Japan’s Power Market Transition

Implications for Coal Power Profitability

Assessing the impact of battery storage and grid expansion. Exploring the rationale behind ammonia co-firing.

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Key Findings from our Analysis

Following our "**Japan's Ammonia Strategy"** report, this deeper-dive analysis on coal plants' profitability highlights the following insights:

- **Japan's coal-fired power generation** is expected **to become structurally unprofitable by the early 2030s**, with operating margins falling into negative double digits as market revenues continue to decline.
- **Grid expansion and large-scale battery deployment** will be the primary forces, **reshaping electricity pricing** and driving this transition.
- **Ammonia co-firing subsidies** are unlikely to restore profitability. Without further support, co-firing would likely risk either incurring losses or terminating capacity contracts with penalties.

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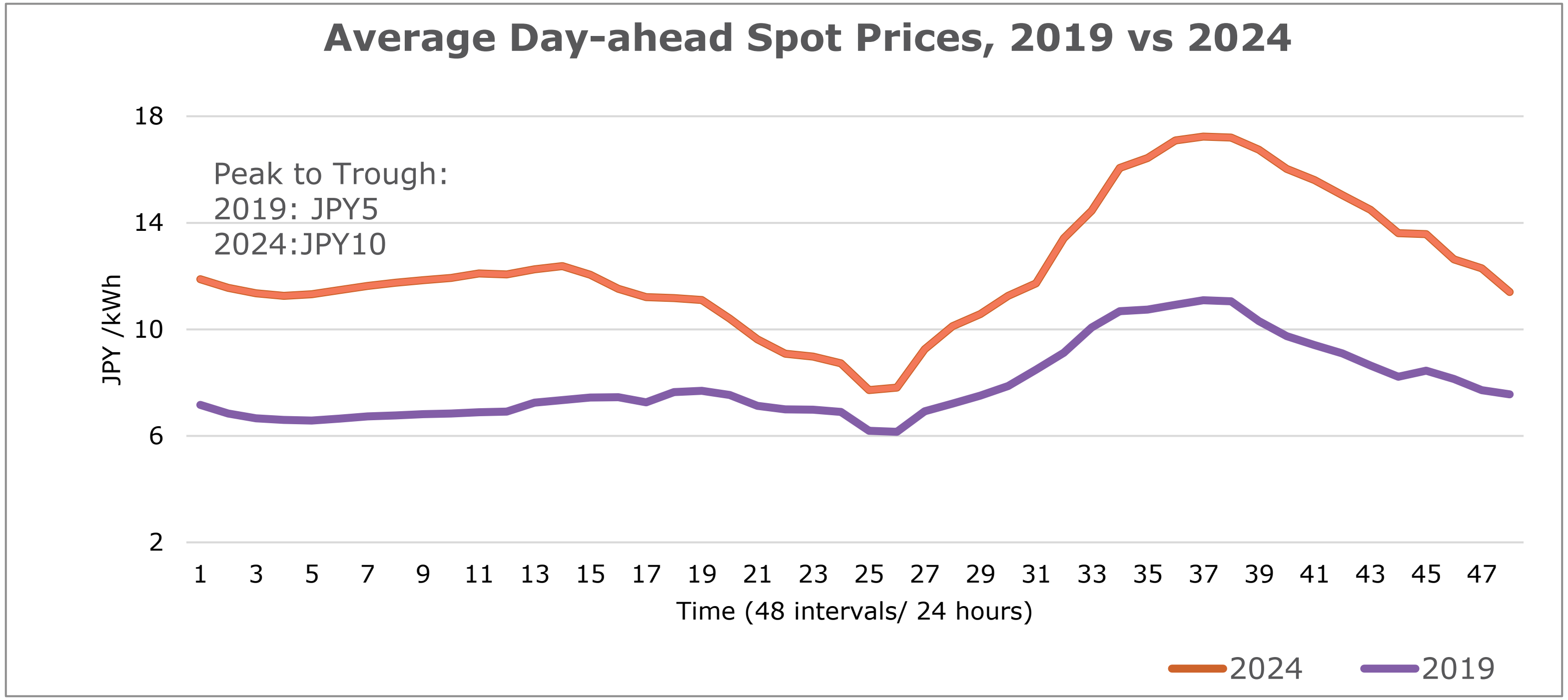
3. **Ammonia Co-firing** – Examining utilities’ rationale for pursuing co-firing, and assessing system costs and decarbonisation impacts.

Part 1: Electricity Pricing Trends – Summary

Japan's electricity market has been evolving, with peak-to-trough prices doubling over the past five years. However, **structural shifts may result in lower price volatility**:

- **BESS build-out will shave pricing peaks**.
- **Expanding grid** interconnections **will bring more electricity to demand centres** and **stimulate further expansion of renewables**, leading to lower average prices.

