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# Can Hydrogen and Carbon Capture and Storage (CCS) help Decarbonize the coal power plants in Asia?

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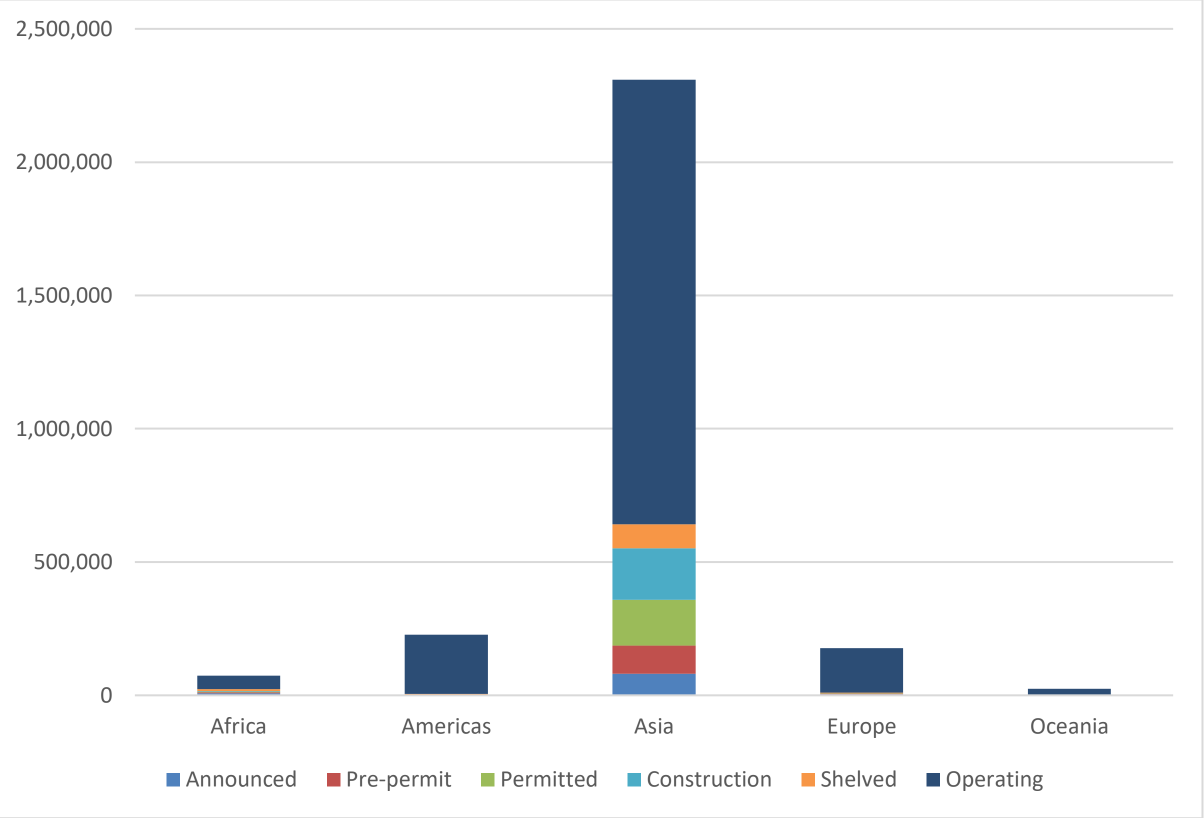
## 1. Introduction

Global energy-related $CO_2$ emissions increased by 1.1% in 2023, reaching a new record high of 37.4 billion tons (Gt) (IEA, 2024). This represents an increase of 410 million tons (Mt) compared to the previous year, which saw an increase of 490 Mt (1.3%). Coal was responsible for approximately 70% of the increase in global emissions from energy combustion in 2023, contributing 270 Mt to the overall total (IEA, 2024). At the sector level, transportation experienced the greatest rise in emissions, increasing by nearly 240 Mt across the globe. The power sector followed closely behind with a significant regional variance, as emissions in advanced economies lessened while those in emerging markets and developing economies grew. Nevertheless, the power sector maintains its position as the leading emitter among all sectors (IEA, 2024).

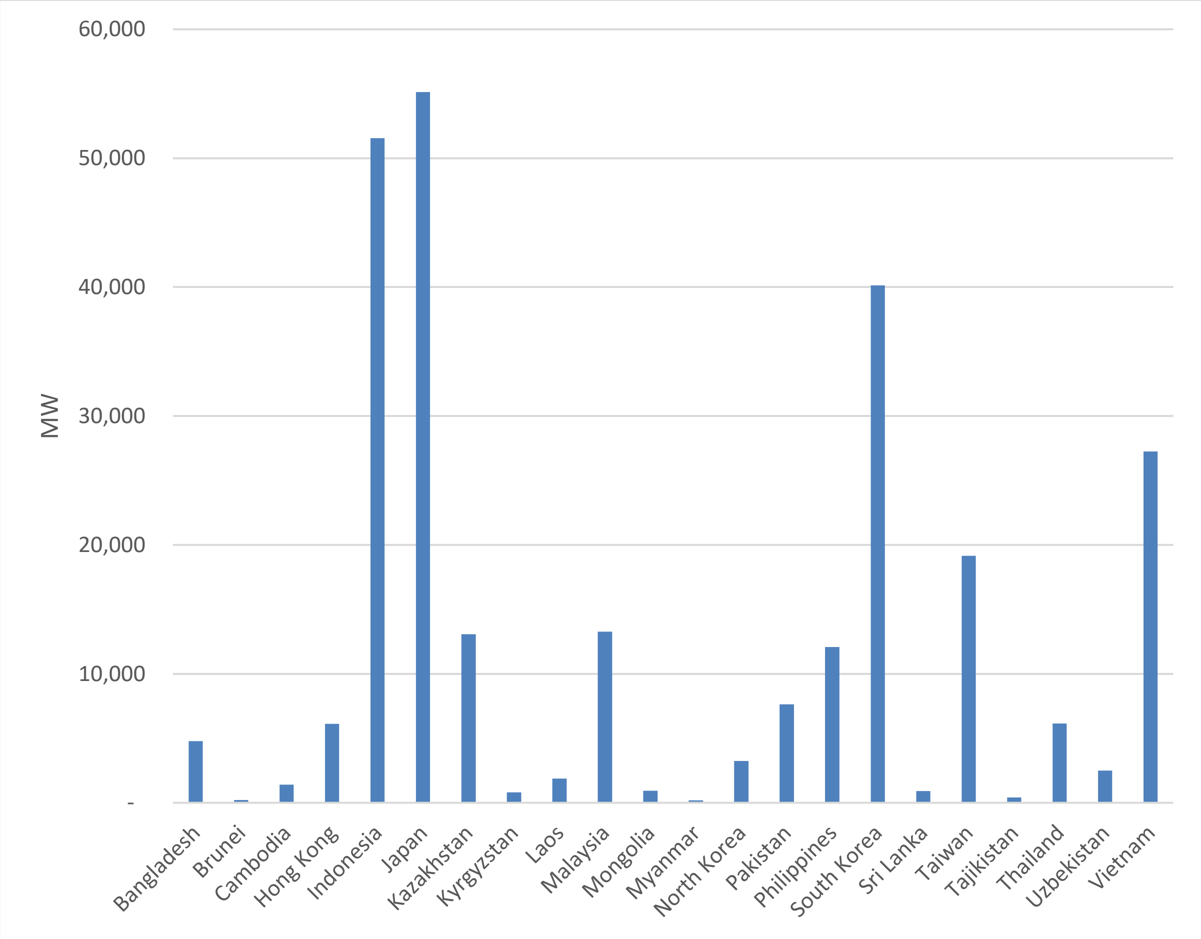
As the power sector is the largest GHG emitter, it is important to investigate the fuels used in this sector. In 2023, coal was the primary source of electricity supply, accounting for 35.9%. Natural gas came in second, representing 23% (IEA, 2023). Asia has the largest number of coal plants in operation, standing at a capacity of 1,667 GW, which is more than seven times the next region, North and Latin America (see Figure 1). Eastern Asia is the largest subregion, with an installed coal plant capacity of 1,261 GW, representing 76% of the total capacity, according to the Global Coal Plant Tracker (2024). China leads the pack with the highest installed capacity, accounting for a staggering 68.17% of the total capacity. India comes in second place, with a respectable 14.22% installed capacity (Global Coal Plant Tracker, 2024) (see Figure 2). The coal plants mentioned above emit an estimated 7,610 million tons of CO2 annually. China and India are the top emitters, responsible for 67.45% and 14.57% of the total emissions, respectively (Global Coal Plant Tracker, 2024). Between 2000 and 2023, 151 GW of coal plants were retired in Asia and around 1,553 GW of plants were cancelled from 2010 to 2023. Nonetheless, 80 GW of coal plant plans have been announced, 105 GW in the pre-permit phase, 171 GW have been permitted, and 193 GW are currently under construction (see Figure 1).

**Figure 1: Coal power plants worldwide (MW)**




Source: Global Carbon Tracker

**Figure 2: Coal power plant operating capacity in Asia (MW, excluding China and India)**



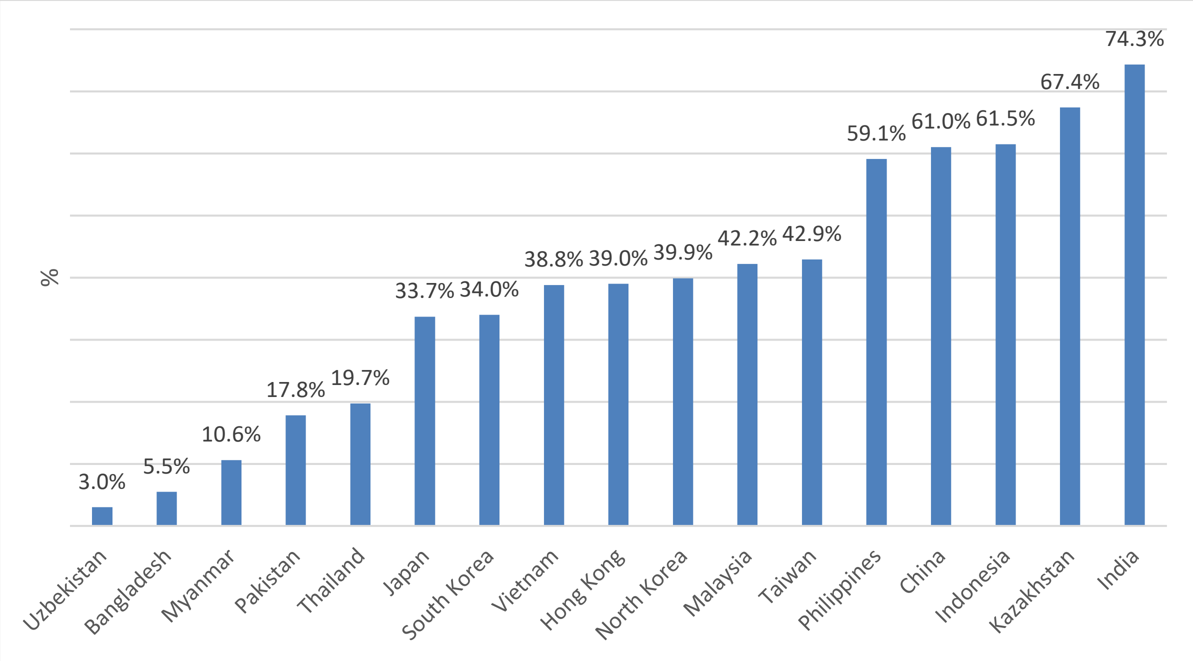

Source: Global Carbon Tracker, 2024

This paper aims to investigate the potential of hydrogen technology and synergies with the Carbon Capture and Storage (CCS) technology in mitigating carbon emissions from coal power plants in Asia. The paper first looks at the environmental footprint of coal fired power plants, then considers ammonia substitution as a means of reducing that impact, and finally discusses the potential of CCS as a pathway to decarbonization, including an introduction to the pairing of the nascent Oxy-fuel combustion technology with CCS, potentially combined with green hydrogen production, as a decarbonization pathway.

## 2. Coal power plants in Asia and decarbonization options

For several decades, coal power plants have been a reliable source of energy that delivers a steady supply of electricity to millions of people across the globe. Despite mounting concerns about their environmental impacts, coal power plants continue to be a crucial part of the energy infrastructure in many Asian countries. The high demand for energy in the region, particularly in South and Southeast Asia, has resulted in a continued reliance on coal to meet energy requirements. Furthermore, the Asian region holds more than 60% of the world's coal reserves, further driving its utilisation in the area. In some countries in the region, coal exports represent a significant source of revenue, which is why some governments continue to support coal mining and coal-fired power generation through subsidies and public financing (ESCAP, 2021). The support of coal and historical dependence on coal for power generation leads to the fact that electricity power generation using coal power plants represents a significant share in some Asian countries and could reach more than 50% of the power generation share. For example, the electricity production using coal amounted to 74.3% of the total electricity share in India in 2022. Figure 3 represents the share of coal power plants in electricity generation in some Asian countries.

