Aggregation of Electricity Supply Plans
Fiscal Year 2017

March 2017

Organization for Cross-regional Coordination of Transmission Operators, JAPAN

＜INTRODUCTION＞

The Organization for Cross-regional Coordination of Transmission Operators, JAPAN (hereinafter, the Organization) has aggregated the electricity supply plans for fiscal year(FY) 2017 according to Article 28 of the Operational Rules of the Organization and Article 29 of the Electricity Business Act which requires the plans to be submitted to the Ministry of Economy, Trade and Industry (METI) by electric power companies (EPCOs) 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 the METI by the end of March annually.

Furthermore, 938 electricity supply plans for FY 2017 were aggregated, including 936 plans submitted by companies that became EPCOs by the end of 2016 and 2 plans submitted by companies that became EPCOs in 2017.

Number of Companies Subject to the Aggregation in FY 2017

Business License	Number
Generation Companies	542
Retail Companies	367
Specified Transmission, Distribution and Retail Companies	16
Specified Transmission and Distribution Companies	1
Transmission Companies	2
General Transmission and Distribution Companies	10
Total	938

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1. Electricity Demand Forecast

(1) Actual and Preliminary Data for FY 2016 and Forecast for FY 2017 (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 in area[2] submitted by 10 general transmission and distribution (GTD) companies for FY 2016 and the forecast[3] value for FY 2017.

Peak demand (average value of the three highest daily load) in August 2017 was forecasted at 156,560MW, a 0.2% increase over 156,170MW in August 2016. In addition, the actual data for FY 2016 was temperature adjusted[4] to 155,760MW, and the forecast value for FY 2017 is a 0.5% increase over the temperature-adjusted value for FY 2016.

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

FY 2016 Actual	FY 2017 Forecast
15,617 (15,576)	15,656 +0.2% (+0.5%)*

Value in parenthis is temperature adjusted.
* % changes over actual data for the previous year.

b. Forecast for FY 2017

Table 1-2 shows the monthly average value of the three highest daily loads in FY 2017 from the aggregated peak demand for each regional service area submitted by the 10 GTD 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 2017
(Nationwide, 10^4 kW at the sending-end)

	Apr.	May	Jun.	Jul.	Aug.	Sep.
Peak Demand	11,794	11,406	12,686	15,607	15,656	14,008
	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Peak Demand	11,802	12,485	13,902	14,618	14,610	13,332

[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 regional service areas refers to the average value of the three highest daily loads in public demand supplied by retail companies and GTD companies through the transmission and distribution network of the GTD companies. The Organization publishes these average values according to the provision of Paragraph 5, Article 23 of the Operational Rules.

[3] Demand forecast beyond F.Y.2017 is based on normal weather. Thus, weather condition for forecast assumption may vary in contrast with the actual data or estimated figure in F.Y.2016

[4] Temperature adjustment is implemented to grasp 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 2016 and the forecast value for FY 2017 from the aggregated electric energy requirements of each regional service area submitted by 10 GTD companies.

The electric energy requirements for FY 2017 is forecast at 880.5 TWh, a 0.7% decrease over 887.1 TWh in the preliminary data for FY 2016. In addition, the preliminary data for FY 2016 was temperature adjusted to 878.7 TWh, and the forecast value for FY 2017 is a 0.2% increase over the temperature-adjusted value in FY 2016.

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

FY 2016 Preliminary	FY 2017 Forecast
887.1 (878.7)	880.5 ▲0.7% (+0.2%)*

Value in parenthis is temperature adjusted.
* % 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 2016 with the preliminary data from December 2016 to March 2017.

(2) 10-Year Demand Forecast (Long-term)

Table 1-4 shows the major economic indicators developed and published on November 24, 2016 by the Organization, which are assumptions for GTD companies to forecast the peak demand in their regional service areas.

The real gross domestic product (GDP)[6] is estimated at ¥540.1 trillion in FY 2017 and at ¥582.0 trillion in FY 2026 with annual average growth rates of 0.8%. The index of industrial production (IIP)[7] is projected at 99.8 in FY 2017 and at 108.2 in FY 2026 with annual average growth rates of 0.9%.

Table 1-4 Major Economic Indicators Assumed for Demand Forecast

	F.Y.2017	F.Y.2026
Gross Domestic Product(GDP)	¥540.1 trillion	¥582.0 trillion [0.8%]*
Index of Industrial Product(IIP)	99.8	108.2 [0.9%]*

* Average annual growth rate for the forecast value of FY 2017

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

Table 1-5 shows the peak demand forecast for FY 2016, FY 2020 and FY 2025 as the aggregation of peak demand for each regional service area submitted by 10 GTD companies.

The peak demand nationwide is forecast at 158,570 MW in FY 2021 and at 160,310 MW in FY 2026, with an average annual growth rate (AAGR) of 0.3% from FY 2017 to FY 2026.

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

In addition, the AAGR forecast becomes lower than that of the previous year, mainly due to a declining level of economic activity level 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)

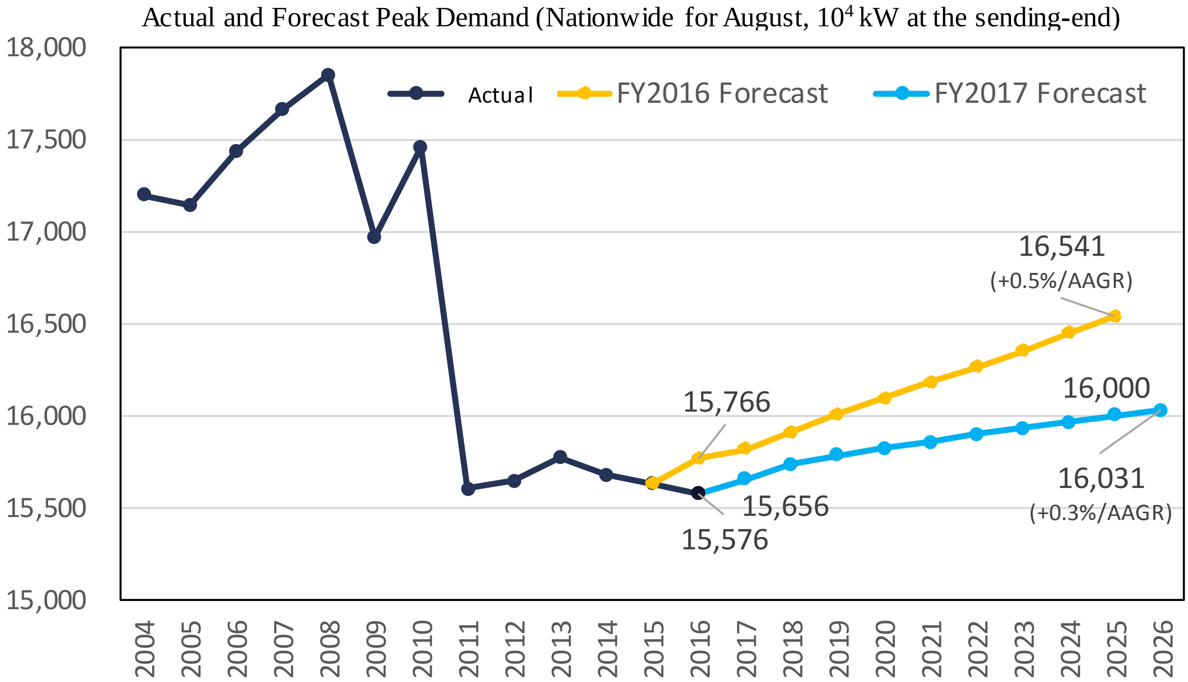
FY 2017 [aforementioned]	FY 2021	FY 2026
15,656	15,857 [0.3%]*	16,031 [0.3%]*

* Average Annual Growth Rate for the forecast value of FY 2017

6 GDP expressed as the chained price for FY 2005.

7 Index value in FY 2010 = 100

<Reference: Actual and Forecast Peak Demand (average value of the three highest daily loads) >



b. Annual Electric Energy Requirement

Table 1-6 shows the forecast for annual electric energy requirements in FY 2017, FY 2021, and FY 2026 as the aggregation of the electric energy requirements for each regional service area submitted by 10 GTD companies.

The nationwide annual electric energy requirement is forecast at 889.1 TWh in FY 2021 and at 900.5 TWh in FY 2026, with an AAGR of 0.2% from FY 2017 to FY 2026.

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

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

FY 2017 [aforementioned]	FY 2021	FY 2026
8,805	8,891 [0.2%]*	9,005 [0.2%]*

* Average annual growth rate for the forecast value of FY 2017

2. Electricity Supply and Demand

(1) Supply-Demand Balance Evaluation Method

The Organization shall evaluate the supply-demand balance for each regional service area as well as nationwide using the supply capacity[8] and peak demand data for regional service areas submitted by GTD companies. Based on the discussion at the 14th meeting of the Study Committee on Regulating and Marginal Supply Capability and Long-Term Supply-Demand Balance Evaluation (March 23, 2017), the Organization implementes its evaluation using the criterion of whether the reserve margin (%)[9] for each regional service area is secured over 8% or not. (In the Okinawa EPCO, 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 in its regional service area.)

Furthermore, supply capacity includes the generation of generating capacity requirements secured by retail and GTD companies for their regional service areas and the production of surplus power[10] of generation companies. Figure 2-1 summarizes the supply-demand balance evaluation method. The supply capacity currently secured by retail company includes power procured 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 future.

Under the circumstances in which the operation of a nuclear power plant has become unknown, the supply capacity of the corresponding unit or plant is recorded as zero where the corresponding supply capacity is reported as "unknown" according to Procedures for Electricity Supply Plans of FY 2016 (published in December 2016, by the Agency for Natural Resources and Energy). In the electricity supply plans for FY 2017, supply capacity was reported as "unknown" by all nuclear power plants except for those that had resumed operation.

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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 regional service area without sales destination.

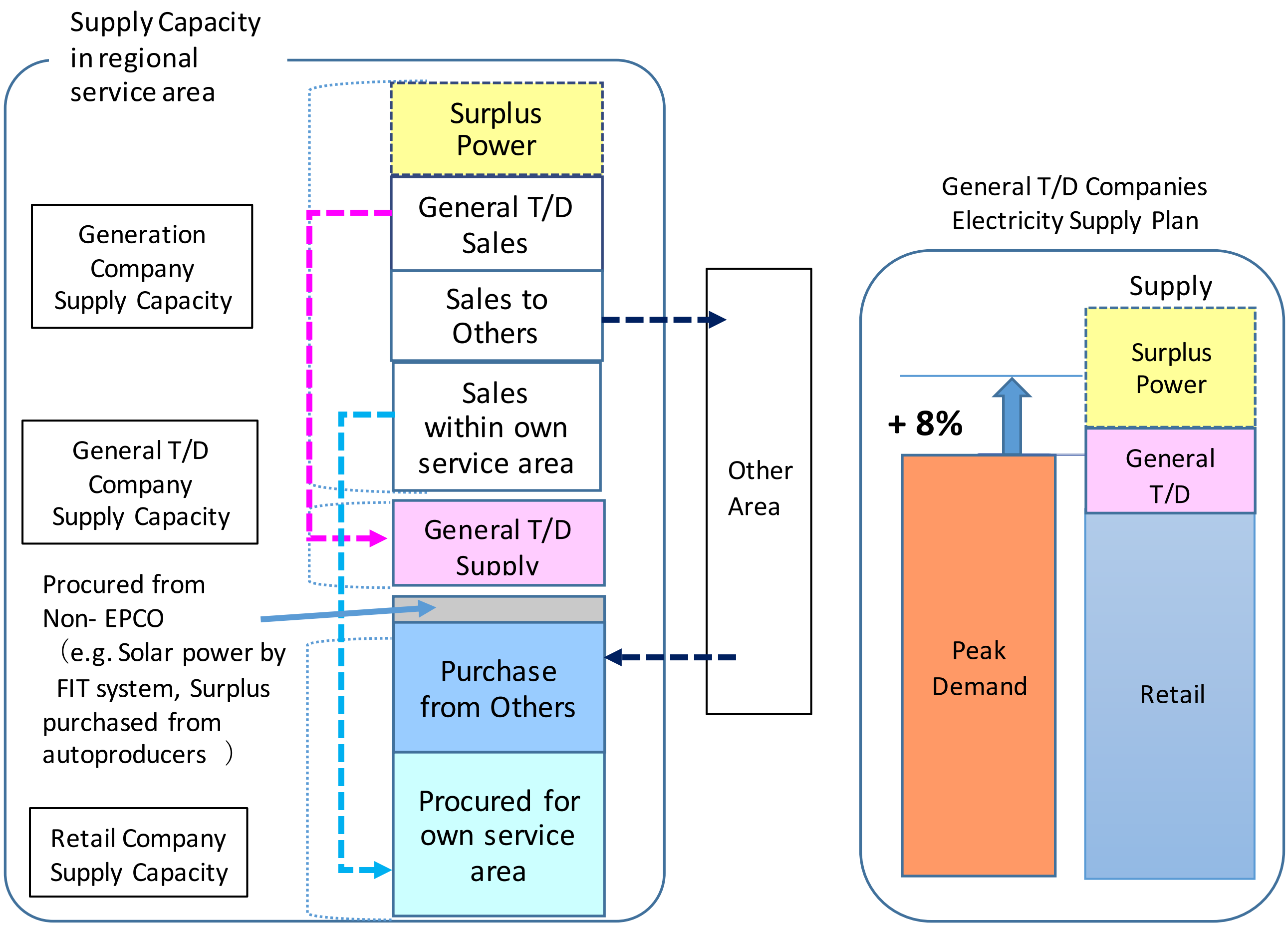

Figure 2-1 Summary of Supply-Demand Balance Evaluation Method

(2) Actual Data for FY 2016 and Projection for FY 2017 (Short-term)

a. Actual Data for FY 2016

Table 2-1 shows the actual supply-demand balance for August 2016 based on the nationwide supply capacity and peak demand data.

Table 2-1 Actual Supply-Demand Balance in August 2016
(Nationwide, 10^4 kW at the sending-end)

Peak Demand (temperature adjusted) [aforementioned]	Supply Capacity	Reserve Capacity	Reserve Margin
15,576	18,040	2,464	15.8%

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

b. Projection of Supply-Demand Balance in FY 2016

Table 2-2 and Figure 2-2 show the projection of a monthly supply-demand balance for FY 2017. A reserve margin of 8% is secured for each month nationwide.

Table 2-2 Projection of the Monthly Supply-Demand Balance for FY 2017
(Nationwide, 10^4 kW at the sending-end)

	Apr.	May	Jun.	Jul.	Aug.	Sep.
Peak Demand	11,794	11,406	12,686	15,607	15,656	14,008
Supply Capacity	14,368	14,269	15,439	17,727	17,692	16,570
Reserve Margin	21.8%	25.1%	21.7%	13.6%	13.0%	18.3%
	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Peak Demand	11,802	12,485	13,902	14,618	14,610	13,332
Supply Capacity	14,724	15,064	16,249	16,910	16,720	15,861
Reserve Margin	24.8%	20.7%	16.9%	15.7%	14.4%	19.0%

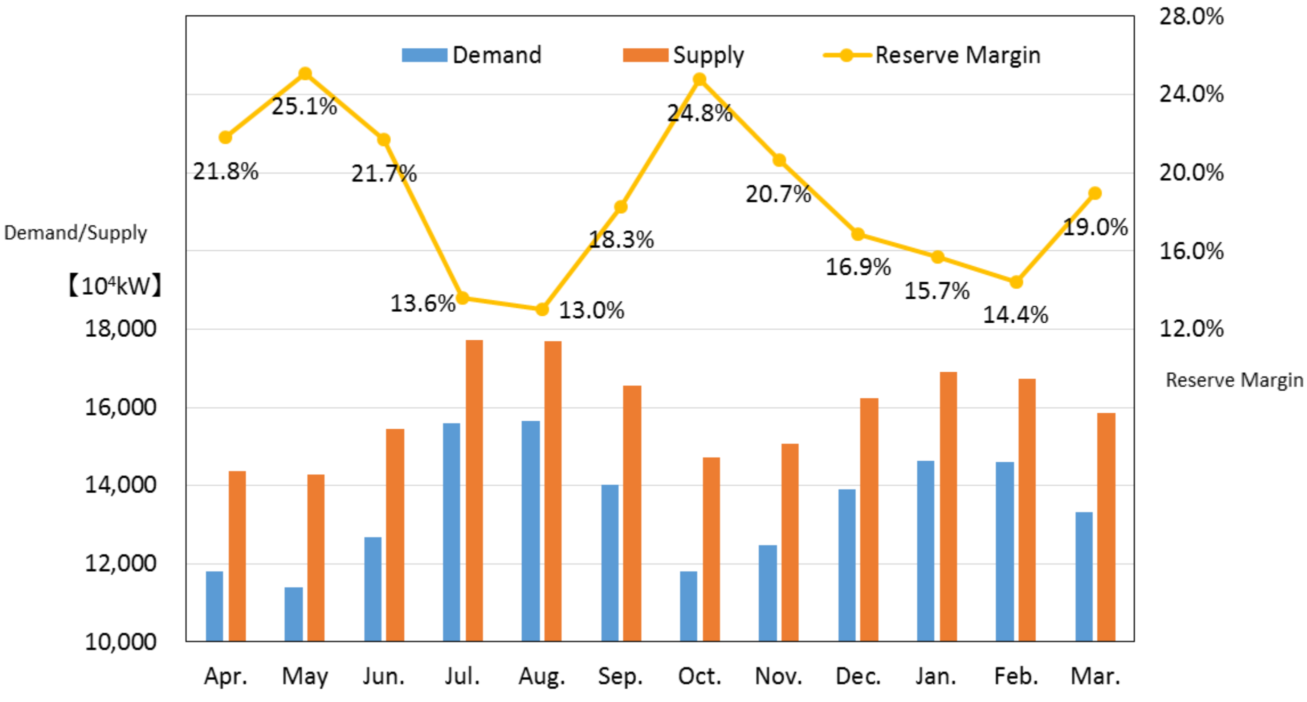

Figure 2-2 Projection of the Monthly Supply-Demand Balance for FY 2017
(Nationwide, at the sending-end)

Table 2-3 shows the monthly projection of the reserve margin for each regional service area. In addition, Table 2-4 shows the monthly projection of the reserve margin for each regional service area recalculated using power exchanges to areas of below 8% reserve margin from areas of over 8% reserve margin based on the available transfer capability (ATC)[11].

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

The 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 2-3 Monthly Projection of 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	17.4%	30.7%	34.9%	24.0%	19.7%	16.0%	24.7%	19.5%	19.2%	17.0%	16.6%	21.6%
Tohoku	13.6%	19.6%	19.4%	17.5%	17.0%	13.0%	19.8%	14.3%	13.0%	18.1%	19.5%	12.6%
Tokyo	22.2%	25.6%	22.2%	7.0%	8.0%	15.9%	29.7%	22.2%	21.2%	17.3%	13.0%	19.8%
50Hz areas Total	20.1%	24.8%	22.5%	9.9%	10.4%	15.4%	27.3%	20.4%	19.3%	17.5%	14.6%	18.4%
Chubu	12.1%	11.7%	18.2%	9.5%	8.2%	19.8%	14.8%	14.2%	7.7%	7.8%	5.9%	7.8%
Hokuriku	9.4%	22.2%	8.5%	18.4%	9.1%	10.0%	10.8%	9.6%	8.2%	9.1%	9.9%	11.5%
Kansai	28.3%	30.1%	16.3%	13.6%	13.4%	16.9%	31.5%	28.0%	23.3%	19.1%	18.4%	27.2%
Chugoku	35.2%	31.2%	27.2%	28.9%	28.4%	30.0%	30.2%	23.9%	21.5%	20.4%	19.9%	24.9%
Shikoku	43.4%	56.1%	34.0%	28.4%	25.2%	31.1%	26.0%	17.1%	11.1%	16.2%	30.1%	37.5%
Kyushu	19.6%	24.6%	26.5%	16.9%	15.3%	18.3%	16.9%	19.8%	8.6%	10.4%	9.6%	14.1%
60Hz areas Total	22.7%	24.9%	20.5%	16.0%	14.5%	20.0%	22.1%	20.3%	14.3%	13.7%	13.6%	18.6%
Interconnected	21.5%	24.8%	21.4%	13.3%	12.7%	17.9%	24.4%	20.3%	16.5%	15.4%	14.1%	18.5%
Okinawa	59.0%	49.3%	51.2%	46.5%	50.4%	54.6%	55.4%	58.2%	61.9%	56.4%	69.2%	81.9%
Nationwide	21.8%	25.1%	21.7%	13.6%	13.0%	18.3%	24.8%	20.7%	16.9%	15.7%	14.4%	19.0%

Below 8% Criteria

Note: The reserve margin in the Tokyo EPCO area in August is lower than 8.0% and was rounded up to 8.0%.

Table 2-4 Monthly Projection of 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	17.4%	30.7%	34.9%	24.0%	19.7%	16.0%	24.7%	19.5%	19.2%	17.0%	16.6%	21.6%
Tohoku	13.6%	19.6%	19.4%	13.3%	16.9%	13.0%	19.8%	14.3%	13.0%	18.1%	19.5%	12.6%
Tokyo	22.2%	25.6%	22.2%	8.0%	8.0%	15.9%	29.7%	22.2%	21.2%	17.3%	13.0%	19.8%
50Hz area Total	20.1%	24.8%	22.5%	9.9%	10.4%	15.4%	27.3%	20.4%	19.3%	17.5%	14.6%	18.4%
Chubu	12.1%	11.7%	18.2%	9.5%	8.2%	19.8%	14.8%	14.2%	8.0%	8.0%	8.0%	8.0%
Hokuriku	9.4%	22.2%	8.5%	18.4%	9.1%	10.0%	10.8%	9.6%	8.2%	9.1%	9.9%	11.5%
Kansai	28.3%	30.1%	16.3%	13.6%	13.4%	16.9%	31.5%	28.0%	23.0%	18.9%	16.3%	27.1%
Chugoku	35.2%	31.2%	27.2%	28.9%	28.4%	30.0%	30.2%	23.9%	21.5%	20.4%	19.9%	24.9%
Shikoku	43.4%	56.1%	34.0%	28.4%	25.2%	31.1%	26.0%	17.1%	11.1%	16.2%	30.1%	37.5%
Kyushu	19.6%	24.6%	26.5%	16.9%	15.3%	18.3%	16.9%	19.8%	8.6%	10.4%	9.6%	14.1%
60Hz area Total	22.7%	24.9%	20.5%	16.0%	14.5%	20.0%	22.1%	20.3%	14.3%	13.7%	13.6%	18.6%
nterconnected	21.5%	24.8%	21.4%	13.3%	12.7%	17.9%	24.4%	20.3%	16.5%	15.4%	14.1%	18.5%
Okinawa	59.0%	49.3%	51.2%	46.5%	50.4%	54.6%	55.4%	58.2%	61.9%	56.4%	69.2%	81.9%
Nationwide	21.8%	25.1%	21.7%	13.6%	13.0%	18.3%	24.8%	20.7%	16.9%	15.7%	14.4%	19.0%

Improved above Criteria

Contributors to improvement

In the Okinawa EPCO regional service area,[12] 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 this capacity with frequency control ('Generator I', total of 301 MW), without applying the criteria of other interconnected areas. Table 2-5 shows the monthly reserve margin against the deduction of the capacity of Generator I, which indicates the stable supply secured in each month.

