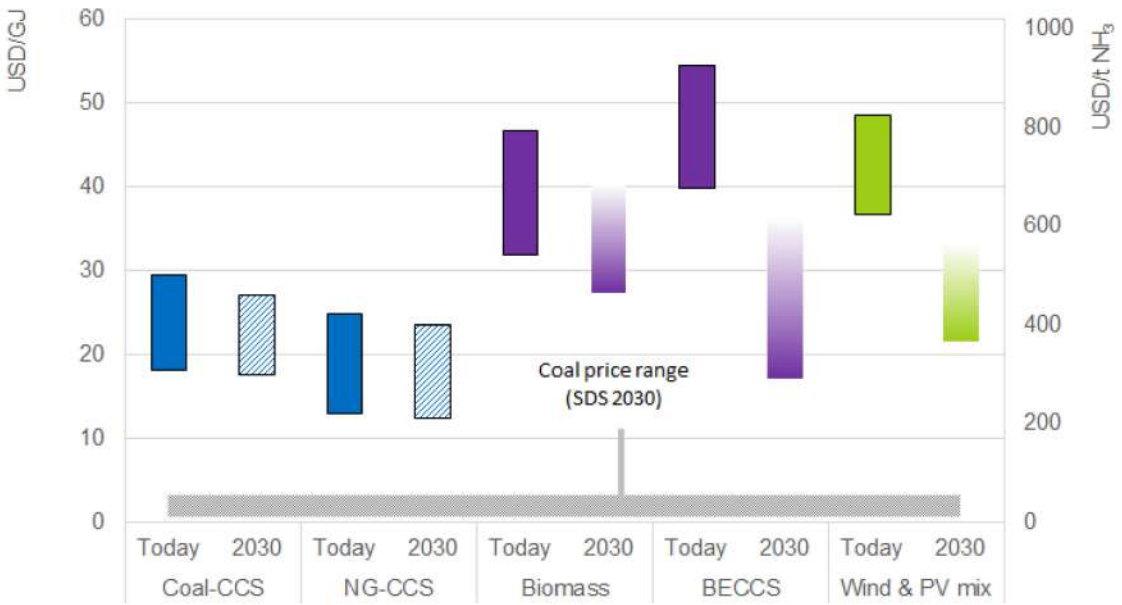
Production cost estimates for low-carbon ammonia for today and 2030



Note: WACC 5%; Coal 15-80 (today), 12-62 USD/t (2030); Natural gas 1.2-6.6 (today) 1.2-5.3 USD/GJ (2030); biomass residues \$50-100/t(dry) (today & 2030); CAPEX estimates for ammonia plants: Coal with CCUS USD 3500/kW_{H2}; NG with CCUS USD 2830/kW_{H2}; Biomass USD 7470/kW_{H2} (today), USD 6170/kW_{H2} (2030); Electrolyser USD 1480/kW_e (today), USD 560/kW_e (2030); CAPEX range for thermo-chemical routes ±15%; CO_2 capture cost from BECCS: USD 25/tCO_2, pipeline and storage cost USD 20/tCO_2. Results for electrolytic ammonia are based on a dynamic optimisation of the wind/PV mix for the process, see Annex A for details.

Prices for unabated ammonia have been fluctuating between USD 160-700/t during recent years. However, when low-carbon ammonia is used in the power sector, it should be compared with the price of coal that it replaces. In the SDS, the price of steam coal imports for Japan and Europe in 2030 are USD 55-65/t, or USD 2-3/GJ. This would compare with a fuel ammonia price of just USD 40-50/t. Adding carbon price of USD 82/tCO_2, would increase the coal price by about USD 10/GJ and lead to a comparable fuel ammonia price of USD 210-230/t.

Transport and storage of ammonia

Ammonia pipelines and ships have been transporting liquid ammonia for the fertiliser industry for several decades. Ammonia is well developed also in terms of intercontinental transmission, which relies largely on semi-refrigerated liquefied petroleum gas (LPG) tankers. Trade routes today include transport from the Arabian Gulf and Trinidad and Tobago to Europe and North America. TogliattiAzot in Russia produces up to 3 Mt of ammonia per year, most of which then travels about 2 500 km to Odessa along the world's longest ammonia pipeline, followed by shipping to a number of locations globally.

