Metrics Measuring the Economic Efficiency of Power Sources upon Large-scale Introduction of VREs: LCOE and the System LCOE[1]

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1. Introduction

Growing concerns over climate change and the falling cost of variable renewable energies (VREs, which refer mainly to wind and solar PV) are transforming the electricity sector in many countries. From the perspective of the power system, VRE differs from conventional power sources in three main ways: VRE output changes with natural conditions and therefore cannot be adjusted in line with electricity demand; VRE plants are limited to locations with good wind conditions and solar radiation, and cannot be selected solely on convenience particularly for wind power generation; VRE generally has a very low marginal cost and a VRE plant, once established, can supply electricity at extremely low cost when wind and solar radiation conditions are favorable. With large VRE capacities already introduced in Europe and many other countries and expected to increase further, establishing appropriate expansion plans for generation facilities in the future has become a vital issue for the governments, regulators, and power companies of all countries.

Needless to say, an expansion plan for power sources should be based on a careful evaluation of economic efficiency. So far, the economic efficiency of each power source has been evaluated using a metric known as the levelized cost of electricity (LCOE). LCOE is the cost necessary to generate 1 kWh of electricity using a certain power source based on given assumptions (i.e., the unit cost). It is calculated by factoring in the characteristics of each power source, and it varies greatly even for the same power source depending on the capacity factor. As described later in this report, for example, coal-fired thermal and natural gas-fired thermal power have different fluctuation patterns, so their optimal shares (that would minimize the total cost) would be determined based on the electricity demand curve.

However, the characteristics of VRE described above often cannot be expressed fully using LCOE. For instance, since VRE does not offer flexible operation unlike thermal power, if thermal power and solar PV have the same LCOE, the former would generally have a higher value in the power system. In other words, the latter would be relatively more costly. Simply put, the issue is, what is the economic (in)efficiency of VRE that is not being adequately expressed by LCOE? This economic (in)efficiency can also be called “the additional cost of VRE associated with natural variation.” However, to be accurate, the economic efficiency calculated for thermal power or VRE capacity is valid only within the power system it belongs to, and even thermal power is not completely flexible and has a similar economic inefficiency to some extent. This issue clearly is not simple and calls for any additional costs to be allocated to both VRE and conventional power sources through an accurate simulation of how each power source would behave in a power system with large amounts of VRE installed.

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Based on these perspectives, this report outlines the key matters in considering the economic efficiency of the power sector when large amounts of VRE are introduced. There are ongoing international studies on this topic, including the report by the Nuclear Energy Agency of the Organisation for Economic Cooperation and Development (OECD/NEA) and the International Energy Agency (IEA)[1)].

In the following sections, Chapter 2 presents an overview of LCOE centering on the results of the assessment by OECD/NEA and IEA. Then, Chapter 3 outlines methodologies for assessing economic efficiency that "go beyond LCOE" based on the latest research trends.

2. Levelized Cost of Electricity (LCOE)

2-1 Concept of LCOE

As described earlier, LCOE is the "cost of electricity" or the cost of generating 1 kWh of electricity with a certain technology. To be precise, it is defined as the constant p that satisfies the following equation:

$$\sum_t \frac{C_t}{(1+r)^t} = \sum_t \frac{pE_t}{(1+r)^t} = p\sum_t \frac{E_t}{(1+r)^t} \tag{1}$$

In this equation, t is a variable representing the number of years elapsed since year 0 when the plant started operation. It changes starting from the year before the start of operation when costs were first incurred (i.e., $t < 0$) to the year in which operation ends and costs arise for the final time. C_t is the cost incurred in year ts and includes all costs incurred during a plant's life cycle spanning from construction, operation and maintenance, to the costs for plant decommissioning and final disposal of spent fuel. E_t represents the electricity produced in year t. The left side of Equation (1) is the total cost translated into the present value as of the year plant operation started by dividing it by the discount rate r described later; the right side of the equation is the total estimated income assuming that electricity generated in that plant is sold at p yen per kWh. As described, LCOE is the unit cost at which the "cost" strikes a balance with "value."

Based on Equation (1), LCOE can be defined as:

$$p = \sum_t \frac{C_t}{(1+r)^t} \Big/ \sum_t \frac{E_t}{(1+r)^t} \tag{2}$$

For convenience, the denominator is called the "discounted output." However, it is not the output itself that is being discounted but the value p at a certain time in the future presented in Equation (1).

LCOE can be understood as a linear approximation of the change in the total cost arising from replacing the output of one power source with another in a power system at a certain year in the future, in a greenfield construction project in which a power supply facility was constructed from scratch. In other words, when the LCOEs of power sources A and B are defined as L_A and L_B, and one kWh of supply from power source A is replaced with that from source B, the cost for the system as a whole would increase by $L_B - L_A$. Put differently, LCOE must be considered insufficient for assessing the economic efficiency of the power system if this linear approximation does not hold; this highlights the importance of a metric "beyond LCOE" as described later. Furthermore, since the cost C_t (the initial investment and fixed O&M cost thereof) relies heavily on the plant's installed capacity, the capacity factor, i.e., how much electricity E_t can be produced by a given capacity, will significantly impact LCOE.

Note that C_t should only include actual cash spending and not accounting-term expenses. For instance, power plant construction costs should typically be reported before the start of plant operation, and not be depreciated over time. This is because the latter would cause the discounted present value to vary depending on when the expenses were incurred, and generally result in a somewhat smaller LCOE. In the 2011 LCOE assessment of power sources by the Japanese government, the capital cost was depreciated over time. However, this was later found to be inappropriate, and so the cost is reported as incurred at the start of operation in the 2015 government estimate.[2)]

2-2 Points to note regarding the calculation of LCOE

2-2-1 Notion of the discount rate

The variation in timing at which expenses are incurred is important not only for the assessment of LCOEs but also for various economic indicators. This is typically represented by the discount rate r.