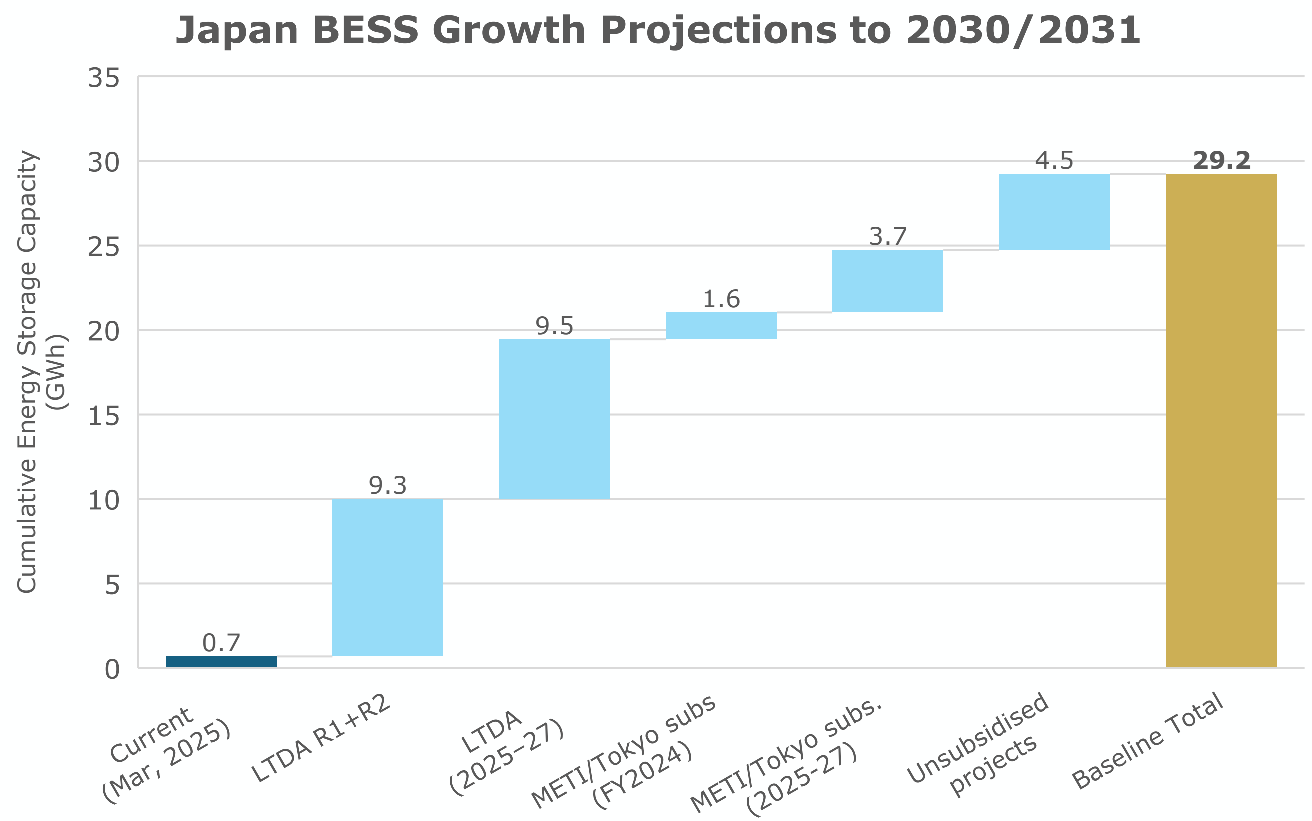


Source: JEPX, ARE

Battery Storage to Shave Peak Pricing

Coal's market revenues will decline as price peaks erode.

- BESS deployment accelerating quickly from tiny base.
- Policy is driving growth: national & metropolitan subsidies, alongside Long-Term Decarbonisation Power Auctions (LTDA), are main catalysts.
- Some recent projects are proceeding without government support, relying only on market-based revenue projections.
- LTDA design is evolving to favour longer-duration storage. Battery system costs are likely to decline gradually.



In GW:	0.23	2.5	2.1	0.4	0.8	1	**7.0**

Assumptions: METI & LTDA subsidies taper down; Capex – 70,000 yen/kWh; 50% of capex subsidised.

Source: OCCTO, METI, Tokyo Met. Gov't, Mitsubishi Rsrch. Institute, ARE

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Why Battery Deployment is Accelerating in Japan

BESS growth is driven by market signals, system needs and policy design

- **Market incentives to optimise supply**
  - Reduce renewable curtailment (largest curtailment rates in Kyushu, Shikoku, Chugoku, Tohoku)
  - Shift daytime solar to evening peaks, shift wind to evening/night demand (market arbitrage)
  - De-risk and enable new renewable projects in resource-rich areas (Kyushu, Tohoku, Hokkaido)
- **System needs - congestion relief & grid stability**
  - Grid-side BESS at key substations to manage interregional flows (Hokkaido-Honshu, Kyushu-Chugoku)
  - Fast frequency response, ramping support, voltage/inertia services.
- **Policy incentives + new market rules**
  - Participation in capacity markets via the LTDA provides reliable revenue streams.
  - Capex subsidies through METI and Tokyo Met. Govt schemes catalyse early projects.
  - A new primary balancing market where BESS has the structural advantage to respond within seconds.
- **Data & transparency improvements at JEPX**
  - Existing: bidding curves, transaction volumes, half-hour supply-demand forecasts
  - Coming: more granular price signals (15-min), day-ahead market for balancing services

Types of BESS Reinforcing Japan's Grid

A variety of BESS, all reinforcing grid capacity and renewable integration

- **Renewable-co-located BESS** ⚡ (VPP*-capable)→ avoid curtailment, firm renewable output.
- **Merchant / price-arbitrage BESS** (utility-scale, participating in JEPX) → charge when prices are low, discharge at evening peaks.
- **Aggregator/portfolio BESS** ⚡ (VPP) → optimise multiple small assets, provide portfolio balancing.
- **Grid-side / substation BESS (TSO-owned or coordinated)** → located at transmission nodes to manage flows, stabilize frequency.
- **Distribution-side BESS** ⚡ (VPP / municipal) → relieve local congestion, voltage control, defer grid upgrades.
- **Ancillary-service BESS** → optimised for fast frequency response, ramping, and voltage/inertia response (short duration, high charge/ discharge rate)

Note: VPP: Virtual Power Plant – aggregated distributed storage and flexibility resources

