Aggregation of Electricity Supply Plans
Fiscal Year 2019

May 2019

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 fiscal year (FY) 2019 according to Articles 29 and 181 of the Operational Rules of the Organization and Paragraph 1, Article 29 of the Electricity Business Act, which require the plans to be submitted by electric power companies (EPCOs), and publish their results.
The Organization has aggregated the plans for FY 2019 according to Article 29 of the Act and Article 28 of the Operational Rules, which were submitted to the Ministry of Economy, Trade and Industry (METI) under the same article of the Act.
The electricity supply plans are submitted by the EPCOs according to the Network Code of the Organization, aggregated by the Organization, and sent to METI annually by the end of March.
In total, 1,299 electricity supply plans for FY 2019 were aggregated, including 1,296 plans submitted by companies that became EPCOs by the end of November 2018 and three plans submitted by companies that became EPCOs by March 1, 2019.

Number of Electric Power Companies Subject to the Aggregation in FY 2019

Business License	Number
Generation Companies	725
Retail Companies	535
Specified Transmission, Distribution and Retail Companies	22
Specified Transmission and Distribution Companies	5
Transmission Companies	2
General Transmission and Distribution Companies	10
Total	1,299

CONTENTS

I. Electricity Demand Forecast 1
1. Actual and Preliminary Data for FY 2018 and Forecast for FY 2019 (Short-Term) 1
2. 10-Year Demand Forecast (Long-Term) 3
II. Electricity Supply and Demand 5
1. Supply–Demand Balance Evaluation Method 5
2. Actual Data for FY 2018 and Projection for FY 2019 (Short-Term) 6
3. Projection of Supply–Demand Balance for 10 years (Long-Term) 10
III. Analysis of the Transition of Power Generation Sources 19
1. Transition of Power Generation Sources (Capacity) 19
2. Transition of Gross Electric Energy Generation 21
3. Transition of Capacity Factor by Power Generation Sources 23
4. Installed Power Generation Capacity and Gross Electric Energy Generation for Each Regional Service Area 25
5. Development Plans by Power Generation Sources 26
IV. Development Plans for Transmission and Distribution Facilities 27
1. Development Plans for Major Transmission Lines 30
2. Development Plans for Major Substations 33
3. Summary of Development Plans for Transmission Lines and Substations 35
V. Cross-Regional Operation 37
VI. Analysis of Characteristics of Electric Power Companies 40
1. Distribution of Retail Companies by Business Scale (Retail Demand) 40
2. Retail Company Business Areas 42
3. Supply Capacity Procurement by Retail Companies 43
4. Distribution of Generation Companies by Business Scale (Installed Capacity) 46
5. Generation Company Business Areas 49
VII. Findings and Current Challenges 51
VIII. Conclusions 57
APPENDIX 1 Supply–Demand Balance for FY 2019 .... A1
APPENDIX 2 Long-Term Supply–Demand Balance for the 10-year Period FY 2019–2028 .... A3

I. Electricity Demand Forecast

1. Actual and Preliminary Data for FY 2018 and Forecast for FY 2019 (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 the 10 general transmission and distribution (GT&D) companies for FY 2018 and the forecast[3] value for FY 2019.

Peak demand (average value of the three highest daily loads) for FY 2019 was forecast at 159,070 MW, which represents a 0.4% decrease over 159,700 MW, that is, the temperature-adjusted[4] value for FY 2018.

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

FY 2018 Actual (temperature adjusted)	FY 2019 Forecast
15,970	15,907 (-0.4%)*

* % change compared with actual data for the previous year

b. Forecast for FY 2019

Table 1-2 shows the monthly average value of the three highest daily loads in FY 2019 from the aggregated peak demand for each regional service area submitted by the 10 GT&D companies. The monthly average value of the three highest daily loads in summer (August) is greater than that in winter (January) by about 10 GW; therefore, nationwide peak demand occurs in summer.

Table 1-2 Monthly Peak Demand (average value of the three highest daily loads) in FY 2019
(nationwide, 10^4 kW at the sending end)

	Apr.	May	Jun.	Jul.	Aug.	Sep.
Peak Demand	11,641	11,446	12,748	15,872	15,907	13,899
	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Peak Demand	11,887	12,552	14,285	14,892	14,870	13,536

[1] Peak demand (average value of the three highest daily loads) corresponds to the average value of the three highest daily loads (hourly average) in 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 2019 is based on normal weather. Thus, weather conditions for forecast assumption may vary in contrast to the actual data or estimated value in FY 2018.

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

c. Annual Electric Energy Requirements

Table 1-3 shows the preliminary data[5] for FY 2018 and the forecast value for FY 2019 from the aggregated electric energy requirements of each regional service area submitted by the 10 GT&D companies. The electric energy requirements for FY 2019 are forecast at 890.5 TWh, a 0.4% increase over the 886.9 TWh in the preliminary data for FY 2018.

Table 1-3 Annual Electric Energy Requirements
(nationwide, TWh at the sending end)

FY 2018 Preliminary (temperature-adjusted)	FY 2019 Forecast
886.9	890.5 (+0.4%)*

* % 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 2018 with the preliminary data from December 2018 to March 2019.

2. 10-Year Demand Forecast (Long-Term)

Table 1-4 shows the major economic indicators developed and published on November 28, 2018 by the Organization, which are assumptions for the GT&D companies to forecast the peak demand in their regional service areas.

The real gross domestic product (GDP)[6] is estimated at ¥538.3 trillion in FY 2018 and ¥572.5 trillion in FY 2028 with an annual average growth rates (AAGR) of 0.6%. The index of industrial production (IIP)[7] is projected at 104.3 in FY 2018 and 108.5 in FY 2028 with an AAGR of 0.4%.

Table 1-4 Major Economic Indicators Assumed for Demand Forecast

	FY 2018	FY 2028
Gross Domestic Product(GDP)	¥538.3 trillion	¥572.5 trillion [+0.6%]*
Index of Industrial Product(IIP)	104.3	108.5 [+0.4%]*

* Average annual growth rate for the forecast value of FY 2018

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

Table 1-5 shows the peak demand forecast for FY 2019, FY 2023, and FY 2028 as the aggregation of peak demand for each regional service area submitted by the 10 GT&D companies. In addition, Figure 1-1 shows the actual data and the forecast of peak demand from FY 2006 to 2028. The peak demand nationwide is forecast at 158,140 MW in FY 2023 and 157,350 MW in FY 2028, with an AAGR of minus 0.1% from FY 2018 to FY 2028.

The peak demand forecast over 10 years shows a slightly decreasing trend, which is largely due to negative factors, such as efforts to reduce electricity use, wider utilization of energy-saving electric appliances, a shrinking population, and load-leveling measures, and despite positive factors such as the expansion of economic scale and greater dissemination of electric appliances.

In addition, the AAGR forecast is lower than that of the previous year, mainly due to a declining level of economic activity and a decreasing trend in actual electricity demand because of progress in energy conservation.

Table 1-5 Peak Demand Forecast (average value of the three highest daily loads) for August (nationwide, 10^4 kW at the sending end)

FY 2019 [aforementioned]	FY 2023	FY 2028
15,907	15,814 [-0.2%]*	15,735 [-0.1%]*

* Average Annual Growth Rate for the forecast value of FY 2018

[6] GDP expressed as the chained price for CY 2011.
[7] Index value in CY 2015 = 100

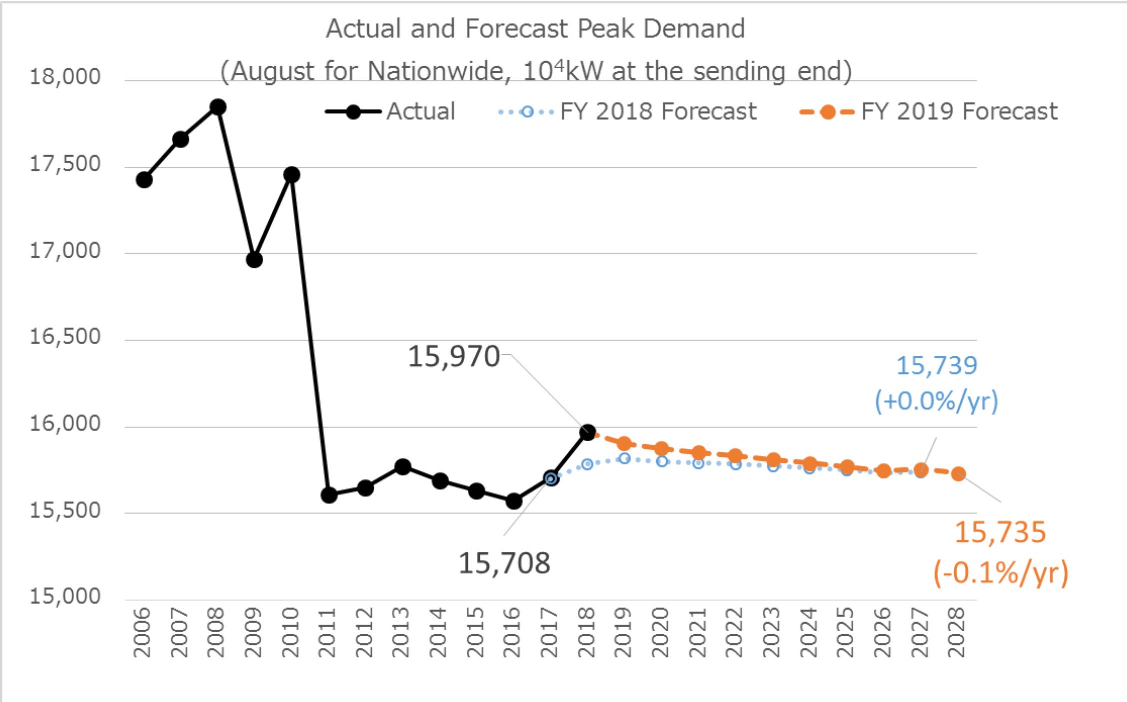

Figure 1-1 Actual and Forecast Peak Demand (August for Nationwide, 10^4 kW at the sending end)

b. Annual Electric Energy Requirement

Table 1-6 shows the forecast for annual electric energy requirements in FY 2019, FY 2023, and FY 2028 as the aggregation of the electric energy requirements for each regional service area submitted by the 10 GT&D companies. The nationwide annual electric energy requirement is forecast at 884.6 TWh in FY 2023 and 882.1 TWh in FY 2028, with an AAGR of minus 0.1% from FY 2018 to FY 2028.

The annual electric energy requirement forecast over 10 years shows a slightly decreasing trend, which is largely due to negative factors, such as efforts to reduce electricity use, wider utilization of energy-saving electric appliances, and a shrinking population, and despite positive factors such as the expansion of economic scale and greater dissemination of electric appliances.

Table 1-6 Annual Electric Energy Requirement Forecast
(nationwide, TWh at the sending end)

FY 2019 [aforementioned]	FY 2023	FY 2028
890.5	884.6 [-0.1%]*	882.1 [-0.1%]*

* AAGR for the forecast value of FY 2018.

II. Electricity Supply and Demand

1. Supply–Demand Balance Evaluation Method

The Organization will evaluate the supply–demand balance for each regional service area as well as nationwide using the supply capacity[8] and peak demand data for the regional service areas. Based on the discussion at the 37th meeting of the Study Committee on Regulating and Marginal Supply Capability and Long-Term Supply–Demand Balance Evaluation (March 20, 2019), the Organization will implement its evaluation using the criterion of whether the reserve margin (%)[9] for each regional service area is secured over 8% or not, and when the least reserve margin emerges at the time other than the average value of the three highest daily loads, the least reserve margin also is secured over 8%.

In the Okinawa EPCO regional service area, the criterion is to secure power supply capacity over peak demand against an interruption of its largest generating unit and balancing capacity with frequency control function in its regional service area.

Figure 2-1 summarizes the supply–demand balance evaluation. Supply capacity includes the generating capacity requirements secured by retail and GT&D companies for their regional service areas and the production of surplus power[10] of generation companies. The supply capacity currently secured by retail companies includes power procured[11] from other regional service areas through cross-regional interconnection lines. Thus, the surplus power of generation companies or reserve capacity of retail companies might provide supply capacity for other regional service areas in the future.

Under the circumstances in which the operation of a nuclear power plant has become uncertain, the supply capacity of the corresponding unit or plant is recorded as zero where the corresponding supply capacity is reported as "uncertain" according to Procedures for Electricity Supply Plans of FY 2019 (published in December 2018 by the Agency for Natural Resources and Energy). In the electricity supply plans for FY 2019, supply capacity was reported as "uncertain" by all nuclear power plants except for those that had resumed operation by the time of the submission of the electricity supply plans (March 1, 2019).

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

[9] 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).

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

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

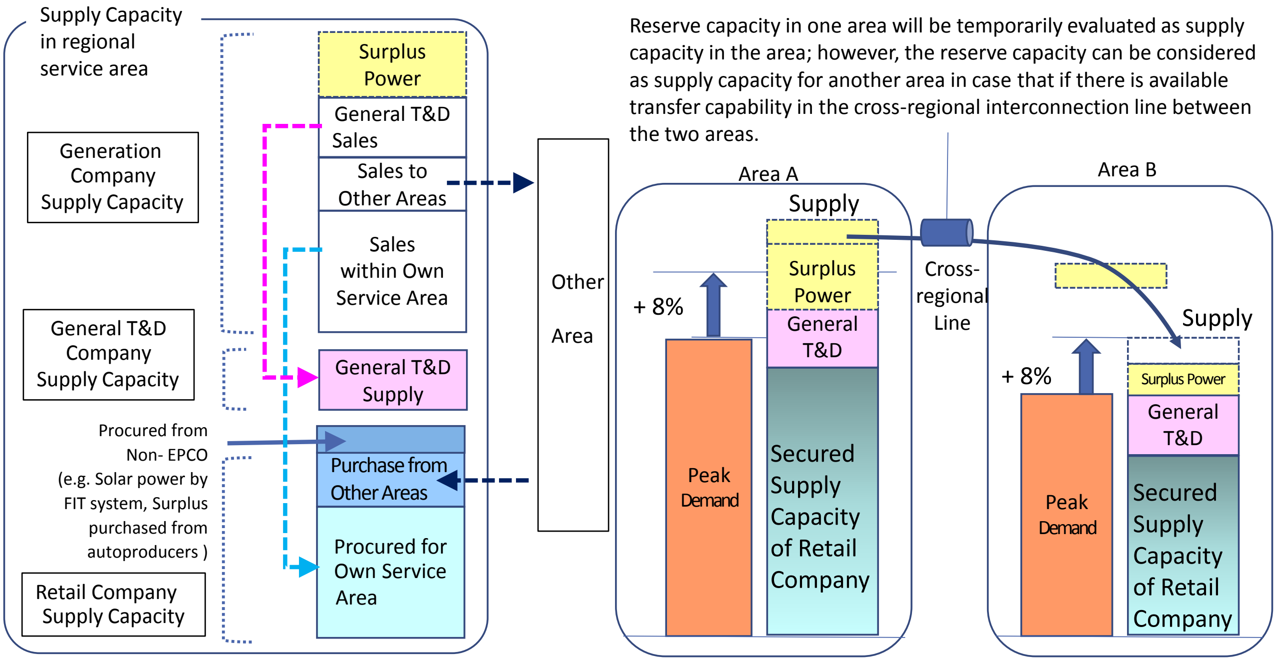

Figure 2-1 Summary of Supply–Demand Balance Evaluation

2. Actual Data for FY 2018 and Projection for FY 2019 (Short-Term)

a. Actual Data for FY 2018

Table 2-1 shows the actual supply–demand balance in August 2018 based on the nationwide supply capacity and peak demand data.

A reserve margin of 8%, which is the criterion for stable supply, was secured in all regional service areas supplied by GT&D companies.

Table 2-1 Actual Supply–Demand Balance in August 2018
(nationwide, 10^4 kW at the sending end)

Peak Demand (temperature adjusted) [aforementioned]	Supply Capacity (nationwide)	Reserve Capacity	Reserve Margin
15,970	17,891	1,921	10.7%

Table 2-2 shows the actual supply–demand balance in each regional service area in August 2018. A reserve margin of 8% could not be secured in the Tokyo area; a reserve margin of 3%, which is the criterion for stable daily operation, was secured.

Table 2-2 Actual Supply–Demand Balance in August 2018
(each regional service area, 10^4 kW at the sending end)

	Hokkaido	Tohoku	Tokyo	Chubu	Hokuriku	Kansai	Chugoku	Shikoku	Kyushu	Okinawa
Peak Demand	419	1,297	5,377	2,473	504	2,639	1,028	504	1,552	150
Supply Capacity	550	1,603	5,697	2,736	582	2,886	1,222	551	1,877	187
Reserve Margin	31.4%	23.6%	6.0%	10.6%	15.4%	9.4%	19.0%	9.2%	20.9%	24.7%

b. Projection of Supply–Demand Balance in FY 2019

Table 2-3 and Figure 2-2 show the projection of a monthly supply–demand balance (at the time of the least reserve margin) for FY 2019. A reserve margin of 8% is secured for each month nationwide.

Table 2-3 Projection of the Monthly Supply–Demand Balance for FY 2019
(at the time of the least reserve margin; nationwide, 10^4 kW at the sending end)

	Apr.	May	Jun.	Jul.	Aug.	Sep.
Peak Demand	11,623	11,389	12,640	15,661	15,680	13,826
Supply Capacity	14,679	14,535	15,016	17,253	17,141	16,303
Reserve Margin	26.3%	27.6%	18.8%	10.2%	9.3%	17.9%
	Oct.	**Nov.**	**Dec.**	**Jan.**	**Feb.**	**Mar.**
Peak Demand	11,861	12,552	14,285	14,892	14,870	13,536
Supply Capacity	14,218	14,668	16,130	16,893	16,836	16,228
Reserve Margin	19.9%	16.9%	12.9%	13.4%	13.2%	19.9%

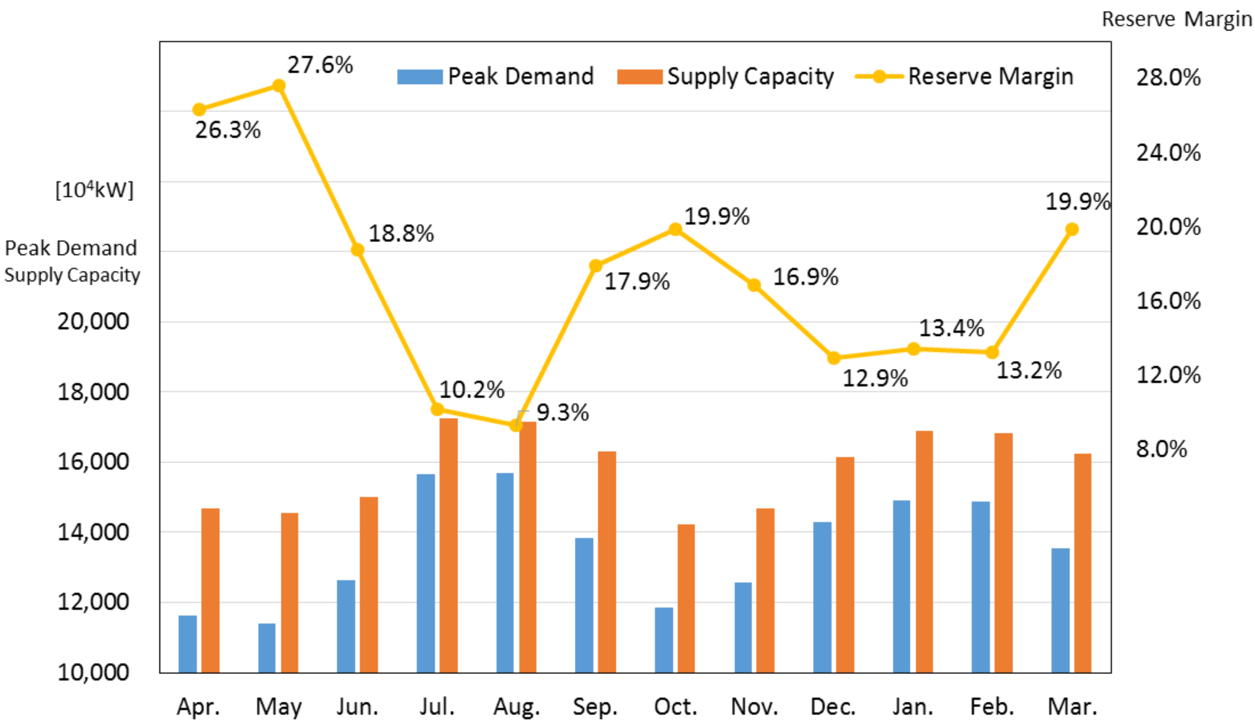

Figure 2-2 Projection of the Monthly Supply–Demand Balance for FY 2019
(at the time of the least reserve margin; nationwide, at the sending end)

Table 2-4 shows the monthly projection of the least reserve margin for each regional service area. In addition, Table 2-5 shows the monthly projection of the least reserve margin[12] for each regional service area recalculated using power exchanges to areas below the 8% reserve margin from areas of over 8% reserve margin based on the available transfer capability (ATC)[13].

The least reserve margin for each regional service area almost secures the criterion of a stable supply, with a reserve margin of 8%, except for some areas and months. However, a nationwide reserve margin of 8% (the criterion of stable supply) is secured by using cross-regional interconnection lines to share power from other areas with sufficient supply capacity.

Table 2-4 Monthly Projection of the Least Reserve Margins Nationwide and for Each Regional Service Area (resources within own service area only, at the sending end)

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	36.2%	47.4%	57.0%	21.1%	22.2%	24.9%	19.7%	19.5%	25.0%	19.6%	21.5%	23.8%
Tohoku	19.8%	26.8%	16.9%	14.3%	11.5%	13.1%	9.8%	12.0%	11.3%	10.9%	12.0%	12.4%
Tokyo	20.2%	30.8%	18.7%	8.5%	8.7%	22.6%	23.8%	16.5%	20.0%	18.4%	16.7%	23.8%
50 Hz area Total	21.3%	31.2%	20.9%	10.3%	10.0%	20.9%	20.6%	15.8%	18.6%	16.9%	16.1%	21.4%
Chubu	26.9%	21.1%	19.7%	8.4%	10.1%	17.8%	19.0%	17.2%	8.7%	10.1%	11.8%	17.6%
Hokuriku	28.1%	24.0%	15.0%	16.1%	11.0%	15.6%	13.3%	8.1%	13.7%	9.4%	9.3%	16.2%
Kansai	30.6%	25.3%	14.0%	6.5%	5.5%	16.0%	19.9%	19.9%	8.7%	11.8%	10.4%	17.3%
Chugoku	24.1%	21.9%	16.8%	12.6%	11.2%	14.8%	19.3%	12.6%	0.6%	8.4%	9.8%	16.6%
Shikoku	42.9%	39.9%	30.1%	20.2%	16.1%	14.9%	23.8%	26.0%	15.8%	4.2%	5.3%	2.4%
Kyushu	35.5%	26.0%	12.7%	9.6%	4.8%	9.3%	16.3%	15.9%	5.4%	9.6%	9.1%	25.7%
60 Hz area Total	30.1%	24.5%	16.8%	9.7%	8.3%	15.1%	18.8%	17.1%	7.8%	9.9%	10.1%	17.8%
Interconnected	26.0%	27.5%	18.6%	9.9%	9.1%	17.7%	19.6%	16.5%	12.5%	13.0%	12.8%	19.4%
Okinawa	55.3%	41.9%	35.7%	33.1%	33.5%	38.1%	46.9%	53.9%	73.8%	70.3%	78.0%	84.3%
Nationwide	26.3%	27.6%	18.8%	10.2%	9.3%	17.9%	19.9%	16.9%	12.9%	13.4%	13.2%	19.9%

Below 8% Criteria

Table 2-5 Monthly Projection of the Least Reserve Margins Nationwide and for Each Regional Service Area (with power exchanges through cross-regional interconnection lines, at the sending end)

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	21.3%	29.8%	45.2%	11.3%	12.4%	19.2%	19.6%	16.0%	16.9%	15.4%	14.6%	22.3%
Tohoku	21.3%	28.9%	17.8%	11.3%	9.0%	19.2%	19.6%	16.0%	16.9%	15.4%	14.6%	19.3%
Tokyo	21.3%	28.9%	17.8%	9.8%	9.0%	19.2%	19.6%	16.0%	16.9%	15.4%	14.6%	19.3%
Chubu	30.1%	26.3%	17.8%	9.8%	9.0%	16.8%	19.6%	17.0%	9.1%	11.1%	11.3%	19.3%
Hokuriku	30.1%	26.3%	17.8%	9.8%	9.0%	16.4%	19.6%	17.0%	9.1%	11.1%	11.3%	19.3%
Kansai	30.1%	26.3%	17.8%	9.8%	9.0%	16.4%	19.6%	17.0%	9.1%	11.1%	11.3%	19.3%
Chugoku	30.1%	26.3%	17.8%	9.8%	9.0%	16.4%	19.6%	17.0%	9.1%	11.1%	11.3%	19.3%
Shikoku	30.1%	26.3%	17.8%	9.8%	9.0%	16.4%	19.6%	17.0%	9.1%	11.1%	11.3%	19.3%
Kyushu	30.1%	26.3%	17.8%	9.8%	9.0%	16.4%	19.6%	17.0%	9.1%	11.1%	11.3%	19.5%
Interconnected	26.0%	27.5%	18.6%	9.9%	9.1%	17.7%	19.6%	16.5%	12.5%	13.0%	12.8%	19.4%
Okinawa	55.3%	41.9%	35.7%	33.1%	33.5%	38.1%	46.9%	53.9%	73.8%	70.3%	78.0%	84.3%
Nationwide	26.3%	27.6%	18.8%	10.2%	9.3%	17.9%	19.9%	16.9%	12.9%	13.4%	13.2%	19.9%

Improved to over 8%

[12] This evaluation is implemented based on the following. The evaluation of 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.

