

October 13, 2026

Methodology for Estimating System Integration Costs in a Technology Selection Model

Hideaki Obane, Seiya Endo, Kan Kotegawa
Senior Economist, Economist, Researcher
The Institute of Energy Economics, Japan

Yuhji Matsuo
Professor
Ritsumeikan Asia Pacific University

Takashi Otsuki
Associate Professor
Waseda University

1. Introduction

In recent years, the deployment of renewable energy has been expanding worldwide to enhance energy security and achieve decarbonization. Among renewable energy sources, variable renewable energy (VRE), represented by solar photovoltaic (PV) and wind power, has experienced particularly rapid growth, driven by substantial declines in power generation costs. However, the large-scale deployment of VRE raises concerns about increasing integration costs incurred across the power system.

Unlike dispatchable thermal power generation, VRE is characterized by output variability due to weather conditions, geographical concentration of suitable sites, and uncertainty in generation forecasts. These characteristics are generally considered to give rise to three types of integration costs: (1) Profile costs: additional costs resulting from temporal mismatches between electricity generation and demand; (2) Grid-related costs: costs associated with the construction and reinforcement of grid infrastructure; and (3) Balancing costs: costs associated with balancing electricity supply and demand to accommodate forecast errors [1]. Following previous studies [2]–[4], we define the power system cost as the sum of the levelized cost of electricity (LCOE), which represents the cost of individual generation technologies, and the additional integration costs incurred across the power system. Reducing overall power system costs, rather than focusing solely on LCOE, will be an important consideration in future electricity and energy policy.

Several countries, including the United Kingdom, as well as Japan, have attempted to evaluate generation costs by technology while accounting for integration costs in addition to LCOE [5]–[7]. However, integration costs depend strongly on factors such as power system flexibility and the

generation mix, resulting in substantial uncertainty in their estimates. It has therefore been pointed out that there are limitations to assigning fixed integration costs to individual generation technologies [8]. In addition, many previous analyses have relied on models focusing specifically on the power sector. Because integration costs are also strongly affected by demand-side flexibility technologies, such as demand response (DR), models focusing solely on the power sector may not adequately capture these effects.

To address these limitations, this study seeks to develop a methodology for evaluating integration costs at the power-system level rather than by individual generation technology, using a sector-coupled technology selection model that represents the entire energy system, from primary energy supply through energy transformation to final energy consumption. Building on our previous analysis of Japan's energy system in 2050 [9], this study introduces several refinements to the integration cost evaluation methodology and presents the calculation methods for its individual components. Accordingly, the primary objective of this study is not to evaluate a specific energy policy or generation mix, but rather to provide a basis for further discussion and methodological development in the evaluation of integration costs.

2. Methodology

2.1 Technology selection model

This study employs a technology selection model (NE_Japan) that covers the entire energy system of Japan from primary energy supply to final energy consumption [10]–[12]. The model is a dynamic linear programming model that takes the capital costs, fuel costs, and operation and maintenance costs of individual energy technologies as input assumptions and determines the optimal technology mix and operation that minimize the total energy system cost over the evaluation period, subject to constraints such as energy service demands and carbon dioxide (CO₂) emissions. The main constraints also include energy supply–demand balances at each time step and land-use constraints.

Fig. 1 shows the energy flows represented in the model. The model simultaneously optimizes not only technologies in the power sector but also demand-side technologies in each sector, energy transformation technologies, and energy transportation technologies. Unlike models focusing solely on the power sector, technology choices such as hydrogen production and CO₂ capture and storage are therefore considered simultaneously under the CO₂ emissions constraint for the entire energy system. This framework captures competition between the power and non-power sectors for hydrogen use and CO₂ storage capacity. In addition, electricity demand is calculated based on the endogenously determined deployment of electrification and other technologies required to meet energy service demands. This enables a consistent analysis of the impacts of electrification and the deployment of demand-side technologies on the power system. The model has an hourly temporal resolution of 8,760 hours per year and divides Japan into five regions: Hokkaido, Tohoku, Tokyo, West Japan (Chubu,

Hokuriku, Kansai, Chugoku, and Shikoku), and Kyushu/Okinawa. Interregional electricity transfers are represented by transmission interconnectors connecting adjacent regions, whereas reinforcement of intra-regional electricity transmission and distribution networks is not considered. The analysis covers the years 2022, 2030, 2035, 2040, and 2050.

