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Temporally detailed modeling and analysis of global net zero energy systems focusing on variable renewable energy

Takashi OTSUKI [a,b,*], Ryoichi KOMIYAMA [c], Yasumasa FUJII [c], Hiroko NAKAMURA [b]

[a] *Division of Intelligent Systems Engineering, Faculty of Engineering, Yokohama National University, Japan*
[b] *Electric Power Industry & New and Renewable Energy Unit, The Institute of Energy Economics, Japan*
[c] *Department of Nuclear Engineering and Management, School of Engineering, The University of Tokyo, Japan*

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ABSTRACT

This study newly develops a recursive-dynamic global energy model with an hourly temporal resolution for electricity and hydrogen balances, aiming to assess the role of variable renewable energy (VRE) in a carbon-neutral world. This model, formulated as a large-scale linear programming model (with 500 million each of variables and constraints), calculates the energy supply for 100 regions by 2050. The detailed temporal resolution enables the model to incorporate the variable output of VRE and system integration options, such as batteries, water electrolysis, curtailment, and the flexible charging of battery electric vehicles. Optimization results suggest that combing various technical options suitable for local energy situations is critical to reducing global CO_2 emissions cost-effectively. Not only VRE but also CCS-equipped gas-fired and biomass-fired power plants largely contribute to decarbonizing power supply. The share of VRE in global power generation in 2050 is estimated to be 57% in a cost-effective case. The results also imply economic challenges for an energy system based on 100% renewable energy. For example, the average mitigation cost in 2050 is 69USD/tCO_2 in the cost-effective case, while it increases to 139USD/tCO_2 in the 100% renewable case. The robustness of this argument is tested by sensitivity analyses.

1. Introduction

Achieving carbon neutrality by around midcentury has become a critical agenda for the international community as it aims to limit the global average temperature increase to 1.5 °C above pre-industrial levels. The European Union Climate Law sets a legally binding target of net zero greenhouse gas (GHG) emissions by 2050 [1]. Countries with large GHG emissions, including China, the United States, and Japan, have announced targets to achieve economy-wide carbon neutrality by 2050 or 2060. Furthermore, as of May 2022, 136 countries have joined the Climate Ambition Alliance, a United Nations initiative for achieving net zero CO_2 emissions by 2050 [2].

Energy system transition is critical for achieving the temperature goal because energy-related CO_2 contributes to about three-quarters of greenhouse gas emissions today. Therefore, in recent years, many integrated assessment models (IAMs) and energy system models have explored pathways to net zero energy systems. The International Energy Agency (IEA) [3] presented a global scenario to achieve net zero CO_2 emissions by 2050, with key sectoral milestones to materialize the pathway. The Special Report on Global Warming of 1.5 °C (SR15) of the Intergovernmental Panel on Climate Change (IPCC) [4] summarizes 90 scenarios (from 9 models) that are consistent with limiting global warming to 1.5 °C with overshoot. IPCC SR15 also indicates four illustrative scenarios to characterize different mitigation strategies [5–8]. The Network for Greening the Financial System (NGFS) [9] has developed pathways for 132 countries by downscaling the regional results estimated by three global IAMs, with an aim to analyze climate-related risks to the economy and financial system. Akimoto et al. [10] investigated the global mitigation strategy with a focus on direct air capture and carbon utilization technologies in net zero systems, using an energy system model with detailed regional and technological granularities. More recently, the Working Group III of the IPCC finalized its contribution to the 6th Assessment Report (WG3 AR6) [11], summarizing implications from 230 "Below 1.5 °C" scenarios. Like SR15, the WG3 AR6 shows five illustrative mitigation pathways with different climate policies and sectoral mitigation strategies, including a renewable-focused pathway, a negative emission pathway, and a low energy demand pathway. Other studies illustrate pathways based on

* Corresponding author: Postal address: 79-5, Tokiwadai, Hodogaya, Yokohama, 240-8501, Japan.
E-mail addresses: otsuki-takashi-fx@ynu.ac.jp, takashiotsuki@19.alumni.u-tokyo.ac.jp (T. OTSUKI).

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100% renewable energy [12,13]. Although these studies project broad energy portfolios, they commonly imply the increasing importance of renewable energy, driven primarily by declining costs of variable renewables (VRE) such as solar PV and wind power. The projected share of VRE in global power generation in 2050 is 68% in the IEA analysis [3], 45%–68% in the four illustrative scenarios of SR15 [5–8], and 54%–74% in NGFS [9]. These shares are about fivefold to eightfold from the actual level (9%) in 2020 [14]. WG3 AR6 also pointed out that solar and wind will play an important role in many low-carbon electricity systems [11].

