RESEARCH ARTICLE

Analysis of value of flexibility in Japan’s power system with increased VRE

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Abstract

The growth of renewable energy has accelerated globally toward a low-carbon economy since the Paris Agreement entered into force in 2016. As a result of the increase of variable renewable energy (VRE), namely solar PV and wind, power systems require more flexibility from conventional power plants with less power generation to regulate increased variability. There are sources of flexibility other than conventional power plants, including enhanced power networks, storage capacity and demand response. To maximize economic utilization of VRE power generation, it is necessary to use the flexibility potential from all these sources. In Japan, the share of VRE has increased since the introduction of a feed-in tariff (FIT) and, in parallel, power market reform is underway. Japan has a unique power system of nine grids connected like a fish bone, making the uptake of an increasing share of VRE challenging. This paper assesses the value of flexibility by source in Japan’s power system in 2030. An analysis of different VRE scenarios is undertaken based on a newly developed production cost model. The result of the simulation shows the quantitative impact of each source of flexibility to the generation cost and VRE curtailment and demonstrates the mechanism by which flexibility works to impact VRE curtailment.

Key words: component; power demand and supply; renewable energy; flexibility; Japan’s power system; production cost model analysis

Introduction

According to the International Energy Agency’s World Energy Outlook 2017 [1], the share of global renewable energy in power generation reached 24% in 2016. The annual increase of renewable energy power generation in 2016 recorded a historical high of 426 TWh, supported by the Paris Agreement reached at the 21st Conference of Parties (COP21) on climate change in late 2015. The growth was remarkable in variable renewable energy (VRE)—namely solar PV and wind—with an annual growth rate in 2016 of 23% and 17% respectively. A new trend in VRE growth was observed as China was the country that recorded the largest VRE growth (77 GW) in 2016, more than double that in all of Europe, which had led global VRE deployment for a long time. The increased share of VRE has led to power systems facing new challenges. In particular, the requirement of more flexibility from conventional power plants to regulate increased variability while power generation from
conventional power plants is reduced by more VRE. There are sources of flexibility other than conventional plant operation: grid expansion by interconnection lines, storage, demand response and control of VRE.

Utilization of the flexibility potential from all sources is necessary to maximize economic utilization of VRE power generation. In Japan, the value of flexibility is not recognized as there has been no necessity due to the low share of VRE. This situation has been changing as the share of VRE has grown since the introduction of a feed-in tariff (FIT) in 2012, and further growth is expected. Unlike many other countries that have a meshed network, such as in Europe, Japan has a unique power system of nine grids connected like a fish bone. The grids are connected through interconnection lines and frequency converters with limited capacity. These unique characteristics make the full utilization of growing VRE more challenging. In parallel with the increase of VRE, the government has been conducting power market reforms. Currently four different markets are being designed—intra-day, baseload, zero-emission credit and capacity—with the aim for them to be operational by 2020. The value of flexibility is to be reflected in the intra-day market. This will require the market to be designed correctly and necessitate quantitative evaluation during the design process.

The objective of this study is to conduct a quantitative analysis on the value of flexibility by comparing the impact of the share of VRE and the source of flexibility. This was carried out to understand the implications for the market design to monetize the value of the flexibility. The analysis is based on a newly developed production cost model that can simulate Japan’s power system in 2030. Section 1 provides background information on Japan’s current power system. Section 2 describes the methodology and assumptions and results of the analysis are covered in Sections 3 and 4.

1 Power generation in Japan

Japan’s 2030 target for its power generation portfolio is set out in the “Long term plan for energy supply and demand” [2] adopted by the cabinet in July 2015. The plan also underpins Japan’s greenhouse gas (GHG) reduction target stated in the Nationally Determined Contribution (NDC) submitted to the United Nations Framework Convention on Climate Change (UNFCCC). The targeted share of each energy source is respectively oil 3%, LNG 27%, coal 26%, nuclear 20–22% and renewable energy 22–24%. This target reflects historical energy policy goals of improving energy security by reducing oil dependency and development of a low-carbon economy. The new challenge set by the government is to achieve 44% share of non-fossil power generation using nuclear and renewable energy. The delay in restarting nuclear power generation due to the time-consuming safety assessment process makes this challenge difficult. Fig. 1 depicts the historical trend of the power generation portfolio in 1990–2015 and the 2030 target [2, 3].