In the model, the annual total cost, $ac_{k,y}$ [USD/year], of technology k in year y is defined as the sum of its annualized investment cost, $ivc_{k,y}$ [USD/year], variable operation and maintenance cost, $voc_{k,y}$ [USD/year], fixed operation and maintenance cost, $fovc_{k,y}$ [USD/year], and energy procurement cost, $flc_{k,y}$ [USD/year]. For power generation technologies, the energy procurement cost is calculated based on the fuel consumption of each technology and the shadow price of each energy carrier, which reflects fuel import prices and the costs of associated infrastructure, such as liquefied natural gas (LNG) import terminals. All costs are expressed in constant 2022 prices, corresponding to the model base year, and are calculated based on technology deployment, activity levels, energy consumption, and other relevant variables. Using a discount rate r ($= 7\%/year$) and base year BY ($= 2022$), the model endogenously determines technology deployment and activity levels by minimizing the cumulative discounted energy system cost over the entire evaluation period, as expressed in Eq. (1).

$$\min \sum_{y \in Y} \sum_{k \in K} (ac_{k,y}) \left(\sum_{t \in YEAR_y} (1+r)^{BY-t} \right) \quad (1)$$

$$ac_{k,y} = ivc_{k,y} + fovc_{k,y} + voc_{k,y} + flc_{k,y} \quad (2)$$

where K denotes the set of all technologies, Y denotes the set of analysis years in the model, and $YEAR$ denotes the set of calendar years represented by analysis year y .

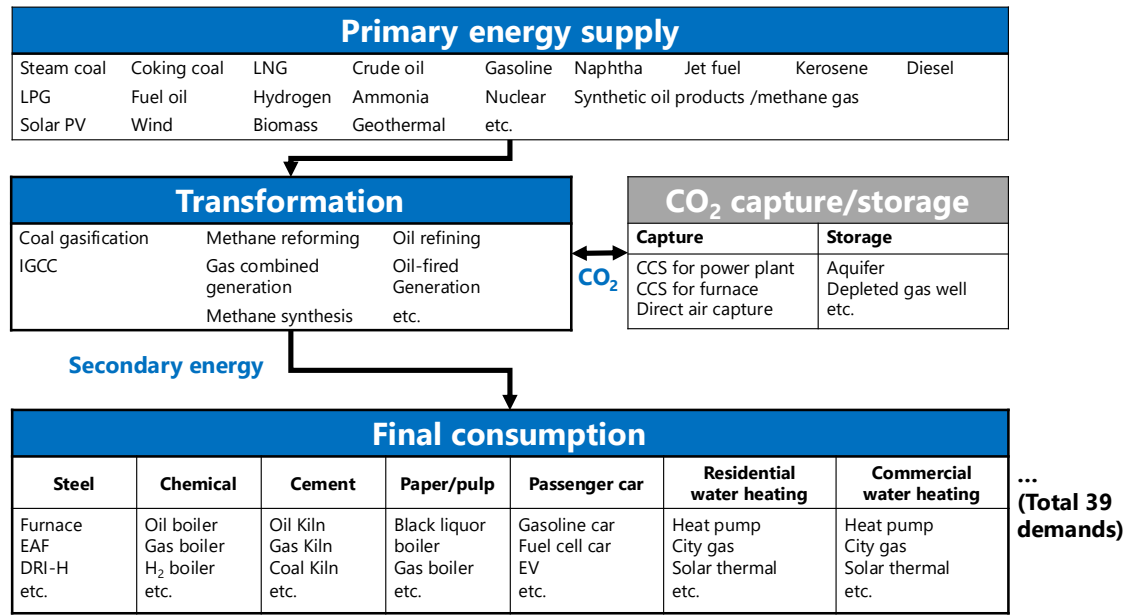


Fig. 1. Schematic representation of the modelled energy system and examples of technologies considered in the technology selection model.

2.2 Methodology for evaluating integration costs

Based on the results obtained from the technology selection model described in the previous section, this study develops an evaluation framework that broadly divides the power system cost into LCOE-equivalent costs and integration costs, and further decomposes the integration costs into six components. A previous study [1] and Japan's Working Group on Power Generation Cost Verification [6] have commonly adopted a marginal-cost approach, in which the additional costs incurred across the power system when VRE deployment is marginally increased are evaluated as integration costs for each generation technology. However, because integration costs depend strongly on factors such as power system flexibility and the generation mix, there are limitations to comparing or applying integration costs calculated on a marginal basis as fixed values across different power systems.

Therefore, rather than evaluating marginal integration costs for individual generation technologies, this study adopts an approach that evaluates the total annual integration costs incurred across the entire power system. The average cost per unit of electricity generation can also be calculated by dividing the annual total cost by total annual electricity generation. Some of the individual components of integration costs correspond to more than one of the categories of profile costs, balancing costs, and grid-related costs. Some cost components, such as the start-up and shutdown costs of thermal power plants, are difficult to evaluate endogenously using the technology selection model. Therefore, this study estimates partial integration costs, covering only the major cost components that can be evaluated endogenously by the model (Fig. 2).

In addition to power-sector technologies, the technology selection model considers demand-side

technologies such as electric vehicles and heat pumps. The marginal cost of electricity, which is determined by factors such as the generation mix, affects the deployment of these demand-side technologies. Changes in the generation mix can therefore affect not only the power sector but also the cost of the overall energy system, including non-power sectors. However, it is difficult to clearly separate the portion of demand-side technology deployment costs that is attributable to the power system. Therefore, this study does not directly include the deployment costs of demand-side technologies as components of the power system cost, but instead reflects only their impacts on the power system through changes in electricity demand.

