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SPECIAL FEATURE: ORIGINAL ARTICLE

Energy Scenarios for Long-Term Climate Change Mitigation in Japan

System LCOE of variable renewable energies: a case study of Japan's decarbonized power sector in 2050

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Abstract
Decarbonization of the power sector is an important milestone for the achievement of ambitious GHG reduction targets. Given the intrinsic shortcomings of nuclear power and zero-emission thermal power generation, such as large investment costs and public acceptance, along with the locational limits of dispatchable renewables such as hydro and geothermal, variable renewable energies (VRE) should play an important role to decarbonize the power sector. Very high penetration of VRE, however, would require additional "integration" costs related to grid expansion, power curtailment, and power storage. In this article, focusing on a decarbonized power system in Japan in 2050, we calculated two metrics that capture the non-linear nature of the integration cost related to high VRE penetration: Average system LCOE (levelized cost of electricity) and relative marginal system LCOE. The former metric allocates the integration cost to each power source, which is divided by the adjusted power output, while the latter measures the changes in the total system cost with the substitution of two types of power sources. The results show that both the average and the relative marginal system LCOE of VRE will rise when the share of VRE rises, but the latter will rise much more sharply than the former. This suggests that the anticipated challenges for achieving very high shares of VRE may still exist even if the cost of VRE may decline rapidly in the future. As the relative marginal system LCOE of VRE can be heavily dependent on meteorological conditions, it is essential to use multi-annual data to estimate it. The metric relative marginal system LCOE can be used for the soft-linking of a detailed power sector model to an integrated assessment model, which can contribute to a better quantitative analysis of climate policies.

Keywords System LCOE · Integration cost · Variable renewable energies · Linear programming · Meteorological data

Introduction

Due to the increasing concerns about climate change, as well as to recent cost declines, variable renewable energies (VRE), such as wind and solar PV, have been experiencing rapid diffusion worldwide, which have also boosted future targets for the expansion of renewables; for example, Europe aims to achieve net zero greenhouse gas (GHG) emissions by 2050, which would require the decarbonization of the power sector almost completely by 2040 (European Commission 2018). Although many types of zero-emission technologies, including nuclear and zero-emission thermal power, can contribute to achieving this target, renewable energies, especially VRE, have been viewed as the most promising energy sources that can generate electricity with high cost-competitiveness. The share of VRE in the power generation mix in the European Union (EU) has risen from 5% in 2010 to 16% in 2018 (IEA 2019a), and European Commission (2018) proposes a scenario that aims to boost the share to more than 70% by 2050.

In Japan, the government officially targets to reduce GHG emissions by 80% by 2050 from current levels (Ministry of the Environment 2016), also aiming to realize a "decarbonized society" in the latter half of this century (Government of Japan 2019). To achieve these ambitious targets, the government has set forth a plan to promote renewable energies as a "main power source" in the

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electricity system (Government of Japan 2018). Under these situations, identifying the challenges associated with achieving high penetration of VRE, and finding the proper ways to overcome those challenges, have been regarded as key issues for future energy policy debates.

The challenges of high penetration of VRE has been with reference to the "integration cost." This term usually refers to the non-linear relationship between the penetration of VRE and the total system cost. Traditionally, the economics of the power sector have been analyzed using a metric known as the levelized cost of electricity (LCOE) (OECD/NEA, IEA 2015). This indicates the unit cost of a power generating technology, counting all the related costs including the fixed, variable, operational and maintenance, decommissioning, and waste disposal costs, divided by the total electricity output, with consideration of an assumed discount rate. With an assumption of the load factor of the technology, LCOE can be calculated as a constant value. This means that LCOE is a metric that measures the change in the cost of the power system with a substitution of power sources with a linear approximation. For example, denote the LCOE of technologies (or "sources") A and B as L_A and L_B, respectively. If the output of source A is substituted to that of B by x kWh, the total cost increase equals $(L_B - L_A)x$. Under high penetration of VRE, however, this linear approximation obviously does not hold; while the required investment on power storage systems can be almost negligible with low shares of VRE, it can increase nonlinearly with increasing demand for balancing the intermittency of VRE. In this regard, the economics of the power sector under high penetration of VRE cannot be captured with the traditional metric of LCOE, highlighting the need for considering the non-linear integration cost properly.

It may be worth mentioning that this was also the case with conventional power systems in which LCOE was relevant. Suppose we introduce coal-fired power generation into a system with predominant natural gas-fired power generation. If the LCOE of coal with the highest load factor, e.g. 80%, is lower than that of natural gas, introducing coal is cost-effective. However, if coal power generation exceeds a certain level, the load factor becomes lower than 80% to meet the fluctuating power demand, and the "marginal LCOE" begins to decline. At the optimal point where the total cost takes the smallest value, the marginal LCOE of coal equals that of natural gas. Thus, the attempt to perform cost estimation using marginal costs in decarbonized power systems can be regarded as a generalization of the conventional method with systems with conventional technologies. Note that the concept of integration cost can contribute to climate policy development greatly, given that the assessment of the cost of the power sector with high VRE shares can be crucial for policy analyses using integrated assessment models (IAMs) (Sugiyama et al. 2021; Shiraki et al. 2021).

Many academic and non-academic studies have been carried out to assess the integration cost with high VRE shares, especially after the latter half of the 2010s. Although most studies focus on Europe (e.g. Scholz et al. 2017; Van Zuijlen et al. 2019) and the U.S. (e.g. Frew et al. 2016; Noel et al. 2017), some research groups have attempted to estimate it with explicit consideration of many other countries over the world (e.g. Ram et al. 2017; Jacobson et al. 2018). With several studies criticizing the inappropriateness of the modeling frameworks (Heard et al. 2017), and other studies rebutting these criticisms (Brown et al. 2018; Esteban et al. 2018), ongoing discussions have been underway on this important topic.

Several studies have also tried to summarize the estimated amount of the integration cost; OECD/NEA (2012) estimated the average integration cost with a VRE share of 30% at 2–8 cents/kWh, while OECD/NEA (2018) puts it at 2.5–4 cents/kWh, and OECD/NEA (2019) estimates it at 2 cents/kWh for Europe. In addition to these quantitative uncertainties, we must note that these estimated costs refer to the "average" integration cost, which is the additional system cost divided by the VRE output, rather than the "marginal" integration cost. As economic principles imply that the optimal state is determined by marginal costs, rather than by average costs, the estimation of the marginal cost, referred to as the marginal system LCOE, or simply as the system LCOE (Ueckerdt et al. 2013; Hirth et al. 2016), can also be useful. Reichenberg et al. (2018) attempted the quantification of both average and marginal system LCOE focusing on Europe, although they only calculated these metrics for "thermal power" and "VRE", without explicit reference to individual technologies.

