# Feasibility Study for Low-Carbon Grid with Renewables in Japan

Shuichi Ashina and Junichi Fujino

National Institute for Environmental Studies
Onogawa 16-2, Tsukuba, Ibaraki, JAPAN 305-8506
Tel: +81-29-850-2227
Fax: +81-29-850-2422
E-mail: ashina.shuichi@nies.go.jp

## Abstract

This study identifies future visions for Japan's electricity sector in the year 2050 under three different conditions: (1) maximizing on-grid renewables potentials, (2) minimizing annual generation cost and (3) minimizing $CO_2$ emissions, based on quantitative evaluation using a multi-regional generation planning model which has been developed to model both the distribution of electricity demands and location of power plants. The results show that coal-fired power plants will play a key role in order to strengthen on-grid renewable potentials. In contrast, both least-cost operation and low-carbon electricity will come from the shift of fuel to natural gas. If electric utilities take a scenario for maximizing on-grid renewables potentials, the annual generation of on-grid renewables reaches 181.3 TWh, which corresponds to 14% of total generation of the electricity sector, however, the annual generation cost is 57% higher than the least-cost scenario and CO2 emissions are eight times those of the CO2 reduction scenario.

## 1. Introduction

Based on past reports (Ministry of Economy Trade and Industry, 2004), on-grid potentials of renewables in Japan are constrained by the following factors: (1) the capabilities of the power generators to absorb fluctuations both in frequency and voltage, (2) the thermal capacity of transmission lines and bank capacity of substations, and (3) stability of transmission system. The key to enhancing installation of renewables into grid is to relax the constraint condition (1). Utilities meets fluctuations by on-grid renewables by means of three types of control measures depending on the fluctuation cycle, including (a) governor-fee control (short-period region, with a cycle ranging from 2 to 3 minutes), (b) load frequency control, LFC (intermediate-period region, with a cycle ranging from a few minutes to 20minutes) and (c) economic-load dispatching control, EDC (long-period region, with a cycle ranging over 20 minutes). Among them, the on-grid potentials of renewables are mainly affected by the capacity of LFC to absorb output fluctuations (LFC capability).

So far, quantitative analyses have been performed on the methods to control fluctuations in frequency and voltage caused by grid-interconnection of solar and wind power generation as well as their effect on increasing the potential(Kubota and Genji, 2006; Matsuda et al., 2006; Murakami et al., 2006). However, the capacity of grid electricity to incorporate renewable energies was assumed to be constant in many of these studies. Few studies have been performed on the future direction of the electricity sector to investigate the effects of changes in configurations of power sources and power plant operation from the viewpoint of increased grid-interconnection.

Using a non-linear optimization model(Ashina and Fujino, 2007) that can take into account each region’s electricity demand and configuration of power plants, we quantitatively analyzed the power plant configuration and operation that can maximize grid-interconnection of renewable energies for Japan’s electricity sector in 2050. Based on the results, we then determined the possibility of achieving all of the following three goals: (1) increased on-grid renewables, (2) high economic efficiency of power plant operation and (3) $CO_2$ emissions reduction in the electricity sector. Specifically, we quantitatively analyzed power plant configuration, power generation configuration, $CO_2$ emissions reduction and on-grid potential of renewables by setting each of renewables potential maximization, cost minimization and $CO_2$ minimization as the objective function of an optimization model. Based on the analysis results, we then qualitatively investigated a possible system and its implementation scenario for supplying low-carbon electricity generated from renewable energies in the future.

## 2. Overview of quantitative analysis of on-grid potential of renewables

### 2.1 The multi-regional optimum generation planning model

Through assessing hourly operation of generators for each electricity utility using the multi-regional optimum generation planning model(Ashina and Fujino, 2007; Ashina and Nakata, 2005), and based on installed capacities and power output, potential of on-grid renewable is calculated endogenously by the time of day, season and region.

Figure 1 shows the configuration of the model. In this model, Japan was divided by prefecture into 60 regions. In each region, a single demand node representing electricity demand in that region and multiple power generation nodes representing power plants were established. The demand node was placed at the location of the prefectural government office, and the power generation nodes were established in accordance with the actual locations of power source centers. Between the demand nodes in adjacent regions, hypothetical power transmission lines based on the actual power transmission network (Ministry of Economy Trade and Industry, 2006a) were established. For example, in Miyagi Prefecture shown in the figure, the demand node was placed at the city of Sendai, where the prefectural government office is located, and this location was connected by power transmission lines to the demand nodes in Iwate, Akita, Yamagata and Fukushima Prefectures. Power generation nodes were placed at two locations, Onagawa-cho (nuclear power plant) and the city of Tagajo (coal-fired boiler, oil-fired boiler, gas-fired boiler). One additional power generation node representing conventional hydropower plants and pumped hydropower plants was placed in a mountainous region.

