

Techno-economic and Environmental Assessment of LNG Export for Hydrogen Production

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Abstract

A critical requirement of a widely contemplated hydrogen economy is the development of a low carbon hydrogen supply chain that is cost competitive. This comprehensive techno-economic assessment demonstrates, for the first time, the viability of a complete hydrogen supply chain based on the transport of liquefied natural gas (LNG). This is demonstrated via the established LNG trade route from Australia to Japan against three key performance indicators (KPIs): delivered hydrogen cost, CO₂ emissions intensity (EI) across the entire supply chain, and technology readiness level (TRL). The hydrogen supply chain entails LNG export to Japan where it is used for blue hydrogen production; the by-product CO₂ is then liquefied and repatriated to Australia for sequestration or utilisation. Within this supply chain, various hydrogen production technologies are assessed, including steam methane reforming (SMR), autothermal reforming (ATR) and natural gas pyrolysis (NGP). SMR with carbon capture and storage (CCS) resulted in the lowest total hydrogen supply cost of 19 USD/GJ (2.3 USD/kg_{H2}) which comfortably meets the 2030 Japanese hydrogen cost target of 25 USD/GJ (3 USD/kg_{H2}) and is very close to the 17 USD/GJ 2050 Japanese hydrogen cost target. This technology also obtained the lowest CO₂ emission intensity (EI) of 38 kgCO₂/GJ (4.5 kgCO₂/kg_{H2}); this was surprisingly lower than ATR with CCS primarily due to the emissions associated with ATR electricity provision for air separation. Future technologies and strategies are detailed so as to further reduce cost and supply chain emissions; these were shown to be able to reduce total CO₂ EI to 14 kgCO₂/GJ (1.6 kgCO₂/kg_{H2}). Hence this analysis indicates that this supply chain can act to significantly reduce CO₂ emissions whilst uniquely meeting targeted hydrogen supply costs up to 2050. As such it is proposed here as an eminently viable hydrogen export option deploying both existing technology and capacity, at least until other hydrogen supply chain vectors (such as liquid hydrogen and ammonia) derived from green hydrogen production become competitive across all the KPIs.

Keywords

Hydrogen economy; Closed carbon cycle; Supply chain; Energy vector; Delivered cost; Emissions intensity

1. Introduction

The complex task of providing a secure energy supply whilst reducing greenhouse gas (GHG) emissions is critical if climate change is to be mitigated [1]. A critical target of 50% global emissions reductions by 2030 has been highlighted as necessary if global temperature increase is to be curtailed [2, 3]. Meeting this target is contingent on rapid change in global energy supply chains, for which hydrogen provides a potential candidate. In response, the concept of a ‘hydrogen economy’ has become an enticing prospect which has gained increasing traction. A ‘hydrogen economy’ can be defined as an envisioned future in which hydrogen is used as a fuel source for both transportation and stationary energy production. Hydrogen is seen to offer a range of benefits as a clean energy carrier [4-9], which include: the potential to mitigate carbon emissions in the energy supply chain with no CO₂ emissions on combustion, a high gravimetric energy density at 2.4 times that of conventional natural gas (based on lower heating value (LHV)) [10] and applicability to a wide range of manufacturing and energy sectors as chemical feedstock [11]. On this basis, global hydrogen demand in 2050 is projected to reach 220 million tonnes per annum (Mtpa) [12], which is comparable to the global liquefied natural gas (LNG) market which stood at 360 Mt in 2020 [13]. This increasing hydrogen demand coupled with strict emissions targets motivates the implementation of hydrogen supply chains (HSC) to allow for a rapid transition to a ‘hydrogen economy’.

However, at present, both the cost and technology readiness levels of hydrogen production via electrolysis [14] (so called green hydrogen [15]) coupled with various forms of hydrogen storage and transport (including liquid hydrogen [16], compressed hydrogen and ammonia [17]) present significant barriers. Given numerous hydrogen supply chain options, prior work has focused on establishing the optimum pathway for various supply chain scenarios. For example, Hong et al. [18] undertook a ‘techno-enviro-economic’ analysis which compared nine hydrogen supply chains based on four energy carriers (Compressed H₂, LH₂, LOHC and LNH₃) with three transport methods (pipeline, ship and truck) utilised by two end-use sectors (power/industry for application in combined cycle gas turbines, and fuel-cell based transport for application in FCEVs). As grounds for comparison, Hong et al. quantified the carbon emissions (from process fuel consumption) and hydrogen losses (generated from supplying energy for processing such as additional compression, gasification or pumping) along a supply chain via an associated ‘energy penalty’ value, as well as a ‘carbon avoidance’ percentage (relative to a comparable NG supply chain) and the associated cost to achieve this carbon abatement. This study demonstrates the potential issues introduced by the long-distance transport of hydrogen, including the increased infrastructure and elevated costs associated with hydrogen liquefaction.

Lee et al. [19] compared the economic and environmental performances of five different hydrogen export technologies (i.e., liquid hydrogen, ammonia, toluene-methylcyclohexane (TOL-MCH), dibenzyltoluene-perhydrodibenzyltoluene (H₆DBT-H₁₈DBT), and methanol [20]) when applied to a large-scale hydrogen supply chain that carries 300,000 tonne of hydrogen per year via ship from Melbourne (Australia) to South Korea. This techno-economic review compared hydrogen production from various sources (natural gas, coal or renewable energy) via different processes, namely SMR, ATR, CG or electrolysis. It was found that TOL-MCH was the optimum energy carrier for this particular large-scale and long-distance supply chain, with a 5.8 USD/kg_{H₂} levelized hydrogen cost and 18.5 kgCO₂-eq/kg_{H₂} carbon intensity. To compare the long-term performance, a 2050 scenario of increased renewable electricity availability was considered, in which case the ammonia supply chain generated

the lowest carbon emissions (2.23 kg_{CO2-eq}/kg_{H2}), while the TOL-MCH supply chain remained the most cost-effective (4.57 USD/kg_{H2}). A decrease in process energy consumption and the use of renewable energy sources was found to be essential for efficient and sustainable hydrogen seaborne transport.

Additional techno-economic studies can be found in references [21-26]. Collectively such studies show that no one hydrogen supply chain will be appropriate for every scenario, also none considers the use of LNG as an established means of effectively exporting hydrogen with return of the CO₂ following reforming processing for hydrogen generation. This study is thus motivated to compare hydrogen supply chains based on existing Australian LNG export followed by on-site, blue hydrogen production in Japan coupled with CO₂ repatriation against hydrogen supply chains based on imported liquid hydrogen or ammonia (blue and green) from Australia (WA). This leads to the proposition here of an alternate hydrogen supply chain, which importantly leverages the existing, established LNG industry and infrastructure. In this supply chain, LNG is transported as an energy vector in place of liquid hydrogen or ammonia. The LNG can then be subsequently used as feedstock for hydrogen production via reforming technology at the location of hydrogen use. Carbon emissions from this production can be captured and transported to a location of permanent storage or utilisation to ensure a low emission carbon cycle. Such a supply chain is the focus of this work which executes a detailed techno-economic analysis of the entire chain in terms of the ultimate cost of the delivered hydrogen and the total CO₂ emissions incurred. This is then benchmarked against both relevant hydrogen cost targets and an equivalent analysis for domestic hydrogen production followed by liquid hydrogen export.

The feasibility of such an LNG-based hydrogen supply chain is founded on knowledge of the existing LNG industry. LNG production and maritime transportation is a well-established and reliable industry that has been in operation for decades, with global LNG trade peaking at over 350 Mtpa in recent years [27], due to its prominence as a fuel for various applications including energy generation in regions such as Asia. The well-established and stringently regulated nature of the LNG industry has consequently given rise to both low cost and safe operations. Furthermore, the LNG shipping fleet is also well established and comprised of over 600 vessels at the close of 2020, with an average individual vessel capacity of 150,000 m³ and a total capacity of nearly 100 million cubic meters [27]. This large-scale LNG production infrastructure and existing shipping fleet can hence be readily and immediately deployed into a hydrogen supply chain without any further technological development. To this end, a specific scenario has been selected to assess the viability of such a supply chain, whereby LNG is produced and exported from Western Australia, with subsequent blue hydrogen production (methane reforming or pyrolysis coupled with carbon capture and storage (CCS)) in Japan using the imported LNG as feedstock. Australia is the largest global LNG exporter, accounting for 22% of all global exports in 2020, with Western Australia (WA) alone exporting 44 Mtpa [28]. An established very large LNG market already exists between WA and Japan which has been in operation since 1989. Today, Japan accounts for approximately 50% of all WA LNG exports and is one of the largest LNG importers globally [28].

Japan also has ambitious hydrogen cost and emissions targets, rendering it a poignant subject for such scenario analysis. Japan has announced a target to reach net-zero GHG emissions by 2050 which was enshrined into legislation in 2020 [29]. At the 2021 Leaders' Climate Summit, Japan also announced a new domestic emissions reduction target of 50% by 2030 relative to 2013 GHG emissions [29], and the country's 'Green Growth Strategy' was revised to provide sector-level, technology-focused roadmaps towards the net zero target. CCS is critical if such

emissions targets are to be met, however CCS projects in Japan are in pilot or demonstration phases and can't support commercial scale operation [30]. Consequently, CO₂ generated in Japan would require long distance transport to viable sites for carbon sequestration, for which Australia currently has commercial-scale facilities in operation [31]. For cost-effective long distance transport in cargo vessels, CO₂ should be in a dense form (i.e. liquid) [32]. As such, liquefaction of CO₂ and subsequent possible re-gasification for sequestration form key components of the proposed low-carbon cycle supply chain. In relation to the delivered cost of hydrogen, the Japan Ministry of Economy, Trade and Industry (METI) outlines a target hydrogen cost of 30 yen/Nm³_{H₂} (3 USD/kg_{H₂}) by 2030, with an ultimate goal of 20 yen/Nm³_{H₂} (2 USD/kg_{H₂}) by 2050 to allow hydrogen to become cost-competitive with traditional energy sources when carbon-pricing cost adjustments are incorporated [33].

To the best of our knowledge, there is no literature considering an LNG transport route specifically for hydrogen production with the return of the CO₂ produced for storage or utilization. This work thus presents a new hydrogen supply chain option which utilizes a substantial existing trade route thus leveraging off existing infrastructure and networks. Economic viability and emission intensity are considered for a variety of permutations of the various components of this chain.

2. Scope and Methodology

On the basis outlined above, this paper undertakes a techno-economic and environmental assessment of an Australia-Japan hydrogen supply chain scenario that uses LNG as the energy-vector. The supply chain also incorporates carbon capture and utilisation or storage (CCUS) [34] to ensure a low emission carbon cycle in alignment with emission targets. As outlined in **Figure 1**, the sequential stages of the supply chain include:

1. Natural gas (NG) extraction and LNG production within Australia
2. LNG export via cargo vessel from Australia
3. Blue hydrogen production in Japan using the imported LNG as feedstock and fuel
4. CO₂ capture from blue hydrogen production with subsequent CO₂ liquefaction
5. Liquefied CO₂ (or solid carbon) shipment to Australia
6. CO₂ storage via geological sequestration, or utilisation via the Sabatier process to generate methane for reuse as feedstock for LNG production

Three potential blue hydrogen production methods will be analysed within this supply chain, namely steam methane reforming (SMR), autothermal reforming (ATR) and natural gas pyrolysis (NGP) for a 100 tpd hydrogen production rate scenario. Such a scale is indicative of a commercial SMR production plant while also being within the capability bounds of current technology used for the more emerging processes of NGP and ATR [35]. The cost and CO₂ emissions intensity generated from each stage of the supply chain is determined to develop a comprehensive understanding of cumulative supply chain cost and CO₂ emissions. Economic and emissions data is sourced from multiple sources for each stage of the supply chain with every plausible effort being made to ensure that these are as applicable as possible to the relevant stage location.