One approach to evaluating integration costs is to consider only the additional costs caused by VRE deployment as integration costs [1]. While the marginal-cost approach enables the quantification of the impacts of additional VRE deployment, evaluations based on annual total costs or average costs per unit of electricity generation include costs incurred across the entire power system, making it difficult to isolate the impacts attributable specifically to VRE deployment. For example, grid-related costs may arise not only from grid reinforcement associated with VRE deployment but also from infrastructure expansion necessitated by increasing electricity demand or the construction of new thermal power plants and other generation facilities. Because this study defines the power system cost as the sum of LCOE-equivalent costs and integration costs, integration costs are defined more broadly to encompass not only costs attributable to VRE deployment but also additional costs incurred across the power system as a result of the deployment of other generation technologies, changes in the demand structure, and other factors.

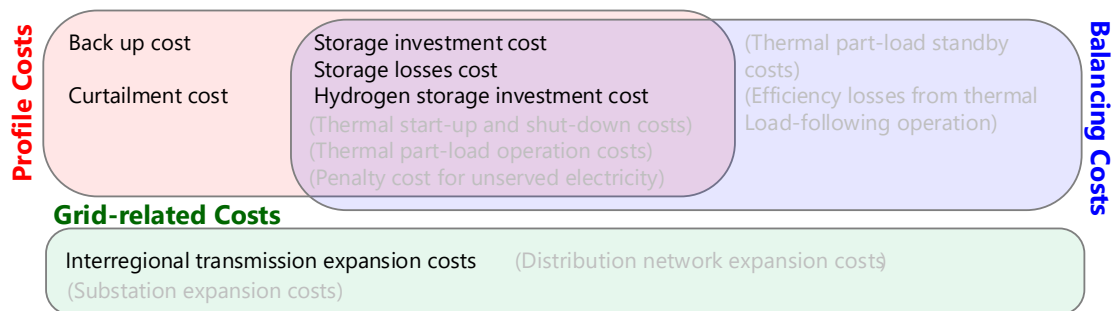


Fig. 2. Integration cost components considered and not considered in this study (black: considered; gray: not considered).

2.2.1 LCOE-equivalent cost

Let $K^{generator}$ denote the set of all power generation technologies in the technology selection model. The annual total cost corresponding to LCOE, $LCOEq_y$, is calculated using Eq. (3). While LCOE generally represents the cost per unit of electricity generated, the LCOE-equivalent cost in this study represents an annual total cost [USD/year]. To avoid double counting with the integration costs described below, however, costs that are separately accounted for as integration costs are deducted from the annual total cost of power generation. Specifically, the backup cost BC_y , which represents a portion of the fixed costs of backup generation capacity; the curtailment cost CC_y , corresponding to curtailed VRE generation; and the storage loss cost SLC_y are deducted. The calculation methods for these costs are described in Sections 2.2.2, 2.2.3, and 2.2.5, respectively. Existing pumped-hydro storage is included in the LCOE-equivalent cost, whereas newly installed pumped-hydro storage is included in the storage investment cost in Section 2.2.4.

$$LCOEq_y = \sum_{k \in K^{generator}} ac_{k,y} - BC_y - CC_y - SLC_y \quad (3)$$

2.2.2 Backup cost

The backup cost, BC_y , refers to the additional cost of maintaining the generation capacity required to compensate for reductions in the capacity factors of other generation technologies due to VRE output variability and other factors. In liberalized electricity markets, these costs may not necessarily be fully recovered through wholesale electricity markets. In Japan, they may instead be compensated through mechanisms such as the capacity market and the long-term decarbonized power source auctions. However, the amount of compensation provided through these capacity mechanisms depends on factors such as market design, load curves, and auction outcomes, making it difficult to quantify accurately.

Therefore, rather than estimating the actual compensation paid through these markets, this study uses the fixed costs required to maintain generation capacity despite reduced capacity factors as a proxy for the power system costs associated with backup capacity. Hydropower and geothermal power are excluded from the calculation of backup costs because differences between their actual and maximum capacity factors may arise from natural conditions and operational constraints rather than from their role as backup capacity.

Let K^{backup} denote the set of thermal and nuclear power generation technologies considered in the calculation of backup costs in the technology selection model. The annual backup cost, BC_y , is calculated using Eq. (4), based on the maximum capacity factor specified for each generation technology, $CF_{max_{k,y}}$ and the actual capacity factor obtained from the model solution, $CF_{k,y}$.

$$BC_y = \sum_{k \in K^{backup}} (ivc_{k,y} + foc_{k,y}) \left(1 - \frac{CF_{k,y}}{CFmax_{k,y}} \right) \quad (4)$$

