Japan's Costly Ammonia Coal Co-Firing Strategy

September 28, 2022

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Section 1. Executive summary

30x

Japan's proposed 2050 ammonia demand target compared to the current size of its domestic ammonia market

2.8x

LCOE of a retrofitted coal plant running on 100% green ammonia produced in Japan compared to offshore wind

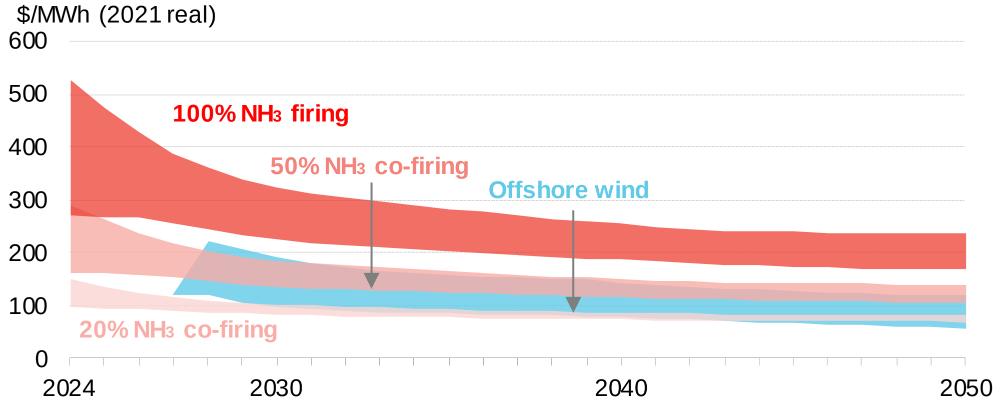
$223/MWh

Levelized cost of electricity generation in 2050 for a retrofitted coal power plant running on green ammonia produced in Japan

Japan wants to retrofit its existing coal power plants to enable co-firing of coal with ammonia to reduce carbon dioxide emissions. This report examines the potential emission reduction benefits, safety and energy security concerns as well as economics of Japan's proposed strategy.

- The Japanese government has committed to reducing the country's emissions by 46% by 2030 relative to 2013 and reach net-zero emissions by 2050. Electricity generation remains Japan's largest source of emissions due to heavy reliance on thermal power plants, including new coal-fired power plants built in recent years. Japanese utilities supported by the government are exploring co-firing of ammonia at existing coal plants to reduce emissions.
- The CO_2 emissions from a coal power plant burning ammonia at a co-firing ratio of below 50% will still emit as much CO_2 as a natural gas fueled combined cycle gas turbine. Coal power plants co-firing ammonia may also emit more nitrous oxide, a greenhouse gas with global warming potential 273 times larger than that of CO_2 for a 100-year timescale. Additionally, handling ammonia requires more care than coal due to its volatility and toxicity.

Figure 1: Levelized cost of electricity for retrofitting coal-fired power plants for ammonia co-firing at different blend rates compared to new offshore wind in Japan



Source: BloombergNEF. Ammonia co-firing cost range shows ammonia types. NH_3 = ammonia.

- The levelized cost of electricity (LCOE) generation for a retrofitted coal power plant in Japan using a 50% clean ammonia co-firing ratio is expected to be at least $136/MWh in 2030. By 2050, the LCOE of a retrofitted coal power plant running 100% on clean ammonia is expected to be at least $168/MWh. These values are costlier than the LCOE of renewable alternatives such as offshore wind, onshore wind or solar with co-located batteries. Clean ammonia is better suited for decarbonization of applications such as fertilizer production than power.
- As Japan's domestic clean ammonia production remains more expensive than green ammonia produced in Australia or blue ammonia produced in the Middle East, the country's proposed ammonia co-firing strategy would create new energy import dependence.
- *Corrects references to IHI and MHI in paragraphs three and four on page 5.*

Section 2. Overview of Japan's decarbonization goals and the power sector's role

Japan has set ambitious emission reduction targets by 2030 and 2050. The power sector is the biggest source of emissions in Japan due to its heavy reliance on fossil-fueled thermal power plants.

2.1. Why Japan wants to use ammonia in power generation

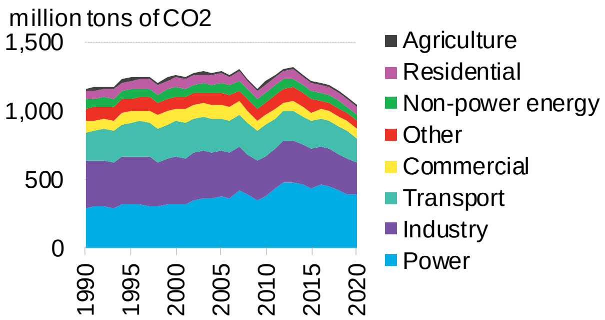
Japanese incumbent utilities and the government are advocating for ammonia co-firing at existing coal power plants for the following reasons:

- Japan has a relatively large – 49GW – fleet of coal power plants, which accounted for 30% of electricity supplied in fiscal year 2021. Co-firing coal with ammonia offers a pathway to reduce carbon dioxide (CO_2) emissions, without the need to phase out these coal plants.
- Japanese incumbent utilities cite land constraints as a challenge for the development of renewables, although Japan's Ministry of the Environment analysis[1] shows the country still has ample space to add renewables.
- The government and Japan's thermal power industry hope commercialization of ammonia co-firing technology can bolster exports.

2.2. Japan's current emissions trend and targets

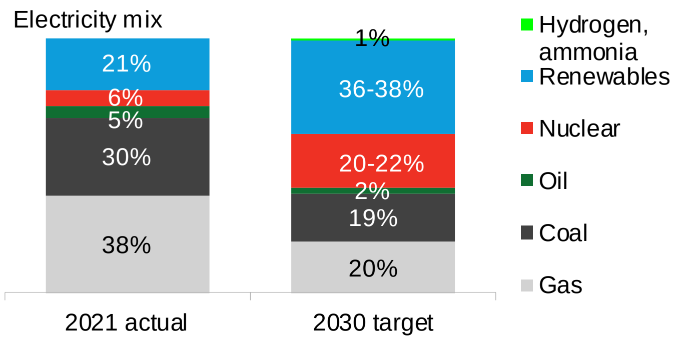
Japan emitted 1,044 million tons of carbon dioxide (CO_2) in fiscal year 2020 (Figure 2), accounting for about 2% of global emissions. The power sector is Japan's largest source of emissions, accounting for 37% of emissions in FY2020, due to heavy reliance on fossil-fueled thermal power plants (Figure 3).

Figure 2: Historical carbon dioxide emissions in Japan



Source: National Institute for Environmental Studies. Note: Years show Japan's fiscal year starting from April to March.

Figure 3: Japan's annual electricity generation mix



Source: BNEF, Ministry of Economy, Trade, and Industry. Note: Years show Japan's fiscal year starting from April to March.

[1] Japan's Ministry of the Environment estimates the resource potential of solar and onshore to be 2,746GW and 284GW (excluding unavailable sites due to topography and regulations), respectively. Japan had installed 78GW of solar and 5GW of onshore wind by the end of 2021.

In 2021, Japan updated its nationally determined contribution (NDC) to the Paris Agreement to increase its emission reduction target to 46% by 2030 compared to 2013 levels. Japan also legislated its 2050 net-zero target. Japan is also signatory to the G-7 June 2022 Summit statement calling for "a fully or predominantly decarbonized power sector" by 2035.

To meet its interim emission reduction target, Japan's Sixth Strategic Energy Plan calls for reducing coal's share of electricity generation to 19% in 2030 from 30% in 2021. The plan calls for ammonia and hydrogen to account for 1% of electricity supply in 2030.

2.3. Policy framework for coal power plant retrofits

Japan has been implementing policy mechanisms to support the reduction of emissions from coal power plants. In 2021, the country adopted a new efficiency standard for coal power that requires power generators with coal plants to meet a fleet-wide energy efficiency of 43% by 2030. While the goal of the plan is to phase out existing inefficient coal plants, the policy allows such plants to remain online if they adopt co-firing with ammonia or biomass[2].

In May 2022, the government also introduced a new classification recognizing hydrogen and ammonia as non-fossil energy sources from April 2023 onward, regardless of how the hydrogen and ammonia is produced.