[13] The projection of the reserve margin is based on the ATC of transactions among areas indicated in the electricity supply plan.

In the Okinawa EPCO regional service area,[14] which is a small and isolated island system unable to receive power through interconnection lines, the criterion of stable supply is to secure supply capacity over peak demand by deducting the capacity of the largest generating unit and balancing capacity with frequency control ('Generator I', total of 301 MW), without applying the criteria of other interconnected areas. Table 2-6 shows the monthly reserve margin against the deduction of the capacity of Generator I, which indicates the stable supply was secured in each month.

Table 2-6 Monthly Reserve Margin against the Deduction of the Capacity of Generator I (at the sending end)

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Okinawa	26.4%	17.1%	14.0%	12.7%	13.1%	17.1%	24.2%	27.0%	43.4%	41.3%	48.8%	53.4%

[14] In the Okinawa EPCO regional service area, the evaluation excludes the reserve margins of several isolated islands.

3. Projection of Supply–Demand Balance for 10 years (Long-Term)

a. Supply–Demand Balance

Table 2-7 and Figure 2-3 show the annual supply–demand balance projection for a 10-year period. A reserve margin of 8% is secured each year nationwide.

Table 2-7 Annual Supply–Demand Balance Projection from FY 2019 to 2028
(nationwide at 17:00 in August, 10^4 kW at the sending end)

	2019	2020	2021	2022	2023
Peak Demand	15,556	15,526	15,504	15,483	15,463
Supply Capacity	17,088	17,575	17,113	16,980	17,303
Reserve Margin	9.8%	13.2%	10.4%	9.7%	11.9%
	2024	2025	2026	2027	2028
Peak Demand	15,441	15,421	15,399	15,406	15,385
Supply Capacity	17,365	17,480	17,476	17,530	17,537
Reserve Margin	12.5%	13.4%	13.5%	13.8%	14.0%

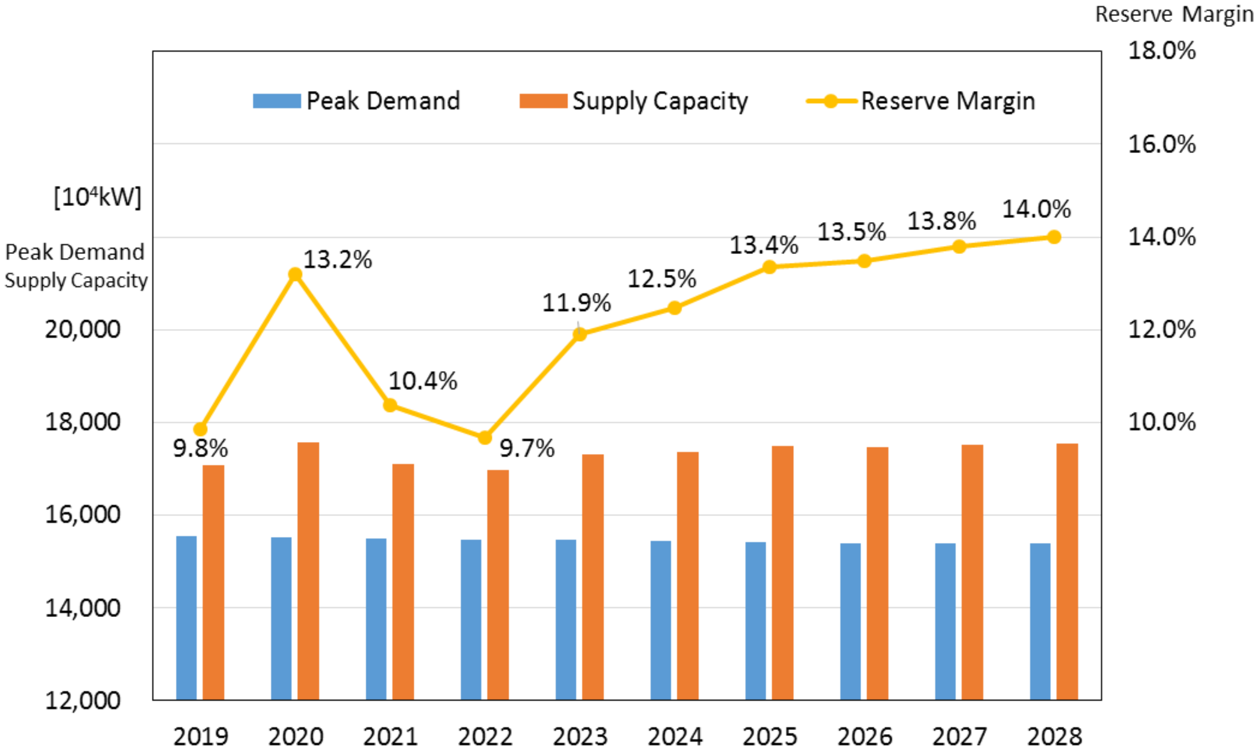

Figure 2-3 Mid-to-Long-Term Annual Supply–Demand Balance Projection
(nationwide at 17:00 in August, at the sending end)

The hours with the least reserve margins vary; for example, 15:00 in the areas of Tokyo, and Shikoku[15], 17:00 in the areas of Hokkaido, Tohoku, Chubu, Hokuriku, Kansai, and Chugoku, 19:00 in the Kyushu area, and 20:00 in Okinawa. Reserve margins at each time calculation include some areas and years that cannot achieve the criterion of a stable supply, i.e., a reserve margin of 8%. However, the criterion of a stable supply is projected to be secured in all areas and years by sharing power from other areas with sufficient supply capacity through cross-regional interconnection lines (see Referential Review A).

Table 2-8 shows the annual projection of reserve margins at 17:00 in August judged as the most severe supply–demand balance for each regional service area from FY 2019 to 2028. Table 2-9 shows these projections recalculated by adding power exchanges for the years and areas of below 8% reserve margin even with additional generated surplus from areas of over 8% reserve margin based on the ATC.

The evaluation shows that the reserve margin will fall below 8% as follows: in the Tokyo EPCO regional service area in FY 2022; in the Chubu EPCO area in FY 2021–2028; and in the Kansai EPCO area in FY 2019, and 2021–2028. However, all areas will be projected to secure 8% reserve margin required for a stable supply by sharing power from other areas with sufficient supply capacity through cross-regional interconnection lines during the projected period.

Table 2-8 Annual Projection of Reserve Margins for Each Regional Service Area
(at 17:00 in August, resources within own service area only, at the sending end)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Hokkaido	22.2%	21.3%	36.8%	37.4%	38.5%	39.0%	39.3%	38.7%	50.0%	50.1%
Tohoku	11.5%	8.7%	18.5%	20.0%	20.3%	21.3%	21.8%	24.6%	25.1%	25.7%
Tokyo	9.0%	12.4%	9.8%	6.6%	9.9%	12.1%	16.5%	15.8%	15.5%	15.5%
50 Hz area Total	10.3%	12.3%	13.1%	11.0%	13.6%	15.4%	18.9%	18.8%	19.3%	19.5%
Chubu	10.1%	9.2%	1.0%	4.2%	4.8%	5.4%	5.6%	6.3%	6.2%	6.7%
Hokuriku	11.0%	11.7%	10.2%	9.9%	9.9%	9.8%	8.8%	8.6%	8.4%	8.3%
Kansai	5.5%	11.5%	3.3%	4.6%	7.1%	7.5%	3.4%	4.3%	4.7%	4.9%
Chugoku	11.2%	16.2%	19.3%	11.0%	14.6%	15.0%	15.6%	16.0%	15.8%	16.1%
Shikoku	16.1%	30.2%	13.6%	11.5%	21.2%	21.2%	21.7%	22.1%	22.5%	22.8%
Kyushu	9.1%	16.7%	15.5%	16.5%	17.3%	12.1%	12.1%	10.9%	11.0%	11.0%
60 Hz area Total	9.1%	13.4%	7.8%	8.1%	10.2%	9.6%	8.4%	8.7%	8.8%	9.1%
Interconnected	9.6%	12.9%	10.1%	9.4%	11.7%	12.2%	13.1%	13.2%	13.5%	13.7%
Okinawa	35.7%	42.1%	36.1%	38.5%	33.9%	41.1%	40.7%	40.0%	39.5%	39.0%
Nationwide	9.8%	13.2%	10.4%	9.7%	11.9%	12.5%	13.4%	13.5%	13.8%	14.0%

Below 8% Criteria

[15] At 17:00 beyond the third year of the projection.

Table 2-9 Annual Projection of Reserve Margins for Each Regional Service Area
(at 17:00 in August, with power exchanges through cross-regional interconnection lines, at the sending end)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Hokkaido	12.4%	12.3%	27.6%	27.2%	28.3%	28.8%	29.0%	29.0%	40.4%	40.4%
Tohoku	9.5%	12.3%	9.6%	8.7%	11.2%	11.7%	14.6%	14.8%	14.6%	13.2%
Tokyo	9.5%	12.3%	9.6%	8.7%	11.2%	11.7%	14.6%	14.8%	14.6%	13.2%
Chubu	9.5%	13.4%	9.6%	8.7%	11.2%	11.7%	11.1%	11.3%	11.4%	12.8%
Hokuriku	9.5%	13.4%	9.6%	8.7%	11.2%	11.7%	11.1%	11.3%	11.4%	12.8%
Kansai	9.5%	13.4%	9.6%	8.7%	11.2%	11.7%	11.1%	11.3%	11.4%	12.8%
Chugoku	9.5%	13.4%	9.6%	8.7%	11.2%	11.7%	11.1%	11.3%	11.4%	12.8%
Shikoku	9.5%	13.4%	9.6%	8.7%	11.2%	11.7%	11.1%	11.3%	11.4%	12.8%
Kyushu	9.5%	13.4%	9.9%	10.5%	11.2%	11.7%	11.1%	11.3%	11.4%	12.8%
Interconnected	9.6%	12.9%	10.1%	9.4%	11.7%	12.2%	13.1%	13.2%	13.5%	13.7%
Okinawa	35.7%	42.1%	36.1%	38.5%	33.9%	41.1%	40.7%	40.0%	39.5%	39.0%
Nationwide	9.8%	13.2%	10.4%	9.7%	11.9%	12.5%	13.4%	13.5%	13.8%	14.0%

Improved above Criteria

The Organization did not count newly developing facilities at EPCOs that are not obliged to submit development plans or at EPCOs that are obliged to submit plans, but that have not reported such plans. Therefore, the Organization has investigated generating facilities that are not included in the electricity supply plans, although they were already applied to generator connection to GT&D companies and submitted construction plans according to the provisions of Article 48 of the Act in cooperation with the Government.

As a result, there are 1,300 MW of such generating facilities nationwide; thus, the Organization includes those facilities to supply capacity and recalculates reserve margins as outlined in Table 2-10.

Table 2-10 Annual Projection of Reserve Margins for Each Regional Service Area
(at 17:00 in August, with power exchanges through cross-regional interconnection lines and generating facilities not included in the electricity supply plans, at the sending end)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Hokkaido	12.4%	13.8%	30.1%	29.7%	30.7%	31.3%	31.5%	31.5%	42.9%	42.9%
Tohoku	9.6%	13.7%	13.2%	14.5%	14.8%	15.5%	16.2%	16.8%	17.3%	14.8%
Tokyo	9.6%	13.7%	10.2%	9.0%	11.8%	12.2%	16.2%	16.2%	15.8%	14.8%
Chubu	9.6%	13.7%	10.2%	9.0%	11.8%	12.2%	11.4%	11.5%	11.6%	13.0%
Hokuriku	9.6%	13.7%	10.2%	9.0%	11.8%	12.2%	11.4%	11.5%	11.6%	13.0%
Kansai	9.6%	13.7%	10.2%	9.0%	11.8%	12.2%	11.4%	11.5%	11.6%	13.0%
Chugoku	9.6%	13.7%	10.2%	9.0%	11.8%	12.2%	11.4%	11.5%	11.6%	13.0%
Shikoku	9.6%	13.7%	10.2%	9.0%	11.8%	12.2%	11.4%	11.5%	11.6%	13.0%
Kyushu	9.6%	13.7%	10.3%	11.0%	11.8%	12.2%	11.4%	11.5%	11.6%	13.0%
Interconnected	9.6%	13.7%	11.0%	10.2%	12.5%	13.0%	13.9%	14.1%	14.4%	14.6%
Okinawa	35.7%	42.1%	36.1%	38.5%	33.9%	41.1%	40.7%	40.0%	39.5%	39.0%
Nationwide	9.9%	14.0%	11.2%	10.5%	12.7%	13.3%	14.2%	14.3%	14.6%	14.8%

Table 2-11 shows the annual projection of reserve margins with the capacity of 301 MW equivalent to Generator I in the Okinawa EPCO area deducted, which indicates a stable supply is secured throughout the period.

Table 2-11 Annual Projection of a Reserve Margin with the Capacity Equivalent to Generator I in Okinawa Deducted (at 20:00 in August, at the sending end)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Okinawa	13.1%	19.6%	13.6%	16.0%	11.4%	18.7%	18.3%	17.6%	17.2%	16.7%

Table 2-12 shows the annual projection of reserve margins in January for winter peak demands in the Hokkaido and Tohoku EPCO areas. A stable supply is secured throughout the period.

Table 2-12 Annual Projection of Reserve Margins for Winter Peak Demand in the Hokkaido and Tohoku Areas (at 18:00 in January, at the sending end)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Hokkaido	19.6%	20.1%	14.7%	16.5%	16.8%	17.0%	17.1%	27.2%	27.2%	27.2%
Tohoku	10.9%	9.8%	11.2%	12.5%	12.8%	13.3%	13.7%	16.0%	16.5%	16.9%

b. Supply Capacity Secured by GT&D Companies

GT&D companies secure their supply capacity for the demand of isolated island areas throughout the projected period, and also secure a balancing capacity equivalent to 7%[16] over their peak demand in their regional service areas for FY 2019 by public solicitation. Table 2-13 shows the secured balancing capacity procured by GT&D companies.

Table 2-13 Secured Balancing Capacity[17] Procured by GT&D Companies (%, 10^4 kW in Okinawa)

	Hokkaido	Tohoku	Tokyo	Chubu	Hokuriku	Kansai	Chugoku	Shikoku	Kyushu	Okinawa
Balancing Capacity	7.0%	7.0%	7.2%	7.0%	7.0%	7.2%	6.9%	7.0%	7.0%	30.1

c. Conclusions Concerning Supply–Demand Balance Evaluation

Supply–Demand Balance Evaluation for FY 2019 (short-term): The criterion of stable supply (i.e., 8% of reserve margin) is secured throughout the areas and for the short-term period.

Supply–Demand Balance Evaluation for FY 2019–2028 (mid-to-long term): The criterion of stable supply is also secured throughout the areas and for the mid-to-long-term period.

The Organization continuously and carefully evaluates the supply–demand balance, with monitoring of the submission of altering supply plans and the accompanying supply–demand balance.

16 Public solicitation of balancing capacity is implemented so as to secure a balancing capacity equivalent to 7% over their peak demand in their regional service areas, and its procurement is based on the peak demand of the second projected year of the previous electric supply plan. Therefore, the procured balancing capacity may be lower than the capacity equivalent to 7% over their peak demand of the current year.

17 The capacity is the ratio of the balancing capacity to the peak demand in the regional service areas of GT&D companies. The ratios for the Hokkaido and Tohoku EPCO areas are in January, and in August for the other areas.

[Referential Review A]

[1] For reference, evaluations for the reserve margin for the short term are stated as below.

<Reference 1> Reserve Margin Projection for Each Month in FY 2019
(at the peak demand, the sending end, resources within own service area only)

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	36.2%	47.4%	59.1%	21.1%	24.0%	24.9%	19.7%	19.5%	25.0%	19.6%	21.5%	23.8%
Tohoku	19.8%	28.5%	19.4%	17.5%	14.7%	14.9%	9.8%	12.0%	11.3%	10.9%	12.0%	12.4%
Tokyo	20.2%	30.8%	18.7%	8.5%	8.7%	22.6%	23.8%	16.5%	20.0%	18.4%	16.7%	23.8%
50 Hz area Total	21.3%	31.6%	21.5%	10.8%	10.7%	21.3%	20.6%	15.8%	18.6%	16.9%	16.1%	21.4%
Chubu	26.9%	21.1%	19.7%	9.4%	11.3%	17.8%	19.0%	17.2%	8.7%	10.1%	11.8%	17.6%
Hokuriku	28.3%	24.0%	15.0%	17.2%	12.3%	15.6%	15.9%	8.1%	13.7%	9.4%	9.3%	16.2%
Kansai	30.6%	25.3%	14.8%	9.2%	8.2%	16.9%	19.9%	19.9%	8.7%	11.8%	10.4%	17.3%
Chugoku	24.1%	21.9%	16.8%	14.6%	13.2%	14.8%	19.3%	12.6%	0.6%	8.4%	9.8%	16.6%
Shikoku	42.9%	39.9%	30.1%	20.2%	16.1%	14.9%	23.8%	26.0%	15.8%	4.2%	5.3%	2.4%
Kyushu	35.5%	26.3%	13.4%	18.8%	14.5%	10.9%	16.3%	15.9%	5.4%	9.6%	9.1%	25.7%
60 Hz area Total	30.1%	24.5%	17.1%	12.7%	11.5%	15.6%	18.9%	17.1%	7.8%	9.9%	10.1%	17.8%
Interconnected	26.0%	27.6%	19.0%	11.9%	11.1%	18.1%	19.7%	16.5%	12.5%	13.0%	12.8%	19.4%
Okinawa	55.3%	42.7%	38.7%	37.1%	38.0%	41.5%	46.9%	53.9%	73.8%	70.3%	78.0%	84.3%
Nationwide	26.3%	27.8%	19.3%	12.1%	11.4%	18.4%	20.0%	16.9%	12.9%	13.4%	13.2%	19.9%

Below 8% Criteria

<Reference 2> Reserve Margin Projection for Each Month in FY 2019
(at the peak demand, the sending end, with power exchanges through cross-regional interconnection lines)

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	21.3%	29.8%	47.3%	13.7%	14.1%	19.6%	19.7%	16.0%	16.9%	15.4%	14.6%	22.3%
Tohoku	21.3%	29.3%	18.2%	13.7%	10.5%	19.6%	19.7%	16.0%	16.9%	15.4%	14.6%	19.3%
Tokyo	21.3%	29.3%	18.2%	10.0%	10.5%	19.6%	19.7%	16.0%	16.9%	15.4%	14.6%	19.3%
Chubu	30.1%	26.3%	18.2%	12.4%	11.5%	17.0%	19.7%	17.0%	9.1%	11.1%	11.3%	19.3%
Hokuriku	30.1%	26.3%	18.2%	12.4%	11.5%	17.0%	19.7%	17.0%	9.1%	11.1%	11.3%	19.3%
Kansai	30.1%	26.3%	18.2%	12.4%	11.5%	17.0%	19.7%	17.0%	9.1%	11.1%	11.3%	19.3%
Chugoku	30.1%	26.3%	18.2%	12.4%	11.5%	17.0%	19.7%	17.0%	9.1%	11.1%	11.3%	19.3%
Shikoku	30.1%	26.3%	18.2%	12.4%	11.5%	17.0%	19.7%	17.0%	9.1%	11.1%	11.3%	19.3%
Kyushu	30.1%	26.3%	18.2%	14.1%	11.5%	17.0%	19.7%	17.0%	9.1%	11.1%	11.3%	19.5%
Interconnected	26.0%	27.6%	19.0%	11.9%	11.1%	18.1%	19.7%	16.5%	12.5%	13.0%	12.8%	19.4%
Okinawa	55.3%	42.7%	38.7%	37.1%	38.0%	41.5%	46.9%	53.9%	73.8%	70.3%	78.0%	84.3%
Nationwide	26.3%	27.8%	19.3%	12.1%	11.4%	18.4%	20.0%	16.9%	12.9%	13.4%	13.2%	19.9%

Improved to over 8%

[2] For reference, annual evaluations of the supply–demand balance at 15:00 and 19:00 for the 10-year period FY 2019–2028 are presented below.

<Reference 3> Annual Reserve Margin Calculated at 15:00 in August (resources within own service area only, at the sending end)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Hokkaido	24.0%	23.4%	39.1%	39.7%	40.8%	41.3%	41.6%	41.1%	52.4%	52.5%
Tohoku	14.7%	12.9%	23.1%	25.0%	25.6%	26.9%	27.7%	30.8%	31.6%	32.5%
Tokyo	8.7%	12.0%	9.5%	6.4%	9.5%	11.7%	16.0%	15.2%	14.9%	15.0%
50 Hz area Total	10.7%	12.8%	13.8%	11.8%	14.3%	16.2%	19.6%	19.6%	20.2%	20.4%
Chubu	11.3%	10.7%	2.8%	6.0%	6.7%	7.3%	7.5%	8.2%	8.2%	8.7%
Hokuriku	12.3%	13.1%	12.0%	11.9%	12.1%	12.3%	11.5%	11.4%	11.4%	11.5%
Kansai	8.2%	14.3%	6.3%	7.8%	10.3%	10.8%	6.8%	7.9%	8.3%	8.6%
Chugoku	13.2%	16.9%	20.6%	14.6%	19.5%	20.0%	20.8%	21.3%	20.4%	20.7%
Shikoku	16.1%	30.2%	14.4%	16.3%	26.3%	26.6%	27.4%	28.1%	28.7%	29.3%
Kyushu	14.5%	26.6%	24.3%	25.5%	26.6%	21.0%	21.0%	19.7%	19.8%	19.9%
60 Hz area Total	11.5%	16.6%	11.1%	12.0%	14.3%	13.8%	12.7%	13.1%	13.2%	13.5%
Interconnected	11.1%	14.9%	12.3%	11.9%	14.3%	14.9%	15.8%	16.0%	16.3%	16.6%
Okinawa	38.0%	44.4%	38.6%	41.1%	36.5%	43.8%	43.4%	42.8%	42.4%	42.0%
Nationwide	11.4%	15.2%	12.5%	12.2%	14.6%	15.1%	16.1%	16.3%	16.6%	16.9%

Below 8% Criteria

<Reference 4> Annual Reserve Margin Calculated at 15:00 in August (with power exchanges through cross-regional interconnection lines, at the sending end)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Hokkaido	14.1%	13.5%	29.9%	29.5%	30.6%	31.1%	31.4%	31.4%	42.7%	42.8%
Tohoku	10.5%	12.8%	11.0%	11.8%	12.9%	14.4%	15.4%	15.6%	16.1%	15.9%
Tokyo	10.5%	12.8%	11.0%	10.4%	12.9%	14.4%	15.4%	15.6%	15.5%	15.9%
Chubu	11.5%	15.3%	11.0%	10.4%	12.9%	14.4%	15.4%	15.6%	15.5%	15.9%
Hokuriku	11.5%	15.3%	11.0%	10.4%	13.6%	14.4%	15.4%	15.6%	15.5%	15.9%
Kansai	11.5%	15.3%	11.0%	10.4%	13.6%	14.4%	15.4%	15.6%	15.5%	15.9%
Chugoku	11.5%	15.3%	11.0%	10.4%	13.6%	14.4%	15.4%	15.6%	15.5%	15.9%
Shikoku	11.5%	15.3%	11.0%	10.4%	13.6%	14.4%	15.4%	15.6%	15.5%	15.9%
Kyushu	11.5%	22.7%	18.7%	19.6%	20.5%	14.9%	15.4%	15.6%	15.5%	15.9%
Interconnected	11.1%	14.9%	12.3%	11.9%	14.3%	14.9%	15.8%	16.0%	16.3%	16.6%
Okinawa	38.0%	44.4%	38.6%	41.1%	36.5%	43.8%	43.4%	42.8%	42.4%	42.0%
Nationwide	11.4%	15.2%	12.5%	12.2%	14.6%	15.1%	16.1%	16.3%	16.6%	16.9%

Improved to over 8%

<Reference 5> Annual Reserve Margin Calculated at 19:00 in August (resources within own service area only, at the sending end)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Hokkaido	24.6%	23.5%	39.3%	39.9%	41.0%	41.5%	41.8%	41.2%	52.9%	52.9%
Tohoku	18.3%	14.9%	25.1%	26.6%	26.7%	27.6%	28.0%	30.8%	31.2%	31.6%
Tokyo	9.6%	13.2%	10.5%	7.0%	10.5%	12.9%	17.6%	16.8%	16.5%	16.5%
50 Hz area Total	12.2%	14.2%	15.0%	12.7%	15.4%	17.4%	21.0%	20.9%	21.4%	21.6%
Chubu	12.8%	12.1%	3.2%	6.8%	7.6%	8.3%	8.5%	9.3%	9.3%	9.8%
Hokuriku	13.8%	13.1%	11.3%	17.0%	10.9%	16.6%	11.1%	15.2%	9.0%	14.8%
Kansai	10.2%	16.7%	8.0%	9.8%	12.5%	13.0%	8.5%	9.5%	9.8%	10.0%
Chugoku	13.6%	17.1%	20.7%	12.2%	15.9%	16.1%	16.6%	16.8%	16.5%	16.7%
Shikoku	16.1%	30.3%	14.4%	12.4%	22.3%	22.6%	23.0%	23.3%	23.6%	23.7%
Kyushu	4.8%	12.3%	10.6%	11.3%	11.4%	5.7%	5.6%	4.2%	4.1%	4.1%
60 Hz area Total	10.9%	15.2%	9.2%	10.1%	11.8%	11.5%	9.9%	10.4%	10.1%	10.7%
Interconnected	11.4%	14.8%	11.8%	11.3%	13.4%	14.1%	14.9%	15.1%	15.2%	15.6%
Okinawa	38.4%	44.9%	38.6%	41.0%	36.2%	43.6%	43.1%	42.3%	41.9%	41.3%
Nationwide	11.7%	15.1%	12.1%	11.6%	13.7%	14.4%	15.2%	15.4%	15.5%	15.8%

Below 8% Criteria

<Reference 6> Annual Reserve Margin Calculated at 19:00 in August (with power exchanges through cross-regional interconnection lines, at the sending end)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Hokkaido	14.5%	14.2%	29.9%	29.4%	30.6%	31.1%	31.4%	31.3%	43.0%	43.0%
Tohoku	11.4%	14.2%	11.3%	12.1%	12.9%	13.6%	16.5%	16.6%	16.3%	14.9%
Tokyo	11.4%	14.2%	11.3%	10.6%	12.9%	13.6%	16.5%	16.6%	16.3%	14.9%
Chubu	11.4%	15.2%	11.3%	10.6%	12.9%	13.6%	12.8%	13.2%	12.9%	14.7%
Hokuriku	11.4%	15.2%	11.3%	10.6%	12.9%	13.6%	12.8%	13.2%	12.9%	14.7%
Kansai	11.4%	15.2%	11.3%	10.6%	12.9%	13.6%	12.8%	13.2%	12.9%	14.7%
Chugoku	11.4%	15.2%	11.3%	10.6%	12.9%	13.6%	12.8%	13.2%	12.9%	14.7%
Shikoku	11.4%	15.2%	11.3%	10.6%	12.9%	13.6%	12.8%	13.2%	12.9%	14.7%
Kyushu	11.4%	15.2%	11.3%	10.6%	12.9%	13.6%	12.8%	13.2%	12.9%	14.7%
Interconnected	11.4%	14.8%	11.8%	11.3%	13.4%	14.1%	14.9%	15.1%	15.2%	15.6%
Okinawa	38.4%	44.9%	38.6%	41.0%	36.2%	43.6%	43.1%	42.3%	41.9%	41.3%
Nationwide	11.7%	15.1%	12.1%	11.6%	13.7%	14.4%	15.2%	15.4%	15.5%	15.8%

Improved to over 8%

[Referential Review B]

Adding Supply Capacity of Generating Facilities Not Included in the Electricity Supply Plans

Figure 2-4 shows mid-to-long-term projections of suspended thermal power plants, which indicates that suspended thermal power plants include generators available for rapid power generation that have the possibility of being counted on as additional supply capacity. Figure 2-5 shows the recalculated projection of mid-to-long-term supply–demand balance(with power exchanges through cross-regional interconnection lines and generating facilities not included in the electricity supply plans, at the sending end), which include the additional supply capacity such as the above stated generators and the generators with delayed planned outage by the maximum coordination of their work schedules.