2.2.3 Curtailment cost

VRE generation curtailed is regarded as electricity that could otherwise have been generated and utilized. In this study, the associated opportunity cost is evaluated as the curtailment cost. Strictly speaking, the curtailment cost should ideally be evaluated by multiplying the amount of curtailed electricity from each VRE technology by its respective LCOE. However, both in the technology selection model and in the actual Japanese electricity market, it is difficult to identify which VRE generation technology is curtailed in each time period. Therefore, this study alternatively calculates the annual curtailment cost, CC_y , using Eq. (5), based on the annual amount of curtailed VRE generation, $Curt_y$, obtained from the technology selection model and the generation-weighted average LCOE of VRE technologies, $LCOE_y^{VRE}$, calculated from the same model. It should therefore be noted that this approach cannot reflect differences in curtailment costs when the composition of VRE technologies subject to curtailment differs from the composition of actual VRE generation.

$$CC_y = Curt_y \times LCOE_y^{VRE} \quad (5)$$

2.2.4 Storage investment cost

The storage investment cost, SIC_y , represents investment in electricity storage facilities required for short-term supply–demand balancing, temporal shifting of surplus electricity, and other purposes. In this study, let $K^{storage}$ denote the set of storage technologies deployed by the technology selection model, including newly installed pumped-hydro storage, lithium-ion (Li-ion) batteries, redox flow batteries, and sodium-sulfur (NaS) batteries. The storage investment cost is calculated using Eq. (6) as the sum of the annualized investment cost and fixed operation and maintenance cost of each storage technology determined by the model.

$$SIC_y = \sum_{k \in K^{storage}} (ivc_{k,y} + foc_{k,y}) \quad (6)$$

2.2.5 Storage loss cost

The storage loss cost, SLC_y , represents the economic value of electricity lost due to charging and discharging efficiencies of less than 100%. In the technology selection model, the difference between the annual amount of electricity charged, $Charge_y$, and discharged, $Discharge_y$, is defined as the annual storage loss. Although it is difficult in practice to identify the generation sources of the electricity used to charge batteries or pump water for pumped-hydro storage, this study assumes that the electricity

charged into storage is supplied by VRE. Accordingly, the annual storage loss cost is calculated using Eq. (7) as the product of the annual amount of electricity lost in storage and the generation-weighted average LCOE of VRE.

$$SLC_y = \sum_{k \in K^{storage}} (Charge_{k,y} - Discharge_{k,y}) \times LCOE_y^{VRE} \quad (7)$$

2.2.6 Hydrogen storage investment cost

The hydrogen storage investment cost, HSC_y , represents the additional investment in hydrogen storage facilities required for long-term supply–demand balancing for electricity. Let $K^{H2storage}$ denote the set of hydrogen storage technologies. The cost is based on the sum of the annualized investment cost and fixed operation and maintenance cost of each hydrogen storage technology calculated by the model. However, because hydrogen is also consumed in non-power sectors, these costs are allocated to the power sector according to the share of power-sector hydrogen consumption in total energy-system hydrogen consumption. Accordingly, the hydrogen storage investment cost is calculated using Eq. (8), using power-sector hydrogen consumption, Con_{power} , and non-power-sector hydrogen consumption, $Con_{non-power}$.

$$HSC_y = \sum_{k \in K^{H2storage}} (ivc_{k,y} + foc_{k,y}) \cdot \frac{Con_{power}}{(Con_{power} + Con_{non-power})} \quad (8)$$

2.2.7 Interregional transmission expansion cost

The interregional transmission expansion cost, ITC_y , represents additional investment in interregional electricity transmission capacity required due to factors such as increased VRE deployment. Let K^{tie} denote the set of interregional transmission interconnectors. For each interconnector, the interregional transmission expansion cost is defined as the difference between the annualized investment cost of interregional transmission capacity in year y , as determined by the technology selection model, and that in the model base year, 2022. The annual interregional transmission expansion cost is calculated using Eq. (9) as the sum of these differences across all interregional interconnectors. It should be noted that, under this formulation, the calculated cost may reflect not only investment in interregional transmission associated with increased VRE deployment, but also the effects of changes in the regional generation mix, such as the construction of new nuclear power plants, as well as changes in electricity demand.

$$ITC_y = \sum_{k \in K^{tie}} (ivc_{k,y} - ivc_{k,2022}) \quad (9)$$

2.2.8 Power system cost

The power system cost, PC_y , is calculated as the sum of the LCOE-equivalent cost, $LCOEq_y$, and the integration cost, IC_y , as shown in Eq. (10).

$$\begin{aligned} PC_y &= LCOEq_y + IC_y \\ &= LCOEq_y + BC_y + CC_y + SIC_y + SLC_y + HSC_y + ITC_y \end{aligned} \quad (10)$$

3. Case study

Using the evaluation methodology described above, a case study was conducted to decompose the power system cost calculated under a specific set of assumptions into the LCOE-equivalent cost and individual components of integration costs.

3.1 Main assumptions

The capital costs of power generation technologies were set based on publicly available sources, including those published by Japan's Procurement Price Calculation Committee [13]. For offshore wind power, however, considering the recent increase in material prices, the cost projected by the Japan Wind Power Association [14] for 2045 (4,000 USD/kW at a distance of 5 km from shore and a water depth of 10 m) was adopted as the reference value, assuming an exchange rate of 150 JPY/USD. Based on a cost model, the capital cost was assumed to increase with distance from shore and water depth, thereby accounting for the deterioration in site conditions as deployment expands [15]. Because the model endogenously accounts not only for the LCOE of VRE but also for the impacts of associated transmission expansion, curtailment, and other factors on the total energy system cost, VRE capacity is sequentially deployed at locations that minimize the total cost including these factors.