Who is Building BESS: Players & Business Models

Multiple business archetypes emerge as storage scales

- **IPP-style developers to deliver large grid-scale projects** – companies with generation/IPP ambitions pursuing mega-BESS (Gurin Energy, Sumitomo Corp.)
- **Utility-Developer co-aggregation** – partnerships where utilities collaborate with developers/aggregators (NTT Anode Energy x TEPCO/ x Kyushu EPCO)
- **Utility-led aggregation JVs** – KEPCO's E Flow- SPARX- JA Mitsui Lease: multi-site programs combining utility operations with development and third-party capital.
- **Tolling/VPP operator models** – an aggregator/operator (Power X, Tokyo Gas) pays fixed fees to BESS owners and takes market risk and trading upside.
- <u>**Utilities' Oil-to-battery hub conversions:**</u>
  - Kansai EPCO - Former Tanagawa Power Station (Osaka):99MW/396MWh BESS
  - Chugoku EPCO – former Kudamutsu power plant (Yamaguchi): 10MW/30MWh BESS
  - Shikoku EPCO - former Matsuyama Power Station (now Shikoku Matsuyama Solar): 12MW/36MWh
  - **Could coal-to-battery conversions be next?**

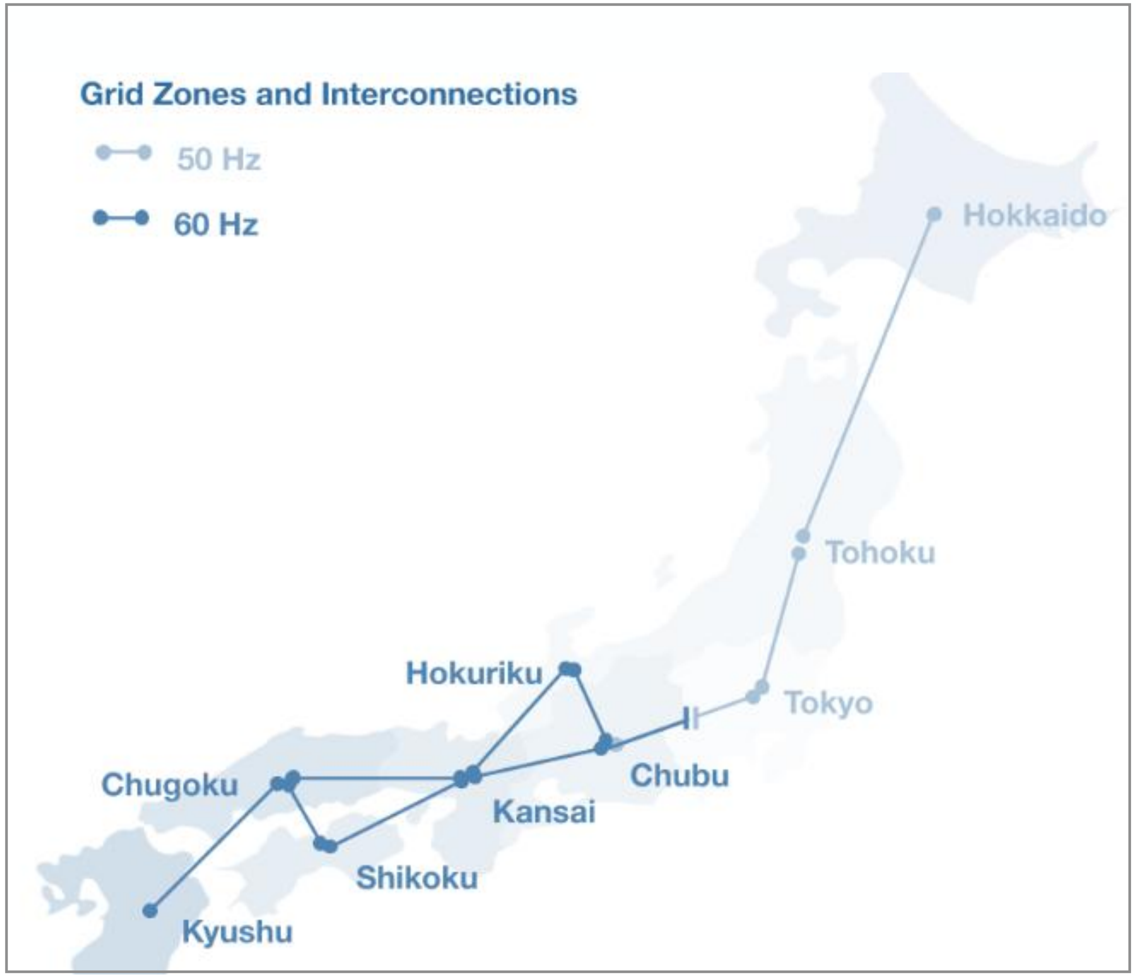
Grid Expansion to Connect Demand & Supply Centers

- Larger interconnections enable larger electricity flows into demand centres.

- South → Kansai inflows: Grid upgrades will channel the abundant solar of Kyushu, Chugoku and Shikoku into Kansai, Japan's key industrial and energy hub.

- North → Tokyo inflows: Reinforcements and subsea cables will bring more offshore wind from Tohoku and Hokkaido into Tokyo, the largest demand centre.

- Grid reinforcements within Hokkaido, Tohoku, Kyushu, and other will allow greater absorption of local renewable output.



Source: Shulman Advisory

Japan’s Grid Expansion by 2030/31

- Japan aims to add 12.5GW of interregional lines in the next 5-6 years, curbing curtailment and stimulating further renewables build-out.

- Subsea HVDC links connecting renewables-rich regions to demand centres are in procurement or planning stages.

- Grid projects are highly capital-intensive and rely on new financing models, such as early cost recovery under METI’s Nex-Generation Network framework, alongside nationwide renewable surcharges, revenues from JEPX price differentials, and public loans.

