Aggregation of Electricity Supply Plans for Fiscal Year 2023

October 2023

Organization for Cross-regional Coordination of Transmission Operators, Japan

INTRODUCTION

The Organization for Cross-regional Coordination of Transmission Operators, Japan (hereafter, the Organization) has aggregated the electricity supply plans for the 2023 fiscal year (FY). This aggregation was conducted according to the provisions of Article 28 of the Operational Rules of the Organization and Article 29 of the Electricity Business Act(hereafter, the Act), which require the electric power companies (EPCOs) to submit their plans and publish the results.

The EPCOs submit the electricity supply plans according to the Network Code of the Organization; they are aggregated by the Organization, and sent to the Ministry of Economy, Trade and Industry (METI) annually by the end of March.
In total, 1,816 electricity supply plans for FY 2023 were aggregated, including 1,812 submissions from companies that became EPCOs by the end of November 2022 and 4 submissions from four companies that became EPCOs by March 1, 2023.

Number of Electric Power Companies Subject to the Aggregation in FY 2023

Business License	Number
Generation Companies	1,040
Retail Companies	688
Specified Wholesale Suppliers	39
Specified Transmission, Distribution and Retail Companies	29
Specified Transmission and Distribution Companies	7
Transmission Companies	3
General Transmission and Distribution Companies	10
Distribution Companies	0
Total	1,816

[Reference] Electricity supply plan

The EPCOs shall develop a comprehensive plan for electricity supply, and development of a generation or transmission facility for 10 years according to the provisions of Article 29 of the Act.

The METI shall recommend to EPCOs any alterations to the supply plan if it is recognized as inadequate for the security of a stable supply by cross-regional operation or for other development of the electricity business comprehensively and rationally.

Due Date of Submission of Supply Plans	
(1)Electric Power Company (EPCO) except General Transmission and Distribution Company submission to the Organization	March 1 (draft: Feb. 10)
(2)General Transmission and Distribution Company submission to the Organization	March 25 (draft: Mar. 10)
(3)The Organization submission to the METI	the End of March

[Reference] Items to be aggregated in the electricity supply plan

Items aggregated in the electricity supply plan are described in the covering letter of the aggregation of electricity supply plans according to the provisions of METI's ordinance. The Organization has aggregated the plans according to this description

Items to be reported in the Aggregation (determined by the Ordinance of the METI)	Contents
I. Electricity Demand Forecast	
1. Actual and Preliminary Data for FY 2020, and Forecast for FY 2021 and 2022 (Short-Term)	Actual peak demand for the previous year, and forecast peak demand for the 1st and 2nd years of the projected period in both each regional area and nationwide
2. 10-Year Demand Forecast (Long-Term)	Forecast peak demand from the 3rd to 10th years of the projected period in both each regional area and nationwide
II. Electricity Supply and Demand	
1. Actual Data for FY 2020, and Projection for FY 2021 and 2022 (Short-Term)	Actual supply-demand for the previous year, and projected supply-demand for the 1st and 2nd years of the projected period in both each regional area and nationwide
2. Projection of Supply–Demand Balance for 10 years (Long-Term)	Projected supply-demand from the 3rd to 10th years of the projected period in both each regional area and nationwide
III. Analysis of the Transition of Power Generation Sources	Development and retirement plans of power generation sources which express the transition of power generation in nationwide
IV. Development Plans for Transmission and Distribution Facilities	Aggregated reinforcement plans of inter- and intra-regional transmission and distribution facilities
V. Cross-Regional Operation	Aggregated transaction plans between each area
VI. Analysis of Characteristics of Electric Power Companies	Aggregated situation for electric power companies by each business licenses
VII. Findings and Current Challenges	Opinion to the Minister of Economics, Trade & Industry

CONTENTS

I. Electricity Demand Forecast

1. Actual and Preliminary Data for FY 2022 and Forecast for FY 2023 and 2024 (Short Term)

a. Peak Demand (Average Value of the Three Highest Daily Loads[1]) in August

Table 1-1 shows the actual data for the aggregated peak demand for each regional service area[2] submitted by 10 general transmission and distribution (GT&D) companies for FY 2022 and the forecast[3] value for FY 2023 and 2024.

The peak demand (average value of the three highest daily loads) for FY 2023 was forecast at 161,820 megawatts (MW), representing a 0.4% increase over 161,180 MW, i.e., the temperature-adjusted[4] value for FY 2022.

Peak demand for FY 2024 was forecast at 162,200 MW, representing a 0.6% increase over the temperature-adjusted[4] value for FY 2022.

Table 1-1 Peak Demand (average value of the three highest daily loads) in August
(Nationwide, 10^4 kW at the sending end)

FY 2022 Actual (temperature adjusted)	FY 2023 Forecast	FY 2024 Forecast
16,118	16,182 (+0.4%*)	16,220 (+0.6%*)

*% change compared with actual data for FY 2022 (temperature adjusted)

b. Forecast for FY 2023 and 2024

Tables 1-2 and 1-3 show the monthly peak demand in FY 2023 and 2024, respectively, from the aggregated peak demand for each regional service area submitted by 10 GT&D companies. The monthly peak demand in summer (August) is ~10 gigawatts (GW) over than that in winter (January) ; therefore, nationwide peak demand occurs in summer.

---

1 Peak demand (average value of the three highest daily loads) corresponds to the average value of the three highest daily loads (hourly average) each month.

2 Peak demand in the regional service areas refers to the average value of the three highest daily loads in public demand supplied by retail companies and GT&D companies through the transmission and distribution network of the GT&D companies. The Organization publishes these average values according to the provisions of paragraph 5, Article 23 of the Operational Rules.

3 Demand forecast beyond FY 2023 is based on normal weather. Thus, weather conditions for forecast assumption may vary in contrast to the actual data or estimated value in FY 2022.

4 Temperature adjustment is implemented to capture the current demand based on normal weather, which excludes demand fluctuations triggered by air-conditioner operation.

Table 1-2 Monthly Peak Demand (average value of the three highest daily loads) in FY 2023
(Nationwide, 10^4 kW at the sending end)

	Apr.	May	Jun.	Jul.	Aug.	Sep.
Peak Demand	11,509	11,338	12,840	16,146	16,182	14,013
	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Peak Demand	11,778	12,327	14,203	15,187	15,174	13,253

Table 1-3 Monthly Peak Demand (average value of the three highest daily loads) in FY 2024
(Nationwide, 10^4 kW at the sending end)

	Apr.	May	Jun.	Jul.	Aug.	Sep.
Peak Demand	11,563	11,396	12,906	16,184	16,220	14,083
	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Peak Demand	11,838	12,387	14,272	15,221	15,209	13,318

c. Annual Electric Energy Requirements

Table 1-4 shows the preliminary data[5] for FY 2022 and the forecast value for FY 2023 from the aggregated electric energy requirements of each regional service area submitted by the 10 GT&D companies.

The electric energy requirements for FY 2023 are forecast at 873.5 terawatt hours (TWh), an increase of 0.3% over the 870.6 TWh in the preliminary data for FY 2022.

Table 1-4 Annual Electric Energy Requirements
(Nationwide, TWh at the sending end)

FY 2022 Preliminary (temperature- and leap-year-adjusted)	FY 2023 Forecast
870.6	873.5(+0.3%*)

* % changes over the preliminary value for the previous year

5 Preliminary data for annual electric energy requirements are an aggregation of the actual data from April to November 2022 with the preliminary data from December 2022 to March 2023.

2. 10-Year Demand Forecast (Long Term)

Table 1-5 shows the significant economic indicators developed and published by the Organization on November 24, 2022; these indicators are assumptions to be used by the GT&D companies to forecast the peak demand in their regional service areas.

The real gross domestic product (GDP)[6] is estimated at 546.2 trillion Japanese yen (JPY) in FY 2022 and 587.7 trillion JPY in FY 2032, with an annual average growth rate (AAGR) of 0.7%. The index of industrial production (IIP)[7] is projected at 97.0 in FY 2022 and 103.5 in FY 2032, with an AAGR of 0.6%. In contrast, the population was estimated at 124.97 million in FY 2022, with a projected 118.24 million in FY 2032, representing an AAGR of −0.6%.

Table 1-5 Major Economic Indicators Assumed for Demand Forecast

	FY 2022	FY 2032
Gross Domestic Product(GDP)	546.2 trillion JPY	587.7 trillion JPY [+0.7%]*
Index of Industrial Product(IIP)	97.0	103.5 [+0.6%]*
Population	124.97 million	118.24 million [−0.6%]*

* Average annual growth rate for the forecast value of FY 2022

a. Peak Demand (average value of the three highest daily loads) in August

Table 1-6 shows the peak demand forecast for FY 2023, FY 2027, and FY 2032 as the aggregation of peak demand for each regional service area submitted by the 10 GT&D companies. In addition, Furthermore, Figure 1-1 shows the actual data and the forecast of peak demand forecast from FY 2011 to 2032.

The peak demand nationwide is forecast at 161,130 MW in FY 2027 and 159,180 MW in FY 2032, with an AAGR of −0.1% from FY 2022 to 2032.

The peak demand forecast over 10 years shows an upward motion in FY 2023 and 2024 by economic recovery, then a slightly decreasing trend beyond FY 2025. This pattern is primarily due to negative factors, such as efforts to reduce electricity use, wider use of energy-saving electric appliances, a decreasing population, and load-leveling measures, and despite positive factors, such as the expansion of the economic scale and greater dissemination of electric appliances.

Table 1-6 Peak Demand Forecast (average value of the three highest daily loads) for August (Nationwide, 10^4 kW at the sending end)

FY 2023 [aforementioned]	FY 2027	FY 2032
16,182	16,113 [-0.0%]*	15,918 [-0.1%]*

* Average Annual Growth Rate for the forecast value of FY 2022

[6] GDP expressed as the chained price for calendar year (CY) 2015.

[7] Index value in CY 2015 = 100.

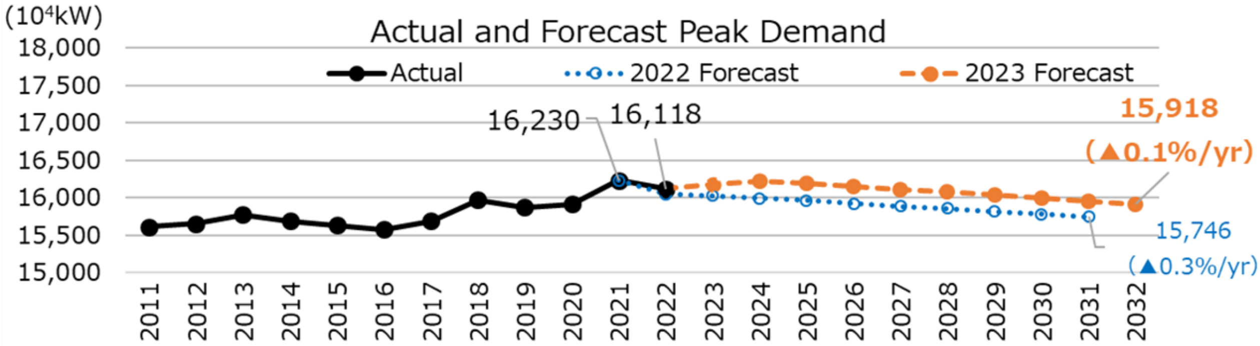


Figure 1-1 Actual and Forecast Peak Demand (August for Nationwide, 10^4 kW at the sending end)

b. Annual Electric Energy Requirement

Table 1-7 shows the forecast for annual electric energy requirements forecast in FY 2023, 2027, and 2032 as the aggregation of the electric energy requirements for each regional service area submitted by 10 GT&D companies.

The nationwide annual electric energy requirement is forecast at 870.0 TWh in FY 2027 and 857.2 TWh in FY 2032, with an AAGR of −0.2% decrease from FY 2022 to 2032.

The annual electric energy requirement forecast over 10 years shows an increase in FY 2023 by economic recovery, and a slightly decreasing trend beyond FY 2024. This pattern is attributable to negative factors, such as efforts to reduce electricity use, and a decreasing population offsetting the positive factors such as the expansion of economic scale and greater dissemination of electric appliances, despite the increase in FY 2023, in the projected period.

Table 1-7 Annual Electric Energy Requirement Forecast
(Nationwide, TWh at the sending end)

FY 2023 [aforementioned]	FY 2027	FY 2031
873.5	870.0 [−0.0%]*	857.2 [−0.2%]*

* AAGR for the forecast value of FY 2022

II. Electricity Supply and Demand

1. Supply Reliability Criteria

As a reliability criterion, the Organization has applied expected unserved energy (EUE) to the electricity supply plan based on the discussions of the Study Committee on Regulating and Marginal Supply Capability and Long-Term Supply–Demand Balance Evaluation.[8] From FY 2021, annual EUE values of 0.048kWh/kW-year nationwide and 0.498kWh/kW-year for the Okinawa area, are the newly applied reliability criteria for the electricity supply plan.

The supply reliability criteria for the electricity supply plan now apply annual EUE criteria to confirm supply reliability; however, supply capacity must be balanced for each month according to the consideration of area characteristics, such as winter in the Hokkaido area or severe weather. Therefore, the Organization evaluates whether the supply capacity in the short term (the first and second year of the projected period) is satisfied by the annual EUE criteria, and simultaneously confirms the reserve margin of each area and month.

Based on the discussion at the 81st meeting of the Study Committee on Regulating and Marginal Supply Capability and Long-Term Supply–Demand Balance Evaluation, the basic principle for severe weather to be considered in the supply reliability criteria is reviewed. However, new criteria must be coordinated with the capacity market, and supply reliability analysis for this year's aggregation is implemented using the present criteria to secure supply capacity.[9]

(Reference) Characteristics of Annual EUE

Figure 2-1 shows the characteristics of annual EUE. For evaluation by annual EUE criteria, the stable supply is secured through the year at the usual level if the annual EUE value is less than 0.048 kWh/kW-year.

Still, as it is difficult to understand the lowering of the reserve margin in a specific area and month solely by the annual EUE evaluation, because of an imbalance in the supply capacity caused by the scheduled maintenance of the generating facilities and other factors; therefore, the Organization implements a conventional approach to evaluate the reserve capacity for each month.

[8] Source: Material 2, 58th meeting of the Study Committee on Regulating and Marginal Supply Capability and Long-Term Supply–Demand Balance Evaluation (March 3, 2021) [written only in Japanese] https://www.occto.or.jp/iinkai/chouseiryoku/2020/files/chousei_58_02.pdf

[9] Source: Material 4, 84th meeting of the Study Committee on Regulating and Marginal Supply Capability and Long-Term Supply–Demand Balance Evaluation (March 22, 2023) [written only in Japanese] https://www.occto.or.jp/iinkai/chouseiryoku/2022/files/chousei_84_04.pdf

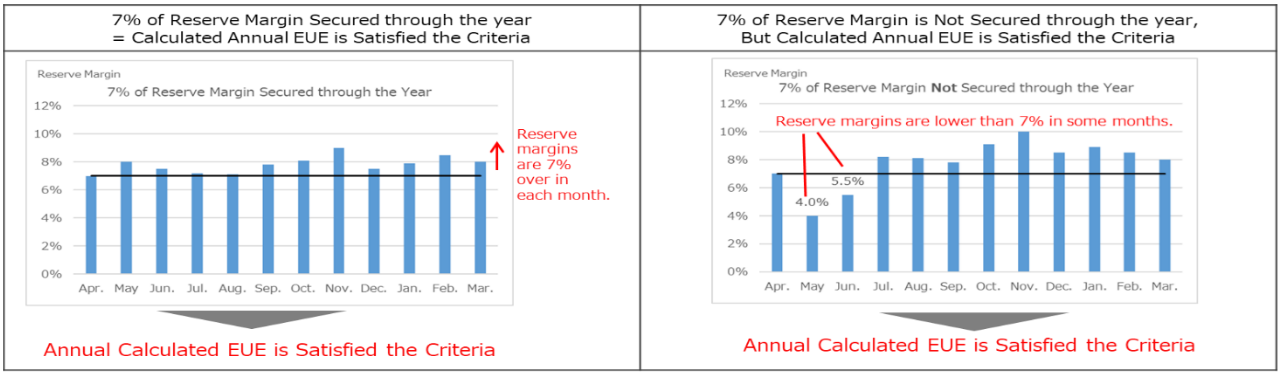


Figure 2-1 Characteristic of Annual EUE

2. Evaluation of Supply Capacity by EUE Approach in the Projected Period (FY 2023 Through 2032)

Table 2-1 shows the calculated result of supply capacity by annual EUE. In the short term (the first and second year of the projected period), a supply capacity shortage is forecasted in the Tokyo area in July, August, and November 2023. The criteria of secure supply (0.048kWh/kW-year nationwide, 0.498kWh/kW-year in Okinawa) is forecasted to exceed in the corresponding months.

In the long term, due to the suspension of generating units, the calculated results do not fall within the criteria for FY 2027 in the Hokkaido area, the Tokyo area for FY 2025 and 2026, the Kyushu area for FY 2025, and from FY 2027 to 2029, or the Okinawa area for FY 2025 and 2026, from FY 2029 to 2032.

Table 2-1 Calculated Result of Supply Capacity by Annual EUE

(kWh/kW-year)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Hokkaido	0.000	0.004	0.014	0.030	0.078	0.006	0.004	0.004	0.006	0.007
Tohoku	0.001	0.000	0.002	0.012	0.004	0.002	0.002	0.001	0.001	0.001
Tokyo	0.049	0.011	0.056	0.184	0.047	0.003	0.002	0.001	0.001	0.001
Chubu	0.000	0.000	0.004	0.011	0.002	0.001	0.000	0.000	0.001	0.001
Hokuriku	0.000	0.000	0.001	0.001	0.001	0.000	0.000	0.000	0.000	0.000
Kansai	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Chugoku	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Shikoku	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Kyushu	0.000	0.000	0.138	0.029	0.061	0.058	0.050	0.017	0.013	0.011
Interconnected	0.017	0.004	0.034	0.070	0.025	0.007	0.006	0.002	0.002	0.002
Okinawa	0.042	0.026	0.677	1.722	0.473	0.491	0.563	1.715	0.651	0.696

3. Short Term Evaluation of Supply Capacity by Conventional Approach

The Organization evaluates the supply–demand balance nationwide and for each regional service area using the supply capacity[10] and peak demand data for the regional service areas.

The Organization implements its evaluation using the criterion of whether the reserve margin (%)[11] for each regional service area is secured over 8%. ' `

In the Okinawa EPCO regional service area, the criterion is to secure the supply capacity (which is deducted necessary reserve capacity based on actual operation[12]) or the activating standard of Generator I'[13], (whichever is bigger), which must cover the average three highest loads in its regional service area. The evaluation is implemented at the time of the least reserve margin.

Figure 2-2 summarizes the supply–demand balance evaluation. The supply capacity includes the generating capacity requirements secured by retail and GT&D companies for their regional service areas and the generation companies' surplus power production.[14] The supply capacity currently secured by retail companies includes power procured[15] from other regional service areas through cross-regional interconnection lines; thus, the generation companies' surplus power or the reserve capacity of retail companies might provide future supply capacity for other regional service areas.

When the operation of a nuclear power plant becomes uncertain, the corresponding unit or plant's supply capacity is recorded as zero. Furthermore, the corresponding supply capacity is reported as "uncertain" according to Procedures for Electricity Supply Plans of FY 2023, published in November 2022 by the Agency for Natural Resources and Energy. In the electricity supply plans for FY 2023, the supply capacity was reported as "uncertain" for all nuclear power plants except those that had resumed operation when the plans were submitted. Additionally, figures for sending and receiving between EPCOs at the trade-in baseload market are adjusted by OCCTO.

---

[10] Supply capacity is the maximum power generated steadily during the peak demand period (average value of the three highest daily loads).

[11] Reserve margin (%) describes the difference between supply capacity and peak demand (average value of the three highest daily loads) divided by peak demand (average value of the three highest daily loads).

[12] Reference: Material 3, 74th meeting of the Study Committee on Regulating and Marginal Supply Capability and Long-Term Supply–Demand Balance Evaluation (June 28, 2022) [written only in Japanese] https://www.occto.or.jp/iinkai/chouseiryoku/2022/files/chousei_74_03.pdf

[13] Reference: Guideline for soliciting balancing capacity of Generator I' activating at severe weather [written only in Japanese] https://www.okiden.co.jp/shared/pdf/business/free/2022/ps1/dengen_tyousei_07.pdf

[14] Surplus power is the surplus power generation capacity of generation companies in a regional service area without a sales destination.

[15] In case of congestion in cross-regional interconnection lines, the rebated figure for each area calculated by the Organization is added.

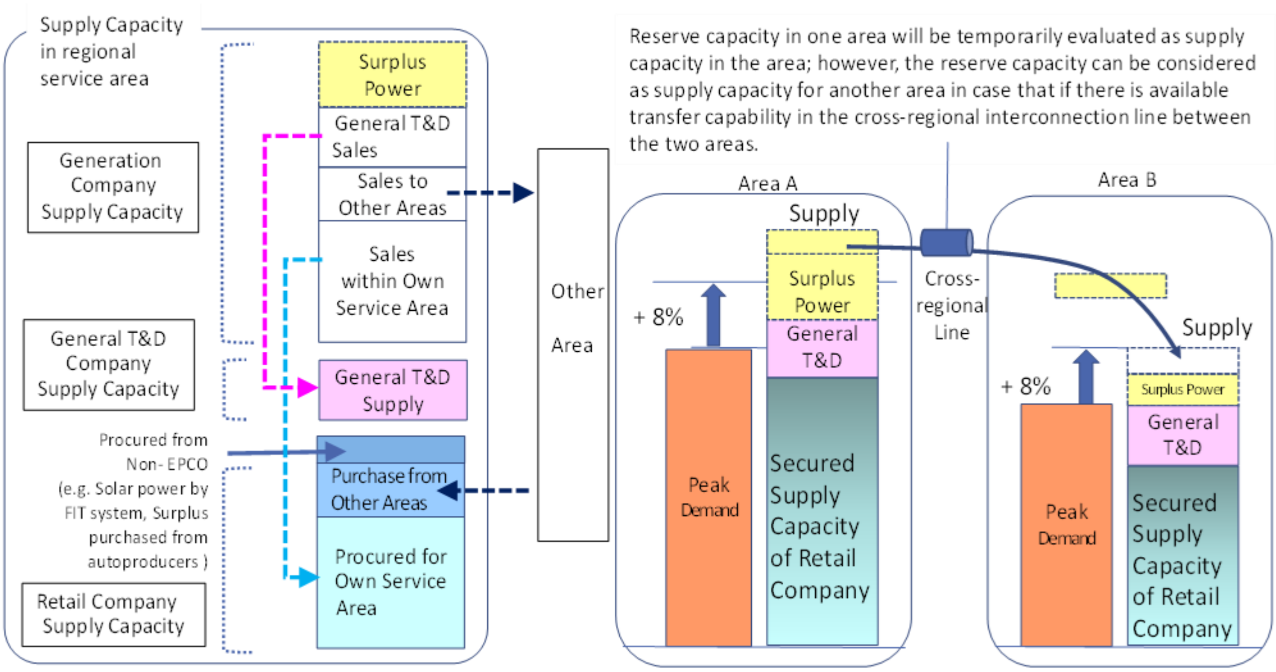


Figure 2-2 Summary of Supply–Demand Balance Evaluation

[Reference] Calculation Method of Supply Capacity

The calculation method for supply capacity or surplus power is based on the description in the "Guideline for the Calculation of Demand and Supply Capacity"[16](Agency for Natural Resources and Energy: November 2022) and "Procedures for Electricity Supply Plans of FY 2023"[17](Agency for Natural Resources and Energy: November 2022).

[16] Guideline for the Calculation of Demand and Supply Capacity [written only in Japanese]
https://www.enecho.meti.go.jp/category/electricity_and_gas/electricity_measures/001/pdf/guideline.pdf

[17] Procedures for Electricity Supply Plans of FY 2023 [written only in Japanese]
https://www.enecho.meti.go.jp/category/electricity_and_gas/electricity_measures/001/pdf/kisai-youryo.pdf

[Reference] Calculation Method of Available Transfer Capability(ATC)

The calculation method of the available transfer capability of cross-regional interconnection lines is stated below.

ATC = Transfer Capability (1) – Transfer Margin (2) – Schedule Power Flow of cross-regional interconnection line at 15:00 h in August (3).

<u>Short term</u>

(1) Based on "Transfer Capability of Cross-regional Interconnection Lines FY 2023-2032" (annual and long-term plans) (March 1, 2023: The Organization)[18]

(2) Based on "Transfer Margin of Cross-regional Interconnection Lines FY 2023 and 2024" (annual plan) (March 1, 2023: The Organization)[19], and the calculated figures considering expected contribution from external areas (equivalent to 3% of transfer capability of the interconnection lines)

(3) Based on monthly scheduled power flows reported in the "Plan for Transaction of Electricity (Table 36)" of the electricity supply plan for FY 2023 and 2024

<u>Mid-to-Long term</u>

(1) For FY 2023 and 2024, the August value was calculated from (1) in the short term above; the value for FY 2025-2032 was based on "Transfer Capability of Cross-regional Interconnection Lines FY 2023-2032" (annual and long-term plans) (March 1, 2023: The Organization)[18]

(2) For FY 2023 and 2024, the August value was calculated from (2) in the short term above; the value for FY 2025-2032 was based on "Transfer Margin of Cross-regional Interconnection Lines FY 2023-2032" (long-term plans) (March 1, 2023: The Organization), [19], and the calculated figures considering expected contribution from external areas (equivalent to 3% of transfer capability of the interconnection lines).

(3) Based on 15:00 in August scheduled power flows of the period reported in the "Plan for Transaction of Electricity (Table 32-8)" of the electricity supply plan for FY 2025-2032

[18] Reference: "Cross-regional Transfer Capability from FY 2023 to FY 2032" (annual and long-term)[written only in Japanese]
https://www.occto.or.jp/renkeisenriyou/oshirase/2022/230301_renkeisen_unyouyouryou.html

[19] Reference: "Cross-regional Transmission Margin from FY 2023 to FY 2032 (annual and lont-term), consideration and securing reasens for the margin setting at actual supply-demand timing" [written only in Japanese]
https://www.occto.or.jp/renkeisenriyou/oshirase/2022/230301_2023_2032_margin_kakuhoriyu.html

a. Projection of Supply–Demand Balance in FY 2023 and 2024

To present the cross-regional reserve margin, the Organization recalculates the monthly projection of the least reserve margin for each regional service area to the level around neighboring areas. This recalculation is done by using power exchanges to transfer electricity from areas of over the 8% reserve margin to areas of below the 8% reserve margin based on the available transfer capability of each interconnection line.[20]

Furthermore, additional supply capacity has been applied to the interconnected areas (except Okinawa) in July and August based on the correlation between solar power generation and electric demand.[21]

Furthermore, information on the environmental assessment of thermal power plants[22] probably includes some generating facilities in which EPCOs confirm their business judgment and proceed to their construction. Therefore, the Organization has investigated generating facilities that are not included in the electricity supply plans; however, they have already applied for generator connections to GT&D companies and submitted construction plans according to the provisions of Article 48 of the Act in cooperation with the government.