Fuel prices for 2022 were based on actual cost, insurance, and freight (CIF) import prices. From 2023 onward, fuel prices were set based on trends in international fuel prices under the Net Zero Emissions by 2050 (NZE) Scenario of the International Energy Agency (IEA) World Energy Outlook [16]. The costs of interregional transmission expansion were based on the construction cost per unit of transmission capacity for each interconnector presented in the Long-term Cross-regional Network Development Policy (Master Plan) of the Organization for Cross-regional Coordination of Transmission Operators (OCCTO). The capital cost of Li-ion batteries in 2050 was set at 226 USD/kWh based on the Mid case in Cole et al. [17]. Further details of these key assumptions are provided in Appendix A.

3.2 Decomposition of power system cost

Based on the evaluation methodology and assumptions described above, Fig. 3 shows the decomposition of the power system cost into the LCOE-equivalent cost and individual components of integration costs when the total cost of Japan's energy system is minimized under the assumption that carbon neutrality is achieved by 2050 in Japan. In this case, the VRE share is 51% in 2050. When the LCOE-equivalent cost and integration costs, calculated as annual total costs, are each divided by total annual electricity generation to obtain the average cost per unit of electricity generation, the LCOE-equivalent cost is 15.5 US cents/kWh and the integration cost is 1.8 US cents/kWh in 2050. Consequently, the power system cost is 17.3 US cents/kWh, of which integration costs account for 10%. Among the components of integration costs, the backup cost of thermal power generation makes a relatively large contribution, while storage investment costs, curtailment costs, interregional transmission expansion costs, and other cost components are also observed.

These results demonstrate that the proposed methodology can decompose the power system cost obtained from the technology selection model into the LCOE-equivalent cost and integration costs, while quantitatively identifying the contribution of each component to the overall integration cost. Such a cost-component decomposition is useful for evaluating measures to reduce integration costs, such as demand response and battery storage, as it helps identify the potential and magnitude of cost reductions for each cost component, rather than focusing solely on changes in the overall power system cost.

However, this case study presents the results of a single case intended to demonstrate an application of the proposed methodology. The results are not intended, by themselves, to establish the relative merits of specific generation mixes or technologies or to derive policy implications. The power system cost and its composition may vary depending on model assumptions, including the VRE share, capital costs of storage technologies, potential for interregional transmission expansion, and deployment levels of thermal and nuclear power generation. Therefore, when applying the proposed methodology to policy evaluation and related analyses, it is important to compare the effects of changes in these assumptions on the LCOE-equivalent cost and individual components of integration costs through multiple scenarios and sensitivity analyses, rather than relying on results based on a single set of assumptions. This case study thus illustrates the integration cost decomposition methodology, which can serve as a basis for such comparative analyses.

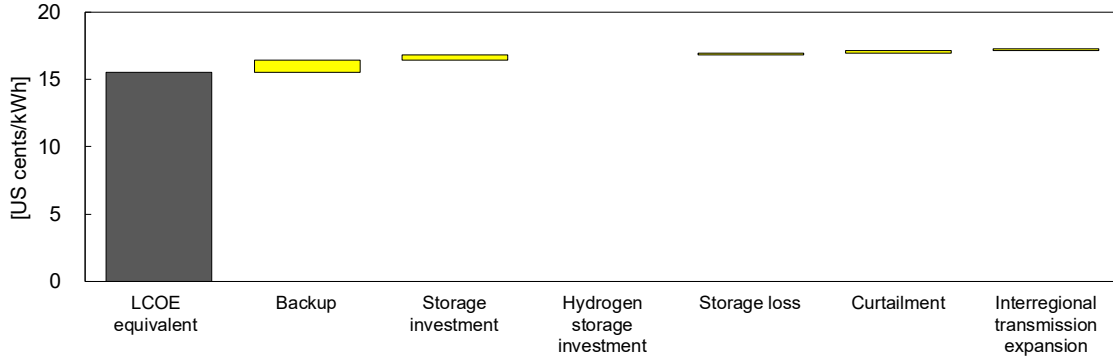


Fig. 3. Example of decomposition of power system cost in 2050
(2050 carbon neutrality scenario; VRE share: 51%)

4. Limitations and Future Work

This study investigates a methodology for decomposing and evaluating the overall power system cost into the LCOE-equivalent cost and integration costs using a technology selection model, providing a perspective different from conventional evaluations of individual generation technologies. The proposed methodology is applicable not only to technology selection models but also to power generation mix models that endogenously determine generation capacity, electricity generation, curtailment, electricity storage, and other relevant variables.