However, existing studies face challenges regarding VRE assessment due to limited representations of "integration" costs. According to Ueckerdt et al. [15], the accelerated deployment of VRE requires three types of costs due to spatiotemporal gaps between VRE resources and electricity demand: 1) balancing costs to compensate for short-term weather forecast errors; 2) grid costs to overcome the spatial gaps; and 3) profile costs to manage the intermittency of VRE (e.g., backup generators, energy storage, and curtailment). In addition, inverter-based VRE poses challenges to power grid stability, including system inertia, frequency, and voltage [16]; costs for maintaining grid stability are necessary. Some national or regional assessments (like those on the power system in Japan [17] and the United States [18] and the energy system in Europe [19]) suggest that these costs would increase under the very high penetration of VRE.

These integration costs would be critical to analyzing the role of VRE in the global energy transition. Yet, they are modeled in a simplified manner in most global IAMs and energy system models. As for the profile costs which are the focus of this study, temporal features are aggregated into annual or seasonal snapshots using "time slice", "representative period (e.g., day or week)", or "load band" approaches. For example, according to Pietzcker et al. [20], residual load duration curves using 156 time slices or much simpler resolutions are adopted by five leading global IAMs (AIM/CGE, IMAGE, MESSAGE, REMIND, WITCH). The purpose of these simplifications is usually to reduce computational costs. Also, some IAMs are designed to focus more on the macroscopic interactions among sectors, such as energy, land use, climate, and economy, rather than on a detailed energy system behavior. Yet, simplified resolution can hardly capture the variability of VRE and the costs for flexibility options, thus resulting in less robust and credible results. In fact, aforementioned Pietzcker et al. [20] indicated the limitations of the existing IAMs in terms of electricity system and VRE integration representation. Many other in-depth studies also suggest that temporal resolution is crucial in energy modeling. Merrick [21] found that to represent VRE's output sufficiently in a power dispatch analysis, the number of time slices needs to be in the order of 1000. Several other studies pointed out that low resolution models tend to underestimate flexibility requirements, including flexible dispatchable generation [22, 23] and curtailment [24]. Shirizadeh and Quirion [25] found that simplified resolution in the "representative period" approach lowers the accuracy of multi-sector optimization models, seemingly caused by a reduction in weather variations, especially for wind power. Improving temporal resolution is an important research agenda for global energy system analysis.

To overcome these challenges, several studies proposed new methodologies, such as soft linking between energy system models and detailed power system models [26,27] and improving the time slices of energy system models (e.g., selecting representative periods instead of averaged typical days and incorporating VRE's stochastic characteristics into an integral balancing method) [28]. However, each methodology has limitations. Collins et al. [28] pointed out that further research is needed to handle the interface between the two soft-linked models to arrive at consistent results. They also indicated that a careful selection of analysis periods is essential to maintain the quality of the "representative period" method. As for the integral balancing method, it cannot capture the chronology of electricity demand and supply. There are research efforts to develop a methodology for correctly reducing the temporal dimension of datasets. Marcy et al. [29] assessed the performance of several methods, but they highlighted some limitations even for an approach with the best performance (e.g., the loss of chronology in an "hourly multi-criteria clustering" approach).

Given this background, this study has two objectives: 1) the development of a global energy system model, namely NE_Global-R (NE = New Earth), which covers the entire energy sector with an hourly temporal resolution for electricity and hydrogen balances (24 h for consecutive 365 days) for a total of 100 regions in the world; and 2) using the model to analyze the economic viability of net zero systems with a focus on VRE. As for the second objective, we attempt to quantify the cost-effective shares of solar PV and wind power (onshore, fixed-bottom offshore, and floating offshore wind turbines) considering various mitigation options, such as carbon capture and storage (CCS), nuclear, and hydrogen-based secondary energy (hydrogen, ammonia, synthetic methane, methanol, and Fischer-Tropsch liquid fuels). In addition, we investigate the economics of a 100% renewable-based global energy system. It should be noted that several studies have performed hourly-based energy system analyses [12,13], although they only discuss a 100% renewable-based system. The cost-effective energy technology mix, considering nuclear and CCS-equipped thermal plants, has not been explored by temporally detailed energy system models. It should also be noted that there are many power dispatch models with hourly or sub-hourly temporal resolution [30,31]. Yet, these single-sector models are not able to analyze the entire energy system, including sector coupling options. Investigating the role of VRE in the global energy transition with fine temporal resolution, while maintaining technological comprehensiveness, marks the novelty of this study. Other strengths of the model include the detailed spatial resolution, which is critical to capturing the regionality of VRE resource endowments and assessing scenarios with very high shares of VRE [32]. The NE_Global-R is by far the largest global energy system model in terms of the number of variables and constraints (about 500 million each, as described in subsection 2.1). The development of such a large model is another contribution of this study.