Table 2-5 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	29.8%	25.9%	31.4%	27.5%	31.5%	34.0%	33.1%	35.8%	32.0%	29.3%	41.2%	52.3%

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

(3) Projection of Supply-Demand Balance for 10 years (Long-term)

a. Supply-Demand Balance

Table 2-6 and Figure 2-3 show the annual supply-demand balance projection for 10 years. A reserve margin of 8% is secured each year nationwide.

Table 2-6 Annual Supply-Demand Balance Projection from FY 2017 to FY 2026
(Nationwide in August, 10^4 kW at the sending-end)

	2017 [Aforementioned]	2018	2019	2020	2021
Peak Demand	15,656	15,737	15,784	15,822	15,857
Supply Capacity	17,692	17,608	17,747	17,755	17,555
Reserve Margin	13.0%	11.9%	12.4%	12.2%	10.7%
	2022	2023	2024	2025	2026
Peak Demand	15,896	15,930	15,964	16,000	16,031
Supply Capacity	17,763	18,204	18,540	18,571	18,591
Reserve Margin	11.7%	14.3%	16.1%	16.1%	16.0%

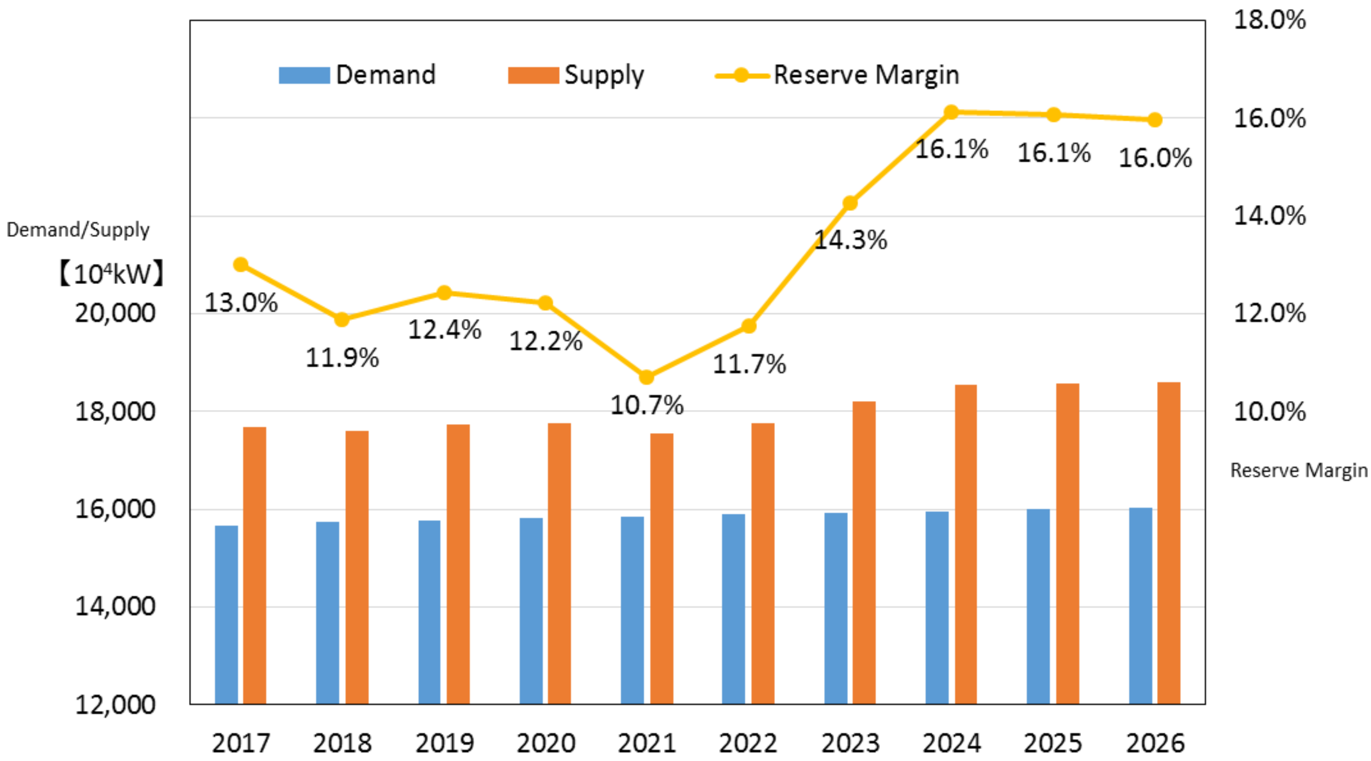

Figure 2-3 Mid- to Long-term Annual Supply-Demand Balance Projection
(Nationwide in August, at the sending-end)

Table 2-7 shows the annual projection of reserve margins for each regional service area from FY 2017 to FY 2026. Table 2-8 shows these projections recalculated by adding power exchanges to the year and areas of below 8% reserve margin even with additional generated surplus from areas over 8% reserve margin based on ATC.

The evaluation shows that the reserve margin will still fall below 8% in the Tokyo EPCO regional service area from FY 2019 to FY 2023, in the Chubu EPCO area from FY 2019 to FY 2021 and in the Kansai EPCO area in FY 2021. All other years and areas will secure more than 8% reserve margin required for stable supply.

During its aggregation of electricity supply plans, the Organization has not captured newly developing facilities at EPCOs that are not obliged to submit the development plans or at EPCOs that are obliged to submit plans, but not included the relevant information. Even though those newly developing facilities are in various stages of development, some facilities might be to be counted as future supply capacity.

Table 2-7 Annual Projection of Reserve Margins for Each Regional Service Area from FY 2017 to FY 2026
(Resources within own service area only, at the sending-end)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Hokkaido	19.7%	20.3%	43.8%	44.3%	43.7%	43.0%	41.5%	40.5%	39.5%	38.6%
Tohoku	17.0%	18.4%	23.9%	24.2%	25.5%	25.7%	27.2%	27.1%	26.9%	26.9%
Tokyo	8.0%	6.3%	5.4%	5.3%	1.7%	1.8%	6.3%	11.6%	11.5%	10.9%
50Hz areas Total	10.4%	9.4%	11.2%	11.2%	8.7%	8.8%	12.4%	16.3%	16.1%	15.6%
Chubu	8.2%	9.9%	6.5%	5.8%	6.0%	9.5%	9.6%	9.6%	9.6%	9.5%
Hokuriku	9.1%	11.6%	18.8%	12.0%	12.0%	11.9%	11.7%	11.4%	11.2%	11.0%
Kansai	13.4%	9.8%	11.4%	10.9%	7.8%	10.5%	13.2%	13.5%	13.8%	14.6%
Chugoku	28.4%	21.1%	19.1%	20.0%	20.1%	20.8%	27.0%	26.7%	26.2%	26.0%
Shikoku	25.2%	35.7%	24.8%	29.9%	30.0%	25.3%	26.3%	26.4%	26.5%	26.6%
Kyushu	15.3%	11.9%	15.0%	15.0%	15.7%	16.4%	16.8%	17.8%	17.9%	18.0%
60Hz areas Total	14.5%	13.2%	12.8%	12.5%	11.7%	13.5%	15.2%	15.4%	15.4%	15.7%
Interconnected	12.7%	11.5%	12.1%	11.9%	10.4%	11.4%	13.9%	15.8%	15.7%	15.7%
Okinawa	50.4%	53.5%	52.9%	49.0%	48.7%	52.2%	52.4%	51.8%	50.4%	49.1%
Nationwide	13.0%	11.9%	12.4%	12.2%	10.7%	11.7%	14.3%	16.1%	16.1%	16.0%

Below 8% Criteria

Note: The reserve margin in the Tokyo EPCO area in FY 2017 is lower than 8.0% and was rounded up to 8.0%.

Table 2-8 Annual Projection of Reserve Margins for Each Regional Service Area
(With additional surplus power and power exchanges through cross-regional interconnection lines, at the sending-end)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Hokkaido	19.7%	20.3%	43.8%	44.3%	37.2%	36.3%	41.5%	40.5%	39.5%	38.6%
Tohoku	16.9%	11.6%	13.3%	13.2%	8.0%	8.0%	20.3%	27.1%	26.9%	26.9%
Tokyo	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	11.6%	11.5%	10.9%
50Hz area Total	10.4%	9.4%	11.2%	11.2%	9.8%	9.7%	12.4%	16.3%	16.1%	15.6%
Chubu	8.2%	9.9%	8.0%	8.0%	8.0%	8.0%	9.6%	9.6%	9.6%	9.5%
Hokuriku	9.1%	11.6%	18.8%	12.0%	8.0%	11.9%	11.7%	11.4%	11.2%	11.0%
Kansai	13.4%	9.8%	10.0%	8.7%	8.0%	9.4%	13.2%	13.5%	13.8%	14.6%
Chugoku	28.4%	21.1%	19.1%	20.0%	9.4%	20.8%	27.0%	26.7%	26.2%	26.0%
Shikoku	25.2%	35.7%	24.8%	29.9%	30.0%	25.3%	26.3%	26.4%	26.5%	26.6%
Kyushu	15.3%	11.9%	15.0%	15.0%	15.7%	16.4%	16.8%	17.8%	17.9%	18.0%
60Hz area Total	14.5%	13.2%	12.8%	12.5%	10.8%	12.7%	15.2%	15.4%	15.4%	15.7%
Interconnected	12.7%	11.5%	12.1%	11.9%	10.4%	11.4%	13.9%	15.8%	15.7%	15.7%
Okinawa	50.4%	53.5%	52.9%	49.0%	48.7%	52.2%	52.4%	51.8%	50.4%	49.1%
Nationwide	13.0%	11.9%	12.4%	12.2%	10.7%	11.7%	14.3%	16.1%	16.1%	16.0%

Improved above Criteria

Contributors to improvement

Table 2-9 shows the annual projection of a reserve margin with the capacity equivalent to Generator I in the Okinawa EPCO area deducted, which indicates a stable supply is secured throughout the period.

Table 2-9 Annual Projection of a Reserve Margin with the capacity equivalent to Generator I in Okinawa Deducted (At the sending-end)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Okinawa	29.6%	32.7%	32.2%	28.5%	28.2%	31.8%	32.1%	31.6%	30.3%	29.1%

Table 2-10 shows the annual projection of reserve margins in January for winter peak demands in the Hokkaido and Tohoku EPCO areas, which indicates a stable supply is secured throughout the period.

Table 2-10 Annual Projection of Reserve Margins for Winter Peak Demands in the Hokkaido and Tohoku Areas (At the sending-end)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Hokkaido	17.0%	21.3%	20.4%	21.8%	20.4%	19.8%	19.2%	18.5%	17.4%	26.6%
Tohoku	18.1%	16.2%	17.5%	16.6%	16.9%	16.1%	16.8%	15.7%	14.7%	13.9%

b. Supply Capacity Secured by Retail Companies According to their Demand

Table 2-11 and Figure 2-4 show the supply capacity secured by retail companies according to their demand for a 10-year period from FY 2017 to FY 2026.

Particulary in the mid- to long-term, retail companies have planned their supply capacity as "unspecified procurement[13]".

Table 2-11 Supply Capacity Secured by Retail Companies According to their Demand for 10-Year Period from FY 2017 to FY 2026 (In August, 10^4 kW at the sending-end)

	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021
Peak Demand Nationwide	15,656	15,737	15,784	15,822	15,857
Secured Supply Capacity	16,213	15,956	16,187	15,776	15,478
Ratio*	103.6%	101.4%	102.6%	99.7%	97.6%
	FY 2022	**FY 2023**	**FY 2024**	**FY 2025**	**FY 2026**
Peak Demand Nationwide	15,896	15,930	15,964	16,000	16,031
Secured Supply Capacity	15,625	15,521	15,365	15,364	15,357
Ratio*	98.3%	97.4%	96.2%	96.0%	95.8%

Note: * denotes the ratio of peak demand nationwide to the secured supply capacity.

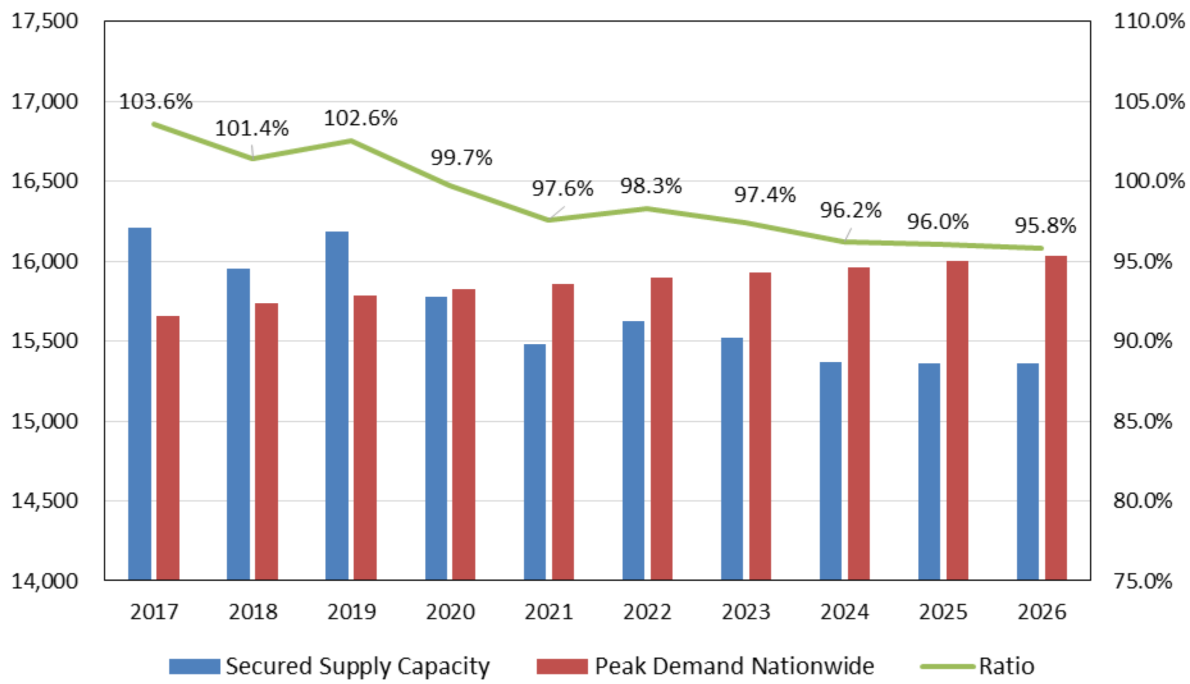

Figure 2-4 Supply Capacity Secured by Retail Companies According to their Demand for 10 Years Period from FY 2017 to FY 2026 (In August, at the sending-end)

[13] "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.

c. Supply Capacity Secured by General Transmission and Distribution Companies

GTD Companies secure their supply capacity for the demand of isolated islands respectively throughout the planning period, and also secure a balancing capacity equivalent to 7% over their peak demand in their regional service areas for FY 2017 by public solicitation. Table 2-12 shows the secured balancing capacity procured by GTD companies.

Table 2-12 Secured Balancing Capacity[14] Procured by GTD Companies

	Hokkaido	Tohoku	Tokyo	Chubu	Hokuriku	Kansai	Chugoku	Shikoku	Kyushu	Okinawa
Balancing Capacity	7.2%	7.1%	7.6%	7.0%	7.0%	7.3%	7.1%	7.0%	8.7%	20.8%

[14] The capacity is the ratio of the balancing capacity to the peak demand in the regional service areas of GTD companies. The ratios for the Hokkaido and Tohoku EPCO area are from January, and others are from August.

3. 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 other than EPCOs, which are registered as the procured supply capacity of retail and GTD companies.

Table 3-1 and Figure 3-1 show the transition of installed power generation capacity by power generation sources. Figure 3-2 shows the composition of the transition of installed power generation capacities.

Coal and LNG fired capacities are projected to increase although it may decrease through replacement according to future power development plans for thermal generation, which is based on the large increase in renewable energy, such as solar power. 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

(Nationwide, 10^4 kW)

Power Generation Sources		FY 2016(Actual)	FY 2017	FY 2021	FY 2026
Hydro		4,910 [16.3%]	4,911 [15.9%]	4,917 [15.1%]	4,922 [14.5%]
	Conventional	2,163 [7.2%]	2,164 [7.0%]	2,168 [6.7%]	2,174 [6.4%]
	Pumped Storage	2,747 [9.1%]	2,747 [8.9%]	2,748 [8.4%]	2,748 [8.1%]
Thermal		16,485 [54.7%]	16,536 [53.6%]	16,766 [51.5%]	17,687 [52.1%]
	Coal	4,335 [14.4%]	4,390 [14.2%]	4,809 [14.8%]	5,168 [15.2%]
	LNG	8,212 [27.3%]	8,266 [26.8%]	8,247 [25.3%]	8,812 [25.9%]
	Oil and others[15]	3,938 [13.1%]	3,880 [12.6%]	3,710 [11.4%]	3,706 [10.9%]
Nuclear		3,900 [13.0%]	3,900 [12.6%]	3,500 [10.7%]	3,032 [8.9%]
Renewables		4,774 [15.9%]	5,491 [17.8%]	7,363 [22.6%]	8,311 [24.5%]
	Wind	370 [1.2%]	390 [1.3%]	584 [1.8%]	774 [2.3%]
	Solar	4,060 [13.5%]	4,740 [15.4%]	6,403 [19.7%]	7,162 [21.1%]
	Geothermal	52 [0.2%]	49 [0.2%]	48 [0.1%]	48 [0.1%]
	Biomass	195 [0.6%]	210 [0.7%]	235 [0.7%]	232 [0.7%]
	Waste	96 [0.3%]	102 [0.3%]	93 [0.3%]	95 [0.3%]
Miscellaneous		44 [0.1%]	20 [0.1%]	24 [0.1%]	24 [0.1%]
Total		30,114 [100%]	30,859 [100%]	32,569 [100%]	33,976 [100%]

[15] The Oil and others category includes the total installed capacities from oil, LPG, other gas and bituminous mixtures fired capacities.

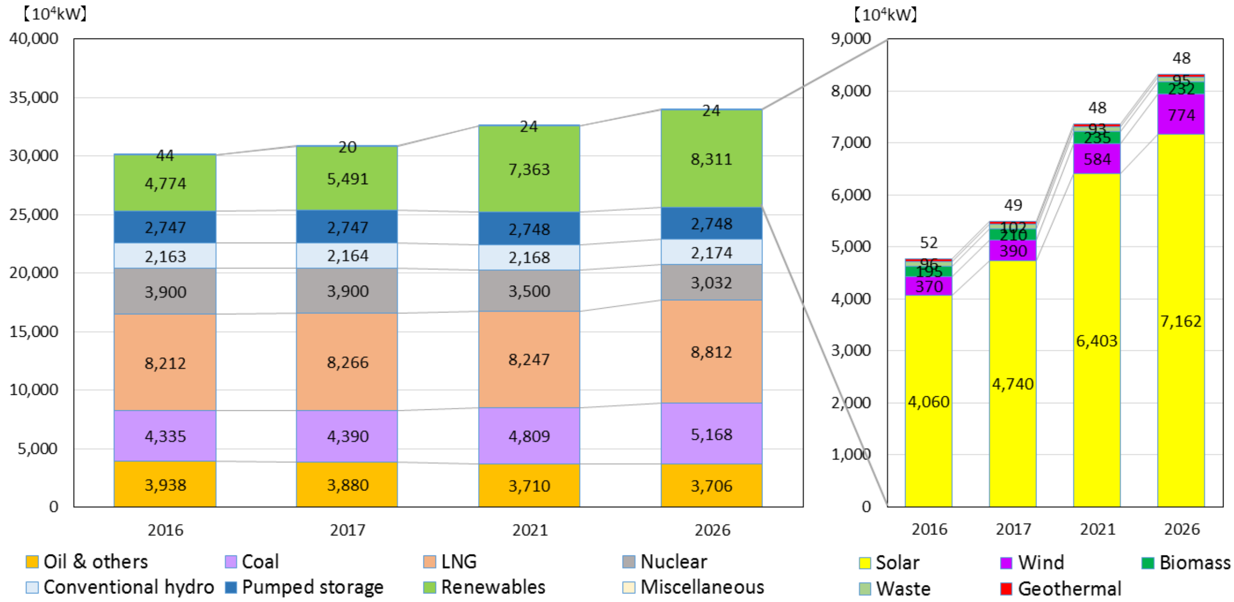

Figure 3-1 Transition of Installed Power Generation Capacities by Power Generation Sources (Nationwide)

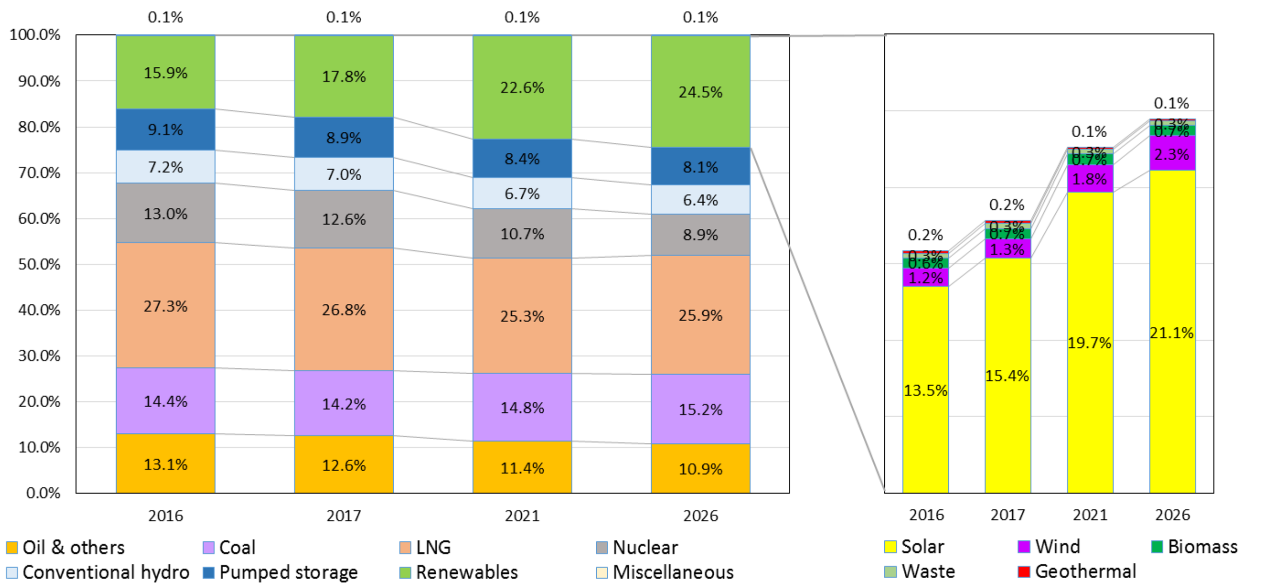

Figure 3-2 Composition of the Transition of Installed Power Generation Capacities by Power Generation Sources (Nationwide)

(2) Transition of Gross Electric Energy Generation

Table 3-2 and Figure 3-3 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 GTD companies from companies other than EPCOs. Figure 3-4 shows the composition of the transition of gross electric energy generation. For nuclear power plants, energy generation is calculated as zero for their capacity reported as “unknown”, however, changes to the composition of gross electric energy generation may be expected according to the operating conditions of nuclear power plants.