IEA (2018) and IEA (2019b) estimated the marginal cost by technology, under the name of value-adjusted LCOE (VALCOE). This metric estimates LCOE by technology with the observed load factor in an energy mix, adjusting them using three kinds of market values, i.e. energy values, capacity values, and flexibility values. It is conceptually similar to (marginal) system LCOE by Hirth et al. (2016). As an example, according to IEA (2019b), the LCOE of solar PV in India continues to decline through 2040, when it reaches 30 USD/MWh, which is significantly lower than the LCOE of coal power generation at 55 USD/MWh. However, as the market values of solar PV will also decline until that year, the VALCOE of coal and solar PV stand closer at 50 USD/MWh. Despite these studies, as far as the authors know, there are no studies that explicitly estimate the average system LCOE by source. We should also note that these marginal metrics admit of further improvement, in that they do not necessarily consider changes in the total power output properly (Matsuo et al. 2019).

When estimating the costs of the power sector with high VRE penetration, mathematical models with tens or hundreds of time slices per year used to be exploited until several years ago (IRENA 2017). However, more recent studies tend to use models with hourly or higher time resolutions, which correspond to no less than 8760 time slices. In IAMs, that encompass total energy flows, detailed representation of the intermittency of VRE is more difficult, mainly because of the required large computational load. To address this problem, for example, Ueckerdt et al. (2015) developed a method to use residual load duration curves (RLDC) to assess integration costs under high penetration of VRE, which has been applied to policy analyses using IAMs such as REMIND and MESSAGE (Ueckerdt et al. 2017; Johnson et al. 2017). This RLDC method, however, cannot estimate storage requirements properly, unless it is soft-linked to another model that analyzes the power sector in detail, because it cannot simulate the risk of electricity disruption during windless periods (Matsuo et al. 2020). Although a small number of studies have attempted to incorporate a detailed power generation model with an hourly time resolution to an IAM (Kawakami and Matsuo 2020), this kind of hard-linking of models has not been common for the moment. Thus, developing a proper method for soft-linking is essential for energy and climate analysis.

In view of these circumstances, in this study, we calculated the average and marginal system LCOE focusing on a decarbonized power system in Japan, and tried to draw policy implications. Although this study exploits the same mathematical model and the same data that we used in our previous studies (Matsuo et al. 2018, 2020), and analyzes the same Japan's decarbonized power system in 2050, it is essentially different from them, because previous studies only calculated increases in the total system cost, without reference to cost allocated to each technology. This study has new findings as the first comprehensive application of our system LCOE methods: Both average and marginal system LCOE naturally depends heavily on the assumptions on the costs of VRE, but the relationship is not straightforward, as average system LCOE depends also on the integration path, and marginal system LCOE is susceptible to large uncertainties. In the context of risk management, using multi-annual meteorological data is essential for obtaining good estimates of marginal system LCOE under high penetration of VRE. As this study is, to the best of our knowledge, the first attempt to estimate system LCOE by technology focusing on the power sector of Japan, the results shown here can also contribute to evidence-based energy and climate policy making. In addition, this study proposes a method to incorporate the estimation of integration costs to IAMs using marginal system LCOE, which can contribute to better quantitative analyses of climate policies.

The remainder of this article is organized as follows: in the method chapter, the concepts of average and marginal system LCOE, the model structure, and major assumptions were presented; in the result chapter, the calculation results and discussions were given; in the conclusion chapter, conclusions and policy implications were proposed.

Methods

Concepts of average system LCOE and relative marginal system LCOE

In this study, we quantify "average system LCOE" and "relative marginal system LCOE", which is also referred to simply as "marginal system LCOE" in this study, for a decarbonized power sector in Japan in 2050. This section provides qualitative discussions on the methodology, and the Electronic Supplementary Material describes the methods for calculating these metrics. For more detailed discussion on the methodology, the reader is referred to our previous paper (Matsuo et al. 2019).

Figure 1 illustrates the concept of integration cost for a simple system with two technologies, i.e. conventional (thermal) power generation and VRE. The LCOE, denoted as L_{conv} and L_{VRE}, respectively, for the two technologies, are defined as those calculated with the maximum possible load factors (e.g. 80% for the conventional technology and 22% for VRE). We define the integration cost I as the gap between the total annual cost and the sum of C_{conv} and C_{VRE}, which are the annual power outputs multiplied by the LCOE.

Average system LCOE can be calculated by allocating the integration cost I to each technology, but this allocation has

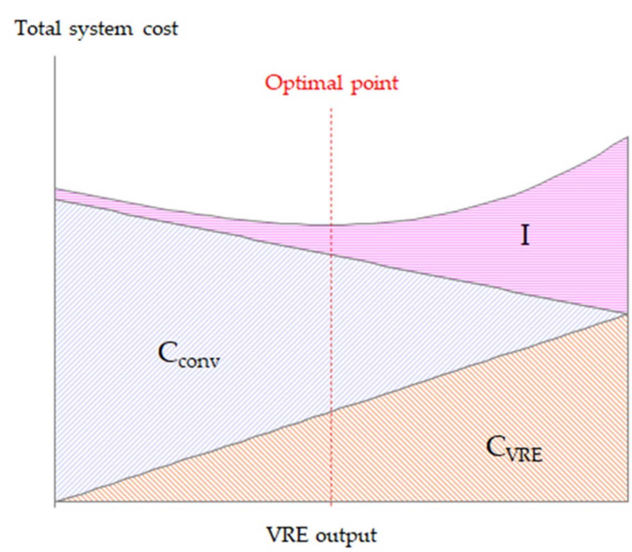


Fig. 1 An illustrative diagram of integration cost

methodological complexities. In a greenfield system with the total cost responding to changes in power outputs linearly, traditional LCOE represents the cost increase associated with unit increase in the output of a technology. In a system with strong non-linearity, we should be aware that the cost changes associated with different technologies differ depending on the order of the introduction of the technologies. Suppose a situation in which we introduce VRE to an initial system with conventional technologies. If we introduce solar PV in the first place and wind power in the second place, the cost increase is larger for wind power than for solar PV, and vice versa. For this reason, we increase all the power outputs equally from the origin of the coordinate, using the straight integration path as shown in the Electronic Supplementary Material. Here, the "origin of the coordinate" represents the zero-cost state, in which all the electricity is supplied with the "costless" technology without any fixed and variable costs, and with infinite flexibility. An important point to note is that the integration cost is allocated not only to VRE but also to conventional technologies; in case the system is supplied only with coal-fired power generation, the load factor is lower than the maximum value, e.g. 80%, and the cost increase associated with this decline in the load factor can be viewed as the integration cost caused by the inflexibility of coal-fired power generation.

Another important point to note is that the total annual power output is not a constant, but increases with high VRE penetration due to the energy losses associated with transmission and/or power storage. If we divide the allocated total cost by the power output to calculate the average system LCOE, it can take unjustifiably small values because of the large power output. For this reason, we select a reference technology, which is hydrogen thermal power generation for the calculations in this study, and adjust all the power outputs with reference to it. Suppose we replace one unit of the power output of the reference technology with that of technology i, which increases by $1/R_i$ unit. If i denotes a VRE which requires larger storage losses than the reference technology, $0<R_i<1$. In this case, the annual output of technology i, denoted as x_i, is adjusted as $dx'_i=R_i dx_i$. Using the adjusted power output thus defined and the allocated cost C_i, we can calculate the average system LCOE $\overline{L_i}$ by $\overline{L_i} = C_i/dx'_i$.