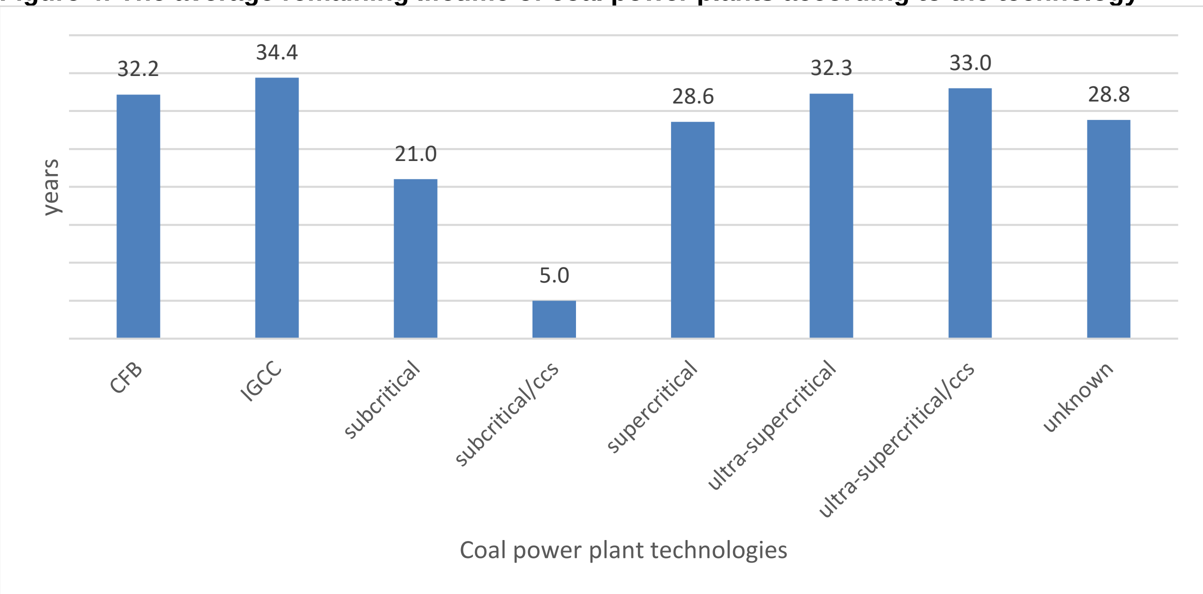
**Figure 3: Coal share in electricity production in some Asian countries**




Source: EMBER, 2023

Coal-fired power plants have a considerably long lifespan, which can exceed 40 years. In Asia, the average remaining lifespan of coal-fired power plants varies depending on the combustion technologies used, as illustrated in Figure 4 below. The data clearly indicate that most of these power plants still have a significant amount of time left before they are expected to be decommissioned. It is estimated that during the remaining lifespan of these coal plants, approximately 194,065 million tons of $CO_2$ emissions will be released, thus exacerbating the problem of global warming (Global Coal Plant Tracker, 2024).

**Figure 4: The average remaining lifetime of coal power plants according to the technology**




Source: Global carbon tracker, 2024. Note: CFB: Circulating fluidised bed, IGCC: Integrated gasification combined cycle, Subcritical/CCS: Subcritical with carbon capture and sequestration

Almost half (43.8%) of the installed capacity of coal-fired power plants uses subcritical technologies. Supercritical and ultra-supercritical technologies make up 27% and 25.6% of the total capacity, respectively. The subcritical plants have lower average efficiencies of 30.8% and higher operating costs resulting in the need for larger volumes of fuel input. Supercritical and ultra-supercritical plants, on the other hand, are more efficient, with estimated efficiencies of 36.8% and 39.8%, respectively (Global Coal Plant Tracker, 2024).

Around the world, countries are increasingly turning away from coal as an energy source. The continued use of coal-fired power plants could have dire consequences for the environment, public health, and the economy. The deleterious impact of coal-fired power stations on society and the environment has been increasingly conspicuous in contemporary times. Consequently, it is common for regional authorities and communities to resist new coal power development plans. This trend is observable in countries such as Vietnam, Indonesia, the Philippines, and India, among others (Trivedi, 2021).

Also, recently, solar and wind power have become much more affordable, especially solar PV, along with storage technologies. In fact, in most countries, investing in solar and wind power is now more cost-effective than constructing new coal or gas-fired power plants. Policies against air pollution (like those in India) and the growing adoption of climate change policies have raised awareness about the importance of phasing out coal. Moreover, many governments and investors are increasingly averse to financing new coal-fired power plants. Consequently, there is a growing global trend towards phasing out coal as an energy source at national and subnational levels (ESCAP, 2021).

Alternative energy sources and cleaner technologies must be pursued to mitigate the impact of CO2 emissions from the power sector. Nevertheless, decarbonising the power sector is a challenging task, particularly in Asia.

There are three potential routes to reduce carbon emissions from coal power plants.

The first route is to replace coal power plants with renewable energy plants[1]. This transformation will have significant implications for the power sector, especially with the high shares of coal power plants in some countries, requiring the management of renewable variability with flexible resources such as dispatchable power plants, energy storage, demand response, and transmission expansion. The suitability of additional wind and solar investments will depend on local conditions, and some systems may lack sites with high potential for wind and solar generation. This may result in lower output than global averages and systems with high development potential. Lower capacity factors increase the average cost of energy provided by these assets (IEA, 2021).

From a social and economic perspective, this transformation will affect regions that depend on energy-intensive industries for employment and economic activity. The early retirement of coal—and gas-fired generation will require additional investment in these regions to ensure a just transition and avoid social and economic disruption. Policy decisions would affect the owners of such assets and may cause asset stranding, which may lead to financial pressure (IEA, 2021).

The second route for reducing carbon emissions from power plants is to equip them with carbon capture and storage (CCS) technology. By doing so, these thermal power plants can continue to provide sustainable power sources in the future while utilising their existing resources, infrastructure, and supply chains. However, implementing CCS technology can lead to additional operational costs due to the decrease in efficiency caused by CO2 capture, transportation, and storage (IEA, 2021). The energy requirements of CO2 capture are the primary driver of these expenses, which ultimately translate into increased fuel costs for the power plant operator (IEA, 2021).

The third option is to co-fire with low-carbon fuel. This approach would enable coal-powered plants to continue functioning as sources of reliable power while utilising their existing assets and infrastructure. Co-firing would enable a gradual shift away from fossil fuels while also progressively building up the production and transportation infrastructure for low-carbon fuels. However, besides the increased costs, the degree to which emissions are reduced will depend on the type of fuel that is used (IEA, 2021).

[1] Other technologies, such as geothermal and nuclear, could also play a role. However, we focus on renewable energy because these technologies might not be widely available in all Asian countries.

## 3. Co-firing with Ammonia

As discussed above, co-firing ammonia with coal is one potential pathway (GISEBURT, 2023) to reduce emissions from coal power plants. Since coal has a higher carbon content than natural gas or ammonia, replacing some of the coal with a non-carbon fuel significantly reduces the amount of $CO_2$ emissions. Green or blue ammonia is a non/low-carbon fuel that can be mixed with coal for this purpose. One of the reasons ammonia is being considered for use is that thermal power plants have the necessary facilities to handle it for denitrification (which is the removal of nitrogen oxides) from the exhaust gas (ERIA, 2022). That's true for the advanced plants where ammonia substitution is being considered, but many older plants may not be adequately equipped. Furthermore, reasons to consider ammonia include that it is a commodity with proven technology and experience, there already exists some infrastructure, and it is relatively easier to transport and store especially compared to hydrogen[2]. Several countries, including Malaysia, Indonesia, South Korea, and other Asian countries, are considering this technology, with Japan leading the pack.

At the beginning of April 2024, JERA, Japan's largest power generation company, announced that it had begun a demonstration of co-firing 20% of ammonia with coal at its Hekinan thermal power station in Aichi Prefecture, in what it said is the world's first trial using a large amount of the ammonia at a major commercial plant (The Japan Times, 2024). JERA and IHI (Japanese engineering corporation) investigated the necessary parameters for developing the required suitable burners. To achieve this, they conducted small-scale ammonia co-firing tests using burners made of different materials at Unit 5 of the Hekinan Thermal Power Station. At Unit 5, two of the 48 burners have been replaced with test burners. The performance of these burners was assessed to determine the effects of different burner materials and combustion times. This will help identify the necessary conditions for co-firing burners. The goal is to develop co-firing burners that can be used at a ratio of around 20% (Kelsall & Baruya, 2022). JERA is planning to increase the co-firing rate to 50% later and to reach zero emissions under its 'JERA Zero $CO_2$ Emissions 2050' objective (JERA, 2022).

The development of the required boiler and burner technology is being undertaken by Mitsubishi Power, which has conducted combustion tests at the MHI Research & Innovation Centre using basic combustion test furnaces that can simulate the combustion conditions of coal-fired boilers. These tests were used to compile basic data on ammonia and coal cofiring up to 100% ammonia substitution. The company has also identified optimal systems and conditions for combustion based on its knowledge of ammonia firing characteristics. These include the generation of NOx, which is a concern for ammonia firing, and the potential for unreacted residual ammonia to be released outside the power generation system (Kelsall & Baruya, 2022). The next section explains the co-firing ammonia technology and why it is currently a topic of heated debate[3].

The process of generating electricity in coal-fired power plants involves producing high-temperature and high-pressure steam in a boiler. This steam is then utilised to power a turbine, which in turn rotates the generator. Unlike natural gas-fired plants, the turbine is not in direct contact with the gas from combustion. Prior to being introduced into the boiler, coal is crushed into small fragments. Further, ammonia, in either liquid or gaseous form, is mixed with air for combustion and subsequently supplied to the boiler (ERIA, 2022).

When burning, ammonia tends to have a slower burn rate than methane, and it includes nitrogen, which can lead to unburned ammonia downstream of the boiler and NOx emissions. To properly address this issue, it is crucial to have a stable ignition of the ammonia burner and ensure proper air distribution. Incorporating ammonia into a coal power plant for co-firing requires adjustments to achieve optimal combustion and reduce emissions. This entails modifying the boiler burners to regulate the proportion and velocity of the combination of ammonia, pulverised coal, and air. A comprehensive approach to

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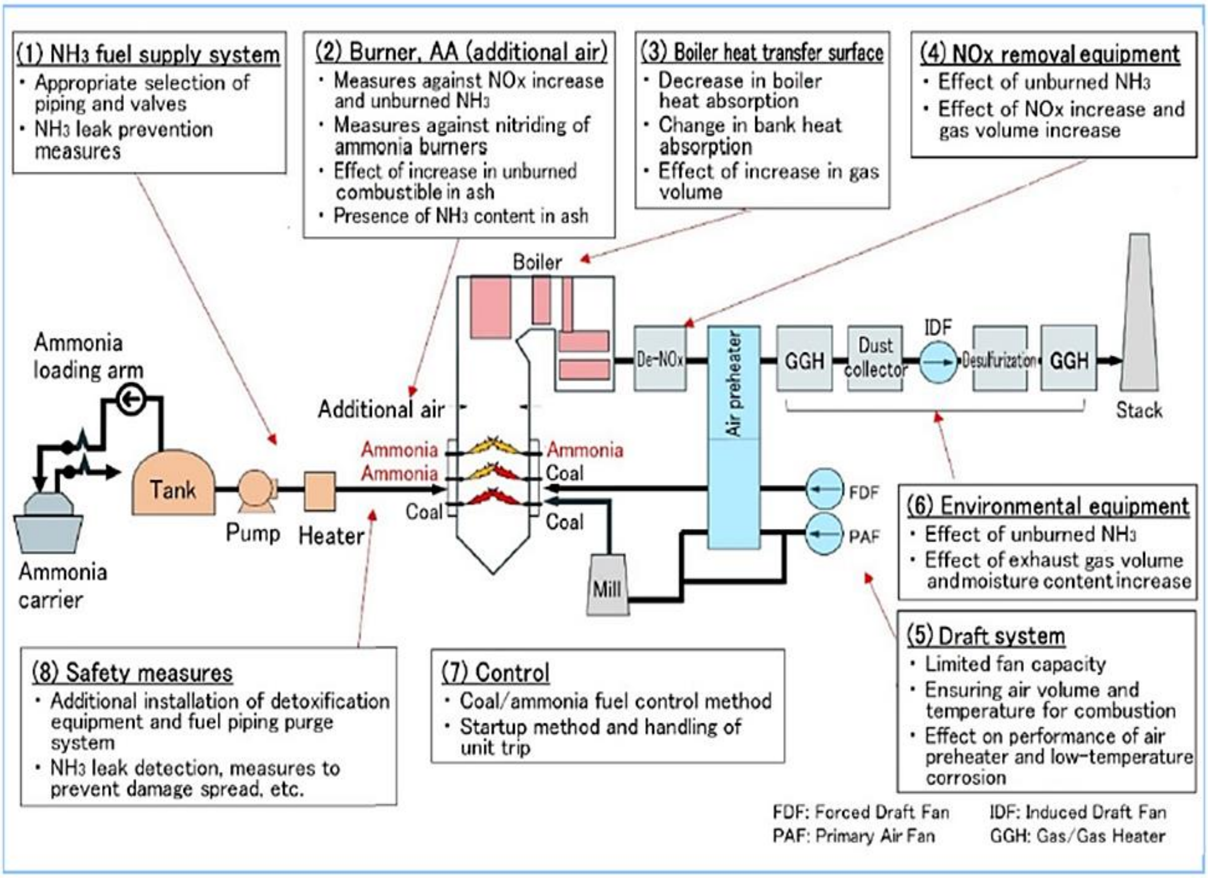
[2] Another technology that meets these criteria is biomass co-firing, and it would not increase net emissions. Biomass is readily available in Asia and is already being implemented, sparking a debate. However, it is out of the scope of this paper.

