Japan's Ammonia Strategy

Excessive costs signal need for alternatives in the power sector

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Executive Summary

- **Japan's 7th Strategic Energy Plan upholds the future use of thermal power generation, while implying the need for its substantial decarbonisation to meet national emission reduction targets.**
- **For coal power, the primary decarbonisation strategy is gradual replacement with blue or green ammonia.**
- **Our modelling suggests that a coal plant co-firing a fuel mix of 50% blue ammonia and 50% coal would face production costs twice as high as its revenues.**
- **Japan's government has committed up to JPY3 trillion (USD20 billion) in subsidies to support hydrogen and ammonia in power generation and other industries. However, our analysis indicates that up to ten times more would be needed just to halve the use of coal.**
- **The logical course of action is to redirect resources toward scaling alternative electricity sources, strengthening the grid, investing in battery storage, and accelerating the reduction of coal's share in the electricity mix.**

Thermal power generation remains an important component of Japan's electricity mix even as the country maps out a low-carbon future. Under Japan's 7th Strategic Energy Plan, thermal power is projected to account for 30-40% of the electricity mix in 2040.

While renewables hold a steadily growing share of Japan's power generation, electricity planners and companies maintain that thermal plants, including coal, are essential for ensuring reliability when renewable sources are unavailable. To mitigate greenhouse gas emissions from coal-fired power plants, the strategy is to introduce co-firing of low-carbon ammonia with coal. To offset the higher costs of low-carbon ammonia and hydrogen as a fuel, the government has allocated JPY3 trillion (USD20 billion) in subsidies for power generation and other hard-to-decarbonise industries.

Unfortunately, blue and green ammonia prices have not declined as quickly as initially expected when the original plans were formulated. As a result, the economic outlook for coal plant operators has worsened.

We assessed coal power generation costs using a plant-level profit-and-loss model for a coal facility. Our Baseline model reflects current operating conditions. We then created two future scenarios where blue ammonia replaces 20% and 50% of the coal.

Our analysis shows that coal plants generate modest returns under current conditions. However, both co-firing scenarios result in significant losses in the absence of subsidies. We find that subsidies of JPY15-30 trillion (USD100-200billion) would be needed for Japan's coal plant fleet just to reduce the use of coal by half. For this calculation, we project that the share of coal power generation in Japan's electricity mix in the 2030s will be in the range of 10-19%.

The high subsidy requirements for blue ammonia co-firing raise the question of whether there are more cost-effective solutions to decarbonising Japan's power grid. Alternative approaches for the government include lowering the cost of capital for renewables coupled with storage solutions, strengthening the grid, or providing support for research and development to drive down future costs in these areas.

Key findings

- **Analysis of coal operators' financial fundamentals reveals that under current market conditions, plants are operating with slim margins. Co-firing with blue ammonia will impose a significant financial burden. At a co-firing rate of 20% ammonia, production costs are 1.5 times revenues; at 50% co-firing, those costs are more than double revenues.**
- **Support for blue ammonia co-firing would entail considerable cost. Assuming a blue ammonia co-firing rate of 50% and a 10-19% share of coal power in Japan's future electricity mix, we estimate that JPY15-30 trillion (USD100-200 billion) of fuel subsidies will be needed over a 15-year period.**
- **According to our analysis, the subsidies needed to support coal power generation alone would be 5-10 times greater than the JPY3 trillion (USD20 billion) currently allocated to support hydrogen and ammonia in power generation and other hard-to-decarbonise industries in Japan.**

Figure 1: Plant level co-firing model shows heavy losses

USD million	**Baseline (2025)**	**20% Co-firing (2030)**	**50% Co-firing (2030)**
Revenue	474	345	345
Fuel Cost	328	391	598
Operating Cost	83	81	92
EBITDA	63	(127)	(345)
Depreciation	35	37	40
EBIT	28	(164)	(385)
EBITDA Margin	13%	-37%	-100%
EBIT Margin	6%	-48%	-112%

Source: ARE

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Japan’s Electricity Landscape

Why Government and Operators are Backing Coal

In Japan, thermal power generation remains crucial for energy security, price stability, and reliability. As a result, coal and LNG plants receive substantial capacity payments through auctions, ensuring revenue stability and supporting their profitability.