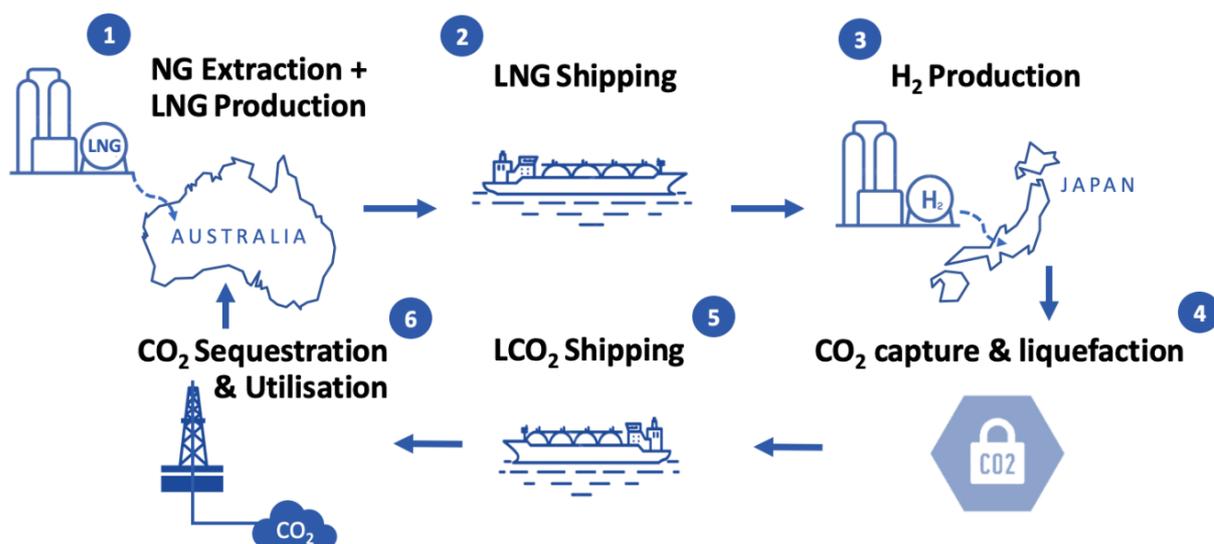


Figure 1. LNG energy-vector hydrogen supply chain for an Australia-Japan scenario.

It should be noted that the cost of hydrogen's end-utilisation within Japan (e.g., the cost of refuelling stations) are beyond the scope of this study and not included in the total emissions intensity and cost estimates, respectively. Hence, all references to 'total cost' refer to the 'delivered' cost of hydrogen to Japan and not the 'dispensed' hydrogen cost in Japan. It is assumed that hydrogen produced on-site in Japan is subsequently delivered as compressed hydrogen via pipeline (i.e. it is not compressed to the high pressures required for refuelling stations and FCEVs). Similarly, delivered LH₂ is re-gasified to the same pressure for compressed gas distribution in pipelines. Delivered ammonia is cracked back to H₂ at the destination and the produced hydrogen is compressed to the same pressure. This essentially creates a 'level playing field' between the three supply chain pathways in terms of cost and emissions for 'end-use' and eliminates the need to consider refuelling station technology and costs.

The viability of this supply chain is thus assessed against three key performance indicators (KPIs); the delivered hydrogen cost (USD/kg_{H₂}), the total CO₂ emissions intensity (kg_{CO₂}/kg_{H₂}) and the overall technology readiness level (TRL). These KPIs are benchmarked against Japan's 2030 target hydrogen cost of 3 USD/kg_{H₂}, an idealised emissions intensity of zero, and a TRL of 9 or above which represents commercially implementable technology. The results are compared to the equivalent KPIs of both the existing Australia-Japan LNG supply chain, and conceptual Australia-Japan liquid hydrogen and ammonia supply chains. Viability for this specific scenario can be used to indicate broader viability for both Asia-Pacific hydrogen supply chains and potentially hydrogen supply chains globally. Methodology used in this work is outlined in the **supplementary information—section 1**.

3. Current Hydrogen Supply Chain Options

The hydrogen supply chain, as displayed in **Figure 2**, consists of four key stages: (1) production, (2) storage, (3) transport, and (4) utilisation. Within each of these stages, there are various potential technologies, leading to multiple supply chain pathways which can support a hydrogen economy.

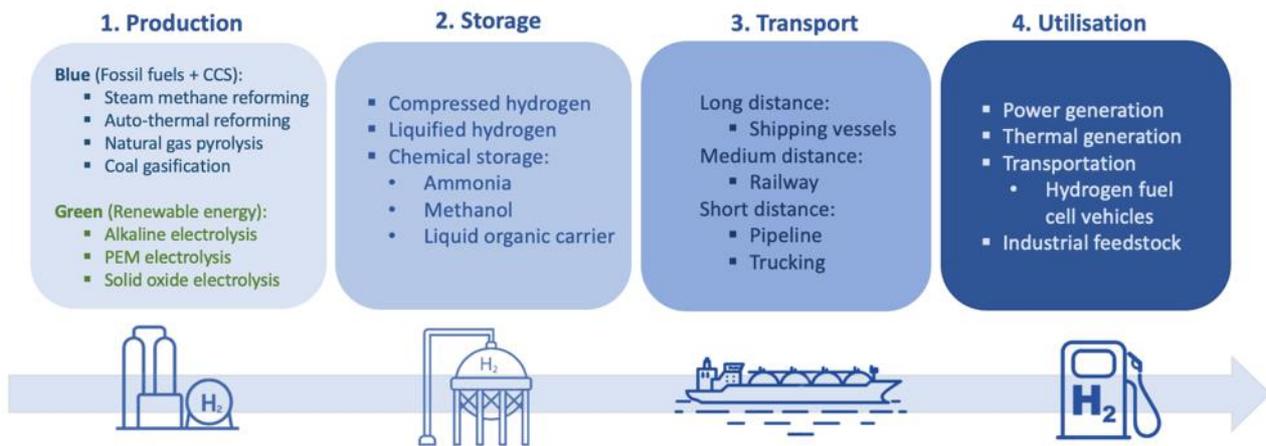


Figure 2. The four key stages of a hydrogen supply chain, with a non-exhaustive list of relevant technology and processes.

3.1 Production

Approximately 50% of the 70 Mtpa of hydrogen currently produced is generated from natural gas using steam methane reforming (SMR) [36-40], and another 18% from coal gasification (CG) [41]. SMR and CG thus form the most established production methods and are currently implemented on a commercial scale, however, very seldom integrate CCS. Blue hydrogen production methods continue to evolve however, with two technologies – namely auto-thermal reforming (ATR) and natural gas pyrolysis (NGP) – identified as having the potential to be utilised on a commercial scale in this capacity. ATR builds on current SMR technology, with the potential to achieve higher efficiencies and strongly reduce flue gas emissions [42-44]. Owing to its superior energy efficiency, ATR with CCS may be critical in achieving cost-effective decarbonisation [42].

In NGP, methane is heated in the absence of oxygen and air, which precludes the formation of GHG emissions. Crucially, if energy from an exclusively renewable grid is used in conjunction with the pyrolysis technology, it presents no direct CO₂ emissions. Although it is still arguably at pilot scale and requires a renewable or low-carbon heat source, this technology has four-to-five times lower electricity consumption than electrolysis and potentially lower hydrogen production costs [45]. On this collective basis, blue hydrogen produced from fossil fuels is being recognised as a means to develop the infrastructure, regulatory standards, trading relationships and economies of scale that will be required for green hydrogen production in the future.

As of 2020, global green hydrogen production via electrolysis utilising renewable energy sources such as wind and solar photovoltaics (PV) is reported to be just 0.3% of total hydrogen production [46]. Proton exchange membrane (PEM) electrolysis and alkaline electrolysis (AE) are key technologies that have been demonstrated as viable on a commercial scale [47], and there is a growing view that an ultimate transition to green hydrogen will be necessary for full decarbonisation. However, green hydrogen is still limited in scale and is not yet cost-competitive with blue hydrogen. Commercial electrolysis is energy intensive and consumes approximately (45 - 60) kWh/kg_{H₂} (0.16 – 0.22 GJ/kg_{H₂}) [14, 48]. Consequently, current renewable energy supply can't adequately meet production demands if hydrogen was to match the commercial

scale of the LNG industry today. Due to its high energy consumption, electrolysis production costs typically range from (3.50 - 13) USD/kg_{H2} [45, 46, 49-53] depending on plant capacity and the renewable or grid electricity price, making it at least 2 to 3 times more expensive than blue hydrogen in most locations [45].

The high energy demands of electrolysis also result in high emissions intensities when powered from the current electricity grid which is not fully decarbonised. Based on Australia's grid emissions intensity (EI) of (678 – 738) kg_{CO2}/MWh [49, 54], the current emissions intensity for electrolysis is estimated at 25 - 40 kg_{CO2}/kg_{H2} [49]. As a result, truly green hydrogen production from electrolysis will only be feasible once large-scale renewable energy sources are both widely available and provided at low cost. Australia's energy mix is currently only 7% renewables [54]. Low capacity factors of renewable energy also form current barriers to green hydrogen; solar PV and wind energy have typical capacity factors of 30 and 40% respectively [55], requiring a hybrid system with grid power or a supplementary battery to supply a continuous energy source. Green hydrogen from electrolysis is only expected to become cost-competitive with blue hydrogen (i.e. less than 3 USD/kg_{H2}) in Australia from 2030 onwards [51] subject to several assumptions: renewable electricity costs decrease to at least 20 USD/MWh, electrolyser efficiencies increase to 75% and capital costs decrease by 80% [45].

3.2 Storage & Transport

Given its low density in a gaseous state hydrogen must be converted into a denser form to enable cost effective bulk storage and transport. Liquid hydrogen is one of many technologies [11] likely to play a significant role in the international trade of hydrogen. Liquid hydrogen at -253 °C and 1 bar has a density close to 71 kg/m³. A key challenge for hydrogen liquefaction is the high-power consumption required by the compressor trains. In practice, existing liquefiers require (11.9 - 15) kWh/kg_{H2} which is (35 - 45)% of the lower heating value of hydrogen [56, 57]. This high energy demand adds considerably to the cost and, potentially, the carbon emissions intensity of the hydrogen delivered in a LH₂ supply chain. Current operational liquefaction costs are typically (2.5 - 3) USD/kg_{H2}. Existing liquefaction infrastructure is also limited; the liquid hydrogen supply chain has a current known global capacity of 350 tpd (approximately 0.2% of global hydrogen production) supplied by approximately 25 plants [58, 59]. The largest plant is operated by Air Products in New Orleans, and produces 64 tpd, made up by two 32 tpd liquefiers [60]. In comparison, plants for production of liquefied natural gas (LNG) have capacities exceeding 10,000 tpd [61].

Long distance transport of liquid hydrogen from producer to end-user requires maritime transportation, yet this is not a practice in current operation and vessel designs remain conceptual [62]. The Hydrogen Energy Supply Chain Project (HESC), will be the first pilot hydrogen supply chain project to implement LH₂ transport globally [63-65]. HESC intends to produce hydrogen via coal gasification, and transport it as LH₂ from Australia's Latrobe Valley in Victoria to Kobe Airport Island in Japan, with pilot operations having commenced in 2022 [63]. The LH₂ Suiso Frontier vessel used in this trial has a capacity of 1250 m³ and utilises a vacuum-insulated hydrogen storage tank with an expected boil-off gas (BOG) rate of 0.4% per day [66]. Hence, significant up-scale of maritime transport will be required to meet commercial demand, along with a means of limiting LH₂ BOG through advancements in the thermal insulation of storage tanks, providing on-board BOG re-liquefaction, or utilising BOG as the maritime fuel [16].

Ammonia presents an alternate means of hydrogen storage and transport. Using the Haber Bosch (HB) process, the production of ammonia from H_2 and N_2 consumes power in the range of (2 – 4) kWh/kg $_{NH_3}$ [67-71], which is equivalent to (11.2 – 22.5) kWh/kg $_{H_2}$ and is comparable to energy consumption for hydrogen liquefaction. Though ammonia provides a relatively simple means of transport and storage with comparatively minimal losses, it must be converted via catalytic cracking when pure hydrogen is required by the end consumer, utilising an additional 7.94 kWh/kg $_{H_2}$ [67]. Finally, the widespread use of ammonia for energy applications has safety challenges potentially comparable in significance to those faced by liquid hydrogen. These include increased rates of corrosion and material wear of storage containers and high toxicity to biological systems [72]. Thus, while commercial scale storage and transport of NH_3 involves mature technology, significant handling and containment challenges remain if it is to be used on an even larger scale for energy applications.

The potential applications of hydrogen are varied, from use as an industrial feedstock to bulk electricity production and transportation via fuel cell electric vehicles (FCEVs) [11]. It is hence worth noting that hydrogen storage and transport will depend on end use. For example, Wijayanta et al. [73] concluded that when highly pure H_2 is needed (such as for fuel cell vehicles), liquid hydrogen is more promising than ammonia and other hydrogen storage methods. Ishimoto et al. [74] conducted a hydrogen export value chain analysis over distances ranging from (2,500 to 23,407) km for both LH_2 and ammonia, and found that when ammonia is cracked back to H_2 at the destination, the LH_2 supply chain costs and emissions were generally below those of NH_3 . Similarly, an analysis by the EU Science Hub – Joint Research Centre [75] found that LH_2 resulted in a lower hydrogen delivery costs than NH_3 for supply chain distances up to 22,000 km. Their analysis found that LH_2 also had a supply chain cost below that of either pipelines or liquid organic hydrogen carriers for distances between (3,000 and 17,000) km.