Ammonia liquefies at -33°C or at 8.6 bar. The current largest refrigerated ammonia tanks in the world are located in Qatar and each has a capacity of 50 kt. The United States alone has over 10,000 ammonia storage sites, many of which connect to a pipeline network stretching more than 3 000 km and connecting the Gulf of Mexico to the Midwest. The current largest plant in the world is the SAFCO IV site in Saudi Arabia with a capacity of 1.3 Mt of ammonia per year.

If ammonia is used only as a hydrogen carrier and is to be reconverted back to hydrogen before end-use, the advantages related to transport and storage need to be weighed against energy losses (about 25-30% depending on the required hydrogen purity) and the required equipment for the conversion and reconversion back to hydrogen.

Transport and storage of hydrogen

The most appropriate storage medium for hydrogen depends on the volume to be stored, the duration of storage, the required speed of discharge and the geographic availability of different options. Salt caverns are used today in the UK and the US for large-scale and long-term hydrogen storage. They provide significant economies of scale, high storage efficiency, low operational costs and low land costs. These characteristics mean that they are likely to be the lowest-cost option for hydrogen storage even though hydrogen has low energy density compared to natural gas.

Where geology does not allow storage in caverns, hydrogen needs to be stored in tanks either in compressed or liquefied form. Today, hydrogen is most commonly stored in small tanks as a gas or liquid for small-scale mobile and stationary applications. Much larger storage options would need to become available if hydrogen were used to bridge major seasonal changes in electricity supply or heat demand, or to provide system resilience.

Hydrogen transmission via pipelines is a mature technology. Currently there are about 4 600 km of hydrogen pipelines, with over 90% located in Europe and the United States. These are usually closed pipeline systems owned by large merchant hydrogen producers and are concentrated near industrial consumer centres (such as petroleum refineries or chemical plants). The cost of transporting hydrogen via pipelines represents a relatively small part of the overall hydrogen costs, generally in the range of USD 0.2-0.7/kg for a distance of a 1 000km assuming a large pipeline with a transport capacity of 500 tH_2 per day.

For marine transport purposes, hydrogen can be liquefied in a manner similar to what is done for natural gas to increase its density. However, liquefaction of hydrogen requires cooling it to -253°C and the required cooling work is equivalent to 20% - 30% of the energy content of the liquefied hydrogen itself. This is considerably more energy than is required to liquefy natural gas, which consumes the equivalent of 10% of the energy content of natural gas. The efficiency of the liquefaction system is also sensitive to size, and large-scale systems can achieve higher efficiencies.

Currently no commercial ships can transport liquefied hydrogen. Such ships would be broadly similar to LNG ships and would require the hydrogen to be liquefied prior to transport. Excellent insulation of the ship's storage tanks is required to keep the unavoidable boil-off from exceeding the average consumption of the propulsion system, thereby avoiding net losses. The expectation is that these ships will be powered by hydrogen that boils off during the journey (around 0.2% of the cargo would likely be consumed per day, similar to the amount of natural gas consumed in LNG carriers). The world's first prototype liquefied hydrogen carrier, the Suiso Frontier, features a double-shelled and vacuum-insulated 1,250 m^3 tank to hold the liquefied hydrogen.

