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Risk Analysis of Coal-Fired Power Plant Investment in Japan

Exposure to Stranded Asset Risk in the Energy Transition Period

October 2019



Acknowledgements

The Institute would like to thank the organizations, corporations and individual researchers who assisted in the production of this report.

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Renewable Energy Institute

Renewable Energy Institute is a non-profit think tank which aims to build a sustainable, rich society based on renewable energy. It was established in August 2011, in the aftermath of the Fukushima Daiichi Nuclear Power Plant accident, by its founder Mr. Son Masayoshi, Chairman &CEO of SoftBank Corp., with his own resources.

Cover Photo

Eemshaven Power Plant, a state-of-the-art coal-fired thermal power plant with capacity of 1,560 MW located in the northern part of the Netherlands. The plant went online in 2015, but because the Dutch government has adopted a policy of phasing out coal completely by 2030, the plant will have to be decommissioned or converted to a biomass facility.

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Executive Summary

After the Great East Japan Earthquake, plans were announced to build approximately 21,000 MW of new coal-fired thermal power plants on the grounds that they were needed to compensate for capacity lost due to nuclear plants being shut down. More recently, however, many of these plans have been canceled or changed. In the three years since 2017, construction plans for 7,030 MW of this capacity have been canceled or switched to LNG or biomass.

The background to these changes is mounting domestic and international criticism of coal-fired power, a huge emitter of carbon dioxide, as the climate change crisis has emerged in sharper relief. The main reason private-sector operators are scrapping or altering their plans, however, is simply the fact that coal-fired power plants have become unprofitable amid changes in the market environment. Coal-fired power has typically been seen as an inexpensive base load power source with high economic performance compared to other sources, but its relative superiority in this regard is being undermined.

In the Aggregation of Electricity Supply Plans to 2028 published by the Organization for Cross-regional Coordination of Transmission Operations (OCCTO), thermal power's installed capacity, which includes coal-fired power, will increase even though electricity demand will decrease. This will result in lower capacity factor and a corresponding decline in electricity sales revenue, which means profitability will worsen. An increase in renewable energy will strike another blow that lowers the capacity factor for coal-fired power. If the competitiveness of the electricity market increases with reforms to the power system, the electricity sales price will fall further and further reduce profitability. It is also possible that stronger climate change measures and other developments will impose restrictions on coal fired power.

This report makes clear that due to these changes in market conditions and the political environment, there is a substantial risk that coal-fired power investment will not be profitable. New coal-fired plant projects currently underway in Japan include 14 units under construction and six units in the pre-construction phase¹. This report conducts a case study based on these facilities going into operation and, in order to clarify whether the level of revenue expected from such enormous investments can be generated, analyzes business profitability and stranded asset risks in three different scenarios: 1) Operator Scenario, 2) Market Change Scenario, and 3) Policy Change Scenario.

Key Findings

1. According to OCCTO, maximum electricity demand will decrease by 3.7% by 2028 compared to 2018, while coal-fired thermal's installed capacity will increase by 20%. The capacity factor at coal-fired power plants will decline from 73.2% to 69.5% on average nationwide. Most of the new coal-fired power plants under construction or in the planning stages assume capacity factor of 80-90%, so in light of OCCTO's projections, it is possible that these assumptions will miss the mark and that business risk will be higher.
2. The internal rate of return (IRR) that is needed to execute coal-fired power investment is 8% at minimum and is generally set at 10%. Taking investment in a new 1,300 MW Ultra-Supercritical (USC) coal-fired power plant as the model and setting baseline case parameters of an 85% capacity factor, an electricity sales price of 9.5 yen per 1 kWh, fuel prices of 11,000 yen per ton of coal, a service life of 40 years and no carbon tax, the IRR works out to be 8.7%. When market and policy trends are taken into consideration, there is little likelihood that these assumptions can be maintained as they are. Coal-fired power investment carries with it a level of business risk that cannot be taken lightly.

¹ Of the six coal fired power plants categorized by this report as "pre-construction," a groundbreaking ceremony was held for the Yokosuka Thermal Power Plant (two units) on August 30, 2019.

3. When capacity factor is the only baseline assumption that is changed, and it is set at the nationwide average of 69.5% in 2028, IRR declines to 6.0%. Even with the capacity factor maintained at 85%, if the electricity sales price falls to 8.0 yen/kWh, IRR declines to 3.3%. With the capacity factor at 69.5% and the electricity sales price at 8.0 yen, it is 0.9%.
4. Most recently, the LNG price has fallen and its price difference with coal has reversed; coal is even losing its competitive advantage as an inexpensive power source. If this situation continues, as the capacity factor of gas-fired thermal power rises, coal's capacity factor will fall further.
5. There are also policy factors associated with strengthening climate change measures that have the potential to increase the business risk of coal-fired power investment. Even assuming a capacity factor of 85%, if a carbon tax of 3,000 yen per ton of CO₂ emissions is instituted, IRR will decrease to -1.5%. With the capacity factor at 69.5%, it declines further to -5.0%.
6. Future investment in coal-fired power will carry significant business risk. Due to decreasing electricity demand, falling renewable energy costs, declining capacity factors, falling wholesale electricity prices, rising coal prices, stronger regulations to address climate change, and other factors, new coal-fired power projects currently underway face the significant risk that they will become stranded assets.

[Stranded Assets]

Stranded assets are assets whose value has been greatly damaged due to major changes in market or societal conditions. Of particular note are assets associated with fossil fuels like coal, oil, and natural gas. Currently, as an important energy source, fossil fuels have value, but when carbon dioxide reduction measures must be carried out to address climate change, they will not be able to be utilized as an energy source and their asset value will decline substantially.

When the asset value declines, the company holding the asset must impair the asset's value on its financial accounts and this inflicts serious damage on the company's income statement and balance sheet. Assets whose value has eroded considerably are called "stranded assets." Source: Environmental Information Center

1. Medium/Long-Term Outlook for Electricity Supply-Demand

Japan’s annual electricity sales have been declining since fiscal 2010. Electricity sales from 2010 to 2018 declined from 931.1 million MWh to 852.5 million MWh over this eight year period, a decrease of 8.4%². Since the Great East Japan Earthquake in 2011, real GDP has grown by around 1% annually, so the decline in electricity sales is considered to be due to energy efficiency gains and greater energy conservation.

According to OCCTO, annual maximum electricity demand is projected to decrease by 3.7% from 159,700 MW in 2018 to 153,850 MW in 2028. The main reasons for this decline are given as improved energy efficiency, further load leveling measures, and population declines. The reserve ratio, which expresses the availability of supply capacity against maximum electricity demand, will stay above 8%, the standard for stable supply, over the medium/long term to 2028³.

OCCTO has aggregated the plans submitted by power utilities based on the Electricity Business Act and compiled a future supply plans. According to the plan, even though maximum electricity demand will decrease, the installed capacity of thermal power facilities is expected to increase. Total coal-fired power capacity varies as new plants are built, rebuilt or retired, but it will increase by 20% from 43,120 MW in 2018 to 51,890 MW in 2028. By contrast, gas-fired thermal (LNG) will increase by 3% from 82,010 MW to 84,850 MW, and oil-fired power will decrease as it continues to be retired.

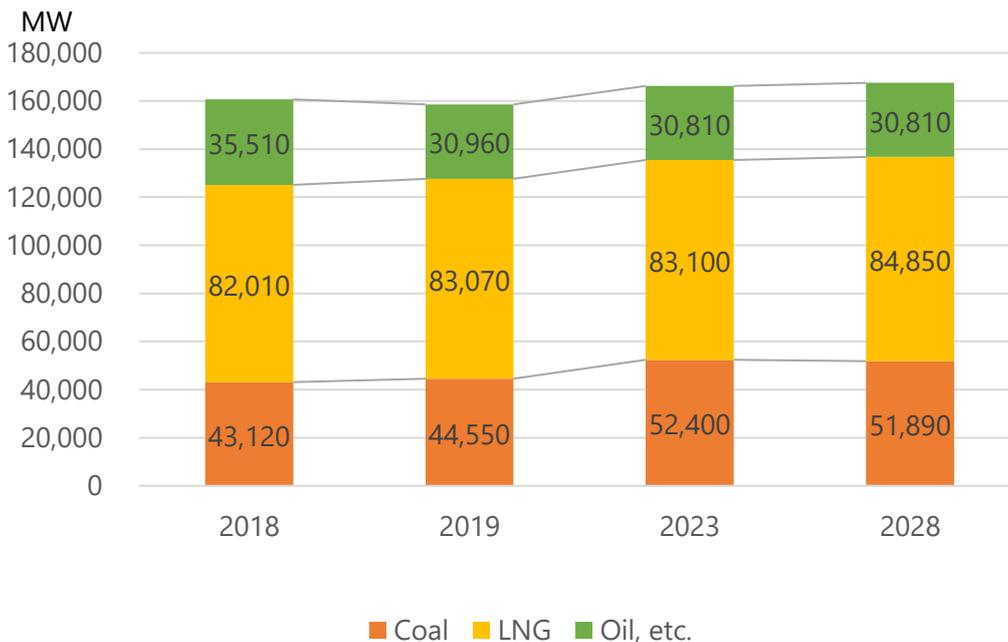


Chart 1 Thermal Power’s Power Source Mix (MW) (Nationwide)

Source: Aggregation of Electricity Supply Plans for FY2019 (OCCTO)

https://www.occto.or.jp/en/information_disclosure/supply_plan/190522_aggregation_supplyplan.html

2 Electric Power Statistics (METI) https://www.enecho.meti.go.jp/statistics/electric_power/ep002/results.html

3 Aggregation of Electricity Supply Plans for FY2019 (OCCTO) https://www.occto.or.jp/en/information_disclosure/supply_plan/190522_aggregation_supplyplan.html

At the same time, according to OCCTO’s summary, electricity generation trends going forward show thermal power declining overall, but coal is projected to increase by 14% from 276.4 million MWh in 2018 to 316 million MWh in 2028. By contrast, in the Japanese government’s Strategic Energy Plan⁴, coal-fired power generation is assumed to account for 26% (276.9 million MWh) of the overall energy mix in 2030. The government’s plan, which has a fourth of the country’s electricity being supplied by coal as of 2030, has been criticized for being completely at odds with the global effort to decarbonize. However, the 316 million MWh in 2028 presented in OCCTO’s summary represents 37% of the nation’s total electricity generation. Based on the current plans of the power utilities, coal-fired power will greatly exceed even the assumptions of the government’s Strategic Energy Plan.