Japan Grid Expansion Projections by 2030/2031

	Additions (GW)	Timing	REC*	UF* (Est)	Renewable GWh	Non-renewable GWh
Flows to Tokyo (Total)	**7.1**				**4.9**	**1.9**
Hokkaidō–Honshū HVDC expansion	0.3	March 2028	54%	60% (Est)	0.1	0.1
Tōhoku–Tokyo expansion	4.8	FY2027	68%	100%	3.2	1.5
Hokkaidō–Honshū new HVDC cable (Sea of Japan)	2	FY2030	85% (est)	100%	1.6	0.3
Flows to Kansai (Total)	**1.5**				**1.2**	**0.2**
Kanmon (Kyūshū–Chūgoku) new HVDC cable	1	FY2030	85% (est)	100%	0.8	0.1
Kyūshū–Chūgoku expansion	0.5 (est)	FY2030	85%(est)	100%	0.4	0.1
West-East Flows (Total)	**3.9**				**1.3**	**2.2**
Kansai - Chubu expansion	3	FY2030	38%	100%	1.1	1.8
Chūbu -Tokyo (frequency converter)	0.9	FY2027	38%(est)	70%	0.2	0.4
Total	**12.5**				**7.5**	**4.3**

Notes**: **REC** is Renewable Energy Contribution Rate - share of transmitted energy originating from renewable generation; **UF** is Utilisation Factor - share of the year the extra capacity is used in the export direction, used REI's interregional interconnection flow data; GWh renewables = **GW*UF*REC*(1-loss of 3%)

Source: METI's Next gen. Power Network Updates, OCCTO 's Electricity Supply Plans, METI, OCCTO and media press releases

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Shifting Market Dynamics by 2030/2031

Electricity Market Drivers

- **~29 GWh** of energy storage capacity to curb curtailment, firm renewables supply, and stabilise the grid.
- **~12 GWh** of new grid capacity, facilitating the flow of predominantly renewable power into demand centres.

→ **Flatter pricing curves**, **lower average prices**, and a **shrinking share of balancing power** (coal, LNG).

Coal Power Contracting & Sales

- Most coal-fired power is still **sold under long-term PPAs or dispatched internally** within utility groups.
- But **JERA** (8.9GW USC fleet) will **not renew PPAs** with Chubu & TEPCO — coal output to be traded by **JERAGM.**

Evolving Power Trading Landscape

- Currently, **30%** of Japan's electricity trades on the **JEPX spot market, 7-9%** - on the **EEX derivatives market.**
- **Derivative trading surged** after JERA's July announcement not to renew PPAs, and **strong momentum is expected to continue** as retailers engage in hedging and arbitrage on a new (from FY2026) mid- to long-term market for continuous trading of one- and three-year delivery products.
- Current **EEX Japan contracts** (Tokyo/Kansai; base & peak) are **zone-based**, **fuel-neutral**, and **settled to JEPX indices.**

Notes: JEPX: Japan Electric Power Exchange; JERAGM – JERA Global Management – a Singapore-based JV with EDF Trading; EEX Japan – European Energy Exchange where >90% of Japan's total electricity derivatives volume is traded

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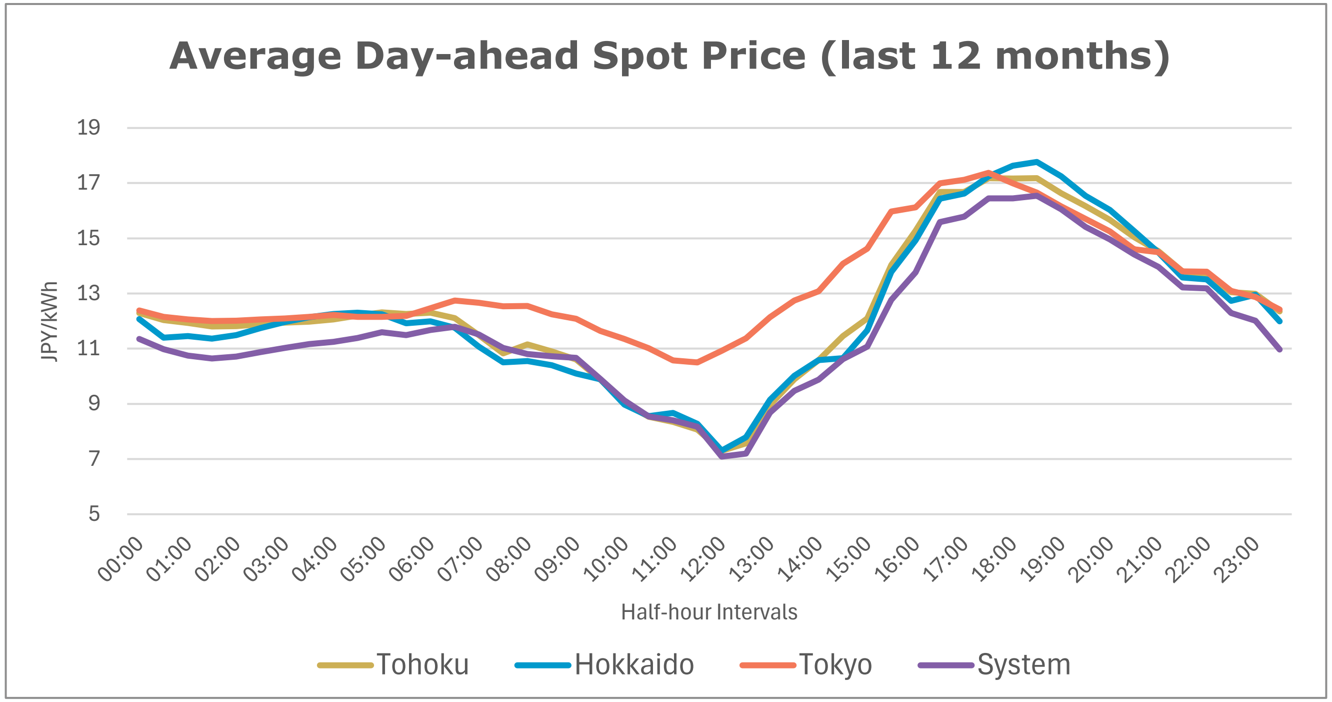
Tokyo's Spot Prices as Benchmark for the East

