Firm dispatchable capacity will still be needed in these regions

The STEPS and SDS maintain dispatchable generation capacity despite the increasing competitiveness of new solar and wind investment compared to coal and gas. For example, in the United States, the cost of onshore wind is currently estimated at USD 35/MWh in levelised cost of energy (LCOE) terms and is expected to decline to USD 25 in 2040, while new solar PV is currently estimated at USD 50/MWh and is expected to be reduced by half in 2040 to USD 25/MWh. This is compared to a combined-cycle gas turbine (CCGT) that is estimated to cost USD 65/MWh in 2019 and USD 95/MWh in 2040 under the SDS.

In purely LCOE terms, new solar and wind is cheaper than the alternatives — mainly gas, but also coal, hydro, geothermal and nuclear. However, the capacity and flexibility provided by these plants is required in order to maintain secure operation. This is captured by the World Energy Model (WEM), the framework upon which the STEPS and SDS are built, through the value-adjusted levelised cost of energy (VALCOE) metric. VALCOE assigns additional value to resources that are able to contribute to meeting hour-by-hour demand reliably. This results in lower VALCOE when compared to the LCOE for dispatchable generation. The impact can be quite substantial – for example, in the European Union under the STEPS, the LCOE of a new gas CCGT in 2040 is USD 110/ MWh in LCOE terms but only USD 75 in VALCOE terms. This is in contrast to a weather-dependent resource like solar PV, where the LCOE is USD 50 USD/MWh but the VALCOE is USD 80/ MWh. If looking only at the LCOE, additional solar PV is cheaper by USD 60/MWh, but when using the VALCOE to consider overall system value, the gas CCGT is the cheaper option.

Chapter 2. Technical options for decarbonising thermal power plants

Highlights

- **Co-firing with low-carbon fuels is a complementary approach for decarbonising existing fossil fuel power plants, alongside retrofitting with carbon capture, utilisation and storage (CCUS)**. As countries search for context-specific tools and solutions for achieving clean energy transitions, low-carbon hydrogen (H_2) and ammonia (NH_3) are emerging fuel options for co-firing. Both approaches would allow plants to operate with firm capacity while reusing existing assets and infrastructure.
- **A few Asian countries have stated explicit targets for the use of hydrogen or ammonia in the power sector.** Hydrogen plays only a negligible role in the power sector today, accounting for less than 0.2% of electricity generation globally. However, Japan is aiming to use 0.3 Mt/yr of hydrogen and 3 Mt/yr of ammonia in the power sector by 2030. Korea has a target of 1.5 GW installed fuel cell capacity in the power sector by 2022 and of 15 GW by 2040.
- **Using hydrogen in turbines is already a common practice in industry.** Gas turbine suppliers have significant experience in combusting hydrogen-containing fuels, with some smaller units already operating at a >90% share of hydrogen in refineries and in chemical and petrochemical applications. A number of projects have announced plans to convert large-scale (up to 500MW_e) plants for hydrogen co-firing around the world.
- **Combustion of 20% ammonia in a 1-GW coal-fired unit is announced for 2025.** Modifying existing coal plants for ammonia co-firing requires boiler modifications and investment in additional facilities like ammonia tanks and vaporisers. Through RD&D efforts, plans exist in Japan to demonstrate higher co-firing shares at commercial scale by 2040. In addition, gas turbine manufacturers have announced plans to offer large-scale ammonia-fired gas turbines around 2025.

Existing fossil fuel power plants can be decarbonised by switching to low-carbon fuel or by retrofitting with a CCUS technology. Both approaches would allow these plants to operate into the future as low-emission sources of firm capacity, while reusing existing assets and their associated infrastructure. In particular, co-firing would allow a gradual transition away from fossil fuels, while continuously expanding the production and transport infrastructure for low-carbon fuels.

Co-firing with low-carbon hydrogen

Hydrogen plays only a negligible role in the power sector today, accounting for less than 0.2% of electricity generation globally, linked mostly to the use of hydrogen-containing mixed gases from the steel industry, petrochemical plants and from refineries.

