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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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1 Adjunct Industry Research Fellow, Centre for Applied Energy Economics and Policy Research, Griffith University, South Brisbane, Australia. Corresponding author - andrew.fletcher@griffith.edu.au

2 Department of Engineering Science, University of Oxford, Parks Road, Oxford, UK

3 Staff, Centre for Applied Energy Economics and Policy Research, Griffith University, South Brisbane, 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.

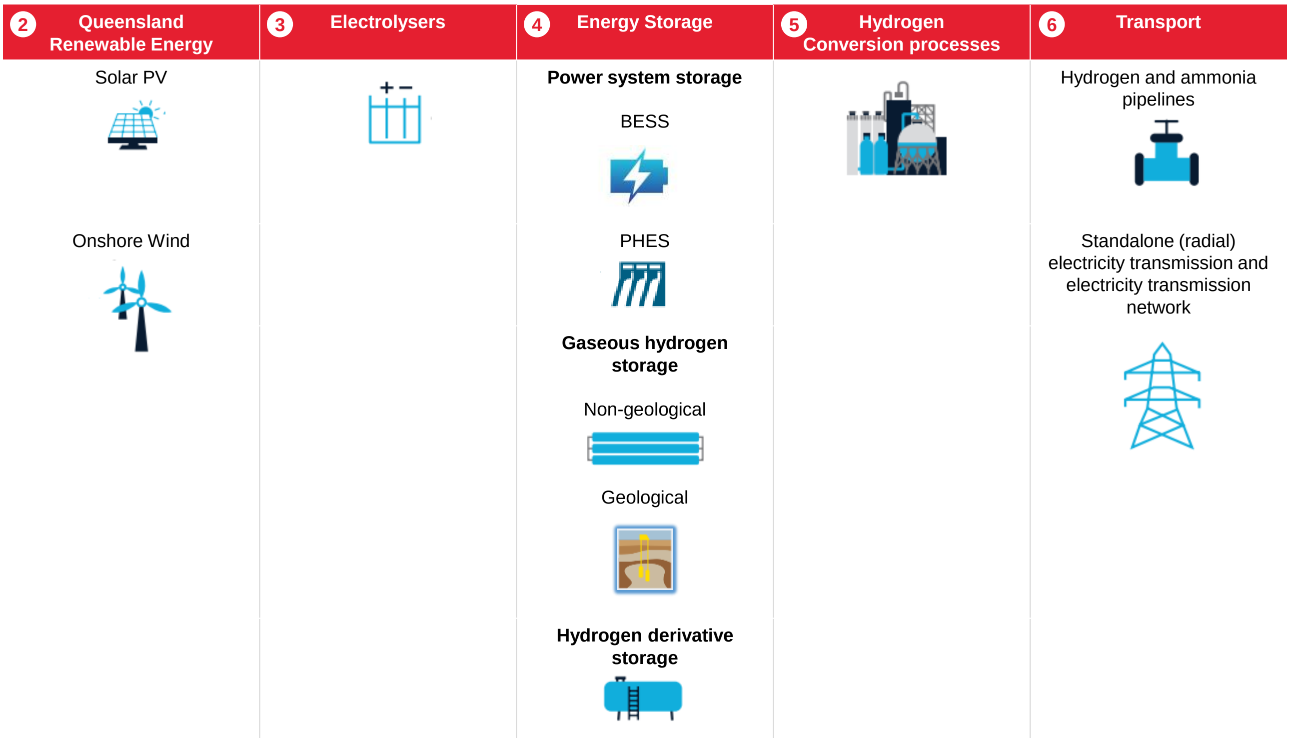

Figure 1: Information Sheets Map | *Image source: CSIRO (2023) Hydrogen vehicle refuelling infrastructure*

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).

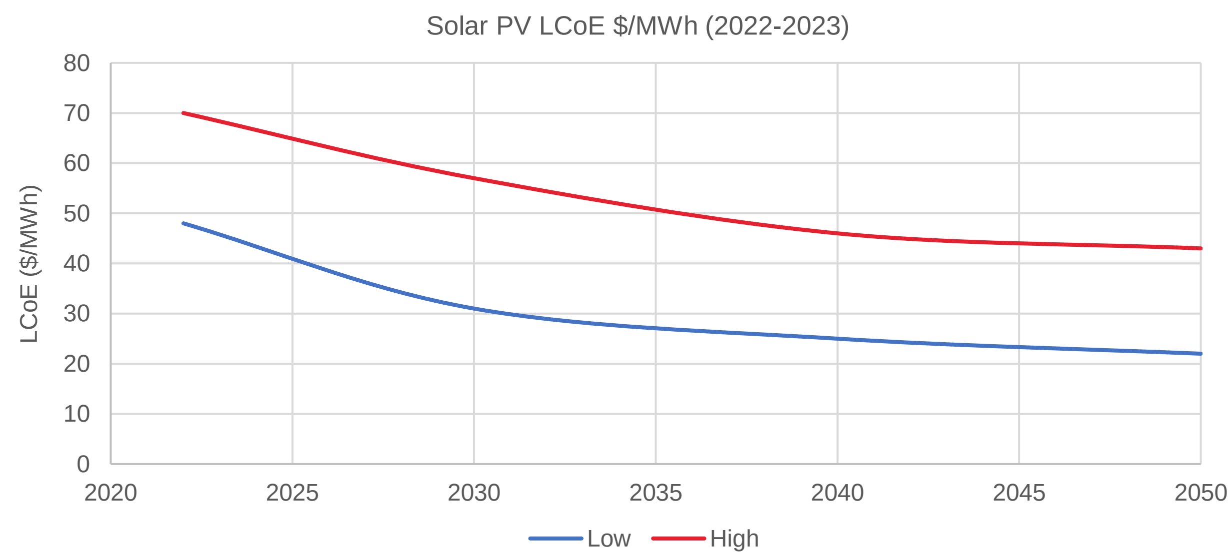

Figure 2: Solar PV LCoE $/MWh (2022-2023) | *Source: CSIRO GenCost 2022-23: Consultation Draft (2022)*

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.

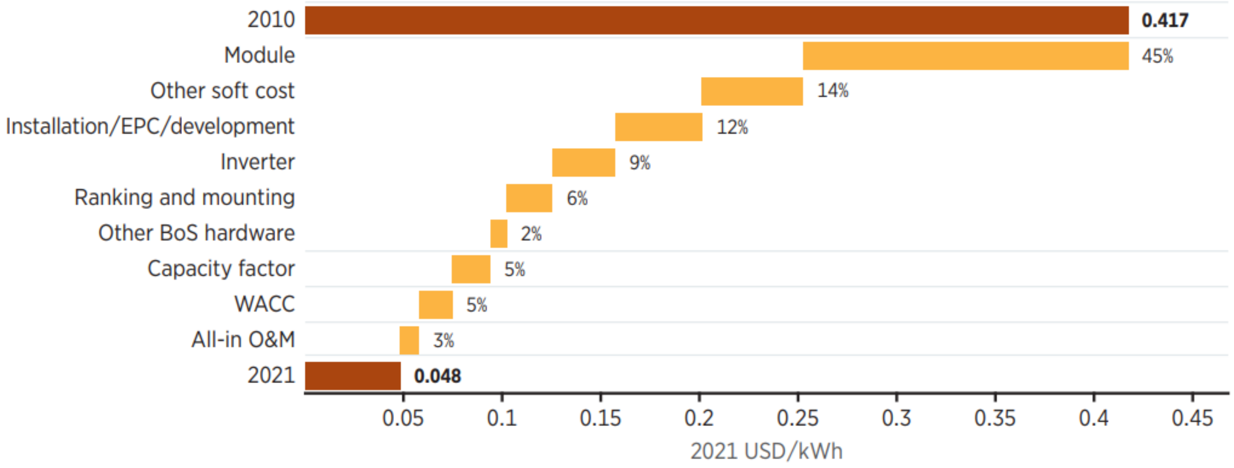

Figure 3: Drivers of the decline of LCoE of utility-scale solar PV (2010-2021) | Source: IRENA Renewable Cost Database

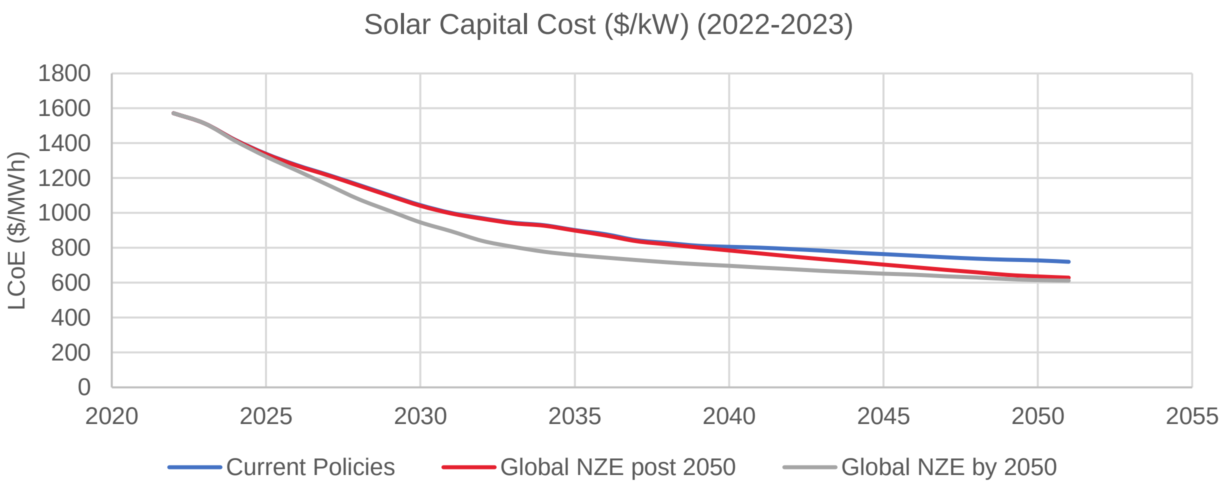

Figure 4: Solar Capital Cost ($/kW) (2022-2023) | Source: CSIRO GenCost 2022-23: Consultation Draft (2022)

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:

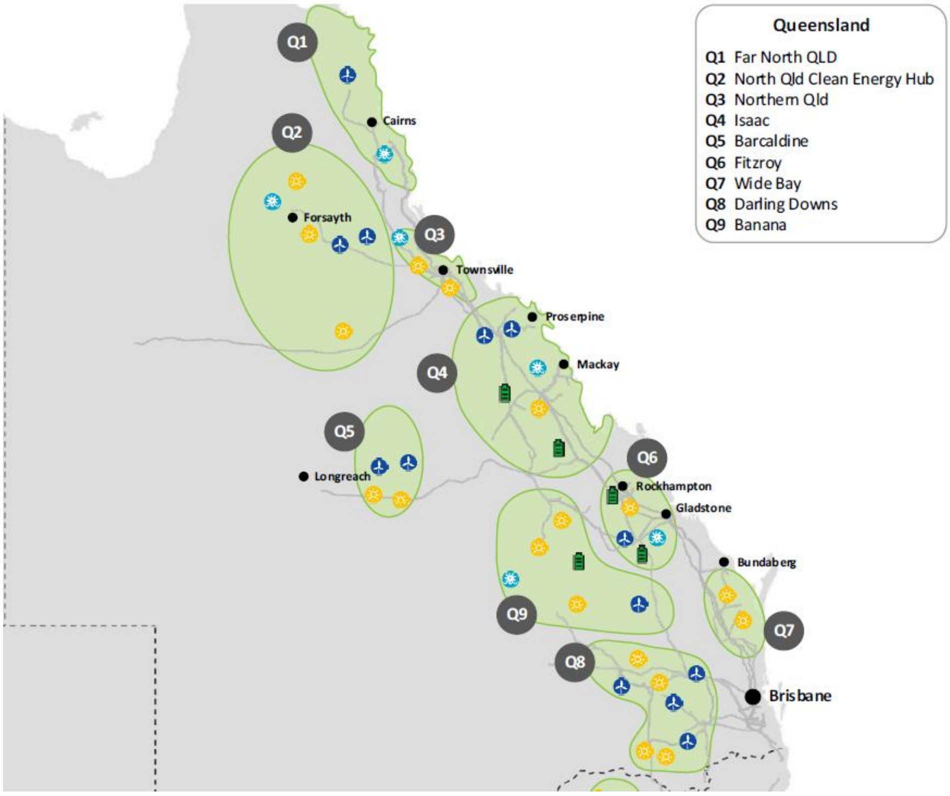

Figure 5: AEMO – Queensland Renewable Energy Zone Map | *Source: AEMO ISP Appendix 3 Renewable Energy Zones (2022)*

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.

