%	665	665	1,184	33%	33%	32%	6.07	6.07	3.43
2040	**Hybrid**	NQCEH (Q2)	3.02	3.14	3.58	88%	98%	100%	195	591	1,184	35%	33%	32%	16.63	6.71	3.46
		Isaac (Q4)	3.26	3.29	3.68	91%	100%	100%	474	591	1,184	36%	33%	33%	7.35	6.76	3.39
		Barcaldine (Q5)	3.09	3.09	3.45	100%	100%	100%	648	648	1,184	35%	35%	34%	6.24	6.24	3.43
		Banana (Q9)	3.23	3.24	3.64	100%	100%	100%	554	591	1,184	33%	32%	33%	7.27	6.82	3.42
	Solar	North Qld (Q2)	3.43	3.43	3.77	100%	100%	100%	659	659	1,184	31%	31%	31%	6.27	6.27	3.50
		Fitzroy (Q6)	3.36	3.36	3.74	100%	100%	100%	590	591	1,184	33%	33%	32%	6.85	6.85	3.43
		Darling Downs (Q2)	3.48	3.48	3.80	100%	100%	100%	670	670	1,184	32%	32%	32%	6.02	6.02	3.43
2050	**Hybrid**	NQCEH (Q2)	2.35	2.48	2.93	93%	100%	100%	211	591	1,184	33%	31%	32%	17.10	6.92	3.46
		Isaac (Q4)	2.59	2.60	3.01	100%	100%	100%	350	591	1,184	31%	33%	32%	11.36	6.77	3.39
		Barcaldine (Q5)	2.44	2.45	2.83	100%	100%	100%	434	591	1,184	32%	34%	33%	9.26	6.83	3.43
		Banana (Q9)	2.54	2.56	2.98	100%	100%	100%	340	591	1,184	31%	32%	32%	11.78	6.82	3.42
	Solar	North Qld (Q2)	2.69	2.71	3.08	100%	100%	100%	433	591	1,184	28%	30%	31%	9.48	6.98	3.50
		Fitzroy (Q6)	2.66	2.66	3.06	100%	100%	100%	384	591	1,184	30%	33%	32%	10.46	6.84	3.44
		Darling Downs (Q2)	2.77	2.77	3.11	100%	100%	100%	671	671	1,184	32%	32%	31%	6.02	6.02	3.43

Table 14: Optimisations results – Levelised Cost of Hydrogen (LCOH): Fixed – Salt Cavern - salt cavern cycling sensitivities

6.2 Ammonia – Ammonia plant (HB) turndown (min load)

A number of additional optimisations were undertaken on Barcaldine (Q5) for the year 2040, assuming a fully islanded plant, to explore the impact of changes in the partial flexibility of the ammonia plant (HB) on LCOA and plant design. In the base case, the cost benefit from introducing salt cavern for ammonia production is not as significant as in the hydrogen case due to the high partial flexibility of the HB plant and ammonia storage offering an alternative form of low-cost energy storage. However, salt caverns could provide significant cost benefits if the HB plant is assumed to have less flexibility. If the HB plant runs at a constant rate, incorporating salt cavern can lead to a 32% reduction in the LCOA compared to using hydrogen tank storage vs 8% under the base case (Figure 69). The LCOA in the salt cavern case is relatively insensitive to varying HB min load. There is little benefit associated with reducing the HB minimum rate requirement below 50%. The chart also illustrates one of the techno-economic challenges with inflexible hydrogen liquefaction, with LCOA increasing by 49% from the base case (30% HB minimum load) to the inflexible case (no HB turndown).

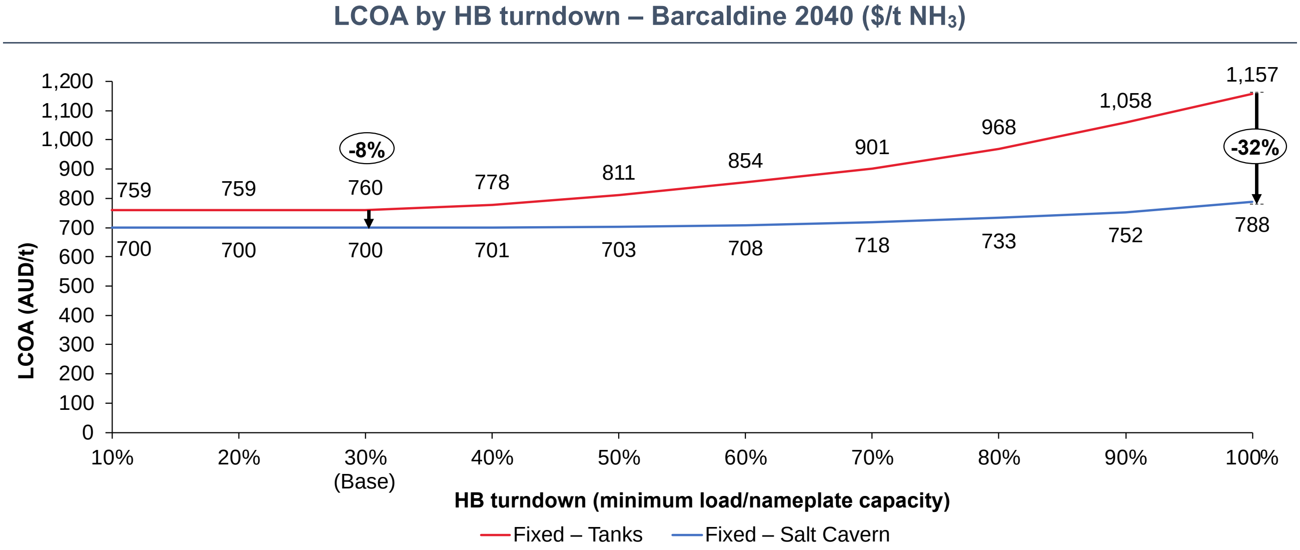


Figure 69: LCOA at different HB turndowns - Barcaldine 2040 Fixed cases

When the HB plant flexibility is reduced, the plant requires significantly more wind and hydrogen storage to firm the hydrogen supply to the HB plant, which increases at a faster rate with tanks than salt cavern (Figure 70, Figure 71).

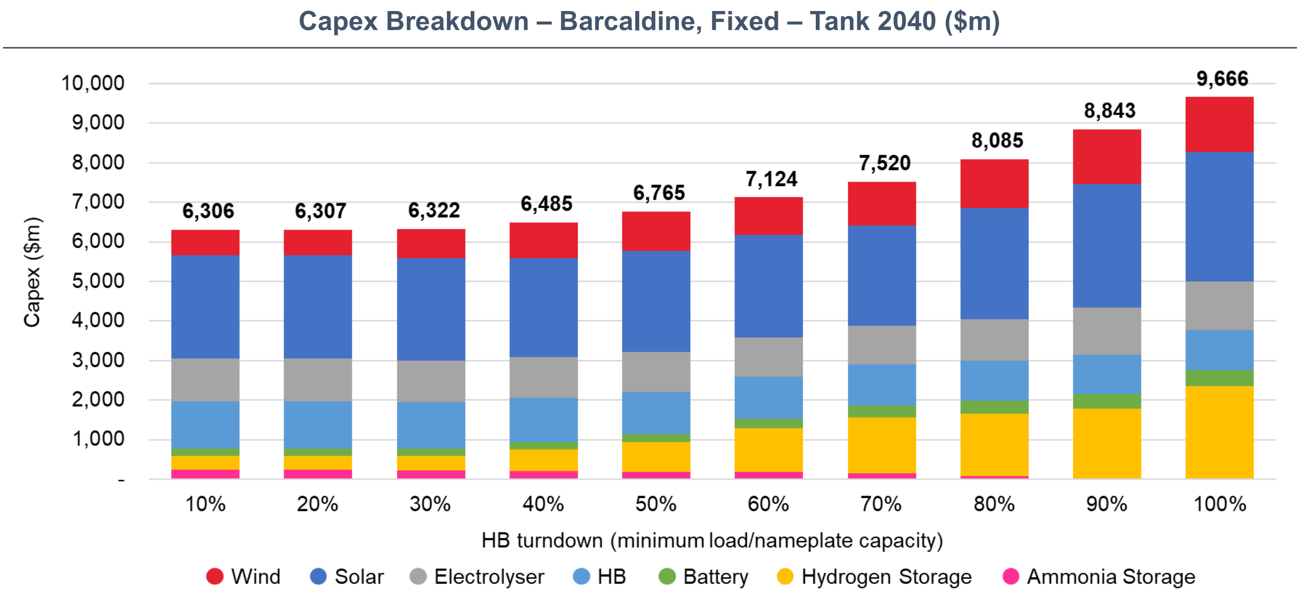


Figure 70: Capex breakdown by varying HB turndown – Barcaldine, Fixed - Tank 2040

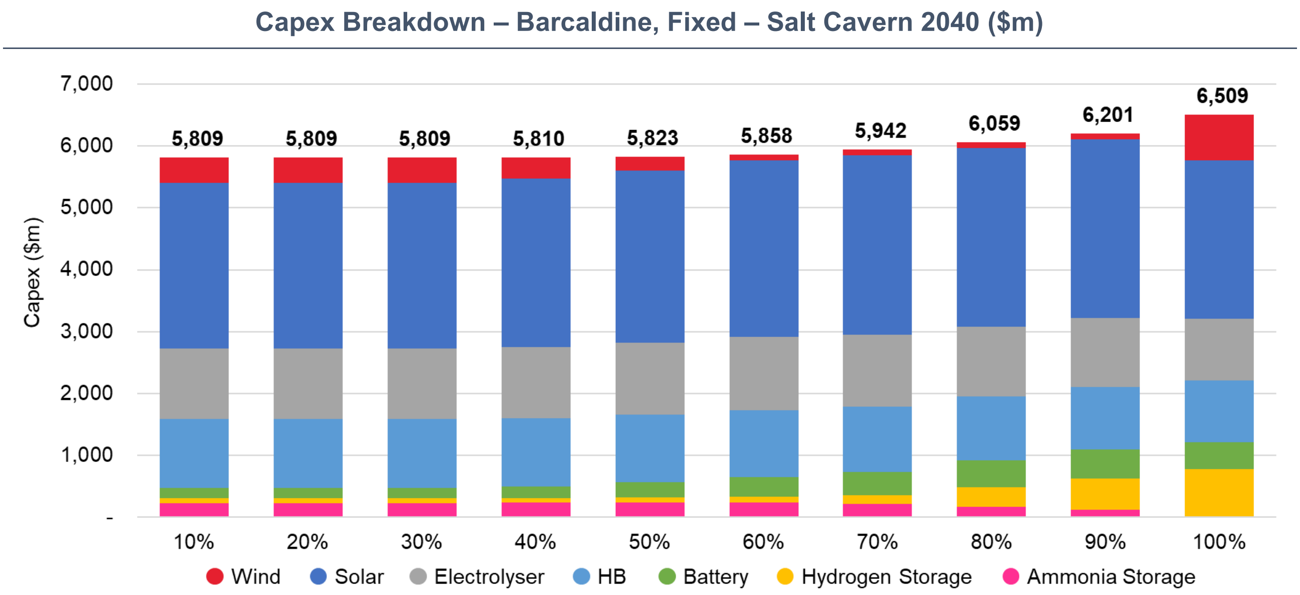


Figure 71: Capex breakdown by varying HB turndown – Barcaldine, Fixed- Salt Cavern 2040

The low capital cost of salt cavern allows the volume of storage to increase significantly without capex increasing significantly (Figure 71). As the flexibility of the HB plant decreases, the flexibility of the system shifts from ammonia tanks to hydrogen storage with ammonia storage declining to zero at the extreme end. In the salt cavern case hydrogen storage increases significantly when HB min load exceeds 0.7. Due to high capital cost, batteries continue to play only a small role in firming the system.

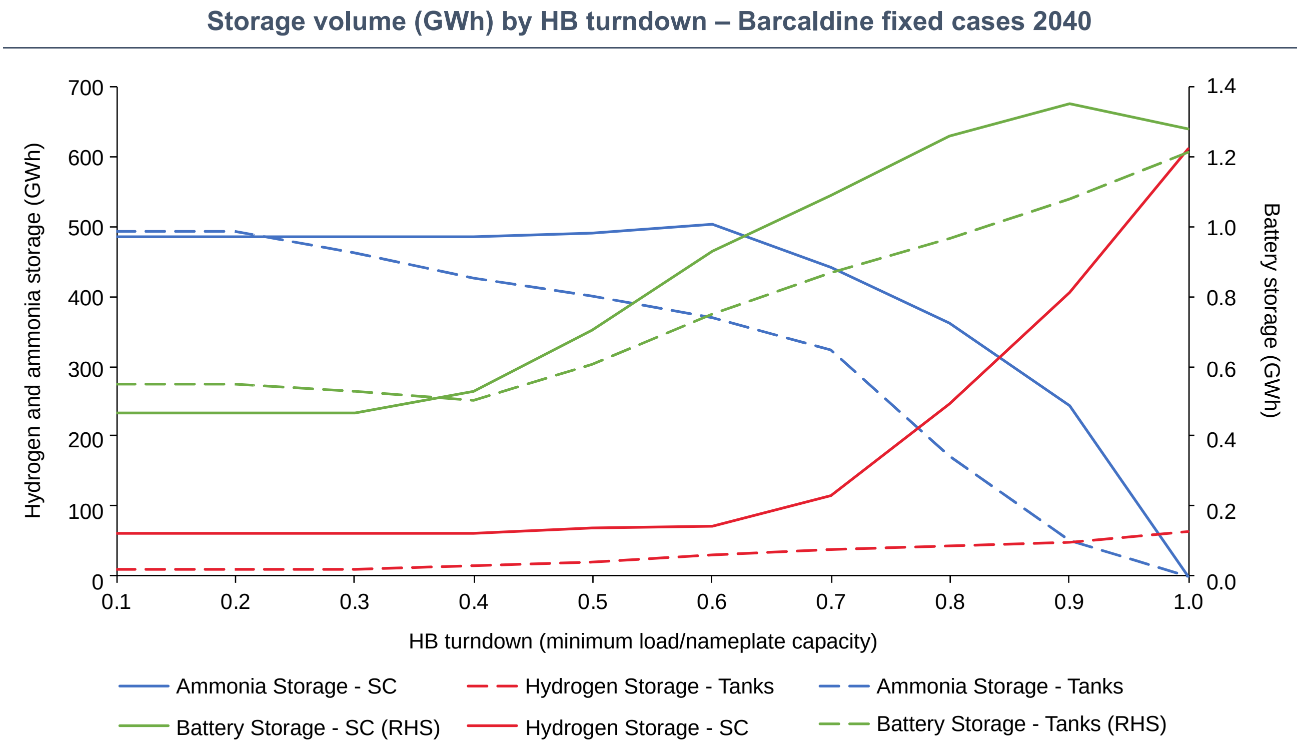


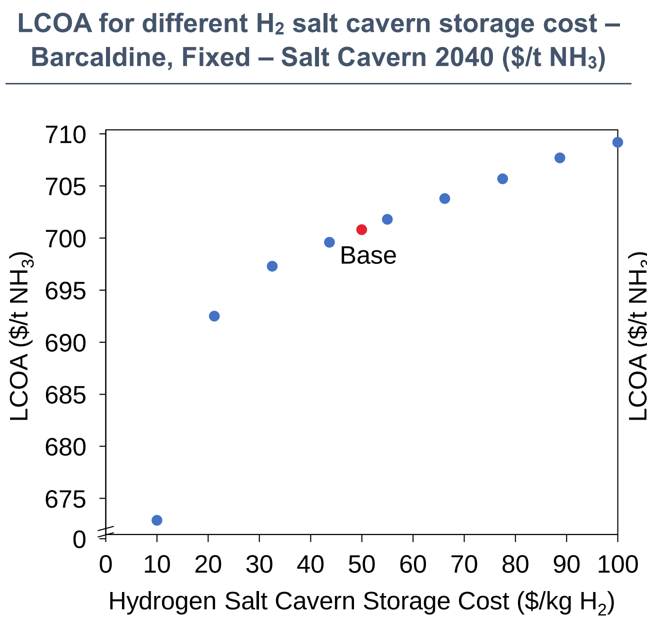
Figure 72: Storage volume at different HB turndowns – Barcaldine, Fixed cases 2040

6.3 Ammonia – Energy storage capex

A number of additional optimisations were undertaken on Barcaldine (Q5) for the year 2040, assuming a fully islanded plant, to explore the impact of changes in energy storage capex on LCOA and plant design for the Fixed – Salt Cavern case. The costs of salt cavern hydrogen storage and ammonia storage are highly uncertain due to limited availability of reliable capital cost estimates for proposed and completed projects. The base case capex values are $3000/t (ammonia) and $50/kg (salt cavern hydrogen).

The LCOA is relatively insensitive to hydrogen salt cavern capex with a 100% increase from $50/kg H_2 to $100/kg H_2 resulting in a 1.2% increase in LCOA ($700/ t NH_3 to $709/ t NH_3), noting that the relationship is not linear. In contrast, the LCOA for the Fixed - Tank scenario is $760/t NH_3 with hydrogen tank storage capex assume to be $1,428/kg H_2. The salt cavern hydrogen storage is cycled 51.7 times pa for this scenario and thus the storage may need to be oversized by a factor 5-6x (implied cost of $250/$300/kg H_2) to mitigate the cycling constraint. Thus the cost benefit of hydrogen salt caverns for green ammonia production is materially lower than modeled.

The LCOA is more sensitive to ammonia storage capex with a 100% increase from $3,000/t to $6,000/t resulting in a 3.8% increase in LCOA ($700/t to $727/t).



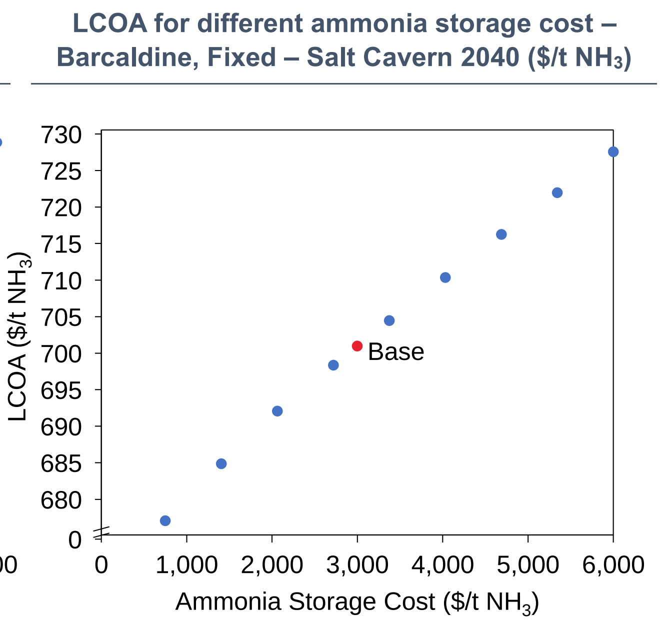


Figure 73: LCOA for different storage costs –Fixed – Salt Cavern, Barcaldine 2040

Apart from changes in the storage mix between hydrogen salt caverns and ammonia, the change in other plant is limited. Ammonia storage dominates over a wide range of possible cost values, driven by its lower cost per MWh by LHV (Figure 74, Figure 75). The tipping point is observed at ammonia storage cost of $3000/t (~$600/MWh by LHV) and hydrogen storage cost of $21/kg ($630/MWh by LHV). Ammonia still dominates at the maximum sensitivity value of $6,000/t (~$1,150/MWh by LHV) as salt cavern hydrogen storage cost of $50/kg (~$1,500/MWh by LHV) is higher cost. This demonstrates that the cost per MWh by LHV is a key driver as to what form of storage dominates and ultimately plays the role of seasonal storage.

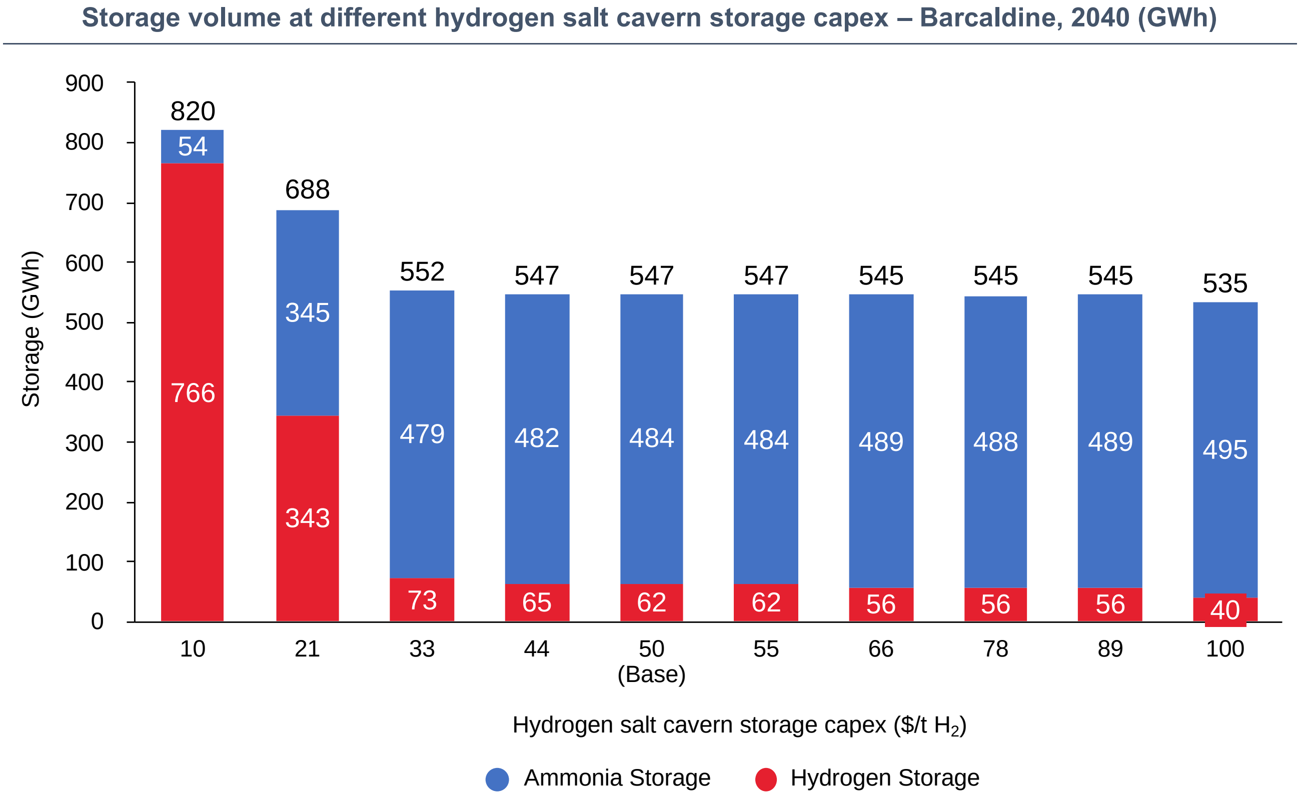


Figure 74: Storage volume at different hydrogen salt cavern storage capex – Fixed – Salt Cavern, Barcaldine 2040

Storage volume at different ammonia storage capex – Barcaldine 2040 (GWh)

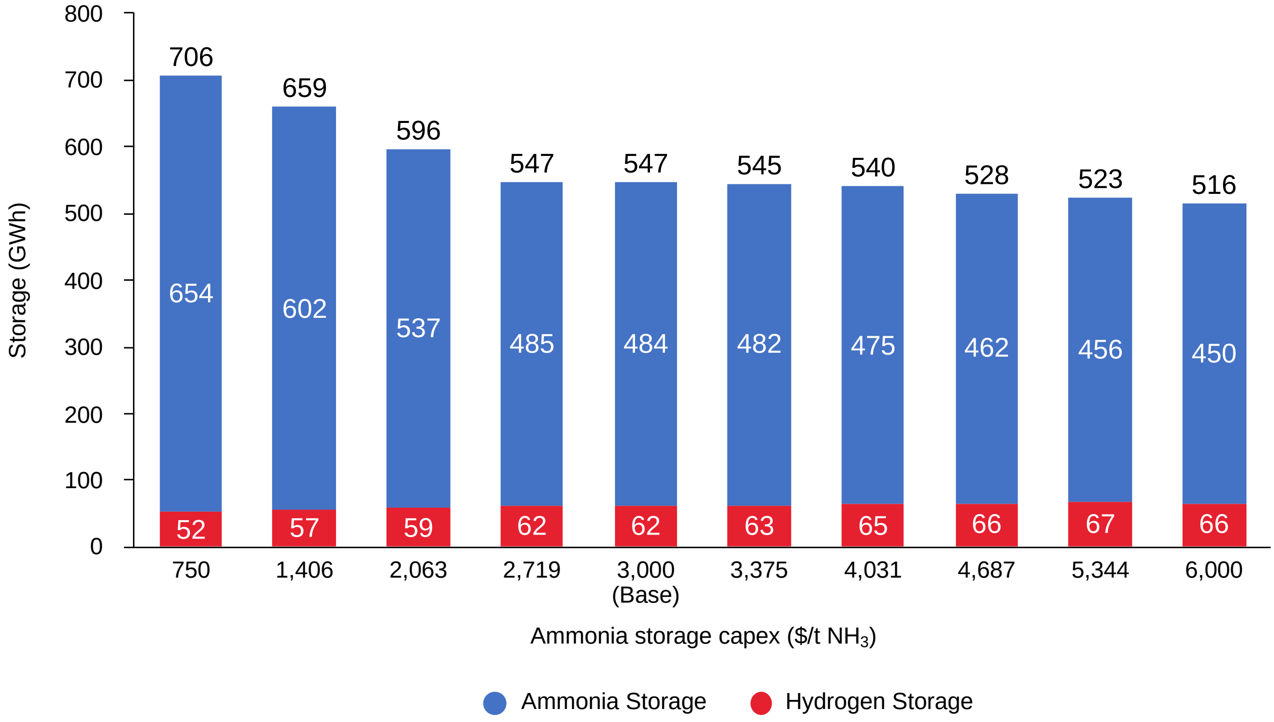


Figure 75: Storage volume at different ammonia storage capex – Fixed – Salt Cavern, Barcaldine 2040

6.4 Ammonia – Ammonia plant (HB) capex

A number of additional optimisations were undertaken on Barcaldine (Q5) for the year 2040, assuming a fully islanded plant, to explore the impact of changes in the capital cost of the ammonia plant (HB) on LCOA and plant design. Despite ammonia plants (HB) being mature technology, there is uncertainty regarding capex as there is limited reliable capital cost estimates for proposed or completed projects, particularly in Australia. The base case figure is $1 billion for a million tonnes of nameplate annual ammonia production. The LCOA varies linearly with HB capex (Figure 76) and the build mix remains almost unchanged between the tanks and salt cavern cases (Figure 77, Figure 78). This is due to the HB capital cost representing a relatively small portion of the capex stack, as well as the high cost of the HB plant per MW (approximately ~$8760/kW of nameplate electricity load), which is significantly higher than the other components of the plant. Therefore, the plant build mix is insensitive to the HB plant capex cost.

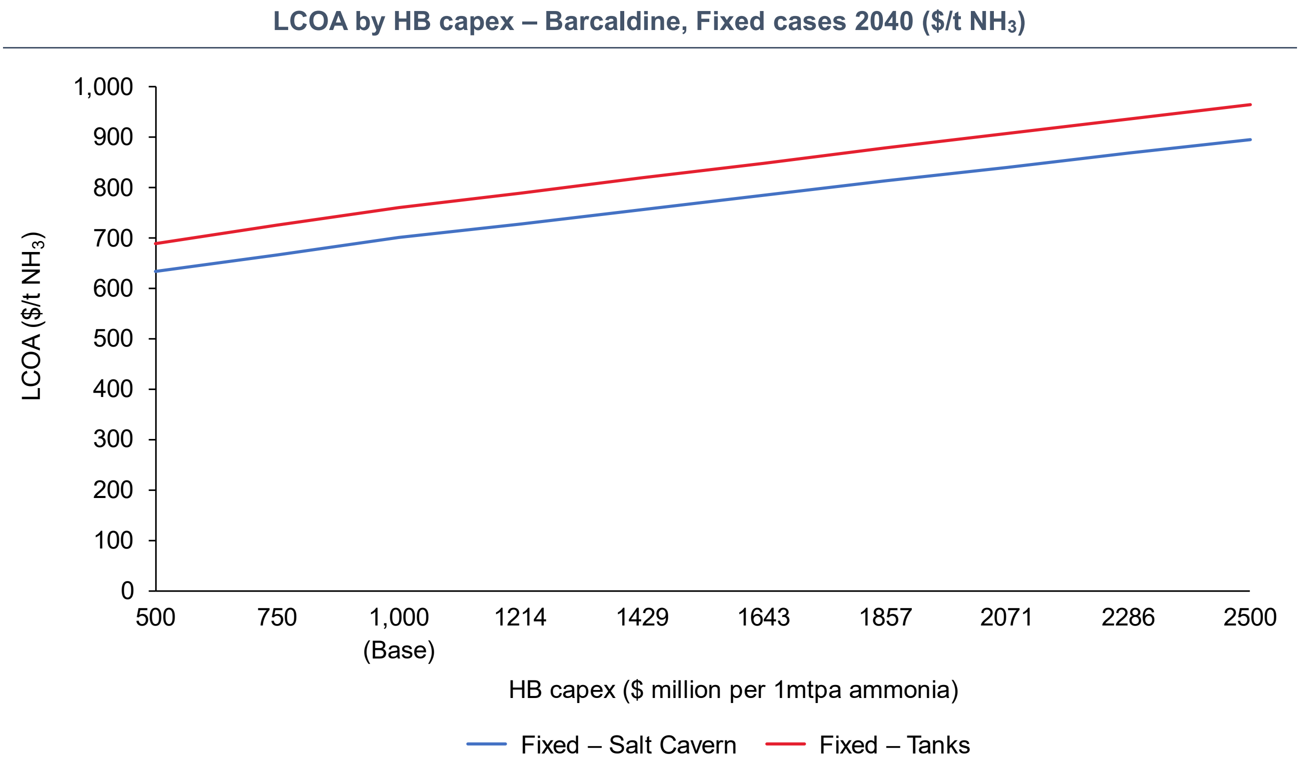


Figure 76: LCOA at different HB capex cost – Barcaldine, Fixed cases 2040

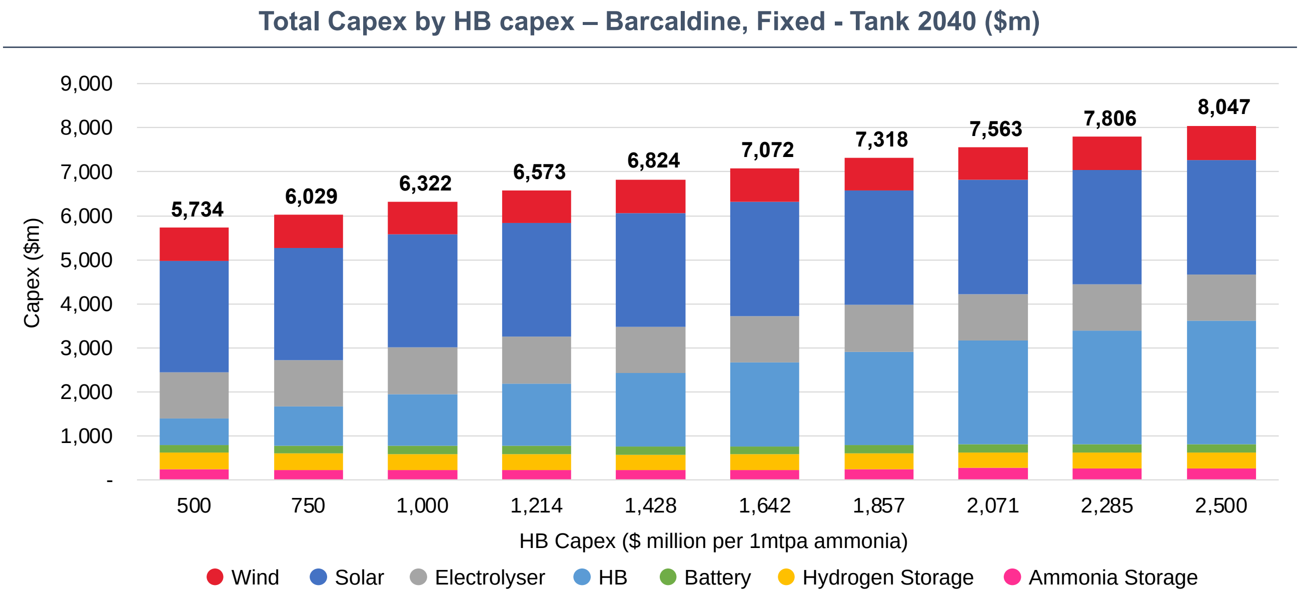


Figure 77: Total capex at different HB capex costs – Barcaldine, Fixed – Tank 2040

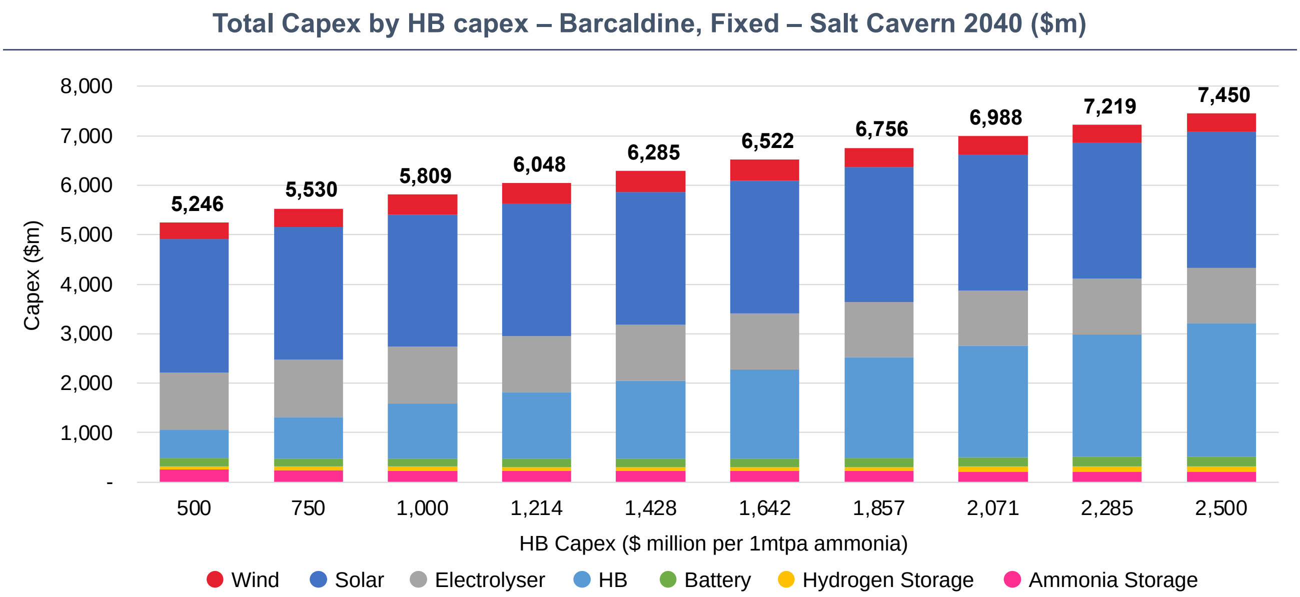


Figure 78: Total capex at different HB capex costs – Barcaldine, Fixed – Salt Cavern 2040

6.5 Ammonia - Ammonia pipeline transport

A scenario of co-locating all the plant components and using ammonia pipeline to transport ammonia to port was also considered consistent with Figure 79. Ammonia is transported in pipeline as a liquid as it only requires approximately 10 bar of pressure to liquefy at room temperature.

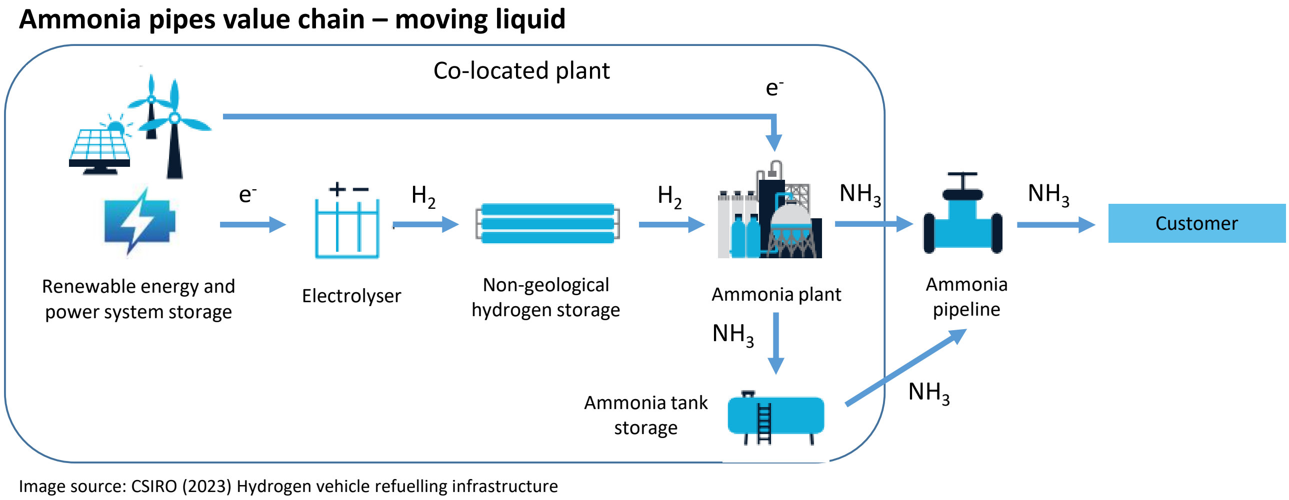


Figure 79: Ammonia pipes value chain diagram

This value chain achieves the lowest LCOA and benefits from two factors relating to ammonia being further down the value chain than hydrogen:

- For the Fixed-Tank (NH_3 pipe) case the ammonia pipeline delivers the ammonia to the customer at a constant rate and is thus fully utilised, while in contrast for the Fixed Tank (pipe) case the hydrogen pipeline has less than full utilisation due to variable hydrogen input into the HB plant.
- The ammonia production process (Haber-Bosch) uses hydrogen as a feedstock and involves significant energy losses. Thus the amount of energy that needs to be transported in a hydrogen pipeline (as feedstock) is more than the energy that needs to be transported in an ammonia pipeline to the customer.

Industry feedback is that there is significant social license risk associated with ammonia pipelines in Queensland due to environmental and safety concerns.

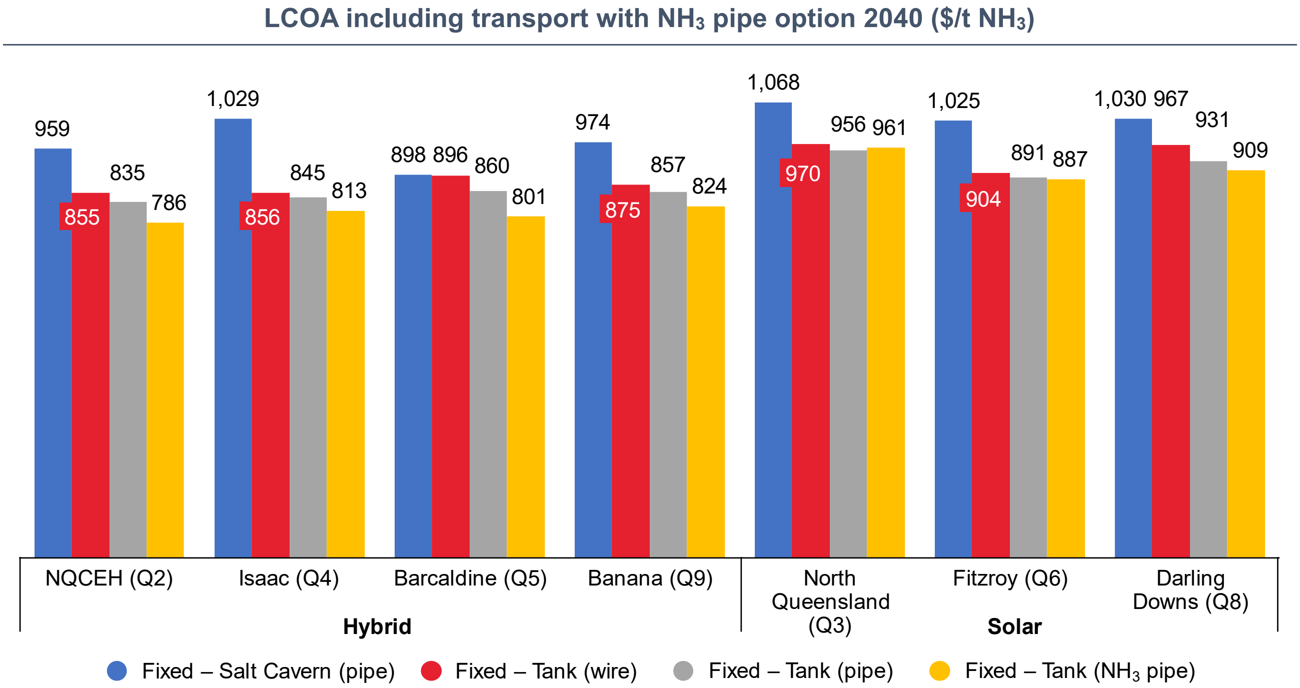


Figure 80: LCOA including transport with NH_3 pipe option (all REZ 2040)

			Islanded LCOA ($/t NH_3)	Ammonia pipe cost ($/t NH_3)	LCOA including transport ($/t NH_3)
		REZ	**Fixed – Tank**	**Fixed – Tank**	**Fixed – Tank (NH_3 pipe)**
2030	**Hybrid**	NQCEH (Q2)	958	25	983
		Isaac (Q4)	1,013	7	1,019
		Barcaldine (Q5)	965	41	1,007
		Banana (Q9)	1,032	13	1,045
	Solar	North Queensland (Q3)	1,220	2	1,221
		Fitzroy (Q6)	1,139	1	1,141
		Darling Downs (Q8)	1,142	26	1,168
2040	**Hybrid**	NQCEH (Q2)	761	25	786
		Isaac (Q4)	806	7	813
		Barcaldine (Q5)	760	41	801
		Banana (Q9)	811	13	824
	Solar	North Queensland (Q3)	960	2	961
		Fitzroy (Q6)	885	1	887
		Darling Downs (Q8)	883	25	909
2050	**Hybrid**	NQCEH (Q2)	646	25	671
		Isaac (Q4)	687	6	693
		Barcaldine (Q5)	641	41	682
		Banana (Q9)	684	13	697
	Solar	North Queensland (Q3)	817	2	819
		Fitzroy (Q6)	885	1	887
		Darling Downs (Q8)	738	26	764

Table 15: LCOA including transport for Fixed -Tank with NH_3 pipe transport by REZ

6.6 Ammonia – Ammonia plant (HB) plant grid connection

Battery or a grid connection is required to satisfy the minimum load requirement of the ammonia plant. Two grid electricity prices were tested \$50/MWh and \$100/MWh. As 1MWh of electricity is required by the ammonia plant (along with hydrogen feedstock) to produce 1 tonne of ammonia, for every dollar increase in grid electricity price, the LCOA increases by the same amount (Figure 81). The outcomes of the Fixed-Tank (Islanded) and Fixed - Tank (Grid connected HB \$100MWh) cases for Banana in 2030 imply that the cost of providing firmed electricity from the REZ using wind, solar and BESS at the 83% load factor of the ammonia plant is around \$92/MWh. By 2050 the implied cost has fallen to \$72/MWh due to reduction in renewable and BESS costs. Implied firmed renewable energy cost is higher for Darling Downs, as only solar and BESS is available, with an implied cost of \$124/MWh for 2030 (82% load factor) in 2030 and \$88/MWh in 2040 (84% load factor).