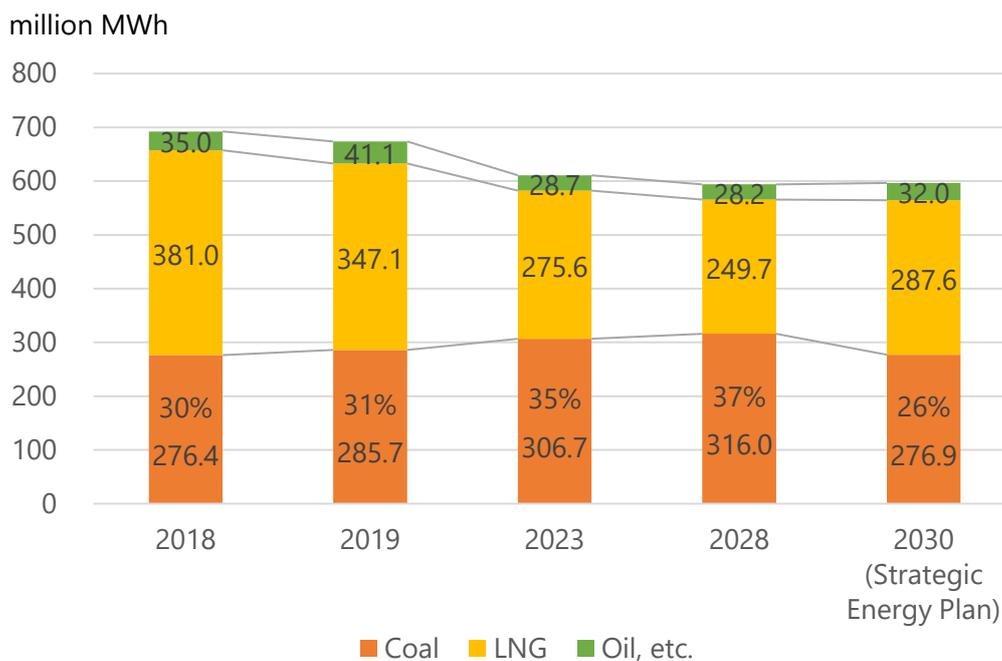


Chart 2 Thermal Electricity Generation (MWh) (Nationwide)

Source: Aggregation of Electricity Supply Plans for FY2019 (OCCTO)

https://www.occto.or.jp/en/information_disclosure/supply_plan/190522_aggregation_supplyplan.html

4 5th Strategic Energy Plan (Agency for Natural Resources and Energy) https://www.enecho.meti.go.jp/en/category/others/basic_plan/5th/pdf/strategic_energy_plan.pdf

2. Trends in New Coal-Fired Power Plants

Following the Great East Japan Earthquake and Fukushima nuclear disaster of March 2011, a series of new construction plans for coal-fired power plants with combined capacity of around 21,000 MW were announced on the grounds that they were needed to compensate for capacity lost due to nuclear facilities being shut down. Of this amount, 2,460 MW has been built and is currently operating. However, plans for 7,030 MW have been cancelled or changed to LNG or biomass in the wake of mounting climate change-driven criticism at home and abroad and deteriorating profitability from market changes. As a result, facilities totaling 7,970 MW are currently under construction at 12 sites, and facilities at three sites, in Akita, Yokosuka, and Yamaguchi, totaling 3,200 MW are in the environmental assessment or post-assessment, pre-construction phase⁵.

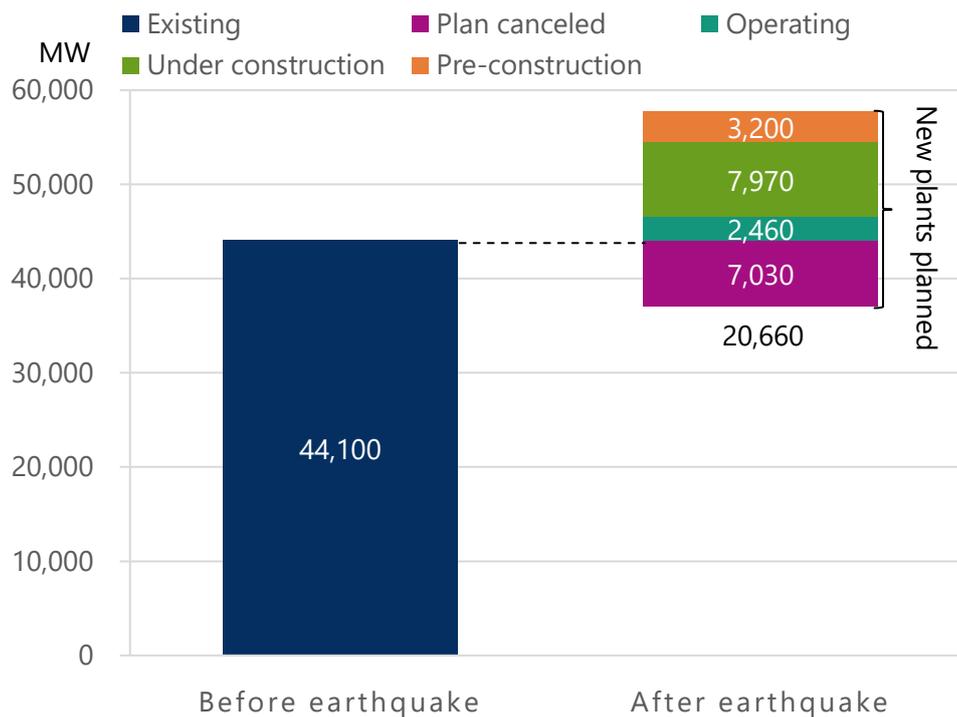


Chart 3 Change in Coal-Fired Power Plants Post-Earthquake

Source: Created by Renewable Energy Institute

(1) Akita Port Power Plant Units 1 and 2

Akita Port Power Plant is being planned by Kanden Energy Solution, a subsidiary of Kansai Electric, and Marubeni. Two coal-fired units with ultra-supercritical (USC) facilities will be built with capacity totaling 1,300 MW. The new plant will be built on prefectural land at Akita Port for the purpose of supplying electricity from the Tohoku region to the Tokyo metropolitan area in anticipation of market liberalization⁶. However, to transmit power to the Tokyo area will require enhancing interconnectors that connect the power grids of Tohoku Electric Power and Tokyo Electric Power, and in return for obtaining interconnector usage slots the power provider will bear a portion of the enhancement costs⁷. In the initial plan, coal was the only fuel to be used, but mixed combustion with biomass, in

⁵ A groundbreaking ceremony was held for the Yokosuka Thermal Power Plant (two units) on August 30, 2019.

⁶ Summary of Opinion on Environmental Impact Assessment Draft related to Construction Plan for Akita Port Power Plant (provisional name) and Provider Opinion https://www.meti.go.jp/policy/safety_security/industrial_safety/sangyo/electric/files/akitako/junbisyo_kenkai.pdf

⁷ The Environmental News, February 6, 2019, "Cancellations of Coal-Fired Thermal for Tokyo Metro Area Continue to be Announced: MOE Focused on Kanden/Marubeni Akita Port Plan"

which wood chips are burned, and conversion to LNG are now being considered⁸. Unit 1 was scheduled to go online in March 2024 and Unit 2 in June of the same year, but in August 2019, when construction was initially planned to start, it was announced that it was being delayed⁹.

(2) Yokosuka Thermal Power Plant New Units 1 and 2

This facility is being planned by JERA, which has TEPCO Fuel & Power and Chubu Electric Power as an investor, and is scheduled to commence operations in 2023 or 2024. An oil- and gas-fired thermal plant that has aged is being upgraded to a coal-fired USC facility with two units and combined capacity of 1,300 MW. It is outside the LNG pipeline network, so major construction would be needed, and this is why, it has been explained, that coal was chosen over LNG¹⁰. When a plant is rebuilt, according to government guidelines, a portion of the environmental assessment can be omitted and the time period shortened if certain conditions are met, like reduced GHG emissions compared to the existing plant. No Coal Tokyo Bay, a community organization opposed to this, argues it is unreasonable to simplify environmental assessments and has taken the government to court through the Tokyo District Court demanding that the Minister of Economy, Trade and Industry, who approved the plan, revoke it. It has been reported in the media that a groundbreaking ceremony was held on August 30, 2019¹¹.

(3) Nishiokinoyama Power Plant Units 1 and 2

Yamaguchi Ube Power, whose investors are Ube Industries and Electric Power Development (J-POWER), is planning to build a new plant on a company-owned site next to one of Japan's largest coal storage facilities, which is owned by Ube Industries. Initially, Osaka Gas was also involved, and the plan was to build two USC coal-fired units with total capacity of 1,200 MW, but in April 2019 Osaka Gas announced it was withdrawing from the project. Citing the risk of stronger environmental regulations and lower future electricity sales prices, the company concluded that the project no longer met its own investment criteria¹². Currently, the environmental impact assessment is being withdrawn and changes being considered that would result in a 600 MW USC unit or a 300 MW integrated coal gasification combined cycle (IGCC) unit¹³. Toshiba and Orix also had plans to build a 1,000 MW coal-fired power plant on the same site in 2006, but due to slower electricity demand, rising coal prices, and intensifying climate change, profitability could not be firmly projected, and the plan was abandoned¹⁴.

8 Nihon Keizai Shimbun, February 22, 2019, "Kanden/Marubeni Akita Port Coal-Fired Thermal Being Reconsidered; Biomass Conversion Possible"

9 Nihon Keizai Shimbun, August 14, 2019, "Kanden Group and Marubeni Postpone Construction on Akita Coal-Fired Thermal Power Plant"

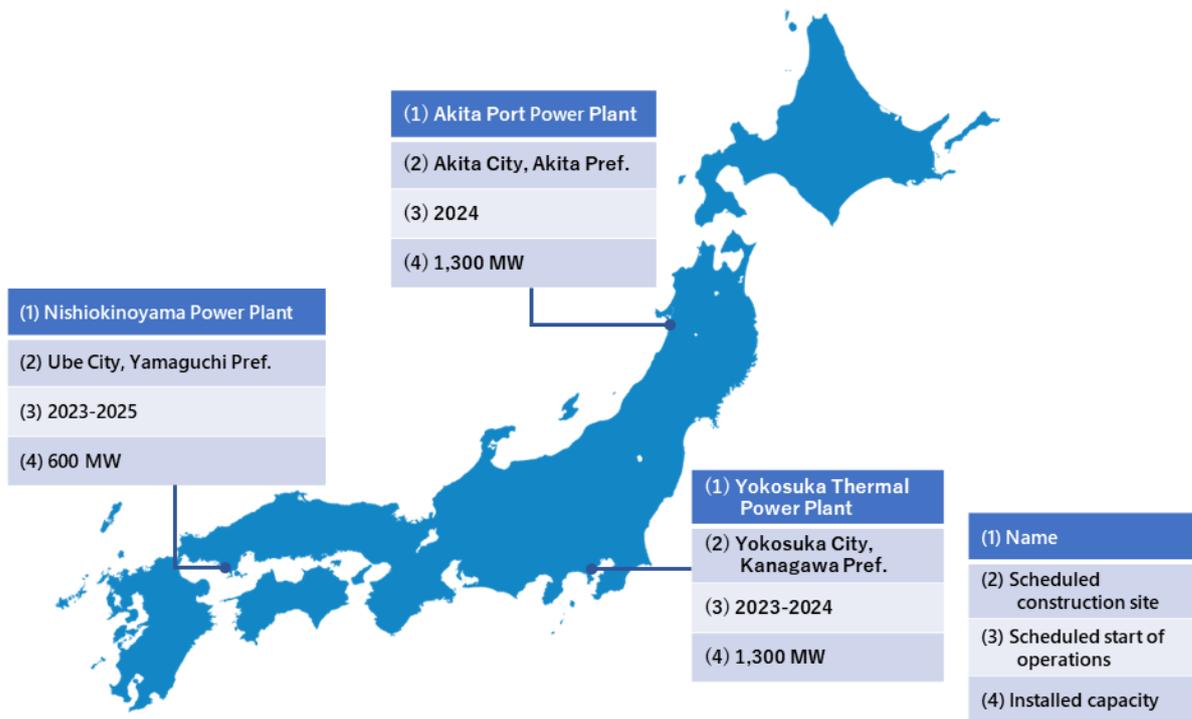
10 Presentation documents from Briefing for Yokosuka Thermal Power Plant New Units 1 and 2 (provisional name) Construction Plan Environmental Impact Assessment Draft <http://www.pref.kanagawa.jp/docs/ap4/documents/201806hosokushiryou.pdf>

11 Yomiuri Shimbun, August 30, 2019, "Groundbreaking Ceremony in Yokosuka for Coal-Fired Thermal Power Plant"

12 Denki Shimbun, April 25, 2019, "J-POWER, Ube Coal-Fired Thermal Plan Reconsidered: Osaka Gas Withdraws, IGCC Under Consideration"

13 Nihon Keizai Shimbun, April 24, 2019, "Osaka Gas Withdraws from Yamaguchi Coal-Fired Thermal Plan, Outlook Cloudy"

14 Denki Shimbun, March 1, 2006, "Sigma Power Yamaguchi Cancels Coal-Fired Thermal Plan"



	Provisional name	Capacity	Operators	Investors	Scheduled launch	Note
1	Akita Port Power Plant Units 1 & 2 (Akita)	1,300 MW	Kanden Energy Solution, Marubeni	Kansai Electric Power, Marubeni	2024	New
2	Yokosuka Thermal Power Plant New Units 1 & 2 (Kanagawa)	1,300 MW	JERA	TEPCO F&P, Chubu Electric	2023-2024	Switch from oil to coal
3	Nishiokinoyama Power Plant Units 1 & 2 (Yamaguchi)	600 MW	Yamaguchi Ube Power	J-POWER, Ube Industries	2023-2025	New

Chart 4 New Construction Plans at Three Domestic Sites (3,200 MW)

Source: Created by Renewable Energy Institute

3. Revenue Structure of Coal-Fired Power Plants

Three factors have a major impact on the profitability of coal-fired power plants: construction costs (the initial investment), fuel costs, which are incurred annually, and revenue from electricity sales. The revenue structure of coal-fired power is as shown in the following chart. Net profit is revenue (electricity sales) net of fuel costs and other expenses. The initial investment is recovered out of net profit each year. Revenue from electricity sales is electricity generated (installed capacity × capacity factor (see the box below)) multiplied by the electricity sales price, so it depends greatly on the capacity factor and electricity prices. When the capacity factor or electricity prices go up (or down), electricity sales revenue increases (or decreases); they are directly correlated.