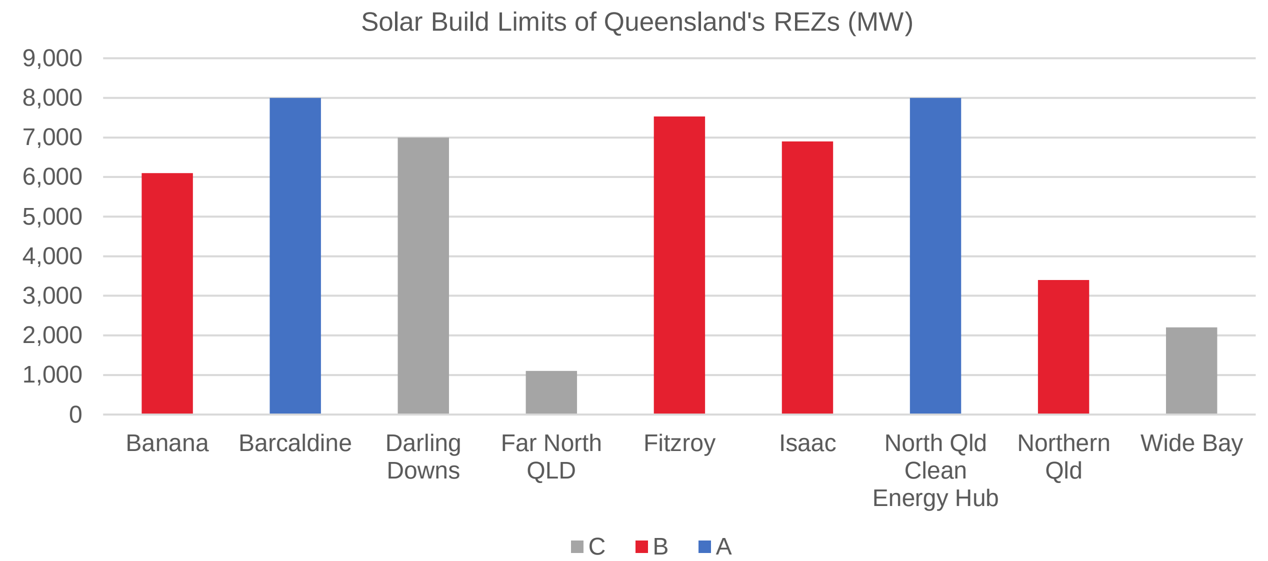

Figure 6: Solar PV resource grade – capacity factor | *Source: AEMO ISP Appendix 3 Renewable Energy Zones (2022)*

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.

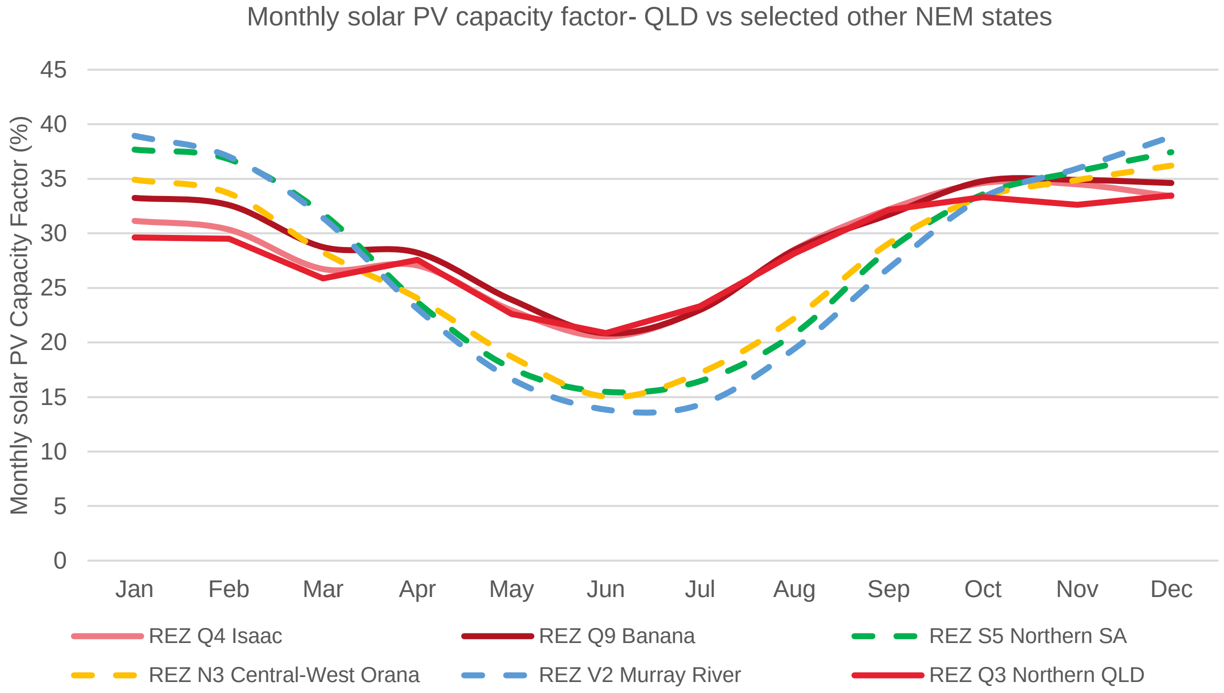

Figure 7: Monthly solar PV capacity factor- QLD vs. selected other NEM states | *Source: AEMO ISP 2022 ISP Solar traces (2022)*

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.

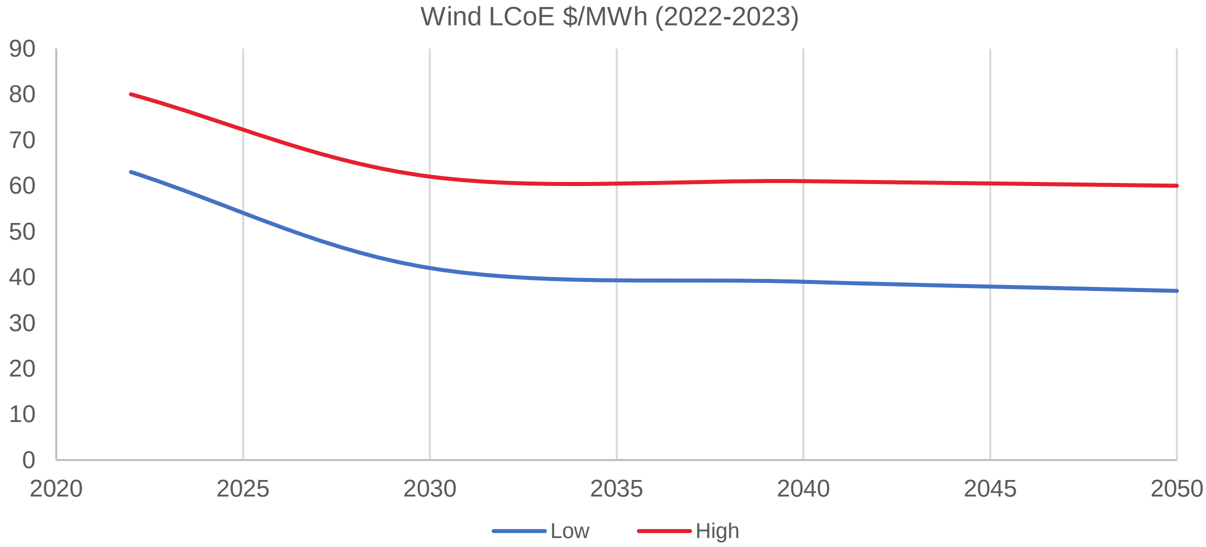

Figure 8: Wind LCoE $/MWh (2022-2023) | *Source: CSIRO GenCost 2022-23: Consultation Draft*

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.

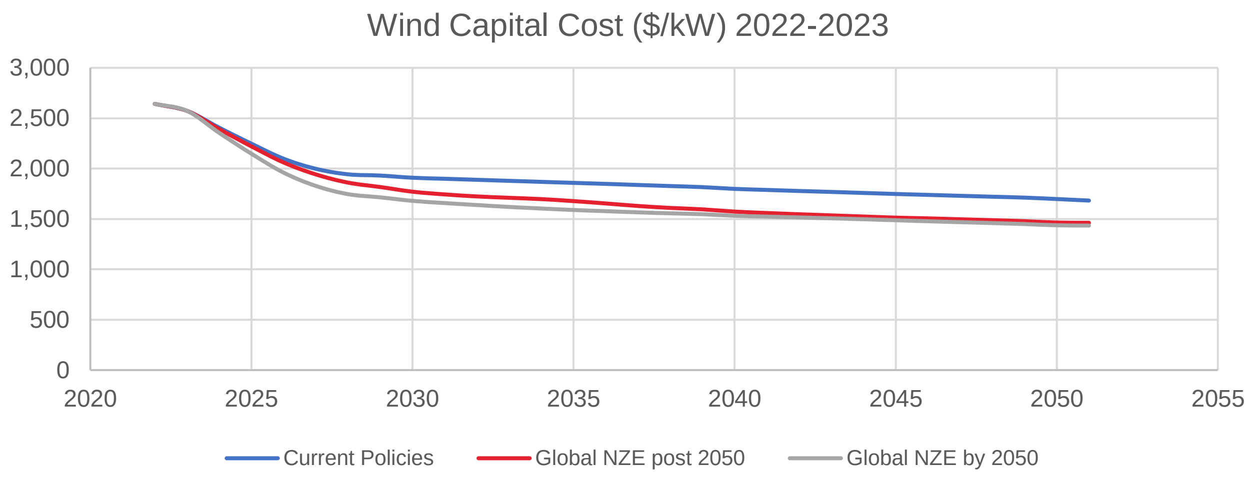

Figure 9: Wind Capital Cost ($/kW) 2022-2023 | *Source: CSIRO GenCost 2022-23: Consultation Draft*

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 .

