Vietnam: A Techno-Economic Analysis of Power Generation

October 23, 2023

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Section 1. Executive summary

2026

Year when a new onshore wind becomes cost competitive against a new combined-cycle gas turbine plant in Vietnam

3.3x

Levelized cost of electricity of a retrofitted coal plant in Vietnam running on 100% green ammonia imported from Australia compared with solar plus batteries in 2050

2x

Levelized cost of electricity of a retrofitted combined-cycle gas turbine plant in Vietnam running on 100% domestic green hydrogen compared with solar plus batteries in 2050

Vietnam's ambitious long-term goals to phase out coal power generation by the 2040s and achieve net zero by 2050 face challenges posed by rapid economic and energy demand growth. BloombergNEF's analysis shows that retrofitting thermal power plants for hydrogen or ammonia will not be more economical than scaling renewables. Renewables are the most economic and sustainable choice for Vietnam achieve its net-zero goals.

- This is a pivotal moment for Vietnam to accelerate the low-carbon transition of its power sector. Efforts will be backed by the country's ambitious climate and emission reduction goals and international financing support under its Just Energy Transition Partnership agreement. Vietnam needs to grow its power system in a manner that allows the country to reach its climate aims while maintaining energy security and affordability.
- Vietnam's latest power development plan aims to expand the country's thermal power plant fleet, in particular gas-fired power plants relying on liquefied natural gas (LNG) imports. Starting in the 2030s, the plan calls for co-firing ammonia or biomass with coal and blending hydrogen with natural gas to reduce emissions. This approach will not be the most cost-effective option for Vietnam, according to BloombergNEF analysis. To achieve tangible emission reductions, a coal power plant would have to be retrofitted to be capable of co-firing ammonia with coal at energy ratios above 50%. At such high ratios, electricity generation costs will be far higher than renewables. The same applies to retrofitting combined-cycle gas turbines (CCGTs) for hydrogen.
- Utility-scale solar is already the cheapest source of electricity generation in Vietnam. The levelized cost of electricity (LCOE) – the financial measure used by developers and investors – for a new utility-scale solar project in Vietnam today ranges from $53 to $105 (1.3 million to 2.5 million dong[1]) per megawatt-hour (MWh), compared with $84-104/MWh for a CCGT and $74-94/MWh for a coal power plant. By 2030, solar paired with batteries will also achieve a cheaper LCOE than new thermal power plants.
- Onshore wind is also set to undercut the LCOE of a CCGT and coal plant by 2026 and 2028, respectively. BNEF expects an onshore wind project paired with batteries to become cheaper than a new coal and gas plant in the first half of the 2030s.
- Vietnam has good potential for the development of offshore wind power and has big ambitions, but no projects are operational in the country yet. Offshore wind power on average would likely remain more costly than a new thermal power plant by the end of this decade in Vietnam. However, the most competitive offshore wind installations that can access the cheapest development and financing costs and the best wind resources would also become competitive against a new thermal power plant by 2030.

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[1] Currency conversion rate on a real 2020 basis assumed to be $1 to 23,952.50 dong.

Figure 1: Levelized cost of electricity comparison for new renewables and retrofitted combined-cycle gas turbines for hydrogen in Vietnam

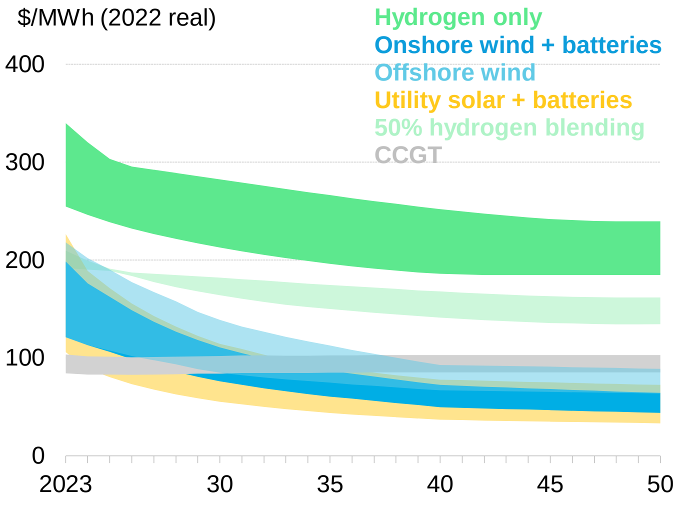
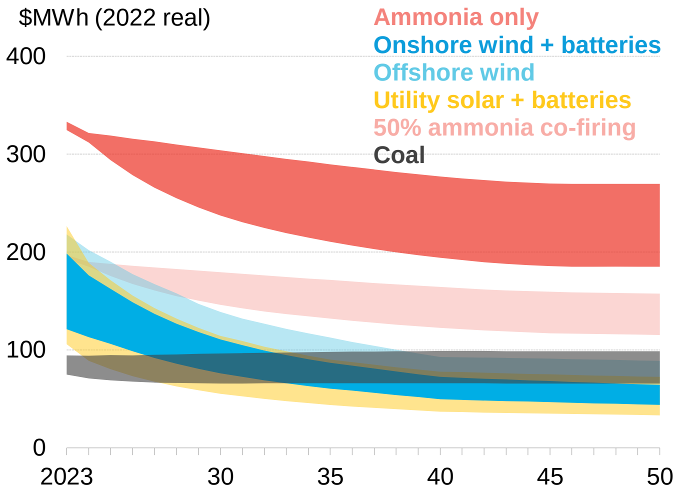


Figure 2: Levelized cost of electricity comparison for new renewables and retrofitted coal power plants for ammonia in Vietnam



Source: BloombergNEF. Note: Blending ratio based on energy content. Batteries refers to four-hour lithium-ion battery energy storage systems. Levelized costs of electricity for hydrogen and ammonia are based on imported fuel scenarios.

- Vietnam also aims to produce domestic green hydrogen powered by offshore wind as outlined in the country's latest power development plan. BNEF's analysis suggests that green domestic hydrogen could be cheaper than hydrogen imports. However, the hydrogen produced will be better suited for hard-to-abate sectors where electrification is not possible rather than for the power sector due to the low efficiency of the hydrogen production process. Direct renewable energy use would be far more effective and much cheaper than such indirect uses of renewables in decarbonizing the power sector.

Section 2. Introduction

Solar already accounts for 21% of Vietnam's installed power capacity

Vietnam has expanded its power supply over the last decade to meet growing electricity demand, particularly from the manufacturing sector. The country's electricity supply has historically been dominated by hydro, gas and coal. Generous feed-in tariffs kicked off a boom in solar and wind, resulting in the installation of 19.8 gigawatts (GW) and 3.8GW of capacity, respectively, in just four years. As of 2022, Vietnam's total installed capacity stood at 80GW, 32% of which comes from coal-fired power plants, followed by hydro power (29%) and solar power facilities (21%). Solar and wind together accounted for 13% of electricity generation in 2022, exceeding gas.

Figure 3: Vietnam's historical installed power capacity

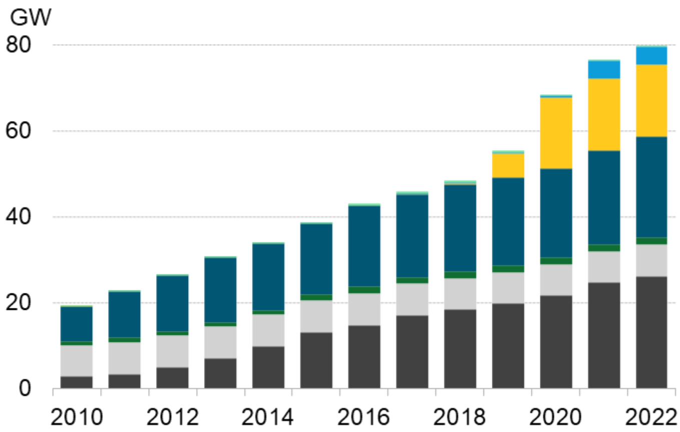
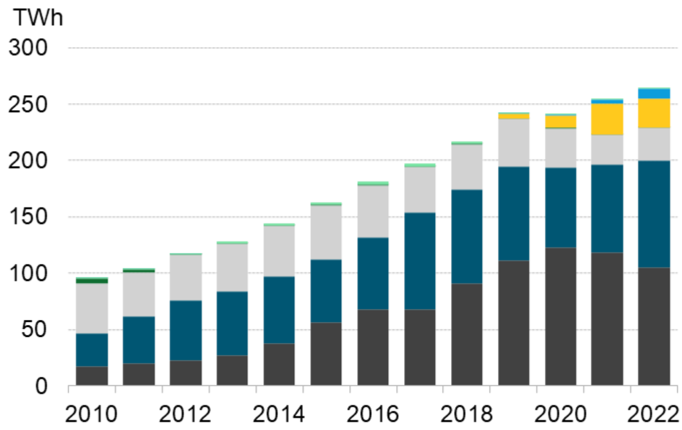


Figure 4: Vietnam's historical electricity generation



Coal　Natural gas　Oil and diesel　Hydro　Solar　Wind　Biomass and waste

Sources: BloombergNEF, Ministry of Industry and Trade

Vietnam's ambitious climate targets and progress

Vietnam leads Southeast Asia in terms of the scale of its long-term climate targets. At the 26th UN Climate Change Conference in Glasgow (COP26) in 2021, the country announced that it would aim to achieve net-zero emissions by 2050, the most aggressive goal among Southeast Asian countries at the time. Vietnam also joined the Global Methane Pledge to reduce methane emissions by 30% by 2030 from 2020 levels. Further, the country committed to move away from unabated coal power in the 2040s under the Global Coal to Clean Power Statement.

Vietnam has since put in place several strategies to support its net-zero goal, including a National Climate Change Strategy for 2050 (Decision 896/QD-TTg) and a Long Term Strategy on Environment Decision to 2030 with a vision to 2050 (Decision 450/Qd-TTg).

In October 2022, Vietnam enhanced its 2030 emissions reduction targets under its Nationally Determined Contribution, which is a country's plan to help achieve the goals of the Paris Agreement. It committed to an unconditional and conditional target of 15.7% and 43.5% emissions reduction against a business-as-usual scenario, respectively. The country followed this up quickly with an announcement in December 2022 of a $15.5 billion Just Energy Transition

Partnership (JETP) financing agreement with the International Partners Group[2] to accelerate the country's energy transition. Under the JETP agreement, Vietnam has committed to stretched goals of peaking emissions at 170 million metric tons by 2030 and generate at least 47% of electricity from renewables by 2030, assuming its international partners also fully implement their pledges.

Power Development Plan VIII

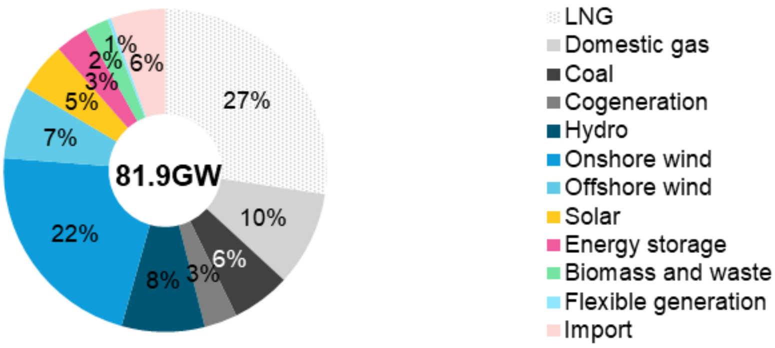
Vietnam's climate goals are reflected in its latest power development plan, the Power Development Plan VIII, or PDP VIII. On May 15, 2023, Vietnam's Prime Minister Pham Minh Chinh signed off on the country's long-awaited latest long-term power development plan. The approved plan envisions Vietnam's power capacity to more than double from 70.2GW in 2020 to 150.5GW in 2030, with wind and gas – in particular combined-cycle gas turbine (CCGT) plants reliant on LNG imports – leading generation capacity additions this decade. Together, these two technologies account for 66% (or 54.1GW) of proposed capacity additions between 2023 and 2030 – comprising 17.9GW of onshore wind, 6GW of offshore wind, 22.4GW of LNG plants and 7.8GW of domestic gas plants.

The plan also calls for 6% of the capacity expansion to come from coal power generation, despite previously planned coal power plants already facing delays due to difficulties in securing land and financing.

To support Vietnam's goal of net-zero emissions by 2050, PDP VIII aims to lower greenhouse gas emissions from the power sector to between 204 million and 254 million tons in 2030, and 27 million to 31 million tons in 2050. To reach these targets, the plan calls for the co-firing of coal with biomass and/or ammonia and blending of gas with hydrogen starting from the mid-2030s.

By 2050, Vietnam looks to have no unabated coal power generation and between 25.6GW and 32.4GW of coal plants running completely on biomass or ammonia. The country also aims to have 4.5-9GW of CCGT plants fueled by a blend of LNG and hydrogen and 23.4-27.9GW of gas plants fully fueled by hydrogen.

Figure 5: Vietnam's targeted 2023-2030 gross capacity addition



Source: Vietnam Decision 500/QD-TTg, BloombergNEF. Note: Excludes historical rooftop solar capacity installed before 2023. The 2030 solar capacity value includes 2.6 gigawatts of new solar capacity for self-consumption. Flexible generation refers to international combustion engines and single cycle gas turbines.

2 The grouping consists of the European Union, the UK, the US, Japan, Germany, France, Italy, Canada, Denmark and Norway.

Vietnam must grow its power system in a manner that allows it to attain its climate goals while maintaining energy security and affordability. This report examines the levelized cost of electricity generation (LCOE) for the different power generation technologies applicable for Vietnam, namely solar, wind, CCGTs and coal power plants. It also looks at the economics of Vietnam's proposed co-firing and hydrogen blending strategies for its existing coal and gas power plants. Beyond LCOE, the report also examines the advantages and disadvantages of each technology in terms of impact on Vietnam's energy security and affordability, as well as emissions.

Levelized cost of electricity

LCOE refers to the long-term offtake power price on a per megawatt-hour (MWh) basis required to recoup all project costs to meet the equity investment hurdle rate. BNEF uses its proprietary *Energy Project Asset Valuation Model* (web | terminal) to calculate the LCOE based on input data relevant for each technology in consideration of the location where the project would be built. The calculation is based on a project finance schedule accounting for the full life of the project. This allows us to capture the project cost impact of the timing of cash flows, development and construction costs, multiple stages of financing, interest and tax implications of long-term debt instruments and depreciation, among other factors. For the input parameters used in the LCOE calculations in this report, refer to Appendix A.

Section 3. Economic analysis

Utility-scale solar already outcompetes new coal and gas plants in Vietnam. The LCOE generation for solar in Vietnam declined sharply since 2019, thanks to the technology's rapid deployment in the country, coupled with falling solar equipment prices. Onshore wind is also nearing the range of the LCOE for a new CCGT plant. By 2030, some offshore wind projects will also outcompete thermal power plants.

Meanwhile, the cost of electricity generation for CCGT plants is subject to greater volatility as Vietnam becomes more reliant on LNG imports. Using green hydrogen or its derivative ammonia as a fuel will not become a cost-effective route to decarbonization of existing thermal power plants.

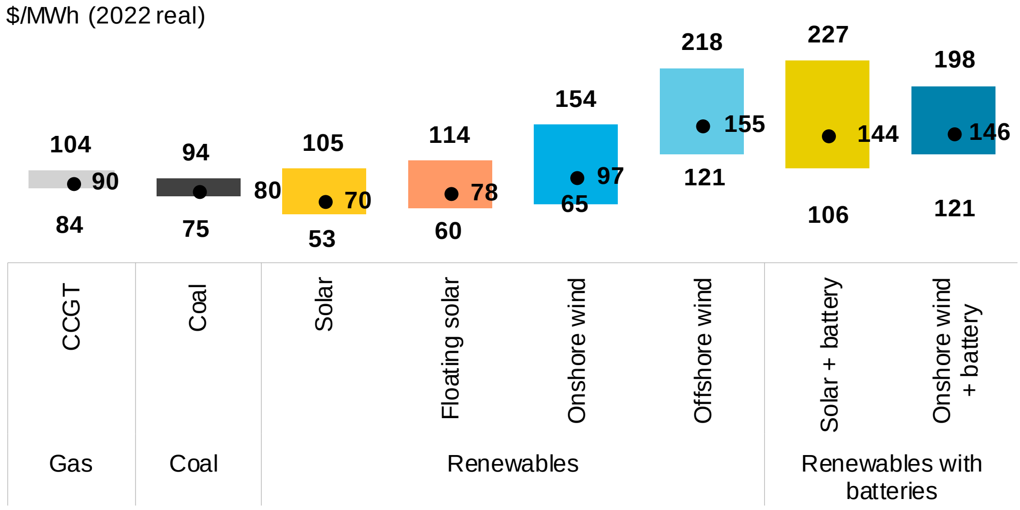
3.1. New power plants

Utility-scale solar is already the cheapest source of new bulk generation in Vietnam

Floating solar can help to circumvent land constraint challenges

The LCOE for a new utility-scale solar plant currently stands at $53-105/MWh (in real 2022 dollar terms), making it the cheapest source of new bulk electricity generation in Vietnam. The country's relatively generous solar feed-in tariff schemes drove large volumes of solar deployment in 2019 and 2020. The increase in activity, build-up of domestic capabilities and access to affordable equipment from China have driven down the LCOE of solar significantly.

Figure 6: Levelized cost of electricity of new power plants in Vietnam in 2023, by technology



Source: BloombergNEF. Note: Solar and onshore wind plus batteries modeled with a four-hour battery. CCGT is combined-cycle gas turbine.

Floating solar is gaining traction in Southeast Asia, including in Vietnam, as an option to overcome growing land constraint challenges. There are also synergies between floating solar projects and the existing portfolio of hydro plants in Vietnam. Hydro can help to balance the intermittency of solar plants and existing transmission infrastructure can be optimized. Floating solar could also reduce evaporation. BNEF's estimates suggest the LCOE of a benchmark floating solar photovoltaic (PV) project in Vietnam is approximately 12% higher than that of a ground-mounted solar project due to higher capital expenditure required but is already competitive against a new thermal power plant at $60-114/MWh.

Onshore wind also becomes cost competitive against coal and CCGT plants by the end of the decade

New onshore wind becomes cost competitive against a new CCGT plant and a new coal plant by 2026 and 2028, respectively. The cheapest onshore wind project today at $65/MWh already undercuts new thermal power plants. The LCOE for a new coal plant in Vietnam has a range of $75-94/MWh and a new CCGT plant has a range of $84-104/MWh.

The economics of renewables in Vietnam are likely to continue to improve thanks to declining equipment costs, technology improvements and increased economies of scale. Little cost reduction is expected for the mature thermal power plant technologies. The LCOE of a new solar and onshore wind plant in Vietnam is estimated to decline by 46% and 33%, respectively, between now and 2030.

By 2030, the most competitive offshore wind projects could out-compete new thermal power plants

The LCOE of offshore wind is expected to decline by 30% between 2030 and 2050

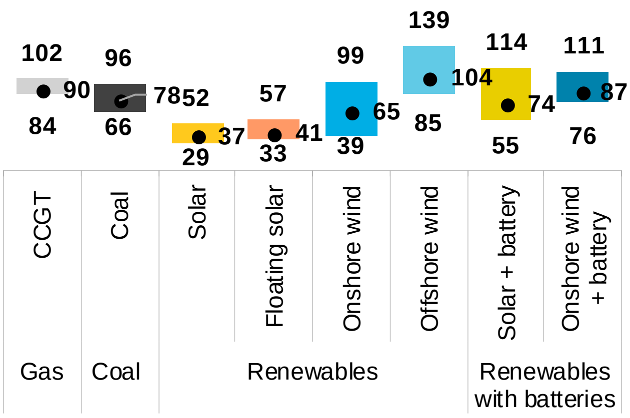
Vietnam does not have any operational offshore wind plants yet. However, there is strong interest from the government and developers. BNEF estimates the LCOE of an offshore wind project in Vietnam today to have a range of $121-218/MWh.

On average, an offshore wind project would likely still be more costly than a new thermal power plant by the end of this decade in Vietnam. However, the most competitive offshore wind installations that can access the cheapest development and financing costs and the best wind resources would also become competitive against a new thermal power plant by 2030.

By 2050, all renewable technologies including offshore wind will be cheaper sources of electricity than new thermal power plants in Vietnam. The LCOE of solar in 2050 is estimated to be less than 25% that of the LCOE for a new CCGT plant and 27% that of coal. The LCOE of offshore wind declines by 32% between 2030 and 2050 and becomes lower than a new CCGT or coal plant by 2035 and 2039, respectively.