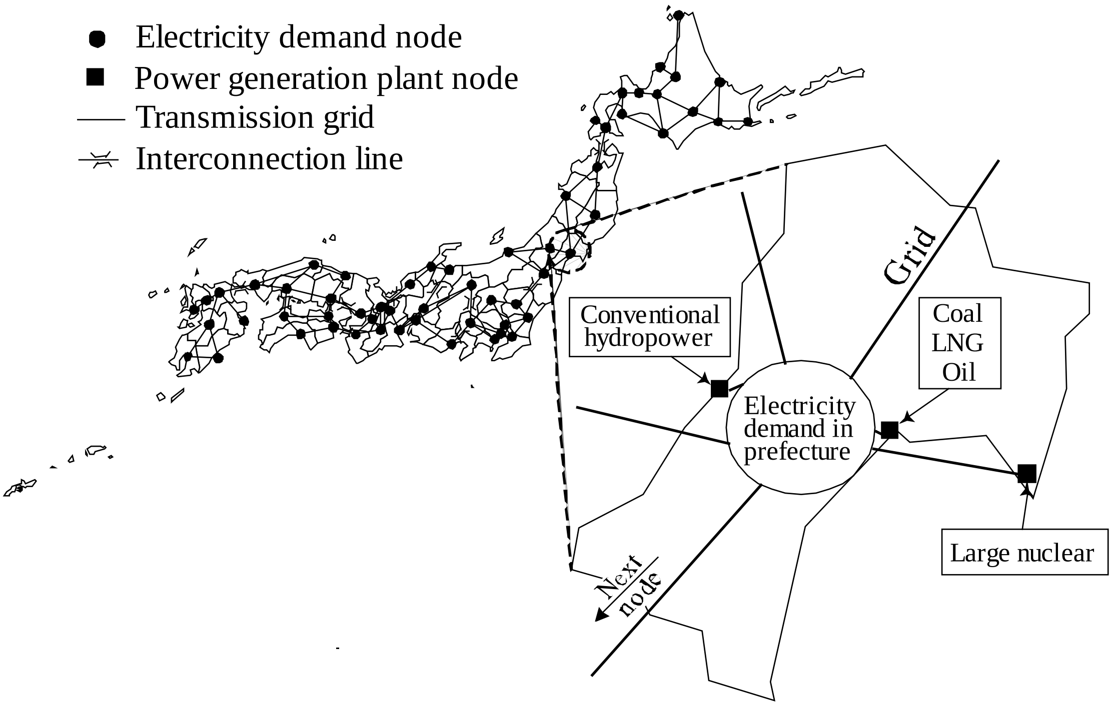

Figure 1. Configuration of the multi-regional generation planning model

At the demand nodes, the electricity demand was set for every hour, using the annual electricity demand and daily load curve for each prefecture. The future electricity demand for individual prefectures was based on the actual figures for the year 2000 (The Federation of Electric Power Companies, 2006) and took into consideration the rate of increase predicted in the “Prospects for Energy Demand in 2030” published by METI (Ministry of Economy Trade and Industry, 2006b). Specifically, values of 1.1% and 1.2% per year were used for the rate of demand increase during periods 2000-2010 and 2010–2020 respectively. For years after 2020, the rate of increase was set to 0.4%, as the number of households is likely to decrease and energy efficient appliances will become common in that period. The same rate of increase was postulated for all prefectures due to lack of disaggregated data. For the daily load curve, hourly fluctuations in electricity demand throughout the year were categorized into seven patterns as shown in Table 1, and a representative value for each pattern was used. As an example, Figure 2 shows the daily load curve for Miyagi Prefecture in the year 2000. Regional differences were not taken into consideration and the same daily load curve was used for all demand nodes throughout the modeling horizon.