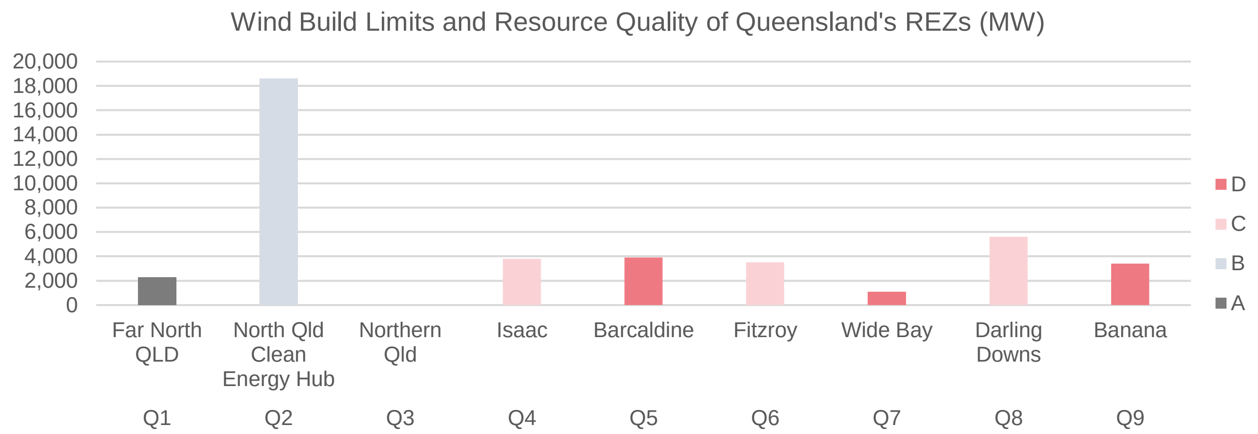

Figure 10: Wind Build Limits and Resource Quality of Qld's REZs (MW) | *Source: AEMO ISP Appendix 3 Renewable Energy Zones (2022)*

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.

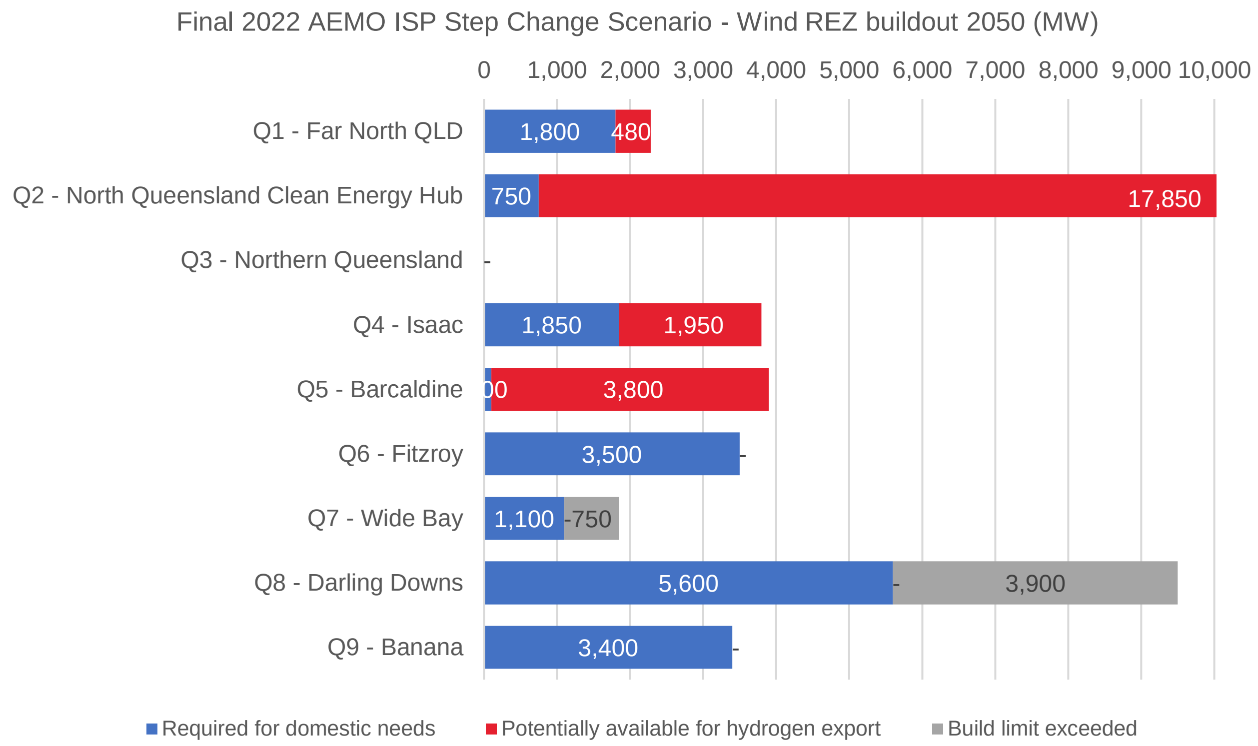

Figure 11: Final 2022 AEMO ISP Wind REZ buildout 2050 (MW of build limit) | *Source: AEMO ISP Appendix 3 Renewable energy zones (2022)*

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.

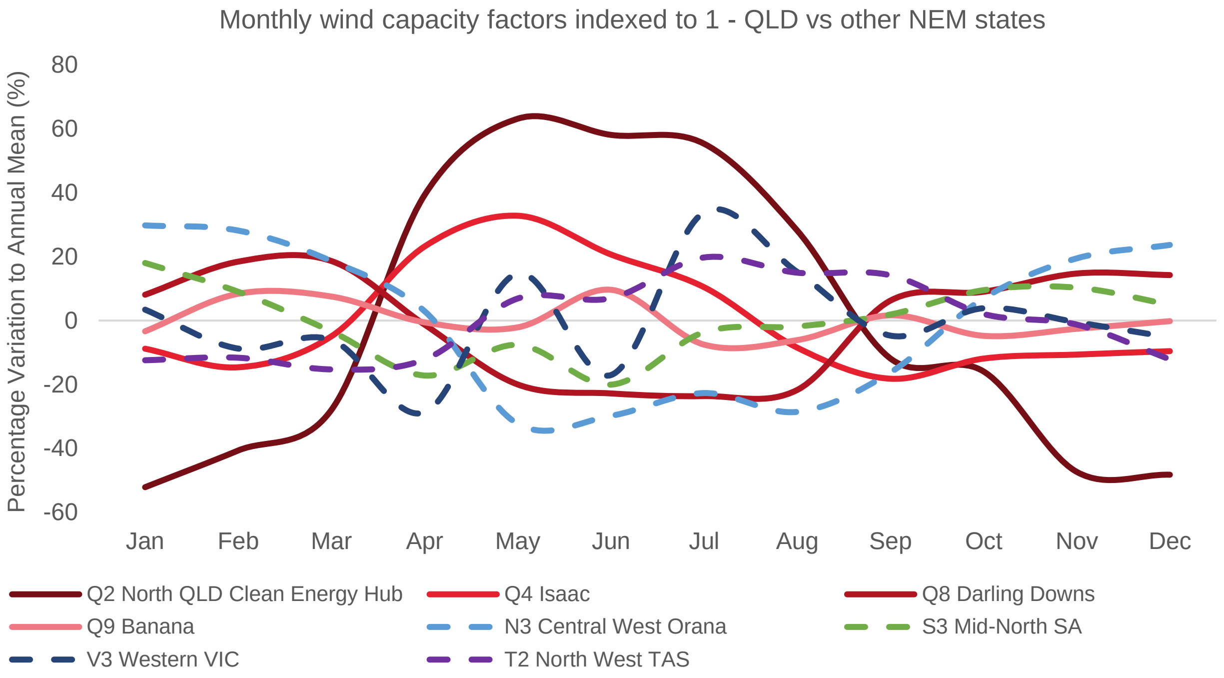

Figure 12: Monthly wind capacity factors indexed to 1 - QLD vs. other NEM states | *Data source: AEMO ISP 2022 Wind traces (2022)*

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.

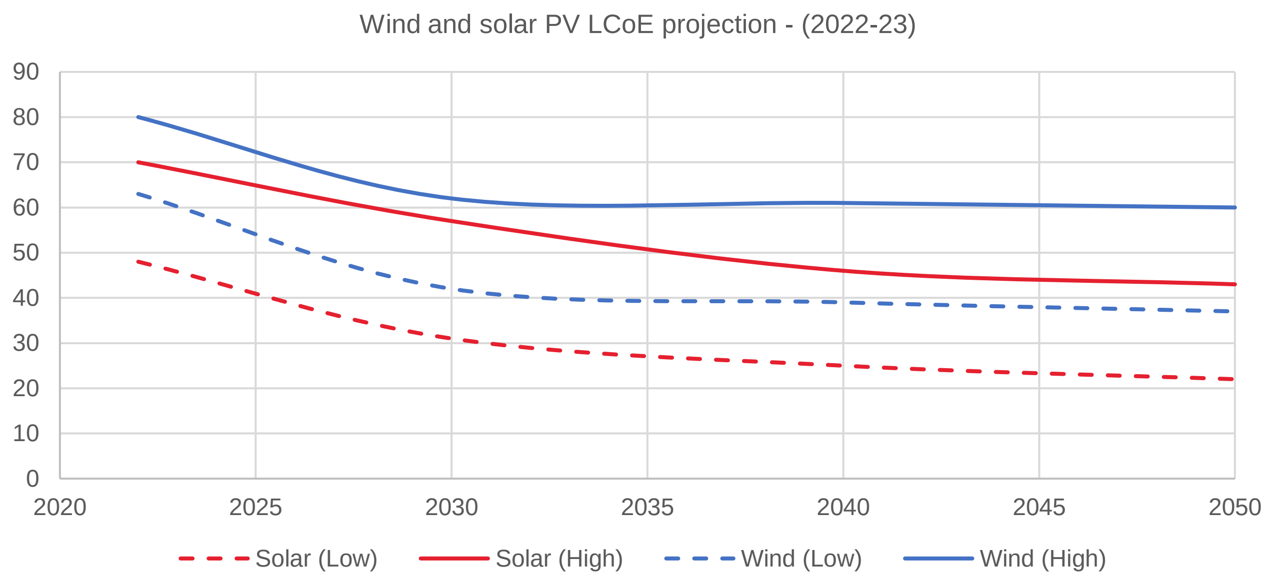

Figure 14: Wind and solar PV LcoE projection – (2022-23) | *Source: CSIRO GenCost 2022-23: Consultation Draft*

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.