[3] Co-firing with ammonia involves substituting it for a portion of the coal. However, as we will discuss later, it is possible to substitute coal with ammonia as the sole fuel completely. Despite this complete substitution, the term "100% ammonia firing" will be used to minimize confusion

burner design and modification is necessary, taking into account the complex interplay of fuel and air mixing, flame stability, and emissions control (IHI Corporation, 2019). Figure 5 below illustrates the challenges in modifying coal-fired plants to operate with ammonia co-firing.

**Figure 5: Modifications to coal power plants for co-firing**




Source: (YAMASHITA, et al., 2022)

Boilers that employ pulverised coal are typically customised to the properties of specific coal types. However, the introduction of ammonia as a gaseous fuel can have an impact on the heat transfer performance of the boiler. Recent research has shown that as the co-firing ratio increases, the temperature of the flue gas discharged from the boiler also increases significantly. This elevates the flue gas volume, leading to an efficiency loss of up to 0.7-0.8% at co-firing ratios of 30% and 40% (Wang & Sheng, 2023).

When considering the use of ammonia as a fuel, it is imperative to take into account the consequential effects on downstream equipment such as the boiler and draft systems such as fans. Therefore, a detailed analysis of the changes in exhaust gas properties and gas volume is warranted. This analysis requires consideration of start-up procedures and procedures for emergency shutdown (YAMASHITA, et al., 2022).

Given the aforementioned, employing ammonia as a fuel necessitates the installation of additional facilities. These facilities include equipment to inject ammonia gas into the burner and systems that address concerns related to the use of ammonia. Moreover, it is necessary to incorporate a gas system between the ammonia gasification facility and the burner. This involves gasifying liquid ammonia and combining it with coal in a system configuration similar to that of a boiler's gas fuel system. It is also important to prevent any leakage of the harmful and toxic ammonia gas. As part of the basic design policy, the ammonia gas is purged to pretreatment facilities using $N_2$, rather than being released into the atmosphere as with other gas fuels (Genichiro, et al., 2020).

It is also imperative to consider measures to prevent the leakage of ammonia, which is a hazardous chemical. Such measures include the installation of ammonia detoxification equipment which can convert the chemical into a less harmful substance and fuel purge systems to remove any ammonia residue from the fuel lines. Additionally, the formulation of an operation policy in the event of fuel shutdown can greatly reduce the risk of ammonia leakage (YAMASHITA, et al., 2022).

There are two main concerns associated with ammonia co-firing. Firstly, burning ammonia produces nitrous oxide, commonly known as laughing gas. This gas has a potential impact on global warming that is 265 times greater than that of $CO_2$ over a 100-year period (IPCC, 2013). However, it's important to mention that nitric oxide (NO) and nitrogen dioxide ($NO_2$) do not contribute to greenhouse effects; however, they have an indirect effect on climate change (EPA, 2002). Secondly, the expected high levelized cost of electricity (LCOE) can be prohibitive when implementing this technology.

### 3.1 Ammonia Co-firing Emissions

In its report, Japan's Costly Ammonia Coal Co-Firing Strategy, Bloomberg NEF (BNEF) indicated that the research has demonstrated that co-firing ammonia with coal in power plants can lead to an increase in nitrous oxide emissions at blend rates below 20%. These emissions continue to rise until 40% ammonia is co-firing, after which they decrease. The cost of retrofitting coal plants to use ammonia and capture nitrous oxide emissions is quite high, and the economic feasibility of ammonia co-firing remains questionable, especially when considering the additional costs of emission capture technologies. (BNEF, 2022).

Nevertheless, other researchers indicate different results. For example, YAMASHITA et al. (2022) have reported that using independent coal and ammonia burners allows for improved control of NOx emissions even at higher ammonia co-firing rates. This is due to the ease of regulating the air ratio of each fuel, which in turn enables control over NOx emissions. Additionally, the co-firing rate can be adjusted to any level by modifying the number of operational burners and the burner load. A small-scale combustion test furnace was used to demonstrate the effectiveness of this approach. The results showed that NOx generation could be suppressed to the same level or less than that generated by single-fuel coal-firing, even when the ammonia co-firing rate was increased (YAMASHITA, et al., 2022).

In 2020, Genichiro and his team demonstrated that limiting NOx emissions to the same level as coal firing is achievable through co-firing ammonia. By providing ammonia from the centre of a coal-fired burner, they were able to maintain a stable flame. The team also evaluated the impact of combustion ratio, heat input, and coal fuel ratio on flue gas composition. They confirmed that, under appropriate conditions, NOx concentration does not exceed that of coal firing. As a result, it was concluded that additional large NOx-related facilities are unnecessary when performing co-firing of pulverised coal and ammonia (Genichiro, et al., 2020).

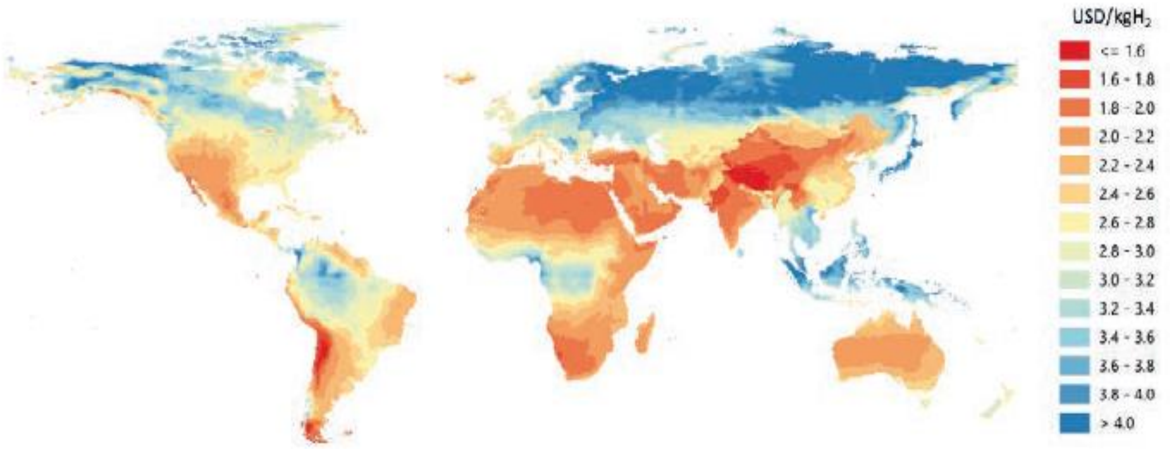
A recent comprehensive technical review examined the application of NH3 co-firing with coal. The review gathered data from numerous studies and determined that it's possible to control NOx emissions from co-firing, and in some cases, they could even be reduced by regulating ammonia injection methods and location (Lee, et al., 2023).

### 3.2 Co-firing LCOE

The use of ammonia co-firing presents a potential challenge in terms of the projected high LCOE. To determine the cost components and the most influential cost factors, a model was constructed to calculate the LCOE (for details please see the Appendix). The cost of ammonia will be discussed first, followed by the presentation of the model's outcomes. All assumptions are presented in the Appendix with their respective references.

The costs involved in generating renewable ammonia are chiefly determined by the cost of renewable hydrogen, which makes up more than 90% of the entire production cost. The remaining two critical stages in ammonia production, specifically nitrogen purification and the Haber-Bosch process, contribute only a minor fraction of the total expenditure (IRENA and AEA, 2022). Figure 6 illustrates the significant variation in the cost of producing green hydrogen throughout Asia.

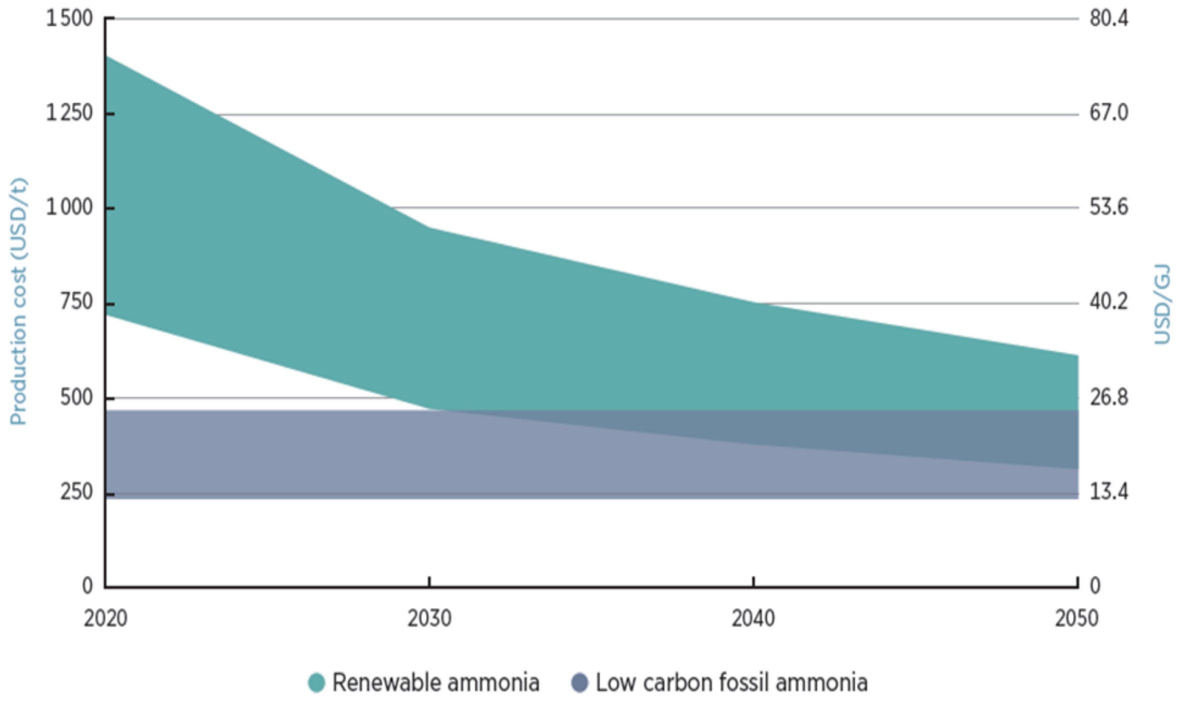
**Figure 6: Green hydrogen production cost 2030**




Source: IEA, 2019

Owing to divergent costs in green hydrogen production, the cost of green ammonia will also have significant variations. The estimated cost of producing renewable ammonia in new plants currently ranges from USD 720 to USD 1,400 per ton, but this figure is projected to decrease considerably by 2050 to a more affordable USD 310-610 per ton (Figure 7). For existing ammonia plants, using co-produced fossil-based and renewable hydrogen is an effective strategy for reducing costs by utilising readily available assets and infrastructure. Hybrid plants, on the other hand, are expected to cost around USD 300-400 per ton by 2025, with an anticipated reduction to approximately USD 250 per ton by 2040 (IRENA and AEA, 2022).

**Figure 7: Ammonia production costs (renewable and low-carbon fossil ammonia)**




Source: (IRENA and AEA, 2022)

At present, the cost of producing natural gas-based ammonia and coal-based ammonia ranges from USD 110-340 per ton. However, the addition of carbon capture and sequestration (CCS) would increase these costs by an extra USD 100-150 per ton, bringing the production costs of low-emission fossil-based ammonia up to USD 210-490 per ton. It is worth noting that the cost of low-emission fossil-based ammonia is comparable to that of renewable ammonia from hybrid plants in 2025. However, it is more expensive than renewable ammonia from some new plants in 2050 (IRENA and AEA, 2022). In 2020, Japan imported the world's first shipment of blue ammonia from Saudi Arabia (Benny, 2023).

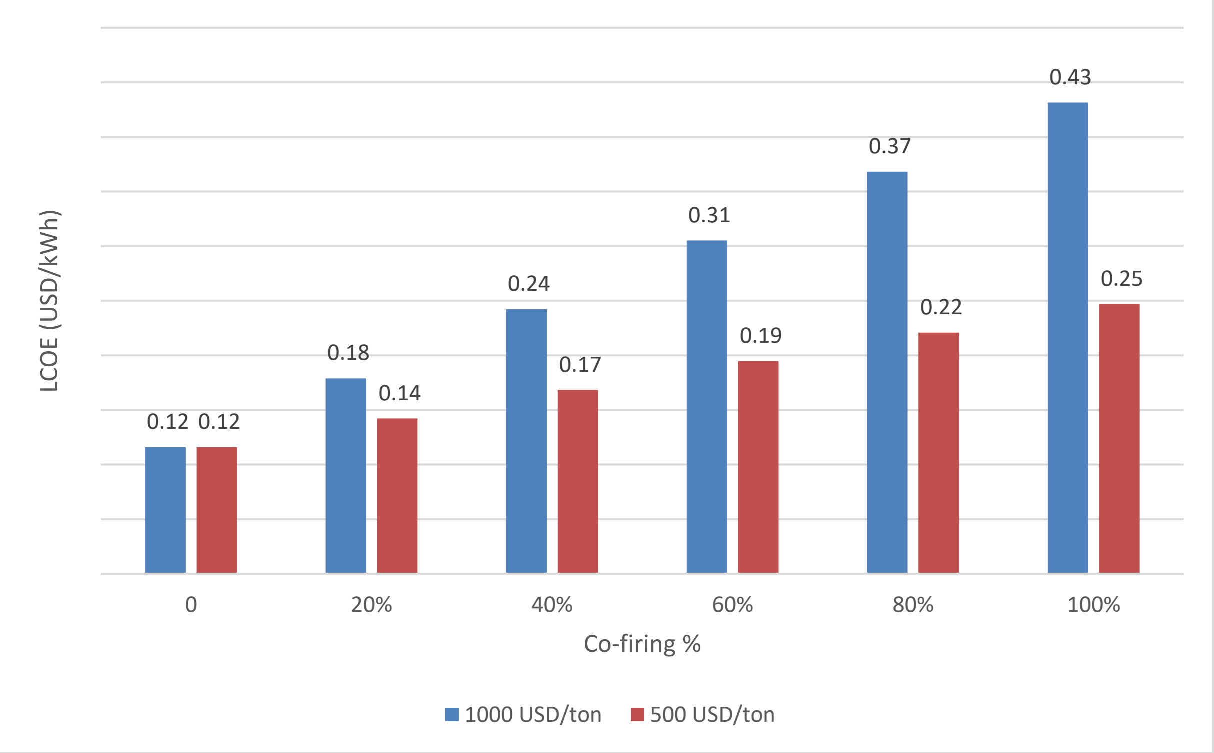
The LCOE calculation is based on the assumption that the initial year is 2025 and a project lifespan is 25 years. It takes into account two pricing scenarios: USD 1000 per ton for green ammonia and USD 500 per ton for blue ammonia. The cost reduction is projected to follow a similar trend as illustrated in Figure 7, gradually decreasing until it reaches parity with current ammonia costs. Additional assumptions and details of the model can be found in the Appendix.