The largest expense is fuel costs (coal), which accounts for around 80% of overall costs. Fuel costs are determined by procurement prices on the coal market. When the coal price falls, or when the price falls indirectly due to yen appreciation, costs fall and profits thereby increase. To raise the profitability of coal-fired power investment, it is necessary to either lower construction costs or increase profits or both. When construction costs are fixed, profitability is increased by increasing electricity sales revenue or lowering fuel costs or both.

Table 1 Revenue Structure of Coal-Fired Power

Revenue	
Electricity sales revenue	[Installed capacity (kW) × Time (h) × Capacity factor (%) = Electricity generation (kWh)] × Electricity sales price (yen/kWh)
Expenses	
Fuel costs, etc.	Volume of coal used (tons) × Coal price (yen/ton)
Net profit (loss)	
	Revenue – expenses

Source: Created by Renewable Energy Institute

[Capacity Factor]

An indicator that shows the degree to which a power facility operated in a single year. It is the ratio of the amount of electricity actually generated to the amount of electricity that would be generated if the facility continuously operated at 100% output. The formula for annual capacity factor can be expressed as follows.

Annual capacity factor (%)

$$= \text{Actual amount of electricity generated in 1 year (kWh)} / (\text{Maximum output (kW)} \times 24 \text{ hours} \times 365 \text{ days}) \times 100$$

4. Analysis for New Coal-Fired Power Profitability

(1) Profitability Simulation for New Coal-Fired Power Plant

In order to consider the matter of profitability, parameters were set based on a new USC facility with installed capacity of 1,300 MW as the model case, with reference to the new plants currently under construction or in the planning stages, and profitability was analyzed on this basis. When there was published data available for facilities of an equivalent size, in environmental impact assessments or other such documents, this data was used, and when there was no data, data from the Agency for Natural Resources and Energy's Power Generation Cost Verification Working Group¹⁵ and other sources was used.

According to Project Finance International, a financial research firm, 272 billion yen (US\$2.5 billion, ¥108.8/\$1) was raised to cover construction costs for a new USC coal-fired power plant with capacity of 1,300 MW¹⁶, while related media reports¹⁷ put the figure at around 300 billion to 350 billion yen. Supposing construction costs are 300 billion yen, the cost per kilowatt works out to around 230,000 yen, which is close to the 250,000 yen per kilowatt (325 billion yen) calculated by the Power Generation Cost Verification Working Group based on past model plants. In the case of a rebuilt plant, the existing coal storage facility and other ancillary facilities can be reused, so construction costs decrease accordingly. In this report profitability is analyzed assuming an initial investment of 300 billion yen for a new plant with a revenue structure in which this amount is recovered from annual profit, which is figured as electricity sales revenue net of costs.

For the amount of coal used and electricity generated, data was used from environmental impact reports¹⁸ of similarly sized plants. For the price of coal, 11,000 yen per ton was used, which is the average of the past three years of CIF prices at arrival in Japan, the actual import price, as recorded in the Ministry of Finance's Trade Statistics of Japan. The capacity factor was set at 85%, the level assumed in provider plans for stable electricity supply to the Tokyo metropolitan area. The electricity sales price assumes that electricity will be sold on the wholesale electricity market, as a result of generation and transmission being separated by retail power liberalization, and was set at 9.5 yen/kWh, the past one-year average of the Tokyo Area Price on the Japan Electric Power Exchange (JEPX). The service life was set at 40 years, which is the general service life for coal-fired power plants. The profitability analysis uses internal rate of return (IRR; see definition below), a key indicator used to make investment decisions in Japan and overseas.

[Internal Rate of Return]

Discount rate when the present value of future cash flow from the investment is equal to the present value of the investment amount. It is utilized as the return used in investment decisions.

$$0 = CF_0 + \frac{CF_1}{(1 + IRR)} + \frac{CF_2}{(1 + IRR)^2} + \frac{CF_3}{(1 + IRR)^3} + \dots + \frac{CF_n}{(1 + IRR)^n}$$

CF₀ = Initial investment (construction costs), CF = Cash flow (net profit), n = Year

15 Power Generation Cost Verification Working Group https://www.enecho.meti.go.jp/committee/council/basic_policy_subcommittee/

16 "Jera takes coal in Yokosuka" <http://www.pfie.com/jera-takes-coal-in-yokosuka/21380010.article>

17 *Denki Shimbun*, April 25, 2016 "TEPCO Fuel & Power to Replace Yokosuka Thermal: 2 USC Units, Construction Scheduled for 2019"

18 Document summarizing environmental impact assessment results for Yokosuka Thermal Power Plant Units 1 and 2 (provisional name) Construction Plan <https://www.jera.co.jp/static/files/business/thermal-power/environment/assessment/yokosuka/pdf/gaiyou-shiryou.pdf>

Table 2 Baseline Parameters for New Coal-Fired Power Plant Income Calculations

Installed capacity	650 MW × 2 units = 1,300 MW	
Operating period	40 years	
Construction costs	1,300 MW × 231,000 yen/kW = 300,000 million yen	
Revenue	Electricity sales revenue	Generating end: 1,300 MW × 24 hours × 365 days × 85% (capacity factor) = 9,679,800,000 kWh
		Sending end: Generating end × 93.6% (internal plant use) = 9,060,292,800 kWh
		Electricity sales revenue: Sending end × 9.5 yen/kWh (Sales price: JEPX Tokyo Area price) = 86,073 million yen/year
Expenses	Fuel costs	3,600,000 tons/year (amount of coal used) × 11,000 yen/ton (CIF price) = 39,600 million yen/year
	Fuel expenses ¹⁹	3,600,000 tons/year × 2,000 yen/tons = 7,200 million yen/year
	Personnel expenses ²⁰	360 million yen/year (model plant average value)
	Repair costs ²¹	5,400 million yen/year (1.8% of construction costs)
	Miscellaneous expenses ²²	4,500 million yen/year (1.5% of construction costs)
	General and administrative expenses ²³	1,467 million yen/year (14.3% of personnel expenses, repair expenses, and miscellaneous expenses)
	Decommissioning reserve ²⁴	375 million yen/year (construction costs × 5% / 40 years)

Source: Created by Renewable Energy Institute based on public documents.

Table 3 Income Statement for New Coal-Fired Power Plant

(Millions of yen)

Expenses			Revenue		
Fuel costs	39,600		Electricity sales revenue	86,073	100%
Fuel expenses	7,200		Capacity revenue	-	
Personnel expenses	360				
Repair expenses	5,400				
Misc. expenses	4,500				
General/admin. expenses	1,467				
Decommission reserve	375				
Carbon tax (emissions tax)	-				
Total expenses	58,902	68%			
Net profit					
	27,171	32%			
Total	86,073		Total	86,073	

19 Fossil fuel tax, import fees, domestic freight charges, coal center usage fees, unloading fees, etc. Average of most recent results of each company.

20 Personnel expenses required for plant operations. Includes pay and benefits, social welfare, retirement benefits, etc.

21 Average of inspection and repair costs for maintaining regular usage conditions for generating facilities throughout service life. Model plant average.

22 Waste processing costs, supplies, lease payments, consignment fees, damage insurance premiums, miscellaneous wages, miscellaneous taxes, etc. Model plant average.

23 Expenses related to electricity business overall (personnel expenses, repair expenses and miscellaneous expenses of headquarters, etc.) allocated as expenses related to this power business. Model plant average.

24 Value used in OCED/IEA "Projected Costs of Generating Electricity 2015 Edition" estimates when there is no specific waste expenses data from a country.

Based on interviews with major financial institutions, the assumed IRR for coal-fired power plant investment, in which a risk premium is added to the risk-free rate, must be at least 8% and is generally 10%. Basic calculations with baseline case parameters of a fuel price of 11,000 yen per ton-coal, an electricity sales price of 9.5 yen per 1 kWh, an 85% capacity factor, and an operating service life of 40 years put the IRR at 8.7%. Power providers planning to build new coal-fired power plants must make revenue and cost assumptions that make this level of profitability possible.

The problem, however, is whether it will be possible to maintain these parameters in the future. Along with this baseline case, it is also necessary to consider how the parameters will change amid various trends now and expected in the future and how profitability will be affected. The following sections will take up the factors that have a major impact on the profitability of coal-fired power plants (capacity factor, fuel price, electricity sales price, service life, carbon tax) and conduct a sensitivity analysis that looks at how profitability (IRR) changes when each of these factors change.

(2) Decrease in Capacity Factor

According to OCCTO, going forward, thermal power’s installed capacity will increase, but electricity generation will decrease. Increased capacity with decreased generation means that the capacity factor will decline. Medium/long-term projections of the capacity factor calculated by OCCTO based on the power source mix (kW) and electricity generation (kWh) are as shown in the following diagram; the ratios for coal, LNG and oil will all decrease. Coal-fired power will decline by 3.7 percentage points from 73.2% to 69.5%. The projection’s calculations do not include nuclear power plants resuming operations whose status is currently uncertain, so if more of nuclear power plants do go back online, coal-fired power’s capacity factor will decline further. As the capacity factor falls, so does electricity sales revenue by the same extent, which then lowers profitability.