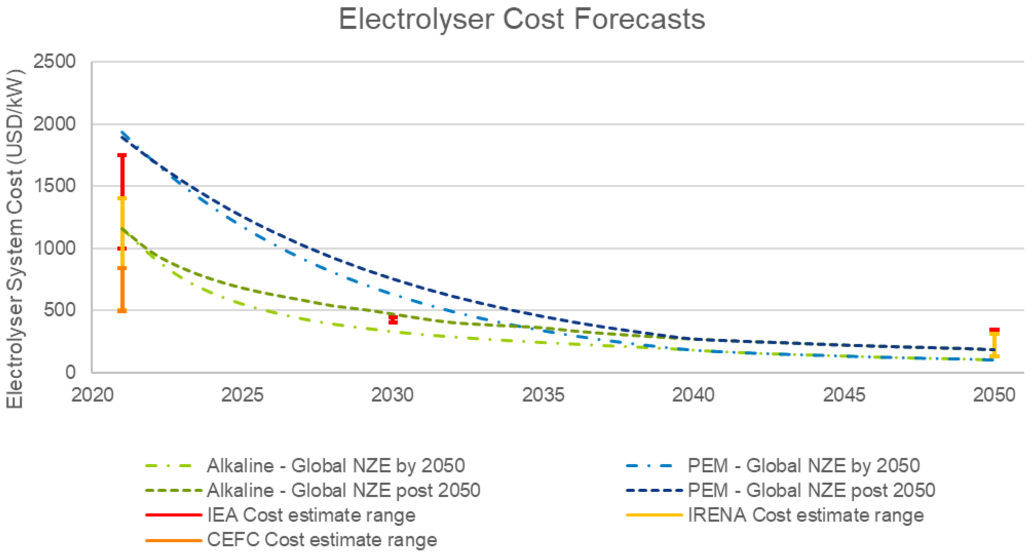

Figure 15: Estimates of electrolyser system costs as a function of time | *Source: CSIRO (2022), CEFC (2021), IEA (2022), IRENA (2021)*

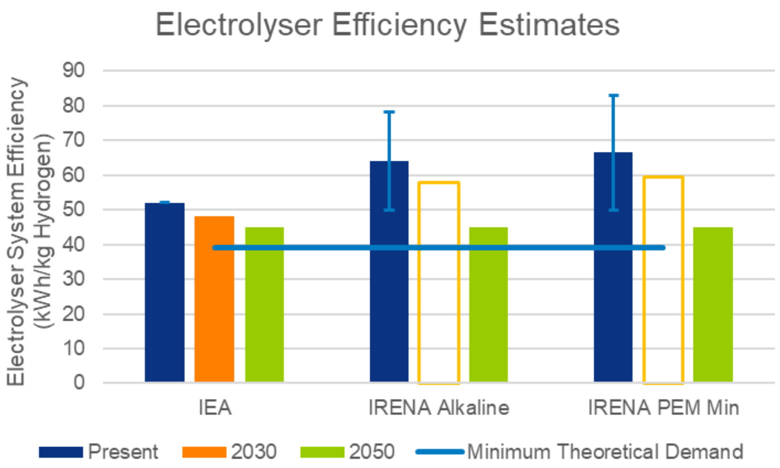

Figure 16: Estimates of electrolyser efficiencies from various sources changing over time | *Source: IEA (2022), IRENA (2021)*

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.

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[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.*

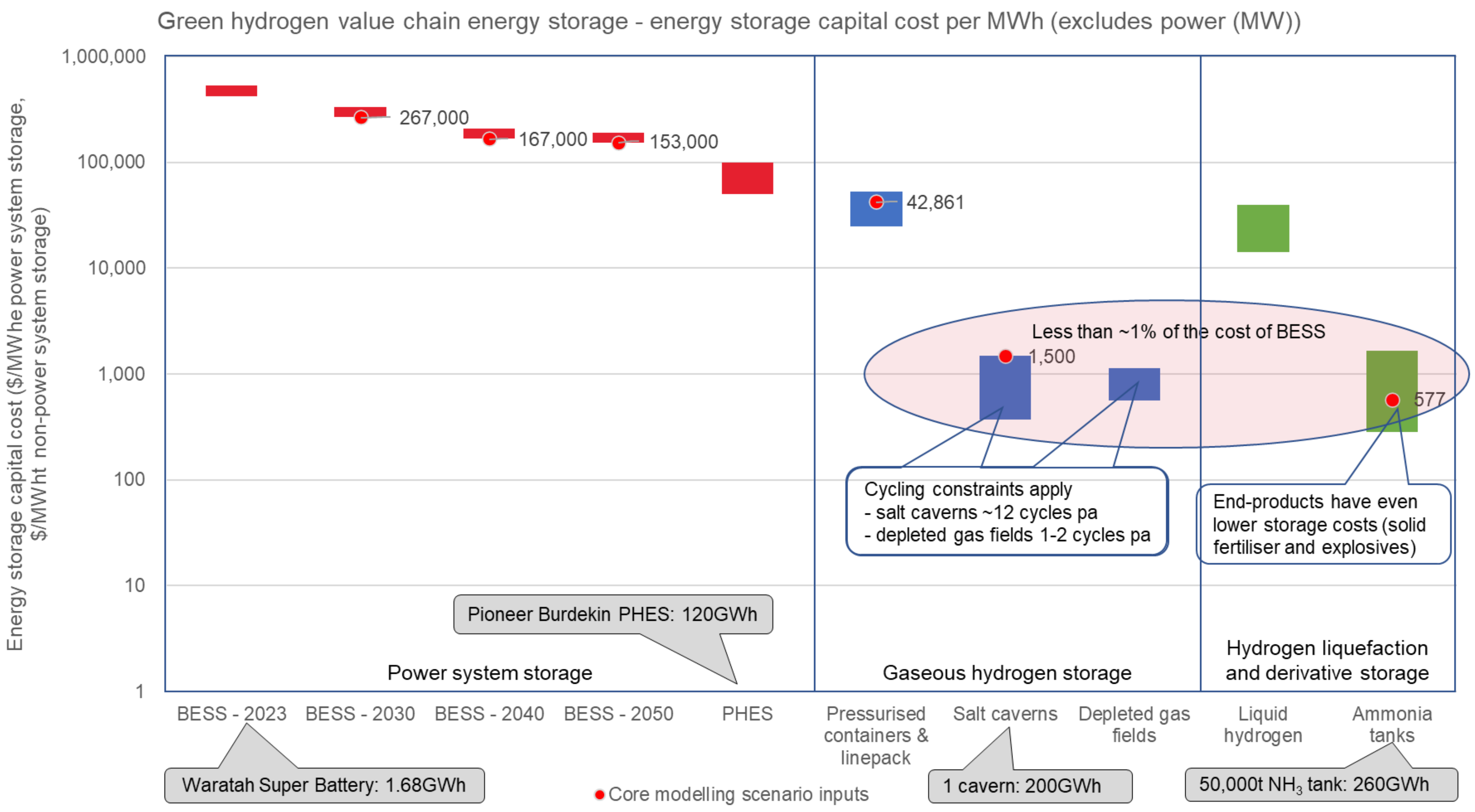

Figure 17: Green hydrogen value chain energy storage – energy storage capital cost per MWh (excludes power (MW))

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.

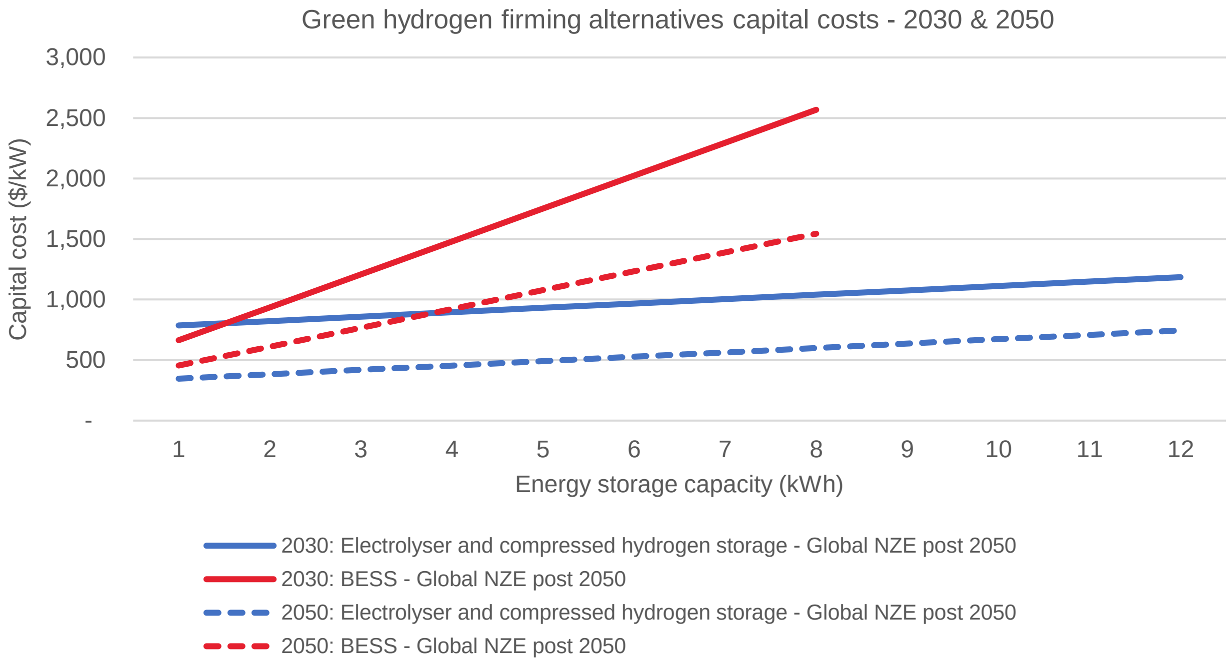

Figure 18: Green hydrogen firming alternatives capital costs - 2030 & 2050 | *Data source: CSIRO GenCost 2022-23: Consultation Draft (2022)*

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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.

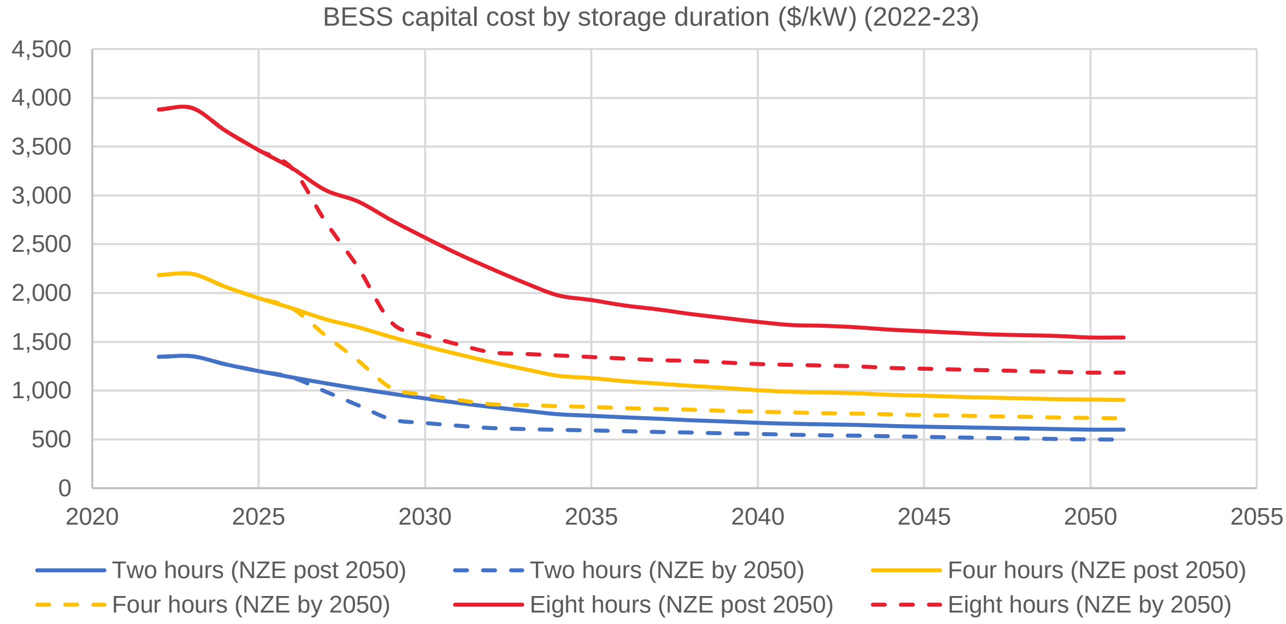

Figure 19: BESS capital cost by storage duration ($/kW) (2022-23) | *Source: CSIRO GenCost 2022-23: Consultation Draft (2022)*

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.