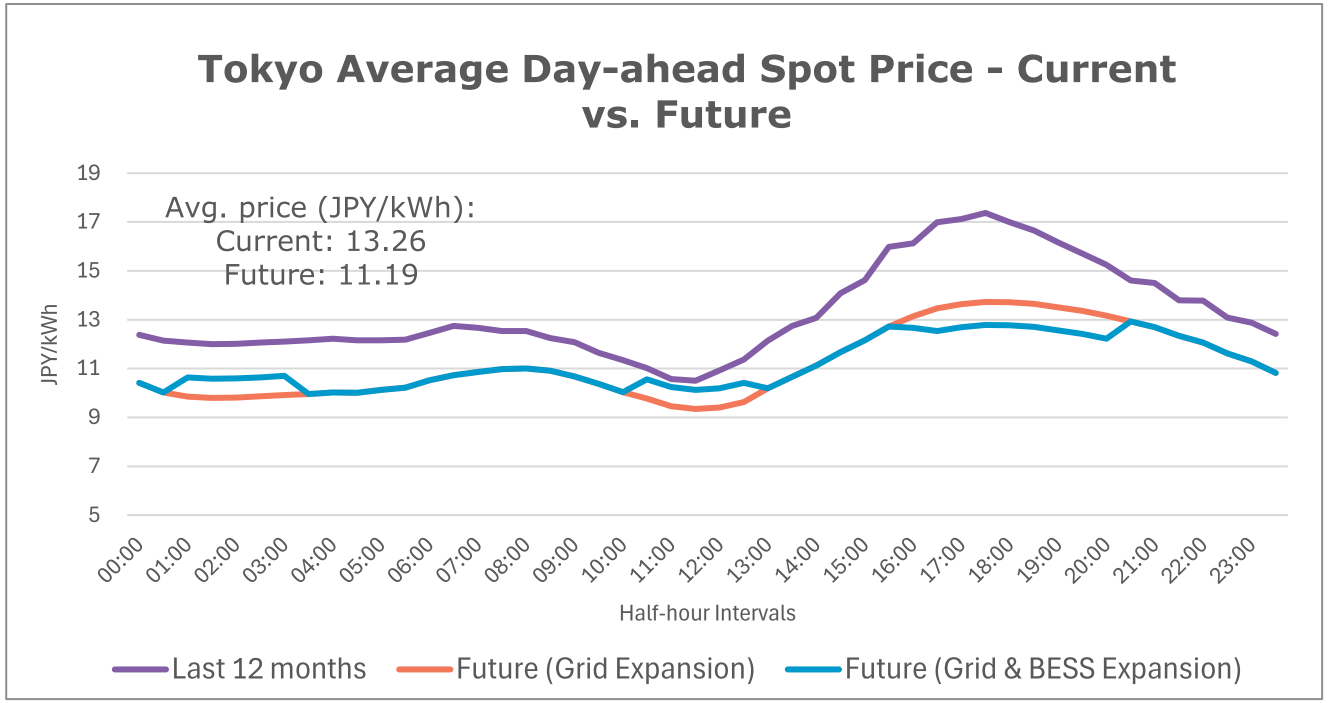
- **Tokyo** consistently records the **highest spot prices**, reflecting its place as Japan's **largest demand centre** (peak demand ~**57 GW**).
- Tokyo thus serves as the **benchmark region** for assessing future **pricing trends in eastern Japan**.
- For context: **JERA's coal plants** are concentrated in the East (Tokyo) and Central (Chubu) regions.



Sources: JEPX, ARE

Electricity Prices in Eastern Japan to Fall by ~18%

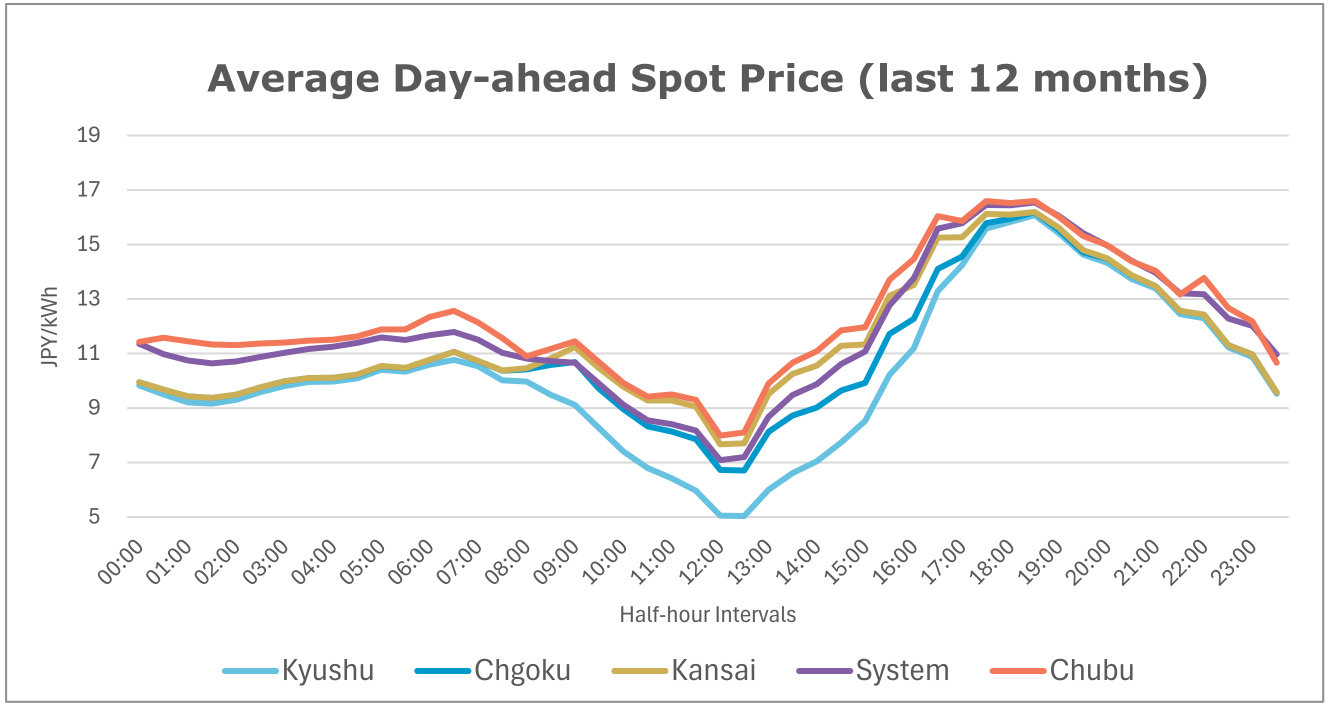
- BESS buildout and grid expansion will **flatten and lower average prices** in Tokyo and the broader eastern region.
- We project **average prices to decline by ~18.5% by 2030/31.**
- The analysis assumes that **two-thirds of new BESS capacity** will be deployed **in eastern Japan**, reflecting the roughly 2:1 peak electricity demand ratio between Tokyo and Kansai.