4. Module Analysis of an LNG H_2 Supply Chain

4.1 LNG export: production & transport

Total LNG export cost depends on both production and transport costs. Production incurs the costs of feed gas, conversion of feed gas to LNG and LNG interim storage, while transport costs entail charter rates, fuel costs and port charges. The global LNG market is still largely a long-term contract market, without public disclosure of prices or contract terms with LNG spot-market prices being highly volatile [76]. Based on LNG spot market and netback price estimates, Japan's LNG import prices from Australia have fluctuated between 6 - 19 USD/GJ over the past decade, with an average of 10 USD/GJ during the 2020-21 financial year [28]. Given the volatility of LNG prices, however, this average cost can be used as an indicative value for LNG import costs in a hydrogen supply chain. Indicative studies provide a breakdown of key cost components, with the typical NG wellhead cost at 3.5 - 4.5 USD/GJ, amortised LNG production CAPEX and OPEX at 4.4 USD/GJ, and shipping transportation at 0.57 USD/GJ [77-81].

CO_2 emissions are generated directly during LNG production from combustion in gas turbines (GTs) to power energy intensive processes such as compression and liquefaction, as well as from the venting of CO_2 that is present in the gas and from gas flaring. Methane is also generated in upstream production from gas venting and fugitive emissions (i.e., methane slip from points of leakage). Typical equivalent CO_2 emissions from the aforementioned LNG production processes are 0.6 - 0.7 kg $_{CO_2 eq.}/kg_{LNG}$ [79-81].

The transport of LNG generates emissions that largely depend on the engine and fuel type, which varies significantly between vessels [82]. Dual-fuel diesel engines have become preferable for maritime transport, with 50% engine efficiency and speeds up to (18 - 21) knots [78, 83]. LNG BOG used to drive the engine typically represents 0.1% of the ships capacity per day or more [78]. Emissions from a dual-fuel diesel engine range from 626 kg_{CO2 eq.}/MWh when running on LNG BOG (including methane slip) up to 690 kg_{CO2 eq.}/MWh when running on marine gas oil (MGO) [82]. Assumed parameters include: a typical LNG vessel size of 150,000 m³ [27], an average speed of 19 knots [83], and an approximate MGO fuel consumption of 72 tpd [78, 84]. Based on these parameters, the specific CO_{2,eq.} emissions for LNG shipping to Japan (dual fuel engine) were calculated in the range of 0.8 - 1.7 kg_{CO2 eq.}/GJ (0.1 - 0.2 kg_{CO2 eq.}/kg_{H2}). (see **supplementary information–section 6**). CO₂ emission due to combustion in Natural Gas Combined Cycle (NGCC) power plants is estimated at 109 kg_{CO2}/GJ (\approx 5.6 kg_{CO2}/kg_{LNG}) [85].

4.2 Blue hydrogen production

Steam methane reforming

SMR is the most established hydrogen production method and accounts for 48% of all hydrogen production at present [86]. SMR involves an endothermic reaction of methane and water (steam) at high temperatures in the presence of a catalyst, coupled with an exothermic water-gas shift (WGS) reaction to increase the hydrogen yield as outlined in Equation 1 and 2 respectively [87]. SMR has been used for several decades and operates close to the theoretical limits of the process. The heat of reaction for SMR is typically provided by an external natural gas burner system.



As a viable method of blue-hydrogen production, SMR must be completed with two key processes: hydrogen purification and carbon capture. The purity of hydrogen is often required to be more than 99.9% for application in refineries and fuel cells. Consequently there has been a recent adoption of SMR units with hydrogen pressure swing adsorption (H₂-PSA) systems, which provide the capability to produce high purity hydrogen (> 99.9%) [88]. Industrial H₂-PSA systems have a TRL of 9 and are currently available for commercial service [89]. In relation to carbon capture, CO₂ emissions from an SMR-based supply chain can exceed 70 - 100 kg_{CO2}/GJ (8 - 12 kg_{CO2}/kg_{H2}) [88]. Approximately 45.4 kg_{CO2}/GJ (5.5 kg_{CO2}/kg_{H2}) is generated from the SMR reformer reaction and 10 kg_{CO2}/GJ (1.2 kg_{CO2}/kg_{H2}) from combustion of the NG to produce the required process heat given that 2.15 MJ/m³_{H2} [90-92] is needed to provide the necessary temperature and pressure to drive the SMR reaction. To ensure low carbon hydrogen production, SMR units require the application of a carbon capture process which can reduce CO₂ emissions from an SMR plant by up to 80 - 90% [86, 93]. CO₂ can be captured from three possible locations during SMR, each with various capture capabilities ranging from (55 to 95)% and associated costs ranging from less than 20 USD/tonne_{CO2} to in excess of 80 USD/tonne_{CO2} as summarised in **Figure 3** [90, 94]. Costs vary significantly depending on the partial pressure of CO₂ in the gas stream and the plant capacity.

Carbon capture across these three locations traditionally entails chemical absorption processes, including scrubbing columns containing absorbent solutions (typically Methyl diethanolamine (MDEA)) which bind to and allow the CO₂ to be separated [95]. These absorption-based CO₂ capture

processes, however, are energy intensive due to the energy consumption for solvent regeneration in a subsequent stripper column. Accounting for the reboiler duty required to produce steam for the stripper column, 95% capture of syngas CO₂ requires 0.25 kWh/kg_{CO2} [96], while 90% capture of the flue gas CO₂ requires an additional 0.54 kWh/kg_{CO2} [97]. The application of this technology at a large scale consequently requires a reduction in the energy supply of the regeneration column reboiler used for solvent purification [98]. In particular, post-combustion capture of the highly dilute flue gas stream via conventional amine scrubbing can introduce high costs at 80 USD/t_{CO2} [90, 93, 98]. This estimate accounts for an increase in the overall cost of hydrogen production by up to 20% due to CAPEX for scrubbing units and increased energy consumption. SMR improvements methods [22, 36, 38, 99-104] and advancements in methods of carbon capture [105, 106], however, provide future opportunities for cost reduction. For example, CO₂ vacuum swing adsorption (CO₂-VSA), CO₂ pressure swing adsorption (CO₂-PSA) and cryogenic CO₂ capture have been proposed as such methods (see **supplementary information–section 2**).

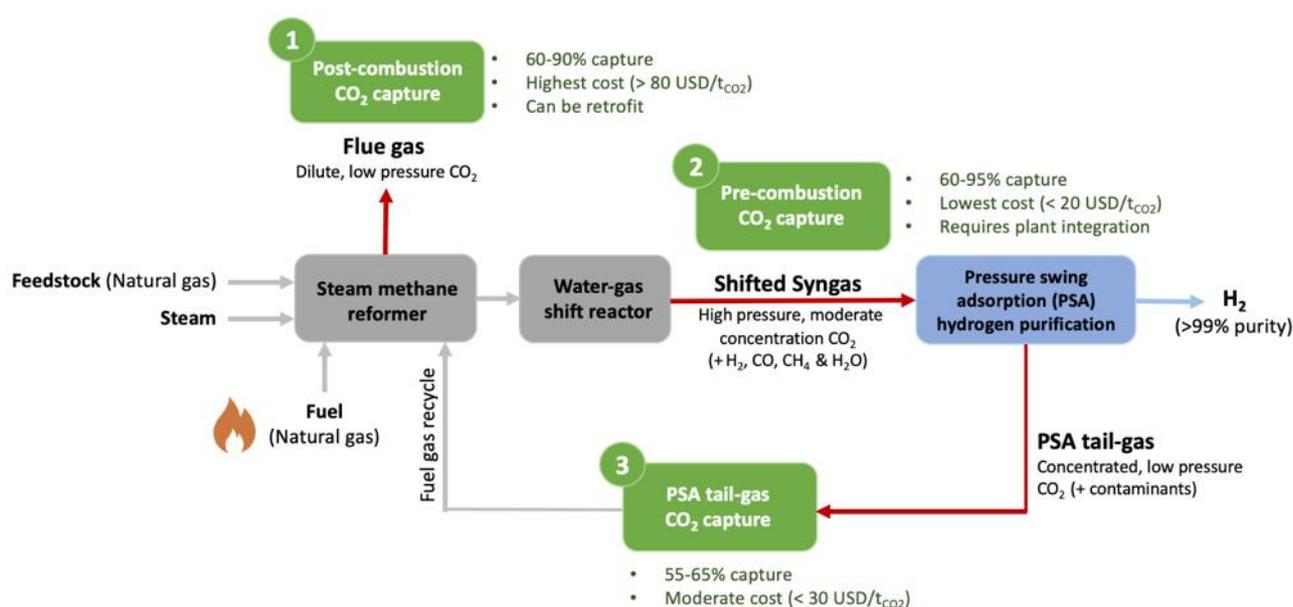


Figure 3. Cost and capture capabilities for the three streams of potential carbon-capture in SMR.

Table 1 presents the results of six key techno-economic analyses for SMR with carbon-capture integration, with production capacities ranging from 24 to 1900 tpd [90, 98, 107-110]. It was found that the cost of SMR with carbon capture ranged between (0.73 - 1.84) USD/kg_{H2}, dependent on the plant's scale of hydrogen production and the cost of feed gas. This cost range is consistent with both estimates from CSIRO and the IEA, at (1.59 – 1.94) USD/kg_{H2} [47] and (1.4 - 1.5) USD/kg_{H2} [93] for SMR with carbon capture, respectively. When the cost of the natural gas is excluded however, the production cost drops to (0.27 - 0.84) USD/kg_{H2}. This demonstrates that natural gas is the largest cost-component and dictates the cost of hydrogen produced via SMR, with feed-gas expenditure typically accounting for (50 - 80)% of production costs. Furthermore, **Table 1** displays an average emissions intensity of 2.1 kg_{CO2}/kg_{H2}, down from an average of 9.4 kg_{CO2}/kg_{H2} without carbon capture applied, indicating typical CO₂ capture efficacies of 80%.

Table 1. Key results for techno-economic analyses of SMR with carbon capture*

	Cost w/o carbon capture (USD/kg _{H2})	Feed-gas cost excluded (USD/kg _{H2})	Cost w. carbon capture integrated (USD/kg _{H2})	Feed-gas cost excluded (USD/kg _{H2})	EI w/o carbon capture (kg _{CO2} /kg _{H2})	EI w. carbon capture integrated (kg _{CO2} /kg _{H2})
Maximum	1.55	0.60	1.84	0.84	10.2	4.4
Minimum	0.61	0.15	0.73	0.27	8.0	1.0
Average	1.11	0.29	1.24	0.43	9.4	2.1

*Cost evaluation of hydrogen produced by SMR considers the capital and operational expenses associated with the plant construction, operation and maintenance. When CO₂ capture is included, the cost of the associated reactors (i.e. amine scrubbers) and equipment is added. The operational expenses include the cost of fossil fuels, electricity, chemicals and consumables (catalyst material), plus the cost of labour, supervision and maintenance.

Autothermal reforming

ATR is an alternative technology whereby the required heat of reaction is effectively produced within the reformer reaction vessel using combustion and partial oxidation of oxygen-rich natural gas, thus eliminating the need for an external furnace [93]. ATR provides potential benefits over SMR as it doesn't generate diluted flue gas CO₂, and it has a higher reforming temperature which improves methane conversion [111]. However, it has had limited use in industrial applications at present due partially to a comparative lack of commercial experience [111]. The ATR reaction is displayed in Equation 3, where hydrogen and CO₂ production is dictated by the oxygen and steam molar ratios, x and y , respectively.



Conventional ATR is currently at a TRL of 9 [112]. In a conventional ATR process, as displayed in **Figure 4**, natural gas, steam and oxygen are combined in the autothermal reformer, with oxygen supplied via a cryogenic air separation unit (ASU). Catalytic reforming and the WGS reaction occur sequentially inside the reformer reactor. The resulting high-pressure syngas can then undergo both carbon capture and H₂-PSA for hydrogen purification. ASU contributes significantly to the cost of ATR, however, both due to its high CAPEX (estimated at 196 M USD for a 450 tpd plant [111]) and high energy consumption (0.36 - 0.64 kWh/Nm³O₂) [113, 114]. Thus, ATR production costs are currently higher than those of SMR [111].

Table 2 [115-117] presents the results of three key techno-economic analyses for ATR with carbon-capture integration at production capacities of 200 to 600 tpd. It was found that the feed-gas cost constituted 45% of the total cost, and carbon capture increased the supplied hydrogen cost by over 10%. As with SMR, the supplied hydrogen cost is thus highly dependent on the cost of the natural gas feedstock.