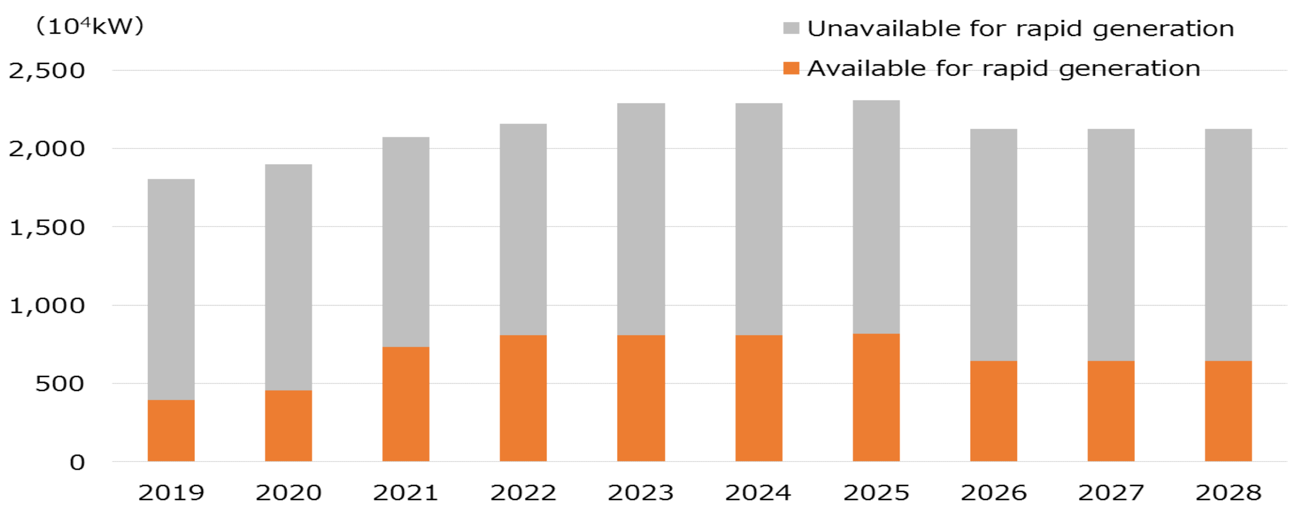

Figure 2-4 Mid-to-Long-Term Projections of Suspended Thermal Power Plants

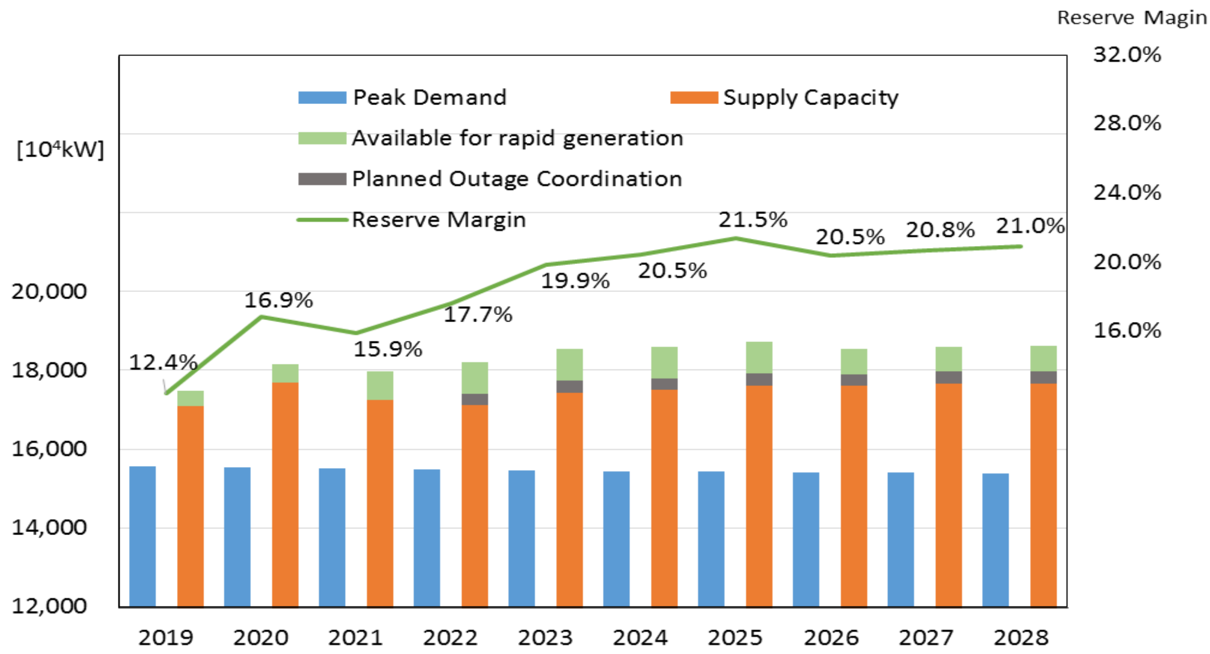

Figure 2-5 Annual Projection of Reserve Margins for Each Regional Service Area

(at 17:00 in August, with power exchanges through cross-regional interconnection lines and generating facilities not included in the electricity supply plans, at the sending end)

On the other hand, the reserve margins will decline by 2–5 % after review of the evaluation method of supply capacity (kW value) of renewable energy*.

* according to the calculation of the expected unavailable energy (EUE) evaluation of renewable energy generation based on the figures in August, page 37 of document 3 for the 3rd meeting of the Subcommittee on Electricity Resilience.

The original document [only in Japanese] is available at
http://www.occto.or.jp/iinkai/kouikikeitouseibi/resilience/2018/files/resilience_03_03_01.pdf

In addition, the necessary supply capacity in severe weather or rare occurrence risk is under review. It is possible that the minimum necessary supply capacity is secured if proper coordination of maintenance schedules of generators, or the utilization of suspended thermal generators is implemented at this moment.

Table 2-14 Supply Capacity of Renewable Energy (EUE Evaluation)

(10^4kW, %)

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Solar [6,252]	135	650	764	838	1,119	630	407	29	104	172	83	70
	(2%)	(10%)	(12%)	(13%)	(18%)	(10%)	(7%)	(0%)	(2%)	(3%)	(1%)	(1%)
Wind [488]	105	89	64	59	55	63	98	111	145	136	147	121
	(22%)	(18%)	(13%)	(12%)	(11%)	(13%)	(20%)	(23%)	(30%)	(28%)	(30%)	(25%)
Hydro [1,828]	1,049	1,095	1,006	1,011	855	819	695	708	695	618	649	777
	(57%)	(60%)	(55%)	(55%)	(47%)	(45%)	(38%)	(39%)	(38%)	(34%)	(35%)	(42%)
Total [8,569]	1,289	1,834	1,833	1,908	2,029	1,512	1,200	847	944	927	878	968
	(15%)	(21%)	(21%)	(22%)	(24%)	(18%)	(14%)	(10%)	(11%)	(11%)	(10%)	(11%)

[ ]: Total installed capacity ( ): Ratio of the supply capacity to the total installed capacity

III. Analysis of the Transition of Power Generation Sources

1. Transition of Power Generation Sources (Capacity)

The installed power generation capacity is the aggregation of the capacity of electric power plants owned by EPCOs and those owned by companies other than EPCOs that are registered as the procured supply capacity of retail and GT&D companies.

Table 3-1 and Figure 3-1 show the transition of installed power generation capacity by power generation sources.

Solar power will notably increase its capacity. Coal- and LNG-fired capacities are also projected to increase, although they may temporarily decrease through replacement according to future power development plans for thermal generation. Oil-fired capacity is projected to decrease through retirement.

Table 3-1 Composition of the Transition of Installed Power Generation Capacities by Power Generation Sources[18]
(nationwide, 10^4 kW)

Power Generation Sources		FY 2018 (actual)	FY 2019	FY 2023	FY 2028
Hydro		4,905	4,911	4,922	4,928
	Conventional	2,158	2,164	2,175	2,181
	Pumped Storage	2,747	2,747	2,747	2,747
Thermal		16,064	15,858	16,630	16,754
	Coal	4,312	4,455	5,240	5,189
	LNG	8,201	8,307	8,310	8,485
	Oil and others[19]	3,551	3,096	3,081	3,081
Nuclear		3,804	3,804	3,804	3,804
Renewables		5,740	6,351	7,853	8,703
	Wind	380	442	811	1,039
	Solar	4,955	5,491	6,553	7,182
	Geothermal	49	53	53	53
	Biomass	267	287	367	361
	Waste	90	79	70	67
Miscellaneous		35	19	19	20
Total		30,548	30,944	33,228	34,209

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

[18] The installed power generation capacity is the sum of the values submitted by EPCOs.
[19] The category 'Oil and others' includes the total installed capacities from oil, LPG, and other gas and bituminous mixture fired capacities.

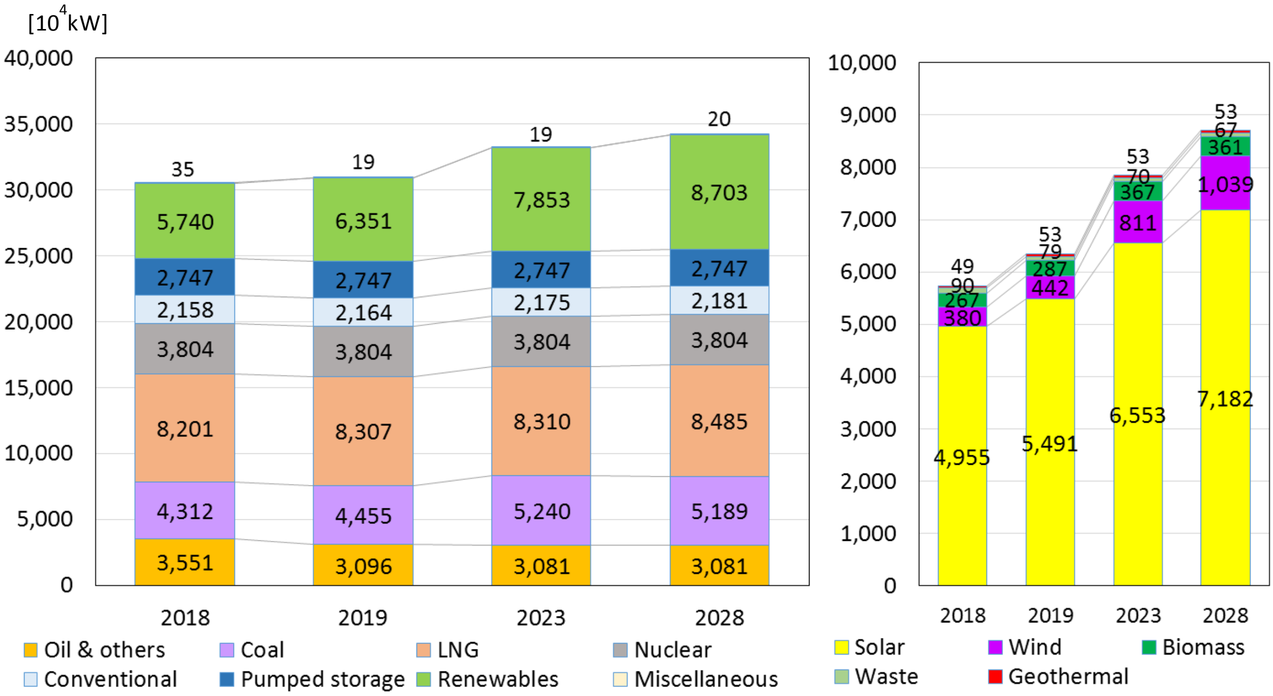

Figure 3-1 Transition of Installed Power Generation Capacities by Power Generation Sources (nationwide)

2. Transition of Gross Electric Energy Generation

Table 3-2 and Figure 3-2 show the transition of gross electric energy generation by power generation sources aggregated with the reported values submitted by generation companies and those procured by retail and GT&D companies from companies other than EPCOs.

For nuclear power plants, energy generation is calculated as zero for their capacity reported as "uncertain." However, the composition of gross electric energy generation may alter according to the operating conditions of nuclear power plants, change in generation sources, which is specified as "miscellaneous" in future trends, and regulating measures of generation efficiency by the Energy Conservation Act.

Table 3-2 Composition of the Transition of Gross Electric Energy Generation by Power Generation Sources[20]
(nationwide, 10^8 kWh at the generating end)

Power Generation Sources		FY 2018	FY 2019	FY 2023	FY 2028
Hydro		852	817	847	896
	Conventional	791	777	795	806
	Pumped Storage	61	40	52	90
Thermal		6,924	6,740	6,110	5,939
	Coal	2,764	2,857	3,067	3,160
	LNG	3,810	3,471	2,756	2,497
	Oil and others[19]	350	411	287	282
Nuclear		614	579	593	364
Renewables		846	938	1,234	1,354
	Wind	76	88	154	194
	Solar	566	627	778	851
	Geothermal	23	27	29	29
	Biomass	148	171	250	258
	Waste	33	25	23	23
Miscellaneous		84	47	65	36
Total		9,319	9,121	8,849	8,588

20 The gross electric energy generation is the sum of the values submitted by EPCOs. For nuclear power plants, energy generation is calculated as zero for their capacity reported as zero.

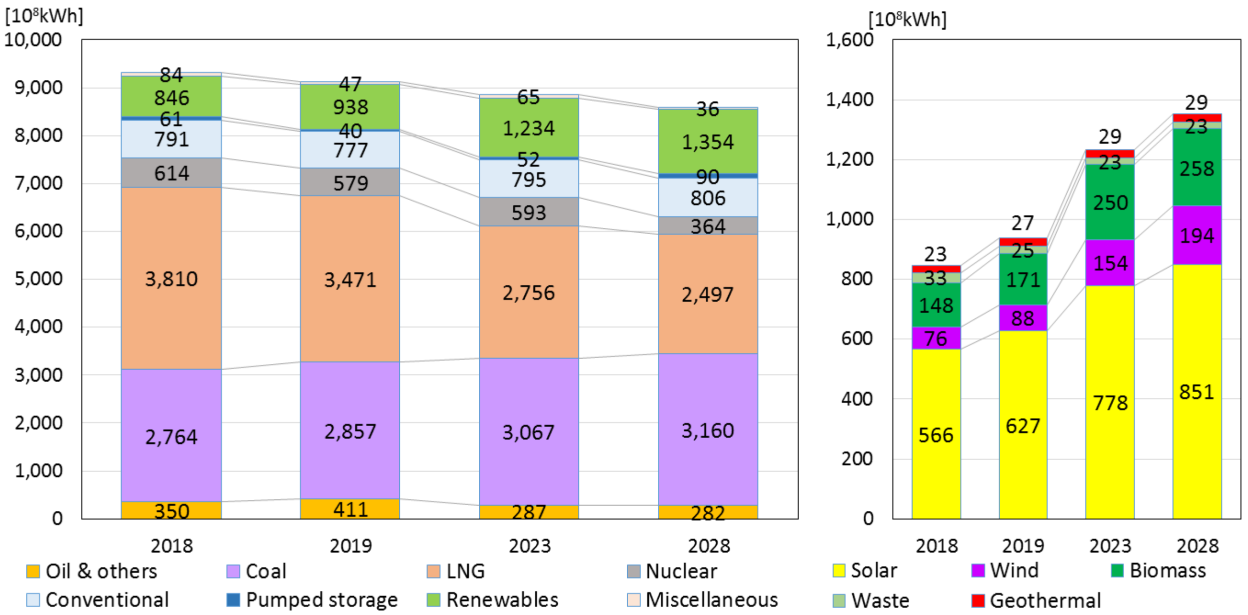

Figure 3-2 Transition of Electric Energy Generation by Power Generation Sources (nationwide)

3. Transition of Capacity Factor by Power Generation Sources

Table 3-3 and Figure 3-3 show the capacity factor by power generation sources. The projection of the capacity factor is calculated using the aforementioned power generation sources and gross electric energy generation data provided by the Organization.

According to future power development plans, the installed power generation capacity for thermal generation is projected to increase. However, this does not mean an increase in thermal generation, as the power supply from renewable energy is projected to increase; therefore, the capacity factor of thermal power plants is projected to decrease gradually.

For nuclear power generation, the installed power generation capacity contains that specified as "uncertain" and the capacity factor appears lower; therefore, this projection does not necessarily indicate the real capacity factor for nuclear power plants actually in operation.

Table 3-3 Capacity Factors by Power Generation Sources (nationwide)[21]

Power Generation Sources		FY 2018	FY 2019	FY 2023	FY 2028
Hydro		19.8%	18.9%	19.6%	20.8%
	Conventional	41.8%	40.9%	41.7%	42.2%
	Pumped Storage	2.5%	1.7%	2.2%	3.7%
Thermal		49.2%	48.4%	41.9%	40.5%
	Coal	73.2%	73.0%	66.8%	69.5%
	LNG	53.0%	47.6%	37.9%	33.6%
	Oil and others[19]	11.3%	15.1%	10.6%	10.4%
Nuclear		18.4%	17.3%	17.8%	10.9%
Renewables		16.8%	16.8%	17.9%	17.9%
	Wind[22]	22.7%	22.6%	21.7%	21.3%
	Solar[22]	13.0%	13.0%	13.6%	13.5%
	Geothermal	55.0%	57.3%	61.6%	61.6%
	Biomass	63.3%	68.0%	77.9%	81.6%
	Waste	41.8%	36.9%	37.9%	38.3%

[21] The capacity factor of nuclear power appears lower due to the calculation using the supply capacity reported as "uncertain" and does not indicate the real capacity factor for nuclear power plants.

[22] The capacity factors of wind and solar do not consider the decrease due to output shedding.

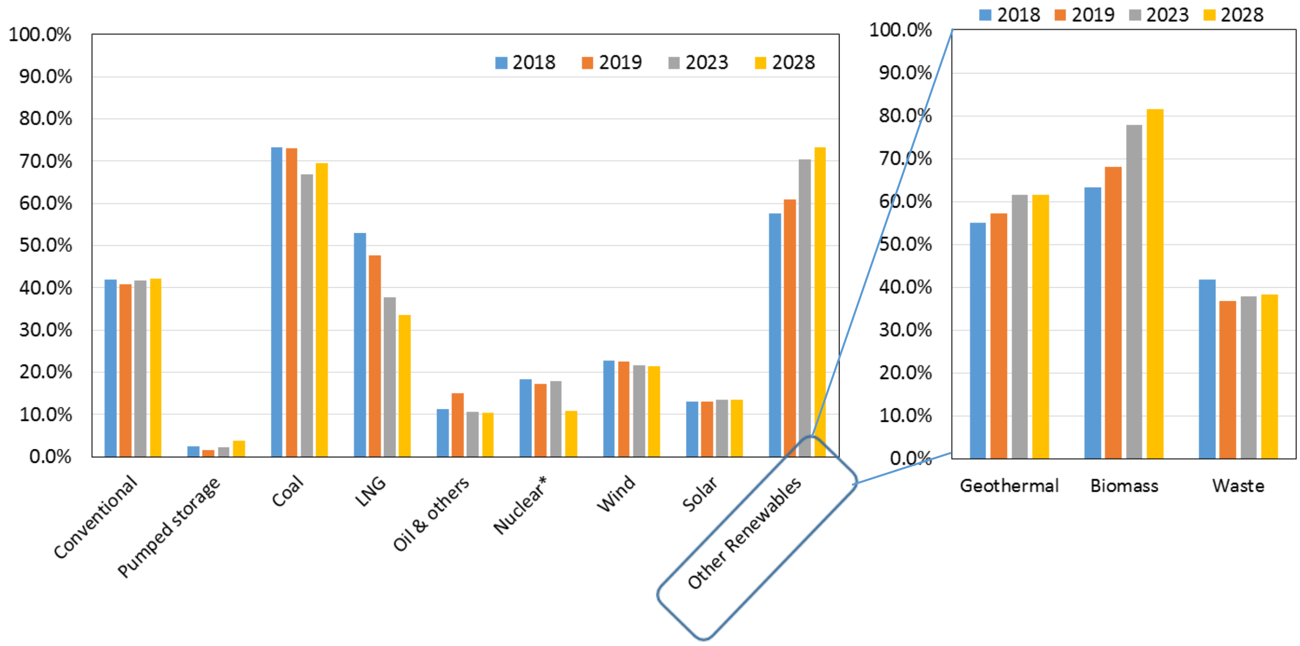

Figure 3-3 Capacity Factor by Power Generation Sources (Nationwide)[21]

4. Installed Power Generation Capacity and Gross Electric Energy Generation for Each Regional Service Area

Figure 3-4 shows the installed power generation capacity for each regional service area at the end of FY 2018. Figure 3-5 shows the gross electric energy generation for each regional service area in FY 2018.