Figure 7: Levelized cost of electricity of new power plants in Vietnam in 2030, by technology

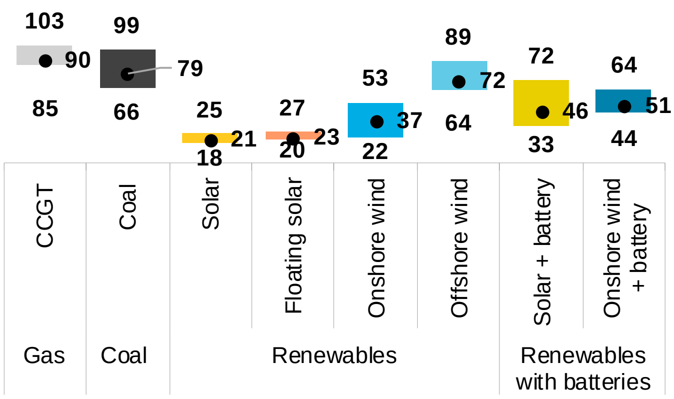
$/MWh (2022 real)



Source: BloombergNEF. Note: Solar and onshore wind plus batteries modeled with a four-hour battery. CCGT is combined-cycle gas turbine.

Figure 8: Levelized cost of electricity of new power plants in Vietnam in 2050, by technology

$/MWh (2022 real)



Source: BloombergNEF. Note: Solar and onshore wind plus batteries modeled with a four-hour battery. CCGT is combined-cycle gas turbine.

Solar with batteries becomes cheaper than thermal power plants by 2030

BNEF estimates a solar plus battery storage system (PVS) project is set to become cost competitive against a new coal and gas plant by the end of this decade in Vietnam. The LCOE of a PVS system is expected to fall to $55-114/MWh by 2030 and $33-72/MWh by 2050, thanks to declining costs of solar and lithium-ion batteries. Likewise, an onshore wind project paired with batteries is also expected to become cheaper than a new coal and gas plant in the first half of the 2030s.

A benchmark floating PVS project is expected to be cost competitive by the end of this decade, with LCOEs estimated to fall to $48-149/MWh by 2030 and $30-81/MWh by 2050. However, the costlier floating solar plants paired with battery storage at 100% of capacity may not be cost competitive against coal power plants due to the much higher capital expenditure involved.

For battery system sizes used in the LCOE calculations, refer to Appendix A.

Figure 9: Levelized cost of electricity of a solar-plus-battery project compared with a new coal and gas plant in Vietnam

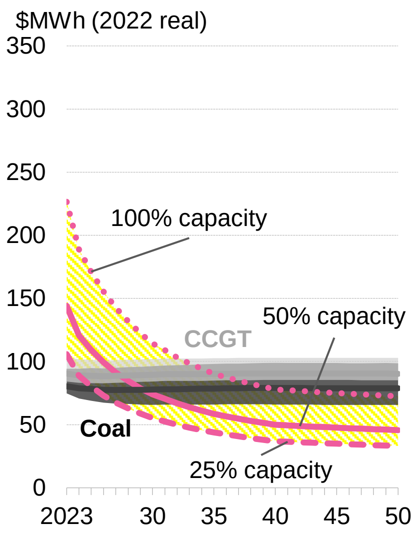


Figure 10: Levelized cost of electricity of a floating solar-plus-battery project compared with a new coal and gas plant in Vietnam

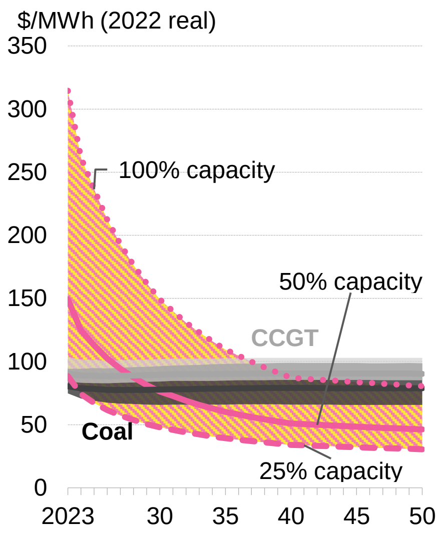
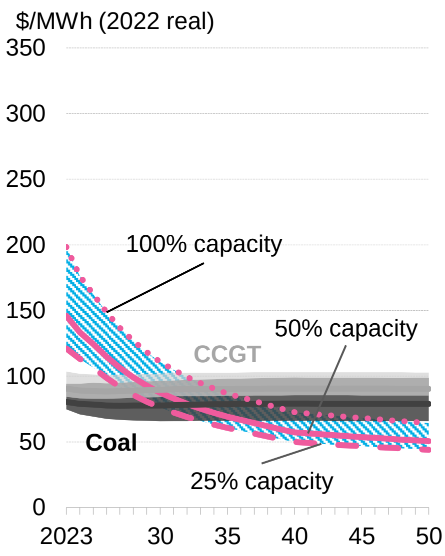


Figure 11: Levelized cost of electricity of an onshore wind-plus-battery project compared with a new coal and gas plant in Vietnam

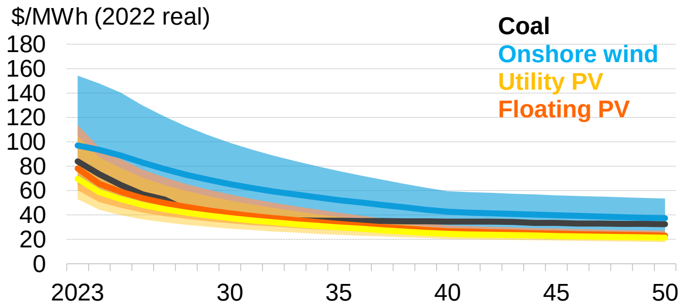


Source: BloombergNEF. Note: Levelized cost of electricity ranges for solar-plus-battery, floating solar-plus-battery and onshore wind-plus-battery represent storage sized between 25% and 100% of solar and onshore wind capacity. Does not account for additional costs that may be incurred through local cost provisions on equipment. CCGT is combined-cycle gas turbine.

A new solar power plant in Vietnam can already generate electricity more cheaply than existing thermal power plants

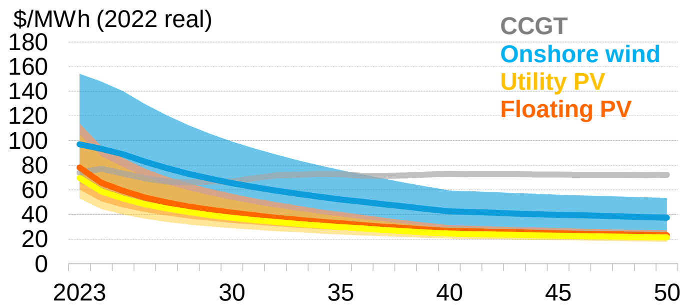
The current benchmark LCOE of $70/MWh for new ground-mounted solar and $78/MWh for new floating solar are lower than the short-run marginal cost (SRMC) of existing coal and gas power plants in Vietnam today. By 2030, the LCOE of onshore wind will be similarly below that of existing CCGTs. Coal and gas power generation also face higher fuel price volatility. Higher-than-expected fuel costs would further raise the SRMCs of coal and gas plants already in operation.

Figure 12: Levelized cost of electricity of a new solar photovoltaic and onshore wind plant compared with short-run marginal cost of an existing coal plant in Vietnam



Source: BloombergNEF

Figure 13: Levelized cost of electricity of a new solar photovoltaic and onshore wind plant compared with short-run marginal cost of an existing combined-cycle gas turbine plant in Vietnam



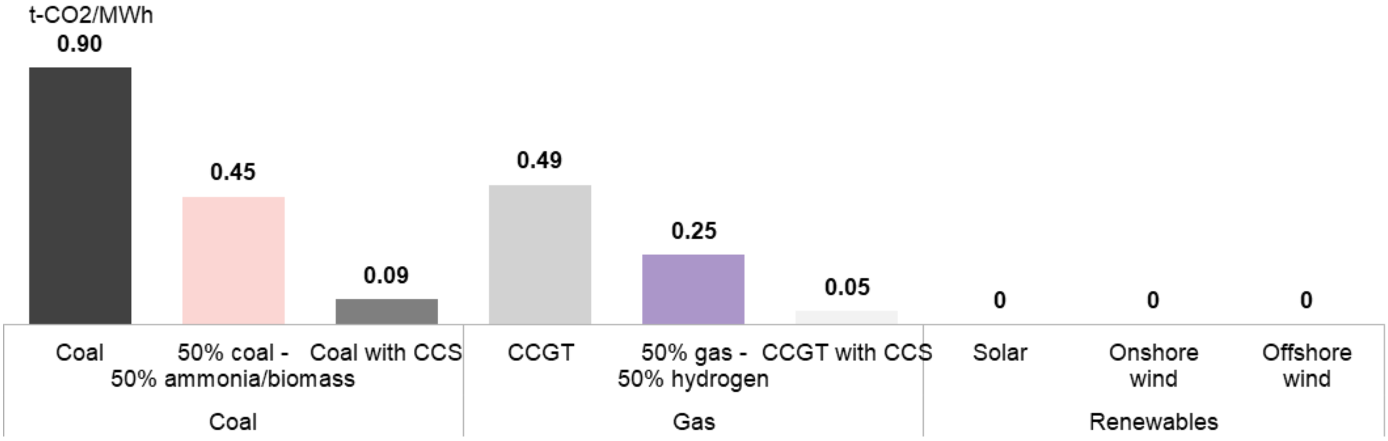
Source: BloombergNEF

3.2. Retrofitting thermal power plants for hydrogen and ammonia

A few countries, notably Japan and South Korea, are considering co-firing coal with ammonia and blending natural gas with hydrogen to lower emissions from existing thermal power plants. Vietnam is also exploring this strategy. Molecules such as hydrogen and ammonia do not release carbon dioxide during combustion given the absence of carbon in their molecular chemistry. Still, such approaches entail higher risks (see Section 4) and costs than renewables.

Only co-firing 20% ammonia with coal (on an energy content basis) has so far been tested in pilot projects. At such low levels of co-firing, the emissions reduction from the coal power plant is marginal (See Appendix D for more details). The commercial feasibility of co-firing at ratios higher than 20% is still highly uncertain.

Figure 14: Emissions intensity of coal, gas and renewables during electricity generation



Source: BloombergNEF. Note: Blending ratio based on energy content. Assuming 90% capturing rate for carbon capture and storage (CCS) technologies. CCGT is combined-cycle gas turbine; t-CO2/MWh is metric ton of carbon dioxide per megawatt-hour.

Environmental benefits are limited when using hydrogen and ammonia for power generation

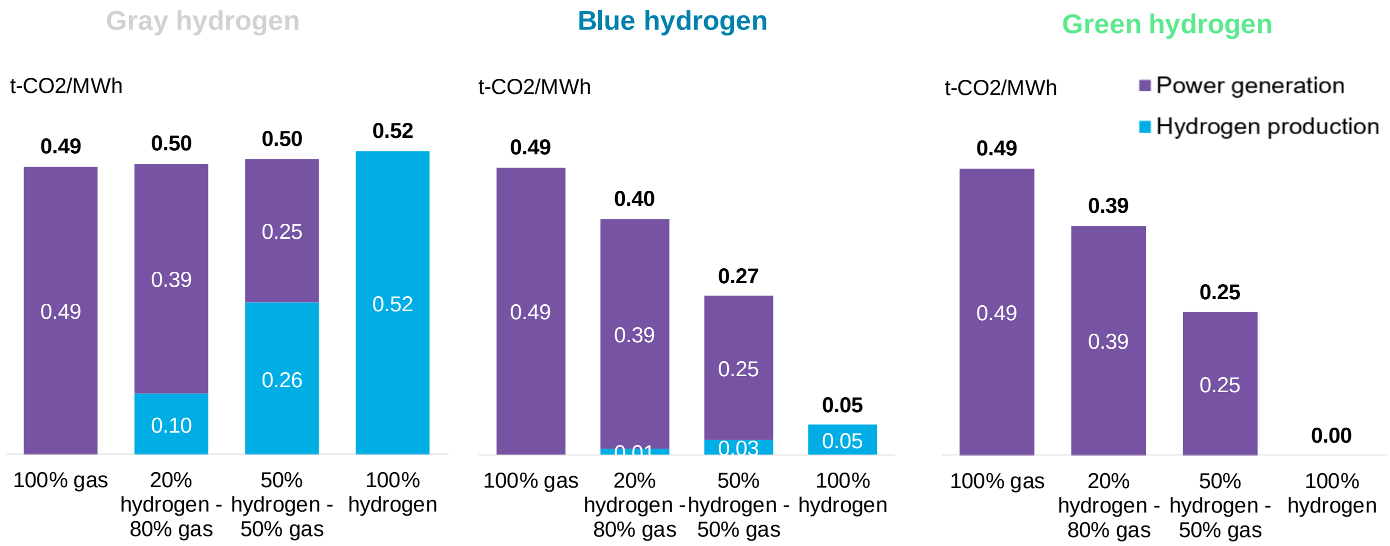
Gray hydrogen combustion emits more carbon dioxide emissions than burning gas

To achieve significant carbon dioxide emission reductions from a thermal power plant, the ratio of hydrogen to natural gas as well as ammonia to coal has to be very high. Additionally, the hydrogen – and its derivative ammonia – would have to be produced with low emissions. This could either be green hydrogen, which is produced from water electrolysis using renewable electricity, or blue hydrogen produced from fossil fuels with emissions mitigated through carbon capture and storage (CCS).

Hydrogen and ammonia co-firing also leads to increased risks of air pollution. The combustion of fuels such as ammonia or hydrogen at high temperatures leads to nitrogen oxide (NOx) emissions. Since hydrogen and ammonia burn hotter than fossil fuels, the nitrogen and oxygen present in the air during their combustion react at a higher rate, leading to more NOx emissions. NOx is a class of air pollutants that contributes to the greenhouse gas effect indirectly as well as to rain acidification. These combustion technologies also emit nitrous oxide (N2O), which is a greenhouse gas. The global warming potential (GWP) of nitrous oxide is 273 times greater than that of carbon dioxide over a 100-year timescale.

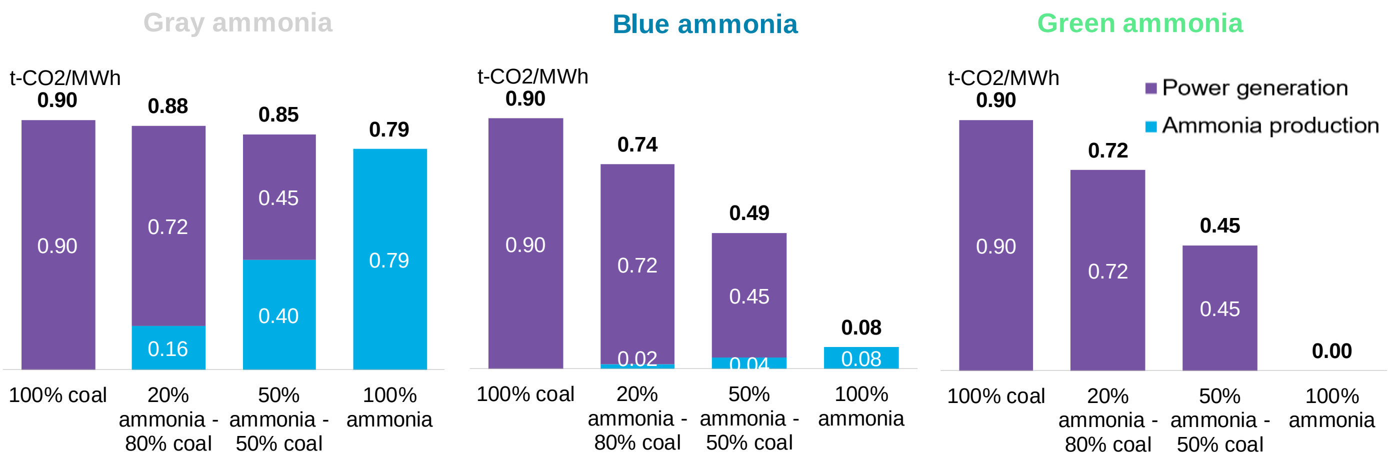
Retrofitted thermal power plants for hydrogen or ammonia combustion would also need to invest in technologies to capture both NOx and nitrous oxide emissions to reduce air pollution sources while ensuring greenhouse gas emission reduction benefits. This further highlights the poor economics of this strategy.

Figure 15: Combined-cycle gas turbine emissions during electricity generation depending on fuel type



Source: BloombergNEF. Note: Blending ratio based on energy content. t-CO2/MWh is metric ton of carbon dioxide per megawatt-hour.

Figure 16: Coal power plant emissions during generation depending on fuel type

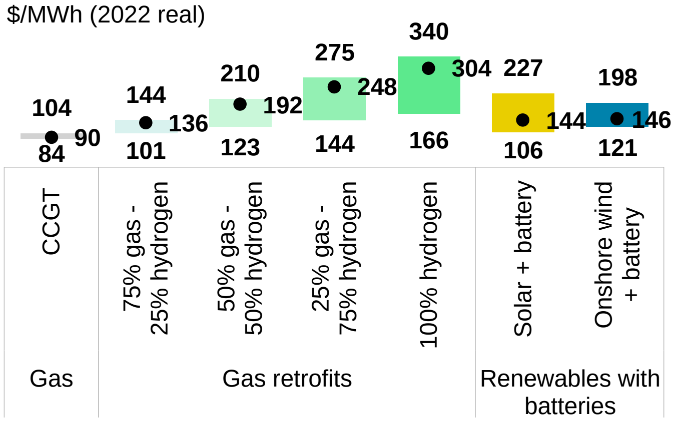


Source: BloombergNEF. Note: Blending ratio based on energy content. t-CO2/MWh is metric ton of carbon dioxide per megawatt-hour.

Renewables are a more economical decarbonization pathway than using hydrogen and ammonia as fuel for thermal power plants

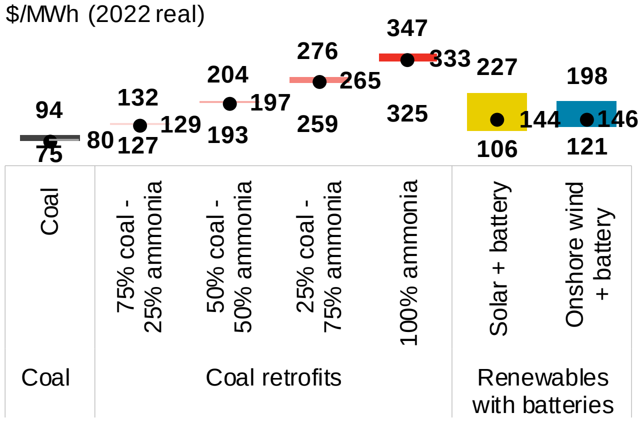
At low co-firing and blending ratios of clean ammonia and hydrogen, retrofitting thermal power plants appears to cost less than using renewables today (Figure 17 and Figure 18). However, to achieve significant emission reduction, thermal power plants must be retrofitted for at least 50% combustion of hydrogen or ammonia, which would be far more expensive than renewables. For the cost parameters used in the adjustments for retrofits of fossil fuel plants, see Appendix A.

Figure 17: Levelized cost of electricity for gas plants retrofitted for hydrogen compared with new renewables in Vietnam in 2023



Source: BloombergNEF. Note: Blending ratio based on energy content. CCGT is combined-cycle gas turbine.

Figure 18: Levelized cost of electricity for coal plants retrofitted for ammonia compared with new renewables in Vietnam in 2023



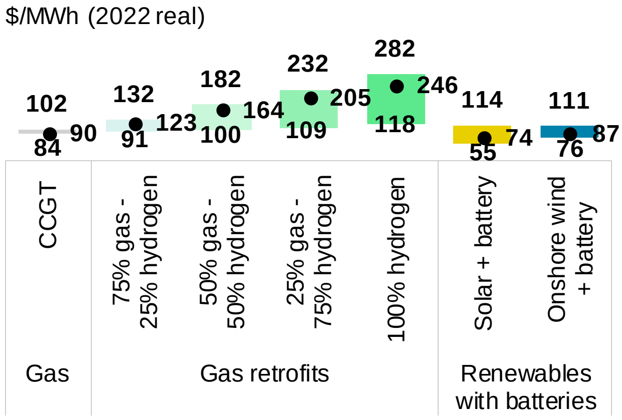
Source: BloombergNEF. Note: Blending ratio based on energy content.

By 2030, solar with batteries would be the cheapest dispatchable technology (Figure 19 and Figure 20). Similarly, onshore wind with batteries would become economically competitive against CCGT and coal retrofits, even at 25% blending/co-firing ratios. The economic competitiveness of renewables paired with batteries improves compared with hydrogen or ammonia combustion over the coming years (Figure 21 and Figure 22).

BNEF's analysis assumes that green hydrogen produced in Vietnam is powered by solar, the cheapest renewable energy in the country. Vietnam aims to produce green hydrogen through electrolysis powered by offshore wind projects. Using green hydrogen produced from offshore wind would be costlier given the higher LCOE of offshore wind compared with solar.