Table 1 Predicted power demand pattern

| | Demand pattern | Number of days per year |
|---|---|---|
| A | Three peak days in summer | 3 |
| B | Summer weekdays | 98 |
| C | Winter weekdays | 95 |
| D | Spring/autumn weekdays | 97 |
| E | Summer non-work days | 21 |
| F | Winter non-work days | 26 |
| G | Spring/autumn non-work days | 25 |

Source: (Federation of Electric Power Companies of Japan, 2005) and (Takahashi, 2002)

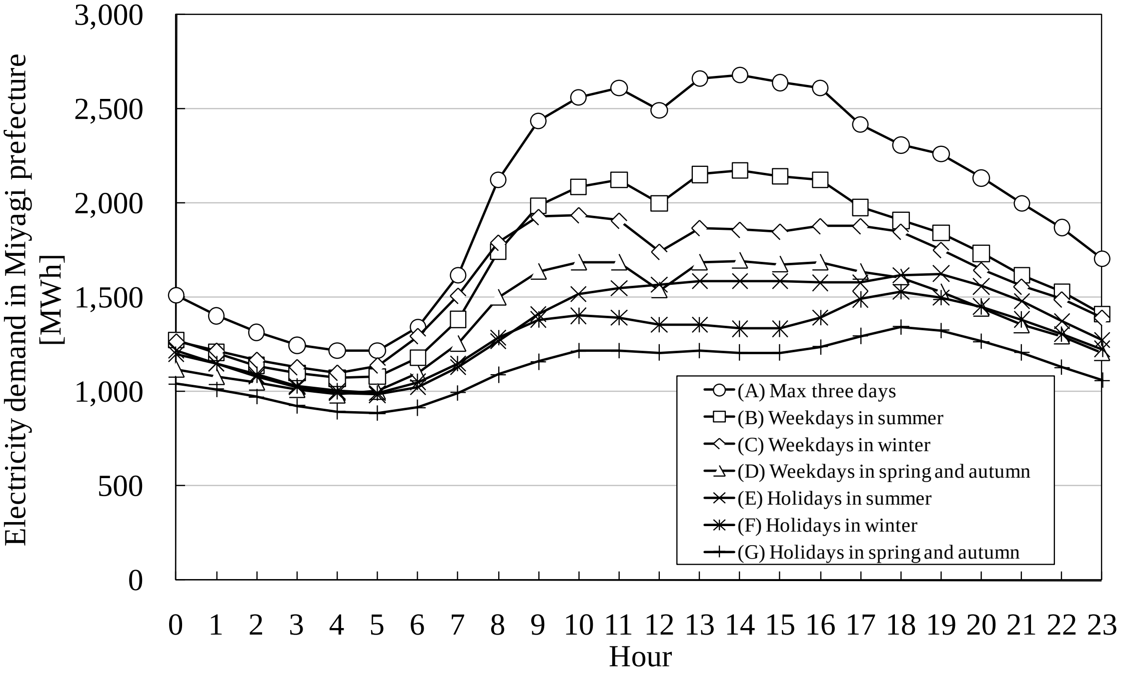

Figure 2. Examples of daily load curve (Miyagi Prefecture)

The power generation nodes took into consideration 11 types of power plants. Specifically, the following eight types were considered: nuclear power plants, coal-fired boiler, integrated coal gasification combined cycle (IGCC), oil-fired boiler, gas-fired boiler, gas combined cycle, conventional hydropower plants and pumped hydropower plants. To these eight types, three additional types were added. These were plants (coal-fired boiler, IGCC and gas combined cycle) that are also equipped with carbon capture and storage (CCS).

In this study, we set three different objective functions: (1) minimization of total generation cost, (2) minimizing total CO2 emissions, and (3) maximizing potentials of on-grid renewable. Using the General Algebraic Modeling System (GAMS) optimization tool, both capacity and outputs of power plants were determined. The power generation costs comprise capital costs, operation and maintenance (O&M) costs (both fixed and variable), and fuel costs. Future costs were converted into current values at a discount rate of 3% for calculating net present value of generation cost.

In the formulation of multi-regional generation planning problem in this study, the following four constraints were imposed.

(1) Constraints on supply and demand balance

This constraint requires that the electricity demand for each demand node must be equal to the sum of the quantity of power generated by plants in the area and power supplied from other regions via the transmission grid. In the process of formulation, the electricity supplied to pumped hydropower plants and to other regions was also considered as electricity demand.

(2) Constraints on load tracking at power plants

For power plant nodes, the following equation was used to impose constraint for the output variations per hour for each type of power plant, based on the values shown in Table 2. In equation 2, $Q_g(p,t,r,s,y)$ indicates outputs of power plants in each node; $p$ indicates time period (hour); $t$ indicates type of demand pattern, shown in Table 1; $r$ indicates the regional location of the power plant node; $s$ indicates the types of power plants; and $y$ indicates the year for analysis (year). $F_u(s)$ and $F_l(s)$ indicate the upper and lower limit, respectively, for the rate of output variations.

$$1 - F_l(s) \leq \frac{Q_g(p,t+1,r,s,y)}{Q_g(p,t,r,s,y)} \leq 1 + F_u(s) \qquad (1)$$