Even as renewable energy and battery storage expand, some thermal plants will likely remain for balancing and reserve capacity. Consequently, the government and operators are exploring ways to decarbonise thermal power.

In 2023, coal accounted for 28.2% of the country’s electricity generation, alongside natural gas (29%), nuclear (7.7%), renewables (26.1%), oil and other thermal power (9%). As part of Japan’s decarbonisation efforts, the government aims to reduce coal's share in the electricity mix.

The 6th Strategic Energy Plan projected coal power will form 19% of the electricity mix by 2030. The 7th Strategic Energy Plan, finalised in early 2025, does not mention a specific share for coal as part of the envisaged 30-40% thermal power allocation for 2040. However, Japan will not be able to both meet its emissions targets and maintain coal’s place in the grid unless coal plants are significantly decarbonised.

Thermal plant operators are planning to develop and scale up deployment of decarbonising technologies, such as low-carbon ammonia and hydrogen co-firing, and carbon capture and storage (CCS). For coal plants, they intend to implement ammonia co-firing at rates between 20% to 50% in the late 2020s and early 2030s, transitioning to 100% ammonia combustion or co-firing combined with CCS by 2050.

Leading companies in the power sector and heavy industries have already received funding for demonstration projects, aimed at advancing ammonia co-firing technologies. The government has allocated a budget of JPY68.8 billion (about USD459 million) for research and development in ammonia-based electricity generation. This funding is part of Japan's Green Innovation Fund, which was established to support key decarbonisation technologies.

However, uncertainties remain regarding the technological and economic feasibility of these plans. There has only been one large scale demonstration test of ammonia co-firing, which was at a 20% rate, conducted in 2024 at Hekinan power station. Moreover, the absence of industrial-scale blue ammonia production presents a significant challenge to supply-chain development, as high production costs deter buyers from committing to offtake agreements, further delaying projects.

Government Support for Co-firing

Japan's **Hydrogen Society Promotion Act** was enacted and promulgated in May 2024 to promote low-carbon hydrogen, and its derivatives, as a key energy source. A **Contracts for Difference (CfD) programme** was set up to subsidise the cost gap between low-carbon hydrogen or ammonia and the long-term average price of gas or coal for 15 years.

The government has committed JPY3 trillion (USD20 billion) to the CfD programme. After that, the government expects projects based on hydrogen or its derivatives to operate without direct financial support for an additional 10 years. If projects start around 2030, they will need to break even by 2045, at which point hydrogen and ammonia technologies will either have reached cost parity with conventional energy sources or require further government support.

This 25-year framework (15 years subsidised + 10 years unsubsidised) is designed to give investors and stakeholders confidence in the long-term stability and viability of the hydrogen and ammonia vision.

The Hydrogen Society and Promotion Act, also includes a **hub development programme** that will subsidise infrastructure development for the transportation and storage of hydrogen and ammonia.

In addition, Japan has launched **the Long-term Decarbonisation Power Source Auction (LTDA)** which is a capacity payment auction aiming to provide long-term revenue support to developers of electric power projects that contribute to the decarbonisation of Japan's power industry. The first auction was held in January 2024 and saw successful bids for about 4.1 gigawatts (GW) of future capacity, broken down as follows:

- Nuclear: 1.31GW
- Battery Energy Storage Systems: 1.1GW
- Thermal Plant Upgrades: 0.83GW (0.77GW for ammonia co-firing; 0.055GW for hydrogen)
- Pumped hydro: 0.57GW
- Other: 0.27GW

The second auction took place in January 2025 and the results were released on April 28, 2025. Of the 6.3GW of capacity awarded, 1.37GW (or 22%) went to battery energy storage systems, across 27 projects. Only one small ammonia co-firing conversion project (95MW) was selected. This mirrors the 2024 auction and highlights an emerging trend: the rapid scale-up of battery storage and continued marginalisation of ammonia co-firing.