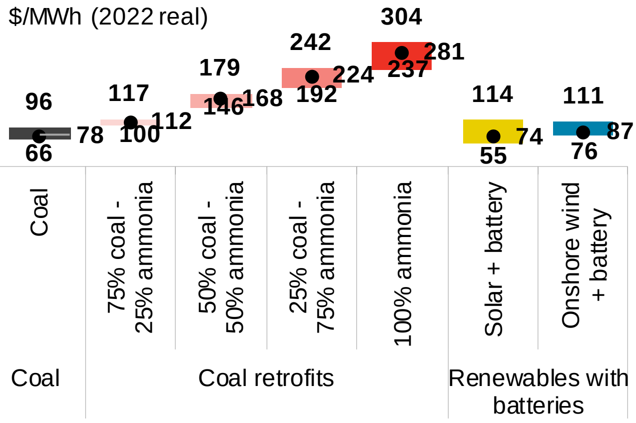
For more details on hydrogen and ammonia that are relevant to Vietnam, see Appendix B (delivered costs of hydrogen and ammonia), Appendix C (production costs of hydrogen and ammonia) and Appendix D (blended fuel prices).

Figure 19: Levelized cost of electricity for gas plants retrofitted for hydrogen compared with renewables in Vietnam in 2030



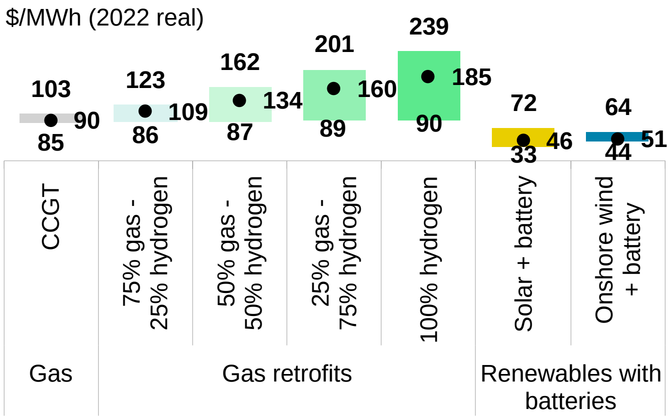
Source: BloombergNEF. Note: Blending ratio based on energy content. CCGT is combined-cycle gas turbine.

Figure 20: Levelized cost of electricity for coal plants retrofitted for ammonia compared with renewables in Vietnam in 2030



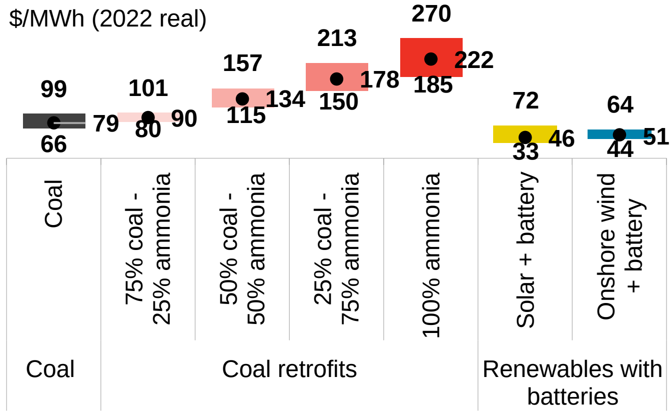
Source: BloombergNEF. Note: Blending ratio based on energy content.

Figure 21: Levelized cost of electricity for gas plants retrofitted for hydrogen compared with renewables in Vietnam in 2050



Source: BloombergNEF. Note: Blending ratio based on energy content. CCGT is combined-cycle gas turbine.

Figure 22: Levelized cost of electricity for coal plants retrofitted for ammonia compared with renewables in Vietnam in 2050



Source: BloombergNEF. Note: Blending ratio based on energy content.

3.3. Retrofitting coal power plants for biomass co-firing

Securing sufficient continuous supply of affordable and sustainable biomass would be challenging

The use of biomass in co-firing with coal entails similar challenges to that of ammonia. At low co-firing ratios, emission reduction benefits are limited. At high co-firing ratios, significant upgrades to the coal power plant would be needed.

Securing sufficient continuous supply of biomass for high co-firing ratios would also be challenging given the significant increase in feedstock supply required. The viability of using biomass as an alternative fuel supply also hinges on the feedstock price, which is highly sensitive to transportation distance.

If there is insufficient biomass feedstock locally, Vietnam will have to turn to imports but will likely find itself facing stiff competition from other countries that are pursuing a similar strategy. Indonesia's state-owned utility, PT Perusahaan Listrik Negara, in its current 10-year electricity supply business plan projects a significant ramp-up in required biomass fuel of 23- to 27-fold in 2025 from the 0.5 million to 0.6 million tons required in 2021 to support the country's co-firing ambitions. This may limit the amount of biomass available for import in the region in the future.

3.4. Using carbon capture and storage

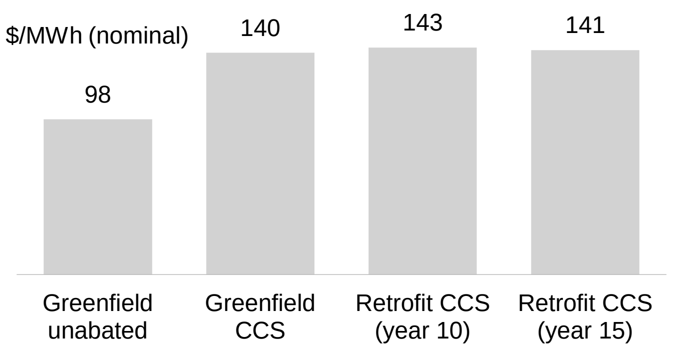
Retrofitting existing plants with CCS won't reduce the reliance on fossil fuels and is costlier

Many countries are also considering the use of CCS to reduce emissions from thermal power plants, but there are few operational projects to date. BNEF has modeled the LCOE for several CCS scenarios: greenfield thermal power plants with CCS, as well as retrofitting existing thermal power plants with CCS at 10 years and 15 years after the commercial operational date.

BNEF analysis suggests that a greenfield coal or gas plant equipped with CCS upfront is the most economical scenario, due to higher capital expenditure required for retrofits than a greenfield project designed with CCS in mind. Retrofitting a thermal power plant 15 years later would be slightly cheaper than retrofitting 10 years later, due to expected reductions in CCS costs. However, this would then pose risks for emissions reduction pathways, as the thermal power plant would continue unabated for an additional five years.

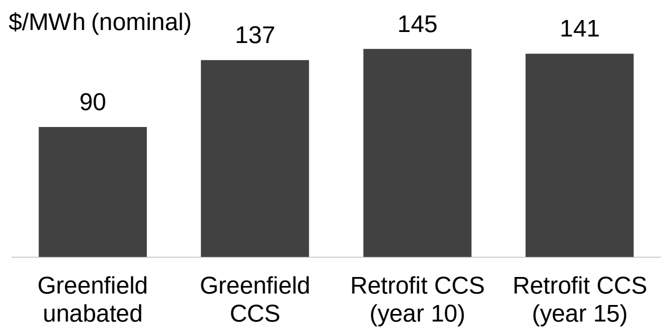
All CCS scenarios in BNEF's analysis are still more expensive than solar and wind in Vietnam. Although CCS scenarios appear to be more economical than co-firing ammonia with coal or blending hydrogen with natural gas at high energy ratios, the amount of potential carbon storage available in Vietnam as well as feasibility of transporting captured emissions from existing thermal power plants to carbon storage sites also still needs to be evaluated. Vietnam also currently lacks the regulatory framework for the deployment of CCS.

Figure 23: Levelized cost of electricity for a new combined-cycle gas turbine plant and CCGT with carbon capture and storage in Vietnam



Source: BloombergNEF. Note: Greenfield plants represent a plant financed today and expected to commission in 2025. Retrofits at year 10 and 15 refer to 2035 and 2040, respectively.

Figure 24: Levelized cost of electricity for a new coal plant and coal with carbon capture and storage in Vietnam



Source: BloombergNEF. Note: Greenfield plants represent a plant financed today and expected to commission in 2025. Retrofits at year 10 and 15 refer to 2037 and 2042, respectively.

Section 4. Challenges with using hydrogen as a fuel for electricity generation

The previous section explored the LCOE associated with retrofitting thermal power plants for co-firing with fuels derived from hydrogen. Here we examine additional safety as well as energy security and affordability challenges associated with retrofitting thermal power plants for clean fuels.

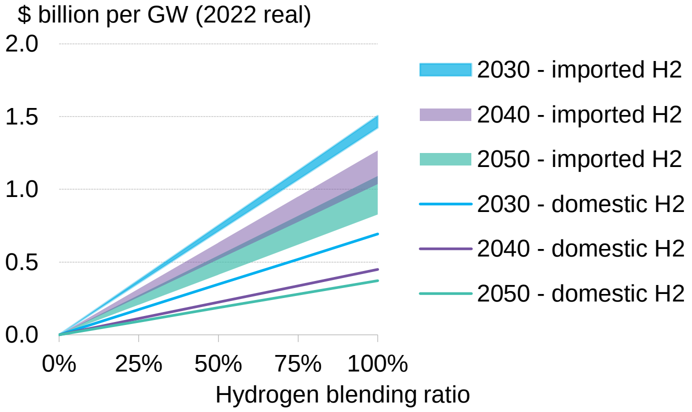
Reliance on hydrogen as a fuel for electricity would increase Vietnam's financial burden

Hydrogen and ammonia are more expensive fuels than gas and coal on an energy-equivalent basis due to these molecules' lower volumetric energy density. This explains the rise in LCOE at higher ratios of hydrogen or ammonia. Reliance on such fuels would increase power prices and potentially the financial burden on taxpayers depending on whether the government decides to support the higher costs of these clean fuels through raising regulated electricity tariffs or taxes.

Procuring hydrogen imports could be three to five times more expensive than natural gas

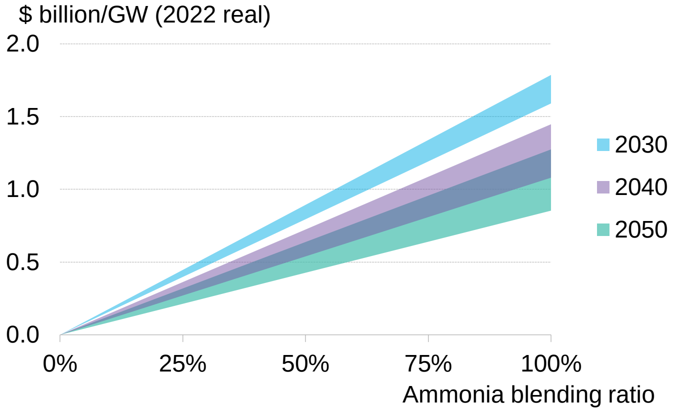
BNEF estimates a retrofitted 1GW gas power plant running on 100% hydrogen would need 276.4 thousand tons of hydrogen annually. To source this much hydrogen locally, the annual hydrogen procurement costs per GW would be $0.69 billion in 2030, $0.45 billion in 2040, and $0.37 billion in 2050 (Figure 25). These would be lower than the cost of imported hydrogen procurement: $1.51 billion -$1.54 billion in 2030, $1 billion-$1.27 billion in 2040, and $0.83 billion-$1.1 billion in 2050. To generate the same amount of electricity, CCGT plants in the country would only spend $0.28 billion per GW in 2030, $0.24 billion in 2040, and $0.26 billion in 2050 annually on gas procurement. Imported hydrogen procurement could be three to more than five times costlier than gas procurement, leading to the need for much higher power tariffs.

Figure 25: Vietnam's annual hydrogen procurement cost per GW of combined-cycle gas turbine power plants, by blending ratio and year



Source: BloombergNEF. Note: BNEF estimates 0.06 metric tons of hydrogen is needed to generate 1 megawatt-hour of electricity. Assumes a CCGT power plant operates at 55% capacity factor, or average fleet annual capacity factor from 2018 to 2022. Blending ratio based on energy content.

Figure 26: Vietnam's annual ammonia procurement cost per GW of coal power plants, by blending ratio and year



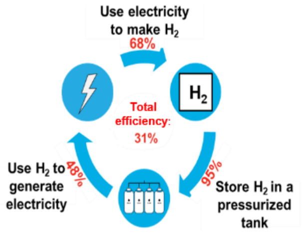
Source: BloombergNEF. Note: BNEF estimates 0.5 metric tons of ammonia is needed to generate 1 megawatt-hour of electricity. Assumes a coal power plant operates at 57% capacity factor, or average fleet annual capacity factor from 2018 to 2022. Blending ratio based on energy content.

Ammonia procurement could be seven to nine times more expensive than coal procurement in 2030

For a retrofitted 1GW coal power plant in Vietnam, the required volume of ammonia would be 1.25 million tons of ammonia for 50% co-firing and 2.5 million tons for 100% firing. BNEF estimates 50% ammonia co-firing in 2040 would cost $0.54 million-$0.72 million per GW annually (Figure 26). In addition, burning only ammonia at the same size of coal power plants would require $1.6 billion to $1.8 billion per GW in 2030, $1.1 billion to $1.4 billion in 2040, and $0.9 billion to $1.3 billion in 2050. On the other hand, burning only coal at a 1GW coal power plant in Vietnam would annually cost $0.21 billion in 2030, $0.19 billion in 2040, and $0.18 billion in 2050. Ammonia procurement would be seven to nine times more expensive than coal procurement in 2030.

4.1. Marginal abatement cost for thermal power plants retrofitted for hydrogen and ammonia

Figure 27: Efficiency of hydrogen to power

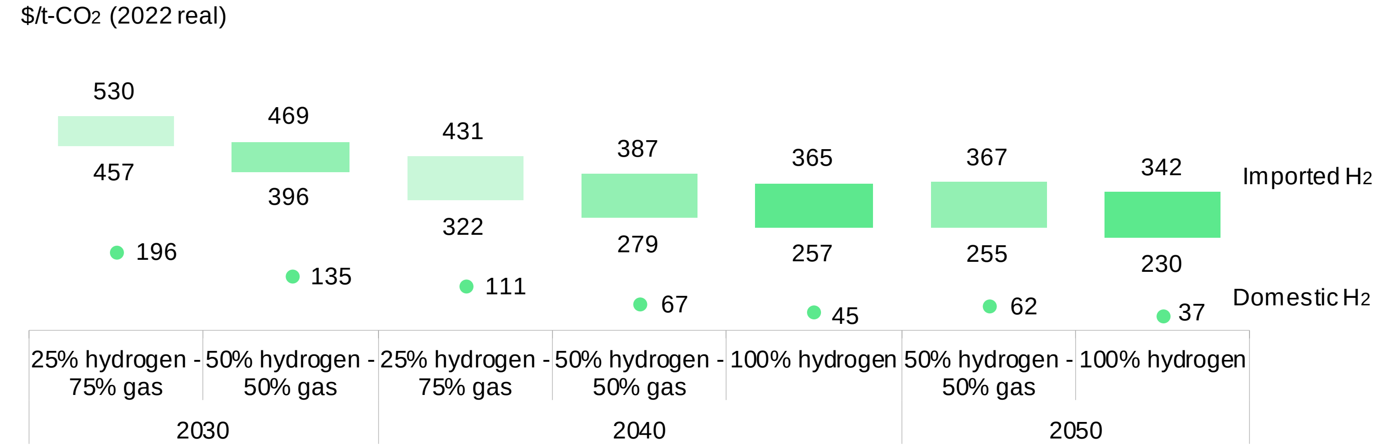


Source: BloombergNEF

While using domestically produced green hydrogen would theoretically have a lower marginal abatement cost (Figure 28), production of that fuel would be dependent on using domestic renewable electricity for producing hydrogen and then using the hydrogen for producing electricity. Such an indirect use of renewable electricity would be less efficient and much more expensive than just directly using the electricity generated by the renewables.

To domestically supply hydrogen needed to power a 1GW retrofitted CCGT plant, Vietnam would need to build 9.8GW of solar projects. For reference, only 3.2GW of solar projects would be needed to generate the same amount of electricity. Similarly, to produce ammonia locally for a 1GW retrofitted coal power plant, Vietnam would need to add 15.7GW of new solar builds. This is more than four times larger than solar capacity needed (3.4GW) to generate the same amount of electricity as the coal plant.

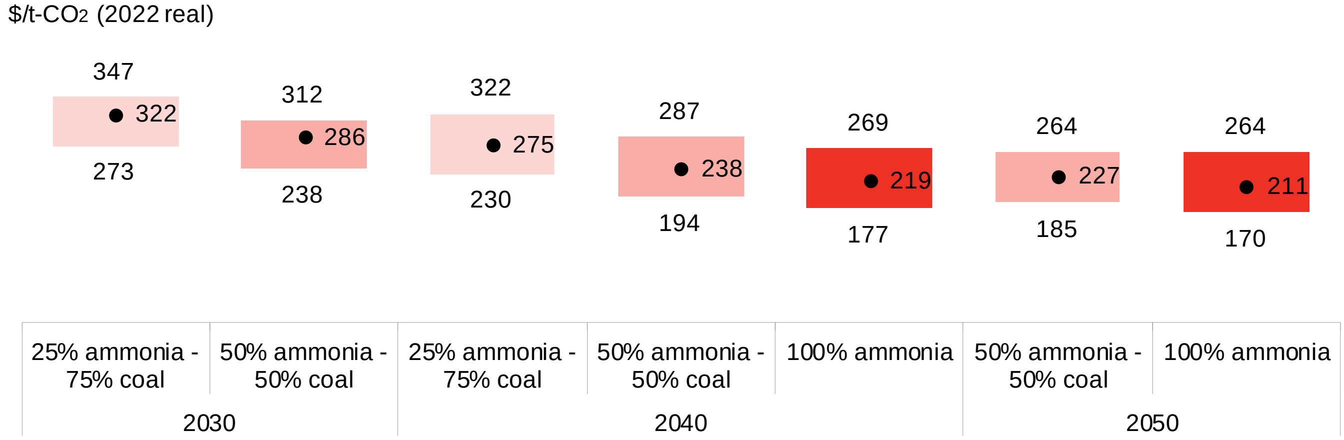
Figure 28: Marginal abatement cost for CCGT retrofitted for hydrogen blending



Source: BloombergNEF. Note: Blending ratio based on energy content. t-CO2 is metric ton of carbon dioxide.

BNEF estimates the marginal abatement cost for 25% ammonia co-firing in 2030 would be in the range of $273-347 a metric ton of carbon dioxide (t-CO2) (Figure 29). For 50% ammonia co-firing, the abatement cost would be $194-287/t-CO2 in 2040 and $185-264/t-CO2 in 2050. These levies would be a huge financial burden for power plant owners and electricity end-users. If Vietnam were to put in carbon prices anywhere near these levels, power plant owners would likely opt to shut down existing thermal power plants and build cheaper renewables.

Figure 29: Marginal abatement cost for coal power plant retrofitted for ammonia co-firing in Vietnam



Source: BloombergNEF. Note: Blending ratio based on energy content. t-CO2 is metric ton of carbon dioxide.

4.2. Safety

Figure 30: Hydrogen-related accident in the US in 2007

Source: WHA International

Ammonia and hydrogen need to be handled with care due to their flammability and explosiveness when exposed to heat (Figure 30, Table 1). A leak of liquid ammonia at a poultry plant in China's Jilin province in 2013 caused a fire and killed 120 people. In the same year, another ammonia leak killed 15 and injured 25 at a frozen seafood plant in Shanghai, China. In 2017, a hydrogen leak from a coolant at a coal-fired power plant in Ohio, US, caused an explosion that killed one person and injured 10 people. Since hydrogen does not have a distinct odor and color, it is difficult to detect leaks.

In addition, ammonia must be stored carefully as the molecule could pose a big threat to human health. The molecule reacts with water to form ammonium hydroxide, which is corrosive and damages cells in the body on contact. It's easier to detect an ammonia leak due to its odor but contact with ammonia could be fatal.

Table 1: Safety comparison of ammonia, hydrogen and natural gas

	Ammonia	Hydrogen	Natural gas (methane)
Flammability	Flammable	Flammable	Flammable
Explosiveness	May explode if heated	May explode if heated	May explode if heated
Toxicity	Acute poisoning from inhaling, skin/eye/respiratory damages	None; still, high levels of hydrogen could cause a lack of oxygen in bodies	None; still, high levels of methane could cause a lack of oxygen in bodies
Odor	Strong (easy to detect)	None (hard to detect)	None (hard to detect); gas companies add artificial smell
Visibility (color)	Colorless (hard to detect)	Colorless (hard to detect)	Colorless (hard to detect)

Source: BloombergNEF, Globally Harmonized System of Classification and Labeling of Chemical (GHS) classification. Note: Red represents danger. Green indicates no harm.

Section 5. The way forward for Vietnam

Solar and wind are already economically preferable options to meet Vietnam's growing power demand while keeping the country aligned with its 2050 net-zero target and decarbonization commitments under the JETP agreement. Expansion of Vietnam's thermal power fleet risks the country's energy security and affordability. Retrofitting thermal power plants later for combustion of hydrogen or ammonia is unlikely to become an economically viable option. Vietnam can better manage its energy transition by accelerating renewable power additions and grid capacity expansion, while limiting new thermal power capacity addition.