Levelised cost of ammonia – Islanded HB vs Grid Connected HB (\$/t NH_3)

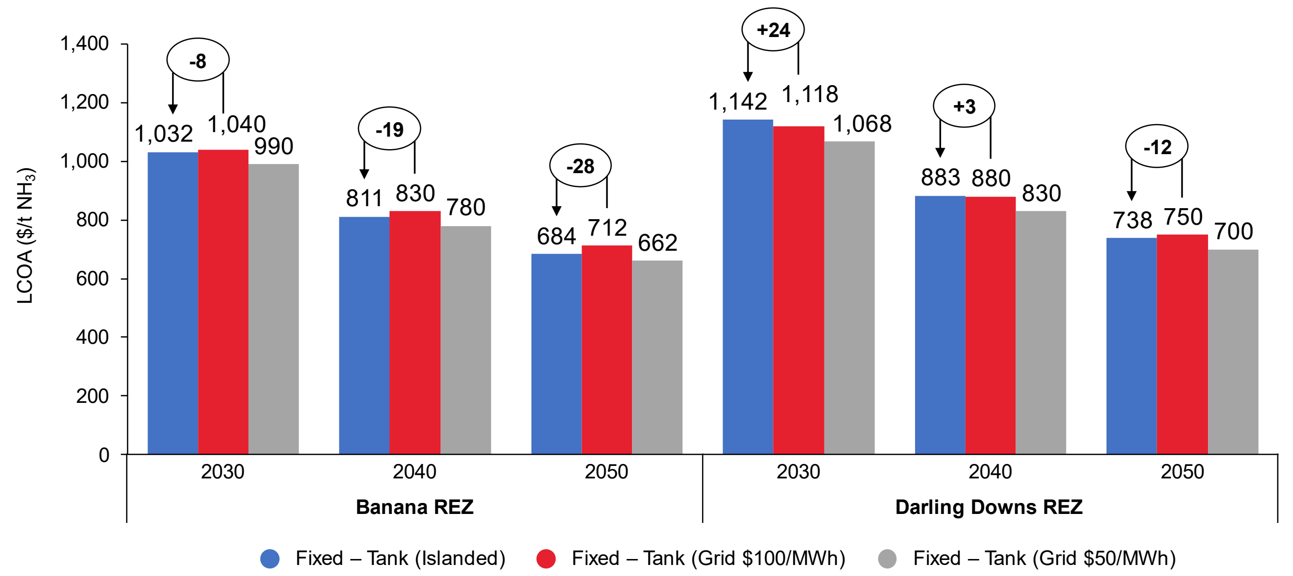


Figure 81: Islanded vs grid connected HB plant at different grid prices (\$50/MWh and \$100/MWh) for Banana and Darling Downs

The capacity builds are identical in the two grid connected scenarios. The grid connection has a negligible impact on electrolyser and HB plant capacities, but it reduces the solar build by ~10% and wind by ~20% (Figure 82).

Capacity Build in Banana – Islanded HB vs Grid Connected HB (MW)

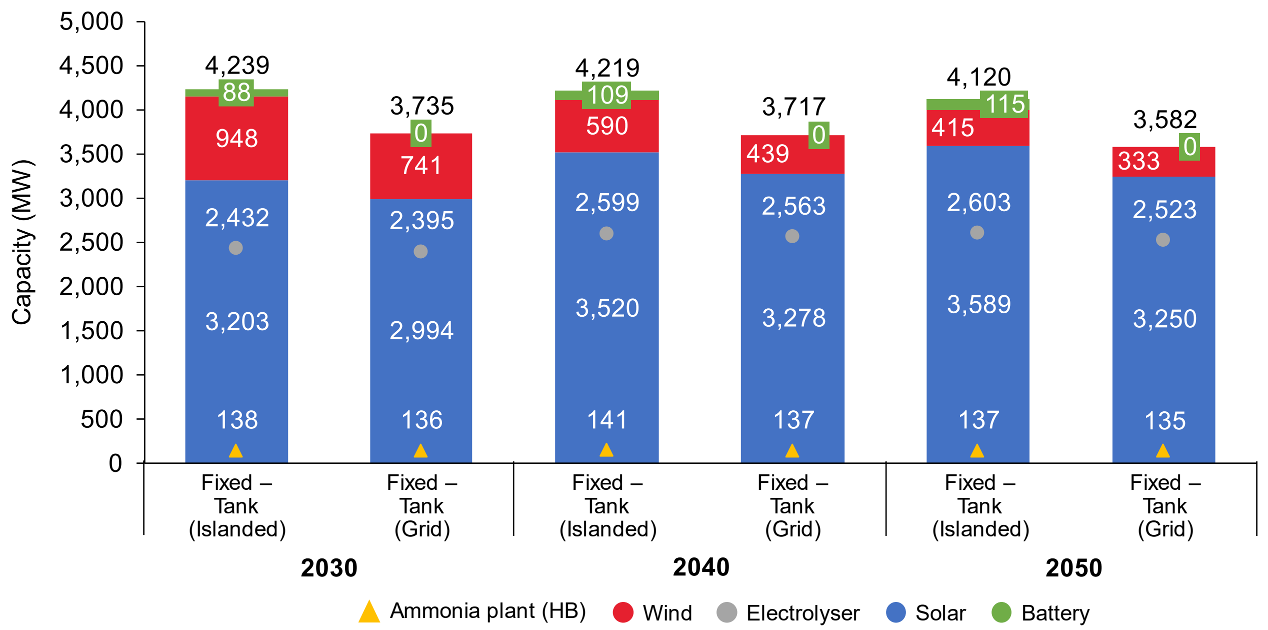


Figure 82: Ammonia - capacity build for Banana Fixed- Tank, islanded vs grid connected HB plant scenarios

			Levelised cost of ammonia (LCOA) ($/t NH_3)		Solar capacity (MW)		Wind capacity (MW)		Battery capacity (MW)		Electrolyser capacity (MW)		HB capacity (MW)	
		REZ	Fixed – Tank (islanded)	Fixed - Tank (Grid $100MWh)	Fixed – Tank (islanded)	Fixed – Tank (Grid)	Fixed – Tank (islanded)	Fixed – Tank (Grid)	Fixed – Tank (islanded)	Fixed – Tank (Grid)	Fixed – Tank (islanded)	Fixed - Tank (Grid)	Fixed – Tank (islanded)	Fixed – Tank (Grid)
2030	**Hybrid**	NQCEH (Q2)	958	973	2,698	2,441	1,084	966	341	966	2,203	2,134	135	134
		Isaac (Q4)	1,013	1,025	2,841	2,604	1,226	1,079	332	1,079	2,221	2,159	141	139
		Barcaldine (Q5)	965	978	2,708	2,681	1,107	798	333	798	2,183	2,251	134	135
		Banana (Q9)	1,032	1,040	3,203	2,994	948	741	344	741	2,433	2,395	138	136
	Solar	North Queensland (Q3)	1,220	1,187	4,552	4,088	0	0	1,051	0	3,150	3,059	129	129
		Fitzroy (Q6)	1,139	1,117	4,489	4,033	0	0	1,074	0	3,009	2,935	132	132
		Darling Downs (Q8)	1,142	1,118	4,584	4,115	0	0	1,132	0	3,046	2,971	139	139
2040	**Hybrid**	NQCEH (Q2)	761	787	2,863	2,766	836	570	370	570	2,279	2,326	135	135
		Isaac (Q4)	806	829	3,006	2,927	964	700	354	700	2,294	2,332	138	136
		Barcaldine (Q5)	760	783	3,286	3,121	470	266	529	266	2,490	2,500	134	133
		Banana (Q9)	811	830	3,520	3,278	590	439	477	439	2,599	2,563	141	137
	Solar	North Queensland (Q3)	960	949	4,411	3,936	0	0	1,039	0	3,041	2,946	127	127
		Fitzroy (Q6)	885	884	4,360	3,973	0	0	1,057	0	2,923	2,894	129	133
		Darling Downs (Q8)	883	880	4,443	4,045	0	0	1,109	0	2,961	2,939	136	138
2050	**Hybrid**	NQCEH (Q2)	646	679	3,036	2,907	584	364	470	364	2,365	2,379	137	134
		Isaac (Q4)	687	716	3,178	3,114	724	454	477	454	2,354	2,425	136	134
		Barcaldine (Q5)	641	672	3,399	3,102	259	177	654	177	2,511	2,450	133	131
		Banana (Q9)	684	712	3,589	3,250	415	333	567	333	2,603	2,523	137	135
	Solar	North Queensland (Q3)	817	820	4,346	3,853	0	0	1,023	0	2,958	2,851	125	125
		Fitzroy (Q6)	744	756	4,358	3,873	0	0	1,062	0	2,924	2,829	130	130
		Darling Downs (Q8)	738	750	4,404	3,915	0	0	1,109	0	2,939	2,848	136	136

Table 16: LCOA and plant design – Fixed – Tank, Islanded vs fixed grid connected HB by REZ

6.7 Hydrogen – Modelling output summary

2030			LCOH ($/kg H_2)	Solar PV capacity (MW)	Wind capacity (MW)	solar capacity / renewable capacity	% of Renewables Curtailed	Electrolyser capacity (MW)	Electrolyser cap factor (%)	Hydrogen Storage (GWh)	Storage cycles pa	Solar capex ($m)	Wind capex ($m)	Electrolyser capex ($m)	Storage capex ($m)	Total capex ($m)
Fixed – Tank	**Hybrid**	NQCEH (Q2)	6.29	3,493	745	82%	23%	2777	36%	75	36.0	3,637	1,320	2,000	2,707	9,663
		Isaac (Q4)	6.36	3,090	1,406	69%	23%	2378	42%	66	29.2	3,216	2,490	1,712	2,393	9,812
		Barcaldine (Q5)	6.30	2,885	1,534	65%	27%	2212	46%	67	25.2	3,003	2,717	1,593	2,420	9,732
		Banana (Q9)	6.23	3,634	1,113	77%	26%	2528	40%	56	42.9	3,783	1,972	1,820	2,031	9,606
	Solar	North Queensland (Q3)	9.87	5,917	0	100%	39%	4259	24%	162	24.7	6,160	0	3,067	5,863	15,089
		Fitzroy (Q6)	9.07	6,633	0	100%	46%	4652	22%	101	38.7	6,905	0	3,349	3,660	13,914
		Darling Downs (Q8)	8.86	7,605	0	100%	52%	4467	23%	69	56.2	7,917	0	3,216	2,496	13,629
Fixed - Salt Cavern	**Hybrid**	NQCEH (Q2)	4.12	2,422	947	72%	5%	2270	44%	409	5.9	2,522	1,677	1,635	741	6,574
		Isaac (Q4)	4.41	2,359	1,340	64%	7%	2080	48%	392	5.3	2,455	2,374	1,497	711	7,037
		Barcaldine (Q5)	4.18	2,207	1,275	63%	7%	2053	49%	342	6.0	2,298	2,257	1,478	620	6,654
		Banana (Q9)	4.39	2,793	1,031	73%	8%	2325	43%	302	8.5	2,907	1,827	1,674	547	6,955
	Solar	North Queensland (Q3)	4.76	3,964	0	100%	9%	3246	31%	655	6.3	4,127	0	2,337	1,186	7,650
		Fitzroy (Q6)	4.67	4,035	0	100%	11%	3082	33%	589	6.9	4,200	0	2,219	1,067	7,487
		Darling Downs (Q8)	4.81	4,138	0	100%	12%	3098	33%	665	6.1	4,308	0	2,231	1,206	7,745
Flexible	**Hybrid**	NQCEH (Q2)	3.66	1,868	1,333	58%	3%	1912	53%	0	2.2	1,944	2,360	1,377	0	5,681
		Isaac (Q4)	3.87	3,600	0	100%	4%	3044	33%	0	3.2	3,748	0	2,192	0	5,940
		Barcaldine (Q5)	3.57	3,211	0	100%	2%	2952	34%	0	3.8	3,343	0	2,125	0	5,468
		Banana (Q9)	3.80	3,485	0	100%	3%	3042	33%	0	3.0	3,628	0	2,190	0	5,818
	Solar	North Queensland (Q3)	3.98	3,643	0	100%	3%	3209	31%	0	2.8	3,793	0	2,310	0	6,103
		Fitzroy (Q6)	3.94	3,661	0	100%	4%	3104	32%	0	3.1	3,811	0	2,235	0	6,046
		Darling Downs (Q8)	4.01	3,728	0	100%	4%	3152	32%	0	2.6	3,880	0	2,270	0	6,150

Table 17: Hydrogen - optimisation results –2030 data output summary

2040			LCOH ($/kg H_2)	Solar PV capacity (MW)	Wind capacity (MW)	solar capacity / renewable capacity	% of Renewables Curtailed	Electrolyser capacity (MW)	Electrolyser cap factor (%)	Hydrogen Storage (GWh)	Storage cycles pa	Solar capex ($m)	Wind capex ($m)	Electrolyser capex ($m)	Storage capex ($m)	Total capex ($m)
Fixed – Tank	**Hybrid**	NQCEH (Q2)	5.02	3,401	699	83%	24%	2607	37%	74	36.6	2,670	1,100	1,111	2,674	7,554
		Isaac (Q4)	5.13	2,923	1,324	69%	23%	2328	41%	66	29.4	2,295	2,083	992	2,393	7,762
		Barcaldine (Q5)	5.03	3,761	786	83%	33%	2890	33%	59	44.4	2,952	1,236	1,231	2,153	7,572
		Banana (Q9)	4.90	3,636	997	78%	28%	2503	38%	53	47.1	2,855	1,569	1,066	1,908	7,398
	Solar	North Queensland (Q3)	8.00	5,595	0	100%	39%	4086	23%	162	24.7	4,392	0	1,741	5,877	12,009
		Fitzroy (Q6)	7.01	6,259	0	100%	45%	4493	21%	101	38.6	4,913	0	1,914	3,672	10,499
		Darling Downs (Q8)	6.67	7,102	0	100%	51%	4430	22%	70	55.7	5,575	0	1,887	2,521	9,983
Fixed - Salt Cavern	**Hybrid**	NQCEH (Q2)	3.02	3,094	437	88%	11%	2707	35%	195	16.6	2,429	687	1,153	353	4,623
		Isaac (Q4)	3.26	3,346	326	91%	9%	2669	36%	474	7.3	2,627	512	1,137	859	5,135
		Barcaldine (Q5)	3.09	3,328	0	100%	8%	2733	35%	648	6.2	2,612	0	1,164	1,174	4,950
		Banana (Q9)	3.23	3,668	0	100%	11%	2875	33%	554	7.3	2,880	0	1,225	1,003	5,108
	Solar	North Queensland (Q3)	3.43	3,746	0	100%	8%	3123	31%	659	6.3	2,940	0	1,330	1,194	5,464
		Fitzroy (Q6)	3.36	3,838	0	100%	11%	2934	33%	590	6.9	3,013	0	1,250	1,069	5,332
		Darling Downs (Q8)	3.48	3,923	0	100%	11%	2962	32%	670	6.0	3,080	0	1,262	1,214	5,556
Fixed - Flexible	**Hybrid**	NQCEH (Q2)	2.55	3,209	0	100%	2%	2971	32%	0	3.7	2,519	0	1,266	0	3,785
		Isaac (Q4)	2.64	3,384	0	100%	3%	2960	32%	0	3.1	2,656	0	1,261	0	3,917
		Barcaldine (Q5)	2.42	3,025	0	100%	1%	2854	34%	0	3.7	2,374	0	1,216	0	3,590
		Banana (Q9)	2.58	3,274	0	100%	2%	2957	32%	0	2.9	2,570	0	1,260	0	3,830
	Solar	North Queensland (Q3)	2.71	3,426	0	100%	2%	3114	31%	0	2.7	2,690	0	1,326	0	4,016
		Fitzroy (Q6)	2.69	3,438	0	100%	3%	3023	32%	0	3.0	2,698	0	1,288	0	3,986
		Darling Downs (Q8)	2.73	3,496	0	100%	3%	3077	31%	0	2.5	2,744	0	1,311	0	4,055

Table 18: Hydrogen - optimisation results –2040 data output summary

2050			LCOH ($/kg H_2)	Solar PV capacity (MW)	Wind capacity (MW)	solar capacity / renewable capacity	% of Renewables Curtailed	Electrolyser capacity (MW)	Electrolyser cap factor (%)	Hydrogen Storage (GWh)	Storage cycles pa	Solar capex ($m)	Wind capex ($m)	Electrolyser capex ($m)	Storage capex ($m)	Total capex ($m)
Fixed – Tank	**Hybrid**	NQCEH (Q2)	4.31	3,596	621	85%	29%	2669	34%	67	41.3	2,287	909	747	2,430	6,372
		Isaac (Q4)	4.44	2,887	1,177	71%	23%	2303	40%	67	30.7	1,836	1,723	645	2,421	6,625
		Barcaldine (Q5)	4.22	3,781	820	82%	37%	2905	31%	50	49.6	2,405	1,200	813	1,827	6,245
		Banana (Q9)	4.16	3,475	950	79%	28%	2383	38%	53	47.2	2,210	1,391	667	1,906	6,174
	Solar	North Queensland (Q3)	6.99	5,386	0	100%	39%	4008	23%	160	25.0	3,425	0	1,122	5,806	10,354
		Fitzroy (Q6)	7.01	6,259	0	100%	45%	4493	21%	101	38.6	4,913	0	1,914	3,672	10,499
		Darling Downs (Q8)	5.47	6,956	0	100%	52%	4349	21%	65	59.7	4,424	0	1,218	2,350	7,991
Fixed - Salt Cavern	**Hybrid**	NQCEH (Q2)	2.35	3,218	226	93%	12%	2739	33%	211	17.1	2,047	331	767	383	3,527
		Isaac (Q4)	2.59	3,877	0	100%	17%	2945	31%	350	11.4	2,466	0	825	634	3,924
		Barcaldine (Q5)	2.44	3,449	0	100%	16%	2812	32%	434	9.3	2,194	0	787	787	3,768
		Banana (Q9)	2.54	3,781	0	100%	17%	2972	31%	340	11.8	2,405	0	832	616	3,853
	Solar	North Queensland (Q3)	2.69	3,837	0	100%	15%	3206	28%	433	9.5	2,440	0	898	785	4,123
		Fitzroy (Q6)	2.66	3,951	0	100%	17%	3004	30%	384	10.5	2,513	0	841	697	4,051
		Darling Downs (Q8)	2.77	3,742	0	100%	11%	2826	32%	671	6.0	2,380	0	791	1,216	4,387
Flexible	**Hybrid**	NQCEH (Q2)	1.91	3,040	0	100%	1%	2874	32%	0	3.6	1,933	0	805	0	2,738
		Isaac (Q4)	1.98	3,200	0	100%	2%	2878	32%	0	3.0	2,035	0	806	0	2,841
		Barcaldine (Q5)	1.81	2,866	0	100%	1%	2757	33%	0	3.6	1,823	0	772	0	2,595
		Banana (Q9)	1.93	3,099	0	100%	1%	2866	32%	0	2.9	1,971	0	803	0	2,774
	Solar	North Queensland (Q3)	2.03	3,242	0	100%	1%	3019	30%	0	2.6	2,062	0	845	0	2,908
		Fitzroy (Q6)	2.01	3,250	0	100%	2%	2938	31%	0	2.9	2,067	0	823	0	2,890
		Darling Downs (Q8)	2.05	3,304	0	100%	2%	2994	30%	0	2.4	2,101	0	838	0	2,940

Table 19: Hydrogen - optimisation results –2050 data output summary

2030 Fixed – Salt Cavern: salt cavern cycling constraint sensitivity			LCOH ($/kg H_2)	Solar PV capacity (MW)	Wind capacity (MW)	solar capacity / renewable capacity	% of Renewables Curtailed	Electrolyser capacity (MW)	Electrolyser cap factor (%)	Hydrogen Storage (GWh)	Storage cycles pa	Solar capex ($m)	Wind capex ($m)	Electrolyser capex ($m)	Storage capex ($m)	Total capex ($m)
Max 12 cycles pa	**Hybrid**	NQCEH (Q2)	4.20	2,252	1,033	69%	3%	2172	46%	591	3.8	2,345	1,830	1,564	1,071	6,809
		Isaac (Q4)	4.49	2,585	1,060	71%	5%	2239	45%	591	4.1	2,691	1,878	1,612	1,071	7,252
		Barcaldine (Q5)	4.23	3,100	338	90%	6%	2669	38%	591	5.9	3,227	598	1,922	1,071	6,819
		Banana (Q9)	4.51	3,782	0	100%	9%	3091	33%	591	6.8	3,937	0	2,226	1,071	7,233
	Solar	North Queensland (Q3)	4.76	3,964	0	100%	9%	3246	31%	655	6.3	4,127	0	2,337	1,186	7,650
		Fitzroy (Q6)	4.67	4,029	0	100%	11%	3087	33%	591	6.8	4,194	0	2,223	1,071	7,488
		Darling Downs (Q8)	4.81	4,138	0	100%	12%	3098	33%	665	6.1	4,308	0	2,231	1,206	7,745
Max 6 cycles pa	**Hybrid**	NQCEH (Q2)	4.67	1,844	1,384	57%	3%	1869	54%	1,184	1.5	1,919	2,451	1,345	2,145	7,861
		Isaac (Q4)	4.91	3,588	80	98%	3%	2979	34%	1,184	3.3	3,735	142	2,145	2,145	8,167
		Barcaldine (Q5)	4.61	3,281	0	100%	2%	2948	34%	1,184	3.4	3,415	0	2,123	2,145	7,683
		Banana (Q9)	4.87	3,646	0	100%	5%	2982	34%	1,184	3.4	3,795	0	2,147	2,145	8,087
	Solar	North Queensland (Q3)	5.07	3,815	0	100%	5%	3173	32%	1,184	3.5	3,971	0	2,285	2,145	8,401
		Fitzroy (Q6)	5.01	3,819	0	100%	6%	3052	33%	1,184	3.4	3,975	0	2,198	2,145	8,318
		Darling Downs (Q8)	5.09	3,897	0	100%	6%	3106	32%	1,184	3.4	4,057	0	2,237	2,145	8,439
Max 2 cycles pa	**Hybrid**	NQCEH (Q2)	6.66	1,844	1,384	57%	3%	1869	54%	3,551	0.5	1,919	2,451	1,345	6,435	12,151
		Isaac (Q4)	6.90	3,677	0	100%	4%	3041	33%	3,551	1.1	3,828	0	2,189	6,435	12,452
		Barcaldine (Q5)	6.59	3,281	0	100%	2%	2948	34%	3,551	1.1	3,415	0	2,123	6,435	11,973
		Banana (Q9)	6.82	3,559	0	100%	3%	3040	33%	3,551	1.1	3,705	0	2,189	6,435	12,328
	Solar	North Queensland (Q3)	7.01	3,724	0	100%	3%	3204	31%	3,551	1.2	3,877	0	2,307	6,435	12,619
		Fitzroy (Q6)	6.97	3,740	0	100%	4%	3100	32%	3,551	1.1	3,893	0	2,232	6,435	12,560
		Darling Downs (Q8)	7.04	3,807	0	100%	4%	3149	32%	3,551	1.1	3,963	0	2,268	6,435	12,665

Table 20: Hydrogen – Salt cavern cycling constraint sensitivity optimisation results - 2030 data output summary

2040 Fixed – Salt Cavern: salt cavern cycling constraint sensitivity			LCOH ($/kg H_2)	Solar PV capacity (MW)	Wind capacity (MW)	solar capacity / renewable capacity	% of Renewables Curtailed	Electrolyser capacity (MW)	Electrolyser cap factor (%)	Hydrogen Storage (GWh)	Storage cycles pa	Solar capex ($m)	Wind capex ($m)	Electrolyser capex ($m)	Storage capex ($m)	Total capex ($m)
Max 12 cycles pa	**Hybrid**	NQCEH (Q2)	3.14	3,290	65	98%	4%	2925	33%	591	6.7	2,583	102	1,246	1,071	5,002
		Isaac (Q4)	3.29	3,697	1	100%	9%	2911	33%	591	6.8	2,902	2	1,240	1,071	5,215
		Barcaldine (Q5)	3.09	3,328	0	100%	8%	2733	35%	648	6.2	2,612	0	1,164	1,174	4,950
		Banana (Q9)	3.24	3,572	0	100%	8%	2982	32%	591	6.8	2,804	0	1,270	1,071	5,146
	Solar	North Queensland (Q3)	3.43	3,746	0	100%	8%	3123	31%	659	6.3	2,940	0	1,330	1,194	5,464
		Fitzroy (Q6)	3.36	3,835	0	100%	11%	2936	33%	591	6.8	3,011	0	1,251	1,071	5,332
		Darling Downs (Q8)	3.48	3,923	0	100%	11%	2962	32%	670	6.0	3,080	0	1,262	1,214	5,556
Max 6 cycles pa	**Hybrid**	NQCEH (Q2)	3.58	3,285	0	100%	2%	2966	32%	1,184	3.5	2,578	0	1,264	2,145	5,987
		Isaac (Q4)	3.68	3,508	0	100%	4%	2899	33%	1,184	3.4	2,754	0	1,235	2,145	6,134
		Barcaldine (Q5)	3.45	3,096	0	100%	1%	2849	34%	1,184	3.4	2,430	0	1,214	2,145	5,789
		Banana (Q9)	3.64	3,429	0	100%	4%	2903	33%	1,184	3.4	2,692	0	1,237	2,145	6,074
	Solar	North Queensland (Q3)	3.77	3,594	0	100%	4%	3079	31%	1,184	3.5	2,821	0	1,312	2,145	6,278
		Fitzroy (Q6)	3.74	3,596	0	100%	5%	2967	32%	1,184	3.4	2,823	0	1,264	2,145	6,232
		Darling Downs (Q8)	3.80	3,680	0	100%	5%	3006	32%	1,184	3.4	2,889	0	1,280	2,145	6,314
Max 2 cycles pa	**Hybrid**	NQCEH (Q2)	5.56	3,285	0	100%	2%	2966	32%	3,551	1.2	2,578	0	1,264	6,435	10,277
		Isaac (Q4)	5.65	3,461	0	100%	2%	2957	32%	3,551	1.1	2,717	0	1,259	6,435	10,411
		Barcaldine (Q5)	5.43	3,096	0	100%	1%	2849	34%	3,551	1.1	2,430	0	1,214	6,435	10,078
		Banana (Q9)	5.59	3,350	0	100%	2%	2952	32%	3,551	1.1	2,630	0	1,258	6,435	10,322
	Solar	North Queensland (Q3)	5.72	3,508	0	100%	2%	3109	31%	3,551	1.2	2,754	0	1,324	6,435	10,513
		Fitzroy (Q6)	5.70	3,517	0	100%	2%	3019	32%	3,551	1.1	2,761	0	1,286	6,435	10,482
		Darling Downs (Q8)	5.75	3,576	0	100%	2%	3073	31%	3,551	1.1	2,807	0	1,309	6,435	10,551

Table 21: Hydrogen – Salt cavern cycling constraint sensitivity optimisation results - 2040 data output summary

2050 Fixed – Salt Cavern: salt cavern cycling constraint sensitivity			LCOH ($/kg H_2)	Solar PV capacity (MW)	Wind capacity (MW)	solar capacity / renewable capacity	% of Renewables Curtailed	Electrolyser capacity (MW)	Electrolyser cap factor (%)	Hydrogen Storage (GWh)	Storage cycles pa	Solar capex ($m)	Wind capex ($m)	Electrolyser capex ($m)	Storage capex ($m)	Total capex ($m)
Max 12 cycles pa	**Hybrid**	NQCEH (Q2)	2.48	3,202	0	100%	4%	2899	31%	591	6.9	2,036	0	812	1,071	3,919
		Isaac (Q4)	2.60	3,530	0	100%	9%	2775	33%	591	6.8	2,245	0	777	1,071	4,093
		Barcaldine (Q5)	2.45	3,234	0	100%	10%	2680	34%	591	6.8	2,057	0	750	1,071	3,878
		Banana (Q9)	2.56	3,409	0	100%	8%	2843	32%	591	6.8	2,168	0	796	1,071	4,035
	Solar	North Queensland (Q3)	2.71	3,631	0	100%	10%	3094	30%	591	7.0	2,309	0	866	1,071	4,247
		Fitzroy (Q6)	2.66	3,660	0	100%	11%	2799	33%	591	6.8	2,328	0	784	1,071	4,182
		Darling Downs (Q8)	2.77	3,742	0	100%	11%	2826	32%	671	6.0	2,380	0	791	1,216	4,387
Max 6 cycles pa	**Hybrid**	NQCEH (Q2)	2.93	3,116	0	100%	1%	2867	32%	1,184	3.5	1,982	0	803	2,145	4,930
		Isaac (Q4)	3.01	3,323	0	100%	3%	2817	32%	1,184	3.4	2,113	0	789	2,145	5,047
		Barcaldine (Q5)	2.83	2,937	0	100%	1%	2751	33%	1,184	3.4	1,868	0	770	2,145	4,784
		Banana (Q9)	2.98	3,241	0	100%	3%	2835	32%	1,184	3.4	2,061	0	794	2,145	5,000
	Solar	North Queensland (Q3)	3.08	3,402	0	100%	4%	2994	31%	1,184	3.5	2,164	0	838	2,145	5,147
		Fitzroy (Q6)	3.06	3,402	0	100%	4%	2891	32%	1,184	3.4	2,164	0	810	2,145	5,118
		Darling Downs (Q8)	3.11	3,477	0	100%	4%	2939	31%	1,184	3.4	2,211	0	823	2,145	5,179
Max 2 cycles pa	**Hybrid**	NQCEH (Q2)	4.92	3,116	0	100%	1%	2867	32%	3,551	1.2	1,982	0	803	6,435	9,219
		Isaac (Q4)	4.99	3,278	0	100%	2%	2872	32%	3,551	1.1	2,085	0	804	6,435	9,323
		Barcaldine (Q5)	4.81	2,937	0	100%	1%	2751	33%	3,551	1.1	1,868	0	770	6,435	9,073
		Banana (Q9)	4.94	3,176	0	100%	1%	2860	32%	3,551	1.1	2,020	0	801	6,435	9,255
	Solar	North Queensland (Q3)	5.03	3,324	0	100%	1%	3013	30%	3,551	1.2	2,114	0	844	6,435	9,393
		Fitzroy (Q6)	5.02	3,331	0	100%	2%	2933	31%	3,551	1.1	2,118	0	821	6,435	9,374
		Darling Downs (Q8)	5.06	3,385	0	100%	2%	2989	31%	3,551	1.1	2,153	0	837	6,435	9,424

Table 22: Hydrogen – Salt cavern cycling constraint sensitivity optimisation results - 2050 data output summary

REZ where entire wind resources build limit required for domestic decarbonisation			LCOH ($/kg H_2)	Solar PV capacity (MW)	Wind capacity (MW)	solar capacity / renewable capacity	% of Renewables Curtailed	Electrolyser capacity (MW)	Electrolyser cap factor (%)	Hydrogen Storage (GWh)	Storage cycles pa	Solar capex ($m)	Wind capex ($m)	Electrolyser capex ($m)	Storage capex ($m)	Total capex ($m)
2030	**Fixed – Tank**	Fitzroy (Q6)	6.43	3,878	1,090	78%	30%	2778	36%	54	43.0	4,037	1,931	2,000	1,952	9,920
		Darling Downs (Q8)	6.79	4,473	995	82%	36%	2892	35%	54	42.9	4,656	1,761	2,082	1,972	10,472
	Fixed - Salt Cavern	Fitzroy (Q6)	4.35	2,671	1,020	72%	6%	2272	44%	398	6.3	2,780	1,806	1,636	720	6,942
		Darling Downs (Q8)	4.42	2,011	1,586	56%	7%	1838	55%	498	3.6	2,094	2,809	1,323	902	7,127
	Flexible	Fitzroy (Q6)	3.93	2,885	673	81%	3%	2593	39%	0	3.5	3,004	1,192	1,867	0	6,063
		Darling Downs (Q8)	3.89	1,956	1,471	57%	3%	1948	52%	0	2.1	2,036	2,605	1,402	0	6,044
2040	**Fixed – Tank**	Fitzroy (Q6)	5.03	3,692	1,054	78%	30%	2826	34%	50	45.4	2,898	1,658	1,204	1,825	7,585
		Darling Downs (Q8)	5.27	4,316	1,068	80%	38%	2717	35%	48	44.8	3,388	1,681	1,158	1,723	7,949
	Fixed - Salt Cavern	Fitzroy (Q6)	3.24	2,842	756	79%	7%	2339	41%	361	7.8	2,231	1,189	996	654	5,070
		Darling Downs (Q8)	3.38	3,184	565	85%	10%	2547	38%	473	6.5	2,499	889	1,085	858	5,331
	Flexible	Fitzroy (Q6)	2.69	3,438	0	100%	3%	3023	32%	0	3.0	2,698	0	1,288	0	3,986
		Darling Downs (Q8)	2.73	3,496	0	100%	3%	3077	31%	0	2.5	2,744	0	1,311	0	4,055
2050	**Fixed – Tank**	Fitzroy (Q6)	4.23	3,534	1,021	78%	31%	2781	33%	48	46.8	2,248	1,495	779	1,753	6,274
		Darling Downs (Q8)	4.43	4,244	964	81%	39%	2547	36%	48	46.5	2,699	1,411	713	1,727	6,550
	Fixed - Salt Cavern	Fitzroy (Q6)	2.62	3,103	612	84%	14%	2498	37%	206	14.5	1,973	895	699	373	3,941
		Darling Downs (Q8)	2.73	3,050	537	85%	10%	2420	38%	471	6.5	1,940	786	678	854	4,257
	Flexible	Fitzroy (Q6)	2.01	3,250	0	100%	2%	2938	31%	0	2.9	2,067	0	823	0	2,890
		Darling Downs (Q8)	2.05	3,304	0	100%	2%	2994	30%	0	2.4	2,101	0	838	0	2,940

Table 23: Hydrogen – REZ where entire wind resources build limit required for domestic decarbonisation - data output summary

6.8 Ammonia - Modelling output summary

				Levelised cost of ammonia (LCOA) ($/kg)	Solar PV capacity (MW)	Wind capacity (MW)	Battery capacity (MWh)	Solar portfolio weighting (solar capacity / renewable capacity)	% of renewable energy curtailed	Battery capacity factor (%)	Electrolyser capacity (MW)	Electrolyser cap factor (%)	HB capacity (MW)	HB Load factor	Hydrogen Storage (GWh)	Storage cycles pa	Ammonia Storage (GWh)
2030	**Fixed - Tank**	**Hybrid**	NQCEH (Q2)	958	2,698	1,084	341	71%	6%	13%	2,203	46%	135	84%	9	208	442
			Isaac (Q4)	1,013	2,841	1,226	332	70%	6%	15%	2,221	45%	141	81%	8	246	589
			Barcaldine (Q5)	965	2,708	1,107	333	71%	6%	11%	2,183	46%	134	85%	9	236	565
			Banana (Q9)	1,032	3,203	948	344	77%	6%	11%	2,433	41%	138	83%	10	235	683
		Solar	North Queensland (Q3)	1,220	4,552	0	1,051	100%	12%	16%	3,150	32%	129	89%	42	80	559
			Fitzroy (Q6)	1,139	4,489	0	1,074	100%	11%	14%	3,009	33%	132	87%	22	150	878
			Darling Downs (Q8)	1,142	4,584	0	1,132	100%	11%	15%	3,046	33%	139	82%	18	185	839
	Fixed - Salt Cavern	**Hybrid**	NQCEH (Q2)	906	2,486	1,199	290	67%	4%	14%	2,115	48%	127	90%	53	35	464
			Isaac (Q4)	963	2,957	1,101	299	73%	5%	17%	2,337	43%	127	90%	47	46	483
			Barcaldine (Q5)	915	3,028	786	306	79%	6%	14%	2,432	41%	125	91%	62	41	442
			Banana (Q9)	973	3,195	970	293	77%	7%	13%	2,485	41%	123	93%	58	44	445
		Solar	North Queensland (Q3)	1,037	4,408	0	1,049	100%	9%	16%	3,202	31%	129	89%	82	41	519
			Fitzroy (Q6)	1,032	4,347	0	1,044	100%	8%	15%	3,074	33%	128	89%	76	45	788
			Darling Downs (Q8)	1,053	4,477	0	1,075	100%	9%	15%	3,078	33%	132	87%	84	40	760
	Flexible	**Hybrid**	NQCEH (Q2)	927	2,356	1,333	311	64%	5%	11%	2,010	50%	136	84%	10	162	0
			Isaac (Q4)	977	2,815	1,222	335	70%	5%	10%	2,223	45%	142	81%	8	248	0
			Barcaldine (Q5)	931	2,865	907	348	76%	5%	11%	2,335	43%	137	83%	9	254	0
			Banana (Q9)	990	3,407	687	411	83%	6%	10%	2,602	39%	140	81%	11	245	0
		Solar	North Queensland (Q3)	1,174	4,386	0	1,066	100%	9%	15%	3,089	33%	131	87%	44	78	0
			Fitzroy (Q6)	1,087	4,395	0	1,098	100%	9%	14%	2,989	34%	135	85%	24	140	0
			Darling Downs (Q8)	1,084	4,427	0	1,165	100%	8%	13%	3,025	33%	143	80%	19	176	0

Table 24: Ammonia – optimisation results – 2030 data output summary

				Solar capex ($m)	Wind capex ($m)	Battery capex ($m)	Electrolyser capex ($m)	HB capex ($m)	Hydrogen storage capex ($m)	Ammonia storage capex ($m)	Total capex ($m)
2030	**Fixed - Tank**	**Hybrid**	NQCEH (Q2)	2,809	1,919	158	3,110	1,186	332	212	9,726
			Isaac (Q4)	2,958	2,171	154	3,135	1,234	281	283	10,214
			Barcaldine (Q5)	2,819	1,960	154	3,081	1,176	311	271	9,773
			Banana (Q9)	3,335	1,678	159	3,433	1,206	370	328	10,508
		Solar	North Queensland (Q3)	4,739	0	451	4,445	1,128	1,515	268	12,545
			Fitzroy (Q6)	4,673	0	461	4,247	1,153	813	422	11,768
			Darling Downs (Q8)	4,772	0	485	4,298	1,214	644	403	11,817
	Fixed - Salt Cavern	**Hybrid**	NQCEH (Q2)	2,588	2,124	134	2,984	1,111	67	223	9,231
			Isaac (Q4)	3,079	1,950	138	3,298	1,109	60	232	9,866
			Barcaldine (Q5)	3,152	1,391	142	3,433	1,097	79	212	9,506
			Banana (Q9)	3,326	1,718	136	3,507	1,079	73	214	10,053
		Solar	North Queensland (Q3)	4,589	0	450	4,518	1,126	104	249	11,036
			Fitzroy (Q6)	4,526	0	448	4,337	1,121	96	378	10,906
			Darling Downs (Q8)	4,660	0	461	4,343	1,154	107	365	11,091
	Flexible	**Hybrid**	NQCEH (Q2)	2,453	2,361	144	2,837	1,195	352	0	9,341
			Isaac (Q4)	2,930	2,163	155	3,137	1,242	284	0	9,912
			Barcaldine (Q5)	2,982	1,606	161	3,295	1,204	326	0	9,574
			Banana (Q9)	3,547	1,216	190	3,673	1,230	399	0	10,255
		Solar	North Queensland (Q3)	4,566	0	457	4,359	1,144	1,588	0	12,114
			Fitzroy (Q6)	4,575	0	471	4,218	1,178	872	0	11,315
			Darling Downs (Q8)	4,609	0	500	4,268	1,250	686	0	11,313

Table 25: Ammonia –optimisation results – 2030 capex summary

				Levelised cost of ammonia (LCOA) ($/kg)	Solar PV capacity (MW)	Wind capacity (MW)	Battery capacity (MWh)	Solar portfolio weighting (solar capacity / renewable capacity)	% of renewable energy curtailed	Battery capacity factor (%)	Electrolyser capacity (MW)	Electrolyser cap factor (%)	HB capacity (MW)	HB Load factor	Hydrogen Storage (GWh)	Storage cycles pa	Ammonia Storage (GWh)
2040	**Fixed - Tank**	**Hybrid**	NQCEH (Q2)	761	2,863	836	370	77%	7%	15%	2,279	42%	135	85%	9	250	406
			Isaac (Q4)	806	3,006	964	354	76%	7%	15%	2,294	42%	138	83%	9	250	510
			Barcaldine (Q5)	760	3,286	470	529	87%	9%	15%	2,490	38%	134	85%	10	271	461
			Banana (Q9)	811	3,520	590	477	86%	10%	15%	2,599	37%	141	81%	11	242	347
		Solar	North Queensland (Q3)	960	4,411	0	1,039	100%	13%	16%	3,041	31%	127	90%	41	82	531
			Fitzroy (Q6)	885	4,360	0	1,057	100%	12%	14%	2,923	33%	129	88%	21	159	832
			Darling Downs (Q8)	883	4,443	0	1,109	100%	13%	15%	2,961	32%	136	84%	17	194	783
	Fixed - Salt Cavern	**Hybrid**	NQCEH (Q2)	707	3,090	597	306	84%	6%	20%	2,522	38%	127	90%	71	38	312
			Isaac (Q4)	750	3,359	630	320	84%	7%	16%	2,575	37%	131	87%	58	46	411
			Barcaldine (Q5)	700	3,411	255	466	93%	7%	14%	2,692	36%	127	90%	62	52	484
			Banana (Q9)	745	3,687	360	378	91%	9%	16%	2,802	34%	128	89%	82	38	374
		Solar	North Queensland (Q3)	779	4,192	0	1,058	100%	9%	16%	3,092	31%	130	88%	70	48	527
			Fitzroy (Q6)	779	4,219	0	1,051	100%	9%	16%	3,037	32%	129	89%	73	46	538
			Darling Downs (Q8)	796	4,350	0	1,064	100%	11%	16%	3,051	31%	130	88%	85	40	527
	Flexible	**Hybrid**	NQCEH (Q2)	732	2,925	726	394	80%	5%	10%	2,366	40%	136	84%	9	267	0
			Isaac (Q4)	769	3,072	848	355	78%	6%	10%	2,362	41%	137	83%	10	248	0
			Barcaldine (Q5)	724	3,274	358	535	90%	6%	10%	2,578	37%	136	84%	11	266	0
			Banana (Q9)	768	3,432	509	474	87%	6%	10%	2,591	37%	138	83%	12	250	0
		Solar	North Queensland (Q3)	920	4,270	0	1,043	100%	10%	16%	3,010	32%	128	89%	42	82	0
			Fitzroy (Q6)	837	4,269	0	1,072	100%	10%	15%	2,909	33%	131	87%	23	150	0
			Darling Downs (Q8)	831	4,275	0	1,134	100%	9%	13%	2,956	32%	139	82%	18	185	0