Source: JEPX, REI, ARE.

Kansai’s Spot Prices as Benchmark for the West

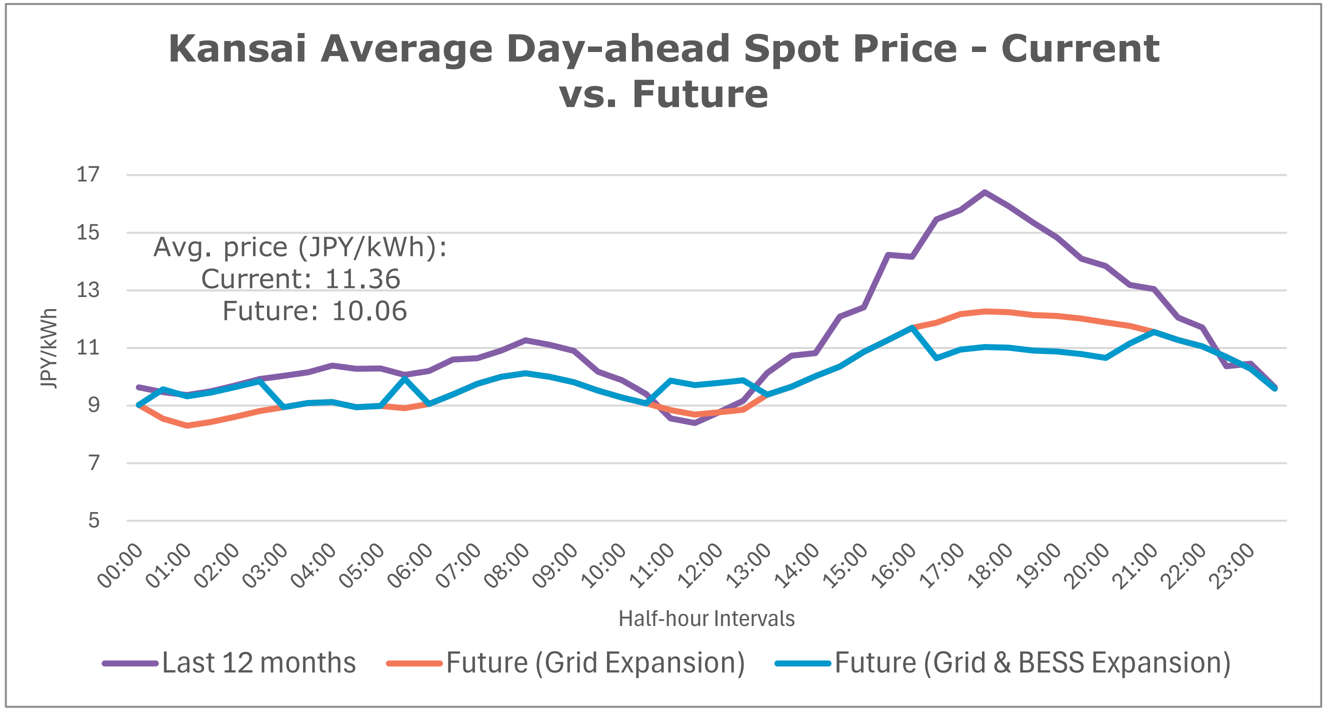
- **Kansai** is Japan’s **second- largest demand center** (peak demand ~27 GW).
- Kansai thus serves as the **benchmark region** for assessing **future pricing trends in western Japan**.
- For context: **the majority of J-Power’s coal fleet** (4.5GW USC fleet) is concentrated in the Western region (Chugoku, Kyushu).



Sources: JEPX, ARE

Electricity Prices in Western Japan to Fall by ~13%

- BESS deployment and grid expansion will **flatten and lower average prices** in Kansai and the broader western region.
- We project **average prices to decline by ~13% by 2030/31,** to JPY10.06/kWh. For comparison, we estimate J-Power's average PPA price at ~JPY13/kWh.
- The analysis assumes that **one-third of new BESS capacity** will be installed **in western Japan.**



Source: JEPX, REI, ARE.