5.1. Measures to accelerate renewable power expansion

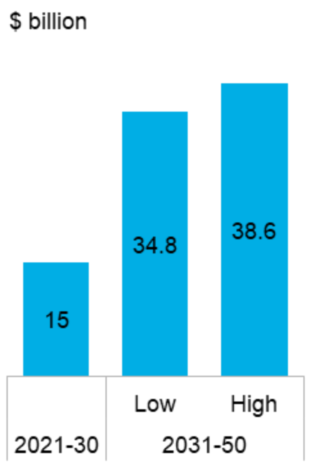
Have a clear, long-term pipeline of renewable energy auctions

A clear pipeline of long-term opportunities will help to build investor confidence, aid capacity planning and facilitate local supply chain investment

Vietnam has signaled its long-term commitment to developing renewable power through its recently approved PDP VIII. Both domestic and international investors and developers have strong interest in Vietnam's renewable sector that contributed to a rapid growth of solar and onshore wind capacity from 2019. However, opportunities have stalled since the expiry of the feed-in tariff schemes due to a lack of regulatory and policy clarity. Repeated boom-bust cycles can undermine investor confidence in the market. This can be addressed through having a clear, long-term pipeline of opportunities. This would also aid other related developments such as capacity planning and could help attract investments to build up local supply chains.

Vietnam could also leverage auctions to support utility-scale renewable projects. A well-designed auction program with transparent rules can increase competition and lower the cost of renewable electricity. Auctions designed around identified available substation capacity could also help reduce curtailment risks that is currently a challenge in Vietnam and hence lower financing costs for developers and ease grid operational challenges.

Figure 31: Required transmission grid investment under Vietnam's PDP VIII



Source: BloombergNEF, Ministry of Industry and Trade

Facilitate private grid investments

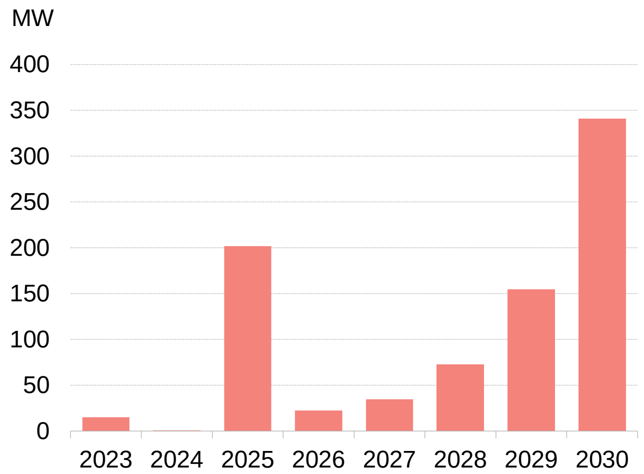
Grid infrastructure is currently one of the biggest challenges for renewables integration in Vietnam. The boom in solar and wind capacity between 2019 and 2021 gave rise to grid congestion and curtailment challenges due to the concentration of renewable capacity in the Central and Southern regions of Vietnam. A mismatch in solar generation profile and Vietnam's load also led to an oversupply of power during the day. To allow for higher penetration of renewables, Vietnam's grid will need expanding and strengthening. The responsibility of grid development currently lies solely with Vietnam Electricity Group (EVN), which has a monopoly over the transmission and distribution segment. However, EVN's financial limitations are slowing down the upgrades. One potential avenue is to tap into private capital.

A 2022 amendment to Vietnam's Law on Electricity permits private transmission grid investments and operations. Clarification on the frameworks for such investments will allow Vietnam to access a wider pool of capital for grid development and speed up the enhancement required for further integration of renewables.

Allow the participation of flexible sources in Vietnam's power system

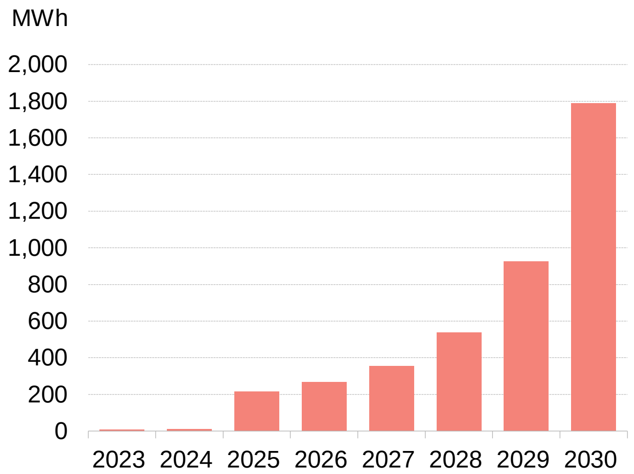
By 2030, solar with batteries could out-compete new thermal power plants in Vietnam. However, there is no framework for energy storage to operate in Vietnam. The country's latest power development plan mentions pairing solar with battery storage, but the target is small at just 300MW of storage by 2030. The experience of neighboring Philippines suggests Vietnam can achieve far larger deployments of battery storage under the appropriate regulatory framework. BNEF expects that even under current conditions, energy storage deployments will be more than double the 2030 target.

Figure 32: Vietnam's annual battery storage build forecast based on power capacity



Source: BloombergNEF. Note: Forecast as of 1Q 2023.

Figure 33: Vietnam's cumulative battery storage deployment forecast based on energy capacity



Source: BloombergNEF. Note: Forecast as of 1Q 2023.

Implementing frameworks for the participation of flexible assets in Vietnam's power system can help Vietnam leverage economic dispatchable generation sources. It can also ease the curtailment challenges and enhance grid flexibility for the integration of variable renewable energy sources. This includes the use of controllable load assets such as virtual power plants, demand response and interruptible load schemes, which can increase the stability of the grid and better align the demand profile with the generation profile of renewable energy plants in Vietnam.

Accelerate planned retail power market reform

Vietnam has plans to liberalize its electricity retail market by 2025. However, a planned direct power purchase agreement (DPPA) pilot has been delayed over the last few years as the government worked on finalizing the PDP VIII. Accelerating the implementation of both the DPPA and electricity retail market liberalization can allow Vietnam to tap into the growing corporate demand for clean power procurement.

Vietnam has a large base of manufacturers and suppliers to multinational companies with ambitious sustainability targets. This includes Samsung Group, which joined the RE100 initiative in 2022. Providing corporations with clean power procurement options can boost Vietnam's attractiveness as a manufacturing hub.

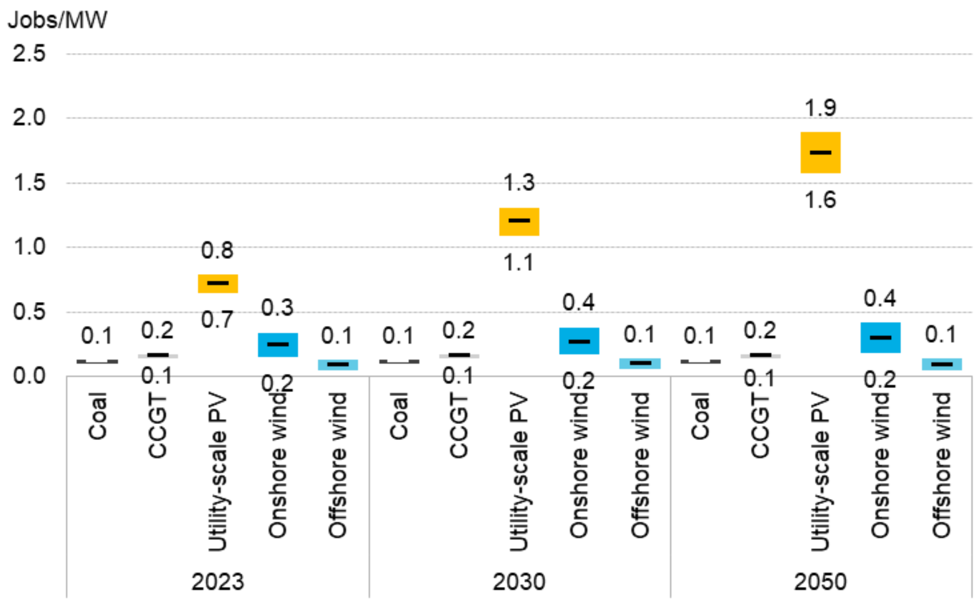
Co-ordinate cross-sectoral planning to facilitate offshore wind developments

Offshore wind can significantly boost the share of renewable energy in Vietnam. The generation profile of offshore wind also tends to complement that of solar. Vietnam's ambitious long-term offshore wind target is an encouraging first step. The country can further expedite the development of the offshore wind industry through co-ordination of national level plans such as marine spatial planning. Early engagement of the different stakeholders allows Vietnam to identify suitable areas for offshore wind projects and ease the development process, lowering risks and costs.

Plan training programs for clean tech jobs

Renewable energy projects can create long-term job opportunities. BNEF analysis suggests renewables have a significantly higher employment factor for local labor than thermal power plants. To take full advantage of the renewables' job creation dividend, the government will need to ensure relevant training programs are available. It would also need to ensure the programs can expand in tandem with the growth of its renewable energy market.

Figure 34: Anticipated operation and maintenance jobs per $1 million of capital expenditure investment in Vietnam



Source: BloombergNEF. Noted: The capital expenditure investment of $1 million is in real 2022 dollar terms.

5.2. Vietnam would benefit from limiting thermal power expansion

Vietnam's PDP VIII targets 30.2GW of new gas plants in this decade, almost 75% of which is to be fueled by LNG imports despite last year's sharp rise in LNG prices. This will greatly increase Vietnam's exposure to the global LNG market volatility. BNEF expects such LNG import-dependent projects to face difficulties in securing mutually acceptable power purchase agreements (PPAs) with EVN. LNG import-dependent gas power project owners will need EVN to agree to some type of fuel cost pass-through clause in the PPA to ensure financial viability of their projects against a potential rise in LNG prices. This would increase the procurement cost for EVN and likely lead to higher power tariffs.

Evaluation of planned pipeline thermal power plants

It is also important for Vietnam to have frequent and timely reviews of the feasibility and economic viability of the country's planned pipeline of thermal power plants. Delays in planned coal and gas power plants in Vietnam have led to power supply shortage concerns previously, particularly in northern Vietnam. It is crucial for Vietnam to put in place a review process to ensure that projects that are no longer viable are canceled, enhancing energy security, and allowing the country to choose the most economical options to meet growing power demand. This will also enable the country to stay on track for its commitments under the JETP agreement and its net-zero target.

Build agility into power purchase agreements for new thermal power plants

Many existing thermal power plants developed by private investors have rigid power purchase agreements including capacity payments. This means, when such power plants are not fully utilized, they still receive partial payments. While such mechanisms are helpful in getting the power plants financed, they saddle EVN with additional financial burden and are a hindrance to future renewable capacity expansion.

As much as possible, Vietnam should look to replace some of these existing planned coal and gas plants with renewables instead. BNEF's sensitivity analysis shows that the cost parity between renewables and thermal power plants will only be delayed by a few years even with depressed fuel costs and would not change the long-term dynamics that solar and wind are more economic options for the power sector. See Appendix E for more details.

Appendices

Appendix A. Levelized cost of electricity assumptions

Table 2: Levelized cost of electricity assumptions, nominal values

Technology	Variable	Unit	2023	2030	2050
Coal	Capital expenditure	$/MW	1,409,685	1,626,199	2,432,594
	Fixed operational expenditure	$/MW/year	33,231	37,243	55,059
	Variable opex	$/MW	5.4	5.9	8.9
	Capacity factor	%	60	61.8	61.8
	Hurdle internal rate of return (IRR)	%	13	14.75	15.5
	Cost of debt	bps	750	820	850
	Debt-to-equity ratio	%	75	56	49.3
	Loan tenor	Years	18	18	18
CCGT	Capex	$/MW	1,068,030	1,232,069	1,843,024
	Fixed opex	$/MW/year	28,929	32,418	47,926
	Variable opex	$/MW	2.4	2.7	4
	Capacity factor	%	60	61.8	61.8
	Hurdle IRR	%	14	14	14
	Cost of debt	bps	750	750	750
	Debt-to-equity ratio	%	75	68	65
	Loan tenor	Years	18	18	18
Utility-scale solar	Capex	$/MW	790,520	536,787	533,852
	Fixed opex	$/MW/year	14,414	13,781	18,186
	Variable opex	$/MW	-	-	-
	Capacity factor	%	17	17	17
	Hurdle IRR	%	14	12	8.5
	Cost of debt	bps	1,000	784	600
	Debt-to-equity ratio	%	75	75	75
	Loan tenor	Years	15	15	15
Floating solar	Capex	$/MW	897,960	672,477	889,626
	Fixed opex	$/MW/year	14,414	13,781	18,186
	Variable opex	$/MW	-	-	-
	Capacity factor	%	17	17	17

	Hurdle IRR	%	14	12	8.5
	Cost of debt	bps	1,000	784	600
	Debt-to-equity ratio	%	75	75	75
	Loan tenor	Years	15	15	15
Onshore wind	Capex	$/MW	1,517,257	1,533,048	1,880,790
	Fixed opex	$/MW/year	40,460	39,389	49,164
	Variable opex	$/MW	-	-	-
	Capacity factor	%	29	32	35
	Hurdle IRR	%	16	13.5	8.5
	Cost of debt	bps	1,000	784	600
	Debt-to-equity ratio	%	70	70	70
	Loan tenor	Years	15	15	15
Offshore wind	Capex	$/MW	3,854,683	4,020,743	5,967,322
	Fixed opex	$/MW/year	75,000	71,076	79,339
	Variable opex	$/MW	-	-	-
	Capacity factor	%	43	46.2	51.4
	Hurdle IRR	%	14	12	8.5
	Cost of debt	bps	1,000	692	600
	Debt-to-equity ratio	%	75	75	75
	Loan tenor	Years	15	15	15

Source: BloombergNEF

Adjustment for retrofits of fossil fuel power plants

Retrofits of fossil fuel power plants to blend hydrogen, ammonia, or biomass require new equipment or facilities added to existing power plants. Table 3 summarizes BNEF's assumptions of adjustments to project costs and efficiency used in our analysis based on interviews with market players and open-source research.

Table 3: Impacts of fossil fuel power plant upgrades on hydrogen, ammonia, or biomass use

	Coal retrofits with ammonia	Coal retrofits with biomass	Combined-cycle gas turbine retrofits with hydrogen
Capital expenditure	11% of coal capex	4.5% of coal capex	20% of CCGT capex
Variable operational expenditure	Not appliable	Not applicable	+20% from CCGT variable opex
Fixed opex	+10% from coal fixed opex	Not applicable	+12.5% from CCGT fixed opex
Efficiency	-12% from coal plant efficiency	-4% from coal plant efficiency	-7.5% from CCGT efficiency
Emission reduction	Same as blending ratio of ammonia in energy	Same as blending ratio of biomass in energy	Same as blending ratio of hydrogen in energy
Lifetime	20 years	20 years	20 years
Financing	Same as a new coal plant	Same as a new coal plant	Same as a new CCGT plant

Source: BloombergNEF. Note: Assumes retrofits take place after full depreciation of original power plants.

Coal retrofits with **ammonia** include upgrading burners and additional balance of plant expenses to receive and store ammonia. Controlling the exhaust NO_X emissions will also be key to each plant's combustion strategy. 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 Japan's 20% ammonia co-firing as the retrofit costs for more than 20% co-firing, namely 25%, 50%, 75% 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. See *Japan's Costly Ammonia Coal Co-Firing Strategy* (web | terminal) for more details.

Coal retrofits with **biomass**, especially at a low blending ratio, only require a small upgrade, such as a new covered silo storing feedstock. This is because the volume of to-be-blended biomass feedstock would be negligible at a low blending ratio. Like ammonia co-firing, a high biomass blending ratio would likely need major reinforcement as a large amount of biomass feedstock would need to be processed separately before blending fuels.

Hydrogen combustion also requires new equipment including more resilient materials to sustain higher combustion temperatures and more operations and maintenance to deal with these higher temperatures and increased use of water for cooling. The scales of these adjustment-associated costs and efficiency will likely decline over time. For this analysis, we refer to estimated cost and efficiency of a hydrogen-fueled turbine relative to state-of-the-art natural gas turbines between 2019 and 2040. To estimate additional costs and lower efficiency for retrofits, we took simple averages of these two categories and applied the adjustments to CCGT plants. See *Hydrogen: The Economics of Power Generation* (web | terminal) for more details.

Appendix B. Assumptions for delivered costs of clean fuels relevant to Vietnam

Hydrogen labeling

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 carbon capture and storage (CCS) – this releases more emissions than green hydrogen, but less than gray hydrogen.
- Gray, made via steam reforming of methane or gasification of coal without CCS – the most common method today that releases large volumes of carbon dioxide.

BNEF's research incorporates three different types of clean molecules: green hydrogen/ammonia produced in Vietnam, green hydrogen/ammonia imported from Australia and blue hydrogen/ammonia imported from the Middle East. Both Australia and the Middle East are aiming to become clean hydrogen exporters. Australia has cheap solar with vast land areas while the Middle East has ample availability of oil and gas as well as potential carbon storage sites. Leveraging on these resources, many companies in these regions have been partnering with hydrogen buyers in other markets to develop hydrogen supply chain.

Our research does not consider fossil fuel-based hydrogen and ammonia without emission mitigation, although almost all ammonia and hydrogen produced today are gray. Use of these molecules without emission abatement defies the justification of promoting these technologies in the first place. Many markets are also encouraging the use of clean molecules by defining 'low-carbon' hydrogen or ammonia.

We estimate fuel hydrogen/ammonia prices by the costs of hydrogen production, conversion to ammonia (and conversion back to hydrogen if needed), and shipping to Vietnam.

Hydrogen production

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

- Vietnam: alkaline electrolysis using fixed-axis PV projects and Chinese electrolyzers (green hydrogen)
- Australia: alkaline electrolysis using tracking PV projects and Western electrolyzers (green hydrogen)
- Middle East: steam methane reforming using natural gas (blue hydrogen)

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 after 2027 and push down the conversion cost subsequently.

Table 4: Cost of conversion to ammonia from hydrogen

	$/kilogram of hydrogen (in real 2022 terms)
Up to 2027	1.61
2028-2049	Linear interpolation for each year using values for 2027 and 2050
2050	1.00

Source: BloombergNEF

Transportation of ammonia

Ammonia produced outside Vietnam needs to be shipped to the country. Below is our assumption on transportation costs added to ammonia made in Australia and the Middle East. We used the following estimates for our calculations: 2,585 nautical miles between Dampier in Australia and Vietnam and 4,820 nautical miles between Das Island in the United Arab Emirates and Vietnam. Ammonia shipping is already mature, so these transportation costs are used throughout the modeling period:

- Molecules from Australia: $0.21/kilogram (kg) of hydrogen (in real 2022 dollar terms)
- Molecules from the Middle East: $0.22/kg of hydrogen (real 2022)

Conversion back to hydrogen from ammonia

Shipped ammonia must be converted back from hydrogen if end-use sectors use hydrogen, not ammonia. Similar to the conversion to ammonia, below shows the conversion cost to hydrogen.

Table 5: Cost of conversion to hydrogen from ammonia

	$/kilogram of hydrogen (in real 2022 terms)
Up to 2027	1.63
2028-2049	Linear interpolation for each year using values for 2027 and 2050
2050	1.07

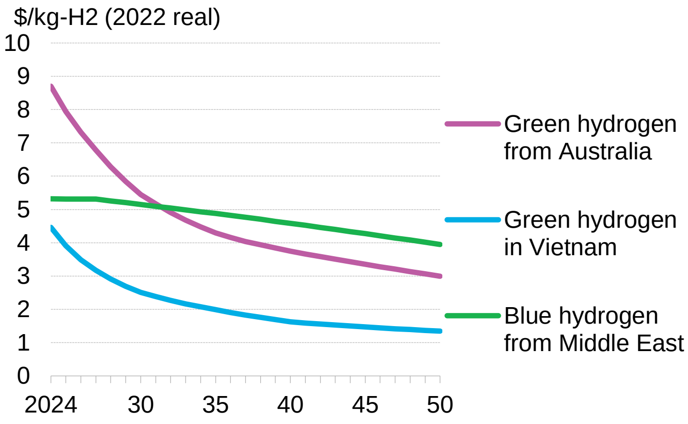
Source: BloombergNEF

Appendix C. Production cost of hydrogen and ammonia

Domestic green hydrogen is the cheapest option

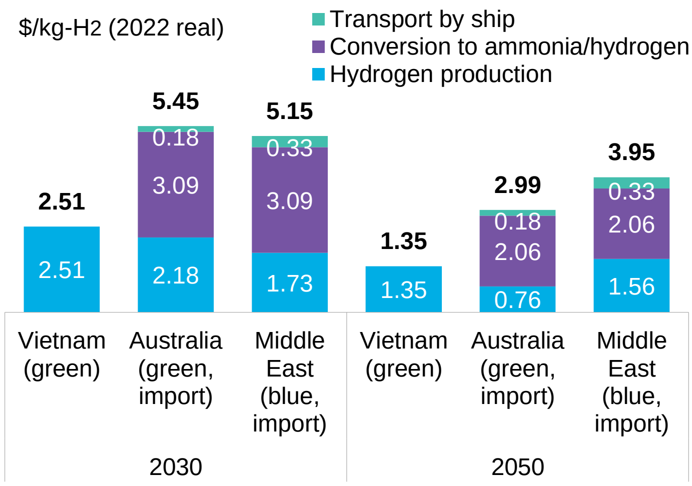
Green hydrogen produced in Vietnam is already the cheapest and continues to cost the least through to 2050 supported by cost-competitive renewable electricity and the cost reduction of electrolyzers. By 2050, imported clean hydrogen from Australia and the Middle East would cost twice or three times more than green hydrogen in Vietnam.