Global installed stationary fuel cell capacity has been rapidly growing over the last ten years, reaching almost 2.2 GW in 2020, although only around 150 MW use hydrogen as fuel. Most of the existing fuel cells today run on natural gas. The number of globally installed fuel cell units is around 468 000, largely dominated by micro co-generation systems.

Selected activities in co-firing of hydrogen in gas turbines

Project	Description	Status	Location
FLEXnCONFU	European consortium developing power to fuel to power solutions.	On-going	Five testing sites in Europe.
Hydrogen to Magnum	Aims to convert one 440 MW gas turbine unit to 100% hydrogen by 2025	Announced	Netherlands
Mitsubishi Power	Developing NH_3-fired 40 MW gas turbine by 2024, and NH_3 cracking to H_2 with turbine exhaust heat by 2025	Announced	Japan
GE	25 gas turbines have operated on fuels with at least 50% (by volume) hydrogen.	In operation	Various locations
EnergyAustralia	Over 300 MW gas turbine plant with blending of H_2 by 2024	Announced	Australia
HyFlexPower	Modification of a 12MW$_e$ CHP unit for hydrogen-firing.	On-going at pilot scale	France
Long Ridge Energy Terminal	Transition of 485 MW combined-cycle power plant to co-firing 5% of hydrogen with intention to reach 100% over the next decade.	First phase completed	USA
Mitsubishi Power	Three projects initially capable of co-firing 30% of hydrogen, with future capability of 100% hydrogen.	Targeted to come online between 2023 and 2025	Three locations in the USA

Very few countries have stated explicit targets for the use of hydrogen or hydrogen-based fuels in the power sector. Japan is one of the few exceptions: it is aiming to reach 1 GW of power capacity based on hydrogen by 2030, corresponding to an annual hydrogen consumption of 0.3 metric tonnes of (Mt), rising to 15–30 GW in the longer-term, corresponding to annual hydrogen use of 5–10 Mt H_2. In its hydrogen roadmap, Korea has set a target of 1.5 GW installed fuel cell capacity in the power sector by 2022, and 15 GW by 2040. A number of countries have, however, recognised the potential of hydrogen as a low-carbon option for power and heat generation, e.g. to provide flexibility for an energy system with high shares of VRE.

Modification requirements for hydrogen co-firing

Reciprocating gas engines today can handle gases with a hydrogen content of up to 70% (on a volumetric basis), while testing has been successfully completed with engines running on pure hydrogen. Gas turbine suppliers already have significant experience in combusting hydrogen-containing fuels, with some smaller units already operating at a >90% share of hydrogen in refineries and in chemical and petrochemical applications. For example, in Korea a 40 MW gas turbine at a refinery has run on gases with a hydrogen content of up to 90% for 20 years. However, blend rates vary depending on the specific technology, condition of the equipment, available infrastructure and their suitability to hydrogen blending.

Most experience has been gained on diffusion flame (non-premixed) combustion systems, which offer high flame stability but utilise an expensive and bulky water or steam injection system (Wet Low Emissions technology) to reduce the high NO_x emissions associated with very high flame temperatures, resulting in large efficiency penalties. State-of-the-art gas turbines (GTs) for power generation are of Dry Low NO_x (DLN) type, which utilise lean-premixed or multi-cluster combustion technology to achieve single digit NO_x levels (with non-premixed systems used only during start up and/or at low load to ensure combustion stability). The maximum allowable H_2 concentration in commercial DLN NG-fired turbines can vary significantly across the fleet of different manufactures, due to the different burner design and combustion strategy implemented, with typical values ranging from 30-60% by volume. R&D activities are in progress to develop DLN GTs which are able to handle the full range of 0-100% fixed H_2 contents blended with natural gas. A successful verification of 100% hydrogen-fuelled Dry Low NOx combustion technology was recently achieved in Japan at 1 MW_e scale.

