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Advancement of the Long-Term Transmission Expansion Plan for Achieving Carbon Neutrality by 2050

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SUMMARY

Japan’s electric power system is expected to integrate a markedly larger share of renewable energy sources in pursuit of carbon neutrality by 2050. To ensure reliable grid operation and enhance system resilience, substantial reinforcement of interregional transmission capacity is required. This paper presents Japan’s Long-Term Transmission Network Expansion Plan (the Long-Term Plan), developed by the Organization for Cross-regional Coordination of Transmission Operators (OCCTO), outlining the desired future configuration of Japan’s power grid toward 2050. Transmission reinforcement projects derived from the Long-Term Plan are also examined.

The OCCTO Long-Term Plan identifies common reinforcement candidates across multiple scenarios through cost–benefit analysis, based on merit-order simulations using a detailed nodal model. Individual projects are subsequently evaluated using refined technical assumptions, updated demand and supply projections, and detailed cost and benefit assessments—including construction and O&M costs, generation cost reduction benefits, adequacy enhancement benefits, and reduced transmission losses. Implementation decisions are made based on these evaluation outcomes.

This paper highlights key reinforcement projects already approved for implementation, including AC loop reinforcement in the central region, and a new HVDC subsea interconnection between the Chugoku and Kyushu areas. Technical considerations, the benefit-evaluation framework, and supporting decision-making processes are discussed. Through these case studies, the paper clarifies Japan’s wide-area grid evaluation methodology and identifies how uncertainty is incorporated into investment decisions, including additional quantitative assessment of risk mitigation effects. The findings provide insights into future large-scale transmission expansion initiatives required to support deep decarbonization.

KEYWORDS

Cost–Benefit Analysis - HVDC System - Transmission Development

1 Introduction

To advance decarbonization and strengthen the resilience of Japan's power system, the Organization for Cross-regional Coordination of Transmission Operators (OCCTO) formulated Japan's Long-Term Transmission Network Expansion Plan (the Long-Term Plan) in March 2023 [1]. This plan outlines strategic policies for reinforcing interregional transmission infrastructure, including major expansions of interconnection. Several reinforcement measures have already received approval and are progressing toward implementation. This paper provides an overview of the structure and analytical framework of the Long-Term Plan, and describes the decision-making process used to translate it into executable grid development projects.

2 Overview of the Long-Term Plan

The Long-Term Plan functions as a long-term grid development roadmap aimed at enabling large-scale renewable energy source (RES) deployment and achieving carbon neutrality by 2050 (Figure 1). A merit-order simulation using a detailed nodal model consisting of approximately 1200 nodes was constructed to quantify generation cost reduction benefits, which serve as the primary metric in cost–benefit analysis (CBA) for identifying candidate transmission reinforcements. Based on this analysis, a total investment of the order of JPY 6–7 trillion (approximately 40–47 billion USD; based on an exchange rate of 150 JPY/USD throughout this paper) is expected to increase Japan's interregional transfer capability by more than 15 GW, yielding estimated annual benefits of JPY 420–730 billion (approx. 2.8–4.9 billion USD).