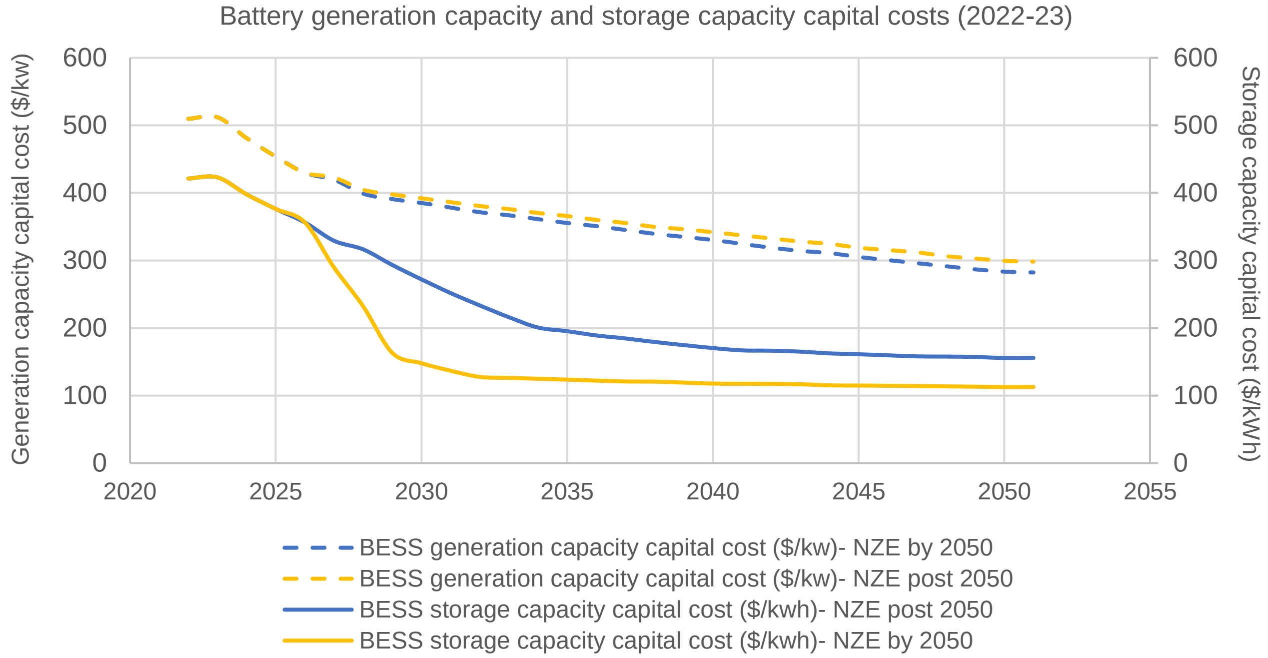

Figure 20: Battery generation capacity and storage capacity capital costs (2022-23) | *Data source: CSIRO GenCost 2022-23: Consultation Draft (2022)*

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.

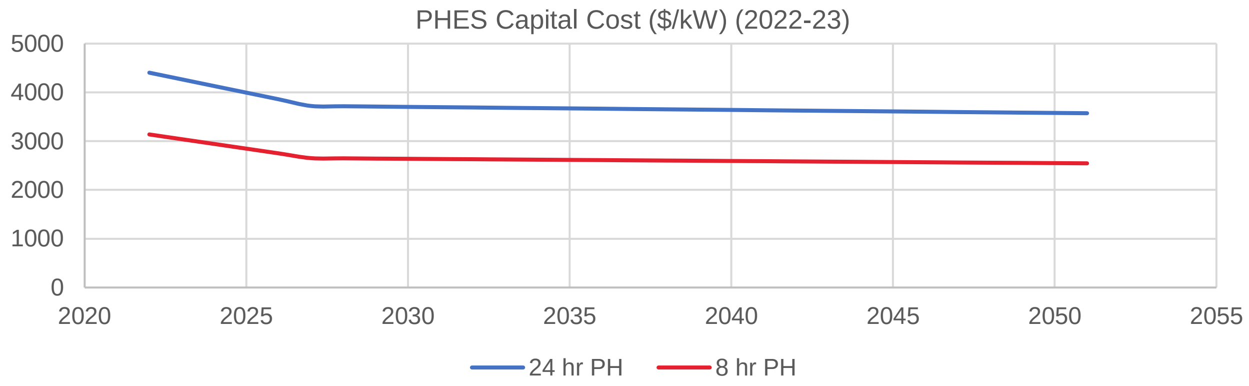

Figure 21: PHES Capital Cost ($/kW) (2022-23) | *Source: AEMO ISP Inputs, assumptions and scenarios workbook (2022)*

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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.

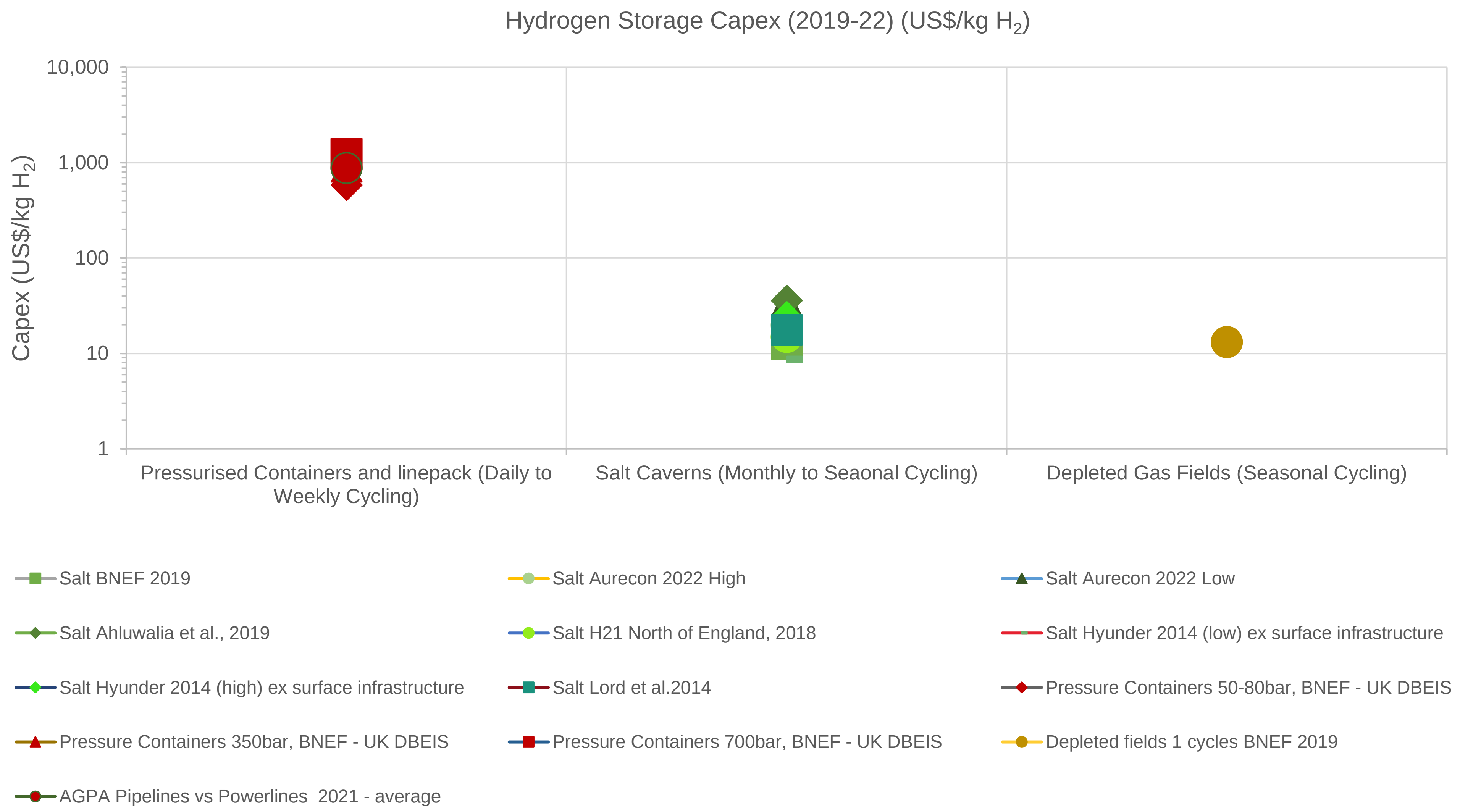

Figure 22: Hydrogen gas storage costs for different storage types (capex per kilogram H_2). Current prices (2019-22)

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.

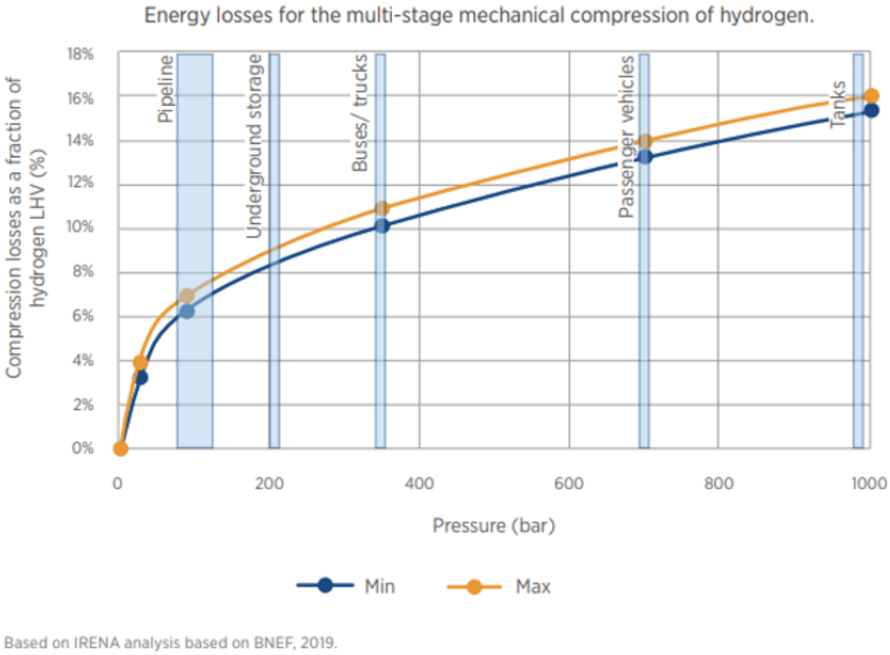

Figure 23: Energy losses for the multi-stage mechanical compression of hydrogen | Source: Based on IRENA analysis based on BNEF, 2019

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.