We also calculate the (relative) marginal system LCOE L_{R_i} of technology i as defined in the Electronic Supplementary Material. This is defined as the cost increase with the substitution of one unit of the output of the reference technology with that of technology i. Again, we must adjust the value with the coefficient R_i because of the change in the total output. Note that we can only define the difference between the marginal system LCOE of two technologies. However, for illustration purposes, it would be convenient to define that the marginal system LCOE of the reference technology as equal to its LCOE, and calculate the marginal system LCOE of technology i by adding the estimated difference to that of the reference technology. In the case of the system with two technologies illustrated by Fig. 1, the slope of the total cost $C=C_{\mathrm{conv}}+C_{\mathrm{VRE}}+I$ represents the difference in the marginal system LCOE of the conventional technology and VRE. There are two important points to note here: First, the optimal point with the smallest C is the point where the marginal system LCOE of the two technologies take the same value. Generally speaking, at the optimal or the "equilibrium" point, the marginal system LCOE of all technologies take the same value. In this sense, marginal system LCOE of technology i can be viewed as a metric that represents the "distance" from the equilibrium point with regard to i. Second, at any point other than the equilibrium point, the marginal system LCOE of unconstrained technologies take the same value. For example, if the upper limit of nuclear power capacity and the total output of thermal power generation are constrained, and if the installed capacities of wind and solar PV are not constrained, the optimal solution exhibits the same marginal system LCOE for wind and solar PV.

As described later, system LCOE are dependent on meteorological conditions. For this study, we mainly used meteorological data for 2012 following Matsuo et al. (2018), also using other data for 2013–2017 following Matsuo et al. (2020).

It is noteworthy that since these methods use only the total system cost for calculation, as described in the Electronic Supplementary Material, it can allocate any kind of related costs consistently, as long as they are counted in monetary terms.

Japan's power generation mix in 2050: decarbonization of the power sector

In this study, we calculate average and marginal system LCOE, as explained in the previous subsection, for Japan, based on our prior studies that assessed integration costs. As the government's target to reduce GHG emissions by 80% by 2050 is supposed to require almost complete decarbonization of the power sector (Sugiyama et al. 2019), and even if we cannot achieve this mitigation target, the decarbonization of the power sector should be required at some stage beyond 2050, we assume a system only with decarbonized sources, i.e. zero-emission thermal power, nuclear power, onshore wind, offshore wind, solar PV, hydro, geothermal, and biomass, although the outputs of the last three technologies are fixed for simplicity in this study, as described later. Zero-emission thermal power can either be fossil-fuel fired thermal power generation with carbon capture and sequestration (CCS), or hydrogen-fired thermal power generation. In this study, we assumed the use of imported hydrogen, which costs 20 JPY/Nm^3 according to the cost reduction target of the government (Ministry of Trade, Economy and Industry 2019). This assumes that hydrogen is produced either by steam reforming from fossil fuels in resource-rich countries, with the CO_2 emitted during the process being stored by CCS, or by electrolysis from renewable sources, and then the "carbon-free" H_2 is exported to Japan for use in power generating plants. Note that the assumption on the type of zero-emission power generation is not essential for this study; as long as the fuel cost remains the same, the calculation results are almost interchangeable with those with other technology assumptions. It is also worth mentioning that the fuel cost in 2050 is uncertain, given that massive commercial use of imported hydrogen has not been realized to date. In case the operating cost of zero-emission thermal power generation does not decline to reasonable levels, thermal power output will practically be limited. For this reason, we performed calculation fixing thermal power output fixed in a wide range from 20 to 600 TWh.

Nuclear power is assumed to be used with an upper limit of 25.5 GW, which is the total capacity of the existing plants that can still be in use assuming a year lifetime of 60 years, along with that of the three nuclear plants currently under construction.

Modeling framework and major assumptions

We used an optimal power generation mix (OPGM) model that we developed for previous studies. This is a linear programming optimization model, that minimizes the total annual cost of the power system, including all the capital, operation and maintenance, and fuel costs, to obtain the optimal power supply and demand operation. It uses wind and solar PV hourly output data calculated from the Automated Meteorological Data Acquisition System (AMeDAS) observation database (Japan Meteorological Agency 2020). For more details of the OPGM model, the reader is referred to our previous works (Komiyama and Fujii 2017; Matsuo et al. 2018, 2020).

Several points should be noted here: First, for this study, we used historical hourly demand data for 2012–2017, corresponding to the meteorological data, which means that the calculations in this study neglect possible future changes in load curves. This implicitly assumes that the current electric tariff system remains the same until 2050. Second, as we have not modeled the possible contributions of electric vehicles (EVs), plug-in hybrid vehicles (PHEVs) and other demand side management (DSM) technologies to the stabilization of power grids, the calculations may somewhat overestimate the cost increases with high shares of VRE. However, the effects of these technologies are not supposed to change the overall picture, given that the cost increases are mainly determined by the duration of "windless periods," which may last for several days or weeks (Matsuo et al. 2020). Third, nuclear power plants are assumed to be operated flexibly with the assumptions shown in the Electronic Supplementary Material. However, flexible operation of nuclear power plants has not been allowed under the current regulation framework in Japan; if this remains the case in 2050, the average and marginal system LCOE of nuclear will become slightly higher than the values presented below. Fourth, for offshore wind, we assumed the same output profiles as onshore wind, adjusting the load factor to 30% (Power Generation Cost Analysis Working Group 2015). We could also use reanalysis data (Staffell and Pfenninger 2016), which is left for future work. Fifth, as the model assumes perfect foresight for both power demand and VRE output, the total cost may be underestimated, especially for the cases with very high VRE shares.

To reduce the large computational load, we made several simplifications for this study:

- *Modeled technologies* We simulated electricity supply for one year, only with respect to zero-emission thermal power, nuclear power, onshore wind, offshore wind, and solar PV. Power generation profiles of other technologies are fixed and subtracted from the electricity demand.
- *Temporal resolution* Matsuo et al. (2018) and Matsuo et al. (2020) used an OPGM model with a 10-min and an hourly resolution, respectively. For this study, we used a model with an hourly resolution.
- *Spatial resolution* Unlike Matsuo et al. (2018), which exploited a nine-regional model, we divided Japan into three regions: Hokkaido, Tohoku, and other areas. This is at least partly justified by the observation that in our previous studies, the largest part of the transmission cost was associated with the Hokkaido-Tohoku and Tohoku-Tokyo grid lines, because of the unevenly distributed electricity demand and VRE resources.