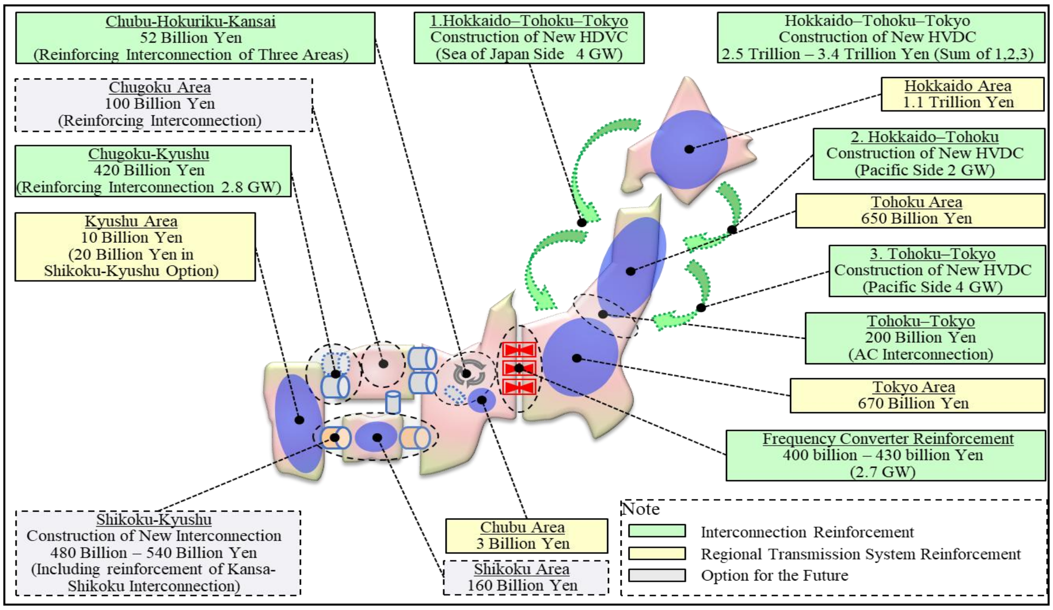

Figure 1 – Overview of the Long-Term Plan

Multiple future scenarios were assessed to capture uncertainty in demand evolution and changes in the future generation mix. Reinforcements consistently identified across the scenarios—specifically, western/central region reinforcement, the Chugoku–Kyushu interconnection expansion, and eastern region reinforcement—were prioritized for further detailed study. While OCCTO coordinates the overall planning and evaluation process, the design, implementation, and construction of each reinforcement project are executed by the respective TSOs or TOs responsible for the relevant service area.

3 Cost–Benefit Analysis Framework for Project Selection

3.1 Role of the Analysis

For each reinforcement project, updated CBA was performed using revised assumptions and a higher level of granularity compared with the analysis conducted for the Long-Term Plan.
In CBA, a benefit–cost ratio (B/C) is calculated to evaluate whether the expected benefits justify the investment. This section describes the methodology used to perform this assessment.

3.2 Cost Assumptions

The cost assessment includes both construction costs and O&M expenditures for the corresponding transmission facilities. Here, O&M costs were estimated using category-specific annualized conversion factors derived from historical performance data of TSOs.

3.3 Benefit Framework and Assumptions

3.3.1 Benefit Categories

Three benefit categories were evaluated:

(1) Generation cost reduction (including fuel and CO_2 cost impacts)
(2) Adequacy enhancement effects attributable to expanded interregional support
(3) Changes in transmission losses

3.3.2 Supply and Demand Assumptions

Two planning horizons—2030 and 2050—were analyzed to reflect reinforcement commissioning timelines and long-term decarbonization pathways (Figure 2). Demand projections incorporate expected growth from large-scale emerging loads such as hydrogen production, DACCS, data centers, and semiconductor manufacturing [2]. Supply assumptions reflect offshore wind deployment targets and survey-based assessments conducted by OCCTO regarding future generation development plans.

Year			2030	2050
Demand			884 TWh	1,200 TWh
Energy source	RES	PV	101 GW	260 GW
		Onshore Wind	21 GW	41 GW
		Offshore Wind	23 GW	45 GW
		Hydro, Biomass, and Geothermal	62 GW	62 GW
	Thermal		141 GW	141 GW
	Nuclear		37 GW	37 GW
	Battery		4 GW	21 GW

Figure 2 – Supply and demand assumptions for 2030 and 2050

3.3.3 Generation Cost Reduction Benefits

Generation cost reduction benefits were quantified using a merit-order simulation framework. Multiple fuel price cases were applied to incorporate uncertainty in future fuel price trends.

3.3.4 Adequacy Enhancement Benefits

Adequacy enhancement benefits were evaluated based on improvements in interregional resource sharing capability. The reliability index Expected Unserved Energy (EUE), defined as the expected annual unserved energy per unit of demand, is applied by OCCTO. Two valuation methods were considered:

- Capacity cost-based valuation: quantified as the reduction in reserve capacity requirements and monetized using Net Cost of New Entry (Net-CONE).
- Outage cost-based valuation: quantified as the reduction in expected outage cost resulting from lower EUE.