Electricity generated by coal is projected to stay at a certain level according to future power development plans for thermal generation, which is based on the large increase in renewables energy such as solar power. Electricity generated by LNG is projected to decrease sharply.

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

Power Generation Sources		FY 2016	FY 2017	FY 2021	FY 2026
Hydro		788 [8.3%]	792 [8.5%]	839 [9.1%]	884 [9.4%]
	Conventional	740 [7.8%]	764 [8.2%]	790 [8.5%]	795 [8.5%]
	Pumped Storage	48 [0.5%]	28 [0.3%]	49 [0.5%]	89 [1.0%]
Thermal		7,692 [81.1%]	7,402 [79.4%]	6,592 [71.3%]	6,511 [69.5%]
	Coal	2,904 [30.6%]	2,864 [30.7%]	2,942 [31.8%]	3,120 [33.3%]
	LNG	4,158 [43.8%]	3,951 [42.4%]	3,200 [34.6%]	2,992 [32.0%]
	Oil and others[15]	630 [6.6%]	586 [6.3%]	450 [4.9%]	399 [4.3%]
Nuclear		179 [1.9%]	198 [2.1%]	196 [2.1%]	66 [0.7%]
Renewables		625 [6.6%]	725 [7.8%]	1,010 [10.9%]	1,149 [12.3%]
	Wind	65 [0.7%]	71 [0.8%]	112 [1.2%]	146 [1.6%]
	Solar	444 [4.7%]	513 [5.5%]	730 [7.9%]	815 [8.7%]
	Geothermal	25 [0.3%]	24 [0.3%]	26 [0.3%]	26 [0.3%]
	Biomass	74 [0.8%]	99 [1.1%]	124 [1.3%]	144 [1.5%]
	Waste	17 [0.2%]	18 [0.2%]	18 [0.2%]	17 [0.2%]
Miscellaneous		203 [2.1%]	205 [2.2%]	269 [2.9%]	368 [3.9%]
Unspecified[16]		0 [0.0%]	0 [0.0%]	340 [3.7%]	385 [4.1%]
Total		9,487 [100%]	9,322 [100%]	9,245 [100%]	9,363 [100%]

[16] Unspecified means shortage which is calculated from the balance between the electric energy generated converting the peak demand of regional service area (nationwide, at the sending end) and the addition of electric energy generated by the type of power generation sources.

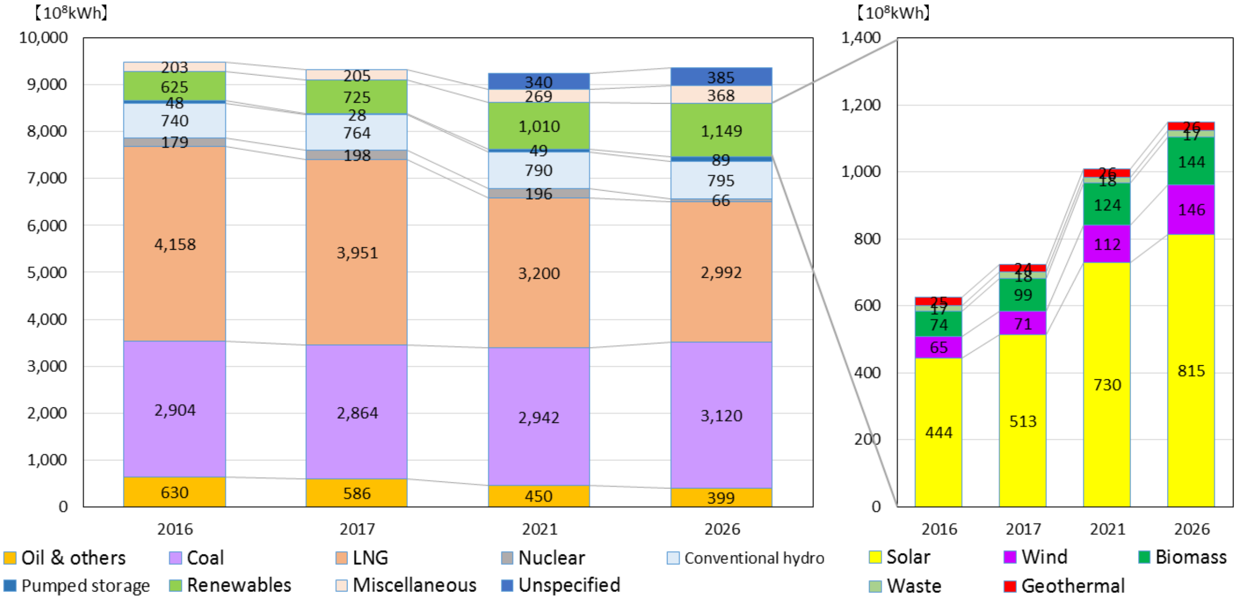

Figure 3-3 Transition of Electric Energy Generation by Power Generation Sources (Nationwide)

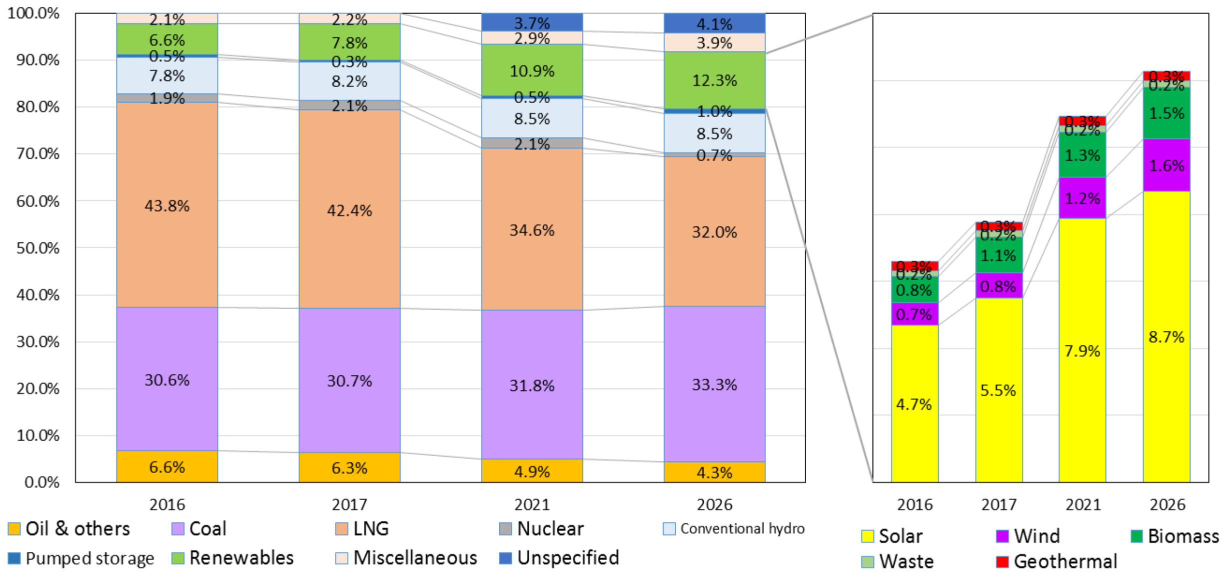

Figure 3-4 Transition of Electric Energy Generation Composition by Power Generation Sources (Nationwide)

(3) Transition of Capacity Factor by Power Generation Sources

Table 3-3 and Figure 3-5 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 projectd to increase. Energy from coal-fired power plants is projected to stay at a certain level, while energy from LNG-fired power plants is projected to decrease; therefore, the capacity factor of thermal power plants is projected to decrease gradually.

As for nuclear power generation, the installed power generation capacity is calculated using the supply capacity reported as "unknown"and the capacity factor is apparently lower; therefore, this projection does not necessarily indicate the real capacity factor for nuclear power plants currently in operation.

Table 3-3 Capacity Factors by Power Generation Sources (Nationwide)

Power Generation Sources		FY 2016	FY 2017	FY 2021	FY 2026
Hydro		18.3%	18.4%	19.5%	20.5%
	Conventional	39.1%	40.3%	41.6%	41.7%
	Pumped Storage	2.0%	1.2%	2.0%	3.7%
Thermal		53.3%	51.1%	44.9%	42.0%
	Coal	76.5%	74.5%	69.8%	68.9%
	LNG	57.8%	54.6%	44.3%	38.8%
	Oil and others[15]	18.3%	17.2%	13.9%	12.3%
Nuclear		5.2%	5.8%	6.4%	2.5%
Renewables		14.9%	15.1%	15.7%	15.8%
	Wind	19.9%	20.7%	21.9%	21.6%
	Solar	12.5%	12.3%	13.0%	13.0%
	Geothermal	55.1%	55.7%	62.1%	62.0%
	Biomass	43.3%	53.9%	60.4%	71.1%
	Waste	20.0%	20.7%	21.8%	21.0%
Miscellaneous		-	-	-	-

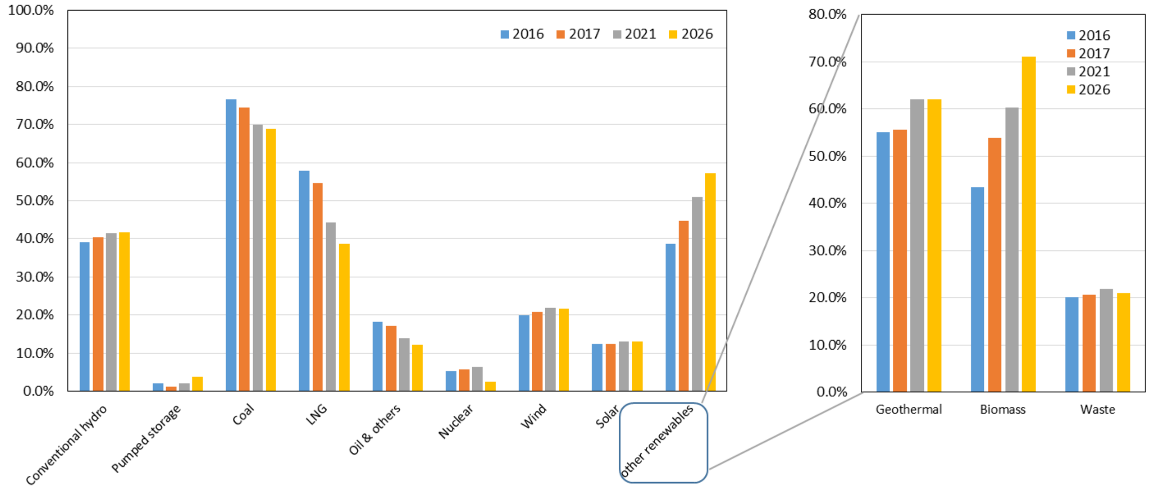

Figure 3-5 Capacity Factors by Power Generation Sources (Nationwide)

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

Figure 3-6 shows the installed power generation capacity for each regional service area at the end of FY 2016. Figure 3-7 shows the gross electric energy generation for each regional service area at the end of FY 2016.

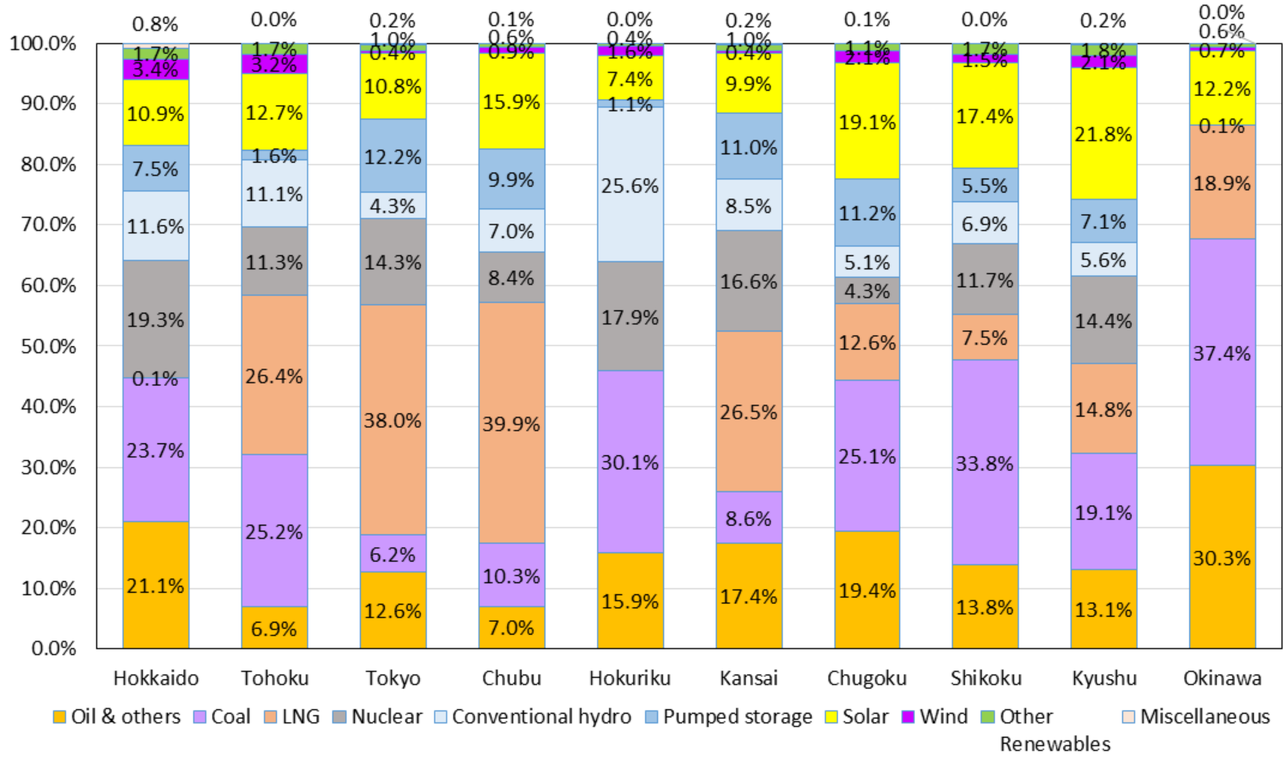

Figure 3-6 Composition of Installed Power Generation Capacity for Each Regional Service Area

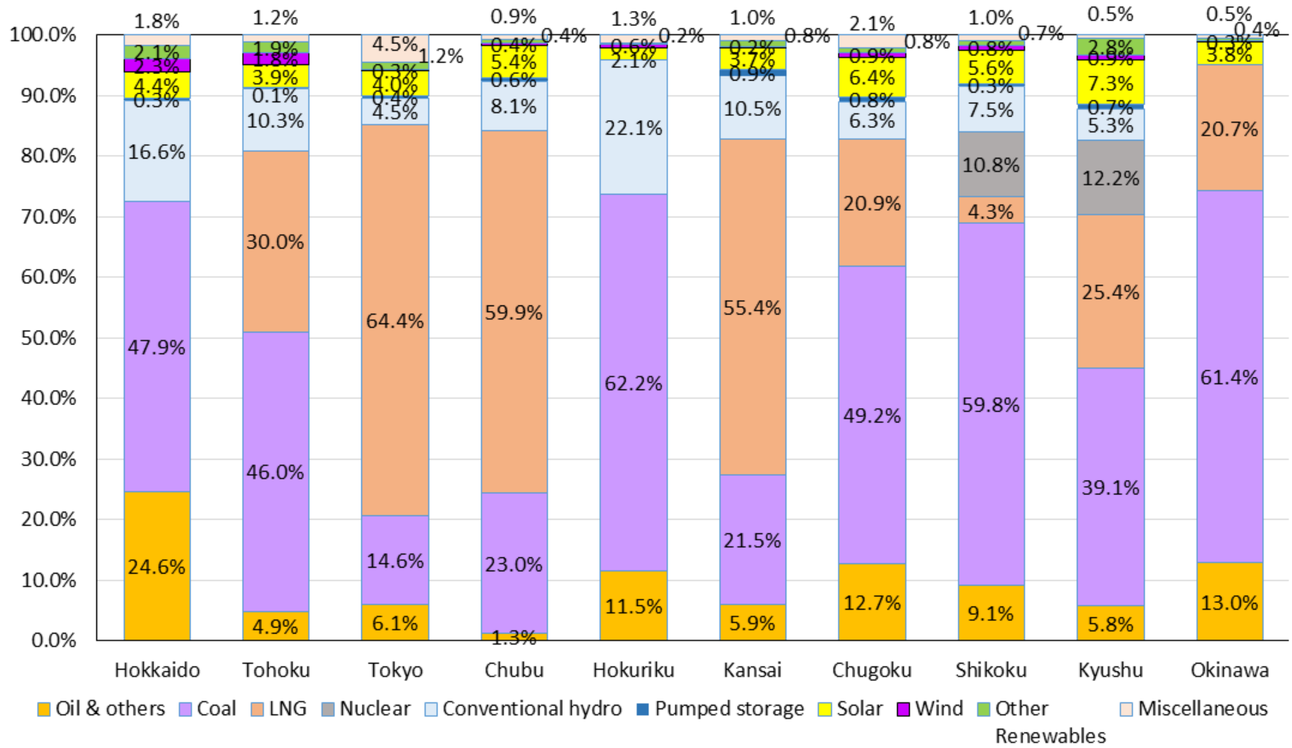

Figure 3-7 Composition of Gross Electric Energy Generation for Each Regional Service Area

(5) Development Plans by Power Generation Sources

Table 3-4 shows the development plans[17] up to FY 2026 submitted by generation companies, according to their new developments, uprating or derating installed facilities, and planned retirement of facilities in the projected period, respectively.

Table 3-4 New Development Plans up to FY 2026 by Stages (Nationwide, 10^4 kW)

Power Generation Sources		New Installation		Uprating/Derating		Retirement	
		Capacity	Sites	Capacity	Sites	Capacity	Sites
Hydro		**29.4**	**31**	**5.4**	**44**	**▲ 21.0**	**12**
	Conventional	29.4	31	4.0	43	▲ 21.0	12
	Pumped Storage	-	-	1.4	1	-	-
Thermal		**2,009.0**	**55**	**45.3**	**20**	**▲ 1,143.5**	**62**
	Coal	726.3	14	4.5	2	▲ 106.0	6
	LNG	1,243.5	23	40.1	16	▲ 751.5	17
	Oil	5.5	16	0.1	1	▲ 262.8	37
	LPG	-	-	-	-	-	-
	Bituminous	10.6	1	0.7	1	-	-
	Other Gas	23.1	1	0.0	0	▲ 23.1	2
Nuclear		**1,018.0**	**7**	**15.2**	**1**	-	-
Renewables		**448.6**	**353**	**▲ 2.4**	**5**	**▲ 26.0**	**33**
	Wind	102.9	37	-	-	▲ 13.3	22
	Solar	296.4	297	1.2	1	-	-
	Geothermal	0.5	1	▲ 2.9	3	▲ 1.8	2
	Biomass	41.6	13	▲ 0.7	1	▲ 4.6	5
	Waste	7.4	5	-	-	▲ 6.4	4
Total		3,505.0	446	63.6	70	▲ 1,190.5	107

[17] Aggregated using facilities for which the date of commercial operation is “unknown”.

4. Development Plans for Transmission and Distribution Facilities

The Organization has aggregated the development plans[18] for cross-regional transmission lines and substations (transformers and AC/DC converters) up to FY 2026 submitted by GTD 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. Following (1), (2), and (3) 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 *19*20		668 km
	Overhead Lines*	628 km
	Underground Lines	40 km
Uprated Capacities of Transformers		18,415 MVA
Uprated capacities of AC/DC Converters[21]		2,100 MW
Decreased Length of Transmission Lines (Retirement)		▲ 64 km
Derated Capacities of Transformers (Retirement)		▲ 1,425 MVA

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[18] Development plans for transmission lines and substations are required to be submitted for voltages of more than 250kV, or within 2 classes from the highest voltage available in the regional service areas. (For the Okinawa EPCO, only 132kV or more is required.)
Total is not necessarily equal due to the independent rounding.

[19] Development plans corresponding to changes in line category or circuit numbers that were not added up in measuring the increased length of transmission lines were treated as no change for the length of transmission lines.

[20] Increased length does not include the item with * because of an undefined in-service date.

[21] Installed capacity for the converter station on one side is added up for the DC transmission system.