### 3.2.1 Model Results

Initially, a comparison was made between the model results and the LCOE of various Asian nations that rely on coal. According to the model, the LCOE for the base case (100% coal) was calculated to be 0.116 USD/kWh. When compared with other Asian countries, the results were deemed acceptable as they fell within the same range. For example, China's LCOE is 0.090 USD/kWh, India's is 0.084 USD/kWh, Indonesia's is 0.108 USD/kWh, Japan's is 0.133 USD/kWh, the Philippines' is 0.147 USD/kWh, South Korea's is 0.128 USD/kWh, and Vietnam's is 0.126 USD/kWh (IRENA, 2023).

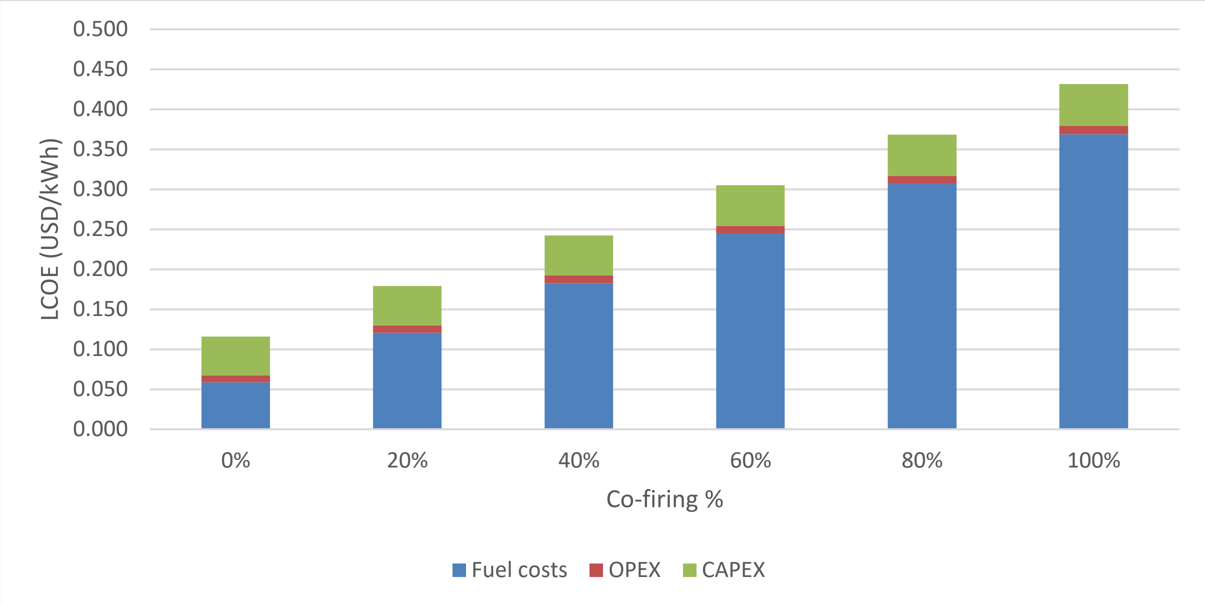
Based on the model's analysis, as the proportion of ammonia usage increases, there is a notable rise in the LCOE (see Figure 8). The extent of this increase is largely dependent on the price of ammonia. For instance, if the cost of ammonia is 1000 USD/ton, the LCOE at 100% ammonia firing is nearly four times higher than the baseline scenario. However, if the cost of ammonia is 500 USD/ton, the LCOE only doubles compared to the base case, as demonstrated in Figure 8. The increased cost can be attributed primarily to the cost of ammonia itself (see Figure 9).

**Figure 8: LCOE at different levels of co-firing**




Source: Author Calculations

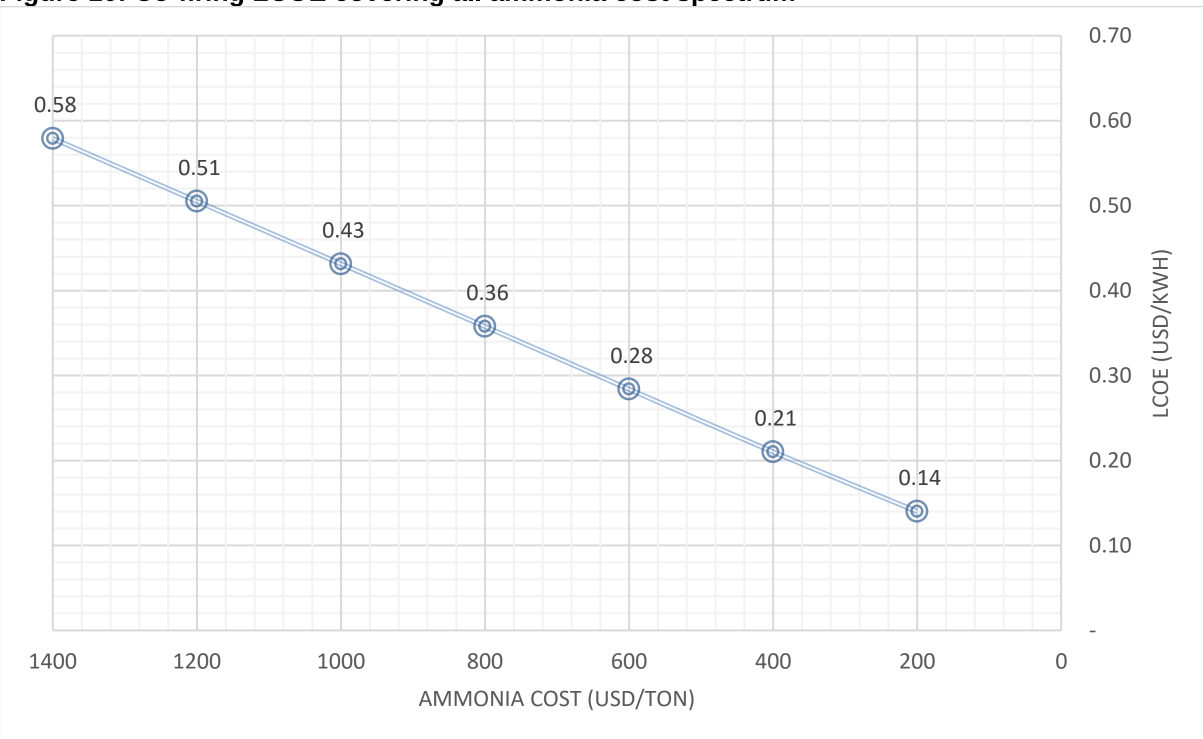
**Figure 9: LCOE cost component (assuming ammonia cost = 1000 USD/ton)**




Source: Author Calculations

In order to assess the influence of varying ammonia prices on the LCOE, a thorough sensitivity analysis was carried out, encompassing the entirety of the cost spectrum. The results indicate that reduced ammonia prices lead to a corresponding reduction in LCOE. Notably, the LCOE spanned from 0.58 USD/kWh at the highest estimated ammonia cost level of 1400 USD/ton according to IRENA, down to a mere 0.14 USD/kWh at the lowest estimated cost of 200 USD/ton (see Figure 9).

**Figure 10: Co-firing LCOE covering all ammonia cost spectrum**

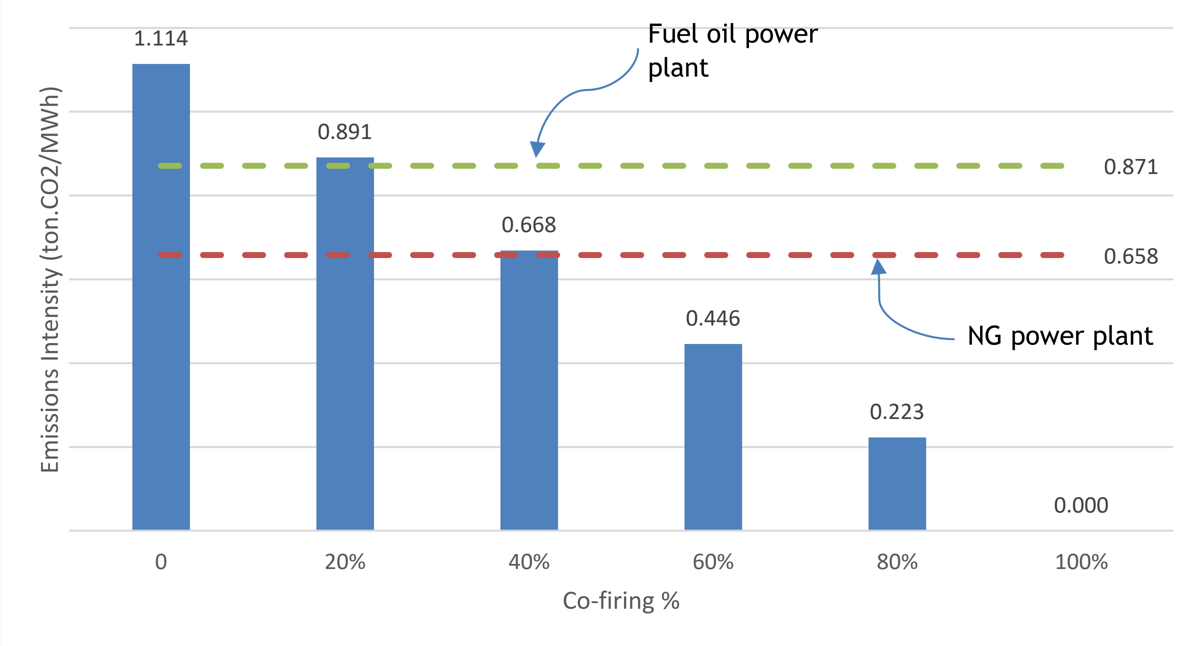



Source: Author Calculations

### 3.2.2 Emissions

In order to gauge the decrease in emissions achieved by co-firing, an online resource that calculates emission intensity was utilised[4] .This tool is versatile and can also provide estimations for the emissions of natural gas and fuel oil power plants that share similar parameters such as capacity, efficiency, and capacity factor. Our findings demonstrate that the application of 20% ammonia in co-firing would yield an emission intensity on par with that of fuel oil power plants operating at the same efficiency and capacity factor. Moreover, a 40% ammonia co-firing approach would result in a comparable emission intensity to natural gas power plants that operate under the same conditions as depicted in Figure 11.

**Figure 11: Emission intensity at different co-firing rates**




Source: Author Calculations

## 3.3 Discussion

The results of the model are consistent with previous studies. For instance, a BNEF study estimated the LCOE between $0.324 and 0.269 USD/kWh, depending on ammonia costs ranging from $1000 to $550. The model's results are between $0.430 and $0.250 /kWh, assuming ammonia costs between $500 and $1000 per ton (BNEF, 2022). There is a slight difference at the high end, which may be due to our model assuming a lower efficiency for the coal power plant compared to Japan's more efficient plants. IEA has estimated that the LCOE for co-firing 20% and 60% low-carbon ammonia from Saudi Arabia ranges from $260 to $390 per ton. For the former, the LCOE is estimated to be between $0.10 to 0.145 USD per kWh, and for the latter, it is estimated to be between $0.12 to 0.175 USD per kWh (IEA, 2021). These estimates are similar to the model's results.

### 3.3.1 Comparison with Renewables

To thoroughly assess the efficacy of co-firing technology, it is imperative to evaluate it alongside other alternative technologies. Specifically, we will compare it to renewable technologies such as PV, onshore, and offshore wind. To facilitate this comparison, we will be utilising the LCOE for renewable plants, which was derived from the IRENA report entitled "Renewable power generation costs in 2022" (IRENA, 2023).

[4] https://capraenergy.com/powerplant-emissions-calculator/, The tool calculates the emission intensity based on capacity, thermal efficiency, capacity factor, and fuel.