Costs of Blue Ammonia/Coal Co-firing

Banks, investors, and power-generation companies need to assess whether, under current and projected regulatory and market conditions, coal power in Japan will be financially viable. To reach our conclusion, we examined the sector's current operating performance, and its future operating performance under two ammonia co-firing scenarios.

We created a Baseline profitability model to understand coal plant profitability under current conditions. We then developed profitability models for two future scenarios with co-firing rates incorporating 20% and 50% ammonia, respectively. The future scenarios have modified assumptions on electricity pricing and capacity utilisation.

Baseline Profitability Model

Our Baseline model is essentially a deconstructed profit and loss (P&L) statement, outlining the operating performance of a hypothetical, highly efficient Ultra-Supercritical (USC) plant. This plant is assumed to have a capacity of 1GW and operate at 65% capacity utilisation.

According to this model, coal-fired plants are operating with minimal margins. With an EBITDA margin of 13% and an EBIT margin of just 6%, they are near break-even, leaving little room for profitability under current market conditions.

Figure 2: Coal-fired power plant profitability model: the "Baseline Model"

P&L Statement	Value in USD, LTM FX rate	Inputs
REVENUE		
Electricity Price per MWh	$85	JEPX spot-market LTM hourly pricing, see Section 3.
Electricity Price per MWh for PPAs	$93	10% premium over spot prices (assumption)
Generation Capacity (MW)	1000	
Capacity factor	65%	Current utilisation of USC plants (assumption), see Section 3
Electricity Produced (MWh)	5,694,000	
Internal Plant Electricity Use	6.5%	(assumption)
Electricity Sold (MWh)	5,323,890	
Total Revenue	**$474,102,049**	Sales evenly split between PPAs and JEPX
FUEL COSTS		
Coal Price per tonne	$150	LTM price of the Argus McCloskey's NEWC FOB Index
Amount of Coal needed per MWh (tonnes)	0.325	7.8 MJ/kWh efficiency, 24 MJ/kwh coal energy content
Coal Consumed (tonnes)	1,850,550	
Coal Int'l Freight Charges	$25,537,590	USD13.80 per tonne in February 2024 (Argus)
Coal Int'l Freight Insurance Cost	$832,748	Midpoint of generally assumed range of 0.1% to 0.5%
Coal Costs	$303,952,838	
Carbon Taxes on Coal	$16,734,347	Tax for climate change mitigation; Petroleum and coal tax
Port & Domestic Freight Expenses	$7,695,356	USD4/t estimate
Total Fuel Costs	**$328,382,540**	
OPERATING COSTS		
Personnel Costs	$9,236,634	130 employees, avg. total comp of USD68,000 (assumption)
Fixed Operations & Maintenance Costs	$27,621,224	2% of capital cost/year (assumption)
Variable Operations & Maintenance Costs	$30,395,284	10% of fuel costs (assumption)
Plant Cycling Costs	$15,825,427	4% of total opex (assumption), see Section 3.
Total Operating Costs	**$83,078,568**	
Total Fuel + Operating Costs	**$411,461,109**	
EBITDA	**$62,640,940**	
DEPRECIATION	**$34,526,530**	(assumption), see Section 3.
EBIT	**$28,114,411**	
EBITDA Margin	*13.2%*	
EBIT Margin	*5.9%*	

Source: ARE

Comment on Assumptions

Key model assumptions are discussed in *Section 3: Key Factors Shaping Coal's Future in Japan*. These include trends in electricity pricing, capacity utilisation, plant cycling, ammonia costs, capital costs & depreciation expense, and capacity payments.

Ammonia Co-firing Profitability Models

The 20% and 50% ammonia co-firing profitability models are extensions of the Baseline model, incorporating adjustments to key assumptions.

According to our models, blue ammonia prices have a considerable impact on the profitability of co-firing. Fuel expenses surpass revenues at both 20% and 50% co-firing levels, leading to deeply negative operating results. For 20% co-firing, the –48% EBIT margin effectively means that production costs are 1.5-times higher than revenue. Co-firing at 50% is even less viable, with an EBIT margin of –112% as production costs rise to more than double revenues.