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

○Interconnection Facility Enhancement Plan between Tokyo and Chubu

Frequency Converter Stations	・Shin Sakuma FC station(prov.): 300 MW ・Higashi Shimizu FC station: 300 MW→900 MW
275 kV Transmission Lines Installation	・Higashi Shimizu Line (prov.): 20km ・Sakuma Higashi Bulk Line/ Shin Sakuma FC Branch Line (prov.): 1km ・Sakuma Nishi Bulk Line/ Shin Sakuma FC Branch Line (prov.): 1km ・Shin Toyone-Toei Line: 1km ・Sakuma Nishi Bulk Line/ Toei Branch Line (prov.): 2km
275 kV Transmission Lines Enhancement	・Sakuma Higashi Bulk Line：125 km ・Sakuma Nishi Bulk Line：11 km
500 kV Transformers Addition	・Shin Fuji Substation: 1,500MVA×1 ・Shizuoka Substation: 1,000MVA×1 ・Toei Substation: 800MVA×1→1,500MVA×2

○Interconnection Facility Enhancement Plan between Tohoku and Tokyo

500 kV Transmission Lines Installation	・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: 10 circuits

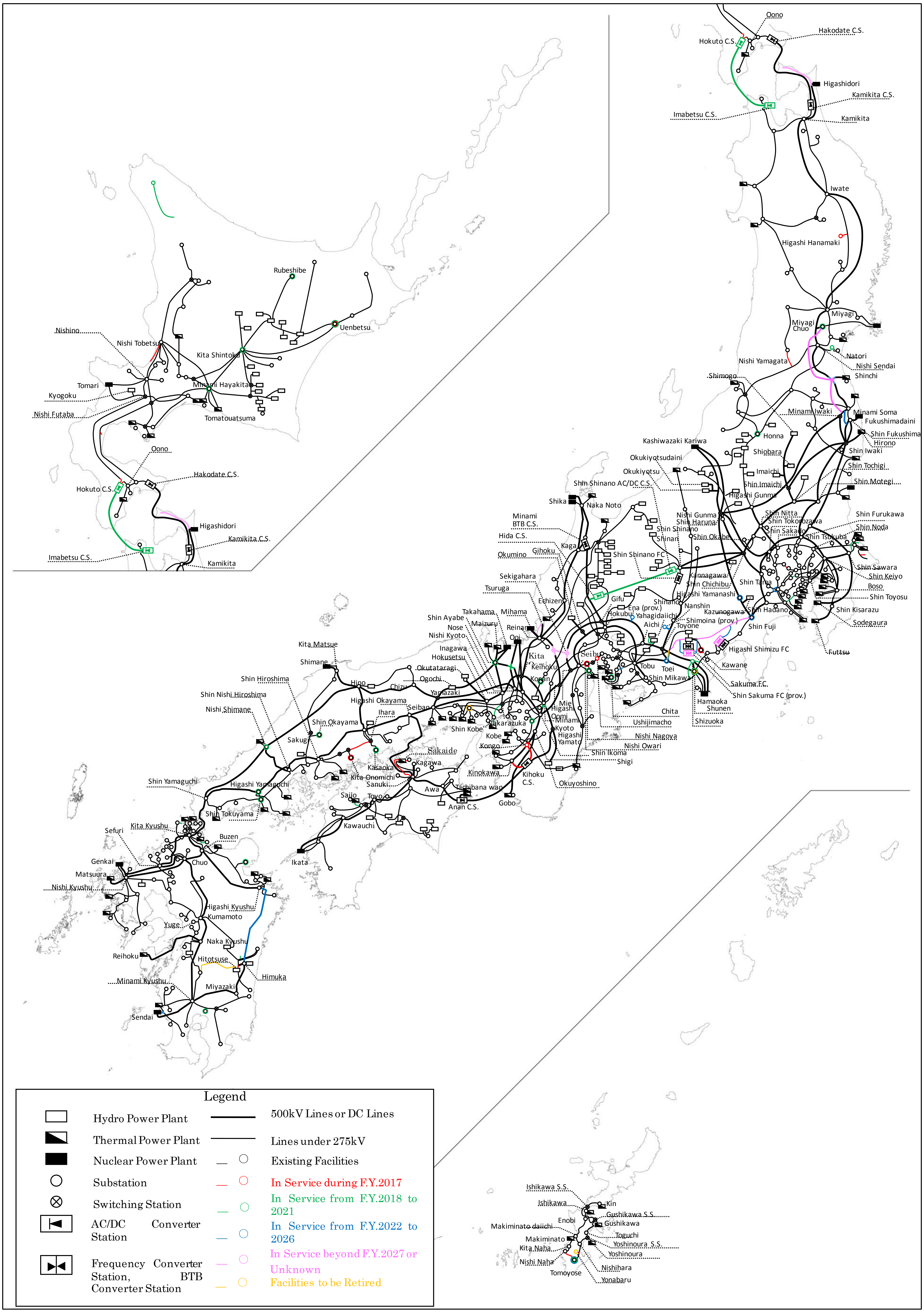


Figure 4-1 Power Grid Configuration in Japan

(1) Development Plans for Major Transmission Lines

Table 4-2 Development Plans under Construction

Company	Line	Voltage	Length[22,23]	Circuit	In-construction	In-service	Purpose[24]
Hokkaido EPCO	Hokuto-Imabetsu DC Bulk Line	DC250kV DC250kV	97.7km 24.4km*1	SP 1	Apr.2014	Mar. 2019	Reliability upgrade*3
	Ishikari Thermal Power Line	275kV	21km	2	Apr. 2015	Feb.2018	Generator connection
	Donan Bulk Line	275kV	0.3km	2	May 2016	Oct. 2017(No.2) Nov. 2017(No.1)	Reliability upgrade*3
	Hokuto Bulk Line	275kV	0.6km	2	May 2016	Oct. 2017(No.2) Nov. 2017(No.1)	Reliability upgrade*3
	Imakane-Nakazato Branch Line	187kV	0.1km	1	Mar. 2017	May 2017	Generator connection
Tohoku EPCO	Minami Yamagata Bulk Line	275kV	22.5km	2	Apr.2015	Dec. 2017	Reliability upgrade
	Higashi Hanamaki Branch Line	275kV	3.3km	2	Feb.2016	Oct. 2017	Demand coverage
	Customer Line/ AC/DC CS Dπ lead-in	275kV	2.2km	2	Aug.2016	Jun. 2018	Reliability upgrade*3
TEPCO Power Grid	G3060016 access line (prov.)	275kV	1km	1	Jan. 2017	Dec. 2017	Generator connection
	G3060006 access line (prov.)	275kV	6km	2	Jan. 2017	Jan. 2019	Generator connection
	Kita Musashino Line	275kV	7km*1,*2	3→2	Dec. 2016	Jun. 2017	Reliability upgrade
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
Kansai EPCO	Kongo Line uprated to 500kV	500kV	2.4km	2	Oct. 2016	Dec. 2017	Aging management Economic upgrade
	Izumi Line/Kongo Sub. π lead-in	500kV	0.1km	2	Oct. 2016	Jun. 2017	Aging management Economic upgrade
Chugoku EPCO	Hiroshima Higashi Bulk Line	220kV	33km*2	2	May 2015	Dec. 2017	Demand coverage Generator connection
Shikoku EPCO	Sakaide Thermal Power Line	187kV	4.6km*2	2	Feb.2017	May 2017	Aging management
Kyushu EPCO	Hyuga Bulk Line	500kV	124km	2	Nov. 2016	Jun. 2022	Reliability upgrade Economic upgrade
	Himuka-Hitotsuse Line	220kV	3km*2	1→2	Oct. 2015	Feb.2018	Aging management Economic upgrade
Okinawa EPCO	Nishi Naha-Tomoyose Bulk Line	132kV	10km*1	2	Jun. 2015	Oct. 2017	Economic upgrade
EPDC	Ooma Bulk Line	500kV	61.2km	2	May 2006	Unknown	Generator connection

Table 4-3 Development Plans on Planning Stages

Company	Line	Voltage	Length[22,23]	Circuit	In-construction	In-service	Purpose[24]
Tohoku EPCO	Customer Line/ Natori Sub. Dπ lead-in	275kV	0.4km	2	Apr. 2018	Jun. 2019	Demand coverage
	1408G02 Branch Line	500kV	3.0km	2	Aug. 2017	Jul. 2019	Generator connection
	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 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	Hida-Shinano DC Bulk Line	DC±200kV	89km	BP 1	Jul. 2017	FY 2020	Reliability upgrade*3
	Shinjuku-Jonan Line	275kV	16.4km *1,*2	3	Nov. 2017	Jul.2018(No.1) Apr.2019(No.2) Apr.2020(No.3)	Aging management
	Minami Kawasaki Line	275kV	29km*1,*2	3→4	Jan. 2018	Jan. 2022	Generator connection
	G7060005 access line(prov.)	275kV	1km*1	2	Aug. 2020	Aug. 2021	Generator connection
	Keihin Line No.1,2 /Connecting Point Change	275kV	22.7km →23.1km	2	Jul. 2021	Apr. 2022	Generator connection
	Higashi Shimizu Line (prov.)	275kV	13km 7km	2	FY 2021	FY 2026	Reliability upgrade*3
	Nishi Gunma Bulk Line No.1/Higashi Yamanashi Sub. T lead-in	500kV	1km	1	Nov. 2022	Oct. 2023	Demand coverage
Chubu EPCO	Hida Branch Line	500kV	0.4km	2	Apr. 2018	FY 2020	Reliability upgrade*3
	Yahagi daiichi Branch Line	275kV	4km	1	Jul. 2019	Feb.2021	Aging management Economic upgrade
	Ena Branch Line(prov.)	500kV	1km	2	Sep. 2021	Oct. 2024	Demand coverage
	Shimo Ina Branch Line(prov.)	500kV	1km	2	Sep. 2021	Oct. 2024	Demand coverage
	Higashi Nagoya - Tobu Line	275kV	8km*2	2	Apr. 2019	Jun. 2026	Aging management Economic upgrade
	Sekigahara Kita Oomi Line	500kV	2km	2	Unknown	Unknown	Generator connection*3
	Sekigahara S.S.	500kV	—	6	Unknown	Unknown	Generator connection*3
	Sangi Bulk Line/ Sekigahara S.S. π lead-in	500kV	1km	2	Unknown	Unknown	Generator connection*3

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 obsolence)
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

22 Length with *1 denotes "Underground", if otherwise, "Overhead"
23 Length with *2 denotes the change of line category or circuit numbers, not included in Table 4.
24 Purpose is stated in the right, and with *3 indicates the enforcement relating to cross-regional interconnection lines.

Company	Line	Voltage	Length[22,23]	Circuit	In-construction	In-service	Purpose[24]
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	Feb. 2019	Dec. 2019	Economic upgrade
	Kita Yamato Line/ Minami Kyoto Subs. Lead-in change	500kV	0.1km	2	Jun. 2021	Dec. 2021	Economic upgrade
	Kita Oomi S.S.	500kV	—	6	Unknown	Unknown	Generator connection*3
	Kita Oomi Line/ Kita Oomi S.S. π lead-in	500kV	0.5km	2	Unknown	Unknown	Generator connection*3
	Kobe Ironworks/ Thermal Power Line(prov.)	275kV	4.4km*1	3	Apr. 2017	Feb. 2021 (No.1) Feb. 2022(No.2･3)	Generator connection
	Shin Kobe Line/ reinforcement	275kV	20.2km*2	2	Apr. 2019	Mar. 2020	Generator connection
Shikoku EPCO	Customer line	187kV	0.7km*1*2	1	May 2017	Aug. 2017	Aging management
	Saijo Thermal Power Line	187kV	6.5km*2	2	Feb. 2020	May 2021	Generator connection
Kyushu EPCO	Power access line	220kV	0.3km	1	Nov. 2018	Jul. 2019	Generator connection
	Shin Kagoshima Line/Sendai Nuclear π lead-in	220kV	2→5km*2	1→2	Aug. 2020	Jul. 2023	Economic upgrade
	Customer line	220kV	4km*1*2	1	Oct. 2017	Jan. 2019	Aging management
	Power access line	220kV	4km	2	Jul. 2019	Jul.2021	Generator connection
Okinawa EPCO	Yonabaru Bulk Line -Tomoyose Bulk Line/ Connecting Point Change	132kV	0.1km	1	Nov. 2017	Dec. 2017	Aging management Economic upgrade
EPDC	Sakuma Higashi Bulk Line/ Shin Sakuma FC Branch Line(prov.)	275kV	1km	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/Toei Branch Line(prov.)	275kV	2km	2	FY 2022	FY 2026	Reliability upgrade*3
	Sakuma Higashi Bulk Line	275kV	125km*2	2	FY 2022	FY 2027	Reliability upgrade*3
	Sakuma Nishi Bulk Line	275kV	11km*2	2	FY 2022	FY 2027	Reliability upgrade*3
NHWETC	NHWETC Toyotomi-Nakagawa Bulk Line (prov.)	187kV	50km	2	Apr. 2019	Oct. 2021	Generator connection

Table 4-4 Retirement Plans

Company	Line	Voltage	Length	Circuit	Retirement	Purpose[24]
Kyushu EPCO	Hitoyoshi Bulk Line	220kV	Δ61km	1	Feb. 2018	Aging management
EPDC	Shin Toyone-Toei Line	275kV	Δ2.6km	1	FY 2026	Reliability upgrade*3

(2) Development Plans for Major Substations

Table 4-5 Development Plans under Construction

Company	Substation[25]	Voltage	Capacity	Nos.	In-construction	In-service	Purpose[24]
Hokkaido EPCO	Hokuto Converter Station*4	—	300MW	—	Mar. 2015	Mar. 2019	Reliability upgrade*3
	Imabetsu Converter Stattion*4	—	300MW	—	Mar. 2016	Mar. 2019	Reliability upgrade*3
	Uenbetsu	187/66kV	75MVA→100MVA	1→1	Apr. 2016	Nov. 2017	Aging management
Tohoku EPCO	Higashi Hanamaki*4	275/154kV	300MVA×2	2	Mar. 2015	Oct. 2017	Demand coverage
	Miyagi Chuo	500/275kV	1,000MVA	1	Feb. 2016	Nov. 2018	Economic upgrade
	Natori*4	275/154kV	450MVA×2	2	Feb. 2017	Jun. 2019	Demand coverage
TEPCO Power Grid	Shin Shinano AC/DC Convrter Station*4	—	900MW	-	Mar. 2016	FY 2020	Reliability upgrade*3
Chubu EPCO	Kawane	275/154kV	200MVA×2→ 300MVA×2	2→2	Aug. 2015	Apr. 2017	Aging management
	Nishi Owari	275/154kV	450MVA×2→ 500MVA×2	2→2	Aug. 2016	Apr. 2017	Aging management
	Ushijimacho	154/33kV→ 275/33kV	150MVA×2	2→2	Dec.2013	May 2017	Economic upgrade
	Nishi Nagoya	275/154kV	450MVA	1	Apr. 2011	Jun. 2018	Economic upgrade
	Shizuoka*4	500/275kV	1000MVA	1	Aug.2001	Jun.2019	Aging management Economic upgrade
Kansai EPCO	Kongo*4	500/275kV	1,000MVA×2	2	Jun.2014	Apr. 2017	Economic upgrade Reliability upgrade
Chugoku EPCO	Kita Onomichi	220/110kV	300MVA	1	Sep. 2016	Jan. 2018	Demand coverage Generator connection

Table 4-6 Development Plans in Planning Stages

Company	Substation[25]	Voltage	Capacity	Nos.	In-construction	In-service	Purpose[24]
Hokkaido EPCO	Uenbetsu	187/66kV	75MVA→ 100MVA	1→1	Mar. 2019	Nov. 2019	Aging management
	Rubeshibe	187/66kV	60MVA→ 100MVA	1→1	Jun.2017	Jul. 2018	Aging management
	Rubeshibe	187/66kV	60MVA×2→ 100MVA	2→1	Mar. 2019	Oct. 2019	Aging management
	Minami Hayakita	187/66kV	200MVA	1	Aug. 2018	Jun.2019	Generator connection
	Kita Shintoku	275/187kV	450MVA	1	Jul. 2018	Nov. 2019	Generator connection
Tohoku EPCO	Honna	275/154kV	120MVA→ 150MVA	1→1	Aug. 2017	Sep. 2018	Aging management
TEPCO Power Grid	Shin Fuji	500/275kV	1500MVA	1	FY 2023	FY 2026	Reliability upgrade*3
	Higashi Yamanashi	500/154kV	750MVA	1	Apr. 2019	Dec. 2022	Demand coverage

25 Substation with *4 denotes substation or converter station installed anew, including uprated electric facility.

Company	Substation[25]	Voltage	Capacity	Nos.	In-construction	In-service	Purpose [24]
Chubu EPCO	Hida Converter Station*4	—	900MW	—	Jul. 2017	FY 2020	Reliability upgrade*3
	Shunen	275/154kV	450MVA×1→ 300MVA×1	1→1	Dec. 2017	Jun. 2020	Aging management
	Chita Thermal Power	275/154kV	300MVA×1→ 450MVA×1	1→1	Dec. 2018	Mar. 2021	Aging management
	Chita Thermal Power	275/154kV	450MVA×2	2	Dec. 2018	Aug. 2021	Generator connection
	Ena(prov.)*4	500/154kV	200MVA×2	2	Apr. 2021	Oct. 2024	Demand coverage
	Shimo Ina(prov.)*4	500/154kV	300MVA×2	2	Apr. 2021	Oct. 2024	Demand coverage
	Toei	500/275kV	800MVA×1→ 1,500MVA×2	1→2	FY 2020	FY 2026	Reliability upgrade*3
	Shizuoka	500/275kV	1,000MVA×1→ 1,000MVA×2	1→2	FY 2024	FY 2026	Reliability upgrade*3
	Higashi Shimizu	—	300MW→ 900MW	—	FY 2020	FY 2027	Reliability upgrade*3
Kansai EPCO	Shin Ayabe	275/77kV	200MVA→ 300MVA	1→1	Apr. 2018	Mar. 2019	Aging management
	Konan	275/77kV	300MVA→ 200MVA	1→1	Aug. 2018	Jun. 2019	Aging management
	Higashi Osaka	275/77kV	300MVA→ 200MVA	1→1	Sep. 2019	Jun. 2020	Aging management
Chugoku EPCO	Higashi Yamaguchi	500/220kV	1,000MVA	1	Apr. 2017	Apr. 2019	Demand coverage Generator connection
	Shin Tokuyama	220/110kV	150MVA→ 300MVA	1→1	Jun. 2018	Apr. 2019	Aging management Generator connection
	Kasaoka	220/110kV	250MVA→ 300MVA	1→1	Aug. 2018	Jun. 2019	Aging management
	Sakugi	220/110kV	200MVA	1	Jun. 2019	Apr. 2020	Generator connection
	Nishi Shimane	500/220kV	1,000MVA	1	Jul. 2020	Mar. 2022	Generator connection
Kyushu EPCO	Hayami	220/66kV	250MVA	1	Apr. 2019	Jun. 2020	Generator connection
	Kirishima	220/66kV	300MVA	1	Nov. 2019	Sep. 2021	Generator connection
Okinawa EPCO	Tomoyose	132/66kV	125MVA×2→ 200MVA×2	2→2	Oct. 2017	Jun. 2020 Oct. 2023	Aging management
EPDC	Shin Sakuma FC (prov.)	—	300MW	—	FY 2021	FY 2027	Reliability upgrade*3
NHWETC	Kita Toyotomi(prov.)	187/66kV	155MVA×3	3	Apr. 2019	Oct. 2021	Generator connection

Table 4-7 Retirement Plans

Company	Substation	Voltage	Capacity	Nos.	Retirement	Purpose
Chubu EPCO	Shunen	500/275kV	▵1,000	▵1	Jun. 2019	Aging management
Kansai EPCO	Shin Kakogawa	275/77kV	▵300	▵1	Sep. 2018	Aging management
Okinawa EPCO	Yonabaru	132/66kV	▵125	▵1	Nov. 2017	Aging management

○Other development plan (not subject to submit by the electric supply plan)

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

◇ Minami Fukumitsu Intreconnection Facility・Substation 500kV AC Buses Connecting Line Addition (In-service: Sep. 2019)

(3) Summarized 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 2026 submitted by GTD and transmission Companies.

Table 4-8 Development Plans for Major Transmission Lines

Category	Voltage	Lines	Length[51]	Extended Length[52]	Total Lengh	Total Extended Length
Newly Installed or Extended	500kV	Overhead	295 km*[53]	589 km*	295 km*	589 km*
		Underground	0 km	0 km		
	275kV	Overhead	92 km	177 km	97 km	193 km
		Underground	5 km	15 km		
	220kV	Overhead	4 km	8 km	4 km	8 km
		Underground	0 km	0 km		
	187kV	Overhead	50 km	100 km	50 km	100 km
		Underground	0 km	0 km		
	132kV	Overhead	0 km	0 km	10 km	20 km
		Underground	10 km	20 km		
	DC	Overhead	187 km	187 km	211 km	211 km
		Underground	24 km	24 km		
	Total	Overhead	628 km	1,061 km	668 km	1,121 km
		Underground	40 km	60 km		
To be Retired	275kV	Overhead	△3km	△3km	△3km	△3km
		Underground	0km	0km		
	220kV	Overhead	△ 61 km	△ 61 km	△ 61 km	△ 61 km
		Underground	0 km	0 km		
	Total	Overhead	△64 km	△64 km	△ 64 km	△ 64 km
		Underground	0 km	0 km		

Table 4-9 Revised Plans for Line Category and the Numbers of Circuit[54]

Voltage	Length Extended	Total Extended Length
500kV	0 km	0 km
275kV	215 km	493 km
220kV	45 km	86 km
187kV	12 km	23 km
132kV	0 km	0 km
DC	0 km	0 km
Total	272 km	602 km

[51] Length denotes both the increased length for newly installed or extended plans, and the decreased length for retirement. Development plans corresponding to the change of line category or the number of circuitswere not added up in the increased length of transmission lines shown in Table 4-8 and are treated as no change for the length.
In addition, the total length is not necessarily equal due to independent rounding.

[52] 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 added up in the increased length of transmission lines in Table 4-8 and are treated as no change in the length.

[53] The length with * includes undefined in-service dates and were not added up in length or extended length.

[54] 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[55]	Voltage[56]	Increased Numbers	Increased Capacity
Newly Installed or Extended	500kV	14 [7]	12,450 MVA [4,000MVA]
	275kV	10 [4]	3,830 MVA [1,500MVA]
	220kV	4 [0]	1,250 MVA [0MVA]
	187kV	3 [3]	735 MVA [465MVA]
	132kV	0 [0]	150 MVA [0MVA]
	Total	31 [14]	18,415 MVA [5,965MVA]
To be Retired	500kV	△ 1	△ 1,000 MVA
	275kV	△ 1	△ 300 MVA
	220kV	0	0 MVA
	187kV	0	0 MVA
	132kV	△ 1	△ 125 MVA
	Total	△ 3	△ 1,425 MVA

[ ] : The aforementioned increase in the number of transformers was due to new substation installations.

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

Category	Company and Number of Site		Capacity[57]
Newly Installed or Extended	Hokkaido EPCO	2	300MW each
	TEPCO Power Grid	1	900MW
	Chubu EPCO	2	900MW 600MW
	Electric Power Development Company	1	300MW

55 Retirement plans with transformer installations are included in Newly Installed or Extended, and negative figures are added up in the increased numbers or the increased capacity.
56 Voltage class by upstream voltage.
57 Installed capacity of the converter stations in both side of the DC lines are added up.

5. Cross-regional Operation

Retail companies shall procure the supply capacity for their customers in their regional service areas. The scheduled procurement from the external service areas at 15:00 August 2017 was developed into 4 figures. Figure 5-1 and 5-2 show the ratio of the supply capacity and the supply capacity, respectively. Likewise, Figure 5-3 and 5-4 show the ratio of the energy supply and the energy supply, respectively.