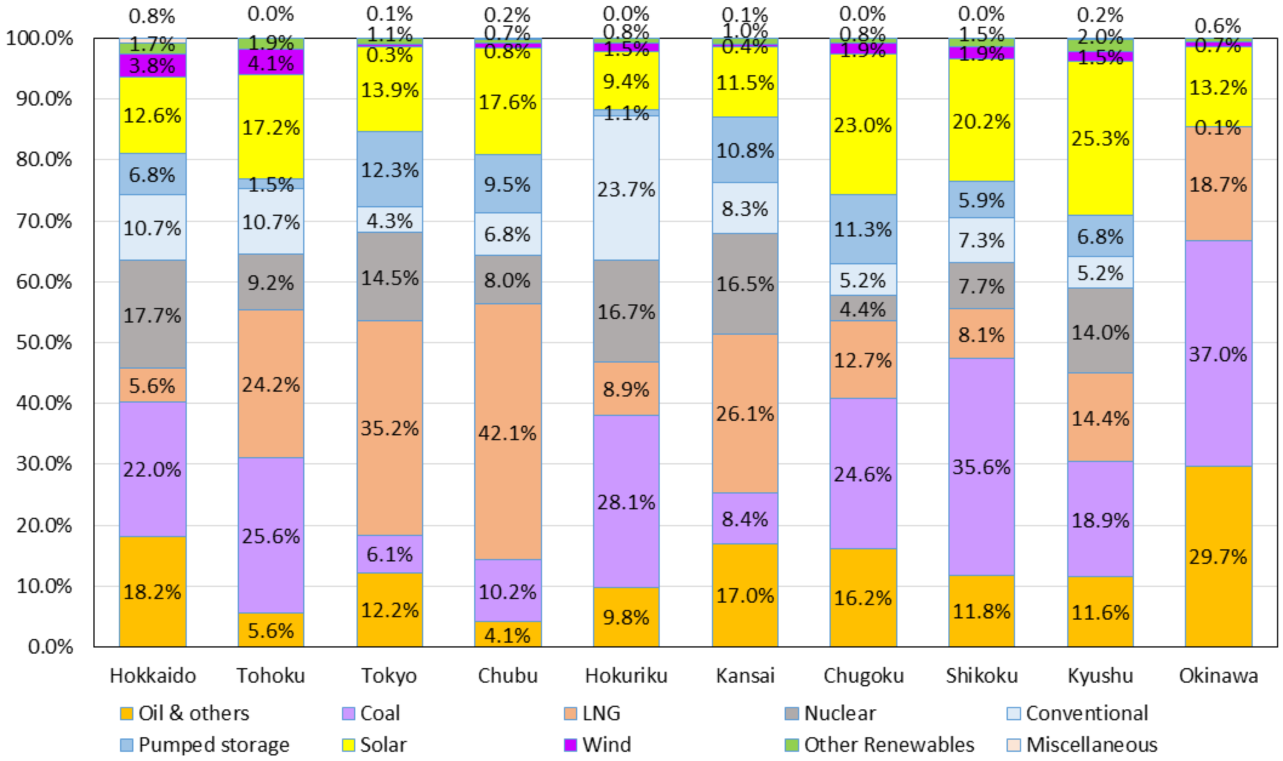

Figure 3-4 Composition of Installed Power Generation Capacity (kW) for Each Regional Service Area

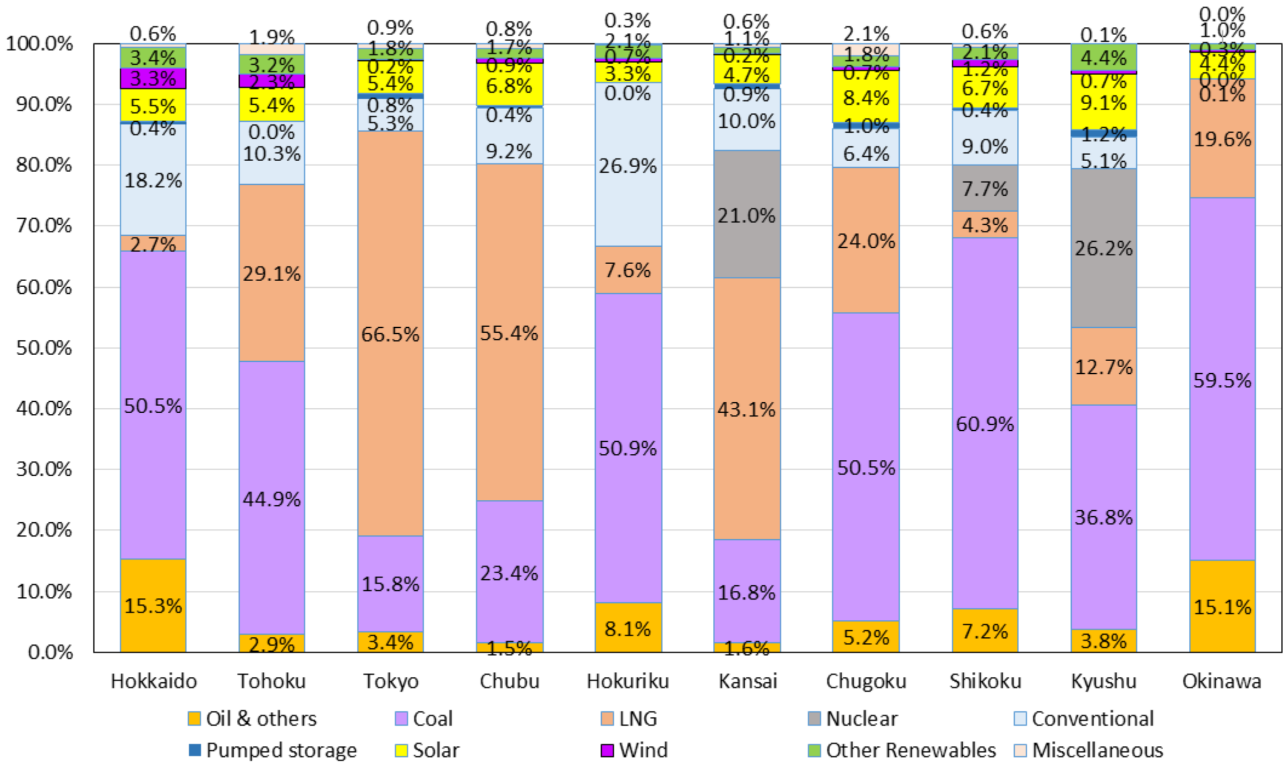

Figure 3-5 Composition of Gross Electric Energy Generation (kWh) for Each Regional Service Area

5. Development Plans by Power Generation Sources

Table 3-4 shows the development plans[23] up to FY 2028 submitted by generation companies, according to their new developments, uprated or derated installed facilities, and planned retirement of facilities in the projected period.

Table 3-4 Generation Development Plans up to FY 2028 by Stages (nationwide, 10^4 kW)

Power Generation Sources		New Installation		Uprating/Derating		Retirement	
		Capacity	Sites	Capacity	Sites	Capacity	Sites
Hydro		**32.6**	**41**	**5.2**	**47**	**▲ 20.0**	**26**
	Conventional	32.6	41	5.2	47	▲ 20.0	26
	Pumped Storage	-	-	-	-	-	-
Thermal		**1,611.8**	**41**	**▲ 24.0**	**1**	**▲ 1,009.6**	**45**
	Coal	824.1	13	-	-	▲ 75.6	3
	LNG	781.7	16	-	-	▲ 528.7	10
	Oil	6.0	12	▲ 24.0	1	▲ 405.3	32
	LPG	-	-	-	-	-	-
	Bituminous	-	-	-	-	-	-
	Other Gas	-	-	-	-	-	-
Nuclear		**1,018.0**	**7**	**15.2**	**1**	**▲ 55.9**	**1**
Renewables		**665.8**	**379**	**0.6**	**2**	**▲ 32.4**	**45**
	Wind	185.9	62	-	-	▲ 17.0	33
	Solar	378.0	285	-	-	▲ 0.2	1
	Geothermal	4.6	1	0.6	2	-	-
	Biomass	90.9	26	-	-	▲ 6.9	5
	Waste	6.4	5	-	-	▲ 8.3	6
Total		3,328.2	468	▲ 2.9	51	▲ 1,117.9	117

[23] Aggregated including facilities for which the date of commercial operation is "uncertain."

Ⅳ. Development Plans for Transmission and Distribution Facilities

The Organization has aggregated the development plans[24] for cross-regional transmission lines and substations (transformers and AC/DC converters) up to FY 2028 submitted by GT&D and transmission companies. Table 4-1 shows the development plans for cross-regional transmission lines and substations. Figure 4-1 shows the outlook for electric systems nationwide. (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

Increased Length of Transmission Lines*[25]*[26]		549 km
	Overhead Lines*	542 km
	Underground Lines	6 km
Uprated Capacities of Transformers		17,400 MVA
Uprated Capacities of AC/DC Converters[27]		1,800 MW
Decreased Length of Transmission Lines (Retirement)		▲ 108 km
Derated Capacities of Transformers (Retirement)		▲ 2,700 MVA

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

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

500kV Transmission Lines	・Cross-regional North Bulk Line(prov.): 81 km ・Cross-regional South Bulk Line(prov.): 62 km ・Soma-Futaba Bulk Line/ Connecting Point Change: 15 km ・Shinchi Thermal Power Line/ Cross-regional Switching Station(prov.) lead-in: 1 km ・Joban Bulk Line/ Cross-regional Switching Station(prov.) Dπ lead-in: 1 km
Switching Stations	500kV Switching Station(prov.): 10 circuits

[24] Development plans for transmission lines and substations are required to be submitted for voltages of more than 250 kV, or within two classes of the highest voltage available in the regional service areas. (For the Okinawa EPCO, only 132 kV or more is required.) The totals are not necessarily equal due to independent rounding.
[25] 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.
[26] Increased length does not include the item with * because of an undetermined in-service date.
[27] Installed capacity for the converter station on one side is included in the DC transmission system.

Interconnection Facility Enhancement Plan between Tokyo and Chubu
(120 MW→210 MW; in-service: March 2021)

AC/DC Converter Stations	・Shin Shinano AC/DC Converter Station： 900 MW ・Hida AC/DC Converter Station： 900 MW
DC Bulk Line 500kV Transmission Lines	・Hida-Shinano DC Bulk Line: 89 km ・Hida Branch Line: 0.4 km

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

Frequency Converter Stations	・Shin Sakuma FC station(prov.): 300 MW ・Higashi Shimizu FC station: 300 MW→900 MW
275 kV Transmission Lines	・Higashi Shimizu Line (prov.): 20 km ・Sakuma Higashi Bulk Line/ Shin Sakuma FC Branch Line (prov.): 3 km ・Sakuma Nishi Bulk Line/ Shin Sakuma FC Branch Line (prov.): 1 km ・Shin Toyone-Toei Line: 1 km ・Sakuma Nishi Bulk Line: 11 km , 2km ・Sakuma Higashi Bulk Line: 123 km
500 kV Transformers	・Shin Fuji Substation: 1,500MVA×1 ・Shizuoka Substation: 1,000MVA×1 ・Toei Substation: 800MVA×1 →1,500MVA×2

Interconnection Facility Enhancement Plan between Chubu and Kansai
(in-service: undetermined)

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: 1 km
Switching Stations	・Sekigahara Switching Station: 6 circuits ・Kita Oomi Switching Station: 6 circuits

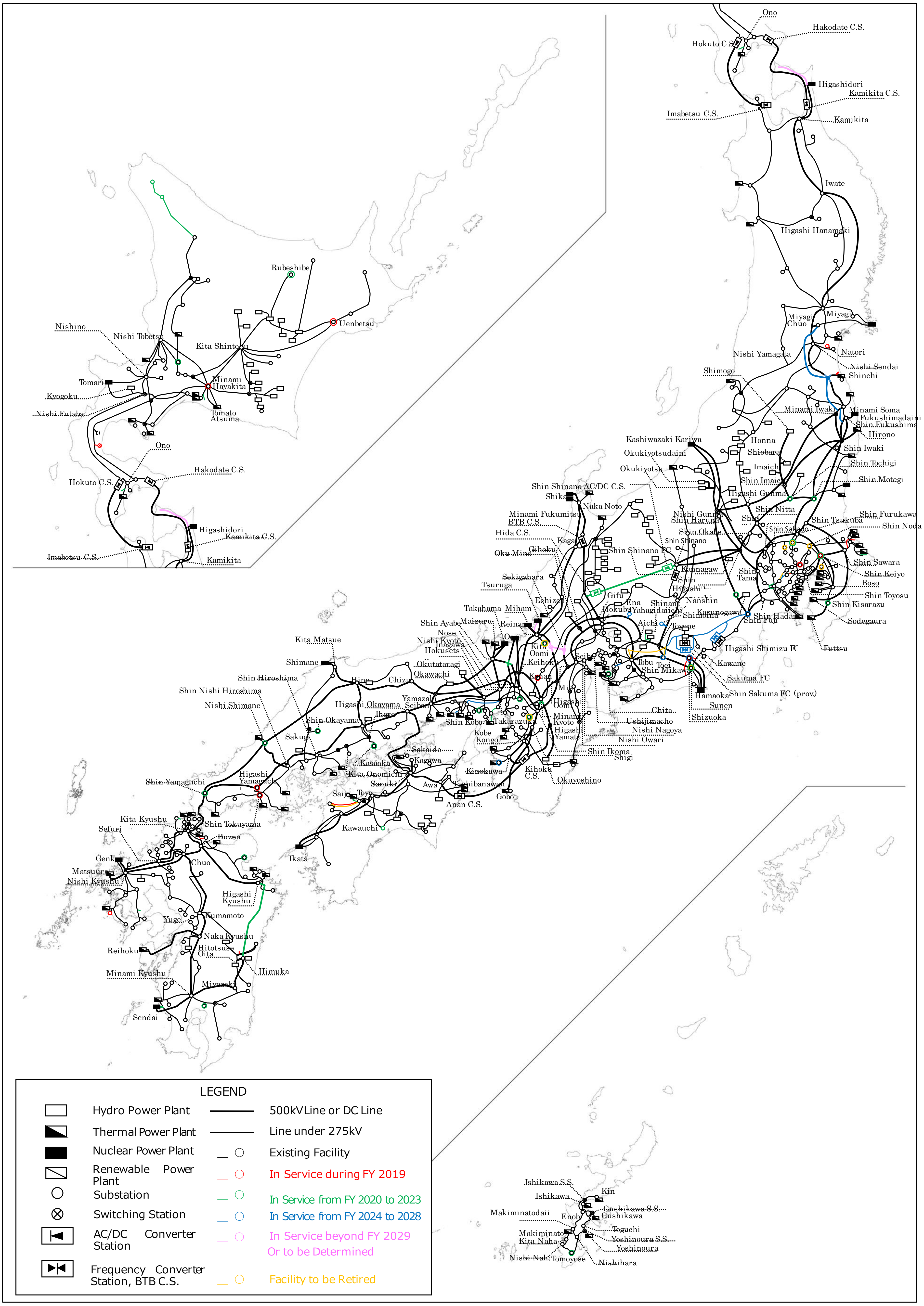

Figure 4 Power Grid Configuration in Japan

1. Development Plans for Major Transmission Lines

Table 4-2 Development Plans under Construction

Company	Line	Voltage	Length[28,29]	Circuit	In-construction	In-service	Purpose[30]
Hokkaido EPCO	Kami Yakumo Switching Station	187kV	-	2	Aug. 2018	Oct. 2019	Generator connection
	Kami Yakumo Branch Line	187kV	0.2km	1	Mar. 2019	Nov. 2019	Generator connection
Tohoku EPCO	1408G02 Branch Line	500kV	3km	2	Sep.2017	Jul. 2019	Generator connection
	Customer Line/ Natori Substation Dπ lead-in	275kV	0.4km	2	May 2018	Jun. 2019	Demand coverage
TEPCO Power Grid	G3060006 access line (prov.)	275kV	5.6km	2	Jan. 2017	Apr. 2019	Generator connection
	Shinano-Hida DC Bulk Line	DC± 200kV	89km	BP 1	Jul. 2017	Mar. 2021	Reliability upgrade*3
	Shinjuku-Jonan Line replacement	275kV	16.4km *1,*2	3	Nov. 2017	Jul. 2018(No.1) Apr. 2020(No.2) Apr. 2019(No.3)	Aging management
	Higashi Shinjuku Line replacement	275kV	23.4→ 5.0km (No.2) *1, *2 23.4→ 5.3km (No.3) *1, *2	2	Jan. 2019	Nov. 2032(No.2) Nov. 2025(No.3)	Aging management
Chubu EPCO	Shizuoka Higashi Branch Line	275kV	2km	2	Jul.2001	Jun. 2019	Aging management Economic upgrade
	Shizuoka Nishi Branch Line	275kV	3km	2	Jul.2001	Jun. 2019	Aging management Economic upgrade
	Hida Branch Line	500kV	0.4km	2	Jun. 2018	Sep. 2020	Reliability upgrade*3
Kansai EPCO	Kobelco Power Kobe daini Thermal Power Line	275kV	4.4km*1	3	Apr. 2017	Feb. 2021(No.1) Feb. 2022(No.2)	Generator connection
Shikoku EPCO	Matsuyama Higashi Line	187kV	47.8km*2	1→2	Aug. 2018	Nov. 2019	Aging management Economic upgrade
Kyushu EPCO	Hyuga Bulk Line	500kV	124km	2	Nov. 2014	Jun. 2022	Reliability upgrade Economic upgrade
	Karita Thermal-Nissan line	220kV	4km*1*2	1	Oct. 2017	May 2019	Aging management
	GNE Togo Mega Solar branch line	220kV	0.3km	1	Oct. 2018	Oct. 2019	Generator connection
Electric Power Development Company (EPDC)	Ooma Bulk Line	500kV	61.2km	2	May 2006	Uncertain	Generator connection
Northern Hokkaido Wind Energy Transmission Company (NHWETC)	NHWETC Toyotomi-Nakagawa Bulk Line	187kV	51km	2	Sep. 2018	Sep. 2022	Generator connection

28 Length with *1 denotes "Underground," otherwise "Overhead."

29 Length with *2 denotes the change of line category or circuit numbers, not included in Table 4.

30 Purpose is stated below: *3 indicates the enforcement relating to cross-regional interconnection lines.

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

Table 4-3 Development Plans in the Planning Stages

Company	Line	Voltage	Length[28,29]	Circuit	In-construction	In-service	Purpose[30]
Hokkaido EPCO	Tomakomai Biomass (prov.) access line	187kV	0.2km	1	Apr. 2021	Oct. 2022	Generator connection
	Kaminokuni daini Wind Power (prov.) access line	187kV	0.1km	1	May 2021	Aug. 2021	Generator connection
	Kita Horonobe Line partly uprated	187kV	69km	2	Apr. 2021	Jul. 2022	Generator connection
Tohoku EPCO	Cross-regional North Bulk Line(prov.)	500kV	81km	2	Sep. 2022	Nov. 2027	Generator connection Reliability upgrade*3
	Cross-regional South Bulk Line(prov.)	500kV	62km	2	Sep. 2024	Nov. 2027	Generator connection Reliability upgrade*3
	Soma-Futaba Bulk Line/connecting point change	500kV	15km	2	Apr. 2022	Nov. 2025	Generator connection Reliability upgrade*3
	Shinchi Thermal Power access line / Cross-regional Switching Station (prov.) lead-in	500kV	1km	2	Jul. 2024	Jun. 2026	Generator connection Reliability upgrade*3
	Joban Bulk Line/Cross-regional Switching Station(prov.) Dπ lead-in	500kV	1km	2	May 2025	Jul. 2026	Generator connection Reliability upgrade*3
	Cross-regional Switching Station(prov.)	500kV	-	10	May 2023	Nov. 2027 (Jun. 2026)	Generator connection Reliability upgrade*3
TEPCO Power Grid	G7060005 access line(prov.)	275kV	1km*1	1	Sep. 2020	Apr. 2022	Generator connection
	MS18GHZ051500 access line (prov.)	275kV	0.1km	2	Mar. 2021	Sep. 2021	Generator connection
	Keihin Line No.1&2 /connecting point change	275kV	22.7→ 23.1km*2	2	May 2021	Apr. 2022	Generator connection
	Higashi Shimizu Line (prov.)	275kV	13km 7km	2	FY 2022	FY 2026	Reliability upgrade*3
	Nishi Gunma Bulk Line /Higashi Yamanashi Substation T lead-in	500kV	0.1km(No.1) 0.1km(No.2)	2→3	Nov. 2022	Oct. 2023	Demand coverage
	Shinjuku Line replacement	275kV	22.1→ 21.1km (No.1) *1, *2 19.9→ 21.1km (No.2,3)*1, *2	3	Sep. 2019	Aug. 2028(No.1) Nov. 2032(No.2) Nov. 2025(No.3)	Aging management
Chubu EPCO	Yahagi daiichi Branch Line	275kV	5km	1	Aug. 2019	Feb.2021	Aging management Economic upgrade
	Ena Branch Line(prov.)	500kV	1km	2	May 2020	Oct. 2024	Demand coverage
	Shimo Ina Branch Line(prov.)	500kV	1km	2	Mar. 2022	Oct. 2024	Demand coverage
	Higashi Nagoya -Tobu Line	275kV	8km*2	2	Apr. 2019	Jun. 2025	Aging management Economic upgrade
	Sekigahara-Kita Oomi Line	500kV	2km	2	Uncertain	Uncertain	Generator connection*3
	Sekigahara Switching Station	500kV	—	6	Uncertain	Uncertain	Generator connection*3
	Sangi Bulk Line/ Sekigahara Switching Station π lead-in	500kV	1km	2	Uncertain	Uncertain	Generator connection*3

Company	Line	Voltage	Length[28,29]	Circuit	In-construction	In-service	Purpose[30]
Kansai EPCO	Tsuruga Line/ North side improvement	275kV	9.8km→ 9.3km*2	2	Beyond FY 2020	Beyond FY 2023	Aging management
	Ooi Bulk Line/ Shin Ayabe Line route change	500kV	1.9km	2	Jun. 2019	Jan. 2020	Economic upgrade
	Kita Yamato Line/ Minami Kyoto Substation Lead-in change	500kV	0.1km	2	Aug. 2021	Dec. 2021	Economic upgrade
	Kita Oomi Switching Station	500kV	—	6	Uncertain	Uncertain	Generator connection*3
	Kita Oomi Line/ Kita Oomi Switching Station π lead-in	500kV	0.5km	2	Uncertain	Uncertain	Generator connection*3
	Shin Kobe Line/ reinforcement	275kV	20.2→ 21.5km*2	2	Apr. 2019	Jul. 2020	Generator connection Aging management
	Himeji LNG Thermal Power Line(prov.)	275kV	0.9km*1	1	Feb. 2021	Jun. 2024	Generator connection
	Shin Kakogawa Line/ reinforcement(prov.)	275kV	25.3→ 25.3km*2	2	Jul. 2021	Jun. 2025	Generator connection Aging management
Shikoku EPCO	Saijo Thermal Power access line	187kV	6.5km*2	2	Nov. 2019	May 2021	Generator connection
Kyushu EPCO	JR Shin Isahaya Branch Line	220kV	1km	2	Jul. 2019	Apr. 2021	Demand coverage
	Saibu Gas/ Hibiki Thermal Power Line	220kV	4km	2	Feb. 2021	Feb. 2023	Generator connection
	Shin Kagoshima Line/ Sendai Nuclear Power π lead-in	220kV	2→5km*2	1→2	Aug. 2020	Jul. 2023	Economic upgrade
EPDC	Sakuma Higashi Bulk Line/ Shin Sakuma FC Branch Line(prov.)	275kV	3km	2	FY 2022	FY 2026	Reliability upgrade*3
	Sakuma Nishi Bulk Line/ Shin Sakuma FC Branch Line (prov.)	275kV	1km	2	FY 2022	FY 2026	Reliability upgrade*3
	Shin Toyone-Toei Line	275kV	1km	1	FY 2022	FY 2026	Reliability upgrade*3
	Sakuma Nishi Bulk Line	275kV	10.6→ 11km*2	2	FY 2022	FY 2027	Reliability upgrade*3
	Sakuma Nishi Bulk Line	275kV	2km	2	FY 2022	FY 2026	Reliability upgrade*3
	Sakuma Higashi Bulk Line	275kV	123.7→ 123km*2	2	FY 2022	FY 2027	Reliability upgrade*3

Table 4-4 Retirement Plans

Company	Line	Voltage	Length	Circuit	Retirement	Purpose[30]
Shikoku EPCO	Kita Matsuyama Line	187kV	∆47.5km	1	Nov. 2019	Aging management Economic upgrade
EPDC	Shin Toyone-Toei Line	275kV	∆2.6km	1	FY 2026	Reliability upgrade*3
	Sakuma Nishi Bulk Line	275kV	∆58.0km	2	FY 2026	Economic upgrade

2. Development Plans for Major Substations

Table 4-5 Development Plans under Construction

Company	Substation[31]	Voltage	Capacity	Number	In-construction	In-service	Purpose[30]
Hokkaido EPCO	Minami Hayakita	187/66kV	200MVA	1	Aug. 2018	Sep.2019	Generator connection
	Uenbetsu	187/66kV	75MVA→ 100MVA	1→1	Feb. 2019	Nov. 2019	Aging management
Tohoku EPCO	Natori*4	275/154kV	450MVA×2	2	Feb. 2017	Jun. 2019	Demand coverage
TEPCO Power Grid	Shin Keiyo	275/154kV	300MVA×2→ 450MVA×2	2→2	Jul. 2018	Sep. 2019(5B) Apr. 2021(6B)	Aging management
	Shin Shinano AC/DC Converter Station*4	—	—	-	Mar. 2016	Mar. 2021	Reliability upgrade*3
	Ueno	275/66kV	300MVA	1	Feb. 2019	Dec. 2019	Economic upgrade
Chubu EPCO	Shizuoka*4	500/275kV	1,000MVA	1	Aug.2001	Jun.2019	Aging management Economic upgrade
	Hida Converter Station*4	—	—	—	Aug. 2017	Mar. 2021	Reliability upgrade*3
	Shunen	275/154kV	450MVA×1→ 300MVA×1	1→1	Feb. 2019	May 2020	Aging management
Kansai EPCO	Konan	275/77kV	300MVA×1→ 200MVA×1	1→1	Dec. 2018	Oct. 2019	Aging management
Chugoku EPCO	Higashi Yamaguchi	500/220kV	1,000MVA	1	May 2017	Apr. 2019	Demand coverage Generator connection
	Shin Tokuyama	220/110kV	150MVA×1→ 300MVA×1	1→1	Jul. 2018	Apr. 2019	Aging management Generator connection
Okinawa EPCO	Tomoyose	132/66kV	125MVA×2→ 200MVA×2	2→2	Oct. 2017	Jun. 2020 Oct. 2023	Aging management
NHWETC	Kita Toyotomi*4	187/66kV	165MVA×3	3	Apr. 2019	Sep. 2022	Generator connection

Table 4-6 Development Plans in the Planning Stages

Company	Substation[31]	Voltage	Capacity	Number	In-construction	In-service	Purpose[30]
Hokkaido EPCO	Rubeshibe	187/66kV	60MVA×2→ 100MVA	2→1	Mar. 2021	Oct. 2021	Aging management
	Nishi Nakagawa(prov.)	187/100kV	100MVA×2	2	Jul. 2020	Jul. 2022	Generator connection
	Kita Ebetsu	187/66kV	100MVA×1→ 150MVA	1→1	Feb. 2022	Oct. 2022	Aging management
TEPCO Power Grid	Shin Motegi	500/275kV	1,500MVA	1	Nov.2019	Mar. 2021	Generator connection
	Shin Kisarazu	275/154kV	450MVA×2	2	Jun. 2020	Apr. 2022	Generator connection
	Higashi Yamanashi	500/154kV	750MVA	1	Apr. 2019	Dec. 2022	Demand coverage
	Shin Tochigi	500/154kV	750MVA	1	Apr. 2021	Jan. 2023	Generator connection
	Shin Fuji	500/275kV	1,500MVA	1	FY 2023	FY 2026	Reliability upgrade*3
	Kita Tokyo	275/66kV	300MVA	1	Sep. 2020	Jun. 2022	Economic upgrade
Chubu EPCO	Chita Thermal Power	275/154kV	300MVA×1→ 450MVA×1	1→1	Jul. 2019	Apr. 2021	Aging management
	Chita Thermal Power	275/154kV	450MVA×2	2	Jul. 2019	Nov. 2020(N1B) Aug. 2021(N2B)	Generator connection
	Ena(prov.)*4	500/154kV	200MVA×2	2	Dec. 2020	Oct. 2024	Demand coverage
	Shimo Ina(prov.)*4	500/154kV	300MVA×2	2	Dec. 2020	Oct. 2024	Demand coverage
	Toei	500/275kV	800MVA×1→ 1,500MVA×2	1→2	Nov. 2020	FY 2024(N2B) FY 2026(1B)	Reliability upgrade*3

[31] Substation with *4 denotes a substation or converter station newly installed, including an uprated electric facility.