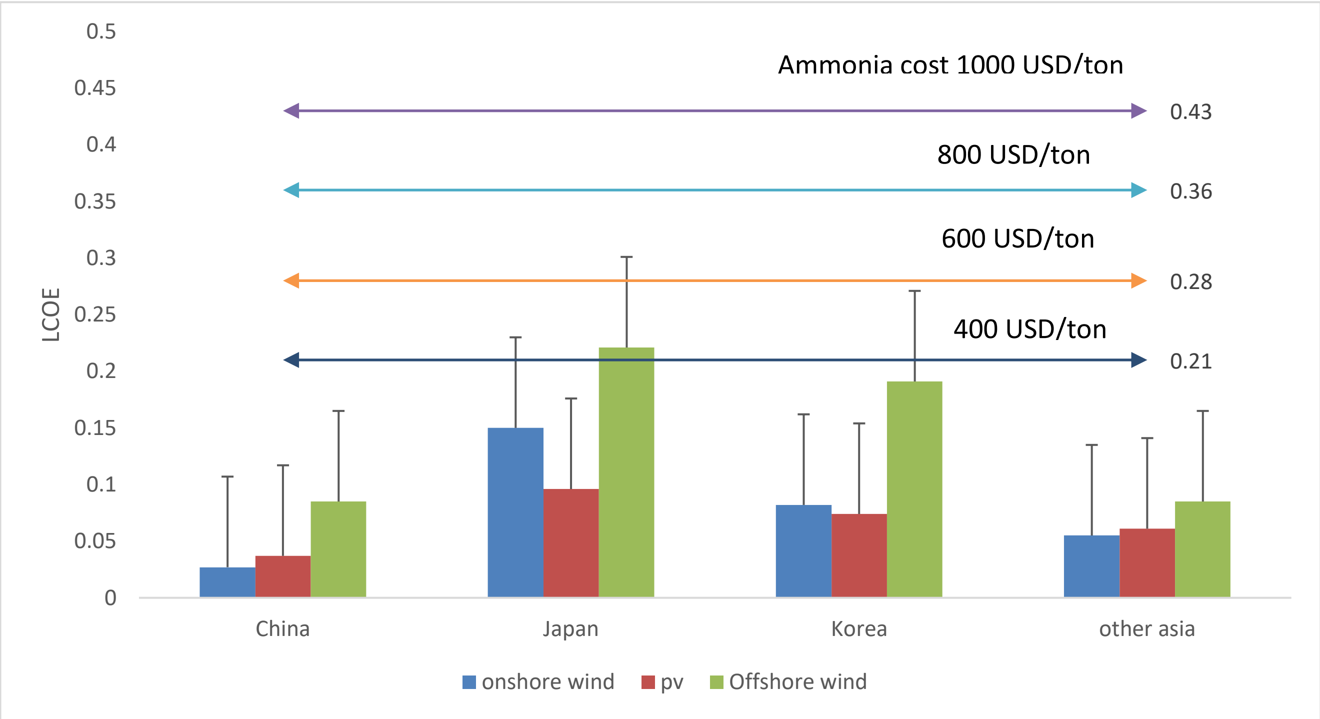
To provide a comprehensive analysis, the report has categorised the costs into three groups: low, average, and high. The low case denotes the 5th percentile, the average case represents the average cost, and the high case represents the 95th percentile (IRENA, 2023).

The levelized cost of electricity (LCOE) is commonly used to assess renewable plants, but it fails to consider the entire cost of integrating renewable energy into the power grid, including 'hidden costs' like backup and balancing expenses. Several Asian countries have confronted difficulties due to the growing adoption of renewable energy and have taken measures to combat them. It is anticipated that numerous other Asian countries will confront comparable challenges in the future as they increase their dependence on renewable energy sources (World Energy Council , 2020).

The term 'grid-level costs' pertains to the supplementary expenses that arise when incorporating renewable energy sources into the power grid. These costs can be categorised into four groups: backup, balancing, grid connection, and grid reinforcement and extension. The overall grid-level costs are expected to fluctuate between 15 to 80 USD/MWh in Asia, depending on the extent of renewable energy integration (World Energy Council , 2020).

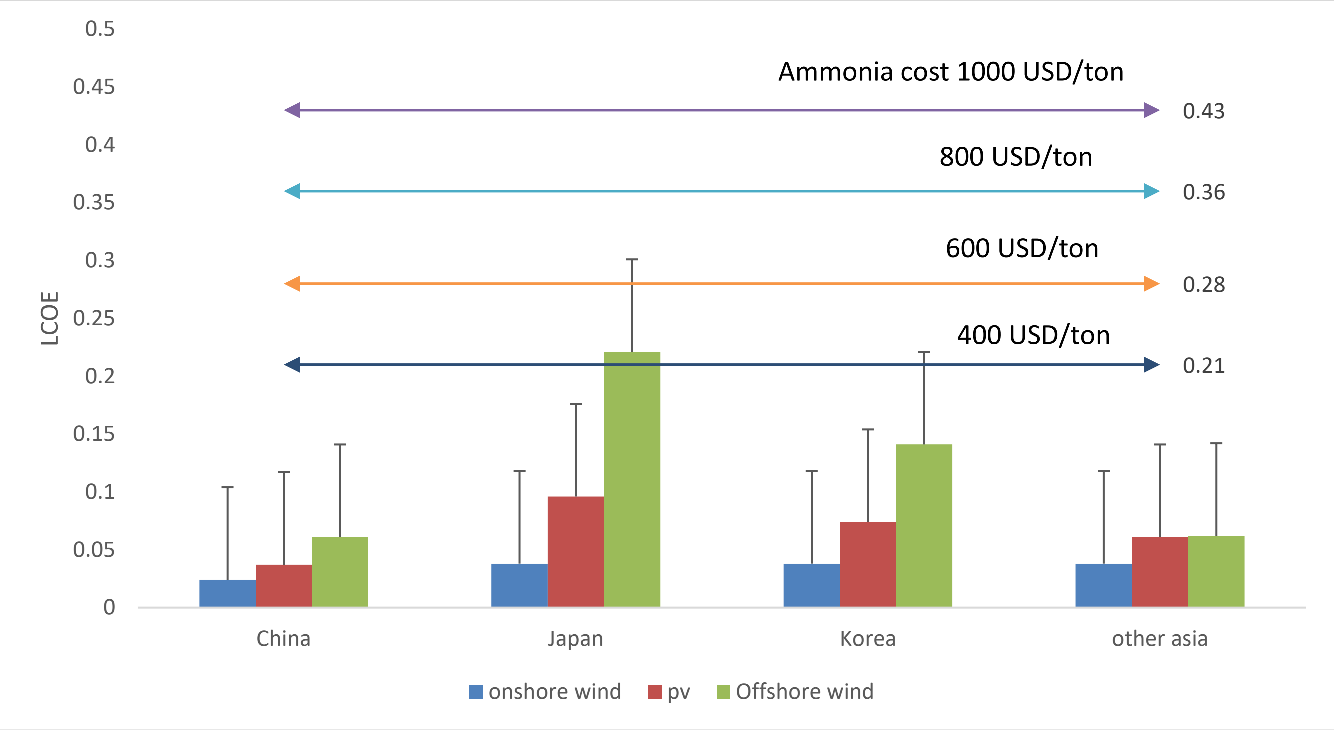
In order to assess the practicality of ammonia co-firing, we must merge the expenses of renewable energy production with projected grid costs and weigh them against the anticipated costs of ammonia co-firing. Our benchmark for comparison will be the cost of 100% ammonia substitution, which boasts zero carbon emissions. Figures 12, 13, and 14 present the various levels of ammonia costs when compared to low, average, and high scenarios for renewable energy expenses.

**Figure 12: Renewable Vs 100% ammonia, average case**



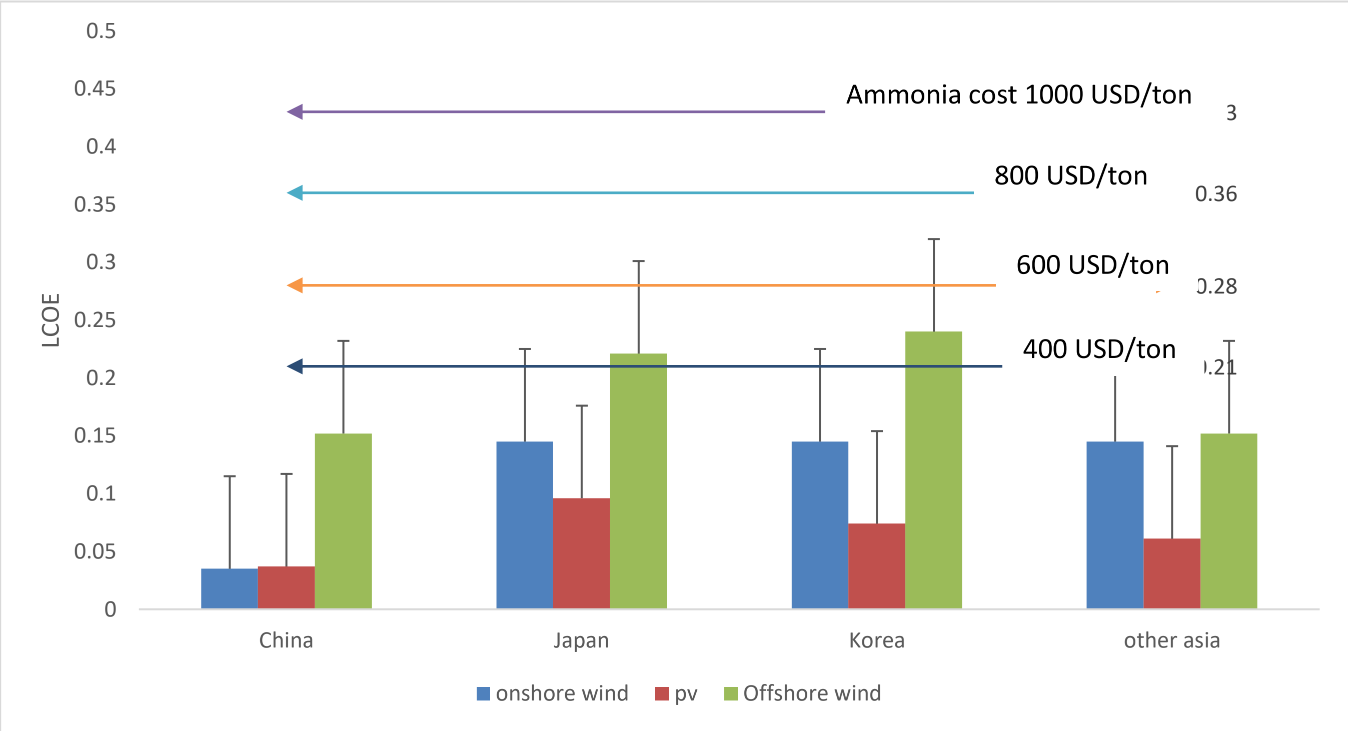

Source: Author drawing, Error bars represent the grid costs, PV values are average only in all cases; the value of offshore wind in Japan is the same for all cases.

**Figure 13: Renewable vs 100% ammonia, low case**




Source: Author drawing, Error bars represent the grid costs, PV values are average only in all cases; low case values for Japan and Korea were estimated as other Asia, and the value of offshore wind in Japan is the same for all cases.

**Figure 14: renewables vs 100% ammonia, high case**




Source: Author drawing, Error bars represent the grid costs, PV values are average only in all cases; low case values for Japan and Korea were estimated as other Asia, and the value of offshore wind in Japan is the same for all cases.

Based on the data presented in the above graphs, it appears that ammonia fuel may offer a more economical alternative to other renewable energy sources in select countries. However, certain prerequisites must be met before realising these cost benefits. In situations where land availability constraints prevent the deployment of PV technology, and high grid cost to connect onshore and offshore wind, ammonia firing could be the preferred option. The grid costs associated with onshore and offshore wind energy tend to be higher, which could be attributed to the high penetration of renewable energy sources or the need for costly transmissions due to the plants' remote location.

It is necessary for the requirement mentioned above to be fulfilled when the cost of ammonia is relatively low and lies between the range of 400-500 USD per ton. This could be a possible reason why a country such as Japan is showing interest in ammonia. Various studies conducted in Japan have revealed that the approximate cost of blue ammonia is around 400 USD/ton (k.Hiraoka, et al., 2018) (Tainaka, et al., 2023).

### 3.3.2 Blue versus green ammonia

Numerous Japanese utilities are presently exploring the feasibility of producing blue ammonia in Australia. Additionally, Marubeni aims to develop a blue ammonia supply chain from Canada. In a collaborative effort, heavy industry manufacturer IHI, shipping company Mitsui O.S.K. Lines, and oil company INPEX are conducting a demonstration project aimed at producing and shipping blue ammonia from the United Arab Emirates. Similarly, JERA has agreed to partner with a UAE state-owned oil and gas company to work on ammonia. In Saudi Arabia, the Japanese government and Japanese firms are also supporting a blue ammonia project with Aramco (Giseburt, 2023).

Furthermore, JERA has signed a Memorandum of Understanding (MOU) with Yara Clean Ammonia Norge AS (YCA) to collaborate on developing a one million-ton-per-annum blue ammonia project on the US Gulf Coast (JERA, 2023). JERA is also involved in two other low-carbon ammonia projects in the United States. The first project entails a Joint Development Agreement with CF Industries Holdings, Inc. to jointly explore the development of a low-carbon ammonia production facility with an annual capacity of approximately 1.4 million tons, to be located at CF Industries' Blue Point Complex in Louisiana (JERA, 2024). The second project is in collaboration with ExxonMobil, with whom JERA has reached a Project Framework Agreement to jointly explore the development of what is expected to be the world's largest low-carbon hydrogen production plant at its Baytown Complex east of Houston, Texas, United States. The plant is expected to have an annual production capacity of approximately 900,000 tons of low-carbon hydrogen and more than one million tons of low-carbon ammonia. The Project aims to commence production in 2028 (JERA, 2024).