(i) Projection for FY 2023

Table 2-2 shows the projected reserve margin in each regional service area for FY 2023. The reserve margin in every area and month is over 8% of the criteria.

Table 2-2 Monthly Projection of the Cross-regional Reserve Margins Nationwide and for Each Regional Service Area

(Power exchanges through cross-regional interconnection lines and generating facilities are not included at the sending end at the sending end of the electricity supply plans,)

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	23.4%	46.4%	50.8%	24.0%	25.3%	36.4%	27.1%	28.2%	20.3%	15.4%	16.0%	24.4%
Tohoku	16.4%	16.0%	21.3%	18.2%	24.1%	36.4%	25.2%	28.2%	20.3%	15.4%	16.0%	24.1%
Tokyo	16.4%	12.0%	12.3%	8.7%	9.7%	18.9%	22.0%	8.5%	15.0%	15.3%	15.0%	21.1%
Chubu	26.8%	24.8%	28.1%	18.7%	20.8%	22.0%	22.0%	14.8%	15.3%	15.3%	15.0%	21.1%
Hokuriku	26.8%	27.5%	28.1%	18.7%	20.8%	22.0%	22.0%	14.8%	15.3%	15.3%	15.0%	21.7%
Kansai	26.8%	27.5%	28.1%	18.7%	20.8%	22.0%	22.0%	14.8%	15.3%	15.3%	15.0%	21.7%
Chugoku	26.8%	27.5%	28.1%	18.7%	20.8%	22.0%	22.0%	14.8%	15.3%	15.3%	15.0%	21.7%
Shikoku	26.8%	27.5%	28.1%	18.9%	22.4%	22.0%	22.0%	14.8%	15.3%	15.3%	15.0%	39.4%
Kyushu	33.0%	30.2%	28.1%	18.7%	20.8%	29.9%	44.7%	23.3%	15.3%	15.3%	15.0%	21.7%
Okinawa	42.6%	42.6%	27.7%	30.5%	26.9%	22.1%	41.5%	44.4%	72.6%	61.9%	60.4%	81.3%

* Cross-regional reserve margins becoming the same value are shown in the same background colors after utilization of cross-regional interconnection line. The least reserve margins in the Okinawa area are included.

[20] This evaluation is implemented based on the following. The evaluation of the timing of utilization of interconnection lines varies in the regional service areas; power exchange availability is calculated based on the least reserve margin, and the calculated results are lower than those based on the reserve margin at a given time. Therefore, this evaluation covers a more severe condition, which is better for a stable supply.

[21] Reference: 69th meeting of the Study Committee on Regulating and Marginal Supply Capability and Long-Term Supply–Demand Balance Evaluation [written only in Japanese] https://www.occto.or.jp/iinkai/chouseiryoku/2021/files/chousei_69_01.pdf

[22] Reference: Information on the environmental assessment of thermal power plants (METI website, written only in Japanese) http://www.meti.go.jp/policy/safety_security/industrial_safety/sangyo/electric/detail/thermal.html

The Okinawa EPCO regional service area[23] is a small, isolated island system unable to receive power through interconnection lines; thus, the same criterion used in other areas cannot be applied. In this area, the criterion of stable supply is to secure supply capacity over peak demand (average value of the three highest daily loads) by deducting the necessary reserve capacity based on actual operation of 337 MW.[24]

Table 2-3 shows the monthly reserve margin, indicating that the stable supply was secured in each month.

Table 2-3 Monthly Reserve Margin Forecasted by Conventional Approach in Okinawa Area (at the sending end)

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Okinawa	11.1%	16.7%	5.8%	9.1%	5.6%	1.0%	17.1%	15.8%	39.1%	30.8%	27.7%	46.9%

(ii) Projection for FY 2024

Table 2-4 shows a result of the similar calculation result for FY 2024, indicating that the reserve margins are over the criteria of 8% in every month and area.

Table 2-4 Monthly Projection of the Cross-regional Reserve Margins Nationwide and for Each Regional Service Area
(Power exchanges through cross-regional interconnection lines and generating facilities are not included at the sending end at the sending end of the electricity supply plans,)

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	22.9%	34.8%	38.1%	22.7%	37.8%	41.0%	26.9%	18.5%	25.3%	18.9%	19.0%	26.5%
Tohoku	22.9%	34.3%	28.0%	21.0%	16.7%	26.5%	26.9%	18.5%	25.3%	18.9%	19.0%	26.5%
Tokyo	22.9%	23.6%	13.5%	15.4%	16.7%	26.5%	18.6%	11.5%	25.3%	18.9%	19.0%	26.5%
Chubu	25.5%	33.2%	30.0%	20.6%	22.5%	26.5%	31.7%	26.6%	24.5%	18.9%	19.0%	26.5%
Hokuriku	34.3%	33.2%	30.0%	20.6%	22.5%	26.5%	31.7%	26.6%	24.5%	18.9%	19.0%	26.5%
Kansai	34.3%	33.2%	30.0%	20.6%	22.5%	28.1%	32.7%	26.6%	24.5%	18.9%	19.0%	26.5%
Chugoku	34.3%	33.2%	30.0%	20.6%	22.5%	28.1%	32.7%	26.6%	24.5%	18.9%	19.0%	26.5%
Shikoku	49.1%	52.2%	55.4%	20.6%	22.5%	28.1%	32.7%	55.6%	35.0%	39.4%	35.2%	46.0%
Kyushu	34.3%	33.2%	30.0%	20.6%	22.5%	28.1%	32.7%	26.6%	24.5%	18.9%	19.0%	26.5%
Okinawa	65.0%	49.4%	37.8%	33.7%	35.4%	30.2%	50.7%	57.1%	76.2%	53.7%	63.7%	63.5%

* Reserve margins becoming the same value are shown in the same background colors after utilization of cross-regional interconnection line. The least reserve margins in the Okinawa area are included.

In the Okinawa EPCO regional service area,[25] a small and isolated island system unable to receive power through interconnection lines, the same criterion used in other areas cannot be applied. In this area, the criterion of stable supply is to secure supply capacity over peak demand (average value of the three highest daily loads) by deducting the necessary reserve capacity based on actual operation of 337 MW.[26]

Table 2-5 shows the monthly reserve margin, indicating that the stable supply was secured in each month.

[23] In the Okinawa EPCO regional service area, the evaluation excludes the reserve margins of several isolated islands.
[24] The evaluation is implemented at the time of the least reserve margin instead of the peak demand occurrence.
[25] See footnote 23.
[26] See footnote 24.

Table 2-5 Monthly Reserve Margin Forecasted by Conventional Approach in Okinawa Area (at the sending end)

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Okinawa	33.6%	23.7%	16.1%	12.3%	14.3%	9.2%	26.4%	28.7%	42.8%	22.8%	31.2%	29.3%

b. Difference Between Scheduled Maintenance of Generating Facility for FY 2023 Evaluated by the Conventional Approach

Figure 2-3 shows the monthly scheduled maintenance planned for FY 2023 in the 2023 Supply Plan (which is subject to the generation capacity of 100 MW and over). Figure 2-4 shows the difference in scheduled maintenance for FY 2023 between the supply plans of FY 2023 (the 1st year) and FY 2022 (the 2nd year), which is also subject to the generation capacity of 100 MW and over.

The Organization has requested that all EPCOs avoid tight supply and demand balance periods of for their generating facilities' scheduled maintenance.[27] As a result, scheduled maintenance decreased compared with the 2022 Supply Plan in the summer period (August and September), and winter period (December, January, and February).

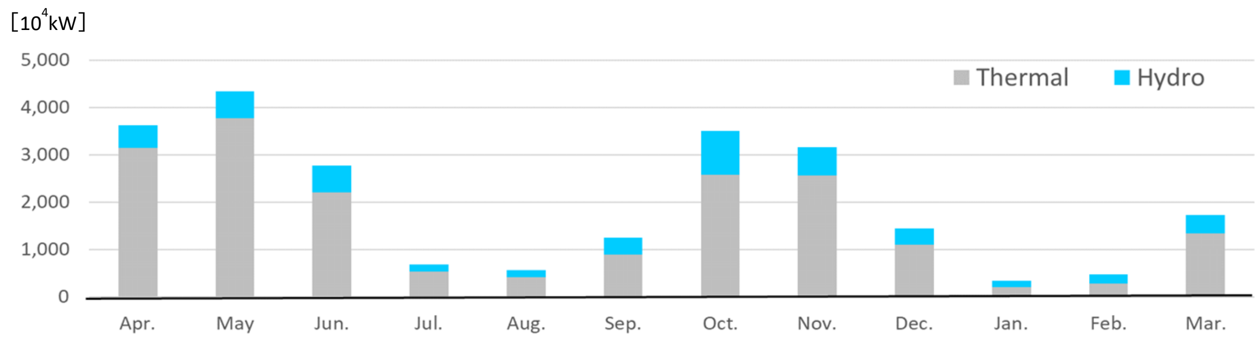


Figure 2-3 Monthly Scheduled Maintenance Planned for FY 2023 in 2023 Supply Plan

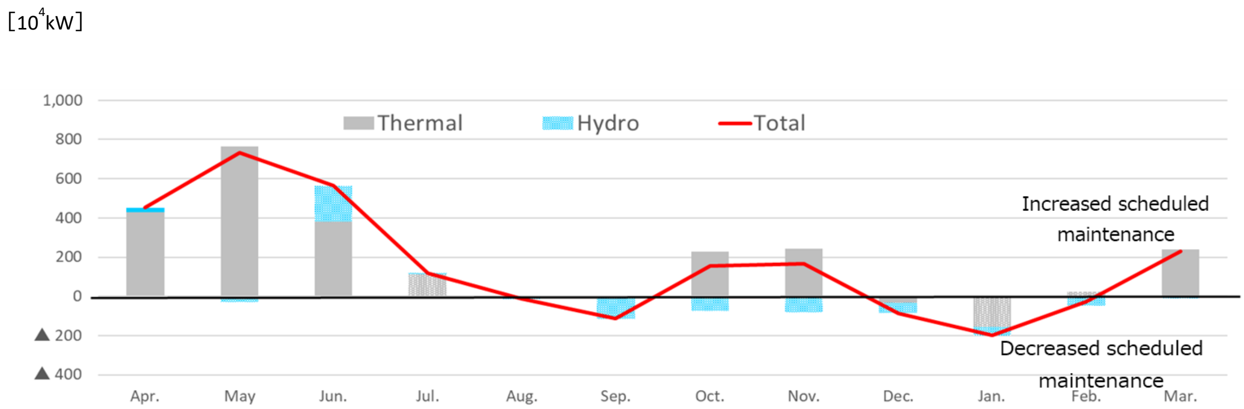


Figure 2-4 Difference in Scheduled Maintenance for FY 2023 between FY 2022 (the 2nd year) and FY 2023 (the 1st year) Supply Plan

[27] Reference: "Further Security of Supply Capacity in FY 2023" [written only in Japanese]
https://www.occto.or.jp/kyoukei/oshirase/220916_2023kyoukyuryokukakuho.html

c. Suspension and Decommission of Generating Facilities in 2023 Supply Plan

Table 2-6 shows the suspension and decommission of thermal generating facilities (subject to the generation capacity of 1 MW and over, excluding isolated island facility) in the 2023 Supply Plan.

The plan adds a capacity of 1,430 MW to the suspension and decommission plan. Furthermore, 1,000 MW of generating facilities has already been included in the suspension and decommission plan until FY 2022. In total, a 2,430 MW capacity is planned for the suspension and decommission in FY 2023.

Table 2-6 Suspension and Decommissioning of Generating Facilities in 2023 Supply Plan (10^4 kW)

Fuel	Newly Added	Already Included	Total Capacity to be Decommissioned
LNG	0	100	100
Oil	110	0	110
Coal	33	0	33
Total	143	100	243

d. Capacity to be Procured by Retail Company and Surplus Power of Generation Company Expected for Market Trade Evaluated by the Conventional Approach

Figure 2-5 compares the supply capacity to be procured[28] by retail companies for their forecasted peak demands, and the surplus power of generation companies expected for market trade.[29] The surplus power to be traded in the market exceeds the supply capacity to procure in every month.

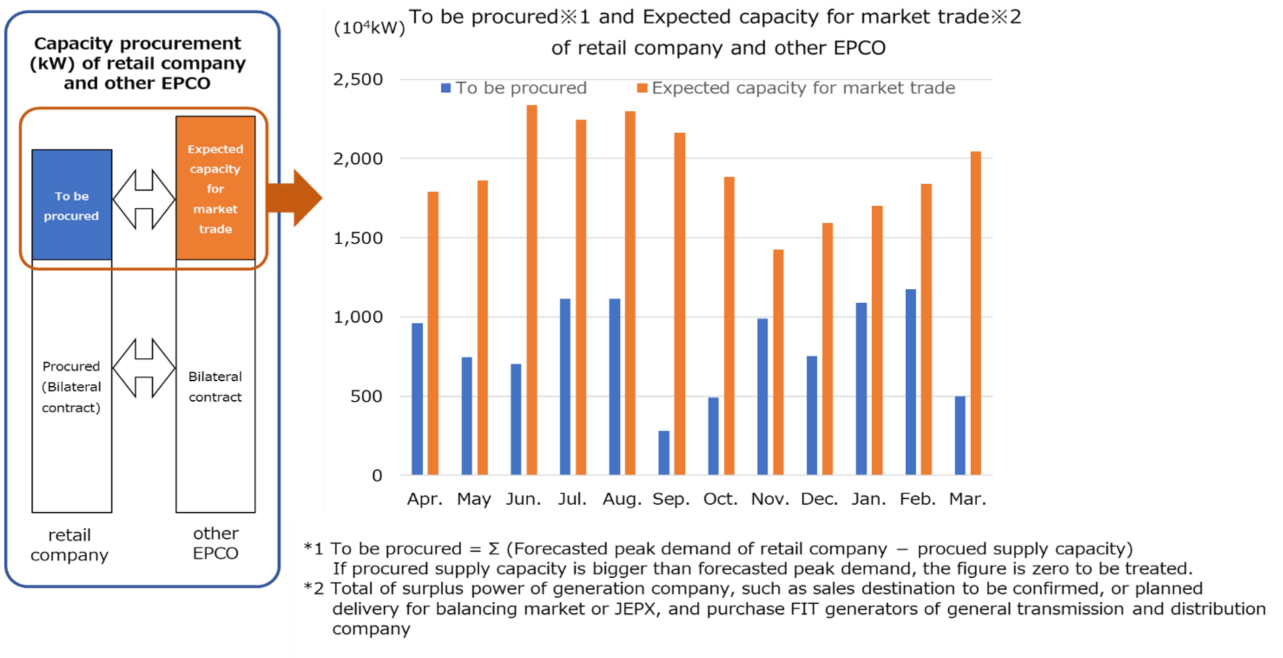


Figure 2-5 Comparison Between Supply Capacity to Be Procured by Retail Companies for Their Forecasted Peak Demand and Surplus Power of Generation Companies Expected for Market Trade

[28] Supply capacity to be procured: Σ(forecasted peak demand of retail companies – procured supply capacity of retail companies).

[29] Surplus power expected for market trad: total of surplus power of generation companies and FIT generators output purchased by GT&D companies.

4. Evaluation of Energy Supply

To evaluate the energy supply (kWh), the Organization has implemented a semiannual evaluation, known as an "Supply Energy Monitoring," for summer and winter periods since FY 2021. This evaluation is implemented when various information for demand forecast, such as weather forecast and generation fuel inventory, is available, making additional generation fuel procurement possible. The Organization plans to continue the evaluation and publish the results.

The Organization does not implement the evaluation of the energy-supply balance in the aggregation of the supply plans; however, it confirms the annual energy supply balance at this point and publishes information that will lead to a response from the EPCOs.

a. Projection of Energy Supply

Figure 2-6 shows the monthly energy-supply balance for nine interconnected areas in FY 2023 (the 1st year of the projected period of FY 2023 plans). Table 2-7 shows the forecasted energy requirement of the FY 2023 plan, and volumes and shortage rates from the forecast. In some months, the energy supply[30] will be 1.0–1.1 TWh/month less than the forecasted energy requirement (equivalent to 0.2-1.7% against the forecast energy requirement).

The Organization expects retail companies to procure supply capacity premeditatedly, and generation companies to procure generation fuel to increase energy generation for actual demand and supply timing based on the projection. Additionally, the Organization shall confirm the projection of securing energy supply by implementing kWh monitoring for the high demand period.

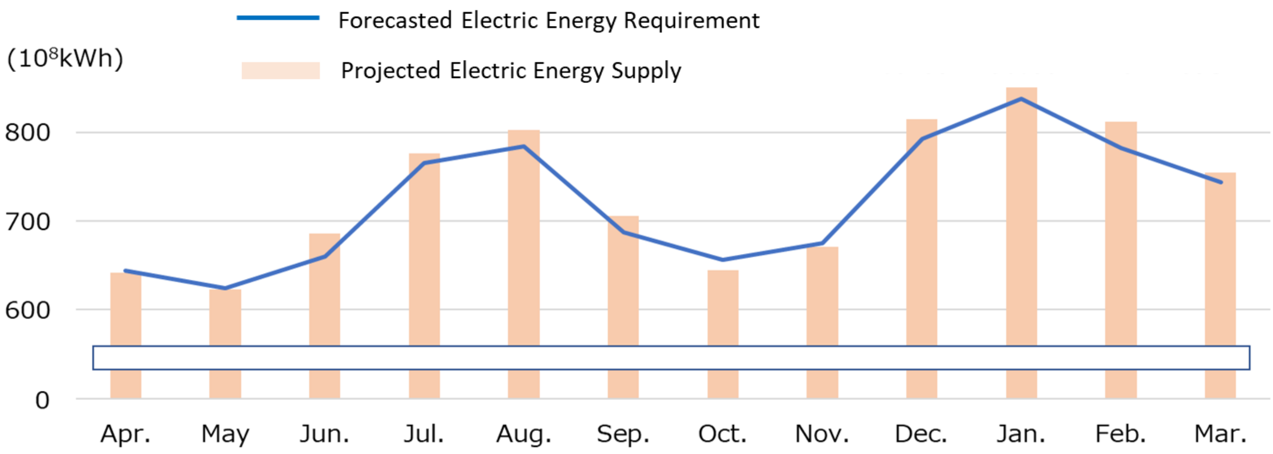


Figure 2-6 Monthly Energy-Supply Balance for a Total of Nine Interconnected Areas in FY 2023

Table 2-7 Forecasted Energy Requirement of FY 2023 Plan, Volumes, and Rates of Shortage from the Forecast

(10^8kWh)

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Annual total
Forecasted Energy Requirement	645	624	660	765	784	687	656	675	793	838	782	744	8,653
Projected Energy Supply Shortage	-3	-1	26	11	18	19	-11	-4	22	35	30	11	153
Projected Shortage Rate	-0.5%	-0.2%	3.9%	1.4%	2.3%	2.8%	-1.7%	-0.6%	2.8%	4.2%	3.8%	1.5%	1.8%

[30] Projected energy supply is an addition of energy supply with bilateral contract to retail companies which includes generation of nonelectric power companies, and surplus power expected for market trade.

b. Energy Procured by Retail Companies and Surplus Energy Expected for Market Trade, Evaluated by Energy Supply Forecast [10^8 kWh]

Figure 2-7 compares energy supply, which retail companies plan to procure from the energy market, and surplus energy that the generation companies intend to trade. Surplus energy exceeds the procurement by retail companies throughout the year.

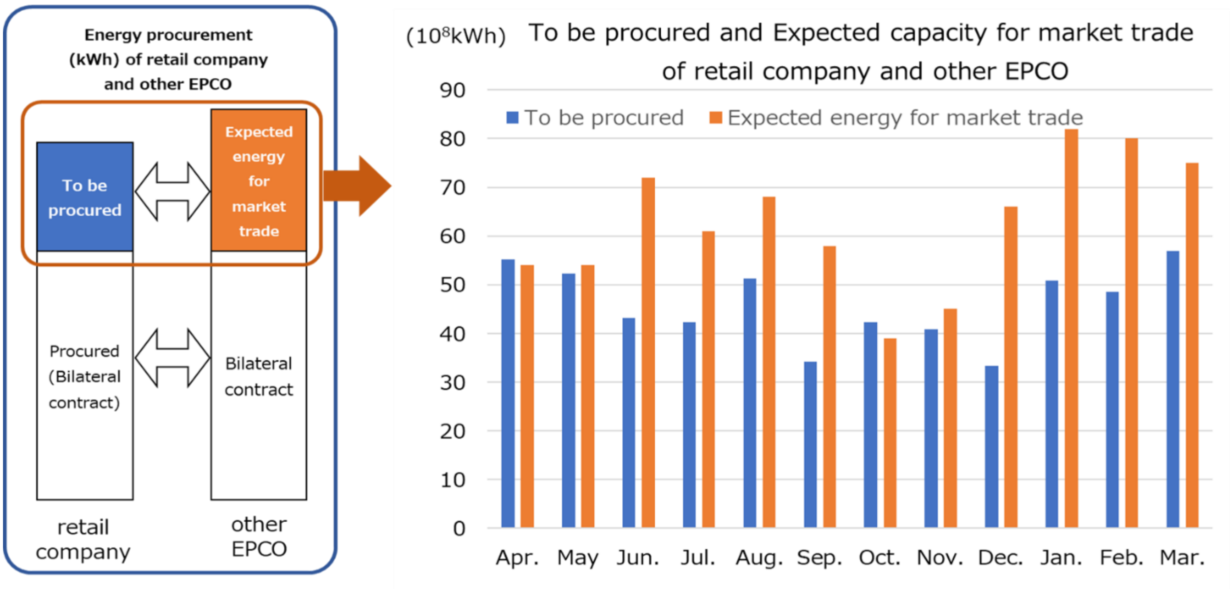


Figure 2-7 Comparison of Energy Supply Procurement of Retail Companies and Surplus Energy Provision

5. Evaluation of Supply-Demand for Supply Capacity and Energy Supply

・ Evaluation of Supply Capacity by the EUE Approach

For the short term of the projected period (FY 2023 and 2024), the EUE indices are over the criterion in the Tokyo area. For the mid to long term, the EUE indices exceed the criteria for the Hokkaido area in FY 2027, the Tokyo area in FY 2025 and 2026, the Kyushu area in FY 2025, and from FY 2027 to 2029, and the Okinawa area in FY 2025 and 2026, from FY 2029 to 2032.

・ Evaluation of Supply Capacity by the Conventional Approach

The 8% reserve margin is secured in FY 2023 and 2024 in every area and for all months.

・ Evaluation of Energy Supply

The energy supply in FY 2023 is expected to be 1.0–1.1 TWh/month of volume less than the forecasted energy requirement (equivalent to 0.2%–1.7% against the forecast energy requirement) in some months.

・ In the short term of FY 2023 and 2024, the annual EUE of the Tokyo area for FY 2023 becomes 0.049 kWh/kW-year, which exceeds the criteria of stable supply, and careful monitoring for supply–demand will be needed; however, there is no month drops below the 8% criteria by the conventional approach. The Organization proceeds to review the necessity of supply measures based on the analytical result of supply–demand variance risk which premises severe climate conditions (heatwave and severe cold) emerge once in 10 years.

・Annual EUEs of the Tokyo area in FY 2025 and 2026 and the Kyushu area in FY 2025 exceed the criteria despite of implementing the main capacity market auction. The reasons are attributable to the conditions stated below.

- The forecasted peak demand for the FY 2023 supply plan is revised upward from the forecast used at the main auction of the capacity market.
- Supply capacity to be procured at the main auction for FY 2025 and 2026 decreases due to the premise that part of supply capacity, equivalent to 2% of forecasted peak demand, is planned to be procured at the incremental auction of the capacity market.
- At present, incremental auctions for FY 2025 and 2026 are not planned, and the supply capacity of certain areas decreases due to the additional suspension plan of the thermal generating facility after the main auction for the corresponding years.

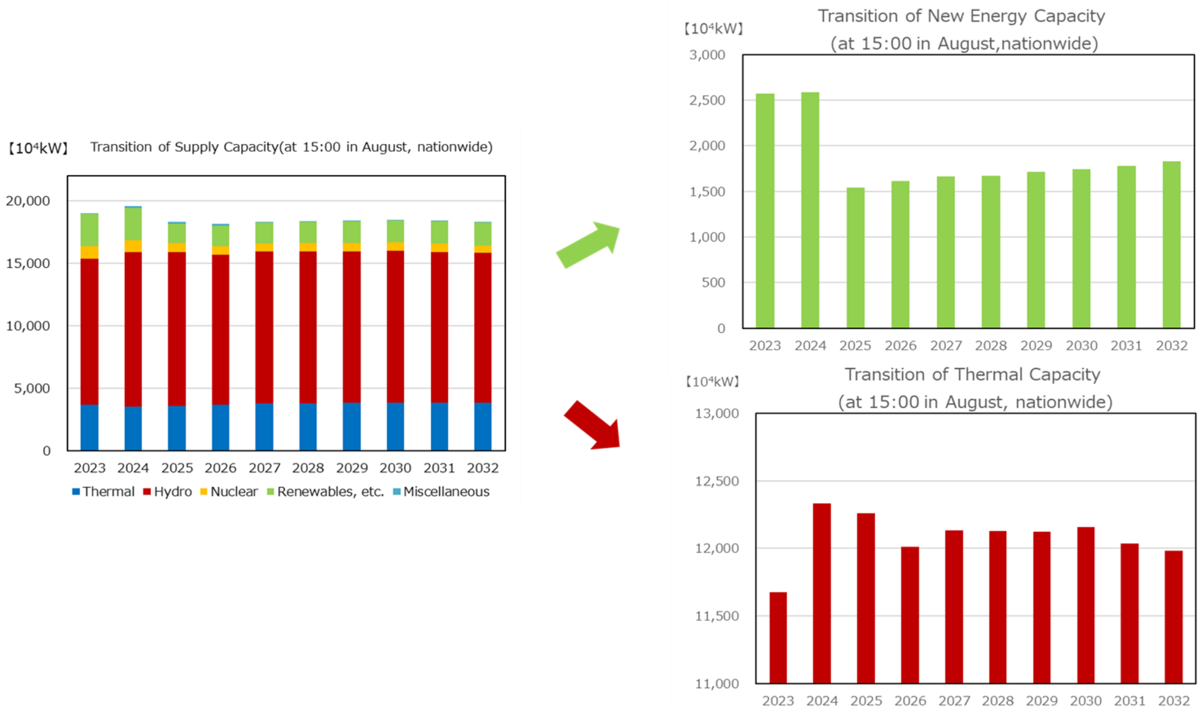
For FY 2025 and 2026, the Organization shall determine the necessity of the incremental auction while considering the result of coordinated scheduled maintenance of supply capacity. Furthermore, the Organization shall carefully re-examine supply capacity in future supply plans based on the continuous watch on generation facility development in the mid to long term and after FY 2027.