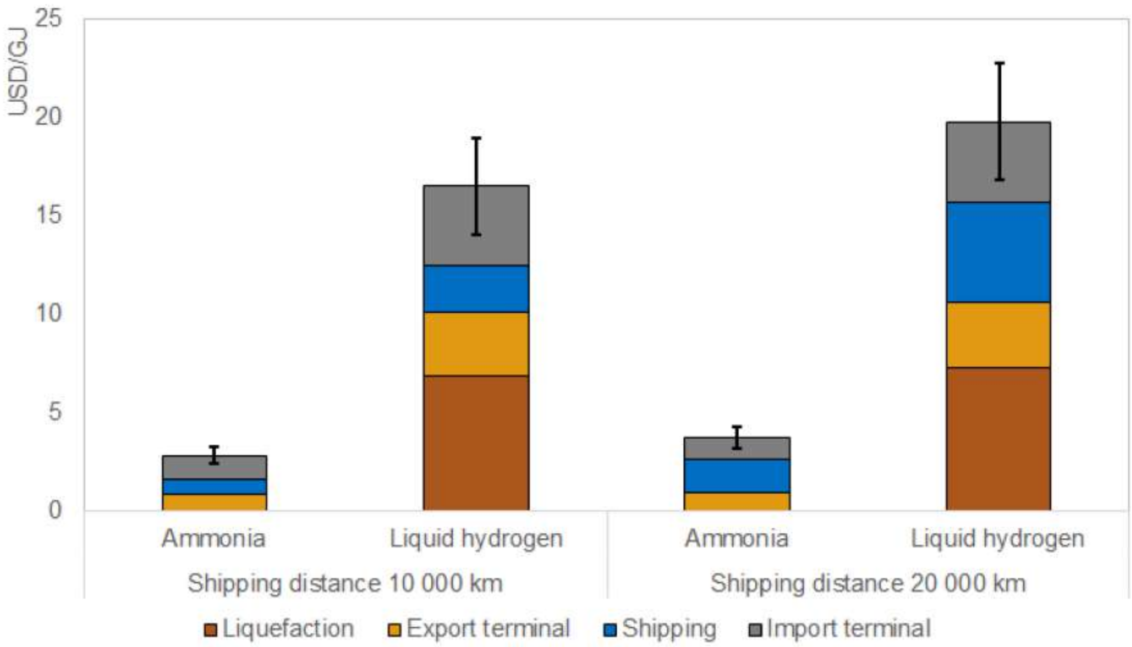
An alternative to liquid hydrogen shipping is the use of liquid organic hydrogen carriers (LOHCs), which involves loading a carrier molecule with hydrogen, transporting it, and then extracting pure hydrogen again at its destination. LOHCs have similar properties to crude oil and oil products, and their key advantage is that they can be transported as liquids without the need for cooling. However, there are costs associated with the conversion and reconversion processes, and carrier molecules are often expensive.

Several different LOHC molecules are under consideration, each with their own characteristics. Methylcyclohexane (MCH) is considered a relatively low-cost LOHC option with toluene as the carrier molecule. Around 22 Mt of toluene is currently produced annually (for commercial products), a quantity that could carry 1.4 MtH_2 if it were to be used as an LOHC. It costs around USD 400–900 per tonne. However, toluene is toxic and would require careful handling. A non-toxic alternative LOHC is dibenzyltoluene. Although it is much more expensive than toluene today, scaling up could make it a more attractive option in the long-term, especially given its non-toxic nature.

Transport cost estimates

The overall cost estimate for transporting LH_2 via shipping for a distance of 10 000 km is USD 14-19/GJ (USD 1.7-2.3/kgH_2); while for ammonia it is significantly lower at USD 2-3/GJ (USD 40-60/tNH_3). In the long-term, further efficiency improvements and process optimisation could reduce the transport costs, and thus the total supply costs for all carriers. The cost of shipping increases with transport distance, but not very significantly. The overall cost estimate for shipping LH_2 over a distance of 20 000 km is USD 17-23/GJ (USD 2.0-2.7/kgH_2) compared to USD 3-4/GJ (USD 60-80/tNH_3) for ammonia.