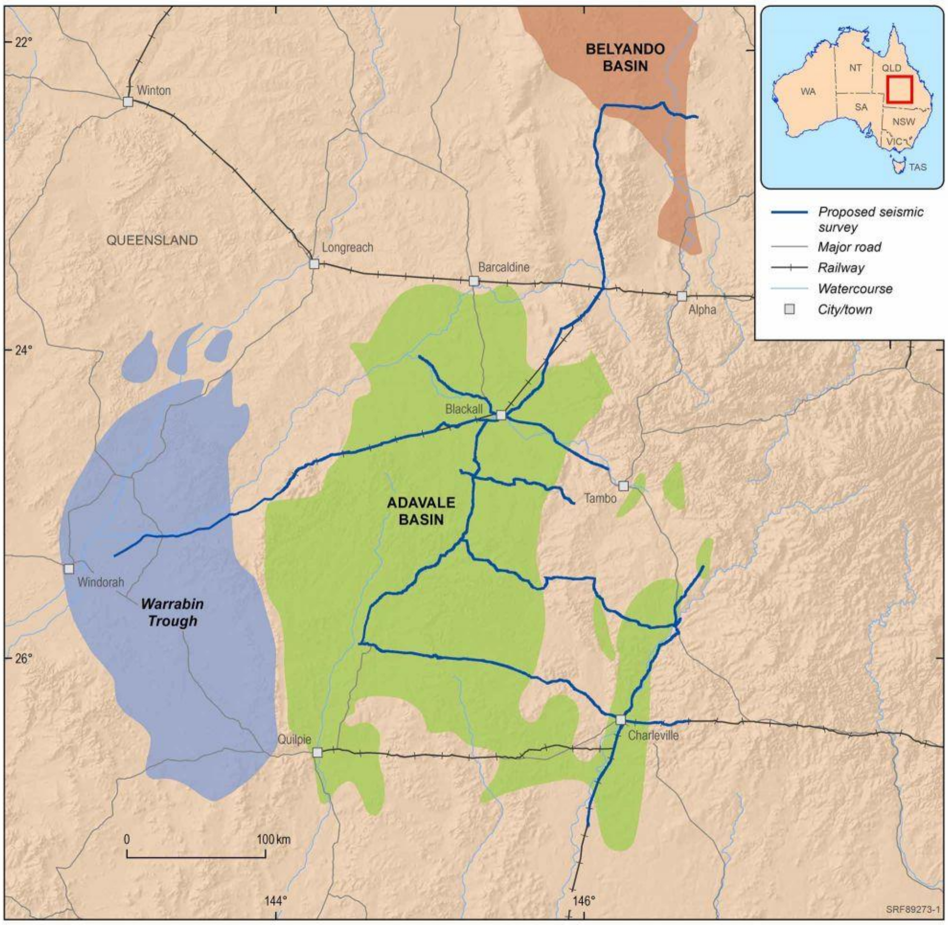

Figure 25: Adavale Basin map - seismic acquisition survey | *Source: Geoscience Australia (2023)*

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^{o}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^{o}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

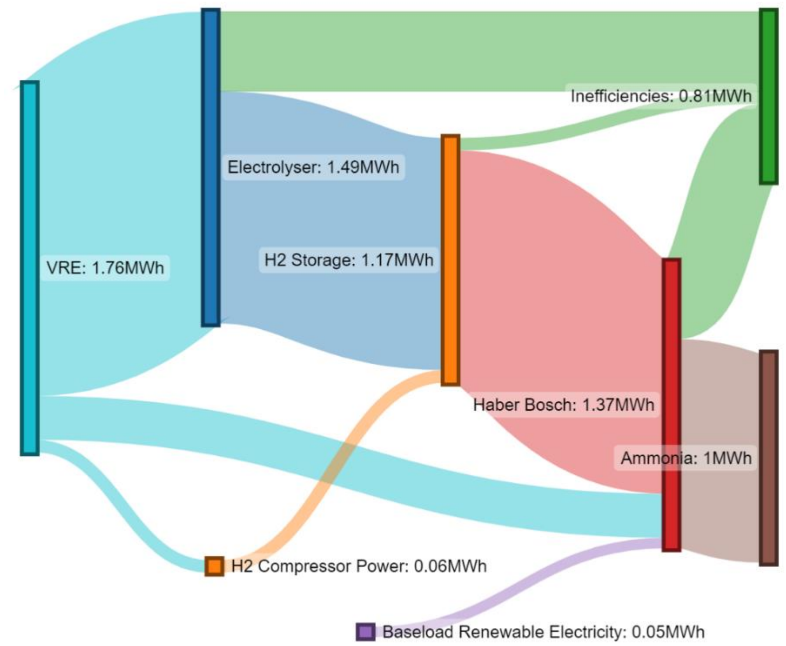
Table 8: Estimation of ammonia production cost and efficiency

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

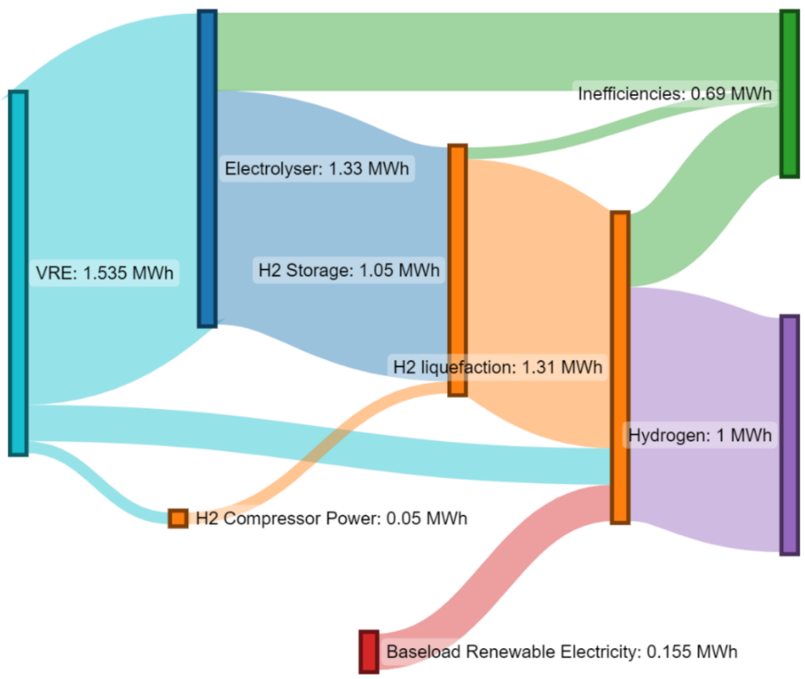


Figure 29: Comparison of energy flows for Liquid Hydrogen and Chemical Fuels, normalised to 1 MWh of fuel production

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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TRANSPORT

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.

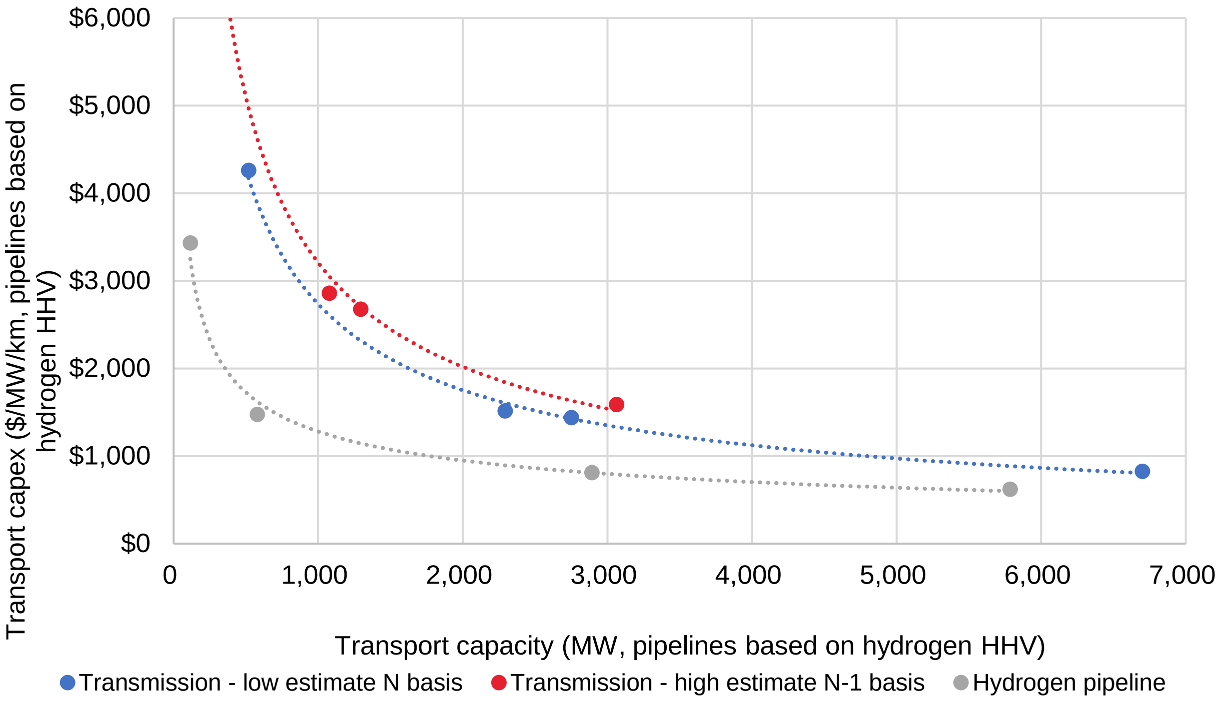

Figure 30: Capex vs. capacity for 250km transmission and one way hydrogen pipelines

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.

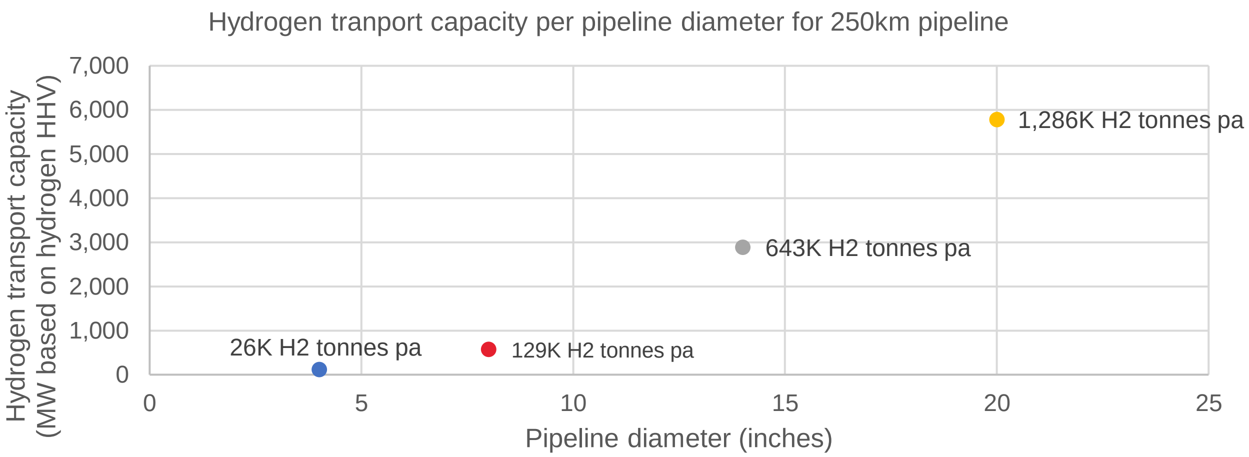

Figure 31: Hydrogen transport capacity per pipeline diameter for 250km pipeline | *Data source: Australian Gas and Pipeline Association. (2021).*