Thus, the model used in this study assumes 15 technologies, i.e. five technologies for three regions. The system LCOE of the technologies of the same type in different regions take similar values in many cases, but they can differ depending on the assumptions on resource potentials. We calculated marginal system LCOE for the 15 technologies, the results of which are given in the Electronic Supplementary Material, and presented them as the weighted average value for the three regions, with respect to the power output, in the figures presented below. For average system LCOE, we aggregated the power outputs in the three regions, calculating the values for the five technologies, to avoid the long calculation time.

Following Matsuo et al. (2018), we set upper limits for VRE capacities as estimated by Ministry of the Environment (2019), as shown in the Electronic Supplementary Material.

Note that these numbers roughly correspond to maximum potentials, and that there may be stronger limits in reality, especially for onshore wind power (Hamagata et al. 2019).

We set three VRE cost cases for this study. The high case corresponds to the "medium" VRE cost case in Matsuo et al. (2018). Although the initial cost of solar PV has been declining in Japan, it still remains at higher levels than in other countries (IEA-PVPS 2019). For wind power, we have not observed significant cost declines (IEA Wind TCP 2018). In the high cost case, the initial cost of solar PV is assumed to continue declining in line with past trends, and that of wind power will also decline significantly (Power Generation Cost Analysis Working Group 2015). At the same time, the Japanese government has set targets to reduce the LCOE of solar PV and onshore wind to 7 JPY/kWh by 2025 and to 8–9 JPY/kWh by 2030, respectively (Calculation Committee for Procurement Price, etc. 2020), although these targets deviate from past trends. In the medium cost case, we assumed that these targets will be achieved by 2050, and in the low cost case, we assumed that the LCOE of solar PV and onshore wind decline further to 5 JPY/kWh. The Electronic Supplementary Material presents the cost assumptions. For other cost assumptions, we followed Matsuo et al. (2018) and Matsuo et al. (2020); as power storage systems, we assumed the use of pumped hydro, which has an upper limit of 27 GW, li-ion batteries with a unit cost of 11,000 JPY/kWh, and hydrogen storage, which is cheaper but less efficient than batteries. The LCOE of hydrogen thermal and nuclear power generation are assumed at 12.2 JPY/kWh and 8.9 JPY/kWh, respectively, with a load factor of 80%. All the costs are measured in 2014 real JPY and are calculated with a real discount rate of 3%.

For each cost case, we calculated the optimal power generation mix, fixing the annual output of thermal power generation at 20 TWh, 50 TWh, 100 TWh, 200 TWh, 300 TWh, 400 TWh, 500 TWh, and 600 TWh. Thus we calculated three cost cases and eight power generation mix cases, totaling 24 independent cases.

Results and discussion

Power generation mix and the total cost

Figure 2 shows the power generation mix and the total annual cost for the three cost cases with different thermal power output. The VRE shares with the thermal output of 600 TWh are 4%, 20%, and 21% for the high, the medium, and the low cost cases. The share rises along with decreasing thermal power output, reaching around 68% in all cases. Total power output increases with decreasing thermal power output, due to increasing transmission and storage losses.

With large thermal power output, the share of solar PV is much higher than that of onshore wind for the medium and the low cost cases, while for the high cost case it is lower than that of onshore wind. This simply depends on the assumptions on the costs of wind and solar PV.

In the high cost case, nuclear capacity reaches the upper limit of 25.5 GW irrespective of the thermal power output level. In the medium cost case, nuclear capacity does not always reach the upper limit; it declines to 24.8 GW with 500 TWh, and 19.9 GW with 600 TWh. In the low cost case, nuclear power is not introduced for the 500 TWh and 600 TWh cases, which is a natural consequence of the lower assumed LCOE for wind and solar PV than for nuclear. In a more realistic setup, however, this may not be the case because capital costs are not required if the lifetime of the existing nuclear power plants is extended to 60 years. Another important point to note is that the load factor of nuclear power facilities declines with high shares of VRE; while it takes 80% for more than 200 TWh thermal power,

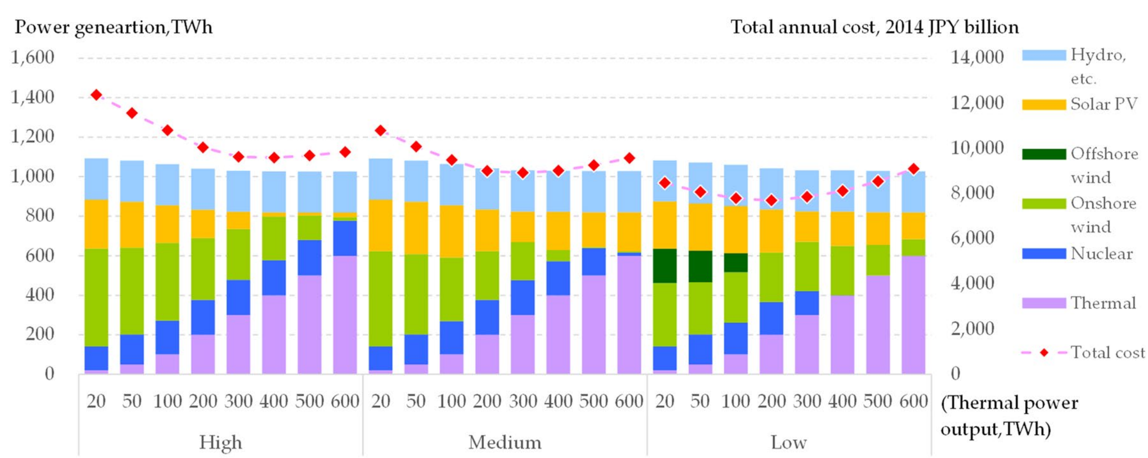


Fig. 2 Power generation mix and total annual system cost

it declines to 54% for 20 TWh, resulting in smaller nuclear power output.

The total annual system cost declines and then gradually increases along with the thermal power output declining from 600 TWh. The thermal power output with the minimum total cost stands at 400 TWh, 300 TWh, and 200 TWh for the high, the medium, and the low cost cases, respectively. While the total cost for 20 TWh is lower than that for 600 TWh in the low cost case, it is significantly higher in the high cost case.

Average system LCOE

Figure 3 illustrates the average system LCOE for the 24 cases. Unlike marginal system LCOE that are described later, the average system LCOE of thermal (hydrogen) power generation differs by case. However, the differences are slight; for all the cost cases, it rises to 12.9 JPY/kWh with 20 TWh, compared to 12.8 JPY/kWh with 600 TWh. The latter value is roughly equivalent to the LCOE of thermal power generation with a load factor of 60%, which corresponds to the situation in which all the power demands, subtracted with hydro and other power generation, are supplied with thermal power. As thermal power output decreases, the load factor also declines; it is less than 5% for 20 TWh. This means that the LCOE of thermal power generation, reflecting its load factor in the energy mix, is significantly higher than that with the load factor of 80%. However, as the decline in the load factor is mainly because of the increase in the VRE share, a large part of the cost increases are allocated to VRE, and not to thermal power.