The discount rate is a rate used for converting a future monetary value into its present value. For example, assuming interest income of 3% per annum is guaranteed, an amount of 1 thousand yen now is equivalent in value to 1.34 thousand yen 10 years later. In other words, an amount of 1 thousand yen 10 years in the future can be discounted to 740 yen in present value. The rate of 3% used in this type of calculation is called the discount rate. As shown by this example, on a time scale of a few years to several decades, the discount rate can be considered as almost equivalent to the interest rate.

In many cases, the cost C_t that appears in Equations (1) and (2) is expressed as a real value with the impact of inflation or deflation removed. In these cases, the real discount rate is used for r. For example, when the nominal interest rate is 5% and the inflation rate is 2%, the real interest rate is approximately 3% and the relationship between the nominal discount rate and the real discount rate is the same. Note that equivalence is being discussed in two different contexts here, i.e., inflation/deflation and conversion into present value. First, because of inflation, 1 thousand yen in the current year is equal in value to 1.02 thousand yen in nominal terms next year, and the value for next year is indicated as (real) 1 thousand yen. When converted into present value, the equivalent of 1 thousand yen this year would be real 1.03 thousand yen and nominal 1.05 thousand yen next year.

2-2-2 Change in LCOE associated with the discount rate

As shown by Equation (2), the value of LCOE will vary greatly depending on the value used for discount rate r. Specifically, a higher r would significantly increase LCOE for nuclear power and renewables whose initial costs are high, but the impact of r would not be so large for sources such as thermal power, which incurs high costs when generating power (fuel costs) but not at the time of construction. This can be understood more easily by imagining borrowing money to build a nuclear power plant and repaying the loan with the income from power generation. The fact that a higher r would significantly increase LCOE for nuclear means that the higher the interest rate on the loan, the more income the plant must earn, otherwise repayment will become impossible. For this reason, the discount rate is considered one of the factors with the greatest impact on the economic efficiency of nuclear power. In Japan, costs have typically been calculated assuming a discount rate of 3%. However, the results may change greatly depending on the assumed discount rate.

2-2-3 The issue of backend costs

As described above, when calculating LCOE, all costs are converted to the present value as of the start of plant operation. This generally results in a smaller contribution of backend costs to LCOE. For example, in the 2015 estimate by the Japanese government[2)], decommissioning only accounts for 0.1 yen/kWh, fuel reprocessing for only 0.5 yen/kWh, and high-level radioactive waste disposal for only 0.04 yen/kWh of the LCOE of nuclear power of 8.8 yen/kWh. This is because the costs for decommissioning and reprocessing are not incurred until at least 40 years after the plant starts operation, meaning that if the discount rate is set to 3%, the costs would decrease to a third ($1/1.03^{40}$) or less. The implications are clear in light of the discount rate concept described above. If a certain percentage of the proceeds from plant operation is set aside for decommissioning the plant after its closure, even a small percentage will be enough to cover the decommissioning and reprocessing costs because it will usually yield investment returns. Thus, the decommissioning cost will not have a substantial impact on the economic efficiency of nuclear power if a small amount is put aside in a well-planned manner during the plant's lifetime for decommissioning.

The problem is somewhat more complex for high-level radioactive waste (HLW) disposal. The cost for geological disposal of HLW produced in Japan to date is estimated at 3 trillion yen. After disposal, the wastes must be monitored for a certain period, but thereafter, they would basically not be managed by humans. It is assumed that the location and design of the repository will be considered sufficiently conservatively to ensure no burden is placed on future generations, and to ensure that safety would not be undermined even without human involvement. These costs only arise several decades after the start of operation and have a small impact on LCOE. Rather than economic costs, this issue raises the question of how to ensure safety for hundreds of thousands of years.

It is worth considering what would happen if it became necessary to manage the repository for several hundred thousand years after waste disposal. If the possibility of radioactivity leaking into the human living space after disposal is not absolutely zero, then potential damage with a certain monetary value could occur and continue for a long time. Assuming that a latent or manifest cost of X yen is incurred from now into eternity at a discount rate of r, the cumulative costs into the future are expressed as the sum of the geometric series $X + X/(1 + r) + X/(1 + r)^2 + \ldots = X/r$. For example, when X is 1 billion yen/year and r is 3%, the cumulative costs would be 33.3 billion yen, which would have hardly any impact on the cost of nuclear power generation even when added onto the waste disposal cost of 3 trillion yen. Specifically, it is possible to cover the necessary costs permanently by saving a finite amount of funds (for example, 33.3 billion yen) by the time of disposal and investing those funds.

However, this does not solve all the problems. When it is necessary to handle such a long timeline, the discount rate should be assumed to decrease into the future[3)] and it becomes difficult to conduct quantitative analyses based on such assumptions. But here again, the key question is how to reduce the risk of leakage in the future when designing the repository, and not economic efficiency.

2-2-4 Initial costs and accident risk costs

As discussed so far, the contribution of backend costs to the LCOE of nuclear power typically decreases considerably by discounting. Conversely, costs that are not discounted may have a significant impact on the economic efficiency of power sources. From this perspective, the cost for additional safety measures warrants particular caution for Japanese nuclear power. As this cost is added onto the initial cost, i.e. the plant construction cost, how to curb this cost to reasonable levels will strongly affect the economic efficiency of nuclear power going forward.

In addition, the cost related to nuclear accidents should also be excluded from the discount calculation, because a nuclear accident could occur potentially while generating power. Accident risks should normally be estimated as the monetary value of damages caused by an accident multiplied by the frequency at which accidents occur, but it is not easy to estimate the frequency. In any case, the accident-related cost per kWh estimated by some means should not be discounted, but be added to LCOE as is.