Figure 35: Production cost of hydrogen delivered in Vietnam



Source: BloombergNEF

Figure 36: Cost of hydrogen supply relevant to Vietnam



Source: BloombergNEF

The biggest cost driver behind imported hydrogen is the conversion processes. In our analysis, we assume that hydrogen is exported to Vietnam from Australia or the Middle East in the form of ammonia as it is the most economical shipping option.[3] This requires ammonia synthesis using hydrogen. Once in Vietnam, ammonia must be converted back to hydrogen (and nitrogen) via thermolysis, the reverse of ammonia synthesis. These conversion processes are costly and increase the landed costs of imported hydrogen.

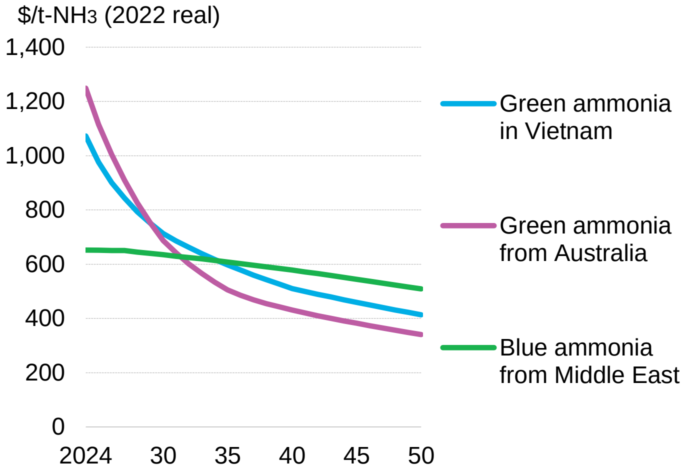
We have not considered the scenario of domestically produced blue hydrogen in Vietnam. Directly using CCS to capture emissions from thermal power plants would be cheaper than using CCS to capture emissions from the process of converting imported LNG or coal to hydrogen or ammonia, and then using that resulting blue hydrogen/ammonia in thermal power plants. Applying CCS directly to the thermal power plant is a more energy efficient process than using CCS for hydrogen production and then running thermal power plants on hydrogen or its derivative.

3 Liquid ammonia has a very high hydrogen density (107-121 kilograms of hydrogen per cubic meter) – higher than liquid hydrogen (at 70.8kg per cubic meter). In addition, ammonia can be shipped in a liquid form at -33C, which is technically more manageable than liquid hydrogen that needs to be chilled at -253C.

Blue ammonia from the Middle East becomes the most expensive by 2035

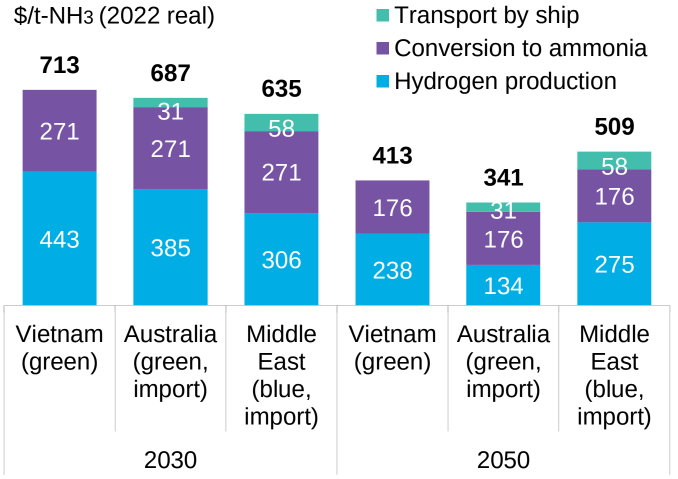
Local green ammonia in Vietnam would be the most expensive in the near term because of the comparatively higher cost of renewables in the country compared against gas prices in the Middle East (Figure 37 and Figure 38). Green ammonia imported from Australia would be cheaper than local green ammonia but would be costlier than blue ammonia imported from the Middle East. Production costs of imported green ammonia from Australia and local green ammonia in Vietnam should undercut the costs of blue ammonia from the Middle East in 2032 and 2035, respectively. From 2035, blue ammonia from the Middle East would be the costliest option. Blue ammonia (as well as blue hydrogen) has limited cost reduction potential because of constrained cost reductions of fossil fuels in the future.

Figure 37: Production cost of ammonia delivered to Vietnam



Source: BloombergNEF. Note: t-NH3 is metric ton of ammonia.

Figure 38: Cost of ammonia production relevant to Vietnam



Source: BloombergNEF. Note: t-NH3 is metric ton of ammonia.

Appendix D. Blended clean fuel prices

Hydrogen-gas blended fuel prices, by blending ratio

Figure 39: Blended fuel price for 25% hydrogen mix

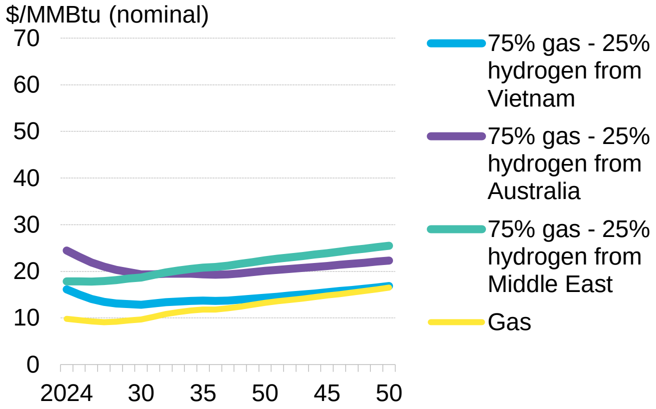
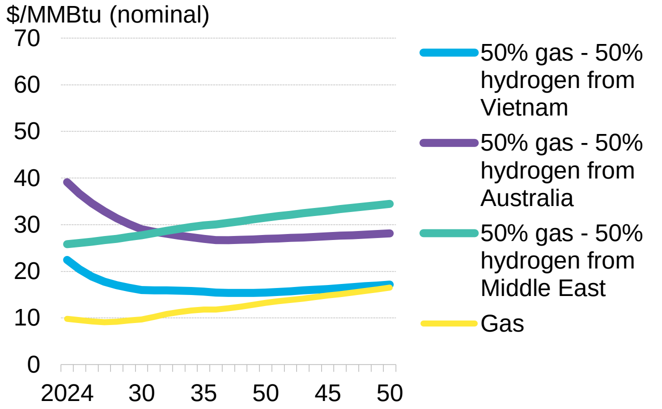


Figure 40: Blended fuel price for 50% hydrogen mix



Source: BloombergNEF. Note: Blending ratio based on energy content. MMBtu is million British thermal units.

Figure 41: Blended fuel price for 75% hydrogen mix

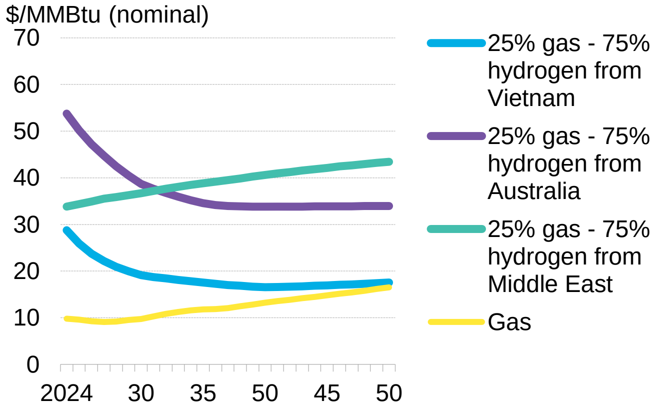
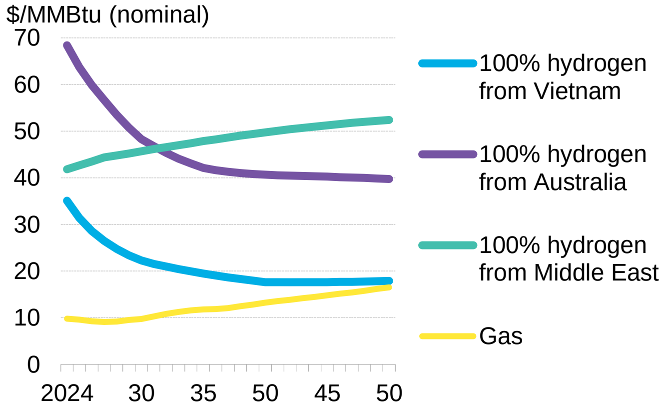


Figure 42: Blended fuel price for 100% hydrogen mix



Source: BloombergNEF. Note: Blending ratio based on energy content. MMBtu is million British thermal units.

Ammonia-coal blended fuel prices, by blending ratio

Figure 43: Blended fuel price for 25% ammonia mix

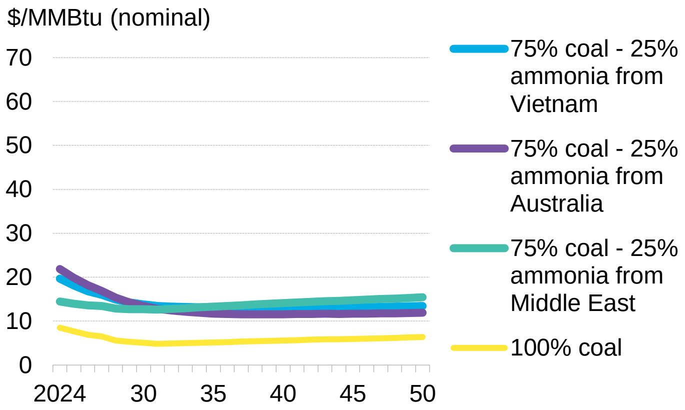
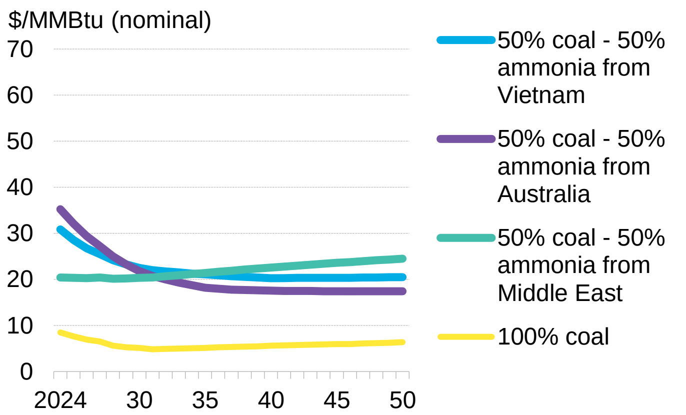


Figure 44: Blended fuel price for 50% ammonia mix



Source: BloombergNEF. Note: Blending ratio based on energy content. MMBtu is million British thermal units.

Figure 45: Blended fuel price for 75% ammonia mix

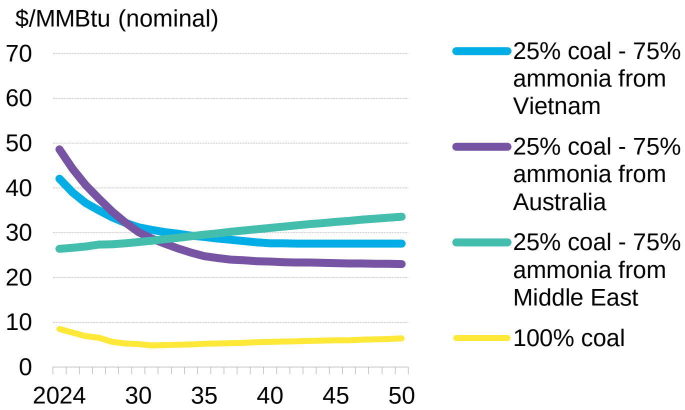
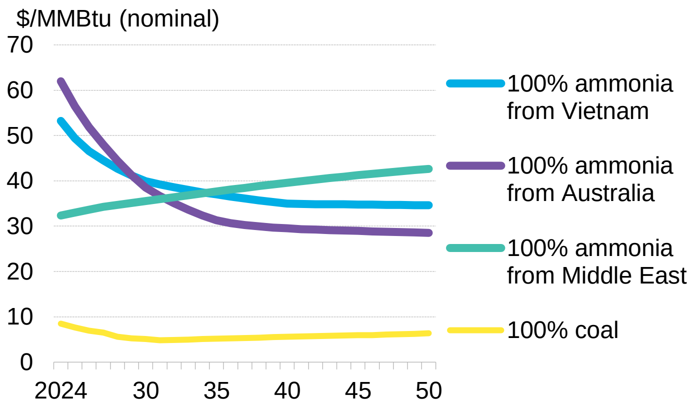


Figure 46: Blended fuel price for 100% ammonia mix

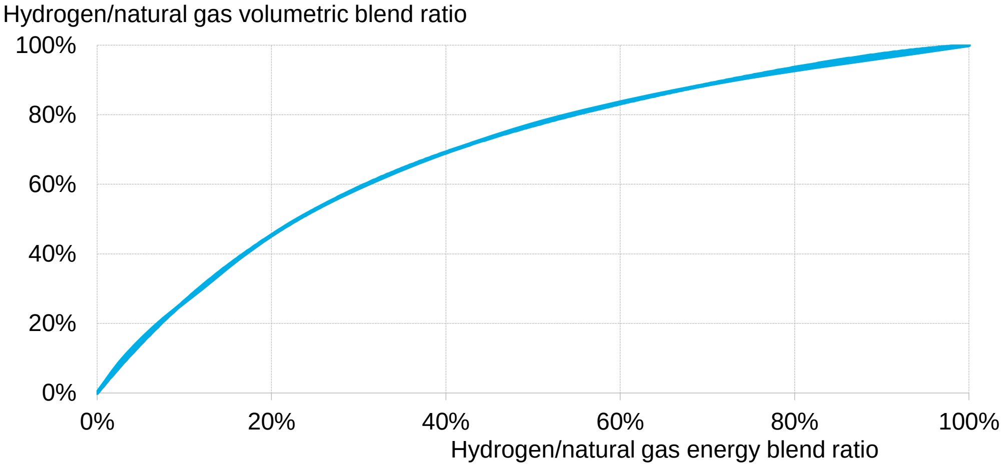


Source: BloombergNEF. Note: Blending ratio based on energy content. MMBtu is million British thermal units.

Energy density of hydrogen

As hydrogen has a lower volumetric energy density than natural gas, higher volumes of hydrogen than natural gas are required to achieve a similar energy blend ratio. As a result, to significantly reduce CCGT carbon dioxide emissions, higher volumes of hydrogen than natural gas would have to be consumed. Throughout this report, we use a blending ratio based on energy content.

Figure 47: Relationship between energy and volume for hydrogen blending



Source: BloombergNEF, GE Power to Gas: Hydrogen for Power Generation

Appendix E. Sensitivity analyses

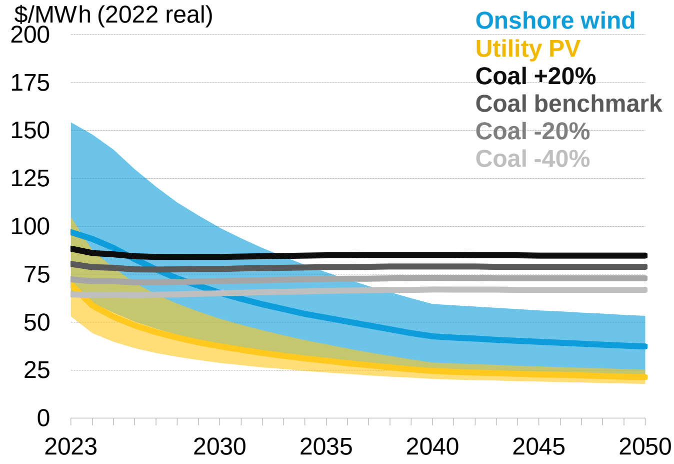
Depressed fuel costs are insufficient to compete with the cost evolution of a new solar PV and onshore wind plant

As the growth of cost-competitive renewables displaces coal and gas power generation, it is possible that less global demand could cut coal and gas prices, resulting in lower LCOEs and marginal running costs of the fossil fuel power plants. On the other hand, geopolitical tensions could raise fuel prices, increasing the LCOE further. To explore what the competitiveness landscape of the different power generation technologies would look like in such a scenario, the LCOE of a new coal and CCGT plant was calculated with the fuel cost set at a 20% premium to a discount of 40% against the benchmark case, which is covered in Section 3.1.

A 40% drop in seaborne thermal coal prices would lower the LCOE benchmark of a new coal plant by 15.8% on average throughout the forecast period (Figure 48). This would only delay the tipping point where a new utility-scale solar PV plant and a new onshore wind plant achieves cost parity with a new coal plant just marginally by two years for both technologies to 2025 and 2031, respectively.

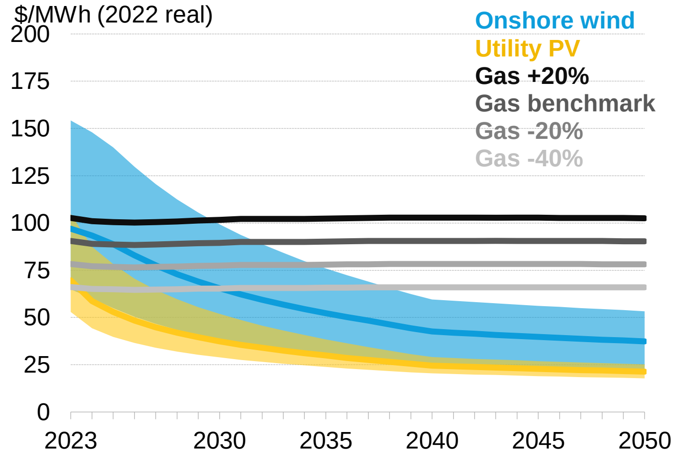
Reduced gas prices have a more significant impact on the LCOE of a new CCGT plant. The LCOE of a new CCGT plant could be reduced by an average of 27% against the benchmark case throughout the forecast period (Figure 49). Like the case of coal, this would only delay when a new utility-scale PV plant achieves cost-parity against a new CCGT plant by just two years to 2024. The lower fuel price helps a new CCGT plant remain cost competitive against a new onshore wind plant for slightly longer, delaying the cost-parity year by five years from 2026 to 2031 but it does not change the long-term cost dynamics.

Figure 48: Levelized cost of electricity of a new solar and onshore plant versus range of LCOE for a new coal plant in Vietnam



Source: BloombergNEF

Figure 49: Levelized cost of electricity of a new solar and onshore plant versus range of LCOE for a new gas plant in Vietnam

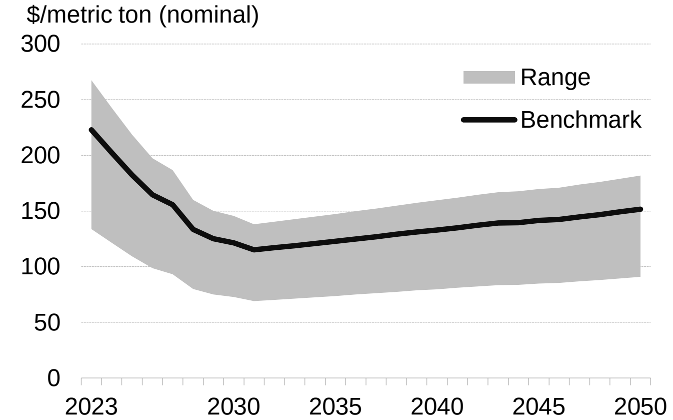


Source: BloombergNEF

Significant fuel price reduction would be needed to keep existing coal and gas plants competitive

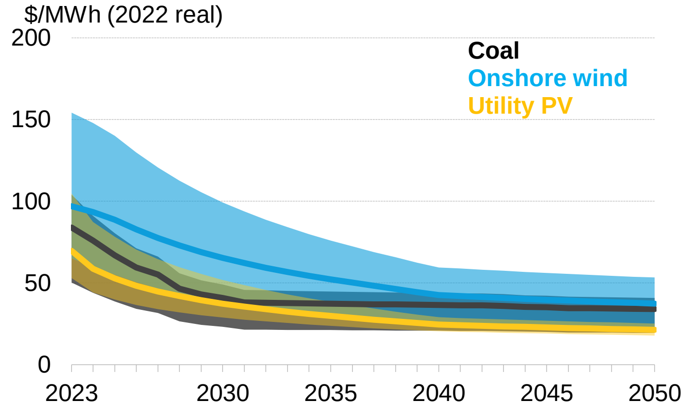
Due to the cost competitiveness of renewables, fossil fuel power plants could be stranded in the future as expensive power generation sources. Without significant fuel price reductions, thermal power plants wouldn't be economically viable in Vietnam's power system. For instance, the coal fuel price will have to drop by at least 35% (an average of $49.7/metric ton in nominal terms between 2023 and 2030) against our benchmark fuel price scenario to allow the SRMC of an existing coal plant to be cheaper than that of a new utility-scale PV plant.