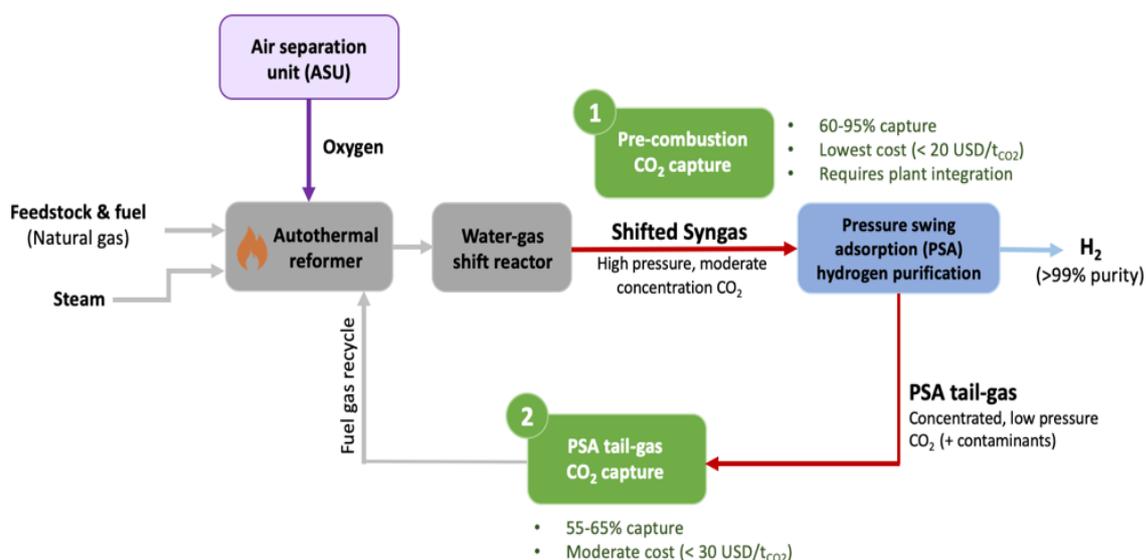


Figure 4. ATR process schematic with carbon capture.

Importantly, all CO₂ is produced inside the reactor during ATR. This means only CO₂ in the syngas is required to be captured and no flue gas is generated. This allows for higher CO₂ recovery rates at lower costs than can be achieved with SMR as the emissions stream contains concentrated CO₂ [93]. Utilising carbon capture techniques such as amine scrubbing or CO₂-PSA applied to the syngas stream, up to (94 - 95)% of CO₂ can be theoretically captured [49]. According to **Table 2**, the emissions intensity for ATR was estimated at an average value of 9.3 kg_{CO2}/kg_{H2}. The average emissions intensity reduced to 0.9 kg_{CO2}/kg_{H2} with integrated carbon capture, indicating 90% carbon capture efficacy. A number of studies have shown that the cost of SMR with carbon capture exceeding 90% is higher than that of a comparable ATR system [93]. The cost of the CO₂ capture process itself is estimated to be roughly (0.2 to 0.3) USD/kg_{H2} for an SMR plant, and 0.1 USD/kg_{H2} for an ATR plant due to the concentrated CO₂ stream [118]. New developments and improvements [40, 119, 120] in ATR technologies are discussed in **supplementary information–section 3**.

Table 2. Key results for techno-economic analyses of ATR with carbon capture.

	Cost w/o carbon capture (USD/kg _{H2})	Feed-gas cost excluded (USD/kg _{H2})	Cost w. carbon capture integrated (USD/kg _{H2})	Feed-gas cost excluded (USD/kg _{H2})	EI w/o carbon capture (kg _{CO2} /kg _{H2})	EI w. carbon capture integrated (kg _{CO2} /kg _{H2})
Maximum	2.12	1.17	2.23	1.34	9.6	1.1
Minimum	1.35	0.75	1.76	0.87	8.8	0.7
Average	1.73	0.96	1.99	1.11	9.3	0.9

Natural gas pyrolysis

Thermal decomposition (pyrolysis) of methane is an emerging technology for hydrogen production which doesn't lead to direct CO₂ formation. The pyrolysis reaction (Equation 4) involves the non-oxidative thermal decomposition of methane, and is moderately endothermic [121].



Methods of Natural Gas Pyrolysis (NGP) can be broadly categorised into non-catalytic processes (i.e., thermal decomposition (TD) and plasma decomposition (PD)) and catalytic processes (i.e., thermo-catalytic decomposition (TCD)), each with various reactor technologies (**Figure 5**). Heat required for these different processes can be supplied in several ways depending on the operation reactor temperature. In TD and TCD, the heat of reaction can be provided by combustion of natural gas, combustion of part of the hydrogen product, electrical heating via electric arc firing (EAF) or by the use of concentrated solar energy [122]. Non-catalytic TD requires temperatures up to 1500 °C to achieve 90% methane conversion [123]. The use of metal catalysts such as Ni and Fe however, can allow the reaction temperature to be reduced to 1000 °C [124] and in some cases as low as 500 °C [125-127]. In PD, the energy is provided by electricity which is used to heat a plasma gas to high temperatures (> 1800 °C) using a plasma torch [128]. While SMR for hydrogen production is industrially mature, pyrolysis of natural gas for hydrogen production has not yet been commercialised at a large scale [129].

The solid carbon by-product may play a critical role in commercialisation of NGP. The type of catalyst used in the process and the reactor temperature dictate the type of solid carbon that is produced, and consequently its market value, as shown in **Table 3** [130-132]. The global market for different qualities of carbon black is in the range of USD (14 – 15) billion, with an average sales price of 1000 USD/tonne [131]. Thus, monetisation of the solid carbon by-product presents a key opportunity for NGP commercialisation, with the sale of co-produced carbon generating economic viability of NGP (see Section 4.4).

CO₂ emissions are also a critical factor in determining the sustainability of NGP, given the potential for indirect emission production. These emissions are associated with the combustion of fuels, or the use of electricity generated from non-renewable sources to provide the heat of reaction. Such energy requirements can be substantial given the high reactor temperatures required, albeit that they can be significantly reduced via the application of solar technology. **Table 4** presents the results of five key techno-economic analyses for various NGP methods. Existing and planned projects and new developments in NGP technologies are discussed further in **supplementary information–section 4**.

Emission intensities range between (0 - 2.5) kgCO₂/kgH₂, indicating the potential of renewable NGP to generate green hydrogen. Costs are highly variable and range between (1.4 - 7) USD/kgH₂ dependent on the technology used and the carbon sales price [43, 122, 130, 132, 133]. **Table 4** indicates that the cost of hydrogen could be maintained below 2.5 USD/kgH₂ assuming reasonable market prices for the carbon product (in the range of (150 – 1350) USD/tonne). Hence, pyrolysis processes have the potential to produce hydrogen at a moderate price and with a low CO₂ footprint, provided that the heat of reaction required for pyrolysis can be achieved with no or low CO₂ emissions or CH₄ slip [121]. New developments and improvements in pyrolysis has been recently explored in the literature [134-138].

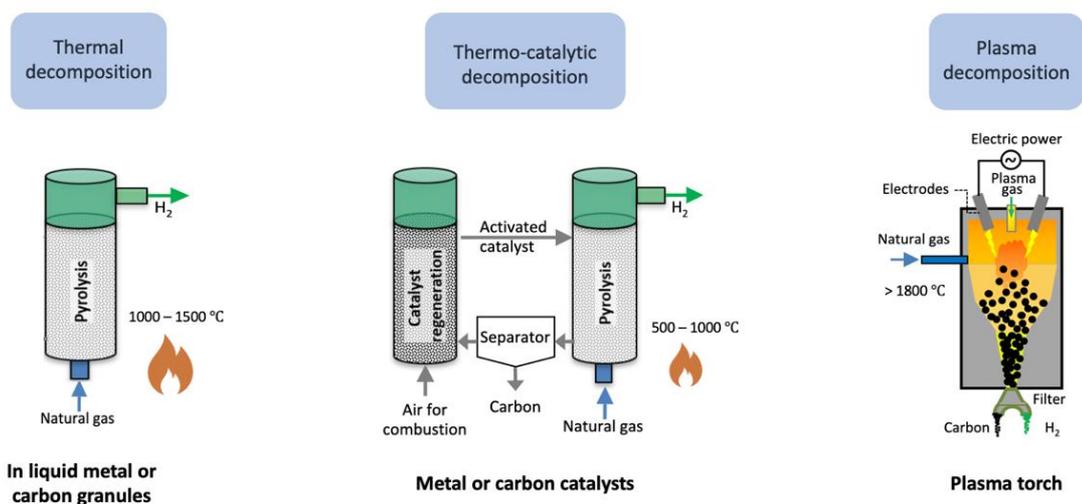


Figure 5. Key methods of natural gas pyrolysis and associated reactor temperatures and conditions.

Table 3. Main carbon products and their market price obtained as a function of temperature and catalyst employed in natural gas pyrolysis

Catalyst type	Temperature (°C)	Carbon type	Market price (USD/kg)
None	1000–1300	Graphitic	0.22 – 0.41
	1330–1850	Carbon Black	0.85 – 2.5
Activated Carbon	1025–1125	Carbon Black	0.85 – 2.5
Carbon Black	750–1050	Graphitic	0.22 – 0.41
	1050–1125	Amorphous	0.22 – 0.3
Co-based	500–800	Nanotubes	0.1 – 60,000
	800–900	Filamentous	25 – 113
Fe-based	700–780	Nanotubes	100 – 600,000
	780–800	Carbon-plates	
Ni-based	400–670	Nanofibers	25 – 113
	670–800	Multi-Walled nanotubes	100 – 600,000
	1025–1100	Nanofibers	25 – 113

Table 4. Key results for techno-economic analyses of various NGP technologies.

Production method	Hydrogen production rate (tpd)	Feed-gas price (USD/GJ)	Electricity price (USD/kWh)	Carbon sale price (USD/tonne)	Hydrogen production cost (USD/kg_{H2})	Production emission intensity (kg_{CO2}/kg_{H2})
TCD (3 vessel system)	Small: 15 Med: 51 Large: 153	6.64	0.045	300	Small: 2.46 Med: 2.00 Large: 1.80	2.17
TD	1.73	6.5	0.035	Not assessed	2.8	2.0
TCD (Molten metal bubble column with NG firing)	270	4	0.10	150	1.39	2.5
TD (EAF)					1.74	3.1
TCD (EAF)	547	3	0.045	Not assessed	1.62	2.7
TCD (NG firing)					1.61	1.5
TCD (H ₂ firing)					1.58	0
PD (Plasma torch)	1.7	5	0.056	0 1350	7.0 2.5	NA

4.3 Carbon dioxide and solid carbon handling

CO₂ liquefaction, transport, and sequestration

There are currently six CCS projects in Japan, all of which are in pilot or demonstration phases [30]. While CO₂ aquifer storage capacity in Japan is estimated at > 100 Gt-CO₂ [139], a comprehensive policy and legal framework for commercialising large-scale CCS in Japan, including long-term liability issues [140-142], has yet to be defined. Additionally, some concerns still remain regards the safety of CO₂ storage in Japan such as potential damage of storage sites caused by earthquakes [142]. Two CCS pilot scientific projects in research facilities in Nagouka and Tomakomai, Japan, have investigated whether natural earthquakes will cause damage and leakage risks to geological CO₂ storage facilities [142]. As such, CO₂ generated in Japan would likely require long distance transport to viable sites for carbon sequestration [143]. CO₂ liquefaction is energy intensive however, and can exceed more than 10% of the total energy consumption in the entire CCS chain due to the energy consumption of compressors and refrigerators [32, 143]. The cost of CO₂ liquefaction is highly sensitive to the inlet pressure [143-146]. A table of CO₂ liquefaction studies and typical operating conditions can be found in **supplementary information– section 7**. Estimates of the cost and emissions intensity values are also presented in **supplementary information–section 7**. On average, the cost of pre-pressurised and non-pressurised CO₂ can be approximated at 5 USD/t_{CO2} and 10 USD/t_{CO2} respectively. The liquefaction emissions intensity is estimated at (0.2 - 0.4) kg_{CO2 eq./kg_{H2}}.

Long distance, commercial transport of LCO₂ is not an established practice. Whilst the London Protocol adopted a resolution to allow export of CO₂ for storage in sub-seabed geological formations [147], the transboundary transportation of CO₂ still gives rise to international legal issues around ownership and risk that will need to be resolved [148]. Currently, small-scale semi-pressurized ships have been operating in the North Sea for the transport of food grade liquid CO₂. Such ships have a transport pressure of (1.5 – 2) MPa, operate at a temperature of

243 K (-30 °C) and have a capacity between 1000 and 1500 m³ [144]. A cost breakdown and relevant model assumptions can be found in **supplementary information–section 8**. The cost of LCO₂ transport was estimated at (35 - 45) USD/tCO₂ for a 100 tpd hydrogen production scenario indicative of a commercial scale project with transport over approximately 4000 nautical miles from the port of Tokyo, Japan to Dampier, Western Australia. Shipping of LCO₂ also introduces GHG emissions, both from exhaust gas generated by the combustion of ship fuel (MGO or HFO) and from CO₂ boil-off gas (BOG) removed to maintain the pressure in the ship's storage tanks [149]. The EI was found to be (1.6 - 1.9) kgCO₂/kgH₂ for a 100 tpd scenario, which decreased with economies of scale. (see **supplementary information–section 8**).