As per IRENA projections, it is anticipated that the cost of green ammonia will achieve parity with that of low-carbon ammonia by 2030. This development may pave the way for the potential replacement of low-carbon ammonia with green ammonia.

The production of blue ammonia, while promising, raises concerns.

First, the expected decline in green ammonia cost might not happen as fast as expected. According to a recent report by the Hydrogen Council and management consultancy McKinsey (Hydrogen Council, Mckinsey $ Company, 2023), the cost of producing green hydrogen without subsidies has increased by 30-65% in the 12 months leading up to June 2023. The cost has risen to $4.50-6.50 per kilogram, in comparison to $2.50-4.50 per kilogram in the middle of last year. The report cites several reasons for this increase, including higher labour and material costs, higher expenses for building the balance of electrolyser plants, 3-5 percentage points higher cost of capital, and an increase of more than 30% in renewable power costs (Collins, 2023). However, the recent cost increase does not exclude the possibility that costs could fall in the future due to scaling up and learning by doing effects.

Another major concern is the need to monitor the captured emissions effectively. The process of capturing and storing these emissions is crucial. If the process is not executed correctly, the net emission will increase, resulting in negative environmental impacts (Myllyvirta & Kelly, 2023). Therefore, it is imperative to ensure that the emissions are captured and stored with the utmost care and precision to avoid any potential negative outcomes.

## 4. CCS and synergy with green hydrogen production

This section will address the potential synergies between green hydrogen production and one of carbon capture, utilisation, and storage (CCUS) technologies. These synergies may not necessarily stem from the direct use of hydrogen or its derivatives but rather from the utilisation of a by-product released during the production of green hydrogen. It is imperative to note that this alternative is still in its nascent stage and is not as developed as ammonia co-firing.

In certain countries such as China and India, where the economic viability and competitiveness of renewable energy generation are apparent, the implementation of ammonia co-firing or complete ammonia substitution to mitigate carbon emissions from coal power plants may be considered less feasible. Consequently, CCS emerge as a promising alternative for the decarbonisation of coal power plants while also offering additional benefits associated with green hydrogen production, as will be elucidated subsequently.

Asia is following the international trend with the increased interest in carbon capture, utilisation, and storage (CCUS). Currently, there are at least seven potential CCUS projects in the early development stages in Indonesia, Malaysia, Singapore, and Timor-Leste. Singapore recognises the pivotal role of CCUS in its long-term emissions reduction strategy and is actively seeking research and international partnerships, including with Australia. The establishment of the Asia CCUS Network in 2021 marks a significant milestone towards promoting collaboration and the deployment of CCUS in the region (IEA, 2021). In Asia, there are approximately 1030 MW coal plants that have CCS (Global Coal Plant Tracker, 2024).

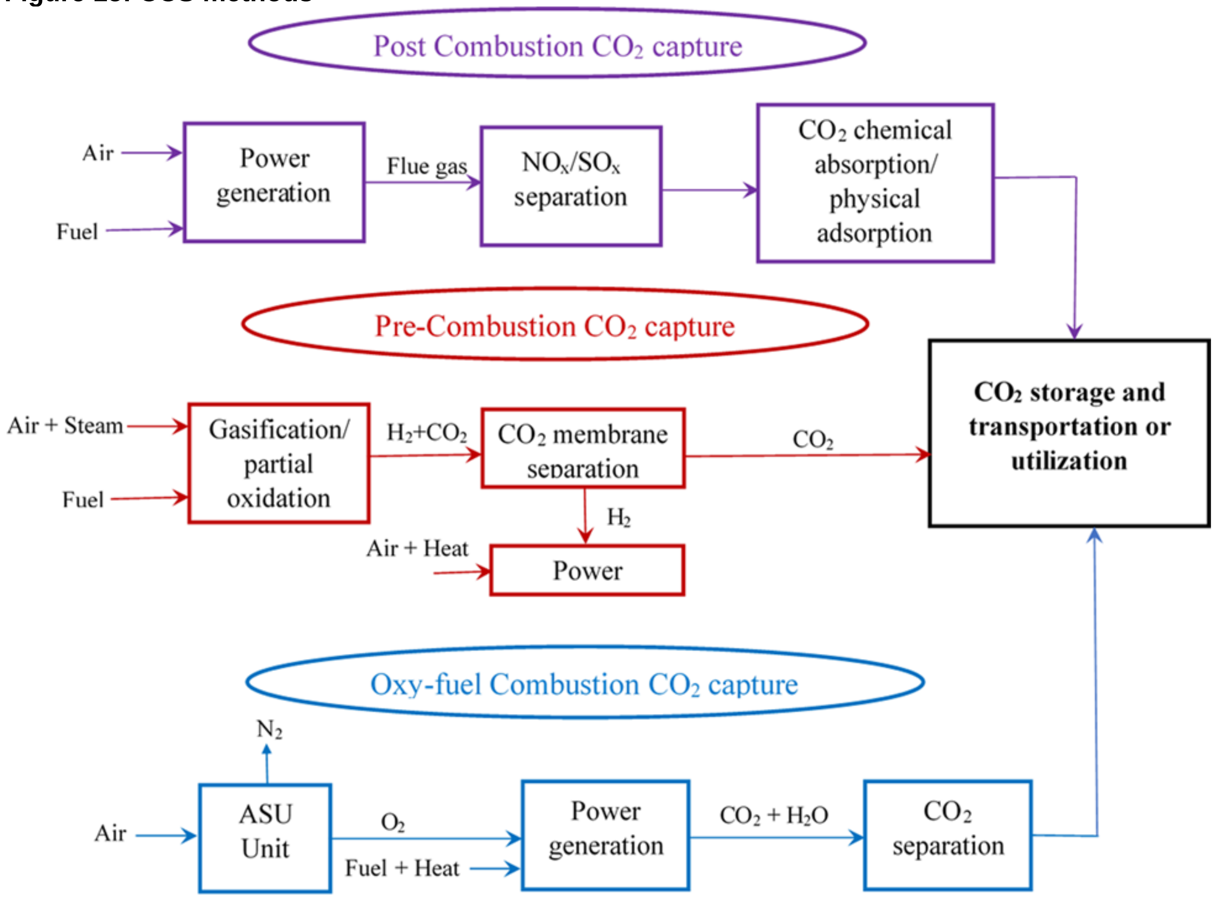
### 4.1 CCS Technologies for reducing CO2 Emissions from coal-fired power generation

Three technologies exist for reducing CO2 emissions from coal-fired power generation: post-combustion capture, pre-combustion capture, and oxyfuel combustion capture (see Figure 15).

- **Post-combustion capture** is a process that involves separating CO2 from flue gases using chemical solvents and sorbents (such as calcium oxide or carbon fibres and membranes) without altering the combustion process. However, adding a post-combustion capture unit may affect the steam cycle as a significant amount of low-pressure steam needs to be extracted from the cycle to allow for solvent regeneration (Chen, et al., 2011).
- The process of **pre-combustion capture** entails the conversion of fuel into syngas, which is a combination of hydrogen and carbon monoxide. Subsequently, steam reforming is employed to treat the syngas, whereby CO2 is separated from it using steam. This culminates in the production of pure hydrogen via the water gas shift reaction (Chen, et al., 2011).
- **Oxy-fuel combustion** refers to the process of utilising pure oxygen or a combination of recycled flue gas and oxygen in lieu of air to generate a concentrated CO2 product gas. This process brings about a significant transformation in the combustion procedure (Chen, et al., 2011).

Recently, a study was conducted to compare three different CCS methods (Kheirinik, et al., 2021). The results of the study showed that pre-combustion is the costliest method to implement and operate over its lifespan. This is due to the significant investment required compared to the post-combustion power plant and oxy-fuel CCS technology. On the other hand, Oxy-fuel had the lowest LCOE. However, the Oxy-fuel process has yet to be implemented on a commercial scale, despite its economic benefits in terms of LCOE, capital, and investment costs. Finally, post-combustion is the most mature technology and is currently in operation on a commercial scale (Kheirinik, et al., 2021).

**Figure 15: CCS methods**




Source: (Yadav & Moddal, 2022)

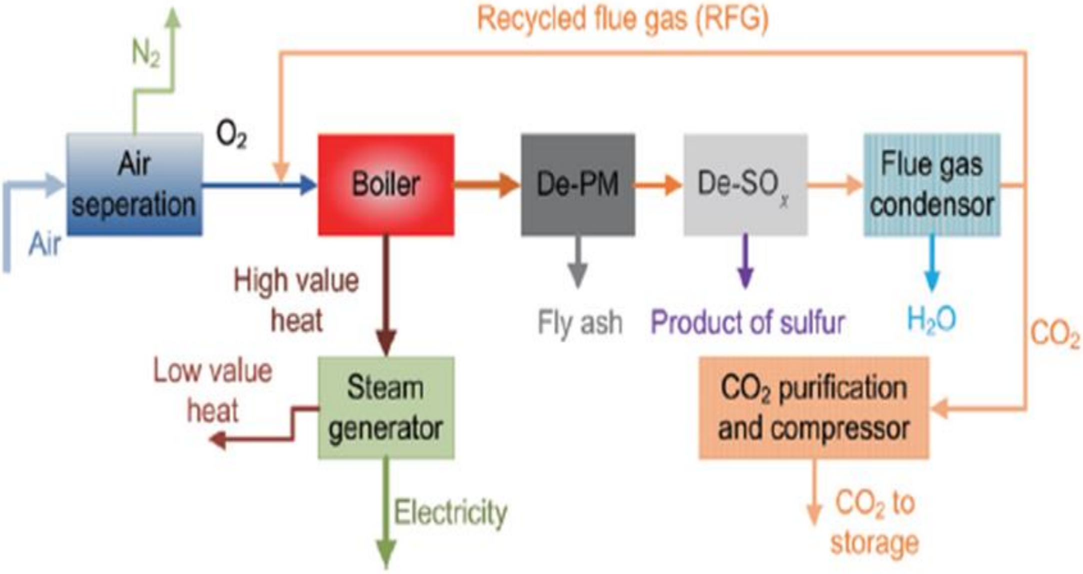
## 4.2 Oxy-Fuel CCS

This paper will focus on the Oxy-fuel Carbon capture method, which synergises with green hydrogen production. The Oxy-fuel Carbon capture method requires less energy as compared to the air combustion process, especially if the process aims to remove more than 90% of carbon dioxide. This method can even capture the entire 100% carbon dioxide produced during the combustion process. Additionally, the carbon capture process can function at a lower absorbent/flue gas ratio and with a smaller amount of absorbent than air-based processes. According to several reports, Oxy-fuel is the most economical option among the three CCUS capture methods (Zheng, et al., 2015). It boasts higher thermal efficiency and lower energy penalties compared to the other alternatives. Furthermore, this technology is adaptable and can be incorporated into both new and existing power plants without any technological hindrances. In addition, it is an eco-friendly process that can concurrently eliminate pollutants (Zheng, et al., 2015).

Oxy-fuel combustion is a process that involves the use of a mixture of pure oxygen and recycled flue gas instead of the traditional air-fired environment. This results in a flue gas that is mostly composed of carbon dioxide (CO2) and water vapour (H2O), which can be compressed and stored underground through a process called geosequestration. Figure 16 shows a schematic diagram for Oxy-fuel combustion.

To retrofit existing coal-fired power plants, several additional pieces of equipment are deemed necessary for functioning CCS oxy-fuel plants. The primary additional equipment required includes the Air Separation Unit (ASU), CO2 Compression and Purification Unit (CPU), and Flue Gas Recycling (FGR) system.

**Figure 16: Schematic diagram for oxy-fuel plant**




Source: (Zheng, et al., 2015)

**Air Separation Unit (ASU):** The ASU produces an oxygen-rich stream for combustion. Cryogenic distillation is the most suitable ASU technology for large-scale coal-fired utility boilers. The process involves compressing, cooling, and cleaning air before separating it into an oxygen-rich stream and a nitrogen-rich stream in a distillation column. Oxygen afterwards is combusted with coal instead of air. However, using the ASU method consumes a significant amount of energy (about 0.24 kWh/kg $O_2$ with 95% oxygen purity), with cryogenic separation processes consuming more than 15% of gross power output. Despite the lower oxygen purity requirement for oxy-coal combustion (85-98%) compared to the process industry (99.5-99.6%), it is still an energy-intensive process (Chen, et al., 2011). The elimination of the ASU could be achieved by sourcing oxygen from a green hydrogen production plant, where oxygen is produced as a by-product. This will be explained below.

**Carbon dioxide purification unit (CPU):** A CPU is employed to purify flue gas prior to compression for storage. The CPU comprises gas cleanup units that effectively eliminate water, particulate matter, and other pollutant gases from the flue gas. Although retrofits are compatible with oxy-combustion, pollutant control devices such as selective catalytic reduction (SCR), electrostatic precipitator (ESP), and flue gas desulphurisation (FGD) are commonly utilised to remove NOx, particulate matter, and SOx from the flue gases. Such control devices are also well-suited for use with amine-type absorbents in post-combustion capture plants (Chen, et al., 2011).