Figure 3: Plant level co-firing model shows heavy losses

USD million	20% Co-firing	50% Co-firing
Revenue	$345	$345
Fuel Cost	$391	$598
Operating Cost	$81	$92
EBITDA	($127)	($345)
Depreciation	$37	$40
EBIT	($164)	($385)

EBITDA Margin	-37%	-100%
EBIT Margin	-48%	-112%

Source: ARE

Figure 4: Modified assumptions for ammonia co-firing models

Factor	20% Co-firing	50% Co-firing
Electricity price	10% below current levels	10% below current levels
Capacity utilisation	50%	50%
Ammonia price	$500	$500
Operating costs	13% increase vs Baseline with 50% capacity factor	28% increase vs Baseline with 50% capacity factor
Co-firing capex depreciation	8% increase in plant depreciation	16% increase in plant depreciation

Source: ARE

Comment on Assumptions

- **Electricity price**: we believe that in the long run, battery storage solutions will reduce pricing peaks when renewables are not available.
- **Capacity utilisation**: we selected roughly the mid-point of the capacity-factor range, calculated based on the government's projected share of coal in the 2030 electricity mix, noted in its 6th Strategic Energy Plan, and the 2033 projections of electric power companies, outlined in the 2024 Aggregation of Electricity Supply report from the Organization for Cross-regional Coordination of Transmission Operators (OCCTO).
- **Operating costs**: the higher proportion of ammonia is likely to lead to higher operating and maintenance costs, including additional personnel for ammonia handling, higher environmental compliance costs, and maintenance of ammonia-specific equipment.
- **Depreciation**: the increase is due to new capital expenditure for ammonia co-firing, such as storage tanks. It is depreciated over a 20-year lifespan.

Further details on the model assumptions are provided in *Section 3: Key Factors Shaping Coal's Future in Japan*.

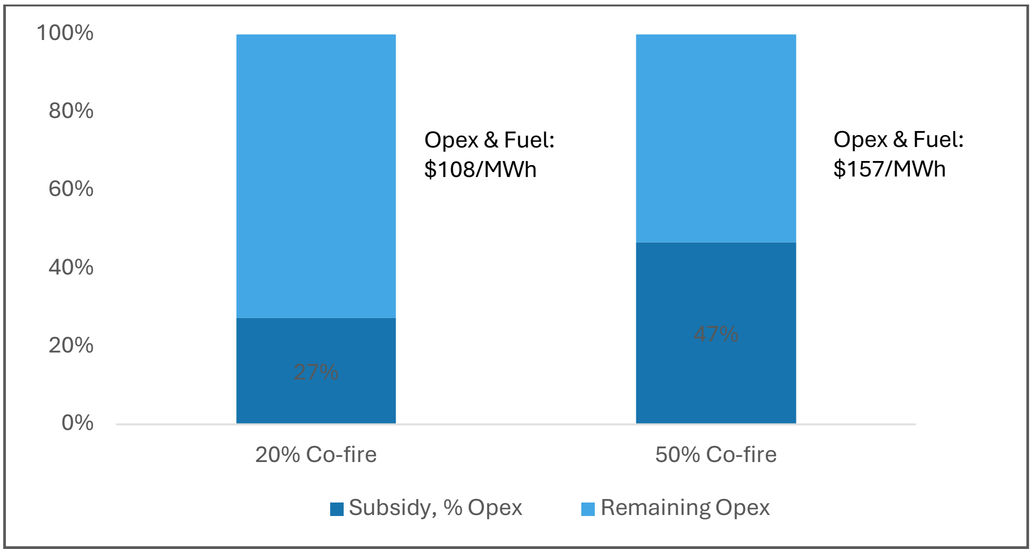
Financial Burden of Co-firing Subsidies

For Japan to maintain and simultaneously decarbonise coal power's presence in the national electricity mix will require substantial financial support. The Japanese government has signalled a strong commitment to developing ammonia technology and fostering the rapid growth of the ammonia market. But at what cost?