This paper proceeds as follows. Section 2 gives an overview of the NE_Global-R model. Section 3 presents the optimization results. Finally, Section 4 summarizes major conclusions and implications, and proposes a future research agenda.

2. Method

The model was initially developed in a spatially disaggregated but temporally simplified manner to investigate the role of energy and CO_2 trade in a low-carbon world [33,34]. In this study, we improved the temporal resolution for electricity supply and demand balances, thus enabling the model to incorporate variability effects of VRE on energy system. This section aims to overview the model, key assumptions, and case settings.

2.1. Model descriptions

The NE_Global-R is a recursive dynamic linear programming model, which calculates long-term energy system to meet exogenous demand based on myopic decision making. The analysis period is from 2015 to 2050 with five representative years (2015, 2020, 2030, 2040, and 2050). This model optimizes each representative year individually and then passes on results to the subsequent representative years. We selected this myopic foresight approach, rather than a perfect foresight model, to reduce the computational costs, although this model is still very large compared to existing global models (see the last paragraph of this subsection for model metrics). The objective function is the single-year total system cost, consisting of fuel costs, operation & maintenance costs, and annualized capital costs for the whole world. Hence, all countries are assumed to cooperate fully towards achieving a cost-effective system without energy security and geopolitical considerations. Uncertainties exist regarding the degree of energy cooperation