The power generation capacity portfolio in Japan has also changed over time. Table 1 shows power generation capacity by type in 1990, 2000 and 2015 [3, 4].

With the exception of hydro, between 1990 and 2015 the installed capacity of renewable energy increased from <1 GW to 40 GW. A unique feature of Japan’s power generation capacity is 28 GW of pumped storage hydro (PSH).

Fig. 2 depicts the growth of renewable energy, mostly in solar PV. Japan’s VRE promotion policy started as the Renewable Portfolio Standard in 2003 supplemented by the Excess Electricity Purchasing Scheme in 2009. However, both policies failed to effectively boost renewable energy deployment. The replacement of these policies with the FIT in 2012 resulted in a surge in the construction of utility-scale solar PV due to the attractive purchase price. In the latest data, as of the end of March 2017, the total capacity of solar PV in operation reached 42 GW of which 33 GW is certified for FIT.

Japan’s power system consists of 10 local grids divided between East (50 Hz) and West (60 Hz) in frequency and connected with interconnection lines and frequency converters (FC). There are nine grids going through the four main islands connected similarly to a fish bone, that is, one grid is only connected to its neighboring grid(s). This is entirely different from the meshed network used in the US or Europe, where one grid is normally connected with more than four surrounding grids. Fig. 3 shows Japan’s power system and the operational capacity of interconnection lines and FC capacity and type.

The interconnection lines between grids vary in number and depend on the size of power demand. To illustrate, Hokkaido at the north end of Japan has only one DC interconnection line of 600 MW, and Kyushu at the south end of

| Energy Source       | 1990 | 2000 | 2015 |
|---------------------|------|------|------|
| Nuclear             | 31   | 45   | 42   |
| Coal                | 12   | 29   | 40   |
| LNG                 | 38   | 57   | 73   |
| Oil                 | 53   | 52   | 40   |
| Hydro               | 19   | 20   | 21   |
| Pumped storage hydro| 17   | 25   | 28   |
| Other renewables    | <1   | 9    | 40   |
the four main islands has only one AC interconnection line of 2530 MW. Between Tokyo and Chubu, there are three FCs with a total capacity of 1200 MW. The numbers under each grid name in Fig. 3 show the average of the three largest hourly peak demands in 2016 in each grid. Those numbers indicate the necessary capacity of power generation in each grid. Tokyo has the largest power demand followed by Kansai (surrounding Osaka) and Chubu (surrounding Nagoya). The larger the power demand in the grid, the more flexibility provided by fossil-fired power plants is available, and thus more VRE is acceptable. VRE deployment in the grids is proportional to the demand size. Consequently, VRE power generation is efficiently used without a large curtailment. However, the actual deployment of VREs is not proportional to the demand size but concentrated in some areas. Fig. 4 depicts the capacity of installed and FIT-certified and installed solar PV, and the minimum daytime load in each grid. It shows that solar PV is intensively deployed in the Kyushu area regarding the demand size as the installed capacity is close to the minimum daytime load; the hourly share of solar PV to the demand recorded 73% on 30 April 2017.
Methodology

The objective of this analysis is to minimize the system cost for interconnected grids, taking multiple limiting conditions into account for one year or more. It is important to calculate complex problems at high speed. Therefore, we developed a model to achieve this objective by separating the optimization process into two parts: “optimization of energy interchange in interconnected grids” and “optimization of pumping operation of pumped storage hydro in each grid” [6]. The rationale to develop this model is Japan’s unique power grid, as explained above. To calculate maximum available flexibility, we incorporated the balancing capacity interchange and/or ramping capacity interchange through interconnection lines. Commercial production cost models are available in the market, but they do not consider flexibility interchange.