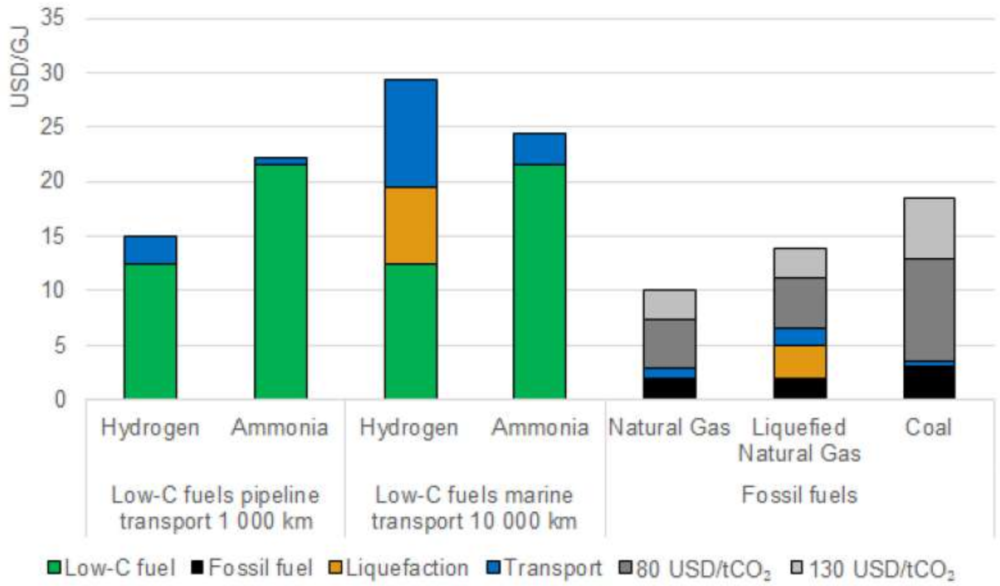
Marine transport cost estimates for ammonia and liquid hydrogen



Note: WACC 5%; energy consumption of H_2 liquefaction 6 kWh/kgH_2. Storage costs included in the cost of terminals. All assumptions available in the Annex.

Although marine transport of liquid hydrogen is significantly more expensive than of ammonia, hydrogen is about 30-40% cheaper to produce, and if hydrogen is needed for the end-use application, reconversion of ammonia to high-purity hydrogen after transport involves further conversion losses and additional costs.

Delivered cost of low-carbon hydrogen and ammonia based on pipeline or marine transport in comparison to the cost of fossil fuels



The overall impact of transport on the supply cost of low-carbon fuels is illustrated above, together with a comparison to fossil fuels at different carbon price assumptions. The cost of pipeline transfer is only a small fraction of the production cost, and does not alter the relative cost difference between hydrogen and ammonia. However, the liquefaction step and more stringent requirements associated with low-temperature storage make hydrogen significantly more expensive to transport by sea than ammonia. As a result, marine transport can double the cost of low-carbon hydrogen, increasing its overall supply cost above that of ammonia. However, both low-carbon hydrogen and ammonia remain expensive fuels compared to natural gas, LNG and coal, even under high carbon price assumptions.