2-3 LCOE and the optimal power mix

LCOE helps determine the optimal share of conventional power sources. Fig. 2-1 illustrates the electricity demand for 8,760 hours in a year in order of the scale of demand (called the load duration curve). Assume that the electricity demand is covered using only coal- and LNG-fired thermal power. Since coal-fired thermal power usually has a higher construction cost and lower fuel cost than LNG-fired thermal power, coal would have a lower LCOE than LNG when its capacity factor is high, and the opposite would be true when its capacity factor is low.

Assume that f is the capacity factor at which the LCOE of coal and LNG are the same. In this case, the ratio of coal- and LNG-fired thermal power at which the total cost of the power system is minimized is shown by the horizontal dotted line in Fig. 2-1. In the area below this line, the capacity factor of coal is higher than f, so it would be economically rational to cover this area with coal-fired thermal power. Meanwhile, it would be more rational to use LNG-fired thermal power for the area above the dotted line. The theoretical optimal supply of electricity can be described simply, by using LCOE.

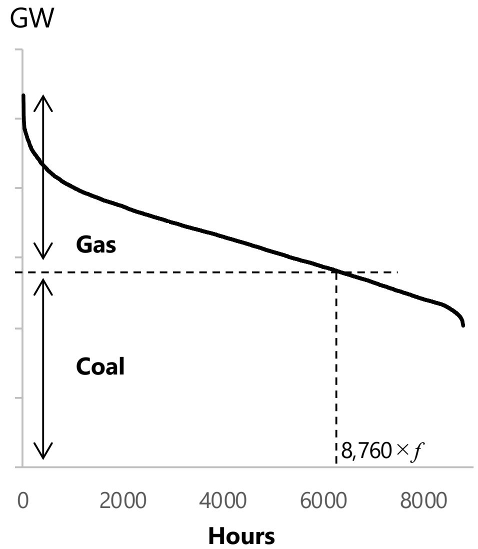


Fig. 2-1 Selection of power sources based on the load duration curve and LCOE

In this example, the LCOE of each power source, with its capacity factor factored in, can be considered to indicate the "marginal cost" of each source. This is because additional capacity installed in step with the increase in coal-fired thermal output will have a lower capacity factor, hence a higher

LCOE (the cost for additional kWh). The point at which the LCOE for coal-fired thermal power, with capacity factor factored in, becomes equal to the LCOE of LNG-fired thermal power is the point at which the power mix becomes optimal. The marginal cost for each power source, described later, can be understood as a general application of this well-known relationship.

2-4 Examples of LCOE: Assessment by the OECD

The OECD/NEA and the IEA have been conducting comprehensive estimations of LCOE by technology and country since 1983, and the 9th report was published in December 2020. This report presents, in a unified format, the LCOEs of energy sources calculated based on the power generation data submitted by the representatives of various countries, mainly OECD member states. This report, the 9th, contains data from 24 countries. In recent years, the report has included data from non-OECD countries, including China, India, and Brazil, as well as Russia and Romania which are NEA member states. Japan's data is based on the values mentioned earlier presented by the Power Generation Cost Verification Working Group, which are the latest estimates for the country. However, for VRE, the 2030 estimates are used as the estimated costs for plants starting operation in 2025, in light of the current and possible future reductions in VRE costs.

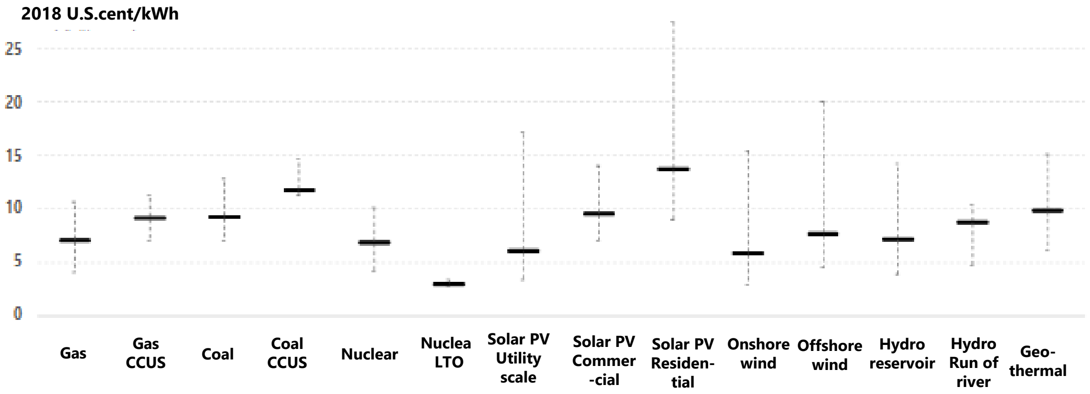
The 9th report is notable in the following ways. First, it discusses not only LCOEs but also the value-adjusted LCOE, or VALCOE, proposed by the IEA as a metric "beyond" the LCOE, for the first time. This topic is outlined later in Chapter 3. Second, it presents estimates for technologies that were not covered previously, namely CCUS (carbon capture, utilization and storage), long-term operation (LTO) of nuclear power plants, and batteries. In particular, for batteries, for which estimates cannot be obtained using the LCOE methodology as it is, a new metric called levelized cost of storage (LCOS) was introduced. LCOE assumes that plant starts operation in 2025 and imposes a carbon price of \$30/tCO_2 on thermal power.

Fig. 2-1 shows the estimated LCOE for each technology. Note that the results for discount rates of 3%, 7%, and 10% are presented in the NEA/IEA report, but only those for 7% are presented here.