Table 2 Load tracking rate by power generation method

| Types of power plant | Upper limit[%/hr] | Lower limit[%/hr] |
|---|---|---|
| Nuclear boiler | +0.0 | -0.0 |
| Coal-fired boiler | +26.2 | -30.9 |
| IGCC | +29.7 | -91.8 |
| Oil-fired boiler | +44.8 | -31.0 |
| Gas-fired boiler | +41.2 | -46.5 |
| Gas combined cycle | +29.7 | -91.8 |
| Conventional hydropower | +0.0 | -0.0 |
| Pumped hydropower | +100.0 | -100.0 |

Source: Takahashi (Takahashi, 2002)

(3) Constraints on newly constructed power plants

In principle, the installed capacities of generators in 2050 were derived from the optimal solutions of the model. However, of all existing and planned power plants, installed capacities of thermal power plants which will be within 40 years after construction and nuclear plants within 60 years after construction in 2050 were incorporated into the optimization model to reflect the lower limit. Furthermore, with regard to the installed capacities of nuclear power plants, their upper limit was determined to be 59 GW based on the Nuclear Power Nation Plan. Cost of power generation includes the construction cost, operation maintenance cost (fixed and variable) and fuel cost. Based on the fuel prices observed in 2000, the price trends proposed by U.S. EIA(Energy Information Administration, 2006) were extrapolated to 2050 and were used as input conditions.

(4) Constraints on power transmission quantity

In the electric power system in Japan, a power transmission capacity, as shown in Figure 3, has been established for the transmission lines between electric utilities. In this model, we allowed newly construction of transmission lines in the future, and lower limits for electricity transmission capacity based on actual capacities were imposed on the transmission lines between the demand nodes of different electric utilities. For the transmission lines between demand nodes, transmission loss was taken into consideration in proportion to the transmission distance. Nationally, the average rate of electricity transmission and distribution loss is estimated to be 5.2% (The Federation of Electric Power Companies, 2006), and the average total loss rate is estimated to be 8.2% (The Federation of Electric Power Companies, 2006). In this study, variations in the transmission capacity, especially in power distribution grid, were taken into consideration, and the average rate of transmission loss was presumed to be 1%/100 km. The rate of electricity loss for BTB (Back-to-Back) facilities and frequency converters between 50 and 60 Hz was established based on the actual transmission loss rate (Agency for Natural Resources and Energy, 2002).

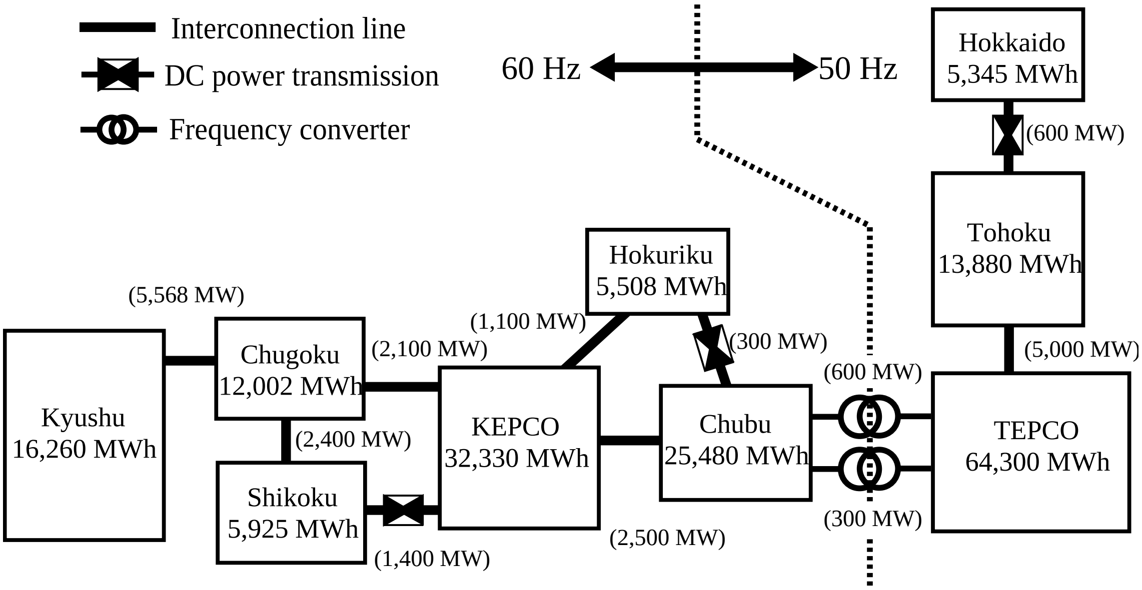

Figure 3. Interconnection lines between electric power suppliers and its transmission capacity