No major drawbacks have been highlighted in relation to the implementation of LCO₂ transportation, however demonstration projects are necessary to build confidence and demonstrate continuous operations. Countries such as Japan, Norway and the UK are actively commercialising large scale CO₂ shipping as part of their decarbonisation strategies with LCO₂ transport to be deployed for demonstration projects in coming years [143]. For example, Norway's Northern Lights JV project is set to develop a European CO₂ transportation network by mid-2024 with a capacity of 1.5 Mtpa [150]. Denbury have also executed a term sheet to transport 50 Mt of CO₂ over 20 years from Mitsubishi's proposed Ammonia project in the Gulf of Mexico [151]. Such projects will pave the way for long distance LCO₂ transport in the near future.

CO₂ storage involves injecting compressed liquid CO₂ or supercritical CO₂ into geological formations such as deep saline aquifers or depleted oil and gas fields [46]. Initial costs of such CO₂ storage are twofold; the costs of energy and infrastructure for CO₂ conditioning (pressurisation and heating) to bring the LCO₂ to the required compressed or supercritical state and the infrastructure capital and operational expenditure required to perform injection of the CO₂ once at the required conditions. Onshore gasification of LCO₂ to the required injection conditions represents a base case, costing approximately 1.3 USD/tCO₂ (see **supplementary information–section 9**). Regarding the capital and operation expenditure for gas injection, costs vary depending on whether existing infrastructure, such as platforms and wells, are utilised or not. One study by the IEA Greenhouse Gas R&D Programme (IEA GHP) and European Zero Emissions Platform (ZEP) [152] estimated the total cost of over 1000 offshore and onshore depleted fields and saline aquifers across their entire lifecycle from exploration to decommissioning. Costs ranged from (3.8 – 11.5) USD/tCO₂ for depleted fields to (6.2 - 16.5) USD/tCO₂ for saline aquifers [152]. The cost of LCO₂ stored underground was estimated at 5 USD/tCO₂ for a 100 tpd hydrogen production scenario. **Table 5** presents the results of key techno-economic analyses for CO₂ liquefaction, transport, and storage.

Table 5. Key results for techno-economic analyses of CO₂ liquefaction, transport, and storage.

Stage	Cost USD/t _{CO2}	Emission kg _{CO2 eq.} /kg _{H2}	Comments/Conditions
CO ₂ Liquefaction	5 –10	0.2 – 0.4	Highly sensitive to the inlet pressure and liquefaction conditions
CO ₂ Shipping	35 – 45	1.6 - 1.9	Sensitive to the hydrogen production rate, the ship fleet size and capacity, and CO ₂ injection parameters
CO ₂ Storage	3.8–16.5		Cost includes the costs of energy and infrastructure for CO ₂ conditioning and the infrastructure capital and operational expenditure required to perform injection

CO₂ and carbon utilisation

Instead of storing CO₂, it can also be utilised and integrated into the hydrogen supply chain. One method for utilising CO₂ is the Sabatier process. This process is known as methanation, whereby captured CO₂ from blue hydrogen production is used as a feedstock to produce methane. This methane can then be used as feedstock for further blue hydrogen production. The methanation reaction is exothermic and is described by Equation 4 [153]. The Sabatier reactor designs include fixed bed reactors or fluidised bed reactors at advanced TRLs of 9 and 7 respectively [154].



Methanation technologies are discussed in **supplementary information–Sections 5 & 10**. A review of techno-economic analyses available in the literature for CO₂ methanation plants has been conducted to obtain a cost estimate for methane production. With (91 - 98)% plant utilization, as is common in industrial plants, this cost was within (0.61 - 1.57) USD/kg_{CH4} and had an average value of 1.0 USD/kg_{CH4} [155-158]. There is limited data on Sabatier emissions, however Bargiacchi et al. [159] estimated emissions from simulations of a commercial scale plant using the emissions intensity factor of the energy mix in Europe (0.28 kg_{CO2}/kWh), and the thermal intensity factor (1.16 kg_{CO2}/kWh), which accounts for the emissions produced by the natural gas boilers used to heat the Sabatier reactor. Considering these two assumptions, the EI for the Sabatier process was estimated at 0.65 kg_{CO2}/kg_{CH4}. New developments and improvements in the Sabatier process has been recently explored [160-164].

The solid carbon by-product generated by natural gas pyrolysis is readily separated, unlike the by-product of CO₂ formed by SMR [121]. However, as with the CO₂, the solid carbon must also be transported and subsequently utilised or stored. Utilisation includes the sale of carbon co-products for various applications, while storage entails depositing carbon at waste disposal sites. Regarding utilisation, different carbon co-products with a range of commercial values can be obtained from NGP depending on the catalysts used and the reactor temperature (**Table 3**), and a sales price of (150 - 1350) USD/tonne could sustain the economic viability of NGP. Potential markets and promising industrial areas that could see expanded pyrolytic carbon utilization in the near future are presented in the **supplementary information–Section 10** [165]. Carbon black can be transported in dry bulk vessels currently employed for seaborne coal or iron trade, such as Panamax vessels with capacities of (60 - 80) kt or Capesize vessels with a high capacity over 80 kt [166]. The current cost of dry bulk shipping is determined mainly by fuel prices and the supply and demand for coal and iron. During the period 2018 - 2020, the freight rate of the

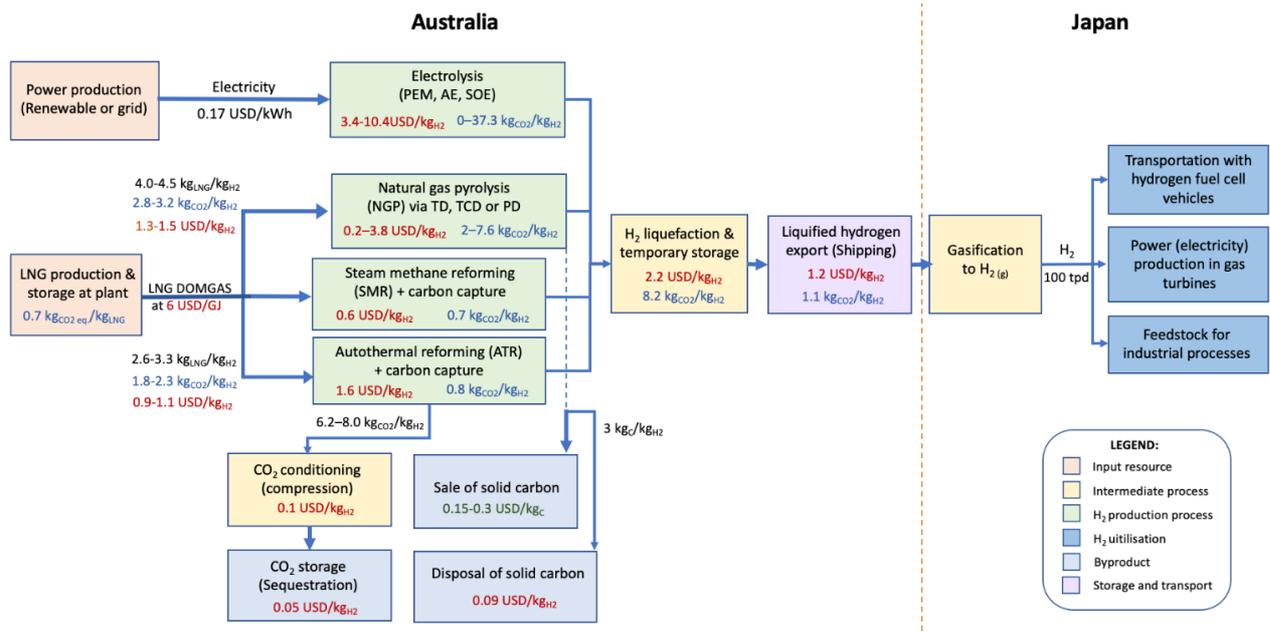


Figure 7. Aggregation of literature values and analysis showing respective cost (red), EI (blue) and reactant consumption (black) for modules of the LH₂ supply chain.

5.1 Economic viability

By aggregating the cost contributions of each stage in the LNG-based H₂ supply chain, the cumulative delivered hydrogen cost was calculated for the various blue hydrogen production technologies as presented in **Figure 8** and **Table 6**. To compare the relative costs of different production pathways, which are affected by economies of scale, all results are for a hydrogen production rate scenario of 100 tpd. As illustrated in **Figure 8**, it is evident that an LNG energy-vector supply chain can meet Japan's 2030 target hydrogen cost of 25 USD/GJ. The SMR pathway achieves a low total cost of 19.2 USD/GJ and 13.9 USD/GJ with and without CCS, respectively, attributed largely to its lower CAPEX and OPEX costs. Given that the TRL of most stages in the SMR production supply chain is 9, such blue hydrogen production technology could be implemented in the near future (2-3) years from a technological standpoint. Successful and reliable implementation of SMR with CCS has been demonstrated by Shell's Quest Project [168], which captures CO₂ from an SMR plant, transports it along a 65 km pipeline and injects it for permanent storage in a saline formation. The Quest facility has successfully captured and injected over 5.7 Mt of CO₂ to the end of 2020. Transportation of liquid CO₂ remains the primary barrier given that existing infrastructure for commercial operations is not currently in existence; however, repurposing existing cargo vessels to create dual LNG-LCO₂ ships could be potentially viable [169]. This result also indicates that CCS contributes a relatively small portion to total cost; hence, abating CO₂ is not a limiting factor in implementation from an economic perspective.

Interestingly, pathways utilising the emerging technology of ATR still achieve a delivered cost close to the 2030 target at 30.0 USD/GJ and 25.6 USD/GJ with and without CCS, respectively. **From Figure 8**, it is evident that the cryogenic air separation unit contributes significantly to the cost of hydrogen production, both due to its high CAPEX (~ 196M USD [111]) and high energy consumption (0.36 – 0.64 kWh/Nm³O₂ [113, 114]) leading to an increase in cost by approximately 4.6 USD/GJ. Consequently, ATR remains a higher cost process relative to SMR. It should be noted however, that the cost of carbon capture in SMR exceeds that of ATR by 56% due to the requirement of a secondary amine scrubber for the CO₂ in the flue gas.

Analysing the delivered costs of various natural gas pyrolysis pathways, there are a number of key findings. Firstly, NGP via thermo-catalytic decomposition with NG firing achieved a cost of 22.1 USD/GJ, making it cost- competitive Japan’s hydrogen cost target. Furthermore, it is clear that the use of a catalyst to reduce pyrolysis reformer temperatures (from 1500°C to 1000°C [124]) improved cost efficiency; both reducing the cost of electric arc firing (EAF) and by making NG firing feasible which decreased costs by a further 11 USD/GJ. In contrast, Japan’s high grid electricity price (0.19 USD/kWh, March 2021 [170]) made the electric-based heating technologies of EAF and plasma torch NGP unviable from an economic standpoint, with costs at 33.1 USD/GJ and 55.4 USD/GJ respectively (assuming no revenue from solid carbon sales). It should be noted however, that NGP has not been implemented at a commercial scale to date and the cost for 100 tpd production is based largely on conceptual studies.

Table 6. Cumulative cost (USD/GJ) and emission intensity (kg_{CO2}/GJ) of an LNG-based hydrogen supply chain from Australia to Japan for various blue hydrogen production scenarios at a 100 tpd hydrogen production rate. Emission intensity values are shown in brackets.