Figures 5-1 and 5-3 indicate that higher ratios for procurement from the external regional service areas are observed in both supply capacity and energy supply for Chugoku, Shikoku and Kansai EPCO areas. Figures 5-2 and 5-4 indicate that more capacity and energy are transmitted to other areas from Tohoku, Shikoku, and Kyushu EPCO areas.

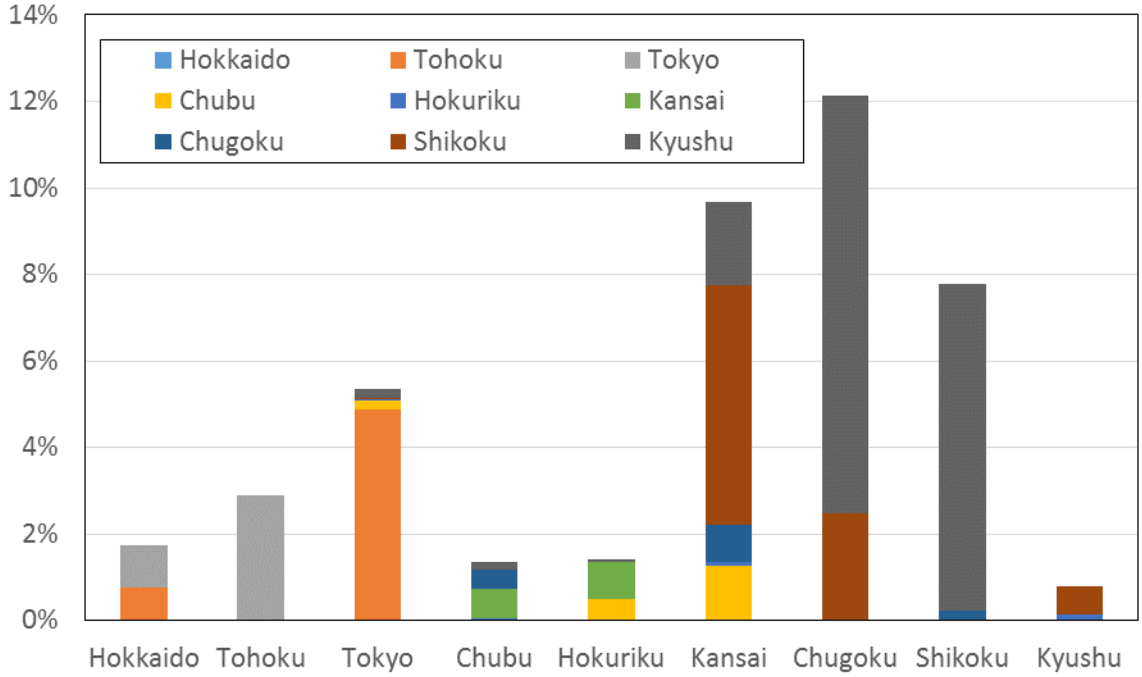


Figure 5-1 Ratio for Scheduled Procurment of Supply Capacity from External Regional Service Areas

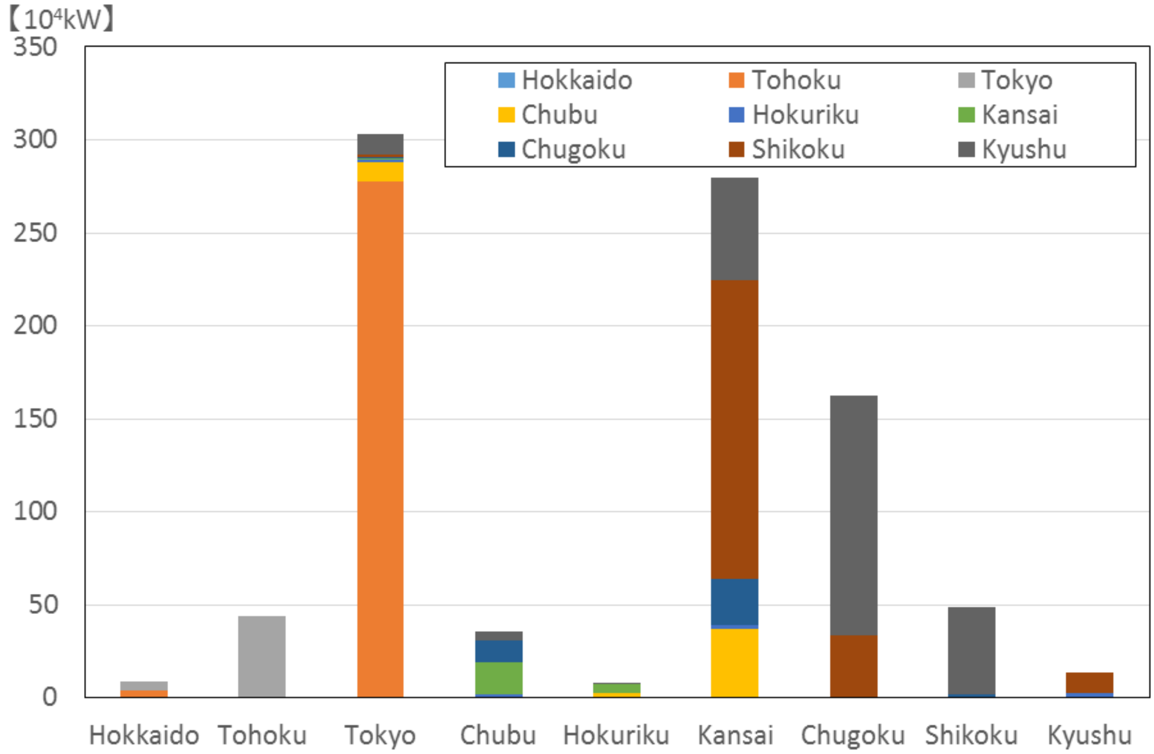


Figure 5-2　Scheduled Procurment of Supply Capacity from External Regional Service Areas

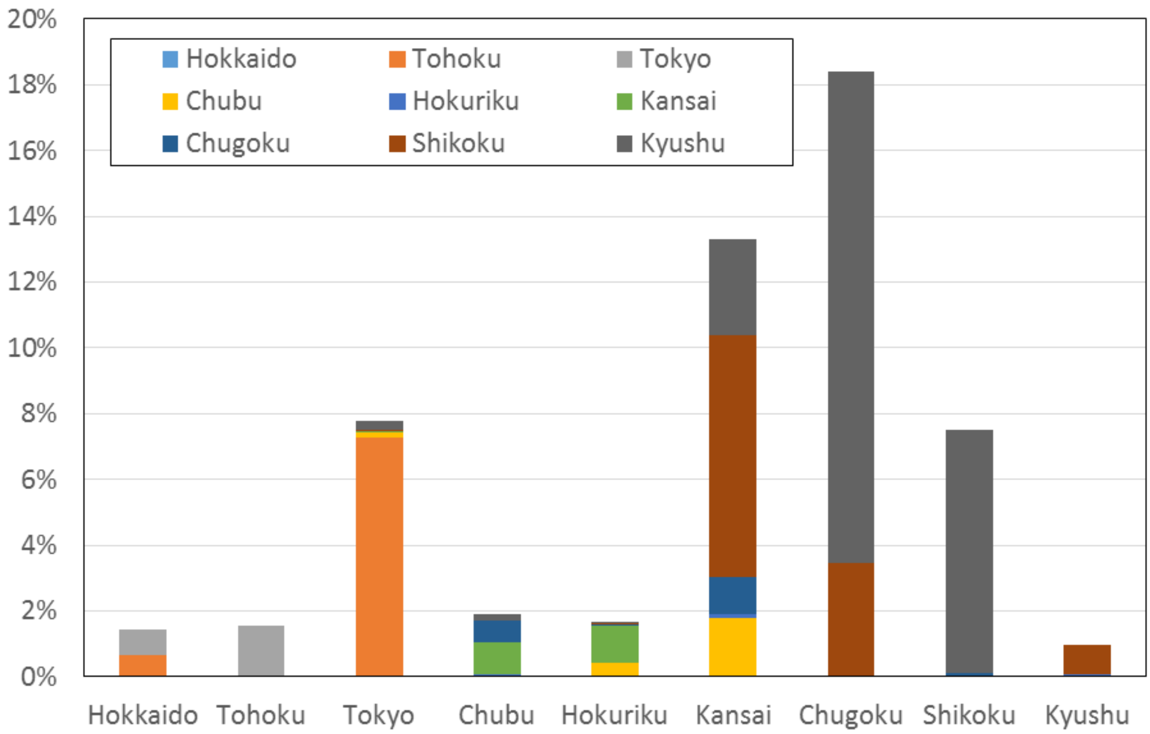


Figure 5-3　Ratio for Scheduled Procurment of Energy Supply from External Regional Service Areas

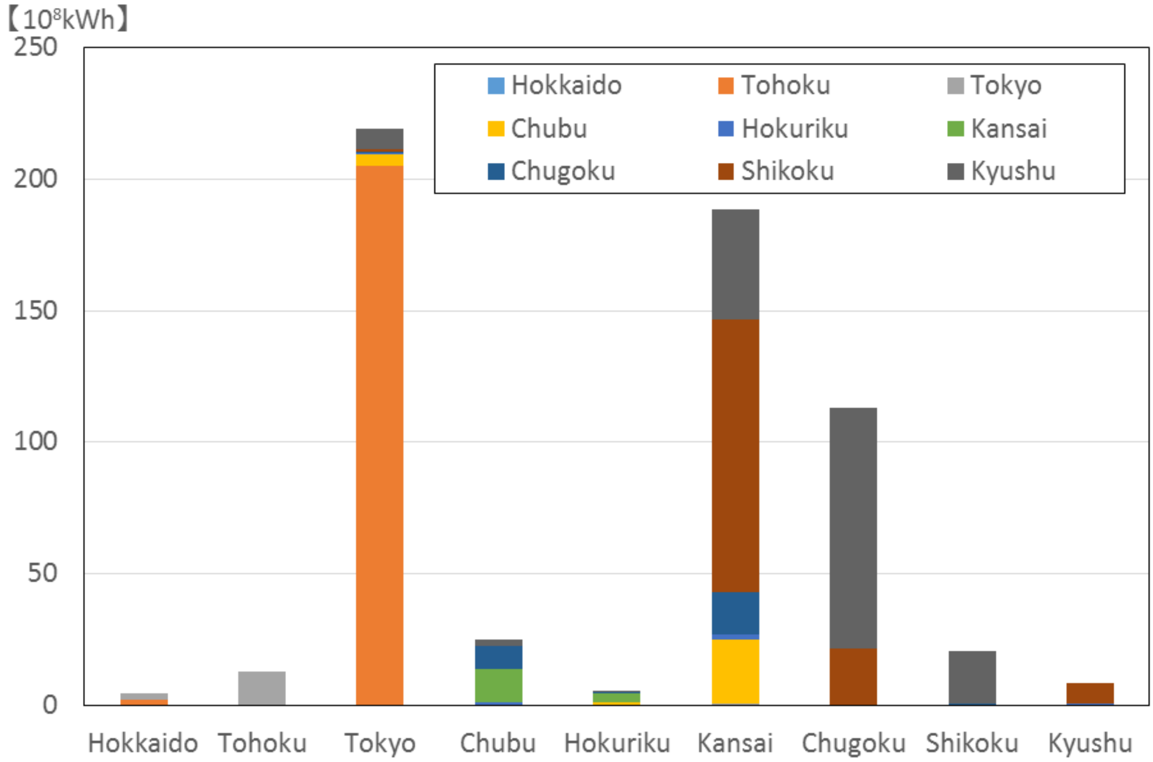


Figure 5-4　Scheduled Procurment of Energy Supply from External Regional Service Areas

6. Characteristics Analysis of Retail Companies

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

Three hundred and sixty-seven retail companies submitted their electricity supply plans, which have been classified by the business scale of the retail demand forecast by corresponding companies. Figure 6-1 and 6-2 show the distributions of the business scale of retail demand and the accumlated retail demand forecast by corresponding companies, respectively. Notably, smaller retail companies forecast greater retail demand.

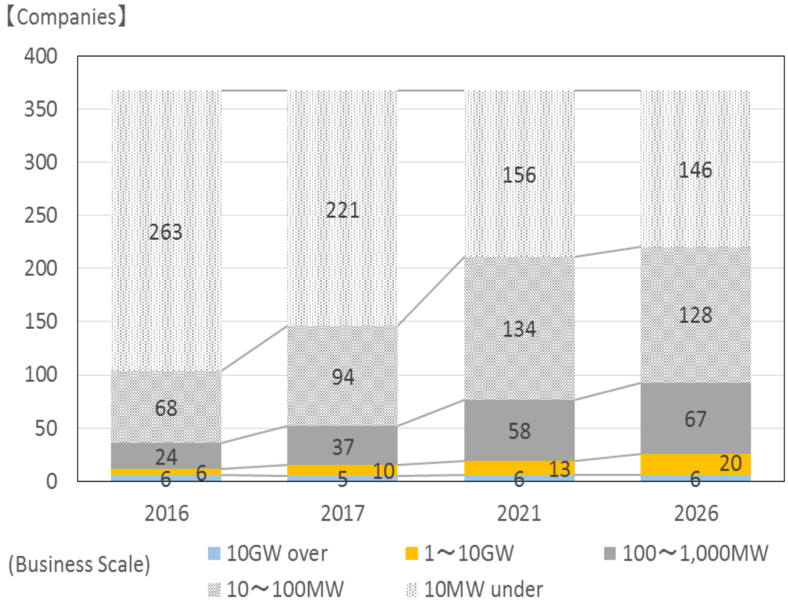


Figure 6-1 Distribution by the Business Scale of the Retail Demand by Retail Companies

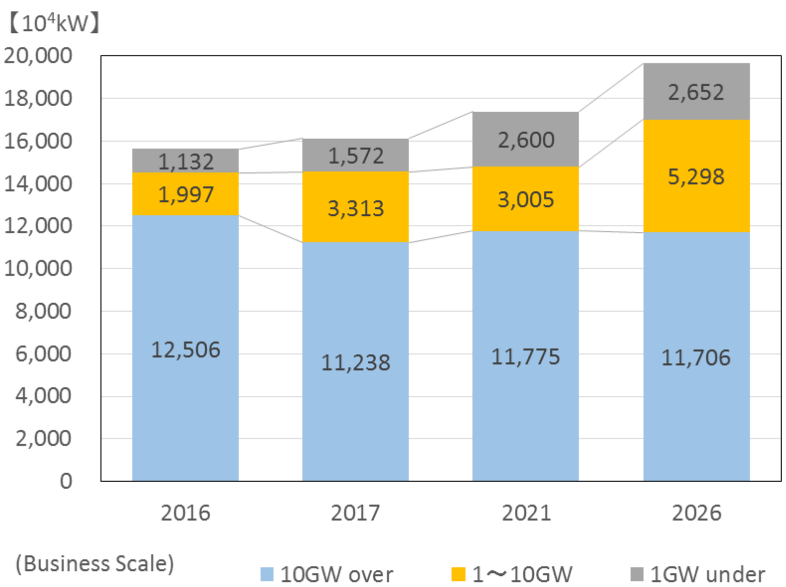


Figure 6-2 Distribution by the Accumulated Retail Demand of Retail Companies

Similarly, retail companies are classified by the business scale of the retail energy sales forecast by corresponding companies. Figure 6-3 and 6-4show the distributions of the business scale of the energy sales and the accumlated by the retail energy sales forecast by corresponding companies, respectively.

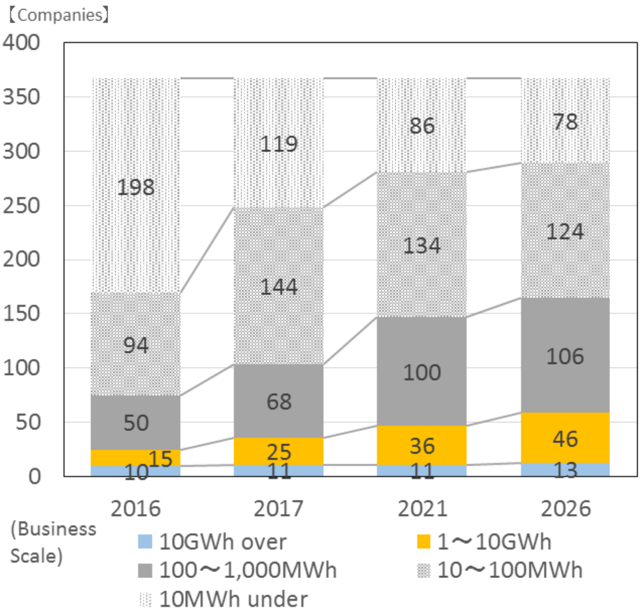


Figure 6-3 Distribution by the Business Scale of Retail Companies' Energy Sales

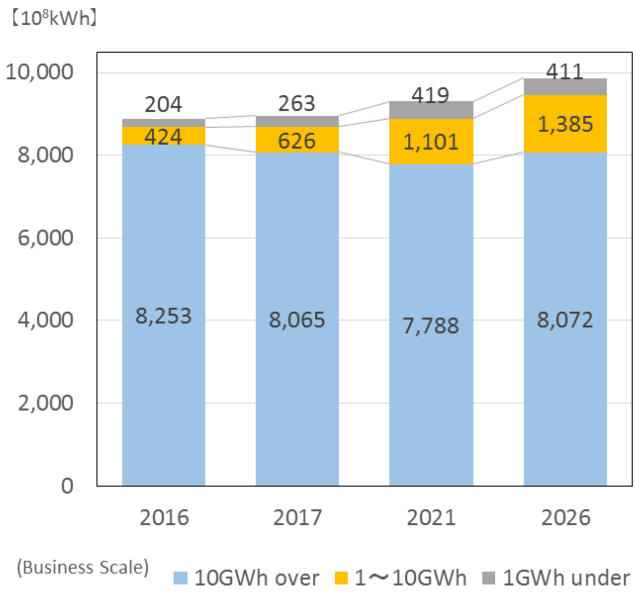


Figure 6-4 Distribution by Retail Companies' Accumulated Energy Sales

(2) Retail Companies' Business Areas

Figure 6-5 shows the ratio of retail companies by the number of areas where they plan to conduct their business and Figure 6-6 shows the number of retail companies by their business planning areas in FY 2017, respectively. The figures exclude 36 retail companies that had not yet developed their retail busiess plans. Half of the retail companies plan their business in a single area.

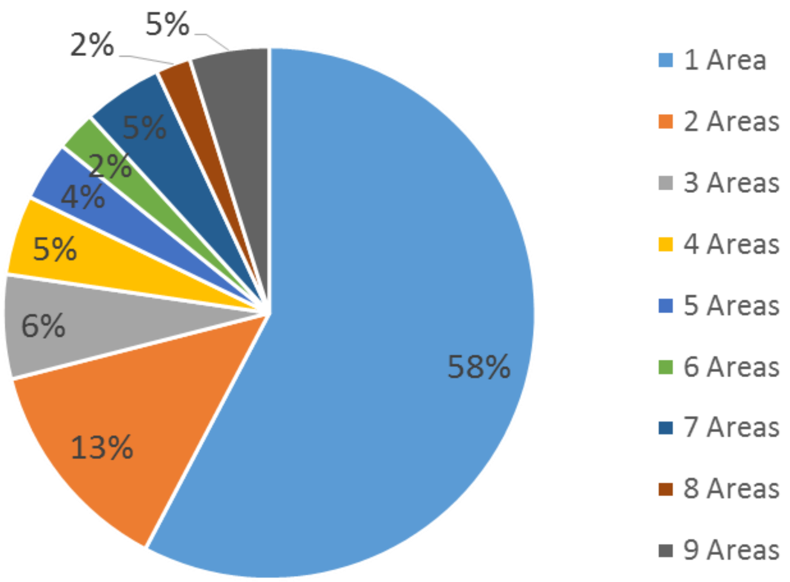


Figure 6-5 Ratio of Retail Companies by the Number of Planned Business Areas in FY 2017

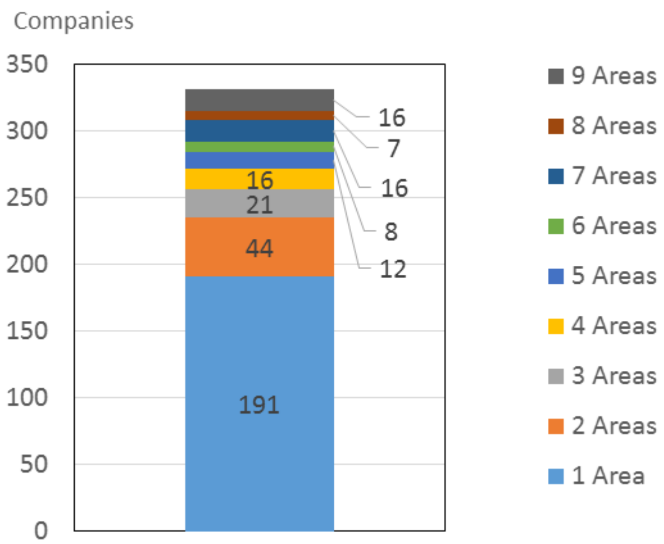


Figure 6-6 Number of Retail Companies by their Business Planning Areas in FY 2017

Figure 6-7 shows the number and the retail demand of retail companies in each regional service areas for GTD companies in FY 2017. In general, the number of companies is comparable to the scale of retail demand in the regional service area.

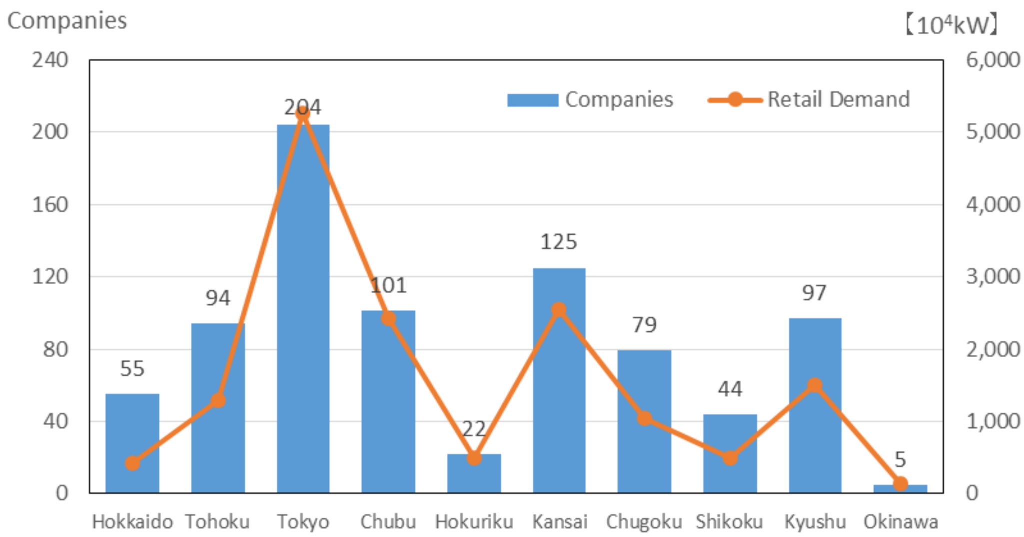


Figure 6-7 Number and Retail Demand of Retail Companies in Each Regional Service Area

(3) Supply Capacity Procurement by Retail Companies

Figures 6-8 and 6-9 show the over- and underaggregated ratios of the contractually procured supply capacity to the forecast retail demand by the business scale of retail companies, respectively.