The integration costs evaluated using the proposed methodology can also be decomposed by region and over time. Because conditions such as the generation mix, electricity demand, and interregional transmission capacity differ across regions, the magnitude and composition of integration costs associated with VRE deployment are also expected to vary regionally. Furthermore, as decarbonization progresses, the relative importance of individual cost components, such as backup capacity, electricity storage, curtailment, and grid expansion, may change over time. Extending the proposed methodology to regional and temporal analyses is therefore expected to provide insights into the structure and drivers of costs that cannot be captured by the total power system cost alone.

On the other hand, the scope and accuracy of the integration costs that can be evaluated using the proposed methodology depend on the technologies and constraints represented in the model. In addition, the integration costs estimated in this study represent costs incurred within the power system as evaluated by the model and do not necessarily correspond to the actual financial burden arising through market mechanisms such as capacity markets. In light of these limitations, future work should expand the range of integration cost components considered and further improve the methodologies used to quantify them.

Despite these limitations, the proposed methodology provides a useful framework for

quantitatively identifying how changes in the technological configuration and assumptions of the power system affect individual cost components and, consequently, overall power system costs. Future applications to comparative analyses across multiple scenarios, regions, and time periods are expected to provide a more detailed understanding of the drivers of increases and decreases in future power system costs and to provide a quantitative basis for power system planning and policy development.

Appendix A

The key assumptions related to LCOE and integration costs in the model are presented in Tables A-1 through A-6.

For the fuel costs of imported hydrogen and ammonia, it was assumed that the lower-cost option between blue and green hydrogen and ammonia produced overseas would be used. The production costs of blue hydrogen and ammonia were estimated based on assumed fossil fuel prices and other parameters derived from international fuel price assumptions under the NZE Scenario of the IEA World Energy Outlook [16]. The production costs of green hydrogen and ammonia were estimated based on renewable energy costs in the Middle East, while transportation costs were estimated assuming transportation over a distance of 10,000 km in the form of ammonia. As a result, blue hydrogen and ammonia were assumed to be less costly through 2035, whereas green hydrogen and ammonia were assumed to become less costly from 2040 onward.

The upper limits on renewable energy deployment were determined using nationwide building data for Japan, land-use data reflecting restrictions under the latest local regulations [18], and marine-use data accounting for factors such as vessel traffic [19]. Renewable energy facilities were assumed to be deployable only in areas with relatively few siting constraints. For detached houses, the maximum rooftop PV deployment potential and solar irradiance profiles were considered separately according to roof orientation. For agrivoltaic PV, based on Asano et al. [20], all agricultural management entities (840,000 entities) were assumed to install 50 kW of PV capacity, corresponding to the maximum capacity that does not require the appointment of a chief electrical engineer.

The technical parameters and capital costs of thermal power generation were set based on various sources [21], [22]. Assumptions for interregional transmission interconnectors were based on the Master Plan for Cross-regional Network Development [23]. The unit cost of transmission expansion was estimated for each interconnector by dividing the estimated expansion cost by the corresponding increase in transmission capacity. To represent these unit costs consistently as a function of interconnector distance in the model, an assumed distance and a proportionality coefficient were specified for each interconnector so as to reproduce the actual interconnector distances as closely as possible.

Table A-1 Capital costs of solar and wind energy systems [USD/kW].

	2022	2030	2035	2040	2050
Ground-mounted PV (Low)	723	581	493	419	405
Ground-mounted PV (Mid)	1,004	807	685	582	563
Ground-mounted PV (High)	1,286	1,033	877	745	720
Building-mounted PV (Low)	1,162	933	796	678	645
Building-mounted PV (Mid)	1,702	1,367	1,166	993	945
Building-mounted PV (High)	2,243	1,801	1,536	1,309	1,246
Onshore wind	1,047	851	728	623	595
Offshore wind (Fixed-bottom)	1,534	1,246	1,067	912	871
Offshore wind (Floating)	2,021	1,642	1,406	1,201	1,147

Table A-2 Assumptions for import prices of carbon-free fuels.

	2030	2035	2040	2050
Hydrogen [USD/Nm ³ -H ₂]	0.45	0.45	0.43	0.39
Ammonia [USD/t]	699	700	672	591
Synthetic oil [USD/bbl]	285	285	285	284
Synthetic methane [USD/MBtu]	48.3	48.2	48.2	48.1

Table A-3 Upper limit of solar and wind energy capacity [GW].

	Hokkaido	Tohoku	Tokyo	West Japan	Kyushu / Okinawa	Total	Reference
Ground-mounted PV	1.8	7.5	12.7	21.4	9.0	52.3	[18]
Building-mounted PV	7.1	18.4	35.1	57.6	19.1	137.2	[18]
Detached house (South-facing)	3.0	6.2	14.6	19.2	6.2	49.2	[18]
Detached house (East-facing)	2.9	6.2	14.4	19.0	5.9	48.6	[18]
Detached house (West-facing)	2.9	6.2	14.4	19.0	5.9	48.6	[18]
Agrivoltaic PV	1.3	7.5	9.6	16.9	6.7	41.9	[20]
Onshore wind	5.7	10.1	0.3	6.4	2.7	25.2	[18]

Table A-4 Assumptions for power generation plants.