[Reference] Detailed Analysis of the Aggregation

a. Transition of Supply Capacity by Generation Sources[31]

Figure 2-8 shows the power generation sources' supply capacity (nationwide in August, at 15:00) in the projected period.

The supply capacity of new energy, etc. is projected to decrease temporarily in FY 2025 due to the calculation using an annual adjustment factor after the year; however, it is projected to increase afterward. Thermal power is projected to increase until FY 2024 by new and added installations and decrease afterward. As a whole, supply capacity is projected to increase until FY 2024 and remain almost the same after that.



Aggregated value submitted by each electric power company

New Energy, etc: Wind, Solar, Geothermal, Biomass and Waste, classified by "Guideline for the Calculation of Demand and Supply Capacity" (Agency for Natural Resources and Energy: Dec. 2011)

Renewable Energy : New Energy and Hydro

Figure 2-8 Transition of Supply Capacity by Generation Sources

[31] Supply Capacity by Generation Sources totalling each EPCO's supply capacity and procured capacity from non-EPCOs. Adjusted capacity of miscellaneous for supply capacity evaluation reflects prorated supply capacity by generation sources.

b. Transition of Suspended Thermal Power Plants

Figure 2-9 shows mid to long term projections of suspended thermal power plants (8–12 GW), which are not counted as part of the supply capacity due to long-term planned outages. They tend to increase, especially in FY 2026, having greater suspension capacity due to suspension for one year.

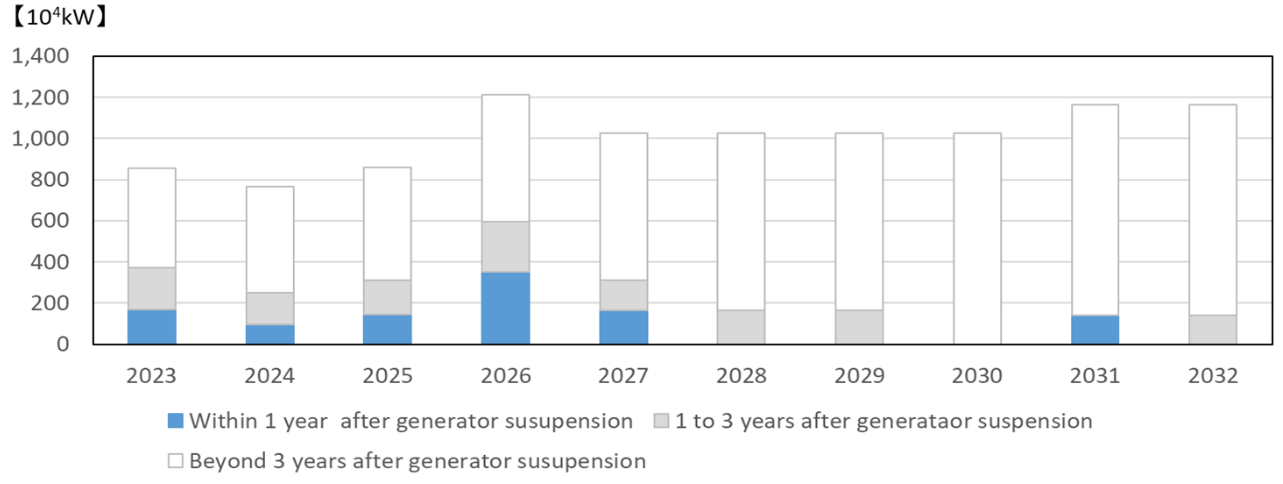


Figure 2-9 Projections of Suspended Thermal Power Plants

III. Analysis of the Transition of Power Generation Sources

This chapter's analysis is based on the automatic aggregation of values submitted by EPCOs. These values will not necessarily be realized in the future due to operating conditions of the power plants or actions due to political measures.

1. Transition of Power Generation Sources (Capacity)

The installed power generation capacity is the automatic aggregation of the capacity of an electric power plant's capacity owned by EPCOs and feed-in-tariff (FIT) generators owned by companies (other than EPCOs) registered as procurers of supply capacity of retail and GT&D companies in the projected period. For EPCOs' development plans, only generating facilities with a given probability of development are included in the calculation; however, not all development plans will necessarily be realized. Inefficient facilities will proceed toward decommission due to political measures in the future.

The installed generation capacity by a power generation source submitted from the EPCOs is calculated from the concepts below.

*1 Hydro and Thermal[32]

For existing facilities, the generation company aggregates the generating facility that it owns. For a newly installed facility, a generating facility such as one proceeding with its environmental assessment or publishing its commercial operation, is included in the aggregation.

*2 Nuclear

The generation company aggregates its generating facilities with actual operation experience, in addition to 33 units for which the date for resuming operation is uncertain, and excludes any facility that terminated operation.

*3 Solar and Wind

The GT&D company aggregates the projected value of the generation facility integration according to preliminary consultation and the available connecting capacity of its transmission lines or the actual growth trend of integration.

Table 3-1 and Figure 3-1 show the transition of installed power generation capacity by a power generation source, which are automatically aggregates the EPCO submission values based on the concepts above.

[32] The same concept is applied to geothermal, biomass, waste power generation sources, and storage facilities.

Table 3-1 Composition of the Transition of Installed Power Generation Capacities by Power Generation Source (Nationwide, 10^4 kW)

Power Generation Sources		2022	2023	2027	2032
Thermal*1		15,140	15,006	15,072	15,061
	Coal	5,065	5,185	5,104	5,094
	LNG	7,912	7,970	8,202	8,199
	Oil and others[33]	2,162	1,851	1,766	1,767
Nuclear*2		3,308	3,308	3,308	3,308
Hydro and Renewables		13,192	13,639	15,446	17,248
	Conventional Hydro	2,180	2,174	2,187	2,197
	Pumped Storage	2,739	2,739	2,739	2,739
	Wind*3	529	623	1,144	1,780
	Solar*3	7,009	7,332	8,542	9,707
	Geothermal*1	51	52	54	55
	Biomass*1	536	605	666	656
	Waste*1	132	91	93	90
	Storage(battery)*1	16	22	22	23
Miscellaneous		217	231	130	185
Total		31,856	32,184	33,956	35,801

Note) The totals are not necessarily equal due to independent rounding.

*1 The Organization automatically aggregates the value of the generating facility that the generation company owns; however, not all development plans will necessarily be realized; inefficient facilities will be retired, resulting from actions due to political measures in the future. For newly installed facilities, generating facilities (e.g., proceeding with its environmental assessments or publishing commercial operations) are included in the aggregation.

*2 Included are the facilities with actual operation experience, in addition to 33 units for which the date for resuming operation is uncertain; operation-terminated facilities are excluded.

*3 The GT&D company aggregates the projected value of integrating the generation facility according to the application of preliminary consultation and the available connecting capacity of its transmission lines or the actual growth trend of integration.

[33] The category “oil and others” includes the total installed capacities from oil, LPG, and other gas and bituminous mixture fired capacities.

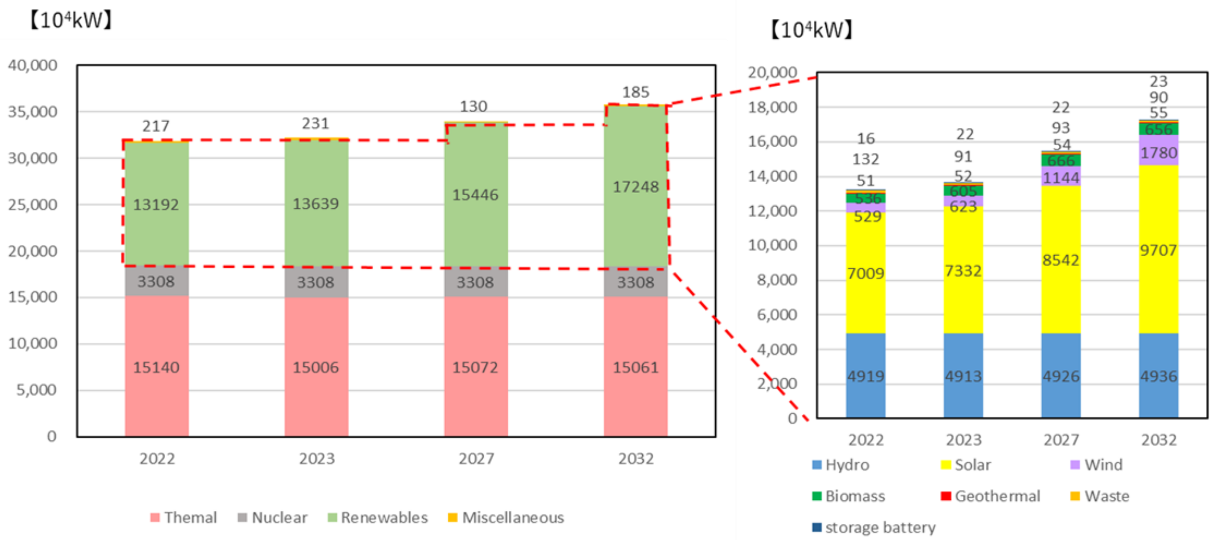


Figure 3-1 Transition of Installed Power Generation Capacities by Power Generation Sources (Nationwide)

* The sum of each power generation source's installed power generation capacity is the aggregation of the values submitted by EPCOs.

2. Installed Power Generation Capacity for Each Regional Service Area

Figure 3-2 shows each regional service area's installed power generation capacity at the end of FY 2022.

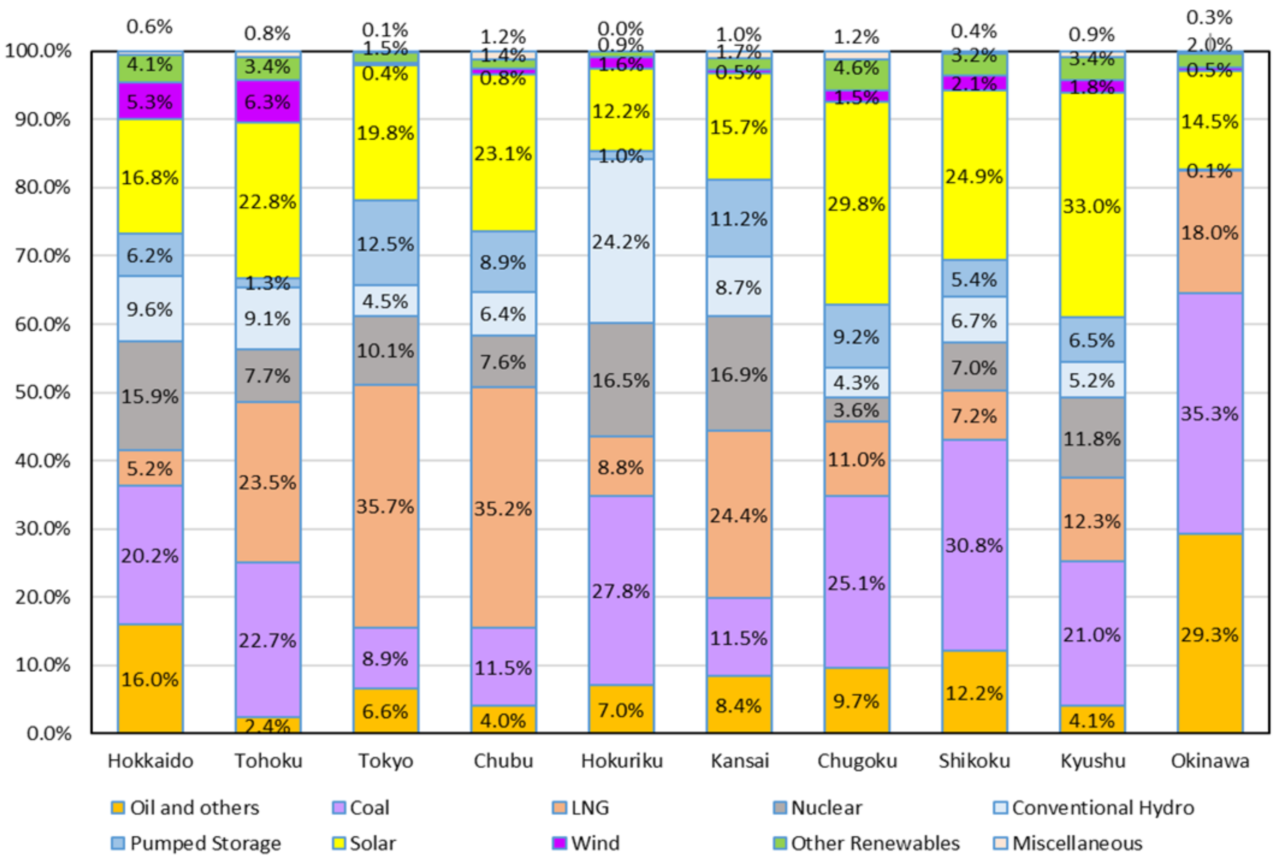


Figure 3-2 Composition of Installed Power Generation Capacity (kW) for Each Regional Service Area

* Each source's installed power generation capacity ratio is calculated by automatically aggregating the values.

3. Transition of Solar and Wind Generation Capacities

Figure 3-3 shows the projection of integrated solar and wind-generation capacities for each regional service area (at the end of the indicated fiscal year).[34]

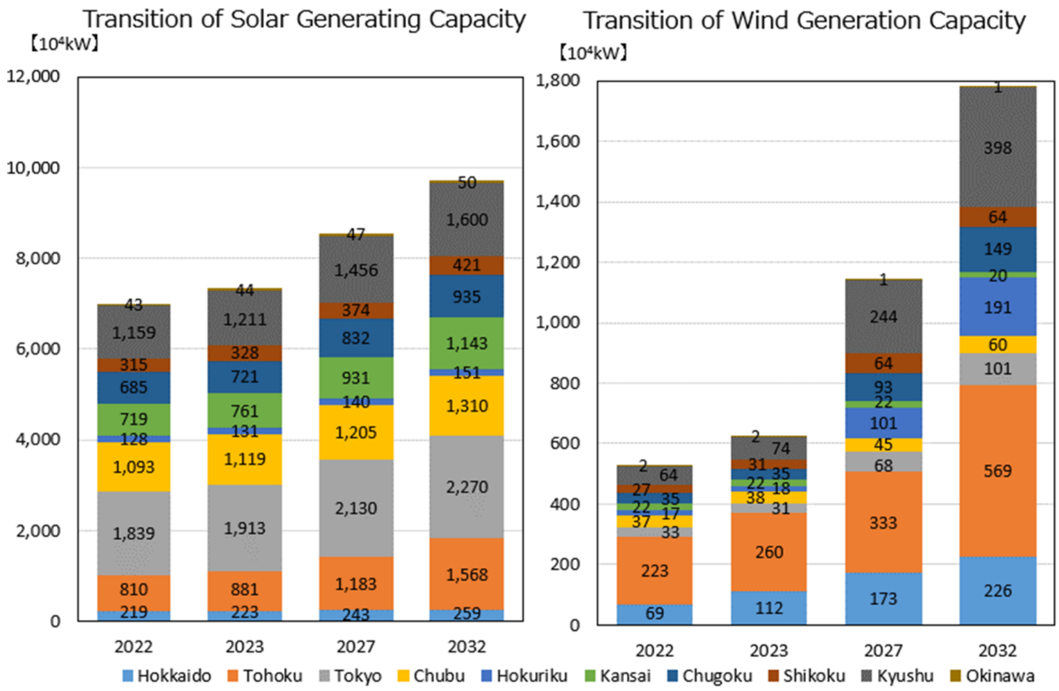


Figure 3-3 Transition of Solar and Wind Generating Capacity for Each Regional Service Area

[34] The GT&D company of each regional area aggregates the projected value of generation facility integration according to the application of preliminary consultation for generator interconnection and the available connecting capacity of its transmission lines or the actual growth trend of integration.

4. Development Plans by the Power Generation Source

Table 3-2 shows the generation companies' development plans[35] up to FY 2032, according to each company's new developments, uprated or derated installed facilities, and planned decommissioning of facilities in the projected period.

Table 3-2 Generation Development Plans up to FY 2032 by Stages (Nationwide, 10^4 kW)

Power Generation Sources		New Installation		Uprating/Derating		Decommission	
		Capacity	Sites	Capacity	Sites	Capacity	Sites
Hydro		**51.6**	**62**	**4.4**	**64**	**△15.3**	**28**
	Conventional	51.6	62	4.4	64	△15.3	28
	Pumped Storage	—	—	—	—	—	—
Thermal		**806.7**	**28**	—	—	**△632.1**	**29**
	Coal	180.0	3	—	—	△85.0	5
	LNG	623.7	14	—	—	△207.5	6
	Oil	3.0	11	—	—	△339.6	18
	LPG	—	—	—	—	—	—
	Bituminous	—	—	—	—	—	—
	Other Gas	—	—	—	—	—	—
Nuclear		**1,018.0**	**7**	**15.2**	**1**	—	—
Renewables		**868.5**	**403**	**△0.6**	**2**	**△82.6**	**66**
	Wind	351.5	90	—	—	△67.4	52
	Solar	377.3	262	—	—	△0.2	2
	Geothermal	7.5	5	—	—	△2.4	1
	Biomass	122.0	41	—	—	△5.3	4
	Waste	4.6	3	△0.6	2	△7.4	7
	Storage(battery)	5.5	2	—	—	—	—
Total		**2,744.8**	**500**	**19.0**	**67**	**△730.0**	**123**

Note: The totals are not necessarily equal due to independent rounding to two decimal places.

[35] These are aggregated, including facilities for which the commercial operation date is "uncertain."

[Reference] Net Electric Energy Generation (at the Sending End)

The net electric energy generation (at the sending end) for the projected period is an estimation[36] of values calculated by the power generation source in a given premise for each generation or GT&D company. This estimation is not necessarily the same as net electric energy generation.

Each generation company submits the value of electric energy generation, which is the sum of the energy generation of available generation facilities in the projected period. This amount is automatically summed in the merit order of operational cost. Furthermore, the value is based on future energy sales led by actual sales and future sales contracts, without considering the effect of regulating measures.

This estimation of net electric energy generation may change according to the operating conditions of nuclear power plants, changes in generation sources (specified as “miscellaneous” in future trends), and energy output shedding of inefficient coal-fired thermal power generation according to the regulating measures of generation efficiency under the Energy Conservation Act. Thus, the estimation is not necessarily the same as the electric energy generation in the future and is likely to approximate the target value of the country’s energy mix.

The calculation method and the result of net electric energy generation by power generation source are stated below.

(1) Renewables (Table 3-3)

For solar and wind power, the GT&D company calculates their energy generation based on the aggregation of the projected value of generation facility integration, according to the preliminary consultation and the available connecting capacity of its transmission lines or the actual growth trend of the integration. For geothermal, biomass, and waste power generation sources, the generation company calculates its energy generation based on the company’s development plans.

Table 3-3 Composition of the Transition of Electric Energy Generated by Renewable Generation Sources (Nationwide, at the sending end; 10^8 kWh)

Generation Source		2022	2023	2027	2032
Renewables		1,296	1,416	1,740	1,976
	Wind	97	117	210	325
	Solar	851	890	1,035	1,156
	Geothermal	25	26	30	32
	Biomass	283	354	434	432
	Waste	40	28	27	27
	Storage(battery)	0	1	4	4

[36] This estimation includes the electric energy generated from generation facilities owned by generation companies and generation facilities such as FIT generators, which retail companies or GT&D companies procure from sources other than generation companies.

(2) Hydro and Thermal (Table 3-4)

The generation company calculates its energy generation based on its development plan. For thermal power generation, the energy generated from coal-fired thermal power, which has a relatively low operation cost, has a large share due to its merit-order ranking (by operation cost) without considering the effect of regulating measures.

Table 3-4 Composition of the Transition of Electric Energy Generated by Hydro and Thermal Generation Sources

(Nationwide, at the sending end; 10^8 kWh)

Generation Source		2022	2023	2027	2032
Hydro		829	817	840	862
	Conventional	741	752	789	799
	Pumped Storage	88	65	51	63
Thermal		6,450	6,203	6,323	5,727
	Coal	2,824	3,003	2,898	2,843
	LNG	3,288	2,873	3,145	2,613
	Oil and others [33]	338	327	280	271

(3) Nuclear (Table 3-5)

The generation company calculates its energy generation based on the plan developed for units resuming operation at the end of February 2022. Units with over 40 years of actual operation require permission from the Nuclear Regulation Authority to resume operation; the energy generation of such units is calculated as zero. Furthermore, projections concerning the resumption of operation are excluded from the estimation.

Table 3-5 Composition of the Electric Energy Transition Generated by Nuclear Generation Sources

(Nationwide, at the sending end; 10^8 kWh)

Generation Source	2022	2023	2027	2032
Nuclear	538	749	555	461

Table 3-6 sums items (1), (2), and (3) above, with the energy generation categorized as “miscellaneous.”

Table 3-6 Composition of the Electric Energy Transition Generated by All Generation Sources

(Nationwide, at the sending end; 10^8 kWh)

	2022	2023	2027	2032
Total	9,133	9,198	9,471	9,037

[Reference] Net Electric Energy Generation for Each Regional Service Area

Figure 3-4 shows each regional service area's net electric energy generation in FY 2022.

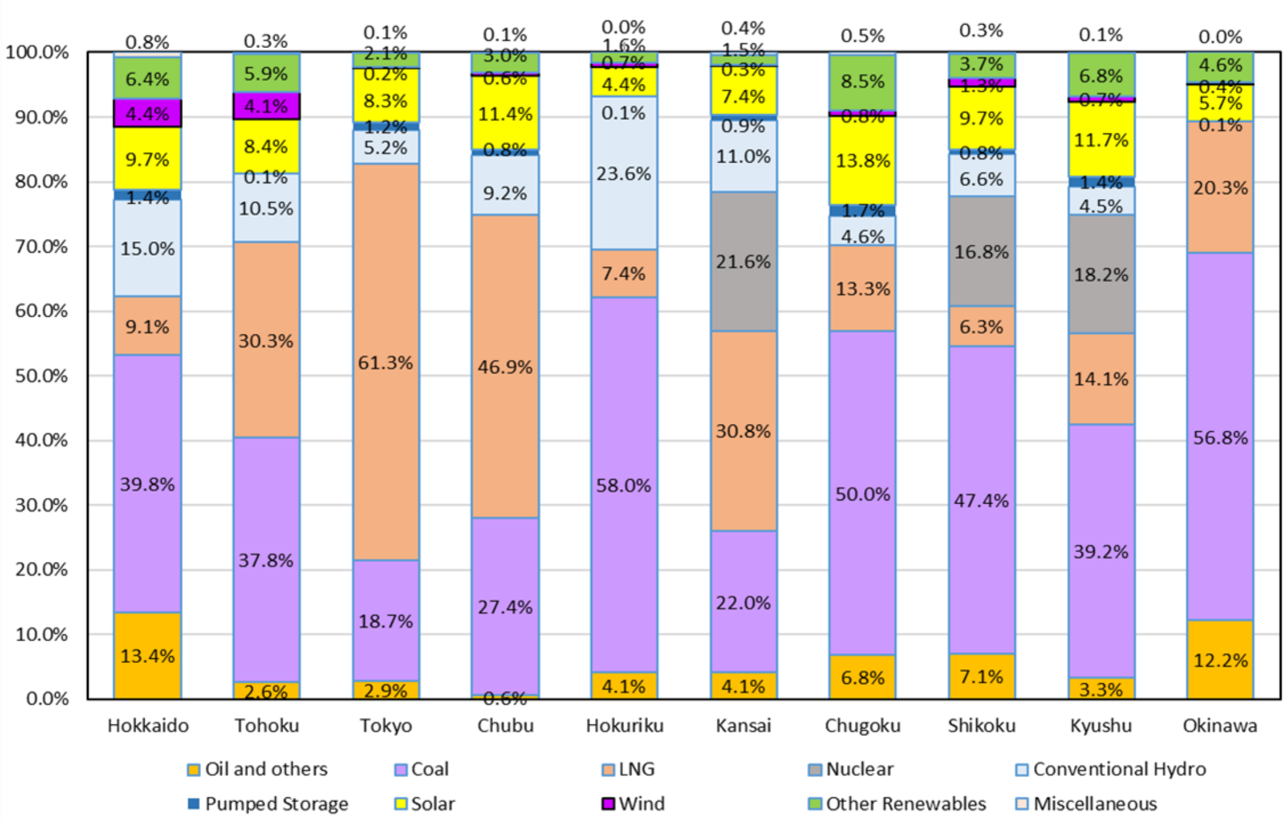


Figure 3-4 Composition of the Net Electric Energy Generation (kWh) for Each Regional Service Area

[Reference] Transition of Capacity Factors by Power Generation Source

Table 3-7 and Figure 3-5 show the capacity factors by the power generation source. Projection of the capacity factors is automatically calculated using the aforementioned power generation sources and the net electric energy generation data provided to the Organization.

As noted, these values are calculated from a given projection; the capacity factors in this chapter differ from those in actual operation.

Table 3-7 Capacity Factors by Power Generation Source (Nationwide)

Power Generation Sources		2022	2023	2027	2032
Hydro		19.2%	18.9%	19.4%	19.9%
	Conventional	38.8%	39.4%	41.1%	41.5%
	Pumped Storage	3.7%	2.7%	2.1%	2.6%
Thermal		48.6%	47.1%	47.8%	43.4%
	Coal	63.6%	65.9%	64.6%	63.7%
	LNG	47.4%	41.0%	43.6%	36.4%
	Oil and others [33]	17.8%	20.1%	18.1%	17.5%
Nuclear		18.6%	25.8%	19.1%	15.9%
Renewables		17.9%	18.5%	18.8%	18.3%
	Wind	20.9%	21.3%	20.9%	20.8%
	Solar	13.9%	13.8%	13.8%	13.6%
	Geothermal	56.1%	56.0%	64.4%	66.1%
	Biomass	60.3%	66.6%	74.2%	75.1%
	Waste	34.6%	35.0%	33.4%	33.9%
	Storage(battery)	3.4%	2.9%	19.1%	18.4%

* These values are calculated from a given projection; note that the capacity factors in this chapter differ from those in actual operation.