Both figures indicate that small and middle-sized retail companies plan their mid- to long-term supply capacity as “undetermined.”

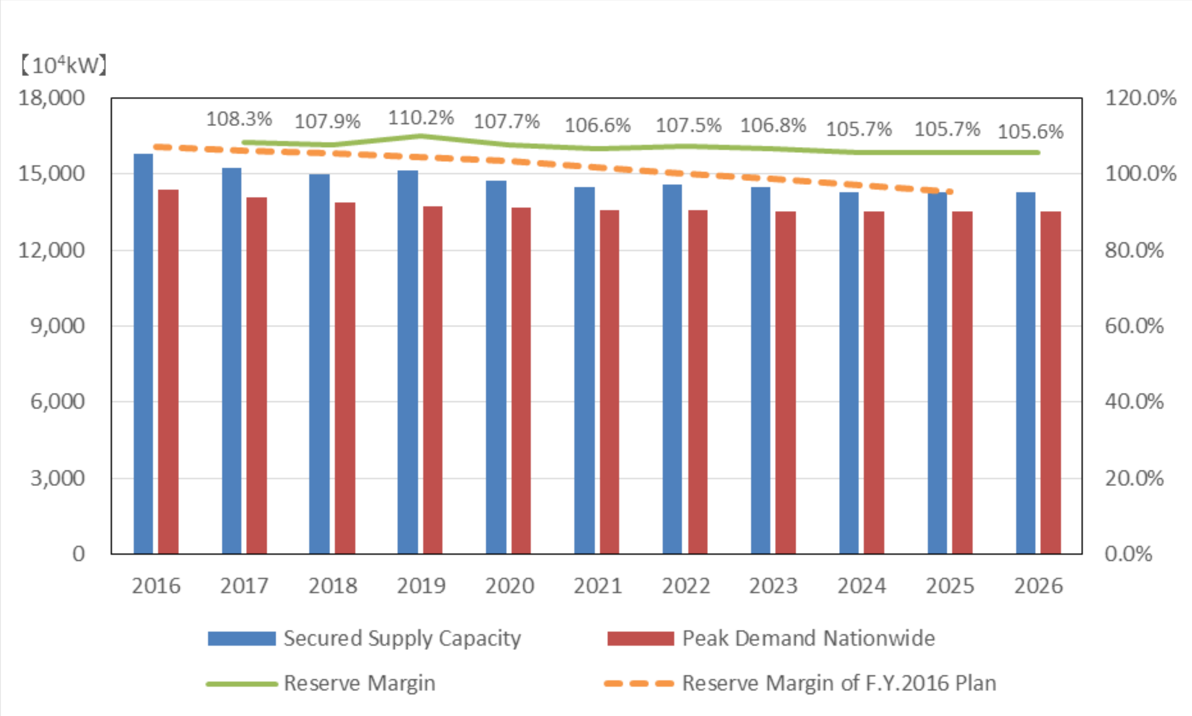


Figure 6-8 Ratio of Contractually Procured Supply Capacity to Forecast Retail Demand
(Retail peak demand 2GW, overaggregated)

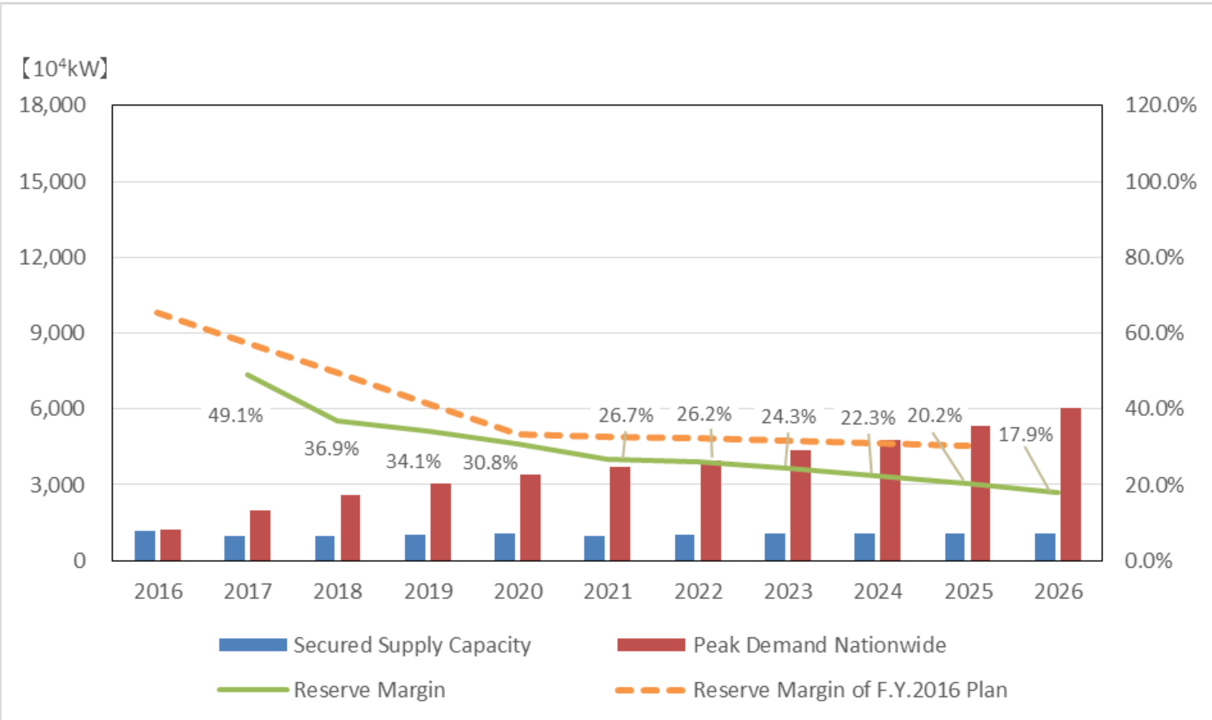


Figure 6-9 Ratio of Contractually Procured Supply Capacity to Forecast Retail Demand
(Retail peak demand 2GW, underaggregated)

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

Five hundred forty-two generation companies submitted their electricity supply plans, which have been classified by the business scale of the installed capacity operated by the corresponding companies. Figure 6-10 shows the distribution by business scale and Figure 6-11 shows the installed capacity operated by the corresponding companies.

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

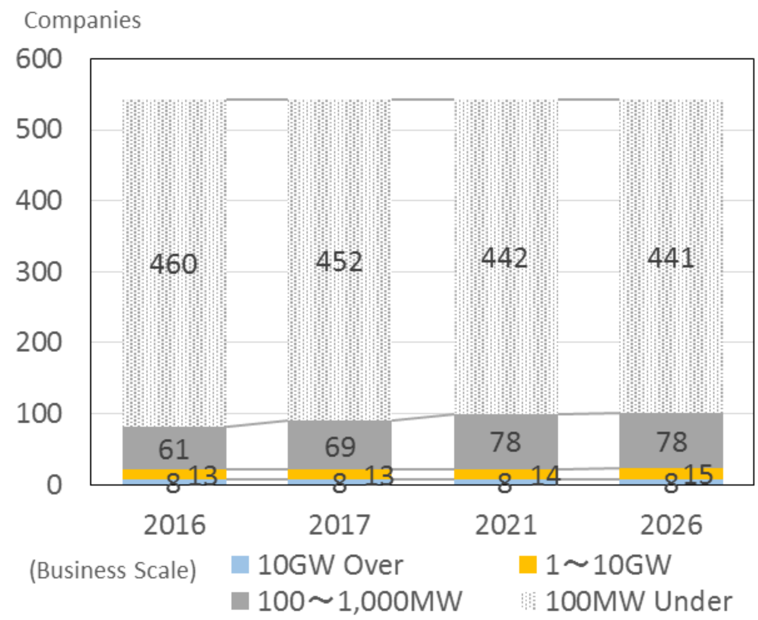


Figure 6-10 Distribution by Business Scale of Generation Companies' Installed Capacity

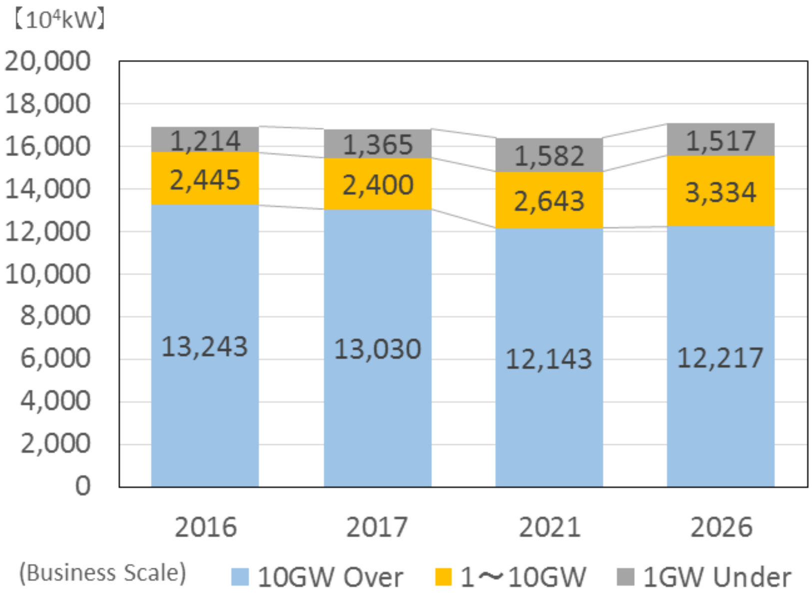


Figure 6-11 Distribution by Generation Companies' Accumulated Installed Capacity

Similarly, generation companies are classified by the business scale of corresponding companies' energy supply forecast. Figure 6-12 shows the distribution by the business scale of the energy supply and Figure 6-13 shows the distribution by corresponding companies' accumlated energy supply forecast.

Generation companies with an energy supply of under 1 TWh are planning to enlarge their business scale.

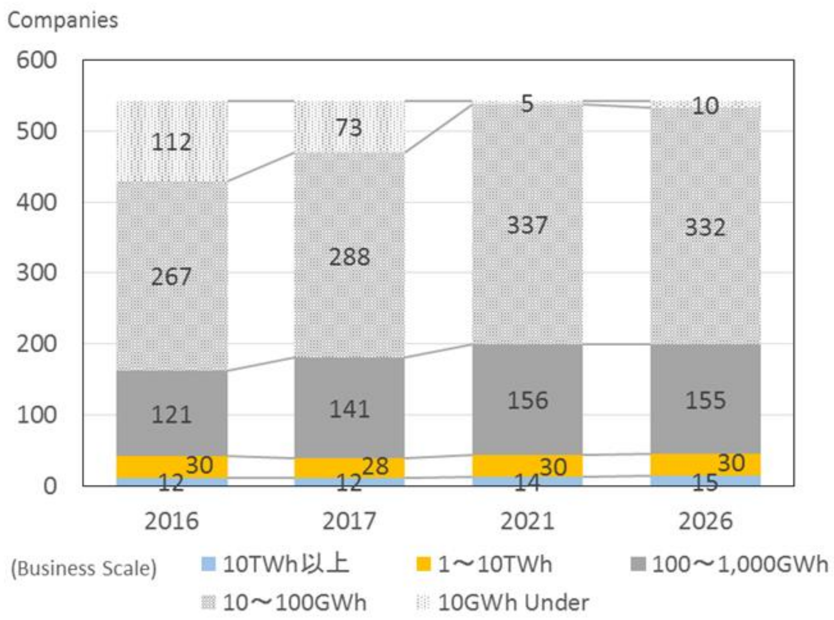


Figure 6-12 Distribution by the Business Scale of Generation Companies' Energy Supply

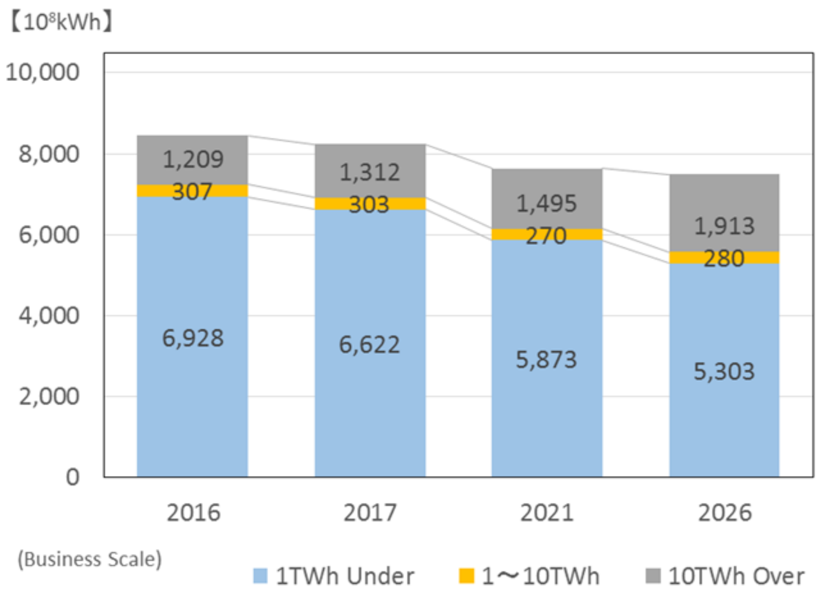


Figure 6-13 Distribution by Generation Companies' Accumulated Energy Supply

(5) Generation Companies' Business Areas

Figure 6-14 shows the ratio of generation companies by the number of areas where they plan to conduct their business and Figure 6-15 shows the number of generation companies by their business planning areas in FY 2017, respectively. The figures exclude 62 generation companies that do not own their generation plants. Seventy-eight percent of generation companies plan their business in a single area.

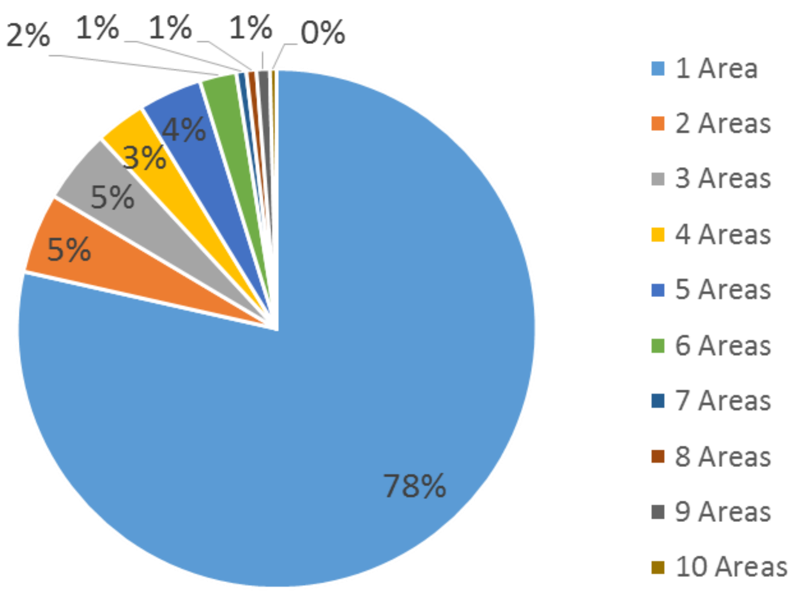


Figure 6-14 Ratio of Generation Companies by the Number of Planned Business Areas in FY 2017

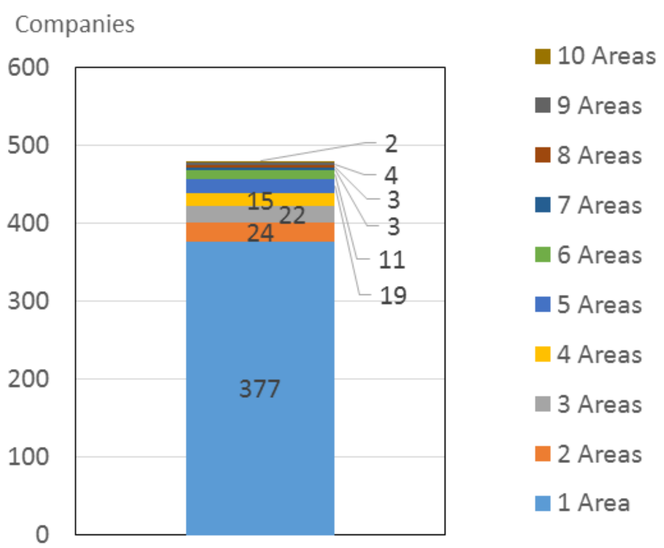


Figure 6-15 Number of Generation Companies by their Business Planning Areas in FY 2017

Figure 6-16 shows the number and installed capacity of generation companies in each regional service area for GTD companies in FY 2017. In general, the number of companies is comparable to the scale of retail demand in the regional service area.

In the Hokkaido, Tohoku, and Kyushu regional service areas, the scale of retail companies is rather small and their supply capacity is comparatively small despite the number of retail companies in these regional service areas.

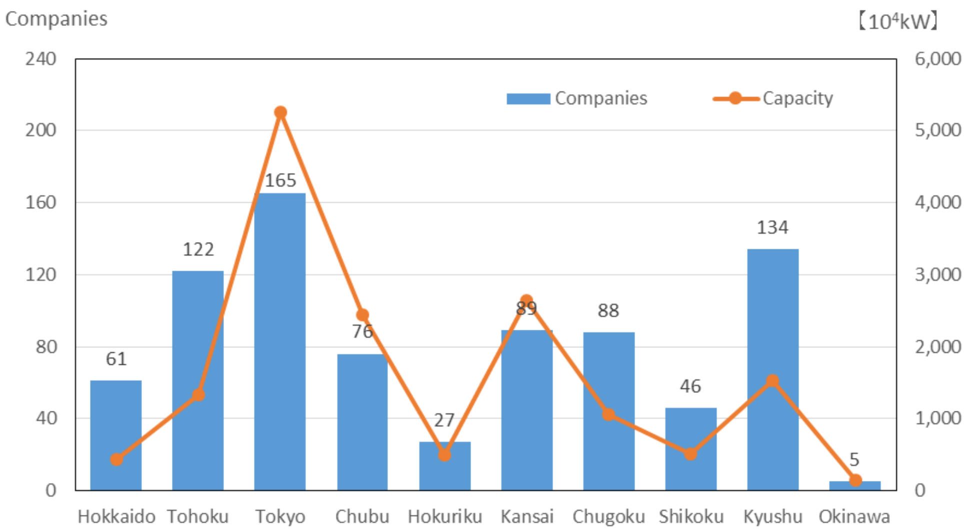


Figure 6-16 Number and Installed Capacity of Generation Companies in Each Regional Service Area

7. Findings and Recent Challenges

(1) Electricity Supply Plan Aggregation Findings

After aggregating the electricity supply plans, the Organization identified the following items for the electricity supply plan and the evaluation of supply-demand balances as stated below during the aggregation of electricity supply plans in circumstance that lead to transition of electric power supply because of the greater integration of renewable energy, the enlargement of the market by the participation of new players, and the proceedings of some changes to the system.

a. Timing of the Evaluation of Supply and Demand

The Organization currently implements its evaluation of supply and demand during peak demand occurrence. The Organization is concerned about the necessity to evalutate supply and demand during the evening hours when lighting demand becomes greater and the supply capability of solar power becomes unavailable, which reflects the increasing presence of renewable energy. To date, the Organizaiton has not yet implemented the corresponding evaluation for evening peak hours based on the assumption that the reserve margin during the evening peak hours will be secured by the output of pumped-storage hydro power plants.

However, the Organization recognizes that the reserve margin will fall to small figures at times other than peak demand occurrence according to the data provided by the GTD companies. However, this tendency will become more common in future following the greater integration of solar power; therefore, the Organization shall consider and implement its evaluation at a time other than the peak demand occurrence for the aggregation of electricity supply plans for the next year.

[Please see (3) Referential Review of Evaluations Implemented at Times other than Peak Demand Occurrence.]

<Reference 1>

Reserve Margins in Regional Service Areas Becoming the Least at Times other than Peak Demand Occurrence (%)

Regional Service Areas	Reserve Margin at the Peak Demand (15:00 in August) ①	17:00 in August		20:00 in August	
		Reserve Margin ②	Decrease of Reserve Margin (=①−②)	Reserve Margin ③	Decrease of Reserve Margin (=①−③)
Hokkaido	19.7	18.8	△0.9	—	—
Tohoku	17.0	15.3	△1.7	—	—
Tokyo	8.0	—	—	—	—
Chubu	8.2	—	—	—	—
Hokuriku	9.1	9.1	△0.0	—	—
Kansai	13.4	11.0	△2.4	—	—
Chugoku	28.4	—	—	—	—
Shikoku	25.2	—	—	—	—
Kyushu	15.3	—	—	10.6	△4.7
Okinawa	50.4	—	—	45.6	△4.8

b. Necessity for the Evaluation of the Supply and Demand Balance at the Bottom Demand Occurence

Isolated islands have already implemented output restriction for renewable energy, which is likely to occur at other than isolated islands. The Organization recognizes the need to assure or implement the evaluation of the supply-demand balance at the bottom demand occurrence in the electricity supply plan.

c. Necessity for the Comprehesion of Unreported Supply Capacity

The generation plant development plans of the EPCOs that are not obliged to submitte their electricity supply plans shall be evaluated comprehensively with other submitted development plans during the aggregation of the plans.

d. Assuring Supply Capacity between Service Areas According to a New Utilization Rule

A new utilization rule for the cross-regional interconnection lines is under review and the supply capacity across the cross-regional interconnection lines shall be traded at the day-ahead market. However, the recent reporting rule does not include the day-ahead trade in the electricity supply plan; therefore, it is necessary to organize the inclusion of this supply capacity in the plans.

(2) Recent Challenges in the Aggregation of Electricity Supply Plans

a. A More Clearly Envisaged Necessity for Introducing a Capacity Mechanism Market Scheme

○The Tokyo, Chubu, and the Kansai EPCO regional service areas (the 3 major areas) have significant electricity demands and are particularly competitive areas. In the supply-demand balance without power exchange, their reserve margins will be below the reserve margin criterion of 8% in these areas. The Organization investigated this factor and identified the followings.

✔ In the 3 Major Areas.

・Retail companies that were formerly vertically integrated power companies are forecast to lose their customers to supplier-switching behavior (so-called "switching").