	Coal	IGCC	Gas (Single cycle)	Gas (Combined cycle)	Oil	Nuclear
Lifetime [year]	40	40	40	40	40	40
Annual fixed O&M cost	5.5%	5.5%	6.0%	4.4%	3.2%	4.3%
Rate [% of capital cost]						
Efficiency (LHV)	44.2%	51.2%	43.2%	63.3%	41.5%	-
Own consumption rate	6.4%	9.9%	4.3%	2.2%	4.8%	4.0%
Max. ramp-up rate [hour]	100%	100%	100%	100%	100%	0%
Max. ramp-down rate [hour]	100%	100%	100%	100%	100%	0%
Seasonal peak availability	95%	95%	95%	95%	95%	70%
Annual average availability	85%	85%	85%	85%	85%	70%
Share of daily start-up and shutdown units	0%	0%	0%	40%	40%	-
Minimum load ratio	30%	30%	30%	20%	20%	-
Emission factor [g-CO ₂ /kWh]	850	730	420	340	720	0

	Hydrogen	Ammonia	Biomass
Lifetime [year]	40	40	40
Annual fixed O&M cost	4.4%	4.4%	6.8%
Rate [% of capital cost]			
Efficiency	63.3%	63.3%	35.0%
Own consumption rate	2.0%	2.0%	16.0%
Max. ramp-up rate [hour]	100%	100%	100%
Max. ramp-down rate [hour]	100%	100%	100%
Seasonal peak availability	95%	95%	95%
Annual average availability	85%	85%	85%
Share of daily start-up and shutdown units	40%	40%	0%
Minimum load ratio	20%	20%	30%
Emission factor [g-CO ₂ /kWh]	0	0	0

*Fuel costs for nuclear and biomass-fired power generation were assumed to be 1.6 ¢/kWh and 10.7 ¢/kWh, respectively, and constant regardless of year.

Table A-5 Assumptions for energy storage and electrolysis in 2050.

	Pumped hydro	NaS battery	Li-ion battery	Redox flow battery	Compressed H ₂ tank	Electrolyzer
Capital cost [USD/kWh]	-	277	226	462	100	-
Capital cost [USD/kW]	920	-	-	187	467	300
Lifetime [year]	60	15	10	10	15	15
Annual fixed O&M cost Rate [% of capital cost]	2.9%	5.0%	1.0%	1.0%	1.0%	1.5%
Cycle efficiency	70%	75%	85%	70%	90%	-
Efficiency (LHV)	-	-	-	-	-	74%
Self-discharge loss (/hour)	0.01%	0.05%	0.05%	0.05%	0.01%	-
Maximum kWh ratio to kW	6	-	-	∞	∞	-
C-rate	-	0.14C	1C	-	-	-

Table A-6 Assumptions for interregional electricity transmission.

	Hokkaido - Tohoku	Tohoku - Tokyo	Tokyo - West Japan	West Japan - Kyushu / Okinawa
Unit expansion cost* ¹ [USD/kW]	1745	1167	1025	1000* ²
Annual cost rate* ³	8.5%	8.5%	8.5%	8.5%
Operating lifetime	36	36	36	36
Discount rate	4%	4%	4%	4%
Distance [km]	600	300	400	500
Transmission loss rate [/1,000km]	10%	10%	10%	10%
Maximum capacity [GW]	∞	∞	∞	∞
Minimum capacity* ⁴ [GW]	1.2	10.3	3.0	2.8

*¹ Calculated by dividing the transmission expansion cost for each interconnector under the Base Scenario of the Master Plan for Cross-regional Network Development [23] by the corresponding increase in transmission capacity. Only High-voltage direct current (HVDC) interconnectors and frequency converters (FCs) are considered; reinforcement of Alternating current (AC) transmission systems and intra-regional networks is not included. Where the expansion cost is presented as a range, the average of the upper and lower bounds was used.

*² In the model, the Kyushu–Shikoku interconnector is also included in the interconnection between Western Japan and Kyushu–Okinawa; however, the unit expansion cost is represented by that of the Chugoku–Kyushu interconnector.

*³ The annual cost rate was set at 8.45% (shown as 8.5% in the table), calculated as the average of 7.9% for overhead transmission lines and 9.0% for underground transmission lines, as reported in the Master Plan. Therefore, this value was not separately calculated from the discount rate and operating lifetime shown in the table.

*⁴ Minimum capacity from 2035 onward. Through 2030, the capacity is fixed at the long-term operational capacity specified by OCCTO [23].