## 2.2 Quantitative evaluation method for on-grid renewable energy

We defined on-grid potential of renewable energies to be its maximum installed capacity within the range of the LFC capability of the grid. Regarding LFC capability, only thermal power plants were considered. For each year and demand pattern, its hourly values were calculated based on equation (2), using the method presented in a technical report by the Institute of Electrical Engineers of Japan. Hydroelectric and nuclear power generation were assumed to have no LFC capability.

$$LFC_t = \min\left(\left|g_{\max} - g_t\right|, \left|g_t - g_{\min}\right|\right) \tag{2}$$

where, $LFC_t$ [MW] is the LFC capability at time $t$ [hr.], $g_t$ [MW] is the output of power plants, and $g_{max}$ and $g_{min}$ [MW] are the upper and lower limits of the output. The upper limit of the output range is derived from the capacity of power plants, whereas the lower limit is derived from the lowest output in actual operation, determined as a percentage of capacity for each generation method. based on documents published by the Institute of Electrical Engineers of Japan. The figure is 30% of the rated power output for coal-fired boiler, whereas those of oil-fired thermal power, gas boiler thermal power and gas combined thermal power are 25%, 20% and 25%, respectively. In cases where power plants are operated at the rated power output or the minimum power output, the LFC capability becomes the minimum, zero, and when they are operated at an intermediate output level, the value becomes maximum.

## 3. Quantitative analysis results on power plant configuration and power generation configuration in 2050

We set each of the following as the objective function of the multi-regional optimum generation planning model: (1) maximization of on-grid renewables potential (Renewables Max case), (2) minimization of the annual cost (Cost Min case) and (3) minimization of $CO_2$ ($CO_2$ Min case). For each case, we obtained power plant configurations and power generation configurations as shown in Figure 4 and Figure 5, respectively.

The lowest total installed capacity was seen in the Cost Min case with 276 GW. In comparison, those of the Renewables Max case and $CO_2$ Min case were approximately 10% greater, with the figures of 304 GW and 309 GW, respectively. This is because the Cost Min case is required to operate with the smallest possible installed capacity at the highest level of efficiency. On the other hand, in the $CO_2$ Min case and Renewables Max case, the priority is put on reduction of $CO_2$ or improvements in on-grid potential of renewable energies instead, permitting somewhat less efficient operation.

Regarding power plant configuration, in the Cost Min case and $CO_2$ Min case, about 20% of the total installed capacity is accounted for by nuclear power plants, about 60% by gas combined thermal power plants (CCS-equipped type in the $CO_2$ Min case) and the rest mostly by hydroelectric power plants (conventional and pumped-storage). Although coal-fired power has a lower fuel price compared to natural gas, it does not get selected from the viewpoint of cost minimization due to its high construction cost. Therefore, gas combined thermal power with low construction cost becomes the major type. In the Renewables Max case, on the other hand, relatively higher variance of power plants is seen, with nuclear power plants, coal-fired thermal power plants and natural gas-fired thermal power plants accounting for 20%, 30% and 35%, respectively, of the total installed capacity.