At 20% co-firing, our model plant requires a CfD subsidy of JPY4,350 (USD29) per MWh, or 27% of total fuel and operating expenses. At 50% co-firing, the subsidy increases to JPY10,950 (USD73) per MWh, accounting for 47% of fuel and operating expenses. For reference, we have modelled an electricity spot price of JPY12,000 (USD80) per MWh.

Additionally, our modelling indicates a depreciation expense of around JPY1,350 (USD9) per MWh must be absorbed in some way for operators to break even before interest and taxes.

Figure 5: CfD subsidies as percentage of opex and fuel



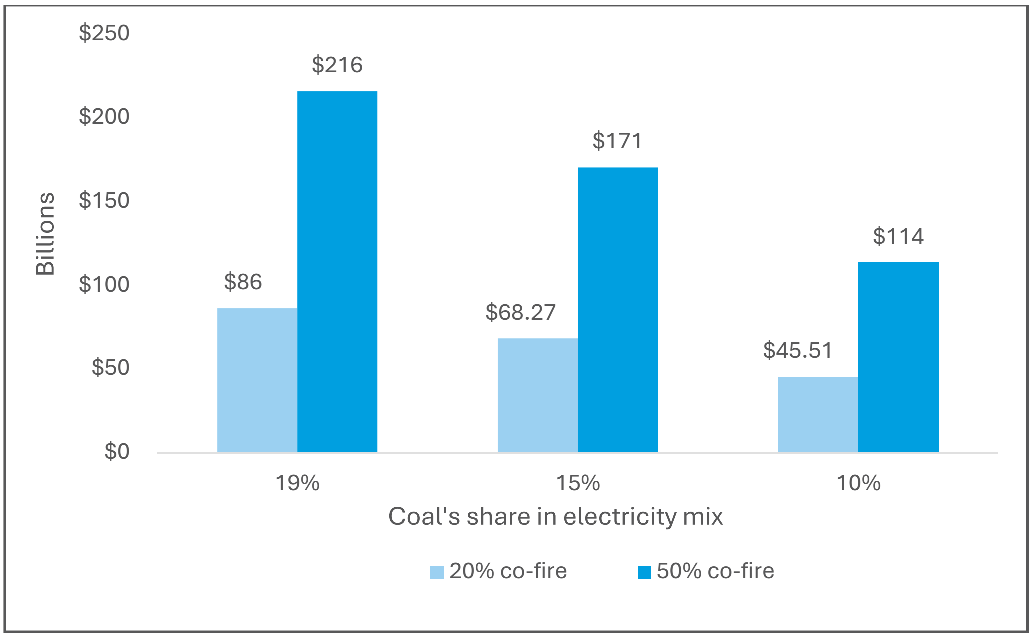
Source: ARE

To estimate the total CfD subsidy costs required to sustain the financial viability of the sector under blue ammonia co-firing, we assume that annual electricity generation increases 5% in 2030, from 984.4 billion kilowatt hours (kWh) in 2023, which is in line with the government's projected 10-20% increase by 2040.

For coal-fired power generation, we assume its share will be in the 10-19% range. This reflects the projected coal power share of 19% by 2030 in Japan's 6th Strategic Energy Plan. We then assume that share will taper in the 2030s to a potential 15% or 10%. Lastly, we assume that subsidies in the form of the CfD programme are maintained for 15 years, as outlined in Japan's Hydrogen Society Promotion Act.

The conclusion is that even considering the Japan's Ministry of Economy, Trade & Industry's (METI) expected reductions in coal's share of the electricity mix over the next two decades, the total CfD subsidies required would range from JPY6.75 trillion (USD45 billion) to JPY32.4 trillion (USD216 billion), depending on the level of co-firing and coal plants' contribution to the electricity mix. This is far greater than the JPY3 trillion (USD20 billion) so far allocated to the CfD programme, which covers all hard-to-decarbonise industries in Japan.