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

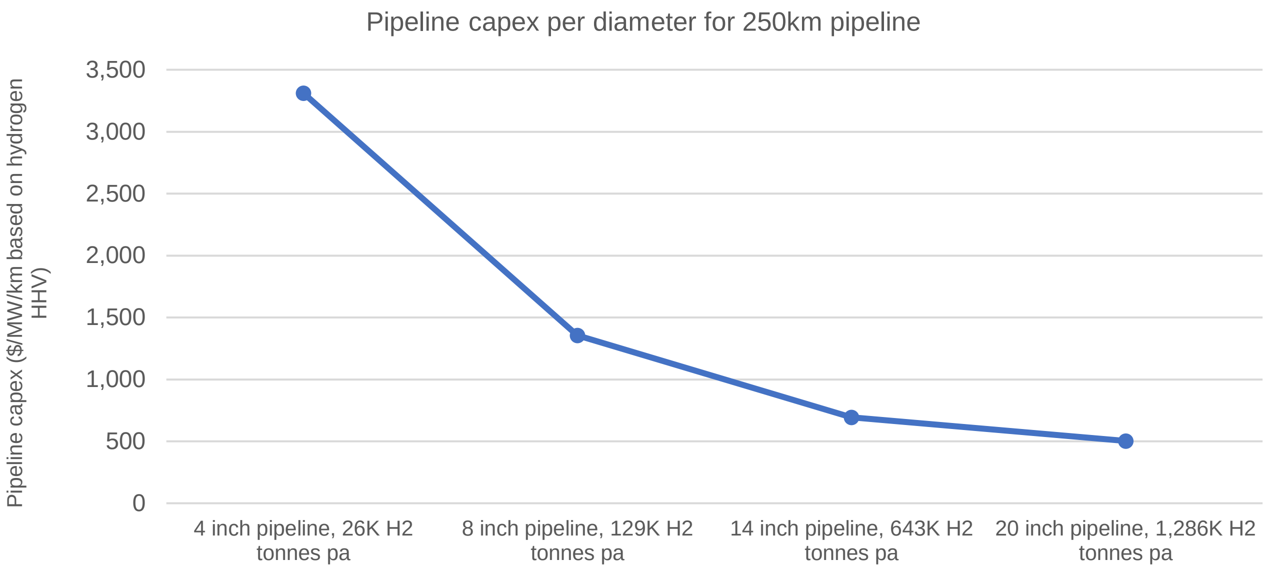

Figure 32: Pipeline capex per diameter for 250km pipeline | *Data source: Australian Gas and Pipeline Association. (2021).*

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.

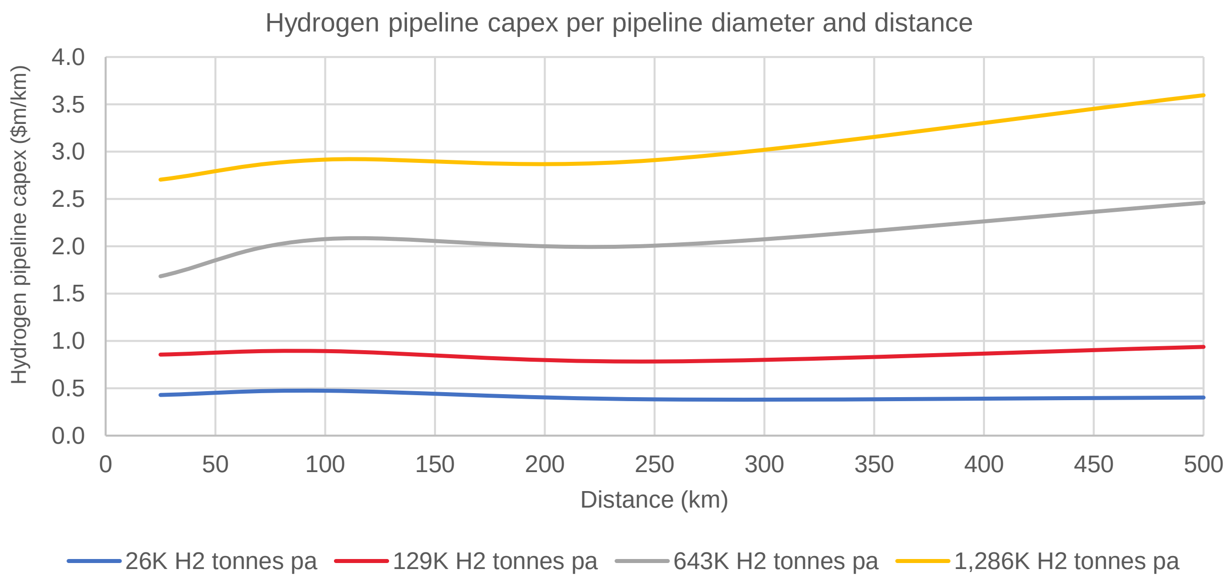

Figure 33: Hydrogen pipeline capex per pipeline diameter and distance | *Data source: Australian Gas and Pipeline Association. (2021).*

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.

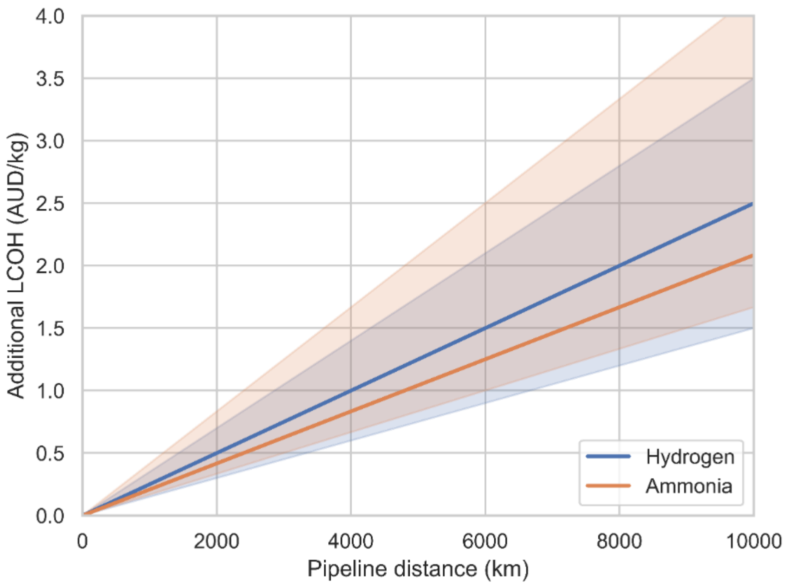

Figure 34: Pipeline transport cost estimates for gaseous hydrogen and liquid ammonia

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.

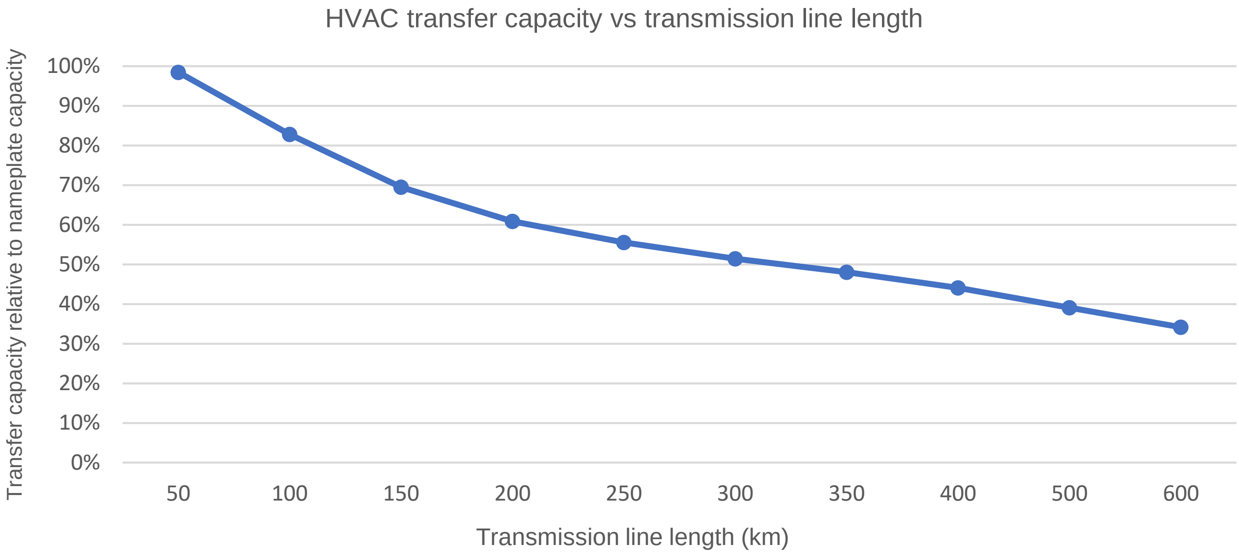

Figure 35: HVAC Transfer capacity vs. Transmission line length | *Source: St Clair, (1953) and Dunlop et al, (1979)*

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.

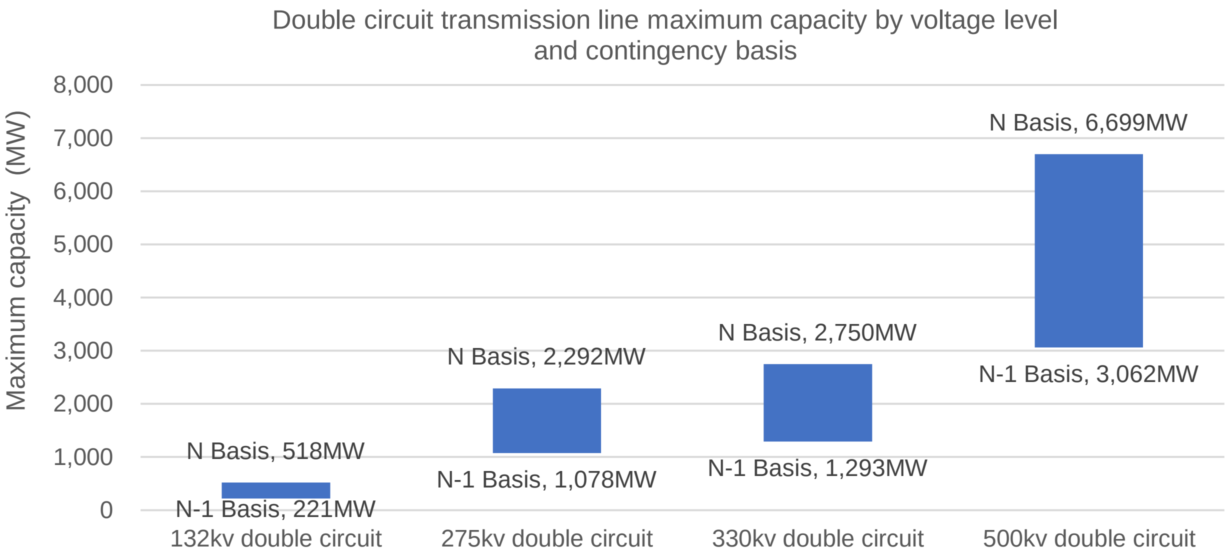

Figure 36: Double circuit line capacity and voltage level | *Data source:* 2022 AEMO Transmission Cost Database (2023).

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.