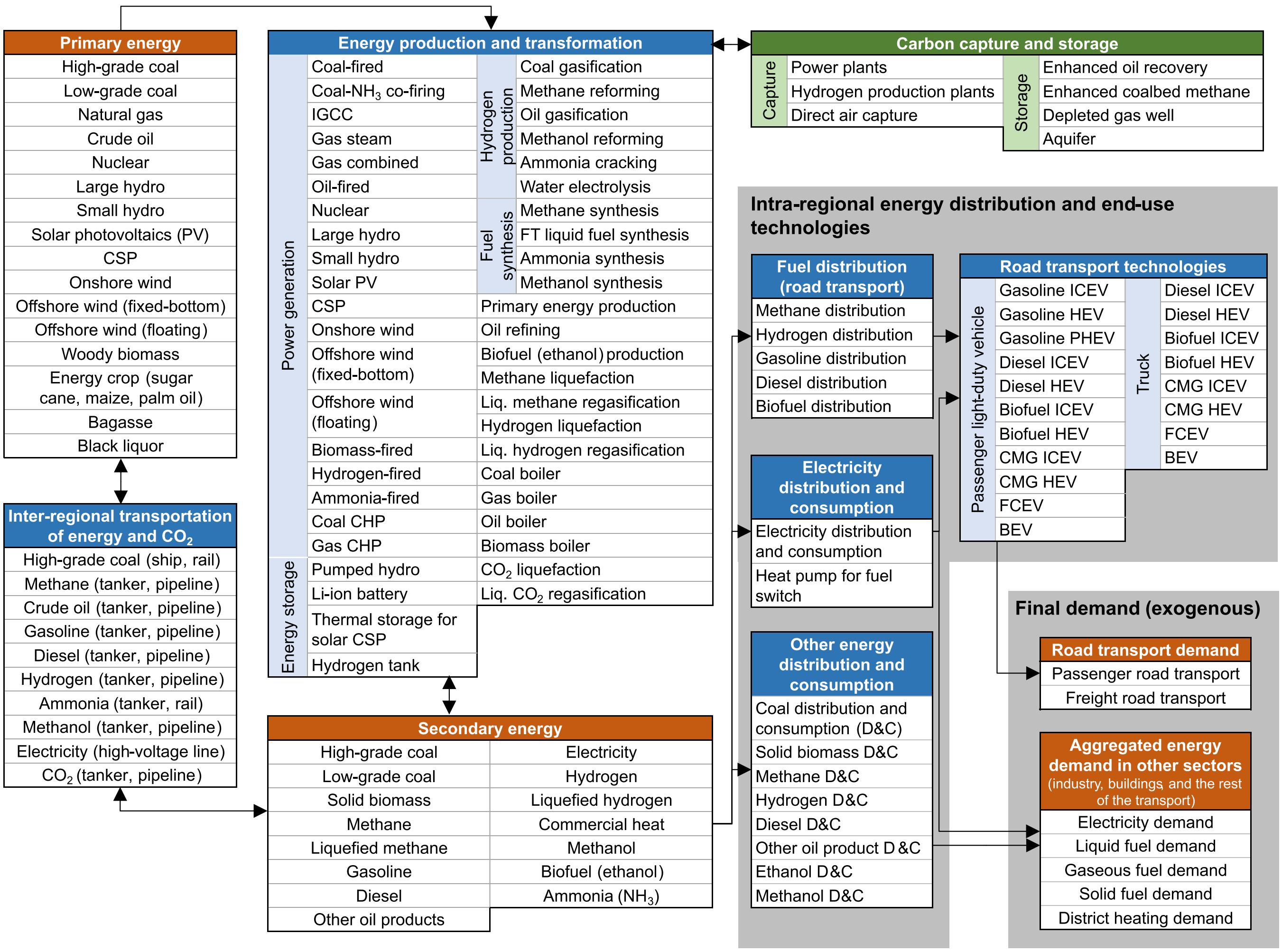


Fig. 1. Reference energy system. NH_3: ammonia; IGCC: integrated coal gasification combined cycle; CSP: Concentrating solar power; CHP: combined heat and power; FT: Fischer-Tropsch, Liq.: liquefied, ICEV: internal combustion engine vehicle; HEV: hybrid electric vehicle; PHEV: plug-in hybrid electric vehicle; FCEV: fuel cell electric vehicle; BEV: battery electric vehicle; CMG: compressed methane gas.

Table 1
List of secondary energy for final energy demand, except for the road transport.

		Final energy demand in end-use sectors (except for the road transport)				
		Solid fuel demand	Gaseous fuel demand	Liquid fuel demand	Electricity demand	District heating demand
Secondary energy	High-grade coal	✓				
	Low-grade coal	✓				
	Solid biomass	✓				
	Methane		✓			
	Hydrogen		✓			
	Diesel			✓		
	Other oil products			✓		
	Biofuel (ethanol)			✓		
	Methanol			✓		
	Electricity				✓	
	Commercial heat					✓

that can be achieved in the future, yet this paper assumes the most ideal situation to quantify the minimum cost required for net zero energy systems. The assumed discount rate to annualize capital costs is 5% for the whole world.

The model encompasses the entire energy system, including 28 types of primary and secondary energy carriers, as well as 250 types of technologies or processes for energy production, transformation, transportation, and final consumption. Modeled energy carriers and technologies are illustrated in Fig. 1. Final demand in the transport, industry, and buildings sectors is divided into the following seven categories. The road transport sector is subdivided into (1) passenger vehicle transport demand (person kilometers traveled) and (2) freight vehicle transport demand (ton kilometers traveled), with the remaining energy demand in the transport sector, as along with heat and electricity demand in the industry and buildings sectors, aggregated into (3) solid fuel demand, (4) gaseous fuel demand, (5) liquid fuel demand, (6) electricity demand, and (7) district heating demand. The choice of vehicle technology, such as the penetration level of battery electric