Figure 6: CfD subsidies needed for blue ammonia co-firing



Source: ARE

Factors Shaping Coal's Future in Japan

Under Japan's climate commitments, the extension of unabated coal power is not viable. The remaining question for investors and other stakeholders, therefore, is whether current decarbonisation plans make sense, after considering key factors driving the profitability of coal power generation, including trends in electricity pricing and capacity utilisation, plant cycling, ammonia costs, capital costs & depreciation expense, and capacity payments.

Capacity Utilisation Trends

The electricity supply strategies of power companies do not yet align with METI's projections for the electricity mix.

Each year, Japan's electric power companies submit to OCCTO their supply plans for the next decade, which OCCTO then aggregates and publishes. According to the 2024 Aggregation of Electricity Supply, coal power is projected to account for 29% of Japan's electricity mix by 2033.

In contrast, METI's last concrete projection for coal's share as outlined in Japan's 6th Strategic Energy Plan was 19% by 2030, a full 10 percentage points lower than the aggregation of supply plans submitted to OCCTO.

Our modelling requires an assumption for coal plant capacity utilisation. The OCCTO report projects coal capacity utilisation as rising from 57% in 2023 to 64% by 2028, before declining to 58% by 2033.

If METI's projection of 19% coal share in the electricity mix in 2030 is maintained without significant closure of coal plants or a dramatic increase in power demand, then coal plants will be used far less. We estimate a low end of the range for coal capacity utilisation of 38% by pro-rating the projected rate of 58% by 2033 in OCCTO's report by the relative shares of coal in the electricity mix in the METI and OCCTO projections i.e. we multiply 58% by 19/29.

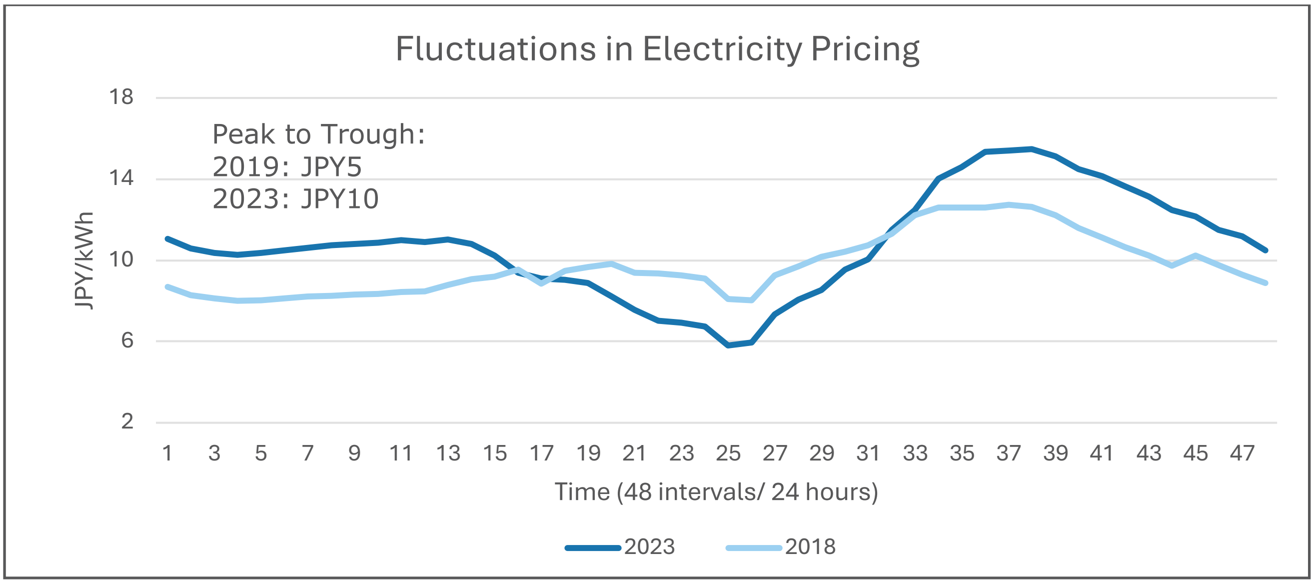
Model assumptions: *Our Baseline model, assessing current conditions, assumes 65% capacity utilisation for USC plants. This is higher than the current average of 57% to reflect their higher use compared with older plants. Our Co-firing Models, assessing profitability past 2030, assume 50% capacity utilisation, which is roughly a midpoint between the projections of electric power companies and our 38% lower bound estimate.*