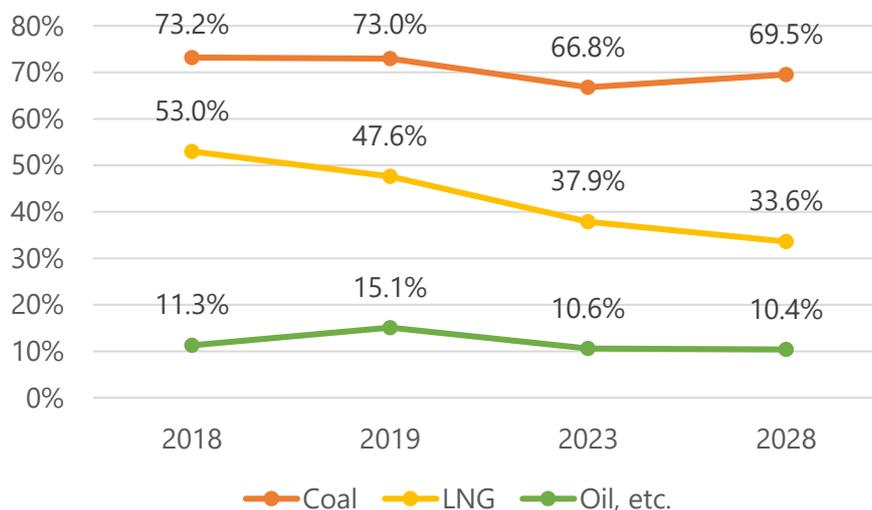


Chart 5 Capacity Factors at Thermal Power Plants (Nationwide)

Source: Aggregation of Electricity Supply Plans for FY2019 (OCCTO)

https://www.occto.or.jp/en/information_disclosure/supply_plan/190522_aggregation_supplyplan.html

The actual capacity factors of major power providers are as shown in the diagram below. For the past three years, the ratio has declined for almost all providers; in 2018, the average was 69%. Looking at TEPCO Fuel & Power, the capacity factor at coal-fired power facilities owned by the company was 85% in 2018. To stably operate coal fired

power plants over the long term, it is essential that a high capacity factor be maintained, and electricity sales revenues generated.

Table 4 Capacity Factors for Coal-Fired Power Plants of Major Power Providers

Provider	Capacity factor		
	2016	2017	2018
Hokkaido Electric Power	66%	70%	67%
Tohoku Electric Power	71%	80%	78%
TEPCO Fuel & Power	83%	86%	85%
Chubu Electric Power	81%	83%	79%
Hokuriku Electric Power	76%	72%	61%
Kansai Electric Power	84%	84%	67%
Chugoku Electric Power	73%	73%	71%
Shikoku Electric Power	81%	76%	73%
Kyushu Electric Power	79%	75%	61%
Okinawa Electric Power	56%	53%	47%
J-POWER	70%	75%	74%

Source: Prepared by Renewable Energy Institute based on Electric Power Statistics (Agency for Natural Resources and Energy)

https://www.enecho.meti.go.jp/statistics/electric_power/ep002/results.html

We also investigated capacity factors assumed for plants currently being built or in the planning stages, as stated in their environmental impact assessments, and the results are shown in the following table. Nearly all the facilities assume a high capacity factor of 80-90%. Even presently, the national average is around 70% and it is clear that it will decrease further in light of the situation with electricity market going forward, so maintaining a high capacity factor of 80-90% outside the Tokyo metropolitan area is projected to be exceedingly difficult, which shows that these are optimistic assumptions even for newly constructed power plants.

Table 5 Assumed Capacity Factors for Coal Fired Plants in Planning/Construction Phase

Name	Location	Service area	Installed capacity (MW)	Planned launch	Assumed capacity factor
Akita Port Power Plant Units 1 & 2	Akita	Tohoku	1,300	2024	85-90%
Hitachinaka Joint Thermal Power Plant Unit 1	Ibaraki	Tokyo	650	2021	85%
Kashima Thermal Power Plant Unit 2	Ibaraki	Tokyo	645	2020	80%
Nakoso IGCC Power Verification Plan	Fukushima	Tohoku	540	2020	85%
Yokosuka Thermal Power Plant New Units 1 & 2	Kanagawa	Tokyo	1,300	2023-24	85%
Taketoyo Thermal Power Plant Unit 5	Aichi	Chubu	1,070	2022	80%
Takehara Thermal Power Plant New Unit 1	Hiroshima	Chugoku	600	2020	79%
Kobe Steel Thermal Power Plant Units 1 & 2	Hyogo	Kansai	1,300	2021-22	80%
Misumi Power Plant Unit 2	Shimane	Chugoku	1,000	2022	80%
Tokuyama East Power Plant Unit 3	Yamaguchi	Chugoku	300	2022	90%
Saijo Power Plant New Unit 1	Ehime	Shikoku	500	2023	75%

Source: Power Plant Environmental Assessment Information Service (METI)

https://www.meti.go.jp/policy/safety_security/industrial_safety/sangyo/electric/detail/thermal.html

The internal rate of return (IRR) declines in stages as the capacity factor declines. If the baseline capacity factor of 85% can be maintained, an IRR of 8.7% can be achieved, but if the market environment changes—specifically, if electricity demand declines, renewable energy increases, or nuclear plants resume operations—and the capacity factor declines. With the capacity factor the same as the nationwide average of 69.5% in 2028 based on the assessment by OCCTO, IRR drops to 6.0%.

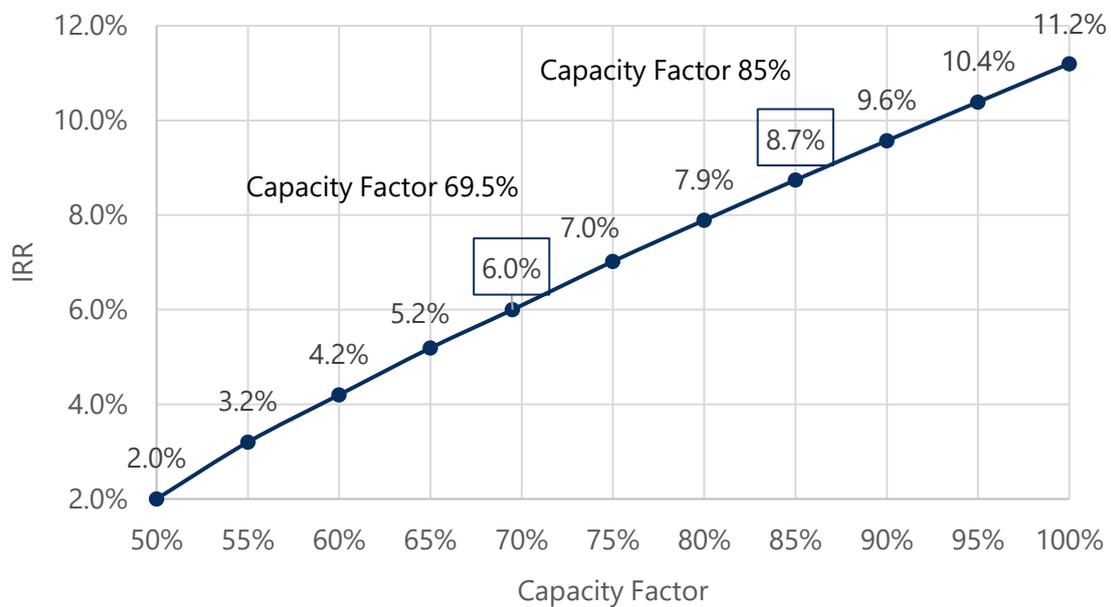


Chart 6 Change in IRR from Decrease in Capacity Factor

Source: Created by Renewable Energy Institute

In the Minister of the Environment’s opinion statement on the environmental impact assessment draft for a new coal-fired power plant in Yokosuka, submitted by the Ministry of the Environment in August 2018, the capacity factor was projected to be approximately 54% in fiscal 2030, as is stated below. In this case, IRR drops to approximately 2.9%.

If the coal-fired power plant is built according to the current plan, its capacity utilization will have to be low to a considerable degree in order for the energy mix target for fiscal 2030 to be achieved. For example, if all plans for new and expanded coal-fired power plants, which have a combined capacity of approximately 16,800 MW, including the project under review, are executed, and supposing that aged coal-fired plants are decommissioned 45 years after going into service, the capacity factor for coal-fired power in fiscal 2030 will be approximately 54%, which is below the 80% average capacity factor in fiscal 2016 and 68% average capacity utilization for thermal power overall assumed in the energy mix.

Source: Opinion of Environment Minister on Environmental Impact Assessment Draft (August 2018)

<https://www.env.go.jp/press/files/jp/109803.pdf>

The following considers the factors that potentially reduce the capacity factor.

The first factor is an increase in renewable power. Globally, the generating costs of solar PV and wind have come down dramatically over the past several years, and renewable power is the most realistic option for achieving a decarbonized society. According to the projections of BloombergNEF, even in Japan, solar PV will be less expensive

than natural gas at the start of the 2020s and be less than even coal in the mid-2020s. According to Renewable Energy Institute estimates as well, the cost of solar PV in Japan will decline to around 5 yen/kWh by 2030²⁵.

Based on realistic development trends for solar PV and wind power, renewable power in 2030 has the potential to account for over 40% of the power supply, far exceeding the government’s projection of 22-24%. Even in Japan, inexpensive renewable energy will be supplied in large quantities, and it can also be assumed that this situation will shut out coal and other thermal power from the electricity market.

In addition, capacity factors at coal-fired power plants are significantly impacted by the operating status of nuclear power plants. According to priority dispatch rules, as a base load power source, nuclear is prioritized for use over coal. Going forward, as nuclear plants resume operations, capacity factors for coal-fired power will decline by that same extent and electricity generation will also decline. For a nuclear plant to resume operations, it has to pass the review of the Nuclear Regulation Authority and obtain the agreement of the local government where the plant is located. The matter is difficult to predict, but if nuclear plants around the country begin going back online, the capacity factor at coal-fired power plants will decline to that extent and business risk will increase.

Moreover, coal-fired power’s capacity factor declines when market prices for LNG drop. In Japan’s Strategic Energy Plan, coal is described as “a fuel for an important base-load power supply because it involves the lowest geopolitical risk and has the lowest price per unit of heat energy among fossil fuels.”²⁶ However, over the past several years, its price advantage over previously high-priced LNG has diminished and its relative superiority is beginning to decline. In 2019, the LNG price hit a 10-year low, and comparing the price on a barrel of oil equivalent basis, LNG has become more inexpensive than coal.



Chart 7 International Spot Prices for Oil, Coal and LNG

Source: BloombergNEF

<https://www.bloomberg.com/news/articles/2019-06-04/diving-gas-costs-spark-potential-rare-switch-from-coal-in-japan>

25 Renewable Energy Institute, “Solar Power Generation Costs in Japan: Current Status and Future Outlook,” July 23, 2019

<https://www.renewable-ei.org/en/activities/reports/20191004.php>

26 5th Strategic Energy Plan (Agency for Natural Resources and Energy) https://www.enecho.meti.go.jp/en/category/others/basic_plan/5th/pdf/strategic_energy_plan.pdf

If coal's price advantage over LNG diminishes, the cost and environmental advantages of LNG-fired thermal power will increase because construction costs and operating and maintenance costs are already much lower than coal and its CO₂ emissions only half. In addition, a majority of LNG-fired facilities are combined cycle and have a maximum generating efficiency of 54%, whereas coal-fired power's is around 43%, a substantial difference, which gives LNG a further advantage per unit of electricity generated. Power providers with both coal-fired and gas-fired facilities monitor price fluctuations for both coal and gas, and when the price of gas goes down, they raise the capacity factor at their gas-fired facilities; conversely, when the price of coal goes down, they raise the capacity factor at their coal-fired facilities, and this serves to maximize profit. If the prices are generally equivalent, they will operate their gas-fired facilities because generating efficiency is higher, and maintenance and management costs are lower. According to reporting by Bloomberg²⁷, Japan's electric power utilities are beginning to consider raising capacity factors for gas-fired plants and lowering them for coal-fired plants. In this way, lower LNG prices are also a factor that causes coal's capacity factor to decline. From the perspective of coal-fired power, they are a source of instability that raises business risk.

In concert with these changes in the global energy market, in December 2018 the Soga Thermal Power Plant (1,070 MW), and in February 2019 the Sodegaura Thermal Power Plant (2,000 MW), both in Chiba Prefecture, began to consider changing their plans for LNG, abandoning coal-fired power generation.