Hydrogen color labels

The hydrogen industry uses labels such as green and blue as shorthand for how hydrogen is made. Production methods differ on the volume of greenhouse gases they emit. The most common hydrogen labels are:

- Green, made via electrolysis of water using renewable electricity – this releases few or no greenhouse gas emissions.
- Blue, made via steam reforming of methane or gasification of coal coupled with CO_2 capture and storage (CCS) – this releases more emissions than green hydrogen, but less than gray.
- Gray, made via steam reforming of methane or gasification of coal without CCS – the most common method today that releases large volumes of CO_2.

The Japanese government is expanding its financial support for ammonia co-firing. In 2021, Japan set up a 2 trillion yen ($14 billion) Green Innovation Fund for research and development (R&D) of key decarbonization technologies. The budget for R&D related to burning ammonia for electricity generation was 68.8 billion yen ($482 million). Companies such as IHI Corporation, Jera, Chiyoda Corp. and Mitsubishi Heavy Industries have received subsidies to launch demonstration projects. See Section 3 for more details on these companies.

Another financial support for ammonia co-firing is a new capacity payment mechanism for low- and zero-carbon technologies. Japan's Ministry of Economy, Trade, and Industry (METI) is drafting a 20-year capacity auction mechanism for low- and zero-carbon technologies from FY2023 to encourage new investment. The initial proposal allows for retrofitting of existing coal plants to burn ammonia however new coal plants would be ineligible (Table 1).

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[2] See *Japan's New Coal Power Efficiency Standard Is Weak* (web | terminal) for more details.

Table 1: Co-firing eligibility under the proposed capacity mechanism for low/zero carbon

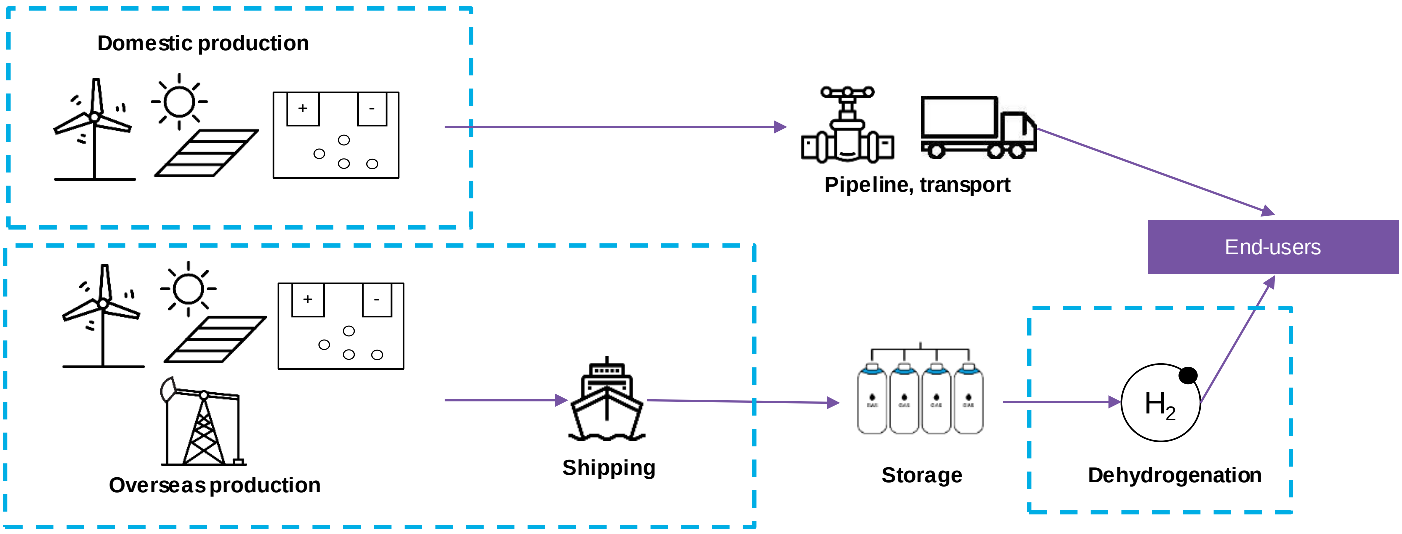
Types	Retrofits	New builds
H_2 / NH_3 co-firing at coal-fired power plants	Applicable	Not applicable
H_2 / NH_3 co-firing at gas-fired power plants	Applicable	Applicable
Biomass co-firing at coal-fired power plants	Not applicable	Not applicable
Conversion to biomass-only	Applicable	Not applicable

Source: BloombergNEF, METI. H_2 = hydrogen. NH_3 = ammonia.

The price cap in the new capacity auction could be around 50,000 yen/kW/year ($350/kW/year) for ammonia co-firing at 20% energy content, according to METI's estimate. Based on the latest discussions, the minimum capacity requirement for ammonia co-firing would be 50MW. Winning coal retrofit projects must be ready for power delivery within seven years from the auction date.

Japan is also considering a new subsidy to cover the costs of producing and transporting clean hydrogen and ammonia relative to existing fuels (Figure 4). The precise details of the subsidy, which was first unveiled on August 26, have yet to be determined. The support will consider the emissions associated with the hydrogen production process. While gray hydrogen projects will be subsidized in the near term, such projects must eliminate emissions by a yet-to-be set deadline.

Figure 4: Coverage of Japan's proposed subsidy for clean hydrogen and ammonia



Source: Ministry of Economy, Trade and Industry, BloombergNEF. Note: Blue dotted lines are covered by the subsidy.

Section 3. Summary of utilities' ammonia co-firing strategies

Japanese companies are actively developing ammonia co-firing projects in Japan and increasingly overseas. One coal-fired power plant in Japan is currently going through a technical test of 20% ammonia co-firing. Japanese companies are also aiming to export their approach to India and Southeast Asian countries. South Korea is also pursuing ammonia co-firing.

3.1. Japan

Japan's 10 vertically integrated regional utilities as well as Electric Power Development Co., better known as J-Power, have committed to achieving net zero emissions by 2050. They all plan to use clean fuels such as ammonia and hydrogen is one of the key decarbonization strategies adopted by the Japanese utilities. These technologies including 20% ammonia co-firing and carbon capture and storage (CCS) are yet to be fully commercialized in Japan, risking Japan's commitment to fully/predominately decarbonize the power sector by 2035.

Figure 5: Jera's Hekinan coal-fired power plant

Source: Jera

Jera, the thermal power joint venture of Tokyo Electric Power Co. (Tepco) and Chubu Electric Power Co., is leading the efforts toward the commercialization of ammonia coal co-firing. The company is currently testing 20% ammonia co-firing in collaboration with IHI Corporation at its 1GW Hekinan 4 coal-fired plant. It plans to trial 50% co-firing at its 1GW Hekinan 5 coal-fired power plant by FY2028. The company wants to expand ammonia co-firing to more of its coal plants by the early 2030s, with the goal of reaching 100% ammonia-fueled thermal plants by 2050. To source ammonia, in February 2022, Jera announced a tender for a long-term (over 10 years) contract for carbon-free ammonia from FY2027. IHI also announced that it successfully tested burning 100% liquid ammonia without nitrous oxide (N_2O) emissions at a 2MW gas turbine.

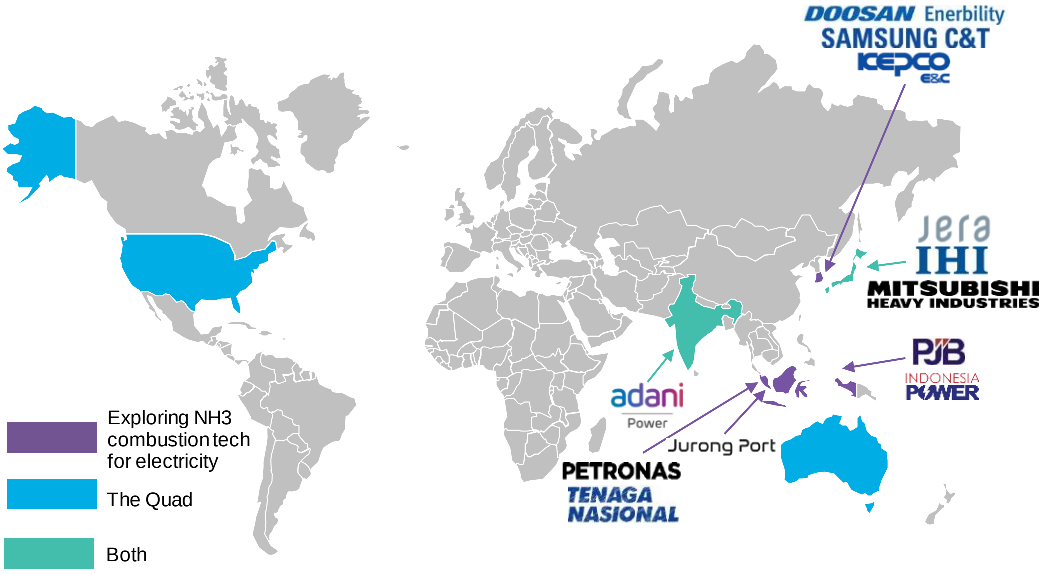
Mitsubishi Heavy Industries (MHI), a competitor of IHI, is also developing ammonia co-firing for coal-fueled thermal plants with Jera.