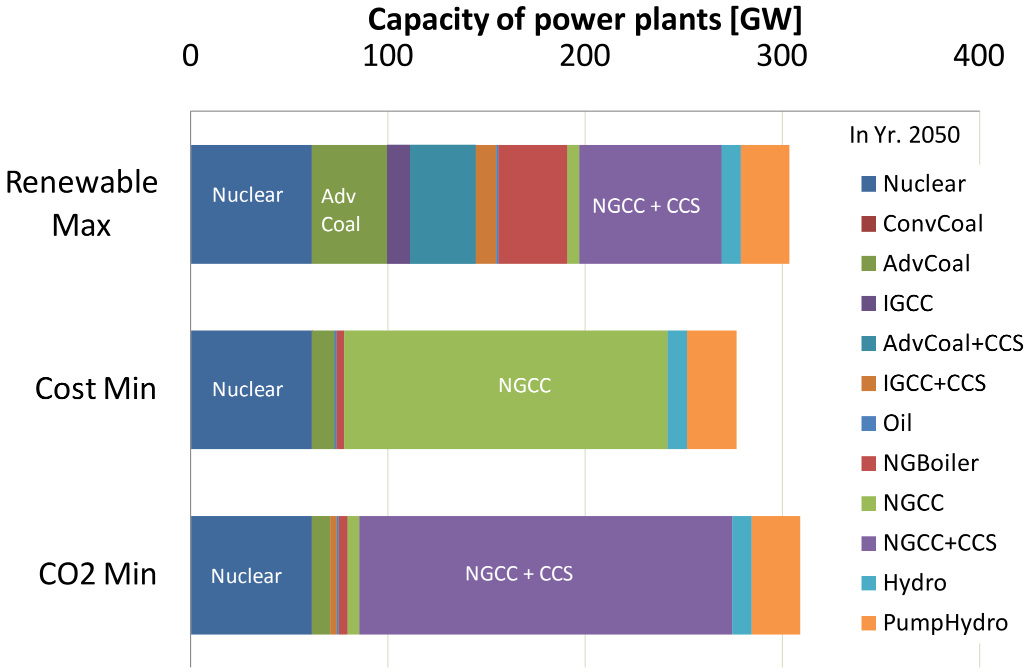

Figure 4 Configurations of power plants in 2050

As for power generation configuration (Figure 5), nuclear power supplies 36% of the annual electricity demand, while gas combined thermal power supplies approximately 50% of it in the Cost Min case and $CO_2$ Min case.

Differing from these, the Renewables Max case has a total generation amount of 1,300 TWh, about 20% greater than the other cases. This is because some power plants in the Renewables Max case incur transmission loss when sending electricity to locations far away during off-peak hours, and also their output is maintained at the intermediate level. As for its power generation configuration by power source, the percentage of nuclear power and gas combined cycle in total generation amount declines to 16% and 46%, respectively, and that of coal-fired thermal power increases to 30%.

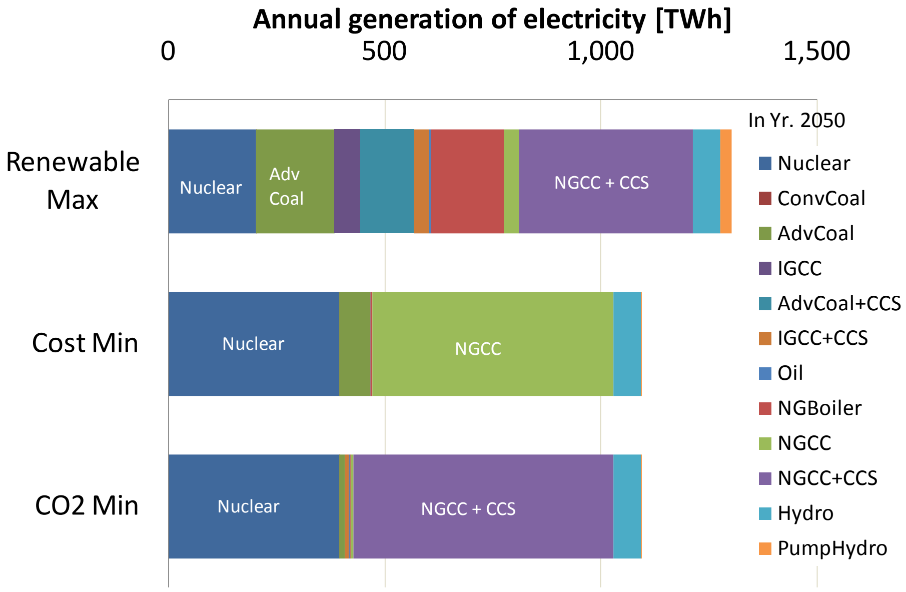

Figure 5 Annual generations of power plants

Table 1 Summary of annual cost, $CO_2$ emissions and on-grid potentials of renewables

| Case | Annual cost | | | $CO_2$ emissions | Annual On-grid potentials | | Max potential | |
|---|---|---|---|---|---|---|---|---|
| | Fixed (tril. JPY) | Variable (tril. JPY) | Total (tril. JPY) | (Mt-C) | (TWh/yr.) | (wrt gen) (%) | (GWh/hr) | (wrt capacity) (%) |
| Renewable Max | 7.17 | 5.10 | 12.27 | 105.6 | 181.3 | 13.9 | 47.8 | 15.7 |
| Cost Min | 4.37 | 3.47 | 7.84 | 82.4 | 167.9 | 15.3 | 47.0 | 17.0 |
| $CO_2$ Min | 6.73 | 4.15 | 10.88 | 13.1 | 113.9 | 10.4 | 41.9 | 13.5 |

Table 1 summarizes annual power generation cost (fixed and variable), $CO_2$ emissions and on-grid renewables potential for each case. The annual generation cost is lowest for the Min Cost case with 7.8 trillion yen, followed by the $CO_2$ Min case and Renewables Max case.