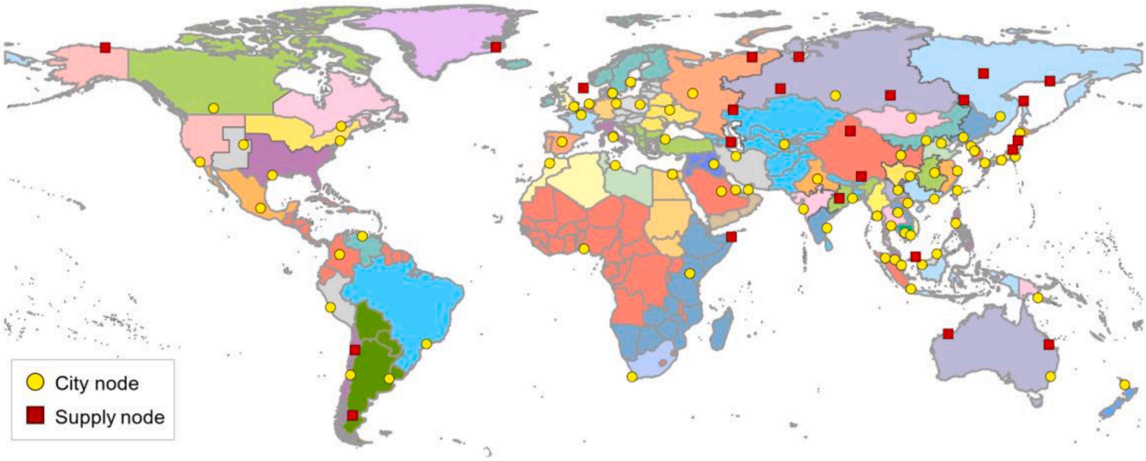


Fig. 2. Regional division.

Table 2
Case settings.

Case	Global energy-related CO_2 emissions	Nuclear power generation	CO_2 storage
NoReg	No upper limits	Available under capacity upper limit constraints	Available under storage capacity constraints
FullTech	Net zero by 2050. Consistent with the 1.5 °C target		
RE100		Phase-out by 2050	Not available

vehicles, is endogenously based on cost-minimization; it should be noted that other consumer preferences, including brand name, design, car classification, and driving range, are not considered. Heat demand in industry and buildings is represented by aggregated demand categories (such as liquid fuel demand, gaseous fuel demand, solid fuel demand, and district heating demand). Secondary energy items that can satisfy each demand category are summarized in Table 1. The choice of secondary energy is optimized considering the costs and vintages of energy transformation, distribution, and consumption technologies. Energy distribution and consumption technologies are modeled in an aggregated manner, for example, "coal distribution and consumption" technology (see Fig. 1 for the list of technologies and Appendix for economic assumptions). Many existing studies indicated that electrifying low-temperature heat supply (like replacing conventional oil boilers or gas boilers with heat pumps) would be cost-effective [11,35,36]. To incorporate such options, this study assumes that liquid fuel and gaseous fuel demand can be partially electrified by installing heat pumps. Final energy demand categories, except for electricity demand, are balanced on an annual basis. Modeled GHG is energy-related CO_2. Solar and wind power generation technologies covered in this analysis are solar PV, concentrating solar power (CSP), onshore wind turbines, fixed-bottom offshore wind turbines, and floating offshore wind turbines. Flexibility options include backup power plants, curtailment, existing pumped hydro storage, Li-ion battery, thermal storage (molten salt storage) for CSP, water electrolysis, power grid interconnection, and flexible charging into battery electric vehicles (BEV). Hydrogen produced by water electrolysis can be utilized for various purposes, including sector coupling. Specifically, we consider hydrogen for energy storage, power generation, heat production, road transport, and fuel synthesis (methane, methanol, Fischer-Tropsch liquid fuels, and ammonia). The model determines the capacity and operation of these technological options in a way that the world achieves a cost-effective system.

The global energy system is represented by 100 regions to explicitly consider the regionality, such as local resource endowments and technology cost variations, as well as the geography of interregional transportation networks of energy and CO_2 (Fig. 2). These regions are categorized into two types: "energy production and consumption regions" (hereafter "city nodes") and "energy production regions" ("supply nodes"). We assume that final energy is consumed at the 75 city nodes; in other words, city nodes cover the global final demand. On the other hand, all the energy-related activities except for final consumption (e.g., primary energy production, energy transformation, interregional transportation, and CO_2 storage) can be conducted at both node types. We selected city nodes from major energy demand centers while supply nodes from the regions with abundant primary energy resources.

Interregional transportation of the following 10 items is endogenously calculated: high-grade coal (rail and tanker), methane (pipeline and liquefied methane tanker), crude oil (pipeline and tanker), gasoline (pipeline and tanker), diesel (pipeline and tanker), hydrogen (pipeline and liquefied hydrogen tanker), ammonia (rail and tanker), methanol (pipeline and tanker), electricity (high-voltage line), and CO_2 (pipeline and liquefied CO_2 tanker). From the viewpoint of renewable energy integration in this model, interregional high-voltage lines provide access to spatially imbalanced resources both domestically and multilaterally, like the concept of Desertec in Europe and North Africa [37] and Gobitec in northeast Asia [38–40]. Interconnected power grids can also reduce excess generation [41]. In addition to high-voltage lines, renewable-based hydrogen and synthetic fuels—synthetic methane, methanol, and ammonia in this study—can be utilized for long-distance renewable energy transportation. These technological options are modeled explicitly (see Fig. 18 for energy transportation routes); however, international electricity transmission routes are excluded in subsections 2.3 and 3.1–3.5 due to very high computational costs (see the last paragraph of this subsection); instead, we performed a sensitivity analysis considering international electricity transmission endogenously in subsection 3.6.