Trends in Electricity Pricing

Our analysis of Japan Electric Power Exchange (JEPX) pricing data over the past five years shows that the gap between peak and trough prices doubled between 2018 and 2023.

As solar capacity grew from 50GW in 2017 to 90GW in 2023, prices during the middle of the day have steadily dropped, when solar power is abundant. However, rates from late afternoon onwards have risen, when thermal power supply takes over, reflecting elevated fuel prices since the start of Russia's invasion of Ukraine in 2022.

If battery storage capacity grows almost five-fold by 2033, as outlined in Japan's electric power companies' projections, renewable power generation could potentially be used in the evening, which will lead to the flattening of the daily price curve. Consequently, peak electricity pricing periods available to thermal power plant operators will decline. At the same time, the continued expansion and integration of renewable energy into the grid should drive average electricity prices lower. Combined, these trends are likely to further erode the economic viability of coal power and render the expense of deploying ammonia co-firing technologies even more prohibitive.



Source: JEPX, ARE

Model assumptions: *For our models, we utilised spot-market pricing data from JEPX, using last-12-month hourly pricing as of Aug 30th 2024. We assumed that power plants would operate at predetermined capacities during peak pricing periods each day. In our Co-firing Models, we assume a 10% reduction in electricity pricing for these peak periods, due to the projected scale-up of batteries and renewables.*

Ammonia as a Decarbonisation Solution

Our analysis assumes the use of blue ammonia for co-firing, which is derived from natural gas with carbon capture and storage (CCS). We have not included green ammonia in our modelling given uncertainties over its future costs.

In June 2024, Argus, a global independent provider of price information and business intelligence for various commodity markets, introduced the Japan Korea Low-Carbon Ammonia Benchmark (JKLAB), an index aimed at supporting trade in low-carbon hydrogen products across key northeast Asian markets. JKLAB reflects the cost of blue ammonia produced using autothermal reforming (ATR) technology with CCS, which captures approximately 93–98% of CO_2 emissions, meeting carbon intensity thresholds set by Japan and South Korea. While we don't have JKLAB pricing data, a 2023 Argus cost analysis suggests that U.S. project developers with CCS rates of 90–95% may require offtake agreements with price floors of approximately USD550 per metric tonne.

Several factors are expected to shape the pricing dynamics for blue ammonia, including:

- **Technological Advancements:** Innovations in CCS and natural gas reforming, a mature technology, could only slightly reduce blue ammonia production costs, according to a 2022 Bloomberg New Energy Finance (BNEF) report.

- **Market Mechanisms and Policy Developments:** As of now, no final investment decisions have been made regarding the commercial production of blue ammonia as a fuel in Japan or other markets. The progression of such projects is heavily dependent on securing long-term offtake agreements, which are essential for ensuring the financial viability and bankability of these capital-intensive initiatives. Potential buyers often hesitate to commit to these agreements because of the current cost disparity between blue ammonia and traditional fuels. This reluctance highlights the sensitivity of ammonia production to policy support and subsidy.

Model Assumptions: *Our Co-firing Model assumes a blue ammonia price of $500 per metric tonne, reflecting an assumed 10% drop in the price modelled by Argus. This decline aims to reflect possible marginal efficiency improvements, as alluded to in BNEF's 2022 analysis.*

Plant Cycling

Coal power plant cycling – also known as ramping – refers to the process of adjusting a coal-fired power plant's output in response to changes in electricity demand. This is particularly important when integrating renewable energy sources with variable outputs, such as wind and solar. While highly efficient USC plants should handle ramping cycles better than older facilities, there is still some efficiency loss and extra costs from additional fuel, wear & tear, and emission controls.