Supply Chain Module	SMR	SMR + CCS	ATR	ATR + CCS	NGP [TD + EAF]	NGP [TCD + EAF]	NGP [TCD + NG firing]	NGP [Plasma torch + grid electricity]
NG/LNG feedstock	10.8	11.2	13.7	13.8	17.2	17.2	19.3	22.9
Incl. LNG shipping	(15.6)	(16.2)	(19.8)	(19.9)	(24.8)	(24.8)	(28.2)	(24.8)
Air separation unit			4.6 (4.0)	4.6 (4.0)				
Hydrogen production (incl. carbon capture)	3.1 (56.3)	4.9 (5.8)	7.3 (71.5)	8.2 (4.9)	14.8 (29.1)	12.4 (25.3)	1.7 (17.0)	31.5 (63.1)
CO ₂ liquefaction		0.52 (2.5)		0.67 (3.2)				
Liquid CO ₂ transport		2.1 (13.1)		2.3 (15.7)				
CO ₂ sequestration		0.42		0.42				
Black carbon transport					0.25 (3.3)	0.25 (3.3)	0.25 (3.3)	0.25 (3.3)
Black carbon storage					0.75	0.75	0.75	0.75
Total (USD/GJ)	13.9	19.2	25.6	30.0	33.1	30.6	22.1	55.4
Total (kg _{CO2} /GJ)	(71.9)	(37.5)	(95.4)	(47.6)	(57.2)	(53.5)	(58.6)	(91.2)

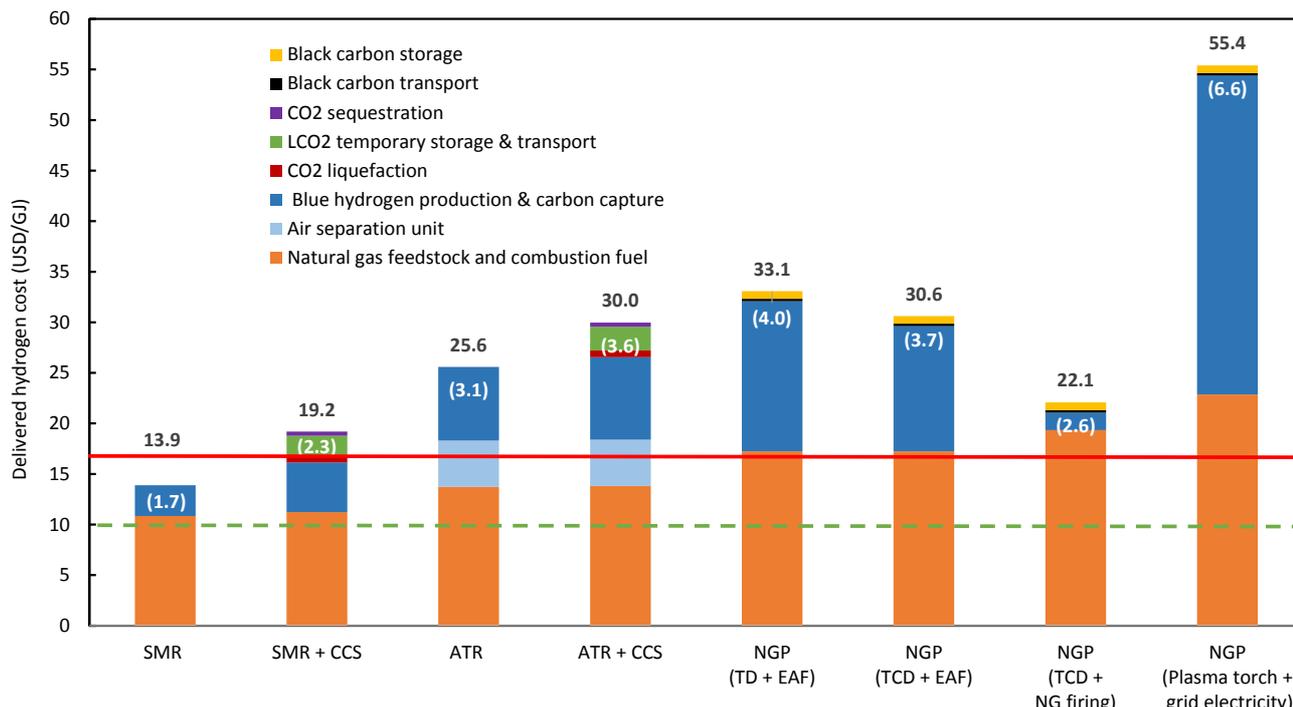


Figure 8. Cumulative cost (USD/GJ) of an LNG-based hydrogen supply chain from Australia to Japan for various blue hydrogen production scenarios at a 100 tpd hydrogen production rate. Costs on mass basis (USD/kg_{H2}) are shown in brackets (white text) using the LHV of hydrogen (120 MJ/kg). The cost of grid electricity is quoted at the Japanese business distribution price of 0.19 USD/kWh (March 2021), and the 2020-21 financial year average of 10 USD/GJ (0.52 USD/kg_{LNG}) is quoted for Japanese import of Australian LNG in all calculations. The green line is the indicative LNG price (10USD/GJ) and the red line indicates Japan's target 2050 hydrogen cost at 2 USD/kg_{H2}.

As summarised in **Figure 8** above, low carbon hydrogen produced via SMR with CCS at 19.2 USD/GJ is currently approximately twice the cost of LNG, which presents a potential barrier to the implementation of a hydrogen economy. Based on this, government economic incentives may be required to drive hydrogen supply chain uptake and methods of cost reduction will need to be implemented. **Figure 9** summarises total supplied hydrogen costs for various manufacturing routes using liquid hydrogen as the export vector (hydrogen is produced and liquified in Australia and exported to Japan). Compared against **Figure 8**, no liquid hydrogen supply chain is currently competitive with the equivalent LNG-based hydrogen supply chain and all exceed Japan's 2050 cost target by more than a factor of 2. In particular, the high costs of Australia's electricity grid currently make both liquefaction and electrolysis in Australia non-competitive from an economic standpoint. The cost of grid electricity is quoted at the Australian business distribution price of 0.17 USD/kWh (March 2021) [171], and NG is quoted at the Australian domestic gas price of 6 USD/GJ (0.31 USD/kg_{LNG}) [172] in all calculations. The cost of electrolysis is estimated based on the findings of CAPEX, OPEX and electrolyser energy consumption from key studies [14, 51-53].

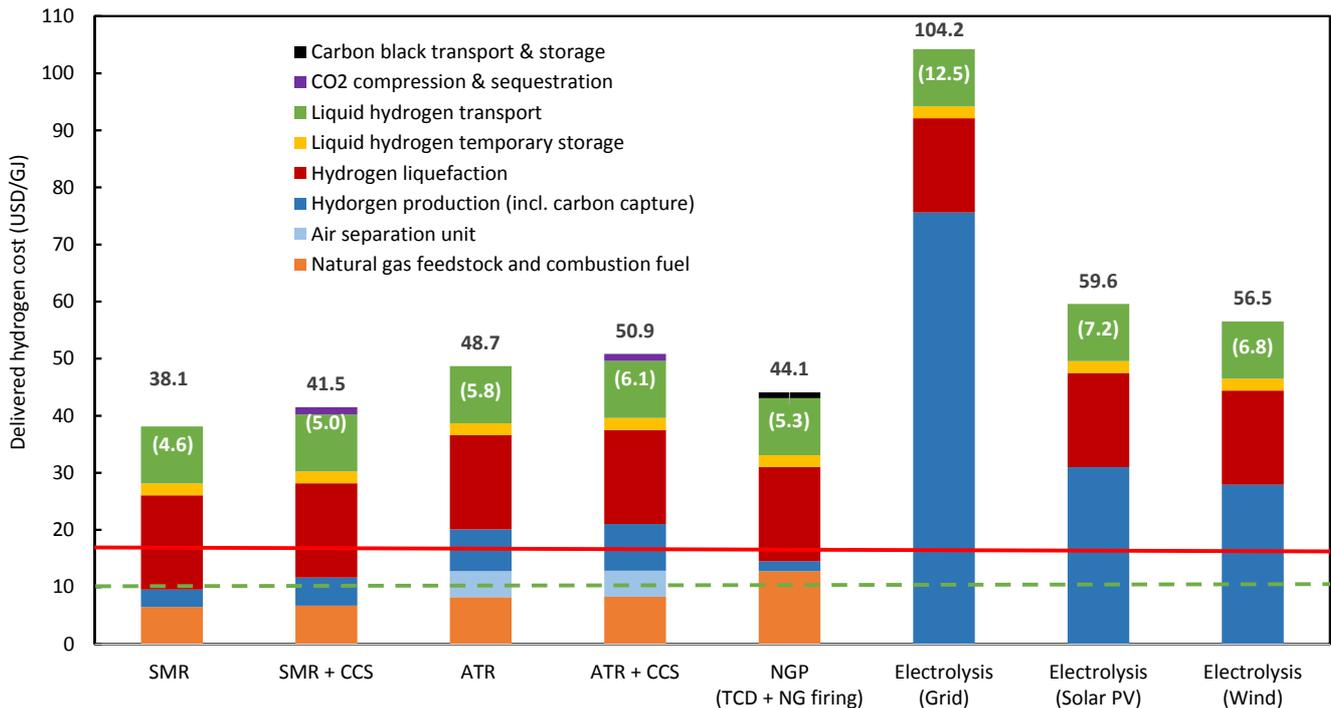


Figure 9. Cumulative cost (USD/GJ) of a liquid hydrogen supply chain from Australia to Japan for various blue and green hydrogen production scenarios. Costs on a mass basis (USD/ kg_{H2}) are shown in brackets (white) using the LHV of hydrogen (120 MJ/kg). SMR, ATR and NGP are presented for a 100 tpd hydrogen production rate, while electrolysis pathways present indicative cost estimates from small-scale production rates based on available data. The green line is the indicative LNG price (10USD/GJ) and the red line indicates Japan’s target hydrogen cost at 2 USD/kg_{H2}.

To ensure a competitive market with LNG, clearly a reduction in cost is required, for which economies of scales will be a key driver. A commercial-scale production rate of 100 tpd is achievable with technologies such as ATR and NGP [35], and hence this value for the plant capacity was used for the relative comparison of production pathways in this study. Due to limited availability of data, cost estimates for larger scales of production are based on extrapolation, and are expected to be less accurate. The reduction in CAPEX and OPEX of SMR with increasing production rate is well established; a 30% reduction is observed with a tenfold increase in production rate from 100 tpd to 1000 tpd [90, 107, 108, 110] (see **Figure S5** in the **supplementary information–section 10**). Such a reduction is foreseeable for ATR by 2030, which could drive the cost of ATR with CCS below 19.2 USD/GJ thus meeting the Japanese government cost target; however this is contingent on efficient upscaling of the energy-intensive ASU technology.

Reduction in grid electricity prices and technological advancements will also act as complementary drivers of cost reduction. The market for carbon black provides an opportunity for NGP net cost reduction, as shown in **Figure S3** in the **supplementary information–section 10**. It was found that the cost of hydrogen production is entirely offset at a carbon sales price of 0.9 USD/kg_C for TCD with NG firing, and 2.25 USD/kg_C for plasma torch pyrolysis drawing from grid electricity. Given the market price for various grades of carbon black is between 0.85 and 2.5 USD/kg_C, NGP has a clear potential to be an economically viable means of blue hydrogen production, assuming that saturation of the market is preventable.

Incorporating methane produced via the Sabatier process into a hydrogen supply chain with SMR and CCS increases the delivered cost of hydrogen by more than double, largely depending on the cost of supplying green hydrogen (used as a feed stock in the Sabatier process) and the percentage of methane produced by the Sabatier process (compared to methane from NG extraction) used in the SMR process, as summarised in **Table S11** and **Figure S4** in **supplementary information–section 10**. As illustrated in **Figure S4**, approximately 10% of the methane supplied can be provided by the Sabatier process whilst still meeting Japan’s 2030 target hydrogen cost. Even if the cost of supplying green hydrogen is reduced to 2 USD/kg_{H₂}, the delivered hydrogen cost can be as high as 4.3 USD/kg_{H₂} when 50% of the methane used in the SMR + CCS process is supplied by the Sabatier process. Nevertheless, this clearly demonstrates a potential for utilizing methane produced from both NG extraction and the Sabatier process in the blue hydrogen production processes.

Total supplied hydrogen costs using ammonia as the export vector is estimated for the Australia to Japan supply chain considered. The primary advantage of ammonia relative to liquid hydrogen is its comparative ease of storage and the minimal loss incurred during transport. However, converting ammonia back to H₂ at the point of delivery in Japan (e.g. prior to use in a fuel cell) adds further complexity; selecting proper materials and technologies (such as membranes) for the required hydrogen purification still remains challenging [67-71]. Various case studies [173-177] have reported the cost of exporting ammonia (as an energy or hydrogen carrier) from Australia to Japan. These studies estimated the current cost for ammonia production, transportation, and reconversion to hydrogen to be between 2.7 and 3.3 USD/kg_{H₂}. Adding the cost of hydrogen production (SMR/ATR + CCS), the current delivery cost for ammonia-based hydrogen estimated in our work can range between (4.6 and 6.5) USD/kg_{H₂}, which is similar to the delivery cost of liquid hydrogen but still significantly higher than the equivalent LNG-based hydrogen supply chain.