Company	Substation[31]	Voltage	Capacity	Number	In-construction	In-service	Purpose [30]
Chubu EPCO	Shizuoka	500/275kV	1,000MVA	1	FY 2024	FY 2026	Reliability upgrade*3
	Higashi Shimizu	—	300MW→ 900MW	—	Feb. 2021	FY 2027	Reliability upgrade*3
Kansai EPCO	Higashi Osaka	275/77kV	300MVA→ 200MVA	1→1	Sep. 2019	Jun. 2020	Aging management
	Nishi Kobe	275/77kV	200MVA×2→ 300MVA	2→1	Nov. 2020	Jun. 2021	Aging management
	Koto	275/77kV	200MVA→ 300MVA	1→1	Oct. 2021	Oct. 2022	Aging management
	Yodogawa	275/77kV	300MVA×2→ 300MVA	2→1	Dec. 2020	Oct. 2021	Aging management
	Kainannko	275/77kV	300MVA×1, 200MVA×2→ 300MVA×2	3→2	Jun. 2021	Jun. 2024	Aging management
Chugoku EPCO	Sakugi	220/110kV	200MVA	1	Jun. 2019	Nov. 2020	Generator connection
	Shin Yamaguchi	220/110kV	400MVA	2	Apr. 2019	Jun. 2021	Economic upgrade
	Kasaoka	220/110kV	250MVA→ 300MVA	1→1	Aug. 2020	Jun. 2021	Aging management
	Nishi Shimane	500/220kV	1,000MVA	1	Apr. 2020	Mar. 2022	Generator connection
Shikoku EPCO	Kochi	187/66kV	200MVA→ 300MVA	1→1	Nov. 2021	Apr. 2022	Aging management Demand coverage
Kyushu EPCO	Hayami	220/66kV	250MVA	1	Apr. 2019	Jun. 2020	Generator connection
	Kirishima	220/66kV	300MVA	1	Nov. 2019	Sep. 2021	Generator connection
	Matsushima	220/66kV	150MVA	1	Apr. 2019	Mar. 2020	Economic upgrade
EPDC	Shin Sakuma FC (prov.)	—	—		FY 2021	FY 2027	Reliability upgrade*3

Table 4-7 Retirement Plans

Company	Substation	Voltage	Capacity	Number	Retirement	Purpose
TEPCO Power Grid	Shin Noda	275/154kV	△300 MVA	△1	Mar. 2020	Demand coverage
	Hanamigawa	275/66kV	△300 MVA	△1	Mar. 2021	Demand coverage
	Kita Tokyo	275/154kV	△300 MVA	△1	Oct. 2020	Economic upgrade
	Ageo	275/66kV	△300 MVA	△1	Feb. 2023	Economic upgrade
Chubu EPCO	Shunen	500/275kV	△1,000 MVA	△1	Jun. 2019	Aging management
Kansai EPCO	Higashi Osaka	275/154kV	△300 MVA	△1	Jan. 2021	Aging management
	Koto	275/77kV	△100 MVA×2	△2	Sep. 2022	Aging management

<u>Other development plans</u> (not subject to submission by the electric supply plan)

The development plan stated below is not required to be included in the electricity supply plan, but will be implemented as a functional improvement by Chubu EPCO and Hokuriku EPCO.

◇Minami Fukumitsu Interconnection Facility・Substation 500 kV AC Connecting Bus Line Addition（in service: October 2019).

3. Summary of Development Plans for Transmission Lines and Substations

Tables 4-8 to 4-11 show the summarized development or extension plans of major transmission lines and substations (transformers and converter stations) up to FY 2028 submitted by GT&D and transmission companies.

Table 4-8 Development Plans for Major Transmission Lines

Category	Voltage	Lines	Length[32]	Extended Length[33]	Total Length	Total Extended Length
Newly Installed or Extended	500kV	Overhead	291 km*[34]	583 km*	291 km*	583 km*
		Underground	0 km	0 km		
	275kV	Overhead	36 km	66 km	42 km	81 km
		Underground	6 km	15 km		
	220kV	Overhead	5 km	10 km	5 km	10 km
		Underground	0 km	0 km		
	187kV	Overhead	121 km	241 km	121 km	241 km
		Underground	0 km	0 km		
	132kV	Overhead	0 km	0 km	0 km	0 km
		Underground	0 km	0 km		
	DC	Overhead	89 km	89 km	89 km	89 km
		Underground	0 km	0 km		
	Total	Overhead	542 km	989 km	549 km	1,004 km
		Underground	6 km	15 km		
To be Retired	275kV	Overhead	△61km	△119km	△61km	△119km
		Underground	0km	0km		
	187kV	Overhead	△ 48 km	△ 48 km	△ 48 km	△ 48 km
		Underground	0 km	0 km		
	Total	Overhead	△108 km	△166 km	△ 108 km	△ 166 km
		Underground	0 km	0 km		

Table 4-9 Revised Plans for Line Category and the Numbers of Circuits[35]

Voltage	Length Extended	Total Extended Length
500kV	0 km	1 km
275kV	311 km	702 km
220kV	9 km	14 km
187kV	54 km	109 km
132kV	0 km	0 km
DC	0 km	0 km
Total	375 km	825 km

[32] Length denotes both the increased length due to newly installed or extended plans, and the decreased length due to retirement. 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. The totals of lengths are not necessarily equal due to independent rounding.
In addition, the overall total length is not necessarily equal due to independent rounding.

[33] Total length denotes the aggregation of length multiplied by the number of circuits. Development plans corresponding to the change of 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.

[34] See footnote 26.

[35] 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[36]	Voltage[37]	Increased Numbers	Increased Capacity
Newly Installed or Extended	500kV	13 [5]	11,700 MVA [2,000MVA]
	275kV	5 [2]	3,000 MVA [900MVA]
	220kV	6 [0]	1,500 MVA [0MVA]
	187kV	5 [5]	1,050 MVA [695MVA]
	132kV	0 [0]	150 MVA [0MVA]
	Total	29 [12]	17,400 MVA [3,595MVA]
To be Retired	500kV	△ 1	△ 1,000 MVA
	275kV	△ 7	△1,700 MVA
	220kV	0	0 MVA
	187kV	0	0 MVA
	132kV	0	0 MVA
	Total	△ 8	△ 2,700 MVA

[ ] : The aforementioned increase in the number of transformers resulted from new substation installations.

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

Category	Company and Number of Sites		Capacity[38]
Newly Installed or Extended	TEPCO Power Grid	1	900MW
	Chubu EPCO	2	900MW 600MW
	Electric Power Development Company	1	300MW

36 Retirement plans with transformer installations are included in Newly Installed or Extended, and negative values are included in the increased numbers or the increased capacity.
37 Voltage class by upstream voltage.
38 Installed capacity of the converter stations on both sides of the DC lines is included.

V. Cross-Regional Operation

Retail companies will procure the supply capacity for their customers in their regional service areas. The scheduled procurement from the external service areas at 15:00 in August 2019 is illustrated in four figures. Figures 5-1 and 5-2 show the supply capacity and the ratio of the supply capacity, respectively, at 15:00 in August. Figures 5-3 and 5-4 show the energy supply and the ratio of the energy supply, respectively, in FY 2019.

Higher ratios for procurement from the external regional service areas are observed in Tokyo, Kansai and Chugoku EPCO areas; those to the external regional service areas are observed in Tohoku, Shikoku and Kyushu EPCO areas. Higher energy is transmitted from other areas to Tokyo, Kansai, Chugoku, and Shikoku EPCO areas by 10% and over.

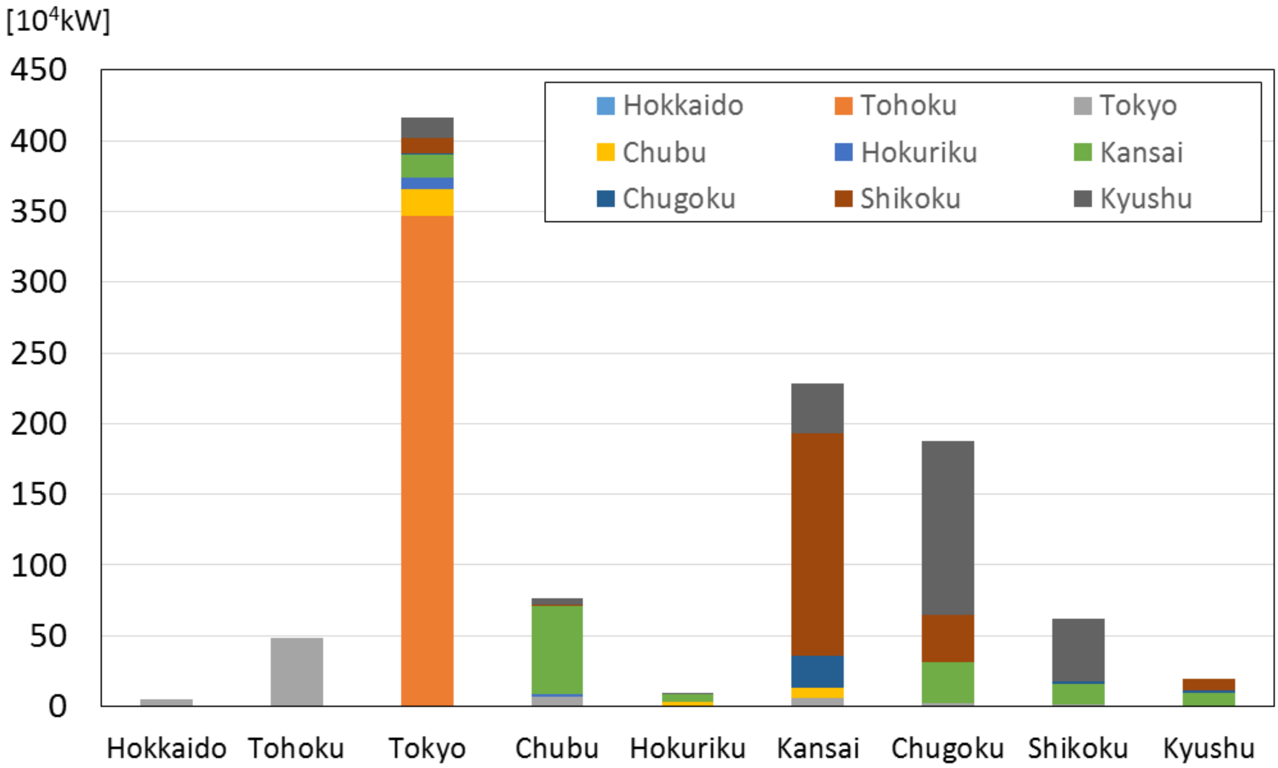

Figure 5-1 Scheduled Procurement of Supply Capacity from External Regional Service Areas

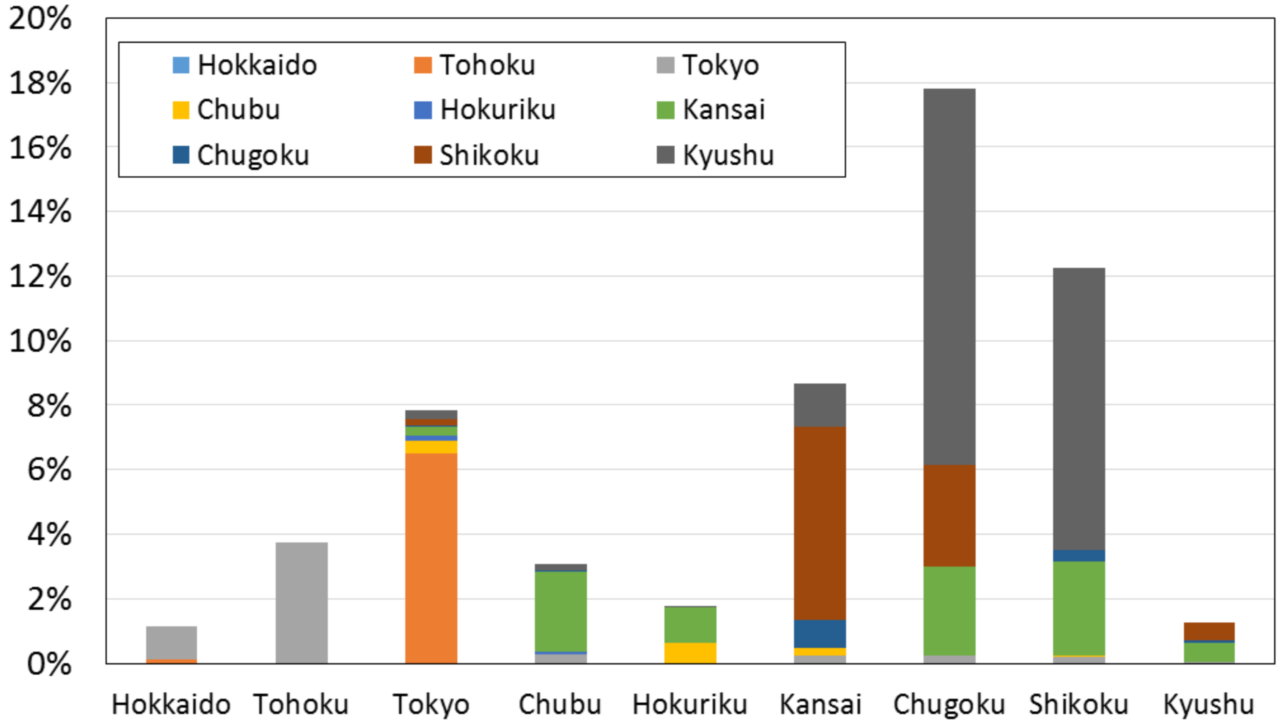

Figure 5-2 Ratio of Scheduled Procurement of Supply Capacity from External Regional Service Areas

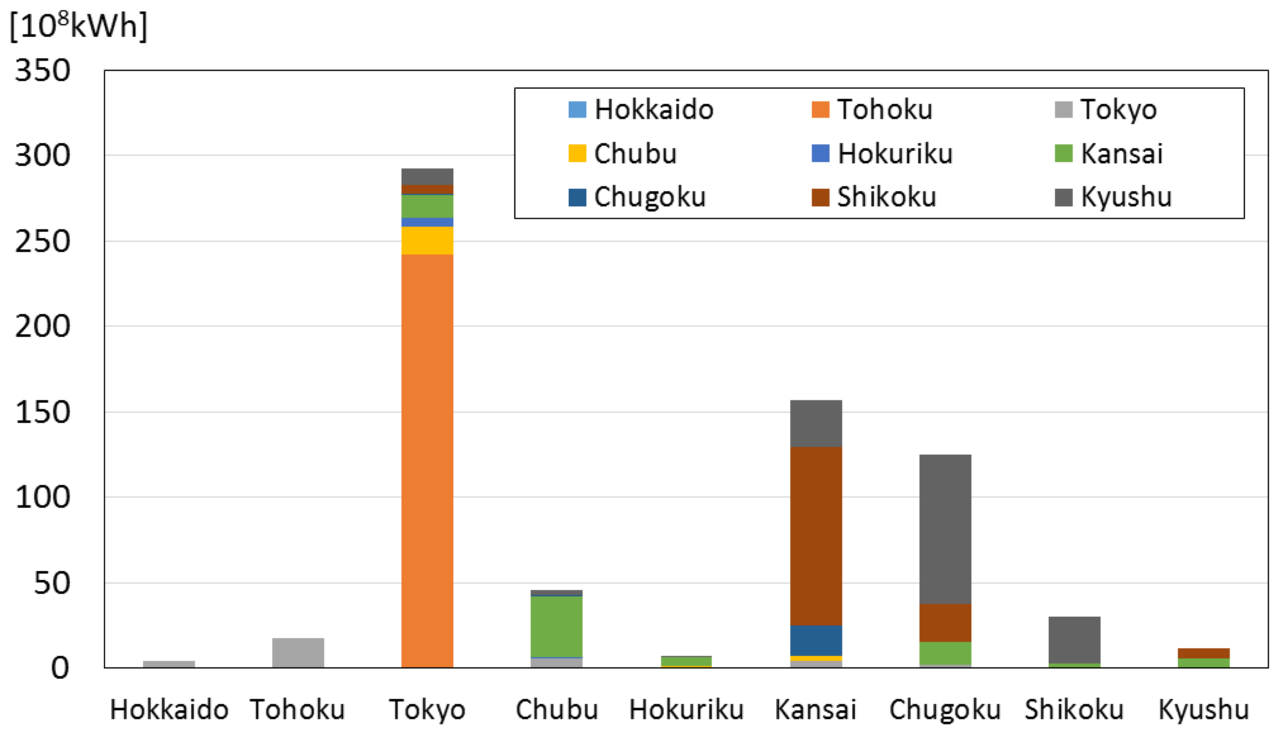

Figure 5-3 Scheduled Procurement of Energy Supply from External Regional Service Areas

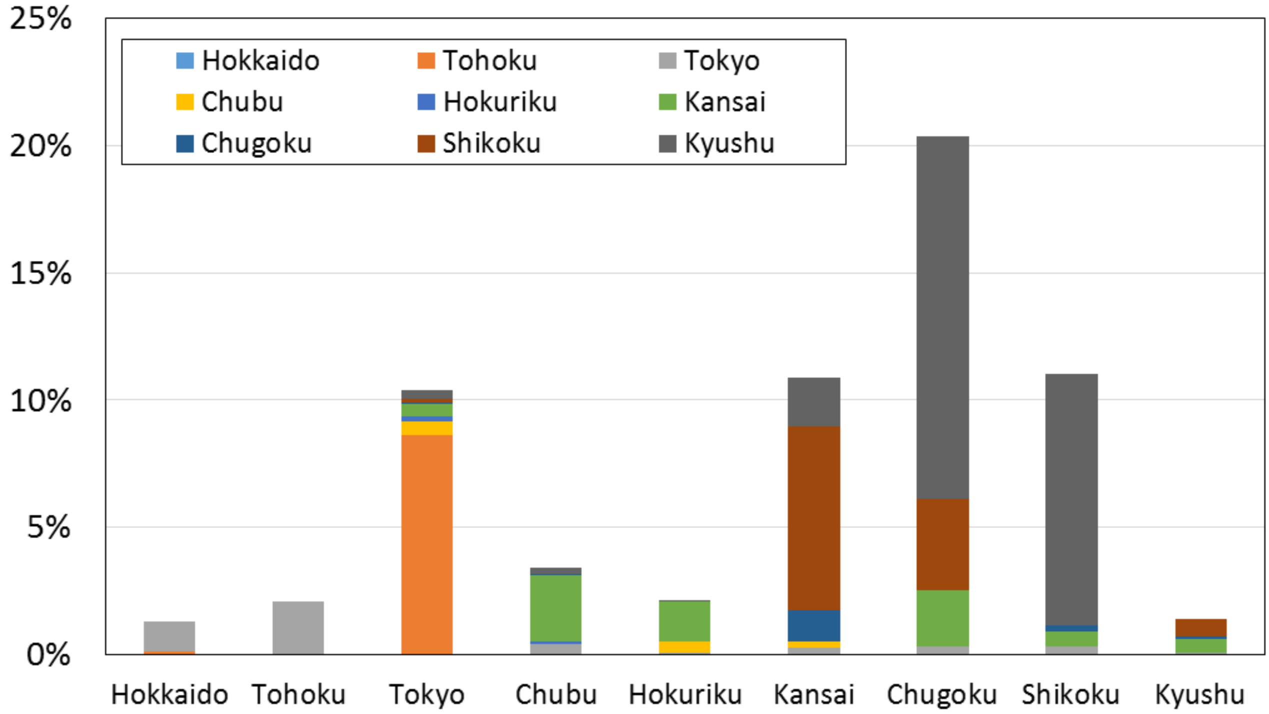

Figure 5-4 Ratio of Scheduled Procurement of Energy Supply from External Regional Service Areas

VI. Analysis of Characteristics of Electric Power Companies

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

In total, 535 retail companies submitted their electricity supply plans, and these are classified by the business scale of the retail demand forecast by the corresponding companies. 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. Notably, small-to-medium-sized retail companies (business scale of under 1 GW) plan to expand business.

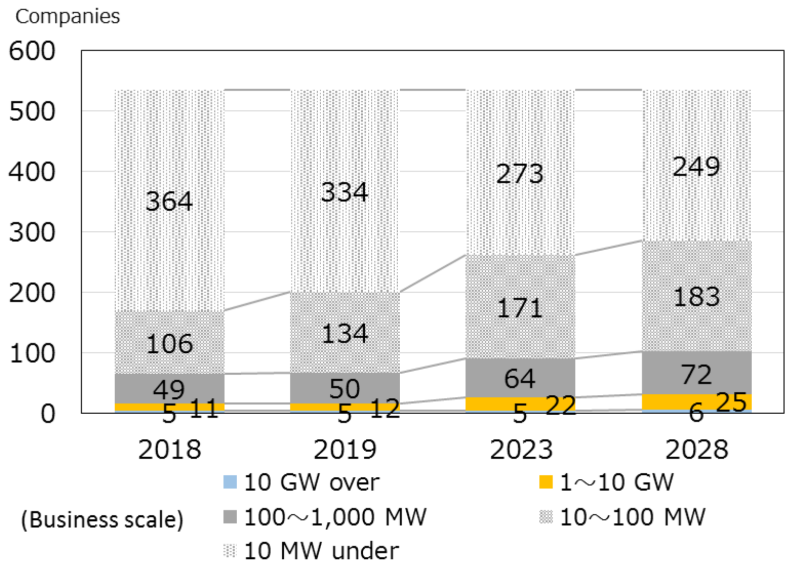

Figure 6-1 Distribution by Business Scale of the Retail Demand by Retail Companies

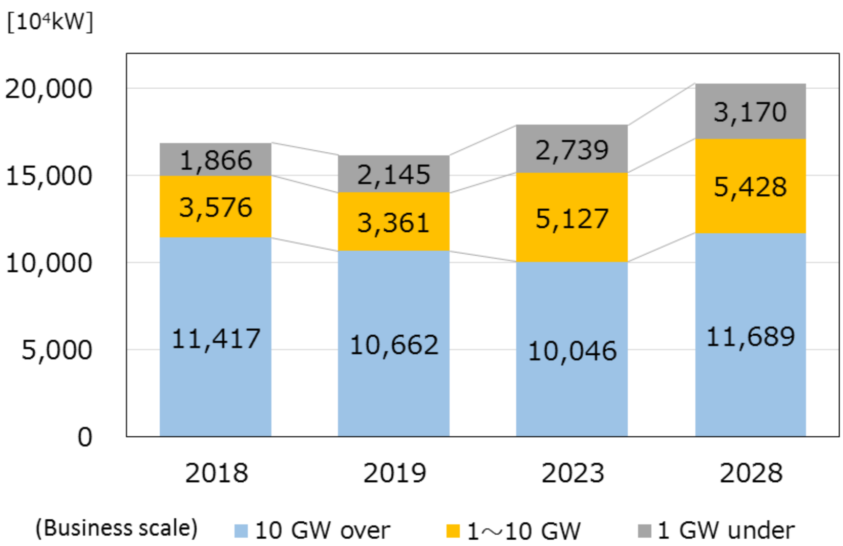

Figure 6-2 Distribution by Accumulated Retail Demand by Retail Companies

Similarly, retail companies are classified by the business scale of the retail energy sales forecast by the corresponding companies. 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, small and medium-sized retail companies (business scale of under 1 GW) plan to expand business.