A conceptual illustration is provided in Figure 3.

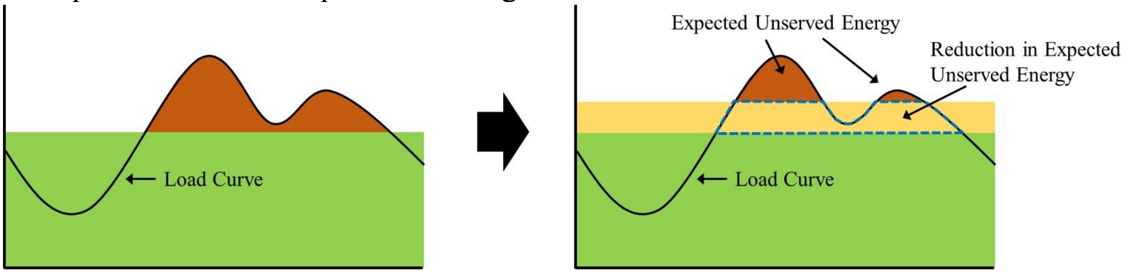

Figure 3 – Conceptual representation of EUE

For the capacity cost-based valuation, the reserve margin required to maintain the reference reliability level—defined by the baseline EUE—was first calculated. Then, under the same reliability standard, the reserve margin was recalculated assuming the reinforcement is implemented. The difference between these reserve margins (unit: kW) represents the reduction in required capacity. The benefit was obtained by multiplying this reduction by the procurement cost unit value. As the procurement cost unit value, Net-CONE was applied, which represents the levelized total cost of constructing and operating new generation capacity, net of revenues other than those from the capacity market.

In contrast, for the outage cost-based valuation, the reserve margin corresponding to the baseline EUE was held constant, and the post-reinforcement EUE was recalculated. The benefit was then derived by multiplying the reduction in EUE by the unit outage cost based on previous survey results.

3.3.5 Transmission Losses

Transmission losses were evaluated on an hourly basis using power flow results and equipment resistance characteristics. Increased losses associated with longer-distance power transfers were treated as a negative component of the benefit assessment.

3.4 Evaluation Method

Evaluation periods were determined based on statutory depreciation periods and OCCTO assessment guidelines. In the Long-Term Plan, benefits were assumed to remain constant over a 36-year evaluation period—the statutory depreciation period for overhead transmission lines—beginning in 2050. In contrast, the present study calculated benefits at two reference points, 2030 and 2050—where 2030 was selected to reflect the expected commissioning timeline of the reinforcement—assuming linear increase between these years to reflect the anticipated growth in RES penetration, and assuming that benefits remain constant after 2050 (Figure 4). Various discount rates were also considered to account for future uncertainties in long-term societal transmission investments and recent macroeconomic conditions. Discount rates of 4%, 2%, and 1% were applied to convert both construction costs and future benefits into present values, enabling assessment of the investment under different financial assumptions.

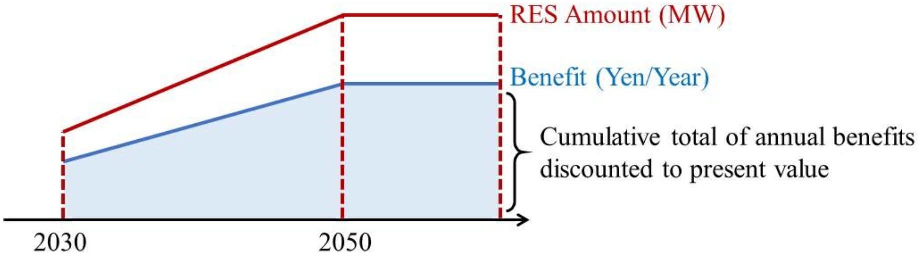

***Figure 4* – Consideration of increased benefits through 2050**

4 Case Studies of Grid Expansion

Building on the assumptions and analytical framework defined in the previous section, this chapter examines two specific grid expansion projects:

1. the reinforcement plan already underway in the central region, and
2. the recently approved reinforcement of the Chugoku–Kyushu interconnection.