Figure 50: Range of coal prices used for sensitivity analysis



Source: BloombergNEF. Note: Range of coal prices represents a 20% premium on the upper end and a 40% discount on the lower end against the benchmark price.

Figure 51: Levelized cost of electricity of a new solar photovoltaic and onshore wind plant versus short-run marginal cost of an existing coal plant in Vietnam

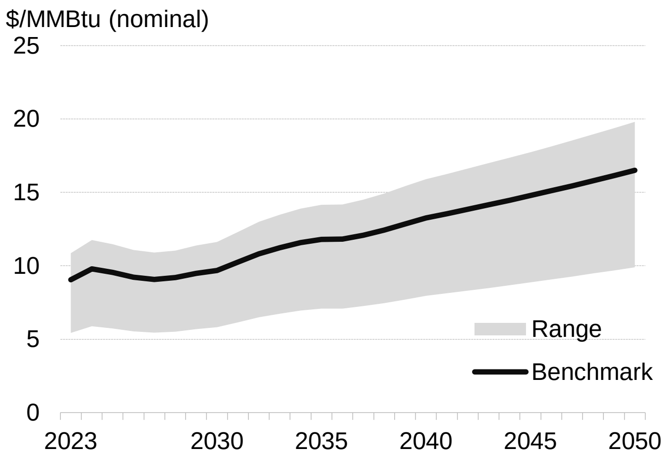


Source: BloombergNEF. Note: Range of coal LCOE represents a 20% premium on the upper end and a 40% discount on the lower end against the benchmark fuel price.

A new PV plant in Vietnam will undercut the SRMC of an existing CCGT plant even with a steep fuel cost reduction. A 40% reduction in fuel cost delays when a new utility-scale PV undercuts the marginal running cost of an existing CCGT plant by six years to 2029. To compete against a new onshore wind plant throughout the forecast duration of 2023 and 2025, an existing CCGT plant will need to run on fuel cost that is 49% below our benchmark case.

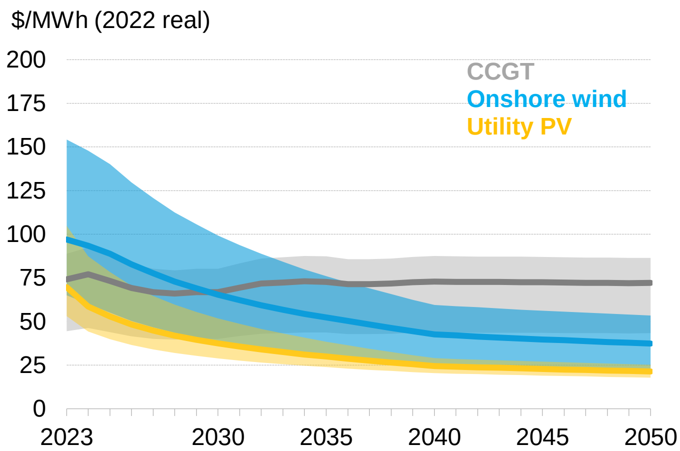
Other factors could also negate the effect of fuel price reduction such as higher-than-expected financing costs for fossil-fueled power assets or the introduction of a carbon price in Vietnam in the future.

Figure 52: Range of gas prices used for sensitivity analysis



Source: BloombergNEF. Note: MMBtu is million British thermal units. Range of gas prices represents a 20% premium on the upper end and a 40% discount on the lower end against the benchmark price.

Figure 53: Levelized cost of electricity of a new solar photovoltaic and onshore wind plant versus short-run marginal cost of an existing combined-cycle gas turbine plant in Vietnam



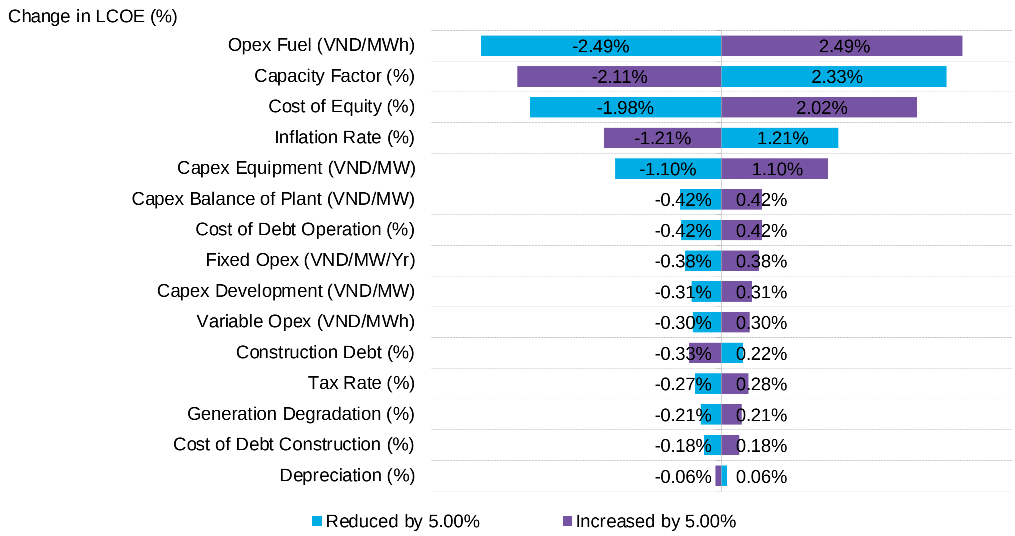
Source: BloombergNEF. Note: Range of CCGT LCOE represents a 20% premium on the upper end and a 40% discount on the lower end against the benchmark fuel price.

Changes in capacity factors to make the biggest impact on the LCOE

When considering the cost competitiveness of different power generating technologies, it is imperative to consider the potential realized capacity factor of each plant due to its significant contribution to the LCOE, especially that of a fossil fuel power plant, instead of the technical potential of the plant. It is also important the competition from increasing renewable energy penetration in the country's power mix.

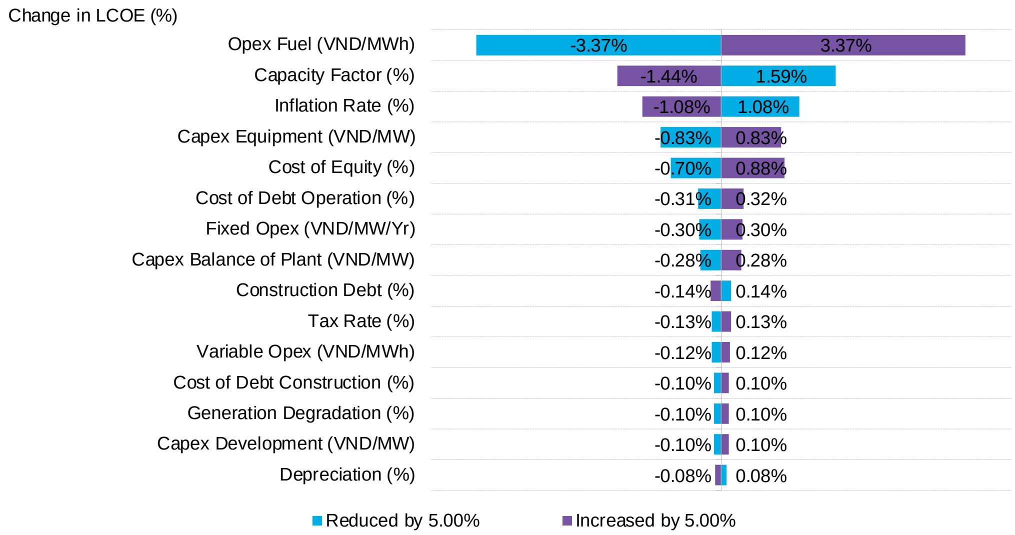
BNEF's analysis shows that capacity factor has a significant impact on the LCOEs of coal and CCGT plants. A 5% increase in the capacity factor lowers the LCOE of a coal plant by 2.11% while a 5% reduction in capacity factor results in a 2.33% rise in LCOE (Figure 54). For a CCGT plant, a 5% increase in the capacity factor lowers the LCOE by 1.44% while a 5% reduction in capacity factor results in a 1.49% rise in LCOE (Figure 55).

Figure 54: Sensitivity analysis of the levelized cost of electricity of a coal power plant in Vietnam



Source: BloombergNEF. Note: Chart shows the percentage impact on the LCOE of a coal plant in Vietnam with a +/-5% variance on each variable based on the benchmark cost scenario.

Figure 55: Sensitivity analysis of the levelized cost of electricity of a combined-cycle gas turbine power plant



Source: BloombergNEF. Note: Chart shows the percentage impact on the LCOE of a CCGT plant in Vietnam with a +/-5% variance on each variable based on the benchmark cost scenario.

The running hours of thermal power plants in Vietnam are already being squeezed by the increased grid penetration of renewables, in particular solar. In 2022, the capacity factors of the coal and gas power plant fleets in Vietnam were both 47% compared with pre-pandemic levels in 2019 of 64% and 66%, respectively. This is despite an 8% increase in total electricity generation in 2022 compared with 2019 levels. As Vietnam targets more solar and wind developments, thermal power plants will likely see their operational hours being limited further.

Vietnam's PPAs for coal and CCGT plants have often been structured with a capacity payment linked to a certain level of availability of the plant which EVN is obligated to pay regardless of offtake. This provides some level of revenue protection for project owners. However, securing further coal and gas power supply on the same structure will increase the financial burden on the state utility as it pays for unused thermal power capacity, likely leading to a need to raise power tariffs to recover costs.

Increasing financing costs further threatens the economics of a new coal or gas plant

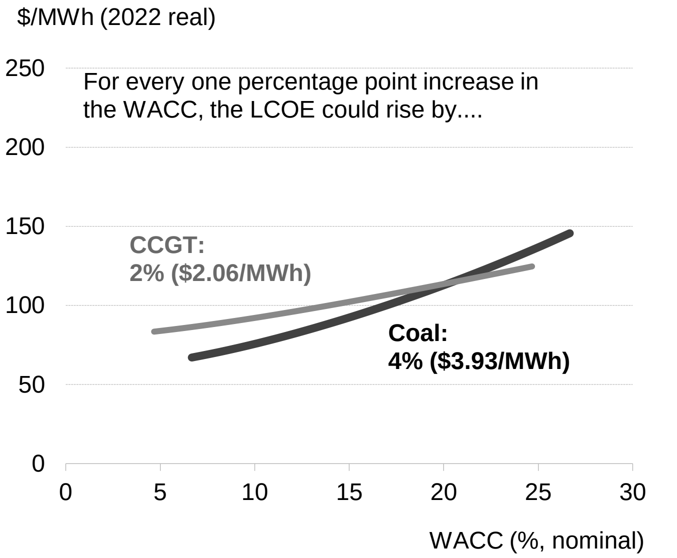
The global turn away from fossil fuel assets, especially coal, has seen the widespread fleeing of capital from new coal facilities and increasingly gas power plants. The growing reluctance to invest in fossil fuel power plants is likely to lead to an increase in debt costs for new projects.

BNEF analysis suggests that a one percentage point increase in the weighted average cost of capital (WACC)[4] will drive up the LCOE of a new coal plant commissioning in 2035 by about $3.93/MWh (equivalent to a 4% rise). For a new CCGT plant coming online in the same year, the LCOE rises by $2.06/MWh (a 2% increase). In addition to higher financing costs, coal and CCGT plants could face increasingly challenging financing conditions such as lower debt-to-equity ratio and shorter loan tenors that would add further pressure on costs.

A new utility-scale PV and PV-plus-storage plant sees LCOE increase by $2.09/MW (a 5.1% rise) and $4.12/MWh (up 5.1%), respectively, with a one percentage point rise in WACC – lower than the LCOE increase for coal in absolute values. An increase in capital costs also has quite a significant impact on a new onshore wind and onshore wind-plus-storage plant. A one percentage point increase in WACC translates to an increase of $3.76/MWh (equivalent to a 5.2% rise) and $7.61/MWh (or a 5.8% increase).

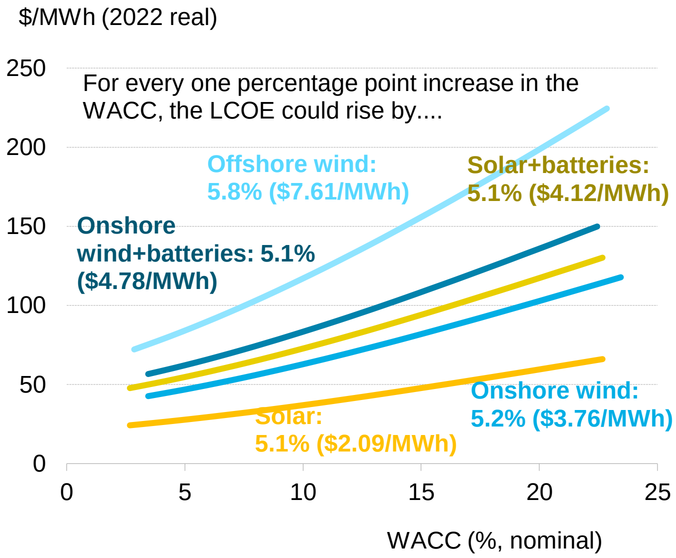
[4] A new coal power plant financed today currently has a WACC of 7.75%.

Figure 56: Levelized cost of electricity of a new coal and gas plant with varying cost of capital in Vietnam



Source: BloombergNEF. Note: WACC is the weighted average cost of capital. Chart shows the LCOE for a power plant commissioned in 2035.

Figure 57: Levelized cost of electricity of renewable plants with varying cost of capital in Vietnam



Source: BloombergNEF. Note: WACC is the weighted average cost of capital. Storage cost is based on a four-hour battery storage system. Chart shows the LCOE for a power plant commissioned in 2035.

Appendix F. Technology factsheets

To mitigate climate change, an immediate reduction in greenhouse emissions is necessary.

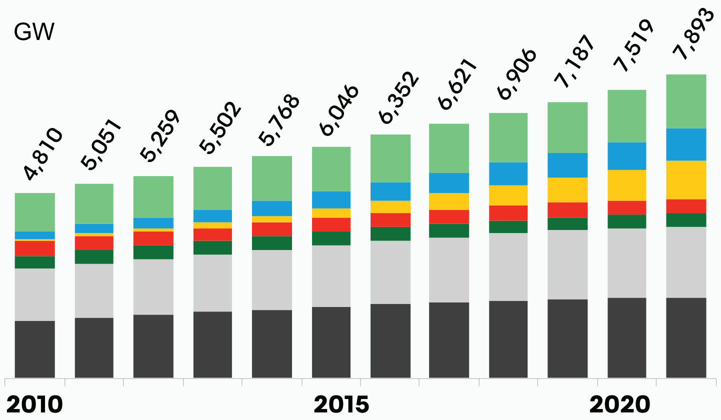
Electricity generation is the single largest source of emissions due to heavy reliance on fossil fuels.

The decline in the cost of solar and wind technologies means they are now the cheapest source of electricity generation in most countries.

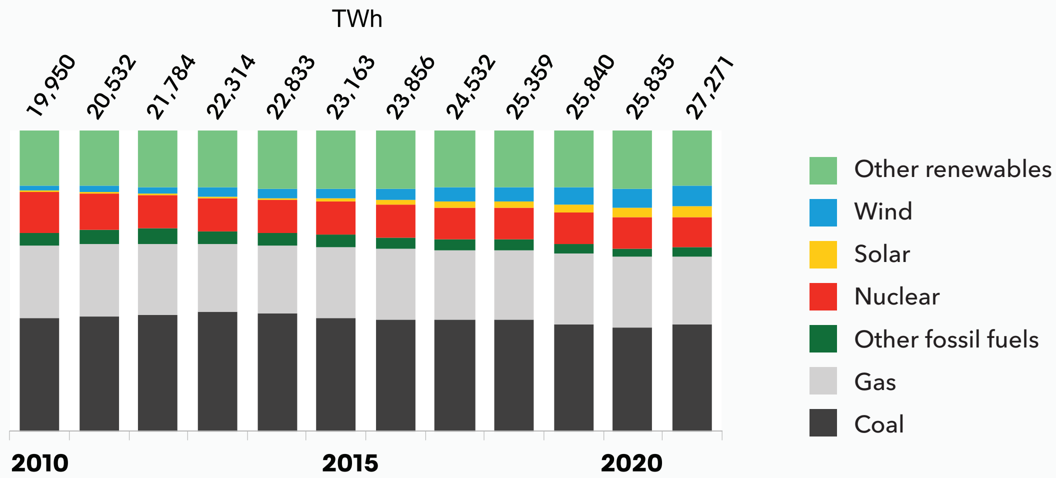
Power sector transition

Coal and gas power plants have historically dominated power generation. However, the share of solar and wind are growing thanks to their cheaper costs and supportive policies.

Global installed power generation capacity



Global generation mix

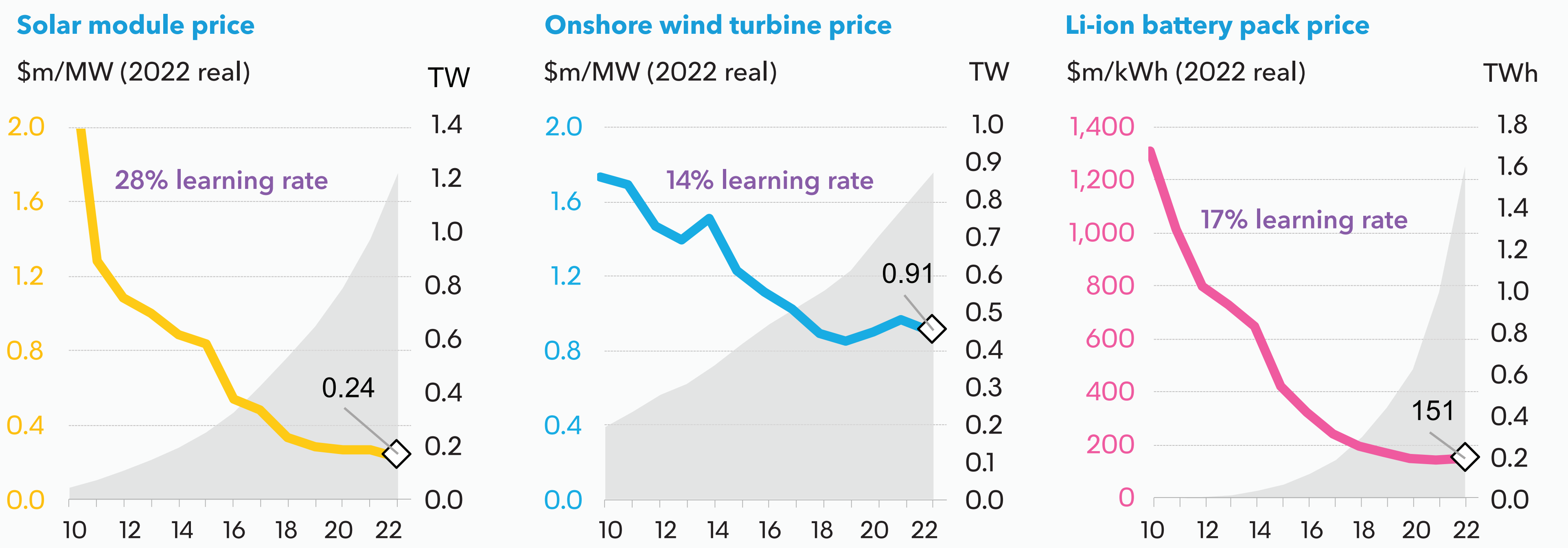


Source: BloombergNEF.

BloombergNEF

Power sector transition

Utility scale solar or onshore wind are now the cheapest sources of bulk electricity generation in countries accounting for 82% of global electricity generation. The scale-up in manufacturing and deployment of renewables, coupled with technology improvements, has resulted in significant cost reduction.