In regard to $CO_2$ emissions, the $CO_2$ Min case has the value of 13.1 Mt-C, showing the possibility of reducing it to a 15% level compared to the Cost Min case. This reduction is mainly contributable to introducing CCS to gas combined thermal power generation, and the average reduction cost is calculated to be 44,000 yen/tC. In the Renewables Max case, $CO_2$ emissions increase by 1.3-fold to 105.6 Mt-C compared to the Cost Min case, due to a higher percentage of coal-fired power and a larger amount of transmission loss.

With reference to on-grid renewables potential, the Renewables Max case, with 181 TWh, and Cost Min case, 167 TWh, did not differ greatly. They did not show substantial difference in the maximum hourly value of on-grid renewables potential, either. In the Renewables Max case, power plants are assigned with separate roles of on-grid potential maintenance (for power plants with low load-following capacity such as coal-fired and gas boiler thermal power plants) and load-following (for power plants with high load-following capacity such as gas combined cycle plants). On-grid potential maintenance power plants are operated at a fixed intermediate output level throughout the day. While load-following power plants are operated only during peak-hours to cover the insufficient supply by on-grid potential maintenance plants in the Cost Min case, all power plants except for nuclear and hydroelectric power plants are operated on a load-following basis. In other words, all power plants fueled by fossil fuels retain their output at an intermediate level, securing on-grid renewables potential. When comparing the on-grid potential per electricity generator, the Renewables Max case is superior to the Cost Min case. However, in terms of the number of power plants that contribute to securing the potential, the Cost Min case is superior. This is most likely the reason for similar results obtained for the Renewables Max and Cost Min cases on the annual on-grid potential of renewables.

## 4. Relationship between capacities of interconnection lines among electric companies and on-grid renewables potential

Figure 6 summarizes the results of the quantitative analysis on power plant configuration and on-grid renewables potential for each region in the Renewables Max case, assuming new interconnection lines can not be introduced among electric utilities. The analysis results displayed as “Interconnection lines introduced” in the figure are equivalent to the Renewables Max case mentioned in Section 3. Compared to the case of introducing new interconnection lines (181.3 TWh), introducing no interconnection lines increases on-grid renewables potential for Japan as a whole by 4-fold to 258.7 Twh. This is because adding no interconnection lines among electric utilities makes power exchange during peak-load hours difficult. Thus, the installed capacity of power plants with high load-following capacity (gas combined thermal power plants) decreases, whereas the percentage increases for on-grid potential maintenance power plants with low load-following capacity (coal-fired and gas boiler thermal power plants).

Performing a comparison based on whether new interconnection lines are introduced or not, the installed capacities and on-grid renewables potentials of Tokyo, Chubu and Kyushu electric companies substantially decrease with the introduction of new interconnection lines, while those of Hokkaido, Tohoku, Chugoku and Shikoku electric companies increase with the introduction. As for Okinawa electric company, neither of the installed capacity and on-grid renewables potential are changed by strengthening of interconnection lines because the company does not have any interconnection line with other electric utilities.

The maximum physical potentials(Ministry of Economy Trade and Industry, 2004) of wind power generation based on the natural conditions are highest in Hokkaido (9,122 MW), followed by Tohoku (4,238 MW), Kyushu (2,875 MW), Tokyo (2,572 MW) and Shikoku (2,522 MW) in order.

Therefore, to increase the on-grid potential of wind power generation, all electricity companies except for Kyushu electric company must introduce new interconnection lines.