4.1 Reinforcement of the AC Loop and Interconnections in the Central Region

The Chubu, Hokuriku, and Kansai systems are interconnected in a triangular topology. Among the three links, the Chubu–Hokuriku connection operates through a Back-to-Back (BTB) converter, while the remaining two interconnections operate synchronously as AC links. The BTB configuration was introduced in the 1990s owing to technical challenges that prevented the establishment of a wide-area AC loop. Consequently, while the operational capability of the Chubu–Kansai and Hokuriku–Kansai interconnections ranges from 1.2 to 2.5 GW, the BTB link remains limited to only 0.3 GW [3].

In 2019, a new AC transmission line was constructed between Chubu and Hokuriku. However, the necessary control and equipment upgrades required for continuous loop operation have not yet been implemented, meaning that the BTB link continues to serve as the primary interface during normal operation. The AC connection is utilized only during outages of the Chubu–Kansai or Hokuriku–Kansai links by switching from BTB to AC operation.

The Long-Term Plan confirmed that technological advancements now make AC loop operation feasible. The analysis indicated that several-billion-JPY control system upgrades could markedly increase operational capacity, and highlighted additional benefits that could be realized through construction of a second Chubu–Kansai interconnection. Figure 5 illustrates the reinforcement concept.

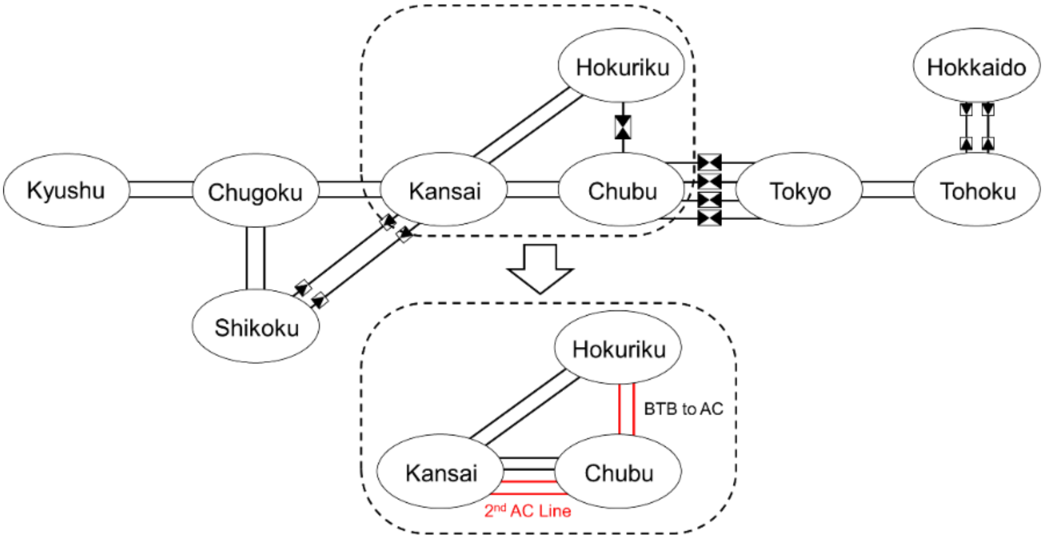

Figure 5 – Reinforcement plan in the Central Region

Subsequently, considering the approaching end-of-life of the BTB equipment, a formal decision was made to decommission the BTB link and to transition to AC loop operation. Most required works consist of upgrades to existing infrastructure, and the TSOs in the three areas will act as implementation entities. With this change, operational capacity management will shift to a fence-based approach, enabling an estimated increase in capacity of 0.5–1.7 GW.

Synchronous stability is expected to become a new operational constraint following the loop conversion, and thus a second Chubu–Kansai interconnection was evaluated in further detail. The reinforcement largely utilizes existing infrastructure; therefore, OCCTO requested the TSOs at both ends to conduct detailed studies. The studies concluded that the new line would double the operational transfer capability between Chubu and Kansai—from 3 to 6 GW—with an estimated construction cost of approximately JPY 59 billion (approx. 0.4 billion USD).