Chapter 4. Case studies

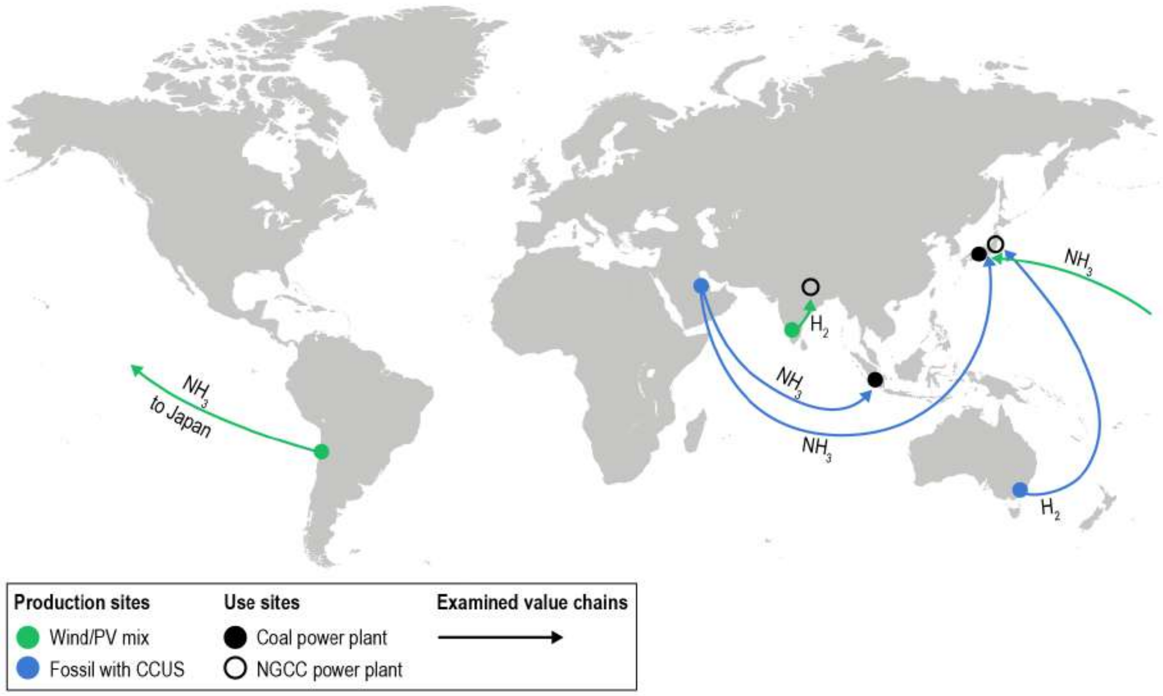
Highlights

- **Three different use categories are examined for low-carbon fuels in the power sector in 2030**. These are: Using imported low-carbon hydrogen and ammonia in an advanced economy having a carbon price of USD 82/tCO_2 (Cases I – III); Using imported low-carbon ammonia in a developing economy without a carbon price (Case IV); Using domestically produced low-carbon hydrogen in a developing economy without a carbon price (Case V).
- **Certain regions are well-positioned to produce low-cost low-carbon hydrogen and ammonia.** Our analysis suggests the following indicative production costs in 2030: USD 210-310/tNH_3 for natural gas based low-carbon ammonia on the east coast of Saudi Arabia, USD 400-540/tNH_3 for renewables based electrolytic ammonia in the Taltal region of Chile, USD 1.3-2.1/kgH_2 for coal-based low-carbon hydrogen in the Latrobe valley of Australia, and 1.3-1.7/kgH_2 for renewables based electrolytic hydrogen in the Karnataka state of India.
- **Low-cost hydrogen and ammonia in one location do not mean low-cost hydrogen and ammonia everywhere.** Full supply chains, including transport and storage, must be considered when comparing the routes and options of low-carbon fuels as delivery by sea can significantly add to the costs. This is especially the case with hydrogen.
- **The impact of co-firing on the levelised cost of electricity (LCOE) at an existing power plant depends on many local factors.** These include the type and efficiency of the power plant, the modification cost, the share of co-firing, the average capacity factor and the carbon price. Our analysis suggests following indicative LCOEs for existing power plants co-firing 60% of low-carbon fuels and operating on average at a capacity factor of 15% in 2030: Japanese coal plant using imported ammonia: USD 119-172/MWh; Japanese gas plant using imported low-carbon hydrogen: USD 152-222/MWh; Indonesian coal plant using imported ammonia: USD 99-142/MWh; Indian gas plant using domestic low-carbon hydrogen: USD 85-115/MWh.
- **High carbon prices in the power sector compensate for increases in generation costs from low-carbon fuels.** In the Japanese case studies that feature USD 82 t/CO_2 carbon price in the SDS in 2030, a large part of the cost increase is compensated by reductions in emission costs. For Indonesia and India, the cost increase from co-firing is reflected fully in the LCOE due to the absence of a carbon price in the SDS in 2030.
- **The LCOE from co-firing should be compared with the system value**. Although the LCOE of co-firing is somewhat higher when operating at a low average capacity factor (CF) compared to a high average CF, higher energy market values are likely achieved at low CFs.

For low-carbon fuels to reach their full potential in clean energy transitions, they will need to be stored in large quantities for long periods of time, and often transported over long distances. The delivery infrastructure is therefore a critically important part of global value chains, and in many instances will govern the cost and availability of low-carbon fuels. When fuels have been delivered, they can be used for displacing fossil fuels at existing power plants leading to reduced emissions depending on the share of co-firing.

With the help of case studies, three different use categories for low-carbon fuels in the power sector in 2030 are examined. These are: Using imported low-carbon hydrogen and ammonia in an advanced economy having a carbon price of USD 82/tCO_2 (Cases I – III); Using imported ammonia in a developing economy without a carbon price (Case IV); Using domestically produced low-carbon hydrogen in a developing economy without a carbon price (Case V).