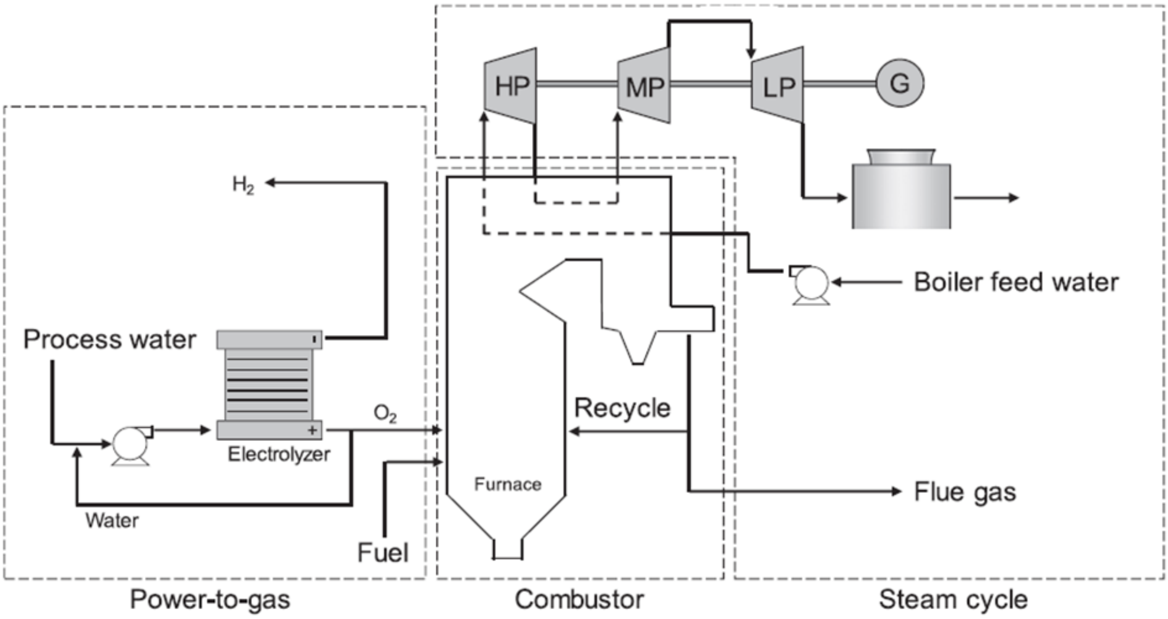
**Flue gas recycling (FGR) system:** When oxygen is burned instead of air, the combustion temperature increases considerably. To moderate the combustion temperature, recycled flue gas is needed to replace nitrogen in the air. Flue gases can be recycled in different locations downstream of the economiser as dry or wet recycling, depending on system efficiency and operational practices.

The Oxy-fuel boiler needs to be upgraded so that the coal is combusted in an oxygen-rich environment. This requires a more extensive and expensive upgrade of the plant, and energy is required for the production of oxygen from the air, but there is a cost-saving in $CO_2$ separation compared to post-combustion CCS because the resulting flue gas stream is almost 100% $CO_2$ (IEA, 2021).

Adding CCS to a power plant incurs an operational cost due to the reduction of efficiency caused by the energy requirements of $CO_2$ capture, transport and storage. $CO_2$ capture is responsible for the overwhelming majority of additional energy requirements, which translate into fuel costs for power plant operators (IEA, 2021). The efficiency penalty depends on the type of $CO_2$ capture technology used, but for Oxy-fuel, it is usually considered to be 8-12%, with ASU and CPU having a major impact on the economics and efficiency of the plant (IEAGHG, 2010). The ASU has the highest impact and represents approximately 60% of the efficiency loss (Xuchen, et al., 2023). Other additional operational costs, like solvent purchases, have lower costs compared to the impact on fuel purchases per unit of output.

Green Hydrogen can be produced by electrolysing water with renewable energy, which also results in the production of oxygen as a by-product. For every kilogram of hydrogen produced, 8 kilograms of oxygen are also produced. As a result, large-scale industrial production of green hydrogen will generate a substantial volume of oxygen. This presents an opportunity to utilise oxygen in various medical, industrial, and other applications, which will significantly enhance the feasibility of different industrial processes. But it also can be effectively employed in an Oxy-fuel combustion power plant system. This system will eliminate the need for an independent ASU to ensure an uninterrupted and pure supply of oxygen. The adoption of this approach can lead to significant reductions in equipment, energy, and operational costs of the system. In order to gain a better understanding of this concept, the accompanying schematic diagram illustrates an Oxy-fuel plant that is integrated with an electrolyser (Figure 17).

**Figure 17: Schematic diagram for Oxy-fuel plant integrated with electrolyser**




Source: (Sohn, et al., 2021)

The utilisation of by-product oxygen from green hydrogen production has been widely investigated. For example, Kato, et al. (2005) examined the use of by-product oxygen in blast furnaces, electric arc furnaces, glass melting, electric power plants, gasification process, and medical care (Kato, et al., 2005). Berenschot (Dutch consulting firm) investigated if Oxygen synergy[5] will have economic and/or technical potential. The conclusion is that Oxygen synergy leads to reduced $CO_2$ emissions and reduced costs and, therefore, deserves to be taken into account in hydrogen projects (Berenschot, 2019).

The utilisation of oxygen by-products in the decarbonisation of coal power plants is not a new concept. The IEA introduced this idea in its report "The Role of Low-carbon Fuels in the Clean Energy Transitions of the Power Sector" (IEA, 2021). Furthermore, Sohn et al. (2021) conducted a study on the concept and concluded that the resulting net power generation and power-generation efficiency were superior to those of individual oxy-fuel power plants supplied with oxygen through an air separation unit (Sohn, et al., 2021). However, it is imperative to note that these proposals are at the early stage (e.g., the modelling stage) and not mature as co-firing ammonia.

## 4.3 Model Results

A simple model was created to determine the LCOE for coal power plants that have been retrofitted with Oxy-fuel combustion technology. This model takes into consideration various factors and assumptions that are crucial for calculating the LCOE and can help understand the feasibility of such retrofitted power

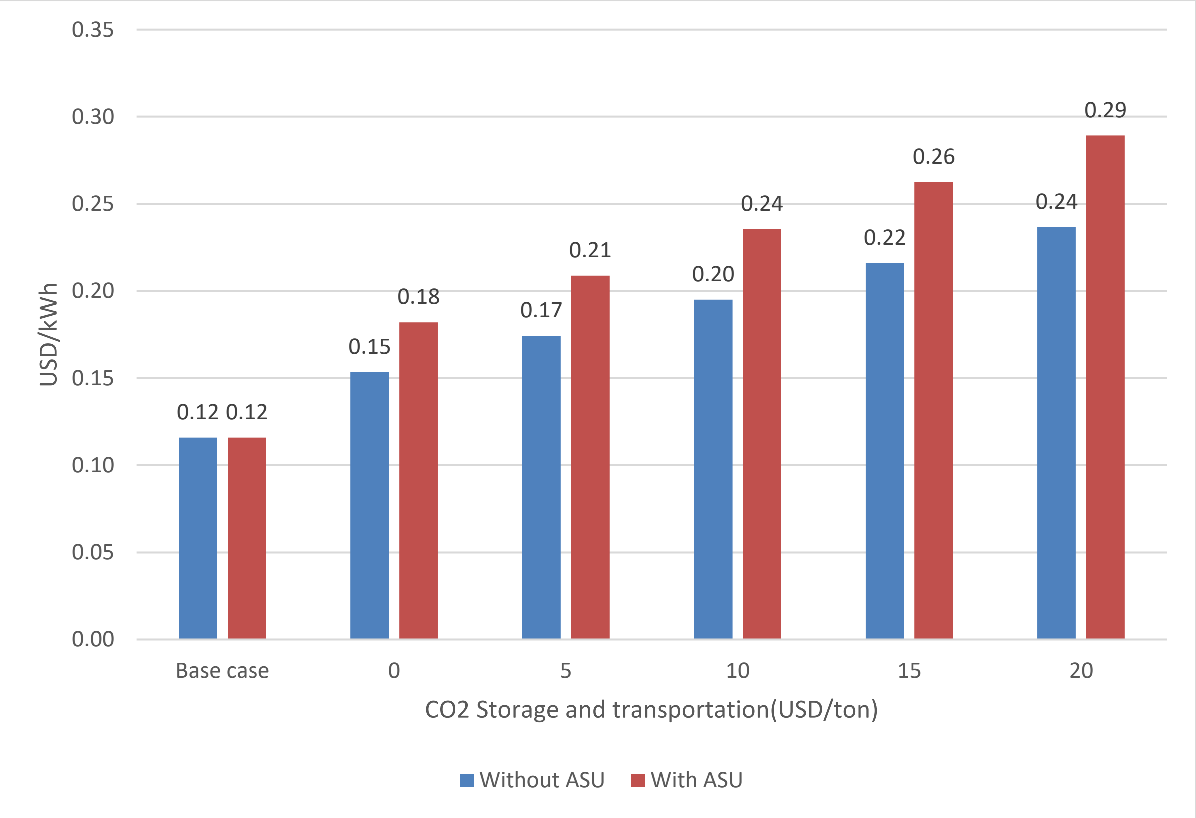
[5] They define Oxygen synergy as the effective use of the oxygen from electrolyser in other processes that use oxygen.

plants. The model's assumptions were collected from various sources and presented in the Appendix. However, the economic assumptions were collected from the Callide Oxy-fuel Project's final results[6]. The Project objective is to Demonstrate Oxy-combustion boiler operation and oxyfuel CO2 capture. The details of the model's assumptions can be found in the appendix.

According to the model results, if ASU is not used, the LCOE will increase by around 30%, and if ASU is employed, it will increase by 57%. However, these numbers do not consider the cost of transporting and storing CO2, which can vary widely depending on the geologic settings, locations, transport and storage technologies, and scales. Many Integrated Assessment Model (IAM) studies combine the cost of CO2 transport and storage into a single estimate and report costs below $15 per ton of $CO_2$ ($tCO_2$) for most CCS deployment scenarios. Some estimates even report costs below $5/$tCO_2$ (Smith, et al., 2021).

According to the 2014 IPCC Fifth Assessment Report, the usual assumption for the cost of $CO_2$ transport and storage is $10/$tCO_2$ (Smith, et al., 2021). IEA estimated the cost of transportation and storage of $CO_2$ to be 20 USD/ton (IEA, 2021). The LCOE was calculated at the transportation and storage cost of 5, 10, 15, and 20 USD/ton. Figure 18 shows the results of the model with rounded numbers. The base case represents the LCOE with no CCS.

**Figure 18: LCOE for retrofitted oxy-fuel coal power plant**



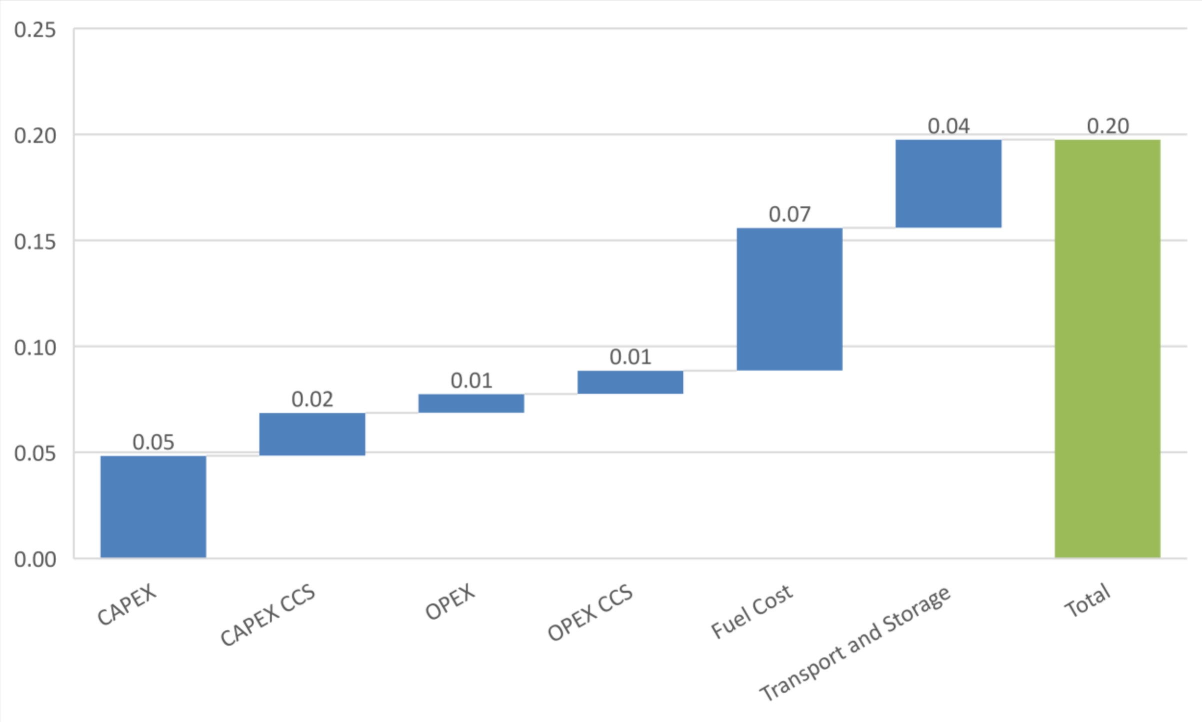

Source: Author Calculations

The model results are in line with the findings and conclusions of the Callide project. According to the project's results, the operation and maintenance costs would increase from 1.5 to 2, leading to the increase of LCOE with the same amount due to increased operation and maintenance costs and other factors such as transportation and storage costs. If we assume that the transportation cost is 10

[6] The Callide Project was a demonstration of the feasibility of CCS Oxy-fuel and $CO_2$ storage options in Queensland, Australia. The Oxyfuel boiler began operating in March 2012, and the $CO_2$ Capture Plant started in December 2012. The operational phase of the project was concluded in March 2015.

USD/ton, the cost will double if ASU is used and increase by 68% if no ASU is used. As shown in Figure 19, the OPEX is doubled after implementing CCS.