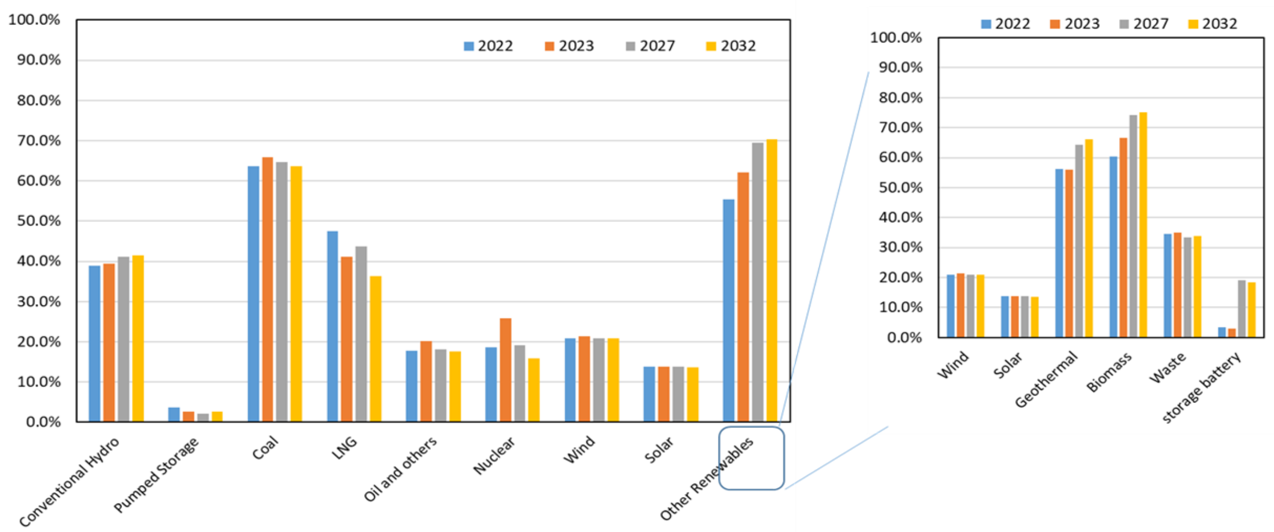


Figure 3-5 Capacity Factors by Power Generation Source (Nationwide)

IV. Development Plans for Transmission and Distribution Facilities

The Organization aggregates the development plans[37] for cross-regional transmission lines and substations (transformers and AC/DC converters) up to FY 2032, as submitted by GT&D and transmission companies. Table 4-1 shows the development plans for cross-regional transmission lines and substations. Figure 4-1 presents the outlook for nationwide electric systems. Items (1), (2), and (3) below list the development plans according to cross-regional transmission lines, major substations, and summaries, respectively.

Table 4-1 Development Plans for Cross-regional Transmission Lines and Substations[38]

Increased Length of Transmission Lines [39]*[40]		439km (672 km)
	Overhead Lines*	381 km (616 km)
	Underground Lines	58 km (56 km)
Uprated Capacities of Transformers		30,163 MVA (28,578 MVA)
Uprated Capacities of AC/DC Converters [41]		1,200 MW (1,200 MW)
Decreased Length of Transmission Lines (Decommission)		△104 km (△101 km)
Derated Capacities of Transformers (Decommission)		△5,600 MVA (△4,550 MVA)

Enhancement plans for cross-regional transmission lines are summarized below.

Interconnection Facility Enhancement Plan between Hokkaido and Honshu
(900 MW→1,200 MW; in-service: March 2028)

AC/DC Converter Stations	・Hokuto Converter Station: 300 MW→600 MW ・Imabetsu Converter Station: 300 MW→600 MW
275 kV DC Lines	・Hokuto Imabetsu DC Interconnection Line: 122 km ・Imabetsu Bulk Line extension: 50 km

37 Development plans for transmission lines and substations must be submitted for voltages higher than 250 kV, or within two classes of the highest voltage available in the regional service areas. (For the Okinawa EPCO, the requirement applies only for 132 kV or more.) The totals are not necessarily equal due to independent rounding.
38 The figures in parentheses are those from the previous year.
39 Development plans corresponding to changes in line category or circuit numbers that were not included in measuring the increased length of transmission lines were treated as "no change in the length of transmission lines."
40 Increased length does not include the item with * because of an undetermined in-service date.
41 The DC transmission system includes installed capacity for the converter station on one side.

Interconnection Facility Enhancement Plan between Tohoku and Tokyo
(In-service: November 2027)

500kV Transmission Lines	・Miyagi-Marumori Bulk Line: 79 km ・Marumori-Iwaki Bulk Line: 64 km ・Soma-Futaba Bulk Line/ Connecting Point Change: 16 km ・Shinchi Access Line/ Miyagi-Marumori Switching Station lead-in: 1km ・Joban Bulk Line/ Miyagi-Marumori Switching Station Dπ lead-in: 1 km ・Fukushima Bulk Line/Mountain Line connecting point change: 1 km
Switching Stations	Miyagi-Marumori Switching Station: 10 circuits

Interconnection Facility Enhancement Plan between Tokyo and Chubu
(210 MW→300 MW; in-service: FY 2027)

Frequency Converter Stations	・Shin Sakuma FC station: 300 MW ・Higashi Shimizu Substation: 300 MW→900 MW
275 kV Transmission Lines	・Higashi Shimizu Line: 19 km ・Sakuma Higashi Bulk Line/ FC Branch Line: 3 km ・Sakuma-Toei Line/ FC Branch Line: 1 km ・Shin Toyone-Toei Line: 1 km ・Sakuma-Toei Line: 11km, 2km ・Sakuma Higashi Bulk Line: 123 km
500 kV Transformers	・Shin Fuji Substation: 750 MVA×1 ・Shizuoka Substation: 1,000 MVA×1 ・Toei Substation: 800MVA×1 →1,500 MVA×2
275 kV Transformers	・Shin Fuji Substation: 200MVA×1→0 MVA

Interconnection Facility Enhancement Plan between Chubu and Kansai
(In-service: Undetermined)*Under review in the master plan [42]

500 kV Transmission Lines	・Sekigahara-Kita Oomi Line: 2 km ・Sangi Bulk Line/ Sekigahara Switching Station π lead-in: 1 km ・Kita Oomi Line/ Kita Oomi Switching Station π lead-in: 0.5 km
Switching Stations	・Sekigahara Switching Station: 6 circuits ・Kita Oomi Switching Station: 6 circuits

Interconnection Facility Enhancement Plan between Chubu and Hokuriku
(In-service: Undetermined)*Under review as part of reinforcement in the master plan

BTB Converter Stations	Minami Fukumitsu Converter Station: 300 MW→0 MW (to be decommissioned)

[42] The master plan is the policy of facility formation targeting the long-term future electricity system.

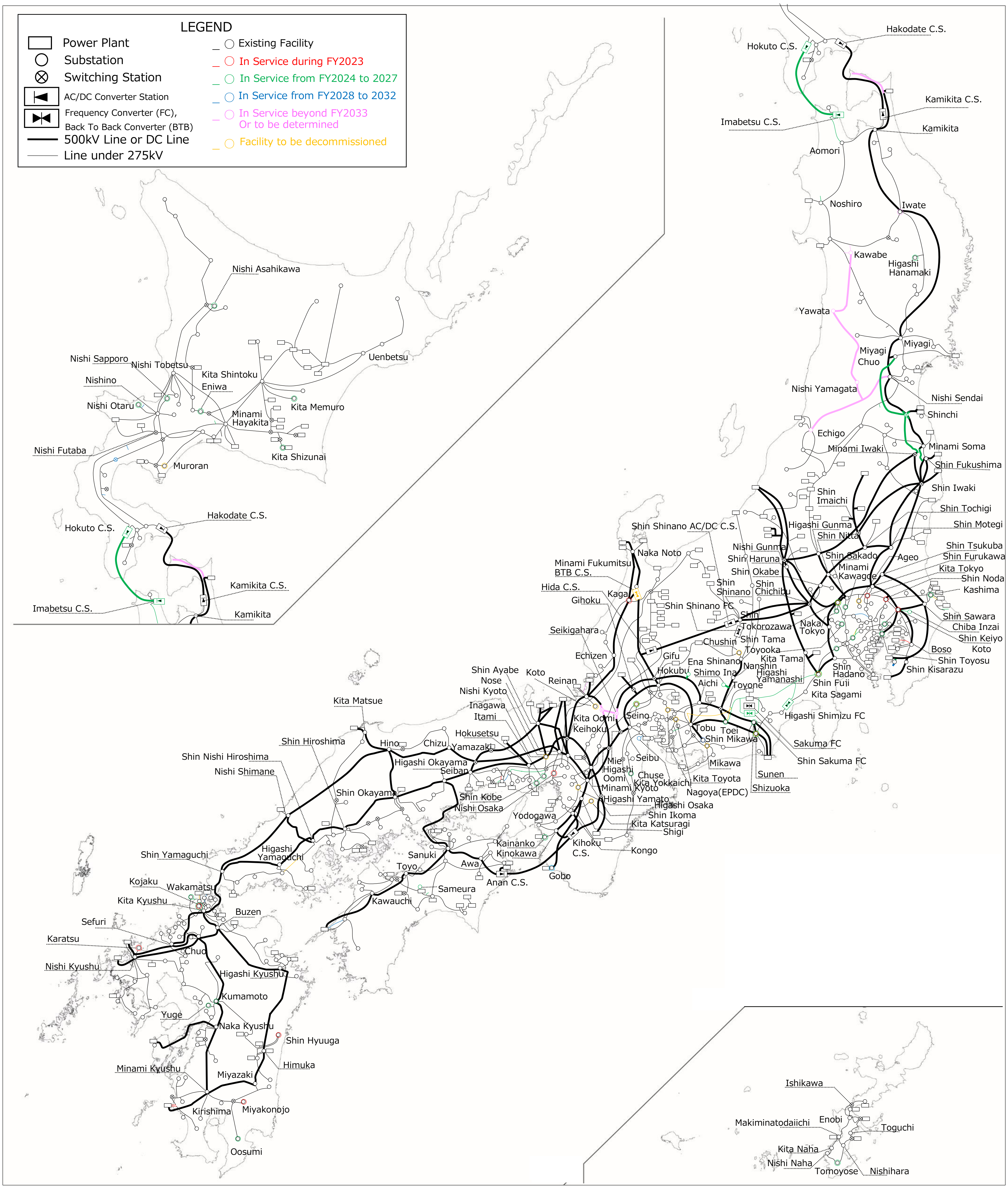


Figure 4-1 Power Grid Configuration in Japan

1. Development Plans for Major Transmission Lines

Table 4-2 Development Plans Under Construction

Company	Line[43]	Voltage	Length[44,45]	Circuit	Under construction	In service	Purpose[46]
Tohoku Electric Power Network Co., Inc.	Soma-Futaba Bulk Line/connecting point change	500 kV	16 km	2	Sep. 2022	Nov. 2025	Generator connection, Reliability upgrade*4
	Dewa Bulk Line	500 kV	96 km	2	Jun. 2022	Beyond FY 2031	Generator connection
	Miyagi-Marumori Bulk Line	500 kV	79 km	2	Sep. 2022	Nov. 2027	Generator connection, Reliability upgrade*4
	Miyagi-Marumori Switching Station	500 kV	-	10	Oct. 2022	Nov. 2027 (Jun. 2026)	Generator connection, Reliability Upgrade*4
TEPCO Power Grid, Inc.	Shinjuku Line replacement	275 kV	22.1 km→ 21.2 km (No.1)*2*3 19.9 km→ 21.2 km (No.2)*2*3 19.8 km→ 21.2 km (No.3)*2*3	3	Aug. 2019	Aug. 2030(No.1) Nov. 2032(No.2) Dec. 2027(No.3)	Aging management
	Chiba Inzai Line	275 kV	10.5 km	2	Jun. 2020	Apr. 2024	Demand coverage
	Johoku Line	275 kV	20.9 km*2	3	Sep. 2022	Feb. 2030	Economic upgrade
	Higashi Shimizu Line	275 kV	12.4 km 6.4 km (diversion)	2	Apr. 2023	Jan. 2027	Reliability upgrade*4
	Goi Access Line*1	275 kV	11.1 km	2	May 2022	Oct. 2023	Generator connection
Chubu Electric Power Grid Co., Inc.	Shimo Ina Branch Line	500 kV	0.3 km	2	Jan. 2022	Oct. 2025	Demand coverage
	Ena Branch Line	500 kV	1 km	2	Sep. 2020	Oct. 2025	Demand coverage
	Higashi Nagoya -Tobu Line	275 kV	8 km*3	2	Apr. 2019	Nov. 2025	Aging management, Economic upgrade
Kansai Transmission and Distribution, Inc.	Himeji Access Line*1	275 kV	0.9 km*2	2	Mar. 2021	Jan. 2025	Generator connection
	Himeji Access West Branch Line*1	275 kV	1.2 km*3	2	Sep. 2021	Feb. 2024	Aging management
	Shin Kakogawa Line	275 kV	25.3 km*3	2	Jul. 2021	Jun. 2025	Generator connection, Aging management
	Himeji Access East Branch Line	275 kV	18.1 km→ 18.2 km*3	2	Feb. 2022	Dec. 203	Aging management

[43] Line with *1 denotes the line renamed not to be identified as the fuel of the connecting power plant.
[44] Length with *2 denotes "underground," otherwise "overhead."
[45] Length with *3 denotes that the change in line category or circuit number change is not included in Table 4-1.
[46] The purpose is stated below: *4 indicates enforcement related to cross-regional interconnection lines.
*5 indicates that the case is under review in the master plan of the cross-regional development.

Demand coverage	Related to increase/decrease demand
Generator connection	Related to generator connection or retirement
Aging management	Related to aging management of facilities (including the proper update of facilities and with evaluation of obsolescence
Reliability upgrade	Related to improvement in the reliability or security of stable supply
Economic upgrade	Related to improvement in economies, such as reducing transmission loss, facility downsizing, or upgrading the stability of the system

Company	Line	Voltage	Length,	Circuit	Under construction	In service	Purpose
Kyushu Electric Power Transmission & Distribution Co., Inc.	Shin Kagoshima Line/ Sendai Plant π lead-in*1	220 kV	2 km→ 4 km*3	1→2	Aug. 2020	Dec. 2023	Economic upgrade
	Shin Kokura Line	220 kV	15 km→ 15 km*2*3	3→2	May 2021	Oct. 2029	Aging management
J-POWER Transmission Network Co.,Ltd.	Ooma Bulk Line	500 kV	61 km	2	Jun. 2006	TBD	Generator connection
	Sakuma Higashi Bulk Line	275 kV	124 km→ 123 km*3	2	Jul. 2022	FY 2027	Reliability upgrade*4
Fukushima Souden	Abukumananbu Line	154 kV	24 km*2	1	Jul. 2020	Jun. 2024	Generator connection

Table 4-3 Development Plans in Planning Stages

Company	Line	Voltage	Length,	Circuit	Under construction	In service	Purpose
Hokkaido Electric Power Network, Inc.	Plant D Access Line*1	275 kV	0.6 km	1	Jul. 2024	Feb. 2026	Generator connection
	Branch Line E *1	187 kV	2.4 km	2	May 2024	Aug. 2028	Demand coverage
	Branch Line F *1	275 kV	7.9 km	2	May 2024	Aug. 2028	Demand coverage
	Branch Line G *1	187 kV	5.8 km	2	May 2024	Aug. 2028	Demand coverage
	Hokuto-Imabetsu DC Interconnection Line	DC-250 kV	98 km*3 24 km*2,3	1→2	Mar. 2024	Mar. 2028	Reliability upgrade
	M Interconnection 187kV Switching Station	187 kV	-	5	Oct. 2025	Aug. 2028	Generator connection
Tohoku Electric Power Network Co., Inc.	Plant A Branch Line*1	275 kV	0.2 km	1	Jun. 2023	May 2024	Generator connection
	Northern Akita Prefecture HS Line	275 kV	0.3 km*2	2	Jul. 2024	Dec. 2025	Generator connection
	Marumori-Iwaki Bulk Line	500 kV	64 km	2	Sep. 2024	Nov. 2027	Generator connection, Reliability upgrade*4
	Shinchi Access Line/ Miyagi-Marumori Switching Station lead-in*1	500 kV	1 km	2	Sep. 2024	Jun. 2026	Generator connection, Reliability upgrade*4
	Joban Bulk Line/ Miyagi-Marumori Switching Station Dπ lead-in	500 kV	1 km	2	Jun. 2024	Jul. 2026	Generator connection, Reliability upgrade*4
	Akita-Kawabe Branch Line	275 kV	5 km	2	Mar. 2023	Beyond FY 2029	Generator connection
	Akimori-Kawabe Branch Line	275 kV	0.3 km	2	Beyond FY 2025	Beyond FY 2029	Generator connection
	Asahi Bulk Line uprating	275kV→500kV	139km→138km	2	Beyond FY 2027	Beyond FY 2030	Generator connection
	Minami Yamagata Bulk Line uprating	275kV→500kV	23 km→23 km	2	Beyond FY 2030	Beyond FY 2030	Generator connection
	Yamagata Bulk Line uprating/ extension	275kV→500kV	53 km→103 km	2	Beyond FY 2026	Beyond FY 2031	Generator connection
	Imabetsu Bulk Line extension	275 kV	50 km*3	2	Apr. 2023	FY 2027	Generator connection, Reliability upgrade, Aging Management*4
TEPCO Power Grid, Inc.	Higashi Shinjuku Line replacement	275 kV	23.4km→5.0km (No.2)*2*3 23.4km→5.3km (No.3)*2*3	2	FY 2026	Nov. 2032 (No.2) Dec. 2027 (No.3)	Aging management
	MS18GHZ051500 Access Line (prov.)	275 kV	0.1 km	2	Jun. 2024	Jan. 2025	Generator connection
	G5100026 Access Line(prov.)	500 kV	0.7 km*2	2	Apr. 2024	Dec. 2028	Generator connection

Company	Line[33]	Voltage	Length[34,35]	Circuit	Under construction	In service	Purpose[36]
TEPCO Power Grid, Inc.	Shin Sodegaura Line	500 kV	0.1 km	2	Oct. 2026	Mar. 2027 (No.1) Feb. 2028 (No.2)	Generator connection, Reliability upgrade
	Fukushima Bulk Line/Mountain Line connecting point change	500 kV	1.1 km	2	Jun. 2024	Jan. 2025 (No.1) Apr. 2025 (No.2)	Generator connection, Reliability upgrade*4
	Kashima Kaihin Line /connecting point change	275 kV	0.2 km→ 0.4 km*2	2	Oct. 2023	Apr. 2025 (No.1) Nov. 2024 (No.2)	Economic upgrade
	Chiba Inzai Line	275 kV	10.5 km	2	Apr. 2024	Feb. 2027 (No.3) Nov. 2025 (No.4)	Demand coverage
Chubu Electric Power Grid Co., Inc.	Kita Yokkaichi Branch Line	275 kV	6 km*2 0.2 km	2	Dec. 2024	Jan. 2029 (No.1) Aug. 2029 (No.2)	Demand coverage, Economic upgrade
	Sekigahara-Kita Oomi Line	500 kV	2 km	2	TBD	TBD	Generator connection*4, *5
	Sekigahara Switching Station	500 kV	—	6	TBD	TBD	Generator connection*4, *5
	Sangi Bulk Line/ Sekigahara Switching Station π lead-in	500 kV	1 km	2	TBD	TBD	Generator connection*4, *5
Kansai Transmission and Distribution, Inc.	Kita Oomi Switching Station	500 kV	—	6	TBD	TBD	Generator connection*4, *5
	Kita Oomi Line/ Kita Oomi Switching Station πlead-in	500 kV	0.5 km	2	TBD	TBD	Generator connection*4, *5
	Tsuruga Line/ North side improvement	275 kV	9.8 km→ 9.3 km*3	2	TBD	TBD	Aging management
Shikoku Electrc Power Transmission and Distribution, Inc.	Ikata North Bulk Line	187 kV	19 km*3	2	Feb. 2024	Sep. 2028	Aging management
Kyushu Electric Power Transmission and Distribution, Inc.	Hibiki-Wakamatsu Line	220 kV	4 km	2	May 2023	Apr. 2025	Generator connection
J-POWER Transmission Network Co.,Ltd.	Sakuma-Toei Line	275 kV	11 km→ 11 km*3	2	May 2023	FY 2027	Reliability upgrade*4
	Sakuma-Toei Line	275 kV	2 km	2	May 2023	FY 2026	Reliability upgrade*4
	Nabari Bulk Line/Reihoku-Kunimisan Branch Line	187 kV	0.1 km	1	FY 2025	FY 2026	Generator connection

Table 4-4 Decommissioning Plans

Company	Line	Voltage	Length	Circuit	Retirement	Purpose[36]
TEPCO Power Grid, Inc.	Kashima Thermal Power Line No.1, No.2	275 kV	△5.0 km	2	Dec. 2024	Economic upgrade
Chugoku Electric Power Network Co., Inc.	Shin Tokuyama Bulk Line	220 kV	△29.3 km	2	Dec. 2023	Economic upgrade
Kyushu Electric Power Transmission and Distribution, Inc.	A Tobata Line*1	220 kV	△9 km*2	2	Apr. 2023	Aging management
J-POWER Transmission Network Co.,Ltd.	Shin Toyone-Toei Line	275 kV	△3 km	1	FY 2026	Reliability upgrade*4
	Sakuma Nishi Bulk Line	275 kV	△58 km	2	FY 2026	Economic upgrade

2. Development Plans for Major Substations

Table 4-5 Development Plans Under Construction

Company	Substation [33,47]	Voltage	Capacity	Unit	Under construction	In service	Purpose [36]
Tohoku Electric Power Network, Inc.	Higashi Hanamaki	275/154 kV	300 MVA	1	Mar. 2023	Oct. 2025	Demand coverage
TEPCO Power Grid, Inc.	Chiba Inzai*6	275/66 kV	300 MVA×2	2	Jun. 2022	Apr. 2024	Demand coverage
	Kita Tokyo	275/66 kV	300 MVA	1	Oct. 2022	Feb. 2024	Economic upgrade
	Shin Keiyo	275/154 kV	450 MVA	1	May 2022	Jun. 2023	Demand coverage
	Shin Noda	275/154 kV	220 MVA→ 300 MVA	1→1	Mar. 2023	Nov. 2023	Aging management
Chubu Electric Power Grid Co., Inc.	Shimo Ina*6	500/154 kV	300 MVA×2	2	Oct. 2021	Oct. 2025	Demand coverage
	Ena*6	500/154 kV	200 MVA×2	2	Oct. 2022	Oct. 2025	Demand coverage
	Toei	500/275 kV	800 MVA×1→ 1,500 MVA×2	1→2	Jun. 2022	Oct. 2024 (N 2B) Mar. 2027 (1B)	Reliability upgrade*4
	Higashi Shimizu	—	600 MW	—	May 2021	Mar. 2028	Reliability upgrade*4
Hokuriku Electric Power Transmission & Distribution Co.	Kaga	275/154 kV	400 MVA	1	Nov. 2021	Dec. 2023	Reliability upgrade
Kansai Transmission and Distribution, Inc.	Nishi Osaka	275/77 kV	300 MVA	1	May 2022	Jun. 2023	Demand coverage
	Kainanko	275/77 kV	300 MVA×1、 200 MVA×2→ 300 MVA×2	3→2	Dec. 2022	Jun. 2024	Aging management
	Shin Kobe	275/77 kV	300 MVA×1、 200 MVA×1→ 200 MVA×1	2→1	Feb. 2023	Oct. 2025	Aging management
Kyushu Electric Power Transmission & Distribution Co., Inc.	Shin Hyuga	220/110/ 66 kV	250/150/ 200 MVA	1	Aug. 2021	Apr. 2023	Generator connection
	Kojaku	220/66 kV	150 MVA→ 200 MVA	1→1	Jul. 2021	Jun. 2023	Aging management
	Karatsu	220/66 kV	150 MVA→ 250 MVA	1→1	Sep. 2022	Nov. 2023	Aging management
	Miyakonojo	220/110 kV	150 MVA	1	Oct. 2021	Mar. 2024	Generator connection
	Wakamatsu	220/66 kV	250 MVA	1	Jan. 2023	Oct. 2024	Generator connection
	Oosumi	110/66 kV → 220/110/ 66 kV	60 MVA → 250/100/ 200 MVA	1→1	Apr. 2022	Feb. 2025	Generator connection
The Okinawa Electric Power Co., Inc.	Tomoyose	132/66 kV	125 MVA×2→ 200 MVA×2	2→2	Jul. 2018	Jun. 2026	Aging management
Fukushima souden	Abukumaminami*6	154/66/ 33 kV	170 MVA	1	Sep. 2022	Jun. 2024	Generator connection

[47] A substation with *6 denotes a newly installed substation or a converter station, including an uprated electric facility.