(3) Trends in Electricity Sales Prices

This report next conducts a sensitivity analysis that looks at how profitability changes when the electricity sales price goes up or down. At a 1,300 MW coal-fired power plant (USC), around 9 million MW of electricity is sold annually when the capacity factor is 85%, so when the price changes by 1 yen per kWh, it amounts to an annual difference of 9 billion yen. At present, actual sales are primarily negotiated transactions between the major power utility and its internal or group retail sales division, but going forward, when negotiated transactions take place at improperly low prices compared to prices on the wholesale electricity market, it will be a violation antitrust law²⁸, so the prices are expected to be rectified by the Electricity and Gas Market Surveillance Commission and converge with wholesale market prices²⁹.

Profitability sensitivity is therefore analyzed using JEPX (Japan Electric Power Exchange) contract prices as the benchmark. Electricity sales prices for Tokyo, Kansai and Kyushu over the past year are as shown in the following graph. The pink line is the one-year moving average. The price for the Tokyo Area is trending at around 9.5 yen/kWh on average as of July 2019.

27 Diving Gas Costs Spark Potential Rare Switch Away from Coal in Japan, Bloomberg News / 4 Jun 2019 <https://www.bloomberg.com/news/articles/2019-06-04/diving-gas-costs-spark-potential-rare-switch-from-coal-in-japan>

28 Guidelines for appropriate electric power transactions (Japan Fair Trade Commission) https://www.enecho.meti.go.jp/category/electricity_and_gas/electric/tekitori/pdf/tekitori.pdf

29 Base Load Market Guidelines (Agency for Natural Resources and Energy) https://www.emsc.meti.go.jp/activity/emsc/pdf/201_03_04.pdf

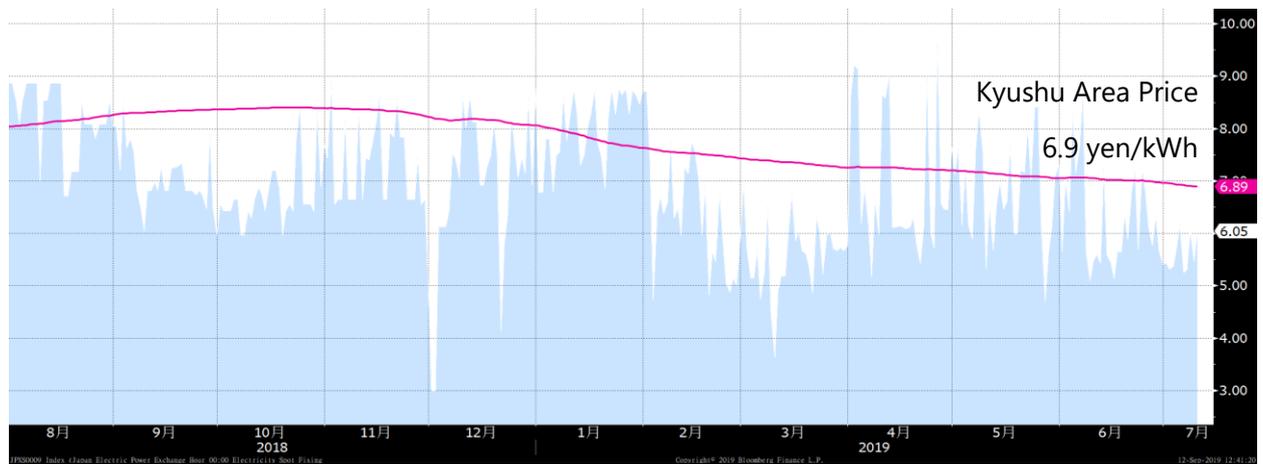
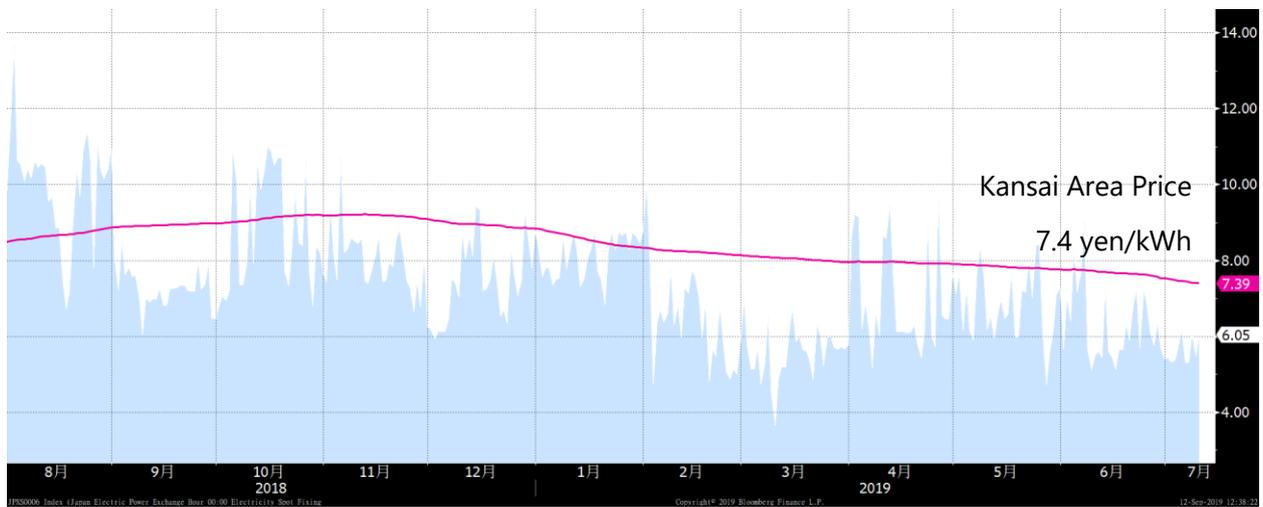
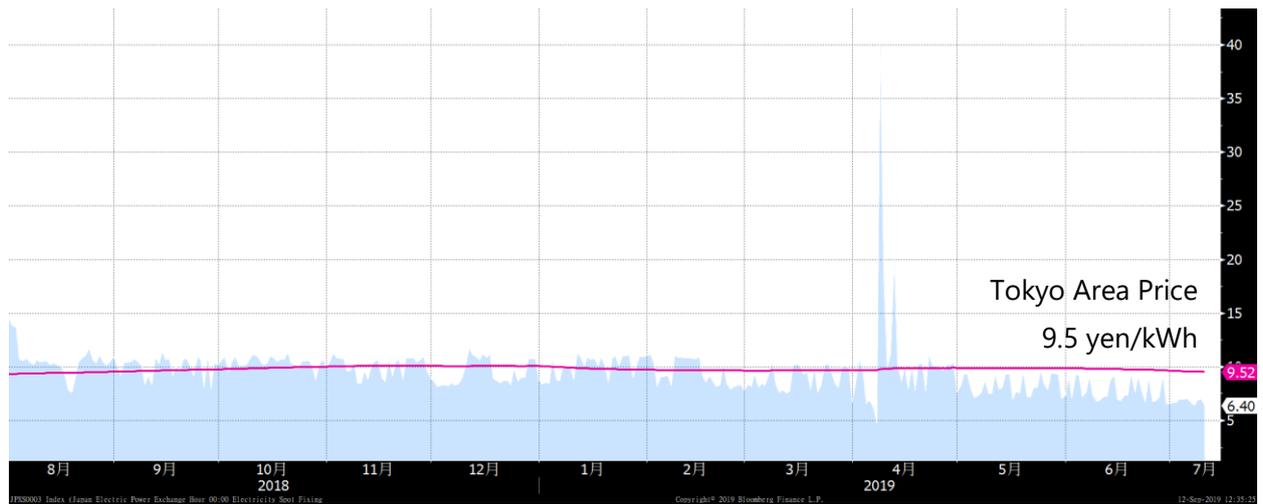


Chart 8 JEPX Tokyo/Kansai/Kyushu Area Prices 344-Day Moving Average (August 2018 – July 2019)

Source: BloombergNEF

Using 9.5 yen/kWh as the baseline parameter, IRR was calculated for upward and downward changes in the price, at increments of 0.5 yen; the results are shown in the graph below. For investment in new coal-fired power plants, when the price falls to 8 yen/kWh, IRR is 3.3% even when the capacity factor is 85%, and with the capacity factor at 69.5%, the nationwide average in 2028, IRR is 0.9%. Though it is not possible to make firm predictions about electricity market prices going forward, if further electricity liberalization causes coal to compete with renewable energy sources like solar PV and wind power, which have no fuel costs, on the wholesale market, it is possible that the electricity sales price will move further downward.

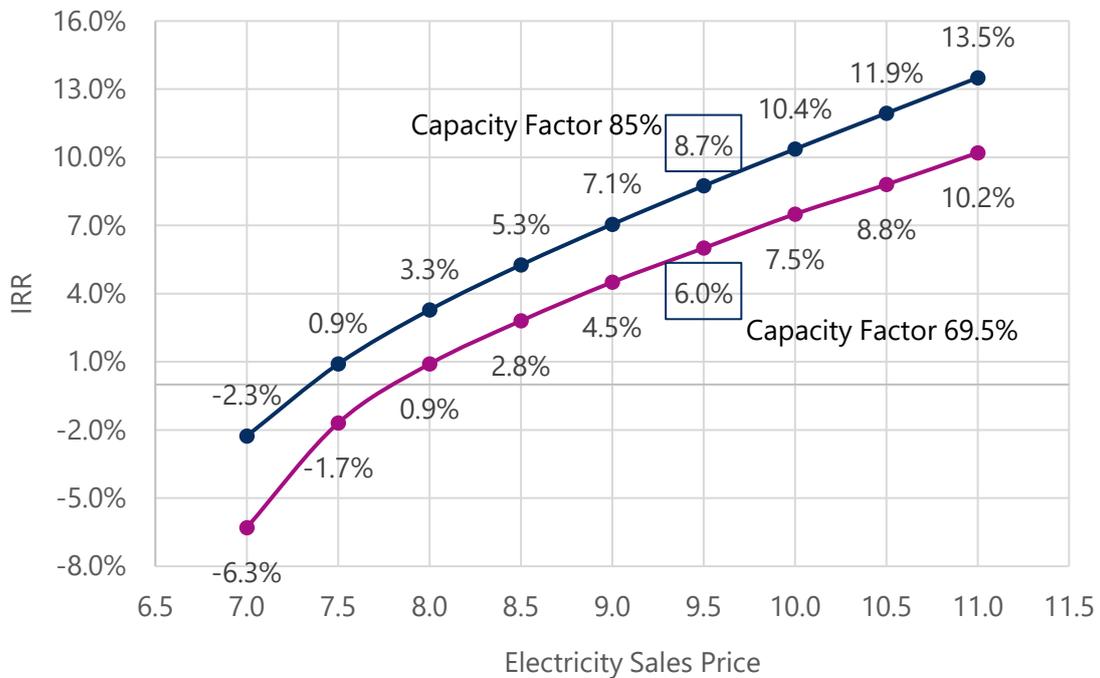


Chart 9 Decrease in IRR from Decrease in Electricity Sales Price

Source: Created by Renewable Energy Institute

(4) Coal Price Fluctuations

The price of coal (fuel cost) naturally impacts the profitability of coal-fired power generation. If the coal procurement price goes up, fuel costs swell expenses and put pressure on electricity sales revenue. Japan’s power providers sign long-term contracts of a year or longer with major overseas coal suppliers in order to reduce the risk of price fluctuations and work to stabilize procurement prices by adopting three-month or one-year fixed prices. However, spot prices are high and if they continue to be so, it will affect fixed prices as well. Fuel costs will correspondingly increase and negatively affect the profitability of coal-fired power.