Part 2. Coal Plant Profitability - Summary

Coal plant economics will be impacted by market and policy factors:

- Declining electricity prices
- Falling plant capacity utilisation
- Increasing carbon costs
  - A new fossil fuel levy (est.~JPY2,100/t-CO_2) will be introduced in 2028.
  - A mandatory emissions trading system will start in 2033.

Co-firing plants will be impacted as much as non-co-firing plants:

- Co-firing subsidies cover fuel cost gap and retrofitting capex.
  - Thus, marginally lower carbon costs of 20% co-firing will be roughly offset by marginally higher operating expenses.

Profitability Outlook: Tokyo vs. Kansai

Profitability of a 1GW USC Plant, CF40:

	Tokyo 2030/31		Kansai 2030/31	
$ million	**No Co-fire**	**Co-fire**	**No Co-fire**	**Co-fire**
Revenue	273	273	242	242
Fuel Subsidy	-	132	-	132
Fuel Cost	219	334	219	334
Operating Cost	78	89	78	89
EBITDA	(23)	(19)	(54)	(50)
Depreciation	4	4	4	4
EBIT	(27)	(23)	(58)	(54)
EBITDA Margin	-8%	-5%	-22%	-13%
EBIT Margin	-10%	-6%	-24%	-14%

- Coal plant operating margins are projected to turn predominantly negative double-digit by 2030–31, driven by falling electricity prices.
- Heavy co-firing subsidies offset higher fuel costs and retrofits, but improve profitability only marginally, through lower carbon costs.
- The model includes only maintenance-capex depreciation – it assumes plants are fully depreciated and retrofitting capex is fully covered by LTDA subsidies.

Key modelling assumptions:

Input	Assumption	Notes
Tokyo Electricity Price per kWh	JPY12.32 / USD0.08	ARE Pricing model, average of the highest 40 half-hour prices
Kansai Electricity Price per kWh	JPY10.90 / USD0.07	ARE Pricing model, average of the highest 40 half-hour prices
Capacity utilisation	40%	as per LTDA limits
Blue ammonia price per tonne	JPY78,000/ USD520	price of the cheapest blue ammonia, produced in the U.S.
Ammonia subsidies (million)	JPY19,751/ USD131	provided through the CfD Programme for LTDA Rounds 1 &2
GX fossil fuel levy ($/ t-CO2)	JPY2,100 / USD14	Starts from FY2028, IEEJ

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Part 3: To Co-fire or Not? Strategic Options

Rationale for Co-firing:

- Secure regulatory **approval to keep operating** through 20-yr capacity contract as carbon policies tighten.
- **Extend the life** of depreciated assets that have remaining economic life of ~ 15years.
- Secure subsidies to **cover ammonia's high costs**.
- **Lower emissions costs.**
- Potentially gain **priority consideration for additional financial support** when operating margins turn negative — for example, through the annual reserve capacity market or other mechanisms.
    - **Without further support**, co-firing risks either **incurring losses or terminating capacity contract** with penalties.

Rationale for No Co-firing:

- **Not all plants can qualify for co-firing** – they must meet minimum efficiency standards and have dedicated coal port facilities that can be upgraded for ammonia handling.
- A company keeps an option to **retire or mothball a coal power unit** when it becomes unprofitable.
- **Examine alternatives**: biomass co-firing, gas conversion, coal-to-battery hub repurposing, and coal-to-renewable & battery hybrid sites.

Source: ARE

Japan’s USC Fleet — Co-firing & Other Pathways

Ammonia co-firing candidates:

Plant Unit	GW	Start Year	Operator	EPCO Area
Approved Projects	**4.5**			
Hekinan-4	1	2001	JERA	Chubu
Hekinan-5	1	2002	JERA	Chubu
Tomatou-Atsuma	0.7	2002	Hokkaido	Hokkaido
Kobe-1 (SC)	0.65	2002	Kobelco	Kansai
Kobe 2 (SC)	0.65	2004	Kobelco	Kansai
Saijo-1 (replacement)	0.5	2023	Shikoku	Shikoku
Projects Marked For Co-firing by 2030				
Tachibanawan-1	1.05	2000	J-Power	Shikoku
Tachibanawan-2	1.05	2000	J-Power	Shikoku
Kashima	0.645	2020	J-Power (50%)	Tohoku
Other Potential Candidates For Co-firing				
Taketoyo-5	1.07	2022	JERA	Chubu
Takehara-1 (new)	0.6	2020	J-Power	Chūgoku
Misumi-2	1	2022	Chugoku	Chūgoku
Kobe-3 (SC)	0.65	2022	Kobelco	Kansai
Kobe-4 (SC)	0.65	2023	Kobelco	Kansai
Reihoku-2	0.7	2003	Kyushu	Kyūshū
Matsuura-2	1	2019	Kyushu	Kyūshū
Hitachinaka-1	1	2003	JERA	Tohoku
Hirono-6	0.6	2013	JERA	Tohoku
Hitachinaka-1 (joint)	0.65	2021	JERA	Tohoku
Isogo-1	0.6	2002	J-Power	Tokyo
Isogo-2	0.6	2009	J-Power	Tokyo
Total	**16.37**			

Prime ammonia co-firing candidates:

- Early-2000s USC units: suitable for **20% co-firing** to extend remaining life.
- Newer USC units: potentially targeting **~50%** ratios.

Oldest USC units: Insufficient efficiency/remaining life to amortise retrofits; likely limited to **biomass co-firing** or alternative pathways.