Challenges associated with the use of H_2/NG blends with high H_2 content in DLN GTs are due to different thermo-chemical properties and combustion characteristics of the two fuels. These include higher risks of autoignition and flashback, due to the higher reactivity and flame speed of H_2, increased risk of combustion instabilities (thermo-acoustic and lean blow out), and higher NO_x emissions due to higher flame temperature. Other combustion-related challenges include changes in the Wobbe Index due to the larger volumetric fuel flow rate required when using H_2 instead of natural gas for a given power, and the need to introduce enhanced cooling measures to avoid overheating of components arising from the higher heat transfer caused by the increased moisture content in the exhaust gas. Importantly, these issues also mean that operating a gas turbine is easier with a fixed blend of H_2 to NG than a variable one, while blend ratios could vary through a gas pipeline distribution network.

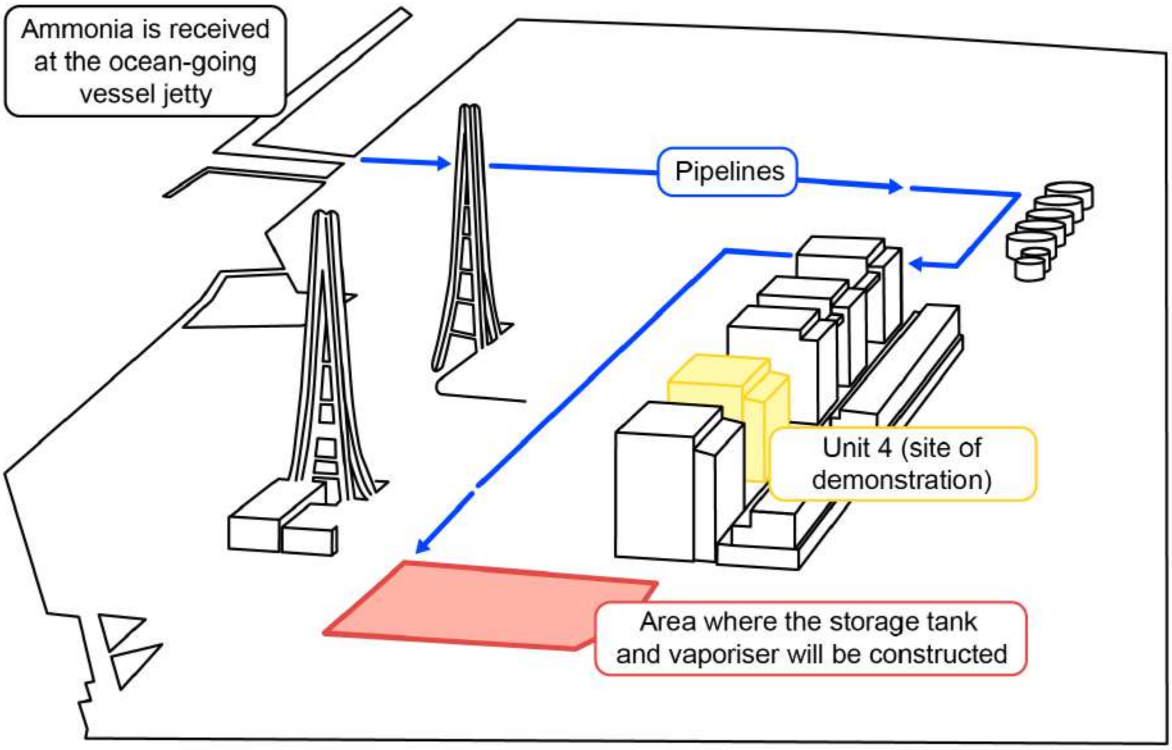
Refurbishment of gas turbine installations to H_2-containing fuels also requires consideration of issues other than those directly related to the combustion process and re-configuration of the burner design/nozzles. Fuel systems operating with high H_2 fractions must be re-configured to allow up to three times higher volume flow to obtain the same heating value input as natural gas. Material compatibility of the fuel system must be ensured, including use of appropriate sealing components. Ventilation, gas/flame detection, fire suppression and electrical systems suitable for H_2-containing environments must be installed in the enclosure to ensure fire safety. There could also be changes in the exhaust energy from the gas turbine necessitating a review of heat recovery steam generator (HRSG) limits. The extent of the modification depends on the type and age of the turbine, fuel composition and emissions requirements.