Examined value chains for the production and use of low-carbon fuels in thermal power plants



Our analysis covers the production of low-carbon hydrogen or ammonia in a low-cost region, transport of the fuel to an existing fossil power plant, modification of the power plant for co-firing, and the ensuing impact on the LCOE under different co-firing shares, operating regimes and carbon price assumptions.

The import terminals are assumed to distribute fuels also for industrial users and other customers beyond the power sector, so that the utilisation rate of the transport infrastructure remains independent of the operation of the power plant (whether peak, mid-merit or baseload).

The calculated LCOEs should be considered in the context of system value because the value of the generated electricity is likely to be higher during peak load times, than the average value of the electricity across the whole year. The system value aspects of using low-carbon hydrogen and ammonia in the power sector are discussed in more detail after case studies in Chapter 5.

Case study I: Natural gas-based low-carbon NH_3 from Saudi Arabia to an existing coal plant in Japan

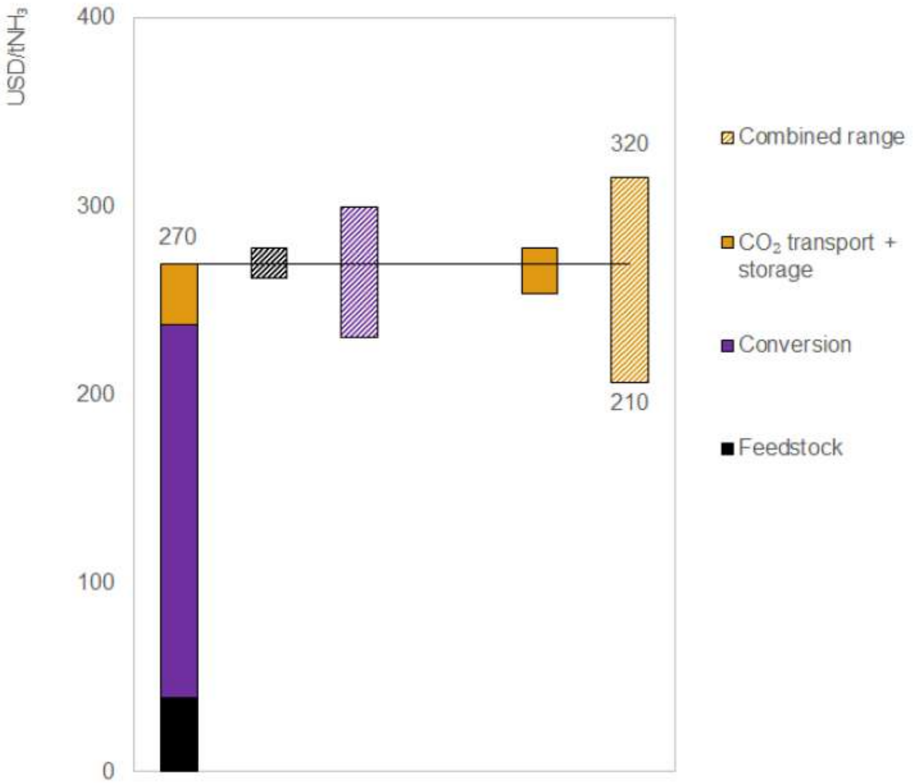
Saudi Arabia could be seen as a potential powerhouse for the production of low-carbon fuels, due to its abundance of natural resources and strategic location for exports. It seeks to become a top exporter of low-carbon fuels produced from both renewables and natural gas with CCUS. The west coast provides a base for exports to Europe, while the east coast has good opportunities to leverage existing ammonia infrastructure, including production plants and ammonia port facilities, to serve the Asian market.

Saudi Arabia has the world's fourth largest proven gas reserves, accounting for 4% of the global total. Most of the natural gas produced in this country is associated with oil production and is therefore available at very low cost. Oil production in Saudi Arabia – and thus also associated natural gas – has low average GHG emission intensities compared to other regions, due to highly productive reservoirs, low energy consumption for the extraction and processing of the oil and gas, and low flaring rates. The Saudi government has been looking for opportunities to capitalise on associated gas resources, such as through LNG exports and investing in low-carbon fuel capacity.