Table 26: Ammonia –optimisation results – 2040 data output summary

				Solar capex ($m)	Wind capex ($m)	Battery capex ($m)	Electrolyser capex ($m)	HB capex ($m)	Hydrogen storage capex ($m)	Ammonia storage capex ($m)	Total capex ($m)
2040	**Fixed - Tank**	**Hybrid**	NQCEH (Q2)	2,248	1,315	143	1,903	1,183	318	195	7,305
			Isaac (Q4)	2,360	1,517	137	1,916	1,210	314	245	7,698
			Barcaldine (Q5)	2,579	739	201	2,079	1,173	368	221	7,360
			Banana (Q9)	2,763	928	182	2,170	1,233	395	167	7,838
		Solar	North Queensland (Q3)	3,463	0	379	2,539	1,115	1,479	255	9,230
			Fitzroy (Q6)	3,423	0	386	2,441	1,134	772	399	8,554
			Darling Downs (Q8)	3,488	0	405	2,472	1,190	620	376	8,551
	Fixed - Salt Cavern	**Hybrid**	NQCEH (Q2)	2,426	939	118	2,106	1,110	90	150	6,939
			Isaac (Q4)	2,637	991	124	2,150	1,144	74	197	7,317
			Barcaldine (Q5)	2,677	401	179	2,247	1,113	79	233	6,929
			Banana (Q9)	2,895	567	146	2,340	1,124	104	180	7,354
		Solar	North Queensland (Q3)	3,291	0	386	2,582	1,135	89	253	7,735
			Fitzroy (Q6)	3,312	0	384	2,536	1,128	93	258	7,709
			Darling Downs (Q8)	3,415	0	388	2,547	1,141	108	253	7,853
	Flexible	**Hybrid**	NQCEH (Q2)	2,296	1,143	152	1,976	1,195	329	0	7,091
			Isaac (Q4)	2,412	1,334	137	1,973	1,202	351	0	7,408
			Barcaldine (Q5)	2,570	563	204	2,152	1,191	409	0	7,089
			Banana (Q9)	2,694	800	182	2,163	1,208	421	0	7,468
		Solar	North Queensland (Q3)	3,352	0	381	2,513	1,119	1,522	0	8,886
			Fitzroy (Q6)	3,351	0	392	2,429	1,151	819	0	8,141
			Darling Downs (Q8)	3,356	0	414	2,468	1,217	657	0	8,111

Table 27: Ammonia – optimisation results – 2040 capex summary

				Levelised cost of ammonia (LCOA) ($/kg)	Solar PV capacity (MW)	Wind capacity (MW)	Battery capacity (MWh)	Solar portfolio weighting (solar capacity / renewable capacity)	% of renewable energy curtailed	Battery capacity factor (%)	Electrolyser capacity (MW)	Electrolyser cap factor (%)	HB capacity (MW)	HB Load factor	Hydrogen Storage (GWh)	Storage cycles pa	Ammonia Storage (GWh)
2050	**Fixed - Tank**	**Hybrid**	NQCEH (Q2)	646	3,036	584	470	84%	8%	15%	2,365	39%	137	84%	9	272	353
			Isaac (Q4)	687	3,178	724	477	81%	9%	15%	2,354	39%	136	84%	10	245	425
			Barcaldine (Q5)	641	3,399	259	654	93%	11%	15%	2,511	36%	133	86%	11	276	459
			Banana (Q9)	684	3,589	415	567	90%	12%	15%	2,603	35%	137	83%	12	242	344
		Solar	North Queensland (Q3)	817	4,346	0	1,023	100%	16%	16%	2,958	31%	125	91%	39	86	506
			Fitzroy (Q6)	744	4,358	0	1,062	100%	16%	16%	2,924	31%	130	88%	21	159	520
			Darling Downs (Q8)	738	4,404	0	1,109	100%	15%	15%	2,939	31%	136	84%	17	193	483
	Fixed - Salt Cavern	**Hybrid**	NQCEH (Q2)	591	3,159	440	401	88%	6%	17%	2,556	36%	125	91%	79	37	279
			Isaac (Q4)	625	3,627	273	561	93%	8%	18%	2,737	33%	130	88%	70	44	441
			Barcaldine (Q5)	581	3,396	140	623	96%	8%	14%	2,646	35%	126	90%	58	58	494
			Banana (Q9)	616	3,721	180	617	95%	10%	16%	2,788	33%	127	90%	83	40	379
		Solar	North Queensland (Q3)	640	4,017	0	1,049	100%	9%	16%	3,002	30%	128	89%	75	45	512
			Fitzroy (Q6)	640	4,033	0	1,050	100%	9%	16%	2,927	31%	129	89%	72	47	544
			Darling Downs (Q8)	654	4,212	0	1,038	100%	12%	16%	2,983	31%	127	90%	84	41	503
	Flexible	**Hybrid**	NQCEH (Q2)	618	3,032	523	488	85%	6%	10%	2,396	38%	136	84%	9	287	0
			Isaac (Q4)	650	3,253	571	446	85%	7%	10%	2,437	37%	135	85%	11	242	0
			Barcaldine (Q5)	606	3,307	206	656	94%	7%	11%	2,569	36%	135	85%	12	273	0
			Banana (Q9)	644	3,438	377	563	90%	7%	11%	2,557	36%	135	84%	12	251	0
		Solar	North Queensland (Q3)	781	4,175	0	1,028	100%	12%	16%	2,922	31%	126	91%	41	84	0
			Fitzroy (Q6)	699	4,151	0	1,058	100%	12%	15%	2,817	32%	130	88%	22	157	0
			Darling Downs (Q8)	692	4,137	0	1,116	100%	10%	15%	2,867	32%	137	83%	18	191	0

Table 28: Ammonia – optimisation results – 2050 data output summary

				Solar capex ($m)	Wind capex ($m)	Battery capex ($m)	Electrolyser capex ($m)	HB capex ($m)	Hydrogen storage capex ($m)	Ammonia storage capex ($m)	Total capex ($m)
2050	**Fixed - Tank**	**Hybrid**	NQCEH (Q2)	1,931	855	158	1,298	1,196	335	169	5,942
			Isaac (Q4)	2,021	1,060	159	1,292	1,191	355	204	6,282
			Barcaldine (Q5)	2,162	379	215	1,378	1,165	394	220	5,914
			Banana (Q9)	2,283	608	188	1,429	1,204	423	165	6,300
		Solar	North Queensland (Q3)	2,764	0	328	1,623	1,098	1,418	243	7,473
			Fitzroy (Q6)	2,772	0	340	1,605	1,140	743	249	6,849
			Darling Downs (Q8)	2,801	0	355	1,613	1,190	610	232	6,801
	Fixed - Salt Cavern	**Hybrid**	NQCEH (Q2)	2,009	644	135	1,403	1,095	100	134	5,520
			Isaac (Q4)	2,307	399	186	1,502	1,138	89	212	5,832
			Barcaldine (Q5)	2,160	206	204	1,452	1,106	74	237	5,438
			Banana (Q9)	2,366	263	203	1,530	1,113	105	182	5,762
		Solar	North Queensland (Q3)	2,555	0	336	1,647	1,126	95	246	6,005
			Fitzroy (Q6)	2,565	0	337	1,606	1,127	91	261	5,988
			Darling Downs (Q8)	2,679	0	333	1,637	1,114	107	241	6,110
	Flexible	**Hybrid**	NQCEH (Q2)	1,928	765	164	1,315	1,194	343	0	5,710
			Isaac (Q4)	2,069	836	151	1,337	1,183	411	0	5,987
			Barcaldine (Q5)	2,104	302	216	1,410	1,178	424	0	5,633
			Banana (Q9)	2,186	552	187	1,403	1,186	441	0	5,956
		Solar	North Queensland (Q3)	2,655	0	329	1,604	1,103	1,472	0	7,163
			Fitzroy (Q6)	2,640	0	339	1,546	1,136	784	0	6,445
			Darling Downs (Q8)	2,631	0	358	1,573	1,198	640	0	6,400

Table 29: Ammonia –optimisation results – 2050 capex summary

			Levelised cost of ammonia (LCOA) ($/kg)	Solar PV capacity (MW)	Wind capacity (MW)	Battery capacity (MWh)	Solar portfolio weighting (solar capacity / renewable capacity)	% of renewable energy curtailed	Battery capacity factor (%)	Electrolyser capacity (MW)	Electrolyser cap factor (%)	HB capacity (MW)	HB Load factor	Hydrogen Storage (GWh)	Storage cycles pa	Ammonia Storage (GWh)
2030	**Fixed - Tank**	Fitzroy (Q6)	1,018	2,848	1,229	436	70%	6%	12%	2,212	46%	140	81%	10	184	414
		Darling Downs (Q8)	1,023	2,136	1,839	330	54%	7%	10%	1,740	58%	141	81%	10	123	674
	Fixed - Salt Cavern	Fitzroy (Q6)	959	2,711	1,295	382	68%	5%	10%	2,188	46%	125	91%	72	28	363
		Darling Downs (Q8)	963	1,976	1,916	298	51%	6%	15%	1,716	59%	128	89%	69	20	534
	Flexible	Fitzroy (Q6)	992	2,926	1,130	438	72%	5%	10%	2,288	44%	141	81%	10	199	0
		Darling Downs (Q8)	983	2,243	1,698	335	57%	6%	9%	1,841	55%	142	80%	11	125	0
2040	**Fixed - Tank**	Fitzroy (Q6)	812	3,027	968	446	76%	8%	14%	2,306	42%	139	82%	10	209	354
		Darling Downs (Q8)	829	2,978	1,094	334	73%	10%	15%	2,231	43%	140	82%	11	166	407
	Fixed - Salt Cavern	Fitzroy (Q6)	753	3,115	864	388	78%	7%	16%	2,418	40%	126	90%	60	40	288
		Darling Downs (Q8)	769	3,267	810	311	80%	9%	17%	2,508	38%	130	88%	68	35	383
	Flexible	Fitzroy (Q6)	778	3,150	784	483	80%	6%	13%	2,411	40%	140	82%	10	237	0
		Darling Downs (Q8)	786	2,988	933	346	76%	6%	10%	2,304	42%	140	81%	12	185	0
2050	**Fixed - Tank**	Fitzroy (Q6)	691	3,174	750	552	81%	9%	14%	2,354	39%	139	82%	10	232	310
		Darling Downs (Q8)	709	3,395	674	466	83%	12%	15%	2,440	37%	139	82%	12	202	402
	Fixed - Salt Cavern	Fitzroy (Q6)	631	3,424	490	443	87%	8%	18%	2,620	35%	128	89%	74	39	356
		Darling Downs (Q8)	642	3,591	420	399	90%	9%	18%	2,694	34%	131	87%	80	37	424
	Flexible	Fitzroy (Q6)	659	3,127	678	527	82%	6%	10%	2,371	39%	138	83%	10	244	0
		Darling Downs (Q8)	666	3,403	501	492	87%	7%	10%	2,515	36%	140	81%	13	219	0

Table 30: Ammonia – REZ where entire wind resources build limit required for domestic decarbonisation - data output summary

			Solar capex ($m)	Wind capex ($m)	Battery capex ($m)	Electrolyser capex ($m)	HB capex ($m)	Hydrogen storage capex ($m)	Ammonia storage capex ($m)	Total capex ($m)
2030	**Fixed - Tank**	Fitzroy (Q6)	2,965	2,176	199	3,121	1,227	369	199	10,256
		Darling Downs (Q8)	2,223	3,257	152	2,456	1,232	357	324	10,000
	Fixed - Salt Cavern	Fitzroy (Q6)	2,822	2,293	173	3,088	1,096	91	174	9,738
		Darling Downs (Q8)	2,058	3,393	138	2,422	1,122	87	256	9,475
	Flexible	Fitzroy (Q6)	3,046	2,002	200	3,228	1,231	370	0	10,077
		Darling Downs (Q8)	2,335	3,007	155	2,598	1,247	382	0	9,725
2040	**Fixed - Tank**	Fitzroy (Q6)	2,376	1,522	171	1,925	1,222	366	170	7,752
		Darling Downs (Q8)	2,338	1,721	129	1,863	1,226	404	195	7,877
	Fixed - Salt Cavern	Fitzroy (Q6)	2,445	1,360	150	2,019	1,107	77	138	7,295
		Darling Downs (Q8)	2,565	1,274	120	2,094	1,137	87	184	7,461
	Flexible	Fitzroy (Q6)	2,473	1,233	184	2,013	1,226	374	0	7,502
		Darling Downs (Q8)	2,345	1,468	134	1,924	1,228	430	0	7,530
2050	**Fixed - Tank**	Fitzroy (Q6)	2,019	1,097	183	1,292	1,219	362	149	6,320
		Darling Downs (Q8)	2,159	987	158	1,339	1,218	425	193	6,479
	Fixed - Salt Cavern	Fitzroy (Q6)	2,178	717	148	1,438	1,118	94	171	5,863
		Darling Downs (Q8)	2,284	615	135	1,479	1,152	102	203	5,969
	Flexible	Fitzroy (Q6)	1,989	993	175	1,301	1,210	380	0	6,048
		Darling Downs (Q8)	2,164	734	165	1,380	1,229	460	0	6,133

Table 31: Ammonia – REZ where entire wind resources build limit required for domestic decarbonisation - capex summary

				Levelised cost of ammonia (LCOA) ($/kg)	Solar PV capacity (MW)	Wind capacity (MW)	Battery capacity (MWh)	Solar portfolio weighting (solar capacity / renewable capacity)	% of renewable energy curtailed	Battery capacity factor (%)	Electrolyser capacity (MW)	Electrolyser cap factor (%)	HB capacity (MW)	HB Load factor	Hydrogen Storage (GWh)	Storage cycles pa	Ammonia Storage (GWh)
2030	**Fixed – Tank, Grid $100MWh**	**Hybrid**	NQCEH (Q2)	973	2,441	966	0	72%	6%	0%	2,134	47%	134	85%	8	217	425
			Isaac (Q4)	1,025	2,604	1,079	0	71%	6%	0%	2,159	47%	139	82%	7	248	535
			Barcaldine (Q5)	978	2,681	798	0	77%	7%	0%	2,251	45%	135	85%	8	261	425
			Banana (Q9)	1,040	2,994	741	0	80%	7%	0%	2,395	42%	136	84%	9	253	716
		Solar	North Queensland (Q3)	1,187	4,088	0	0	100%	12%	0%	3,059	33%	129	89%	38	85	558
			Fitzroy (Q6)	1,117	4,033	0	0	100%	11%	0%	2,935	34%	132	87%	21	157	877
			Darling Downs (Q8)	1,118	4,115	0	0	100%	11%	0%	2,971	34%	139	82%	17	191	845
	Fixed -Salt Cavern, Grid $100MWh	**Hybrid**	NQCEH (Q2)	929	2,333	1,001	0	70%	5%	0%	2,115	48%	126	91%	37	49	449
			Isaac (Q4)	979	2,565	1,092	0	70%	6%	0%	2,181	46%	124	92%	43	45	438
			Barcaldine (Q5)	933	3,146	329	0	91%	8%	0%	2,589	39%	122	93%	66	44	446
			Banana (Q9)	987	2,960	774	0	79%	7%	0%	2,423	42%	123	93%	52	46	520
		Solar	North Queensland (Q3)	1,019	3,945	0	0	100%	9%	0%	3,098	33%	129	88%	67	49	551
			Fitzroy (Q6)	1,017	3,939	0	0	100%	9%	0%	3,003	34%	126	91%	71	47	705
			Darling Downs (Q8)	1,035	4,054	0	0	100%	10%	0%	3,020	33%	129	88%	81	41	672
	Flexible, Grid $100MWh	**Hybrid**	NQCEH (Q2)	945	2,306	1,041	0	69%	5%	0%	2,079	48%	135	85%	9	199	0
			Isaac (Q4)	990	2,611	1,028	0	72%	5%	0%	2,198	46%	140	82%	7	252	0
			Barcaldine (Q5)	945	2,737	667	0	80%	5%	0%	2,342	43%	135	85%	9	265	0
			Banana (Q9)	996	3,137	553	0	85%	6%	0%	2,531	40%	138	83%	10	255	0
		Solar	North Queensland (Q3)	1,143	3,936	0	0	100%	9%	0%	3,008	33%	130	88%	40	83	0
			Fitzroy (Q6)	1,065	3,943	0	0	100%	9%	0%	2,923	34%	135	85%	22	145	0
			Darling Downs (Q8)	1,061	3,972	0	0	100%	8%	0%	2,965	34%	143	80%	18	181	0

Table 32: Ammonia – Islanded, grid connected ammonia plant paying $100MWh optimisation results – 2030 data output summary

				Solar capex ($m)	Wind capex ($m)	Battery capex ($m)	Electrolyser capex ($m)	HB capex ($m)	Hydrogen storage capex ($m)	Ammonia storage capex ($m)	Total capex ($m)
2030	**Fixed – Tank, Grid $100MWh**	**Hybrid**	NQCEH (Q2)	2,541	1,711	0	3,011	1,174	299	204	8,939
			Isaac (Q4)	2,711	1,911	0	3,046	1,216	265	257	9,406
			Barcaldine (Q5)	2,790	1,414	0	3,177	1,180	290	204	9,055
			Banana (Q9)	3,117	1,313	0	3,380	1,191	336	344	9,681
		Solar	North Queensland (Q3)	4,255	0	0	4,317	1,126	1,383	268	11,349
			Fitzroy (Q6)	4,198	0	0	4,142	1,152	757	421	10,670
			Darling Downs (Q8)	4,283	0	0	4,193	1,216	609	405	10,707
	Fixed -Salt Cavern, Grid $100MWh	**Hybrid**	NQCEH (Q2)	2,429	1,773	0	2,985	1,103	47	216	8,552
			Isaac (Q4)	2,670	1,933	0	3,077	1,090	54	210	9,035
			Barcaldine (Q5)	3,275	583	0	3,654	1,071	83	214	8,880
			Banana (Q9)	3,082	1,370	0	3,419	1,073	66	249	9,260
		Solar	North Queensland (Q3)	4,107	0	0	4,372	1,132	86	265	9,961
			Fitzroy (Q6)	4,101	0	0	4,238	1,103	90	339	9,871
			Darling Downs (Q8)	4,220	0	0	4,261	1,132	103	322	10,038
	Flexible, Grid $100MWh	**Hybrid**	NQCEH (Q2)	2,401	1,844	0	2,934	1,178	309	0	8,667
			Isaac (Q4)	2,718	1,821	0	3,102	1,226	271	0	9,137
			Barcaldine (Q5)	2,849	1,181	0	3,305	1,183	315	0	8,833
			Banana (Q9)	3,266	979	0	3,572	1,210	365	0	9,391
		Solar	North Queensland (Q3)	4,098	0	0	4,244	1,142	1,449	0	10,933
			Fitzroy (Q6)	4,105	0	0	4,124	1,179	813	0	10,221
			Darling Downs (Q8)	4,135	0	0	4,185	1,252	648	0	10,219

Table 33: Ammonia – Islanded, grid connected ammonia plant paying $100MWh optimisation results – 2030 capex summary

				Levelised cost of ammonia (LCOA) ($/kg)	Solar PV capacity (MW)	Wind capacity (MW)	Battery capacity (MWh)	Solar portfolio weighting (solar capacity / renewable capacity)	% of renewable energy curtailed	Battery capacity factor (%)	Electrolyser capacity (MW)	Electrolyser cap factor (%)	HB capacity (MW)	HB Load factor	Hydrogen Storage (GWh)	Storage cycles pa	Ammonia Storage (GWh)
2040	**Fixed – Tank, Grid $100MWh**	**Hybrid**	NQCEH (Q2)	787	2,766	570	0	83%	7%	0%	2,326	41%	135	85%	9	274	394
			Isaac (Q4)	829	2,927	700	0	81%	9%	0%	2,332	41%	136	84%	9	251	405
			Barcaldine (Q5)	783	3,121	266	0	92%	10%	0%	2,500	38%	133	86%	10	279	466
			Banana (Q9)	830	3,278	439	0	88%	11%	0%	2,563	37%	137	83%	10	253	338
		Solar	North Queensland (Q3)	949	3,936	0	0	100%	13%	0%	2,946	33%	127	90%	37	88	532
			Fitzroy (Q6)	884	3,973	0	0	100%	14%	0%	2,894	33%	133	86%	20	155	532
			Darling Downs (Q8)	880	4,045	0	0	100%	14%	0%	2,939	33%	138	83%	16	193	513
	Fixed -Salt Cavern, Grid $100MWh	**Hybrid**	NQCEH (Q2)	739	2,868	457	0	86%	6%	0%	2,467	39%	124	92%	49	53	324
			Isaac (Q4)	773	3,687	0	0	100%	9%	0%	2,899	33%	132	86%	56	58	465
			Barcaldine (Q5)	723	3,296	0	0	100%	8%	0%	2,725	35%	124	92%	66	51	515
			Banana (Q9)	764	3,639	0	0	100%	10%	0%	2,890	33%	126	91%	82	40	443
		Solar	North Queensland (Q3)	785	3,745	0	0	100%	9%	0%	2,997	32%	128	89%	67	49	522
			Fitzroy (Q6)	784	3,768	0	0	100%	9%	0%	2,943	33%	127	90%	70	47	527
			Darling Downs (Q8)	798	3,882	0	0	100%	11%	0%	2,955	32%	129	88%	79	41	526
	Flexible, Grid $100MWh	**Hybrid**	NQCEH (Q2)	758	2,796	489	0	85%	5%	0%	2,388	40%	136	84%	9	285	0
			Isaac (Q4)	794	2,997	547	0	85%	6%	0%	2,417	40%	134	85%	10	245	0
			Barcaldine (Q5)	747	3,065	192	0	94%	7%	0%	2,569	37%	134	85%	11	272	0
			Banana (Q9)	788	3,207	334	0	91%	7%	0%	2,566	37%	135	85%	11	248	0
		Solar	North Queensland (Q3)	911	3,811	0	0	100%	10%	0%	2,917	33%	128	90%	38	87	0
			Fitzroy (Q6)	836	3,800	0	0	100%	10%	0%	2,825	34%	132	87%	21	155	0
			Darling Downs (Q8)	830	3,801	0	0	100%	9%	0%	2,876	33%	140	82%	17	188	0

Table 34: Ammonia – Islanded, grid connected ammonia plant paying $100MWh optimisation results – 2040 data output summary

				Solar capex ($m)	Wind capex ($m)	Battery capex ($m)	Electrolyser capex ($m)	HB capex ($m)	Hydrogen storage capex ($m)	Ammonia storage capex ($m)	Total capex ($m)
2040	**Fixed – Tank, Grid $100MWh**	**Hybrid**	NQCEH (Q2)	2,171	896	0	1,942	1,179	308	189	6,686
			Isaac (Q4)	2,298	1,101	0	1,947	1,189	320	194	7,049
			Barcaldine (Q5)	2,450	419	0	2,087	1,162	364	224	6,705
			Banana (Q9)	2,573	691	0	2,140	1,200	371	162	7,138
		Solar	North Queensland (Q3)	3,090	0	0	2,460	1,113	1,346	255	8,265
			Fitzroy (Q6)	3,119	0	0	2,416	1,164	743	255	7,696
			Darling Downs (Q8)	3,175	0	0	2,454	1,211	594	246	7,680
	Fixed -Salt Cavern, Grid $100MWh	**Hybrid**	NQCEH (Q2)	2,251	718	0	2,060	1,087	62	155	6,334
			Isaac (Q4)	2,895	0	0	2,421	1,160	70	223	6,769
			Barcaldine (Q5)	2,587	0	0	2,275	1,083	83	247	6,276
			Banana (Q9)	2,856	0	0	2,413	1,100	104	213	6,686
		Solar	North Queensland (Q3)	2,940	0	0	2,502	1,125	85	250	6,902
			Fitzroy (Q6)	2,958	0	0	2,458	1,114	89	253	6,872
			Darling Downs (Q8)	3,047	0	0	2,467	1,131	101	253	6,999
	Flexible, Grid $100MWh	**Hybrid**	NQCEH (Q2)	2,195	769	0	1,994	1,188	317	0	6,463
			Isaac (Q4)	2,352	861	0	2,018	1,176	369	0	6,777
			Barcaldine (Q5)	2,406	301	0	2,145	1,176	395	0	6,424
			Banana (Q9)	2,517	525	0	2,143	1,180	414	0	6,779
		Solar	North Queensland (Q3)	2,992	0	0	2,435	1,117	1,383	0	7,927
			Fitzroy (Q6)	2,983	0	0	2,359	1,155	768	0	7,265
			Darling Downs (Q8)	2,984	0	0	2,402	1,225	625	0	7,235

Table 35: Ammonia – Islanded, grid connected ammonia plant paying $100MWh optimisation results – 2040 capex summary

				Levelised cost of ammonia (LCOA) ($/kg)	Solar PV capacity (MW)	Wind capacity (MW)	Battery capacity (MWh)	Solar portfolio weighting (solar capacity / renewable capacity)	% of renewable energy curtailed	Battery capacity factor (%)	Electrolyser capacity (MW)	Electrolyser cap factor (%)	HB capacity (MW)	HB Load factor	Hydrogen Storage (GWh)	Storage cycles pa	Ammonia Storage (GWh)
2050	**Fixed – Tank, Grid $100MWh**	**Hybrid**	NQCEH (Q2)	679	2,907	364	0	89%	8%	0%	2,379	38%	134	85%	9	281	365
			Isaac (Q4)	716	3,114	454	0	87%	11%	0%	2,425	38%	134	85%	10	245	366
			Barcaldine (Q5)	672	3,102	177	0	95%	11%	0%	2,450	37%	131	87%	10	286	464
			Banana (Q9)	712	3,250	333	0	91%	13%	0%	2,523	36%	135	84%	11	250	341
		Solar	North Queensland (Q3)	820	3,853	0	0	100%	15%	0%	2,851	32%	125	91%	36	92	509
			Fitzroy (Q6)	756	3,873	0	0	100%	16%	0%	2,829	32%	130	88%	19	168	518
			Darling Downs (Q8)	750	3,915	0	0	100%	15%	0%	2,848	32%	136	84%	16	201	483
	Fixed -Salt Cavern, Grid $100MWh	**Hybrid**	NQCEH (Q2)	622	3,348	0	0	100%	8%	0%	2,762	33%	125	92%	78	43	287
			Isaac (Q4)	651	3,547	0	0	100%	10%	0%	2,808	33%	130	88%	53	61	446
			Barcaldine (Q5)	611	3,147	0	0	100%	8%	0%	2,613	35%	124	92%	55	61	520
			Banana (Q9)	642	3,452	0	0	100%	10%	0%	2,784	33%	126	90%	83	40	439
		Solar	North Queensland (Q3)	659	3,560	0	0	100%	8%	0%	2,889	32%	128	89%	71	47	516
			Fitzroy (Q6)	659	3,584	0	0	100%	9%	0%	2,826	32%	127	90%	70	47	529
			Darling Downs (Q8)	671	3,713	0	0	100%	11%	0%	2,854	32%	126	90%	90	37	508
	Flexible, Grid $100MWh	**Hybrid**	NQCEH (Q2)	650	2,849	348	0	89%	6%	0%	2,380	38%	133	86%	10	282	0
			Isaac (Q4)	680	3,112	323	0	91%	7%	0%	2,474	37%	133	86%	12	238	0
			Barcaldine (Q5)	638	2,951	180	0	94%	7%	0%	2,475	37%	133	86%	11	280	0
			Banana (Q9)	674	3,100	304	0	91%	8%	0%	2,472	37%	133	86%	11	254	0
		Solar	North Queensland (Q3)	784	3,699	0	0	100%	12%	0%	2,818	32%	126	91%	37	90	0
			Fitzroy (Q6)	712	3,682	0	0	100%	12%	0%	2,730	33%	130	88%	20	163	0
			Darling Downs (Q8)	705	3,666	0	0	100%	10%	0%	2,786	33%	137	83%	17	196	0

Table 36: Ammonia – Islanded, grid connected ammonia plant paying $100MWh optimisation results – 2050 data output summary

				Solar capex ($m)	Wind capex ($m)	Battery capex ($m)	Electrolyser capex ($m)	HB capex ($m)	Hydrogen storage capex ($m)	Ammonia storage capex ($m)	Total capex ($m)
2050	**Fixed – Tank, Grid $100MWh**	**Hybrid**	NQCEH (Q2)	1,849	532	0	1,306	1,172	339	175	5,373
			Isaac (Q4)	1,981	665	0	1,331	1,171	370	176	5,693
			Barcaldine (Q5)	1,973	259	0	1,344	1,151	370	222	5,320
			Banana (Q9)	2,067	487	0	1,384	1,187	391	164	5,680
		Solar	North Queensland (Q3)	2,451	0	0	1,565	1,096	1,287	244	6,643
			Fitzroy (Q6)	2,463	0	0	1,552	1,140	690	249	6,094
			Darling Downs (Q8)	2,490	0	0	1,563	1,190	572	232	6,047
	Fixed -Salt Cavern, Grid $100MWh	**Hybrid**	NQCEH (Q2)	2,130	0	0	1,516	1,093	99	138	4,975
			Isaac (Q4)	2,256	0	0	1,541	1,139	67	214	5,216
			Barcaldine (Q5)	2,002	0	0	1,434	1,087	69	250	4,842
			Banana (Q9)	2,195	0	0	1,528	1,105	106	211	5,145
		Solar	North Queensland (Q3)	2,264	0	0	1,586	1,122	90	247	5,309
			Fitzroy (Q6)	2,279	0	0	1,551	1,115	89	254	5,288
			Darling Downs (Q8)	2,361	0	0	1,566	1,108	114	244	5,393
	Flexible, Grid $100MWh	**Hybrid**	NQCEH (Q2)	1,812	509	0	1,306	1,163	348	0	5,138
			Isaac (Q4)	1,979	472	0	1,358	1,163	425	0	5,397
			Barcaldine (Q5)	1,877	263	0	1,358	1,161	385	00	5,044
			Banana (Q9)	1,971	445	0	1,357	1,167	408	0	5,348
		Solar	North Queensland (Q3)	2,353	0	0	1,546	1,102	1,336	0	6,337
			Fitzroy (Q6)	2,342	0	0	1,498	1,137	730	0	5,706
			Darling Downs (Q8)	2,332	0	0	1,529	1,201	603	0	5,664

Table 37: Ammonia – Islanded, grid connected ammonia plant paying $100MWh optimisation results – 2050 capex summary

			Levelised cost of ammonia (LCOA) ($/kg)	Solar PV capacity (MW)	Wind capacity (MW)	Battery capacity (MWh)	Solar portfolio weighting (solar capacity / renewable capacity)	% of renewable energy curtailed	Battery capacity factor (%)	Electrolyser capacity (MW)	Electrolyser cap factor (%)	HB capacity (MW)	HB Load factor	Hydrogen Storage (GWh)	Storage cycles pa	Ammonia Storage (GWh)
2030	**Fixed – Tank, Grid $100MWh**	Fitzroy (Q6)	1,026	2,559	1,111	0	70%	6%	0%	2,143	47%	139	82%	9	190	416
		Darling Downs (Q8)	1,036	1,942	1,650	0	54%	8%	0%	1,708	59%	140	82%	9	126	668
	Fixed -Salt Cavern, Grid $100MWh	Fitzroy (Q6)	971	2,472	1,138	0	68%	5%	0%	2,139	47%	125	92%	56	33	362
		Darling Downs (Q8)	979	1,774	1,755	0	50%	7%	0%	1,685	60%	128	90%	66	19	411
	Flexible, Grid $100MWh	Fitzroy (Q6)	999	2,773	892	0	76%	5%	0%	2,307	44%	139	82%	9	220	575
		Darling Downs (Q8)	997	2,053	1,502	0	58%	6%	0%	1,831	55%	141	81%	10	132	727
2040	**Fixed – Tank, Grid $100MWh**	Fitzroy (Q6)	832	2,908	727	0	80%	9%	0%	2,344	41%	139	82%	9	233	309
		Darling Downs (Q8)	852	2,834	862	0	77%	11%	0%	2,253	43%	138	83%	10	187	384
	Fixed -Salt Cavern, Grid $100MWh	Fitzroy (Q6)	778	2,933	662	0	82%	7%	0%	2,404	40%	124	92%	59	41	288
		Darling Downs (Q8)	796	3,163	559	0	85%	10%	0%	2,518	38%	128	89%	64	38	367
	Flexible, Grid $100MWh	Fitzroy (Q6)	799	2,909	629	0	82%	6%	0%	2,377	40%	137	83%	10	245	667
		Darling Downs (Q8)	810	2,949	624	0	83%	7%	0%	2,379	40%	139	82%	11	209	862
2050	**Fixed – Tank, Grid $100MWh**	Fitzroy (Q6)	719	2,903	614	0	83%	10%	0%	2,316	39%	137	83%	9	243	321
		Darling Downs (Q8)	735	3,276	433	0	88%	13%	0%	2,493	37%	137	83%	11	227	384
	Fixed -Salt Cavern, Grid $100MWh	Fitzroy (Q6)	659	3,584	0	0	100%	9%	0%	2,826	32%	127	90%	70	47	529
		Darling Downs (Q8)	671	3,713	0	0	100%	11%	0%	2,854	32%	126	90%	90	37	508
	Flexible, Grid $100MWh	Fitzroy (Q6)	688	2,831	572	0	83%	7%	0%	2,315	39%	135	84%	10	248	659
		Darling Downs (Q8)	692	3,379	193	0	95%	8%	0%	2,623	35%	139	82%	12	243	1,027

Table 38: Ammonia – REZ where entire wind resources build limit required for domestic decarbonisation: Islanded, grid connected ammonia plant paying $100MWh - data output summary

			Solar capex ($m)	Wind capex ($m)	Battery capex ($m)	Electrolyser capex ($m)	HB capex ($m)	Hydrogen storage capex ($m)	Ammonia storage capex ($m)	Total capex ($m)
2030	**Fixed – Tank, Grid $100MWh**	Fitzroy (Q6)	2,664	1,968	0	3,025	1,213	338	200	9,408
		Darling Downs (Q8)	2,022	2,923	0	2,410	1,224	323	321	9,223
	Fixed -Salt Cavern, Grid $100MWh	Fitzroy (Q6)	2,573	2,015	0	3,019	1,093	72	174	8,944
		Darling Downs (Q8)	1,846	3,108	0	2,378	1,117	84	197	8,731
	Flexible, Grid $100MWh	Fitzroy (Q6)	2,887	1,580	0	3,255	1,220	339	92	9,372
		Darling Downs (Q8)	2,137	2,661	0	2,584	1,236	346	116	9,081
2040	**Fixed – Tank, Grid $100MWh**	Fitzroy (Q6)	2,283	1,143	0	1,957	1,215	335	148	7,081
		Darling Downs (Q8)	2,225	1,356	0	1,882	1,206	367	184	7,219
	Fixed -Salt Cavern, Grid $100MWh	Fitzroy (Q6)	2,303	1,042	0	2,007	1,083	75	138	6,647
		Darling Downs (Q8)	2,483	880	0	2,102	1,120	81	176	6,842
	Flexible, Grid $100MWh	Fitzroy (Q6)	2,284	989	0	1,985	1,203	351	107	6,918
		Darling Downs (Q8)	2,315	982	0	1,987	1,215	403	138	7,040
2050	**Fixed – Tank, Grid $100MWh**	Fitzroy (Q6)	1,846	899	0	1,271	1,199	339	154	5,708
		Darling Downs (Q8)	2,083	633	0	1,368	1,204	395	184	5,868
	Fixed -Salt Cavern, Grid $100MWh	Fitzroy (Q6)	2,279	0	0	1,551	1,115	89	254	5,288
		Darling Downs (Q8)	2,361	0	0	1,566	1,108	114	244	5,393
	Flexible, Grid $100MWh	Fitzroy (Q6)	1,801	837	0	1,271	1,184	353	105	5,551
		Darling Downs (Q8)	2,149	283	0	1,439	1,221	438	164	5,695

Table 39: Ammonia – REZ where entire wind resources build limit required for domestic decarbonisation: Islanded, grid connected ammonia plant paying $100MWh - capex summary

HB Minimum Operating Rate	LCOA ($/MWh)	Solar PV Capacity (MW)	Wind Capacity (MW)	Solar capacity/VRE capacity (%)	Battery capacity (MWh)	Electrolyser capacity (MW)	HB Capacity (MW)	Hydrogen Storage (GWh)	Ammonia Storage (GWh)
10%	759	3,328	408	89%	550	2,529	137	10	493
20%	759	3,328	408	89%	550	2,529	137	10	493
(Base) 30%	760	3,286	470	87%	529	2,490	134	10	461
40%	778	3,184	570	85%	501	2,414	129	15	426
50%	811	3,263	630	84%	605	2,373	121	20	401
60%	854	3,284	607	84%	747	2,356	120	30	370
70%	901	3,242	700	82%	869	2,282	119	39	322
80%	968	3,578	781	82%	964	2,481	115	43	172
90%	1,058	3,998	873	82%	1,078	2,773	114	48	50
100%	1,157	4,158	887	82%	1,211	2,920	114	65	-

Table 40: Ammonia Fixed – Tank, Barcaldine 2040 – Haber Bosch turndown sensitivity – build summary

HB Minimum Operating Rate	Solar capex ($m)	Wind capex ($m)	Battery capex ($m)	Electrolyser capex ($m)	HB capex ($m)	Hydrogen Storage capex ($m)	Ammonia Storage capex ($m)	Total capex ($m)
10%	2,612	642	188	1,077	1,200	350	237	6,306
20%	2,612	642	188	1,077	1,200	350	237	6,307
(Base) 30%	2,579	739	182	1,061	1,173	368	221	6,322
40%	2,499	896	172	1,028	1,127	557	204	6,485
50%	2,561	990	207	1,011	1,063	740	193	6,765
60%	2,578	955	256	1,004	1,053	1,100	177	7,124
70%	2,545	1,101	298	972	1,038	1,411	155	7,520
80%	2,808	1,229	331	1,057	1,008	1,570	83	8,085
90%	3,139	1,373	370	1,181	1,001	1,754	24	8,843
100%	3,264	1,396	415	1,244	1,000	2,347	-	9,666

Table 41: Ammonia Fixed – Tank, Barcaldine 2040 – Haber Bosch turndown sensitivity – capex summary

HB Minimum Operating Rate	LCOA ($/MWh)	Solar PV Capacity (MW)	Wind Capacity (MW)	Solar capacity/VRE capacity (%)	Battery capacity (MWh)	Electrolyser capacity (MW)	HB Capacity (MW)	Hydrogen Storage (GWh)	Ammonia Storage (GWh)
10%	700	3,411	255	93%	466	2,692	127	62	484
20%	700	3,411	255	93%	466	2,692	127	62	484
(Base) 30%	700	3,411	255	93%	466	2,692	127	62	484
40%	701	3,467	214	94%	530	2,703	126	62	485
50%	703	3,553	138	96%	704	2,731	124	69	491
60%	708	3,635	61	98%	928	2,762	124	71	503
70%	718	3,695	62	98%	1,088	2,718	120	116	442
80%	733	3,672	62	98%	1,258	2,646	118	246	362
90%	752	3,672	62	98%	1,350	2,618	116	404	243
100%	788	3,247	475	87%	1,279	2,348	114	610	-

Table 42: Ammonia Fixed – Salt Cavern, Barcaldine 2040 – Haber Bosch turndown sensitivity – build summary

HB Minimum Operating Rate	Solar capex ($m)	Wind capex ($m)	Battery capex ($m)	Electrolyser capex ($m)	HB capex ($m)	Hydrogen Storage capex ($m)	Ammonia Storage capex ($m)	Total capex ($m)
10%	2,677	401	160	1,147	1,113	79	232	5,809
20%	2,677	401	160	1,147	1,113	79	232	5,809
(Base) 30%	2,677	401	160	1,147	1,113	79	233	5,809
40%	2,722	337	182	1,151	1,107	79	233	5,810
50%	2,789	217	242	1,164	1,089	87	235	5,823
60%	2,853	96	318	1,177	1,082	90	242	5,858
70%	2,900	97	373	1,158	1,054	147	212	5,942
80%	2,883	97	432	1,127	1,035	312	174	6,059
90%	2,882	97	463	1,115	1,013	513	116	6,201
100%	2,549	747	439	1,000	1,000	773	-	6,509

Table 43: Ammonia Fixed – Salt Cavern, Barcaldine 2040 – Haber Bosch turndown sensitivity – capex summary

H_2 Storage Cost ($/kg H_2)	LCOA ($/MWh)	Solar PV Capacity (MW)	Wind Capacity (MW)	Solar capacity/VRE capacity (%)	Electrolyser capacity (MW)	HB capacity (MW)	Hydrogen storage (GWh)
10	673	3,467	105	97%	2,813	117	766
21	692	3,457	165	95%	2,731	120	343
33	697	3,444	229	94%	2,697	127	73
44	699	3,413	256	93%	2,688	127	65
(Base) 50	700	3,411	255	93%	2,692	127	62
55	701	3,411	255	93%	2,692	127	62
66	703	3,418	250	93%	2,691	127	56
78	705	3,419	250	93%	2,690	127	56
89	707	3,425	245	93%	2,693	127	56
100	709	3,425	255	93%	2,673	130	40

Table 44: Ammonia Fixed - Salt Cavern, Barcaldine 2040 –Salt Cavern storage capex sensitivity - build summary

H_2 Storage Cost ($/kg H_2)	Solar capex ($m)	Wind capex ($m)	Electrolyser capex ($m)	Battery capex ($m)	HB capex ($m)	Hydrogen Storage capex ($m)	Ammonia tank capex ($m)	Total capex ($m)
10	2,722	165	1,198	238	1,022	194	26	5,565
21	2,714	259	1,164	200	1,047	185	166	5,734
33	2,703	361	1,149	165	1,110	61	230	5,779
44	2,679	402	1,145	157	1,113	72	231	5,799
(Base) 50	2,677	401	1,147	160	1,113	79	233	5,809
55	2,678	401	1,147	160	1,113	87	232	5,817
66	2,683	393	1,146	167	1,115	95	235	5,834
78	2,684	393	1,146	167	1,115	111	234	5,850
89	2,689	385	1,147	168	1,116	127	235	5,866
100	2,689	401	1,139	174	1,138	100	238	5,879

Table 45: Ammonia Fixed - Salt Cavern, Barcaldine 2040 –Salt Cavern storage capex sensitivity - capex summary

Ammonia Storage Cost (AUD/t NH3)	LCOA ($/MWh)	Solar PV Capacity (MW)	Wind Capacity (MW)	Solar capacity/VRE capacity (%)	Battery capacity (MWh)	Electrolyser capacity (MW)	HB Capacity (MW)	Hydrogen Storage (GWh)	Ammonia Storage (GWh)
750	677	3,346	230	94%	464	2,704	133	52	654
1,406	684	3,368	235	93%	457	2,703	131	57	602
2,063	692	3,396	241	93%	468	2,703	129	59	537
2,719	698	3,410	254	93%	465	2,694	127	62	485
(Base) 3,000	700	3,411	255	93%	466	2,692	127	62	484
3,375	704	3,412	258	93%	465	2,682	127	63	482
4,031	710	3,413	268	93%	457	2,662	127	65	475
4,687	716	3,408	292	92%	424	2,635	126	66	462
5,344	721	3,411	301	92%	415	2,619	126	67	456
6,000	727	3,404	318	91%	403	2,601	126	66	450

Table 46: Ammonia Fixed – Salt Cavern, Barcaldine 2040 –Ammonia storage capex sensitivity - build summary

Ammonia Storage Cost (AUD/t NH3)	Solar capex ($m)	Wind capex ($m)	Battery capex ($m)	Electrolyser capex ($m)	HB capex ($m)	Hydrogen Storage capex ($m)	Ammonia Storage capex ($m)	Total capex ($m)
750	2,627	361	159	1,152	1,164	66	79	5,607
1,406	2,644	369	157	1,151	1,145	72	136	5,674
2,063	2,666	379	160	1,151	1,126	75	177	5,734
2,719	2,677	400	160	1,148	1,113	79	211	5,787
(Base) 3,000	2,677	401	160	1,147	1,113	79	233	5,809
3,375	2,679	406	160	1,143	1,111	80	260	5,838
4,031	2,679	422	157	1,134	1,109	82	306	5,889
4,687	2,675	460	145	1,123	1,107	84	347	5,940
5,344	2,677	474	142	1,116	1,105	85	390	5,989
6,000	2,672	501	138	1,108	1,104	84	432	6,038

Table 47: Ammonia Fixed – Salt Cavern, Barcaldine 2040 –Ammonia storage capex sensitivity - capex summary

HB Cost (AUD/t NH3 pa)	LCOA ($/MWh)	Solar PV Capacity (MW)	Wind Capacity (MW)	Solar capacity/VRE capacity (%)	Battery capacity (MWh)	Electrolyser capacity (MW)	HB Capacity (MW)	Hydrogen Storage (GWh)	Ammonia Storage (GWh)
500	690	3,229	479	87%	503	2,485	136	10	496
750	725	3,257	478	87%	515	2,484	135	10	475
(Base) 1,000	760	3,286	470	87%	529	2,490	134	10	461
1,214	790	3,300	468	88%	535	2,492	133	10	453
1,429	819	3,290	486	87%	530	2,479	133	10	447
1,643	849	3,308	481	87%	536	2,477	132	10	461
1,857	878	3,330	466	88%	548	2,486	131	10	503
2,071	907	3,325	471	88%	551	2,470	129	10	554
2,286	936	3,321	484	87%	553	2,463	129	10	543
2,500	965	3,320	495	87%	555	2,456	128	10	530

Table 48: Ammonia Fixed – Tank, Barcaldine 2040 –Haber Bosch capex sensitivity - build summary

HB Cost (AUD/t NH3 pa)	Solar capex ($m)	Wind capex ($m)	Battery capex ($m)	Electrolyser capex ($m)	HB capex ($m)	Hydrogen Storage capex ($m)	Ammonia Storage capex ($m)	Total capex ($m)
500	2,535	754	173	1,059	595	381	238	5,734
750	2,557	753	177	1,058	885	372	228	6,029
(Base) 1,000	2,579	739	182	1,061	1,173	368	221	6,322
1,214	2,590	736	184	1,062	1,419	365	217	6,573
1,429	2,582	765	182	1,056	1,665	359	214	6,824
1,643	2,597	757	184	1,055	1,904	355	221	7,072
1,857	2,614	733	188	1,059	2,128	354	242	7,318
2,071	2,610	741	189	1,052	2,347	357	266	7,563
2,286	2,607	761	190	1,049	2,579	359	261	7,806
2,500	2,606	779	190	1,046	2,807	364	254	8,047

Table 49: Ammonia Fixed – Tank, Barcaldine 2040 –Haber Bosch capex sensitivity - capex summary

HB Cost (AUD/t NH3 pa)	LCOA ($/MWh)	Solar PV Capacity (MW)	Wind Capacity (MW)	Solar capacity/VRE capacity (%)	Battery capacity (MWh)	Electrolyser capacity (MW)	HB Capacity (MW)	Hydrogen Storage (GWh)	Ammonia Storage (GWh)
500	634	3,428	213	94%	473	2,726	130	58	523
750	667	3,418	238	93%	470	2,712	128	62	493
(Base) 1,000	700	3,411	255	93%	466	2,692	127	62	484
1,214	729	3,409	265	93%	465	2,672	127	62	479
1,429	757	3,411	273	93%	467	2,655	126	62	474
1,643	785	3,419	276	93%	475	2,643	126	60	471
1,857	813	3,455	252	93%	524	2,655	125	70	461
2,071	841	3,478	241	94%	553	2,653	124	74	454
2,286	868	3,496	233	94%	584	2,656	123	78	448
2,500	896	3,499	233	94%	594	2,654	123	79	445

Table 50: Ammonia Fixed – Salt Cavern, Barcaldine 2040 – Haber Bosch capex sensitivity – build summary

HB Cost (AUD/t NH3 pa)	Solar capex ($m)	Wind capex ($m)	Battery capex ($m)	Electrolyser capex ($m)	HB capex ($m)	Hydrogen Storage capex ($m)	Ammonia Storage capex ($m)	Total capex ($m)
500	2,691	336	162	1,161	571	73	251	5,246
750	2,683	374	161	1,155	841	78	236	5,530
(Base) 1,000	2,677	401	160	1,147	1,113	79	233	5,809
1,214	2,676	417	160	1,138	1,347	79	230	6,048
1,429	2,678	430	160	1,131	1,581	78	228	6,285
1,643	2,684	434	163	1,126	1,814	76	226	6,522
1,857	2,712	396	180	1,131	2,027	89	221	6,756
2,071	2,730	380	190	1,130	2,247	94	218	6,988
2,286	2,744	366	200	1,132	2,463	99	215	7,219
2,500	2,747	367	204	1,130	2,688	100	214	7,450

Table 51: Ammonia Fixed – Salt Cavern, Barcaldine 2040 – Haber Bosch capex sensitivity – capex summary

6.9 Detailed Optimisation Modelling - Input Assumptions

Where available cost assumptions are sourced from the CSIRO GenCost Consultation Draft 2022-23 released in December 2022 (CSIRO, 2022A). For basis of other input assumptions refer to Information Sheets.