5.2 Emission intensity

By combining the carbon emission contributions of each stage in the LNG-based hydrogen supply chain, the cumulative supply chain emissions were calculated for various blue hydrogen production technologies; these data are shown in **Table 6** and **Figure 10**. Emission intensities vary significantly with each pathway. Application of CCS to SMR and ATR pathways reduces emissions by nearly 50% to 37.5 and 47.6 kg_{CO₂}/GJ in the case of SMR and ATR, respectively. The current emissions associated with ASU electricity provision from the current Japanese grid (GEF 0.47 kg_{CO₂} eq./kWh [146]) drive ATR emissions intensities up to surpass that of SMR. It should also be noted in both CCS pathways, the emissions intensity associated with LCO₂ temporary storage and transport constitutes a significant contribution at 13.1-15.7 kg_{CO₂}/GJ, making it a key area of opportunity for further emissions reductions. Across the various NGP pathways, electricity grid emissions contribute significantly in energy intensive processes such as plasma torch pyrolysis, which can be attributed to Japan’s high GEF. The higher specific LNG feedstock and fuel demand of NGP also lead to higher emissions from LNG production including emissions associated with NG extraction [79, 80]. Hence, it is clear that further decarbonisation of the electricity grid as well as carbon abatement initiatives in LNG production are key drivers for reducing the supply chain emission intensity.

Global average total life cycle emissions of LNG (including NG extraction, liquefaction, LNG export, regasification, combustion and plant’s efficiency) range from 180 to 250 kg_{CO₂} eq./GJ, with 40 - 58% (≈109 kg_{CO₂}/GJ) generated by combustion in power plant operations for electricity generation [178, 179]. Exported LNG used for power generation (in natural gas combined cycle, NGCC, turbines) could

be potentially coupled with carbon capture and storage technologies to reduce emissions (as detailed in [180-183]). However, the flue gas stream is the most expensive stream to capture CO₂ from, with current best technology resulting in costs as high as 4 times more than CO₂ capture from a syngas stream due to the lower CO₂ partial pressure and solvent degradation (as a result of the higher oxygen content) [184]. Rubin et al. [185] have carried out extensive research on the costs of implementing amine scrubbing for natural gas power facilities and found that the capital cost is between 76 and 121% greater compared to a plant without any capture. Evaluating such a simplified direct LNG supply chain for electricity generation is, however, beyond the scope of this work.

The results shown in **Figure 10** indicate that the lifecycle emissions per unit of energy output of a hydrogen supply chain are less than the emissions produced from direct LNG combustion, with SMR, ATR and NGP capable of generating emissions intensities below 60 kg_{CO₂ eq.}/GJ. However, this doesn't consider electrical efficiency when delivered hydrogen is used directly for power generation. For example, electrical efficiency of proton exchange membrane and solid oxide fuel cells ranges between 30 and 60% [186]. SMR without CCS will generate between 120 and 240 kg_{CO₂ eq.}/GJ, upon conversion of the hydrogen into electricity via a fuel cell, which is similar to the life cycle emissions intensity of direct LNG combustion. The emissions intensity shown in **Figure 10** for SMR + CCS accounts only for the CO₂ released during the reforming process relative to the energy content of the hydrogen generated (which is large on a unit mass basis); it does not account for the inefficiency associated with converting the hydrogen into electricity. Importantly, while similar overall emissions intensities are associated with direct LNG combustion and utilisation of H₂ produced from SMR without CCS, capturing CO₂ in the latter process is technically easier and cheaper and then allows electrical energy to be produced and distributed with no further emissions. Overall, SMR with carbon capture provides the lowest emission opportunity at 37.5 kg_{CO₂ eq.}/GJ per unit of energy output. This provides a strong argument for transition to the aforementioned hydrogen supply chains on the grounds of decarbonisation.

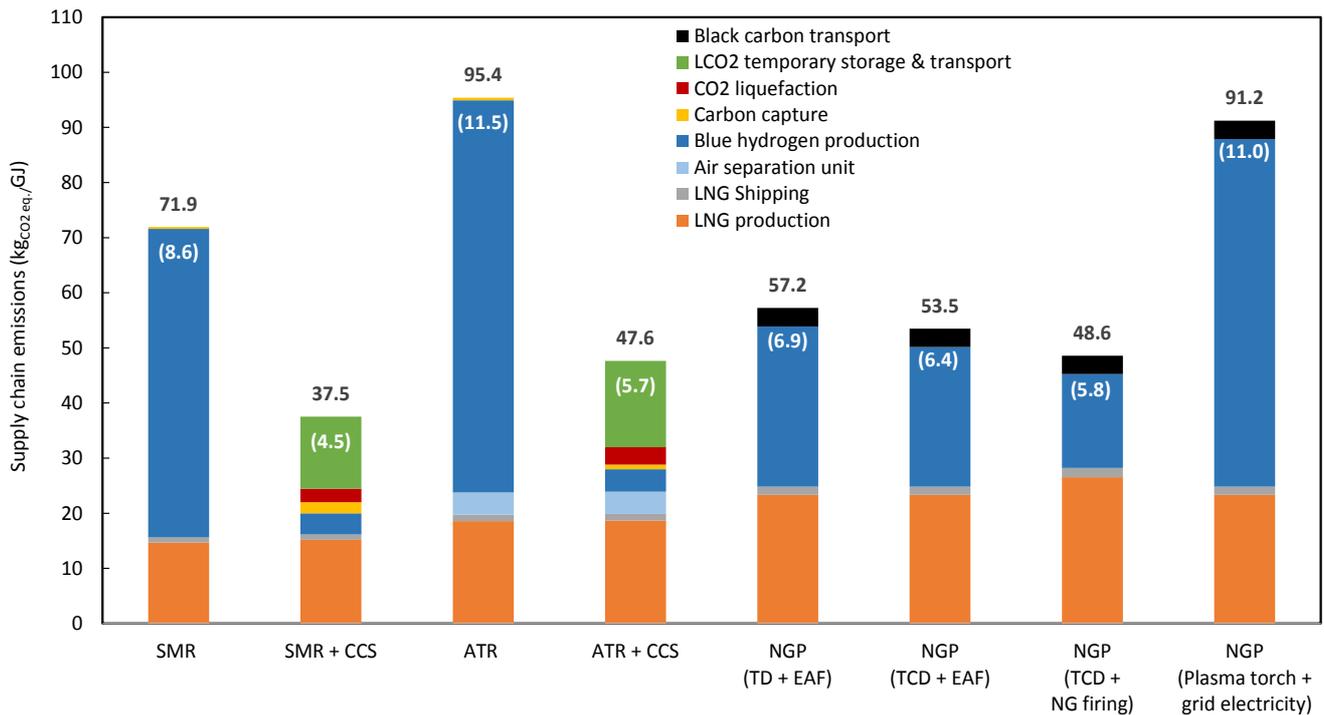


Figure 2. Cumulative emissions intensity ($\text{kg}_{\text{CO}_2 \text{ eq.}}/\text{GJ}$) of an LNG- based hydrogen supply chain from Australia to Japan for various blue hydrogen production scenarios. The emissions intensity on a mass basis ($\text{kg}_{\text{CO}_2}/\text{kg}_{\text{H}_2}$) are shown in brackets (white text) using the LHV of hydrogen (120 MJ/kg). The emissions intensity of grid electricity is based on Japan’s 2020 grid emissions factor (GEF) of $0.47 \text{ kg}_{\text{CO}_2 \text{ eq.}}/\text{kWh}$ in all calculations.

When compared to the emissions intensity of a liquid hydrogen supply chain, as shown in **Figure 11**, (which utilises an Australia 2020 GEF of $0.68 \text{ kg}_{\text{CO}_2 \text{ eq.}}/\text{kWh}$ [54]) the LNG energy-vector based hydrogen supply chain demonstrates significantly lower emissions. For example, the emissions intensity for a SMR pathway with CCS sees an increase from $37.5 \text{ kg}_{\text{CO}_2 \text{ eq.}}/\text{GJ}$ to $98 \text{ kg}_{\text{CO}_2 \text{ eq.}}/\text{GJ}$ through a liquid hydrogen supply chain. Higher emission intensities are generated by the high energy requirement of processes such as hydrogen liquefaction and electrolysis, coupled with Australia’s high GEF. An exception to this is the potential for electrolysis using a renewable energy source which leads to near zero GHG emissions generation for hydrogen production, however a renewable energy supply for commercial scale production is not currently available. Such technology is currently hindered by low capacity factors and high CAPEX and OPEX requirements. Thus, an LNG-based hydrogen supply chain likely presents an opportunity for more significant emissions reduction in the short term. Further reduction in these emissions intensities could be achieved via technological advancements in production and shipping, and diversification of the grid energy mix (based on feasibility studies and forecast emission intensities) as outlined in **Table 7**. Some theoretical supply chain emissions that could be achieved following implementation of these emissions reduction options are displayed in **Figure 12**. The results indicate that SMR and ATR with CCS become arguably the optimum production methods by 2030, generating supply chain emissions below $20 \text{ kg}_{\text{CO}_2}/\text{GJ}$, a reduction of 23.9 and $29.5 \text{ kg}_{\text{CO}_2}/\text{GJ}$ respectively.

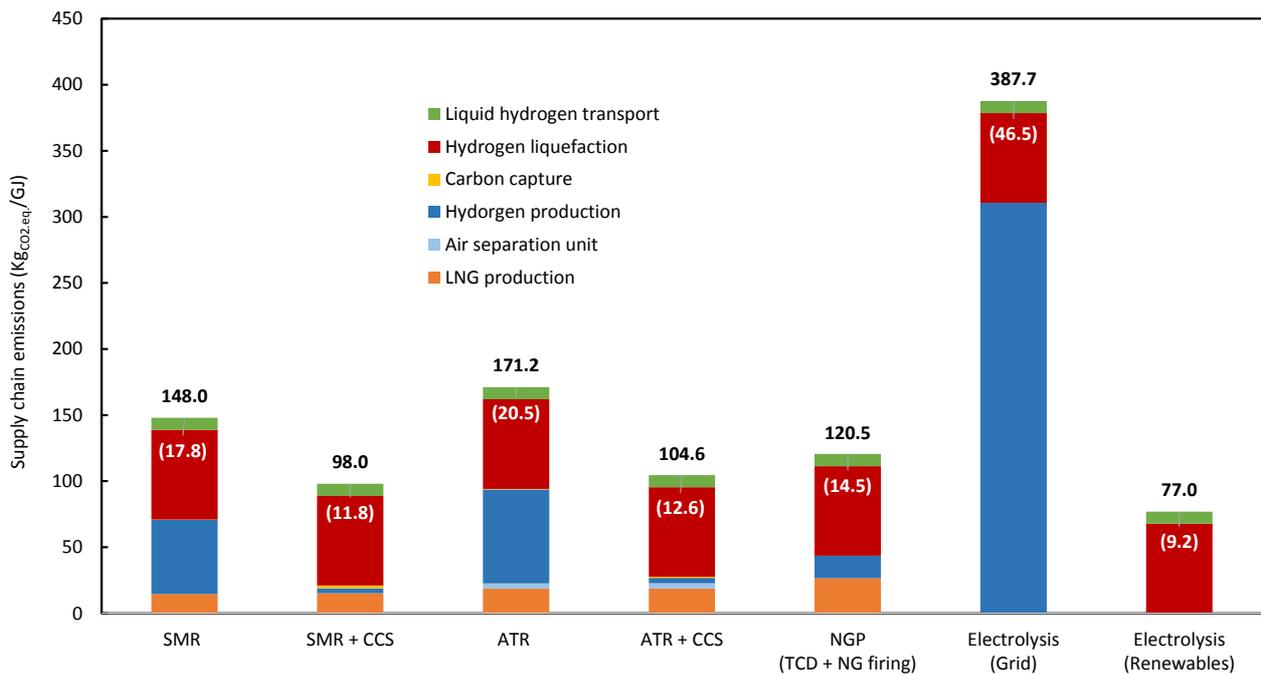


Figure 3. Estimated cumulative emissions intensity (kgCO₂eq./GJ) of a 100 tpd liquid hydrogen supply chain from Australia to Japan for various blue and green hydrogen production scenarios. The emissions intensity on a mass basis (kgCO₂/kgH₂) are shown in brackets (white) using the LHV of hydrogen (120 MJ/kg). The emissions intensity of grid electricity is quoted at Australia’s 2020 GEF of 0.68 kgCO₂eq./kWh in all calculations.