Figure 6 presents the assumptions and results of the B/C analysis. Across multiple uncertainty-driven scenarios, 24 B/C cases were evaluated, and 18 exceeded a ratio of 1.0. In addition to quantified benefits, further expected advantages include improved resilience during low-probability contingency events, reduced risk of complete route loss during scheduled maintenance of the existing interconnection, and shorter outage durations owing to relaxed operational constraints. Based on these results and expert review, the reinforcement project was formally approved.

Case		1	2	3	4	5	6	7	8	9	10	11	12
Assumptions	Evaluation period	22 years						40 years					
	Generation cost	Base Case – High Price Case											
	Adequacy benefit	Lower Limit	Upper Limit	Lower Limit	Upper Limit	Lower Limit	Upper Limit	Lower Limit	Upper Limit	Lower Limit	Upper Limit	Lower Limit	Upper Limit
	Discount rate	4%		2%		1%		4%		2%		1%	
Benefit(Billion Yen) [Billion Yen/Year]	Generation cost	392 to 883 [18 to 40]		478 to 1,060 [22 to 48]		531 to 1,170 [24 to 53]		534 to 1,123 [13 to 28]		735 to 1,495 [18 to 37]		880 to 1,761 [22 to 44]	
	Adequacy benefit	68 [3]	418 [19]	85 [4]	538 [24]	96 [4]	616 [28]	101 [3]	697 [17]	146 [4]	1,046 [26]	178 [4]	1,306 [33]
	Transmission loss(negative benefit shown as ▲)	▲122 to ▲112 [▲6 to ▲5]		▲140 to ▲128 [▲6 to ▲6]		▲150 to ▲137 [▲7 to ▲6]		▲121 to ▲106 [▲3 to ▲3]		▲138 to ▲117 [▲3 to ▲3]		▲147 to ▲122 [▲4 to ▲3]	
Cost(Billion Yen) [Billion Yen/Year]	Construction cost and annual expenses	688 [31]		839 [38]		934 [42]		824 [21]		1,086 [27]		1,269 [32]	
B/C Ratio (Red:B/C≥1)		0.49 to 1.22	1.00 to 1.73	0.50 to 1.21	1.04 to 1.75	0.51 to 1.21	1.07 to 1.76	0.62 to 1.36	1.35 to 2.08	0.68 to 1.40	1.51 to 2.23	0.72 to 1.43	1.61 to 2.32

Figure 6 – Assumptions and results of the B/C for the second Chubu–Kansai Interconnection

4.2 Reinforcement of the Chugoku–Kyushu Interconnection

Given Japan's unique longitudinal grid structure and the absence of international interconnections, the Chugoku–Kyushu interconnection serves as a critical bottleneck for the Kyushu area, which is located at the western end of the main grid. Kyushu has experienced rapid RES deployment, particularly solar PV. Offshore wind integration is also expected to accelerate. However, the Chugoku–Kyushu interconnection, which is the sole transmission link connecting Kyushu to the remainder of Japan, frequently experiences congestion, becoming a major factor contributing to RES curtailment in Kyushu.

While the interconnection has a thermal capability of approximately 2.8 GW, frequency stability constraints reduce operational capability to approximately 1.5 GW toward Chugoku and in some periods to as low as 0.1 GW toward Kyushu. To overcome this bottleneck, the Long-Term Plan proposed developing a second route using HVAC, with potential to expand operational capability to approximately 5.6 GW.

However, additional overhead transmission routes across the strait between Kyushu and Chugoku are highly constrained because of urban development and environmental restrictions. Because submarine cables are required, the feasibility of long-distance 500-kV HVAC submarine cable technology became a key consideration. The comparative evaluation concluded that HVAC was not a viable option, primarily because no manufacturers currently possess the proven capability to produce and install 500-kV large-capacity AC submarine cables for such a long-distance subsea application. In contrast, VSC-HVDC was identified as the only implementable solution, as it is a proven technology for long-distance subsea transmission and allows for a shorter implementation timeframe. In addition to technical feasibility, HVDC was also advantageous in terms of implementation risk and project schedule certainty compared with HVAC alternatives.