The cost for thermal power will rise due to CCUS, even with a carbon price of \$30/tCO_2 factored in. However, CCUS would be cost-competitive for coal-fired thermal power for carbon prices higher than \$50–60/tCO_2 and for natural gas-fired thermal power for prices over \$100/tCO_2. Given that the IEA World Energy Outlook 2020[4)] predicts a carbon price of \$63/tCO_2 in 2025 and \$140/tCO_2 in 2040 in its Sustainable Development Scenario, CCUS would be a rational option, at least in an ambitious GHG emissions reduction scenario of this level.

The LCOE for nuclear power for Russia, which appeared in the report for the first time, was significantly lower than that of other countries at 4.2 cents/kWh for a 7% discount rate, less than two-thirds of the country's land-based wind power (6.7–7.2 cents/kWh for a 7% discount rate). The LCOE for LTO was estimated for the US, France, Sweden, and Switzerland, and was found to be 4.0–4.9 cents/kWh for a 20-year LTO. The technology is regarded as a highly competitive option compared to constructing new plants for other technologies.

There has been a steady reduction in costs since the previous report (2015) for renewable energies, particularly solar PV and wind power. In Europe, a significant reduction in LCOE was observed for offshore wind power, with the lowest LCOE being 4.5 cents/kWh for a 7% discount rate in Denmark. However, the LCOEs of renewable power sources vary greatly by country or even by region within the same country, and how to reduce them in high-cost countries and regions, including Japan, will be a major challenge going forward.



Note: The figure shows the median, the maximum, and minimum values of all data. The values for natural gas represent generation with the combined cycle generation technology (CCGT).

The values are for capacities of 1 MW or higher for land-based wind power and 5 MW or lower for hydropower.

Fig. 2-2 Examples of LCOE Estimates by OECD/NEA and IEA (2020)

3. Metrics "Beyond LCOE"

3-1 The need for new metrics

The LCOE approach has been used widely to compare the generation costs of different power sources. As mentioned earlier, if power source A is replaced with power source B in a certain power mix, the change in the cost for the system as a whole will be equal to the replaced output multiplied by a constant (the difference between the LCOEs of the power sources). However, in many cases, this linear approximation would not hold in a power system with high shares of VREs. For instance, solar PV output has a positive correlation with electricity demand when the capacity is small and thus helps to stabilize the electricity supply. However, as the capacity increases, it will be necessary to install electricity storage systems such as batteries, which pushes up the total cost of the power system accordingly. In such a case, the correlation between the solar PV capacity and the need for storage systems is clearly non-linear, and therefore, LCOE is not able to express the cost of solar PV by itself.

This problem has rapidly captured attention as an important issue in the last decade and was partly discussed in the 2015 NEA/IEA report. The latest report, published in 2020, describes the value-added LCOE (VALCOE) in more detail in Chapter 4. VALCOE is an evaluation indicator first presented in the IEA periodical publication, World Energy Outlook (WEO). As described later, the VALCOE of an energy source is obtained by complementing its LCOE with its value in the energy system and was newly developed to address precisely the issue discussed earlier. However, other similar metrics have also been developed for the same purpose. This paper hereafter describes various metrics including VALCOE based on the literature[5)6)] and introduces the current status of discussions on this problem.

3-2 Integration cost

3-2-1 Concept of integration cost

The problem we are currently considering is essentially the following: what would be the extra cost in addition to the conventional LCOE? From this perspective, the total cost of a power system, which we assume can be calculated in some way, minus the portion corresponding to LCOEs, is called the integration cost in this report (Fig. 3-1). In a simple system consisting only of conventional power sources (CPSs) and VREs, when the output from CPSs multiplied by their LCOEs (L_{conv}) is the cost C_{conv} and the output from VREs multiplied by their LCOEs (L_{VRE}) is the cost C_{VRE}, then the total cost C is expressed as the sum of these costs and the integration cost C_{INT}.

Here, the VRE capacity x at which C becomes the minimum is the value that satisfies the following equation:

$$L_{\boldsymbol{conv}} = L_{VRE} + \frac{dC_{INT}}{dx} \equiv L_{VRE} + L_{INT} \tag{3}$$

The value on the left side of the equation is sometimes called the System LCOE for the VRE. However, as described later, the term System LCOE is more generally used for a somewhat different concept.

It goes without saying that it is crucial to calculate C_{INT} appropriately in order to evaluate the economic efficiency of power systems with large amounts of VRE, and many studies have quantitatively estimated this value in the last decade. It is important to note that C_{INT} includes many different kinds of costs and is often determined using a mathematical model-based simulation. In general, the following classification is often applied[7)].

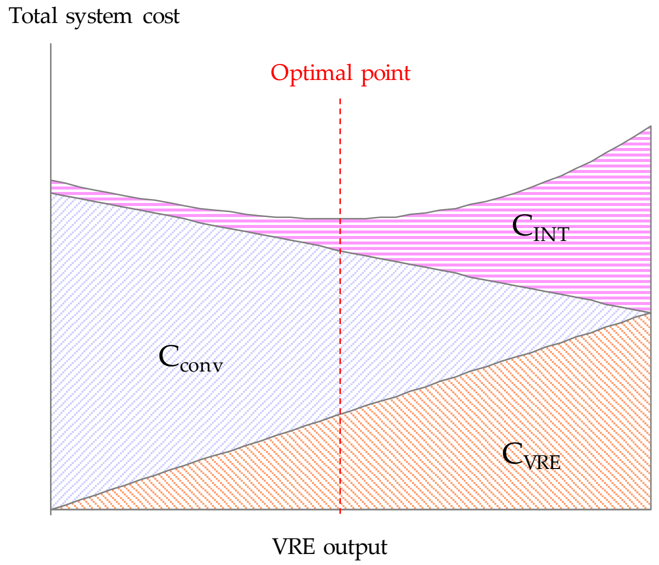


Fig. 3-1 Illustration of integration costs and system LCOE (horizontal axis: share of VRE; vertical axis: total system costs)

(1) Balancing costs

The cost of imbalance is associated with short-term prediction errors. The rise in this cost is recognized as a major challenge in the initial stage of introducing VRE.