With the basic parameter set at 11,000 yen/ton, which is the average CIF import price (price including insurance and freight charges) for the past three years, IRR when the coal price shifts upward and downward at increments of 1,000 yen is shown in the following graph for the capacity factor of 85% and the capacity factor of 69.5%, the nationwide average in 2028. When the coal price rises to 13,000 yen/ton, IRR is 6.0% when the capacity factor is 85% and 3.5%, when it is 69.5%. The actual average price in fiscal 2018 was 13,077 yen/ton (see Chart 13), so this level of increase in the price of coal is realistic.

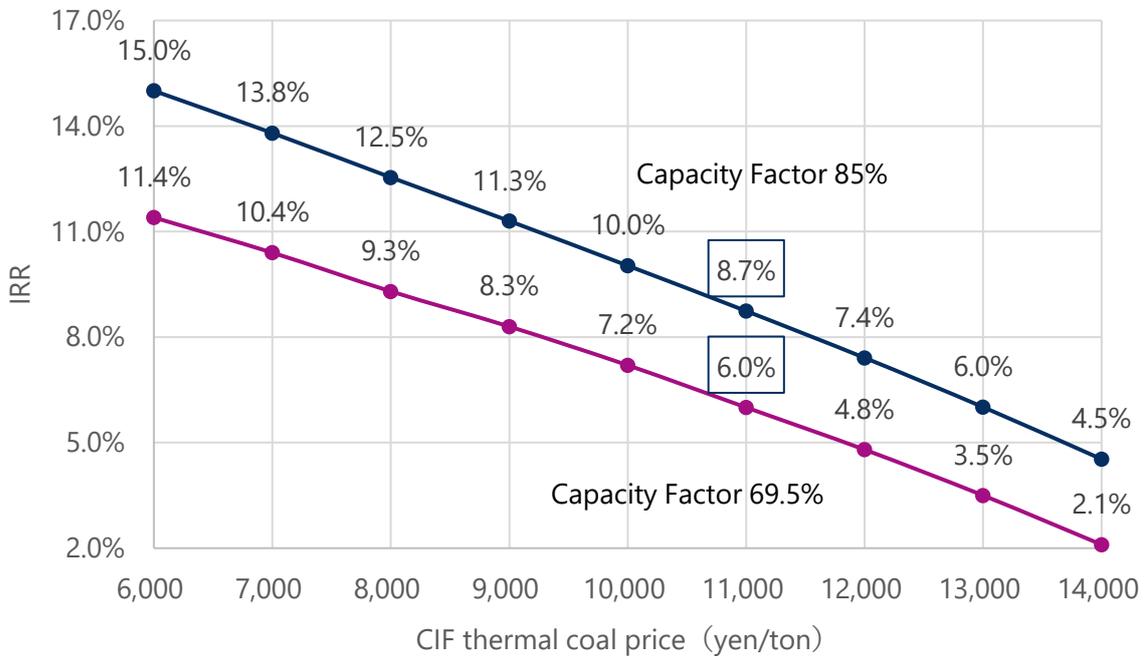


Chart 10 Change in IRR from Change in Coal Price

Source: Created by Renewable Energy Institute

According to International Energy Agency (IEA)’s Coal 2018, the medium-term outlook for international coal prices show coal demand declining in developed countries due to divestment and increasing to 2023 in India and the Asia-Pacific region due to population increases and economic growth; it is also expected to increase on an overall global basis.

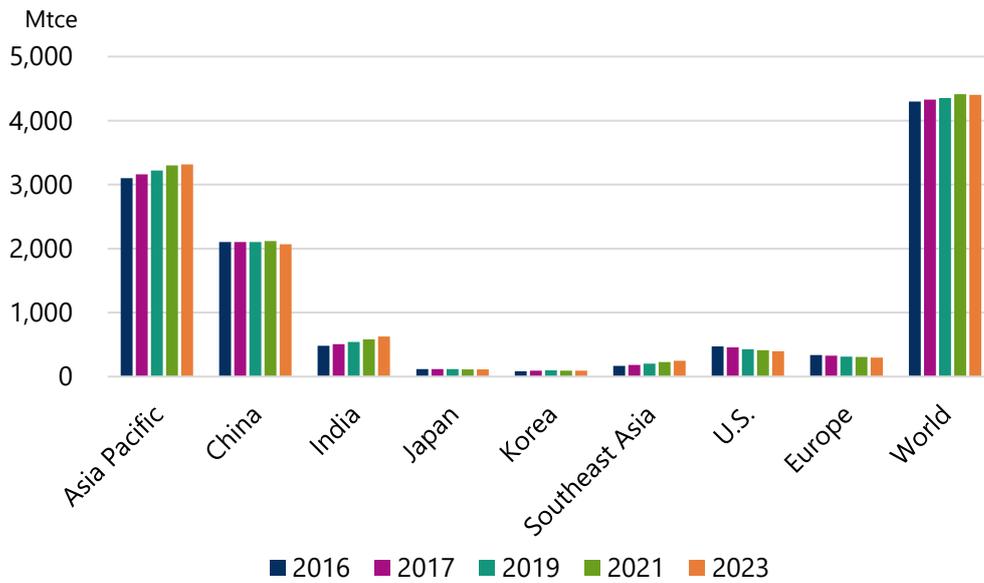


Chart 11 Coal Demand Projections by Country/Region and Worldwide

Source: IEA Coal 2018, Thermal Coal and Lignite Demand

<https://www.iea.org/coal2018/>

Regarding the long-term outlook, the IEA, in its 2018 World Energy Outlook, conducts its analysis under three different scenarios, the Current Policies Scenario, New Policies Scenario, under which the latest energy policies and plans are implemented, and Sustainable Development Scenario, under which policies necessary to achieve the Paris Agreement are implemented. Looking at the analysis, stability is maintained until 2040 and there are no major changes. If prices trend according to this long-term outlook, unless the yen depreciates significantly, business risk caused by rising coal prices is limited.

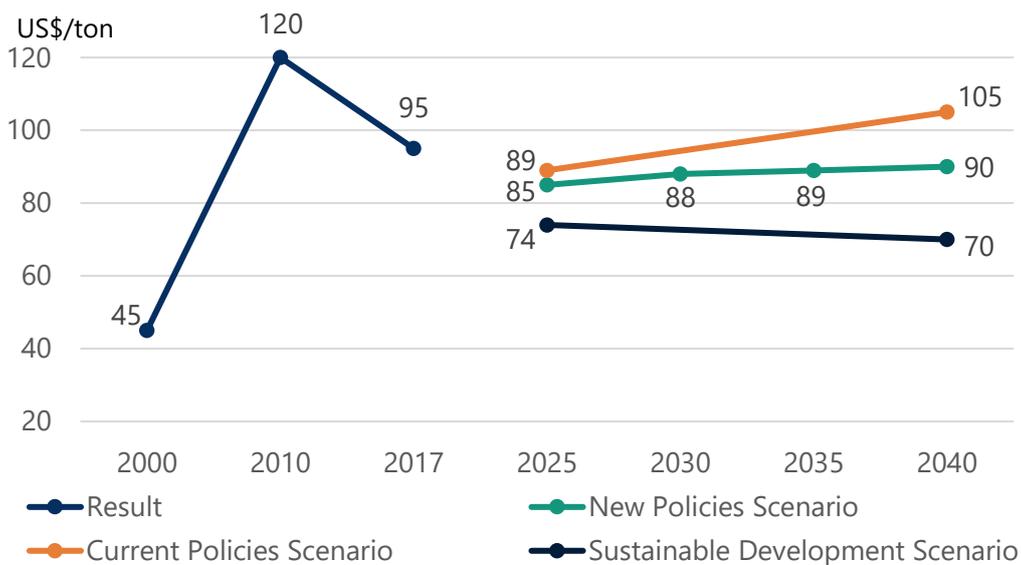


Chart 12 Long-Term Outlook for Japan Thermal Coal Import Price

Source: IEA World Energy Outlook 2018, Fossil Fuel Prices by Scenario

<https://www.iea.org/weo2018/>

Changes to the CIF import price for Japan, which imports nearly all of its coal from overseas, are shown in the following graph. Coal prices fluctuate less than oil and LNG, and the price to the mid-2000s was below 8,000 yen and relatively stable. In the future, if prices trend according to the IEA’s predictions, coal will stay below 10,000 yen/ton, and the risk of the price increasing sharply is low.

However, over the past several years, thermal coal, the coal used to fuel coal-fired power, has trended at the high level of over 10,000 yen/ton. Climate change is a major factor, in the form of torrential rains closing coal mines in 2008 and 2010 in Australia, which accounts for around 70% of Japan’s thermal coal imports, and coal transport rail lines sustaining damage in powerful Cyclone Debbie that occurred in 2017 also in Australia³⁰. There is sufficient reason to think that this situation will continue into the future. New coal investment going forward cannot overlook business risk associated with sharp rises in coal prices.

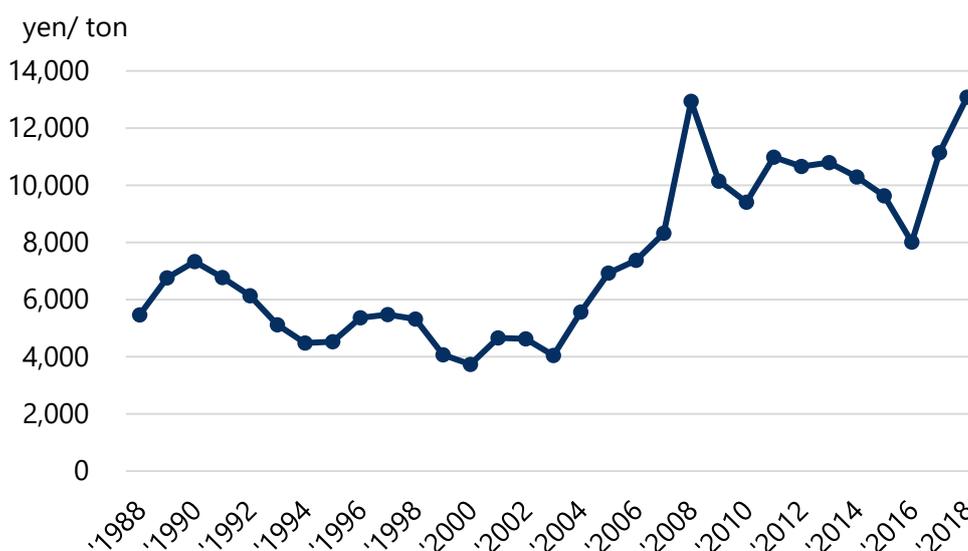


Chart 13 CIF Price for Thermal Coal

Source: Ministry of Finance, Trade Statistics of Japan

<http://www.customs.go.jp/toukei/srch/index.htm>

(5) Policy Factors (Service Life, Carbon Tax)

Along with risks from market factors discussed above, there are also potential policy changes associated with climate change measures that must be considered, including shorter service lives due to decarbonization policy (for example, setting an emissions standard that cannot be met by coal-fired power as has been instituted in Europe), introducing a carbon tax, and mandating carbon capture and storage (CCS) facilities.

If service lives are shortened, the investment amount must be recovered over that much shorter of a time period, so it negatively affects profitability. IRR when the service life is shortened decreases gradually until 20 years, but with any shorter than 20 years IRR quickly deteriorates. This is because in the IRR formula when there are changes in the electricity sales price, coal price or capacity factor, the cash flow, the numerator, increases or decreases on a straight line; but when the service life (n years) changes, the IRR, the denominator, is to the n-th power, so it changes on an accelerating basis. Supposing a service life of 20 years, at the capacity factor of 85%, IRR is 6.3%, but when the capacity factor is 69.5%, the nationwide average in 2028, IRR is 2.7%.