Generation and Electrolysis Capex (AUD/ installed kW)	2030	2040	2050
Wind	1771	1573	1464
Solar	1041	785	636
Battery	267	167	153
Battery interface	394	344	301
Hydrogen Electrolysis - PEM	1769	608	400
Hydrogen Electrolysis - Alkaline	1028	608	400
Fuel Cell	3426	2691	2658

Table 52: Detailed Optimisation Modelling Input Assumptions - Generation and Electrolysis Capex

Generation and Electrolysis Opex (AUD/installed kW/year)	2030	2040	2050
Wind	25	25	25
Solar	17	17	17
Battery	8	7	6
Battery interface	5	3	3
Hydrogen Electrolysis – PEM	25	9	6
Hydrogen Electrolysis – Alkaline	14	9	6
Fuel Cell	69	54	53

Table 53: Detailed Optimisation Modelling Input Assumptions - Generation and Electrolysis Opex

Storage, Transport, Ammonia plant and Other Assumptions	
Compressed H2 Storage (AUD/kg)	1428
Geological Hydrogen Storage (AUD/kg)	50
Ammonia Storage (AUD/t)	3000
Pipeline Transport (Assumed in the same pipeline as designed for storage)	
Maximum hydrogen pipeline velocity (m/s)	30
Pipeline minimum pressure (bar)	40
Pipeline maximum pressure (bar)	100
Hydrogen Compression Costs (AUD/MW)	45180.0
Hydrogen transfer cost (AUD/MW/km) at 125ktpa H_2	1563.7
Hydrogen transfer cost (AUD/MW/km) at 375ktpa H_2	991.5
Hydrogen storage per tonne transport (t/MW/km)	0.0002
Ammonia pipeline cost (AUD/transported t/km)	7.1
HB+ASU Details	
HB + ASU Ammonia Costs (AUD/annual t)	1,000
HB/ASU Electricity demand (MWh/t)	1
HB Minimum Rate as a fraction of rated capacity	0.3

Storage, Transport, Ammonia plant and Other Assumptions	
Other Details	
USD/AUD Conversion	0.7
Electrolyser energy requirement 2022 (kWh/kg)	53
Electrolyser energy requirement 2050 (kWh/kg)	44
Hydrogen compression energy (kWh/kg)	2.016
H2 fuel cell efficiency on HHV as a fraction	50%
Hydrogen HHV (MWh/t)	39.4
Ammonia HHV (MWh/t)	6.25
O&M (% of capex)	2%
Project lifetime (years)	20
Discount Rate	8.73%
Wire Costs	
Total Termination Costs (AUD/MW)	49110
Total Wire costs (AUD/MW/km)	748

Table 54: Detailed Optimisation Modelling Input Assumptions - Storage, Transport, Ammonia plant and Other Assumptions

Category	Location	Latitude	Longitude
Ports	Abbot Point	-19.89	148.08
	Brisbane	-27.41	153.15
	Gladstone	-23.82	151.22
	Townsville	-19.26	146.84
REZ - Hybrid	NQCEH (Q2)	-20.30	144.20
	Isaac (Q4)	-20.55	147.84
	Barcaldine (Q5)	-23.55	145.28
	Banana (Q9)	-24.57	149.98
REZ - Solar	North Queensland (Q3)	-19.40	146.72
	Fitzroy (Q6)	-23.84	151.05
	Darling Downs (Q8)	-26.67	150.19
Salt cavern storage	Adavale Basin	-26.21	145.28

Table 55: Detailed Optimisation Modelling Input Assumptions - Port, REZ and Salt Cavern Storage location coordinates

6.10 Levelised cost calculations

2040		Short duration storage		Medium duration storage		Long duration storage	Gas peaking generation
		Li-Ion BESS 2H	Li-Ion BESS 4H	Li-Ion BESS 8H	PHES 8H	PHES 24H	OCGT (small)
INPUTS							
Economic life	years	20	20	20	40	40	25
Power Capital Cost	$/kW	344	344	344	1,883	1,883	1,285
Energy Storage Capital Cost	$/kWh	193	193	193	72	72	-
Fixed operating and maintenance cost (FOM)	$/kw/pa	13.5	20.2	33.5	18.8	18.8	14.1
Average Round-trip Efficiency	%	82	83	81	76	76	-
Charging cost	$/kWh	0.04	0.04	0.04	0.04	0.04	-
Fuel cost	$/GJ	-	-	-	-	-	9.9
Heat rate	GJ/MWh HHV s.o	-	-	-	-	-	10.19
Short run marginal cost - ex carbon cost (SRMC)	$/MWh	-	-	-	-	-	113
Carbon cost	$/MWh	-	-	-	-	-	172
DAILY							
Capacity Factor	%	8	16.7	20	20	20	20
LCoS and LCOE ex carbon price (LCOE inc. carbon price)	$/MWh	162	134	170	169	218	184 (356)
INTRAWEEK							
Capacity Factor	%	-	-	4.7	4.7	14.2	14.2
LCoS and LCOE ex carbon price (LCOE inc. carbon price)	$/MWh	-	-	559	541	284	212 (385)

Table 56: Levelised cost calculations – power system storage and OCGT (small) 2040 | Source: (Australian Energy Market Operator, 2022d)

2040		Hydrogen reciprocating engine – Salt cavern hydrogen storage	Ammonia reciprocating engine – ammonia tank storage	OCGT (small)
INPUTS				
Economic life	years	25	25	25
Power Capital Cost	$/kW	1,981	1,981	1,285
Energy Storage Capital Cost	$/kWh	4.9	1.9	-
Fixed operating and maintenance cost (FOM)	$/kw/pa	37	37	14.1
Variable operating and maintenance cost (VOM)	$/kWh	-	-	0.012
Fuel cost	various	\$3.20/ kg H_2	\$800/t NH_3	-
Fuel cost	$/GJ	26.67	41.67	9.9
Heat rate	GJ/MWh HHV s.o	11.7	11.7	10.19
Short run marginal cost -ex carbon cost (SRMC)	$/MWh	312	500	113
Carbon cost	$/MWh	-	-	172
DAILY				
Storage Duration	hours	24	24	-
Capacity Factor	%	20	20	20
LCoS and LCOE ex carbon price (LCOE inc. carbon price)	$/MWh	436	620	184 (356)
INTRAWEEK				
Storage Duration	hours	24	24	
Capacity Factor	%	14.2	14.2	14.2
LCoS and LCOE ex carbon price (LCOE inc. carbon price)	$/MWh	486	669	212 (385)
SEASONAL				
Storage Duration	hours	24	24	10
Capacity Factor	%	10	10	14.2
LCoS and LCOE ex carbon price (LCOE inc. carbon price)	$/MWh	967	897	255 (427)

Table 57: Levelised cost calculations – Hydrogen and ammonia engines and OCGT (small) 2040

Source: (Australian Energy Market Operator, 2022d)

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Queensland green ammonia value chain:

Decarbonising hard-to-abate sectors and the NEM

Information Sheets

Andrew Fletcher[1], Huyen Nguyen[1], Nicholas Salmon[2], Nancy Spencer[3], Phillip Wild[3] and Rene Bañares-Alcántara[2]

Abstract

Fossil fuel-based ammonia production currently accounts for around 1% of global greenhouse gas emissions. Ammonia is one of the few hydrogen use cases where no real alternatives exist. Green ammonia could play a pivotal role in decarbonising fertilisers and explosives, that are critical inputs into Australia's agriculture and resources sectors respectively.

This report assesses the design of infrastructure required for a world-scale Queensland green ammonia industry (multiple 1mtpa NH_3 capacity plants) with value chain costs estimated for supplying (a) green hydrogen and (b) green ammonia, to meet variable and fixed customer demand profiles.

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.

In contrast, the predicted partial-flexibility of new-build Haber Bosch green ammonia plants and the low cost of ammonia storage reduces the cost of meeting a fixed customer demand profile. These characteristics could also enable sector coupling benefits through the provision of demand response services to the electricity system. Future levelised costs of green ammonia value chain load shifting and load curtailment could be less than half of that of gas peaking generation, providing the potential to further decarbonise the electricity system, beyond ~90-95% renewables. To maximise sector coupling benefits a hybrid green ammonia value chain is proposed with co-located renewables (primarily solar) and electrolysers connected to the electricity grid to provide demand response services, with electrolysers connected to a hydrogen pipeline for transport to a separately located ammonia plant, that is grid connected.

Key words: green ammonia, green hydrogen, sector coupling, demand response.

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Centre for Applied Energy Economics and Policy Research · Department of Engineering Science · University of Oxford · Griffith University · Griffith Business School · Queensland, Australia

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1 Introduction and Information sheets map

This report documents the findings of the first phase of the study into Infrastructure Investment for Green Hydrogen and Ammonia in Queensland conducted by Griffith and Oxford universities[4]. The report describes each functional component of the green hydrogen and green hydrogen derivatives value chain consistent with Figure 1.

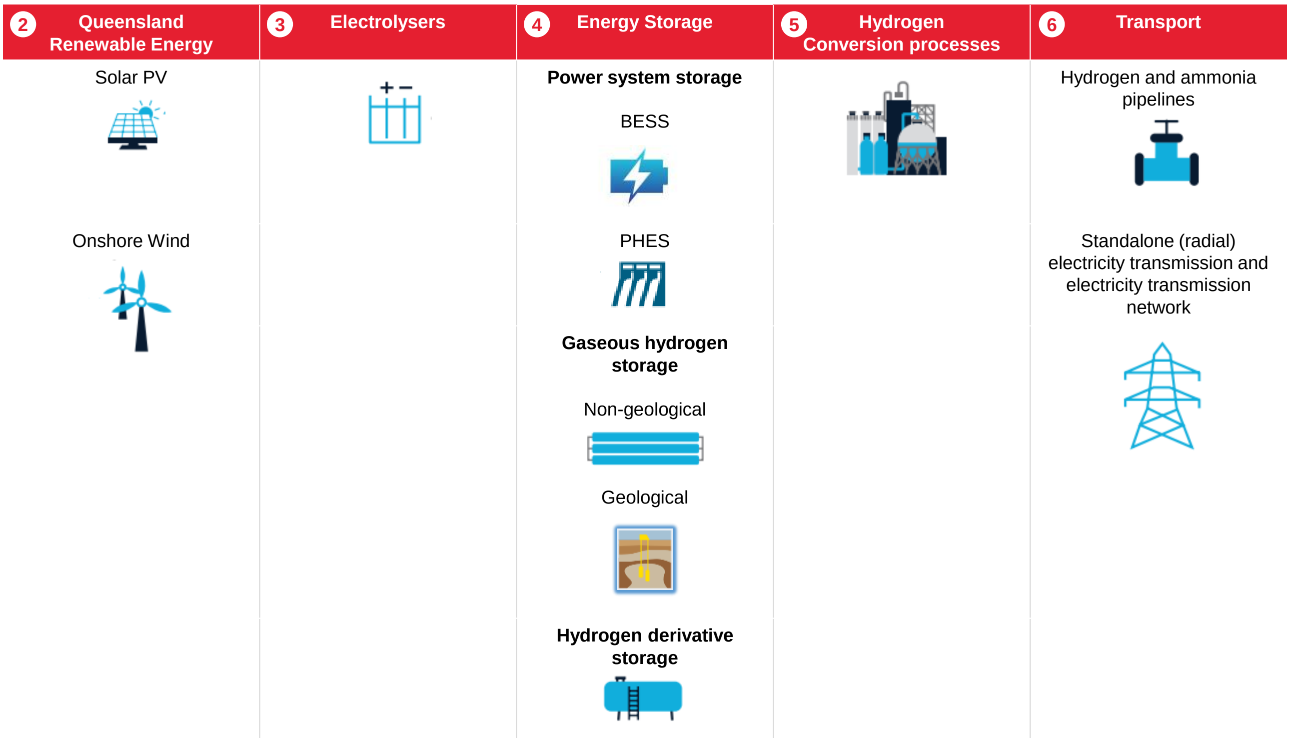

Figure 1: Information Sheets Map | *Image source: CSIRO (2023) Hydrogen vehicle refuelling infrastructure*

The report should be read in conjunction with the Phase 2 main report that explores two main contributions of green hydrogen and ammonia:

1. The decarbonisation of hard-to-abate sectors. Green ammonia could play a pivotal role in decarbonising fertilisers and explosives, that are critical inputs into Australia's agriculture and resources sectors respectively; and
2. Deeper decarbonisation of the electricity system via sector coupling.

2 Queensland Renewable Energy Information Sheet

2.1 Introduction

Renewable energy currently represents around 50% of the cost of green hydrogen projects. Affordable renewable energy is essential to produce green hydrogen cost effectively. Globally, variable renewable energy (wind and solar) is the fastest growing energy source and becoming increasingly important in the energy mix. Both technologies have experienced rapid cost reductions in the last decade. However in recent years capital costs have increased due to the COVID-19 pandemic and the Ukraine conflict's impacts on global supply chains and freight costs. Feedback from various industry sources is that the capital cost estimates for a number of wind projects currently under development may be significantly higher than those sourced from CSIRO GenCost 2022-23 Final Report (2023) that are used by Australian Energy Market Operator (AEMO) as inputs into its Integrated System Plan (AEMO ISP). Over time renewable energy capital costs may return to long term trends of cost declines as supply chains rebalance and growth in global deployment (i.e scale and experience cost declines) continue. Connection costs, including system strength

[4] *Griffith University Centre for Applied Energy Economics and Policy Research and Oxford Green Ammonia Technology (OXGATE)*

remediation requirements (relevant for grid connected projects), is another element that could result in renewable energy project capital costs being higher than those used in the AEMO ISP.

Solar is expected to achieve greater cost reduction than wind across various cost projections. CSIRO GenCost 2022-23 Final Report (2023) was released in July 2023 and shows the projected cost gap between wind and solar has increased materially versus CSIRO GenCost 2022-23: Consultation Draft (2022) released in December 2022, which are key modelling inputs for this research.

While green hydrogen costs are also projected to fall over time, including due to projections of declining renewables energy cost, using only variable renewable energy results in lower electrolyser load factors. As a result, larger electrolysis plant is required to achieve the same hydrogen production, compared to using a continuous power supply, such as provided by conventional hydropower. This information sheet is intended to describe expected cost projections for Queensland's variable renewable energy resources and key attributes that are relevant for the production of green hydrogen given conditions prevailing as of 2023.

2.2 Solar PV

2.2.1 Cost

The Levelised Cost of Electricity (LCoE) is a simple calculation and tool for comparing the competitiveness of different electricity generation technologies, albeit noting intermittency. It is the total unit costs a generator must recover to meet all its costs including a return on investment when operating at practical output levels. It is calculated by dividing the net present value of the total cost of the asset, which includes the initial capital investment, operations and maintenance (O&M), and any fuel costs, by the total electricity generation over its lifetime.

The global weighted average LCoE of newly commissioned utility-scale solar PV projects declined by 88% between 2010 and 2021. However, the CSIRO GenCost 2022-23: Consultation Draft (Dec 2022) (CSIRO GenCost 2022-23) report paused the cost reduction in 2022-23 to reflect supply chain cost pressures. CSIRO's estimates are largely in line with other estimates from Lazard, the U.S. Annual Energy Outlook (AEO), the National Renewable Energy Laboratory (NREL) and the International Renewable Energy Agency (IRENA).

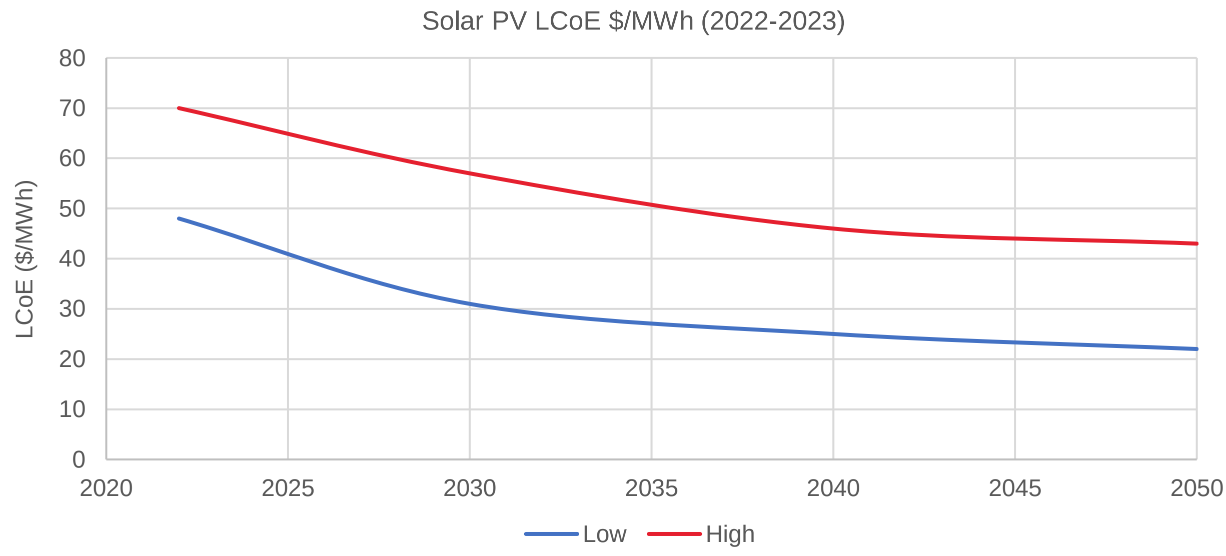

Figure 2: Solar PV LCoE $/MWh (2022-2023) | *Source: CSIRO GenCost 2022-23: Consultation Draft (2022)*

While capital costs are expected to decline over time, CSIRO GenCost 2022-23 assumes a fixed O&M cost of $17/kW in real terms (2021), obtained from Aurecon (2022). Capacity factor, defined as the ratio of actual output over the theoretical maximum output, is also assumed to be fixed at 19% in the low scenario and 32% in the high scenario, obtained from IRENA (2021). These constant assumptions are reasonable as capacity factor and O&M have contributed little to historical cost reduction.

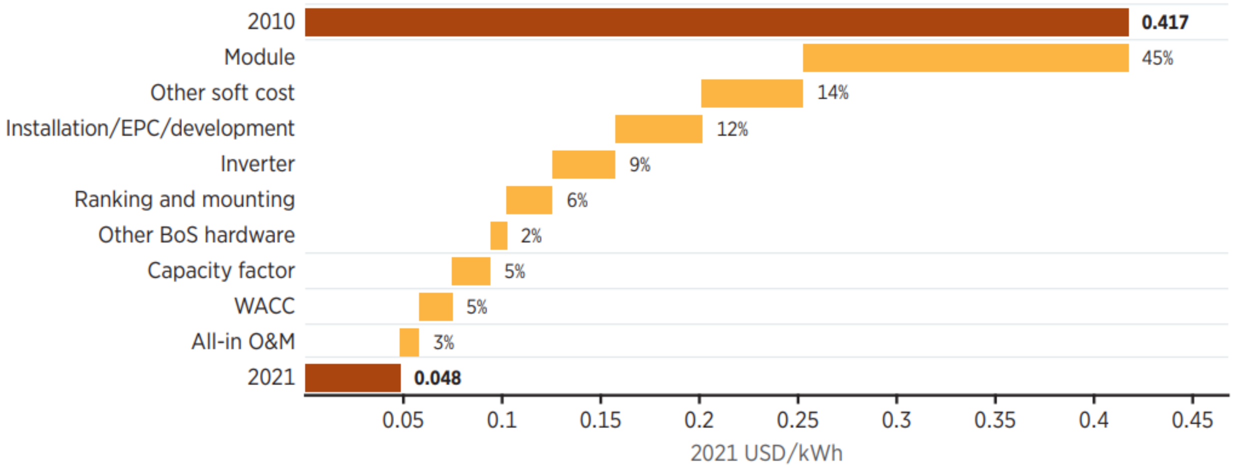

Figure 3: Drivers of the decline of LCoE of utility-scale solar PV (2010-2021) | Source: IRENA Renewable Cost Database

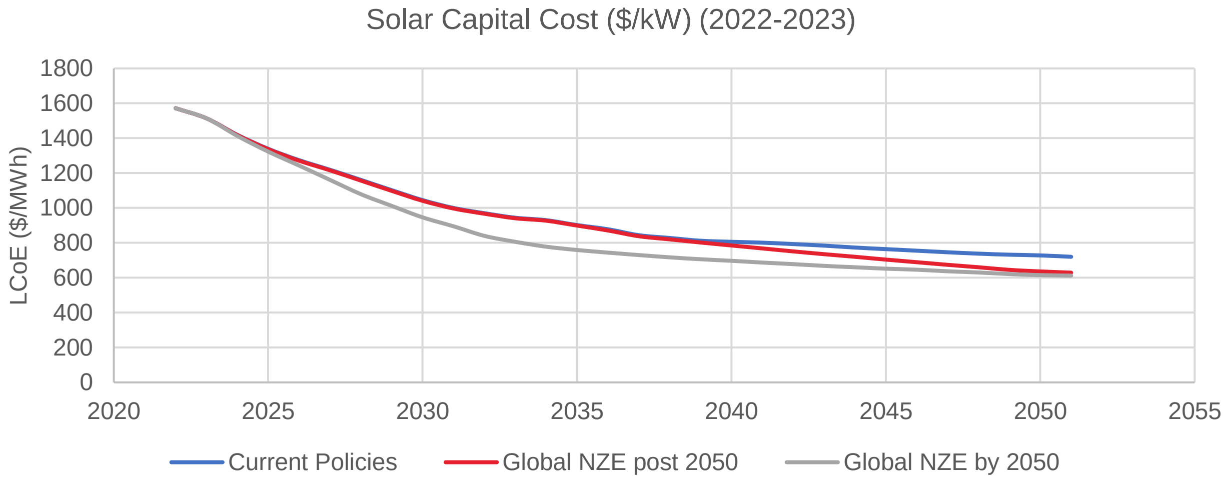

Figure 4: Solar Capital Cost ($/kW) (2022-2023) | Source: CSIRO GenCost 2022-23: Consultation Draft (2022)

2.2.2 Performance

Since 2010, a variety of technological developments have contributed to improvements in the cost competitiveness of solar PV. These have occurred along the whole value chain, including the continued improvement of efficiency, manufacturing optimisation and design innovation. The adoption of bifacial technologies, meaning electricity can be produced from both front and rear surfaces of a solar cell, allows the technology to capture more sunlight leading to greater efficiency compared to traditional mono-facial solar panels, and this trend is expected to continue for utility scale solar development. The average module efficiency of crystalline modules increased from 14.7% in 2010 to 20.9% in 2021, driven by a shift to more efficient monocrystalline products and passivated emitter and rear cell (PERC) architectures. The efficiency of PERC modules is expected to grow towards 22% in the next few years, approaching its limits.

The most recent National Renewable Energy Laboratory (NREL) data shows that modern solar panels have a degradation rate of 0.5% per year – down from 0.8% in 2012. After 20 years of use, a solar panel today would be capable of producing roughly 90% of the electricity it produced when it was new. The average lifespan of a panel is around 25-30 years.

2.2.3 Land use

As the efficiency increases, solar PV modules require less surface area to generate a given quantity of power. The average land requirement in Australia is 2-3 ha/MW, with land cost dependent on location.

2.2.4 Queensland's solar resources

In the 2022 Integrated System Plan, AEMO published a list of Renewable Energy Zones (REZs), high quality resource areas where clusters of large-scale renewable energy projects can be developed. The selection of REZ is influenced by the existing transmission network and distance to existing load centres. Nine REZs were identified for Queensland as per Figure 5:

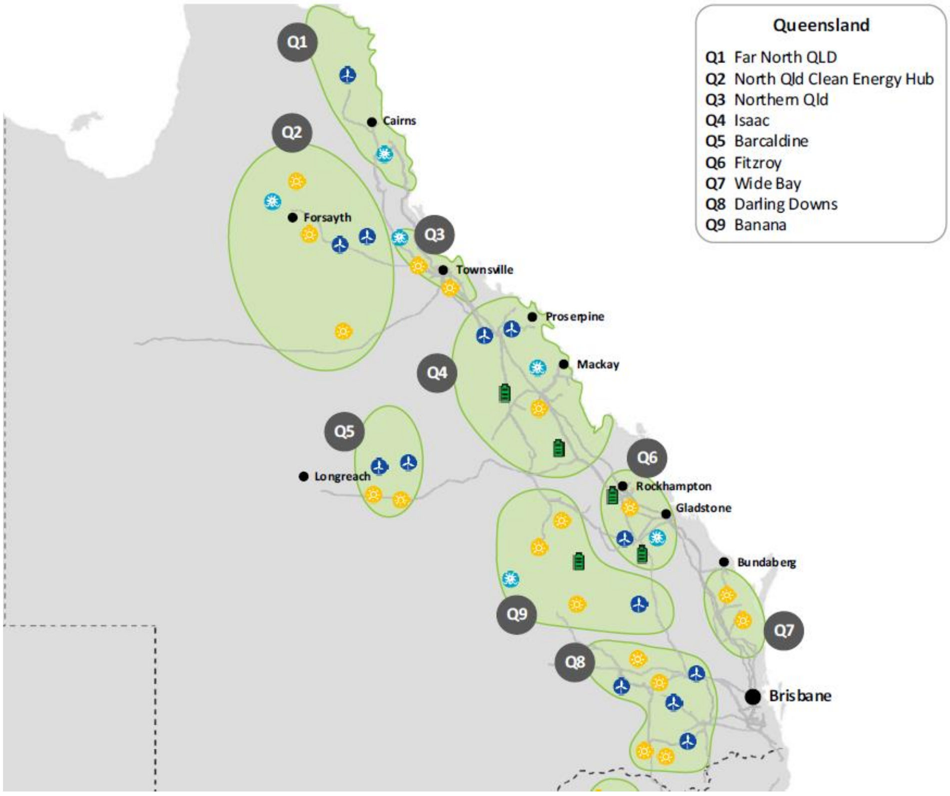

Figure 5: AEMO – Queensland Renewable Energy Zone Map | *Source: AEMO ISP Appendix 3 Renewable Energy Zones (2022)*

In the 2018 ISP, AEMO engaged consultants DNV-GL to provide information on the resource quality for potential REZs. Solar resource quality was assessed using Global Horizontal Irradiance (GHI) and Direct Normal Irradiance (DNI) data from the Bureau of Meteorology (BOM). The work undertaken for the ISP is not intended in any way to replace the specific site assessment of potential sites by developers.

Resource quality is based on expected capacity factor, which was derived from the estimated solar output in eleven reference years and is scored as below:

Capacity Factor	≥30%	≥28%	≥26%	≥24%	≥22%	<22%
Score	A	B	C	D	E	F

Table 1: Solar PV resource grade – capacity factor | *Source: AEMO ISP Appendix 3 Renewable Energy Zones (2022)*

The estimated potential REZ size in MW is based on the geographical size in the REZ, but limited to a maximum of 8,000MW. The availability of land is determined by existing land use and environmental and cultural considerations, as well as the quality of wind or solar irradiance. Queensland's developable solar resources could far exceed the REZ build limits, particularly if arbitrary REZ limits are relaxed or areas outside of REZ are considered.

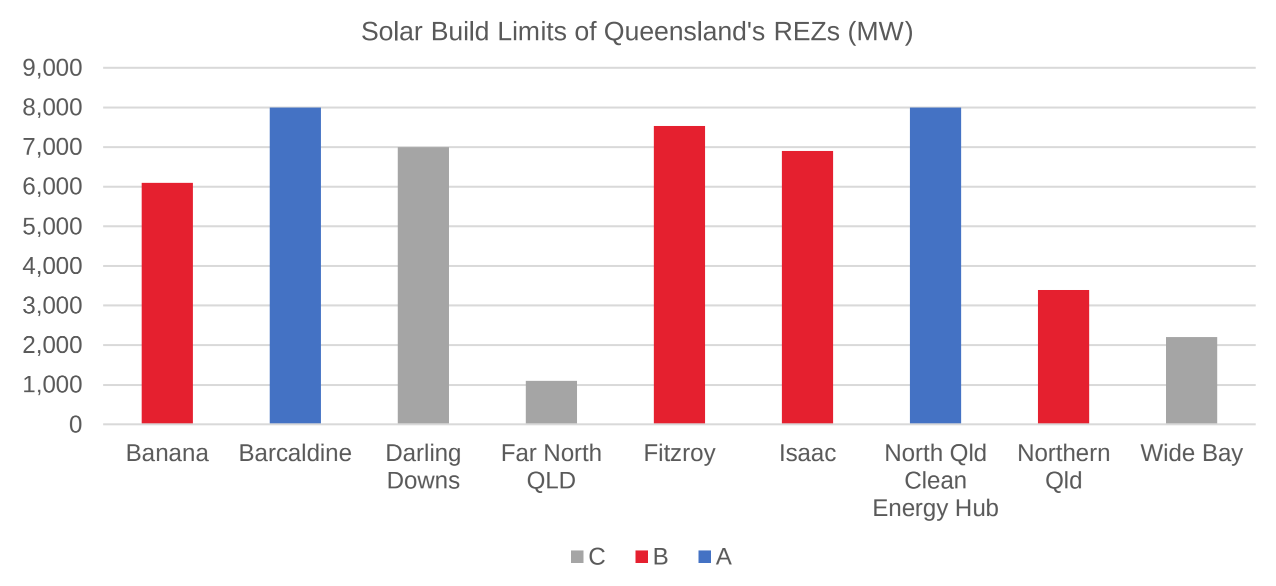

Figure 6: Solar PV resource grade – capacity factor | *Source: AEMO ISP Appendix 3 Renewable Energy Zones (2022)*

2.2.5 Comparison to other NEM states

Compared to other NEM states Queensland REZ generally have higher capacity factor solar resources. below shows capacity factors for single axis tracker (tracks the sun moving east to west) solar PV for Queensland REZ that are reasonably close to the coast, from central Queensland (Q9 Banana) to north Queensland (Q3 Northern QLD). Due to shorter transport distances to ports and potential waters sources these Queensland REZ could be relevant for an export hydrogen industry. Capacity factors are compared to southern NEM states REZ, excluding Tasmania, that have the highest solar PV buildouts for their respective states in AEMO's 2022 ISP's Step Change scenario.

Renewable Energy Zone	Q3 Northern QLD	Q4 Isaac	Q9 Banana	S5 Northern SA	N3 Central West Orana	V2 Murray River
Capacity Factor (%)	28.6%	28.6%	29.2%	28.0%	27.6%	27.1%

Table 2: Solar PV capacity factors (single axis tracker) | *Source: AEMO Draft 2023 Inputs and Assumptions workbook (2022)*

For high fixed cost energy intensive industrial production processes such as green hydrogen and green ammonia, higher load factors reduce average costs of production. Compared to southern NEM states, Queensland's latitude is favourable for green hydrogen and green hydrogen derivative production due to lower seasonal variation in solar PV generation.

For many jurisdictions the 'winter problem' is a key issue to address for a future renewable energy-based electricity system, as high demand from electrified heating coincides with low capacity factors for solar PV resulting in a seaonal eneryy deficit. Lower seasonal variation in solar PV generation means that a Queensland green ammonia value chain and potentially a synthetic hydrocarbon value chain, e.g. methanol, has the greatest potential to provide demand response to the National Electricity Market (NEM) in winter as solar PV generation is far higher than southern NEM states (refer to main report for more detail). The 'winter problem' is more acute in southern NEM states and depending on the size of a future Queensland green ammonia value chain there is the potential to contribute to addressing the 'winter problem' in both Queensland and southern NEM states.

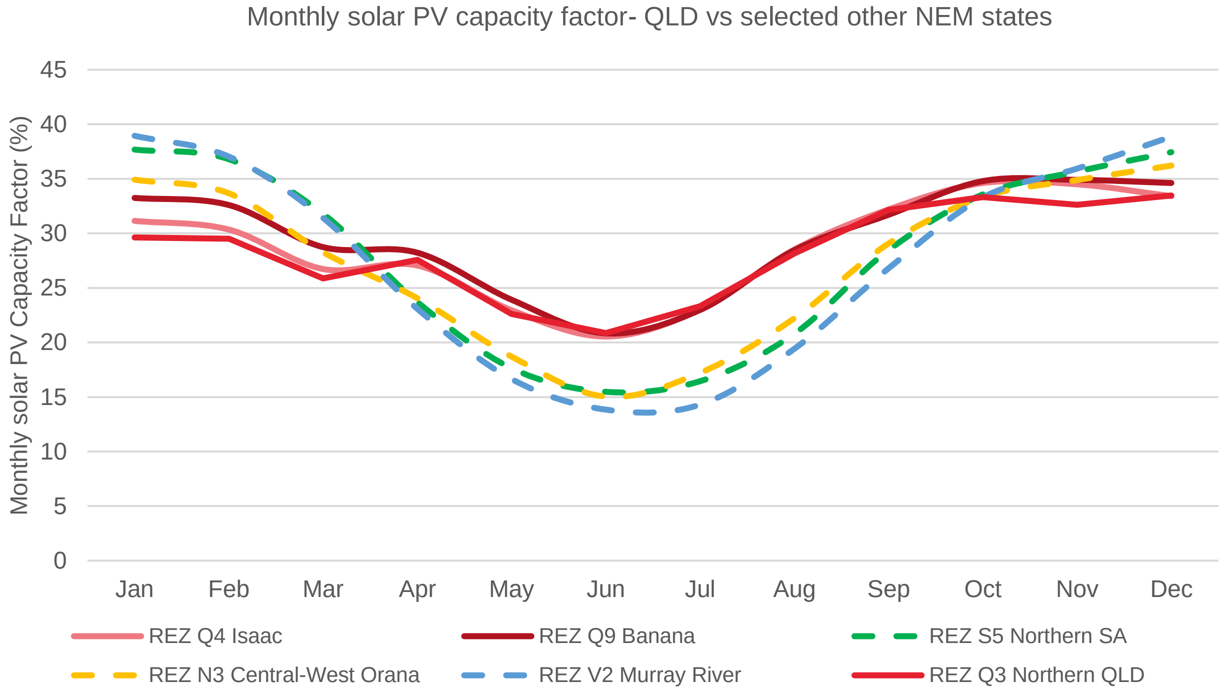

Figure 7: Monthly solar PV capacity factor- QLD vs. selected other NEM states | *Source: AEMO ISP 2022 ISP Solar traces (2022)*

2.3 Onshore wind

2.3.1 Cost

Onshore wind's global average LCoE declined by 68% between 2010 and 2021 [IRENA 2021]. Globally, larger and more reliable turbines, along with higher hub-heights and larger rotor diameters, have combined to lower installation costs ($/MW) and increase capacity factors from 27% (2010) to 39% (2021). Installation and O&M costs have been falling as a result of economies of scale and the growing maturity of the sector.

Figure 8: Wind LCoE $/MWh (2022-2023) | *Source: CSIRO GenCost 2022-23: Consultation Draft*

In CSIRO's GenCost 2022-23: Consultation Draft, onshore wind capital cost for current projects significantly increased ($2000/kW in GenCost 2021-22 vs $2600/kW in GenCost 2022-23: Consultation Draft) and the pace of cost reduction substantially reduced after 2030. These themes were magnified in GenCost 2022-2023: Final Report with capital cost for current projects increasing to $2800/kW and 2050 capital cost increasing by 29% from GenCost 2022-23: Consultation Draft. Capital cost is split between equipment

(68%), installation (29%) and land (3%). 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.

O&M cost is fixed at $25/kW in real terms (2021). Capacity factor is assumed to be fixed at 35% in the low scenario and to gradually increase to 50% in 2050 in the high scenario, which industry feedback suggests is highly optimistic.

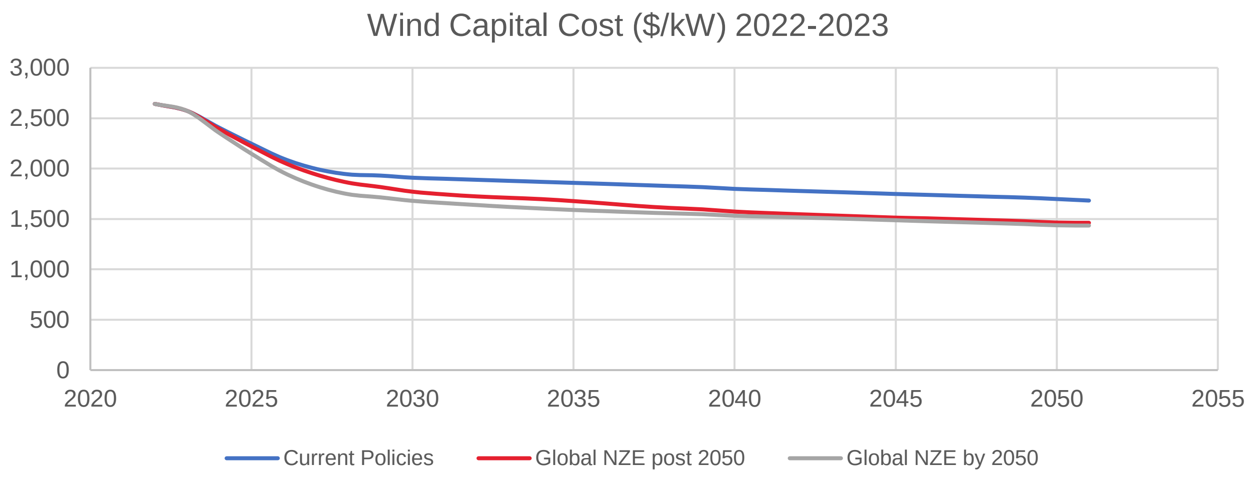

Figure 9: Wind Capital Cost ($/kW) 2022-2023 | *Source: CSIRO GenCost 2022-23: Consultation Draft*

2.3.2 Performance

Wind farm's average annual degradation over design life is around 0.1%. Larger and more efficient turbines, lower capital and operating costs are expected to continue to drive down the cost of wind energy. However, there are limits to turbine heights and rotor diameters due to transport challenges. Research in turbine design with more slender and flexible blades, two-part blades and onsite turbine assembly might alleviate some of these constraints.