(2) Grid costs

The cost associated with strengthening or expanding the power grid. However, in more general terms, it is defined as the cost arising from the spatial separation between VRE generation and electricity demand.

(3) Profile costs

The additional cost arising from temporal discrepancies between VRE generation and electricity demand; also called the utilization cost. This includes all the costs associated with VRE output control and introduction of batteries, low utilization factor of CPS, thermal power operation at part load, and increase in the number of start-ups and shutdowns. Unlike the balance cost, the profile costs would still be necessary even if fluctuations in VRE output and demand were completely predictable. The impact of profile costs is thought to grow when the share of VRE rises above a certain level.

Although Fig. 3-1 is simplified and shows only two types of technologies, the concept of integration cost in the diagram seems to be clear. Nevertheless, in fact the concept has some unclear points. First, a rise in the share of VRE usually results in a lower load factor of CPS and causes its LCOE to rise. Therefore, the problem arises that C_{conv} may not change linearly with the share of VRE, unlike in Fig. 1. Second, even among thermal power sources that are deemed as CPS, natural gas and coal differ in flexibility. Accordingly, as with VRE, some integration costs may be incurred, at least for relatively inflexible sources.

For the integration cost, or the total cost including it, one value is determined for an energy mix, and in that sense, it is different from LCOE whose purpose is to calculate the cost of each power source. As such, as described later, metrics that can show the cost of each power source were devised separately from integration cost. However, for practical purposes, the integration cost is sufficiently useful for formulating policies if the change in the integration cost or the total cost *C* for different shares of VRE can be determined accurately.

3-2-2 Estimating the integration cost

Starting in the 2010s, many studies that aimed to quantify the integration cost have been published. Many of the studies up to around 2015 to 2016 estimated the cost of VRE for shares of up to around 50%, but since 2017, more and more studies are estimating the cost for higher VRE shares. Recently, many studies are estimating the grid costs and profile costs above using a time resolution of at least 1 hour and finer regional divisions in modeling the uneven time and regional distribution of VRE output.

Some of the most common issues when assessing the results of estimating the integration cost are: (1) how much would the total cost rise if an extremely high share of renewables is to be achieved, if at all, and (2) whether the total cost would rise when, in addition to renewables, low-carbon power sources such as nuclear and zero-emission thermal power are used. A typical calculation using a mathematical model would show that, for achieving a zero-emission power sector, it would be less costly if renewables are combined with thermal and nuclear, rather than using renewables only. However, these results depend heavily on the modeling method and underlying assumptions as well as target regions, and some studies concluded that the total cost would be lower, under some conditions, if the share of renewables reaches 100% than if only CPS is used. The methodology for estimating the total cost has been generally consistent to date, yet the results still differ significantly among studies; it is hoped that yet more studies will be conducted in the next few years.

3-3 System value and the Levelized Avoided Cost of Energy (LACE)

3-3-1 Estimation of the system value

In the context of the large-scale introduction of VRE, there are increasing discussions on “values” in addition to the concept of integration “costs” described above. For example, the IEA has defined the “system value” of a power source as the net benefit, meaning all benefits less all costs, arising from adding that power source[8)]. Possible benefits that have been mentioned include reductions in thermal power fuel costs and emission of CO_2 and other pollutants, and costs for other power sources resulting from the introduction of VRE; possible costs include, aside from the cost for introducing and operating facilities, negative effects on the existing power system, the need for additional investment in the transmission networks and other facilities, and the need to adjust the output of VRE itself.

If, hypothetically, the total cost of a power system can be estimated completely, the “value” of the power source in this sense would mean the difference in the total system cost before and after the power source was introduced. This means that if “costs” can be estimated completely, the value can also be estimated. For example, the “value” of pumped-storage hydroelectric power can be estimated explicitly by calculating the difference in total costs with and without the power source in the power system[9)]. However, it is not so simple to estimate the “value” of technologies such as coal-fired thermal and solar PV, because adding these power sources to a given power system usually means that output from other sources must be removed, and the total costs change in different ways depending on which power source is removed, making it impossible to develop a unique definition of "value." This makes it necessary to consider "market value" as described in the next section.

3-3-2 Market value and cannibalization effect

The "market value" discussed here is the amount of revenue that can be derived from a certain power source in the various markets associated with the power sector. Measuring the market value has been attempted in relation to the wholesale electricity market. The market value of a one-kilowatt solar PV plant is obtained by weight-averaging the wholesale electricity price, which changes with time in a given supply-demand structure, by the plant's output. In mathematical modeling, this can be expressed as the weighted average of the shadow prices in supply-demand constraints. Note that when the output from a power source is in equilibrium with those of other power sources, in other words, the power system is at the optimal point or the point at which the total cost is minimized, the market value, i.e., the weight-averaged shadow price, is equal to the average cost of the power source, at least in an optimization calculation in a mathematical model. The market value would be higher than the average cost if the output is kept below the equilibrium by some constraint and would be lower than the average cost if it is introduced in larger amounts than the equilibrium.

This is particularly prominent for VRE whose output fluctuates greatly and is uncontrollable. When solar PV plants are introduced massively, the electricity price would be low, or even zero, in the day-time on a sunny day, making the value of introducing additional plants extremely small. A similar phenomenon occurs for wind power at a comparatively moderate, but remarkable level. This phenomenon, in which the value of VRE drops sharply when introduced in large amounts, is called the "cannibalism effect."