・Generation companies that were formerly vertically integrated power companies are forecast to lose their supply capacity because of the discontinuance or retirment of their aged thermal power plants.

✔Small to middle sized retail companies are likely to secure less supply capacity by itself at the same level as the previous year.

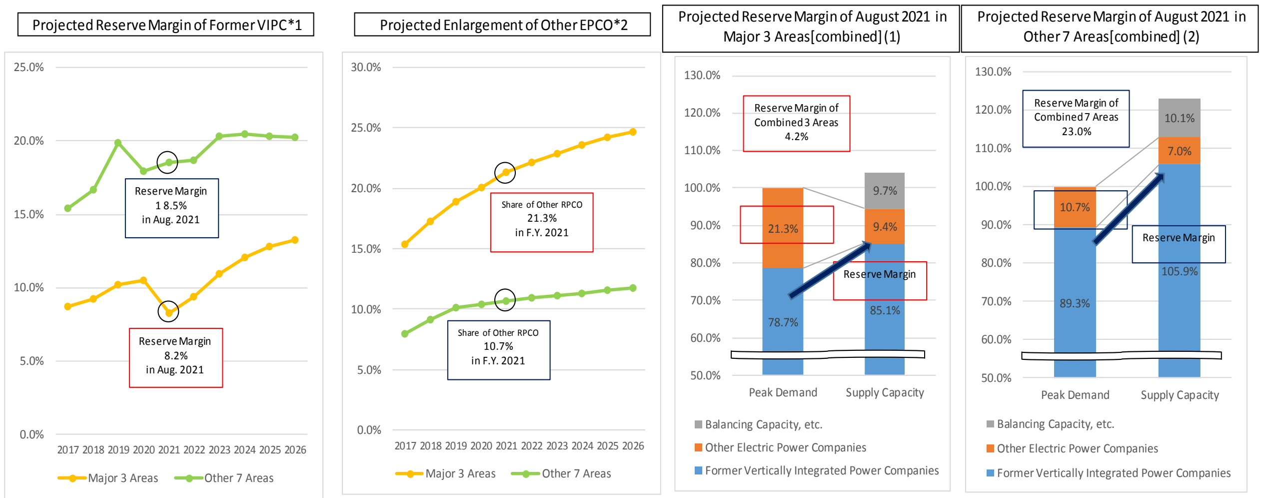
○Even in the above-stated circumstances, a stable electricity supply shall be secured by the new development of power plants as initially scheduled.

○However, in high-competition regional service areas, the reserve margins are going to be relatively lower. In the years to come, competition is likely to become fiercer and the supply-demand balance shall be tighter, which shall lead to price spikes in the electricity market. The market price is likely to stay at the higher level in case of shortfalls in power development investment, considering the leadtime of the power development.

○Thus, in the interim report of the subcommittee regarding electricity system reform, a proposal for establishing a capacity market mechanism has been published as the most effective way to secure supply or balancing capacities in the middle to long-term.

○Based on this situation, which has become clear following the aggregation of the electricity supply plans, the Organization shall steadily proceed to review the capacity market mechanism according to the above-stated interim report with more careful attention to the supply-demand balance. The Organization recommends that the Government steadily proceed to review the basic concept of the mechanism necessary for a detailed review to establish the market as scheduled in the interim report.

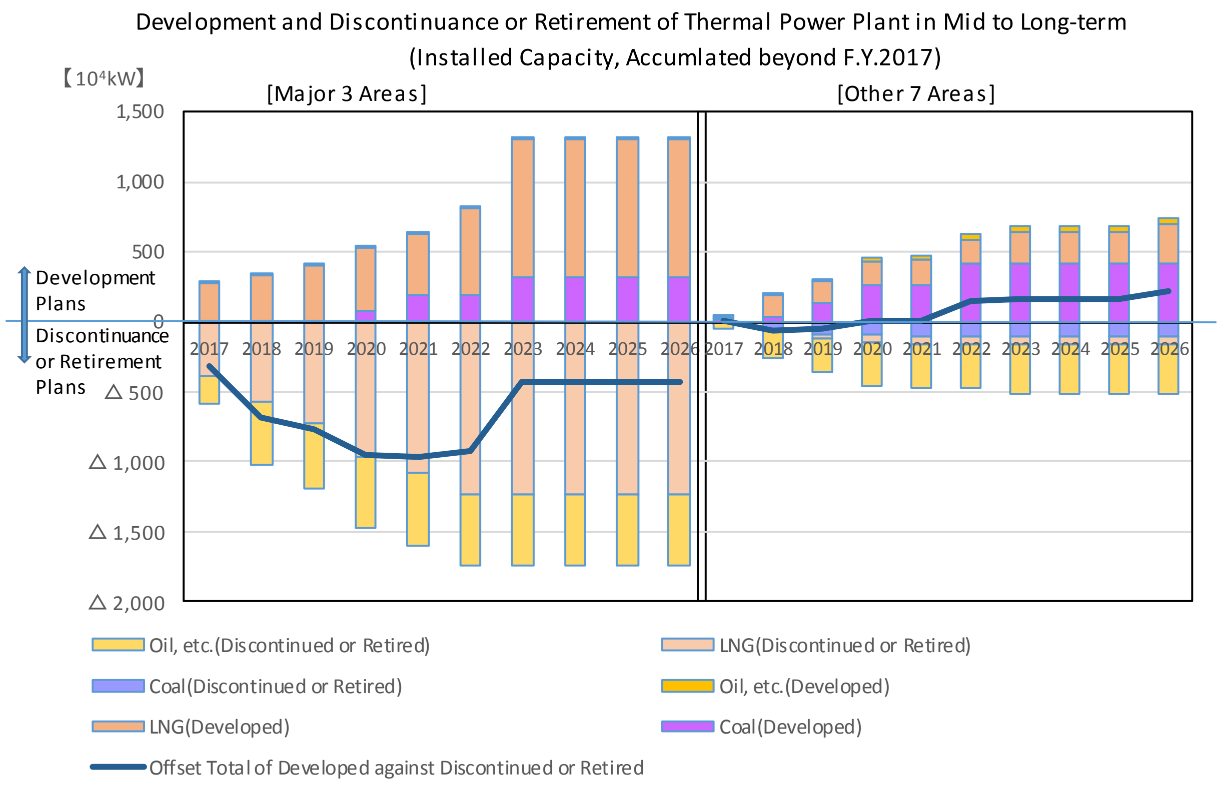
<Reference 2-1> Projected Supply-Demand Balance in the 3 Major Areas



* Note 1: Calculated as (Supply Capacity of Retail Companies + Generating Surplus)/ Peak Demand of Retail Companies
Beyond F.Y.2018, deducting projected balancing capacity.
* Note 2: Calculated as Peak Demand of Regional Service Area - Retail Peak Demand of Former Vertically Integrated Power Companies

(Note 1) Breakdown of Peak Demand and Supply Capacity according to Peak Demand of Regional Service Area as 100%
(Note 2) Balancing Capacity includes purchased power of General T/D Companies by FIT scheme.

<Reference 2-2> Development and Discontinuance or Retirement Plans in the 3 Major Areas



(Note) Oil, etc. includes Oil, LPG, Other Gas and Bituminous Mixtures

b. Measures against Avoiding the Curtailment of the Renewable Energy Output in Cross-Regional Operations

○The installed capacity of renewable energy is increasing every year; in particular, solar power shows significant increase.

○More renewable energy is forecast to be integrated into the network with accordance of output curtailment beyond 30 days as set by each regional service area. This leads to a shortage of balancing capacity for redundancy in other than isolated islands and the possibility to curtail renewable energy output.

○To avoid curtailing the output of renewable energy as much as possible, it is necessary to ensure maximum utilization of the existing transmission and distribution facilities, such as cross-regional interconnection lines, to make the most of the balancing capacity for redundancy in other areas and integrate renewable energy effectively into the network. If the output of renewable energy is significantly curtailed despite the maximum utilization of the existing transmission and distribution facilities, it shall be judged that enhancement of the network is necessary.

○Thus, the Organization recommends that the Government review the necessary mechanisms[58] of employing balancing capacity for redundancy in other areas, including the basic concept of improving transmission and distribution facilities, such as cross-regional interconnection lines, and allocate costs for improving the facilities to integrate renewable energy as much as possible.

c. An Effective Mechanism for Securing Balancing Capacity

○On the one hand, shares of LNG-fired and oil-fired thermal power plants in electric energy generation shall decrease, on the other hand, the necessity of regulating generation resources shall increase with the greater integration of solar power. Furthermore, as stated in "A More Clearly Envisaged Necessity for Introducing Capacity Mechanism Market Scheme", EPCOs are likely to defer the development schedule of new power plants or accelerate the discontinuance or retirement of aged thermal power plants under greater competition for business.

○In the above circumstance, through the aggregation of electricity supply plans, GTD companies have expressed their concerns about the insufficient securing of balancing capacity or insufficient functionality while balancing capacity for newly developed power generation sources under a progressively more competitive business environment.

[58] Mechanisms that operate the thermal power plants with the lowest load operating facility despite economic suitablility in other areas (e.g., operating an oil-fired thermal plant despite the presence of a coal-fired plant), and the basic concept of cost recovery, such as preparing the balancing capacity for redundancy by keeping an upper reservoir pond available to provide balancing capacity in times of power deficiency.

○Based on the recognition that structuring a mechanism for securing the necessary balancing capacity by GTD companies is crucial, it is necessary to set this mechanism to enable GTD companies to secure their balancing capacity economically, with the option of cross-regional procurement through the existing solicitation scheme for balancing capacity, and relaunching a capacity or real-time market.

○The Organization shall proceed with a technical review of the required quantity and quality of the balancing capacity with the scope of cross-regional operation of balancing capacity. The Organization recommends that the Government to steadily proceed to review the basic concept of the mechanism and cooperate with the Organization in the system design.

(3) Referential Review of Evaluations Implemented at Times other than Peak Demand Occurrence

The Organization has preliminarily calculated[59] the supply-demand balance at times other than peak demand occurrence, such as 17:00 and 20:00, because this challenge was recognized in the "Timing of the Evaluation of Supply and Demand" during the aggregation of the plans. As a result, the reserve margin for the Tokyo area shall be secured at the criterion of 8% by including additional supply capacity from the Tohoku and Hokkaido areas throughout the projection period except for FYs 2021 and 2022. However, FYs 2021 and 2022, the Tokyo area shall not achieve the criterion of 8% reserve margin at 17:00 in August, which is because of insufficient additional supply capacity support from the Tohoku and Hokkaido areas .

[59] The assumptions of the preliminary calculations are; 1) consider the greater integration of solar power throughout the projection period; 2) consider the forecast growth in peak demand throughout the period; 3) treat daily load curves as unchanged from FY2017; and 4) treat supply capacity other than solar power and pumped-storage hydro as unchanged with time.

<Reference 3> Reserve Margin Calculated at 17:00 in August (without additional supply capacity support)

without Additional Supply Capacity

Reserve Margin in August in Regional Service Areas(Reserve Capacity/Peak Demand)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Hokkaido	18.8%	19.0%	42.2%	42.6%	42.1%	41.4%	39.8%	38.8%	37.8%	36.9%
Tohoku	15.3%	15.8%	20.8%	20.7%	21.6%	21.4%	22.6%	22.1%	21.5%	21.2%
Tokyo	8.2%	6.5%	5.5%	5.4%	1.8%	1.9%	6.4%	11.8%	11.7%	11.2%
50Hz area Total	10.2%	9.0%	10.6%	10.5%	8.0%	8.0%	11.5%	15.5%	15.2%	14.7%
Chubu	8.4%	10.1%	6.7%	5.9%	6.1%	9.8%	9.8%	9.9%	9.8%	9.7%
Hokuriku	9.1%	11.2%	18.1%	10.9%	10.8%	10.6%	10.4%	10.1%	9.9%	9.7%
Kansai	11.0%	7.0%	8.1%	7.3%	4.1%	6.8%	9.4%	9.5%	9.7%	10.5%
Chugoku	28.4%	21.1%	19.1%	20.0%	20.1%	20.8%	27.0%	26.7%	26.2%	26.0%
Shikoku	25.2%	35.7%	24.8%	29.9%	30.0%	25.3%	26.3%	26.4%	26.5%	26.6%
Kyushu	15.3%	11.9%	15.0%	15.0%	15.7%	16.4%	16.8%	17.8%	17.9%	18.0%
60Hz area Total	13.9%	12.4%	11.9%	11.4%	10.6%	12.4%	14.1%	14.3%	14.3%	14.5%
Interconnected	12.2%	10.9%	11.3%	11.0%	9.4%	10.4%	12.9%	14.8%	14.7%	14.6%
Okinawa	47.7%	50.4%	49.4%	45.3%	44.6%	47.9%	47.8%	47.2%	45.8%	44.6%
Nationwide	12.6%	11.3%	11.7%	11.3%	9.8%	10.8%	13.3%	15.1%	15.0%	14.9%

<Reference 4> Reserve Margin Calculated at 17:00 in August (with additional supply capacity support)

with Additional Supply Capacity

Contributors to the improvement

Improved above Criteria

Reserve Margin in August in Regional Service Areas(Reserve Capacity/Peak Demand)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Hokkaido	18.8%	19.0%	42.2%	42.6%	32.6%	31.9%	39.8%	38.8%	37.8%	36.9%
Tohoku	15.3%	9.7%	10.8%	10.2%	8.0%	8.0%	16.3%	22.1%	21.5%	21.2%
Tokyo	8.2%	8.0%	8.0%	8.0%	7.8%	7.9%	8.0%	11.8%	11.7%	11.2%
50Hz area Total	10.2%	9.0%	10.6%	10.5%	9.4%	9.4%	11.5%	15.5%	15.2%	14.7%
Chubu	8.4%	10.1%	8.0%	8.0%	8.0%	8.0%	9.8%	9.9%	9.8%	9.7%
Hokuriku	9.1%	11.2%	12.4%	8.0%	8.0%	8.0%	10.4%	10.1%	9.9%	9.7%
Kansai	11.0%	8.0%	8.0%	8.0%	8.0%	8.0%	9.4%	9.5%	9.7%	10.5%
Chugoku	28.4%	18.6%	19.1%	15.0%	8.0%	13.7%	27.0%	26.7%	26.2%	26.0%
Shikoku	25.2%	35.7%	24.8%	29.9%	9.1%	25.3%	26.3%	26.4%	26.5%	26.6%
Kyushu	15.3%	11.9%	15.0%	15.0%	15.7%	16.4%	16.8%	17.8%	17.9%	18.0%
60Hz area Total	13.9%	12.4%	11.9%	11.4%	9.4%	11.2%	14.1%	14.3%	14.3%	14.5%
Interconnected	12.2%	10.9%	11.3%	11.0%	9.4%	10.4%	12.9%	14.8%	14.7%	14.6%
Okinawa	47.7%	50.4%	49.4%	45.3%	44.6%	47.9%	47.8%	47.2%	45.8%	44.6%
Nationwide	12.6%	11.3%	11.7%	11.3%	9.8%	10.8%	13.3%	15.1%	15.0%	14.9%

<Reference 5> Reserve Margin Calculated at 20:00 in August (without additional supply capacity support)

without Additional Supply Capacity

Reserve Margin in August in Regional Service Areas(Reserve Capacity/Peak Demand)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Hokkaido	20.5%	20.6%	44.0%	44.4%	43.8%	43.1%	41.5%	40.5%	39.4%	38.5%
Tohoku	25.6%	25.7%	30.9%	30.4%	31.2%	30.7%	31.7%	30.9%	30.0%	29.4%
Tokyo	8.9%	7.1%	6.0%	5.9%	1.9%	2.1%	7.0%	12.9%	12.8%	12.2%
50Hz area Total	12.8%	11.4%	13.1%	12.9%	10.1%	10.1%	13.9%	18.1%	17.8%	17.1%
Chubu	9.5%	11.5%	7.6%	6.7%	6.9%	11.1%	11.1%	11.1%	11.1%	11.0%
Hokuriku	21.8%	24.0%	31.4%	23.2%	23.0%	22.8%	22.5%	22.1%	21.8%	21.5%
Kansai	17.1%	12.4%	13.5%	12.4%	8.8%	11.7%	14.6%	14.7%	14.9%	15.7%
Chugoku	28.4%	21.1%	19.1%	20.0%	20.1%	20.8%	27.0%	26.7%	26.2%	26.0%
Shikoku	25.2%	35.7%	24.8%	29.9%	30.0%	25.3%	26.3%	26.4%	26.5%	26.6%
Kyushu	10.6%	5.8%	7.9%	7.0%	6.8%	6.7%	6.6%	7.5%	7.4%	7.4%
60Hz area Total	15.9%	14.0%	13.1%	12.4%	11.3%	13.1%	14.8%	15.0%	14.9%	15.1%
Interconnected	14.5%	12.8%	13.1%	12.6%	10.8%	11.7%	14.4%	16.4%	16.2%	16.0%
Okinawa	45.6%	48.1%	47.0%	42.6%	41.8%	44.9%	44.7%	44.0%	42.7%	41.5%
Nationwide	14.8%	13.1%	13.5%	12.9%	11.1%	12.1%	14.7%	16.7%	16.5%	16.3%

<Reference 6> Reserve Margin Calculated at 20:00 in August (with additional supply capacity support)

with Additional Supply Capacity

Contributors to the improvement

Improved above Criteria

Reserve Margin in August in Regional Service Areas(Reserve Capacity/Peak Demand)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Hokkaido	20.5%	20.6%	44.0%	44.4%	43.8%	43.1%	41.5%	40.5%	39.4%	38.5%
Tohoku	25.6%	22.0%	22.8%	21.9%	9.2%	8.4%	27.7%	30.9%	30.0%	29.4%
Tokyo	8.9%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	12.9%	12.8%	12.2%
50Hz area Total	12.8%	11.4%	13.1%	12.9%	10.6%	10.4%	13.9%	18.1%	17.8%	17.1%
Chubu	9.5%	11.5%	8.0%	8.0%	8.0%	10.1%	11.1%	11.1%	11.1%	11.0%
Hokuriku	21.8%	24.0%	31.4%	23.2%	14.4%	22.8%	22.5%	22.1%	21.8%	21.5%
Kansai	17.1%	12.4%	13.1%	11.2%	8.0%	11.7%	14.6%	14.7%	14.9%	15.7%
Chugoku	28.4%	17.7%	18.8%	18.4%	18.3%	18.9%	25.0%	25.9%	25.3%	25.1%
Shikoku	25.2%	35.7%	24.8%	29.9%	30.0%	25.3%	26.3%	26.4%	26.5%	26.6%
Kyushu	10.6%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%
60Hz area Total	15.9%	14.0%	13.1%	12.4%	10.9%	12.9%	14.8%	15.0%	14.9%	15.1%
Interconnected	14.5%	12.8%	13.1%	12.6%	10.8%	11.7%	14.4%	16.4%	16.2%	16.0%
Okinawa	45.6%	48.1%	47.0%	42.6%	41.8%	44.9%	44.7%	44.0%	42.7%	41.5%
Nationwide	14.8%	13.1%	13.5%	12.9%	11.1%	12.1%	14.7%	16.7%	16.5%	16.3%

Attached are the Appendices according to the aggregation of the electricity supply plans.

APPENDIX 1　Supply-Demand Balance for FY 2017

Tables A1-1 to A1-4 show the monthly peak demand, monthly supply capcity, monthly reserve capacity and reserve margin for each regional service area in FY 2017, respectively. Tables A1-5 and A1-6 show the monthly projection of power exchange and the monthly projection of reserve margin for each regional service area recalculated with power exchange to the area of below 8% reserve margin from the areas of over 8% reserve margin, respectively.