2.3.3 Land use

Although actual projects may vary significantly, early stage mesoscale wind resource assessments typically assume a power density in the range of 4-5MW per km^2; however, only about 3% of this area will be used for the development of actual turbines and supporting infrastructure. The rest is preserved to ensure limited obstruction to air flow. Topography plays a key role in wind farm design and there is the potential for wind turbines siting to be highly concentrated on topographic features such as ridgelines. Recent research has shown that in the future as wind farms continue to expand, interactions between turbines and the atmosphere might reduce real-world wind power generation and more land may be required than previously estimated.

2.3.4 Queensland's wind resources

Maximum REZ wind generation resource limits have been calculated based on a DNV-GL estimate of:

- Typical wind generation land area requirements
- Land available that has a resource quality of high (in the top 10% of sites assessed) and medium (in the top 30% of sites assessed, excluding high quality sites)

An assumption that only 20% of this land area will be able to be utilised for wind generation was used, considering competing land uses and social limitations. Assessment of planned renewable energy project capacity in REZ such as Fitzroy, which is well prospected by developers and Darling Downs suggests that AEMO's wind build limits are reasonable.

The wind resource quality assessment was based on mesoscale wind flow modelling at a height of 150 m above ground level (typical wind turbine height). Resource quality is based on expected capacity factor, which was derived from the estimated wind output in eleven reference years and is scored as below:

Capacity Factor	≥45%	≥40%	≥35%	≥30%	<30%
Score	A	B	C	D	E

Table 3: Wind resource grade – capacity factor | *Source: AEMO ISP Appendix 3 Renewable energy zones (2022)*

North Queensland has the highest capacity factor wind resource; however it has limited existing load and limited existing transmission capacity. Sites in central and southern Queensland have 23GW capacity of moderate quality wind resources and will see competition for these resources between different demand sources such as decarbonising the power system, transport and industry and new energy-extensive exports, including a potential export hydrogen derivatives industry .

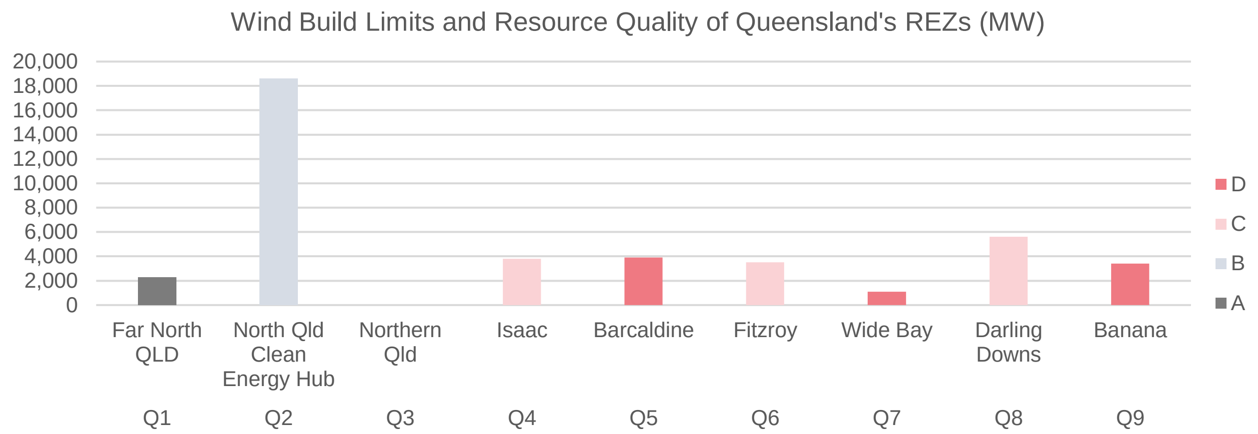

Figure 10: Wind Build Limits and Resource Quality of Qld's REZs (MW) | *Source: AEMO ISP Appendix 3 Renewable Energy Zones (2022)*

The 2022 AEMO ISP step change scenario finds that domestic load growth results in the wind build limits for southern and central Queensland REZ being reached and in the case of Wide Bay and Darling Downs significantly exceeded. AEMO's modelling approach of allowing the breaching of build limits by applying an additional cost penalty per MW is considered optimistic and is not a standard approach taken by industry. Assuming domestic energy customers and existing energy intensive export industries are preferred in the allocation of wind resources, except for the Barcaldine REZ, there could be limited to no wind resources available for export hydrogen derivatives in central and southern Queensland. The dimensions of the Barcaldine REZ could be expanded to capture more wind resources at higher elevation; however the location is remote from the coast and the wind resources are poor quality, rated D.

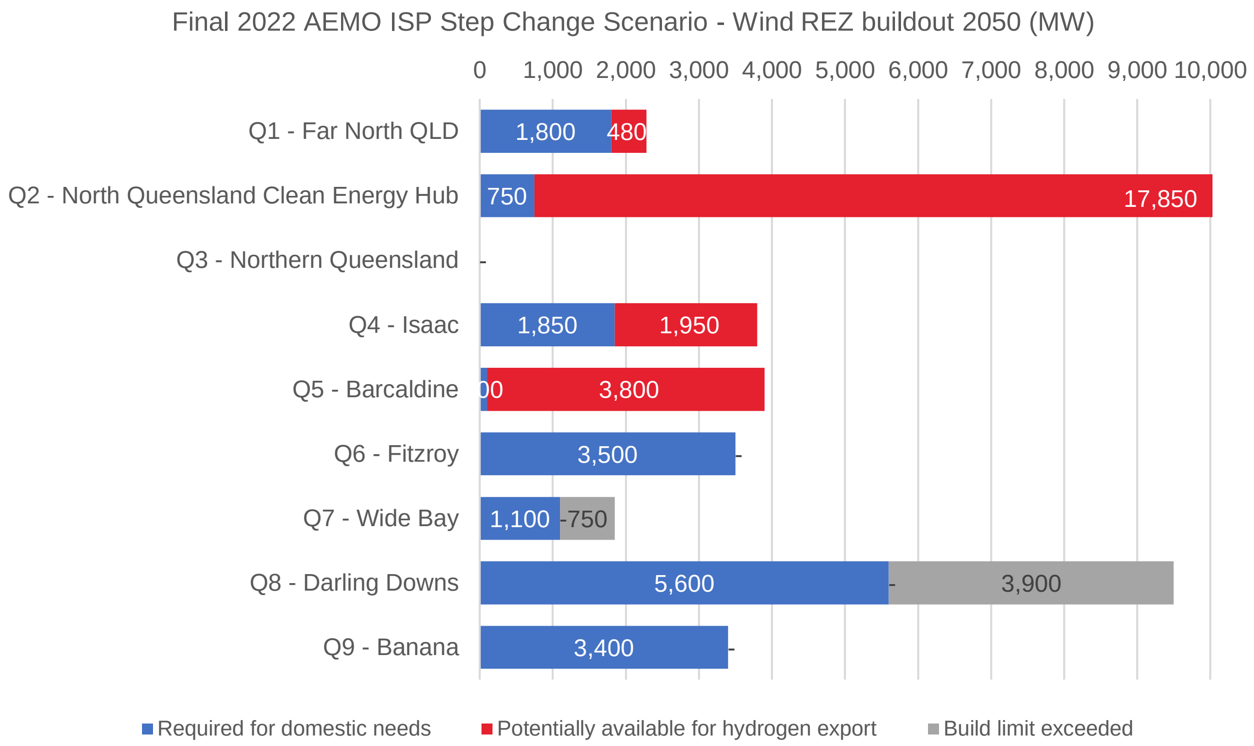

Figure 11: Final 2022 AEMO ISP Wind REZ buildout 2050 (MW of build limit) | Source: AEMO ISP Appendix 3 Renewable energy zones (2022)

2.3.5 Comparison to other NEM states

Queensland REZ wind capacity factors compare reasonably well to southern NEM states. The below Table 4 shows capacity factors for wind for key Queensland REZ. Potential diversity benefits for wind can be significantly higher than solar PV, which is generally highly correlated and thus the REZ relevant for both domestic decarbonisation as well as export hydrogen derivative projects are shown. Capacity factors are compared to southern NEM states REZ, that have the highest wind buildout for their respective states in AEMO's 2022 ISP's Step Change scenario.

Renewable Energy Zone	Q2 North QLD Clean Energy Hub	Q4 Isaac	Q8 Darling Downs	Q9 Banana	N3 Central West Orana	V3 Western Victoria	S3 Mid-North SA	T2 Northwest Tasmania
Capacity Factor (%)	40.4%	33.6%	36.5%	29.3%	35.9%	40.0%	38.1%	48.6%

Table 4: Wind capacity factors | Source: AEMO Draft 2023 Inputs and Assumptions workbook (2022)

Wind resources in north Queensland (Q2 North QLD Clean Energy Hub and Q4 Isaac) have seasonal generation profiles that are anti-correlated with solar generation, which is beneficial for maintaining electrolyser load factors over winter. Seasonal wind generation profiles are driven by the movement of the sub-tropical ridge. A clear pattern is observable in Queensland between the relative strength of winter wind generation increasing as latitude decreases, i.e. higher relative winter generation the further north you move. This seasonal generation pattern makes Queensland's wind resources, particularly in the north of the state, highly favourable for addressing the 'winter problem', as part of a potential green ammonia demand response service.

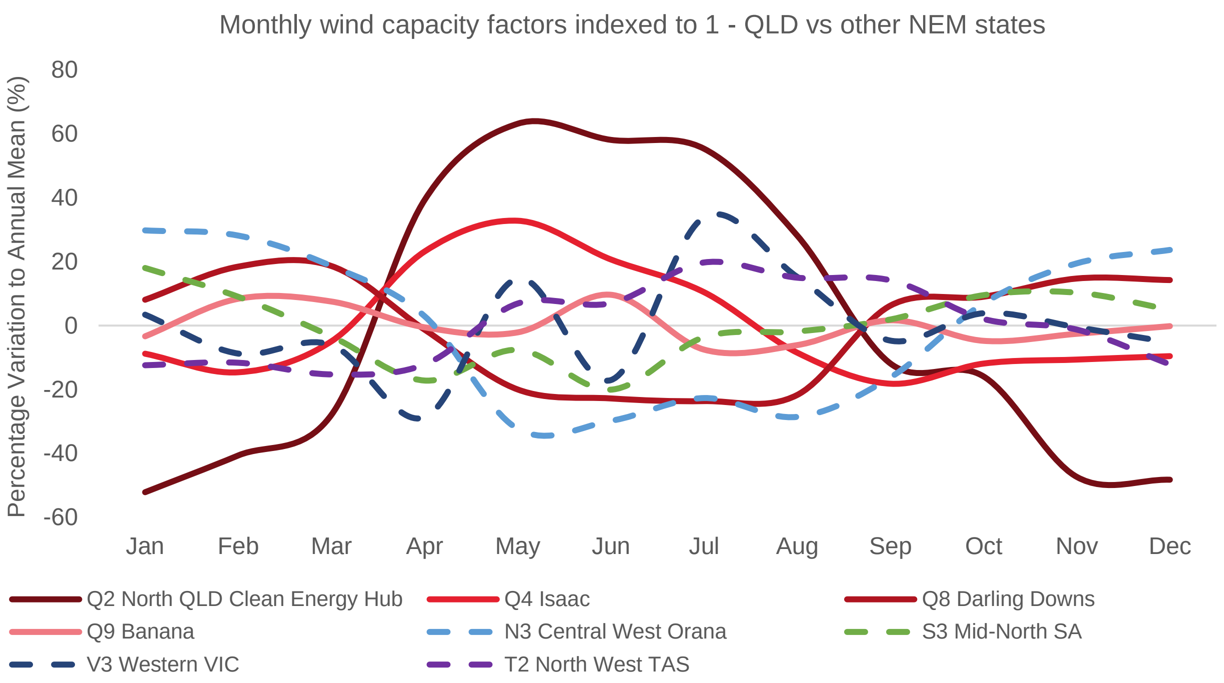

Figure 12: Monthly wind capacity factors indexed to 1 - QLD vs. other NEM states | *Data source: AEMO ISP 2022 Wind traces (2022)*

Unlike other NEM states, Queensland benefits from significant intra state wind diversity as demonstrated by low or negative correlations of daily wind generation between Queensland REZ. This diversity could assist in achieving higher electrolyser load factors and reducing power and hydrogen storage required to meet minimum load requirements of green ammonia plants. Queensland wind REZ also have low or negative correlation with southern NEM state wind REZ, which is potentially a favourable characteristic for exporting renewables to southern NEM states via green ammonia demand response. Correlation is calculated for key QLD wind REZ and the top three REZ from the other NEM states based on buildouts from the AEMO's 2022 ISP's Step Change scenario.

		QLD				NSW			SA			TAS			VIC		
		Q2	Q4	Q8	Q9	N2	N3	N5	S1	S3	S6	T1	T2	T3	V3	V4	V5
QLD	Q2	1.00	0.53	-0.50	0.06	-0.24	-0.58	-0.30	-0.18	-0.35	-0.38	0.17	0.29	0.36	0.10	0.20	0.18
	Q4	0.53	1.00	-0.05	0.33	-0.13	-0.15	-0.19	-0.17	-0.18	-0.03	0.00	0.04	0.18	-0.06	-0.05	-0.08
	Q8	-0.50	-0.05	1.00	0.53	0.43	0.56	0.18	0.07	0.24	0.37	-0.20	-0.25	-0.20	-0.09	-0.18	-0.25
	Q9	0.06	0.33	0.53	1.00	0.32	0.15	0.02	-0.11	-0.02	0.13	-0.06	-0.04	0.03	-0.04	-0.09	-0.13
NSW	N2	-0.24	-0.13	0.43	0.32	1.00	0.47	0.20	0.10	0.11	0.20	-0.14	-0.13	-0.23	0.05	-0.07	-0.09
	N3	-0.58	-0.15	0.56	0.15	0.47	1.00	0.31	0.15	0.38	0.50	-0.30	-0.27	-0.35	-0.05	-0.24	-0.30
	N5	-0.30	-0.19	0.18	0.02	0.20	0.31	1.00	0.57	0.50	0.25	0.17	0.13	0.00	0.52	0.31	0.26
SA	S1	-0.18	-0.17	0.07	-0.11	0.10	0.15	0.57	1.00	0.44	0.11	0.14	0.17	0.04	0.65	0.53	0.31
	S3	-0.35	-0.18	0.24	-0.02	0.11	0.38	0.50	0.44	1.00	0.68	-0.05	-0.04	-0.15	0.20	0.07	-0.04
	S6	-0.38	-0.03	0.37	0.13	0.20	0.50	0.25	0.11	0.68	1.00	-0.20	-0.18	-0.24	-0.08	-0.20	-0.30
TAS	T1	0.17	0.00	-0.20	-0.06	-0.14	-0.30	0.17	0.14	-0.05	-0.20	1.00	0.60	0.58	0.38	0.39	0.58
	T2	0.29	0.04	-0.25	-0.04	-0.13	-0.27	0.13	0.17	-0.04	-0.18	0.60	1.00	0.60	0.39	0.37	0.59
	T3	0.36	0.18	-0.20	0.03	-0.23	-0.35	0.00	0.04	-0.15	-0.24	0.58	0.60	1.00	0.32	0.39	0.47
VIC	V3	0.10	-0.06	-0.09	-0.04	0.05	-0.05	0.52	0.65	0.20	-0.08	0.38	0.39	0.32	1.00	0.72	0.59
	V4	0.20	-0.05	-0.18	-0.09	-0.07	-0.24	0.31	0.53	0.07	-0.20	0.39	0.37	0.39	0.72	1.00	0.53
	V5	0.18	-0.08	-0.25	-0.13	-0.09	-0.30	0.26	0.31	-0.04	-0.30	0.58	0.59	0.47	0.59	0.53	1.00

Figure 13: Selected ISP Wind REZ daily generation correlation | *Data source: AEMO ISP 2022 Wind traces (2022)*

Although findings around seasonal generation profiles and correlation benefits are supported by different weather reanalysis data sets and wind project site wind measurements, there is uncertainly around the magnitude of patterns, including due to a lack of generation data from operating wind farms. Thus the results of detailed models that use such simulated wind traces as inputs should be treated with some caution. For instance although a 2017 presentation by the at the time ASX listed Windlab showed a seasonal pattern for the Kennedy wind resource (proximate to Hughenden within the NQCEH (Q2)) which is significantly weaker than AEMO ISP wind traces. In addition AEMO's December 2022 Forecast Accuracy Report showed that for the top 10 hottest days for 2021 observed output for Queensland wind farms was mostly in the lower end of the simulated range, with the predominant reason identified that wind speeds were lower than simulated.

2.4 Onshore wind versus solar

A consistent finding across most renewable energy LCoE forward estimates is that if wind and solar resources are of comparable quality then solar PV is currently lower cost than wind. LcoE projections, including Bloomberg New Energy Finance and the University of Oxford Institute for New Economic Thinking, also show that the gap between wind and solar increases on an absolute and relative basis over time. For Queensland this pattern is expected to be magnified due to its relative abundance of high-quality solar resources compared to wind. CSIRO GenCost 2022-23 Final Report (2023) was released in July 2023 and shows the projected cost gap between wind and solar has increased materially versus CSIRO GenCost 2022-23: Consultation Draft (2022) released in December 2022, which are key modelling inputs for this research.

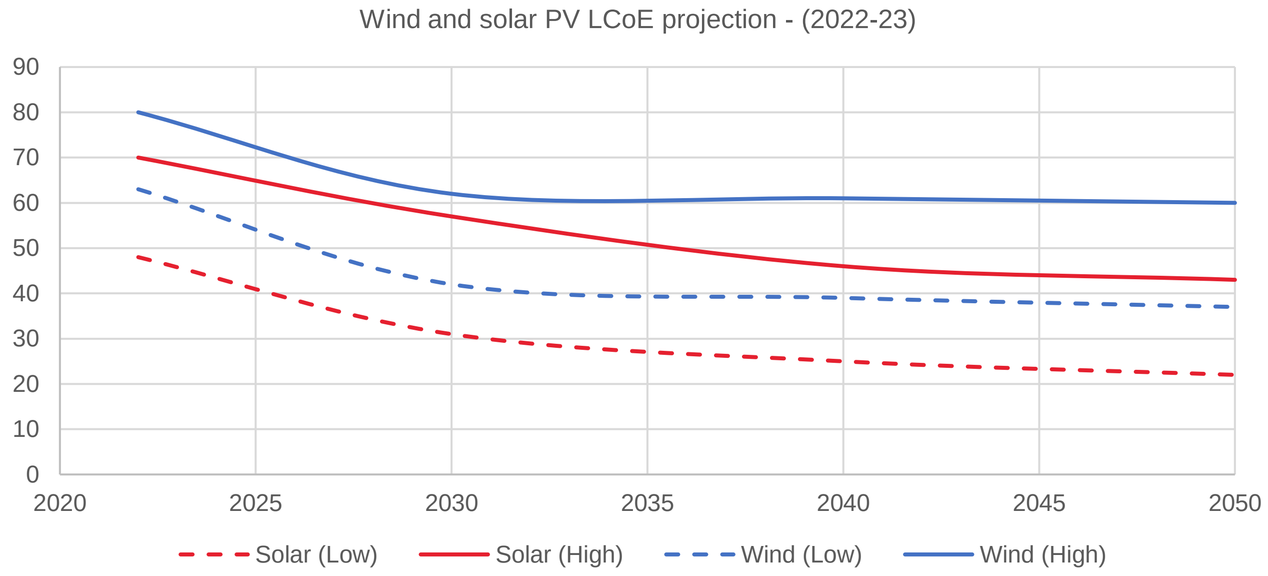

Figure 14: Wind and solar PV LcoE projection – (2022-23) | *Source: CSIRO GenCost 2022-23: Consultation Draft*

An additional challenge for wind relative to solar is social licence risk, particularly due to cumulative social and environmental impacts. Wind resources are highly geographically dependent with the best resources in Queensland typically located on the top of ridges, where wind turbines are most visible and vegetation may not have been previously cleared as it may not be suitable for agriculture. Large wind farms footprints can extend tens of kilometres, typically along ridges, exacerbating visual impacts. In addition to any connection asset potentially required to connect a wind farm to a transmission network, overhead lines may also be required within the wind farm site to connect wind turbines to the network connection point. This compares to solar PV where development footprints can be concentrated including in locations where there are low value alternative land uses and/or community impacts and any transmission potentially required can be minimised. Social license risk and community opposition to a project can lead to longer development timeframes and higher project costs, including payments to affected communities, but can also make a project unviable.

2.5 Offshore wind

Offshore wind is higher cost than onshore wind and this is expected to persist into the future (IRENA, NREL). Queensland has sufficient onshore wind resource to allow the decarbonisation of its domestic economy and thus does not need to rely on more expensive offshore wind. Queensland has high quality offshore wind resources in far north Queensland, however the relatively high cost of offshore wind versus onshore wind, its remoteness from load centres and the location's proximity to the Great Barrier Reef Marine Park presents challenges for its development. Lower quality offshore wind resources exist in southern Queensland. Offshore wind is not considered further in this study.

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3 Electrolyser Information Sheet

3.1 Introduction

The purpose of this Information sheet is to describe electrolysis, a technology that uses electrical energy to split water molecules into their two constituents, hydrogen and oxygen. If the electricity used is from a renewable source, the hydrogen produced by electrolysers is described as 'green'.

Hydrogen electrolysers are highly modular, and most vendors provide a 'Plug and Play' style package between 5 and 20 MW (which is equivalent to between 800 and 3000 tons of hydrogen per annum if the plants are operated at their maximum rate all year). Scale increases are achieved by operating many of these modules in parallel. The vendor packages typically require a source of deionised water, and an 11 kV DC electricity source.

3.2 Types of Electrolyser

There are three main technologies of electrolyser discussed widely in the literature: alkaline, proton exchange membrane (PEM) and solid oxide electrolyser cells (SOECs).

Alkaline electrolysers are the most widely used today, and have a very high commercial readiness, having been used in Norway for fertiliser production from hydropower almost a century ago. At present, they have a lower capital cost, and often report slightly higher efficiencies, although the rate of efficiency improvement is lower than PEM electrolysis. Their footprint and weight are quite high, making alkaline electrolysers not well suited for very small-scale decentralised application.

PEM electrolysers are the fastest growth market, and are the preferred technology by major European vendors (e.g. Siemens). PEM cells rely on membranes made from precious metal catalysts; although the amount of precious metals required is falling quickly, the availability of these materials may constrain growth of this technology. The primary advantage of PEM electrolysis is that it is forecast to have a lower energy demand per unit of hydrogen produced, and it can ramp from minimum to maximum production very quickly (compared to alkaline cells). The extent to which electrolyser flexibility will impact plant costs depends strongly on (i) the specific capability of the equipment to ramp up and down offered by each technology provider, (ii) the renewables mix powering the cells, and (iii) the relationship, if any, of an electrolyser to electricity grids. Case-by-case modelling is needed to determine whether improved flexibility is justified if they are associated with increased capital costs.

Unlike Alkaline and PEM cells, SOECs operate well above room temperature (around 700°C). This enables them to operate at a higher energy efficiency and means that waste heat from other industrial applications can be used to reduce the electricity demand. This may be particularly useful where hydrogen production is co-located with an upgrading process (e.g. ammonia/methanol synthesis), since the heat released by these exothermic reactions can be recovered and used where it would otherwise be wasted. Compared to PEM cells, the precious metal demand in these cells is low. However, these cells currently have very high capital costs and have not been widely demonstrated commercially. Even more importantly, the evidence that these cells can operate flexibly alongside a variable renewable energy profile is very limited. There are fewer SOEC vendors than other technologies, which limits the potential for broad procurement.

3.3 Capex estimates

Green hydrogen production costs are projected to benefit from declining capex and increasing electrolyser efficiency, driven by growth in global deployment. In recent years project capital costs have experienced upward pressure due to the COVID-19 pandemic and Ukraine conflicts impacts on global supply chains and freight costs. Feedback from various industry sources is that capital cost estimates for a number of Australian projects currently under development may be higher than those from CSIRO GenCost: Consultation Draft 2022-2023 (2022), that is used as an input into the AEMO ISP. Potential drivers of higher capital cost may include a transitory mismatch of demand and supply placing upward pressure on equipment costs and higher balance-of-plant costs. Another challenge put forward by industry sources is a lack of contractors willing to offer fixed price EPC contracts, which increases risk and thus potentially required returns for project proponents.

Feedback from some industry sources indicates that capital cost projections are optimistic as a reasonable portion of capital cost relates to balance-of-plant, which is a common, mature technology that is unlikely to be subject to future cost reductions.

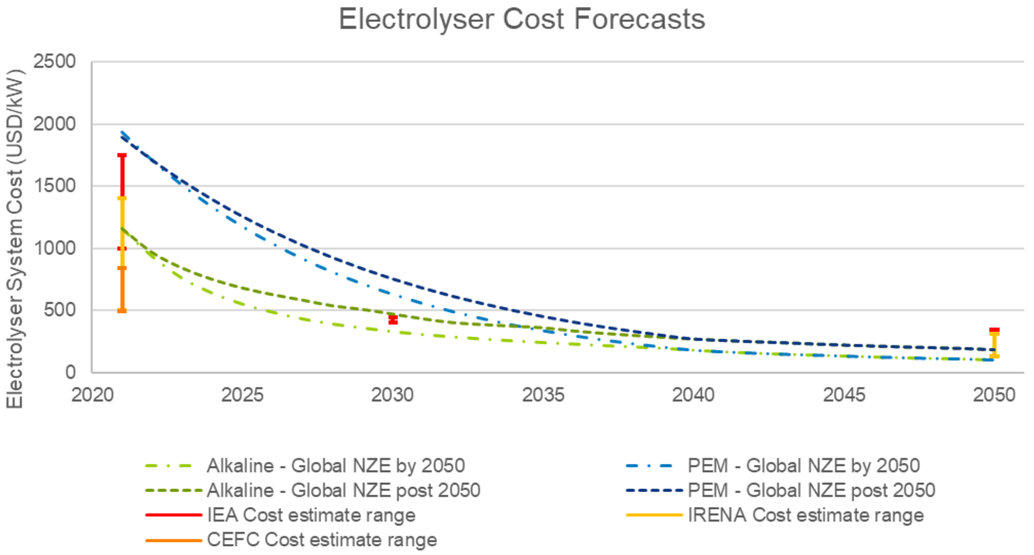

Figure 15: Estimates of electrolyser system costs as a function of time | *Source: CSIRO (2022), CEFC (2021), IEA (2022), IRENA (2021)*

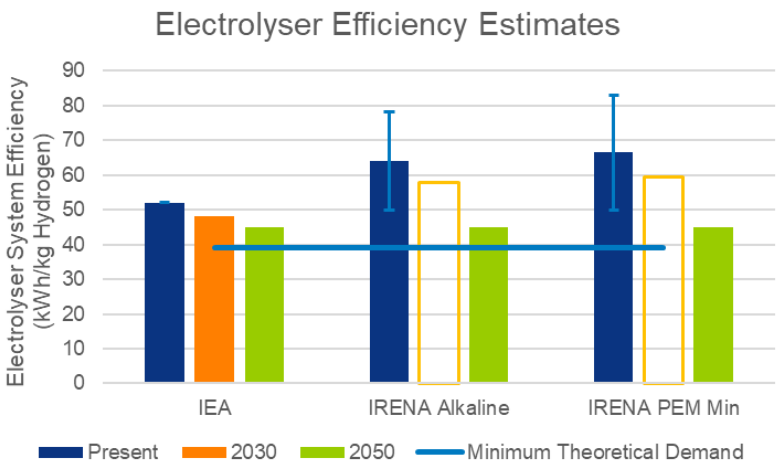

Figure 16: Estimates of electrolyser efficiencies from various sources changing over time | *Source: IEA (2022), IRENA (2021)*

Note that the IEA does not differentiate between electrolyser types, and IRENA does not provide 2030 estimates – the results shown are linearly interpolated as an indication. Uncertainty ranges are shown where provided in the data.

3.4 Electricity Use

For current projects electricity typically represents roughly 50% of the cost of green hydrogen (although the exact value will vary significantly subject to project specific detail), meaning maximising electrolyser efficiency is an important driver for cost reduction. The theoretical minimum energy consumption for hydrogen production is 39.4 kWh/kg, which is referred to as hydrogen's higher heating value (HHV). The true efficiency for best-in-class hydrogen production today is between 48 and 55 kWh/kg, and is forecast to fall to between 40 and 45 kWh/kg by 2050. Electrolyser efficiencies are often reported as a percentage. This is typically the ratio of energy used for production to hydrogen's lower heating value (LHV) of 33.3 kWh/kg. For instance, an efficiency of 50 kWh/kg would be reported as 67%. The LHV is the energy available from hydrogen upon combustion. However, some vendors may quote relative to the HHV, and disambiguation should be sought.

There are several sources of energy losses in green hydrogen production. Different technologies and vendors may scope their design in different ways; meaningful comparison between these options requires that the scoping be unified to include the same energy losses. The primary sources of energy loss include: overpotential (where the cell is operated at a voltage slightly higher than the thermodynamic equilibrium for kinetic reasons); ohmic losses in the electrolysis cell and stack; and balance-of-plant losses (which include energy for hydrogen dewatering, purification and compression).

During use, electrolyser cells degrade and their efficiencies worsen over time. Cell membrane replacement is required approximately once every 40,000 operating hours for PEM and alkaline cells (market reports for SOECs are limited but show much faster degradation). It is not expected that ramping the electrolyser between minimum and maximum operating rates, within vendor specifications, will materially impact membrane lifetimes for alkaline and PEM electrolysers. The cost of membrane replacement is usually between 2 and 5% of the upfront capital cost.

Electrolyser efficiencies are typically higher when operated at currents below their maximum. This may provide advantages when cells are powered using variable renewable energy (since maximum power input to the cell is not always achieved). Operation at low currents also reduces the rate of cell degradation.

Improving electrolyser efficiency reduces project cost as less electrolyser capacity is required for the same hydrogen production, and also reduces the land requirements of the project, since the majority of land use associated with hydrogen production is associated with renewable electricity generation.

3.5 Firmed power requirements

In general, hydrogen electrolysers are highly flexible, and therefore have low, if any, firmed power requirements. This is primarily true of alkaline and PEM electrolysers, although specific turndown properties vary significantly between vendors. In general, alkaline electrolysers have a minimum operating rate in the order of 30-40%, whereas PEM electrolysers can turn down to approximately 10%. Ramping is also rapid; in the order of 10% of the rated operating capacity per second, meaning renewable profiles can be tracked virtually instantaneously. More importantly, start-up and shut down are very quick; typically, this lasts less than a minute for a warm-start, or in the order of five minutes from a cold start.

In order to avoid firmed power requirements, exploiting these start-up and shut-down properties is critical. Very large-scale hydrogen electrolysis installation for export will be on GW scale, meaning even minimum operating rates of 10% would represent significant firmed power requirements; they need to be switched off entirely. Additionally, in general, degradation increases at higher operating rates, meaning turn-downs and shut-downs may increase membrane life.

The flexibility of solid oxide electrolysers is less well understood. The primary difference between these electrolysers and PEM/Alkaline cells is that they operate at much higher temperatures; if they are turned down, they will cool down, and start-up is more difficult. There are therefore three cases for the baseload energy requirements of solid oxide cells: (i) baseload demand similar in size to the plant itself, associated with limited turndown ability so temperature can be maintained; (ii) low baseload power demand, but a moderate baseload heat demand that can be used to sustain temperature (for instance, from a nearby industrial source with waste heat); or (iii) low baseload demand enabled by either highly insulated cells, faster cold-start up or higher down-time in start-up. The technology is still emerging, so an enabler of (iii) may emerge in the future; however, at present, these cells are likely to have higher baseline requirements. A further relevant factor is the degradation of solid oxide cells, which is not well understood, and may be affected by temperature cycling that may also require a minimum baseload power requirement.

3.6 Water Use

The water consumption of each hydrogen electrolyser technology is relatively even and is estimated to be between 9 and 11 kg of water per kilogram of hydrogen. The theoretical minimum is 9 kg of water per kilogram of hydrogen. True water consumption may be considerably higher (15-20 kg water/kg hydrogen) as deionised water is generally required; with water losses occurring during the purification process. Wet cooling may further increase water demand, although in most cases air cooling should be possible.

Desalination is one option for reliable water supply. The energy and financial cost of desalination is small compared to the hydrogen production. A conservative estimate of desalination energy demand is 4.2 kWh per kilolitre of desalinated water; however, this energy use per kilogram of hydrogen produced is just 0.038 kWh/kg. This is approximately 0.1% of the theoretical energy demand for electrolysis. The cost of this desalinated water adds between 1 and 2 cents to the cost of hydrogen per kilogram. However, in addition to potential environmental and approval challenges with the processing and release of brine, if the water needs to be pumped inland from a desalination facility at the coast, costs may be considerably higher, and regulatory barriers and hurdles could be significant.

3.7 Other Considerations

Electrolyser plant equipment (electrolyser stacks) is highly modular, which means that increasing the size of a green hydrogen plant is not likely to reduce a project's equipment capex, disregarding potential scale benefits in procurement and shipping. The main non-technical driver of cost reduction in electrolyser equipment (electrolyser stack) capex will be economies of mass production in facilities where electrolysers are manufactured. There are different views around the degree to which balance-of-plant for electrolyser plants will benefit from economies of scale at a project scale level and/or from mass production. Ultimately green hydrogen plants are expected to benefit from varying degrees of economies of scale in development, construction and operating phases.

At present, electrolyser lead times may exceed 18 months; while the development of greater electrolyser production capacity globally may drive down lead times, this reduction might be offset by the rapidly expanding demand for green hydrogen production around the world. Acceleration in electrolyser deployment is dependent on firm offtake agreements that enable derisked investment in the technology.

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4 Energy Storage Information Sheet

4.1 Comparison of energy storage technologies

4.1.1 Introduction

Storage will be a critical requirement in a future hydrogen industry as it provides firming for a potential value chain consisting of intermittent renewable energy, flexible electrolysers, inflexible or partially flexible hydrogen conversion processes and potentially inflexible steady demand, including potential export customers.

The purpose of this information sheet is to compare the capital costs of the forms of storage that are potentially part of hydrogen industry value chains: power system storage, hydrogen storage and hydrogen derivative storage.

Analysis comparing the cost of using batteries or compressed gaseous hydrogen storage for firming hydrogen supply for an islanded plant is also included.

4.1.2 Energy storage capital cost comparison

Figure 17 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 pumped hydro energy storage (PHES);
- Hydrogen storage – geological and non-geological hydrogen storage; and
- Ammonia and liquid hydrogen

The energy storage potentially available in each step of the multi-stage production process of green ammonia and hydrogen liquefaction is shown by moving left to right across Figure 17. 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 it is based on MWh of thermal energy with hydrogen and ammonia storage is based on their lower heating values (LHV)[5]. Thus Figure 17 does not consider the significant efficiency losses associated with using hydrogen and ammonia as a fuel to produce electricity,

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.

Geological hydrogen storage and hydrogen derivative storage are mega scale with one salt cavern being able to store in the order of 200GWh and one 50,000t ammonia tanks 260GWh. This compares to the Waratah Super Battery at 1.68GWh and Pioneer Burdekin PHES at 120GWh.

The mega scale and ultra-low capital cost of salt caverns and ammonia tanks suggests that for the green ammonia value chain they may be well suited to providing seasonal storage and perhaps storage for more frequent cycling.

[5] *Green ammonia is a valuable product that currently requires 10-11MWh of renewable energy to produce, around double its LHV of 5.2MWh/t NH_3.*

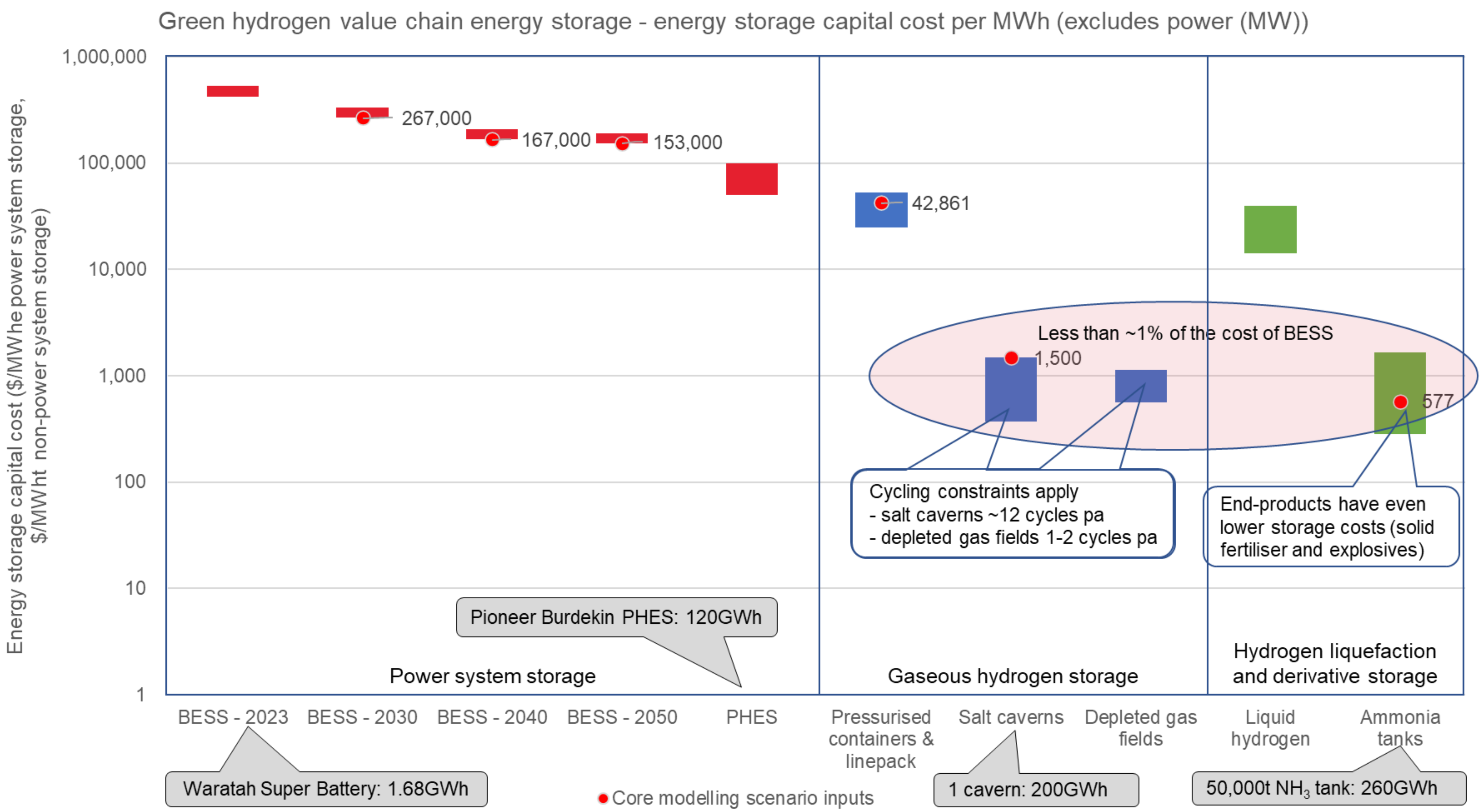

Figure 17: Green hydrogen value chain energy storage – energy storage capital cost per MWh (excludes power (MW))

Data source: AEMO Draft 2023 Inputs and Assumptions Workbook, various seeSection 4.3. Assumptions: Lower heating value of hydrogen of 33.33kwh/kg and lower heating value of ammonia of 5.2MWh/tonne,

4.1.3 Firming green hydrogen – BESS vs compressed gaseous hydrogen storage

For islanded hydrogen production there are two key forms of storage that are available in all locations (as opposed to location-specific technologies including geologic hydrogen storage or PHES) that can be used to firm hydrogen produced with variable renewable energy: BESS and compressed gaseous hydrogen storage such as buried pipe or pressure vessels.

For the BESS option, variable renewable generation is used to charge the BESS when there are excess renewables, i.e. renewable energy would otherwise be 'spilled', since generation exceeds electrolyser capacity. The BESS stores the energy and time-shifts it by discharging in a period where there is lower renewable generation and unutilised electrolyser capacity. The BESS allows higher load factors to be achieved by the electrolyser, increasing fixed cost leverage for this value chain element. The ~85% round-trip-efficiency of a BESS means that ~15% of energy is lost in a charging and discharging cycle, with this loss increasing over time as round-trip-efficiency degrades.

The alternative hydrogen firming option to BESS is to increase electrolyser capacity and use compressed gaseous hydrogen storage, such as buried pipes, or pressure vessels. This option results in a lower electrolyser capacity factor than BESS firming, with the compressed gaseous hydrogen storage acting as the buffer storage to manage variable hydrogen throughput from the electrolyser. Compressing the hydrogen for storage in buried pipe or pipelines results in losses in the range of 6-8% of the hydrogen's energy content, an effective hydrogen storage round-trip-efficiency of 92-94%. Compressor capex is estimated to be $30,000 per MW of hydrogen throughput, equivalent to $1.2 million per ton/hour.

Figure 18 compares the capital cost of 1kW of BESS at various durations compared to 1kW of electrolyser with compressed gaseous hydrogen storage of various durations in 2030 and 2050. The low cost per MWh of compressed gaseous hydrogen storage results in significantly lower capital costs than the BESS options as storage duration increases. As solar generation is significantly lower cost than wind, it tends to dominate the capacity mix for an islanded green ammonia/hydrogen system. Thus, the optimal energy storage duration generally exceeds 8 hours to cover the overnight period. This higher cost of BESS vs compressed gaseous hydrogen storage persists over time despite reductions in BESS costs and no assumed reduction in compressed gaseous hydrogen storage costs. BESS capex per MWh (the slope of the lines in Figure 18) is approximately 8 times in 2030 and 4 times that of gaseous hydrogen storage in 2050. Figure 18 does not consider key factors that are favourable for gaseous compressed hydrogen storage:

- Compressed gaseous hydrogen storage is further down the green hydrogen value chain and is thus post electrolyser efficiency losses in the range of 10%-35% depending on electrolyser technology and year, such that 1MWh of hydrogen storage is equivalent to 1.11-1.54MWh of BESS storage;
- Battery storage capacity degradation (MWh) and round-trip-efficiency degradation; and
- Higher effective round-trip-efficiency of compressed gaseous hydrogen storage (92-94%) compared to BESS (83-85%).

This high-level analysis is based on islanded hydrogen production specifically, and other considerations may be relevant when considering grid connected hydrogen production, or other energy systems. For instance, additional electrolyser capacity may be subject to network charges, such as TUOS, while for the alternative setup of a BESS located behind-the-meter with renewables may allow additional network charges to be avoided.