Source: *BloombergNEF.*

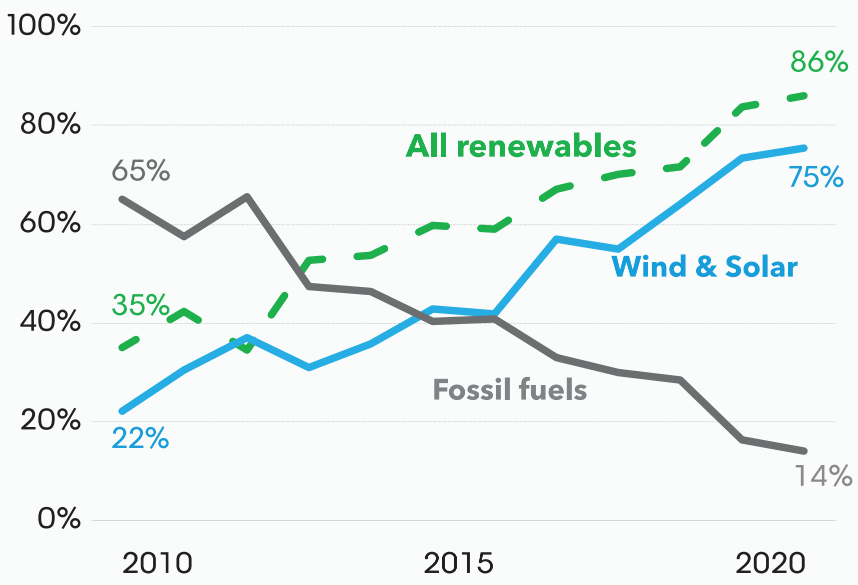
Note: Gray area shows the cumulative global installed capacity of each technology.

BloombergNEF

Power sector transition

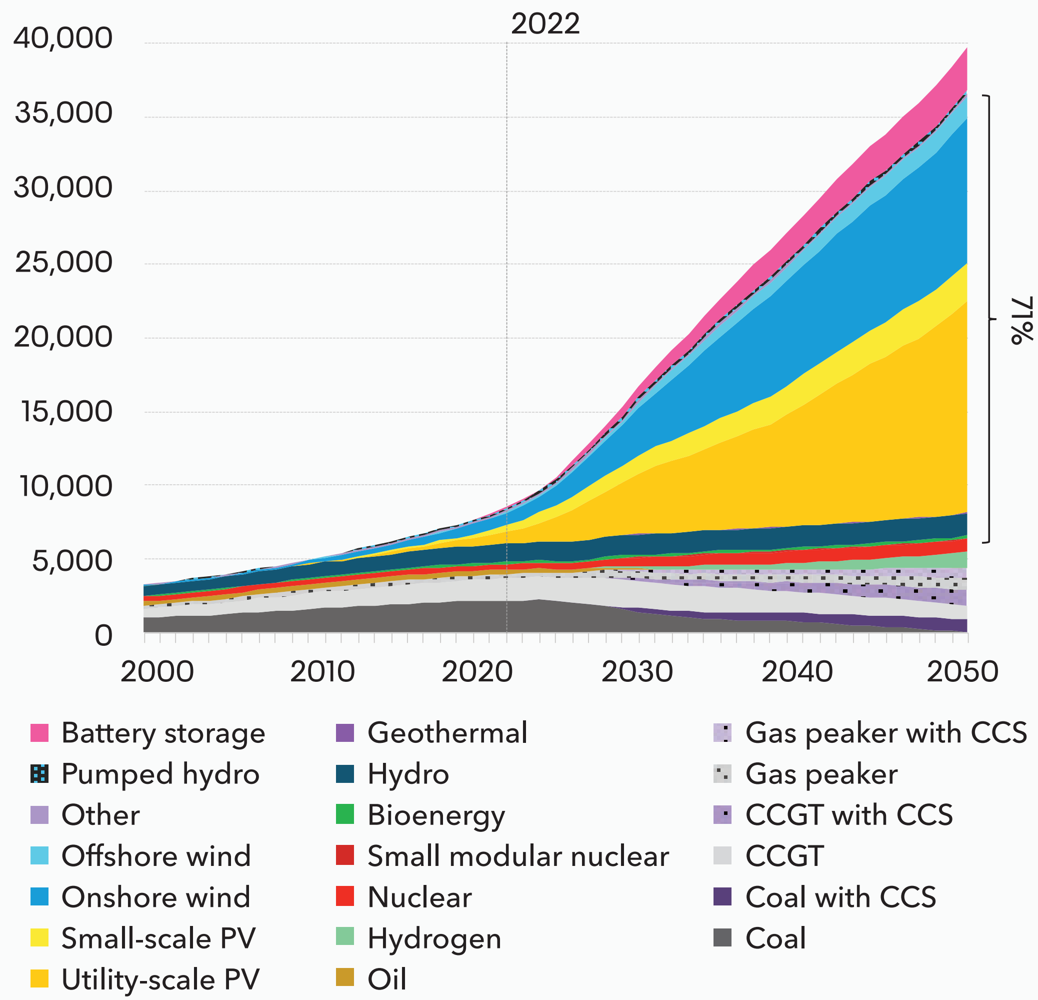
Solar and wind capacity additions exceeded 50% of annual global net capacity additions in 2017. Under BNEF's Net Zero Scenario, solar and wind would account for 71% of global power capacity in 2050.

Global share of net capacity addition by technology



Source: BloombergNEF

Global power capacity, Net Zero Scenario



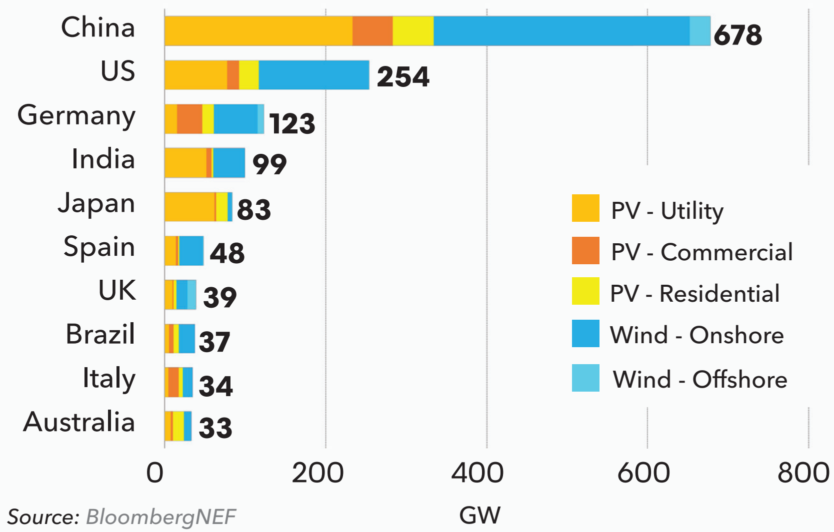
Source: BloombergNEF New Energy Outlook 2022

BloombergNEF

System integration of solar and wind

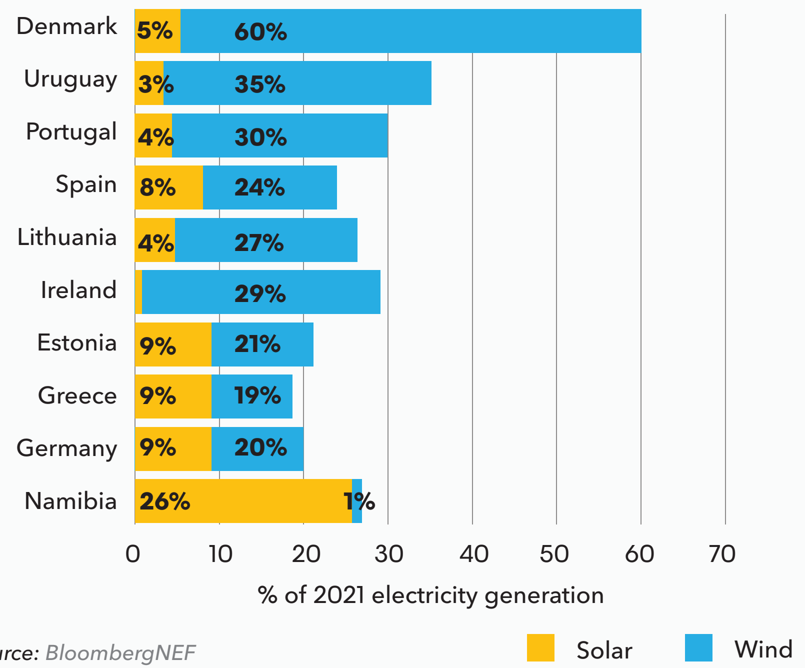
The variability of solar and wind electricity generation often raises operational concerns, as most power markets have been organized around dispatchable thermal power plants. However, as system flexibility becomes a defining characteristic of power systems operations, software and hardware solutions already exist to integrate renewables.

Top-10 countries with the highest installed wind and solar capacity in 2021



Source: BloombergNEF

Top-10 countries with highest wind and solar annual generation share, 2021

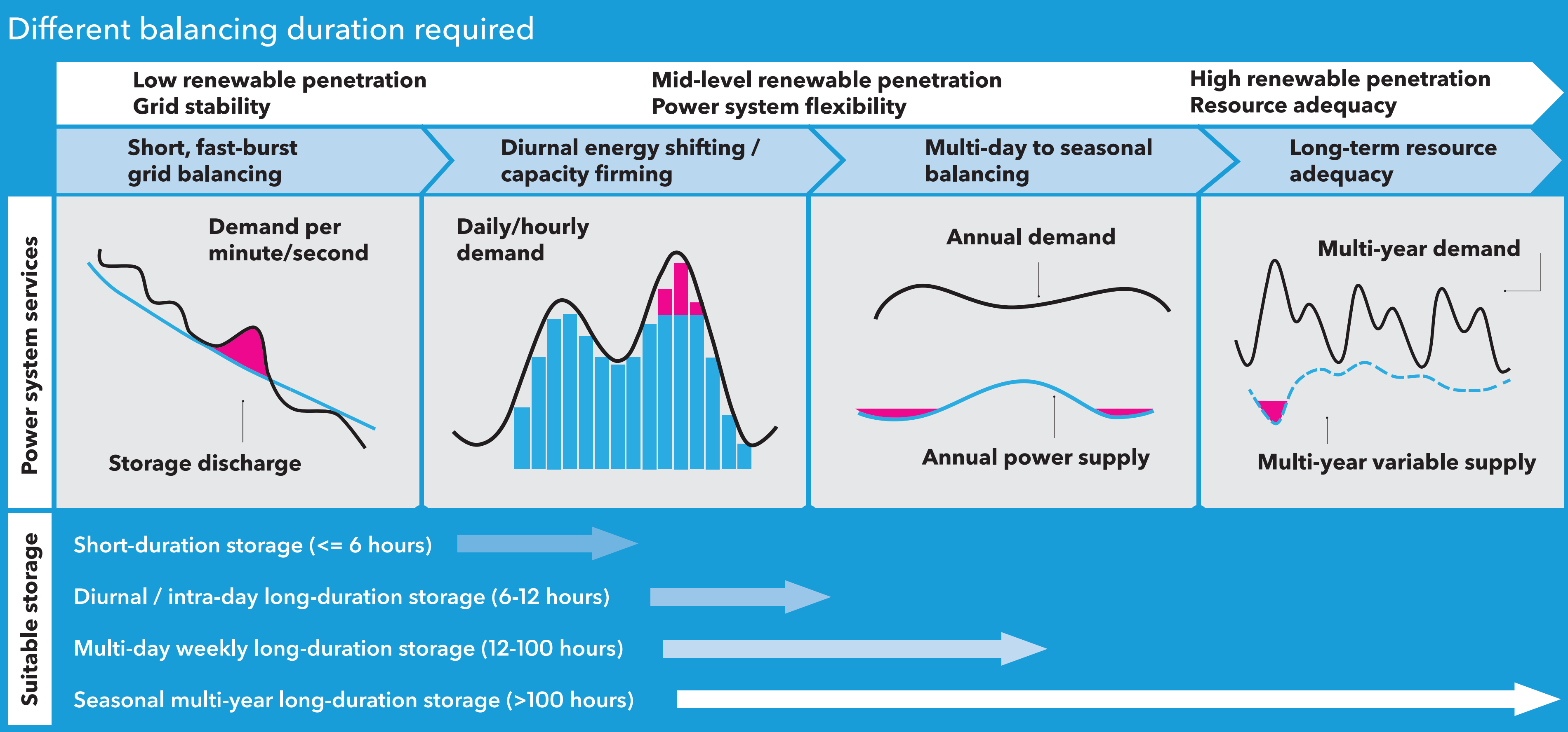


Source: BloombergNEF

Solar and wind already contribute more than a quarter of annual electricity generation in a variety of countries.

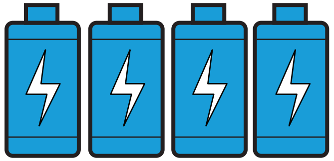
BloombergNEF

System integration of solar and wind



Source: BloombergNEF

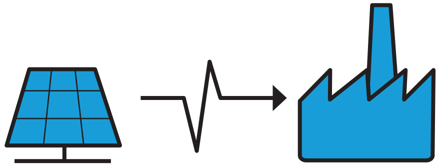
System integration of solar and wind



Batteries

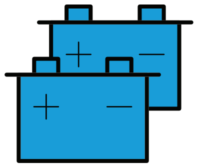
The fast response ability of batteries – in particular lithium-ion batteries – makes them well-suited to smooth the variability of wind and solar. These include applications such as frequency control as well as hourly energy shifting. By the end of 2022, BloombergNEF estimates that over 16GW/35GWh of energy storage systems were using batteries globally.

Batteries can store excess electricity generation from renewables during times of low demand and/or high local grid congestion, and then discharge the stored electricity during times of higher demand and/or lower grid congestion. In this manner, they help system operators and renewable project owners by reducing the need for curtailment, while reducing overall electricity system costs by improving grid utilization.



Supply and demand side management

Variable renewable generation, while variable, is not unpredictable. The deployment of load and generation forecasting tools can help reduce the uncertainty from variable renewable energy generation and aid in grid operations. Use of controllable load assets such as virtual power plants, demand response and interruptible load schemes can help stabilize the grid and provide additional flexibility.



Long-duration energy storage systems

High penetration of renewables calls for flexibility sources over different timescales, from milliseconds to multi-year capacity. Compared to short-duration batteries, long-duration energy storage systems such as pumped hydro and compressed air storage can provide a wider suite of grid services.

Most of the technologies are, however, still much more expensive than lithium-ion batteries and may struggle with low economic viability today.

Technology options to reduce emissions from thermal generation

In the power sector, the most direct and cost-efficient way to mitigate emissions is through the scaling up of renewable energy, a solution that can be deployed now.

What is co-firing or blending of fuels?

Coal power plant

Co-firing of coal with cleaner alternative fuels refers to the replacement of a portion of the coal used for power generation with ammonia or biomass.

Gas power plant

Blending of hydrogen involves the injection of hydrogen into the natural gas fed to the gas turbine.

At low levels of co-firing or blending, limited modifications to the existing thermal power plant are required. However, at such low levels, there is minimal emission reduction.

Co-firing coal with ammonia or biomass and the blending of hydrogen with natural gas can be discussed in terms of a volume ratio or energy ratio. Each fuel has a different volumetric energy density. The cleaner fuels (hydrogen, ammonia and biomass) all have lower volumetric energy densities than fossil fuels. As a result, a higher volume of cleaner fuels is needed to replace the same amount of energy produced by consuming fossil fuels.

During electricity generation, the average emission factor for a coal power plant is around 0.9 tCO_2/MWh, whereas the average emission factor for a combined cycle gas turbine (CCGT) is around 0.4 tCO_2/MWh. For the coal power plant to achieve a lower emission factor than the CCGT, it would have to co-fire ammonia with coal at an energy content ratio higher than 50% (or about 80% volumetric blend ratio).

During electricity generation, renewables have zero emissions, making them the best choice for lowering power sector emissions.

Some countries and companies are considering reducing emissions from fossil-fueled thermal power plants by switching to non-carbon fuels such as hydrogen and/or installing carbon capture and storage (CCS).

These strategies are dependent on the commercial scale-up of complex nascent technologies, and the establishment of new global supply chains.

These strategies would also have to compete for carbon storage capacity and clean fuels with other applications such as aviation and shipping, which have fewer alternative pathways to decarbonization.

Technology options to reduce emissions from thermal generation

Options

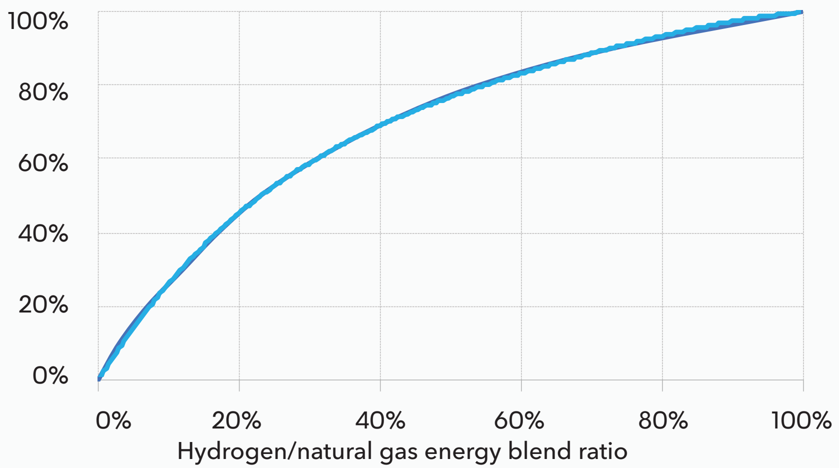
Co-firing coal with ammonia (NH3)

Blending gas with hydrogen (H2)

Co-firing coal with biomass

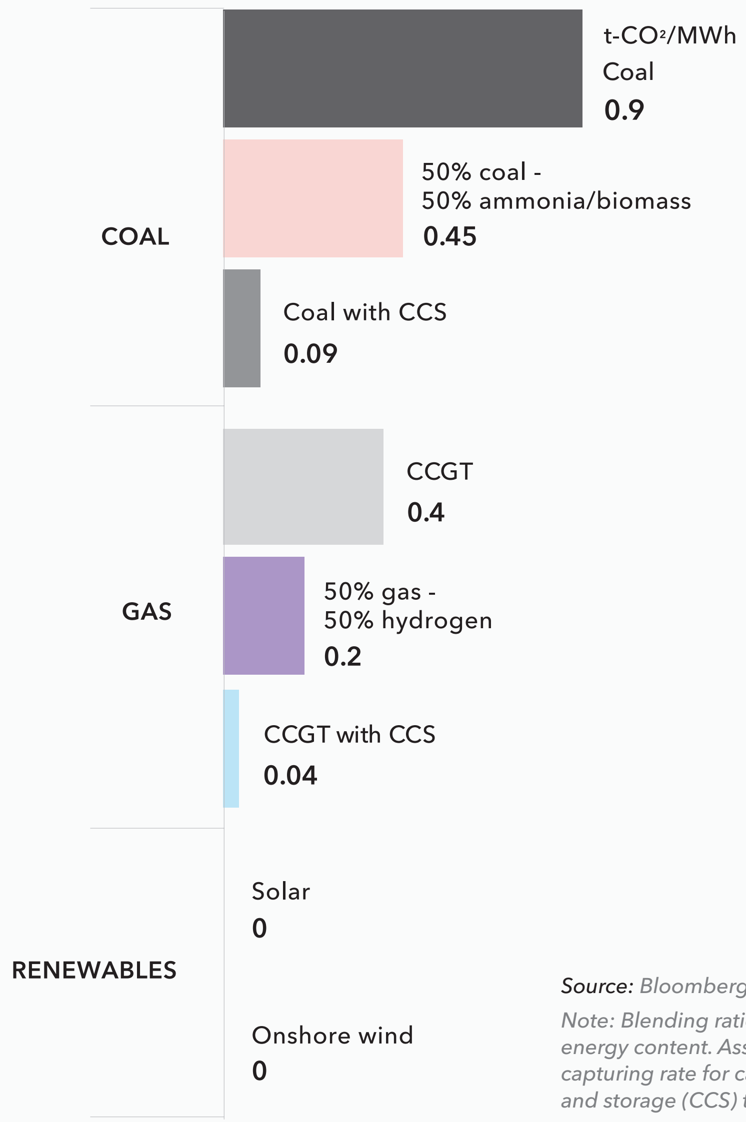
Carbon capture and storage (CCS)

Relationship between energy and volume for hydrogen blending



Source: *BloombergNEF, GE Power to Gas: Hydrogen for Power Generation*

Average emissions intensity of various power generation technologies during operation



Source: BloombergNEF.
Note: Blending ratio is based on energy content. Assuming 90% capturing rate for carbon capture and storage (CCS) technologies.