Co-firing with low-carbon ammonia

The possibility to co-fire with ammonia in existing coal plants has received increasing attention in Japan. Using a 1% share of ammonia was demonstrated in 2017 by Chugoku Electric Power Corporation at one of their commercial coal power stations. Another Japanese utility, JERA, plans to demonstrate a 20% ammonia co-firing at a 1 GW coal-fired unit from 2021 to 2024. For gas turbines, a 70% ammonia co-firing on a 2 MW turbine was recently reported by IHI Corporation. This was achieved by spraying liquid ammonia directly into combustors, thereby eliminating the need for ammonia vaporisation and related peripheral equipment.

For gas turbines, the direct use of ammonia to date has been successfully demonstrated in micro gas turbines with a power capacity of only up to 300 kW. The low combustion speed of ammonia and flame stability have been identified as possible issues preventing its use in larger gas turbines alongside the aspect of increased NO_x emissions. Yet, Mitsubishi Heavy Industries have announced plans to commercialise a 40-MW gas turbine directly combusting 100% ammonia by 2025.

Hekinan Thermal Power Station, where the first large-scale co-firing tests of ammonia with a 20% share are planned to be held in 2024



In the SDS, the use of ammonia for co-firing in coal power stations climbs to 60 Mt per year and 140 TWh of electricity generation by 2050, up from a handful of pilot and demonstration scale projects today. Despite providing only around 0.2% of global electricity generation in 2050, this application accounts for around a third of the consumption of ammonia for purposes other than its existing uses today. A single 1 GW coal power plant will require some 500,000 t/yr of NH_3 for co-firing NH_3 with a 20% share, which represents 2.5% of globally traded ammonia today.

Modification requirements for ammonia co-firing

Modifying existing thermal plants for ammonia co-firing requires boiler modifications and investment in additional facilities like ammonia tanks and vaporisers. As ammonia combustion is characterised by a low flame temperature and generally narrow combustible range, it can cause issues in keeping a stable flame during co-firing. Co-firing also reduces the amount of soot and coal powder particles in the furnace, leading to lower radiative heat transfer but also to reduced ash deposition on heat transfer surfaces and improved boiler performance. The possible formation of large amounts of NO_x from ammonia is a concern. However, the use of NH_3 is already established in coal power plants to reduce NO_x emissions through selective catalytic reduction (SCR) of flue gases. Hence, the required infrastructure and know-how for handling NH_3 already exist.

The NH_3-to-coal ratio and injection methods are two important additional parameters to be considered in ammonia co-firing. With 60% co-firing share, the radiative component of heat transfer was observed to decrease significantly, although total heat transfer to the walls was lowered only by some 3%. In one experiment, NO_x emissions did not rise up to 30% co-firing, when ammonia was mixed in the coal nozzle or injected from the ammonia gun.

Gas turbine systems are also developed for ammonia as a fuel. Such systems can either combust H_2 derived from ammonia (NH_3), blends of NH_3 and H_2 or NH_3 directly. The technology currently has a lower technology readiness level compared to hydrogen co-firing, but gas turbine manufacturers are announcing plans to offer large-scale NH_3-fired GTs around 2025. Ammonia-fired systems benefit from the easier storing of ammonia relative to hydrogen, but the use of NH_3 as fuel poses additional technical challenges arising from its toxic and corrosive nature. Technology is also being developed to supply liquid ammonia directly to the gas turbine without evaporisation, which would lead to a reduction in costs and increase in efficiency. Cracking part of the ammonia back to hydrogen, and combusting the unseparated mix of NH_3, H_2 and N_2 would be one way to achieve combustion characteristics more similar to hydrocarbons.

Co-firing with sustainable biomass

The co-firing of biomass with coal has been developed and practised for over 20 years, first in Western Europe and North America and now in Asia. The main types of biomass that have been co-fired with coal are wood, agricultural residues and grasses. Since relatively high co-firing shares can be achieved with biomass, it provides a quick way to reduce the use of fossil fuels at existing large-scale power plants at capital costs that are much lower than investment in a new thermal power plant.