Kyushu Electric is another utility active in this space. The company signed a memorandum of understanding (MoU) with Norwegian chemical company Yara for procurement of blue ammonia produced in Australia. Kyushu Electric has also partnered with Jera and Chugoku Electric to work together for fuel cost reductions, transportation and storage of ammonia, and policy development.

3.2. Global

Japanese companies and the government are promoting their co-firing strategy overseas. At COP26, Japanese Prime Minister Fumio Kishida announced a new $100 million fund to support the development and export of hydrogen and ammonia co-firing through the Asia Energy Transition Initiative. At the recent Quad meeting in May 2022, leaders from Australia, India, Japan and the US also agreed to collaborate in developing clean hydrogen and ammonia supply chains.

Figure 6: Countries and major companies working on ammonia co-firing tech



Source: BloombergNEF

Utilities in South Korea and India are also adopting ammonia co-firing as a means to continue running their coal power plants. South Korea's Ministry of Trade, Industry and Energy (MOTIE) is aiming to commercialize 20% ammonia co-firing technology at more than half of the country's 43 coal-fired power plants by 2040. KEPCO Engineering & Construction, Doosan Enerbility, and Samsung C&T signed an MoU to collaborate on ammonia co-firing technologies in June 2022. Additionally, Lotte Chemical signed an MoU with Japanese trading house Itochu to develop hydrogen and ammonia infrastructure targeting the Japanese and Korean market. They also plan to jointly invest in clean ammonia production facilities. India's independent power producer Adani Power signed an MoU with IHI and Kowa Company to collaborate on evaluating the feasibility of ammonia co-firing at Adani Power's Mundra coal-fired power plant.

Japanese companies are also promoting the approach in Southeast Asia. In Indonesia, IHI and MHI are working together with local companies. MHI's ammonia proposed co-firing project at the Suralaya co-fired power plant in Indonesia is expected to start operations around 2030. IHI is also conducting technical feasibility with two local partners including Petroliam Nasional Bhd (Petronoas) for power plants in Malaysia. Jera and MHI are also working together with a local company in Singapore to develop a 100% ammonia-fueled thermal plant on Jurong Island.

Japanese players want to develop ammonia supply chains by partnering with companies in other countries, notably in Australia. Osaka Gas signed an MoU with Australia's integrated energy company AGL Energy to examine the feasibility of developing a green ammonia supply chain by the end of 2022. Japanese trading house Itochu has also partnered with Australian companies including Dalrymple Bay Infrastructure and North Queensland Bulk Ports Corp. to produce green ammonia in Australia and export to other countries. IHI is also exploring a blue ammonia supply chain between the United Arab Emirates (UAE) and Japan.

Section 4. Economic Analysis

The levelized cost of electricity (LCOE) for a typical Japanese coal plant retrofitted for ammonia co-firing at 50% or higher energy content is significantly higher than zero-emission sources such as offshore wind. Ammonia co-firing is unlikely to become an economically viable path for Japan to reduce power sector emissions.

4.1. Levelized cost of electricity

Our research estimates the levelized cost of electricity (LCOE)[3] of coal-fired power plant retrofits based on three types of ammonia: green ammonia produced in Japan, green ammonia imported from Australia, and blue ammonia imported from the Middle East[4]. Ammonia is more expensive than coal on an energy-equivalent basis due to ammonia's lower energy content. This explains the rise in LCOE with higher blends of ammonia. See Appendix A and Appendix B for more details on ammonia production costs and other assumptions.

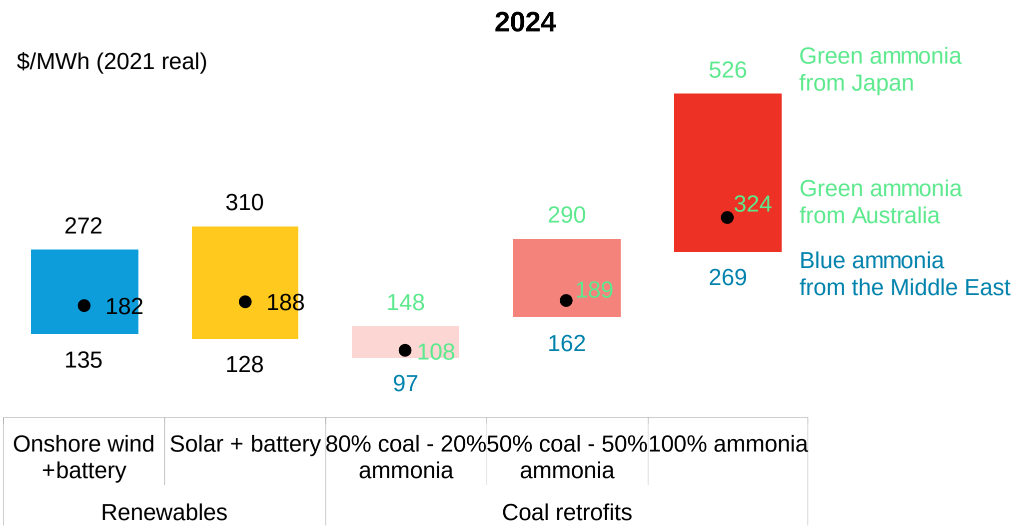
Currently, the high costs of electrolyzers push up the costs of green hydrogen/ammonia. Japan's high costs of renewables also drive up the costs of domestically produced hydrogen/ammonia relative to the molecules imported from Australia. Yet, we expect the costs of electrolyzer and renewable energy projects to continue to decline to 2050, lowering the costs of green hydrogen/ammonia. On the other hand, we expect the costs of blue hydrogen/ammonia imported from the Middle East to change little over 2024-2030 since natural gas reforming is already a well-established process. The cost reductions of blue hydrogen/ammonia are also limited over 2030-2050, compared with green hydrogen/ammonia, largely due to an increase in future natural gas prices, compensating for the fall in emission abatement costs. See *1H 2022 Hydrogen Levelized Cost Update* (web | terminal) for more details.

In 2024, when Jera aims to complete the technical test of 20% ammonia co-firing, coal retrofits burning a 20% blend of locally produced green ammonia should be the most expensive ($148/MWh), followed by retrofits with green ammonia imported from Australia ($108/MWh) and retrofits with blue ammonia imported from the Middle East ($97/MWh), as shown in Figure 7. Blue ammonia is cheaper than green ammonia due to the technical maturity of natural gas reforming. Japan's domestic green ammonia is more expensive than green ammonia from Australia due to the high costs of renewable projects in Japan despite the added cost of transporting ammonia from Australia.

[3] Levelized cost of electricity, or LCOE, shows the long-term offtake price on a MWh-basis required to recoup all project costs and achieve a required equity hurdle rate on the investment.

[4] The United Arab Emirates (UAE) data was used as a proxy for the Middle East.

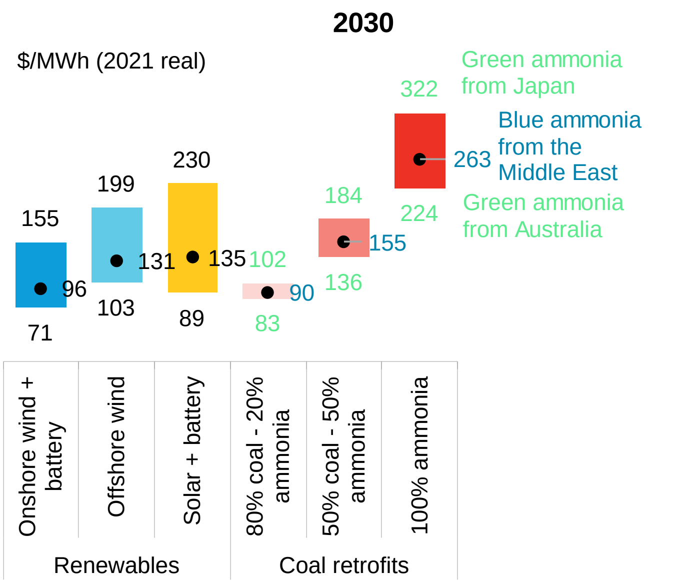
Figure 7: Comparison of levelized cost of electricity in 2024



Source: BloombergNEF. Note: Four hours duration for energy storage systems.