³⁰ Coal Market Study Group Report (Agency for Natural Resources and Energy) https://www.meti.go.jp/report/whitepaper/data/pdf/20180430001_3.pdf

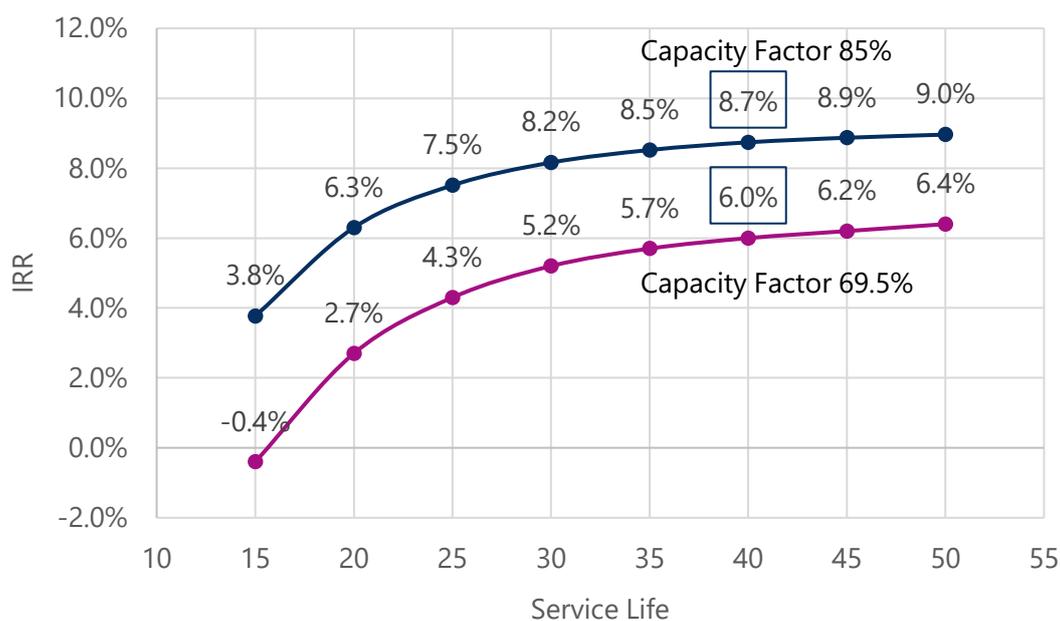


Chart 14 Decrease in IRR from Decrease in Service Life

Source: Created by Renewable Energy Institute

A carbon tax would also have a major impact. Carbon pricing has already been instituted by 44 countries and 27 regions around the world. Taxation methods vary, but according to the World Bank’s State and Trends of Carbon Pricing 2018, the tax per ton of CO₂ ranges from US\$1 to Sweden’s US\$139, the highest in the world. At present, most countries have taxes at or below US\$30/ton-CO₂-equivalent³¹. Japan has a climate change tax of 289 yen/ton-CO₂ it imposes for each fossil fuel based on their CO₂ emissions factors, but it is extremely low. The following shows an analysis of the impact that raising the tax will have on revenue.

According to the environmental impact assessment, the CO₂ emissions factor for a 1,300 MW facility (USC) is 750 g/kWh, and annual emissions are approximately 7.26 million tons-CO₂³². A carbon tax of just 1 yen per ton of CO₂ would amount to annual cost of 7.26 million yen per year. The IRR when a carbon tax is added in increments of 500 yen is shown in the following graph. At the stage of 3,000 yen/ton-CO₂, with the capacity factor of 85%, the IRR is unprofitable -1.5%, and with the capacity factor of 69.5%, the nationwide average in 2028, IRR is -5.0%.

31 State and Trends of Carbon Pricing 2018 <https://openknowledge.worldbank.org/handle/10986/29687>

32 Document summarizing environmental impact assessment results for Yokosuka Thermal Power Plant Units 1 and 2 (provisional name) Construction Plan <https://www.jera.co.jp/static/files/business/thermal-power/environment/assessment/yokosuka/pdf/gaiyou-shiryō.pdf>

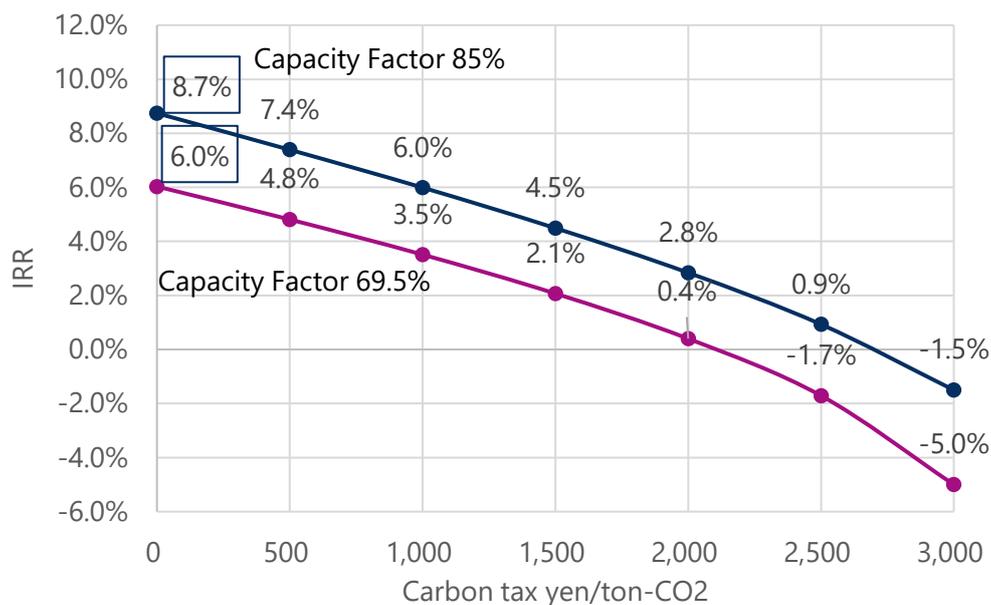


Chart 15 Change in IRR from Carbon Taxation per Ton of CO₂

Source: Created by Renewable Energy Institute

The Japanese government drew up its Long-term Strategy under the Paris Agreement in April 2019, and to achieve its long-term target of reducing GHG emissions by 80% by 2050, states that it will consider introducing carbon capture and storage (CCS) by 2030, premised on its commercial feasibility, for coal-fired power plants³³. Supposing that CCS is made mandatory by 2030, additional capital investment will be required, and this will further worsen profitability. At the same time, if CCS is not introduced, service lives will have to be shortened.

(6) Scenario Analysis

The report thus far has performed a sensitivity analysis on how IRR changes when there are changes in each of five factors, capacity factor, electricity sales price, coal price, service life, and carbon tax. Firstly, an impactful factor is change in the capacity factor. Even when there are no other changes in the baseline assumptions of the other factors, when the capacity factor drops from 85% to 69.5%, IRR declines from 8.7% to 6.0%, which is well short of the around 8% IRR that is needed for investment in new coal-fired power plants. A capacity factor of 85% was achieved in 2018 only in the Tokyo metropolitan area, and 69.5% is the nationwide average in 2028 projected by OCCTO (see Chart 6).

The following is a tornado chart that shows a general picture of the results of this sensitivity analysis for how the other risk factors change IRR when the capacity factor is 85% and when it is 69.5%. The vertical column is the risk factors and the horizontal line shows the changes in IRR that occur with changes in these factors. An assumed range has been set for changes in IRR for each factor.

Even assuming a high capacity factor of 85% and no changes in the policy environment (no new carbon tax or restrictions on service life, for example), IRR drops below 8% with just the slightest decrease in the electricity sales price.

³³ Long-term Strategy under the Paris Agreement <https://www.env.go.jp/press/111913.pdf>

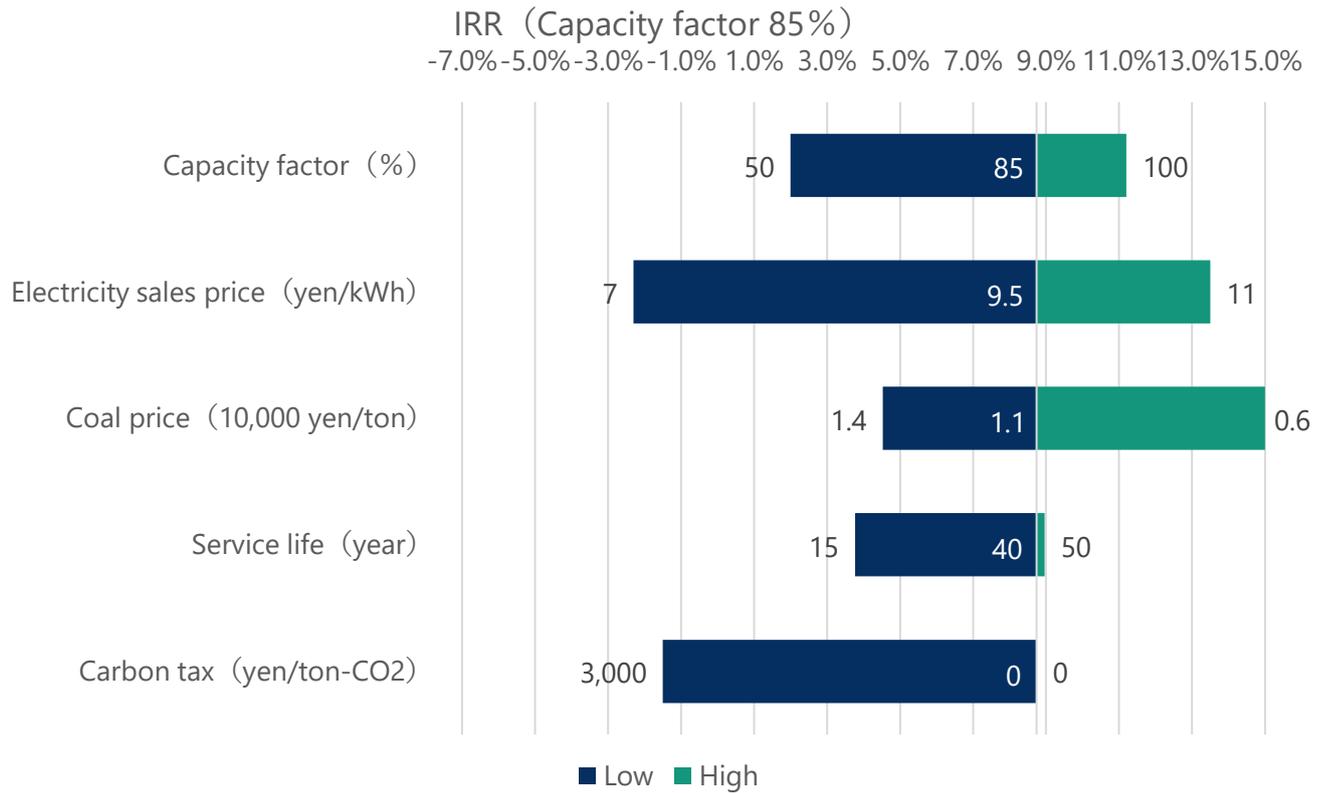


Chart 16 Tornado Chart of IRR Sensitivity Analysis for Risk Factors (1)

Source: Created by Renewable Energy Institute

At the same time, when the capacity factor is at the nationwide average of 69.5% in 2028, to maintain IRR at 8%, it becomes necessary to project a substantial increase in the electricity sales price or a decline in the coal price. If there are changes such as a slight decline in the electricity sales price, an increase in the coal price or the implementation of a carbon tax, not only will the 8% level not be maintained, IRR will deteriorate, and the enterprise will come close to unprofitable.