Key technical options for the conversion of large, pulverised coal (PC) boilers to the firing and co-firing of biomass have been successfully demonstrated over the past 15 to 20 years. Co-firing in PC boilers has dominated the sector for the last

20 years, and remains the most popular method for co-firing in countries such as Japan and South Korea. However, in China co-firing via gasification has been preferred.

Waste materials, agricultural residues and cereal straws are relatively inexpensive feedstock options, but tend to have higher ash content and more problematic ash compositions. They can therefore be used at only modest co-firing ratios. Feedstocks based on clean wood tend to have lower ash content, and can be used at higher co-firing ratios. For 100% direct biomass firing, only the higher grade and more expensive wood materials are currently suitable.

Higher co-firing ratios incur higher retrofitting costs

Three principal methods exist for modifying an existing coal-fired utility boiler for biomass co-firing. In the co-milling method, biomass is mixed with coal and passed through the existing milling system. This method can be implemented relatively quickly with minimal capital cost, involving only investments in biomass storage and handling systems, but the amount of biomass is limited typically to 5-10% co-firing (on energy basis) or less.

In an alternative method, biomass is processed separately either in a modified coal mill, or a new dedicated mill. The separately milled biomass can then be fired together with coal or alone in a modified coal or a new dedicated biomass burner. With separate milling, the co-firing ratio can be significantly increased, but at the expense of higher retrofitting costs.

One of the principal concerns when considering the conversion of a coal boiler to 100% biomass firing is the risk of increased ash depositions and excessive slag formation on the superheater elements, around the burners and on other refractory surfaces in the furnace. These issues can be reduced by modifying the reheater and superheater for larger spacing, using more corrosion resistant high alloy materials, increasing soot blowing and lowering the final temperature. However, the risk should be low with high-grade wood pellet materials that have low ash content and modest levels of alkali metals.

In the third method, biomass is converted to fuel gas in a separate gasifier, followed by combustion either in a boiler or a turbine. This method incurs higher investment costs, but allows up to a 100% co-firing share and the use of lower quality and thus cheaper biomass and waste feedstocks.

This indirect biomass co-firing approach has been realised in Finland, where the world's largest biomass gasification plant was commissioned by a local utility company in 2012. The 140-MWth gasification plant was built adjacent to an existing 565 MW_e coal-fired plant, originally constructed and commissioned in 1982, with the intention to replace 25-40% of the power station's coal use with forest (wood) residue sources within 100 km from the plant. Operation with solely biomass-derived fuel gas was demonstrated in 2014, and since then, the boiler has been run on 100% biomass when the load is low during autumn and spring.

The project involved construction of feedstock handling systems, a circulating fluidised-bed gasifier and modifications to the existing coal boiler. A dryer was built to reduce and control the moisture content of the biomass feedstock using by-product heat from the plant. The dryer further widens the feedstock base, and allows the use of lower quality and therefore cheaper biomass residues.

Co-firing shares can be increased gradually over time

A conversion to 100% biomass firing can be carried out either in a relatively short period of time, or gradually over the course of many years. Drax power station in the UK is an example of converting a large-scale coal-fired power plant to 100% biomass firing through several intermediate stages. The power station itself was commissioned in the 1970s (units 1-3), expanded in the 1980s (units 4-6), and is comprised of six pulverised bituminous coal boilers and turbine units, each of 660 MW_e capacity. The first biomass trials were held in 2003, pre-mixing biomass with coal and using existing coal milling and feeding systems with a few or no modifications. Although this approach would have allowed the co-firing of up to a 10% share of biomass, the share was constrained at the level of the power station to 3%, due to limitations imposed by biomass reception, handling and mixing systems.

As a next step, a direct injection co-firing system was demonstrated in 2005-2006 and eventually realised in 2007-2010. The system enabled the co-firing of around 1.5 Mt of wood pellets, equivalent to around 400 MW_e or 10% of the generation capacity of the total station. During the period of 2012-2016, three generation units were converted to 100% biomass with the help of state aid from the UK government, representing 50% of the stations generating capacity, or around 2 000 MW_e.