The selected design strategy is to construct an initial 1 GW link with an expandable configuration allowing future scale-up to 2 GW. The adopted topology is an asymmetric monopole HVDC system with converter stations and AC interface equipment designed for the eventual 2 GW capacity. This configuration was selected considering cost efficiency, construction feasibility, and compatibility with phased capacity expansion. Figure 7 illustrates the reinforcement concept.

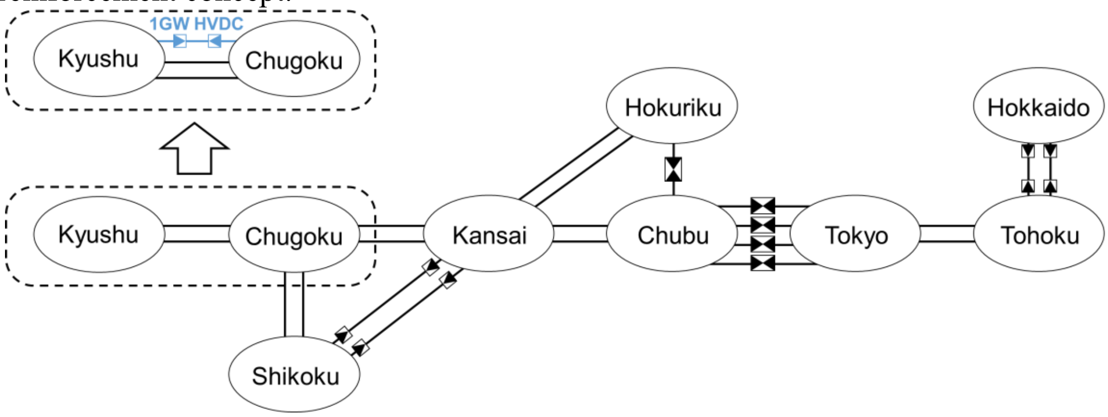

Figure 7 – Reinforcement of the Chugoku–Kyushu Interconnection

OCCTO launched an open call for detailed feasibility studies and appointed three entities: the TSOs in both areas and one transmission operator with HVDC project experience. Based on their assessment, the total project cost was estimated at approximately JPY 450 billion (approx. 3.0 billion USD), with an expected construction period of around 13.5 years.

Figure 8 presents the assumptions and results of the B/C analysis. During the evaluation, governmental generation cost benchmarks were updated [4], leading to higher thermal generation cost assumptions and greater fuel cost savings than estimated previously. Adequacy benefits were evaluated using two reliability reference levels: the projected value from OCCTO's annual 10-year supply–demand adequacy assessment and the long-term adequacy target. In total, 48 B/C scenarios were analyzed, and 33 exceeded 1.0, demonstrating high investment robustness against future uncertainties such as fuel price volatility and varying discount rates. The variation in B/C results across scenarios reflects sensitivity to key uncertainties such as fuel prices and discount rates, while the majority of cases remaining above 1.0 indicates strong robustness.

To strengthen the business case from a risk-based perspective, additional quantitative risk mitigation values were evaluated beyond the standard B/C framework. The reinforcement is expected to reduce market fragmentation by 2,077–2,213 hours per year, mitigating the risk of extreme price spikes. From a reliability standpoint, the potential reduction in load shedding and supply shortages is valued at JPY 122.0–235.6 billion. Additionally, the project hedges against environmental and policy risks by reducing the RES curtailment rate by 2–3 percentage points and CO_2 emissions by up to 1.13 million tons annually. These results confirm that the project serves as a strategic "insurance policy" for long-term grid resilience and carbon neutrality. These additional quantified values complement the conventional B/C framework by explicitly capturing risk-reduction effects that are not fully reflected in deterministic economic metrics, thereby strengthening the overall investment rationale. Based on these findings, the reinforcement project was formally approved.