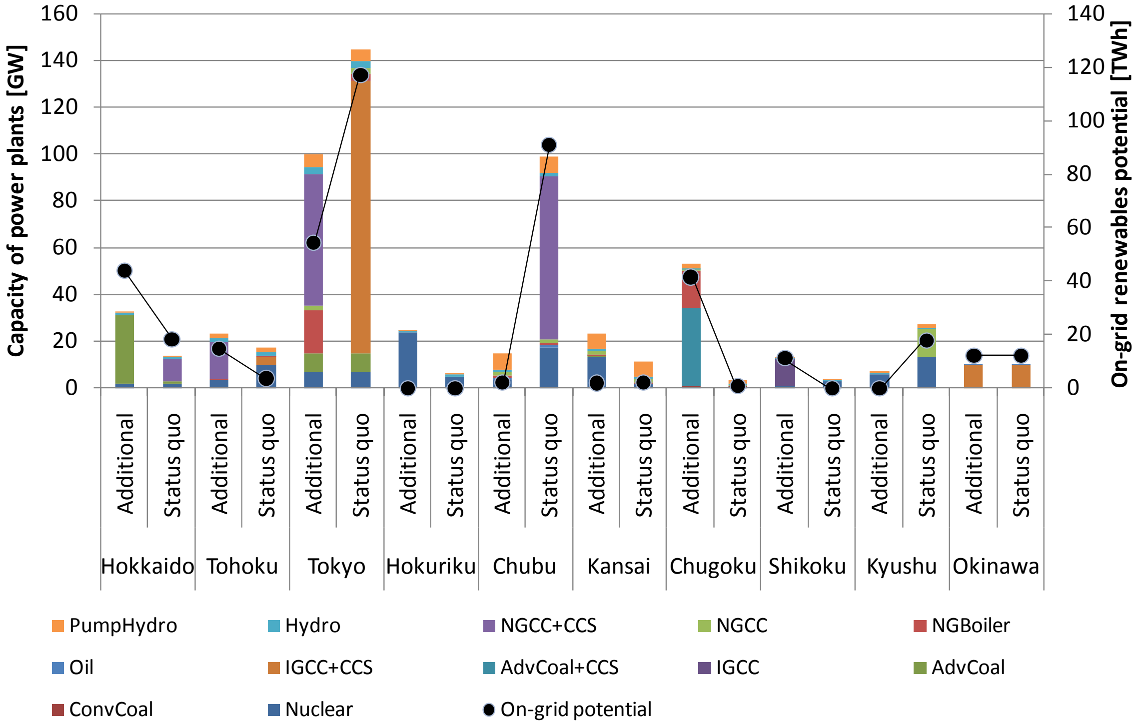

Figure 6 Comparison of results with or without additional interconnection lines among utilities

## 5. Conclusion

Targeting Japan's electricity sector in 2050, we quantitatively analyzed the possibility of achieving all of (1) increased on-grid renewables potential, (2) high economic efficiency of power plant operation and (3) $CO_2$ emissions reduction, using a optimization model for operation of power plants. The future vision for the power plant configuration of the electricity sector in 2050 based on the results of the quantitative analysis is summarized in Figure 7.

With the power plant configuration in 2005 as the baseline, improvements in economic efficiency of power plant operation and $CO_2$ emissions reduction in 2050 share a common characteristic of increasing the percentage of natural gas-fired thermal power generation. In contrast, it is important to increase the percentage of coal-fired thermal power generation to improve the on-grid renewables potential. Therefore, to achieve all of increased renewables potentials, high economic efficiency and $CO_2$ reduction, it is crucial to (1) develop and introduce a method for coal-fired thermal power generation with high economic efficiency and low $CO_2$ emissions, and to (2) utilize peak-load power plants for middle load through load-leveling. Especially, the development and introduction of such coal-fired thermal power will not only contribute to improved economic efficiency as well as $CO_2$ reduction of the electric sector, but will also secure energy for the country, which is an important factor in future scenarios of the electricity sector.

Moreover, if the developed technology could be utilized in China, it would effectively help construct an electricity supply system that is economically efficient and low in $CO_2$ emissions. Thus, its development is crucial to help curb global $CO_2$ emissions. In this study, we quantitatively clarified multiple future scenarios of the electricity sector by targeting the single year of 2050. In the future, however, it is important to quantitatively investigate (1) if the future scenarios can be achieved and (2) what route should be chosen, from the current electricity sector.

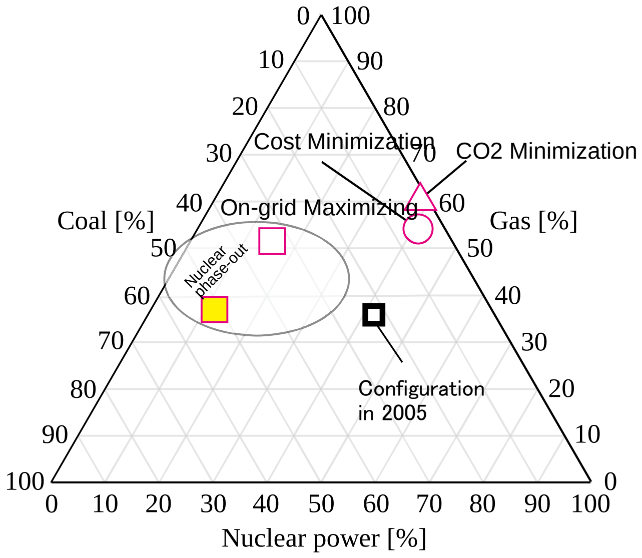

Figure 7 Summary of future visions of Japan's electricity sector in 2050 from the viewpoint of fuel mix

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