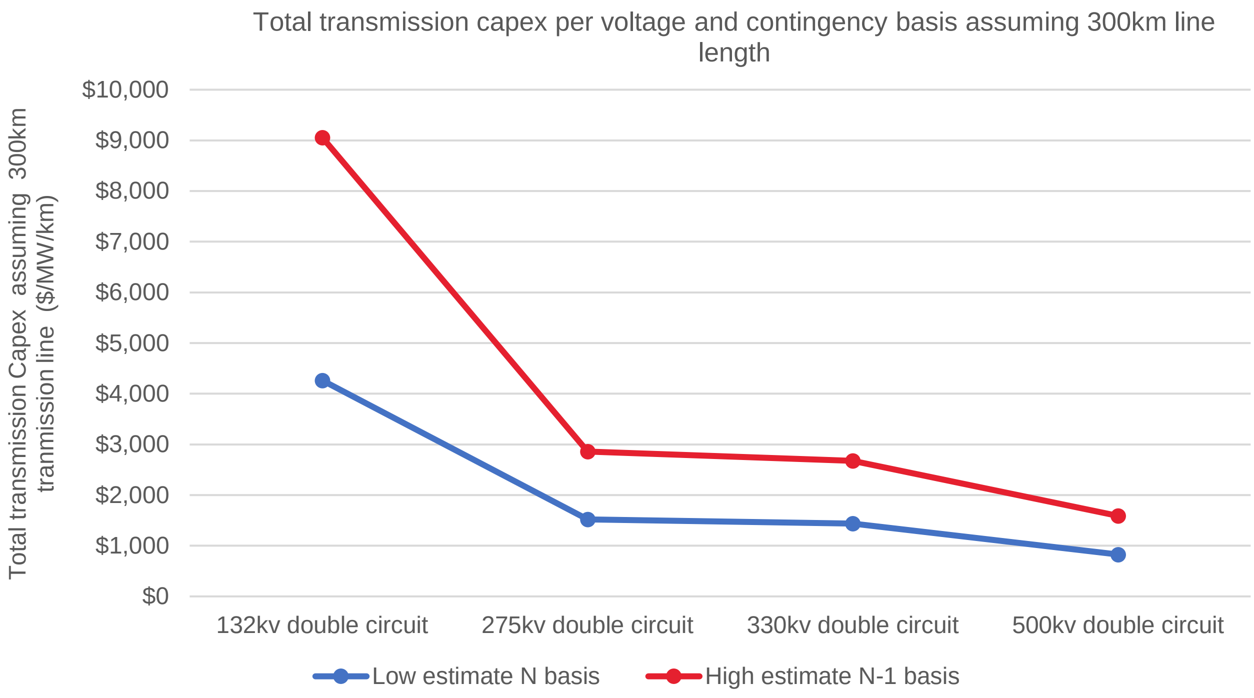

Figure 37: Total transmission capex for 132kV to 500kV | *Data source:* 2022 AEMO Transmission Cost Database (2023)

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.

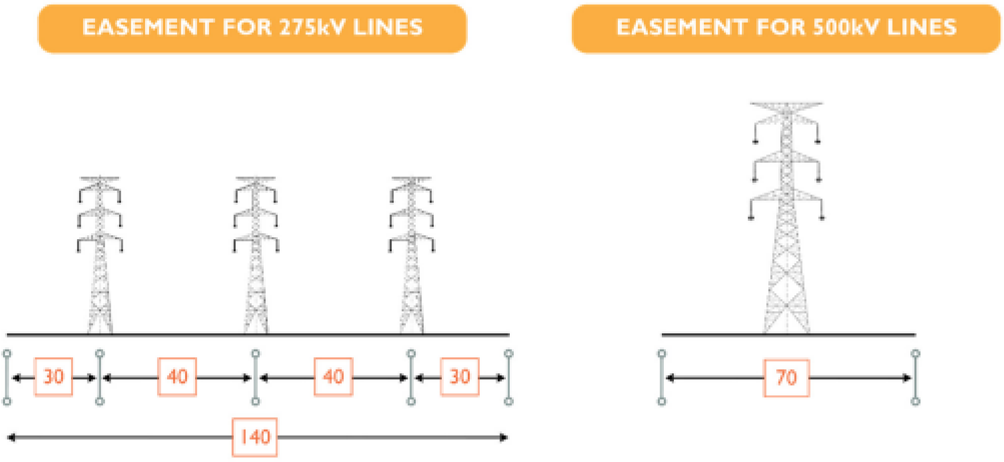

Figure 38: Easement widths | *Source: Powerlink (2022)*

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.

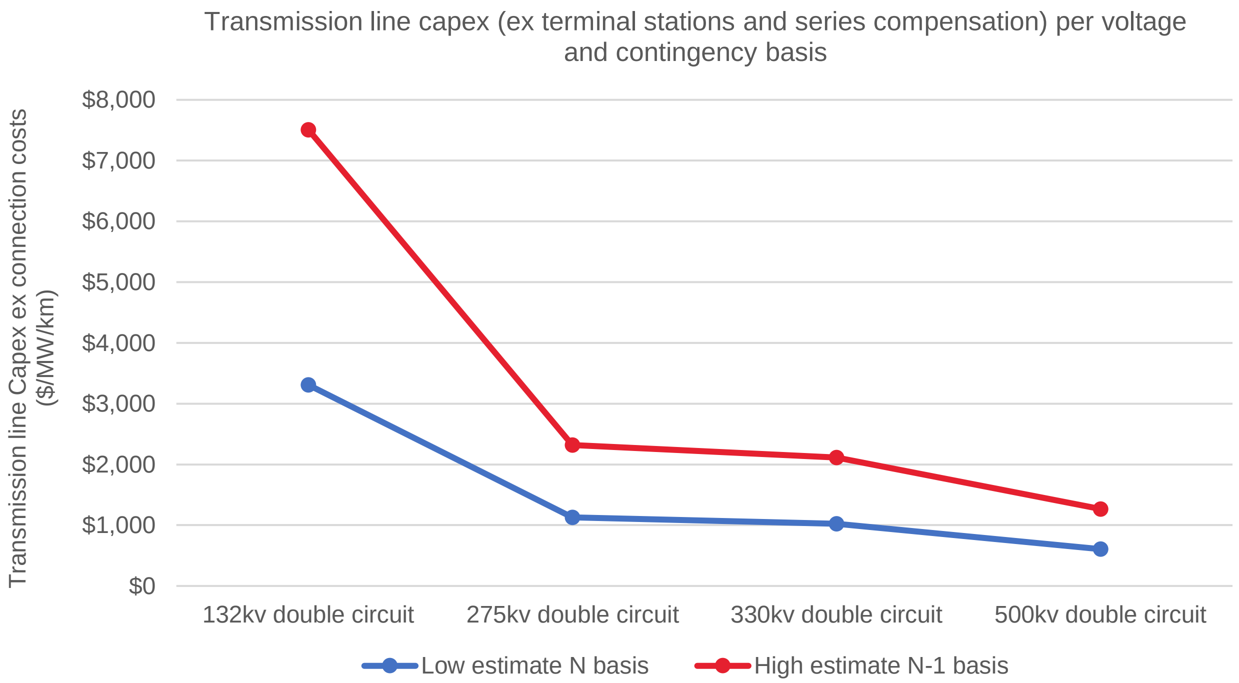

Figure 39: Transmission line capex per voltage and contingency basis | Data source: 2022 AEMO Transmission Cost Database (2023)

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.

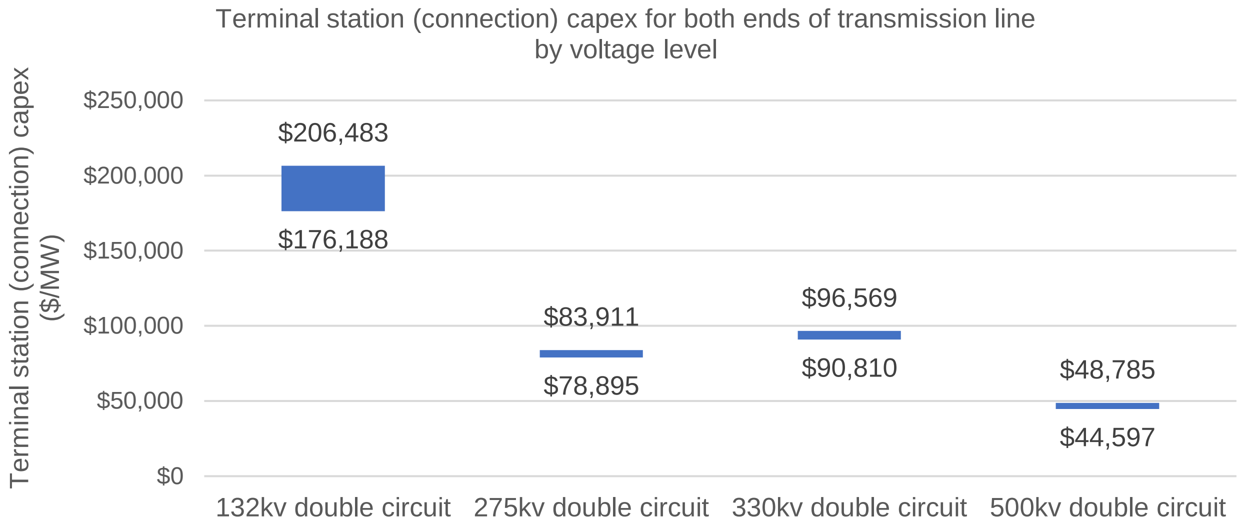

Figure 40: Terminal station (connection) capex for both ends of transmission line by voltage level | *Data source:* 2022 AEMO Transmission Cost Database (2023)

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.

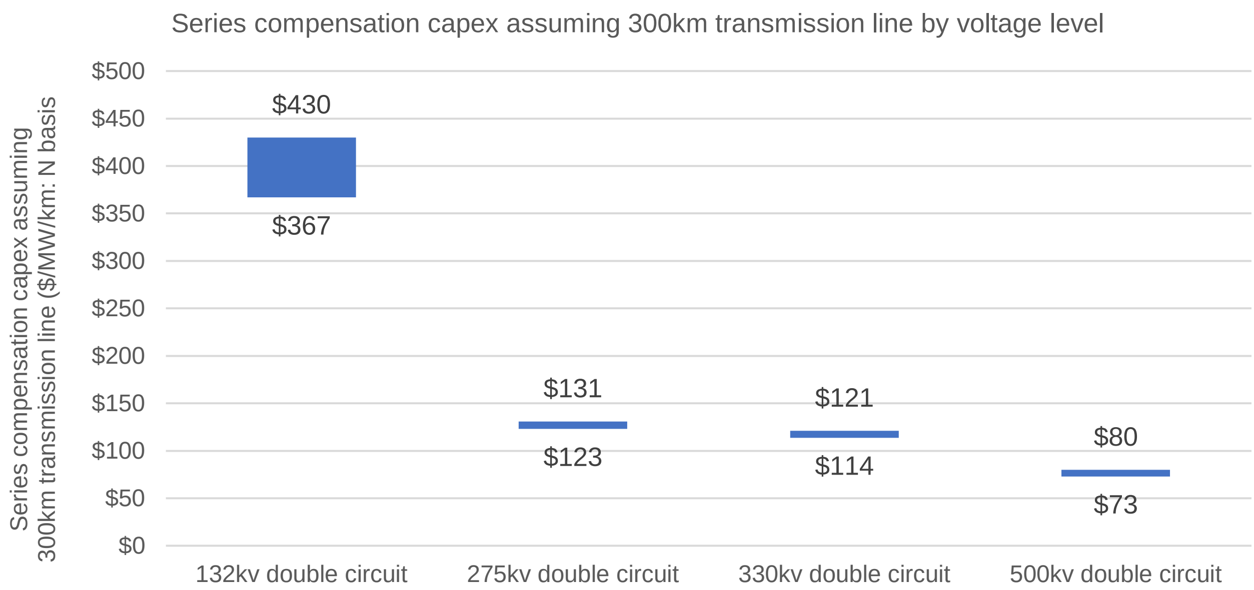

Figure 41: Series compensation capex assuming 300km transmission line by voltage level | *Data source:* 2022 AEMO Transmission Cost Database (2023)

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

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