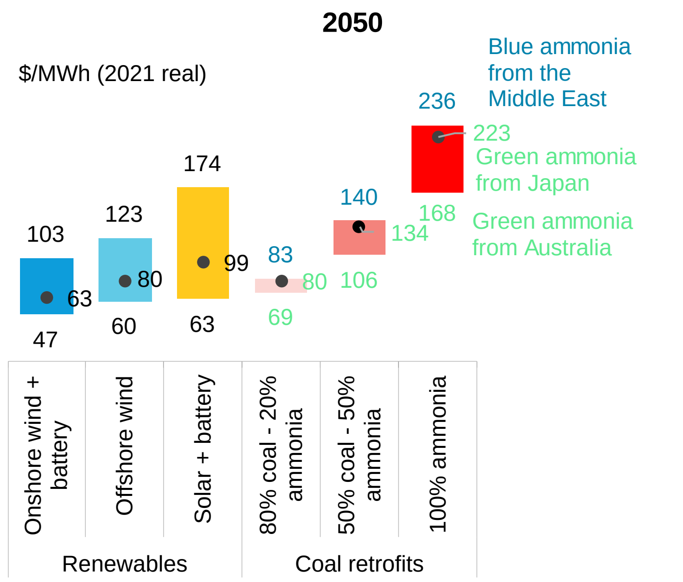
In 2030-2040, the cost of coal retrofits using green ammonia from Australia could undercut the costs of projects using blue ammonia from the Middle East, mainly due to cost reductions of renewable projects in Australia (Figure 8). The retrofits with locally produced green ammonia continues to be the most expensive during this period based on our analysis. By 2050 (Figure 9), coal retrofits co-firing 20% locally produced green ammonia ($80/MWh) could become cheaper than retrofits burning blue ammonia from the Middle East ($83/MWh). We expect retrofits co-firing green ammonia imported from Australia to be the cheapest ($69/MWh) out to 2050.

Figure 8: Comparison of levelized cost of electricity in 2030



Source: BloombergNEF. Note: Four hours duration for energy storage systems.

Figure 9: Comparison of levelized cost of electricity in 2050



Source: BloombergNEF. Note: Four hours duration for energy storage systems.

Retrofitting coal plants to burn ammonia is economically unviable, especially with a high co-firing ratio. Burning 20% ammonia at coal-fired plants would be more expensive than the running costs, or short-run marginal costs, of CCGT plants in 2024-2030. However, the retrofits burning 20% green ammonia from Australia could become cost competitive against CCGT in 2040 and offshore wind in 2050. The retrofits with other ammonia types are also set to remain uncompetitive throughout 2050. Yet, 20% ammonia co-firing would only cut CO_2 emissions by 20% and emit more CO_2 than CCGT. More analysis on emissions can be found in Section 5.1.

The retrofits with 50% and 100% ammonia blending are set to be far more expensive than 20% ammonia blending and therefore uncompetitive against other low-emission technologies (Figure 7 to Figure 9) For instance, offshore wind is one of the most expensive renewable technologies in Japan. Yet, offshore wind would be cheaper than coal retrofits burning 50%+ ammonia in 2030 and onward. This underscores the importance of deploying more offshore wind and other types of renewable energy, not ammonia co-firing technologies, to decarbonize the power sector in a cost-competitive manner. Retrofitting coal-fired power plants with ammonia should be used for seasonal balancing, instead of baseload power, to recoup the high costs.

Based on our analysis on the relative costs of different types of ammonia, retrofitting coal-fired power plants using domestically sourced green ammonia would not become cost competitive against other ammonia options, due to the high costs of domestic green ammonia. This means, from an economic standpoint, Japan will need to import large volumes of ammonia from overseas markets to fuel the retrofitted coal plants. The implication of high volumes of ammonia imports from an energy security angle can be found in Section 7.3.

Proponents of retrofitting existing coal power plants would cite the need for investment in grid infrastructure as well as balancing services for new renewable power plants as major challenges for adding more renewables. Indeed, connecting renewable projects larger than 2MW to the Japanese grid can currently cost up to a few billion yen. The higher capital expenditure can push up the LCOE of a solar plant[5] by up to 37%. This would still be below the LCOE of a retrofitted coal power plant running at 100% ammonia. More importantly, Japan can reduce the costs required by improving its power market regulations. Japan's grid infrastructure is currently underutilized due to legacy contracts prioritizing usage by older thermal and nuclear power plants regardless of their actual usage rates. Japan's grid connection costs for new renewables are also higher than most other OECD markets due to lack of a fair transparent manner for awarding new network connections. Adding more renewables to Japan's electricity system will certainly need more balancing services. Fortunately, Japan already has a large fleet of pumped hydro assets, originally developed to store excess nuclear power at night. And as figures 7 through 9 show, pairing renewables with energy storage would still be more economically viable than ammonia co-firing at the high blend rates required for decarbonization.

4.2. Cost comparison with carbon capture and storage (CCS) technologies

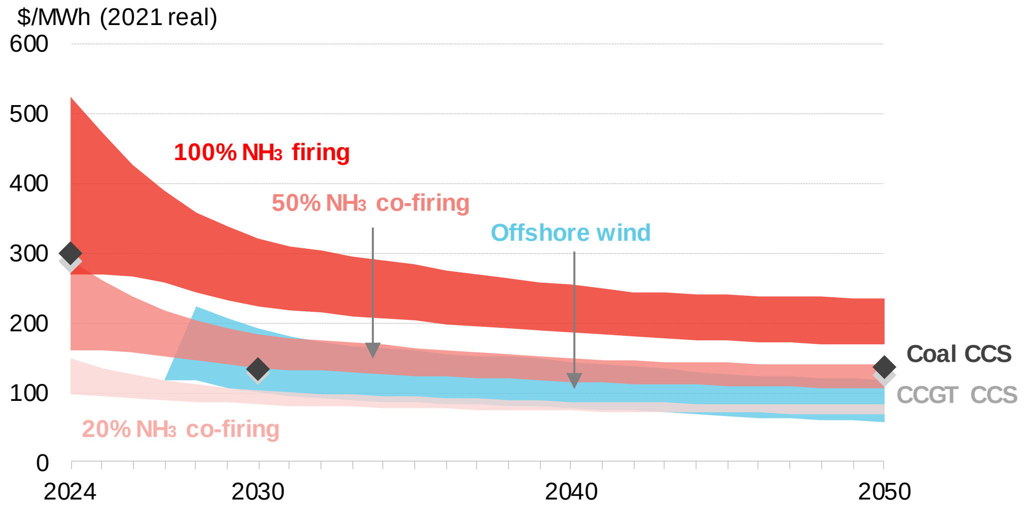
The emissions from fossil-fueled thermal power plants can be captured through chemical reaction either before or after fuel combustion. In this report, we only consider post-combustion liquid absorption capture, using an amine solvent that binds with CO_2–the dominant capture technology

[5] See *Renewable Projects in Japan Challenged by Opaque Grid (web | terminal) for more details.*

in the power sector. See *LCOE Highlights: Hydrogen, CCS, Small Nuclear* (web | terminal) for more details.

Our analysis (Figure 10) shows that carbon capture and storage (CCS) technologies can be cheaper than retrofitting coal plants for ammonia, especially at co-firing ratios above 50%. However, the cost decline of CCS technologies highly depends on global CCS market growth. Our cost forecast assumes that cumulative capacity would reach 30GW by 2030. If the deployment falls below 30GW, the speed of cost reductions could be slower than our expectation. Japan is unlikely to contribute to the pre-2030 deployment of CCS technologies. The country's current target is to begin operations of CCS projects in 2030 by starting feasibility tests by FY2023 and making final investment decisions by FY2026.

Figure 10: LCOE comparison of different technologies



Source: BloombergNEF. Note: CCS stands for carbon capture and storage. CCS LCOEs do not capture the cost of CO_2 transport and storage. Cost declines for CCS in 2024-2030 are contingent on a ramp-up of deployments to around 30GW by 2030 for the technology. Financing years are used for 2030 and 2050 of CCS LCOE.