The Middle East has an estimated theoretical CO_2 storage capacity of more than 2,500 billion tonnes (Gt) of CO_2, with the substantial majority of it in Saudi Arabia in the form of saline aquifers. In particular, the east coast of Saudi Arabia has good onshore sedimentary basins, depleted gas and oil reservoirs as well as opportunities for EOR using CO_2. However, more detailed studies are required to determine the exact potential in Saudi Arabia. The cost of CO_2 transport and storage is expected to be relatively low in Saudi Arabia, especially when storing CO_2 in depleted oil and gas reservoirs. The Uthmaniyah project is currently the only operational large-scale CCUS project in the country. It captures 0.8 Mt of CO_2

per year at the Hawiyah gas plant and transports it via 85 km of pipelines to Uthmaniyah where it is used for EOR in the Ghawar field.

Indicative levelised cost of low-carbon ammonia in 2030 from natural gas with CCUS on the east coast of Saudi Arabia

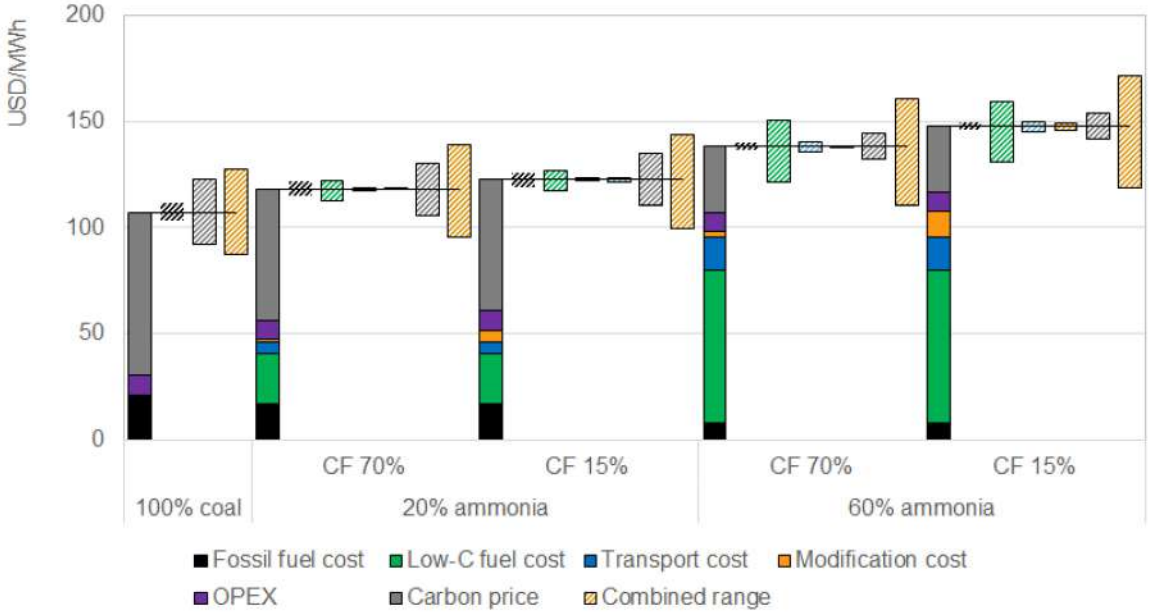


Notes: LCOA = levelised cost of ammonia production; WACC 5%, natural gas USD 1.1-1.6/GJ; ATR efficiency 63%, OPEX 4% of CAPEX; 95% CO_2 capture, CO_2 transport and storage cost = USD 10-25/tCO_2, carbon price = USD 0/tCO_2.
Source: IEA analysis.

The national oil and gas company Saudi Aramco is operating a CCUS pilot project at the SABIC's SAFCO ammonia plant in Jubail, which produces low-carbon ammonia in existing infrastructure. In September 2020, 40 tonnes of ammonia produced from natural gas with CCUS were shipped to Japan for use in power generation. Of the 50 tonnes of CO_2 captured from the pilot project, 30 tonnes were used in methanol production and 20 tonnes were injected for CO_2-EOR in the Ghawar field. The next step would be the scale-up to commercial plant sizes.