Table 4-6 Development Plans in Planning Stages

Company	Substation [33,37]	Voltage	Capacity	Unit	Under construction	In service	Purpose [36]
Hokkaido Electric Power Network, Inc.	Kita Memuro	187/66 kV	60 MVA→ 150 MVA	1→1	Apr. 2024	Nov. 2024	Aging management
	Nishi Asahikawa	187/66 kV	60 MVA→ 100 MVA	1→1	Apr. 2024	Oct. 2024	Aging management
	Kita Shizunai	187/66/11 kV	45 MVA→ 60 MVA	1→1	Feb. 2024	Feb. 2026	Aging management Generator connection
	Eniwa	187/66 kV	200 MVA	1	Jul. 2024	Jun. 2025	Demand coverage
	Nishi Sapporo	187/66 kV	200 MVA	1	May 2025	Jun. 2026	Demand coverage
	Nishi Otaru	187/66 kV	100 MVA→ 150 MVA	1→1	Sep. 2025	Jun. 2026	Aging management
	Hokuto C.S.	—	300 MW	—	Sep. 2023	Mar. 2028	Reliability upgrade*4
	Imabetsu C.S.	—	300 MW	—	Sep. 2023	Mar. 2028	Reliability upgrade*4
Tohoku Electric Power Network Co., Inc.	Iwate	500/275 kV	1,000 MVA	1	Beyond FY 2025	Beyond FY 2028	Generator connection
	Echigo*6	500/275 kV	1,500 MVA×3	3	Beyond FY 2024	Beyond FY 2030	Generator connection
	Yawata*6	500/154 kV	750 MVA	1	Beyond FY 2027	Beyond FY 2031	Generator connection
	Kawabe*6	500/275kV	1,500 MVA×3	3	Beyond FY 2025	Beyond FY 2031 (Beyond FY 2029)	Generator connection
	Nishi Yamagata*6	275/154 kV →500/154 kV	300 MVA×2 →450 MVA×2	2→2	Beyond FY 2025	Beyond FY 2031 (Beyond FY 2030)	Generator connection
TEPCO Power Grid, Inc.	Shin Fuji	500/154 kV	750 MVA	1	Jul. 2024	Feb. 2027	Reliability upgrade*4
	Kashima	275/66 kV	300 MVA	1	Jun. 2023	Jun. 2024	Generator connection
	Kashima	275/66 kV	200 MVA×2 →300 MVA×2	2→2	Aug. 2025	Feb. 2026 (7B) Feb. 2027 (8B)	Aging management
	Toyooka	275/154 kV	450 MVA	1	May 2024	Jun. 2026	Demand coverage
	Naka Tokyo	275/154 kV	200 MVA→ 300 MVA	2→2	Dec. 2023	Jan. 2025 (1B) Jun. 2025 (2B)	Aging management
	Shin Toyosu	275/66 kV	300 MVA	1	Oct. 2024	Mar. 2026	Demand coverage
	Koto	275/66 kV	150 MVA→ 200 MVA	1→1	Dec. 2025	Jun. 2026	Demand coverage
	Kita Sagami	275/66 kV	300 MVA×2	2	Jun. 2024	Jun. 2027	Demand coverage
	Kita Tama	275/66 kV	200 MVA×2 →300 MVA×2	2→2	Dec. 2024	Jun. 2026 (2B) Jun. 2027 (3B)	Aging management
	Chiba Inzai	275/66 kV	300 MVA×2	2	Oct. 2024	Nov. 2025 (4B) Feb. 2027 (1B)	Demand coverage
	Shin Tokorozawa	500/275 kV	1,000,MVA×2 →1,500 MVA×2	2→2	Jun. 2025	Apr. 2026 (4B) Jun. 2027 (5B)	Aging management
Chubu Electric Power Grid Co., Inc.	Nakase	275/77 kV	150 MVA→ 250 MVA	1→1	Oct. 2024	Mar. 2025	Aging management
	Sunen	275/77 kV	150 MVA→ 250 MVA	1→1	Jun. 2025	Apr. 2026	Aging management
	Seino	275/154 kV	300 MVA →450 MVA	1→1	Oct. 2025	Jun. 2026	Aging management
	Shizuoka	500/275 kV	1,000 MVA	1	Feb. 2025	Mar. 2027	Reliability upgrade*4
	Kita Yokkaichi*6	275/154 kV	450 MVA×3	3	Apr. 2026	Jan. 2029	Demand coverage, Economic upgrade
	Shin Mikawa	500/275 kV	1,500 MVA	1	Oct. 2028	Aug. 2030	Generator connection
Kansai	Itami	275/154 kV	300 MVA	1	Feb. 2023	Jun. 2024	Aging management

Company	Substation [33,37]	Voltage	Capacity	Unit	Under construction	In service	Purpose [36]
Transmission and Distribution, Inc.	Gobo	500/154 kV	750 MVA×2	2	Aug. 2024	Nov. 2027	Generator connection
Kyushu Electric Power Transmission & Distribution Co., Inc.	Yuge	220/110/ 66 kV	300/100/250 MVA	1	Apr. 2024	Jun. 2025	Demand coverage
	Kojaku	220/66 kV	180 MVA→ 200 MVA	1→1	Octl. 2023	Jun. 2025	Aging management
	Kumamoto	500/220 kV	1,000 MVA	1	Dec. 2024	Jun. 2027	Demand coverage
J-POWER Transmission Network Co.,Ltd.	Shin Satkuma FC*6	—	300 MW	—	FY 2024	FY 2027	Reliability upgrade*4
	Minami Kawagoe	275/154 kV	264 MVA×3, 300 MVA→ 300 MVA×2, 450 MVA×1	4→3	Sep. 2023	Mar. 2024 (6B) FY 2024 (2B) FY 2025 (1B)	Aging management
	Sameura (prov.)*6	187/13 kV	25 MVA	1	FY 2024	FY 2025	Demand coverage

Table 4-7 Decommissioning Plans

Company	Substation	Voltage	Capacity	Unit	Retirement	Purpose
Hokkaido Electric Power Network, Inc.	Muroran	187/66 kV	100 MVA	1	Aug. 2023	Aging management, Demand coverage
TEPCO Power Grid, Inc.	Ageo	275/66 kV	300 MVA	1	Jun. 2024	Economic upgrade
	Shin Fuji	275/154 kV	200 MVA	1	Apr. 2025	Economic upgrade*4
	Shin Tokorozawa	500/275 kV	1,000 MVA	1	Dec. 2027	Aging management
Chubu Electric Power Grid Co., Inc.	Kita Toyoda	275/154 kV	450 MVA	1	Dec. 2023	Aging management
	Mikawa	275/154 kV	450 MVA	1	Apr. 2025	Aging management
	Minami Fukumitsu	—	300 MW	—	FY 2026	Aging management*4*5
	Sunen	275/77 kV	150 MVA	1	Sep. 2026	Aging management
	Chushin	275/154 kV	300 MVA	1	Oct. 2026	Aging management
	Seino	275/154 kV	300 MVA	1	Jan. 2027	Aging management
Kansai Transmission and Distribution, Inc.	Kita Katsuragi	275/77 kV	200 MVA	1	Sep. 2023	Aging management
	Koto	275/77 kV	100 MVA×2	2	Oct. 2024	Aging management
	Higashi Osaka	275/154 kV	300 MVA	1	Jul. 2025	Aging management
	Inagawa	500/154 kV	750 MVA	1	Mar. 2026	Aging management
J-POWER Transmission Network Co.,Ltd.	Nagoya	275/154 kV	300 MVA×3	3	FY 2024	Economic upgrade

3. Summary of Development Plans for Transmission Lines and Substations

Tables 4-8 to 4-11 summarize the development or extension plans of major transmission lines and substations (transformers and converter stations) up to FY 2032. These are submitted by GT&D and transmission companies.

Table 4-8 Development Plans for Major Transmission Lines

Category	Voltage	Lines	Length [48]	Extended Length [49]	Total Length	Total Extended Length
Newly Installed or Extended	500 kV	Overhead	524 km*	1,047 km*	524 km*	1,948 km*
		Underground	1 km	1 km		
	275 kV	Overhead	△155 km	△311 km	△122 km	△214 km
		Underground	33 km	97 km		
	220 kV	Overhead	4 km	8 km	4 km	8 km
		Underground	0 km	0 km		
	187 kV	Overhead	8 km	17 km	8 km	17 km
		Underground	0 km	0 km		
	154 kV	Overhead	0 km	0 km	24 km	24 km
		Underground	24 km	24 km		
	Total	Overhead	616 km	1,227 km	672 km	1,348 km
		Underground	56 km	121 km		
To be Decommissioned	275 kV	Overhead	△66 km	△129 km	△66 km	△129 km
		Underground	0 km	0 km		
	220 kV	Overhead	△29 km	△59 km	△38 km	△77 km
		Underground	△ 9 km	△18 km		
	Total	Overhead	△95 km	△188 km	△104 km	△206 km
		Underground	△ 9 km	△18 km		

Table 4-9 Revised Plans for Line Category and the Numbers of Circuits[50]

Voltage	Length Extended	Total Extended Length
500 kV	0 km	0 km
275 kV	263 km*	547 km*
220 kV	19 km	23 km
187 kV	19 km	38 km
DC 250 kV	122 km	245 km
Total	423 km	853 km

48 Length denotes the increased length due to newly installed or extended plans and the decreased length due to decommissioning. Development plans corresponding to the change of line category or the number of circuits were not included in the increased length of transmission lines shown in Table 4-8 and are treated as "no change in the length." Due to independent rounding, the total and overall lengths are not necessarily equal.

49 The total length denotes the aggregation of length multiplied by the number of circuits. Development plans corresponding to changes in line category or the number of circuits were not included in the increased length of transmission lines in Table 4-8 and are treated as "no change in the length."

50 Table 4-9 aggregates the extended and total extended lengths corresponding to the revised plans for the line category and the number of circuits.

Table 4-10 Development Plans for Major Substations

Category [51]	Voltage [52]	Increased Numbers	Increased Capacity
Newly Installed or Extended	500 kV	21 [11]	21,600 MVA [10,750 MVA]
	275 kV	13 [5]	6,388 MVA [1,950 MVA]
	220 kV	5 [0]	1,370 MVA [0 MVA]
	187 kV	3 [1]	620 MVA [25 MVA]
	154 kV	1 [1]	170 MVA [170 MVA]
	132 kV	0 [0]	75 MVA [0 MVA]
	110 kV	△1 [0]	△60 MVA [0 MVA]
	Total	40 [18]	30,163 MVA [12,895 MVA]
To be Decommissioned	500 kV	△2	△1,750 MVA
	275 kV	△14	△3,750 MVA
	187 kV	△1	△100 MVA
	Total	△17	△5,600 MVA

The figures in [ ] indicate the increase in the number of transformers resulting from new substation installations.

Table 4-11 Development Plans for AC/DC Converter Stations

Category	Company and Number of Sites		Capacity[53]
Newly Installed or Extended	Hokkaido Electric Power Network, Inc.	2	300 MW×2
	Chubu Electric Power Grid Co.,Inc.	1	600 MW
	J-POWER Transmission Network Co., Ltd.	1	300 MW
To be Decommissioned	Chubu Electric Power Grid Co.,Inc.	1	△300 MW

4. Aging Management of Existing Transmission and Distribution Facility

Existing transmission and distribution facilities installed after the economic expansion (from the 1960s to the 1970s) will reach their replacement time. Facilities to be replaced are increasing trend, and significant facilities will remain unreplaced in place of the recent replacement work. Proper decisions for the replacement schedule are inevitable to secure a stable electricity supply in the future. Figures 4-2–4-4 show the actual installation years of existing transmission and distribution facilities.

51 Decommission plans with transformer installations are included in "Newly Installed" or "Extended," negative values are included in the increased numbers or the increased capacity.
52 Voltage class by upstream voltage.
53 For DC transmission, the capacities of both converter stations is included.

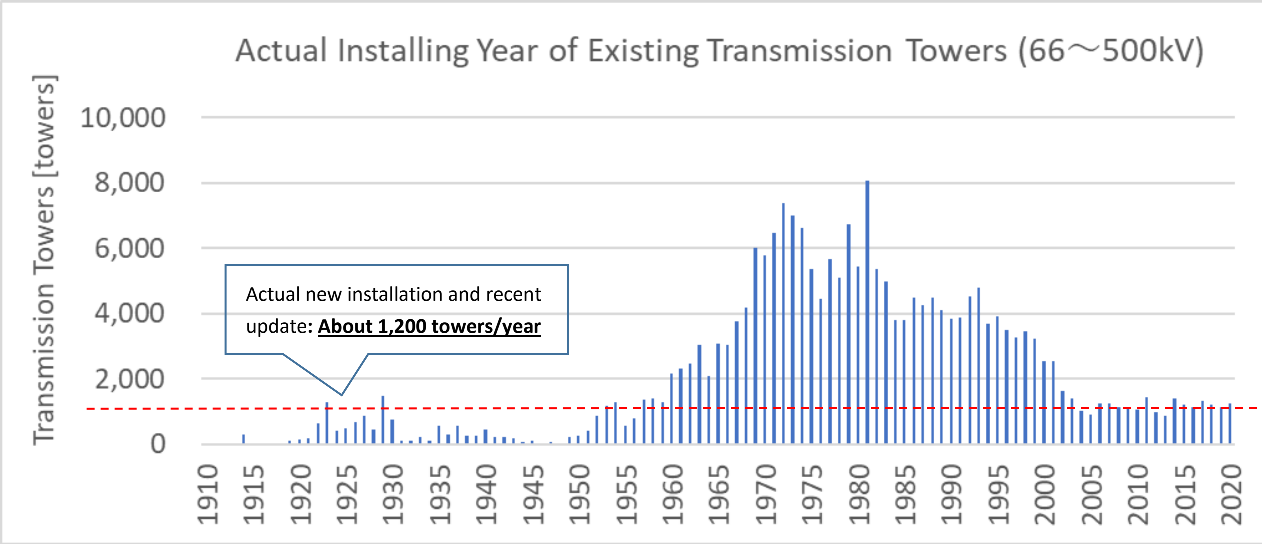


Figure 4-2 Actual Installation Year of Existing Transmission Towers (66–500 kV)

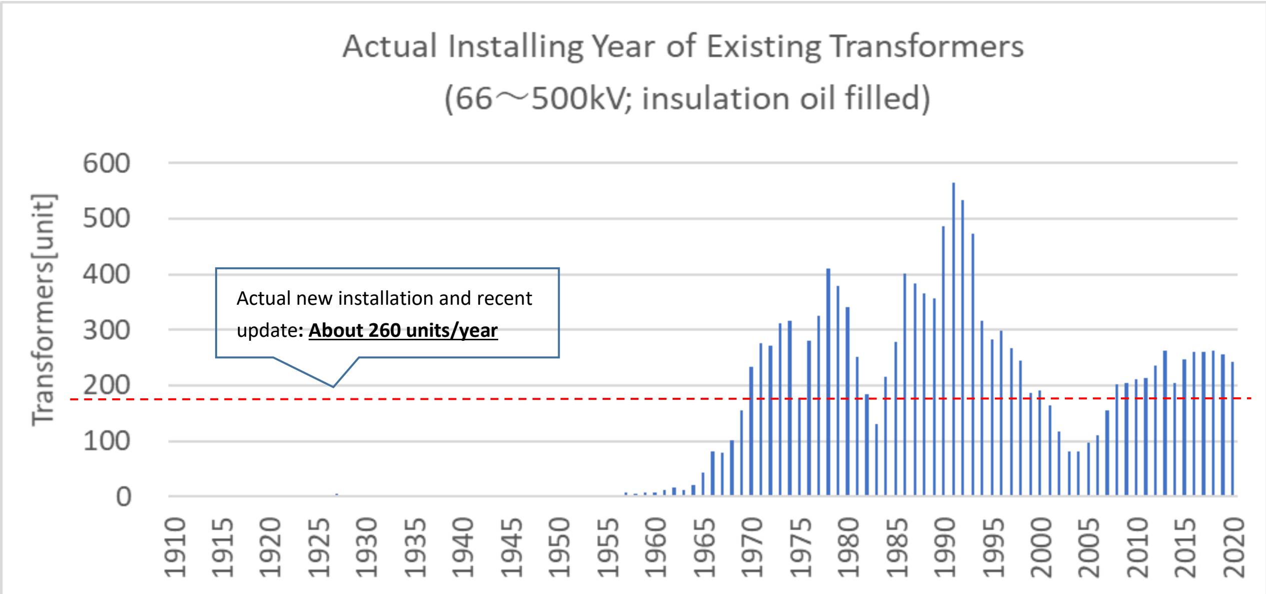


Figure 4-3 Actual Installation Year of Existing Transformers (66–500 kV; insulating oil-filled)

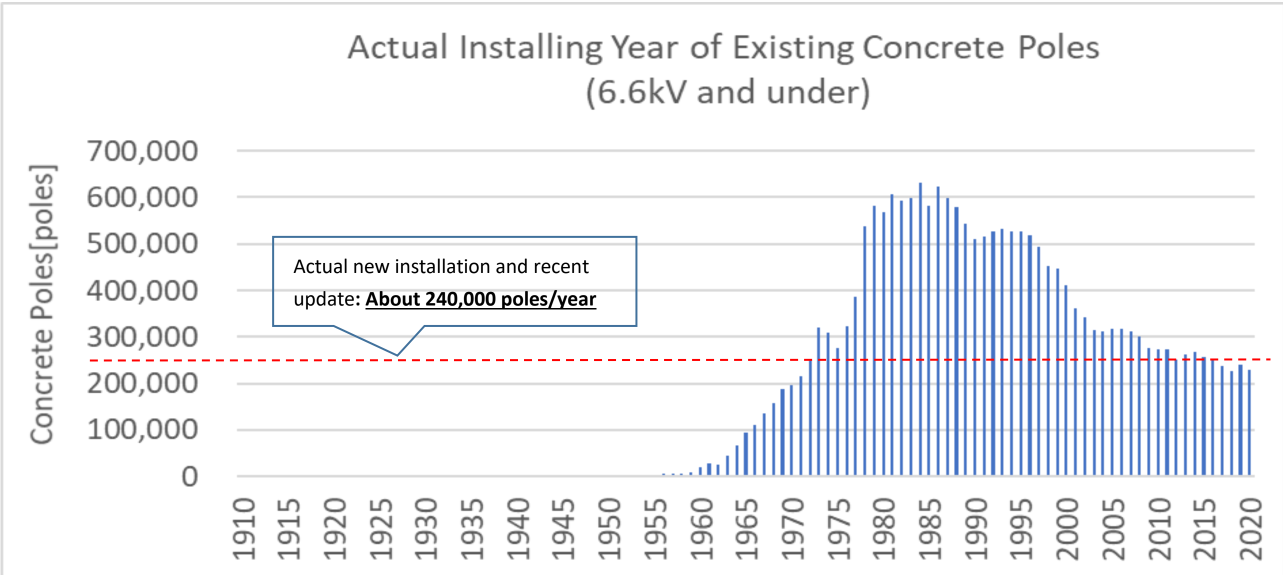


Figure 4-4 Actual Installation Year of Existing Distribution Concrete Poles (under 6.6 kV)

V. Cross-regional Operation

Retail companies procure the supply capacity for customers in their regional service areas. Four figures illustrate the scheduled procurement from external service areas at 15:00 during August 2023; Figures 5-1 and 5-2 show the supply capacity and the ratio of the supply capacity, respectively. Figures 5-3 and 5-4 show the energy supply and the ratio of the energy supply, respectively, in FY 2023.

Higher ratios for procurement from external regional service areas are observed in the Tokyo, Kansai, and Chugoku EPCO areas. In contrast, higher transmission to external regional service areas occurs observed in the Tohoku, Shikoku, and Kyushu EPCO areas.

The analysis result shows the same tendency as in previous years; major bilateral contracts of transmission line use did not change.

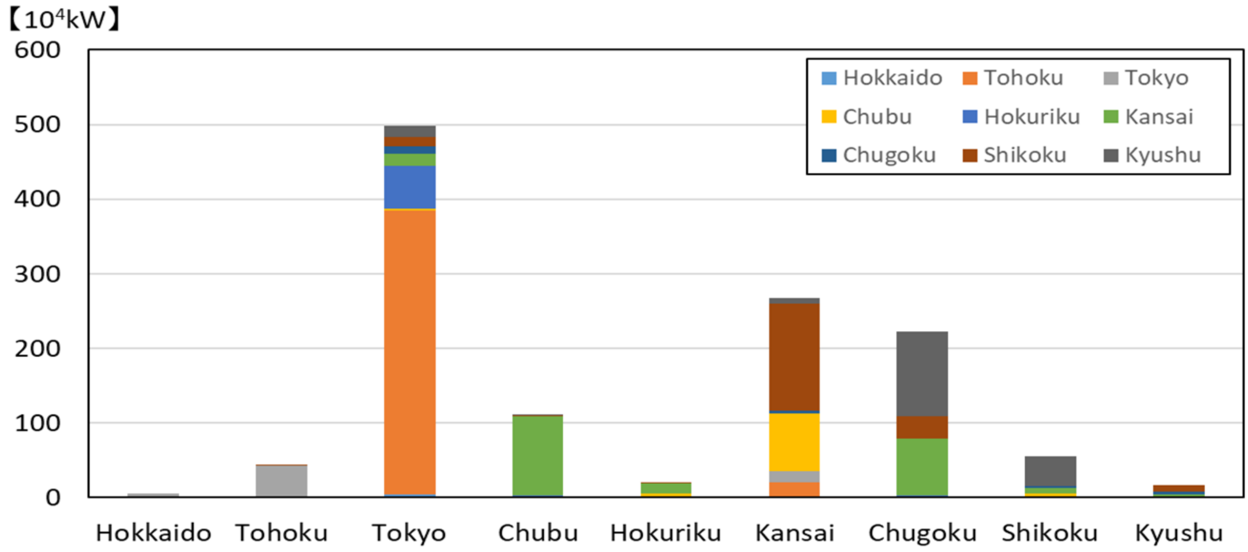


Figure 5-1 Scheduled Procurement of Supply Capacity from External Regional Service Areas

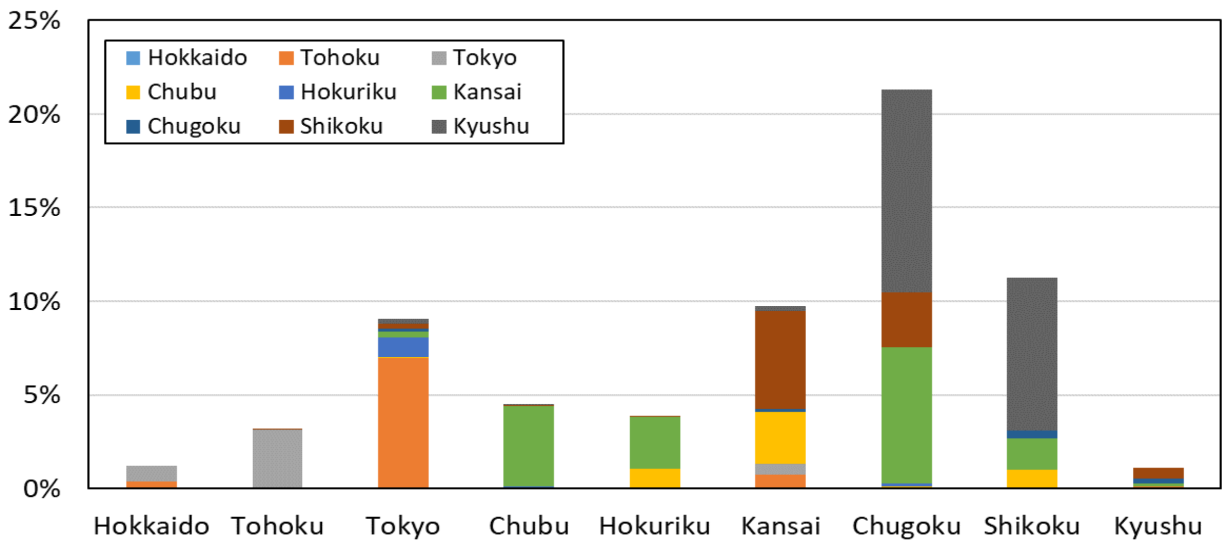


Figure 5-2 Ratio of Scheduled Procurement of Supply Capacity from External Regional Service Areas

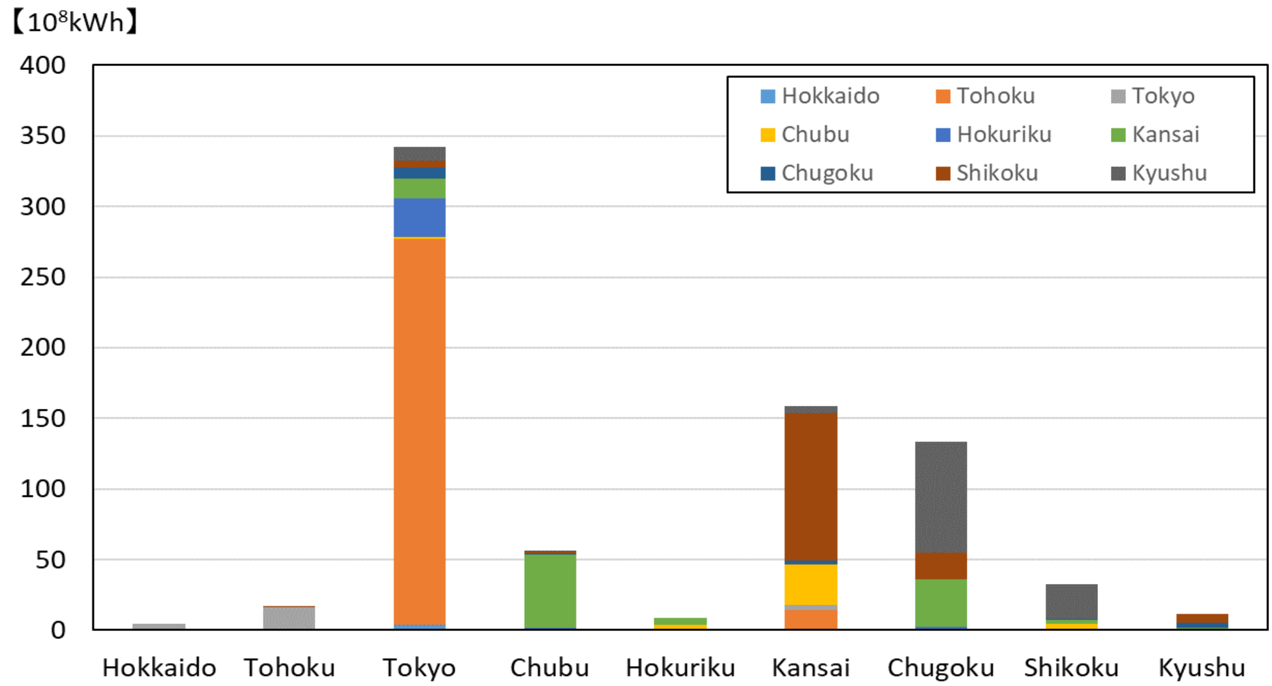


Figure 5-3 Scheduled Procurement of Energy Supply from External Regional Service Areas

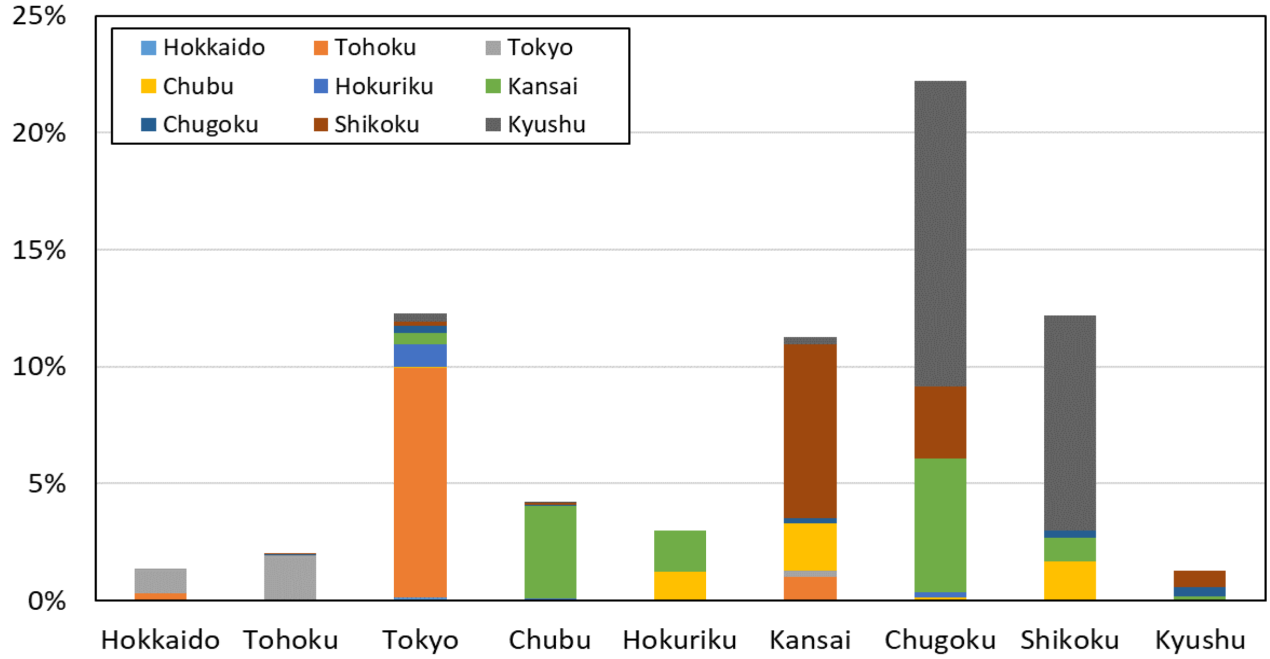


Figure 5-4 Ratio of Scheduled Procurement of Energy Supply from External Regional Service Areas

VI. Analysis of Characteristics of EPCOs

1. Distribution of Retail Companies by Business Scale (Retail Demand)

In total, 688 retail companies submitted their electricity supply plans, classified by the corresponding companies' business scale of the retail demand forecast. Figures 6-1 and 6-2 show the distributions of the business scale of retail demand and the accumulated retail demand forecast by the corresponding companies, respectively. Retail companies under 1 GW comprise the majority through the projected period; however, more than half of the accumulated retail demand was occupied by retail companies whose businesses are 10 GW and over.