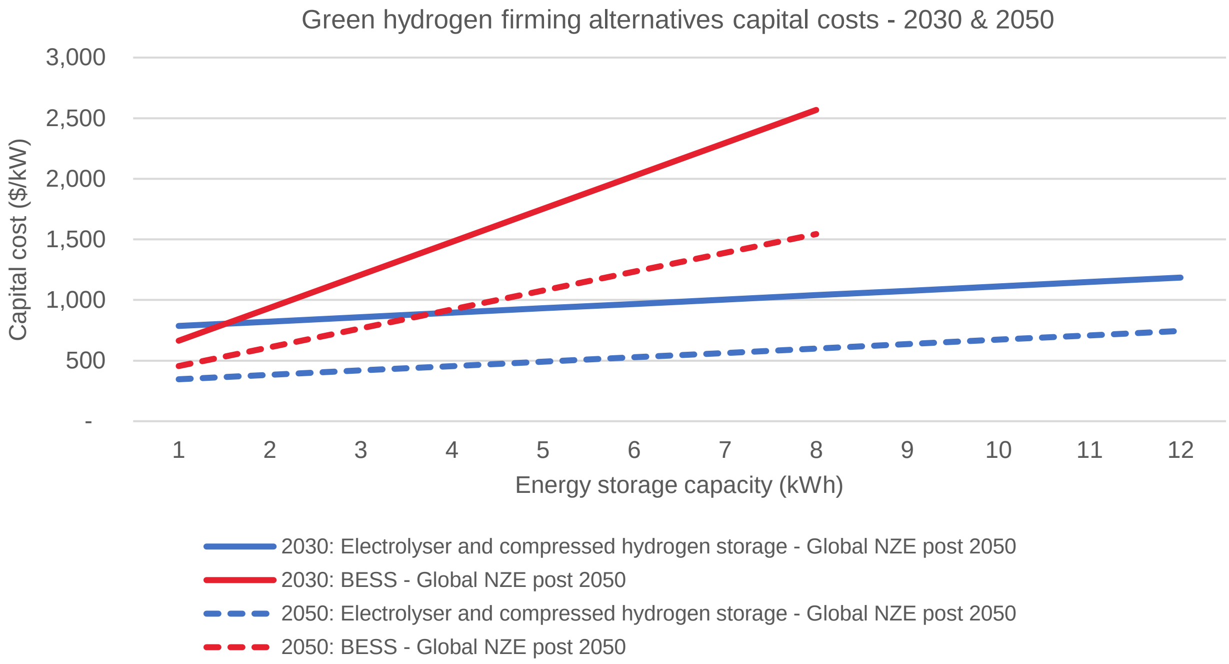

Figure 18: Green hydrogen firming alternatives capital costs - 2030 & 2050 | *Data source: CSIRO GenCost 2022-23: Consultation Draft (2022)*

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4.2 Power system storage

4.2.1 Introduction

Power system storage is critical to firming variable renewable energy in order to provide reliable electricity supply. In the green hydrogen value chain, power system storage can be used to firm renewable power for hydrogen upgrading processes such as ammonia production. It can also be used to provide firmed renewable power for electrolysis to facilitate firmed hydrogen supply, though for islanded (not grid connected) hydrogen production it is not cost competitive with compressed gaseous hydrogen storage for firming hydrogen supply.

This information sheet outlines the key techno-commercial parameters and cost projections for two mature energy storage technologies: battery energy storage systems (BESS) and pumped hydro energy storage (PHES) based on conditions prevailing as of 2023. Other technologies such as compressed air, flow batteries, thermal energy storage are either less mature or have higher costs and will not be considered further in this information sheet. The information sheet also includes a high-level cost comparison of using BESS vs compressed gaseous hydrogen storage for firming renewable hydrogen supply.

4.2.2 Battery energy storage system (BESS)

Large scale batteries can store low-cost electricity, such as renewable energy, when there is an oversupply, or during periods of low demand, so that it is available when demand is higher, or renewable energy supply decreases. BESS is highly suited to addressing energy imbalances on short timescales (hours). Large-scale lithium-ion battery systems (Li-ion BESS) dominate the BESS market due to their high power and energy density, historical trend of falling costs and high efficiency.

Lithium-ion batteries convert alternating current power to a low voltage and direct current through inverters in the batteries. The power can be regenerated back from the batteries to the high voltage AC network through the reverse path. Approximately 10 to 20% of the energy supplied to the batteries during the charge operation is lost as heat and not available when the battery discharges. Round-trip efficiency, measured as a percentage, is a ratio of the energy output from the battery to the energy input to the battery in a cycle. The AEMO Integrated System Plan (AEMO ISP) assumes a round-trip-efficiency of 83-85% depending on storage duration and annual degradation of storage capacity (MWh) of 1.8%. The Aurecon 2022 Technical Cost and Technical Parameter Review, which serves as input assumptions to the AEMO ISP, includes a round-trip-efficiency degradation on generation capacity (MW) of 0.2%, though this has not been included in the 2024 AEMO ISP input assumptions. The AEMO ISP simplifies degradation by reducing storage capacity (MWh) by 19%. The typical technical life is 20 years.

Historical cost reductions have been achieved through widespread deployment in consumer electronics and electric vehicles. In recent years costs have increased due to the COVID-19 pandemic and Ukraine conflict's impacts on global supply chains and freight costs, plus tightness in demand and supply for raw materials including lithium. Over time renewable BESS capital costs may return to long term trends of cost declines as supply chains and raw materials markets rebalance and growth in global deployment (i.e. scale and experience cost declines) continue.

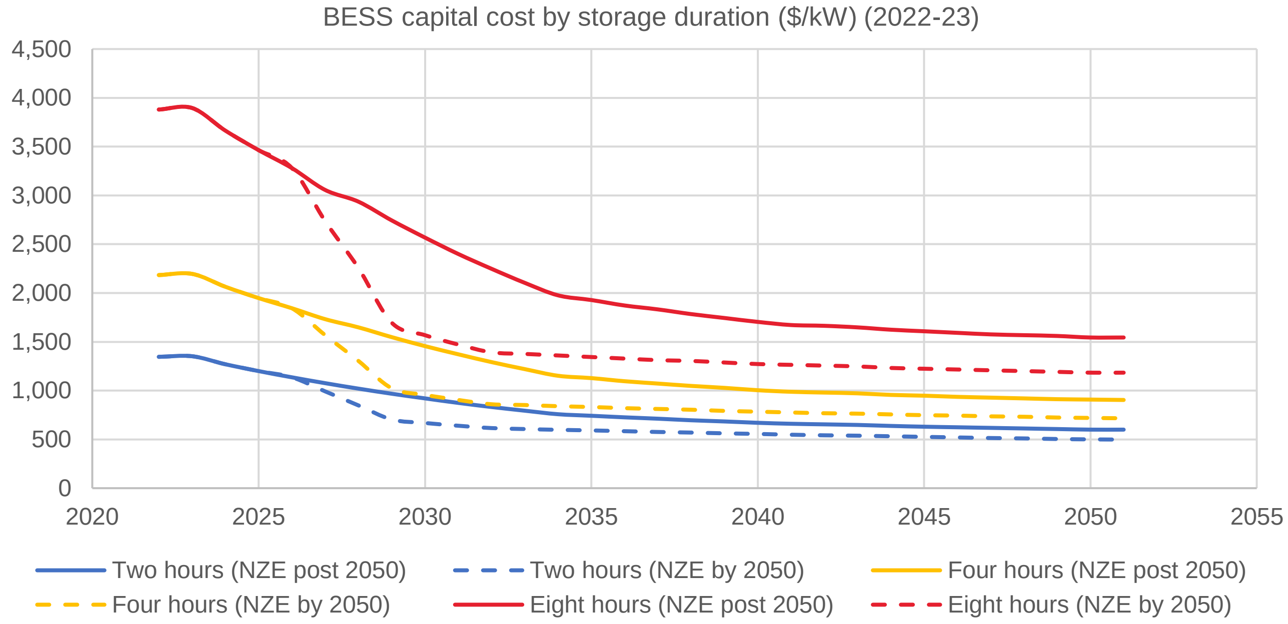

Figure 19: BESS capital cost by storage duration ($/kW) (2022-23) | *Source: CSIRO GenCost 2022-23: Consultation Draft (2022)*

AEMO ISP BESS capital costs estimates are sourced from CSIRO GenCost 2022-23: Consultation Draft (2022) with durations from one to eight hours provided. These battery cost estimates are deconstructed into a cost of generation capacity ($/kW) and cost of energy storage capacity ($/kWh) and used as model inputs.

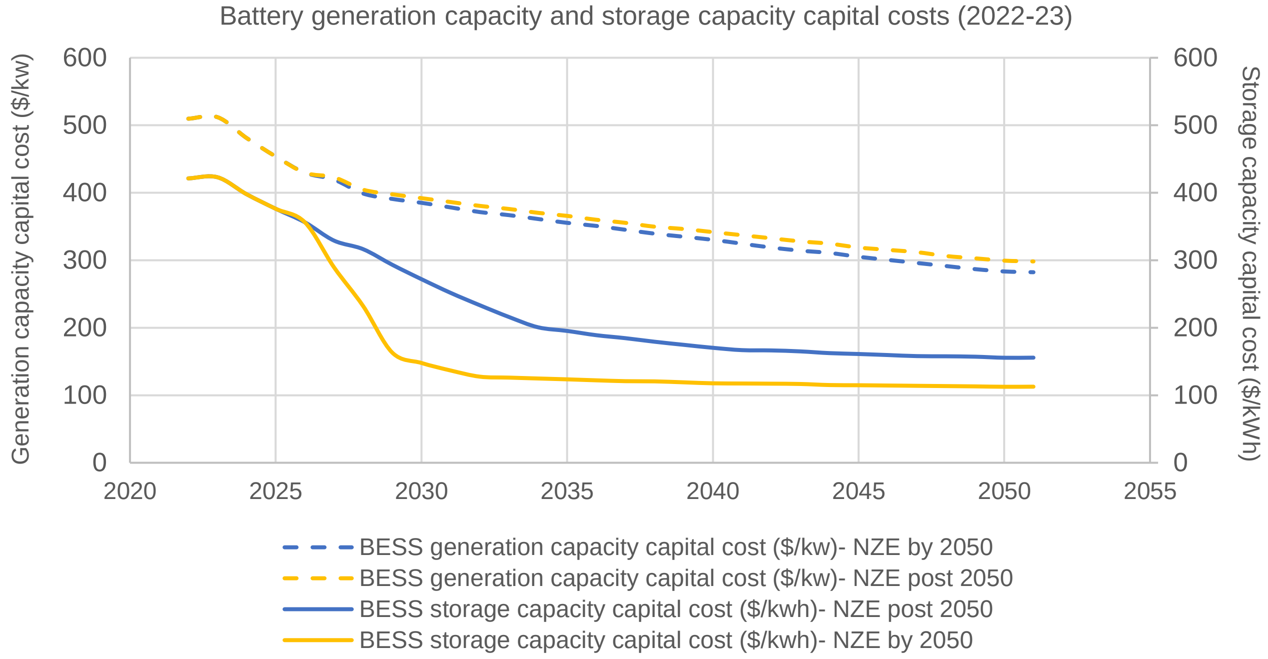

Figure 20: Battery generation capacity and storage capacity capital costs (2022-23) | *Data source: CSIRO GenCost 2022-23: Consultation Draft (2022)*

BESS variable operating cost is assumed to be $0. Total fixed operating and maintenance (FOM) cost ranges between $8-32/kW/year and unlike capex is assumed to remain constant over time. The FOM cost estimates can be deconstructed into a generation capacity charge of $4.5/kW and a storage capacity charge of $3.4/kWh. Total fixed O&M cost includes two approximately equal components: fixed O&M cost and extended warranty (20-year battery life). It is noted that the capital cost reducing over time, while FOM cost, a key component of which is an extended warranty cost that relates to the capital cost, remaining flat, is not intuitively appealing.

4.2.3 Pumped hydro energy storage (PHES)

PHES is a mature technology and is therefore assumed to have limited potential for cost reduction with further deployment. PHES has a high capital cost per MW but long technical life (50-100 years). The efficiency (76%) is lower than batteries, however there is no material degradation over time. Cost estimates in the near term have been adjusted for the current global inflationary pressures. However, the relationship between capacity and duration are site specific and thus there is limited value in decomposing into $/MWh. Based on one of the authors combined experience in Queensland PHES development, energy market modelling and this research there is limited potential commercially viable PHES capacity in Queensland beyond the two sites totalling up to 7,000MW of capacity already envisioned in the Queensland Energy and Jobs Plan. This PHES will be grid connected and thus this study will not assess PHES in modelling islanded/off-grid hydrogen production.

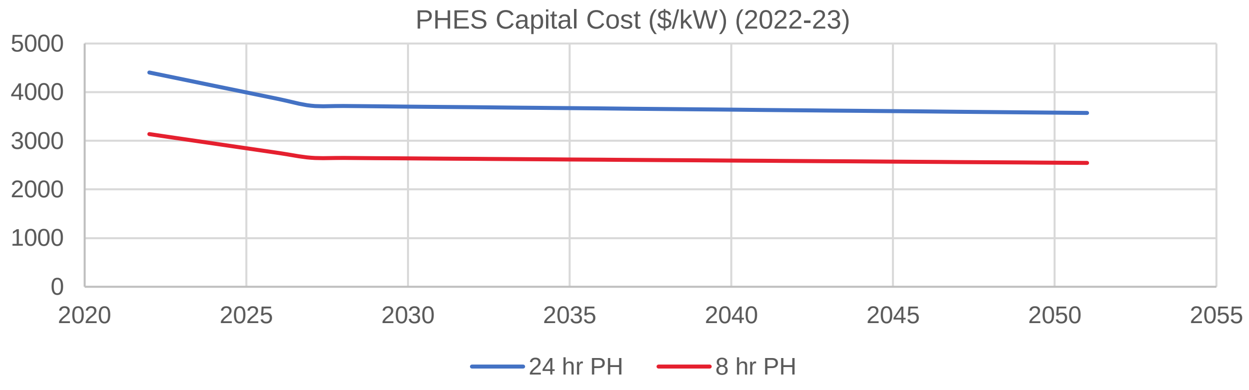

Figure 21: PHES Capital Cost ($/kW) (2022-23) | *Source: AEMO ISP Inputs, assumptions and scenarios workbook (2022)*

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4.3 Hydrogen and hydrogen derivative storage

4.3.1 Introduction

The purpose of this information sheet is to describe the various hydrogen and hydrogen derivative storages and to understand the costs and key technical characteristics of each. Storage will be a critical requirement in a future hydrogen industry as it provides firming between an intermittent hydrogen supply from renewable energy and inflexible or partially flexible hydrogen conversion processes and potentially inflexible demand of customers, including potential export customers.

The contribution of hydrogen storage to the levelised cost of hydrogen (LCoH) for a given renewable energy supply is highly correlated to the:

- Required firmness or reliability of hydrogen deliveries to the customer;
- Capital cost per kg of hydrogen storage capacity;
- Storage pressure, which drives compressor capital costs and energy requirements; and
- Constraints on how frequently the storage can be cycled.

Estimating required hydrogen storage and its contribution to LCoH requires complex modelling incorporating renewable energy intermittency. LCoH storage measures commonly referred to in academic and industry literature rely on specific assumptions around cycling frequency. This can make comparing LCoH storage across technologies with dramatically different capital costs and cycling constraints challenging and LCoH storage analysis is not included in this information sheet and should be treated with caution.

Estimating required hydrogen and hydrogen derivative storage for partially flexible hydrogen derivative production processes such as ammonia, is even more complex.

4.3.2 Gaseous Hydrogen Storage

4.3.2.1 Introduction

Hydrogen storage with high TRL and the capacity to operate at industrial scales can be in either gaseous or liquid states. Hydrogen has a very high energy density per unit mass (142MJ/kg, cf 53.6MJ/kg of natural gas) but has a very low density (0.09kg/m3), approximately eight times less dense than natural gas. This phenomenon creates cost challenges for storing hydrogen as large amounts of compression are required to store it economically. There are a number of gaseous hydrogen storage options, each with differing benefits and costs.

4.3.2.2 Capital cost and cycling constraints

Figure 22 show the significant capital cost differential between non-geological hydrogen storage, such as pressure vessels and pipeline linepack, and geological hydrogen storage such as salt caverns and depleted gas fields, that is location dependent. 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.

In addition to capital cost another key techno-economic consideration is cycling constraints (the number of times a storage can be emptied and refilled within a defined time period). Storage such as pressurised containers and linepack can achieve daily cycling whereas underground geological hydrogen storage can only achieve monthly to annual cycling. Despite lower capital costs, cycling constraints may limit the potential value of geological hydrogen storage to a green hydrogen value chain due to the intermittency of wind and solar PV generation.

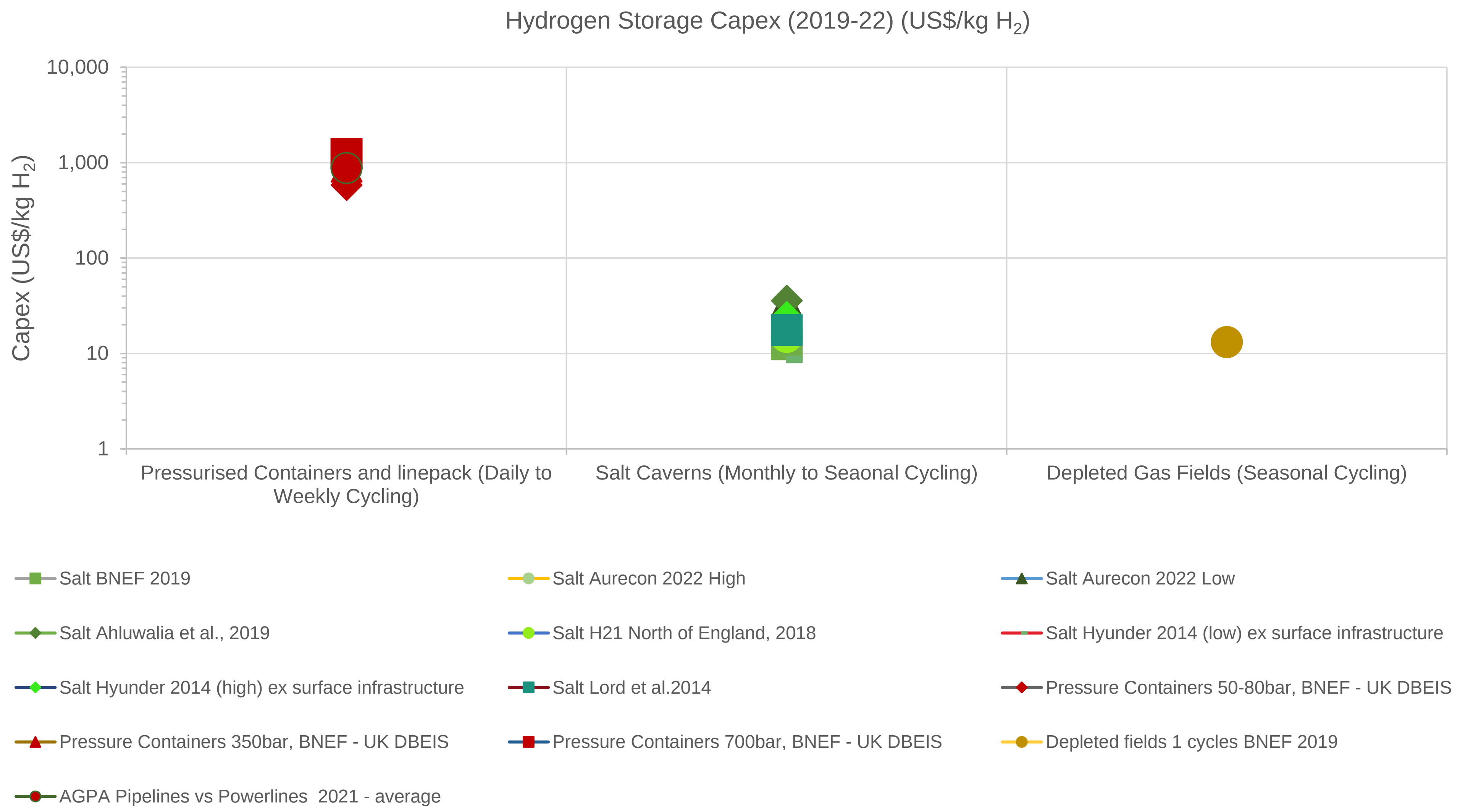

Figure 22: Hydrogen gas storage costs for different storage types (capex per kilogram H_2). Current prices (2019-22)

4.3.2.3 Compression requirements

Hydrogen produced from an electrolyser is in a gaseous state at pressures between 0-30bar, depending on the type of electrolyser used. Additional compression is generally required to transport hydrogen via pipeline (~70bar) and for storage purposes. This additional compression requirement incurs energy losses (e.g. using a standard compressor).

Figure 4 shows the energy losses as a fraction of hydrogen's lower heating value (LHV, 33.3 kWh/kg) that will incur during additional compression required for different pipeline and storage types.

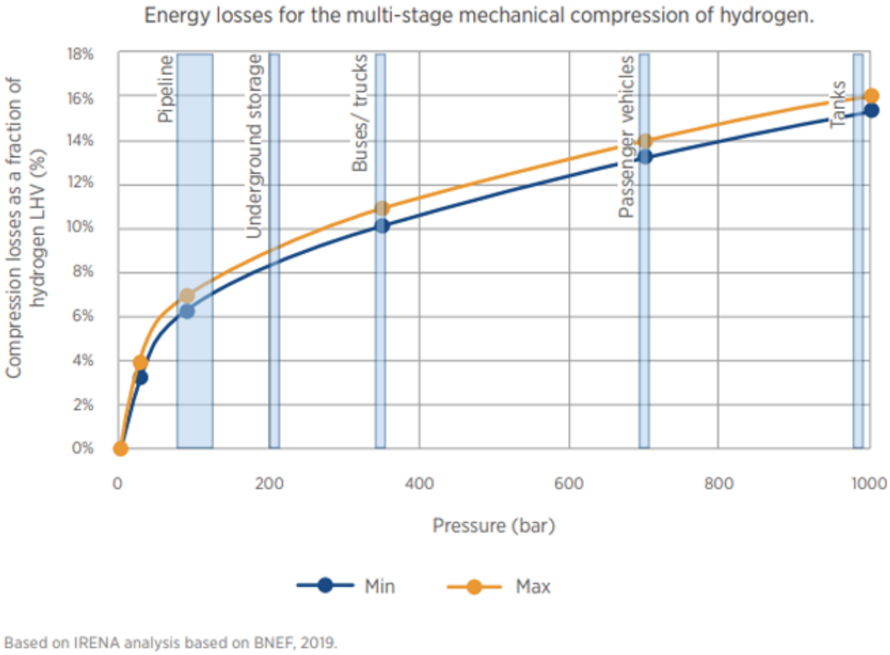

Figure 23: Energy losses for the multi-stage mechanical compression of hydrogen | Source: Based on IRENA analysis based on BNEF, 2019

4.3.2.4 Non-Geological storage - Pressurised Containers and Pipelines (linepack)

Hydrogen gas is currently stored in pressurised containers at pressures between 50-700bar, with working capacities between 1-1,100kg per container. Four container types exist which have different pressure capacities depending on their construction material. Containers are gradually increasing the total mass of hydrogen able to be stored. Containers are highly versatile and can be cycled frequently (multiple times daily) but are unlikely to achieve large scale storage due to high capital costs. Capital costs vary between container types, with large decreases in recent years attributed to reductions in the carbon fibre material input.

Dedicated buried pipe storage and linepack storage within pipelines offer a similar storage capex per kg hydrogen to pressurised containers. Over a 60-bar pressure range, a 1 km pipeline with a diameter of 1 m can provide buffer storage for around 3.5 t of hydrogen, equivalent to 138 MWh by HHV.

4.3.2.5 Geological storage - aquifers

Aquifers are porous and permeable media in the subsurface that host fresh or saline water in their pore spaces and have similar geology to depleted oil and gas fields. Examples exist of gas storage in aquifers which illustrates their potential to store hydrogen in the subsurface. In order to host hydrogen successfully, aquifer host rocks must contain high porosity and permeability and the existence of an overlying cap rock to contain the gas. Unlike depleted oil and gas fields which have a proven ability to contain gases, aquifers have additional challenges to prove their suitability to host hydrogen. Biochemical reactions, potential fault leaks, and hydrogen reactions with the host rock minerals can all lead to issues for hydrogen storage operations. Aquifer storage requires higher upfront capex than depleted oil and gas fields, due to the exploration and study required to uncover their subsurface geology and the lack of surface infrastructure in place.

4.3.2.6 Geological storage - depleted oil and gas fields

Depleted oil and gas storage may be able to be repurposed to store hydrogen. They have suitable subsurface geology with a proven capability to store large volumes of gas in porous sandstone reservoirs over long time periods. When converting to a hydrogen storage facility, existing infrastructure (e.g. surface compressors and infrastructure, wellbores) reduce the upfront capital expenditures required for commissioning. Residual gas in the sandstone reservoir unit can act as cushion gas which further reduces upfront capex, however this gas can reduce the purity of hydrogen through mixing. Processing of gas on the surface is required, with infrastructure required to bring the hydrogen to export quality.

Depleted oil and gas reservoirs are suitable for seasonal storage (bi-annual to annual cycling) of gases due to their large volume capacity. Their historical withdrawal rates are well understood and have been assumed to be less than underground salt cavern. A comprehensive study is required prior to conversion to hydrogen storage in order to understand hydrogen's interaction with any residual hydrocarbons in the reservoir and any potential hydrogen losses through the reservoir and caprock due to hydrogen's lower density and higher diffusivity.

4.3.2.7 Geological storage - salt caverns

Underground salt caverns are engineered structures and are considered the ideal long term hydrogen storage technology given their desirable characteristics including large volumes, monthly cycling frequency, high stability, and low capex.

Figure 24: Salt cavern cross section | *Source: Geoscience Australia (2022).*

Underground caverns are constructed via solution mining where large volumes of water are pumped into the subsurface via a borehole to dissolve the salt. Specific geology needs to exist for caverns to be constructed, specifically large subsurface salt diapirs or thick bedded salt accumulations. Given this, salt cavern locations are limited and can only exist where the appropriate geological conditions exist. Underground hydrogen salt storage sites currently operate at a small number of sites across the UK and the United States. These sites have volumes between 70,000 – 900,000m3 with working gas capacities between 1000-10,000 tonnes (27-274 GWh).

Field / Project	Storage Type	H_2 (%)	Pressure (bar)	Depth (m)	Volume (m^3)	Capacity (MWh)	Capacity (tonnes)
Teeside (UK)	Bedded Salt	95%	45	365	210,000	27,000	810
Clemens Dome (USA)	Salt Dome		70-137	1000	580,000	81,000	2430
Moss Bluff (USA)	Salt Dome	95%	55-152	1200	566,000	123,000	3690
Spindletop (USA)	Salt Dome	95%	68-202	1340	906,000	274,000	8220

Table 5: Current operating underground hydrogen salt storage sites | *Source: Zivar, D., Kumar, S. and Foroozesh, J., (2021) and H21 (2018)*

Salt caverns are generally constructed at subsurface depths of ~0.5-2km and operate at a pressure range of ~45-275bar, depending on cavern depth and volume of hydrogen it contains. Hydrogen is compressed at the surface and injected into these caverns in a gaseous state. Higher pressures increase the stored capacity of a cavern with caverns having approximate working capacities of ~300-10,000 tonnes (10-333 GWh).

Salt caverns have ideal mechanical properties for storing hydrogen, including rock salt's (halite) physical tightness and chemically inert nature which prevents hydrogen losses. Salt caverns' environments have the potential for abundant microbial activity. Microbes may already be present within caverns or introduced during the dissolution of a cavern or during injection and withdrawal cycles. Subsurface microbes can metabolise H2 gas, leading to issues including H2 loss, hydrogen sulfide formation, methane formation, acid formation, clogging and corrosion of pipe infrastructure.

The physical stability of salt enables storage over short to long (inter-seasonal) time periods with injection and withdrawal rates sufficient to achieve monthly cycling, with the literature typically assuming a limit of 10-12 cycles annually. The H21 North of England report modelled salt cavern storage that matched demand and achieved four cycles per year (30 day withdrawal (minimum 19 days), 60 day injection,). Table 2 outlines the technical parameters of a single salt cavern in the study.

Withdrawal and injection rates need to be considered to limit thermo-mechanically induced stress in the salt structure. The change of cavern pressure over time is typically limited to approximately 10 bar/day based on natural gas storage experience. The flow velocity is also constrained to limit vibrations and erosion within the tubing. For gaseous media, values of 20 – 30 m/s are assumed. From a rock mechanical point of view, alternating withdrawal and injection are advantageous because the injection compensates the cooling inside of the cavern due to withdrawal and therefore, reduces thermal effects. Detailed rock mechanical modelling is required to determine the appropriate withdrawal and injection rates.

Field / Project	Pressure (bar)	Volume (m^3)	Working Capacity	Depth (m)	Withdrawal rate (30 days)	Injection rate (60 days)	Annual Cycles	Max Withdrawal Rate (10 bar)
H21 North England	85-275	300,000	144 GWh (4320 tonnes)	1700 - 1800	4.8 GWh/d (144 tonne/d)	2.4 GWh/d (72 tonnes/d)	4	7.5 GWh/d (225 tonnes/d)

Table 6: H21 North of England report – Single salt cavern design parameters | *Source: H21 (2018)*

Construction of subsurface caverns requires dissolution of large volumes of subsurface salt using water. The water requirement to create these salt caverns is significant, with an approximate water volume eight times greater than the volume of salt removed. This poses two significant challenges to salt cavern construction: a location near a readily available water source and an ability to dispose of significant volumes of brine in an environmentally acceptable way. If the salt cavern site was located close to the coast this could involve transporting brine to the ocean, however if inland it is likely that the brine would need to be desalinated and the salt disposed of. Desalination may reduce the quantity of water required considerably. Sourcing water and treating or disposing brine are two aspects that need to be carefully managed to maintain an acceptable social license to construct and operate subsurface salt cavern hydrogen storage. Capital expenditure for greenfield salt cavern storage is typically higher than depleted oil and gas fields, predominantly attributed to exploration and construction costs. Most cost estimates include cavern construction, site preparation, surface facilities (including compressors, gas dehydration equipment, downhole pipes), brine disposal, cushion gas, and other miscellaneous costs. Cushion gas refers to hydrogen gas that is required to remain within a cavern throughout operations to maintain a minimum pressure and generally accounts for a third of the capacity of a cavern. Hydrogen gas in excess of the cushion gas is referred to the working capacity and is the usable gas injected and withdrawn during operations. On the basis that the cost of green hydrogen production will decrease in the future, the cushion gas cost exposure will be reduced. Figure 5 shows present and future capital expenditure estimates for subsurface salt caverns in the future.

Operational expenditure costs have been assumed at 4% of the total capex cost in some studies. Electricity is a key contributor to the operating expenditure costs. An increase in cavern cycling frequency leads to a higher electrical demand to operate pumps, compressors and to run dehydration equipment for water separation from the hydrogen gas prior to delivery.

4.3.2.8 Potential Queensland salt caverns – Adavale Basin

The Adavale Basin in central Queensland contains one of the few laterally extensive and thick subsurface rock salt deposits in Australia, the Boree Salt. It is located on the eastern edge of the basin and is estimated to be several tens of cubic kilometres in volume. The Boree Salt comprises salt deposits from the Devonian period (about 400 million years ago), and it is predominantly halite (NaCl) >90% with minor dolomitic limestone, anhydrite and clastic sediments. The thickest section of Boree Salt found to date is 555 m starting at 1800 m below ground. Although only six wells have intersected the Boree Salt, a recent model of the salt developed by Geoscience Australia using seismic data suggests that the shallowest depth is approximately 1200 m. These characteristics suggest that the Boree Salt could be suitable for salt cavern construction.

The Boree Salt is generally deeper than existing operating hydrogen storage caverns in the US and Europe, though feedback from industry experts is that it is not as deep as some operating natural gas storage caverns. The greater depth could lead to relatively higher construction capex per cubic metre during development of each cavern, though this may be somewhat offset by higher allowable pressures at lower depth. Other challenges include the substantial water requirement for solution mining and the resulting brine which will likely need to be desalinated before the salt is disposed of.

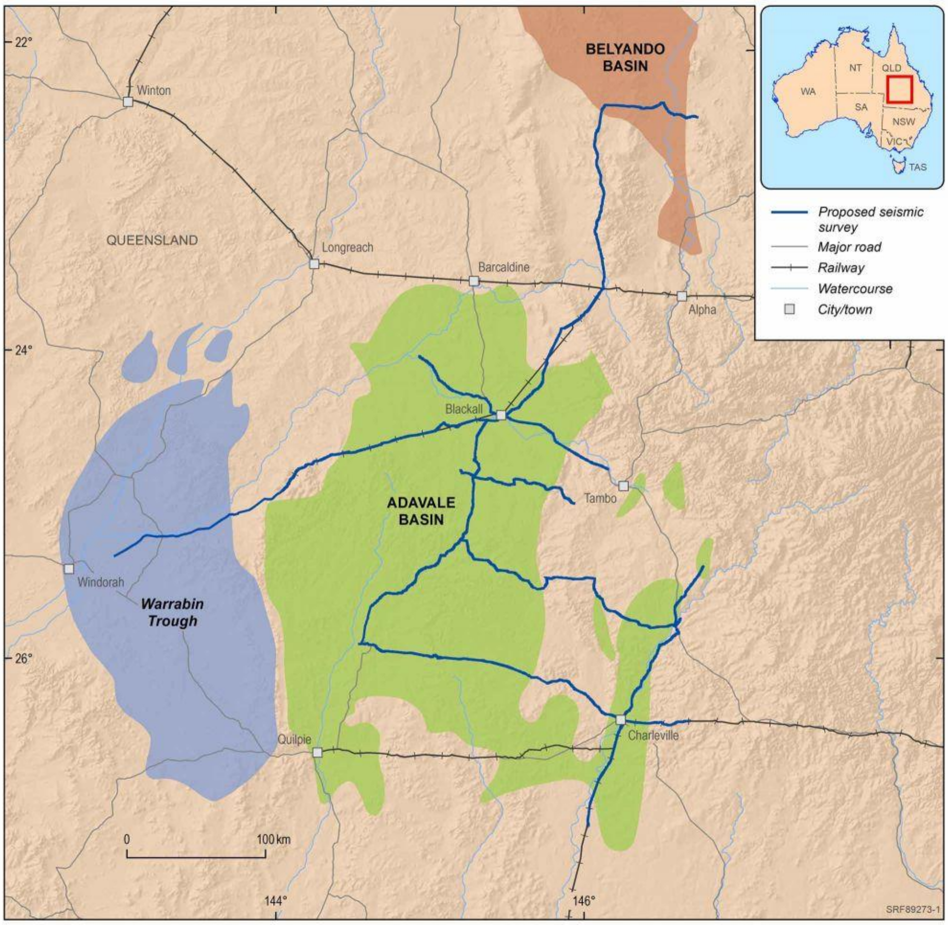

Figure 25: Adavale Basin map - seismic acquisition survey | *Source: Geoscience Australia (2023)*

4.3.3 Ammonia

Ammonia storage currently exists at industrial scale throughout the world. Given the toxic nature of ammonia, storage occurs at industrial sites usually in large tanks. It is also stored on farms, particularly in the United States, where it is used directly. At industrial scale it is stored in liquid form under atmospheric conditions and temperatures of -33˚C where it contains an energy density of 5.2MWh/t based on the lower heating value of ammonia[6]. A 50,000-tonne ammonia tank constructed for Qatar Fertiliser Company had a 50m diameter and 40.5m height. Tanks are typically single or double walled with refrigeration capabilities and are often built off the ground to avoid the ground freezing. H21 North of England report (2018) outlines the capex included for an ammonia inter-seasonal storage concept which includes an ammonia synthesis unit, ammonia storage unit, and ammonia cracker unit. The storage facility included 5 x 55,000 tonne ammonia tanks (49,500 tonnes H_2 by mass), which store 1.43 TWh of energy based on ammonia's lower heating value of 5.2MWh/t NH_3. Capex for the storage tank construction alone was estimated at £222m ($435m at 0.51 AUD/£) which is approximately equivalent to $1,600/t NH_3 or $330/MWh. Feedback from Australian industry sources suggest that the total capex for an installed ammonia tank could be 3-4x this cost estimate.

[6] *The higher heating value of ammonia is 6.25MWh/t NH_3*

Figure 26: 15,000 tonne liquid ammonia tank | *Source: thyssenkrupp Uhde*

Traditional end-product markets for ammonia have been fertiliser, particularly Urea and ammonium nitrate explosives. These end-products are substantially lower cost to store than ammonia as they are solids, though additional production processes are required.

4.3.4 Methanol

Methanol is a corrosive and highly flammable chemical that is predominantly stored in cylindrical austenitic or carbon steel storage tanks. Methanol does not require refrigeration to store as a liquid at atmospheric pressure. Reliable capex estimates for methanol were unable to be sourced. Australian industry feedback is consistent with the intuition that methanol is lower cost to store than ammonia.

Figure 27: Above ground methanol storage tank | *Source: Methanol Institute (2023)*

4.3.5 Liquid Hydrogen

Boil-off of liquid hydrogen occurs due to the large differential in temperature between the environment and liquid hydrogen (-253˚C). Boil-off losses can be ~0.1-0.5% per day (31-84% annually) in the most efficient liquid hydrogen tanks. This phenomenon makes liquid hydrogen a poor energy vector for long term storage.

H21 North of England report (2018) estimated the cost to store 1.5TWh of liquid hydrogen for inter-seasonal storage facility. The facility estimate was inclusive of purification, liquefaction, storage, regasification. The storage component included 180 x 3000m^3 spherical liquid hydrogen storage tanks which contain approximately 38,000 tonnes of liquid hydrogen. Each tank had an estimated diameter of 18m and required an area of 500m^2. Capital estimates of this quantum of storage was £4.5B ($8.82B at 0.51 AUD/£) which is equivalent to $5900/MWh, considerably more expensive than ammonia storage.

Figure 28: Liquid hydrogen storage vessel | Source: National Aeronautics and Space Administration (2015)

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5 Hydrogen Conversion Processes Information Sheet

5.1 Introduction

Although hydrogen has the highest gravimetric density of all fuels, its volumetric density is low under normal conditions. Therefore, if the use case is fuel, it is generally more economic to 'upgrade' hydrogen into a derivative than to use hydrogen as a gas if long-term storage or long-distance transport are required. The hydrogen derivative itself may have value for non-fuel use cases such as input into industrial chemical processes, such as the production of fertilisers and explosives from ammonia. This information sheet describes several upgrading processes, and significant factors which need to be considered.

Four conversion processes have emerged as prime contenders for carrying hydrogen: liquid hydrogen (LH_2); ammonia (NH_3); Liquid Organic Hydrogen Carriers (LOHCs); and synthetic hydrocarbons. All four of the converted molecules described here are sometimes referred to as e-Fuels (because of their electrical origin) or syn-fuels, and the processes which produce them are sometimes referred to as Power-to-X (P2X) processes.

The highest efficiency application of hydrogen fuels is direct on-site consumption because storage, transport, and upgrading processes all require input energy, and typically capital investment. Selection of a suitable upgrading process must consider the costs and efficiencies over the entire value chain, from upgrading, to transport, to application.

In general, upgrading hydrogen will be cheaper if the upgrading process can operate flexibly, such that during periods of low energy generation at the production site, it can reduce its consumption of both hydrogen and power. Where flexible operation is not possible, hydrogen storage and back-up power are required to maintain consistent operation.

Table 3 summarises the advantages and disadvantages of the four carriers, which the information sheet explains in more detail.

5.2 Upgrading Processes

Because it is a very light molecule, hydrogen is gaseous under normal conditions, and very low temperatures (-253°C) are required to liquify it. There are several liquefaction cycles described in the literature; the process in general requires (i) some pre-cooling using a cryogenic liquid, (ii) a reaction stage to convert ortho-hydrogen into para-hydrogen, and (iii) a series of gas compression and expansion stages which achieves the final cooling to the boiling point. The energy intensity of this process is high, in the order of 12 kWh/kg[7]. As technology develops, efficiency improvements are forecast which would reduce the energy requirements to around 6 kWh/kg. Historically, this process has only been performed at small scales, predominantly with applications in space transport; scale-up has yet to occur.

[7] *The maximum energy available to hydrogen on combustion (lower heating value) is 33.3 kWh/kg, and hydrogen production requires approximately 52.5 kWh/kg assuming 75% electrolyser efficiency.*

Carrier	LH2	NH3	LOHC	Synthetic Hydrocarbons
Advantages	Pure state means end use is straightforward; High energy density by weight; No additional raw materials required	Synthesis from gaseous hydrogen is well understood; High density by volume; Mild storage conditions No additional raw materials required; Value chains are well-established	Energy efficiency can be high if waste heat is available to recover the hydrogen at the demand site; Existing value chains for oil can be exploited with limited adjustment; mild storage conditions	Existing value chains can be exploited
Disadvantages	Very cold temperatures make storage expensive; Low density by volume; Highly explosive	At present difficult to use as ammonia in some energy applications; energy efficiency can be low if cracking back into hydrogen is required; toxic	Availability of some organic carriers may be low; shipping complexity is increased by the need to return the carrier to the production site; energy density by volume and weight is not always good	Economics and efficiency of CO_2 extraction from air are very poor in at least the medium term; other CO_2 sources may not be considered green
Technical development expected or required	Improvement in liquefaction efficiency (energy losses expected to halve). Production at scale	Little expected or required due to maturity of technology	Selection of optimum carriers; catalyst improvement may enable dehydrogenation at lower temperatures	Reduction in costs and energy consumption of carbon capture from direct air capture would be necessary to enable this technology on large scales.
Best use cases	Energy storage on days-weeks timescales; applications requiring very pure hydrogen (e.g. fuel cells)	Fertiliser and explosives; Maritime Fuel; Energy storage and generation on seasonal time scales	Industrial applications where waste heat is available; long distance hydrogen transport for energy applications	Maritime fuel; Complex value chains which cannot be rapidly transitioned

Table 7: Summary of advantages and disadvantages of potential hydrogen derivatives

Synthesis of ammonia from hydrogen is the second-most widely conducted chemical process in the world, with an approximate global production in the order of 180 million tonnes each year (mostly used as fertiliser). Ammonia synthesis relies on the Haber-Bosch process, which fixes nitrogen (the main constituent of air) onto the hydrogen. This significantly increases its density, forming a liquid at -33°C, which is easy to achieve using conventional refrigeration techniques. The density of hydrogen in liquid ammonia is higher than the density of liquid hydrogen itself; ammonia has around 120 kg of hydrogen/m^3, whereas liquid hydrogen only holds around 70 kg/m^3. The energy demands of the Haber-Bosch process are quite low – around 0.3 kWh/kg of hydrogen; however, the process of production is exothermic, and typically around 3.7 kWh/kg of hydrogen are lost as process heat.

Traditional end product markets for ammonia have been fertiliser and ammonium nitrate explosives, NH_4NO_3, that does not include a carbon element. Depending on soil conditions the ammonia may be used directly as a fertiliser, however it is more commonly synthesised with CO_2 to produce urea, CH_4N_2O, a high nitrogen fertiliser. For grey ammonia production, the steam reformation process provides the carbon source required for the urea synthesis process. For green fertiliser carbon sources could include industrial carbon emissions, or the by-products of biomass combustion, although the sustainability of both of these sources is not guaranteed. Direct air capture (DAC) is more widely considered to be sustainable but comes at high costs in at least the medium term.