Once captured, CO_2 needs to be permanently stored in a permeable underground layer underneath a cap rock, or re-used as an industrial feedstock. The Japanese government has thus far identified 11 sites in Japan that could store 16 billion metric tons of CO_2, more than Japan's cumulative emissions between 2010-2020 (14.4 billion metric tons of CO_2). While this may suggest there is ample space to store emissions from Japan's coal power plants, the technical and economic feasibility of such an approach is still uncertain. For example, how to transport the emissions captured at a power plant to one of the 11 storage sites remains a key challenge. Public acceptance also remains unclear. In addition, some CCS projects have failed to deploy in other markets due to technical and environmental challenges.

The Japanese government aims to gradually increase the volume of annual CO_2 injections from 2030 and reach 120-140 million tons of CO_2 injections by 2050. This is equivalent to 11-13% of Japan's annual CO_2 emissions in 2020, or the volume of emissions from up to 26GW of coal power plants[6].

[6] The calculation assumes a 75% capacity factor, 0.9 tons of CO_2 per MWh for emissions during electricity generation, and a 90% capturing rate by CCS technology.

Section 5. Greenhouse gas emissions

Reduction in CO_2 emissions is the main advantage of ammonia co-firing at coal power plants. But burning ammonia can lead to emission of other greenhouse gases such as nitrous oxide (N_2O). And a coal power plant retrofitted to co-fire ammonia at 50% or lower blend rates still emits more CO_2 than a natural gas fueled combined cycle gas turbine power plant.

5.1. Carbon dioxide (CO_2) emission reductions

Co-firing ammonia with coal can reduce CO_2 emissions from a coal power plant. Figure 11, Figure 12, and Figure 13 show the emission reduction potential depending on the ammonia source, with green ammonia offering the best option. Japan's current regulations do not differentiate the source of ammonia. Even with green ammonia, at co-firing rates of 50% or lower, CO_2 emissions from a retrofitted coal plant would still be worse than a natural gas fueled combined cycle gas turbine.

Figure 11: Emissions from power generation and production of green NH_3

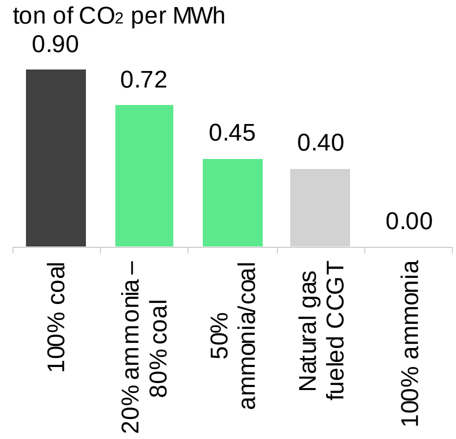


Figure 12: Emissions from power generation and production of blue NH_3

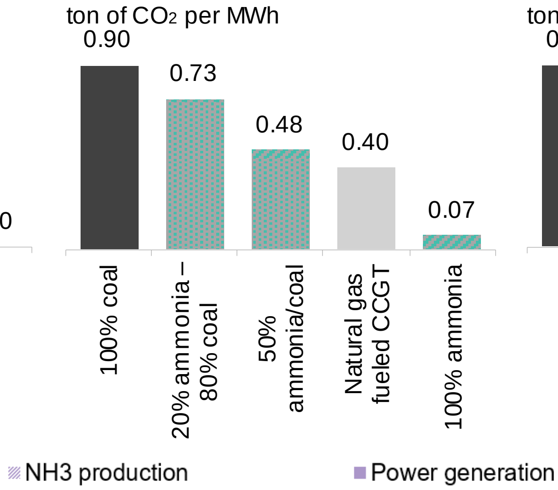
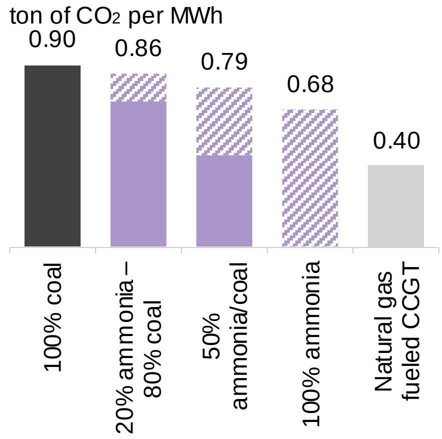


Figure 13: Emissions from power generation and production of gray NH_3

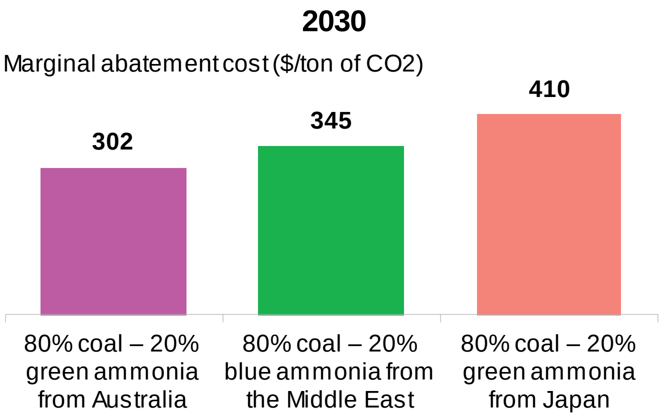


Source: BloombergNEF. Note: Emissions for power generation and ammonia production. Gray (unabated) ammonia production assumes 9kg of CO_2 emissions to produce 1kg of hydrogen. Blue ammonia production assumes 90% CO_2 capture rates of carbon capture and storage (CCS) technologies for unabated hydrogen production.

5.2. Marginal abatement cost of ammonia coal co-firing

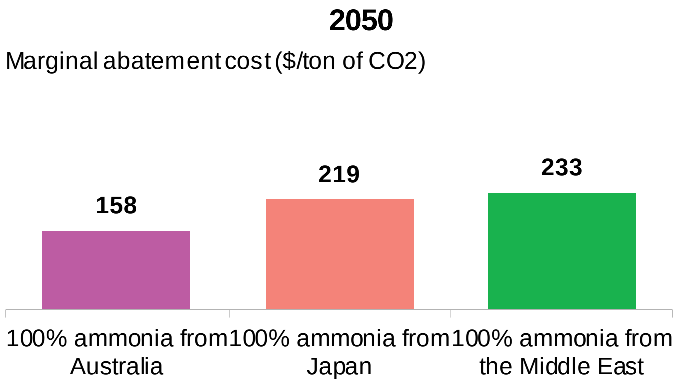
Based on avoided CO_2 emissions (in CO_2 emissions intensity) and project costs (in LCOE), we estimate (Figure 14) a carbon price of at least \$300/ton of CO_2 would be needed to make clean ammonia co-firing at 20% blend rate economically viable in 2030. By 2050 (Figure 15), the carbon price needed to make 100% ammonia fueled retrofitted coal plants economically viable could be reduced to around \$159/ton of CO_2. These values are far higher than Japan's current "tax for climate change mitigation" set at below \$3/ton of CO_2.

Figure 14: Marginal abatement cost in 2030



Source: BloombergNEF

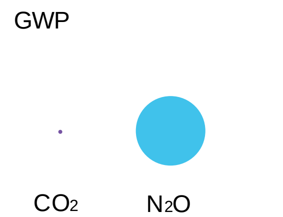
Figure 15: Marginal abatement cost in 2050



Source: BloombergNEF

5.3. Nitrous oxide (N_2O) emissions: no laughing matter

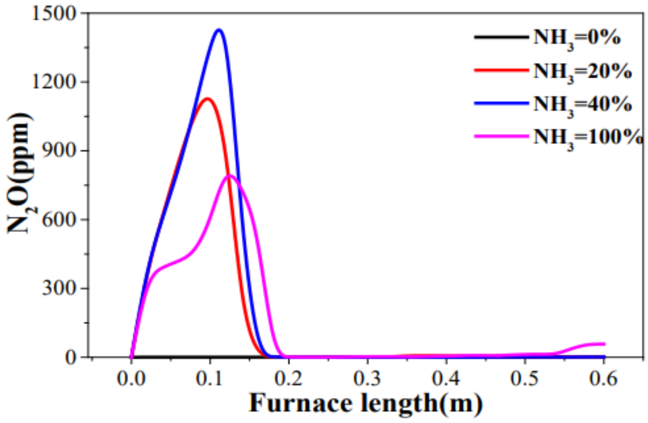
Figure 16: No laughing matter: global warming potential of CO_2 vs. N_2O



Source: BloombergNEF, EPA. Note: GWP for a 100-year timescale.