ケース			1	2	3	4	5	6	7	8	9	10	11	12
Assumptions	Evaluation period		22 years						40 years					
	Generation cost		Base Case – High Price Case											
	Adequacy benefit		Lower Limit	Upper Limit	Lower Limit	Upper Limit	Lower Limit	Upper Limit	Lower Limit	Upper Limit	Lower Limit	Upper Limit	Lower Limit	Upper Limit
	Discount rate		4%		2%		1%		4%		2%		1%	
Benefit(Billion Yen) [Billion Yen/Year]	Generation cost		3,505 to 5,150		4,318 to 6,392		4,827 to 7,172		4,895 to 7,320		6,843 to 10,333		8,257 to 12,525	
	Adequacy benefit	Target defined in the supply plan	800	15,321	976	18,699	1,087	20,808	1,099	20,961	1,519	28,938	1,824	34,718
		Target set under the capacity market	229	2,567	278	3,121	309	3,466	309	3,482	425	4,781	508	5.721
	Transmission loss(negative benefit shown as ▲)		▲127 to ▲192		▲152 to ▲231		▲168 to ▲255		▲167 to ▲252		▲224 to ▲339		▲266 to ▲402	
Cost(Billion Yen) [Billion Yen/Year]	Construction cost and annual expenses		5,585		6,799		7,557		6,621		8,663		10.077	
B/C Ratio (Red:B/C≧1)	Adequacy target defined in the supply plan		0.75 to 1.03	3.35 to 3.63	0.76 to 1.05	3.36 to 3.66	0.76 to 1.06	3.27 to 3.67	0.88 to 1.23	3.88 to 4.23	0.94 to 1.33	4.10 to 4.49	0.97 to 1.38	4.24 to 4.65
	Adequacy target set under the capacity market		0.65 to 0.93	1.06 to 1.35	0.65 to 0.95	1.07 to 1.37	0.66 to 0.96	1.08 to 1.37	0.76 to 1.11	1.24 to 1.59	0.81 to 1.20	1.32 to 1.71	0.84 to 1.25	1.36 to 1.77

***Figure 8** – Assumptions and results of the B/C for the Chugoku–Kyushu Interconnection*

5 Decision-Making for Grid Reinforcement under Uncertainty

In Japan, decisions on transmission reinforcement must account for uncertainties such as RES deployment, fuel prices, and demand growth. Therefore, it is not feasible to rely on a single deterministic assumption. To address this challenge, OCCTO adopts a structured decision-making approach based on the following framework:

- Assessment Under Multiple Scenarios
  - Generation mix (e.g., offshore wind deployment level, thermal power plant retention)
  - Demand growth (data centers, new industrial loads, hydrogen production)

- Fuel prices (low and high fuel price cases)
- Iterative Updates and Reevaluation
  Reinforcement options are evaluated through a phased process—from the Long-Term Plan to detailed feasibility studies and implementation decisions—with the flexibility to update assumptions where needed.
- Consideration of Qualitative Benefits (Though difficult to quantify, these elements strongly influence final decisions.)
  - Improved supply reliability during rare contingency events
  - Coordination with refurbishment of existing assets
  - Alignment with regional economic and industrial policies (e.g., offshore wind hubs)

Through this framework, uncertainties in CBA can be mitigated, enabling decisions that support long-term societal optimization.

6 Conclusion

This paper presented Japan's Long-Term Plan for achieving carbon neutrality by 2050 and outlined the methodologies applied for CBA, together with case studies of specific transmission reinforcement projects. The key findings can be summarized as follows:

- In the era of large-scale RES deployment, expanding interregional transmission capacity is one of the most essential policy measures.
- CBA remains the foundation of decision-making; however, addressing future uncertainty is becoming increasingly important.
- The use of HVDC technology is particularly critical, especially where subsea transmission routes are required.
- Interconnections are not merely transmission assets; they represent strategic national infrastructure linked to supply reliability, market integration, and industrial policy.

As large-scale offshore wind deployment and notable new loads (e.g., data centers, semiconductor facilities, and hydrogen production) become more likely, Japan's grid will require transformation at a scale and pace not experienced previously. The Long-Term Plan and its implementation pathway represent important first steps toward this transition. To ensure continued effectiveness, integrated efforts—including technical solutions, regulatory frameworks, investment mechanisms, and regional coordination—will be essential.
The evaluation framework presented in this paper is applicable not only to current projects but also to future interregional transmission development under high penetration of RES, as well as system planning efforts in other countries. Accordingly, the findings are expected to provide meaningful insights for system operators and planning authorities promoting transmission investment in RES-dominated power systems of the future.

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