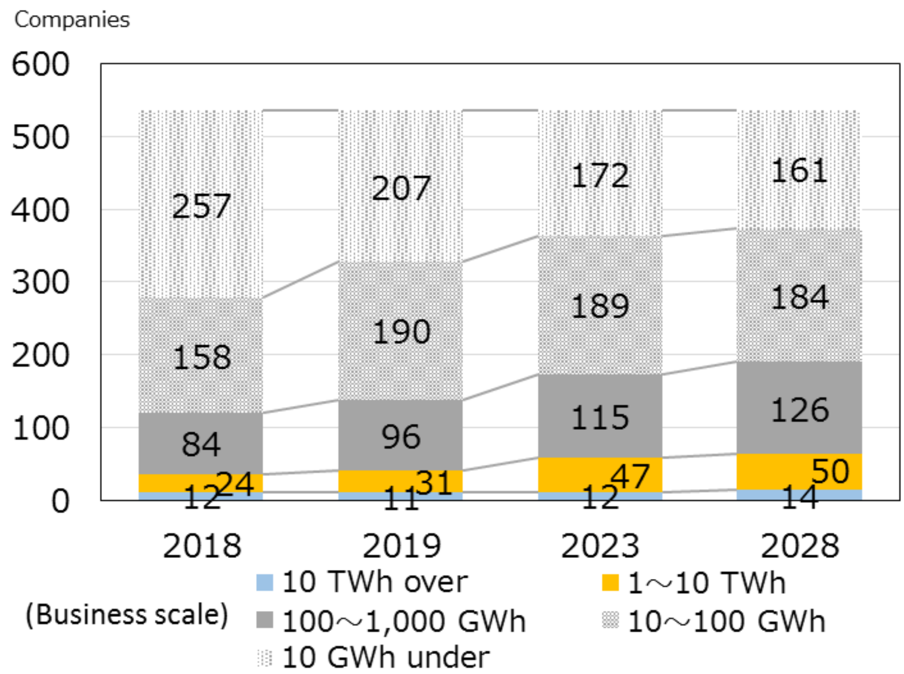

Figure 6-3 Distribution by Business Scale of Retail Company Energy Sales

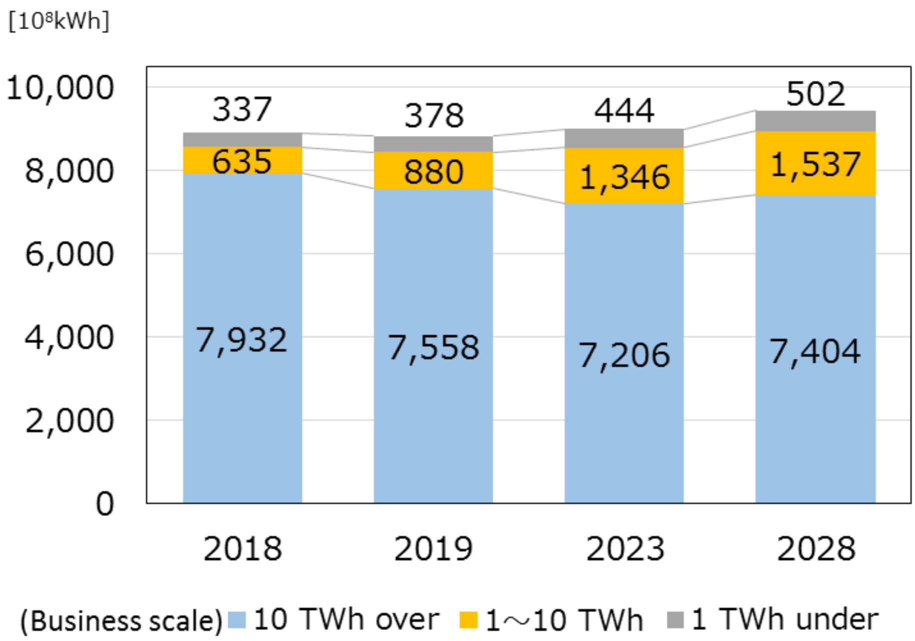

Figure 6-4 Distribution by Retail Company Accumulated Energy Sales

2. Retail Company Business Areas

Figure 6-5 shows the ratio of retail companies by the number of areas where they plan to conduct their business. Figure 6-6 shows the number of retail companies by their business planning areas in FY 2019. The figures exclude 68 retail companies that had not yet developed their retail business plans. Half of the retail companies plan their business in a single area.

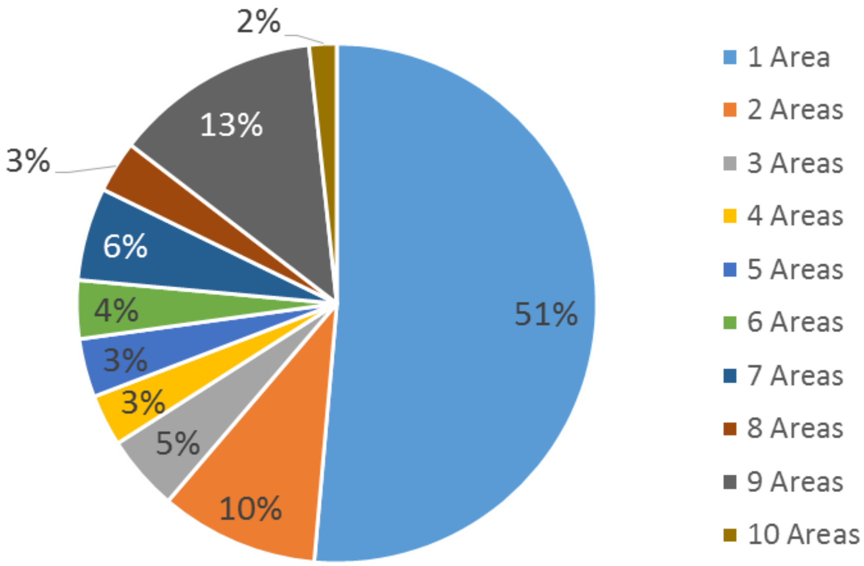

Figure 6-5 Ratio of Retail Companies by the Number of Planned Business Areas in FY 2019

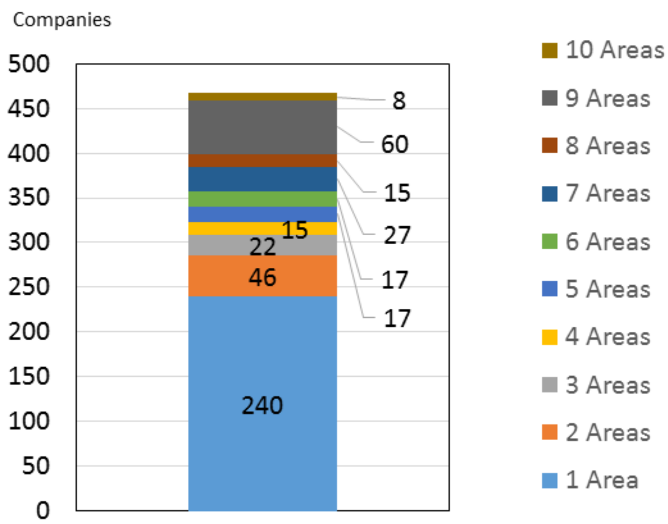

Figure 6-6 Number of Retail Companies by their Business Planning Areas in FY 2019

Figure 6-7 shows the number and the retail demand of retail companies in each regional service areas for GT&D companies in FY 2019. In general, the number of companies is comparable with the scale of retail demand in the regional service area.

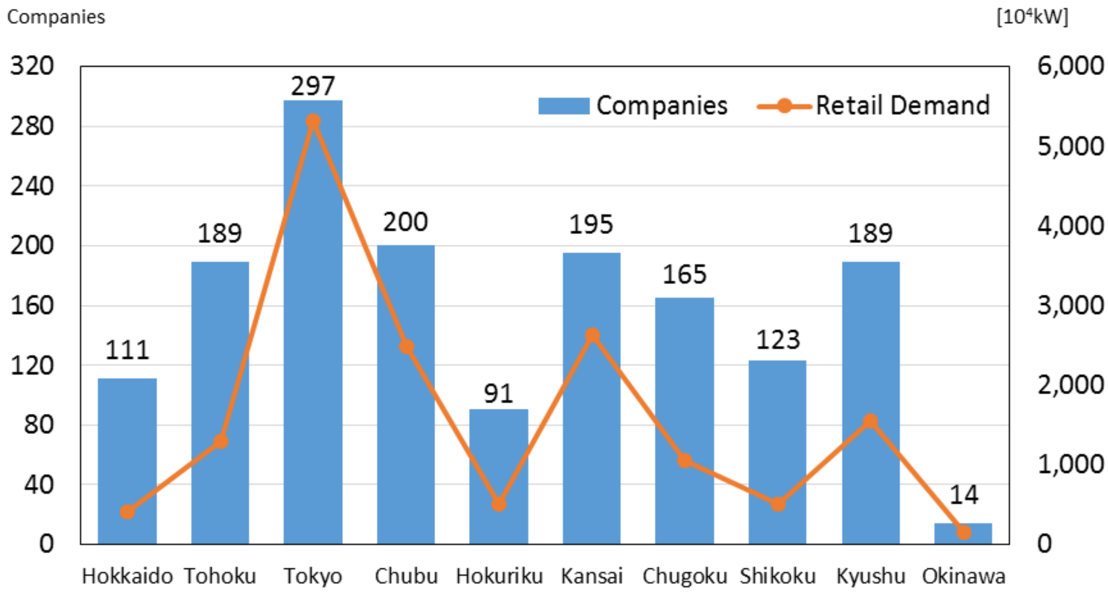

Figure 6-7 Number and Retail Demand of Retail Companies in Each Regional Service Area

3. Supply Capacity Procurement by Retail Companies

Table 6-1 and Figure 6-8 respectively show the supply capacity secured by retail companies according to their forecasted demand, and the ratios of the secured supply capacity[39] for the 10-year period FY 2019–2028, respectively. Particularly in the mid-to-long term, retail companies have planned their supply capacity as "unspecified procurement."[40]

Table 6-1 Supply Capacity Secured by Retail Companies According to Their Demand for the 10-year Period FY 2019–2028
(at 15:00 in August, 10^4 kW at the sending end)

	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023
Peak Demand Nationwide	15,907	15,877	15,855	15,833	15,814
Secured Supply Capacity	15,334	15,368	14,721	14,453	14,239
Ratio[39]	96.4%	96.8%	92.8%	91.3%	90.0%
	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028
Peak Demand Nationwide	15,792	15,771	15,749	15,757	15,735
Secured Supply Capacity	14,110	14,015	12,112	12,105	12,048
Ratio[39]	89.3%	88.9%	76.9%	76.8%	76.6%

[39] Ratio of the secured supply capacity to areal peak demand is the sum of secured supply capacity of retail companies divided by the peak demand nationwide, expressed in %.

[40] "Unspecified procurement" means that retail companies plan to procure their future supply capacity by means of various procurement choices, including procurement from the market, as described in the format of the electricity supply plan.

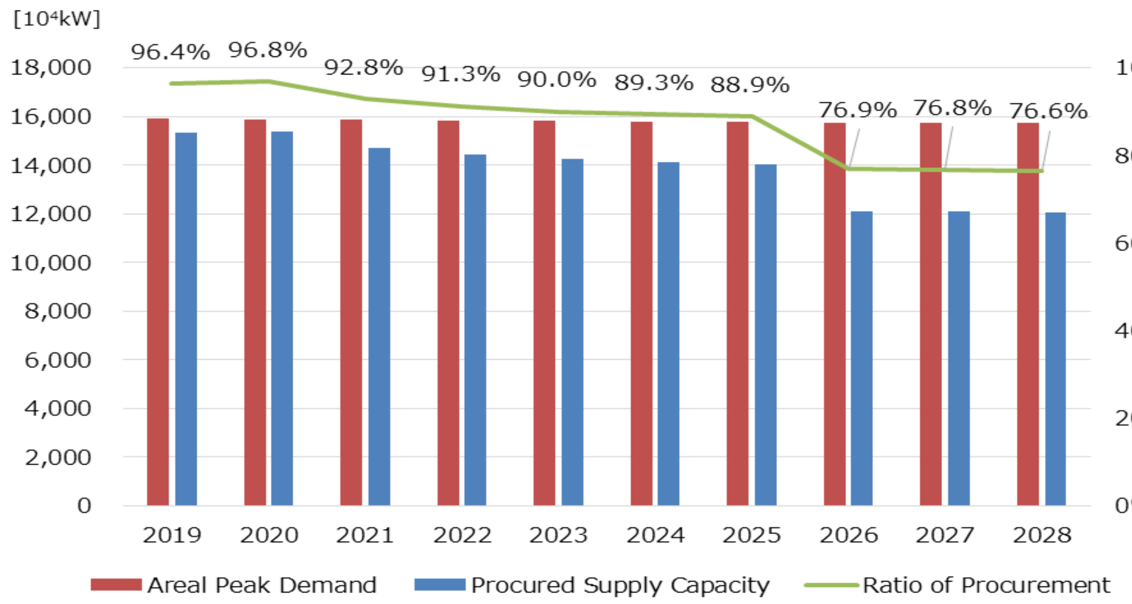

Figure 6-8 Supply Capacity Procured by Retail Companies According to Their Demand for the 10-year Period FY 2019–2028 (at 15:00 in August; at the sending end)

Figure 6-9 shows the retail demand forecasted in the regional service area by the retail department of former general electric utilities and their procured supply capacity to the retail demand. The retail and generation department of the former general electric utilities secure sufficient supply capacity procured to the retail demand of their own area.

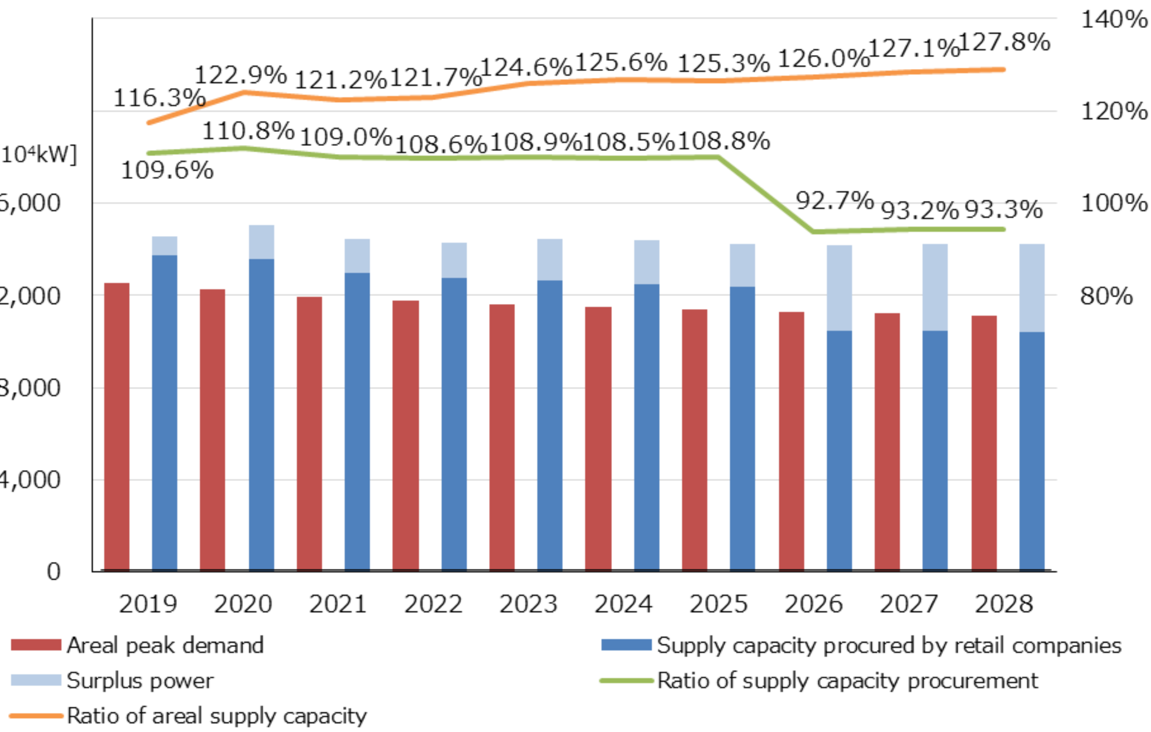

Figure 6-9 Ratio of Secured Supply Capacity to Forecast Retail Demand of Their Own Area for Former General Electric Utilities[41] (at 15:00 in August, at the sending end)

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[41] Includes surplus power of group companies deducting balancing capacity to the secured supply capacity by retail companies.

However, according to a review by the Organization, the ratio of secured supply capacity to forecast retail demand of the external areas that retail departments of former general electric utilities forecast as their own demand (including the demand of companies consisting of those majorly funded by former general electric utilities) has a tendency of procuring the supply capacity as "unspecified procurement", as is the case with other power producers and suppliers (PPSs) in the more competitive conditions among the former general electric utilities. In addition, the ratio of secured supply capacity procured by other PPSs to their own forecast peak demand nationwide will decline in the mid-to-long term as indicated in Figure 6-10.

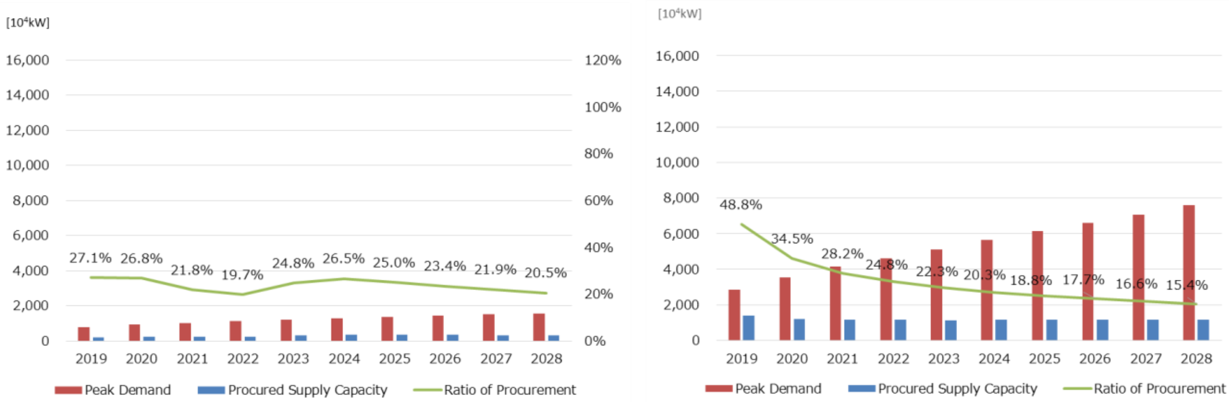


Figure 6-10 Ratio of Procured Supply Capacity to Forecast Retail Demand by Former Electric Utilities in the External Areas (left) and by PPSs (right) (at 15:00 in August, at the sending end)

Figure 6-11 shows the secured supply capacity (including surplus power) nationwide of retail departments of former general electric utilities (including companies consisting of those majorly funded by former general electric utilities). The retail departments of former general electric utilities have secured sufficient supply capacity for both their own service area and other external areas.

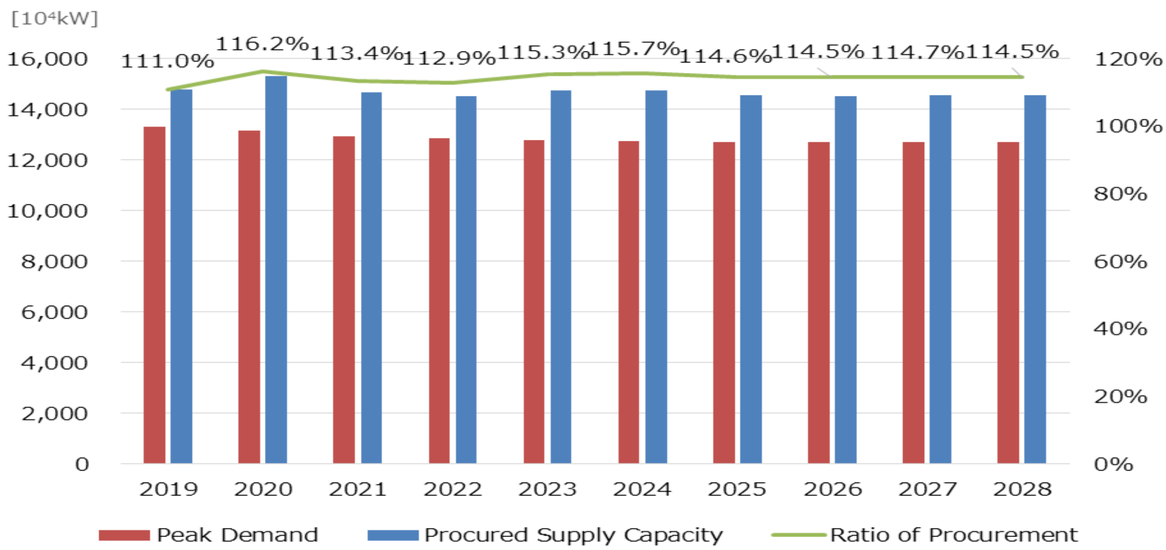


Figure 6-11 Ratio of Procured Supply Capacity to Forecast Retail Demand by Former Electric Utilities and Companies Consisting of Those Majorly Funded by Former Electric Utilities (at 15:00 in August, at the sending end)

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

In total, 725 generation companies submitted their electricity supply plans, and these are classified by the business scale of the installed capacity operated by the corresponding companies. Figure 6-12 shows the distribution by business scale and Figure 6-13 shows the installed capacity operated by the corresponding companies.

Generation companies with an installed capacity of under 100 MW are planning to enlarge the scale of their business.

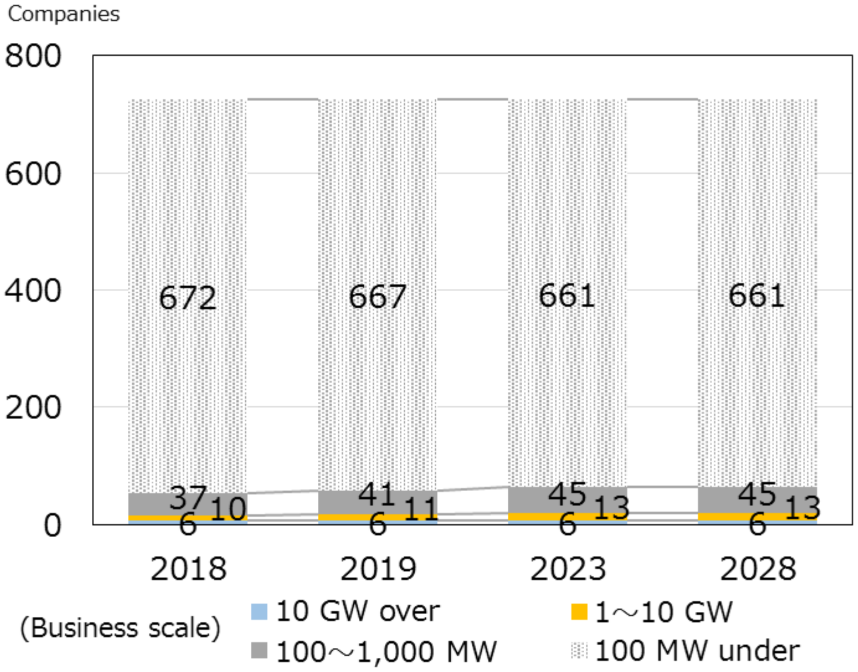


Figure 6-12 Distribution by Business Scale of Generation Company Installed Capacity

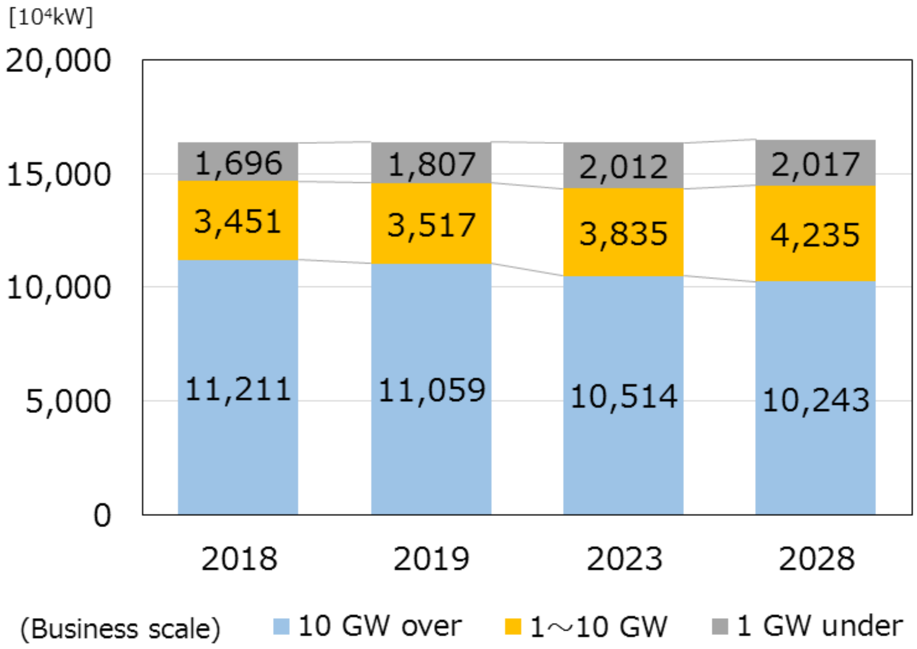


Figure 6-13 Distribution by Generation Company Accumulated Installed Capacity

Similarly, generation companies are classified by the business scale of the corresponding company energy supply forecast. Figure 6-14 shows the distribution by the business scale of the energy supply and Figure 6-15 shows the distribution by the corresponding company accumulated energy supply forecast.
Generation companies with an energy supply of under 10 TWh are planning to decrease their energy generation.