Since the ammonia molecule includes nitrogen, ammonia combustion generates nitrous oxide, colloquially referred to as laughing gas. Nitrous oxide's global warming potential (GWP) is 273 times larger than that of CO_2 for a 100-year timescale. Nitric oxide (NO) and nitrogen dioxide (NO_2) are not greenhouse gases. Japan's Central Research Institute of Electric Power Industry's research has shown at blend rates below 20%, higher rates of ammonia co-firing leads to higher nitrous oxide emissions. Other studies have suggested nitrous oxide emissions rise until 40% ammonia co-firing, while higher ammonia co-firing ratios lead to lower nitrous oxide emissions. Retrofitted coal plants would likely need to invest in technologies to capture the nitrous oxide emissions to ensure GHG emission reduction benefits. This in turn will further undermine the poor economics of ammonia co-firing.

Figure 17: Nitrous oxide (N_2O) emission intensity for different ammonia co-firing ratio



Source: School of Energy and Environment at Anhui University of Technology in China

Section 6. Safety and toxicity

Ammonia needs to be handled with care due to its toxicity and flammability. The regulatory framework around safety is another concern as current regulations were not designed for ammonia use in power generation.

6.1. Safety and toxicity

Figure 18: Ammonia-related fire in China in 2013

Source: Washington Post.

Ammonia is colorless but has a distinct odor. The molecule can pose a big threat to human health as it reacts with water to form ammonium hydroxide, which is corrosive and damages cells in the body on contact. Thus, ammonia is classified as toxic under Japan's regulations such as the Industrial Safety and Health Act and the Poisonous and Deleterious Substances Control Act.

Japan's High Pressure Gas Safety Institution reported 28 minor ammonia-related[7] incidents, such as leakage, in 2021. Other countries saw more severe cases. For example, at a poultry plant in China's Jinlin province, ammonia leakage caused a fire and killed 120 people in 2013. In the same year, another ammonia leakage killed 15 and injured 25 at a frozen seafood plant in Shanghai, China.

Table 2: Safety comparison of ammonia and natural gas

	Ammonia	Natural gas (methane)
Flammability	- Flammable	- Flammable
Toxicity	- Acute poisoning from inhaling - Skin/eye/respiratory damages	- None
Classification under the Industrial Safety and Health Act	- Specified Chemical Substance Type-3: a mass leakage causes acute poisoning - Hazardous chemicals, flammable	- Hazardous chemicals, flammable
Classification under the Poisonous and Deleterious Substances Control Act	- Deleterious substance	- Not listed

Source: BloombergNEF, The Globally Harmonized System of Classification and Labelling of Chemical (GHS), Ministry of Health, Labor, and Welfare of Japan. Safety levels are colored as dangerous, medium, and safe.

6.2. Ammonia-related regulations

Japan's current ammonia regulations were not designed for electricity generation

Since ammonia has been traded internationally and processed domestically in Japan, the country already has multiple regulations on ammonia. These are listed in Table 3 and cover handling, marine transport, storage and supply of ammonia. However, Japan's current ammonia regulations were not designed for electricity generation. To ensure safety, Japan needs to implement new

[7] Ammonia-related accidents in this section distinguish ammonia from ammonium nitrates.

regulations overseeing materials used for boilers, gas leakage at power plants, and safety/hazard sign standards for ammonia use in the power sector.

Table 3: Current regulations related to ammonia use

Type	Relevant regulations
Facilities	- High Pressure Gas Safety Act - Industrial Safety and Health Act - Noise/Vibration Regulation Act - Act on the Prevention of Disaster in Petroleum Industrial Complexes and Other Petroleum Facilities - Building Standard Act - Port and Harbor Act - Fire Services Act - Poisonous and Deleterious Substances Control Act - Offensive Odor Control Law
Marine transport	- Ship Safety Act - Fire Services Act - Cabinet Order Concerning the Control of Hazardous Materials - Regulation Concerning the Control of Hazardous Materials - Port Regulation Act
Storage	- Fire Services Act - Regulation on Safety of General High Pressure Gas - Warehouse Business Act
Ammonia supply via road or pipelines	- Road Traffic Act - Regulation on Safety of General High Pressure Gas - Regulation on Safety of Industrial Complexes - Seacoast Act - River Act

Source: Ministry of Land, Infrastructure, Transport, and Tourism

The government is mulling more stringent requirements for safe distance and empty space near facilities handling ammonia. Current regulations are based on the category of high-pressure gas without considering ammonia's toxicity. Under the current rules, ammonia facilities need to be 20 meters away from other high-pressure gas facilities, 30 meters away from facilities with many people (such as schools, hospitals, and theaters), and 50 meters away from historical sites. Empty space must also be secured within 15 meters of such facilities.

In addition, the government is aiming to revamp regulations for operation and maintenance at fossil-fueled power plants due to ammonia's toxicity and flammability. Currently, regulations do not require dedicated electric/boiler technicians and the submission of construction schedules for small thermal power plants.

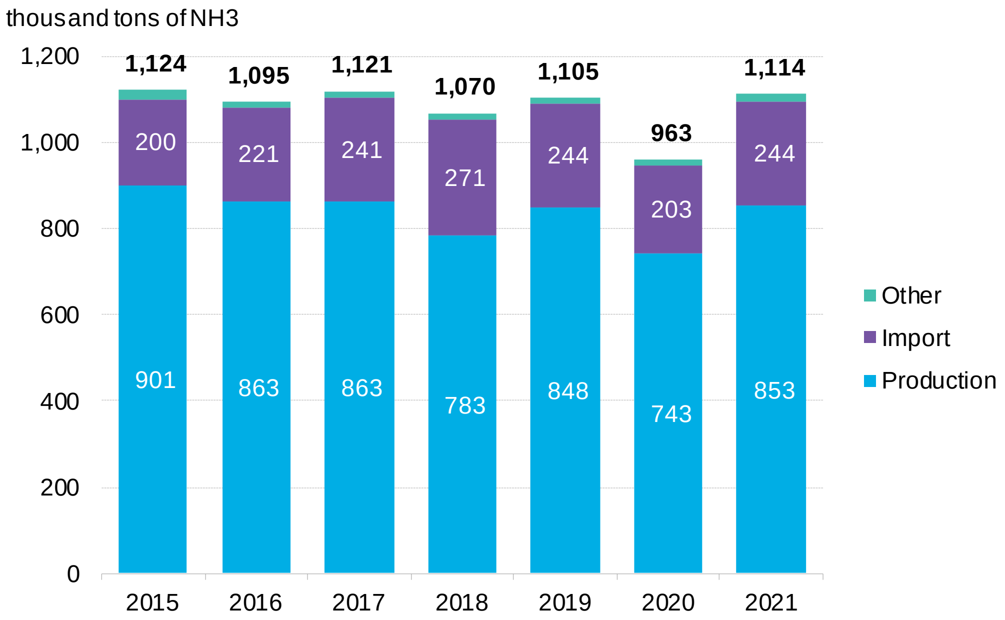
Section 7. Clean ammonia supply and demand

Japan's current ammonia demand is relatively small at around 1 million tons per year, just shy of 1% of global production. The Japanese government wants to grow this demand by promoting ammonia co-firing at coal plants. Given the technology's low economic competitiveness in electricity generation, promoting the use of clean ammonia in other applications such as fertilizer production or even shipping offers more advantages and opportunities for decarbonization.

7.1. Current market size

Japan's annual ammonia demand is about 1 million tons[8], less than 1% of global production[9], in 2021. Around 80% of this demand is met through domestic production, using imported fossil fuel feedstock. The remaining 20% is imported[10] from countries including Indonesia, Australia, and Malaysia.

Figure 19: Japan's historical ammonia demand



Source: Japan Fertilizer & Ammonia Producers Association, BloombergNEF. Note: Years show Japan's fiscal year starting from April to March.

8 Japan Fertilizer & Ammonia Producers Association

9 International Energy Agency (IEA)

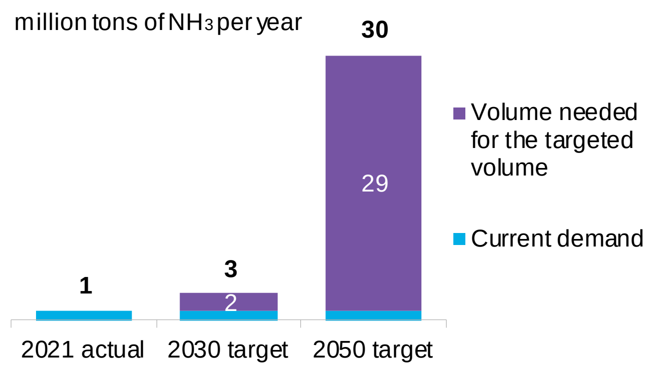
10 Tariff item number for ammonia is 2814-10 for Japan customs.