In contrast, with smaller thermal power outputs and higher VRE shares, the system LCOE of VRE rise gradually. In the high cost case, the average system LCOE of solar PV exceeds that of thermal power for 300 TWh, and that of onshore wind exceeds that of thermal power for 100 TWh. In the low cost case, however, the system LCOE of onshore wind and solar PV are lower than that of thermal power even for 20 TWh. This is due to the low LCOE assumptions of VRE at 5 JPY/kWh, compared with 12.2 JPY/kWh for thermal power and 8.9 JPY/kWh for nuclear, both with a load factor of 80%.

The average system LCOE of nuclear is 9.5 JPY/kWh for 600 TWh. It rises moderately and reaches 11.0 JPY/kWh for 20 TWh. The reason for this rise is the lack of flexibility relative to thermal power. We should note that the average system LCOE of 11.0 JPY/kWh is lower than the LCOE of 12.3 JPY/kWh with a load factor of 54%, which means that part of the cost increase is allocated to VRE, and that nuclear power does contribute to power system stability by lowering its load factor.

Figure 4 displays average system LCOE by technology. For nuclear power, it takes almost the same values for the three cost cases. In contrast, average system LCOE of VRE differ significantly depending on the cost assumptions. Interestingly, for thermal power output smaller than 400 TWh, the average system LCOE of onshore wind takes comparable values for the medium and the high cost cases, taking even higher values for the medium case than for the high case for 20 TWh and 50 TWh. This corresponds to the fact that as shown in Fig. 2, with declining thermal power output, onshore wind is introduced in the first place in the high cost case, while solar PV is introduced preferentially in the medium cost case. In general, the technologies that penetrate earlier bear smaller integration costs, and have lower average system LCOE. As opposed to onshore wind, the average system LCOE of solar PV, which is introduced earlier in the medium case and later in the high case, exhibit considerable gap between the two cost cases.

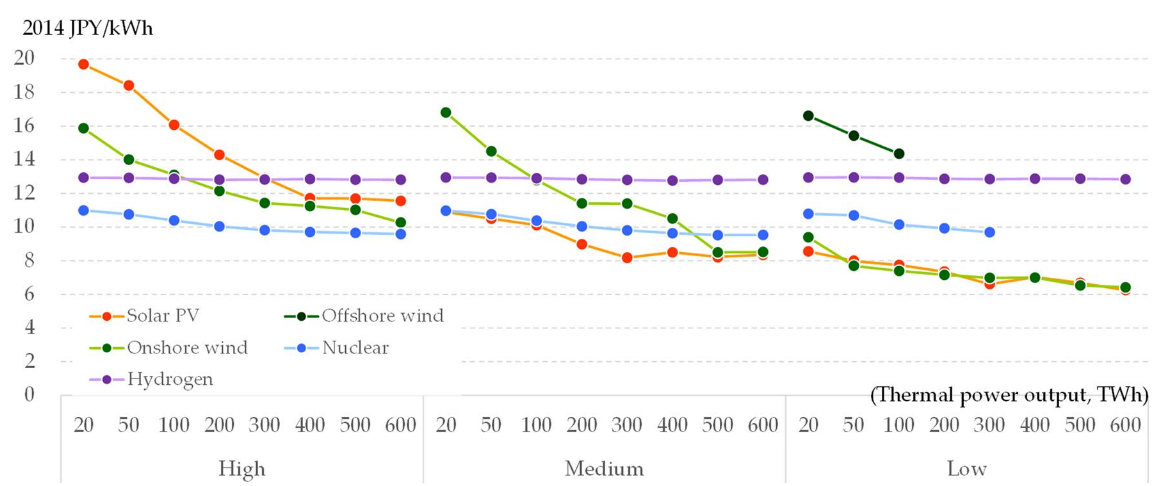


Fig. 3 Average system LCOE by cost case

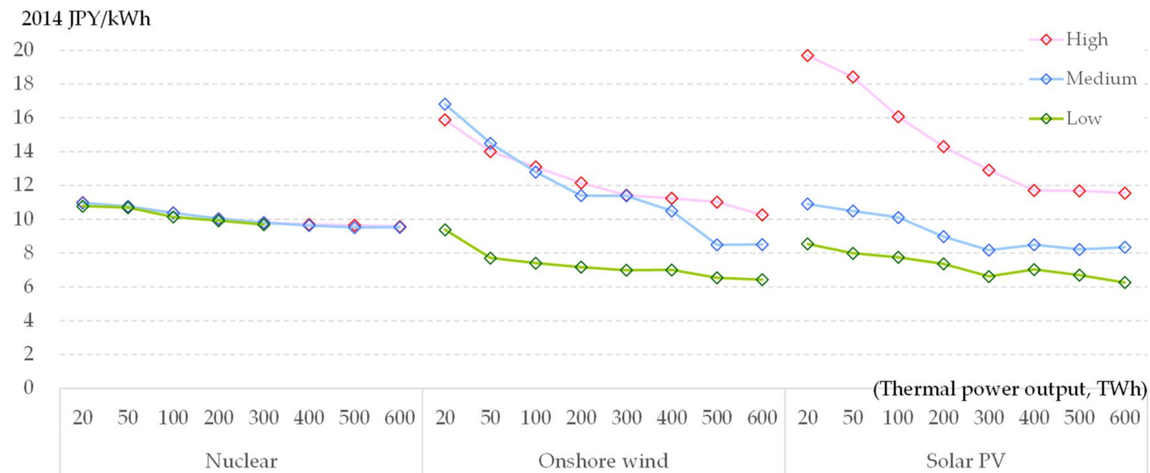


Fig. 4 Average system LCOE by technology

Relative marginal system LCOE

Figure 5 illustrates marginal system LCOE, calculated with the 2012 meteorological data, following the method described in the Electronic Supplementary Material. As is the case with average system LCOE, marginal system LCOE of VRE and nuclear rise along with decreasing thermal power output. However, they take much larger values than the corresponding average system LCOE. Note that the values for thermal power is constant by definition.

In the high cost case, the marginal system LCOE of onshore wind and solar PV intersect with that of thermal power between 300 and 400 TWh. This corresponds to the fact that the cost optimal thermal power output stands at 300–400 TWh for this case. With the thermal power output of 20 TWh, The marginal system LCOE of VRE and that of nuclear rise sharply to 40–50 JPY/kWh and 20 JPY/kWh, respectively.

In the medium and the low cost cases, the point of intersection is at 200–300 TWh and 100–200 TWh, respectively. This means that the effect of changing the costs of VRE on the intersection point is much smaller for marginal system LCOE than for average system LCOE; for all the cost cases, the marginal system LCOE of VRE exceed that of thermal power for thermal power output smaller than 100 TWh.