References

- [1] Ueckerdt, F., Hirth, L., Luderer, G., & Edenhofer, O. (2013). System LCOE: What are the costs of variable renewables? *Energy*, 63, 61–75.
- [2] Heptonstall, P. J., & Gross, R. J. K. (2021). A systematic review of the costs and impacts of integrating variable renewables into power grids. *Nature Energy*, 6(1), 72–83.
- [3] OECD/NEA. (2012). Nuclear energy and renewables: System effects in low-carbon electricity systems.
<https://www.oecd-nea.org/upload/docs/application/pdf/2019-12/7056-system-effects.pdf>
- [4] OECD/NEA. (2018). The full costs of electricity provision.
https://www.oecd.org/en/publications/the-full-costs-of-electricity-provision_9789264303119-en.html
- [5] Frontier Economics. (2016). Whole power system impacts of electricity generation technologies. Report for the Department of Energy and Climate Change. UK Government.
https://assets.publishing.service.gov.uk/media/5a81e0dae5274a2e8ab564f9/Whole_Power_System_Impacts_of_Electricity_Generation_Technologies__3_.pdf
- [6] Ogimoto, K., & Matsuo, Y. (2024). Estimation of power generation costs by technology considering selected integration costs [Material 1, 5th meeting of the Working Group on Verification of Power Generation Costs]. Ministry of Economy, Trade and Industry.
- [7] Matsuo, Y., & Komiyama, R. (2021). System LCOE of variable renewable energies: A case study of Japan's decarbonized power sector in 2050. *Sustainability Science*, 16, 449–461.
- [8] Department for Business, Energy & Industrial Strategy. (2017). Addendum on whole power system impacts peer reviews. UK Government.
https://assets.publishing.service.gov.uk/media/5a823923e5274a2e87dc1cb1/BEIS_Addenddum_on_Whole_Power_System_Impacts_Peer_Reviews__3_.pdf
- [9] Obane, H., Endo, S., Zhang, T., Hirose, R., Kotegawa, K., & Sakaguchi, H. (2026). Japan's energy scenario up to 2050: Topic 1: Strategies for reducing power system costs. The Institute of Energy Economics, Japan.
https://eneken.ieej.or.jp/en/report_detail.php?article_info__id=13378
- [10] Otsuki, T., Komiyama, R., Fujii, Y., & Nakamura, H. (2023). Temporally detailed modeling and analysis of global net zero energy systems focusing on variable renewable energy. *Energy and Climate Change*, 4.
- [11] Kawakami, Y., & Matsuo, Y. (2020). A study on the feasibility of 80% GHG reduction in Japan using a bottom-up energy system model: The effect of changes in meteorological conditions. *Journal of Japan Society of Energy and Resources*, 41(3), 68–76. (in Japanese)
- [12] Otsuki, T., Komiyama, R., & Fujii, Y. (2023). Global energy system model NE_Global-R. - R. doi:10.5281/zenodo.8357653

- [13] Procurement Price Calculation Committee. (2023). Opinion on procurement prices and other matters for FY2023 and beyond. Ministry of Economy, Trade and Industry.
- [14] Japan Wind Power Association. (2023). Initiatives to establish an industrial foundation for offshore wind power and a pathway toward reducing power generation costs [Material submitted to the 38th Joint Meeting of the Offshore Wind Promotion Working Group and the Offshore Wind Promotion Subcommittee]. Ministry of Economy, Trade and Industry.
- [15] Obane, H., Watanabe, H., Otsuki, T., Hirose, R., Morimoto, S., & Shibata, Y. (2026). A study on site suitability assessment based on engineering cost models for offshore wind farm. Proceedings of the 42nd Conference on Energy, Economy, and Environment, 30-3.
- [16] International Energy Agency. (2024). World Energy Outlook 2024.
- [17] Cole, W., & Karmakar, A. (2023). Cost projections for utility-scale battery storage: 2023 update (NREL/TP-6A40-85332). National Renewable Energy Laboratory.
- [18] Obane, H., Sasakawa, A., Morimoto, S., Shibata, Y., & Otsuki, T. (2025). Technical potential of solar energy systems under local regulatory and rooftop constraints. Journal of Japan Society of Energy and Resources, 46(5), 279–290.
- [19] Obane, H., Nagai, Y., & Asano, K. (2021). Assessing the potential areas for developing offshore wind energy in Japanese territorial waters considering national zoning and possible social conflicts. Marine Policy, 129.
- [20] Asano, K., Nagai, Y., & Obane, H. (2020). Development of large-scale deployment scenarios for wind and solar power toward achieving net-zero emissions [Material presented at the 34th meeting of the Strategic Policy Committee, Advisory Committee for Natural Resources and Energy]. Agency for Natural Resources and Energy, Ministry of Economy, Trade and Industry.
- [21] Komiyama, R., Otsuki, T., & Fujii, Y. (2015). Energy modeling and analysis for optimal grid integration of large-scale variable renewables using hydrogen storage in Japan. Energy, 81, 537–555.
- [22] Kawakami, Y. (2021). The value of energy storage in the decarbonized energy system: An energy system optimization approach considering non-synchronous power generation constraints. IEEJ Transactions on Power and Energy, 141(5), 326–335.
- [23] Organization for Cross-regional Coordination of Transmission Operators. (2023). Master plan for cross-regional network development: Supplementary volume (reference materials). https://www.occto.or.jp/assets/kouikikeitou/chokihoushin/files/chokihoushin_23_01_02.pdf

Contact: report@tky.ieej.or.jp