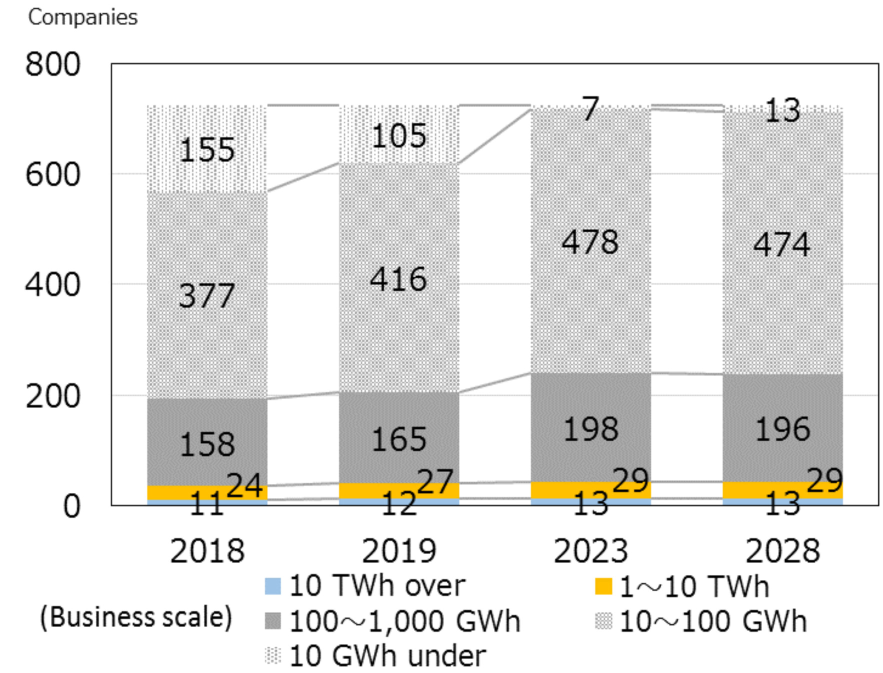


Figure 6-14 Distribution by Business Scale of Generation Company Energy Supply

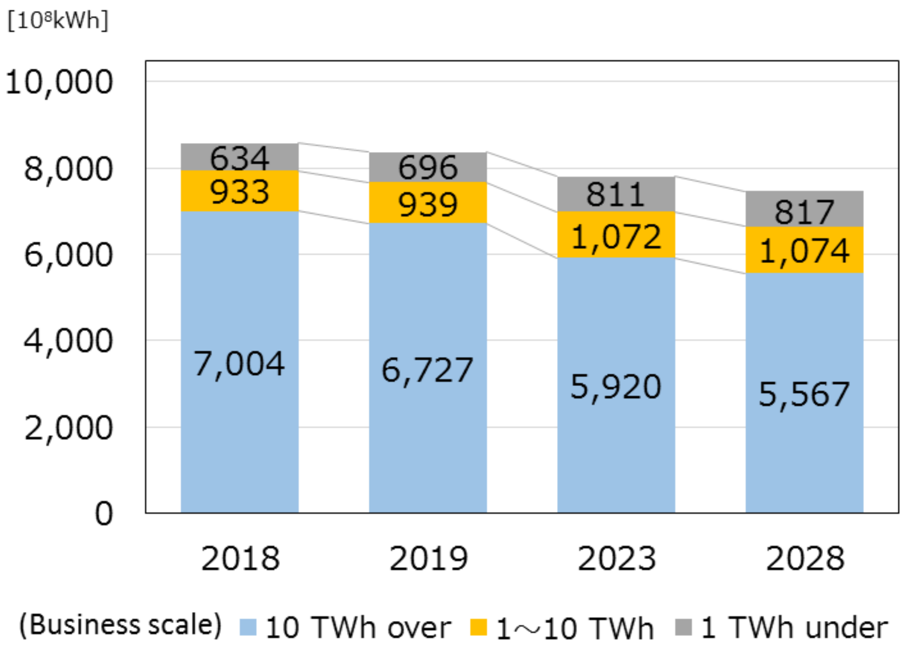


Figure 6-15 Distribution by Generation Company Accumulated Energy Supply

Figure 6-18 shows the number of generation companies by the power generation sources of their own generators at the end of FY 2019. The figures exclude 84 generation companies that do not own their generation plants. Approximately 75% of all generation companies solely own renewable energy generation facilities.

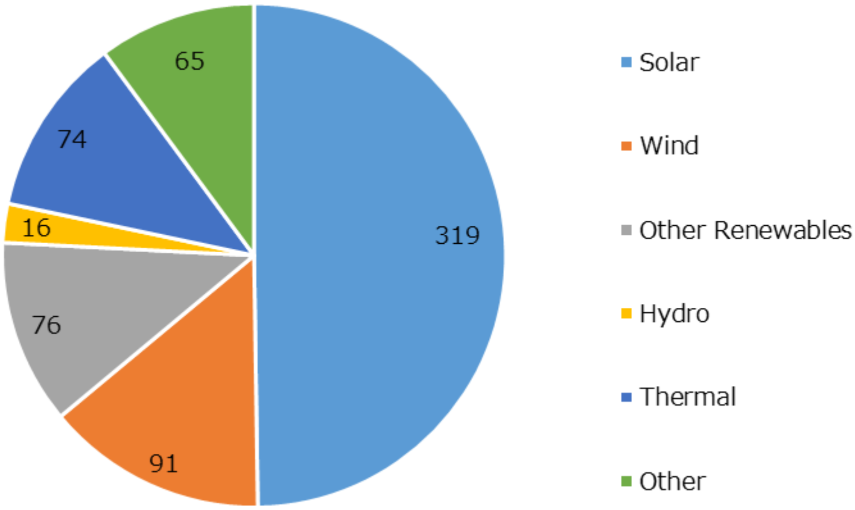


Figure 6-16 Number of Generation Companies by Power Generation Sources

5. Generation Company Business Areas

Figure 6-17 shows the ratio of generation companies to the number of areas where they plan to conduct their business. Figure 6-18 shows the number of generation companies by their business planning areas in FY 2019. The figures exclude 117 generation companies that do not own their generation plants. Approximately 75% of all generation companies plan their business in a single area.

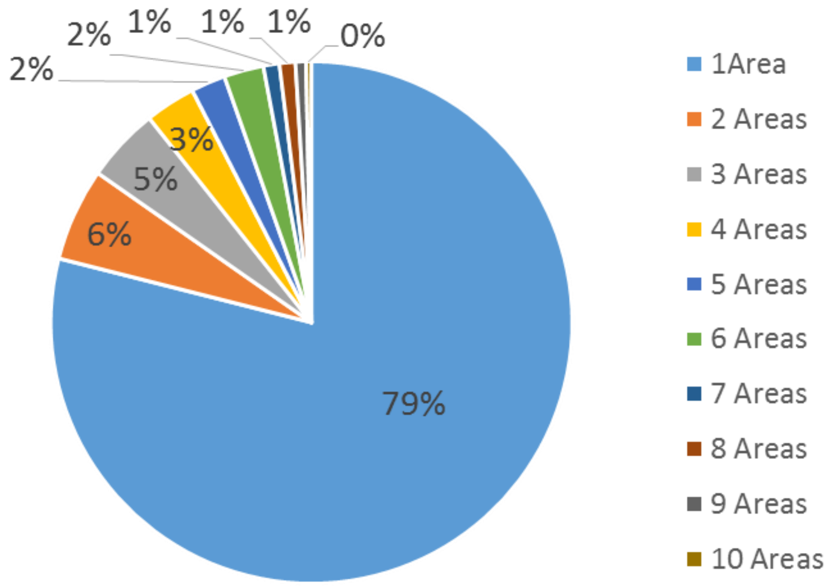


Figure 6-17 Ratio of Generation Companies by the Number of Planned Business Areas in FY 2019

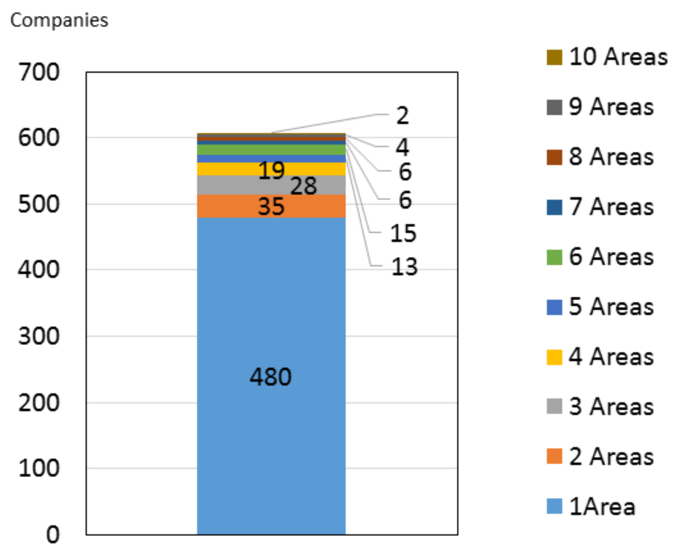


Figure 6-18 Number of Generation Companies by Their Business Planning Areas in FY 2019

Figure 6-19 shows the number and installed capacity of generation companies in each regional service area for GT&D companies in August 2019. In the Hokkaido, Tohoku, Chugoku, Shikoku, and Kyushu regional service areas, the scale of generation companies is rather small and their supply capacity is comparatively small despite the number of generation companies in these regional service areas.

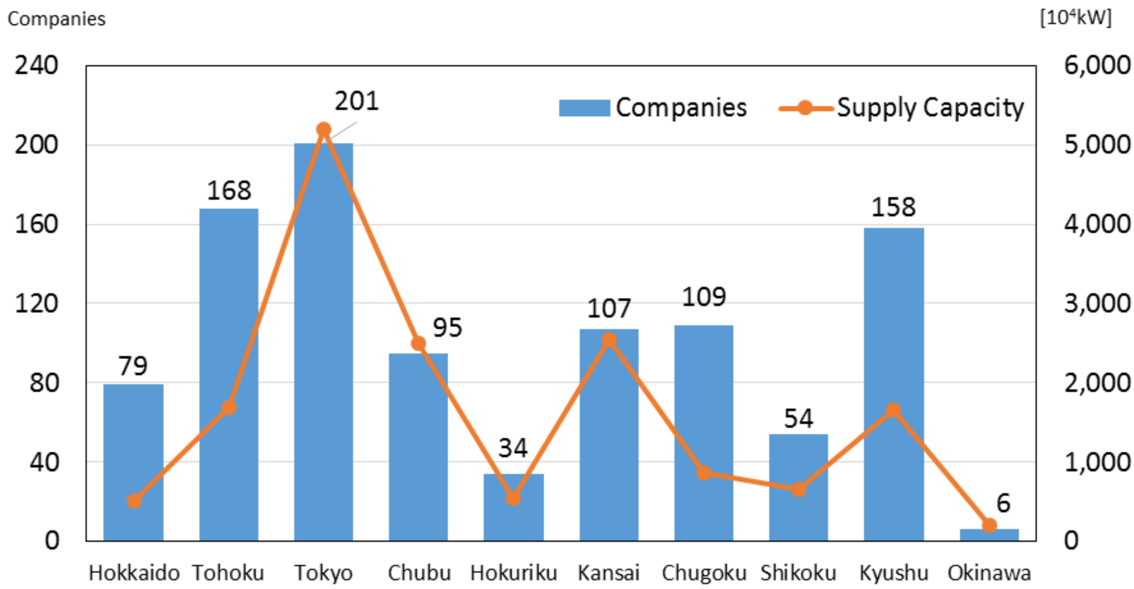


Figure 6-19 Number and Installed Capacity of Generation Companies in Each Regional Service Area

VII. Findings and Current Challenges

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

i. Toward the security of stable supply until the functioning of the capacity market

The following conditions were recognized at the previous year's aggregation of the plans: a) former general electric utilities will decrease their supply capacity according to the decrease in their customers; b) small-to-medium-sized retail companies will grab market share without procuring their supply capacity, which will remain "unspecified procurement." Both conditions lead to declining reserve margins in regional service areas and this tendency is likely to continue. At the current aggregation, the Organization has again recognized this tendency.

In addition, the following new tendencies or conditions are recognized at the current aggregation.

<u>Movement toward increasing supply capacity</u>

・ The Organization requested the cooperation of all electric power companies in securing supply capacity, and made individual requests to major electric power companies and solicited their feedback. As a result, the maintenance work schedule of planned outages of generators was coordinated to avoid summer or winter peak periods. However, based on the actual conditions or feedback from the electric power companies, it cannot be expected that greater coordination of the maintenance work schedule will occur in the future simply by request from the Organization due to constraints of workers and economic reasons.

・ Moves were made to ensure a balance of supply and demand, such as canceling discontinuance plans of generators, taking into account supply–demand conditions during the severe cold of the previous winter in 50 Hz areas.

<u>Movement toward decreasing supply capacity</u>

・ The demand forecasts of retail or generation departments of former general electric utilities indicate a significant loss in their shares in their own regional service areas, and they plan their generators anew based on their demand forecasts. They intend to actively utilize an electronic bulletin board system for information on generating facilities (launched by the Organization in April 2019) before the stage of deciding on generator discontinuance plans in their companies, thereby maintaining the generators in a rapid power-generatable mode in anticipation of launching the capacity market.

・ Under the condition that competition between retail departments of former electric utilities becomes fierce, such retail companies (including companies consisting of those majorly funded by former electric utilities) will indicate the tendency of their supply capacity as "unspecified procurement," as is the case with other PPSs in external areas other than in their own service areas.

Given the tendencies stated above, the Organization has aggregated the supply–demand balance of electric supply plans for FY 2019, and reached the projection that the adequate reserve margin of 8% will be secured in the supply–demand balance with the utilization of cross-regional interconnection lines in both the short- and the mid-to-long term.

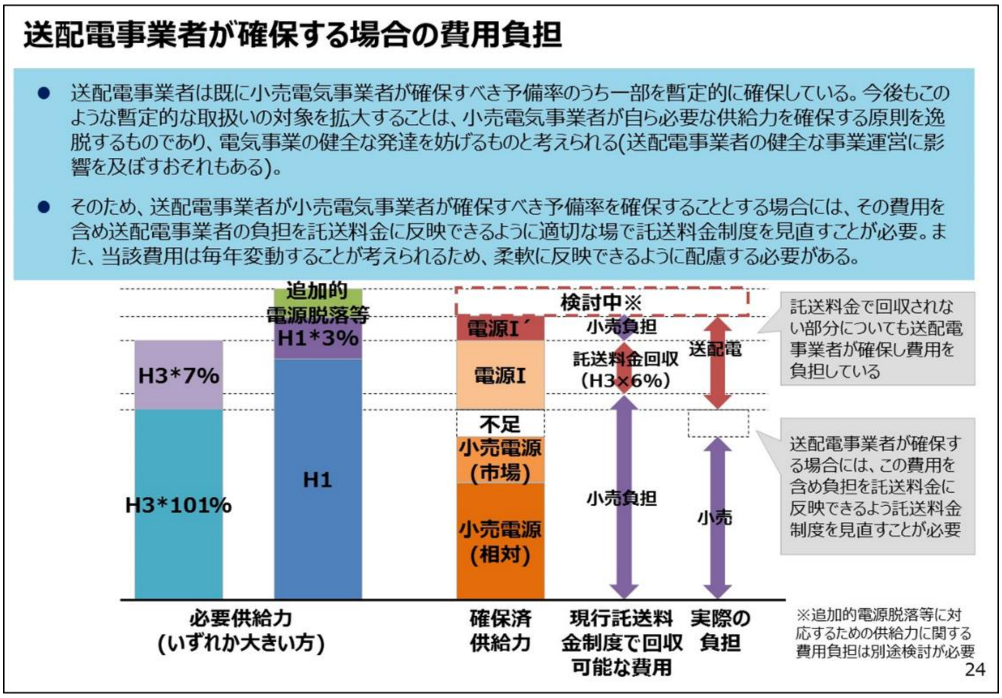
From the perspective of enhancing the resilience of the electric power grid, there are discussions on the necessary reserve capacity against severe weather or rare occurrence risk, and on the evaluation method for calculating renewable energy generation (kW value). The Organization recognizes that the necessary supply capacity will be secured if maintenance work schedules are adequately coordinated and discontinued generators are effectively utilized.

However, it cannot be denied that more generators will be discontinued or retired until FY 2024 when supply capacity is secured in the capacity market. If retail companies are projected to fail to secure the necessary supply capacity, GT&D companies independently have to secure supply capacity as an unavoidable response during the transition period.

The Organization will review the details of the supply capacity-securing scheme including the requirement for generators to clearly and flexibly implement securing supply capacity measures such as coordination of maintenance work schedules of generators, delayed discontinuance of generators, or restoring generators with appropriate timing. The Organization recommends the Government to examine institutional measures including cost allocation and the accompanying security of generators.

In parallel with the above-stated actions and the circumstances outlined in which it is crucial to finely and successively perceive the security of supply capacity in the future, the Organization will focus on the apprehension of discontinuance or retirement of generators in advance, and explore measures such as the utilization of an electronic bulletin board system for information on generating facilities, which aims at effective utilization of generators to be discontinued or retired.

<Reference 1> Review by the National Council



Source: Documents from the 29th task forth meeting of the Strategic Policy Subcommittee, Electricity and Gas Industry Committee, Advisory Committee for Natural Resources and Energy (February 28, 2019)
The original document [only in Japanese] is available at
https://www.meti.go.jp/shingikai/enecho/denryoku_gas/denryoku_gas/seido_kento/pdf/029_03_01.pdf

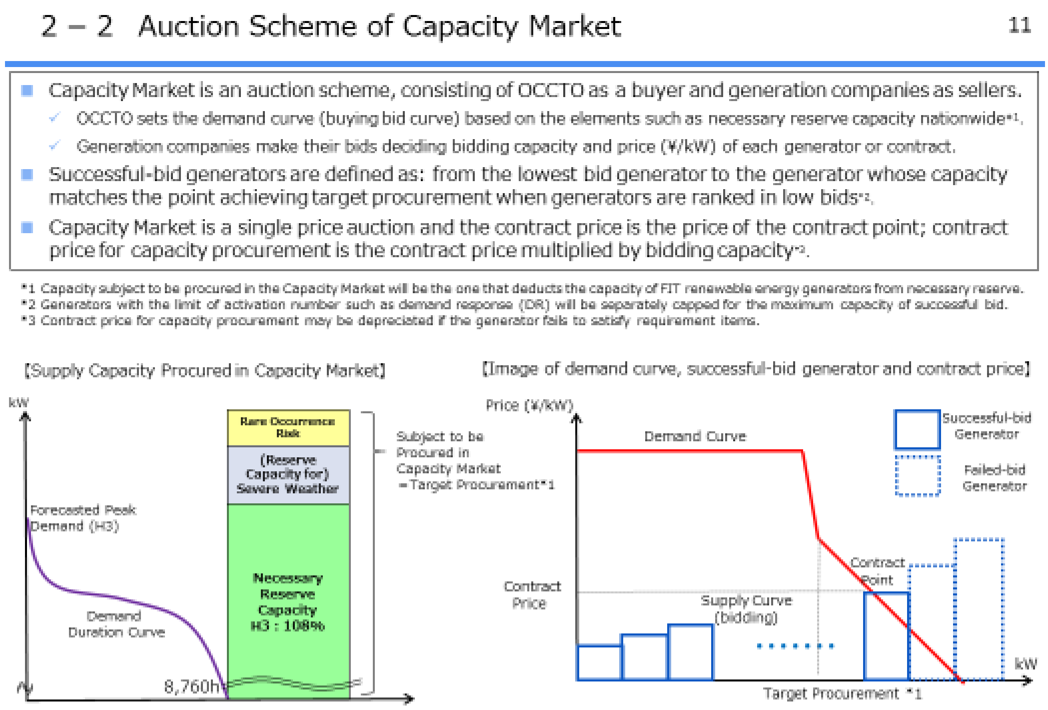
ii. Ideal electricity supply plan after the launch of the capacity market

Currently, supply capacity has been reviewed with respect to whether the necessary capacity is secured in the electricity supply plan. At the same time, a detailed review has been undertaken for the launch of the capacity market, after which the necessary supply capacity will be secured in the market scheme. Increased implementation of securing the supply capacity under the tendency that supply capacity is defined as “unspecified procurement” or “generation without sales destination” is vital.

Regarding the electricity supply plan after the launch of the capacity market, there will be an overlap with the capacity market in terms of aims and roles; these will be distinguished from the current plan for contents and items required for each business license (retail companies, generation companies, and GT&D companies). Therefore, the electricity supply plan will be changed to become a more efficient and effective scheme in the future by clarifying the aims and roles of each business license.

The Organization will review the information to be collected and the aims of the electricity supply plan in anticipation of review of the imbalance tariff system examined by the National Council, such as the Strategic Policy Subcommittee of the Advisory Committee for Natural Resources and Energy, and the Meeting for System Design of Electricity and Gas Market Surveillance Commission, and the balancing capacity market after outlining the information to be secured in the capacity market scheme. The Organization recommends the Government to proceed to examine the ideal electricity supply plan after launching the capacity market in cooperation with the Organization.

<Reference 2> Supply capacity procured in the capacity market



Source: Documents from the Capacity Market Orientation Meeting in March 2019
The original document [only in Japanese] is available at
http://www.occto.or.jp/kaiin/oshirase/files/youryou_setsumei0311.pdf

iii. Balancing capacity toward strengthening resilience of the power grid under the greater integration of renewable energy generation

With publication of the interim report of the Working Group on Electricity Resilience, the Organization continues to review the subject scope of supply capacity in the capacity market to include measures against severe weather or rare occurrence risk; these stand in aspect of adequacy (necessary capacity) of the supply capacity.

Regarding the events that might have led to a power shortage in the Chubu EPCO area due to output decrease of solar power in cloudy weather and demand increase in severe cold in January 2019, it is suggested that maintaining the supply–demand balance requires not only ensuring sufficient supply adequacy but also securing and operating the balancing capacity.

In relation to the abovementioned events, the ideal balancing capacity has been currently reviewed by the Subcommittee on Greater Introduction of Renewable Energy and Advanced Electric Network; balancing capacity will be secured by changing the procurement of Generator I' to year-round operation for the time being. Beyond launching the balancing market, the balancing capacity will be secured by procuring delta kW of Replacement Reserve for FIT and to be operated.

The Organization will proceed to review the ideal balancing capacity and its operation toward launching the balancing market in anticipation of greater integration of renewable energy generation. The Organization recommends the Government to examine a detailed system design such as an imbalance tariff system or cost allocation method.

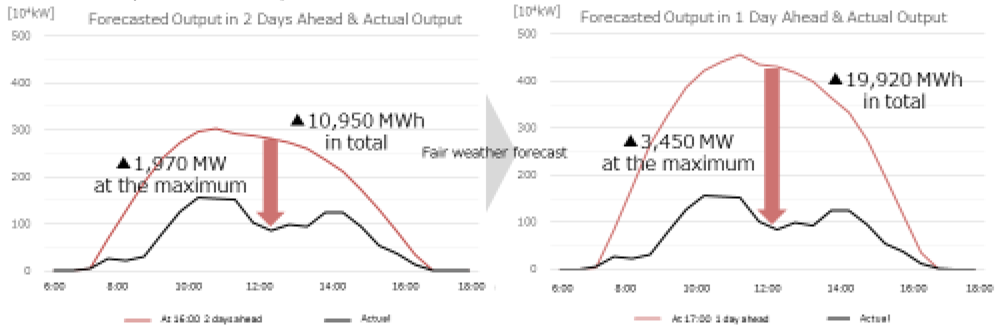
<Reference 3> Supply–demand state in the Chubu EPCO area on January 10, 2019

Forecast Error in Output of Solar Power with FIT Exceptional Contract

8

- Output forecast for solar power generation (distribution of output for FIT exceptional contract type 1) is implemented at 16:00 of 2 days ahead.
- The forecast output of solar power generation for January 10 was substantially higher than the actual output by 1,970 MW in capacity at the maximum and 10,950 MWh in total energy generated.
- In addition, weather forecast after 16:00 of 2 days ahead assumed fair weather, output forecasts afterward were further risen; the difference between forecast at 17:00 of 1 day ahead and actual output has become larger by 3,450 MW in capacity at the maximum and 19,920 MWh in total energy generated.

*For output forecast of solar power of FIT exceptional contract type 3 is implemented in the previous day, the forecast output was added to the forecast output at 16:00 of 2 days ahead for convenience.



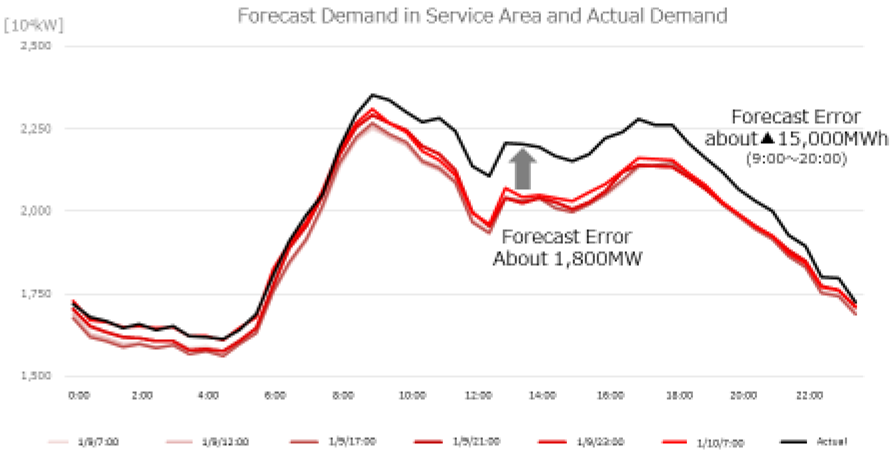
	1/8/16:00	1/9/7:00	1/9/12:00	1/9/17:00	1/9/21:00	1/9/23:00	1/10/7:00
Maximum Error [10^4kW]	197	278	345	345	340	316	276
Total Forecasted Error [10^4kWh]	1,095	1,537	1,992	1,992	1,820	1,608	1,401

<Reference 4> Supply–demand state in the Chubu EPCO area on January 10, 2019

Forecast Demand and Actual Demand

11

- Demand forecasts for January 10 by Chubu EPCO from the previous day to the current morning were lower than the actual demand with average value of 5 to 6%, and 1,800 MW in capacity at the maximum, and 15,000 MWh in energy required.
- Despite of demand forecast review of 5 times in total from the previous morning to the current morning, the actual demand was substantially higher compared with all reviewed forecast.