BloombergNEF

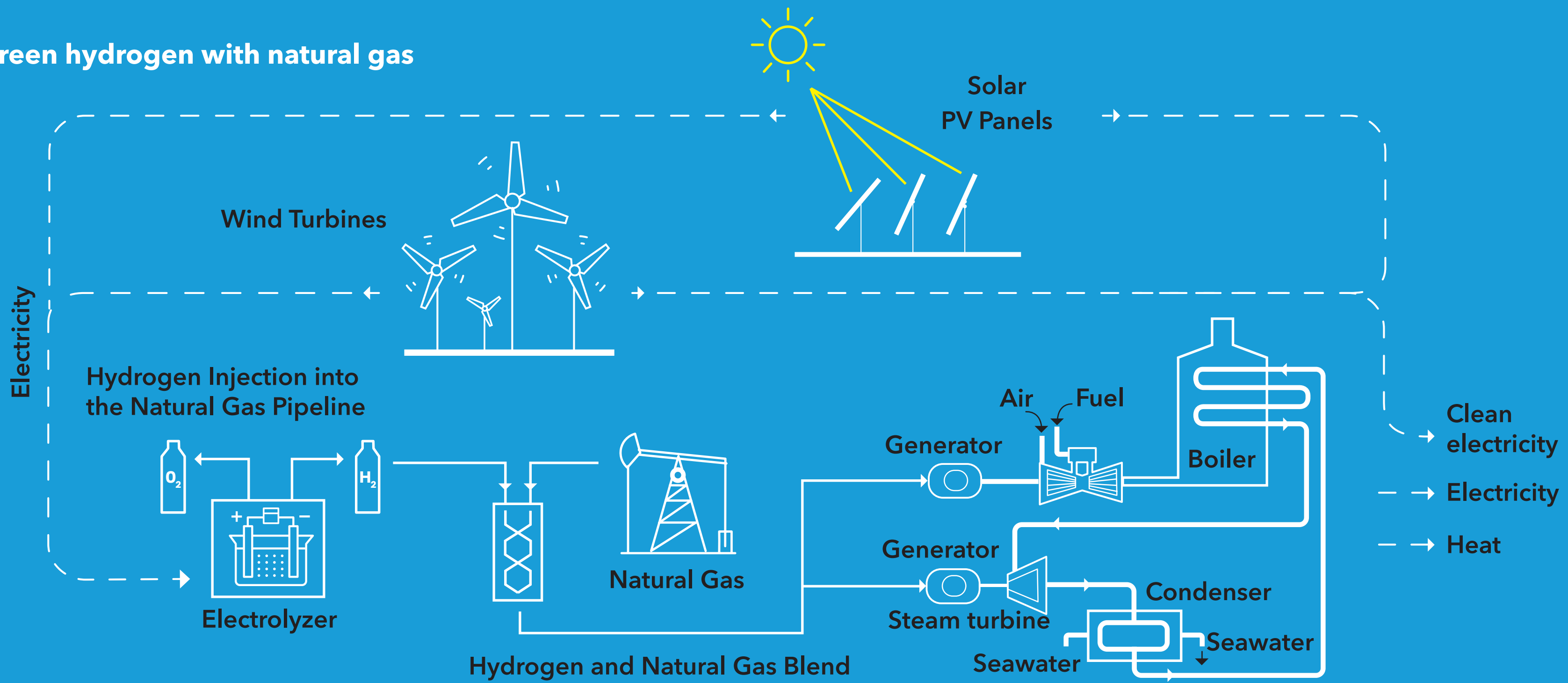
Retrofitting gas power plants for hydrogen

Blending hydrogen with natural gas as a lower carbon fuel for combined cycle gas turbines (CCGT) is under consideration by some countries and companies. To achieve zero-emission, the CCGT would need to be capable of handling 100% hydrogen fuel.

The hydrogen fuel would also have to be produced in an emission-free manner. Hydrogen leakage during the production, transport and consumption would also have to be minimized, as hydrogen is an indirect greenhouse gas, with significantly higher global warming potential than carbon dioxide.

Significant investment would be required to retrofit existing CCGTs to make them compatible with high concentrations of hydrogen fuel. Additionally, the production, transport and storage of clean hydrogen would require significant new investment.

Blending of green hydrogen with natural gas



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Retrofitting gas power plants for hydrogen

Hydrogen labeling

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. Large volumes of CO_2 are released.

Where can hydrogen be more suitable for decarbonization?

Decarbonization of ammonia production
Production of green ammonia from clean hydrogen can be used to decarbonize the production of fertilizers and the agriculture sector, as well as decouple fertilizer prices from natural gas prices.

Decarbonization of hard-to-abate sectors
Clean hydrogen could be deployed in heavy industrial sectors where direct electrification is challenging or impossible, such as methanol production, steel and aluminum production, shipping and aviation as well as providing peaking power.

Risks and considerations for blending hydrogen with natural gas

Fuel and infrastructure cost
Seaborne transport of hydrogen will be significantly more expensive than LNG, regardless of type of hydrogen carrier used. The process would also require new shipping infrastructure.

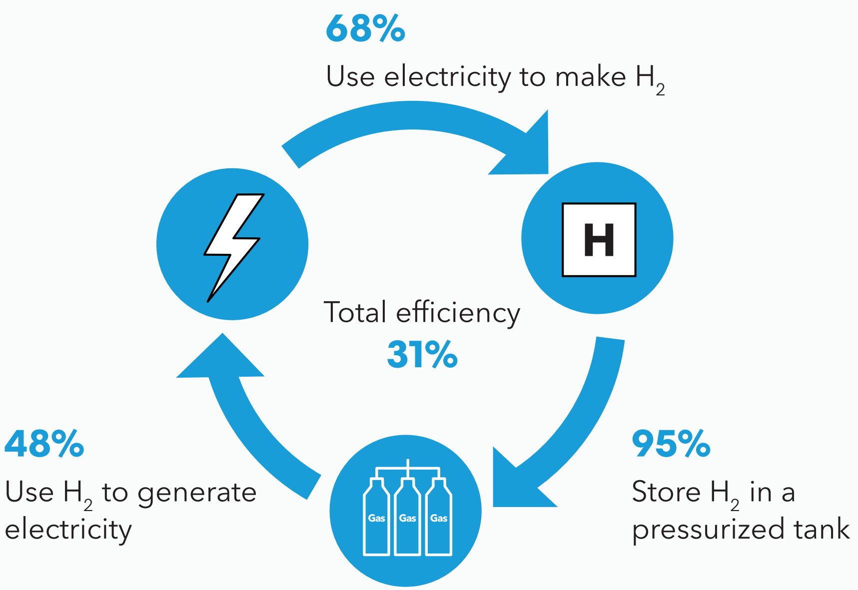
Impact on power tariffs
The higher fuel costs would lead to higher power tariffs, risking energy affordability especially in emerging economies.

Emissions reduction benefit
Due to the lower volumetric energy density of hydrogen, tangible emissions reduction is only possible at blending ratios above 50% even for green or blue hydrogen. This necessitates procurement of a large volume of hydrogen which will be costly. Additionally, CCGTs running on high hydrogen blend rates are still in the development phase.

Safety
Similar to natural gas, hydrogen is also highly flammable. Due to its smaller molecular size, lack of odor and color, detecting hydrogen leaks can be more difficult. Due to hydrogen embrittlement, much of the existing natural gas pipeline infrastructure cannot be used for high concentrations of hydrogen.

Retrofitting gas power plants for hydrogen

Round-trip efficiency of electrical storage via hydrogen



Source: BloombergNEF.

Generating electricity from hydrogen is less efficient than using electricity from renewable energy power plants directly.

The low round-trip efficiency of using clean power to first produce hydrogen, and then use the hydrogen in a CCGT to produce electricity, means such an approach is not economically viable.

For the same amount of power generation, 3-5 times the solar capacity is needed to produce the required hydrogen as compared to direct use of the renewable electricity.

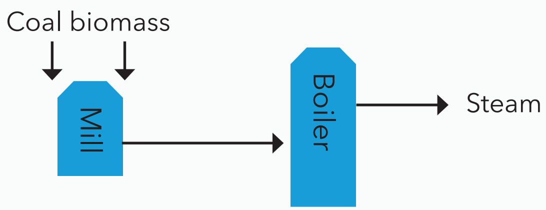
Using a limited quantity of clean hydrogen to fuel open cycle gas turbines providing back-up services in a renewable-heavy grid may become economically viable in the future. However, the high volume of fuel that CCGTs consume means using clean hydrogen to decarbonize 'baseload' power plants will not become economic.

Retrofitting coal power plants for co-firing

Co-firing of coal with biomass

Co-firing of coal with biomass involves a partial substitution of the coal used for power generation with biomass through direct co-firing, or gasification of biomass or parallel co-firing. Biomass co-firing has been widely deployed in many markets including the US and Europe. The substitution with biomass reduces greenhouse gas emissions compared to pure coal-fired power generation.

Direct co-firing

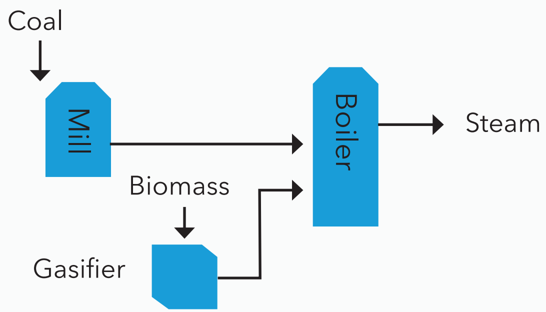


Biomass is processed (if required), mixed with coal and fed directly into the boiler.

This requires the fewest modifications. At low levels of blending, only a small upgrade such as a new covered silo storing feedstock is needed.

Direct co-firing of coal with biomass, however, could lead to slagging and fouling due to ash production, resulting in a limitation in the range of co-firing proportions.

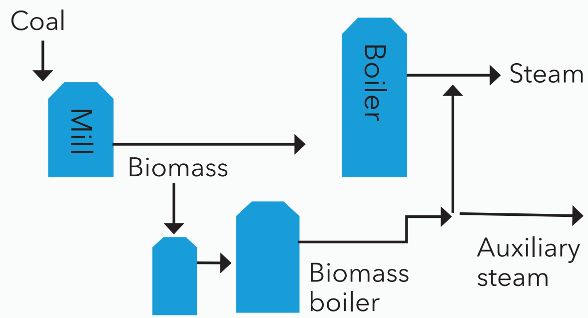
Gasification of biomass



Solid biomass is converted into synthesis gas in a gasifier, which is then injected into the boiler to be used for power generation.

This reduces the slagging as biomass is not fed directly into the boiler. However, a separate gasifier is required to be installed, increasing retrofit costs.

Parallel co-firing



Biomass is processed and combusted in a separate boiler to produce steam, which is then used for electricity generation in the coal power plant.

This technology could achieve higher co-firing ranges but will be the costliest due to the need for additional infrastructure builds. The feasibility of the retrofit will also be subject to the existing site's design.

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Retrofitting coal power plants for co-firing

Risks and considerations

Suitability of biomass feed-stock

The type of suitable biomass and processing required on the feedstock (e.g. particle size) will vary by the coal combustion technology of the power plant.

Sustainability considerations

Biomass is often considered emissions-neutral. There is, however, rising scrutiny on the quality of biomass fuel supply, including the sustainability and environmental aspects of the biomass fuel sources, including deforestation concerns.

Logistics

Economic feasibility of co-firing of coal with biomass can vary by project and its location. The lower energy density of biomass by volume compared to fossil fuels results in higher logistical costs.

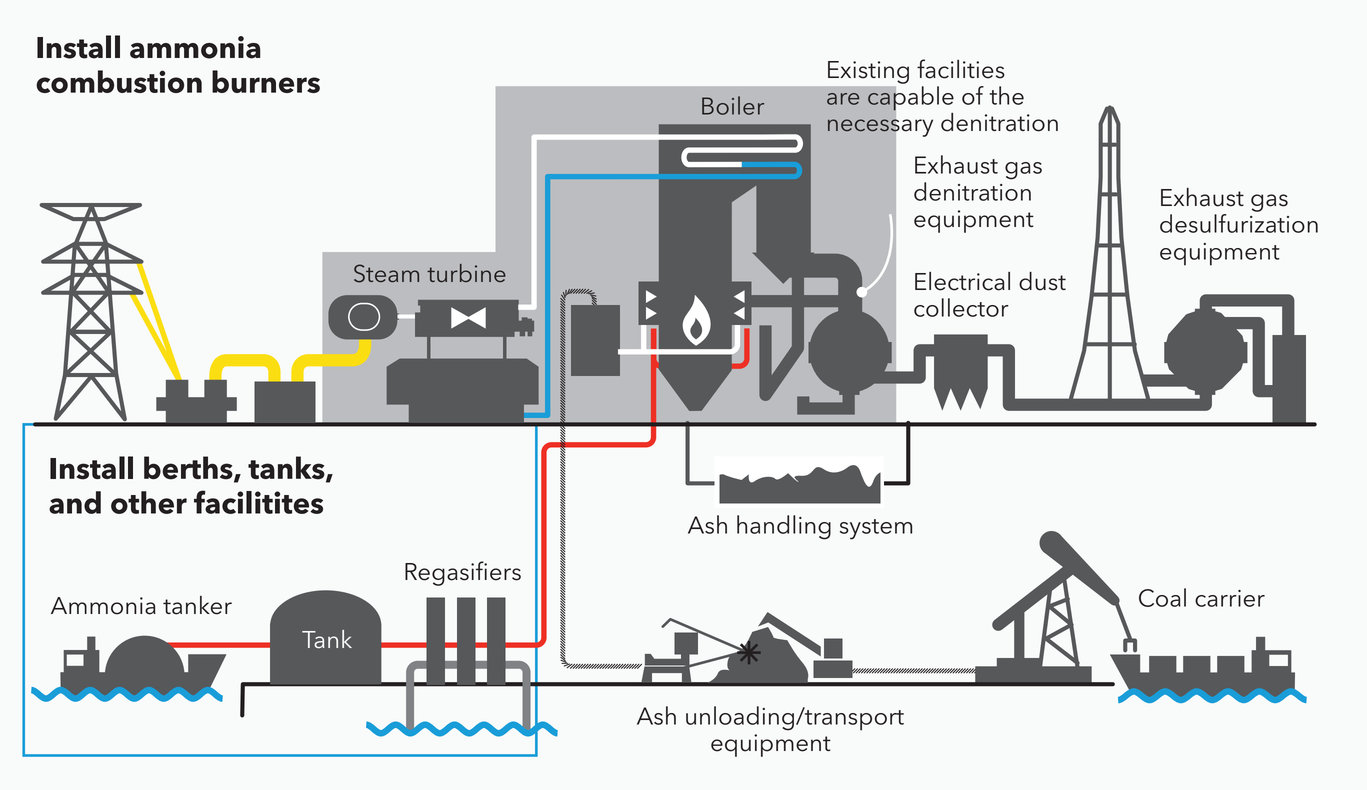
Co-firing of coal with ammonia

Co-firing of coal with ammonia refers to the partial substitution of the coal used for power generation with ammonia. To date, commercial coal power plants have not yet been tested for co-firing with ammonia at energy ratios above 20%.

A higher ammonia co-firing ratio requires higher capital expenditures for upgrading for the coal plant's boilers, as well as onsite storage of ammonia and more advanced equipment to capture nitrogen oxide emissions.

Ammonia is often referred to as a "low-carbon" fuel as it produces no carbon emissions during combustion. The actual emissions reduction benefit from co-firing coal with ammonia is dependent on the type and production source of the ammonia.

Gray ammonia derived from hydrogen produced from unabated fossil fuels will only reduce emissions slightly, even at a 100% co-firing ratio. The technology is also often criticized as a lifetime extension for coal power plants.



Retrofitting coal power plants for co-firing

Ammonia labeling

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
Derived from hydrogen produced via electrolysis of water using renewable electricity.

BLUE
Derived from hydrogen produced via steam reforming of methane or gasification of coal coupled with carbon capture and storage (CCS).

GRAY
Derived from hydrogen produced via steam reforming of methane or gasification of coal without CCS – the most common method today that releases large volumes of carbon emissions.

Where could ammonia be more suitable for decarbonization?

Displacement of fossil-fueled based ammonia

Ammonia is the foundational compound for fertilizers, which make mass food production possible. Worldwide, 81% of ammonia produced is used for this purpose, while the rest is used for industrial processes. Green ammonia can be used to decarbonize the production of fertilizers and the agriculture sector, and decouple fertilizer prices from natural gas prices.

Decarbonization of hard-to-abate sectors

Ammonia could be deployed in heavy industrial sectors where direct electrification is challenging or impossible, such as shipping and aviation.

Risks and considerations for co-firing of coal with ammonia

Fuel cost

BNEF's current analysis suggests that the blended fuel costs of coal and ammonia are more costly than the coal fuel price even at low levels of co-firing ratios. For imports of ammonia, logistical costs (shipping, storage and conversion costs) have a great impact on the final delivered costs. Currently, these costs could more than double the final landed cost of ammonia compared to the production costs of hydrogen.

Impact on power tariffs

The higher fuel costs would lead to higher power tariffs, risking energy affordability especially in emerging economies.

Emissions reduction benefit

Due to the lower volumetric energy density of ammonia, tangible emissions reduction is only possible at co-firing ratios above 50% even for green and blue ammonia. This necessitates procurement of a large volume of ammonia, which will be costly.

Safety

Ammonia is highly flammable and explosive with heat. The toxicity of ammonia necessitates careful storage of the fuel as the molecules could pose a big threat to human health. The molecule reacts with water to form ammonium hydroxide, which is corrosive and damages cells in the body on contact. While ammonia leaks are easier to detect due to its odor, contact with ammonia could be fatal.

Carbon capture and storage

Retrofitting an existing thermal power plant with CCS can be costly depending on proximity to carbon storage site. Current CCS technologies also do not capture 100% of emissions.

Considerations for carbon capture and storage

Technical feasibility

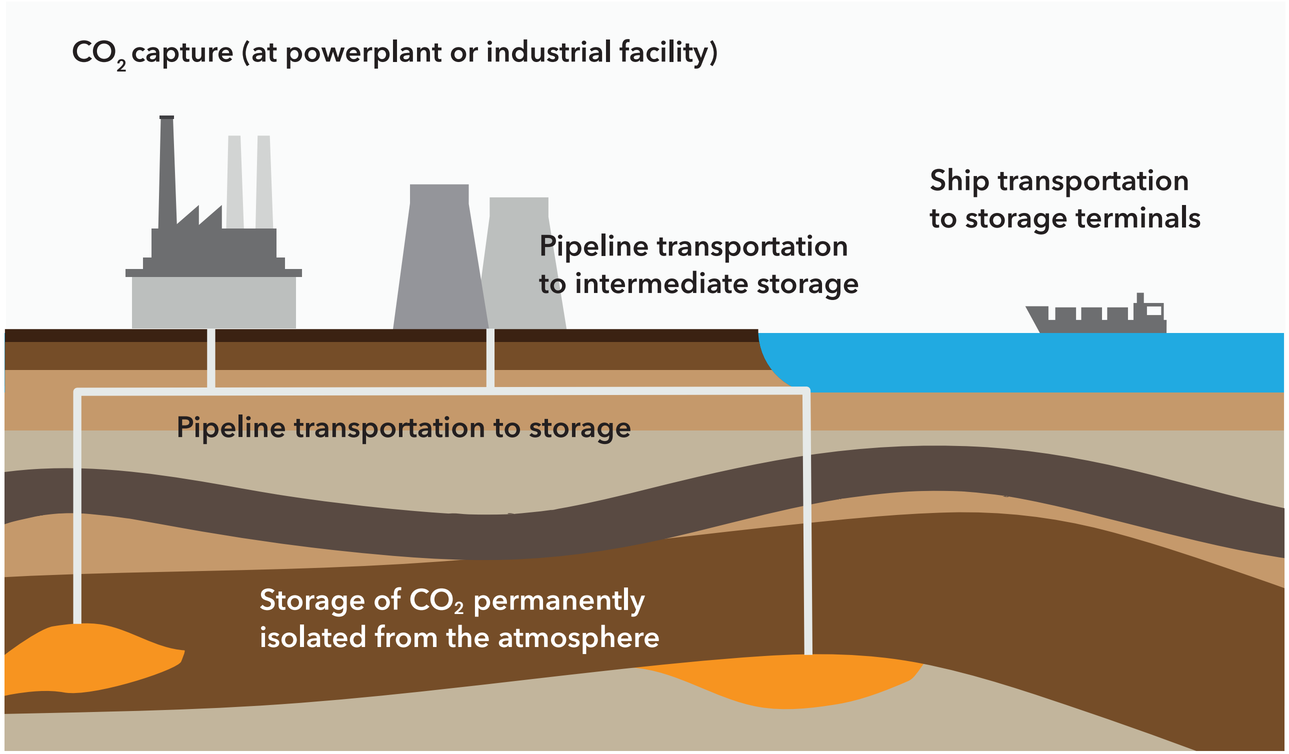
The original site of an existing thermal power plant would have been designed to meet the initial design specifications. There could be technical and logistical complexity of adding an additional system to the site. Not every thermal power plant can be economically retrofitted with CCS due to these constraints.

Availability of carbon storage sites

Implementation of the technology requires the availability of carbon storage sites such as depleted oil and gas fields or saline aquifers at appropriate depths.

Performance

A carbon capture and storage project typically targets a 90% carbon capture rate. However, the capture rates for existing projects have been lower than 90%.



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