7.2. Future market size

Japan's ambitious ammonia target underscores its desire to keep existing coal-fired power plants, which could otherwise become stranded in the country's push for decarbonization.

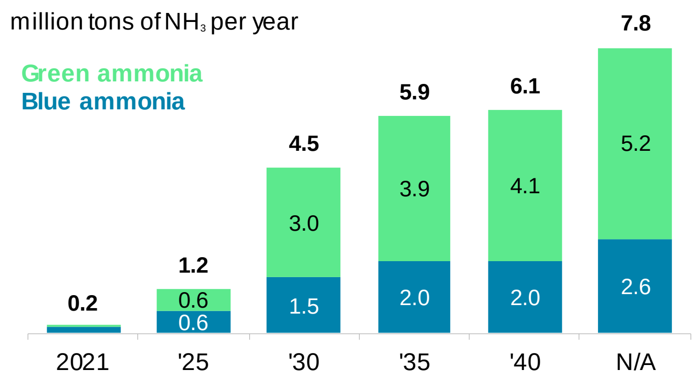
IEA's scenarios suggest global ammonia production could grow to 217-222 million tons by 2030 and to 254-319 million tons by 2050 from 185 million tons in 2020. Japan's government aims to increase its ammonia demand to 3 million tons by 2030 and 30 million tons by 2050 from 1 million tons in 2021 (Figure 20). These targets do not include a breakdown by use case. Japan's ammonia demand target seems ambitious given that the 2050 target would be equivalent to about 11% of IEA's global demand projection in 2050.

Figure 20: Japan's current ammonia demand size and targets for 2030 and 2050



Source: BloombergNEF, Ministry of Economy, Trade, and Industry, Japan Fertilizer & Ammonia Producers Association.

Figure 21: Theoretical cumulative volume of ammonia supply globally (converted from clean hydrogen production projects proposed by developers)



Source: BloombergNEF. Note: The volume of ammonia is converted from the volume of hydrogen assuming all hydrogen supply pipeline was used for ammonia production.

BloombergNEF tracks the volume of clean hydrogen supply pipeline proposed by developers globally. Assuming all of those were used for clean ammonia production, the cumulative volume of clean ammonia supply would be only 6.1 million tons of ammonia per year in 2040 (Figure 21) – much less than Japan's 2050 target, showing how ambitious Japan's ammonia demand target is. At the same time, not all clean hydrogen supply projects would be for ammonia production.

To sense-check the Japanese government's ammonia demand targets, we have estimated (Table 4) the volume of ammonia needed for co-firing at different blend rates, assuming coal power plants are only retired after 45 years of operation. By 2030, if all of Japan's coal power plants were to co-fire ammonia at a 20% blend rate, annual demand would reach 22.6 million tons, significantly higher than the government's 3 million tons target. This suggests the government expects few coal plants will be co-firing with ammonia in 2030. By 2050, if all remaining coal power plants try to run only on ammonia, annual demand would reach 40.4 million tons, higher than the government's 30 million tons. This suggests the government is assuming some coal power retirements and/or usage of carbon capture and storage at some coal plants.

Table 4: Ammonia demand size comparison

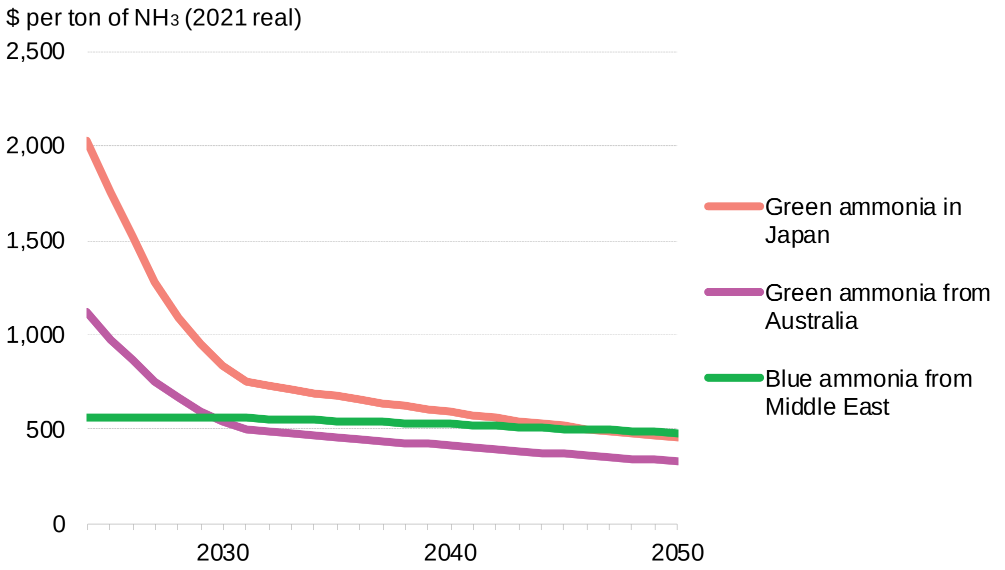
	2030: 20% ammonia co-firing	2040: 50% ammonia co-firing	2050: 100% ammonia firing
Cumulative coal capacity	45GW	35GW	16GW
NH_3 Ammonia burned by all coal-fired power plants	**22.6 million tons of ammonia/year**	**43.7 million tons of ammonia/year**	**40.4 million tons of ammonia/year**
Government target	3	Not applicable	30

Source: BloombergNEF. Note: The volume of ammonia needed per GW per year is assumed to be 500,000 tons for 20% co-firing, 1,250,000 tons of ammonia for 50% co-firing, and 2,500,000 tons of ammonia for 100% firing. Efficient coal-fired power plants include ultra-super critical plants. Inefficient coal-fired power plants include sub-critical and supercritical plants.

7.3. Energy security considerations

Coal retrofits could enable existing coal-fired power plants to stay in the market. However, as discussed in Section 5, it would be crucial for coal-fired power plants to blend at least 50% ammonia to limit CO_2 emissions below that of natural gas-fired CCGT plants. Since Japan is yet to commercialize 20% co-firing technology, it would take time to achieve 50%+ levels. The immaturity of ammonia co-firing technology means that Japan would need to continue thermal coal imports for many years to come, putting its energy security at risk.

Figure 22: Outlook on ammonia production costs for Japan



Source: BloombergNEF. Note: See Appendix B for more details.

In addition, Japan would likely need to rely on clean ammonia from other countries due to the high cost of domestically sourced green ammonia. Green ammonia produced in Japan is set to cost more than green ammonia imported from Australia throughout 2050, as shown in Figure 22. Similarly, Japanese green ammonia could be more expensive than blue ammonia imported from the Middle East until 2040.

Consequently, Japan's energy security may worsen by switching from coal imports to coal and ammonia imports. By relying on two imported commodities to operate coal-fired power plants, rather than one, Japan runs the risk of worsening its long-term energy security.

7.4. Clean ammonia's role in decarbonization

To identify whether clean ammonia can play a role in decarbonization of a particular sector, we need to consider four factors:

1. Are the technologies for ammonia usage in that application already mature?
2. What is the competitiveness of clean ammonia compared to fossil fuels used in that application?
3. How competitive is clean ammonia compared to other decarbonization approaches for that application?
4. How willing are customers for that application to pay for clean ammonia?

Table 5 summarizes these factors for clean ammonia usage in Japan.

Table 5: Suitability of ammonia for end uses in Japan

Use case	Fertilizers	Shipping	Electricity generation (Seasonal balancing)	Electricity generation (Baseload)
Use-case opportunity	**High**	**Medium**	**Medium**	**Low**
Maturity of the technology?	Mature	Testing/R&D began	Testing/R&D began	Testing/R&D began
Competitive with existing fossil fuel processes?	Could be competitive given current gas prices	Costlier	Costlier	Costlier
Competitive with alternative low-carbon processes?	No other low-carbon process than green/blue ammonia for decarbonizing fertilizers	Methanol and ammonia are the only two promising low-carbon fuels. Methanol is more mature than ammonia.	Depends on the uptake of hydrogen-fired power plants and carbon capture and storage (CCS)	No
Customers willing to pay more for clean ammonia?	Yes. Limited decarbonization options are available.	Yes. IMO's 50% emissions reduction target. Limited decarbonization options are available.	Possibly yes. To decarbonize existing fossil-fueled assets.	Possibly yes. To decarbonize existing fossil-fueled assets.