Public information about these additional expenses is limited, but a 2016 analysis on plant cycling by the International Energy Agency ("Operating Ratio and Cost of Coal Power Generation") puts them at nearly 8% of total operating and fuel costs. For more efficient plants using USC technologies, we assume ramping costs to be lower.

Model assumptions: We assume that ramping costs amount to 4% of total operating and fuel costs, taking the mid-point between zero and 8% for older plants.

Capital Costs & Depreciation Expense

Global Energy Monitor's (GEM) coal power data reveal that Japan has operating capacity of 21.8GW from USC plants, 11.8GW from supercritical (SC) plants, and 4.4GW from subcritical (S-C) plants. The USC plants have a capacity-weighted average plant age of 20 years and capacity-weighted average remaining life of 20 years.

Based on a 2019 analysis by Project Finance International, a financial research firm, the capital investment for a new 1.3GW power plant in Yokosuka, Japan, amounted to JPY272 billion (USD1.8 billion). We used this information as an assumption for the capital investment cost of a new USC plant.

We assumed straight-line depreciation over a service life of 40 years for power plants (based on the assumed average unit lifetime in the "Science-Based Coal Phase-Out Timeline for Japan" report by Climate Analytics).

Capacity Payments

Japan introduced capacity payment auctions for electric power companies in 2020, alongside the deregulation of its electric power retail market. These payments enhance the economic viability of stable power sources, such as coal, gas, and nuclear plants.

Each year, there is an auction to ensure supply capacity four years in the future. The inaugural 2020 auction saw approximately 167.7GW of capacity for 2024 secured from existing power sources at an average clearing price of JPY14,137 (USD94.3) per kilowatt (kW). In 2024, a similar volume of 166.2GW was awarded for 2028, but at a lower average price of JPY11,134 (USD74.2) per kW.

For a 1GW coal plant, this pricing translates into capacity payments of JPY14.1 trillion (USD94.3 million) for 2024 and JPY11.1 trillion (USD74.2 million) for 2028, representing significant government support. As the payments relate to capacity, rather than payments for generation, they are similar in principle to a subsidy.

As Japan shifts toward a lower-carbon electricity system, pressure may mount to reduce or phase out capacity payments — even for efficient coal plants — to better align with decarbonisation goals. Indeed, the launch of the LTDA in 2024 signalled a potential shift in policy priorities.

Given that current capacity payments for stable energy sources resemble subsidies, and could change, we have not incorporated them into our models. However, capacity payments, along with the CfD subsidies, could cover the substantial operating losses projected in our ammonia co-firing scenarios. Regardless, this comes at a significant cost to Japan's government and taxpayers.

Model Assumptions: We have excluded capacity payment assumptions from our modelling to provide a clearer picture of the market forces affecting operators' profitability.

Conclusion

The choice to pursue "decarbonised" power through the support of nascent technologies like ammonia co-firing puts Japan's power utilities on a challenging decarbonisation path.

Nevertheless, the government effectively endorsed this path in its 7th Strategic Energy Plan, released in February 2025. The plan aims to reduce greenhouse gas (GHG) emissions 60% from 2013 levels by 2035, and 73% by 2040, while maintaining a 30-40% thermal power share of the electricity generation mix. While the plan does not specify a target for coal's share, the 6th Strategic Energy Plan set it at 19% by 2030.

One component of the current power sector decarbonisation plan is to reduce GHG emissions from coal power through co-firing with blue or green ammonia. As our analysis indicates, this approach requires substantial subsidies to cover operating costs.

We have found limited evidence to suggest that ammonia prices will decline sufficiently to reach price parity with coal, even over the next 20 years. Moreover, it is unlikely that governments will continue subsidising the ammonia cost premium indefinitely.

The logical course of action, then, is to redirect resources toward scaling alternative electricity sources, strengthening the grid, investing in battery storage, and accelerating the reduction of coal's share in the electricity mix.

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