Source of References 3 and 4:Document 2-1 from the 36th Meeting of the Study Committee on Regulating and Marginal Supply Capability and Long-Term Supply–Demand Balance Evaluation (February 19, 2019)
The original document [only in Japanese] is available at
https://www.occto.or.jp/iinkai/chouseiryoku/2018/files/chousei_jukyu_36_02_01.pdf

<Reference 5> Review by the National Council

必要な調整力の具備についての検討の方向性 73

- 自然変動電源（太陽光・風力）の導入量の増加に伴い、必要となる調整力が増大し得るが、**適切な量の調整力を確保し、費用回収するための仕組みの構築が必要**。
- かかる問題意識から、第４回の本小委において、現在の**「ピーク需要の７%」という調整力確保の基準が十分か、定量的に検証した上で負担の在り方についても検討が必要**ではないか、という問題提起をしたところ。
- この点、別途、レジリエンス強化の観点から、別の審議会において「暫定的に追加確保すべき予備力」の議論を進めているところであるが、**再エネ主力電源化に向けて必要な調整力を具備するために、どのような検討を進めるべきか**。
- また、**再生可能エネルギー主力電源化、及びレジリエンス強化双方の観点から、グリッドコードの整備の在り方について検討を深化**させるべきではないか。

Source: Document 4 from the 11th Meeting of the Subcommittee on Greater Introduction of Renewable Energy and Advanced Electric Network, Committee on Energy Efficiency and Renewable Energy/ Electricity and Gas Industry Committee, Advisory Committee for Natural Resources and Energy (December 16, 2018)
The original document [only in Japanese] is available at
https://www.meti.go.jp/shingikai/enecho/denryoku_gas/saisei_kano/pdf/011_04_00.pdf

<Reference 6> Review by the National Council

Ⅲ－２．適切な調整力の確保
３．目指すべき自然変動再エネの出力調整の在り方
（２）再エネ予測誤差に対応するための調整力の費用負担

【アクションプラン】

- 一般送配電事業者による出力予測の予測誤差自体を減らすなど、再生可能エネルギーに起因するインバランスを小さくし、国民負担の抑制を図るため、データの予測精度や運用実態、全体のインバランス設計も踏まえ、実現可能な方策について検討を進める。
【➡資源エネルギー庁、電力・ガス取引監視等委員会、広域機関、一般送配電事業者（2019年度中目途）】
- 一般送配電事業者による再エネ予測誤差の削減について広域機関が適正に監視・確認する仕組みとした上で、なお生じざるを得ない相応の予測誤差が残る場合には、予測誤差を削減し確保するべき調整力を減らすインセンティブが働くようにしつつ、その調整力の確保にかかる費用をFIT交付金により負担する仕組みを構築する。
【➡資源エネルギー庁、電力・ガス取引監視等委員会、広域機関（2020年度を目途に具体化）】

Source: The Second Interim Report of the Subcommittee on Greater Introduction of Renewable Energy and Advanced Electric Network Committee on Energy Efficiency and Renewable Energy/ Electricity and Gas Industry Committee, Advisory Committee for Natural Resources and Energy (January 28, 2019)
The original document [only in Japanese] is available at
https://www.meti.go.jp/shingikai/enecho/denryoku_gas/saisei_kano/pdf/20190128001_01.pdf

VIII. Conclusions

1. Electricity Demand Forecast

The AAGRs of both peak demand nationwide (average of the three highest daily loads) and electric energy requirement nationwide in the mid-to-long term are forecast to decrease by 0.1%. AAGRs have become negative, and this is attributable to a number of major factors, such as efforts to reduce electricity use, wider utilization of energy-saving electric appliances, a shrinking population, and load-levelling measures.

2. Electricity Supply and Demand

Regarding the supply–demand balance evaluation in each regional service area during the 10-year period, the criterion of a stable supply, i.e., a reserve margin of 8% (supply capacity over peak demand by deducting the capacity of the largest generating unit and balancing capacity with frequency control [Generator I] in Okinawa) is projected to be secured in all areas and years by sharing power from other areas with sufficient supply capacity through cross-regional interconnection lines. The Organization will continuously and carefully evaluate the supply–demand balance, by monitoring the submission of changing supply plans and the accompanying supply–demand balance.

3. Analysis of the Transition of Power Generation Sources Nationwide

Regarding the transitions of installed power generation capacity and gross electricity generation, renewable energy such as solar power is projected to increase greatly; at the same time, coal and LNG will increase their capacity but remain the same or decrease in terms of energy generation. For nuclear power plants, energy generations calculated as zero for their capacity is reported as "uncertain".

4. Development Plans for Transmission and Distribution Facilities

Regarding the development plans for major transmission lines or substations, there are no changes for cross-regional interconnection lines from the previous year's plans.

5. Cross-Regional Operation

For procuring supply capacity or energy from the external service areas, aggregated results are almost the same in both the areas with higher procurement from the external service areas and in the areas with higher transmission to the external areas.

6. Analysis of Characteristics of Electric Power Companies

Distributions are calculated for retail companies and generation companies according to business scale and business areas, and aggregated to the projection during the 10-year period. In addition, the ratios of the secured supply capacity are reviewed. In particular, small-to-medium-sized retail companies have planned their supply capacity as "unspecified procurement," as in the previous year's plan. As a result, the ratios of the secured supply capacity indicate declining tendency.

7. Findings and Challenges

The Organization has communicated its opinions to the Minister of Economy, Trade and Industry concerning three major challenges relating to electricity supply plans, the ideal evaluation method for the supply–demand balance, and current challenges in the electricity business in relation to the aggregation of electricity supply plans for FY 2019.

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

APPENDIX 1 Supply–Demand Balance for FY 2019 · A1

APPENDIX 2 Long-Term Supply–Demand Balance for the 10-year Period FY 2019–2028 · · · A3

APPENDIX 1 Supply–Demand Balance for FY 2019

Tables A1-1 to A1-4 show the monthly peak demand, monthly supply capacity, monthly reserve capacity, and reserve margin for each regional service area in FY 2019, respectively. 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 from areas with over 8% reserve margin.

Table A1-1 Monthly Peak Demand Forecast for Each Regional Service Area

[10^4kW]

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	403	369	365	407	420	401	415	456	486	499	493	459
Tohoku	1,060	975	1,047	1,262	1,270	1,145	1,067	1,187	1,312	1,375	1,360	1,268
Tokyo	3,848	3,649	4,081	5,311	5,311	4,512	3,695	4,026	4,382	4,698	4,698	4,312
50 Hz area Total	5,311	4,993	5,493	6,980	7,001	6,058	5,177	5,669	6,180	6,572	6,551	6,039
Chubu	1,837	1,905	2,056	2,416	2,416	2,188	1,961	1,964	2,215	2,311	2,311	2,149
Hokuriku	373	372	410	495	495	458	373	424	476	499	499	471
Kansai	1,847	1,842	2,141	2,607	2,607	2,308	1,913	1,993	2,367	2,420	2,420	2,176
Chugoku	756	757	842	1,028	1,028	911	779	837	998	1,016	1,016	909
Shikoku	350	355	402	503	503	441	364	375	464	464	464	414
Kyushu	1,044	1,044	1,157	1,484	1,482	1,320	1,162	1,179	1,486	1,506	1,506	1,281
60 Hz area Total	6,207	6,274	7,008	8,533	8,531	7,625	6,551	6,772	8,006	8,216	8,216	7,400
Interconnected	11,518	11,267	12,501	15,513	15,532	13,683	11,728	12,441	14,186	14,788	14,767	13,439
Okinawa	104	121	139	148	148	143	132	112	99	104	103	97
Nationwide	11,623	11,389	12,640	15,661	15,680	13,826	11,861	12,552	14,285	14,892	14,870	13,536

Table A1-2 Monthly Projection of Supply Capacity for Each Regional Service Area

[10^4kW]

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	549	544	573	493	513	501	497	545	608	597	599	568
Tohoku	1,270	1,236	1,224	1,443	1,416	1,294	1,171	1,330	1,460	1,525	1,523	1,425
Tokyo	4,624	4,773	4,846	5,761	5,773	5,531	4,574	4,692	5,260	5,561	5,481	5,336
50 Hz area Total	6,442	6,553	6,643	7,697	7,702	7,326	6,243	6,566	7,327	7,683	7,603	7,329
Chubu	2,332	2,306	2,461	2,618	2,660	2,577	2,335	2,301	2,409	2,545	2,584	2,527
Hokuriku	478	461	471	575	550	529	422	458	541	546	545	547
Kansai	2,412	2,308	2,441	2,778	2,751	2,678	2,293	2,390	2,573	2,706	2,673	2,553
Chugoku	938	923	984	1,157	1,143	1,045	929	942	1,004	1,102	1,116	1,060
Shikoku	500	497	523	605	584	507	450	472	537	483	489	424
Kyushu	1,415	1,315	1,304	1,627	1,553	1,443	1,351	1,366	1,566	1,650	1,644	1,610
60 Hz area Total	8,075	7,809	8,184	9,359	9,241	8,778	7,781	7,930	8,631	9,033	9,049	8,719
Interconnected	14,517	14,362	14,827	17,056	16,944	16,105	14,023	14,496	15,958	16,716	16,652	16,049
Okinawa	162	172	188	197	197	198	194	172	172	177	184	179
Nationwide	14,679	14,535	15,016	17,253	17,141	16,303	14,218	14,668	16,130	16,893	16,836	16,228

Table A1-3 Monthly Projection of Reserve Capacity for Each Regional Service Area

[10^4kW]

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	146	175	208	86	93	100	82	89	122	98	106	109
Tohoku	210	261	177	181	146	150	104	143	148	150	163	157
Tokyo	776	1,124	765	450	462	1,019	879	666	878	863	783	1,024
50 Hz area Total	1,131	1,560	1,150	717	701	1,269	1,066	897	1,147	1,111	1,052	1,290
Chubu	495	401	405	202	244	389	374	337	194	234	273	378
Hokuriku	105	89	61	79	55	71	50	34	65	47	46	76
Kansai	565	466	300	170	144	370	380	397	206	286	253	377
Chugoku	182	166	142	129	115	134	150	105	6	86	100	151
Shikoku	150	142	121	102	81	66	86	97	73	19	25	10
Kyushu	371	271	147	142	72	123	189	187	80	144	138	329
60 Hz area Total	1,867	1,535	1,176	826	710	1,153	1,229	1,158	625	817	833	1,320
Interconnected	2,998	3,095	2,326	1,543	1,411	2,422	2,295	2,056	1,772	1,928	1,885	2,610
Okinawa	58	51	50	49	50	55	62	60	73	73	80	82
Nationwide	3,056	3,146	2,376	1,592	1,461	2,477	2,357	2,116	1,846	2,001	1,966	2,692

Table A1-4 Monthly Projection of Reserve Margin for Each Regional Service Area
(resources within own service area only, at the sending end; see Table 2-3)

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	36.2%	47.4%	57.0%	21.1%	22.2%	24.9%	19.7%	19.5%	25.0%	19.6%	21.5%	23.8%
Tohoku	19.8%	26.8%	16.9%	14.3%	11.5%	13.1%	9.8%	12.0%	11.3%	10.9%	12.0%	12.4%
Tokyo	20.2%	30.8%	18.7%	8.5%	8.7%	22.6%	23.8%	16.5%	20.0%	18.4%	16.7%	23.8%
50 Hz area Total	21.3%	31.2%	20.9%	10.3%	10.0%	20.9%	20.6%	15.8%	18.6%	16.9%	16.1%	21.4%
Chubu	26.9%	21.1%	19.7%	8.4%	10.1%	17.8%	19.0%	17.2%	8.7%	10.1%	11.8%	17.6%
Hokuriku	28.1%	24.0%	15.0%	16.1%	11.0%	15.6%	13.3%	8.1%	13.7%	9.4%	9.3%	16.2%
Kansai	30.6%	25.3%	14.0%	6.5%	5.5%	16.0%	19.9%	19.9%	8.7%	11.8%	10.4%	17.3%
Chugoku	24.1%	21.9%	16.8%	12.6%	11.2%	14.8%	19.3%	12.6%	0.6%	8.4%	9.8%	16.6%
Shikoku	42.9%	39.9%	30.1%	20.2%	16.1%	14.9%	23.8%	26.0%	15.8%	4.2%	5.3%	2.4%
Kyushu	35.5%	26.0%	12.7%	9.6%	4.8%	9.3%	16.3%	15.9%	5.4%	9.6%	9.1%	25.7%
60 Hz area Total	30.1%	24.5%	16.8%	9.7%	8.3%	15.1%	18.8%	17.1%	7.8%	9.9%	10.1%	17.8%
Interconnected	26.0%	27.5%	18.6%	9.9%	9.1%	17.7%	19.6%	16.5%	12.5%	13.0%	12.8%	19.4%
Okinawa	55.3%	41.9%	35.7%	33.1%	33.5%	38.1%	46.9%	53.9%	73.8%	70.3%	78.0%	84.3%
Nationwide	26.3%	27.6%	18.8%	10.2%	9.3%	17.9%	19.9%	16.9%	12.9%	13.4%	13.2%	19.9%

Below Criteria of 8%

Table A1-5 Monthly Projection of Reserve Margin for Each Regional Service Area
(with power exchange through cross-regional interconnection lines, at the sending end; see Table 2-4)

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	21.3%	29.8%	45.2%	11.3%	12.4%	19.2%	19.6%	16.0%	16.9%	15.4%	14.6%	22.3%
Tohoku	21.3%	28.9%	17.8%	11.3%	9.0%	19.2%	19.6%	16.0%	16.9%	15.4%	14.6%	19.3%
Tokyo	21.3%	28.9%	17.8%	9.8%	9.0%	19.2%	19.6%	16.0%	16.9%	15.4%	14.6%	19.3%
Chubu	30.1%	26.3%	17.8%	9.8%	9.0%	16.8%	19.6%	17.0%	9.1%	11.1%	11.3%	19.3%
Hokuriku	30.1%	26.3%	17.8%	9.8%	9.0%	16.4%	19.6%	17.0%	9.1%	11.1%	11.3%	19.3%
Kansai	30.1%	26.3%	17.8%	9.8%	9.0%	16.4%	19.6%	17.0%	9.1%	11.1%	11.3%	19.3%
Chugoku	30.1%	26.3%	17.8%	9.8%	9.0%	16.4%	19.6%	17.0%	9.1%	11.1%	11.3%	19.3%
Shikoku	30.1%	26.3%	17.8%	9.8%	9.0%	16.4%	19.6%	17.0%	9.1%	11.1%	11.3%	19.3%
Kyushu	30.1%	26.3%	17.8%	9.8%	9.0%	16.4%	19.6%	17.0%	9.1%	11.1%	11.3%	19.5%
Interconnected	26.0%	27.5%	18.6%	9.9%	9.1%	17.7%	19.6%	16.5%	12.5%	13.0%	12.8%	19.4%
Okinawa	55.3%	41.9%	35.7%	33.1%	33.5%	38.1%	46.9%	53.9%	73.8%	70.3%	78.0%	84.3%
Nationwide	26.3%	27.6%	18.8%	10.2%	9.3%	17.9%	19.9%	16.9%	12.9%	13.4%	13.2%	19.9%

Improved to over 8%

APPENDIX 2 Long-Term Supply–Demand Balance for the 10-year Period FY 2019–2028

Tables A2-1 to A2-4 show a 10-year projection of the annual peak demand, annual supply capacity, annual reserve capacity, and reserve margin for each regional service area from FY 2019 to FY 2028, respectively. Table A2-5 shows the annual projection of the reserve margin for each regional service area recalculated with power exchanges from areas with over 8% reserve margin to areas below the 8% reserve margin. Tables A2-6 to A2-9 show a 10-year projection of the annual peak demand, annual supply capacity, annual reserve capacity, and reserve margin for winter peak areas of Hokkaido and Tohoku, respectively.

Table A2-1 Annual Peak Demand Forecast for Each Regional Service Area (at 17:00 in August)

[10^4kW]

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Hokkaido	420	420	419	419	419	418	418	418	418	418
Tohoku	1,270	1,268	1,267	1,263	1,259	1,254	1,249	1,244	1,239	1,234
Tokyo	5,132	5,109	5,112	5,115	5,118	5,122	5,127	5,131	5,148	5,152
50 Hz area Total	6,822	6,797	6,798	6,797	6,796	6,794	6,794	6,793	6,805	6,804
Chubu	2,416	2,419	2,407	2,397	2,386	2,375	2,365	2,354	2,357	2,346
Hokuriku	495	495	495	495	495	495	494	494	494	494
Kansai	2,607	2,597	2,588	2,581	2,574	2,567	2,560	2,552	2,545	2,538
Chugoku	1,028	1,030	1,029	1,027	1,025	1,024	1,022	1,020	1,019	1,017
Shikoku	496	495	494	492	491	490	488	487	486	485
Kyushu	1,544	1,544	1,544	1,544	1,545	1,545	1,546	1,546	1,547	1,547
60 Hz area Total	8,586	8,579	8,556	8,536	8,516	8,496	8,475	8,453	8,448	8,427
Interconnected	15,408	15,377	15,354	15,332	15,312	15,289	15,269	15,246	15,253	15,231
Okinawa	148	149	150	150	151	152	152	153	153	154
Nationwide	15,556	15,526	15,504	15,483	15,463	15,441	15,421	15,399	15,406	15,385

Table A2-2 Annual Projection of Supply Capacity for Each Regional Service Area (at 17:00 in August)

[10^4kW]

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Hokkaido	513	509	573	576	580	581	582	580	627	627
Tohoku	1,416	1,379	1,500	1,515	1,514	1,521	1,521	1,549	1,550	1,551
Tokyo	5,594	5,743	5,614	5,452	5,623	5,740	5,975	5,940	5,944	5,951
50 Hz area Total	7,523	7,631	7,688	7,543	7,717	7,842	8,077	8,069	8,121	8,129
Chubu	2,660	2,642	2,432	2,498	2,501	2,504	2,496	2,501	2,503	2,503
Hokuriku	550	553	545	544	544	543	537	536	535	535
Kansai	2,751	2,895	2,674	2,700	2,756	2,759	2,646	2,662	2,663	2,663
Chugoku	1,143	1,196	1,227	1,140	1,175	1,177	1,181	1,183	1,180	1,181
Shikoku	576	645	561	549	595	594	594	595	595	595
Kyushu	1,684	1,801	1,783	1,799	1,813	1,733	1,734	1,715	1,718	1,718
60 Hz area Total	9,364	9,732	9,222	9,229	9,384	9,310	9,189	9,193	9,195	9,194
Interconnected	16,887	17,364	16,910	16,772	17,102	17,151	17,266	17,262	17,316	17,323
Okinawa	201	211	204	208	202	214	214	214	214	214
Nationwide	17,088	17,575	17,113	16,980	17,303	17,365	17,480	17,476	17,530	17,537

Table A2-3 Annual Projection of Reserve Capacity for Each Regional Service Area (at 17:00 in August)

[10^4kW]

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Hokkaido	93	89	154	157	161	163	164	162	209	209
Tohoku	146	111	234	253	256	267	272	305	311	317
Tokyo	462	634	502	337	505	618	848	809	796	799
50 Hz area Total	701	834	890	746	922	1,048	1,284	1,276	1,316	1,325
Chubu	244	223	25	101	115	129	131	147	146	157
Hokuriku	55	58	50	49	49	48	44	43	42	41
Kansai	144	298	85	119	182	192	86	110	119	125
Chugoku	115	166	198	113	150	153	159	163	161	164
Shikoku	80	150	67	57	104	104	106	108	109	110
Kyushu	140	258	240	255	268	188	188	169	170	170
60 Hz area Total	778	1,153	666	693	868	814	714	740	747	767
Interconnected	1,479	1,987	1,556	1,440	1,790	1,862	1,997	2,016	2,063	2,092
Okinawa	53	63	54	58	51	62	62	61	61	60
Nationwide	1,532	2,050	1,610	1,498	1,841	1,924	2,059	2,077	2,123	2,152

Table A2-4 Annual Projection of Reserve Margin for Each Regional Service Area
(resource within own service area only, at 17:00 in August, at the sending end; see Table 2-8)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Hokkaido	22.2%	21.3%	36.8%	37.4%	38.5%	39.0%	39.3%	38.7%	50.0%	50.1%
Tohoku	11.5%	8.7%	18.5%	20.0%	20.3%	21.3%	21.8%	24.6%	25.1%	25.7%
Tokyo	9.0%	12.4%	9.8%	6.6%	9.9%	12.1%	16.5%	15.8%	15.5%	15.5%
50 Hz area Total	10.3%	12.3%	13.1%	11.0%	13.6%	15.4%	18.9%	18.8%	19.3%	19.5%
Chubu	10.1%	9.2%	1.0%	4.2%	4.8%	5.4%	5.6%	6.3%	6.2%	6.7%
Hokuriku	11.0%	11.7%	10.2%	9.9%	9.9%	9.8%	8.8%	8.6%	8.4%	8.3%
Kansai	5.5%	11.5%	3.3%	4.6%	7.1%	7.5%	3.4%	4.3%	4.7%	4.9%
Chugoku	11.2%	16.2%	19.3%	11.0%	14.6%	15.0%	15.6%	16.0%	15.8%	16.1%
Shikoku	16.1%	30.2%	13.6%	11.5%	21.2%	21.2%	21.7%	22.1%	22.5%	22.8%
Kyushu	9.1%	16.7%	15.5%	16.5%	17.3%	12.1%	12.1%	10.9%	11.0%	11.0%
60 Hz area Total	9.1%	13.4%	7.8%	8.1%	10.2%	9.6%	8.4%	8.7%	8.8%	9.1%
Interconnected	9.6%	12.9%	10.1%	9.4%	11.7%	12.2%	13.1%	13.2%	13.5%	13.7%
Okinawa	35.7%	42.1%	36.1%	38.5%	33.9%	41.1%	40.7%	40.0%	39.5%	39.0%
Nationwide	9.8%	13.2%	10.4%	9.7%	11.9%	12.5%	13.4%	13.5%	13.8%	14.0%

Below Criteria of 8%

Table A2-5 Annual Projection of Reserve Margin for Each Regional Service Area
(with power exchanges through cross-regional interconnection lines, at the sending end; see Table 2-8)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Hokkaido	12.4%	12.3%	27.6%	27.2%	28.3%	28.8%	29.0%	29.0%	40.4%	40.4%
Tohoku	9.5%	12.3%	9.6%	8.7%	11.2%	11.7%	14.6%	14.8%	14.6%	13.2%
Tokyo	9.5%	12.3%	9.6%	8.7%	11.2%	11.7%	14.6%	14.8%	14.6%	13.2%
Chubu	9.5%	13.4%	9.6%	8.7%	11.2%	11.7%	11.1%	11.3%	11.4%	12.8%
Hokuriku	9.5%	13.4%	9.6%	8.7%	11.2%	11.7%	11.1%	11.3%	11.4%	12.8%
Kansai	9.5%	13.4%	9.6%	8.7%	11.2%	11.7%	11.1%	11.3%	11.4%	12.8%
Chugoku	9.5%	13.4%	9.6%	8.7%	11.2%	11.7%	11.1%	11.3%	11.4%	12.8%
Shikoku	9.5%	13.4%	9.6%	8.7%	11.2%	11.7%	11.1%	11.3%	11.4%	12.8%
Kyushu	9.5%	13.4%	9.9%	10.5%	11.2%	11.7%	11.1%	11.3%	11.4%	12.8%
Interconnected	9.6%	12.9%	10.1%	9.4%	11.7%	12.2%	13.1%	13.2%	13.5%	13.7%
Okinawa	35.7%	42.1%	36.1%	38.5%	33.9%	41.1%	40.7%	40.0%	39.5%	39.0%
Nationwide	9.8%	13.2%	10.4%	9.7%	11.9%	12.5%	13.4%	13.5%	13.8%	14.0%

Improved to over 8%

Table A2-6 Annual Peak Demand Forecast for Winter Peak Areas of Hokkaido and Tohoku (at 18:00 in January)

[10^4kW]

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Hokkaido	499	499	498	498	497	497	497	496	496	496
Tohoku	1,375	1,373	1,371	1,368	1,364	1,360	1,356	1,352	1,348	1,344

Table A2-7 Annual Projection of Supply Capacity for Winter Peak Areas of Hokkaido and Tohoku (at 18:00 in January)

[10^4kW]

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Hokkaido	597	599	571	580	580	581	582	631	631	631
Tohoku	1,525	1,508	1,524	1,539	1,538	1,541	1,542	1,568	1,571	1,572

Table A2-8 Annual Projection of Reserve Capacity for Winter Peak areas of Hokkaido and Tohoku (at 18:00 in January)

[10^4kW]

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Hokkaido	98	100	73	82	83	84	85	135	135	135
Tohoku	150	135	153	171	174	181	186	216	223	228

Table A2-9 Annual Projection of Reserve Margin for Winter Peak Areas of Hokkaido and Tohoku
(at 18:00 in January; see Table 2-10)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Hokkaido	19.6%	20.1%	14.7%	16.5%	16.8%	17.0%	17.1%	27.2%	27.2%	27.2%
Tohoku	10.9%	9.8%	11.2%	12.5%	12.8%	13.3%	13.7%	16.0%	16.5%	16.9%