Liquid organic hydrogen carriers are comparatively heavy molecules onto which hydrogen can be 'loaded' through a simple (exothermic) catalytic chemical reaction; the hydrogen is then transported as a liquid and 'unloaded' at its destination (endothermically). The carrier molecule is then returned and reused. The performance of Liquid Organic Hydrogen Carriers depends on the specific carrier under consideration, and different carriers will be better suited to different duties. In general, it is preferable to have: low heats of reaction (to avoid the need for significant energy inputs at the destination); high hydrogen densities by weight and volume; low toxicities; and low capital costs.

Synthetic hydrocarbon production is an umbrella term for a large number of sub-processes which could produce conventional fuels, such as methane (CH_4, the core component of natural gas), or methanol (CH_3OH). The processes for producing these fuels are similar to that used to produce ammonia: carbon and, in some cases, oxygen, molecules are fixed onto the hydrogen in order to densify them using a catalytic reaction process. The core difference between ammonia and synthetic hydrocarbons at the production stage is the requirement in the latter case for a carbon source. This is a similar issue as for producing green fertiliser from green ammonia, however brownfield ammonia facilities that have both grey and green ammonia plants provide the potential benefit of providing a low-cost CO_2 source from stream methane reformation (grey hydrogen production). The overall energy demand for synthetic hydrocarbons depends strongly on the carbon source, and the composition of the target molecule.

In all cases, upgrading fuels into carrier molecules is an exothermic process, meaning heat is released, a major source of inefficiency if the heat sink is the environment, rather than another process. Recapturing the heat is most difficult in the case of liquid hydrogen, which needs to release energy into ambient or near-ambient temperatures, which likely limits applications for heat recycling to district heating networks in cold climates and is not relevant to Australia. Other upgrading processes release energy as high grade heat, typically at a temperature which is sufficient to raise steam. Beyond district heating, this energy could be used in nearby industrial applications, or to reduce the energy demand for hydrogen production, if a solid oxide electrolyser cell is used (see the electrolysis information sheet).

5.3 Firmed power requirements

Hydrogen upgrading is typically less flexible than hydrogen electrolysis, because of either (i) extreme temperatures, or (ii) chemical reactions, which need to be controlled at a constant rate or within an allowable range to operate safely. These hydrogen upgrading processes require a supply of both hydrogen feedstock and power. To minimise firmed power requirements, hydrogen storage is required as a buffer between the high-flexibility upstream electrolysers and the lower flexibility downstream processes. If there is a limitation on hydrogen storage (for instance, because of land restrictions at the operating site), then the upstream electrolysers must also be supplied with some firmed power to enable continuous downstream operation. For a GW scale export plant, these firmed power requirements would be several hundred MW, and would pose a significant burden to local energy systems or require significant amounts of expensive battery storage.

The remainder of this section assumes an adequate amount of hydrogen can be stored and focusses only on firmed power requirements to maintain power supply to downstream facilities. The performance of the two technologies considered is compared in Figure 4.

5.3.1 Hydrogen Liquefaction

Hydrogen liquefaction relies on very low temperatures (-253°C). If a plant operating under these conditions is stopped, and operating material temperature increases, then: (i) its lifetime may be reduced by significant thermal cycling, and (ii) long delays may occur in start-up times as the equipment is returned to cryogenic conditions. The precise extent of turn-down is not well understood, as these plants have not been operated widely, though it is expected to be significantly less flexible than hydrogen derivatives that rely on catalytic synthesis processes. Current liquefaction plants consume around 12 kWh/kg of electricity (for comparison, the thermodynamic minimum achievable energy input required to produce hydrogen from liquid water is 39.4 kWh/kg). The precise firmed power requirements depend on the variable renewable energy profile in question, but in general a GW scale electrolyser facility would need in the order of 100 MW of firmed power to continuously operate the hydrogen liquefaction plant. (assuming that the electrolysers themselves have no firmed power requirement).

5.3.2 Hydrogen Derivatives

Although plants which synthesise ammonia, methanol and other hydrogen derivatives are well-understood technologies, they are not able to adjust their operation to perfectly match the renewable weather profile; in other words, they are only partially flexible. The reason these plants have a degree of inflexibility is that the reactions which synthesise derivatives from hydrogen are exothermic (i.e. they release energy). This means they require an ongoing minimum operating rate to sustain temperature. However, the electricity input requirements to these plants are low (compared to the upstream electrolyser and compared to a hydrogen liquefaction plant). Although technology development may improve the flexibility of hydrogen derivative production, large-scale production without perfect flexibility is likely to be required to some extent in the coming decades.

The synthesis of ammonia from hydrogen, which occurs using the Haber-Bosch (HB) process, is a promising option for the purpose of large-scale hydrogen derivative production. Table 4 summarises some high-level, rule-of-thumb values which can be used for estimation of ammonia cost.

There are a range of estimates for how flexibly the HB process can operate, but it is typically predicted to be able to operate at between 10 and 40% of its nameplate capacity (in MW). This turndown rate is measured by the rate at which hydrogen is fed to the plant, which is directly proportional to the rate at which ammonia is produced. Although the firmed power requirement of the HB plant will reduce as the hydrogen feed falls, it may not fall by the same amount, to a minimum of around 50%.

Feedback from Australian industry sources suggests that there may be some trade-offs between the capital cost of plants and turndown rates. However, the ammonia plant represents a small proportion of total green ammonia value chain capex, and modelling previously undertaken has shown that reducing turndown rates to below 50% of maximum capacity has limited impact on ammonia production costs.

The flexibility of synthetic hydrocarbon production, particularly methanol is not well covered in academic or industry literature. Given it is a catalytic synthesis process, methanol has similar potential to ammonia for partially flexible operation. However development in the methanol industry lags that of the ammonia industry.

For one ton of ammonia production, the electrical HB process requires approximately 1 MWh of electricity. One ton of ammonia requires about 180 kg of hydrogen, which has an energy value of 7.1 MWh (on a higher heating value basis); the one ton of ammonia produced has an energy value of 6.25 MWh (also on the HHV). These energy flows are shown in more detail on the Sankey Diagrams in Figure 29.

Some rule of thumb figures for estimation of ammonia production cost and efficiency. Exact figures will vary significantly between vendors and should be checked on a case-by-case basis. The scope of the HB plant includes an electrically-powered air separation unit.

Parameter	Unit	Value
HB CAPEX	USD/annual t of production capacity	700
	million USD/MW effective energy input	0.5-0.65
Hydrogen consumption for ammonia production	t hydrogen/t ammonia	0.18
	MWh hydrogen per t ammonia	7.1 HHV 6.0 LHV
HB electricity demand	MWh/t ammonia	1
HB total energy demand (excluding energy lost during H_2 production)	MWh/t ammonia	8.1 HHV 7.0 LHV
HB total energy demand (including energy lost during H_2 and NH_3 production)	MWh/t ammonia	10-11
HB minimum rate as a fraction of rated (nameplate) capacity		-0.1 - 0.4
Minimum power consumption as a fraction of power capacity		-0.5

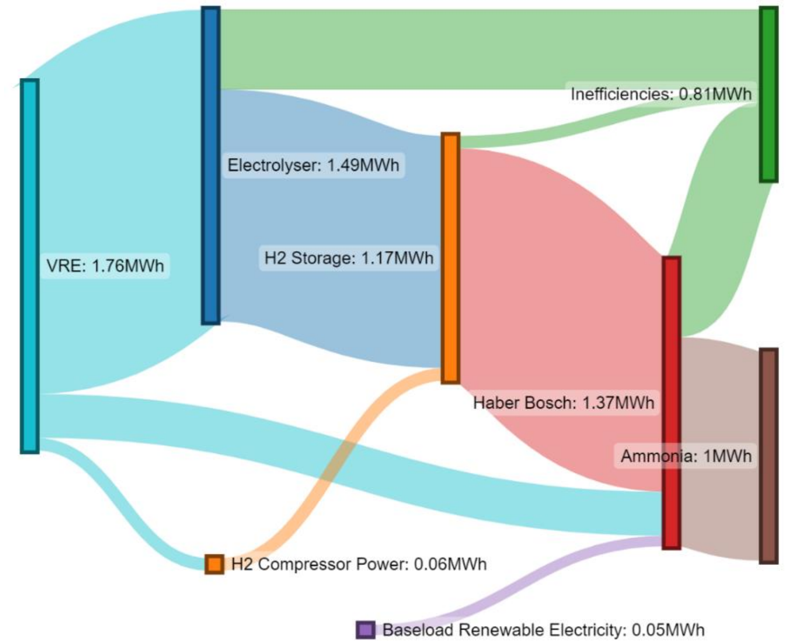
Table 8: Estimation of ammonia production cost and efficiency

Because the firmed power requirements for these plants are quite low, it is generally possible to supply firmed power using in situ energy storage, which comes either from a battery, or from a hydrogen fuel cell which cannibalises some of the stored hydrogen.

Although hydrogen production in general has very low firmed power requirements, the requirements for firmed power may be larger if upgrading is required. Although hydrogen liquefaction is slightly more energy efficient than other processes for upgrading hydrogen, it has higher baseline energy requirements, because a larger fraction of the process inefficiencies originates with firmed power, rather than variable power.

Ammonia is used as an example chemical fuel; synthetic hydrocarbons will be similar, although may be significantly less efficient depending on how the carbon is obtained. Note values are approximate and based on present day energy efficiencies. Where energy flows are of a material (i.e. hydrogen), then they are converted to energy flows using the HHV.

Green ammonia production – Energy flows



Green hydrogen production and liquefaction – Energy flows

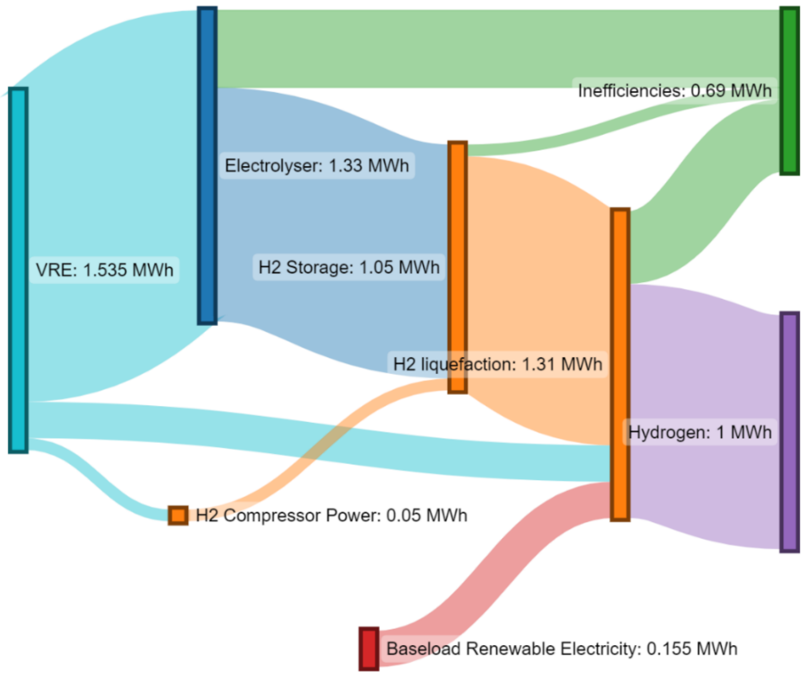


Figure 29: Comparison of energy flows for Liquid Hydrogen and Chemical Fuels, normalised to 1 MWh of fuel production

5.4 Firming technology

Batteries may be a useful in providing firmed power for hydrogen upgrading process minimum loads, particularly for islanded operations. Whether batteries will be the best technology depends on the relative cost of batteries compared to other back-up forms of energy supply, such as hydrogen fuel cells. Most other forms of back-up energy supply store energy less efficiently than batteries, but at a lower cost. Case-by-case analysis of hourly renewable generation traces, and equipment cost estimates are required to decide if a battery is a suitable choice of equipment.

5.5 Storage Considerations

With the exception of liquid hydrogen, all carrier molecules discussed in this information sheet are easily stored by conventional means. Ammonia tanks typically include a refrigeration cycle to manage the low-rate of boil-off which occurs from the tanks, synthetic methane may be stored as liquid natural gas and methanol stored in tanks; these technologies are widely understood and deployed today. These technologies are suitable for large scale energy storage in the order of hundreds of GWh. Ammonia has potential additional safety requirements compared to other hydrogen derivatives due to its toxicity.

However, because liquid hydrogen is stored at very low temperatures, storage is more complex. This typically involves storage in spheres which have a lower surface-area-to-volume ratio than other shapes, although they are more expensive to construct. The largest hydrogen sphere in the world holds less than 4% of the hydrogen which is stored in a conventionally sized ammonia tank. Minimising the boil-off rate of these tanks is important, as rates of 0.5-1% per day are common, which is not suitable for long-term storage or transport. It is important to minimise the leakage of hydrogen at this point, as the greenhouse gas potential of uncombusted hydrogen is around 10 times that of carbon dioxide on a mass basis (although this figure has a high degree of uncertainty). Leakage of this light fuel during loading and unloading of ships may also be significant.

5.6 Transport Considerations

In general, carriers with higher hydrogen densities are preferable during transport. Higher gravimetric densities reduce the energy costs of transport, while higher volumetric densities typically enable more hydrogen to be transported in a single tanker.

For land transport, all carriers can be transported by pipeline, which is the only economic means to do so at any industrial scale. The exception is liquid hydrogen, which would evaporate due to high pipeline surface area; in that instance, hydrogen needs to be transported as a gas and liquified at the port (which may also require the installation of transmission lines to deliver electricity to the liquefaction plant).

For ocean transport, oil tankers can be used for LOHCs and liquid synthetic hydrocarbons (e.g. methanol); gas carriers can be used for ammonia, and LNG ships for synthetic methane. Synthetic hydrocarbons typically have the best volumetric energy density (4-6 kWh/L) depending on the carrier), followed by ammonia (3.5 kWh/L), with LOHCs usually the weakest performing (between 1 and 3 kWh/L).

Again, liquid hydrogen (which has an energy density of 2.7 kWh/L) requires special treatment because of its very low temperature. The first commercial scale liquid hydrogen was shipped from Australia in 2022 using a vessel designed by Kawasaki; it carried 87.5 tons of hydrogen, which is less than 1% of the energy content of a very large carrier transporting a cargo ammonia. Technology expansions are intended to scale up these ships to carry around 11,000 tons of hydrogen, which would be around 85% of the capacity of the largest ammonia ships.

Each of the vessels in question will cannibalise some on-board fuel to power the ship. This may be a suitable use of boil-off hydrogen that would otherwise be lost.

5.7 Use Considerations

Liquid hydrogen and synthetic hydrocarbons can be used directly as energy sources in broadly conventional ways – i.e. through combustion or in a fuel cell. Before it can be used directly, the hydrogen from LOHCs needs to be unloaded from the carrier molecule through catalytic decomposition at elevated temperatures. Depending on the carrier, it may be possible to achieve this decomposition using waste heat from an industrial process or gas turbine; otherwise, the efficiency of this process can be quite low.

The most common uses cases for ammonia do not require conversion back into hydrogen: direct use as a zero-carbon fertiliser, input into the production of other fertiliser products, input into explosive production, potential fuel in the maritime industry and potential fuel/reductant for the direct reduction of iron in steelmaking. For dispatchable energy applications, turbines are emerging which enable the direct combustion of ammonia. At present, however, combustion research focusses on 70% ammonia - 30% hydrogen mixtures, which have similar flame properties to natural gas. This requires a fraction of ammonia to be 'cracked' back into hydrogen, for which heat is required, typically at a temperature of around 500^{o}C, although emerging catalysts may enable this to be achieved at lower temperatures.

Complete cracking of ammonia into hydrogen is highly energy intensive, consuming almost 9 kWh/kg of hydrogen. It is therefore unlikely that cracking will be used unless strictly required, for instance for the green steel sector, or for hydrogen fuel cell vehicles. Achieving acceptable hydrogen purity in cracked hydrogen is a major challenge, as the input requirements for fuel cells are stringent.

5.8 Capital cost estimates

Given it is the most common hydrogen upgrading process, publicly available capital cost estimates for ammonia plants are more prevalent. Ammonia plants are typically single-train facilities that exhibit significant economies of scale, with academic literature pointing to lowest capital cost estimates of US$700/tonne NH3 achieved at around 1 million tonnes pa or greater.

At its June 2022 Capital Markets Day, Yara, a leading global fertiliser producer, provided a capex estimate of US$800m for a generic 1 million tonne pa green ammonia plant located in the Middle East. It is noted that Australia is likely to have materially higher labour costs and standards and equipment freight costs than the Middle East.

In April 2013 Incitec Pivot's brownfield 800,000 tonne pa grey ammonia plant expansion located in Louisiana (US) had an estimated capital cost of $US850m. It is noted that this cost estimate is 10 years old and is for a grey ammonia plant and includes infrastructure not required for a green plant such as methane steam reformer.

Financial close for the Perdaman grey urea project located 20km north of Karratha in the Pilbara region of Western Australia was reached in April 2023. The plant is expected to produce 2.3 million tonnes of grey urea a year, which equates to 1.3 million tonnes of grey ammonia production. The capital costs are estimated to be A$6bn, however it is noted that this includes the methane steam reformer (hydrogen production), ammonia and urea synthesis and potentially common user water and port infrastructure.

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6 Transport Information Sheet

6.1 Hydrogen pipelines vs. electricity transmission

6.1.1 Introduction

Hydrogen pipelines, ammonia pipelines, standalone transmission and connections to Powerlink's transmission network are the key transport infrastructure options for an export scale hydrogen value chain. This information sheet provides a comparison of the capital cost and other key attributes of the two most likely transport alternatives, electricity transmission and hydrogen pipelines.

6.1.2 Capital costs estimates

Based on the industry sourced input assumptions Figure 30 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 30 demonstrates that hydrogen pipelines may be materially lower cost than standalone transmission at all capacities. The chart potentially underestimates the cost gap as:

- In order to allow cost comparison based on similar reliability levels hydrogen pipelines capex estimates should be compared to standalone (radial) electricity transmission capex estimates somewhere in the range between an N and N-1 basis. In addition, the above ground nature of overhead lines may make electricity transmission more susceptible to extreme weather events.
- Transmission lines carry electricity, while hydrogen pipelines transport energy in the form of green hydrogen that has been subject to electrolyser efficiencies of 80%-90% of HHV based on the modelling timeframe of 2030 to 2050. Hence for a true like–for–like comparison, for the purpose of a green hydrogen value chain transport, electricity transmission capacity should be increased 11%-25%.
- Transmission has step changes in capacity as voltage level change which may not be practical for a project to fully utilize. Pipeline diameters should be customisable for a project and excess capacity can allow for future project expansion and/or can be used as linepack storage.

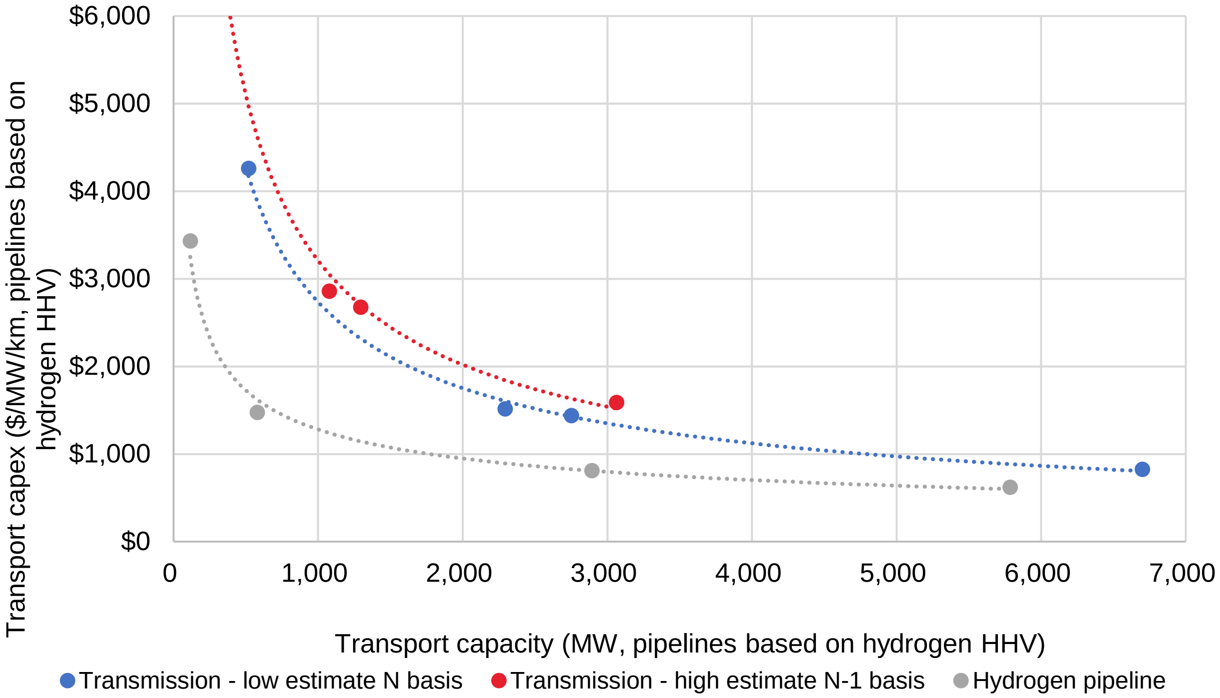

Figure 30: Capex vs. capacity for 250km transmission and one way hydrogen pipelines | *Data source: Australian Gas and Pipeline Association. (2021), 2022 AEMO Transmission Cost Database (2023)*

Ammonia pipelines are not considered in this analysis as it is assumed that there would be value in transporting hydrogen to a range of different users. Industry feedback is that there is significant social license risk associated with ammonia pipelines in Queensland due to environmental and safety concerns.

Absent an operating model that allows network charges such as TUOS to be minimised, connection to Powerlink's network may be considerably higher cost than hydrogen pipelines and standalone (radial) transmission. Assuming future capitalized total non-locational and locational annual equivalent charges could be in the range of $1m-$2m/MW, based on 250km distance this would equate to $4,000-$8,000/MW/km, plus connection costs of $237/MW/km (see Transmission Regulation Information Sheet for basis of estimate).

6.1.3 Storage considerations

A key advantage of pipelines is the potential to connect to potential low-cost geological hydrogen storage options such as salt caverns and/or depleted gas fields.

Apart from energy transport, pipelines can also act as storage via linepack that is likely to be of similar cost to alternative non-geologic gaseous hydrogen storage such as pressure vessels. Linepack can be particularly advantageous if there are land constraints or high-cost land at locations proximate to ports. Over a 60-bar range, 1.5km of 1m diameter hydrogen pipeline can store 5t of hydrogen, equivalent to 197 MWh.

6.1.4 Land use

Electricity transmission has significant social license risks particularly due to visual amenity issues. One large diameter hydrogen pipeline's transport capacity is multiple times that of a 500kv double circuit transmission line. Natural gas and hydrogen pipelines have easements of 30-40m wide with the potential for multiple pipelines to be located within the same right of way. In comparison, transmission line easement widths are significant, requiring 70m for a 500kV double circuit transmission line.

6.1.5 Water considerations

Electricity transmission has a potential advantage over pipelines where there are limited water resources and/or infrastructure proximate to renewable generation. Electricity transmission would allow electrons to be transported to electrolysers at port locations, where access to water through existing suppliers or through desalination is likely to be lower cost. This compares to pipelines where hydrogen is produced proximate to renewables and depending on location, significant pipeline infrastructure may be required to transport water from either dams or coastal desalination plants to electrolysers.

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6.2 Domestic Hydrogen Transport Information Sheet

6.2.1 Introduction

The purpose of this information sheet is to describe options for transporting hydrogen at an industrial scale within the state of Queensland. In particular, it compares the roles of compressed gas hydrogen pipelines and liquid ammonia pipelines.

This information sheet does not discuss in detail the role of hydrogen transport via road or rail, using tube trailers or other gas cannisters. Although these are the most common mode of hydrogen transport at present, they are suitable only for small-scale applications, and are not practical in the context of large industry.

6.2.2 Hydrogen pipelines

Australia has an existing natural gas network which includes over 40,000 km of pipeline. Beyond the most apparent purpose of transporting gas from supplier to consumer, these pipelines serve two additional functions: (i) interconnecting the energy systems of the east coast networks by enabling bidirectional flow to meet the varying requirements of industrial and domestic users; and (ii) to provide gas storage via 'linepack', which refers to the difference between the amount of gas stored in a pipeline at its minimum and maximum pressures.

Hydrogen pipelines can fulfill the first two goals, but are less well suited to linepack, because of the low volumetric density of hydrogen gas. Over a 60-bar pressure range, a 1 km pipeline with a diameter of 1m can provide buffer storage for around 3.5t of hydrogen, which is significantly less than the ~40t which can be stored by an equivalent natural gas pipeline. On an energy basis, the natural gas pipeline stores around 4 times as much as the hydrogen pipeline. It is therefore likely that using pipelines built predominantly for hydrogen transport for hydrogen storage via linepack is likely not to be adequate, and either pipeline oversizing or additional forms of storage will be required; these are discussed in the information sheets on Hydrogen Conversion Processes, and on Energy Storage.

While it is technically possible to blend a small quantity of hydrogen into the existing natural gas grid – various estimates put the limit at between 10 and 20 volume percent – it is not possible to entirely substitute hydrogen in an existing natural gas pipeline. Enabling higher concentrations of hydrogen would require retrofitting of the pipeline, which has not yet been demonstrated successfully at an industrial scale. Retrofitting is required to (i) prevent embrittlement of the steel; (ii) minimise leaks, to which hydrogen is more prone; (iii) modify compressors to suit the new feedstock. Case by case assessments, likely involving detailed studies, will need to be undertaken to assess whether conversions are practical. Although conversions are not straightforward, it is potentially significantly cheaper (around 10 – 30% of the capex) than greenfield construction of new pipelines, with the precise costs depending on the extent of retrofitting required.

Dedicated hydrogen pipelines do already exist – around 2,500 km have been installed in the US, although these are mostly concentrated on the Gulf Coast and connect industrial producers of chemicals, oil and gas. The cost of greenfield construction depends strongly on local regulations, labour costs, and geography, which along with pipeline utilization (load factor) will impact transport costs.

Leak detection and prevention is a challenge for hydrogen pipelines. These add to project costs, are a major safety hazard, and may have significant environmental impacts. The global warming potential of hydrogen gas is not well understood but is estimated to be significantly higher than that of carbon-dioxide, meaning even small leaks may undermine the climate benefits of hydrogen usage.

6.2.2.1 Operational considerations

Operational experience for major hydrogen pipelines is mainly limited to privately owned and operated pipelines in the US Gulf Coast and thus limited data is available. Given similarities in infrastructure, hydrogen transmission pipelines may have similar performance to natural gas pipelines, though leakage is a key risk.

Pipelines are subject to outage risk from leaks or ruptures, however the risk is low enough that redundancy via looping (a second pipeline) is not common. Buried pipelines also have the advantage that they are generally protected from and able to continue to operate in most natural hazards such as bushfires, extreme wind and floods.

6.2.2.2 Transport capacity

Hydrogen pipeline transport capacity is directly related to pipeline diameter (Area = πr^2), with large pipelines able to transfer massive volumes of energy. A 20-inch pipeline is able to deliver 1.3m tonnes pa of hydrogen, which based on the higher heating value of hydrogen is a capacity of ~6GW. Hydrogen pipelines of up to 46 inches, the same diameter to those used to transport gas from western Queensland gas fields to LNG export facilities at Gladstone, are possible and would have a transfer capacity exceeding the ~10GW peak demand record[8] of Queensland's electricity system.

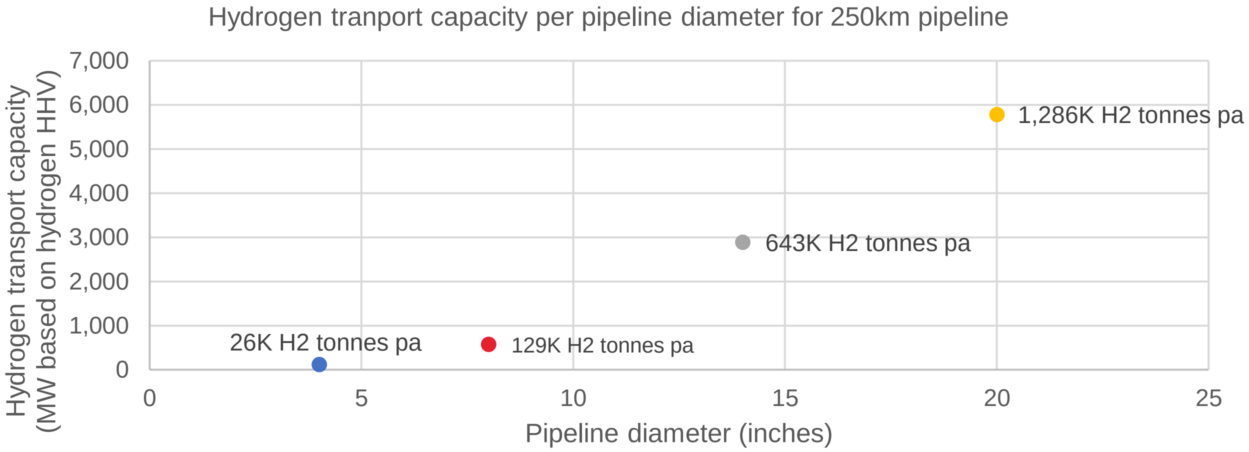

Figure 31: Hydrogen transport capacity per pipeline diameter for 250km pipeline | *Data source: Australian Gas and Pipeline Association. (2021).*

6.2.2.3 Capital cost estimates

Actual completed pipeline capex is typically benchmarked based on the $/inch/km metric and this metric is also used to estimate pipeline project capex estimates. As the transmission capacity of a pipeline is directly related to πr^2, where r is the pipeline radius and pipeline cost is related to the volume of steel which is a function of $2\pi r$ Pipelines are subject to significant economies of scale.

[8] Queensland reached an all-time maximum operational demand record of 10,070 MW at 17:30 on 17 March 2023. Source: AEMO (2023) Quarterly Energy Dynamics Q1 2023

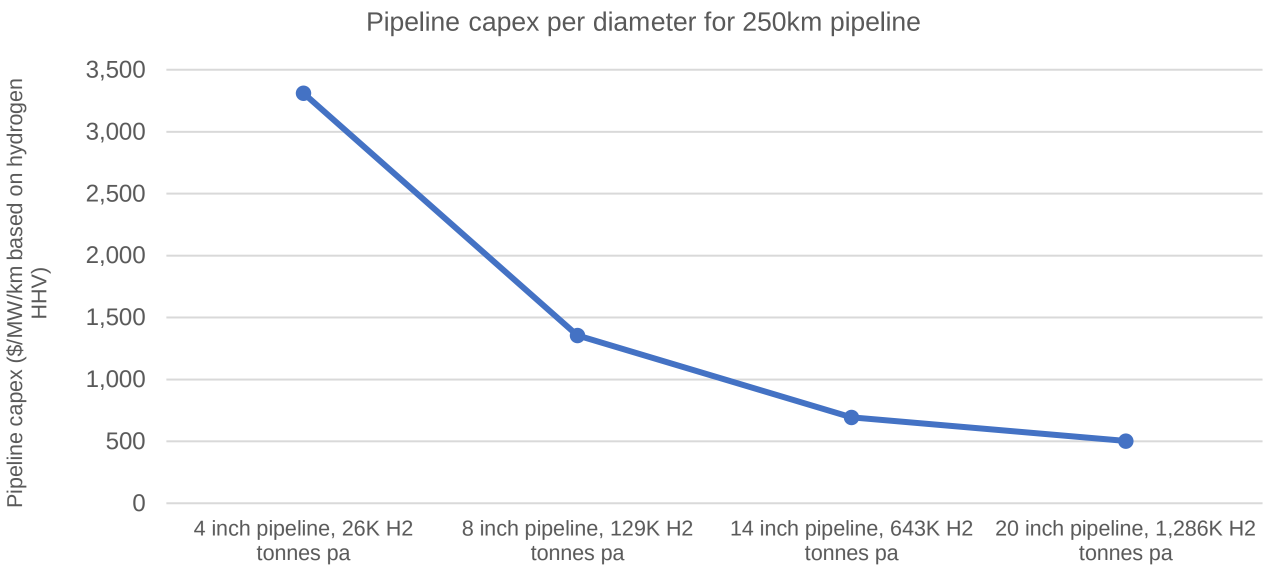

Figure 32: Pipeline capex per diameter for 250km pipeline | *Data source: Australian Gas and Pipeline Association. (2021).*

The capex for a 1 t/h hydrogen compressor is estimated to around $1.2m, or around $30,000 per MW hydrogen HHV. For a bidirectional pipeline, for instance where geological storage is in a different location to electrolysers and hydrogen upgrading process, multiple compressor stations may be required.

6.2.2.4 Transport losses

Capital cost estimates for longer distances account for pressure drops via assuming larger pipeline diameters than for shorter distances.

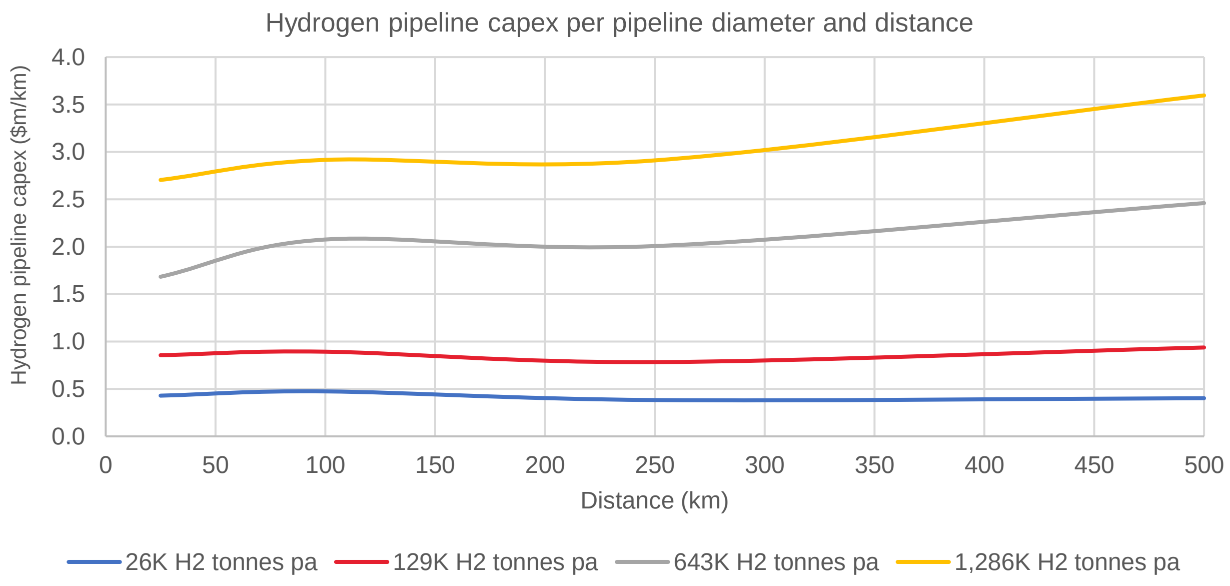

Figure 33: Hydrogen pipeline capex per pipeline diameter and distance | *Data source: Australian Gas and Pipeline Association. (2021).*

For long natural gas pipelines midline compressor stations may be used to maintain pressure, reducing required pipeline diameter and thus capital costs. Hydrogen pipelines can be longer than natural gas pipelines before midline compressor stations are required, as hydrogen has a much lower pressure drop over the same distance. A smaller pipeline diameter and a midline compressor station could be used as an alternative for a hydrogen pipeline of 500km or over, however for a pipeline of 500km total capex and opex are not estimated to be materially different.

6.2.2.5 Operating cost estimates

Operating costs for hydrogen pipelines are expected to experience economies of scale with length. Annual operating cost is estimated to be 2.11% of capex for a pipeline between 200-500km in length, a 0.235% premium to a natural gas pipeline estimate.

Annual operating cost for compressors is estimated to be 5% of capex.

6.2.2.6 Capital cost estimate methodology

Capital cost and operating cost estimate methodology is based on the Australian Gas and Pipeline Association (AGPA) report (March 2021) 'Pipelines vs Powerlines – A Technoeconomic Analysis in the Australian Context'. The methodology is adjusted to include compressor costs which were outside of the value chain boundary considered in the AGPA report.

6.2.2.7 Land use

Natural gas and hydrogen pipelines have easements of 30-40m wide with the potential for multiple pipelines to be located within the same right of way provided there is adequate separation (5-8m). There is also the potential to locate water pipelines within the same easement.

6.2.3 Ammonia pipelines

As described in the other information sheets, there may be advantages to 'upgrading' hydrogen to ammonia; the only raw material required to do so is nitrogen, which can be extracted cheaply from the air, and the end product is denser, and liquid under comparatively mild conditions.

While it is not possible to transport liquid hydrogen via pipeline (insulation over such a large area to prevent hydrogen boil-off would not be practical), ammonia requires only approximately 10 bar of pressure to liquefy at room temperature. The cost of transport via pipeline is therefore less than that of hydrogen. Although frictional energy losses in liquid pipelines are higher than for gases, pumps are both cheaper and more energy efficient than compressors.

However, as shown on Figure 34, the costs of upgrading to ammonia itself are not insignificant and will only be recuperated over very large transport distances – much larger than are likely to be used in Australia. Therefore, conversion to ammonia requires additional market impetus – for instance, a fertiliser market, for long-term energy storage, or for export.

Costs on a per ton of ammonia basis are converted into per kilogram of hydrogen on the basis of the higher heating values. There are large uncertainties, represented by the shaded areas.

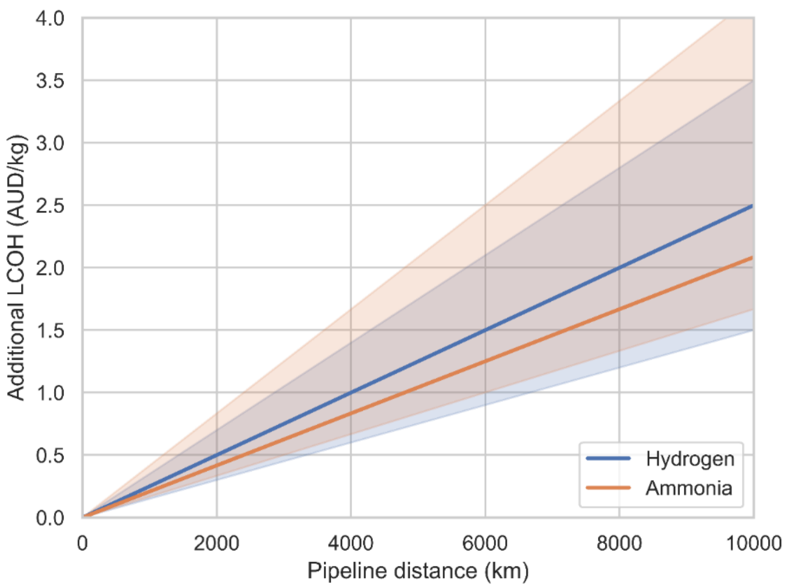

Figure 34: Pipeline transport cost estimates for gaseous hydrogen and liquid ammonia

Over 3,000 km of ammonia pipelines have been installed in the US, demonstrating the technical readiness of this transport mechanism. Although it is far less prone to leakage and explosion than hydrogen, ammonia is highly toxic, meaning clean-up of spills is non-trivial. While this poses a challenge from a health and safety perspective, technically it is not an insurmountable one, as demonstrated by the widespread use of ammonia in Australia. However, industry feedback is that there is significant social license risk associated with ammonia pipelines in Queensland due to environmental and safety concerns.

6.2.4 Conclusions

There are technical challenges and costs associated with both ammonia and hydrogen pipelines, but these ought not require further scientific development to resolve. Per kilometer, ammonia is cheaper to transport than hydrogen, but industry feedback is that there is significant social license risk associated with ammonia pipelines in Queensland due to environmental and safety concerns.

In either case, policy changes will be required in order to enable construction of these pipelines; Queensland is in the process of developing legislation suitable for either hydrogen or ammonia pipelines. The most pressing of these regulations will be changes to the National Gas Law (NGL) and National Energy Retail Law (NERL) which will enable the blending of hydrogen in meaningful concentrations into the natural gas network.

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6.3 Electricity Transmission Cost Information Sheet

6.3.1 Introduction

This information sheet addresses the costs for the construction and operation of transmission network infrastructure to interconnect sources of renewable energy to electrolyser plants and hydrogen upgrading processes at demand centres such as coastal ports.

Cost estimates of overhead transmission lines and terminal station equipment are provided for High Voltage Alternating Current (HVAC) based on the 2022 AEMO Transmission Cost Database[9].

6.3.2 Operational considerations

There are two key operational considerations relating to the performance of transmission network infrastructure underpinning the production of renewable hydrogen and hydrogen upgrading processes.

First, transmission infrastructure is prone to faults which could pose damage to connected infrastructure including electrolysers and hydrogen upgrading processes. Protection systems and equipment in terminal

[9] *Release date of the AEMO transmission cost database was May 2023.*

stations including isolators/circuit breakers are designed to protect against damage from faults and prevent their propagation throughout the system.

Secondly, transmission outages could result in reduced production of green hydrogen or upgraded hydrogen product (e.g. ammonia), resulting in financial and reputational costs from failing to deliver contracted volumes to customers. Redundancy provides a level of protection against this risk. The key form of redundancy is to have multiple circuit capability in case an individual transmission line fails. Given the risk of damage from power outages to plant involved in hydrogen upgrading processes such as ammonia synthesis loops and cryogenic air separation units, single circuit transmission lines are unlikely to be suitable.

To manage the risk of faults and outages on a transmission system, TNSPs generally operate on an N-1 basis. This means that the system is secure against a credible risk and can quickly respond and remain stable following a fault on an individual transmission element. When a standalone double circuit transmission line is operated on an N-1 basis the transfer capacity is half of the thermal capacity of the individual lines (ignoring any other technical stability constraints), to account for the risk of a fault on one of the lines.

In contrast to some inflexible industrial load such as aluminium smelters flexible electrolyser loads and partially flexible hydrogen upgrading processes (e.g. ammonia) can operate continuously at less than nameplate capacities without causing plant damage. As a result for green hydrogen and ammonia value chains, transmission has the potential to be operated above typical N-1 transfer capacities.

One potential concept to increase effective capacity above typical N-1 capacity involves temporarily allowing the system to continue to operate at a transfer capacity higher than the continuous rating that would ordinarily apply to one line (circuit), following a fault on the other line (circuit). Once a fault occurs the remaining line would be operated temporarily at a higher emergency rating or short term rating, until the fault is cleared, or the load is able to be reduced. Prior to the fault occurring the system has the potential to operate at a capacity of N-1 plus the difference between the emergency or short term rating and the continuous rating.

A second potential concept is to increase effective capacity above typical N-1 capacity by tripping some of the load and generation simultaneously in the case of a fault to balance system frequency (run-back scheme). Prior to the fault occurring the system is able to operate at a capacity of N-1 plus the lower of the capacity of load and generation that is able to be tripped. There is the potential to involve battery storage in such a concept, by providing a generation response in the case of a fault, however the battery would be required to be available to provide this response, which could impact on its ability to generate income from providing other services.

At what capacity a transmission line is operated would be part of a whole of project optimisation, which would also consider transmission losses.