3-3-3 Levelized Avoided Cost of Energy (LACE)

The Levelized Avoided Cost of Energy (LACE)[10)], which the US Department of Energy has been using in recent years, is essentially the same metric as market value. The market value of a power source is equal to the decrease in the total costs for other power sources in the power system when a very small amount of that power source is added into an energy mix. Therefore, as described earlier, it would be cost-competitive to introduce additional amounts of that particular power source when its LACE is greater than its LCOE, and its LACE would be equal to its LCOE at the optimal point.

3-4 Value-adjusted LCOE (VALCOE), System LCOE, and Enhanced Levelized Cost

As previously stated, the competitiveness of a power source in the power system can be evaluated more accurately by estimating the "value" of a power source as well as its "cost," and comparing them for different sources. Accordingly, considerations are underway to expand the concept of LCOE using a metric that combines cost and value. Such efforts can be seen as attempts to calculate the "marginal cost of each power source." The three important examples are described below.

3-4-1 Value-adjusted LCOE (VALCOE)

The concept of VALCOE was first presented by the IEA in the World Energy Outlook 2018

(WEO2018) and is used in the joint report by the NEA and IEA as mentioned earlier. The aim of this metric is to complement the conventional LCOE by evaluating "value", as illustrated in Fig. 3-3.

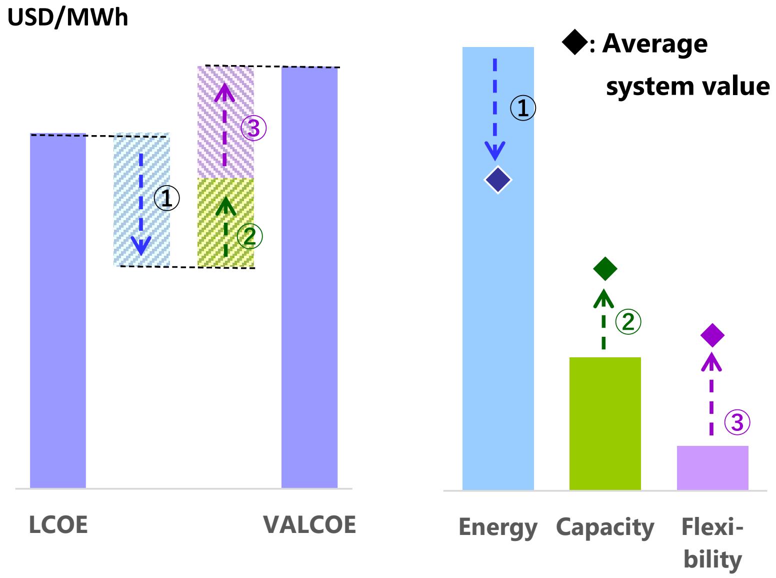


Fig. 3-3 Concept of the value-adjusted LCOE (VALCOE)

First, as shown on the right side of the diagram, the market value of a power source is measured in terms of its energy, capacity, and flexibility values. These values are then compared with the respective average market values (shown by ◆ in the diagram) in a given power system. Here, having a "high value" is synonymous with "low cost." That is, as shown in the left half of the diagram, for these three types of values, if the value of the power source is higher than the market average (as with the output value in this example), the difference is deducted from its LCOE; if it is lower than the market average, the difference is added on to its LCOE. Note that the LCOE used here is calculated based on the capacity factor of the power source in a particular power system. For example, when large amounts of VRE are installed in a system, the capacity factors for conventional power sources usually decrease and the resulting increase in costs is recognized as part of the profile costs. Meanwhile, note that the "LCOE before value-adjustment" referred to in the context of VALCOE already factors in this decrease in capacity factor and thus has a somewhat higher value.

3-4-2 System LCOE_HUE by Hirth et al. (2016)

System LCOE defined by L. Hirth, F. Ueckerdt and O. Edenhofer (2016)[11)] (hereafter System LCOE_HUE) is a metric similar to VALCOE. It is defined as follows:

$$L_{HUE\ i} = c_i - v_i + v_L \tag{4}$$

Here, c_i stands for the LCOE of the power source i. As with the case of VALCOE, it is calculated based on its load factor in a given power system. v_i is the "unit value," which is obtained by the annual income that the power source derives from the markets related to the power system divided by the annual output of the power source. v_L is the "unit value of demand" calculated by dividing the value of demand, i.e., the total annual costs for obtaining electricity from the market to meet the demand, by the total annual output of the power source.

The definition of the "average market value in the system" used to calculate VALCOE cannot be determined accurately from published documents[12). If it means the same as the "unit price of demand," if only the wholesale market, capacity market, and flexibility market exist in the power system, VALCOE and system LCOE_HUE would be the same. Furthermore, if the average market value in a system of VALCOE means the weighted average of all power sources, VALCOE and system LCOE_HUE would be nearly equal when the impacts of battery systems and power grids are small. In any case, the two concepts are similar. The difference may be that, whereas VALCOE actually uses a model used by the IEA for calculation, and thus, the target markets and the data used (such as capacity market prices) are predetermined, system LCOE_HUE is defined as a more general concept.

Problems with the concepts of VALCOE and system LCOE_HUE are described in the following section. It should also be noted that these indicators do not have "separability," which refers to the ability to divide the target power system. For example, when calculating the system LCOE_HUE of wind power plants in a city in Hokkaido Prefecture, the value v_L in Equation (4) will vary depending on whether the electricity demand curve used in the calculation is for the city, Hokkaido Prefecture, or Japan as a whole, and so the system LCOE_HUE value cannot be determined uniquely. It seems appropriate to use the electricity demand for Hokkaido Prefecture if Hokkaido has a fixed wholesale electricity market price, but this does not seem to provide a general solution.