**Figure 19: LCOE cost components; without ASU, storage and transportation costs are 10 USD/ton**




Source: Author Calculations

### 4.4 Discussion

The utilisation of byproduct oxygen produced during the electrolysis process can lead to a considerable reduction of 20% in the LCOE compared to the base case where an ASU is needed. This occurs because of eliminating the requirement for an ASU, which is responsible for producing oxygen separately. It is a cost-effective solution that can be implemented locally, but it is important to note that the model does not consider costs for buying oxygen or for any additional costs that may be incurred during the transportation of oxygen. Therefore, this opportunity should be evaluated based on the specific circumstances and location. The feasibility of this solution will depend on various factors, such as the size of the electrolyser plant, RE availability, carbon tax, and infrastructure, among others.

It is imperative to factor in the cost of storing and transporting $CO_2$, as these expenses can contribute significantly to the overall expenditure. As discussed before, the cost of transporting and storing $CO_2$ can vary widely between projects depending on the geologic settings, the distance of the oxyfuel facility from $CO_2$ storage, and the availability of existing infrastructure for transportation and storage technologies. A noteworthy example of this is when the cost of storage and transportation increases from \$10 to 20 USD per ton, resulting in a 20% rise in LCOE from 0.2 to 0.24 USD/kWh. The development of transportation from the power plant to the location where the CO2 will be stored presents a challenging undertaking. As such, meticulous planning and careful consideration of costs are necessary.

The prospect of CCS has been gaining increasing traction in the Asian market. But it is imperative that Asia's focus on CCS development is aligned with critical mass and commercial viability, given that government support and coordinated policies are still less mature than those in Europe. Nevertheless, with the vast volumes of CO2 involved, Asia is expected to eventually overtake Europe as the leading CCS market (Lampert, 2023).

Countries across Asia are advancing at varying rates in the development of CCS infrastructure. Given Southeast Asia's limited geographical expanse and the presence of oil and gas infrastructure in close proximity to suitable geological sites, the region is strategically positioned to establish a CCS hub. Such a hub could provide comprehensive $CO_2$ storage solutions for the nations within the region and neighbouring jurisdictions. The implementation of a CCS hub-and-cluster network presents significant cost efficiencies, notably by reducing the unit costs associated with $CO_2$ transportation and storage. This network model also enhances its appeal to potential investors while concurrently mitigating financial risks for individual stakeholders. Moreover, the network structure offers enhanced operational flexibility through the facilitation of multiple operators and customers, thus enabling seamless storage site transitions in the event of scheduled or unscheduled outages (Zhang, 2020).

In short, the utilisation of Oxy-fuel CCS technology could present the possibility of yielding a comparable LCOE when compared to ammonia co-firing. The former is primarily contingent on the cost of carbon dioxide transportation and storage, while the latter is highly sensitive to the expense incurred in sourcing ammonia. Notably, both technologies can be retrofitted into existing coal power plants, although neither has achieved full commercial maturity.

## 5. Conclusion

The Asia-Pacific region is facing a daunting task when it comes to reducing coal consumption, given the economic realities at play. Many of the region's largest economies are experiencing a surge in electricity demand, a trend that is expected to persist over the next few decades in order to sustain economic growth.

While there are various options available to meet this demand, coal remains the most affordable option for base-load power. At the recent U.N. Climate Change Conference (COP26), China and India were the only two major countries that did not commit to phasing out coal, instead agreeing to gradually reduce its use. China's coal-fired power generation will remain stable over the next decade, with its share in power generation dropping to 51% by 2030 from the current two-thirds. Conversely, the growth of renewables in China will remain swift. In India, coal-fired power generation will still see significant growth over the next decade to meet the rising demand, despite more than 40 countries pledging to phase out coal at COP26 (Kramarchuk, 2022).

The relatively slow pace of the shift away from coal in Asia generally can be attributed, in part, to the youthfulness of its coal-fired power generation fleet. The average lifespan of coal plants in the United States and Europe ranges between 40 and 50 years, with many approaching the end of their operational lives. In contrast, a significant portion of Asia's coal power fleet has been constructed within the past decade, making the probability of plant closures prior to 2030 unlikely. Moreover, coal exports in certain countries within the region are an essential source of revenue, prompting some governments to support coal mining and coal-fired power generation through subsidies and public financing. The cessation of coal power generation will have substantial social implications.

The decarbonisation of coal power plants is a complex and multifaceted challenge that cannot be resolved by any single technology. Each alternative presents its own set of advantages and disadvantages, and the selection of a suitable technology must consider a range of local factors. As such, there is no universal solution that can be employed across all scenarios.

In situations or regions where low-cost renewable energy sources are accessible, the co-firing of ammonia and oxyfuel CCS is unlikely to present a viable option. The feasibility of both technologies will predominantly hinge on the cost of ammonia in the ammonia firing technology and the expenses associated with transportation and storage in the oxyfuel technology.

Co-firing ammonia presents an option for decarbonising coal power plants, provided that certain conditions are met. Specifically, the cost of ammonia utilised in the co-firing process must be low, and renewable resources must not be available at a reasonable cost due to limitations in space and high integration expenses. The potential for co-firing ammonia to reduce carbon emissions from coal power plants is significant. However, this approach requires careful consideration of various factors that can impact its feasibility, such as the cost of RE production, the cost of supplied ammonia and the availability of infrastructure. Additionally, potential environmental and safety risks must be assessed and addressed to ensure that the co-firing process is safe and sustainable.

It is recommended that a target of 100% ammonia firing be established to reduce emissions, as utilising up to 40% ammonia results in emissions comparable to those of natural gas power plants. However, achieving this target would necessitate a significant quantity of ammonia, which may result in a substantial increase in the LCOE. To facilitate the co-firing of ammonia, blue ammonia may serve as a less expensive source of ammonia until green ammonia attains cost competitiveness, which is anticipated to occur around 2030, according to IRENA estimates. Nevertheless, it is reasonable to assume that this could take more time to accomplish.

CCS technology can provide a reliable alternative for reducing carbon emissions. Among various CCS technologies, Oxy-fuel is considered a promising option and is expected to be the most cost-effective alternative though it is still at very early stage of development. By leveraging synergies with green hydrogen production, this technology can further reduce costs by eliminating the need for ASU. However, the practicality of CCS technology is heavily contingent on the expenses associated with carbon storage and transportation.

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## Appendix

### Co-firing ammonia assumptions

| Parameter | Unit | Value | Reference/Notes |
|---|---|---|---|
| Technical assumptions | | | |
| Lifetime of the coal power plants | Years | 25 | estimated |
| Plant Capacity | MW | 500 | estimated |
| Plant Capacity factor | % | 53% | Similar to Global Coal Plant Tracker (Global Coal Plant Tracker, 2024) |
| Total thermal efficiency of the plant | % | 30.8% | Almost half of the installed capacity of coal-fired power plants uses subcritical technologies with estimated efficiencies of 30.8% (Global Coal Plant Tracker, 2024) |
| Coal HHV | MJ/kg | 23.0 | From IEA, an estimated 5500 Calories/kg of coal at a cost level of 100 USD/ton at South China CFR. https://www.iea.org/reports/coal-market-update-july-2023/prices |
| Coal emissions intensity | Tons CO2eq/MWh | 1.114 | Using the online tool below. It is on the high side due to the low efficiency of the plant<br>https://capraenergy.com/powerplant-emissions-calculator/ |
| Reduction in the boiler efficiency due to the co-firing ammonia | % for every 10% ammonia share | 0.5% | According to BNEF's estimation, a 20% ammonia blend could potentially reduce thermal efficiency in power plants by approximately 12%. This can be attributed to the need to regulate exhaust NOx emissions (BNEF, 2022). This is not valid as discussed in the emission section. Others assume that the loss is insignificant[7,8]. The model assumption is that for every 10% increase in ammonia co-firing, there is a 0.6% decrease in the thermal efficiency of the power plant[9]. |
| Ammonia HHV | MJ/kg | 22.5 | |
| Financial assumption | | | |
| Coal Cost | USD/ton | 100 | From IEA, an estimated 5500 Calories/kg of coal at a cost level of 100 USD/ton at South |

[7] BNEF. (2022). Japan's Costly Ammonia Coal Co-Firing Strategy. BloombergNEF

[8] Wang, S., & Sheng, C. (2023). Evaluating the Effect of Ammonia Co-Firing on the Performance of a Pulverized Coal-Fired Utility Boiler. Energies, 16(2773).

[9] (Ahmad, et al., 2022)

| Parameter | Unit | Value | Reference/Notes |
|---|---|---|---|
| | | | China CFR. https://www.iea.org/reports/coal-market-update-july-2023/prices |
| CAPEX | USD | 1,200,000,000 | The cost of constructing a modern coal-fired power plant can vary from $1.8 million to $4.5 million per megawatt installed capacity. For a 500 MW power plant, this translates to a total cost of around $900 million to $2.2 billion. (ESFC Investment Group, 2024) |
| Reduction in the capacity factor | % | 0% | As more renewable power plants are added to the electricity grid, the capacity factor for baseload plants like coal is expected to decrease. However, our model estimates that there will be no reduction in the capacity factor. This is based on the assumption that no new coal-fired power plants will be built and that electricity demand will grow strongly. However, the model could be modified to reflect changes in these assumptions. |
| Coal cost annual price increase | % | 1.5% | (RMI, 2022) |
| Fixed OPEX | USD/kWh | 32,000 | (RMI, 2022) |
| Variable OPEX | USD/kWh | 0.002 | (RMI, 2022) |
| Ammonia Cost | USD/ton | 1000/500 | (IRENA and AEA, 2022) |
| Ammonia Annual cost price decrease | % | 4% | It is estimated to be the same as the reduction of ammonia (IRENA and AEA, 2022). |
| CAPEX for Ammonia Retrofit costs | USD/kW ammonia | 200.00 | (Ahmad, et al., 2022) |
| OPEX increase after ammonia retrofit | % of new CAPEX | 3% | (Ahmad, et al., 2022) |
| Discount rate | % | 8% | IRENA assumed the latest average value of WACC for renewable is 7.5% (IRENA, 2023) |

## Oxy-fuel assumptions

| Parameter | Unit | Value | Reference/Notes |
|---|---|---|---|
| Technical assumptions | | | |
| Lifetime of the coal power plants | Years | 25 | estimated |
| Plant Capacity | MW | 500 | estimated |
| Plant Capacity factor | % | 53% | Similar to Global Coal Plant Tracker (Global Coal Plant Tracker, 2024) |
| Total thermal efficiency of the plant | % | 30.8% | Almost half of the installed capacity of coal-fired power plants uses subcritical technologies with estimated efficiencies of 30.8% (Global Coal Plant Tracker, 2024) |
| Coal HHV | MJ/kg | 23.0 | From IEA, an estimated 5500 Calories/kg of coal at a cost level of 100 USD/ton at South China CFR. https://www.iea.org/reports/coal-market-update-july-2023/prices |
| Coal emissions intensity | Tons $CO_2$eq/MWh | 1.114 | Using the online tool below. It is on the high side due to the low efficiency of the plant https://capraenergy.com/powerplant-emissions-calculator/ |
| efficiency loss due to CCS | % | 4% for the case without ASU<br>10% for the case of using ASU | (Xuchen, et al., 2023), (IEAGHG, 2010) |
| Capture rate | % | 99.9% | |
| Financial assumption | | | |
| Coal Cost | USD/ton | 100 | From IEA, an estimated 5500 Calories/kg of coal at a cost level of 100 USD/ton at South China CFR. https://www.iea.org/reports/coal-market-update-july-2023/prices |
| CAPEX | USD | 1,200,000,000 | The cost of constructing a modern coal-fired power plant can vary from $1.8 million to $4.5 million per megawatt installed capacity. For a 500 MW power plant, this translates to a total cost of around $900 million to $2.2 billion. (ESFC Investment Group, 2024) |
| Coal cost annual price increase | % | 1.5% | (RMI, 2022) |
| Fixed OPEX | USD/kWh | 32,000 | (RMI, 2022) |
| Variable OPEX | USD/kWh | 0.002 | (RMI, 2022) |
| $CO_2$ transportation and storage Cost | USD/ton | 10/20 | (IEA, 2021) (Smith, et al., 2021) |

| Parameter | Unit | Value | Reference/Notes |
|---|---|---|---|
| CAPEX for CCS Retrofit costs | USD/kW | 1450 | Calculated following the same methodology in Callide's final project results, page 43 (Spero & Yamada, 2018) |
| Fixed OPEX increase after CCS retrofit | % old Fixed OPEX | 22% | (Spero & Yamada, 2018) |
| Variable OPEX increase after CCS retrofit | % old variable OPEX | 360% | (Spero & Yamada, 2018) |
| Discount rate | % | 8% | IRENA assumed the latest average value of WACC for renewable is 7.5% (IRENA, 2023) |

## LCOE Calculation

The LCOE is given by the ratio of the Net Present Value (NPV) of total project costs to the NPV of the total amount of electricity produced over the plant's lifetime, as reflected by the formula below.

$$LCOE = \frac{\text{Discounted total costs}}{\text{Discounted electricity production}} = \frac{\sum_{t=0}^{n} \frac{I_t + M_t}{(1+i)^t}}{\sum_{t=0}^{n} \frac{Ele_t}{(1+i)^t}}$$

Where:

- $I_t$: Capital costs in year t (CAPEX)
- $M_t$: Operational, fuel, and Maintenance costs in year t
- $Ele_t$: electricity production in year t
- i: Discount rate