6.3.3 Transmission losses

Transmission losses refer to the loss of power associated with power flows on transmission lines. In their 2012 document 'Treatment of loss factors in the National Electricity Market' AEMO simplify the drivers of losses on transmission lines down to two factors:

1. Current flowing through the network element. This refers to the magnitude of power flows on the transmission lines. Transmission losses increase with capacity utilisation as they are a function of power flows (or current).
2. Resistance of the network element. Transmission line (conductor) resistance is dependent on a number of technical factors, a detailed discussion of which is beyond the scope of this report. Key factors include conductor material, diameter and bundling (inverse relationship with losses) and transmission line distance (direct relationship with losses).

In addition the 2023 Powerlink document, *Actioning the Queensland Energy and Jobs Plan*, finds that four parallel 275kV double circuit lines would be required to match the network loss performance of one 500kV double circuit line for the same power transfer.

6.3.4 Transmission line loadability

Total transfer capacity (MW) declines as line length increases (km) as represented in Figure 35[10]. Figure 35 uses information on transmission line loadability [(St Clair, 1953) and (Dunlop et al, 1979)], and shows a generic relationship between transfer capacity relative to nameplate capacity and transmission line length. It should be noted that this type of graph is relevant for normal to heavily loaded transmission lines.

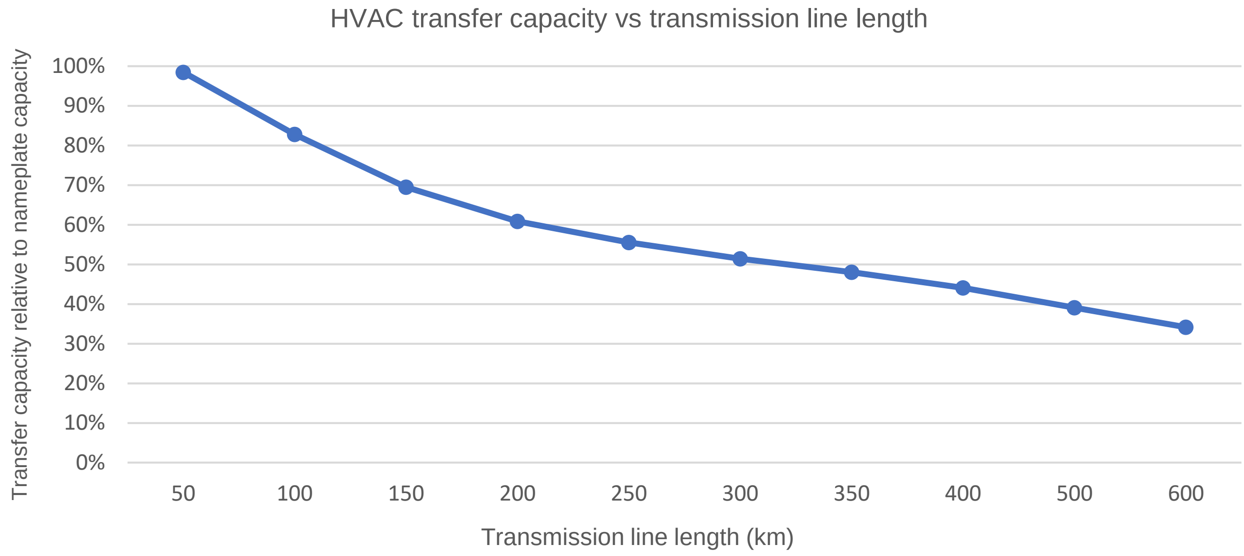

Figure 35: HVAC Transfer capacity vs. Transmission line length | *Source: St Clair, (1953) and Dunlop et al, (1979)*

Potential remedies to offset MW transfer capacity reduction outlined in Figure 35 would include:

- Shortening the effective transmission line length by adding in more switching stations; and/or
- Installing capacitor banks in parallel on each line to provide series compensation which increases MW transfer capability.

It should be noted that in both cases above, detailed engineering assessment should be undertaken to determine what potential remedies offer the best benefits for each project. This is particularly the case for series compensation as this method, while a credible option worth investigating, is not without risks in some situations and is definitely not a panacea for increasing transfer capacity on long transmission lines.

In addition as lines get longer, a variety of remediation options to address reactive power and voltage stability, including the most common remediation (shunt reactive compensation – both static and dynamic) will be employed, dependent on the specific circumstances to manage and minimise these effects.

6.3.5 Transmission capacity

Transmission network service providers (TNSP) in Australia currently use or plan to use voltage levels ranging from 110kV to 500kV. Based on inputs from the AEMO Transmission Cost Database, the Figure 36 shows the positive relationship between voltage level and transmission line capacity for a double circuit fixed line length and equivalent conductors. A range is provided for a system operating in a secure state firstly with N-1 contingency basis and N under any credible contingency basis. As transmission operation for a hydrogen or green ammonia value chain is uncertain, the range highlights different approaches with different voltage HVAC lines.

[10] *Note that the shape of the curve in Figure 35 matches the general shape of the ST Clair Curves listed in St Clair (1953) and Dunlop et al (1979), albeit with the maximum St Clair curve coefficient truncated at a value of 2.5 which is appropriate for a 50 km transmission line where the thermal limit will define maximum MW transfer limit, under normal line loading conditions. Note the shape in Figure 1 is obtained by dividing the St Clair Coefficients associated with 50 km increments in line length (out to 600 km line length) by the truncated maximum of 2.5 mentioned above and multiplying this ratio by the MW nameplate capacity of the transmission line.*

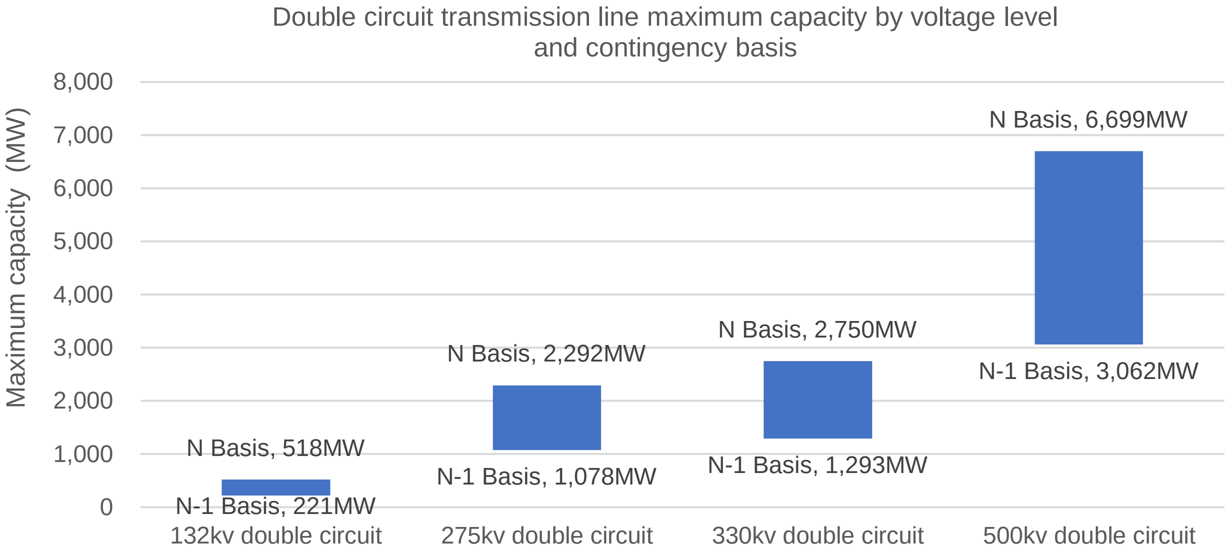

Figure 36: Double circuit line capacity and voltage level | *Data source:* 2022 AEMO Transmission Cost Database (2023).

Similarly the 2023 Powerlink document, *Actioning the Queensland Energy and Jobs Plan,* finds regarding the relationship between voltage and capacity that:

- 500kV transmits up to three times more power per circuit than 275kV. The secure transfer level of one 500kV double circuit line would require a minimum of two parallel 275kV double circuit lines.
- While two parallel 275kV double circuit lines would have equivalent thermal capacity to one 500kV double circuit line, avoiding voltage instability becomes a critical design requirement for long transmission lines. For longer distances, three 275kV double circuit lines may be required.
- 500kV also requires less dynamic reactive power sources.

6.3.6 Capital cost estimates

The total capital cost of transmission capacity including transmission lines, terminal stations (connection assets) and compensation for hydrogen electrolysers and ammonia production is examined in Figure 37, based on the AEMO Transmission Cost Database. In this example, it is assumed a 300km double circuit transmission line, for various voltage levels and contingency levels, using series compensation for illustrative purposes. There is an inverse relationship between voltage level and cost of transmission capacity measured as $/MW/KM, reflecting the economies of scale at higher voltage levels. At each voltage level there are different conductors available with different capacities leading to small differences in this metric, with Figure 37 showing the top and bottom of the range.

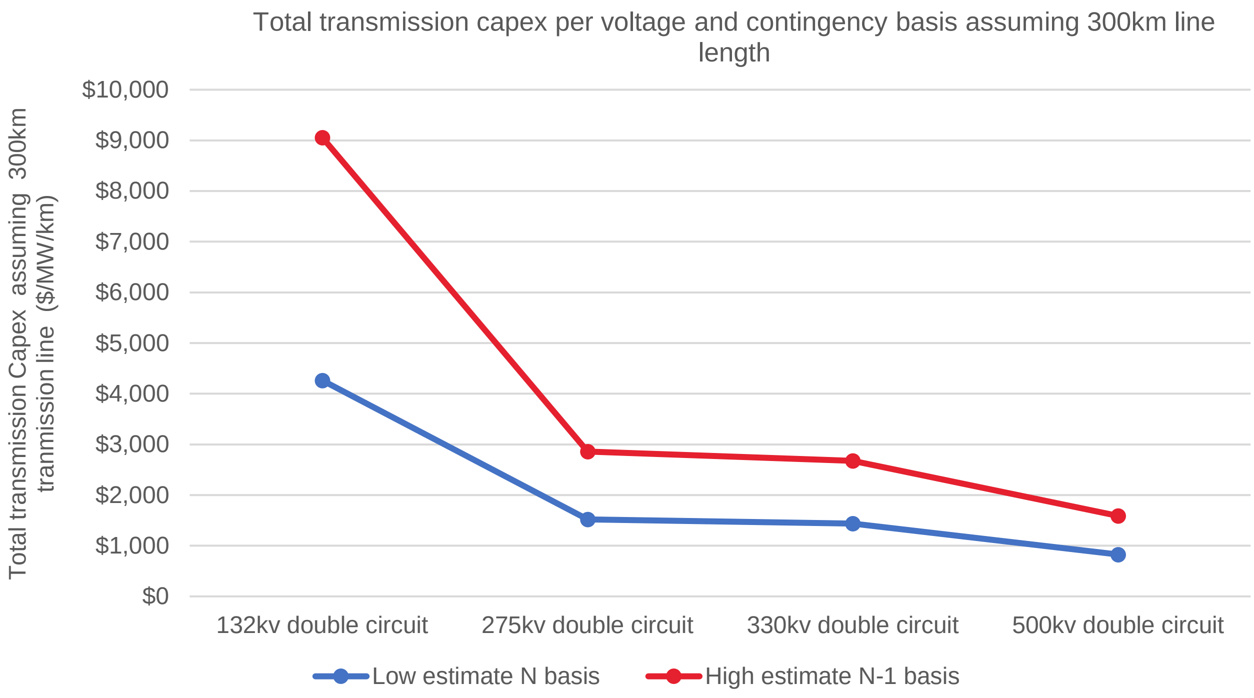

Figure 37: Total transmission capex for 132kV to 500kV | *Data source:* 2022 AEMO Transmission Cost Database (2023)

Using the 2022 AEMO Transmission Cost Database, Figure 37 highlights the relationship between voltage and costs. In addition, the 2023 Powerlink document, *Actioning the Queensland Energy and Jobs Plan*, finds that:

- The capital cost of one 500kV double circuit line is estimated to be about twice as much per kilometre as a 275kV double circuit line. However, only one 500kV double circuit line is required compared with a minimum of two 275kV double circuit lines.
- The ongoing operational and maintenance costs scale with the number of structures and lines and so would be greater for a larger number of 275kV double circuit lines compared to one 500kV double circuit line.

Note also that there are cost savings of approximately 40% when comparing double circuit lines with two separate single circuit lines.

Additionally, a project proponent may incur additional costs associated with voltage regulation or system strength remediation requirements: this isn't considered in this information sheet. These requirements would need to be determined on a *case-by-case* basis from detailed engineering analysis.

6.3.7 Operating cost estimates

The standard approach for approximating operating costs is to assume that OPEX costs are set equal to 1% of capex cost on a per annum basis.

6.3.8 Land Use

Transmission line easement widths are significant, requiring 70m (7ha per km) for double circuit 500kV. Vegetation must be cleared from the easement and there are restrictions on activities and land usage within an easement corridor. 500kV has the least easement footprint per MW of transfer capacity.

TNSPs' usually work with the assumption that a 500kV double circuit line requires a smaller easement than multiple 275kV double circuit lines sharing the same easement. For example, one 500kV double circuit line is expected to need an easement half as wide as three 275kV double circuit lines.

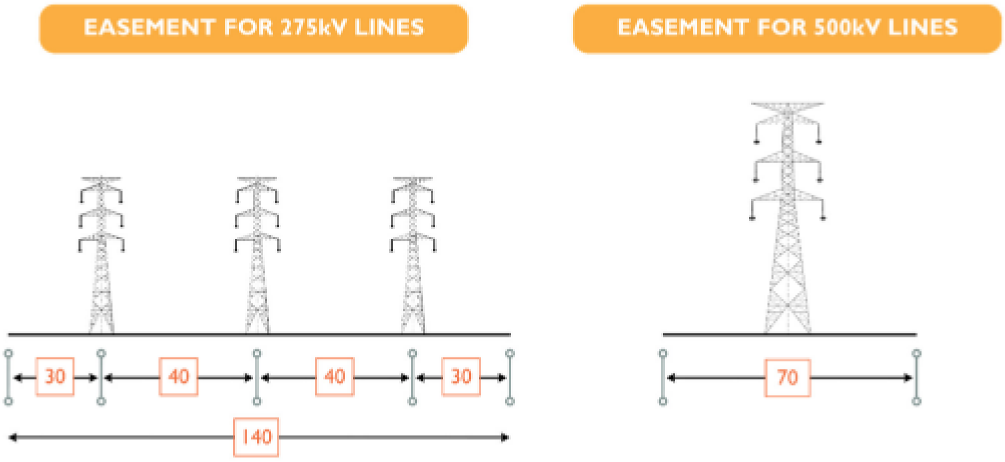

Figure 38: Easement widths | *Source: Powerlink (2022)*

Transmission is an infrastructure asset that has high social licence risk, particularly due to visual amenity impacts. While buried electrical lines may not suffer from these issues, their costs are a multiple of the cost of overhead lines. The cost estimates reported in the information sheet assume overhead line costs associated with both environmental offsets as well as compulsory land acquisitions.

6.3.9 Appendix 1 – Capital cost estimate breakdown

Transmission lines are the key cost component of a transmission system. There is an inverse relationship between voltage level and cost of transmission capacity measured as $/MW/km, reflecting economies of scale at higher voltage levels.

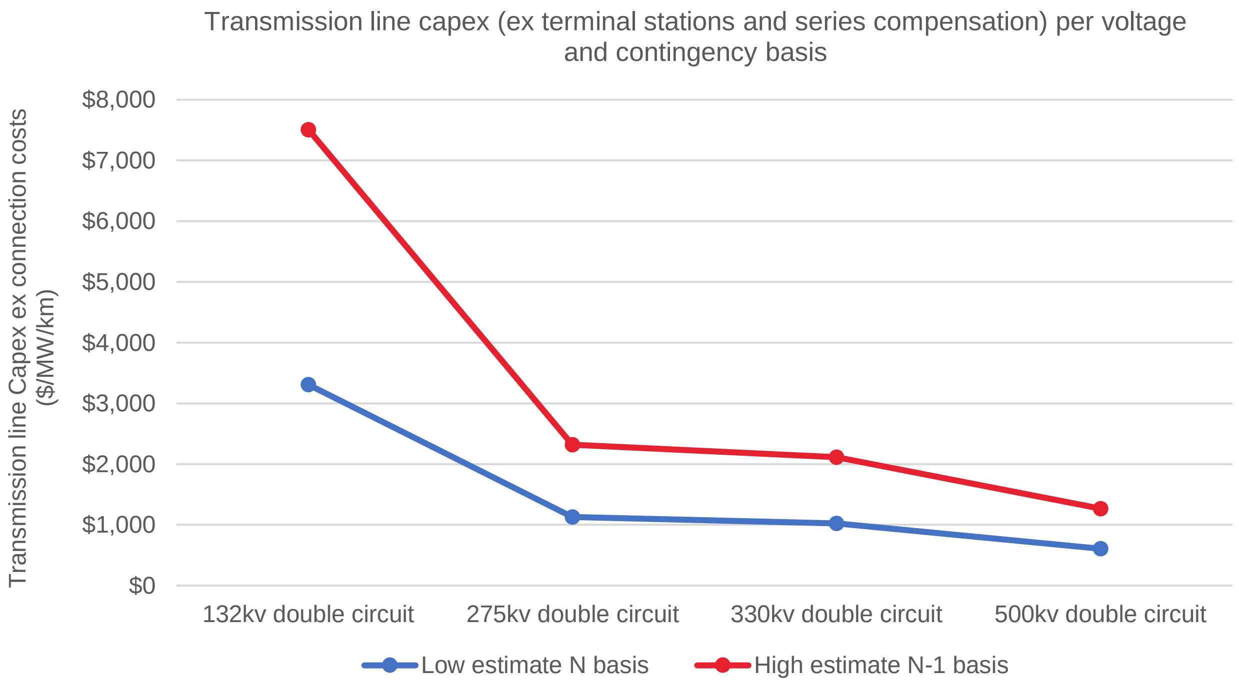

Figure 39: Transmission line capex per voltage and contingency basis | Data source: 2022 AEMO Transmission Cost Database (2023)

In addition to transmission lines, terminal stations (connection assets) will be required to connect renewable generation to an electricity network, as well as electrolysers and upgrading processes at a port. Terminal station costs per MW show strong inverse relationship with voltage level. Terminal station cost is unrelated to line length or contingency basis.

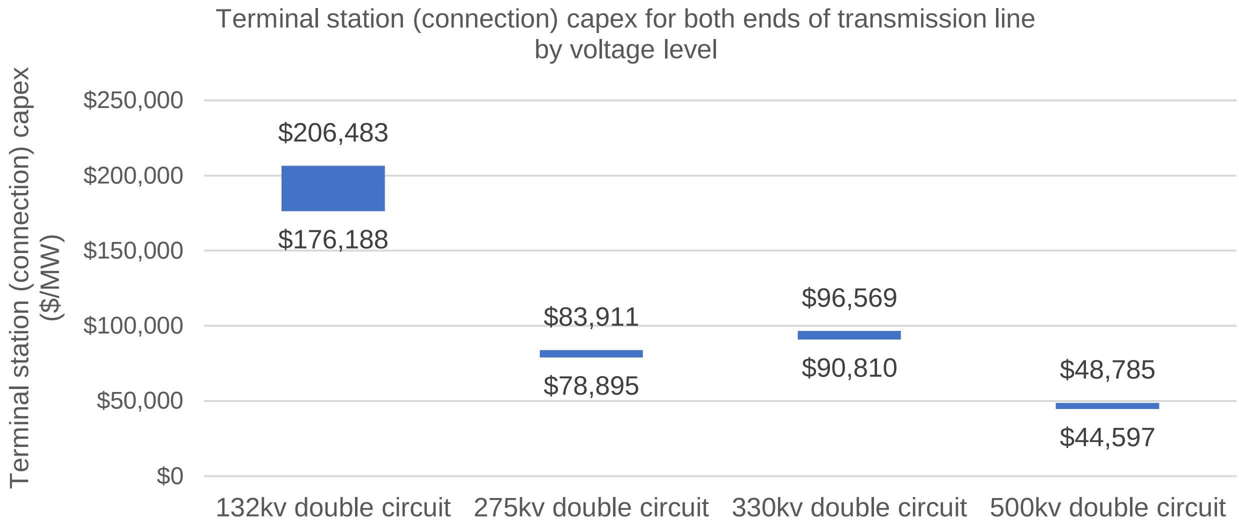

Figure 40: Terminal station (connection) capex for both ends of transmission line by voltage level | *Data source:* 2022 AEMO Transmission Cost Database (2023)

To address reduction in transmission line transfer capacity over long distances the cost of compensation (series or dynamic) needs to be included, assuming that detailed engineering assessment has been undertaken to verify this option on a case-by-case basis. The costs of each are substantially different. For illustrative purposes, the cost of series compensation is estimated using costs drawn from AEMO's 2022 Transmission Cost Database. Again, there is a strong inverse relationship between series compensation capex and voltage level. In terms of $m capex, series compensation increases total transmission capex by up to 9% across all double circuit configurations on an N contingency basis.

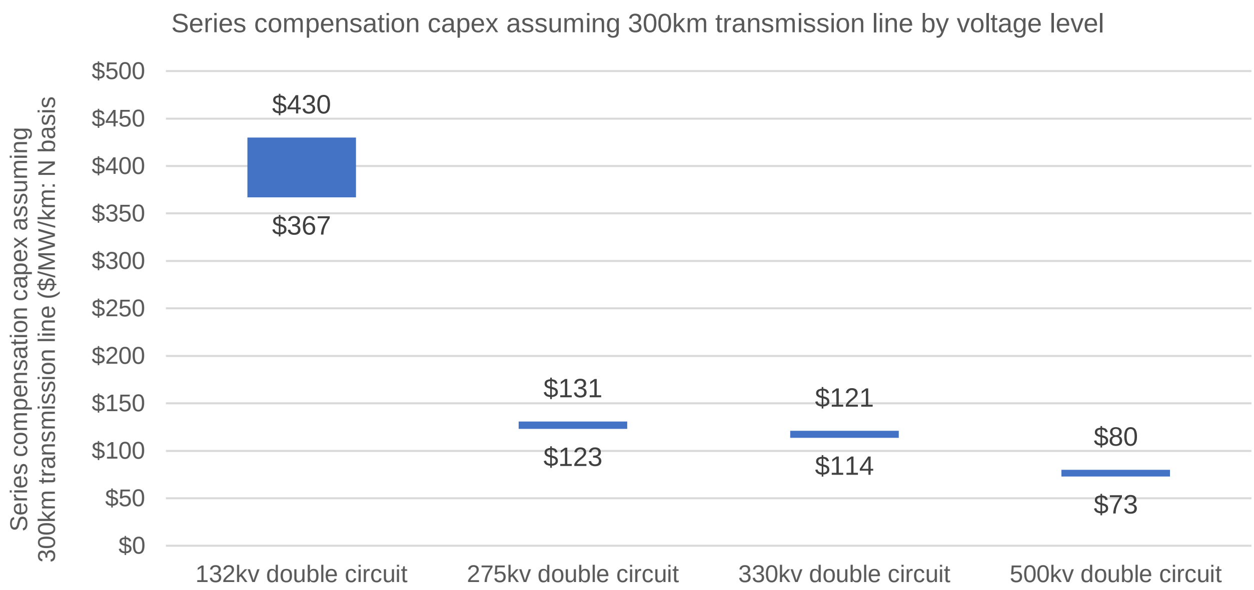

Figure 41: Series compensation capex assuming 300km transmission line by voltage level | *Data source:* 2022 AEMO Transmission Cost Database (2023)

6.3.10 Appendix 2 – Capital cost estimate methodology

Capital cost estimates were sourced from AEMO's Transmission Cost Database[11]. The approach taken is to provide upper estimates of transmission infrastructure. Two cost metrics are utilised:

- Metric one involves expressing the cost in terms of millions of dollars per kilometre ($M/km); and
- Metric two involves expressing the cost in terms of dollars/per megawatt/per kilometre ($/MW/km) on an N and N-1 contingency basis.

In constructing these costs, the capex cost includes the cost of:

- Overhead transmission lines;
- Terminal station equipment involving busbar, isolator, circuit breaker and building infrastructure;
- Transformer infrastructure required to step-up voltages to levels needed to efficiently transmit power over high voltage transmission lines as well as stepping-down voltage levels to lower voltages needed to facilitate power supply to electrolysers;
- Capacitor banks required for series compensation; and
- Indirect project costs associated with project development, work delivery, land and environment, stakeholder and community engagement, procurement costs and insurance.

In compiling the costs, the following assumptions were made:

- Greenfield projects;
- Tight market conditions with elevated labour and productivity costs;
- Elevated cost risks associated with environmental offsets and compulsory acquisition (applied to overhead transmission lines); and
- Costs were compiled assuming project location in regional areas.

Cost estimates are restricted to HVAC infrastructure only. This decision followed from the observations that:

- The AEMO Transmission Cost Database contains significantly less options relating to High Voltage Direct Current (HVDC) infrastructure;
- The database is missing some crucial HVDC components such as converter transformers and AC harmonic filters;
- The length of transmission lines under investigation are envisaged as generally being less than 600 km in length – a distance over which HVAC transmission lines are generally viewed as having a cost advantage relative to HVDC [Larson (2018), National Grid (2023), Rehman (2023)]; and
- HVAC has substantial cost and technical simplicity advantages when mid-point terminal stations are required to connect to renewable resource or load along a transmission route.

The cost estimates for various HVAC overhead transmission line voltage options are listed in Table 9 with both single circuit and double circuit results listed. Double circuit lines, while more expensive, provide some advantages over a single circuit line:

1. higher MW transfer capacity (e.g. twice that of a single circuit line); and

[11] *See https://aemo.com.au/-/media/files/major-publications/isp/2021/transmission-cost-database---ghd-report.pdf?la=en. Also see https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.*

2. beneficial redundancy/protection against the consequences of a loss of a single line – power transfers can still occur on the other single circuit line of the double circuit line but no transfer would be possible following an outage on a single circuit line.

The capex estimate underpinning the cost results in Table 9 (Cost Table A) include the cost of overhead transmission lines as well as terminal station equipment including transformers. The terminal station costings include site work and busbar/circuit breaker infrastructure. For simplicity, the assumption was made to only include circuit breaker costs (noting these can come in single or three phase versions) rather than all of the substation apparatus: isolators, VTs, CTs, earth grid, all of the secondary systems etc.

While TNSPs use a circuit breaker and a half in their operations for 275KV and above the assumption for illustration purposes was to align each circuit breaker with a phase of the transmission line. This is in accordance with the 2022 AEMO Transmission Cost Database's default AIS switchyard option. Consequentially, a single circuit line would have three circuit breakers at both ends of each individual terminal station. For double circuit transmission lines, they would have six circuit breakers at each end of the terminal station. These values double to 12 and 24 respectively for the two terminal stations at both ends of the transmission line accounted for in the costings. However, it should be recognised that different designs are possible and the ultimate choice of design structure should be the subject of detailed engineering analysis on a case-by-case basis.

Costs for transformers are included as follows:

- 500kV: 500/220 and 220/33 transformers
- 330kV: 330/220 and 220/33 transformers and
- 275kV: 275/132 and 132/22 transformers.

In the costings, we associated a single transformer with three phases of the transmission line. This is accomplished using either a three-phase transformer at lower voltage levels (e.g. 275 kV or below) or three one phase transformers at higher voltage levels of 330 kV and 500 kV. The latter are needed because of difficulties in transporting the extremely heavy three phase transformers at 330 kV and 500 kV voltage levels. It was assumed that power supply to electrolysers would have to be stepped down to at least 33 kV. In the case of 275 kV infrastructure listed above, a 33 kV transformer option was not available in the AEMO database, so the next closest option involving a 132/22 kV transformer was adopted instead.

The costings for all equipment [e.g. overhead transmission lines, transformers and capacitor banks (discussed in6.3.6)] are linked to overhead lines with elevated MW transfer limits and with transformer and capacitor banks cost estimates centred on equipment with elevated MVA ratings at each voltage level. As such, at each voltage level estimates represent the top end of the range on a $m/km basis but also include the most favourable estimates on a $/MW/km.

Costings for a terminal station (with control buildings) and capacitor banks are outlined in Table 10 (Cost Table B) for the case that series compensation is to be applied to long distance transmission lines to boost their MW transfer capacity. The ($/MW/km) and ($M/km) costs are listed based on the model of the Black Range terminal station constructed in South Australia for series compensation (ElectraNet, 2016). The capacitor banks are allocated to each phase of the transmission line. For a single circuit line, this will imply the use of three capacitor banks. For double circuit lines, this will entail the use of six capacitor banks. It is assumed that the series compensation terminal station is located halfway between the two terminal stations at both ends of the long transmission branch.

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Cost table A: Transmission Line and connection asset costs

Assuming a 300Km line length. Terminal stations at both ends of the transmission line with 500kV/220kV and 200kV/33kV transformers

Voltage kV	Tower Circuit	Conductor bundling per phase	Maximum capacity (MW): N basis	Maximum capacity (MW): N-1 basis	CAPEX ($m)	Transmission line ($/MW/km): N basis	Transmission line ($/MW/km): N-1 basis	Transmission line capex ($M/km)
500	Double	4	6,699	3,350	$ 1,218	$606	$1,212	$4.06
500	Single	4	3,350	0	$ 966	$961	n/a, no redundancy	$3.22
500	Double	4	6,124	3,062	$ 1,164	$634	$1,267	$3.88
500	Single	4	3,062	0	$ 939	$1,022	n/a, no redundancy	$3.13
330	Double	3	2,750	1,375	$ 844	$1,023	$2,047	$2.81
330	Single	3	1,375	0	$ 700	$1,698	n/a, no redundancy	$2.33
330	Double	2	2,586	1,293	$ 820	$1,056	$2,113	$2.73
330	Single	2	1,293	0	$ 701	$1,807	n/a, no redundancy	$2.34
275	Double	3	2,292[12]	1,146	$ 777	$1,131	$2,261	$2.59
275	Single	3	1,263	0	$ 648	$1,709	n/a, no redundancy	$2.16
275	Double	2	2,155	1,078	$ 749	$1,159	$2,318	$2.50
275	Single	2	1,077	0	$ 606	$1,875	n/a, no redundancy	$2.02
132	Double	1	442	221	$ 498	$3,755	$7,509	$1.66
132	Single	1	221	0	$ 439	$6,618	n/a, no redundancy	$1.46
132	Double	1	518	259	$ 514	$3,309	$6,618	$1.71
132	Single	1	259	0	$ 452	$5,812	n/a, no redundancy	$1.51

[12] *Note that in the AEMO transmission cost database, different conductor types were only available for the 275 kV three conductor bundling options. In the case of the double circuit 275 kV line, 'mango' conductors were the only available conductors. In the case of single circuit 275 kV line, 'orange' conductors were the only conductors available. This explains the differences in MW rating at N-1 level for the double circuit 275 kV line and the rating for the single circuit 275 kV line in Cost Table A above.*

Voltage kV	Tower Circuit	Maximum capacity (MW): N basis	Maximum capacity (MW): N-1 basis	2x Terminal stations ($m)	Transformers ($m)	Total terminal station (connection) capex ($m)	Total terminal station (connection) capex ($/MW)	Transmission line & connection capex ($/MW/km: N Basis)	Transmission line & connection capex ($/MW/km: N-1 Basis)[13]	Transmission line & connection capex ($M/km)
500	Double	6,699	3,350	$ 138	$ 161	$ 299	$44,597	$755	$1,361	$5.06
500	Single	3,350	0	$ 74	$ 81	$ 154	$46,020	$1,115	n/a no redundancy	$3.73
500	Double	6,124	3,062	$ 138	$ 161	$ 299	$48,785	$796	$1,430	$4.88
500	Single	3,062	0	$ 74	$ 81	$ 154	$50,348	$1,190	n/a no redundancy	$3.64
330	Double	2,750	1,375	$ 115	$ 135	$ 250	$90,810	$1,326	$2,350	$3.65
330	Single	1,375	0	$ 62	$ 67	$ 129	$94,078	$2,012	n/a no redundancy	$2.77
330	Double	2,586	1,293	$ 115	$ 135	$ 250	$96,569	$1,378	$2,435	$3.56
330	Single	1,293	0	$ 62	$ 67	$ 129	$100,044	$2,141	n/a no redundancy	$2.77
275	Double	2,292[14]	1,146	$ 114	$ 67	$ 181	$78,895	$1,394	$2,524	$3.19
275	Single	1,263	0	$ 60	$ 34	$ 93	$73,972	$1,956	n/a no redundancy	$2.47
275	Double	2,155	1,078	$ 114	$ 67	$ 181	$83,911	$1,439	$2,598	$3.10
275	Single	1,077	0	$ 60	$ 34	$ 93	$86,747	$2,164	n/a no redundancy	$2.33
132	Double	442	221	$ 68	$ 24	$ 91	$206,483	$4,443	$8,198	$1.96
132	Single	221	0	$ 40	$ 12	$ 52	$235,648	$7,404	n/a no redundancy	$1.64
132	Double	518	259	$ 68	$ 24	$ 91	$176,188	$3,896	$7,205	$2.02
132	Single	259	0	$ 40	$ 12	$ 52	$201,074	$6,483	n/a no redundancy	$1.68

Table 9: Cost table A – Transmission Line and connection asset costs | *Data source:2022 AEMO Transmission Cost Database (2023)*

[13] *Assumes terminal station (connection) capex is half that of N basis as maximum transmission line capacity has halved compared to N basis.*

[14]*Note that in the AEMO transmission cost database, different conductor types were only available for the 275 kV three conductor bundling options. In the case of the double circuit 275 kV line, 'mango' conductors were the only available conductors. In the case of single circuit 275 kV line, 'orange' conductors were the only conductors available. This explains the differences in MW rating at N-1 level for the double circuit 275 kV line and the rating for the single circuit 275 kV line in Cost Table A above.*

Cost Table B: Capacitor bank and terminal station cost for series compensation on long transmission lines

Capacitor bank type	Unit cost ($M)	number of units	Capacitor bank capex ($m)	terminal station including control buildings capex ($m)	Series compensation capex ($m)	Series compensation capex ($/MW/km: N basis)	Series compensation capex ($/MW/km: N-1 basis)[1]	Total transmission capex ($/MW/km: N basis)	Total transmission capex ($/MW/km: N-1 basis)[15]	Total transmission capex ($M/km)
500 kV 400 MVA	$ 13	6	$ 75	$ 72	$ 147	$ 73	$ 146	$828	$1,507	$5.54
500 kV 400 MVA	$ 13	3	$ 38	$ 37	$ 74	$ 74	n/a	$1,189	n/a	$3.98
500 kV 400 MVA	$ 13	6	$ 75	$ 72	$ 147	$ 80	$ 160	$876	$1,590	$5.37
500 kV 400 MVA	$ 13	3	$ 38	$ 37	$ 74	$ 81	n/a	$1,271	n/a	$3.89
330 kV 300 MVA	$ 7	6	$ 41	$ 53	$ 94	$ 114	$ 228	$1,440	$2,577	$3.96
330 kV 300 MVA	$ 7	3	$ 20	$ 27	$ 47	$ 114	n/a	$2,126	n/a	$2.92
330 kV 300 MVA	$ 7	6	$ 41	$ 53	$ 94	$ 121	$ 242	$1,499	$2,677	$3.88
330 kV 300 MVA	$ 7	3	$ 20	$ 27	$ 47	$ 121	n/a	$2,262	n/a	$2.92
275 kV 300 MVA	$ 6	6	$ 37	$ 47	$ 85	$ 123	$ 246	$1,517	$2,771	$3.48
275 kV 300 MVA	$ 6	3	$ 19	$ 24	$ 42	$ 112	n/a	$2,067	n/a	$2.61
275 kV 300 MVA	$ 6	6	$ 37	$ 47	$ 85	$ 131	$ 262	$1,570	$2,860	$3.38
275 kV 300 MVA	$ 6	3	$ 19	$ 24	$ 42	$ 131	n/a	$2,295	n/a	$2.47
132 kV 150 MVA	$ 4	6	$ 23	$ 34	$ 57	$ 430	$ 860	$4,873	$9,057	$2.15
132 kV 150 MVA	$ 4	3	$ 12	$ 17	$ 29	$ 430	n/a	$7,833	n/a	$1.73
132 kV 150 MVA	$ 4	6	$ 23	$ 34	$ 57	$ 367	$ 734	$4,263	$7,939	$2.21
132 kV 150 MVA	$ 4	3	$ 12	$ 17	$ 29	$ 367	n/a	$6,849	n/a	$1.77

Table 10: Cost table B – Capacitor bank and terminal station cost for series compensation on long transmission lines | *Data source:2022 AEMO Transmission Cost Database (2023)*

[15] *Assumes terminal station (connection) capex is half that of N basis as maximum transmission line capacity has halved compared to N basis.*

6.4 Transmission Regulation Information Sheet

6.4.1 Introduction

This information sheet addresses ownership model options for the construction of dedicated transmission network infrastructure to interconnect sources of renewable energy to electrolyser plants located at coastal ports for the purpose of hydrogen production (in the case in which renewables and electrolysis are not co-located).

There are several aspects that require consideration by proponents: ownership models, transmission network obligations and transmission charges. These are discussed in turn below.

A key aspect that was identified was any potential obligations of project proponents if their transmission pathway interconnects with the regulated network that is owned and operated by the Primary Transmission Network Service Provider (TNSP).

6.4.2 Ownership models

The ownership model of the transmission network infrastructure used for renewable electricity determines potential obligations arising under the National Electricity Rules (NER). There are two potential ownership models. The first – Shared Network Assets – is required if any part of the intended transmission pathway connects with any part of the regulated network owned and operated by the Primary Transmission Network Service Provider (TNSP).

The second ownership model – Standalone Assets – applies to projects which do not share any connection with the existing network. It is presumed this project type would not incur any prescribed or regulated transmission service charges liability nor adversely affect other customers. To the authors' knowledge, no projects using a Standalone Asset ownership model have been built in Australia[16]; however, they may be beneficial in the context of green hydrogen projects. In this case, the project proponent would own and finance the complete network infrastructure and manage third-party access arrangements.

This Standalone Asset model provides contracted positions that require the direct physical delivery of renewable energy to the electrolysers to ensure the physically delivery and production of renewable hydrogen for domestic consumption or export.

The remainder of the discussion in this fact sheet will relate to the Shared Network Assets ownership model.

6.4.3 Obligations under Shared Network Asset model

Under clause 6A.6.7 of the NER, the primary TNSP has an obligation to ensure supply to new demand that connects to and utilises the regulated network, maintaining the quality, reliability and security of supply to the new demand.

Shared assets are used to provide both prescribed and non-regulated transmission services or services that are not transmission services. Prescribed transmission services are subject to economic regulation under the national transmission regulatory regime. There is scope for the project proponent to build and own dedicated infrastructure relating to both generation and load connections. Project proponents also have the right to provide and manage access to third parties.

Individual connections to the transmission network may differ with each specific connection", i.e. will depend on whether the service is prescribed, negotiated or non-regulated. For example, whether:

1. components facilitating connection to the transmission network forms part of the shared network;
2. components can be electrically isolated from the shared network; and
3. whether transmission lines being built by the proponent to facilitate connection are less than 30 km.

[16] For context, this statement relates to project transmission infrastructure that is in close proximity to the existing regulated network which would be expected when transferring power from inland REZ's to electrolysers located at coastal ports. It does not relate to mining projects, for example, that utilise genuinely isolated grids, that are not in close proximity to the existing regulated network.

Under these three situations, the regulatory environment can be different.

Electrical equipment installed by the project proponent would have to meet requirements for Power Quality for Queensland as defined in Clause 5.3.4 of the NER.

6.4.4 Transmission Network Charges

If the project proponent connects into the shared network, they will be liable to pay TNSP for the usage of the regulated network via prescribed (or negotiated) charges. Because consumers pay for the cost of the regulated network, the project will be liable to pay prescribed or negotiated charges at the point of connection to the regulated network that shares connection to the electrolysers.

Prescribed Transmission Use of System (TUOS) payments will have a locational and non-locational component (Powerlink, 2023). A prescribed common transmission charge is also payable, covering the functioning of the transmission network service provider. Depending on the charges it may be calculated based on either a demand basis (MW) or energy basis (MWh). There may also be other charges relating to a network connection. The actual prescribed (or negotiated) charges facing a project proponent will depend on several specific case-by-case factors including:

- network configuration determined as part of the connection process;
- contracted network capability;
- number of other customers connected to the network;
- aggregate contract capability and energy taken off the network by all connected customers; and
- location of recent investment in the transmission network (TasNetworks (2023), p.11).

In Queensland, for 2022/23, non-locational TUOS charges are on annual equivalent basis \$19,708/MW/year (demand basis, based on kw/month) or \$4.87/MWh (energy basis) (Powerlink, 2022). Prescribed common transmission service prices are on annual equivalent basis \$22,176 MW/year/(demand basis) or \$5.48/MWh (energy basis)[17]. Total annual equivalent charges are 41,884/MW/year (demand basis) or \$10.37/MWh (energy basis).

Locational TUOS prices vary considerably from location to location and are defined in terms of (\$/kW/month). Generally, however, they are more expensive in North Queensland and at lower voltage levels. They range from an annual equivalent of \$3,418/MW (Braemar 275 kV) to \$102,530/MW (King Creek 132 kV).

Total non-locational and locational annual equivalent charges can vary from \$45,302/MW to \$144,414/MW[18]. Assuming a simple perpetuity valuation based on a 7% pre-tax real discount rate this is equivalent to an upfront cost of between \$647k/MW and \$2,063k/MW.

Delivering the Queensland Energy and Jobs Plan and Copperstring 2032 is expected to result in significant growth in Powerlink's network asset base, which may not be matched by load growth. The level of increase in TUOS and locational charges is uncertain, though in the medium term there is the potential for network charges including TUOS to grow considerably relative to current levels. Transmission investment is a critical enabling component of the Queensland Energy and Jobs Plan. The allocation of the costs of this network investment between customers through TUOS and other charges and TNSP (ultimately taxpayers) has not been determined.

Given the flexible characteristics of electrolysers and hydrogen conversion processes such as ammonia, there could be the potential for reductions in transmission charges, including TUOS, relative to an inflexible load. In principle a project proponent would need to demonstrate that: (1) their operations do not cause the need for any additional network augmentations; or (2) they can implement a beneficial demand response. The concept of Transmission charge discounts for flexible loads and in particular hydrogen electrolyser

[17] *For both these categories, a liable party will either pay the demand or energy based charges.*

[18] *For illustrative purposes calculated as the minimum and the maximum of the sum of annual equivalent prescribed common transmission service (on a demand basis), non-locational TUOS and locational TUOS charges.*

loads, is currently subject to significant industry debate, with TNSPs not highlighting any examples of the concept being implemented on proposed hydrogen projects.

Any unintended consequences of electrolyser operations should also be considered including distortion of marginal loss factors for customers and reduction of latent network capacity, especially considering projected load growth from electrification and potential load growth from less flexible loads that may have higher economic benefits.

6.4.5 List of References

Powerlink. (2022) *Schedule 2 - Shared Network Prices - 2022/23*. https://www.powerlink.com.au/sites/default/files/2022-03/2022-23%20Schedule%20of%20Transmission%20Shared%20Network%20Prices.pdf.

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TasNetwork. (2023) *Renewable Hydrogen Connections to the Tasmanian Electricity Network*. https://www.tasnetworks.com.au/config/getattachment/b1ebfaf0-9061-4c51-846a-3efb26c57eb6/hydrogen-brochure_v5.pdf