Changing the assumptions for the fuel cost of zero-emission thermal power generation does not seem to change the overall picture with very high VRE shares, given the large differences between the system LCOE of VRE and that of thermal power generation. At the same time, as

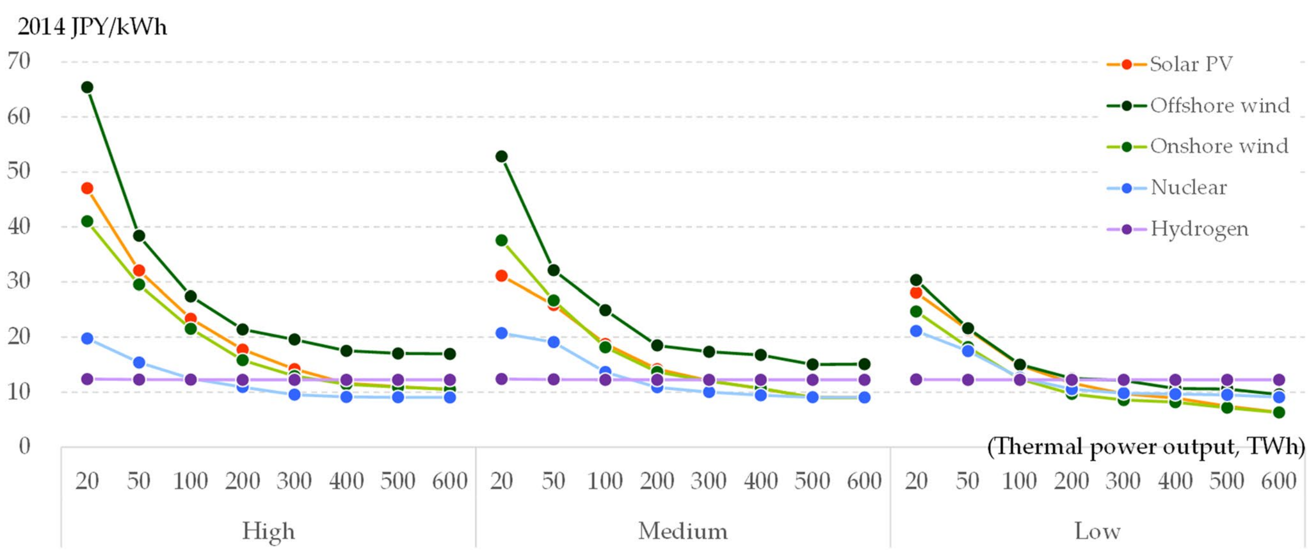


Fig. 5 Relative marginal system LCOE by cost case

we mentioned previously, not only the costs, but also the availability of zero-emission thermal power, are uncertain. However, given the very high marginal costs associated with small thermal power outputs, it would be difficult to achieve a decarbonized power system, unless we can make use of zero-emission thermal power at least to certain extent.

Figure 6 displays marginal system LCOE by technology. Unlike average system LCOE, it always takes smaller values for the medium cost case than for the high cost case both for onshore wind and solar PV. This is because the marginal system LCOE reflects the economics of power sources at only one given point.

In Fig. 6, we can observe strange trends for small thermal outputs: While the marginal system LCOE of nuclear power takes different values depending on the cost assumption for 50 TWh, it takes almost the same value for 20 TWh. This is because marginal system LCOE is susceptible to large fluctuations depending on metrological conditions, especially for very high shares of VRE, because it is calculated as partial derivatives.

Marginal system LCOE can be calculated with Eqs. (ESM-6) and (ESM-7). An important point here is that although the total system cost C has theoretically been regarded as a differentiable function of power output x_i, it can be a discrete function in a mathematical model with a one-hour resolution. For the LP model used in this study, although C varies discretely with a very small change in x_i, it can be regarded as an approximately differentiable function with larger changes in x_i. For this reason, when we calculate the partial derivative $\partial C/\partial x_i$ by computer simulation, the results depend on the scale of $\mathrm{d}x_i$, and smaller $\mathrm{d}x_i$ does not always lead to better estimation of $\partial C/\partial x_i$.

The second source of uncertainty is meteorological variation. With very high shares of VRE, the total system cost depends largely on the amount of deployment of power storage systems, which in turn depends on the duration of "dark doldrums", or "windless periods", in which wind and solar PV power outputs are extremely small (Matsuo et al. 2020). For this reason, the marginal system LCOE of VRE differs greatly depending on meteorological conditions. In contrast, the effect of different meteorological data on average system LCOE is relatively small, because it is an integrated value from low VRE shares.

Figure 7 presents the marginal system LCOE of nuclear, onshore wind, and solar PV, for 20 TWh and 200 TWh cases, calculated using meteorological data from 2012 to 2017. As shown in these charts, the system LCOE vary significantly for 20 TWh. For nuclear power, it changes with standard deviations of 3–5 JPY/kWh, without significant differences between the cost cases. For 200 TWh, standard deviations are small at 0.1–0.2 JPY/kWh.

Figure 8 compares standard deviations associated with two kinds of uncertainty: Meteorological data and the scale of differentiation ($\mathrm{d}x_i$). Here, the scale of $\mathrm{d}x_i$ has been changed between 20 and 200 GWh. This kind of uncertainty produces relatively large deviations for nuclear for 20 TWh, but overall, the deviations are much larger with respect to meteorological conditions.

Comparison with other studies

The results of the calculations of this study shows that with smaller thermal power output and higher VRE shares, the average system LCOE of VRE and other technologies rise, resulting in higher total system cost. Here, we define the unit system cost as the total system cost divided by the total power output with 0% VRE penetration. This stands at 10.9 JPY/kWh, 13.4 JPY/kWh, and 15.0 JPY/kWh for the low, the medium, and the high cost cases, respectively, with 0 TWh thermal power generation, as shown in Fig. 9.