The authors carried out several analyses on Japan’s power system with increased VRE in 2030 from several aspects, including marginal cost, storage capacity and demand response, based on this model [7–9]. The flow of the method is shown in Fig. 5. To optimize the model we used the numerical optimization solver Gurobi Optimizer 6.5.1 [10]. Flexibility evaluation analysis for Japan’s power system in 2030 was carried out with the production cost simulation model. One of the characteristics of the model is its ability to consider balance between variability and balancing capacity (BC), and BC interchange through interconnection lines. Commercial production cost models are available in the market, but they do not consider flexibility interchange.

The objective function of the model is to minimize generation cost (consisting of fuel and start-up costs) of the total power system of nine interconnected power grids and one isolated grid for 8760 hr. By its nature, the model does not take fixed cost into account:

$$\min \left( \sum_{t=1}^{NT} \sum_{k=1}^{Nk} (F(P)) \right) = \min \left( \sum_{t=1}^{NT} \sum_{k=1}^{Nk} \left( b_k \cdot P_k + c_k \cdot U_k + \text{startup ST} \right) \right)$$

The limiting conditions are balance between demand and supply, balance between required variability and available load frequency control (LFC) capacity, upper and lower limit of hourly output in each power generation unit and capacity of interconnection lines for energy interchange. We also added the capacity of interconnection lines for LFC capacity interchange to the limiting conditions for the relevant case. Priority dispatch of VRE regulated by the current FIT law in Japan is not assumed in this study.

Calculation condition

3.1 Power supply and VRE scenario

Japan’s power generation capacity by energy resource in 2030 is assumed based on the governmental power generation target [2] and existing power plants and projects. For nuclear, we assumed all units at Fukushima Daiichi and Fukushima Daini power plants are not available. We assumed that all existing coal and gas units are abolished after a 40-year lifetime, that new projects already under environmental impact assessment are built and that oil remains as it is. Two scenarios were assumed for VRE, solar PV and wind. The PV64 Scenario is consistent with the government’s 2030 target. As the target is given only in power generation by type, generation capacity of solar PV and wind were assumed by back calculation using average capacity factor. The PV103 Scenario is assumed for large-scale VRE deployment based on several studies [11, 12]. The distribution of solar PV and wind in grids reflects the current patchiness in both scenarios. For fossil and nuclear, rated capacity, minimum capacity, auxiliary rate, energy efficiency considering partial load characteristics and periodic repair days were set for each unit. For hydropower, average generated electric power by month is set for the run-of-the-river, and possible output by month is set for regulating reservoir. For pumped storage hydro, rated capacity, minimum output, efficiency and types (constant/variable speed), are set by unit. Table 2 shows VRE installed capacity by grid and Fig. 6 depicts total installed capacity by energy source in each scenario.
3.2 Demand and VRE generation pattern

To calculate the total electricity demand in 2030, the number in the “Long-Term Energy Demand Supply Plan” [2] is used and is allocated to each grid proportional to the share in 2013. Based on the published hourly demand record in 2013 and the annual electricity demand by each utility, the hourly demand curve in 2030 in each area is assumed.

The generation curve for wind in 2030 in each area is assumed based on the hourly wind generation record in 2013 as proportional to the capacity deployed in 2030. The generation curve for solar PV in 2030 in each area is assumed based on the hourly record of solar radiation and temperature in 2013 and the capacity of solar PV deployed in 2030.

3.3 Variability and balancing capacity

The flexibility we analyze is the balancing capacity in the LFC time zone; for conventional generators, LFC capacity is a total of ±5% of the rated capacity of coal, oil and LNG power plants in operation at partial load between a minimum +5% and maximum −5%, ±20% of hydro power plant in operation, ±20% of pumped storage hydro at power generation and ±20% of pumped storage hydro with variable speed pump during pumping.

Demand variability in the LFC time zone is assumed as ±2% of the hourly value according to the assumption made by the Power System Working Group government committee. The variability of VRE for PV power generation is assumed as ±10% of the corresponding output and the variability of wind power is assumed as ±5% of the installed capacity. In the area where the output is 0–15% of installed capacity, variability is assumed to rising from ±0 to ± 5% linearly to 15%.