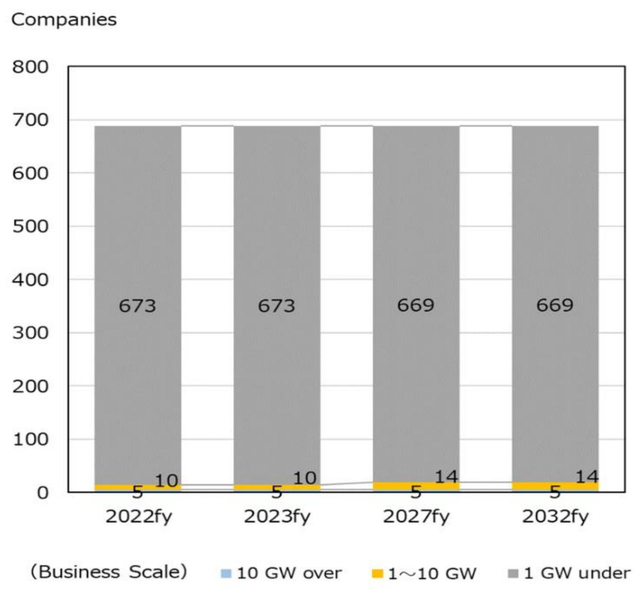


Figure 6-1 Distribution of the Retail Demand by Retail Companies by Business Scale

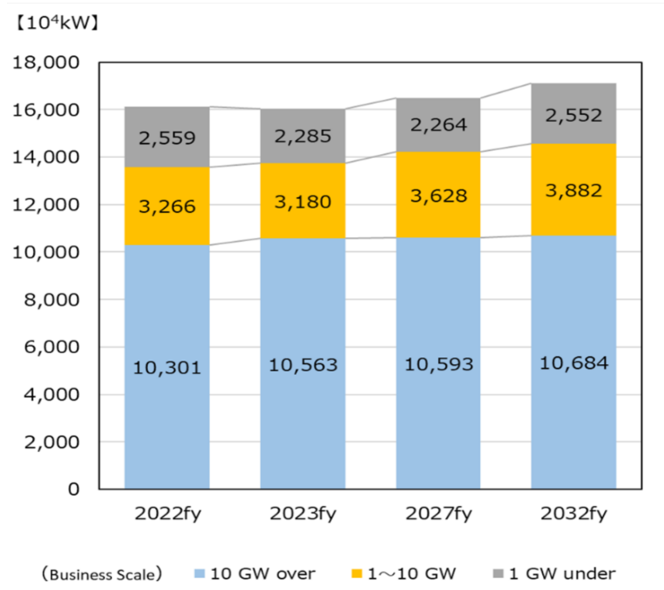


Figure 6-2 Distribution by Accumulated Retail Demand by Retail Companies

Retail companies are classified by the corresponding companies' business scale of the retail energy sales forecast. Figures 6-3 and 6-4 show the distributions of the business scale of retail company energy sales and their accumulated energy sales forecast, respectively. Similarly, retail companies, under 1 TWh comprise the majority through the projected period; however, over half of accumulated retail energy sales were occupied by retail companies whose businesses are 10 TWh and over.

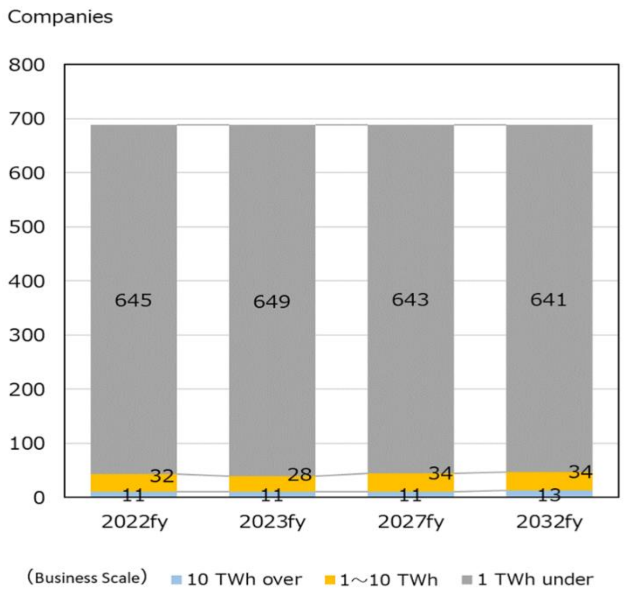


Figure 6-3 Distribution of Retail Company Energy Sales by Business Scale

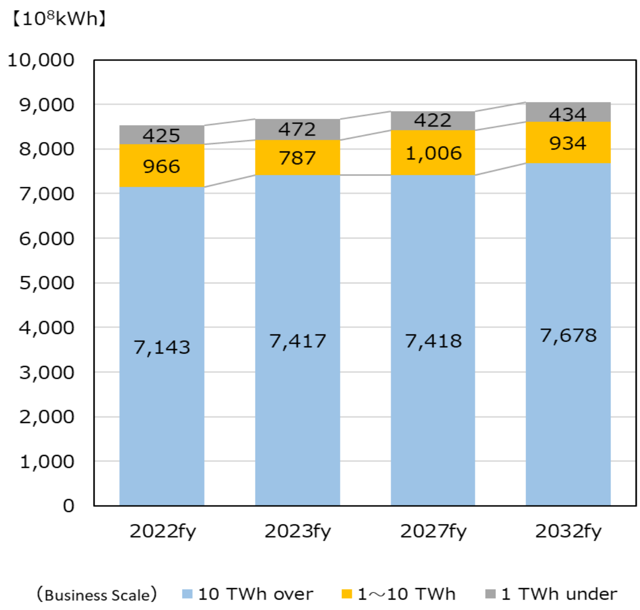


Figure 6-4 Distribution by Retail Company of Accumulated Energy Sales

2. Retail Company Business Areas

Figure 6-5 shows the ratio of retail companies by the number of areas where they plan to conduct business. Figure 6-6 shows the number of retail companies by their business planning areas in FY 2023. The figures exclude 138 retail companies that had not developed their business plans. Half of the retail companies plan their businesses in a single area.

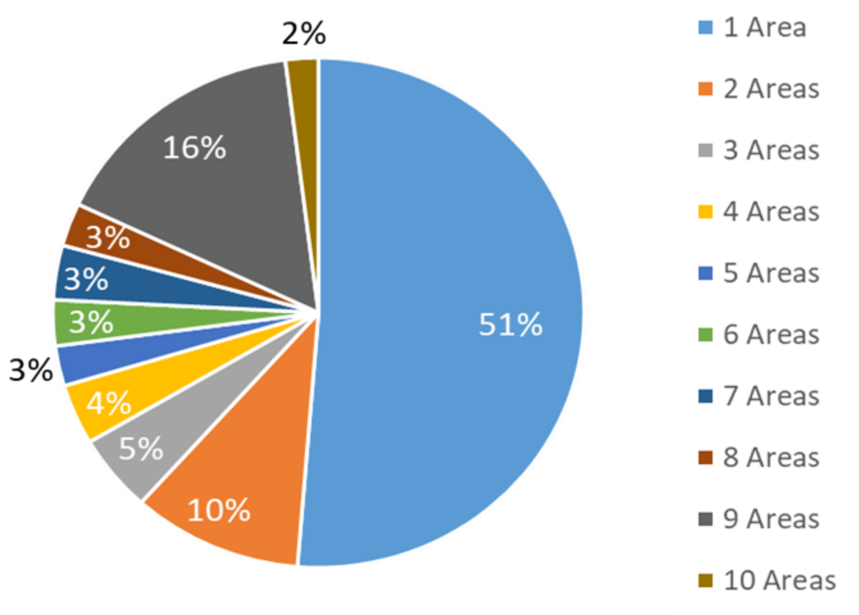


Figure 6-5 Ratio of Retail Companies by the Number of Planned Business Areas in FY 2023

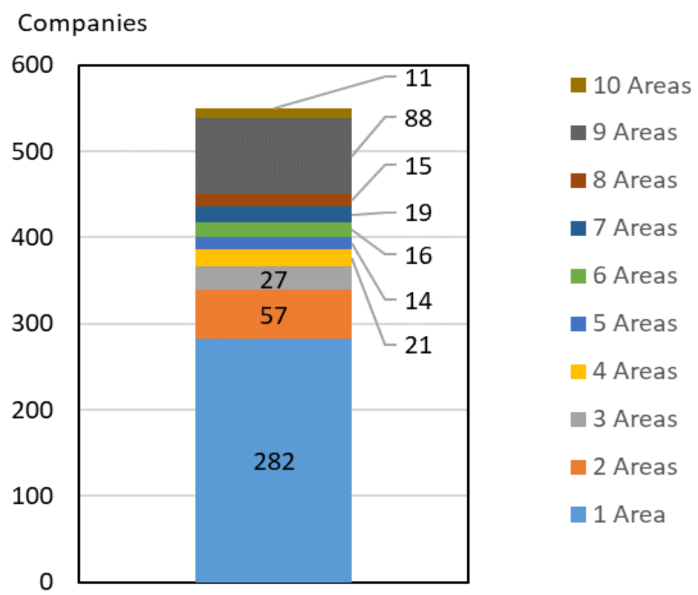
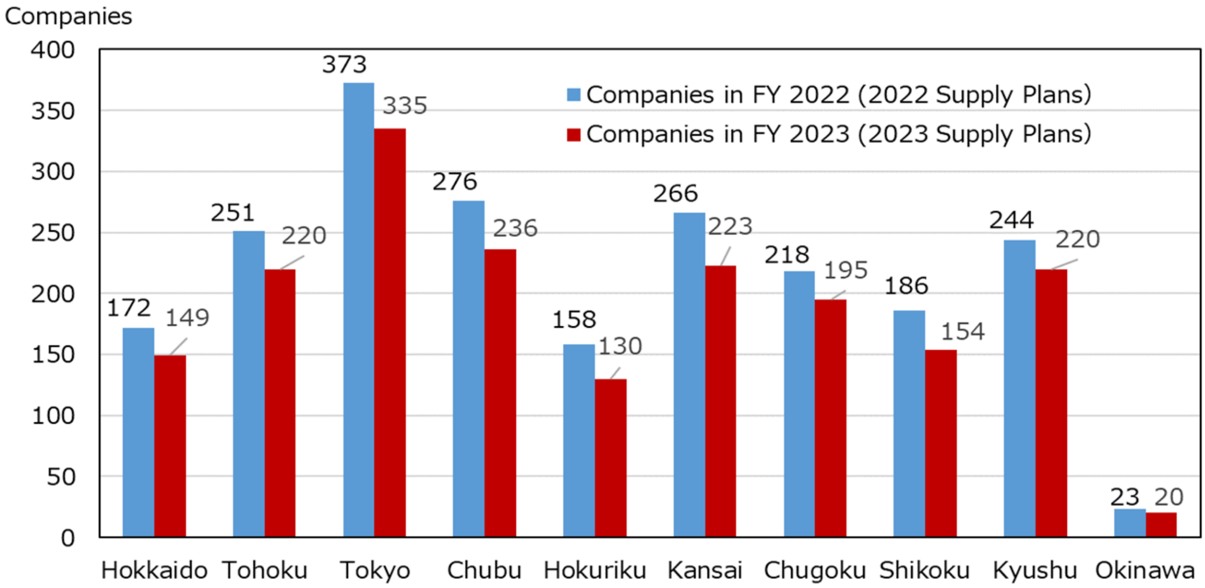


Figure 6-6 Number of Retail Companies by their Business Planning Areas in FY 2023

Figure 6-7 shows the number and the retail demand of retail companies in each regional service area for GT&D companies in FY 2023. The price rise of the electricity wholesale market has been remarkable for the recent environment, and retail companies that depend on more procurement from the market are forced to withdraw or downsize their business. Such analysis shows retail companies decrease their numbers in every regional service area.[54]



[10^4kW]

	Hokkaido	Tohoku	Tokyo	Chubu	Hokuriku	Kansai	Chugoku	Shikoku	Kyushu	Okinawa
Forecasted Area Peak Demand (FY 2023)	416	1,338	5,499	2,455	495	2,741	1,043	497	1,537	161

Figure 6-7 Number and Retail Demand of Retail Companies in Each Regional Service Area

3. Supply Capacity Procurement by Retail Companies

Figure 6-8 shows the transition of retail demand forecast in the regional service area by the retail department of the former general electric utilities and their procured supply capacity for the demand. Since FY 2022, generation departments of the former general electric utilities have started trades based on the wholesale standard menu. Such trades have been applied to retail departments of the same business group; therefore, the ratio of procured supply capacity will decrease for the retail departments of the former general electric utilities.

54 Reference: 55th meeting of the Basic Policy Subcommittee on Electricity and Gas, Electricity and Gas Industry Committee, Advisory Committee for Natural Resources and Energy
https://www.meti.go.jp/shingikai/enecho/denryoku_gas/denryoku_gas/pdf/055_03_01.pdf

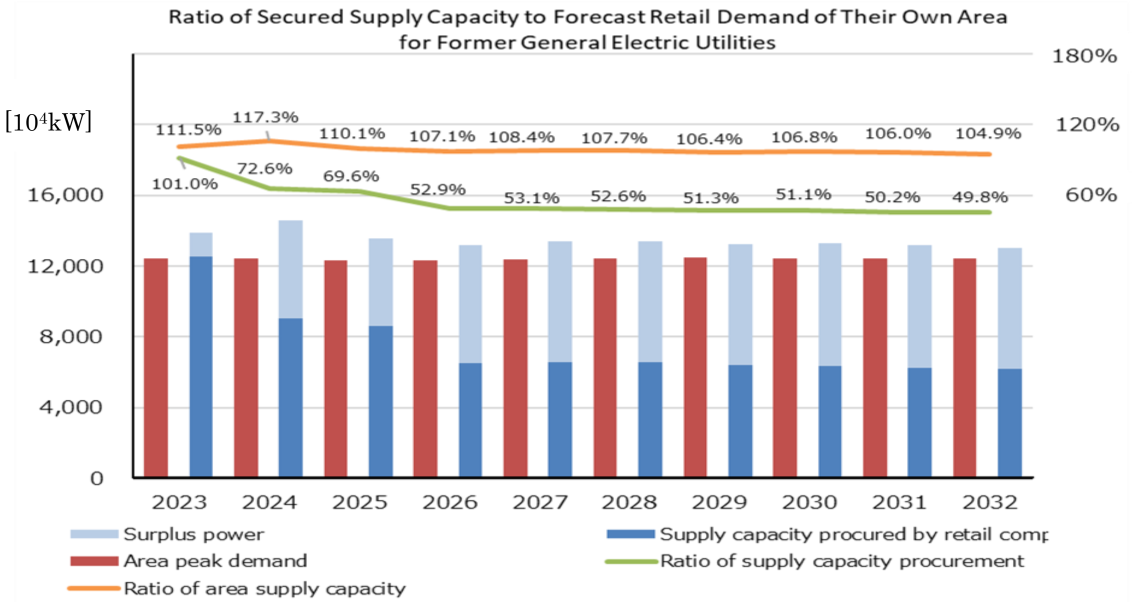


Figure 6-8 Ratio of Secured Supply Capacity to Forecast Retail Demand of Their Own Area for Former General Electric Utilities[55] (at 15:00 in August, at the sending end)

Figure 6-9 shows the forecasted demand other than their regional service areas of retail departments of the former general electric utilities, the forecasted demands of retail companies newly coming after deregulation, and the transition of procured supply capacity. The ratio of procured supply capacity to the forecasted demand of retail companies newly established after deregulation will gradually decrease.

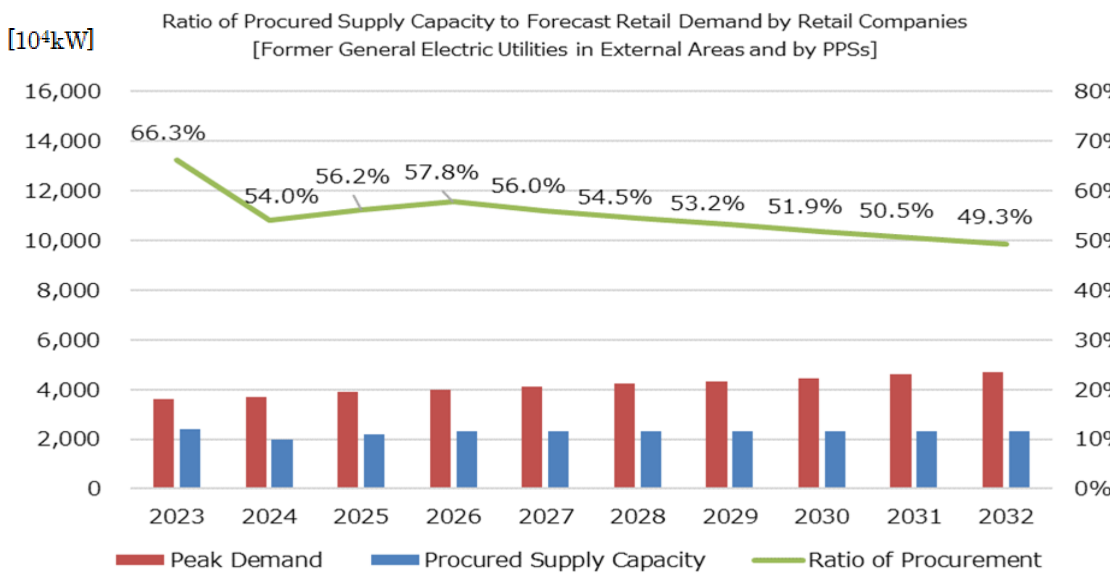


Figure 6-9 Ratio of Retail Companies' Procured Supply Capacity to Forecast Retail Demand [Former General Electric Utilities in External Areas and by retail companies newly coming after deregulation] (at 15:00 in August, at the sending end)

55 This includes the surplus power of a group of companies to the retail companies' secured supply capacity.

4. Distribution of Generation Companies by Business Scale (Installed Capacity)

In total, 1,040 generation companies submitted their electricity supply plans, which are classified by the corresponding companies' the business scale of the installed capacity. Figure 6-10 shows the distribution by business scale, and Figure 6-11 shows the installed capacity operated by the corresponding companies.

Generation companies with an installed capacity of under 10 GW comprises the majority through the projected period; however, more than half of the accumulated supply capacity was occupied by generation companies with an installed capacity of 10 GW and over.

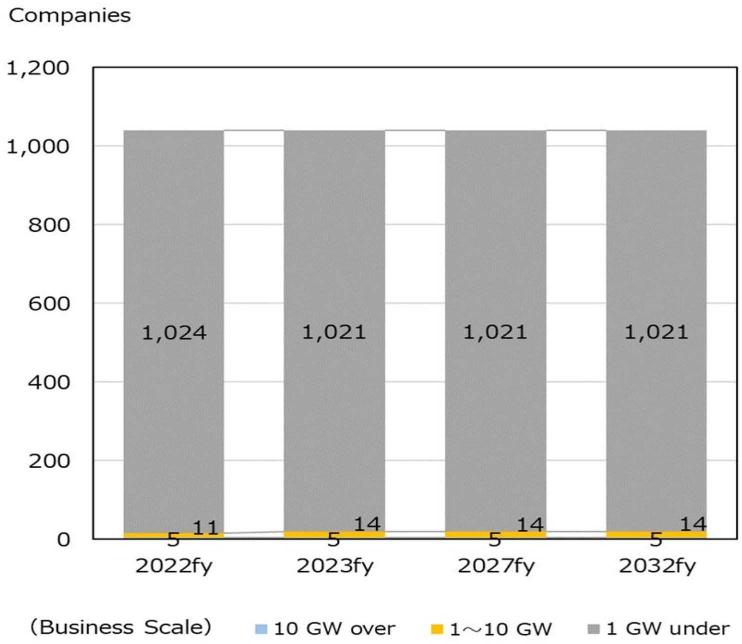


Figure 6-10 Distribution by Business Scale of a Generation Company's Installed Capacity

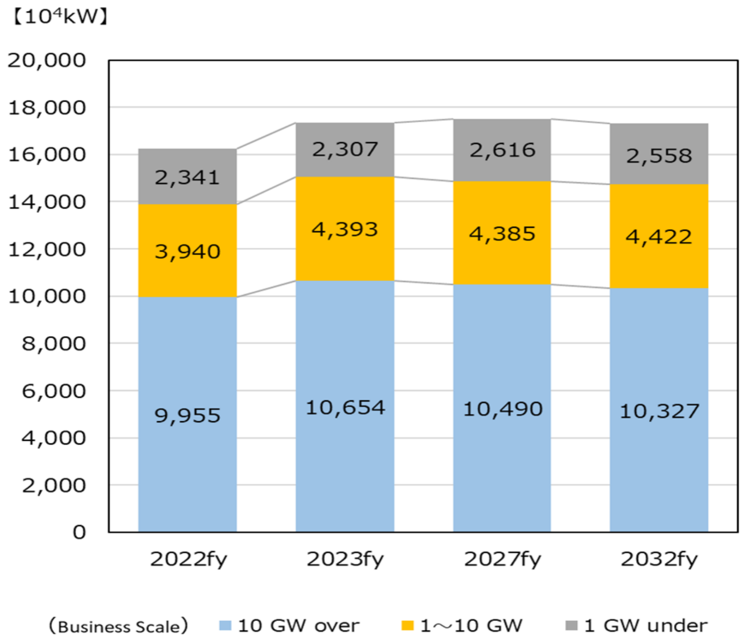


Figure 6-11 Distribution by a Generation Company's Accumulated Installed Capacity

Similarly, generation companies are classified by the business scale of the corresponding company's energy-supply forecast. Figure 6-12 shows the distribution by the business scale of the energy supply, and Figure 6-13 shows the distribution by the corresponding company's accumulated energy-supply forecast.
Generation companies with an energy supply of under 1 TWh comprises the majority throughout the projected period; however, more than half of accumulated energy supply was occupied by generation companies with an energy supply of 10 TWh and over.

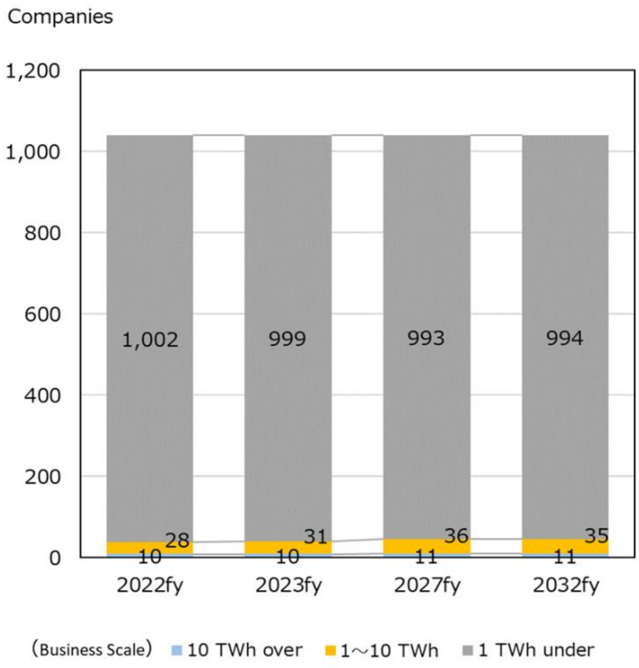


Figure 6-12 Generation Companies' Distribution of Energy Supply by Business Scale

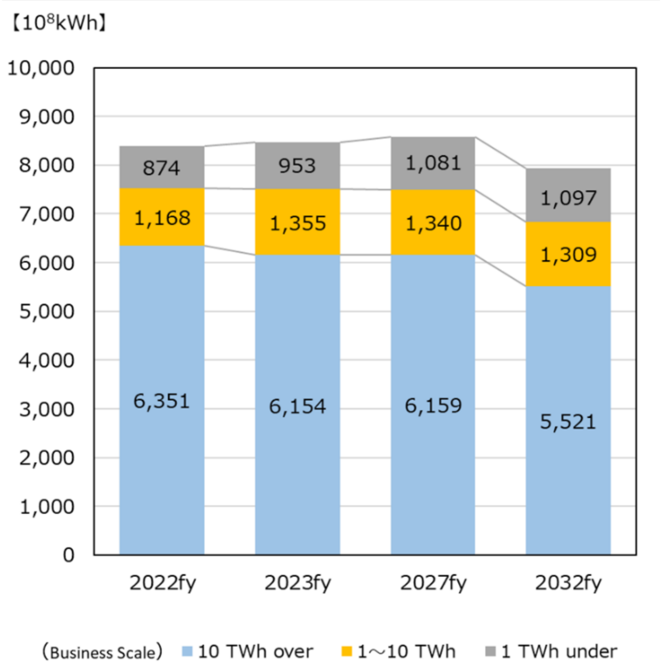
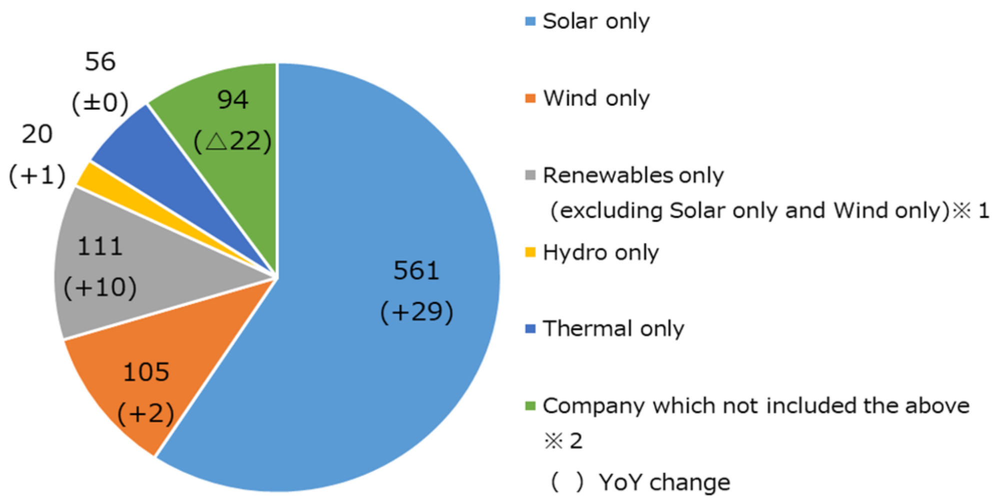


Figure 6-13 Generation Companies' Distribution by Accumulated Energy Supply

Figure 6-14 shows the number of generation companies at the end of FY 2022 by the power generation sources of their generators; the figures exclude 93 generation companies that do not own their generation plants.