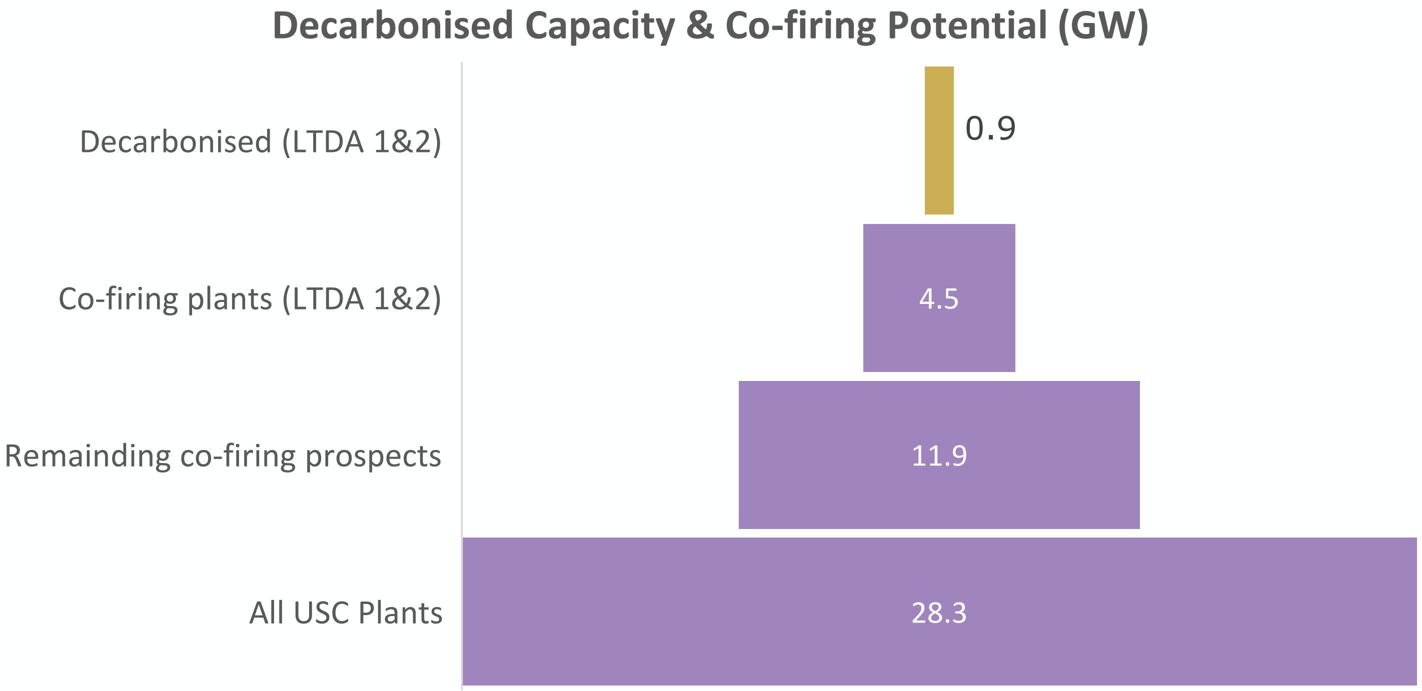
Other USC capacity:

Plant Unit	GW	Start Year	Operator	Decarbonization Strategy
Yokosuka-1	0.65	2023	JERA	CCUS
Yokosuka-2	0.65	2023	JERA	CCUS
Matsuura-2	1	1997	J-POWER	biomass co-firing
Haramachi-1	1	1997	Tohoku	biomass co-firing
Haramachi-2	1	1998	Tohoku	biomass co-firing
Noshiro-3	0.6	2020	Tohoku	biomass co-firing
Maizuru-1	0.9	2004	Kansai	biomass co-firing
Maizuru-2	0.9	2010	Kansai	biomass co-firing
Nanao-Ota-1	0.5	1995	Hokuriku	N/A
Nanao-Ota-2	0.7	1998	Nanao-Ota-1	biomass co-firing
Tsuruga-2	0.7	2000	Nanao-Ota-2	biomass co-firing
Total	**8.6**			

Source: Global Energy Monitor, Company Statements, ARE

Co-firing: High Subsidy Cost, Limited Decarbonization

- Current co-firing projects will decarbonise less than 1GW of coal-fired power. Yet, they will demand 8.2% of Japan's low-carbon fuel subsidy budget.
- A further 11.9GW of potential co-firing plants would multiply subsidy costs while delivering limited decarbonisation gains.
- For future projects, fuel subsidies will be included the LTDA capacity payments, with costs passed on to end-consumers.
- Given the very high co-firing costs, LTDA awarded capacity will be limited to 0.5GW per auction round, with assumed 40% capacity factor.



Subsidies (in billion)	LTDA Rounds1&2	Future Rounds**	Total
Fuel (contract duration)*	JPY1,333/ USD9	JPY3,515/ USD23.4	JPY4,849/ USD32
Total Capex	JPY136.4/ USD0.9	JPY360/ USD2.4	JPY496/ USD3.3
Total Fuel & Capex	JPY1,470/ USD10	JPY3,875/ USD26	JPY5,345/ USD36

*Notes:**Assuming 15-year contracts for fuel subsidies, as stated in the CfD Programme.*
***Assuming 20 % co-firing for all remaining candidates.*

Source: Global Energy Monitor, Beyond Coal, ARE

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Conclusion

Japan’s electricity market is undergoing a profound structural shift.

As battery storage expands and interregional grid connections strengthen, pricing peaks are expected to flatten and average electricity prices are likely to trend downward.

As these developments gradually erode revenues of coal-fired power generation, coal plants are projected to face sustained profitability challenges by the early 2030s.

Against this backdrop, ammonia co-firing has emerged as a strategic pathway for utilities to maintain operations and secure access to government support. Our analysis indicates, however, that even with substantial subsidies, co-firing is unlikely to restore profitability.

In sum, Japan’s coal-to-ammonia transition appears to serve primarily as a policy mechanism to manage transition risk, rather than a long-term economic solution.

Coal plants, whether co-firing or not, will come under growing pressure to repurpose, retire, or redefine their role within an increasingly modernising power system.

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