In May 2021, the utility announced it had started the planning process for deploying a bioenergy with carbon capture and storage (BECCS) system at the power station. This next step in the gradual conversion of the power station would make it possible to start capturing and permanently storing biogenic

CO_2 emissions. Building works could commence in 2024 with plans to become operational by 2027.

Retrofitting with CCUS

Retrofitting with CO_2 capture equipment can enable the continued operation of existing power plants in a low-carbon energy system, as well as the operation of associated existing infrastructure and supply chains, but with significantly reduced emissions (85-98% lower CO_2 emissions than unabated power plants, depending on the technology). In addition to adding capture equipment at the power plant, CO_2 transport and storage infrastructure needs to be built to handle the captured CO_2.

To date, CCUS[1] has been applied to two commercial power plants, the Petra Nova Carbon Capture project in Texas and the Boundary Dam Carbon Capture project in Canada, which are both CCUS retrofits to existing coal-fired power plants. At 240 MW, the Petra Nova project, commissioned in 2017, is the largest post-combustion capture system installed on a coal-fired power plant. The Petra Nova project captured up to 1.4 $MtCO_2$ annually for use in enhanced oil recovery, until CO_2 capture operations were suspended in 2020 in response to low oil prices.

Experience with building and operating CCUS facilities has contributed to progressive improvements in CCUS technologies as well as significant cost reductions. At around USD 65/tCO_2 the capture cost of the Petra Nova coal-fired power plant is more than 30% lower than the Boundary Dam facility, which started operations in 2014. Detailed engineering studies show that retrofitting a coal-fired power plant today could cost around USD 45/tCO_2. There are now plans to equip as many as 29 power plants with capture equipment (including in China, the United Kingdom and the United States). With further RD&D and growing practical experience, there is considerable potential to further reduce energy needs and costs.

In a study for the IEA Coal Industry Advisory Board, the International CCS Knowledge Centre identified a series of opportunities to reduce the cost of retrofitting post-combustion capture at the plant level. Their findings are based on the knowledge and experience gained from the Boundary Dam and Petra Nova

[1] In this report, carbon capture and storage (CCS) includes applications where the CO_2 is captured and permanently stored. Carbon capture and utilisation (CCU) or CO_2 use includes where the CO_2 is used, for example in the production of fuels and chemicals. Carbon capture, utilisation and storage (CCUS) includes CCS, CCU and also where the CO_2 is both used and stored, for example in enhanced oil recovery or in building materials, where its use results in some or all of the CO_2 being permanently stored.

facilities and the 2018 Shand CCS feasibility study. Reductions can be achieved in capital costs, operating costs and CO_2 transport and storage costs.

Capital costs are an important component of CCUS projects and account for more than half of the total cost of capture at the two CCUS retrofitted plants. The operating costs for CCUS-equipped plants are typically higher than for unabated plants due to the additional energy required to operate the capture facility. Further operating expenses relate to the consumption of solvents, chemical reagents, catalysts, the disposal of waste products and additional staff needed to run the CCUS facilities.

Cost reduction potential for next-generation CCUS projects by cost type

Cost component	Cost reduction measure
Capital costs	Scaling up the CCUS plant
	Improved site layout and modularisation
	Increasing capture capacity
	Increased efficiency of the host power unit
	Optimising CCUS operating envelope
	Development of a CCUS supply chain
Operating costs	Reduced amine degradation
	Lower maintenance costs
	Optimisation of thermal energy
	Optimised water consumption
	Increased compression efficiency
	Digitalisation
Transport and storage costs	Siting with complementary partners in industrial CCUS hubs, allowing for shared infrastructure

Note: Based on International CCS Knowledge Centre (2019).

Modification requirements

At the level of an individual plant, the cost of a CCUS retrofit depends on the age and technological characteristics of the asset as well as on the market conditions and regulatory framework. In many cases, the early retirement of assets before full repayment of capital costs is an expensive option for plant owners and governments, particularly in emerging economies with younger assets. Retrofitting these assets with CCUS to allow continued operation can provide plant owners with an asset protection strategy and may prove cheaper than early retirement.