In sum, for a new coal-fired power plant to be profitable, it must maintain a capacity factor of 85%, the current level in the Tokyo metropolitan area, and an electricity sales price of 9.5 yen, the price in the Tokyo Area, and there cannot be changes in the other risk factors.

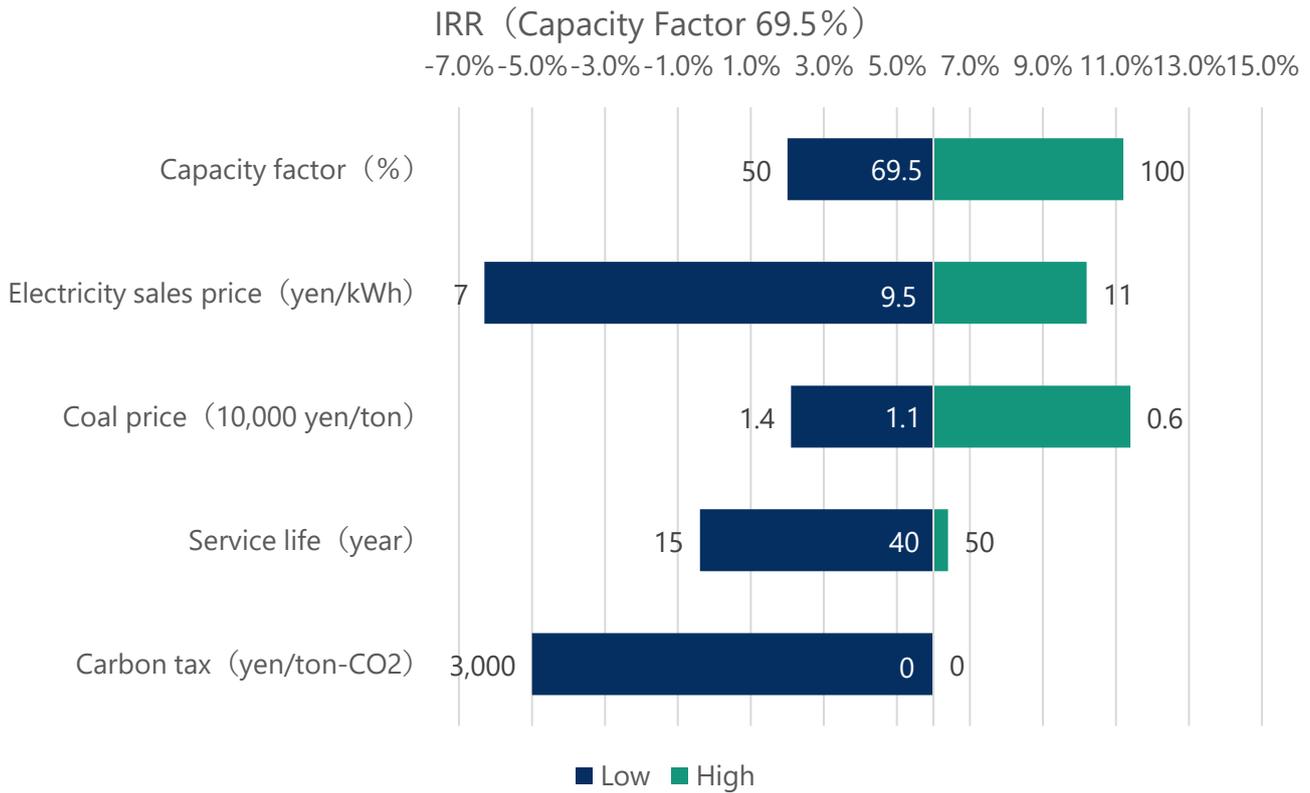


Chart 17 Tornado Chart of IRR Sensitivity Analysis for Risk Factors (2)

Source: Created by Renewable Energy Institute

Analysis of the 3 Scenarios

To further clarify the findings of the report's analysis, the following shows changes in IRR based on three scenarios in which multiple factors simultaneously change.

Scenario (1) Provider Scenario (Baseline Assumptions)

This is the optimistic scenario thought to be assumed by power providers: the capacity factor does not fall below 85%, the current level in the Tokyo metropolitan area; coal prices do not rise sharply; the electricity sales price does not decline lower than 9.5 yen/kWh; a coal phase-out policy makes no progress; and facilities continue to operate for 40 years. This scenario is far removed from climate change policy.

Provider Scenario	Capacity factor	Electricity sales price	Coal price	Service life	Carbon tax (emissions tax)	IRR
	85%	9.5 yen/kWh	11,000 yen/ton	40 years	None ³⁴	8.7%

³⁴ Only current fossil fuel tax and added climate change tax.

Scenario (2) Market Change Scenario

In this scenario, changes in market conditions create a headwind for coal-fired power that erodes earnings and makes plants barely profitable: the capacity factor falls to 69.5%, the level projected by OCCTO to be the nationwide average in 2028 due to electricity demand declining from energy savings measures and efficiency improvements and also due to increased deployment of renewable energy; the electricity sales price decreases to 8.0 yen/kWh due to increased supply of renewable energy to JEPX and other factors. With changes to these two factors only, IRR falls to 0.9%.

With full liberalization of the electricity market, a base load market was established in July 2019 and a new capacity market will also be established in July 2020. It is not realistic, however, to conclude that these changes will restore profitability (see box below).

Market Change Scenario	Capacity factor	Electricity sales price	Coal price	Service life	Carbon tax (emissions tax)	IRR
	69.5%	8.0 yen/kWh	11,000 yen/ton	40 years	None	0.9%

Scenario (3) Policy Change Scenario

In this scenario, environmental regulations are strengthened, and the situation faced by coal-fired power becomes exceeding difficult, with plants becoming stranded assets. This scenario adds changes in policy factors to the changes in the Market Change Scenario (Scenario (2)). Even with the government's current target of reducing GHG emissions 80% by 2050, the electricity sector will have to almost completely decarbonize, so this scenario assumes that the service life of new coal-fired plants built going forward will be restricted to 30 years. In this case, even if only a very small carbon tax is introduced, IRR will be -3.2%.

Policy Change Scenario	Capacity factor	Electricity sales price	Coal price	Service life	Carbon tax (emissions tax)	IRR
	69.5%	8.0 yen/kWh	11,000 yen/ton	30 years	500 yen/ton-CO ₂	-3.2%

Base load market: On the base load market established in July 2019, major power utilities are required to sell on the wholesale electricity market a portion of the electricity previously provided monopolistically within their own company or group through negotiated transaction. The amount supplied is base load sources multiplied by retail electricity provider's market share. This is initially 12% and when it reaches 30%, any additional amount will be voluntary³⁵. Initial transactions were 12.47 yen/kWh in the Hokkaido area, 9.77 yen/kWh in the Tokyo area, and 8.7 yen/kWh in the Kansai area. Of the 60.0 billion kWh deemed to have been put on the market, there were only buyers for 1.6 billion kWh, or 2%. The main reason is that a fixed cost for nuclear power plants currently shut down is included in the generation cost and the price was far from appealing to retail electricity providers, which are its buyers and want a cheaper transaction price in the 5 yen/kWh range³⁶.

Capacity market: In July 2020, along with conventional electricity (kWh) transactions, a new capacity market will be established on which installed capacity (kW) will be traded. In order to secure installed capacity in the future, electricity supply capability will be recognized as having value and a capacity price (kW price) will be paid in line with that value. The benchmark price (Net CONE) is calculated at 9,307 yen/kW, assuming a gas turbine combined cycle (GTCC) plant operating for 40 years as an economical model plant, and the maximum price at 13,960 yen/kW, which is 1.5 times the benchmark³⁷. OCCTO, the buyer on the capacity market, has estimated the target capacity to be secured in four years depending on electricity demand at 180 million kW, and the contract price, for reference, at 2,000 yen/kW³⁸. In this case, this would increase the revenue of a new coal-fired power plant with capacity of 1,300 MW by 2.6 billion yen annually, but the above IRR would only improve from 0.9% to 2.3% and remain far below the 8% IRR that is needed for investment in new coal-fired power plants .

35 Information on the base load market (Agency for Natural Resources and Energy)
https://www.meti.go.jp/shingikai/enecho/denryoku_gas/denryoku_gas/seido_kento/pdf/022_05_00.pdf

36 Nihon Keizai Shimbun, August 10, 2019, "Start of New Base Load Market for Inexpensive Electric Power; Transaction Volume Low"

37 Information on setting demand curve (Net CONE, maximum price, etc.) (Investigative Commission on Capacity Market)
https://www.occto.or.jp/iinkai/youryou/.../youryou_kentoukai_16_04.pdf

38 Summary of capacity market (OCCTO) https://www.occto.or.jp/market-board/market/oshirase/2019/files/youryou_setsumei.pdf

Conclusion

In order to increase the expected return on investment in coal-fired power plants, it is necessary to maintain the capacity factor, coal price, and electricity sales price within a fixed range and obtain electricity sales revenue every year while recovering invested capital. With over 100 years of history since Thomas Edison built the first coal-fired power plants in London and New York in 1882, it has been thought that the assumed risk factors had been taken into account and the risk of an unexpected situation was limited as long as caution was exercised.

However, in recent years, coal-fired power has been increasingly criticized as contributing to climate change, and decarbonization has become the global trend. Moreover, the business model that has provided stable returns to this point is beginning to tremble under the weight of large-scale deployment of inexpensive, CO₂-emissions-free renewable energy and excessive volatility in coal and gas prices.

The following table summarizes the assumed risks and benefits of new coal-fired plants that will be built going forward. Tailwind benefit factors are far outweighed by headwind risk factors.

Table 6 Coal-Fired Power Plant Investment Risk/Benefit Analysis

Benefit Factors	Risk Factors
<ul style="list-style-type: none"> • Decrease in coal price • Yen appreciation (effectively a decrease in coal price) • Increase in capacity factor • Increase in electricity sales price • Revenue from capacity market 	<ul style="list-style-type: none"> • Decrease in capacity factor • Decrease in electricity sales price • Nuclear plants resume operations • Large-scale deployment of low-cost renewable energy • Electricity provided to base load market • Increase in coal price • Yen depreciation (effectively an increase in coal price) • Reduced service life • Increase in fossil fuel tax • Increase in climate change tax • New carbon tax (emissions tax) • Carbon capture and storage (CCS) becomes mandatory

Source: Created by Renewable Energy Institute

As has been shown in this report, investment in coal-fired power going forward will entail a multitude of risks, including ultimately stranded asset risk caused by such factors as lower electricity demand, large-scale deployment of inexpensive renewable energy, declining capacity factors, increasing coal prices, decreasing wholesale electricity prices, and stronger regulations from climate change measures.

The head of commodities research at Legal & General Investment Management (LGIM), the U.K.'s largest asset management company with a trillion pound (129 trillion yen) portfolio, equivalent to Japan's Government Pension Investment Fund (GPIF), has said the following about the risk of investing in new coal-fired power plants.

“Investors who continue to finance new coal projects need to be asking themselves an important question; which is going to end up being burnt first — their coal, or their money?”

Nick Stansbury, head of commodities research at Legal & General Investment Management Ltd., a part of Climate Action 100+

Source: Bloomberg News, 21 February 2019

<https://www.bloomberg.com/news/articles/2019-02-21/the-32-trillion-pushing-fossil-fuel-ceos-to-act-on-climate>

New coal-fired plant investment going forward is at risk of being unprofitable, which means coal power plants will not only burn coal, they will make ash of the money invested. The question is how to face up to this situation. Looking squarely at the reality globally and domestically, the option power providers should be choosing seems clear.

Risk Analysis of Coal-Fired Power Plant Investment in Japan
Exposure to Stranded Asset Risk in the Energy Transition Period

October 2019

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