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	413	376	371	406	426	426	419	460	502	502	502	465
Tohoku	1,069	990	1,070	1,270	1,299	1,186	1,054	1,180	1,298	1,341	1,334	1,242
Tokyo	3,853	3,643	4,073	5,253	5,253	4,528	3,721	4,057	4,438	4,715	4,715	4,323
50Hz areas Total	5,335	5,009	5,514	6,929	6,978	6,140	5,194	5,697	6,238	6,558	6,551	6,030
Chubu	1,842	1,849	2,011	2,429	2,429	2,215	1,974	1,922	2,163	2,260	2,260	2,095
Hokuriku	398	370	413	498	498	463	380	420	467	490	490	464
Kansai	1,923	1,866	2,138	2,548	2,548	2,330	1,847	1,951	2,163	2,321	2,321	2,076
Chugoku	772	757	858	1,045	1,045	924	769	837	932	985	985	892
Shikoku	356	352	401	502	502	439	355	375	458	458	458	408
Kyushu	1,065	1,082	1,212	1,511	1,511	1,358	1,159	1,174	1,381	1,443	1,443	1,269
60Hz areas Total	6,356	6,276	7,033	8,533	8,533	7,729	6,484	6,679	7,564	7,957	7,957	7,204
Interconnected	11,691	11,285	12,547	15,462	15,511	13,869	11,678	12,376	13,802	14,515	14,508	13,234
Okinawa	103	121	139	145	145	139	124	110	100	104	103	99
Nationwide	11,794	11,406	12,686	15,607	15,656	14,008	11,802	12,485	13,902	14,618	14,610	13,332

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	485	491	500	504	510	494	523	550	598	587	585	565
Tohoku	1,214	1,184	1,277	1,492	1,520	1,340	1,262	1,349	1,466	1,583	1,594	1,398
Tokyo	4,708	4,576	4,978	5,620	5,672	5,250	4,827	4,959	5,379	5,532	5,329	5,178
50Hz areas Total	6,407	6,252	6,756	7,615	7,702	7,084	6,612	6,857	7,444	7,703	7,508	7,141
Chubu	2,065	2,066	2,377	2,659	2,627	2,655	2,266	2,194	2,329	2,436	2,394	2,259
Hokuriku	436	452	448	589	543	509	421	460	505	534	538	517
Kansai	2,467	2,428	2,487	2,894	2,889	2,724	2,429	2,496	2,667	2,764	2,747	2,641
Chugoku	1,044	993	1,092	1,347	1,342	1,202	1,002	1,037	1,133	1,186	1,181	1,114
Shikoku	511	550	537	644	629	576	447	439	509	532	596	561
Kyushu	1,274	1,348	1,533	1,766	1,742	1,606	1,355	1,406	1,500	1,593	1,582	1,448
60Hz areas Total	7,796	7,837	8,473	9,900	9,772	9,272	7,919	8,033	8,642	9,045	9,038	8,540
Interconnected	14,203	14,089	15,229	17,515	17,474	16,355	14,531	14,890	16,086	16,748	16,546	15,681
Okinawa	164	180	210	212	218	215	193	174	163	162	174	180
Nationwide	14,368	14,269	15,439	17,727	17,692	16,570	14,724	15,064	16,249	16,910	16,720	15,861

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	72	115	129	98	84	68	104	90	96	85	83	100
Tohoku	145	194	207	222	221	154	208	169	168	242	260	156
Tokyo	855	933	905	367	419	722	1,106	902	941	817	614	855
50Hz areas Total	1,072	1,243	1,242	686	724	944	1,418	1,160	1,206	1,145	957	1,111
Chubu	223	217	366	230	198	440	292	272	166	176	134	164
Hokuriku	38	82	35	91	45	46	41	40	38	45	49	53
Kansai	544	562	349	346	341	394	582	545	504	443	426	565
Chugoku	272	236	234	302	297	278	233	200	201	201	196	222
Shikoku	155	198	136	142	127	137	92	64	51	74	138	153
Kyushu	209	266	321	255	231	248	196	232	119	150	139	179
60Hz areas Total	1,440	1,561	1,440	1,367	1,239	1,543	1,435	1,355	1,078	1,088	1,081	1,336
Interconnected	2,512	2,804	2,682	2,053	1,963	2,486	2,854	2,515	2,284	2,233	2,038	2,447
Okinawa	61	59	71	67	73	76	69	64	62	59	71	81
Nationwide	2,573	2,863	2,753	2,121	2,036	2,562	2,922	2,579	2,346	2,292	2,110	2,528

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

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	17.4%	30.7%	34.9%	24.0%	19.7%	16.0%	24.7%	19.5%	19.2%	17.0%	16.6%	21.6%
Tohoku	13.6%	19.6%	19.4%	17.5%	17.0%	13.0%	19.8%	14.3%	13.0%	18.1%	19.5%	12.6%
Tokyo	22.2%	25.6%	22.2%	7.0%	8.0%	15.9%	29.7%	22.2%	21.2%	17.3%	13.0%	19.8%
50Hz areas Total	20.1%	24.8%	22.5%	9.9%	10.4%	15.4%	27.3%	20.4%	19.3%	17.5%	14.6%	18.4%
Chubu	12.1%	11.7%	18.2%	9.5%	8.2%	19.8%	14.8%	14.2%	7.7%	7.8%	5.9%	7.8%
Hokuriku	9.4%	22.2%	8.5%	18.4%	9.1%	10.0%	10.8%	9.6%	8.2%	9.1%	9.9%	11.5%
Kansai	28.3%	30.1%	16.3%	13.6%	13.4%	16.9%	31.5%	28.0%	23.3%	19.1%	18.4%	27.2%
Chugoku	35.2%	31.2%	27.2%	28.9%	28.4%	30.0%	30.2%	23.9%	21.5%	20.4%	19.9%	24.9%
Shikoku	43.4%	56.1%	34.0%	28.4%	25.2%	31.1%	26.0%	17.1%	11.1%	16.2%	30.1%	37.5%
Kyushu	19.6%	24.6%	26.5%	16.9%	15.3%	18.3%	16.9%	19.8%	8.6%	10.4%	9.6%	14.1%
60Hz areas Total	22.7%	24.9%	20.5%	16.0%	14.5%	20.0%	22.1%	20.3%	14.3%	13.7%	13.6%	18.6%
Interconnected	21.5%	24.8%	21.4%	13.3%	12.7%	17.9%	24.4%	20.3%	16.5%	15.4%	14.1%	18.5%
Okinawa	59.0%	49.3%	51.2%	46.5%	50.4%	54.6%	55.4%	58.2%	61.9%	56.4%	69.2%	81.9%
Nationwide	21.8%	25.1%	21.7%	13.6%	13.0%	18.3%	24.8%	20.7%	16.9%	15.7%	14.4%	19.0%

Below Criteria of 8%

Note: Reserve Margin in Tokyo EPCO regional service area in August is rounded up to 8.0%.

Table A1-5 Monthly Projection of Power Exchange for Each Regional Service Area

【10^4kW】

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	0	0	0	0	0	0	0	0	0	0	0	0
Tohoku	0	0	0	-53	-1	0	0	0	0	0	0	0
Tokyo	0	0	0	53	1	0	0	0	0	0	0	0
50Hz area Total	0	0	0	0	0	0	0	0	0	0	0	0
Chubu	0	0	0	0	0	0	0	0	7	4	47	3
Hokuriku	0	0	0	0	0	0	0	0	0	0	0	0
Kansai	0	0	0	0	0	0	0	0	-7	-4	-47	-3
Chugoku	0	0	0	0	0	0	0	0	0	0	0	0
Shikoku	0	0	0	0	0	0	0	0	0	0	0	0
Kyushu	0	0	0	0	0	0	0	0	0	0	0	0
60Hz area Total	0	0	0	0	0	0	0	0	0	0	0	0
Interconnected	0	0	0	0	0	0	0	0	0	0	0	0
Okinawa	0	0	0	0	0	0	0	0	0	0	0	0
Nationwide	0	0	0	0	0	0	0	0	0	0	0	0

Power Received as additional supply capacity

Power Sent as additional supply capacity

Table A1-6 Monthly Projection of Reserve Margin for Each Regional Service Area
(With power exchange through cross-regional interconnection lines, at the sending-end)(Aforementioned Table 2-4)

	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	30.7%	34.9%	24.0%	19.7%	16.0%	24.7%	19.5%	19.2%	17.0%	16.6%	21.6%
Tohoku	19.6%	19.4%	13.3%	16.9%	13.0%	19.8%	14.3%	13.0%	18.1%	19.5%	12.6%
Tokyo	25.6%	22.2%	8.0%	8.0%	15.9%	29.7%	22.2%	21.2%	17.3%	13.0%	19.8%
50Hz area Total	24.8%	22.5%	9.9%	10.4%	15.4%	27.3%	20.4%	19.3%	17.5%	14.6%	18.4%
Chubu	11.7%	18.2%	9.5%	8.2%	19.8%	14.8%	14.2%	8.0%	8.0%	8.0%	8.0%
Hokuriku	22.2%	8.5%	18.4%	9.1%	10.0%	10.8%	9.6%	8.2%	9.1%	9.9%	11.5%
Kansai	30.1%	16.3%	13.6%	13.4%	16.9%	31.5%	28.0%	23.0%	18.9%	16.3%	27.1%
Chugoku	31.2%	27.2%	28.9%	28.4%	30.0%	30.2%	23.9%	21.5%	20.4%	19.9%	24.9%
Shikoku	56.1%	34.0%	28.4%	25.2%	31.1%	26.0%	17.1%	11.1%	16.2%	30.1%	37.5%
Kyushu	24.6%	26.5%	16.9%	15.3%	18.3%	16.9%	19.8%	8.6%	10.4%	9.6%	14.1%
60Hz area Total	24.9%	20.5%	16.0%	14.5%	20.0%	22.1%	20.3%	14.3%	13.7%	13.6%	18.6%
Interconnected	24.8%	21.4%	13.3%	12.7%	17.9%	24.4%	20.3%	16.5%	15.4%	14.1%	18.5%
Okinawa	49.3%	51.2%	46.5%	50.4%	54.6%	55.4%	58.2%	61.9%	56.4%	69.2%	81.9%
Nationwide	25.1%	21.7%	13.6%	13.0%	18.3%	24.8%	20.7%	16.9%	15.7%	14.4%	19.0%

Improved to above Criteria of 8%

Contributors to improvement

APPENDIX 2　Supply-Demand Balance for 10 Years (Long-term)

Tables A2-1 to A2-4 show a 10-year projection of the annual peak demand, annual supply capcity, annual reserve capacity, and reserve margin for each regional service area from FY 2017 to FY 2026, respectively. Tables A2-5 and A2-6 show the annual projection for the power exchange and annual projection of reserve margin for each regional service area recalculated with the power exchanges from areas of over 8% reserve margin to the areas of below 8% reserve margin, respectively.

Tables A2-7 to A2-10 show a 10-year projection of the annual peak demand, annual supply capcity, 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 (in August)

【10^4kW】

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Hokkaido	426	428	430	433	436	439	443	446	449	452
Tohoku	1,299	1,303	1,312	1,321	1,330	1,339	1,348	1,357	1,366	1,375
Tokyo	5,253	5,328	5,347	5,366	5,382	5,399	5,413	5,427	5,442	5,455
50Hz areas Total	6,978	7,059	7,089	7,120	7,148	7,177	7,204	7,230	7,257	7,282
Chubu	2,429	2,442	2,445	2,449	2,452	2,456	2,460	2,463	2,466	2,469
Hokuriku	498	499	504	505	506	507	508	509	510	511
Kansai	2,548	2,531	2,529	2,526	2,524	2,522	2,519	2,517	2,514	2,512
Chugoku	1,045	1,046	1,055	1,059	1,064	1,070	1,075	1,080	1,086	1,090
Shikoku	502	503	504	504	503	503	502	502	502	502
Kyushu	1,511	1,512	1,512	1,513	1,513	1,514	1,514	1,514	1,515	1,515
60Hz areas Total	8,533	8,533	8,549	8,556	8,562	8,572	8,578	8,585	8,593	8,599
Interconnected	15,511	15,592	15,638	15,676	15,710	15,749	15,782	15,815	15,850	15,881
Okinawa	145	145	146	147	147	148	149	149	150	150
Nationwide	15,656	15,737	15,784	15,822	15,857	15,896	15,930	15,964	16,000	16,031

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

【10^4kW】

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Hokkaido	510	515	618	625	627	628	627	627	626	626
Tohoku	1,520	1,542	1,626	1,640	1,669	1,683	1,714	1,725	1,733	1,745
Tokyo	5,672	5,666	5,636	5,650	5,474	5,498	5,754	6,054	6,067	6,050
50Hz areas Total	7,702	7,723	7,880	7,915	7,770	7,809	8,095	8,406	8,427	8,421
Chubu	2,627	2,683	2,605	2,590	2,598	2,690	2,696	2,699	2,702	2,703
Hokuriku	543	557	599	565	566	567	567	567	567	567
Kansai	2,889	2,780	2,817	2,802	2,720	2,787	2,852	2,856	2,860	2,879
Chugoku	1,342	1,267	1,256	1,271	1,278	1,293	1,365	1,369	1,370	1,373
Shikoku	629	683	629	655	654	630	634	635	635	636
Kyushu	1,742	1,692	1,740	1,740	1,750	1,762	1,768	1,783	1,786	1,788
60Hz areas Total	9,772	9,661	9,644	9,622	9,566	9,729	9,883	9,908	9,919	9,946
Interconnected	17,474	17,385	17,524	17,537	17,336	17,538	17,977	18,314	18,346	18,367
Okinawa	218	223	223	218	219	225	226	226	225	224
Nationwide	17,692	17,608	17,747	17,755	17,555	17,763	18,204	18,540	18,571	18,591

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

【10^4kW】

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Hokkaido	84	87	188	192	191	189	184	181	177	174
Tohoku	221	239	314	319	339	344	366	368	367	370
Tokyo	419	338	289	284	92	99	341	627	625	595
50Hz areas Total	724	664	791	795	622	632	891	1,176	1,170	1,139
Chubu	198	241	160	141	146	234	236	236	236	234
Hokuriku	45	58	95	60	61	60	59	58	57	56
Kansai	341	249	288	276	196	265	333	339	346	367
Chugoku	297	221	201	212	214	223	290	289	284	283
Shikoku	127	180	125	151	151	127	132	133	133	134
Kyushu	231	180	228	227	237	248	254	269	271	273
60Hz areas Total	1,239	1,128	1,095	1,066	1,005	1,157	1,305	1,323	1,326	1,347
Interconnected	1,963	1,793	1,886	1,861	1,627	1,789	2,196	2,499	2,496	2,486
Okinawa	73	78	77	72	72	77	78	77	75	74
Nationwide	2,036	1,870	1,963	1,933	1,698	1,866	2,274	2,576	2,571	2,560

Table A2-4 Annual Projection of Reserve Margin for Each Regional Service Area from FY 2017 to FY 2026 (Resource within own service area only, in August, at the sending-end)(Aforementioned Table 2-7)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Hokkaido	19.7%	20.3%	43.8%	44.3%	43.7%	43.0%	41.5%	40.5%	39.5%	38.6%
Tohoku	17.0%	18.4%	23.9%	24.2%	25.5%	25.7%	27.2%	27.1%	26.9%	26.9%
Tokyo	8.0%	6.3%	5.4%	5.3%	1.7%	1.8%	6.3%	11.6%	11.5%	10.9%
50Hz areas Total	10.4%	9.4%	11.2%	11.2%	8.7%	8.8%	12.4%	16.3%	16.1%	15.6%
Chubu	8.2%	9.9%	6.5%	5.8%	6.0%	9.5%	9.6%	9.6%	9.6%	9.5%
Hokuriku	9.1%	11.6%	18.8%	12.0%	12.0%	11.9%	11.7%	11.4%	11.2%	11.0%
Kansai	13.4%	9.8%	11.4%	10.9%	7.8%	10.5%	13.2%	13.5%	13.8%	14.6%
Chugoku	28.4%	21.1%	19.1%	20.0%	20.1%	20.8%	27.0%	26.7%	26.2%	26.0%
Shikoku	25.2%	35.7%	24.8%	29.9%	30.0%	25.3%	26.3%	26.4%	26.5%	26.6%
Kyushu	15.3%	11.9%	15.0%	15.0%	15.7%	16.4%	16.8%	17.8%	17.9%	18.0%
60Hz areas Total	14.5%	13.2%	12.8%	12.5%	11.7%	13.5%	15.2%	15.4%	15.4%	15.7%
Interconnected	12.7%	11.5%	12.1%	11.9%	10.4%	11.4%	13.9%	15.8%	15.7%	15.7%
Okinawa	50.4%	53.5%	52.9%	49.0%	48.7%	52.2%	52.4%	51.8%	50.4%	49.1%
Nationwide	13.0%	11.9%	12.4%	12.2%	10.7%	11.7%	14.3%	16.1%	16.1%	16.0%

Below Criteria of 8%

Note: The reserve margin in the Tokyo EPCO regional service area in FY 2017 was rounded up to 8.0%.

Table A2-5 Annual Projection of Power Exchanges for Each Regional Service Area

【10^4kW】

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Hokkaido	0	0	0	0	-28	-30	0	0	0	0
Tohoku	-1	-88	-139	-145	-233	-236	-92	0	0	0
Tokyo	1	88	139	145	338	333	92	0	0	0
50Hz area Total	0	0	0	0	77	66	0	0	0	0
Chubu	0	0	36	55	50	-38	0	0	0	0
Hokuriku	0	0	0	0	-20	0	0	0	0	0
Kansai	0	0	-36	-55	6	-29	0	0	0	0
Chugoku	0	0	0	0	-113	0	0	0	0	0
Shikoku	0	0	0	0	0	0	0	0	0	0
Kyushu	0	0	0	0	0	0	0	0	0	0
60Hz area Total	0	0	0	0	-77	-66	0	0	0	0
Interconnected	0	0	0	0	0	0	0	0	0	0
Okinawa	0	0	0	0	0	0	0	0	0	0
Nationwide	0	0	0	0	0	0	0	0	0	0

Power Received as additional supply capacity

Power Sent as additional supply capacity

Table A2-6 Annual Projection of Reserve Margin for Each Regional Service Area
(With power exchanges through cross-regionalinterconnection lines, at the sending-end)(Aforementioned Table 2-8)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Hokkaido	19.7%	20.3%	43.8%	44.3%	37.2%	36.3%	41.5%	40.5%	39.5%	38.6%
Tohoku	16.9%	11.6%	13.3%	13.2%	8.0%	8.0%	20.3%	27.1%	26.9%	26.9%
Tokyo	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	11.6%	11.5%	10.9%
50Hz area Total	10.4%	9.4%	11.2%	11.2%	9.8%	9.7%	12.4%	16.3%	16.1%	15.6%
Chubu	8.2%	9.9%	8.0%	8.0%	8.0%	8.0%	9.6%	9.6%	9.6%	9.5%
Hokuriku	9.1%	11.6%	18.8%	12.0%	8.0%	11.9%	11.7%	11.4%	11.2%	11.0%
Kansai	13.4%	9.8%	10.0%	8.7%	8.0%	9.4%	13.2%	13.5%	13.8%	14.6%
Chugoku	28.4%	21.1%	19.1%	20.0%	9.4%	20.8%	27.0%	26.7%	26.2%	26.0%
Shikoku	25.2%	35.7%	24.8%	29.9%	30.0%	25.3%	26.3%	26.4%	26.5%	26.6%
Kyushu	15.3%	11.9%	15.0%	15.0%	15.7%	16.4%	16.8%	17.8%	17.9%	18.0%
60Hz area Total	14.5%	13.2%	12.8%	12.5%	10.8%	12.7%	15.2%	15.4%	15.4%	15.7%
Interconnected	12.7%	11.5%	12.1%	11.9%	10.4%	11.4%	13.9%	15.8%	15.7%	15.7%
Okinawa	50.4%	53.5%	52.9%	49.0%	48.7%	52.2%	52.4%	51.8%	50.4%	49.1%
Nationwide	13.0%	11.9%	12.4%	12.2%	10.7%	11.7%	14.3%	16.1%	16.1%	16.0%

Improved to above Criteria of 8%

Contributors to improvement

Table A2-7 Annual Peak Demand Forecast for Winter Peak Areas of Hokkaido and Tohoku (in January)

【10^4kW】

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Hokkaido	502	504	505	508	512	515	518	521	525	528
Tohoku	1,341	1,345	1,361	1,377	1,393	1,409	1,425	1,441	1,457	1,472

Table A2-8 Annual projection of Supply Capacity for Winter Peak areas of Hokkaido and Tohoku (in January)

【10^4kW】

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Hokkaido	587	612	608	619	617	617	617	618	617	668
Tohoku	1,583	1,563	1,599	1,606	1,629	1,636	1,664	1,667	1,671	1,677

Table A2-9 Annual projection of Reserve Capacity for Winter Peak areas of Hokkaido and Tohoku (in January)

【10^4kW】

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Hokkaido	85	108	103	111	105	102	99	97	92	140
Tohoku	242	218	238	229	236	227	239	226	214	205

Table A2-10 Annual projection of Reserve Margin for Winter Peak Areas of Hokkaido and Tohoku(Aforementioned Table 2-10)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Hokkaido	17.0%	21.3%	20.4%	21.8%	20.4%	19.8%	19.2%	18.5%	17.4%	26.6%
Tohoku	18.1%	16.2%	17.5%	16.6%	16.9%	16.1%	16.8%	15.7%	14.7%	13.9%

March 30, 2017

Organization for Cross-regional Coordination of Transmission Operators, Japan

Opinions for the Minister of Economy, Trade and Industry on the Aggregation of the Electricity Supply Plan

On the aggregation of the electricity supply plan, the Organizaition sent the results and opinions stated below to the Minister of Economy, Trade and Industry according to paragraph 2 of Article 29 of the Electricity Business Act .

1. A More Clearly Envisaged Necessity for Introducing a Capacity Mechanism Market Scheme

The Tokyo, Chubu, and the Kansai EPCO regional service areas (the 3 major areas) have significant electricity demands and are particularly competitive areas. In the supply-demand balance without power exchange, their reserve margins will be below the reserve margin criterion of 8% in these areas. The Organization investigated this factor and identified the followings.

(1) In the 3 Major Areas.

- Retail companies that were formerly vertically integrated power companies are forecast to lose their customers to supplier-switching behavior (so-called "switching").
- Generation companies that were formerly vertically integrated power companies are forecast to lose their supply capacity because of the discontinuance or retirment of their aged thermal power plants.

(2) Small to middle sized retail companies are likely to secure less supply capacity by itself at the same level as the previous year.

Even in the above-stated circumstances, a stable electricity supply shall be secured by the new development of power plants as initially scheduled.

However, in high-competition regional service areas, the reserve margins are going to be relatively lower. In the years to come, competition is likely to become fiercer and the supply-demand balance shall be tighter, which shall lead to price spikes in the electricity market. The market price is likely to stay at the higher level in case of shortfalls in power development investment, considering the leadtime of the power development.

Thus, in the interim report of the subcommittee regarding electricity system reform, a proposal for establishing a capacity market mechanism has been published as the most effective way to secure supply or balancing capacities in the middle to long-term.

Based on this situation, which has become clear following the aggregation of the electricity supply plans, the Organization shall steadily proceed to review the capacity market mechanism according to the above-stated interim report with more careful attention to the supply-demand balance. The Organization recommends that the Government steadily proceed to review the basic concept of the mechanism necessary for a detailed review to establish the market as scheduled in the interim report.

2. Measures against Avoiding the Curtailment of the Renewable Energy Output in Cross-Regional Operations

The installed capacity of renewable energy is increasing every year; in particular, solar power shows significant increase.

More renewable energy is forecast to be integrated into the network with accordance of output curtailment beyond 30 days as set by each regional service area. This leads to a shortage of balancing capacity for redundancy in other than isolated islands and the possibility to curtail renewable energy output.

To avoid curtailing the output of renewable energy as much as possible, it is necessary to ensure maximum utilization of the existing transmission and distribution facilities, such as cross-regional interconnection lines, to make the most of the balancing capacity for redundancy in other areas and integrate renewable energy effectively into the network. If the output of renewable energy is significantly curtailed despite the maximum utilization of the existing transmission and distribution facilities, it shall be judged that enhancement of the network is necessary.

Thus, the Organization recommends that the Government review the necessary mechanisms of employing balancing capacity for redundancy in other areas, including the basic concept of improving transmission and distribution facilities, such as cross-regional interconnection lines, and allocate costs for improving the facilities to integrate renewable energy as much as possible.

3. An Effective Mechanism for Securing Balancing Capacity

On the one hand, shares of LNG-fired and oil-fired thermal power plants in electric energy generation shall decrease, on the other hand, the necessity of regulating generation resources shall increase with the greater integration of solar power. Furthermore, as stated in “A More Clearly Envisaged Necessity for Introducing Capacity Mechanism Market Scheme”, EPCOs are likely to defer the development schedule of new power plants or accelerate the discontinuance or retirement of aged thermal power plants under greater competition for business.

In the above circumstance, through the aggregation of electricity supply plans, GTD companies have expressed their concerns about the insufficient securing of balancing capacity or insufficient functionality while balancing capacity for newly developed power generation sources under a progressively more competitive business environment.

Based on the recognition that structuring a mechanism for securing the necessary balancing capacity by GTD companies is crucial, it is necessary to set this mechanism to enable GTD companies to secure their balancing capacity economically, with the option of cross-regional procurement through the existing solicitation scheme for balancing capacity, and relaunching a capacity or real-time market.

The Organization shall proceed with a technical review of the required quantity and quality of the balancing capacity with the scope of cross-regional operation of balancing capacity. The Organization recommends that the Government to steadily proceed to review the basic concept of the mechanism and cooperate with the Organization in the system design.