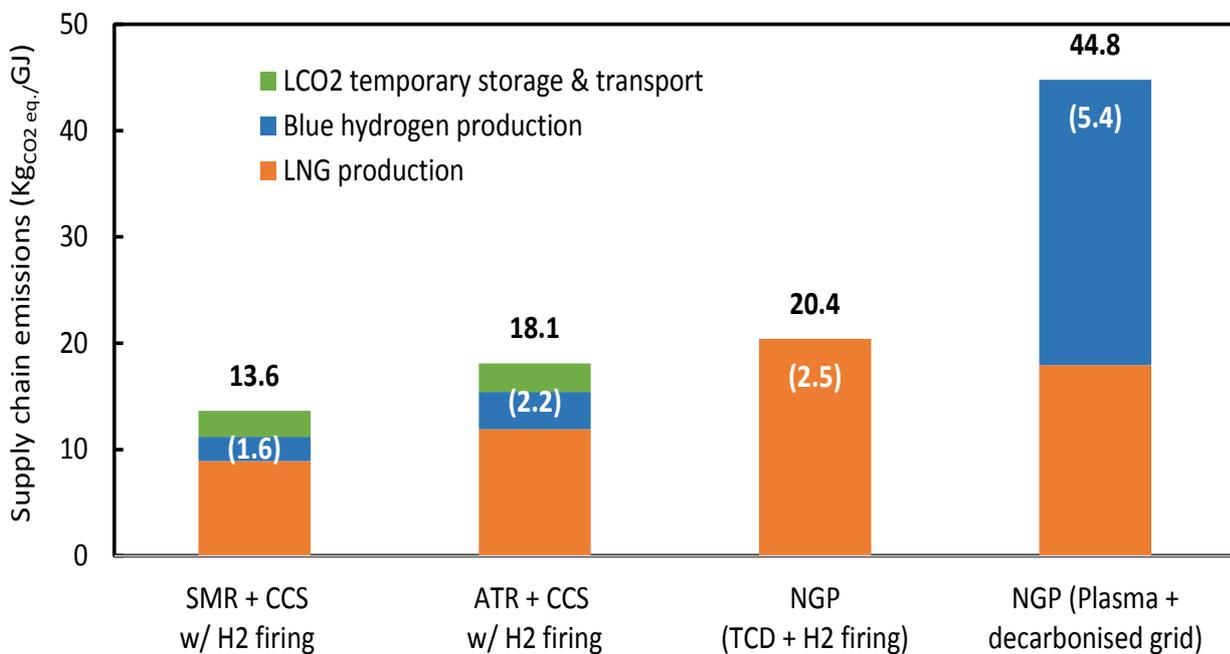


Figure 4. Potential emissions intensity (kgCO₂eq./GJ) of an LNG energy-vector based supply chain from Australia to Japan for select blue hydrogen production scenarios with methods of emission reduction included. The emissions intensity on an energy basis (kgCO₂/kgH₂) are shown in brackets (white) using the LHV of hydrogen (120 MJ/kg). The emissions intensity of grid electricity is quoted at the upper estimate for Japan’s predicted 2030 GEF of 0.2 kgCO₂eq./kWh in all calculations.

Table 7. Methods and impact of potential emissions reduction strategies.

Area of emissions reduction	Description of improvement	Estimated emissions reduction (kgCO _{2,eq} /kgH ₂)	Cost of implementation (USD/kgH ₂)	Implementation readiness
ATR ASU	Oxygen supplied as a by-product from an electrolysis unit, eliminating ASU CAPEX (infrastructure) and OPEX (grid power consumption and O&M). ¹	0.5	-0.5	Process based on conceptual studies using existing technology.
ATR ASU	ASU is powered by LNG ‘cold-energy’ from regasification. Effectively eliminates ASU grid power consumption. ²	0.5	-0.2	Feasibility indicated in conceptual study [187]. Technology is available; however it is difficult to retrofit.
SMR and ATR carbon capture	Use of waste heat generation (i.e. from steam cycle and flue gas CO ₂ streams) to power carbon capture processes in SMR and ATR, with additional potential to power CO ₂ liquefaction. ³	(0.2 - 0.6)	-0.2	Feasibility indicated in conceptual study [188]. Process is used across other industries, such as in LNG production. Technology is available, however difficult to retrofit.
SMR heat source	NG burner can be replaced with a hydrogen burner, using a portion of the output H ₂ to power the reforming process. This eliminates flue gas CO ₂ emissions and emissions associated with production of the NG fuel.	1.6	-0.3	Large-scale 100 Vol. % pure hydrogen burners are developing technology, but not widely used commercially.
NGP heat source	NG firing can be replaced with hydrogen firing to provide the heat source for TCD of the NG feedstock. This eliminates flue gas CO ₂ emissions and emissions associated with production of the NG fuel.	2.1	-0.3	Large-scale 100 Vol. % pure hydrogen burners are developing technology, but not widely used commercially.
LCO ₂ BOG	Reduction in LCO ₂ storage BOG emissions from 0.2% to 0.1% via improved insulation methods, and elimination of LCO ₂ BOG in maritime transport via installation of on-board re-liquefaction units.	0.4	+0.1 indicative value	Process remains conceptual for LCO ₂ , however such practices have been implemented for LNG. Technology to be integrated into new LCO ₂ carrier designs.
Shipping exhaust (TTW emissions)	Zero-carbon emission fuels can be implemented for maritime transport via the use of green/blue ammonia or hydrogen combustion engines to mitigate shipping exhaust emissions in LNG, LCO ₂ and carbon black transport [189]. For ammonia ICEs, catalytic converters are to be implemented to remove NOx emissions. ⁴	1.5	+0.3	Currently in development and trialled in pilot projects, including the HESC LH ₂ carrier the Suiso Frontier, equipped with a SAACKE H ₂ BOG burner [190]. Retrofitting of Ammonia engines to ships commencing 2025 [189].

Japanese GEF	Diversification of the energy mix to reduce the GEF to 0.09 - 0.2 kg _{CO2} /kWh via an increased 63 - 87% share in renewables, fossil fuel with CCUS, and nuclear power production by 2030 [191].	0.1 – 4.3 (Dependent on H ₂ production method)	Variable cost increase	Foreseeable based on Government policy forecasts
¹ Assuming supplied oxygen is a waste product from an electrolysis unit in close proximity to the ATR, with minimal infrastructure costs for transport between facilities. ² Assuming minimal additional costs for associated infrastructure (heat exchangers and compressors) required compared to a conventional ASU. ³ Assuming complete elimination of grid power use for carbon capture, with minimal additional costs for associated infrastructure (i.e. heat exchangers) for waste heat system relative to a traditional carbon capture unit powered by a steam boiler connected to grid power. ⁴ Assuming green or blue ammonia with minimal well-to-tank emissions during production of the fuel.				

5.3 Pathway forward

On the basis of this techno-economic analysis, it is clear that a hydrogen supply chain based on LNG as the export vector is close to meeting the target KPIs; it has the potential to be economically viable, technologically feasible and appreciably reduces the supply chain emission intensity. Currently, SMR with CCS was found to be the optimum hydrogen production technology for such a supply chain, obtaining the lowest emissions intensity while also remaining below the 3 USD/kg_{H2} cost target. As such, this supply chain provides a clear opportunity for the rapid development of a hydrogen economy between Australia and Japan within the next (2-3) years, against which other supply chains such as liquid hydrogen can't currently compete. With the potential for rapid implementation, this pathway may prove a valuable aid in working towards the 2030 50% global emissions reduction target, with the hydrogen generated used to decarbonise both the power and transport sector. Additionally, the large number of commercial-scale SMR units in operation today present the potential to implement such a supply chain more broadly outside the Asia-Pacific region.

SMR with CCS is likely to remain the dominant technology for large-scale hydrogen production in the near future because of its favourable economics and high TRL. There remains strong motivation, however, to continue to improve the blue hydrogen production processes based on ATR and NGP. ATR provides the potential for higher carbon capture rate and improved reaction efficiency, NGP provides the potential for a zero-carbon emissions methodology, and both were demonstrated to already attain delivered hydrogen costs close to Japan's target. Finding alternate markets for the solid carbon by-product of NGP will be critical in developing it as a means of commercial hydrogen production whilst preventing saturation of the carbon market.

In regard to green hydrogen, electrolysis currently suffers from high CAPEX and low-capacity factors and requires a substantial source of low-cost renewable energy which is not currently available in most regions. At present, low carbon energy constitutes only 8% and 13% to the Australian and Japanese energy mix, respectively [54, 146]. However, multiple techno-economic feasibility studies, including the Hydrogen Council report and CSIRO National Hydrogen Roadmap [47, 118], project the cost of green hydrogen in Australia to decrease below 3 USD/kg_{H2} by 2030 on account of reduction in green energy pricing, increased capacity factors via battery technology, improved electrolyser lifespan and economies of scale. One study estimated 2030 hydrogen production costs from solar PV and wind powered electrolysis at 2.25 - 2.95 AUD/kg_{H2} (1.74 - 2.29 USD/kg_{H2}) and 2.70 - 3.20 AUD/kg_{H2} (2.10 - 2.48 USD/kg_{H2})

respectively in Australia [51]. On these grounds, blue hydrogen will provide a short to medium term pathway when transitioning to a hydrogen economy, and investment in developing hydrogen supply chains will be instrumental to provide a long-term sustainable energy source. Crucially in this respect, adoption of an LNG-vector hydrogen supply chain will help drive much of the large-scale demand and infrastructure needed for viable green hydrogen pathways.

6. Conclusion

This techno-economic review assessed the viability of an LNG-based hydrogen supply chain from Australia to Japan against three KPIs: the delivered hydrogen cost, CO₂ emissions intensity across the entire supply chain, and the TRL. The proposed hydrogen supply chain entailed the export of LNG as an energy vector from Australia to Japan, where it was used for blue hydrogen production with integrated CCUS. Existing and emerging hydrogen production technologies were assessed within this supply chain, including SMR, ATR and NGP.

Analysis suggests that this hydrogen supply chain can act to reduce CO₂ emissions at a viable hydrogen cost over the coming decade, until other hydrogen production supply chains (such as liquid hydrogen and ammonia), incorporating green production, become competitive across all the KPIs. SMR (with CCS) was found to be the optimum hydrogen production technology for an LNG-vector hydrogen supply chain at present, obtaining the lowest emissions intensities at 37.5 kg_{CO2}/GJ (4.5 kg_{CO2}/kg_{H2}), while also remaining close to the 2050 delivered cost target to Japan of 19.2 USD/GJ (2.3 USD/kg_{H2}). This emissions intensity corresponds to a (77 - 84)% reduction on current LNG supply chain emissions, with key areas of future emissions reduction plausibly identified to help drive this emissions intensity further down to 13.6 kg_{CO2}/GJ (1.6 kg_{CO2}/kg_{H2}). Surprisingly SMR with CCS produced lower total supply chain emission intensities than ATR with CCS despite ATR featuring significantly better CO₂ capture efficiencies. This can primarily be attributed to emissions associated with ATR electricity provision for the required ASU.

There remains strong motivation, however, to continue to improve the processes of ATR and NGP, which are currently at comparatively lower levels of commercial readiness. In addition to higher carbon capture rates, ATR could also offer improved reaction efficiency, whilst NGP provides the potential for an extremely low carbon emissions methodology. Current supply chains implementing ATR (with CCS) and NGP (with NG firing) achieved supply chain costs of 30.0 USD/GJ (3.6 USD/kg_{H2}) and 22.1 USD/GJ (2.6 USD/kg_{H2}), respectively. Further cost reductions below the Japanese target are foreseeable for the ATR and NGP pathways if up-scaling and expansion of the carbon black market are realised. The emissions intensity for these supply chains was estimated to be 47.6 and 48.6 kg_{CO2}/GJ (5.7 and 5.8 kg_{CO2}/kg_{H2}) respectively, with key areas of emissions reduction identified that could reduce these further to 18.1 and 20.4 kg_{CO2}/GJ (2.2 and 2.5 kg_{CO2}/kg_{H2}).

Though proven on the grounds of technological and economic feasibility, a number of challenges going forward must be overcome if the proposed supply chain is to be implemented on a commercial scale. Not least is the expansion of hydrogen end use infrastructure; improvements in carbon capture technology and a reduction in grid emission factors remain imperative for driving down supply chain emissions.

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8. Abbreviations

ATR	Auto-thermal reforming
ASU	Air separation unit
CAPEX	Capital expenditure
CCS	Carbon capture and storage
CCU	Carbon capture and utilisation
CCUS	Carbon capture, utilisation or storage
CO ₂	Carbon dioxide
EAF	Electric arc firing
EI	Emissions intensity
ESI	Electronic supplementary information
GEF	Grid emissions factor
GHG	Greenhouse gas
GWP	Global warming potential
H ₂	Hydrogen
HFO	Heavy fuel oil
KPI	Key performance indicator
LCO ₂	Liquified carbon dioxide
LH ₂	Liquid hydrogen
LNG	Liquefied natural gas
LOHCs	Liquid organic hydrogen carriers
MDEA	Methyl diethanolamine
MGO	Marine gas oil
NG	Natural gas
NGP	Natural gas pyrolysis
NTP	Normal temperature and pressure
OPEX	Operational expenditure
PD	Plasma decomposition
PSA	Pressure swing adsorption
SMR	Steam methane reforming
Syngas	Synthesis gas
TCD	Thermo-catalytic decomposition
TD	Thermal decomposition
TRL	Technology readiness level
TTW	Tank-to-wake
WGS	Water-gas shift
WTT	Well-to-tank
WTW	Well-to-wake

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