Generation companies with renewable energy (particularly solar power) are increasing, and new generation companies are leading a stronger introduction of renewable energy.



*1 Subject to the companies which own only geothermal, biomass and waste, or companies which own several types of Renewables generating facilities including solar and wind

*2 Include the companies which own only multifuel facilities of fossil fuel and biomass etc.

Figure 6-14 Number of Generation Companies by Power Generation Sources

5. Generation Company Business Areas

Figure 6-15 shows the ratio of generation companies to the number of areas where they plan to conduct business. Figure 6-16 shows the number of generation companies by their business planning areas in FY 2023. The figures exclude 115 generation companies that do not own their generation plants in August 2023.

Eighty percent of generation companies plan their business in a single area.

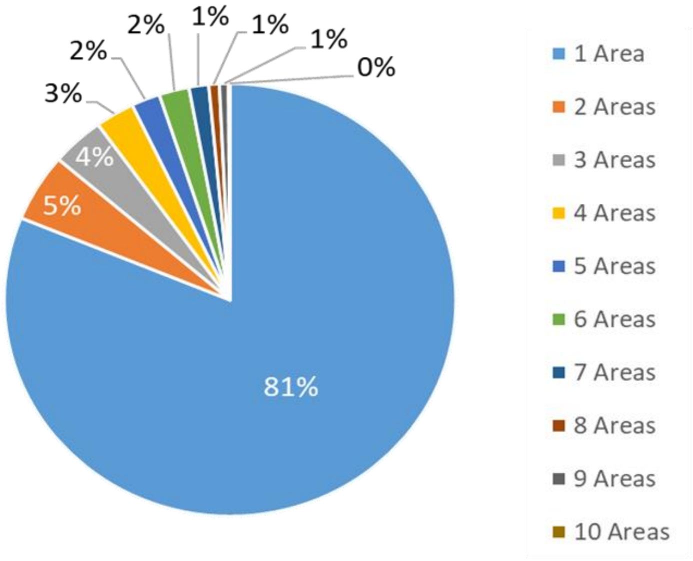


Figure 6-15 Ratio of Generation Companies by the Number of Planned Business Areas in August 2023 (left)

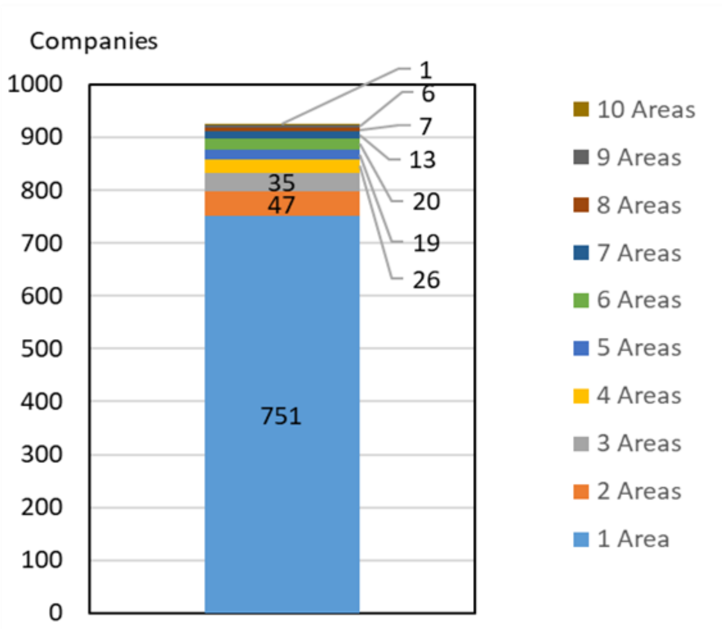
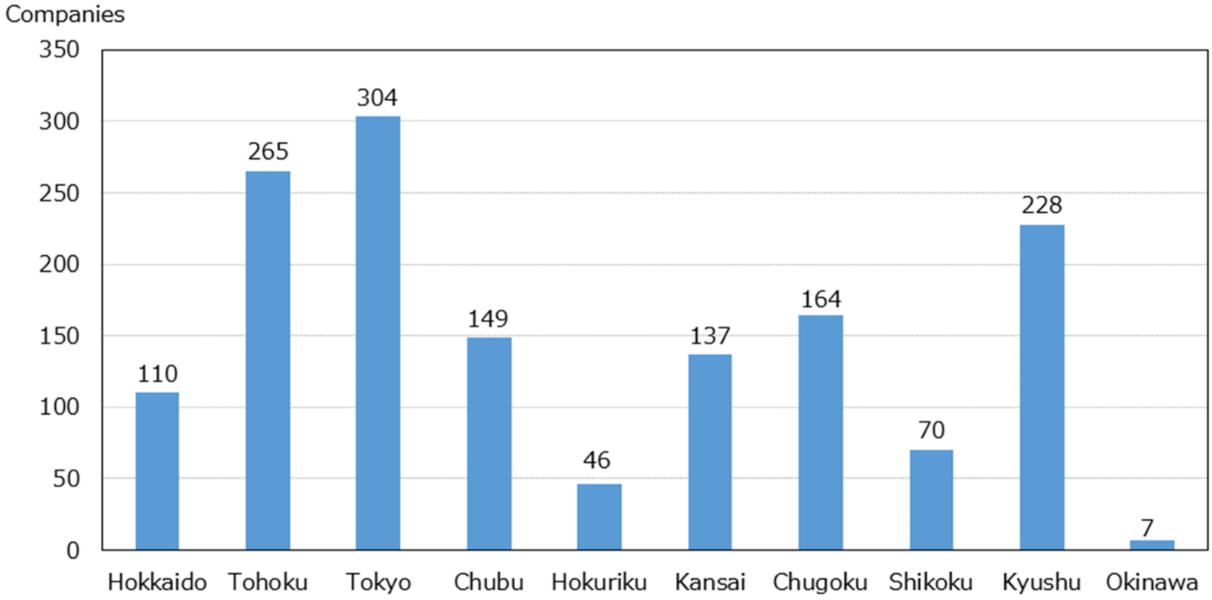


Figure 6-16 Number of Generation Companies by Their Business Planning Areas in August 2023 (right)

Figure 6-17 shows the number and the installed capacity of generation companies in each regional service area for GT&D companies in August 2023. In the Hokkaido, Tohoku, Chugoku, and Kyushu regional service areas, the scale of generation companies is relatively small. Furthermore, their supply capacity is comparatively small despite the number of generation companies in these regional service areas.



Projected Supply Capacity in FY 2023 (10^4 kW)

	Hokkaido	Tohoku	Tokyo	Chubu	Hokuriku	Kansai	Chugoku	Shikoku	Kyushu	Okinawa
Estimated Power Supply for FY 2023	525	1,972	4,957	2,526	544	2,858	1,083	765	1,922	203

Figure 6-17 Number and Installed Capacity of Generation Companies in Each Regional Service Area

VII. Findings and Current Challenges

The current challenges relating to the aggregation of electricity supply plans are as follows.

1. Challenges regarding to the auction result in the capacity market in the supply plan

Aggregation of supply plans for FY 2023 is the previous year's actual supply–demand year (FY 2024) of the capacity market. The Organization analyzes the relationship between the supply plan and the capacity market based on the recent condition.

Some generation companies seem to treat generators that failed at the main auction in the capacity market, as "unnecessary generators as supply capacity", and report them as "generators to suspend their operation, or decommissioned" in the supply plans. Figure 7-1 compares the results of the main auctions for LNG and coal-fired thermal generators. The main auction of the market has been held three times since FY 2020. It is observed that the LNG-fired thermal generators have increased, which failed in the market and were reported as "to be suspended or decommissioned". In contrast, coal-fired thermal generators, which failed in the market and were reported as "to be suspended or decommissioned" have tended to be small.

The Organization recommends that generation companies carefully judge their failed generators for suspension or decommission through a hearing at the supply plan submission. There will be opportunities to win a contract at incremental auctions based on demand growth after the main auction or supplementary bid due to the contracted generator exit. Furthermore, failed generators can become replacement generators to cover the contracted shutdown of generators, or for utilization outside the capacity market, such as the wholesale market or a bilateral contract with a retail company.

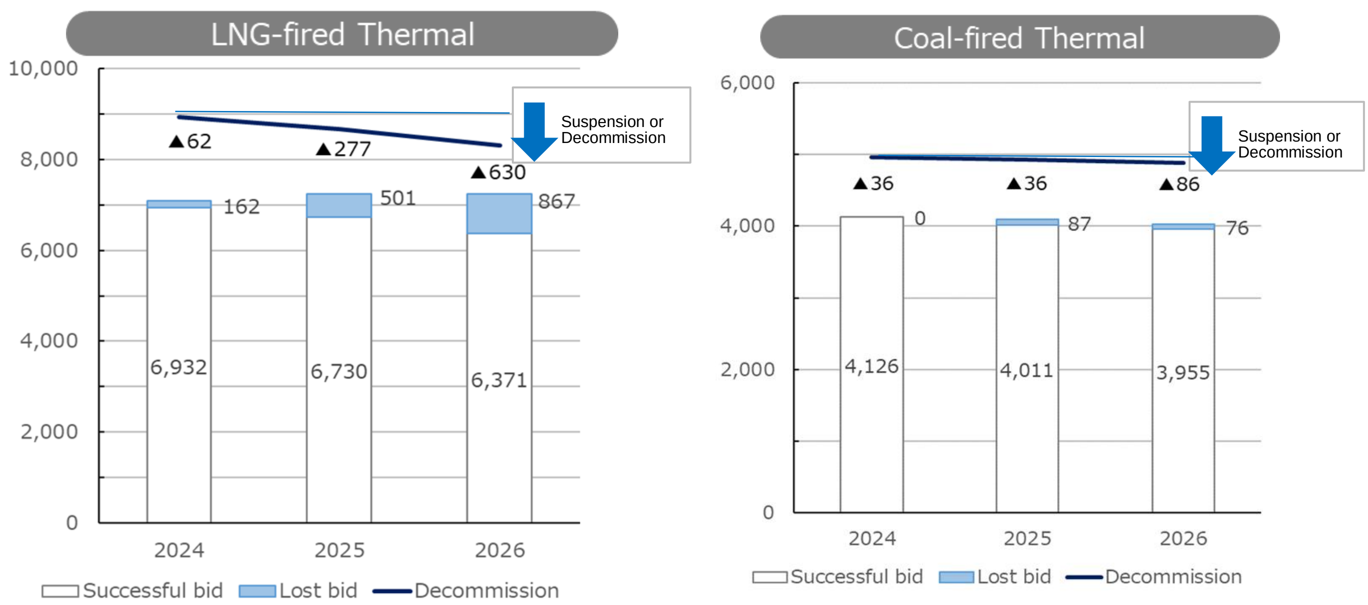


Figure 7-1 Comparison of the Results of the Main Auctions for LNG and Coal-fired Thermal Generators (10^4kW)

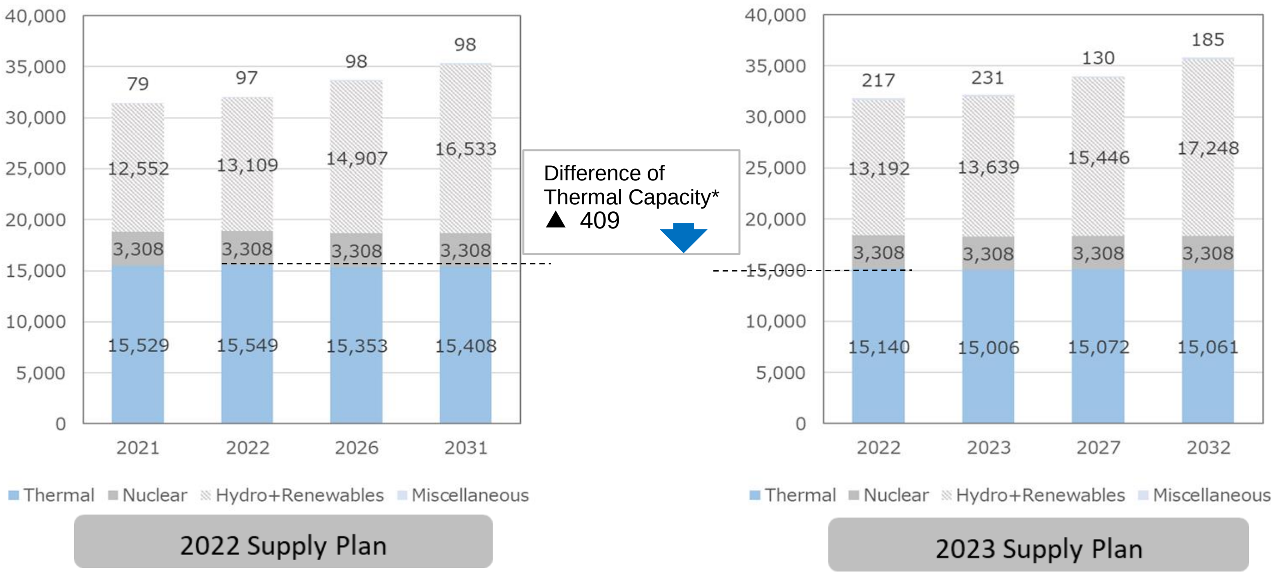
Moreover, some contracted generators, which have won the auction as future supply capacity, have already requested their exit from the market, due to causes such as generator trouble, which is not likely to fulfill their obligation at the market. It is concerning that such exit gathers in a particular area, and the area's supply capacity falls short; thus, proper measures shall be reviewed to procure the necessary supply capacity.

In these circumstances, the Organization will review the necessity of incremental auctions based on reevaluating the necessary procurement of supply capacity. To properly demonstrate the expected function of promoting the security of supply capacity at the capacity market, the Organization thinks environmental improvement for previously preventing considerable generator exit, and preparedness for contingency of supply shortage shall be necessary.

The Organization expects the government to properly supervise and instruct to the expected action of the generation company, and the systematic treatment or measures.

2. Challenges regarding to the security of supply capacity in the long-term and realization of carbon neutral(CN)

The Organization has implemented a transition of supply capacity composition in the annual aggregation of the electricity supply plans. Figure 7-2 compares the aggregation result of FY 2023 with FY2022 aggregation, indicating that the install capacity of nuclear generation has not changed, and renewable generation has increased. Contrarily, thermal generation capacity tends to decrease based on the trend of long-term development plans and suspension or decommission plans.



* Comparison of the aggregated result of FY 2023 supply plan and FY 2022 supply plan

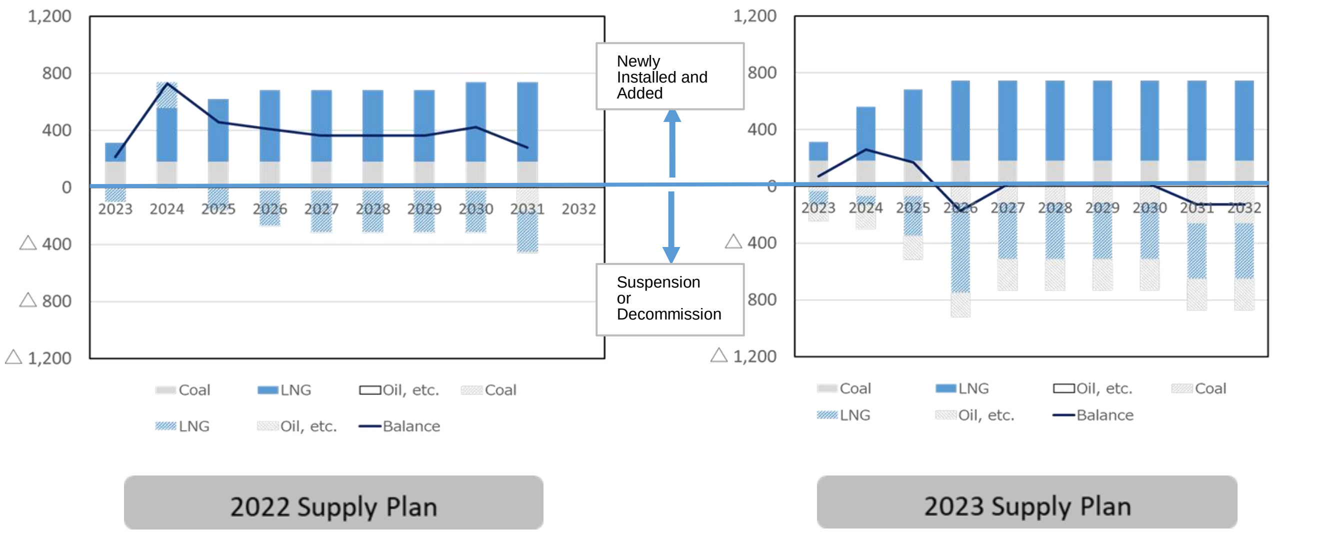
*1 The Organization automatically aggregates the value of the generating facility that the generation company owns; however, not all development plans will necessarily be realized; inefficient facilities will be retired, resulting from actions due to political measures in the future. For newly installed facilities, generating facilities (e.g., proceeding with its environmental assessments or publishing commercial operations) are included in the aggregation.

*2 Included are the facilities with actual operation experience, in addition to 33 units for which the date for resuming operation is uncertain; operation-terminated facilities are excluded.

*3 The GT&D company aggregates the projected value of integrating the generation facility according to the application of preliminary consultation and the available connecting capacity of its transmission lines or the actual growth trend of integration.

Figure 7-2 Comparison of the Aggregation Result of FY 2023 with FY2022 Aggregation (10^4kW)

Figure 7-3 shows the compared data between FY 2022 aggregation and FY 2023 aggregation, balanced newly and added installation, with suspension or decommission in each 10-year projected period. In both aggregation results, new and added installations continue to increase for FY 2025; no increase is shown after that. Contrarily, suspension or decommission annually increases in the basic trend, and the balanced capacity gradually decreases between newly added and suspended or decommissioned. In detail, new and added installation of thermal generation is scarcely planned, for suspension or decommission of LNG-fired generation is going to increase; however, those of coal-fired generation will keep its installation capacity. Especially, an increase of suspension or decommission of LNG-fired generation for FY 2026 is observed in FY 2023 aggregation. As stated in the former chapter, this trend is due to the suspension or decommission of failed LNG-fired generators, and the preservation of contracted coal-fired generators in the capacity market. If this trend continues, the suspension or decommission of LNG-fired generators will further increase, and the exit of ineffective coal-fired generators will accerelate due to carbon neutralization toward 2050. Therefore, concerns regarding the security supply stability will emerge.



* LNG-fired thermal generation in FY 2022 supply plan includes resuming operation of the capacity of suspended generators determined before FY 2022.

*1 Aggregation principally subjects to the generators 10 MW and larger according to “Plans of Generator Development” (excluding isolated islands).

*2 “Oil and others” means the total of oil, LPG, other gas, and bituminous coal.

*3 “Suspension or Decommission” includes operation suspension in longer term.

Figure 7-3 Development Plan and Suspension or Decommission Plan for the Long-term (Accumulated from FY 2023, Installed Capacity Base; 10^4kW))

To cope with this condition, the Organization will review and cooperate with the government: 1)to contribute to the review of long-term supply and demand beyond the 10-year period, which becomes the basis of premeditated generator development toward carbon neutral energy supply; 2)to develop measures such as long-term decarbonization energy auction which contributes to the improvement of predictability for generator development.

Simultaneously, it is inevitable to build a supply chain of manufacturing, transport, and storage of decarbonized fuels, such as hydrogen and ammonia, for their stable and continuous procurement, other than the scheme of securing the supply capacity stated above. However, many opinions are delivered, and it is not easy to carry them out by only individual business efforts.
Therefore, to secure the effectiveness of a long-term decarbonization energy auction, the Organization recommends that the government support measures of new installation of decarbonized generators and fuel conversion and building of supply chain of decarbonized fuel such as hydrogen and ammonia, which is consistent with such measures.

3. Principles of supply plans beyond FY 2024

FY 2024 is the year the actual supply and demand delivery of the capacity market begins and balancing capacity (Generator I, GeneratorI', and Generator II, etc.) from the solicitation process to the market trade to be entirely transported.[56] The change probably emerges in the review point and evaluation method for the supply plans that retail or generation companies submit.

a) Regarding to retail companies

The Organization has evaluated the condition of supply capacity procurement, such as bilateral or market procurement, to retail companies from the obligation point of view at the planning stage; however, from FY 2024, the necessary supply capacity will be universally procured in the capacity market nationwide.[57] Thus, the necessity of evaluating the condition of supply capacity procurement by individual retail companies will become less effective.
Furthermore, regarding the contract with the generation department of the former general electric utilities, non discriminatory trade will be implemented for the retail department of the same company and other retail companies. In such circumstances, procured capacity is likely not to be determined after the second year of the period in the supply plans, and such a trend is seen in the aggregation of FY 2023 supply plans.
Conversely, the Organization will continue the evaluation for grasping business continuity and behavioral characteristics of individual retail companies and evaluation method, as well as morphological change of wholesale supply to retail companies for the impact of premeditated fuel procurement of generation companies. A specific effect is expected to grasp bilateral contracts between retail and generation companies for the short and long term.
Therefore, the Organization will continue to strive to grasp the condition of securing supply capacity by retail companies and review the treatment of procured supply capacity from non-EPCO and the demand response, which retail companies utilize in evaluating supply–demand balance.

b) Regarding to generation companies

For generation company's supply plan, further refining and sophistication for grasping supply

[56] In Okinawa, the balancing market will not be held, and the solicitation process will continue for procurement.
[57] Except Okinawa area and isolated islands.

capacity or balancing capacity will be needed. For balancing capacity, procurement will be changed from the solicitation process to trade at the balancing market beyond FY 2024, and its procurement shall become effective and certain near the actual supply–demand timing; however, it is expected to be difficult to grasp annual securing conditions of balancing capacity as in the past. Furthermore, necessary balancing capacity shall be procured and maintained through the capacity market and balancing market; however the contracted generators with balancing function decreased from the result of the main auction of the recent three years.[58]

Necessary supply capacity and balancing capacity (reserve balancing capacity) will be procured cross-regionally and economically utilizing the market mechanism through the capacity market and balancing market. To function the mechanism, the facilities that provide the necessary supply capacity will inevitably continue to exist, and the review is necessary to validate its existence in the aggregated supply plans.

Furthermore, in decreasing bilateral long-term contracts between generation and retail companies the Organization must review the proper procurement of fuel supply for the individual generation company at the aggregated supply plans. Proper fuel procurement will be necessary in bilateral contarcts with retail companies or wholesale market trade.

Therefore, the Organization shall review the necessary measures for cooperating with the government and relevant EPCOs with balancing capacity for procuring mid-to-long term security and grasping the procurement condition for balancing capacity. In the review, the Organization shall try to grasp the trend of new and additional development, suspension or decommission of generators, supply capacity, balancing capacity, and energy production of individual generator. The review also examine the utilization of pumped storage hydro generators or power storage facilities expected at the introduction of long-term decarbonization energy auction.[59]

The Organization recommends that the government review specific measures, including the contents of the supply plans, outlining the effective and ideal way of balancing capacity procurement and the role to be fulfilled by each segment of EPCOs.

---

[58] Reference: Contracted result of the main auction for actual supply and delivery for FY 2026 (written in Japanese only)
https://www.occto.or.jp/market-board/market/oshirase/2022/files/230222_mainauction_youryouyakujokekka_saikouhyou_jitsujukyu2026.pdf

[59] Reference: 56th meeting of the Basic Policy Subcommittee on Electricity and Gas, Electricity and Gas Industry Committee, Advisory Committee for Natural Resources and Energy
https://www.meti.go.jp/shingikai/enecho/denryoku_gas/denryoku_gas/pdf/056_04_02.pdf

VIII. Conclusions

1. Electricity Demand Forecast

The AAGR of peak demand nationwide in the mid-to-long term is forecast to decrease by 0.1%. AAGR is forecasted to be negative. This result is attributable to several major decreasing factors, such as a shrinking population, and efforts to reduce electricity use, notwithstanding increasing factors like economic growth and broader use of electric appliances.

2. Electricity Supply and Demand

The Organization applied EUE as a reliability criterion to the electric supply plan. In the short term (the first and second year of the projected period), only Tokyo areas for FY 2023 are out of the of secure supply criteria (0.048 kWh/kW-year nationwide, 0.498 kWh/kW-year in Okinawa). In the long term, the calculated results for the Hokkaido area in FY 2027, the Tokyo area in FY 2025 and 2026, the Kyushu area in FY 2025, and from FY 2027 to 2029, and the Okinawa area in FY 2025 and 2026, from FY 2029 to 2032, are out of the criterion.

The conventional approach's supply–demand balance evaluation shows that the 8% reserve margin is secured in FY 2023 and 2024 in every area and for all months.

For energy-supply requirement evaluation, the energy supply will be 1.0–1.1 TWh/month of volume below the forecasted energy requirement (equivalent to 0.2%–1.7% against the forecast energy requirement) in some months of FY 2023.

As stated above, in the short-term, the annual EUE of the Tokyo area becomes 0.049 kWh/kW-year, which is out of the criteria of stable supply, and careful monitoring for supply–demand will be needed. However, no month will drop below the 8% criteria by the conventional approach. The Organization proceeds to review the necessity of supply measures based on the analytical result of supply–demand variance risk, which premises severe climate conditions (heatwaves and severe cold) emerge once in 10 years.

3. Analysis of the Transition of Power Generation Sources Nationwide

Renewable energy, such as solar and wind power, is projected to increase regarding the transition of installed power generation capacity and net electricity generation. Conversely, thermal is projected to decrease. Nuclear power plants' energy generation is calculated as zero, given that their capacity is reported as "uncertain."