3-4-3 Enhanced levelized costs by UK BEIS

A metric similar to the above has been proposed by the Department for Business, Energy and Industrial Strategy (BEIS) of the United Kingdom in "Electricity Generation Costs 2020" [13)]. For this metric, the impact on the (1) wholesale electricity market, (2) capacity market, (3) ancillary services market, and (4) power network when a certain power source is added to a given energy mix is quantified using BEIS Dynamic Dispatch Model as wider system impacts[14)]. Then, this value is added onto the LCOE to obtain a value called enhanced levelized costs. However, as with the relative marginal system LCOE described later, this methodology also requires a baseline power source to be determined; the report evaluates the wider system impacts of each power source relative to nuclear power.

According to this assessment, from the present up to 2035, the LCOE of VRE is estimated to be significantly lower than that of thermal power (CCGT + CCUS), while the enhanced levelized costs would be higher than the LCOE for VRE but lower than the LCOE for CCGT + CCUS. However, the degree of increase or decrease depends on what kind of energy mix those power sources are part of. The study calculates the enhanced levelized costs for six types of energy mix with various compositions and electricity demand levels, and suggests that the costs for CCGT + CCUS both may or may not be lower than solar PV, depending on the case.

Unlike VALCOE and system LCOE_HUE above, BEIS' enhanced levelized costs do not use market value in their equations. However, all these indicators can be considered as attempts to evaluate the marginal cost of a power source in a given energy mix, as described in the next section.

3-5 Marginal costs and average costs of a power source: Calculation for Japan

3-5-1 LCOE_HUE and the relative marginal System LCOE

As described earlier, the concepts of VALCOE and system LCOE_HUE are similar. In this section, System LCOE_HUE is taken as an example to see how it is related to the total power system cost *C*.

Assume that the output x_i of power source (or technology) *i* is increased by a small amount Δx_i in a power system. When this is done, the part of cost *C* corresponding to the output of power sources other than *i* decreases by $v_i \Delta x_i$ as x_i increases (recall that the unit value v_i of technology *i* is the same as its avoided unit cost), while the cost related to technology *i* increases in proportion to the amount corresponding to its LCOE, i.e. $c_i \Delta x_i$.

In an actual power system, the increase in x_i must be offset by reducing the output of other power sources. Here, we set up a *reference technology* 0 with an output of x_0, which decreases as x_i increases, and assume that the output of other sources does not change. As described above, *C* increases by $-(v_0 - c_0)\Delta x_0$ as a result. The ratio between the decrease in output of technology *i* and the increase in the reference technology is 1:1. This means that, if $\Delta x_i = -\Delta x_0$,

$$\frac{dC}{dx_i} = (c_i - v_i) - (c_0 - v_0) = L_{HUE\ i} - L_{HUE\ 0} \tag{5}$$

This shows that the difference in system LCOE_HUE would represent the marginal cost when the output of the reference technology is replaced with that of technology *i*.

The problem is that $\Delta x_i = -\Delta x_0$ does not always hold. Assume that technology *i* is solar PV and the reference technology 0 is thermal power, and that $R_i \Delta x_i = -\Delta x_0$ holds true. R_i is mostly equal to 1 when the share of solar PV output is small, but as it increases, the solar PV output corresponding to one unit of thermal power grows due to battery and transmission losses and curtailment, resulting in $R_i < 1$. As such, Equation (5) generally does not hold true in real life.

Based on the above, as an alternative metric to system LCOE_HUE, the relative marginal system LCOE L_i of technology *i*, is defined as follows:

$$L_i = \frac{1}{R_i}\frac{\partial C}{\partial x_i} - \frac{\partial C}{\partial x_0} + L_0 \tag{6}$$

In this equation, when a small output of technology *i* displaces the reference technology 0, $dC = -(L_i - L_0)\, dx_0$. $(L_i - L_0)$ represents the increase in total cost *C* when one unit of the reference technology is replaced with technology *i*. Since it is only the difference in marginal cost between the power sources that matters here, as implied by the name "relative" marginal system LCOE, any number can be adopted as the relative marginal System LCOE L_0 of the reference technology. In many cases, a fixed number, that is, 0, or the LCOE of the reference technology at a certain capacity factor, may be used for simplicity.

3-5-2 Average System LCOE

Whereas the section above described the "marginal" cost of each technology, it is also possible to calculate the "average" cost of it. That is, if the integration cost C_{INT} indicated in Fig. 3-1, and hence total cost C, can somehow be allocated to different power sources based on their contribution, it would be possible to calculate the average system LCOE L_{Ai} of each technology by dividing the allocated cost by the output. However, as conventional technologies are also inflexible in their respective ways, it is necessary to allocate I not only to VREs but to all technologies. In doing so, more flexible technologies should be allocated a smaller C_{INT}, and the C_{INT} allocated to two power sources with exactly the same characteristics must be proportional to the output of each power source.

The main problem here is that the incurred integration cost changes depending on the order in which technologies are introduced. When solar PV is introduced into a grid consisting of conventional power sources, followed by wind power, the rise in C_{INT} attributed to the introduction of wind power would be greater than for solar PV; in contrast, the rise in C_{INT} would be greater for solar PV when the order is reversed. This applies not only to VREs but also to conventional technologies. As a solution, one possible way to allocate C_{INT} in proportion to each power source is to assume a "costless technology" of infinite flexibility and zero cost, and then, starting with a hypothetical state in which power is supplied entirely by this costless technology, increase the outputs of all technologies at the same rate until a realistic state is reached, calculating the integrals in the process[5)].

As is true for many economic problems, it is important to understand the difference between marginal cost and average cost. If a power source has a low average system LCOE, it would mean that the technology is supplying large amounts of power and helping to curb the total cost. Meanwhile, if it has a high marginal system LCOE, it means that it is difficult to install additional capacities of this power source, and from the perspective of total cost reduction, it may be necessary to accelerate the shift to other power sources.