3.4 Case studies to evaluate flexibility

Availability of sources of flexibility and their impact was analyzed: energy interchange through interconnection lines and FCs, coal-fired power plants’ LFC capacity, pumped storage hydro and LFC capacity interchange through interconnection lines and FCs (limited to 10% of their operational capacity).

Table 3 shows the case studies and current situation in Japan. Recent governmental committee discussions on the grid’s stability for increased VRE identified that power utilities do not fully utilize the LFC capacity of coal-fired power plants. One possible reason is that the plants can balance variability and flexibility without LFC. In the Base case in 2030, however, we assumed coal-fired power plants’ full utilization of LFC capacity.

4 Results of analysis

Fig. 7 depicts the result of the model calculation of total annual VRE curtailment by case study and scenario. Table 4 shows the VRE curtailment ratio to VRE power generation before curtailment. The number shown under the scenario name in Table 4 is the VRE power generation before curtailment. In comparison to the Base case, absence of
energy interchange (Case I), coal LFC (Case II), PSH (Case III) and coal LFC/PSH (Case IV) increase VRE curtailment. The availability of BC interchange (Case V) reduces VRE curtailment. Therefore all the sources of flexibility are effective in reduction of VRE curtailment. VRE curtailment is significantly higher when neither coal LFC nor PSH is available.

The Base case of PV64 shows a small VRE curtailment ratio. Thus the government’s 2030 power generation portfolio target is reasonable even considering the balance between variability and flexibility, if coal LFC is fully utilized. However, in the PV103 scenario, VRE curtailment is 14% even in the Base case and more than 55% in Case V (neither coal LFC nor PSH). If all the sources of flexibility are available, including BC interchange, the curtailment ratio can be reduced to 9%. This means that the importance of flexibility is increased to utilize VRE power generation in case of increased VRE deployment.

Due to larger VRE power generation, the absolute cost (fuel and start-up costs) of the PV103 scenario is smaller than PV64 in all cases, as more VRE power generation displaces conventional power generation. We examined the ratio of cost difference between each case and the Base case to analyze the impact of unavailability of flexibility to the cost for power generation. Fig. 8 depicts the cost ratio increase in comparison to the Base case and scenario. Absence of energy interchange (Case I), coal LFC (Case II), PSH (Case III) and coal LFC & PSH (Case IV) increases the cost, and availability of BC interchange (Case V) reduces the cost compared to the Base case. Therefore, all the sources of flexibility are effective in reducing the cost of power generation. This is because the absence of flexibility increases VRE curtailment; thus fossil-fired power generation is increased to meet the demand. The comparison between PV64 scenario and PV103 scenario shows that the larger share of VRE provides the larger impact to cost as the cost ratio increase of the PV103 scenario is larger than PV64. This analysis demonstrates that the value of flexibility can be evaluated economically.

Fig. 9 depicts VRE curtailment by grid by case in the PV103 scenario. It shows that the impact of unavailability of a flexibility source differs by grid. When we look at Grid-B, where VRE curtailment is the largest among all cases, unavailability of coal-LFC has the largest impact to increase VRE curtailment. However, when we look at Grid-C, the VRE curtailment is significant in Case III (no PSH) and Case IV (no coal-LFC & no PSH), so PSH is the most influential source of flexibility for Grid-C. It is considered that such a difference in the impact of flexibility is due to the difference in generation capacity portfolio by grid. In Grid-B, the share of coal-fired power plant is relatively high (16%) and the share of PSH is low (2%). In contrast, Grid-C owns 12 GW of PSH out of 29 GW in Japan, so its share of PSH is high (9%) while the share of coal is low (8%).

We also analyzed the mechanism for how the availability of coal-LFC works in Grid-B and the availability of PSH works in Grid-C.