4. Development Plans for Transmission and Distribution Facilities

Regarding the development plans for major transmission lines and substations, significant generator access lines are planned, as are development plans for cross-regional interconnection lines, including facilities necessary for cross-regional operation.

5. Cross-regional Operation

The aggregated results for procuring supply capacity or energy from external service areas, are almost the same as in the previous year, with higher procurement from external services and higher transmission to external areas.

6. Analysis of Characteristics of EPCOs

Distributions are calculated for retail and generation companies according to business scale and business areas, and are aggregated to the projection for 10-year. Furthermore, the ratios of the secured supply capacity are reviewed. Particularly, small and medium-sized retail companies have planned their supply capacity as “unspecified procurement,” as in the previous year’s plan; therefore, the ratios of the secured supply capacity indicate a declining tendency.

7. Findings and Challenges

The Organization has communicated to METI its opinions concerning three significant challenges concerning the aggregation of electricity supply plans for FY 2023.

Attached are the Appendices for the aggregation of the electricity supply plans.

APPENDIX 1 Supply–Demand Balance for FY 2023 and 2024 (Short-term)

i) Projection for FY 2023

Tables A1-1–A1-4 show the monthly supply–demand balance, such as peak demand, monthly supply capacity, monthly reserve capacity, and reserve margin for each regional service area in FY 2023. Table A1-5 shows the monthly projection of the reserve margin for each regional service area recalculated with power exchanges to areas below the 8% reserve margin. These projections are from areas with over 8% reserve margin with additional supply capacity according to the provision of Article 48 of the Act. Furthermore, Table A1-6 shows the monthly peak demand, supply capacity, reserve capacity, and reserve margin at the designated time.

Table A1-1 Monthly Peak Demand Forecast for Each Regional Service Area in FY 2023 (10^4kW at the sending end)

[10^4kW]

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	397	355	356	409	416	387	390	444	481	498	495	453
Tohoku	1,085	1,012	1,084	1,312	1,338	1,180	1,033	1,161	1,305	1,369	1,365	1,229
Tokyo	3,846	3,717	4,281	5,499	5,499	4,650	3,827	4,020	4,469	4,884	4,884	4,337
50Hz areas Total	5,328	5,084	5,721	7,220	7,253	6,217	5,250	5,625	6,255	6,751	6,744	6,019
Chubu	1,799	1,807	2,019	2,455	2,455	2,208	1,879	1,902	2,159	2,342	2,342	2,050
Hokuriku	386	352	404	495	495	438	373	410	476	518	518	452
Kansai	1,798	1,828	2,117	2,741	2,741	2,314	1,890	1,914	2,349	2,518	2,518	2,115
Chugoku	757	747	835	1,043	1,043	931	770	836	1,013	1,037	1,037	902
Shikoku	334	342	386	497	497	425	369	370	458	458	458	395
Kyushu	1,000	1,048	1,203	1,537	1,537	1,320	1,109	1,152	1,393	1,454	1,454	1,223
60Hz areas Total	6,074	6,123	6,964	8,768	8,768	7,636	6,390	6,584	7,848	8,327	8,327	7,137
Interconnected	11,402	11,207	12,685	15,988	16,021	13,853	11,640	12,209	14,103	15,078	15,071	13,156
Okinawa	107	130	154	157	158	160	138	118	101	109	103	98
Nationwide	11,509	11,338	12,838	16,145	16,179	14,013	11,778	12,327	14,203	15,187	15,174	13,253

Table A1-2 Monthly Projection of Supply Capacity for Each Regional Service Area in FY 2023 (10^4kW at the sending end)

[10^4kW]

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	552	578	547	544	548	524	549	598	605	602	619	629
Tohoku	1,282	1,297	1,411	1,664	1,764	1,630	1,373	1,486	1,640	1,684	1,678	1,592
Tokyo	4,394	3,980	4,686	5,828	5,853	5,496	4,557	4,312	4,977	5,465	5,461	5,174
50Hz areas Total	6,228	5,856	6,643	8,036	8,165	7,649	6,479	6,395	7,223	7,751	7,757	7,395
Chubu	2,238	2,141	2,548	2,810	2,912	2,594	2,251	2,104	2,527	2,630	2,594	2,300
Hokuriku	449	460	493	562	542	473	486	469	494	524	529	545
Kansai	2,199	2,164	2,482	2,983	3,111	2,716	2,030	2,112	2,628	2,827	2,821	2,565
Chugoku	1,025	1,116	1,245	1,477	1,449	1,239	1,033	1,009	1,241	1,326	1,252	1,082
Shikoku	454	491	603	711	727	623	575	507	561	634	644	653
Kyushu	1,398	1,417	1,562	1,864	1,907	1,788	1,650	1,481	1,659	1,691	1,754	1,542
60Hz areas Total	7,763	7,789	8,932	10,407	10,648	9,433	8,025	7,683	9,110	9,632	9,593	8,688
Interconnected	13,991	13,644	15,576	18,443	18,813	17,083	14,504	14,078	16,333	17,383	17,350	16,083
Okinawa	153	186	196	205	201	195	195	170	173	176	165	177
Nationwide	14,143	13,830	15,772	18,648	19,014	17,278	14,700	14,248	16,506	17,559	17,515	16,260

Table A1-3 Monthly Projection of Reserve Capacity for Each Regional Service Area in FY 2023 (10^4kW at the sending end)

[10^4kW]

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	155	223	191	135	132	137	159	154	124	104	124	176
Tohoku	197	285	327	352	426	450	340	325	335	315	313	363
Tokyo	548	263	405	329	354	846	730	292	508	581	577	837
50Hz areas Total	900	772	922	816	912	1,432	1,229	770	968	1,000	1,013	1,376
Chubu	439	334	529	355	457	386	372	202	368	288	252	250
Hokuriku	63	109	89	67	47	35	114	59	18	6	11	93
Kansai	402	336	365	242	370	402	139	198	279	309	303	451
Chugoku	268	369	410	434	406	308	263	173	228	289	215	180
Shikoku	120	149	217	214	230	198	206	137	103	176	186	258
Kyushu	398	369	359	327	370	468	541	329	266	237	300	319
60Hz areas Total	1,689	1,665	1,969	1,639	1,880	1,798	1,635	1,099	1,262	1,305	1,266	1,551
Interconnected	2,589	2,437	2,891	2,455	2,792	3,230	2,865	1,870	2,230	2,305	2,279	2,927
Okinawa	46	55	43	48	43	35	57	52	73	67	62	80
Nationwide	2,635	2,492	2,934	2,503	2,835	3,265	2,922	1,922	2,303	2,372	2,341	3,007

Table A1-4 Monthly Projection of Reserve Margin for Each Regional Service Area in FY 2023

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	39.1%	62.9%	53.6%	33.1%	31.7%	35.3%	40.9%	34.7%	25.8%	20.9%	25.0%	38.7%
Tohoku	18.1%	28.2%	30.2%	26.8%	31.9%	38.1%	32.9%	28.0%	25.7%	23.0%	22.9%	29.5%
Tokyo	14.2%	**7.1%**	9.5%	**6.0%**	**6.4%**	18.2%	19.1%	**7.3%**	11.4%	11.9%	11.8%	19.3%
50Hz areas Total	16.9%	15.2%	16.1%	11.3%	12.6%	23.0%	23.4%	13.7%	15.5%	14.8%	15.0%	22.9%
Chubu	24.4%	18.5%	26.2%	14.4%	18.6%	17.5%	19.8%	10.6%	17.0%	12.3%	10.8%	12.2%
Hokuriku	16.4%	30.9%	22.0%	13.6%	9.5%	8.1%	30.5%	14.3%	**3.9%**	**1.3%**	**2.1%**	20.6%
Kansai	22.4%	18.4%	17.3%	8.8%	13.5%	17.4%	**7.4%**	10.4%	11.9%	12.3%	12.0%	21.3%
Chugoku	35.4%	49.4%	49.1%	41.6%	38.9%	33.1%	34.1%	20.7%	22.5%	27.9%	20.7%	19.9%
Shikoku	35.8%	43.7%	56.3%	43.1%	46.2%	46.7%	55.9%	37.0%	22.5%	38.3%	40.5%	65.4%
Kyushu	39.8%	35.2%	29.8%	21.3%	24.1%	35.5%	48.8%	28.6%	19.1%	16.3%	20.6%	26.1%
60Hz areas Total	27.8%	27.2%	28.3%	18.7%	21.4%	23.5%	25.6%	16.7%	16.1%	15.7%	15.2%	21.7%
Interconnected	22.7%	21.7%	22.8%	15.4%	17.4%	23.3%	24.6%	15.3%	15.8%	15.3%	15.1%	22.2%
Okinawa	42.6%	42.6%	27.7%	30.5%	26.9%	22.1%	41.5%	44.4%	72.6%	61.9%	60.4%	81.3%
Nationwide	22.9%	22.0%	22.9%	15.5%	17.5%	23.3%	24.8%	15.6%	16.2%	15.6%	15.4%	22.7%

Below 8% criteria

Table A1-5 Monthly Projection of Cross-regional Reserve Margin for Each Regional Service Area in FY 2023

(Power exchanges through cross-regional interconnection lines and generating facilities are not included at the sending end at the sending end of the electricity supply plans,)

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	23.4%	46.4%	50.8%	24.0%	25.3%	36.4%	27.1%	28.2%	20.3%	15.4%	16.0%	24.4%
Tohoku	16.4%	16.0%	21.3%	18.2%	24.1%	36.4%	25.2%	28.2%	20.3%	15.4%	16.0%	24.1%
Tokyo	16.4%	12.0%	12.3%	8.7%	9.7%	18.9%	22.0%	8.5%	15.0%	15.3%	15.0%	21.1%
Chubu	26.8%	24.8%	28.1%	18.7%	20.8%	22.0%	22.0%	14.8%	15.3%	15.3%	15.0%	21.1%
Hokuriku	26.8%	27.5%	28.1%	18.7%	20.8%	22.0%	22.0%	14.8%	15.3%	15.3%	15.0%	21.7%
Kansai	26.8%	27.5%	28.1%	18.7%	20.8%	22.0%	22.0%	14.8%	15.3%	15.3%	15.0%	21.7%
Chugoku	26.8%	27.5%	28.1%	18.7%	20.8%	22.0%	22.0%	14.8%	15.3%	15.3%	15.0%	21.7%
Shikoku	26.8%	27.5%	28.1%	18.9%	22.4%	22.0%	22.0%	14.8%	15.3%	15.3%	15.0%	39.4%
Kyushu	33.0%	30.2%	28.1%	18.7%	20.8%	29.9%	44.7%	23.3%	15.3%	15.3%	15.0%	21.7%
Okinawa	42.6%	42.6%	27.7%	30.5%	26.9%	22.1%	41.5%	44.4%	72.6%	61.9%	60.4%	81.3%

Improved over 8%

* Reserve margins with the same value are shown in the same background color after utilization of cross-regional interconnection line.

Table A1-6 Monthly Projection of Supply–Demand Balance in Okinawa in FY 2023 (10^4kW at the sending end)

[10^4kW]

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Peak Demand	107	130	156	158	161	160	138	118	101	109	103	98
Supply Capacity	156	190	199	208	205	203	199	175	176	177	167	180
Reserve Capacity	49	60	44	50	44	43	61	57	75	69	64	82
Reserve Margin	46.2%	45.9%	28.0%	31.5%	27.2%	27.0%	44.0%	48.2%	74.7%	63.2%	61.8%	84.1%

ii) Projection for FY 2024

Tables A1-7–A1-10 show the monthly supply–demand balance, such as peak demand, monthly supply capacity, monthly reserve capacity, and reserve margin for each regional service area in FY 2024. Table A1-11 shows the monthly projection of the reserve margin for each regional service area recalculated with power exchanges to areas below the 8% reserve margin; these projections are from areas with over 8% reserve margin with additional supply capacity according to the provision of Article 48 of the Act. Furthermore, Table A1-12 shows the monthly peak demand, supply capacity, reserve capacity, and reserve margin at the designated time.

Table A1-7 Monthly Peak Demand Forecast for Each Regional Service Area in FY 2024 (10^4kW at the sending end)

[10^4kW]

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	398	356	357	410	417	388	391	445	482	499	496	454
Tohoku	1,081	1,009	1,080	1,308	1,334	1,177	1,031	1,158	1,302	1,366	1,362	1,226
Tokyo	3,859	3,730	4,296	5,514	5,514	4,665	3,839	4,033	4,480	4,895	4,895	4,349
50Hz areas Total	5,338	5,095	5,733	7,232	7,265	6,230	5,261	5,636	6,264	6,760	6,753	6,029
Chubu	1,809	1,818	2,031	2,470	2,470	2,221	1,890	1,913	2,172	2,356	2,356	2,062
Hokuriku	385	350	403	493	493	436	373	410	476	518	518	452
Kansai	1,832	1,862	2,157	2,751	2,751	2,358	1,926	1,950	2,394	2,527	2,527	2,154
Chugoku	757	747	835	1,043	1,043	931	770	836	1,013	1,037	1,037	902
Shikoku	333	342	385	495	495	424	368	369	456	456	456	394
Kyushu	1,002	1,051	1,206	1,541	1,541	1,323	1,112	1,155	1,397	1,458	1,458	1,226
60Hz areas Total	6,117	6,170	7,016	8,793	8,793	7,693	6,439	6,633	7,907	8,352	8,352	7,190
Interconnected	11,455	11,265	12,749	16,025	16,058	13,923	11,700	12,269	14,171	15,112	15,105	13,219
Okinawa	108	131	155	158	159	161	139	119	101	109	104	99
Nationwide	11,563	11,396	12,904	16,183	16,217	14,083	11,838	12,387	14,272	15,221	15,209	13,318

Table A1-8 Monthly Projection of Supply Capacity for Each Regional Service Area in FY 2024 (10^4kW at the sending end)

[10^4kW]

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	510	542	521	512	584	555	537	583	631	615	622	574
Tohoku	1,425	1,451	1,437	1,701	1,736	1,513	1,369	1,430	1,618	1,662	1,649	1,549
Tokyo	4,603	4,423	4,773	6,217	6,233	5,906	4,452	4,383	5,787	5,905	5,922	5,619
50Hz areas Total	6,538	6,416	6,731	8,431	8,553	7,974	6,358	6,395	8,037	8,182	8,193	7,742
Chubu	2,227	2,359	2,688	2,997	3,016	2,659	2,338	2,321	2,618	2,684	2,705	2,442
Hokuriku	528	452	463	591	573	527	463	489	528	542	542	545
Kansai	2,411	2,451	2,699	3,162	3,232	3,038	2,499	2,549	2,959	2,878	2,909	2,596
Chugoku	1,001	1,040	1,126	1,396	1,482	1,307	1,148	1,115	1,255	1,362	1,318	1,277
Shikoku	593	616	694	697	690	613	599	611	656	677	674	630
Kyushu	1,370	1,393	1,573	1,776	1,796	1,628	1,476	1,424	1,691	1,730	1,709	1,560
60Hz areas Total	8,129	8,312	9,242	10,619	10,789	9,772	8,522	8,507	9,708	9,873	9,857	9,051
Interconnected	14,667	14,728	15,973	19,050	19,342	17,747	14,880	14,902	17,745	18,055	18,050	16,793
Okinawa	178	196	213	211	216	209	209	186	178	168	170	161
Nationwide	14,844	14,924	16,187	19,261	19,558	17,956	15,089	15,089	17,923	18,223	18,220	16,954

Table A1-9 Monthly Projection of Reserve Capacity for Each Regional Service Area in FY 2024 (10^4kW at the sending end)

[10^4kW]

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	112	186	164	102	167	167	146	138	149	116	126	120
Tohoku	344	442	357	393	402	336	338	272	316	296	287	323
Tokyo	744	693	477	703	719	1,241	613	350	1,307	1,010	1,027	1,270
50Hz areas Total	1,200	1,321	998	1,199	1,288	1,744	1,097	759	1,773	1,422	1,440	1,713
Chubu	418	541	657	527	546	438	448	408	446	328	349	380
Hokuriku	143	102	60	98	80	91	90	79	52	24	24	93
Kansai	580	589	542	411	481	680	573	599	565	351	382	442
Chugoku	244	293	291	353	439	376	378	279	242	325	281	375
Shikoku	260	274	309	202	195	189	231	242	200	221	218	236
Kyushu	368	342	367	235	255	305	364	269	294	272	251	334
60Hz areas Total	2,012	2,141	2,226	1,826	1,996	2,080	2,084	1,875	1,801	1,521	1,505	1,861
Interconnected	3,212	3,462	3,224	3,025	3,284	3,824	3,181	2,634	3,574	2,943	2,945	3,574
Okinawa	70	65	59	53	56	48	70	68	77	59	66	63
Nationwide	3,281	3,527	3,283	3,078	3,341	3,873	3,251	2,701	3,651	3,002	3,011	3,636

Table A1-10 Monthly Projection of Reserve Margin for Each Regional Service Area in FY 2024

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	28.1%	52.4%	46.0%	25.0%	40.2%	43.1%	37.4%	30.9%	31.0%	23.2%	25.5%	26.5%
Tohoku	31.9%	43.8%	33.0%	30.1%	30.1%	28.6%	32.8%	23.5%	24.3%	21.7%	21.0%	26.3%
Tokyo	19.3%	18.6%	11.1%	12.8%	13.0%	26.6%	16.0%	8.7%	29.2%	20.6%	21.0%	29.2%
50Hz areas Total	22.5%	25.9%	17.4%	16.6%	17.7%	28.0%	20.9%	13.5%	28.3%	21.0%	21.3%	28.4%
Chubu	23.1%	29.8%	32.4%	21.3%	22.1%	19.7%	23.7%	21.3%	20.5%	13.9%	14.8%	18.4%
Hokuriku	37.3%	29.1%	15.0%	20.0%	16.2%	20.8%	24.2%	19.2%	11.0%	**4.7%**	**4.6%**	20.6%
Kansai	31.7%	31.6%	25.1%	14.9%	17.5%	28.9%	29.7%	30.7%	23.6%	13.9%	15.1%	20.5%
Chugoku	32.2%	39.3%	34.9%	33.8%	42.1%	40.4%	49.1%	33.4%	23.9%	31.3%	27.1%	41.6%
Shikoku	77.9%	80.1%	80.2%	40.8%	39.4%	44.6%	62.7%	65.6%	44.0%	48.4%	47.7%	60.0%
Kyushu	36.7%	32.6%	30.4%	15.2%	16.6%	23.1%	32.8%	23.3%	21.1%	18.6%	17.2%	27.3%
60Hz areas Total	32.9%	34.7%	31.7%	20.8%	22.7%	27.0%	32.4%	28.3%	22.8%	18.2%	18.0%	25.9%
Interconnected	28.0%	30.7%	25.3%	18.9%	20.5%	27.5%	27.2%	21.5%	25.2%	19.5%	19.5%	27.0%
Okinawa	65.0%	49.4%	37.8%	33.7%	35.4%	30.2%	50.7%	57.1%	76.2%	53.7%	63.7%	63.5%
Nationwide	28.4%	30.9%	25.4%	19.0%	20.6%	27.5%	27.5%	21.8%	25.6%	19.7%	19.8%	27.3%

Below 8% criteria

Table A1-11 Monthly Projection of Reserve Margin for Each Regional Service Area in FY 2024

(Power exchanges through cross-regional interconnection lines and generating facilities are not included at the sending end at the sending end of the electricity supply plans,)

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	22.9%	34.8%	38.1%	22.7%	37.8%	41.0%	26.9%	18.5%	25.3%	18.9%	19.0%	26.5%
Tohoku	22.9%	34.3%	28.0%	21.0%	16.7%	26.5%	26.9%	18.5%	25.3%	18.9%	19.0%	26.5%
Tokyo	22.9%	23.6%	13.5%	15.4%	16.7%	26.5%	18.6%	11.5%	25.3%	18.9%	19.0%	26.5%
Chubu	25.5%	33.2%	30.0%	20.6%	22.5%	26.5%	31.7%	26.6%	24.5%	18.9%	19.0%	26.5%
Hokuriku	34.3%	33.2%	30.0%	20.6%	22.5%	26.5%	31.7%	26.6%	24.5%	18.9%	19.0%	26.5%
Kansai	34.3%	33.2%	30.0%	20.6%	22.5%	28.1%	32.7%	26.6%	24.5%	18.9%	19.0%	26.5%
Chugoku	34.3%	33.2%	30.0%	20.6%	22.5%	28.1%	32.7%	26.6%	24.5%	18.9%	19.0%	26.5%
Shikoku	49.1%	52.2%	55.4%	20.6%	22.5%	28.1%	32.7%	55.6%	35.0%	39.4%	35.2%	46.0%
Kyushu	34.3%	33.2%	30.0%	20.6%	22.5%	28.1%	32.7%	26.6%	24.5%	18.9%	19.0%	26.5%
Okinawa	65.0%	49.4%	37.8%	33.7%	35.4%	30.2%	50.7%	57.1%	76.2%	53.7%	63.7%	63.5%

Improved over 8%

* Reserve margins with the same value are shown in the same background color after utilization of cross-regional interconnection line.

Table A1-12 Monthly Projection of Supply–Demand Balance in Okinawa in FY 2024 (10^4kW at the sending end)

[10^4kW]

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Peak Demand	108	131	157	159	162	161	139	119	101	109	104	99
Supply Capacity	182	200	216	214	220	217	213	191	180	169	171	164
Reserve Capacity	74	69	59	55	58	56	74	73	79	60	68	65
Reserve Margin	68.7%	52.7%	37.9%	34.5%	35.5%	35.1%	53.2%	61.1%	78.3%	55.1%	65.2%	66.3%

APPENDIX 2 Long-Term Supply–Demand Balance for 10 years: FY 2023–2032

Tables A2-1 and A2-2 show a 10-year projection of the annual peak demand and annual supply capacity for each regional service area from FY 2023 to 2032, respectively. Tables A2-3 and A2-4 show a 10-year projection of the annual peak demand and annual supply capacity for winter peak areas of Hokkaido, Tohoku, and Hokuriku, respectively. Furthermore, Table A2-5 shows Okinawa's annual projection of supply–demand balance.

Table A2-1 Annual Peak Demand Forecast for Each Regional Service Area
(At 15:00 in August, 10^4kW at the sending end)

[10^4kW]

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Hokkaido	416	417	417	417	417	417	417	417	417	417
Tohoku	1,338	1,334	1,330	1,325	1,320	1,315	1,311	1,306	1,301	1,296
Tokyo	5,499	5,514	5,509	5,503	5,496	5,490	5,483	5,475	5,467	5,459
50Hz areas Total	7,253	7,265	7,256	7,245	7,233	7,222	7,211	7,198	7,185	7,172
Chubu	2,455	2,470	2,461	2,452	2,443	2,434	2,424	2,414	2,405	2,395
Hokuriku	495	493	492	491	489	488	487	486	484	483
Kansai	2,741	2,751	2,745	2,735	2,726	2,718	2,710	2,701	2,691	2,683
Chugoku	1,043	1,043	1,042	1,041	1,039	1,038	1,037	1,036	1,034	1,033
Shikoku	497	495	493	490	487	485	482	480	477	474
Kyushu	1,537	1,541	1,538	1,535	1,531	1,527	1,523	1,518	1,513	1,508
60Hz areas Total	8,768	8,793	8,771	8,744	8,715	8,690	8,663	8,635	8,604	8,576
Interconnected	16,021	16,058	16,027	15,989	15,948	15,912	15,874	15,833	15,789	15,748
Okinawa	158	159	163	164	165	166	167	168	169	170
Nationwide	16,179	16,217	16,190	16,152	16,113	16,078	16,041	16,000	15,958	15,918

Table A2-2 Annual Projection of Supply Capacity for Each Regional Service Area
(At 15:00 in August, 10^4kW at the sending end)

[10^4kW]

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Hokkaido	548	584	539	611	589	606	611	617	612	612
Tohoku	1,764	1,736	1,622	1,659	1,660	1,670	1,686	1,695	1,718	1,746
Tokyo	5,853	6,233	6,002	5,776	5,926	5,953	5,962	5,974	5,976	5,936
50Hz areas Total	8,165	8,553	8,163	8,046	8,175	8,229	8,259	8,286	8,306	8,293
Chubu	2,912	3,016	2,755	2,705	2,774	2,773	2,775	2,777	2,646	2,650
Hokuriku	542	573	576	586	575	579	585	585	589	592
Kansai	3,111	3,232	2,906	2,908	2,912	2,901	2,905	2,905	2,908	2,821
Chugoku	1,449	1,482	1,384	1,329	1,324	1,320	1,324	1,324	1,329	1,323
Shikoku	727	690	668	675	676	674	675	681	681	683
Kyushu	1,907	1,796	1,640	1,703	1,664	1,661	1,666	1,714	1,718	1,726
60Hz areas Total	10,648	10,789	9,928	9,906	9,925	9,907	9,929	9,986	9,871	9,794
Interconnected	18,813	19,342	18,091	17,952	18,100	18,136	18,188	18,272	18,177	18,087
Okinawa	201	216	221	211	226	226	226	214	226	226
Nationwide	19,014	19,558	18,312	18,163	18,326	18,363	18,414	18,487	18,404	18,313

* The Supply capacity for Okinawa in FY 2023 and 2024 shows that the supply capacity falls to the least reserve margin.

Table A2-3 Annual Peak Demand Forecast for Winter Peak Areas of Hokkaido, Tohoku, and Hokuriku
(At 18:00 in January, 10^4kW at the sending end)

[10^4kW]

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Hokkaido	498	499	499	499	499	499	499	499	499	499
Tohoku	1,369	1,366	1,361	1,356	1,351	1,346	1,342	1,336	1,331	1,327
Hokuriku	518	518	518	518	517	517	517	517	517	516

Table A2-4 Annual Projection of Supply Capacity for Winter Peak Areas of Hokkaido, Tohoku, and Hokuriku
(At 18:00 in January, 10^4kW at the sending end)

[10^4kW]

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Hokkaido	602	615	632	617	599	614	617	622	618	618
Tohoku	1,687	1,662	1,707	1,708	1,706	1,720	1,735	1,747	1,770	1,799
Hokuriku	524	542	589	597	586	590	594	596	599	602

Table A2-5 Annual Projection of Supply–Demand Balance in Okinawa (10^4kW at the sending end)

[10^4kW]

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Peak Demand	161	162	163	164	165	166	167	168	169	170
Supply Capacity	205	220	221	211	226	226	226	214	226	226
Reserve Capacity	44	58	58	47	61	61	59	47	57	57
Reserve Margin	27.2%	35.5%	35.4%	28.8%	37.3%	36.6%	35.6%	27.8%	34.0%	33.3%