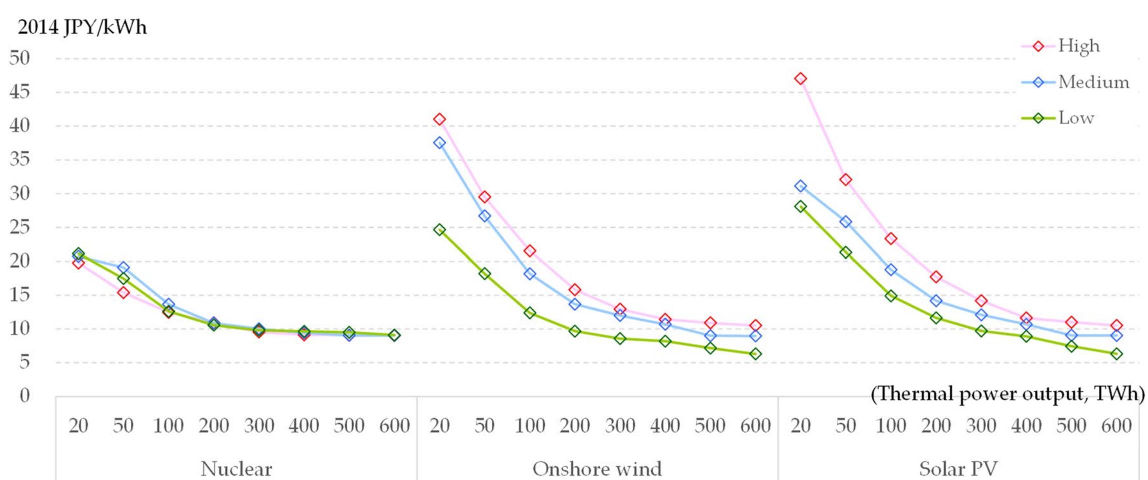


Fig. 6 Relative marginal system LCOE by technology

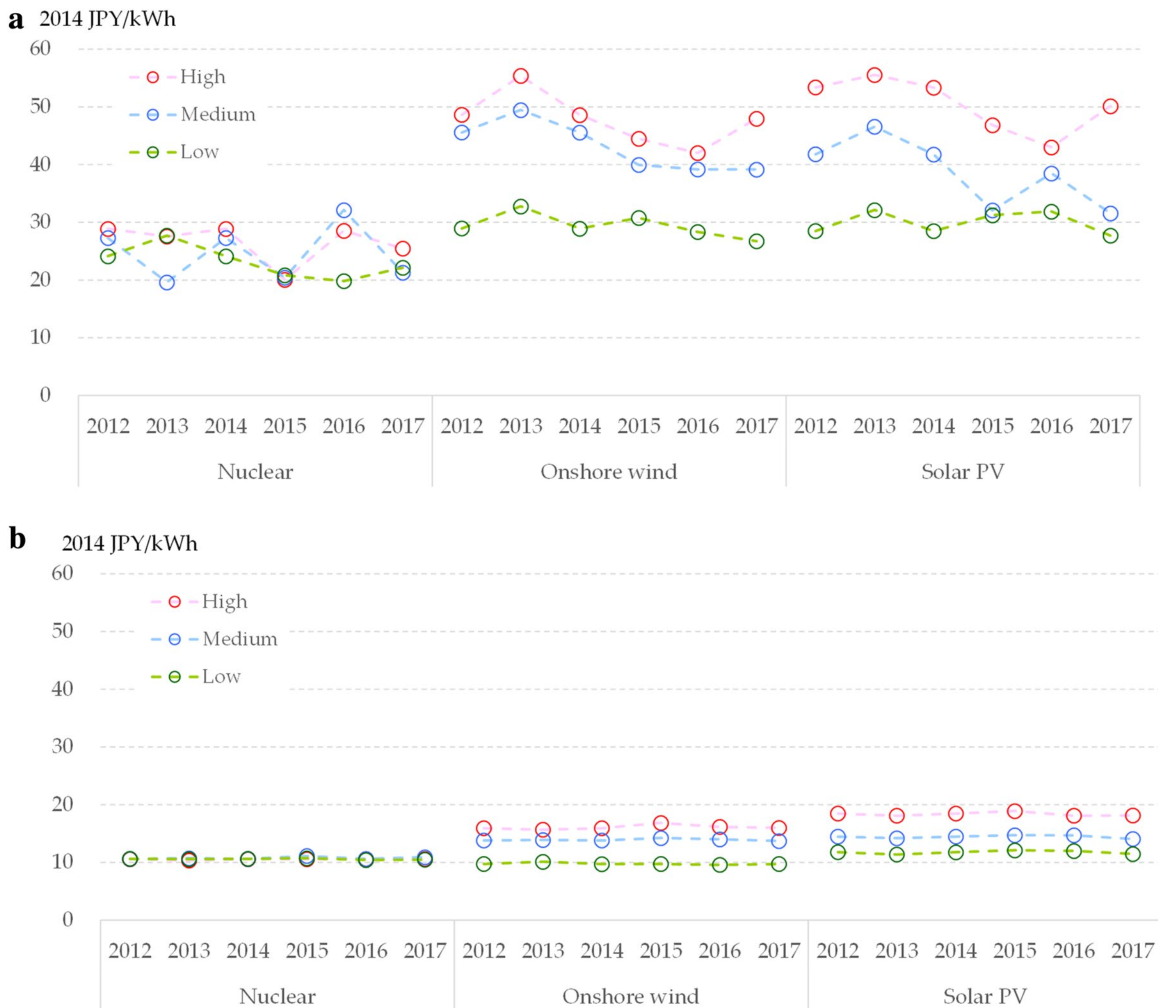
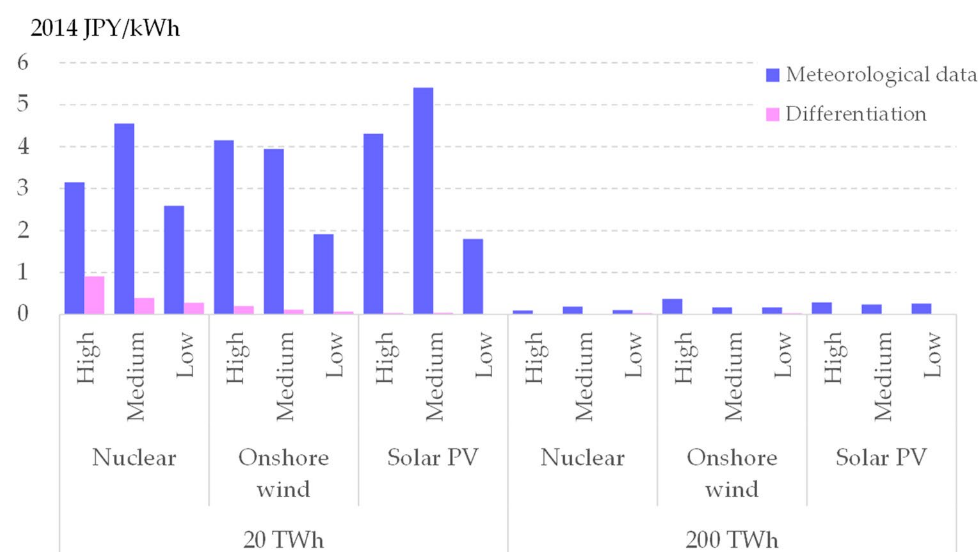


Fig. 7 Dependence of relative marginal system LCOE on meteorological conditions. **a** 20 TWh, **b** 200TWh

Fig. 8 Comparison of standard deviation of marginal system LCOE with two kinds of uncertainties. Note: Meteorological data are taken from observations for six consecutive years (2012–2017), and the scale of differentiation (dx_i) has been changed between 20 and 200 GWh



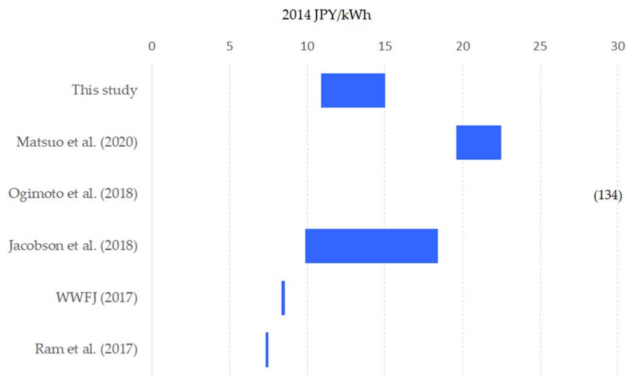


Fig. 9 Unit system cost in 0 TWh thermal power cases

For comparison, in our previous study Matsuo et al. (2020), the unit system costs with 100% renewable penetration are 19.6–22.5 JPY/kWh, dependent on the meteorological data, with cost assumptions that are equivalent to the high cost case in this study, and without nuclear power. The unit system cost by Jacobson et al. (2018) for 100% renewable cases stand between 9 and 18 JPY/kWh, which may roughly be consistent with the low cost case considering the use of nuclear power.