Fig. 10a depicts the hourly profile of residual power demand (green line), residual power demand minus (plus) exported (imported) power (red line) and power supply by source (bars); Fig. 10b depicts the required balancing capacity before curtailment (blue line, main axis), required balancing capacity after curtailment (red line, main axis) and supplied balancing capacity by source (standing bars, main axis), VRE curtailment by type (hanging bars, right axis) in Grid-B in the Base case on 29 April. This date is selected as a typical day with large solar PV and wind power generation against low power demand. Fig. 11 depicts the same information in Case II (no coal-LFC).

In the Base case in Fig. 10, solar PV generation covers a share of total power generation from 0700 to 1700 hours (Fig. 10a). LNG power is not in operation throughout the day. Grid-B is an energy exporter except between 1100 and 1300 hours, as the marginal cost set by coal is lower than Grid-C where LNG sets its marginal cost. Balancing capacity is constantly provided by coal (Fig. 10b), although it is not sufficient to meet required BC and thus VRE curtailment occurs between 0000 and 1800.

But in Case II in Fig. 11 where no coal-LFC is available, PV power is not used for power supply (i.e. curtailed) between 0900 and 1500; during those hours Grid-B imports power from neighboring grids and operates LNG to supply power throughout the day (Fig. 11a). VRE curtailment is larger than the Base case due to the lack of balancing capacity, as supplied BC is smaller (Fig. 11b) while use of LNG results in cost increases compared to the Base case.

This analysis shows how the availability of coal-LFC effectively works to reduce VRE curtailment and fuel costs.
Fig. 12 depicts the hourly profile of residual power demand (green line), residual power demand minus (plus) exported (imported) power (red line), and power supply by source (bars); Fig. 12b depicts the required balancing capacity before curtailment (blue line, main axis), required balancing capacity after curtailment (red line, main axis) and supplied balancing capacity by source (standing bars, main axis) in Grid-C in the Base case on 29 April. Fig. 13 depicts the same information in Case III (no PSH).

In the Base case in Fig. 12, necessary balancing capacity is mostly provided by PSH (Fig. 12b) and PV power generation covers a large share of total power generation with little curtailment (Fig. 12a). Due to more PV power generation, LNG power is not necessary during daytime and only supplies power in the evening for a short time.

In Case III in Fig. 13 where PSH is not available, large curtailment of PV occurs due to a lack of balancing capacity (Fig. 13b) while PV power generation is displaced by LNG power generation (Fig. 13a). This displacement of PV by LNG results in a fuel cost increase.
This analysis shows how availability of PHS works effectively to reduce VRE curtailment and fuel cost.

5 Conclusions

The findings of our study on the value of flexibility for Japan’s power system in 2030 using the cost generation model are as follows:

- Unavailability of each source of flexibility—energy interchange through interconnections and FCs, LFC capacity, pumped storage hydro and BC capacity interchange through interconnections and FCs, respectively—impacts VRE curtailment and generation cost.

- Unavailability of a source of flexibility increases VRE curtailment and generation cost. Consequently, unavailability of flexibility results in economic losses in the power system.

- The impact becomes more significant when the share of VRE is larger and/or multiple sources of flexibility are unavailable.

- The source of flexibility that has the largest impact by grid differs according to the grid’s portfolio of power generation capacity.

- Availability of coal-LFC is effective to provide balancing capacity and thus reduce VRE curtailment in Grid-B, while availability of PSH is effective to provide balancing capacity and thus reduce VRE curtailment in Grid-C.

- Maximum utilization of flexibility potential is essential to minimize VRE curtailment in terms of both the economics aspect and lowering carbon dioxide emissions from the power sector.

These results imply that to sufficiently utilize flexibility potential such flexibility is properly monetized in accordance with the value requires market design, regulation and implementation. Our study demonstrates that the production cost model can evaluate economic value of flexibility supplied by existing facilities.

To achieve a more accurate evaluation of flexibility it would be necessary to evaluate flexibility supplied by the demand side. To evaluate flexibility in the longer time zone, i.e. tertiary control, the ramp-up and ramp-down speeds should be taken into account. To evaluate flexibility supplied by a new facility such as a new fossil-fired power plant or a new interconnection line, it is necessary to take the construction cost into account. These are future research challenges.

Conflict of interest statement. None declared.

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