3-5-3 Calculation for Japan

Fig. 3-4 shows the result of a calculation for the average system LCOE and relative marginal System LCOE for Japan[5)]. They were calculated for solar PV, wind power, nuclear power, and zero-emission thermal power by dividing Japan into three regions, namely Hokkaido, Tohoku, and the rest, and assuming that all electricity is supplied by renewable energies, nuclear power, and zero-emission thermal power (imported hydrogen thermal power, etc.). The total electricity demand was set to just over 1,000 TWh, nuclear power capacity was capped at 25.5 GW, and solar PV and wind power were assumed to be available for mass introduction in line with the potential estimated by the Ministry of the Environment. Furthermore, the LCOEs for solar PV and land-based wind power were set to 7 yen/kWh and 8–9 yen/kWh, respectively. Zero-emission thermal power was selected as the baseline power source for relative marginal system LCOE, and its estimated LCOE of 12 yen/kWh at a capacity factor of 80% was used as L_0 in Equation (6). To be precise, the system LCOE may differ between the three regions even for the same type of power source, and so the values in Fig. 3-4 are the weighted averages of the three regions.

Because it is assumed here that VRE is cheaper than thermal power based on LCOE, the average system LCOE of VRE would be lower than thermal power in many cases. However, the average costs of other power sources rise gradually as thermal power restriction is reduced, and when it reaches 50 TWh or lower, the system LCOE of onshore wind power surpasses that of thermal power. Meanwhile, for relative marginal system LCOE, the values of other technologies rise sharply as thermal power output decreases. Note that all technologies that have reached an "equilibrium," by definition, take the same value. In Fig. 3-4, the value for nuclear power is low because it has an output cap and has not reached equilibrium. Further, offshore wind power is not included in the solution described here because of the high estimated LCOE. Other energies, i.e., solar PV and onshore wind power, have the same relative marginal system LCOE in this calculation, even though their estimated LCOEs are different, because they are at an “equilibrium.” However, when the thermal output becomes 20 TWh, the value for solar PV falls below that of onshore wind power because solar PV reaches the maximum capacity. As this shows, relative marginal system LCOE can be regarded as a metric that shows how far the installed capacity of a power source is from equilibrium.

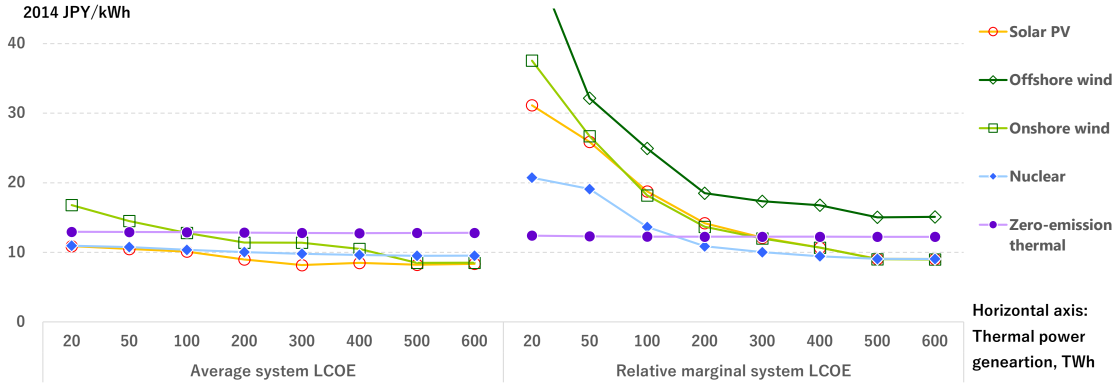


Fig. 3-2 Calculation of average and marginal System LCOEs

Conclusion

This report outlined various metrics “beyond LCOE” that are currently being proposed, while also referring to the relationships between the metrics. As explained, the metrics can generally be described as those for the “total cost (including integration cost),” “market value,” “marginal cost by technology,” and “average cost by technology,” though there are slight conceptual differences and similarities between them. The most important idea among these is the integration cost, or the total cost, calculated for a given energy mix; if this can be estimated accurately with mathematical models or any other measures, it alone can provide very useful information for future energy and environmental policies. Other metrics solely express changes in the total cost.

The “market value” calculated for each technology is essentially the same as the “unit avoided cost.” The market value of a technology is lower than its cost (LCOE) when installed beyond the optimal amount but is higher than the cost when below the optimal point. The marginal cost by power source uses this property to combine cost and value, and VALCOE and system LCOE_HUE fall in this category. Moreover, it would be more appropriate to use the relative marginal system LCOE as a metric representing the marginal costs of power sources.

In any case, these analyses show that, regardless of the type of power source, its marginal cost will rise rapidly once it is deployed beyond the optimal point, or the point of equilibrium. While this report considered the only cost, which can be converted into monetary value, the findings may be true for risk, which may not easily be converted into monetary value. This suggests that even in the future when more power sources become carbon-free and large amounts of VRE are introduced, a best mix of energy will exist, albeit somewhat different from the current one, and pursuing this best mix will be a key point for energy policy. Meanwhile, when VRE costs decrease considerably in the future, their average costs could become extremely low. The results indicate that even hard-to-handle power sources like VRE could help reduce the average cost of electricity, and raise hopes that, depending on the policy, it may be possible to replace all power sources with zero-emission ones without imposing a major burden on the public.

The economic assessment of power systems with a large VRE capacity will be a vital part of discussions on decarbonizing the use of energy. However, discrepancies remain among studies regarding the evaluation of integration cost itself. As the research progresses and researchers approach a consensus, it would be possible to present valuable information that can contribute to decent energy and environmental policies.

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