Source: BloombergNEF, BloombergNEF Talk: Where Are We in the Hydrogen Hype Cycle? (web | terminal). Note: Suitability levels are colored as high, medium, and low. The Japanese government wants to use ammonia as fuel for industrial processes, but BNEF hasn't analyzed ammonia use for industry. For the power sector, solar and wind together with batteries have the potential to decarbonize 70% to 80% of electricity generation on a least-cost basis. Yet the last 20% to 30% shares of generation are hard to decarbonize: these tend to be hours that are difficult to reach cost-efficiently for renewables, such as high demand hours during winter or evening peak.

Appendices

Appendix A. Retrofitting coal-fired power plants

Scenarios

Below is a list of variables used to create the scenarios and cost ranges for retrofitting coal-fired power plants for burning ammonia in this research.

- Different ammonia co-firing ratio (20%, 50%, 100%)
- Production methods of ammonia (See Appendix B for more details).
- Operation year (2024, 2030, 2040, 2050)
- Plant lifetime (15 years, 25 years)
- Financing (75% debt, 100% equity)

In this note, visuals (for Figure 1, Figure 7, Figure 8, Figure 9, Figure 10, Figure 14, Figure 15, Figure 23,Figure 24, and Figure 25) assume a 25-year lifetime for retrofitted power plants and a 75% debt ratio, or gearing rate, for financing. Data for other scenarios and inputs used for LCOE calculation can be found in the accompanying data for this note.

Figure 23: LCOE comparison (20% ammonia co-firing)

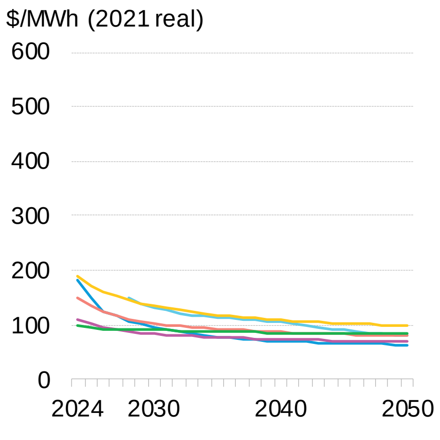


Figure 24: LCOE comparison (50% ammonia co-firing)

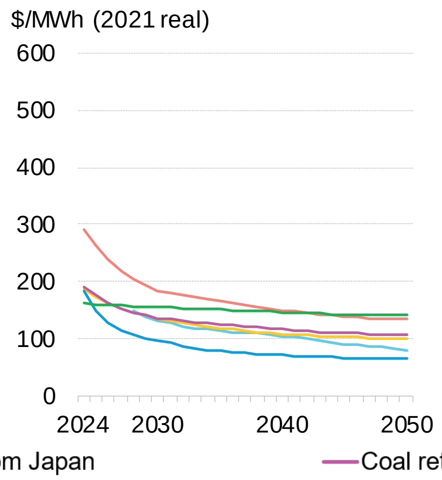
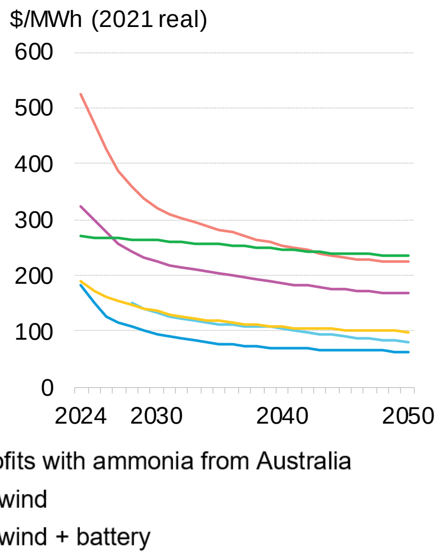


Figure 25: LCOE comparison (100% ammonia firing)



Source: BloombergNEF. Note: Four hours duration for energy storage systems.

Retrofits

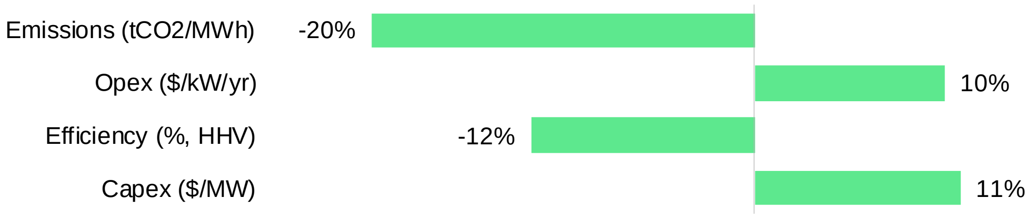
Coal-fired power plants require upgrades to allow for blending of ammonia.

20% ammonia co-firing

Our discussions with companies in Japan indicate that for 20% co-firing, retrofit includes upgrading burners and additional balance of plant expenses to receive and store ammonia (Figure 26). These upgrades come at an estimated 11% premium in capex. Since this research focuses on coal power plant retrofits, we assumed 11% of capex for new coal-fired power plants in Japan as capex needed for retrofits.

Controlling the exhaust NOx emission will be key in each plant's combustion strategy. Based on the available information, we estimate a 20% ammonia blend would reduce the power plant's thermal efficiency by around 12%.

Figure 26: Impacts of coal-fired power plant upgrades to burn a blend with 20% ammonia



Source: BloombergNEF, manufacturer interviews. Note: The efficiency impact is in relative percent, not percentage points. 20% ammonia blend refers a blend by energy content, not volume. HHV is high heating value.

To calculate levelized cost of electricity (LCOE) of coal power plants blending 20% ammonia, we applied the above changes to the benchmark costs for Japan's coal-fired power plants detailed in our *1H 2022 LCOE Update* (web | terminal). We subsequently calculated the LCOE in our *Energy Project Valuation Model* (web | terminal).

Ammonia blending ratio refers to the blend split by energy content, not volumetric. Hence, the decline in the volume of CO_2 emissions would be equivalent to the co-firing ratio. For example, coal-fired retrofits for 20% ammonia blending would reduce CO_2 emissions by 20%.

More than 20% ammonia co-firing

Coal retrofits with more than 20% ammonia co-firing have not been tested or commercialized. Hence, our research applied the same retrofit cost assumptions used in 20% co-firing as the retrofit costs for more than 20% co-firing including 50% and 100%. In reality, a higher ammonia co-firing ratio will likely require higher capex because boilers would require major upgrades or even replacements. Storage tanks for ammonia would also need to be bigger at a higher co-firing ratio. More advanced equipment to capture NO_x emissions would be needed as well.

Appendix B. Ammonia production cost assumptions

Our research incorporates three different types of ammonia: green ammonia produced in Japan, green ammonia imported from Australia, and blue ammonia imported from the Middle East. Fuel ammonia prices are estimated by the costs of hydrogen production, conversion to ammonia, and shipping to Japan.

Hydrogen production

Since ammonia is produced from hydrogen, we rely on the hydrogen production costs derived from BNEF’s *Hydrogen Project Valuation Model* (web | terminal). Below are the assumptions of technologies used for hydrogen production.

- Japan: alkaline electrolysis using fixed-axis PV projects and western electrolyzers
- Australia: alkaline electrolysis using tracking PV projects and western electrolyzers
- Middle East: steam methane reforming using natural gas

Conversion to ammonia from hydrogen

Next, we added the cost of converting hydrogen to ammonia based on the following assumptions. We expect economies of scale to kick in post-2027 and push down the conversion cost going forward.

Table 6: Costs of conversion to ammonia from hydrogen

	$/kg of H_2, real 2021
2022-2027	1.41
2028-2049	Linear interpolation for each year using values for 2027 and 2050
2050	0.87

Source: BloombergNEF

Transportation of ammonia

Ammonia produced outside Japan needs to be shipped to Japan. Below is our assumption on transportation costs added to ammonia produced in Australia and the Middle East. Shipping ammonia is already matured, so these transportation costs are used throughout the modeling period:

- Ammonia from Australia: $0.3/kg of hydrogen (real 2021)
- Ammonia from the Middle East: $0.4/kg of hydrogen (real 2021)

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