The cost of producing low-carbon ammonia in a large-scale facility on the east coast of Saudi Arabia is estimated to be between USD 210-320/tNH_3, depending mainly on the investment cost estimate, natural gas price and cost for CO_2 transport and storage. Due to the high 95% CO_2 capture, carbon emissions from the fuel production plant are minimised. Large plant sizes and the use of existing ammonia infrastructure is important to minimise the costs in the early stages. Autothermal reforming (ATR) plant sizes of 1.0 Mt/yr are possible and would allow for the exploitation of economies of scale. The produced ammonia would have to be transported by pipeline to an ammonia export terminal, after which it would be shipped to an import terminal in Japan over a distance of approximately 12 000 km for co-firing in an existing coal power plant modified for ammonia use. The terminal and shipping steps are estimated to cost on average USD 60/tNH_3 (USD 50-70/t), resulting in an ammonia delivery cost of USD 260-390/tNH_3 to Japan.

Indicative LCOEs for an existing coal power plant in Japan co-firing imported low-carbon ammonia from Saudi Arabia under different shares and operating regimes



Note: Coal USD 52-78/t, Low-carbon NH_3 USD 210-320/t, transport cost USD 50-70/tNH_3 coal plant efficiency 44%, carbon price USD 66-98/tCO_2.
Source: IEA analysis.

The cost impact of ammonia co-firing is illustrated in the figure above. Assuming a 2030 coal price of USD 52-78/t and a carbon price of USD 66-98/tCO_2 for Japan from the IEA SDS, the LCOE of an existing power plant (considering the initial capital investment as a sunk cost) is USD 88-127/MWh.

Co-firing 60% of low-carbon ammonia at a capacity factor of 70% (CF 70%) would lead to a relatively small increase in the LCOE to USD 111-161/MWh given the switch to a much more expensive fuel. However, due to the high implied carbon price of the SDS for advanced economies in 2030, the increase in fuel cost is largely offset by reductions in emissions costs. The increase in costs would be somewhat higher at USD 119-172/MWh if the plant were operated only under peak-load mode (CF 15%), but the value of the generated electricity is also likely to be higher during peak load times as will be discussed in Chapter 5.

Case study II: Wind and PV-based low-carbon NH_3 from Chile to an existing coal plant in Japan

Thanks to its abundant and high-quality renewable resources, Latin America has the potential to produce large amounts of low-carbon hydrogen from renewable electricity. While many parts of the region could see competitive prices in the long-term, the lowest production costs could be located in southern Patagonia (Argentina and Chile) and the Atacama region (Argentina, Bolivia, Chile and Peru), as well as in northern Mexico and northeastern Brazil, among many other regions.

In the Argentine Patagonia, the Hychico pilot project Patagonia has been producing hydrogen from wind power since 2008, using two alkaline water electrolysers with a joint capacity of 0.55 MW. The hydrogen is mixed with natural gas and is used for power generation, using a 1.4MW generation unit that can operate with a large interval of gas/hydrogen blends, as well as pure hydrogen. The Hychico project also comprises Latin America's only hydrogen pipeline system (2.3km) and an underground storage facility. Since 2011, the Ad Astra Rocket pilot in Costa Rica has been producing around 0.8 tH_2/yr from solar and wind power, using a 5 kW PEM electrolyser, to power the first fuel cell bus in the region, as well as four fuel cell cars. Finally, the Cerro Pabellón microgrid pilot project in Chile's Atacama desert has been using solar power to produce 10 tH_2/yr of hydrogen since 2019, using a 50 kW PEM electrolyser. The project provides dispatchable renewable electricity to cover the needs of a microgrid serving a community of over 600 technicians working in the geothermal plant.

Chile has already made relevant announcements in terms of establishing a long-term vision for, and engaging the private sector in low-carbon hydrogen. In November 2020, Chile launched a comprehensive hydrogen strategy. It identified the replacement of fossil-based hydrogen in the country's refineries and new applications in long-distance and heavy-duty transport as key opportunities, and set a target of 5 and 25 GW of electrolysis capacity installed or under development by 2025 and 2030, respectively. Two major low-carbon hydrogen projects have been announced, initially aimed at replacing imported ammonia for applications in the mining sector (HyEx) and synthetic fuel production from methanol (Haru Oni). Both projects plan to target export markets in the long term.