Ogimoto et al. (2018) estimated the total system cost at 134 JPY/kWh, while the estimation by WWFJ (2017) and Ram et al. (2017) were much smaller at 8.5 JPY/kWh and 7.4 JPY/kWh, respectively. One of the reasons for the high estimate by Ogimoto et al. (2018) is that they estimate the cost for a "100% VRE" case, rather than for a 100% renewable case. Another reason could be found in the difference in the assumptions on storage costs.

WWFJ (2017) assumes higher LCOE of VRE than the low case of this study; the LCOE of onshore wind and solar PV are assumed at 6.3 JPY/kWh and 9.3 JPY/kWh, respectively. However, the unit system cost with 100% renewables is even lower than the low case, probably because of the optimistic assumptions for storage requirements (Matsuo et al. 2018). In contrast, Ram et al. (2017) assumed a massive amount of gas storage systems. The reason for their low unit system cost may be found in very low assumptions for the LCOE of VRE, although we cannot verify it with published sources.

We should note that the unit system cost, as shown in Fig. 9, should be a weighted average of average system LCOE of all the power generating technologies in the system. This means that the marginal system LCOE of VRE are expected to be much higher, even in the studies with low unit costs, such as WWFJ (2017) and Ram et al. (2017). Trying to estimate the marginal system LCOE for these studies should be an important future research topic.

As described previously, there is no published study that explicitly estimates marginal system LCOE for Japan. For Europe, Reichenberg et al. (2018) estimate the average and the marginal system LCOE of thermal power generation and VRE, which vary depending on the VRE share. Note that the marginal LCOE by Reichenberg et al. (2018) is slightly different from its counterpart in this study, in that it does not consider the change in total power output explicitly, and that it is not estimated for separate technologies such as wind and solar PV.

According to Reichenberg et al. (2018), the average system LCOE of VRE rises from 4 Eurocents/kWh with 0% VRE penetration to 8 Eurocents/kWh with 99% VRE penetration. In the CO_2 neutral case, which uses biogas power generation that is more expensive than coal and natural gas, the average system LCOE does not differ much with different VRE shares. In contrast, the marginal system LCOE of VRE rises from 5 Eurocents/kWh with 5% VRE penetration to 10 Eurocents/kWh and 15 Eurocents/kWh with 85% and nearly 99% penetration, respectively, and the dependence on the VRE penetration level does not change much in the CO_2 neutral case. These results are roughly consistent with the findings in this study: Assuming complete decarbonization of the power sector, the dependence of average system LCOE on the VRE share is relatively small. However, the marginal system LCOE can be very high with high VRE shares, which could suggest the difficulty in promoting the introduction of VRE beyond certain levels.

Conclusions

In this study, we estimated the average and the marginal system LCOE metrics for a decarbonized power system in Japan, including zero-emission thermal power, nuclear power, and VRE. With higher shares of VRE, although both metrics are stable, or almost stable for thermal power generation, they take increasingly larger values for other power sources. Nonetheless, the two metrics are conceptually different and lead to different policy implications.

In the high cost case, the average system LCOE of VRE exceeds that of thermal power at thermal power output between 100 and 300 TWh. However, in the low cost case, the average system LCOE of VRE is always lower than that of thermal power. This is because even at very high penetration of VRE, most of the VRE facilities have been introduced with relatively low costs. On the contrary, the marginal system LCOE of VRE intersects with that of thermal power at around 200 TWh, even in the low cost case. The sensitivity of the intersection point of marginal system LCOE is by far smaller than that of average system LCOE, because the former metric only reflects the cost of the "last unit output" of VRE, while the latter reflects the total path of VRE diffusion. With very high shares of VRE, the marginal system LCOE of VRE is much higher than the average system LCOE. This means either that it would be difficult to achieve very high VRE shares, or that strong and persistent policy measures would be required to achieve that, even if the LCOE of VRE become significantly lower than that of conventional technologies. In this wise, as average and marginal system LCOE can lead to highly different policy implications, the proper estimation of both metrics would be useful for decent policymaking.

These observations tell us that the costs of power sources cannot be represented by a single constant metric, such as traditional LCOE. The cost competitiveness of one source will change if its share in the energy mix changes. The system LCOE of a technology is small at the initial stage of its diffusion. However, it becomes higher as it penetrates into the system. These results suggest the merit of a well-balanced energy mix in decarbonized energy systems; relying on a small number of power sources can increase the total system cost and enhance the risks of power disruption. Thus, future energy policies should aim to exploit various types of decarbonized power sources.

Incorporating the estimated integration costs to IAMs would be useful for developing climate policies. For this aim, we can approximate marginal system LCOE, properly adjusted with the coefficients R_i, as functions of VRE penetration. Suppose the system has n independent power sources. The marginal system LCOE of source i, L_{R_i}, is a function in an $(n-1)$-dimensional space, which could be excessively complex for practical use. In many cases, it would be reasonable to define L_{R_i} as functions in a lower-dimensional space, parameterized by a small number of variables, such as VRE share in a power generation mix.

It is worth emphasizing that marginal system LCOE can vary significantly depending on meteorological conditions, especially for very high VRE shares. For this reason, using multiannual data is a prerequisite for robust estimation. As the cost increases with high shares of VRE are related with the power supply disruption risk during windless periods (Matsuo et al. 2020), in the context of risk management, we should consider the "real" marginal system LCOE as at least as large as the maximum value, or theoretically, we may have to exploit more sophisticated methods such as minimax optimization. Thus, the estimated marginal system LCOE of VRE is supposed to rise with a larger set of meteorological data.

The calculations for this study assumed a "greenfield" market, which includes the capital costs of all facilities. However, as at least a large part of the nuclear facilities that are used in 2050 are expected to be currently existing plants, real markets are supposed to be "brownfield." In addition, high VRE penetration is supposed to require large additional interregional and intraregional transmission costs (Komiyama and Fujii 2017), which are not fully covered by the simple three-regional model used in this study. Improving the methodology to address these unsolved issues should be an important part of future work.

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