As mentioned above, the most salient feature of the model is temporal resolution that ensures the balance of electricity supply and demand for 24 h across consecutive 365 days at each node. Eq.1 shows the electricity balance in year Y. The left side of the equation indicates the power supply from each generator, together with net discharge from energy storage and net imports, while the right side is electricity consumption, including electricity inputs for energy transformation technologies, electricity charge into EVs, and other final electricity consumption. The operation of VRE and flexibility technologies can be analyzed on an hourly basis in this model. We believe this approach provides high precision computation in assessing the economics of VRE.

$$\sum_{k\in P} \boldsymbol{xp}_{k,d,t,n,Y} + \sum_{k\in S} \left(\boldsymbol{dis}_{k,d,t,n,Y} - \boldsymbol{cha}_{k,d,t,n,Y}\right) + \sum_{n'\neq n} \left(\boldsymbol{TEF}_{n',n} \cdot \boldsymbol{xt}_{d,t,n',n,Y} - \boldsymbol{xt}_{d,t,n,n',Y}\right) = \sum_{k\in C} \boldsymbol{xc}_{k,d,t,n,Y} + \boldsymbol{ev}_{d,t,n,Y} + \boldsymbol{LDC}_{d,t,n} \cdot \boldsymbol{edem}_{n,Y} \tag{1}$$

Where k: technology index, d: day index ($d = 0, 1, \ldots, 364$), t: time index ($t = 0, 1, \ldots, 23$), n: node index, y: year index, P: set of power generation technologies (Fig. 1), $S = \{$Pumped hydro, Li-ion battery$\}$, C: set of energy transformation technologies (e.g., water electrolyzer). Endogenous variables: $xp_{k,d,t,n,y}$: output of power generation technology k at time t in day d, node n in year y [kWh/hour] (hereafter "at time t in day d, node n in year y" is omitted), $dis_{k,d,t,n,y}$: electricity discharge from technology k [kWh/hour], $cha_{k,d,t,n,Y}$: electricity charge into technology k [kWh/hour], $xt_{d,t,n',n,y}$: interregional electricity transmission from node n' to node n [kWh/hour], $xc_{k,d,t,n,y}$: electricity consumption of technology k [kWh/hour], $ev_{d,t,n,y}$: electricity charge into electric vehicles [kWh/hour], $edem_{n,y}$: annual electricity final consumption excluding electric vehicles [kWh/year], Exogenous variables: $TEF_{n',n}$: transmission efficiency between node n' and node n [%], $LDC_{d,t,n}$: load curve shape coefficient ($\sum_d \sum_t LDC_{d,t,n} = 1$).

Other important constraints relevant to power system operation include ramping capability constraint and minimum output constraint. These constraints incorporate the technical characteristics of power plants. The ramping constraints (Eq.2–Eq.3) describe the technical controllability of thermal power plants. Eq.4–Eq.5 indicate that a thermal power plant can generate electricity at more than its minimum output threshold, excluding the power plants that served as *Daily Start and Stop* (DSS) generators. These constraints are formulated based on Ref [30]; see this reference for more detailed explanations.

$$xp_{k,d,t+1,n,Y} \leq xp_{k,d,t,n,Y} + xk_{k,n,Y} \cdot AF_k \cdot RU_k \;\; (for\ k \in TP) \tag{2}$$

$$xp_{k,d,t+1,n,Y} \geq xp_{k,d,t,n,Y} - xk_{k,n,Y} \cdot AF_k \cdot RD_k \;\; (for\ k \in TP) \tag{3}$$

$$mxp_{k,d,n,Y} \geq xp_{k,d,t,n,Y} \;\; (for\ k \in TP) \tag{4}$$

$$xp_{k,d,t,n,Y} \geq \left(mxp_{k,d,n,Y} - xk_{k,n,Y} \cdot AF_k \cdot DSS_k\right) \cdot MIN_k \;\; (for\ k \in TP) \tag{5}$$

Where $TP = \{$Coal-fired, IGCC, Gas steam, Gas combined, Oil-fired, Nuclear, CSP, Biomass-fired, Hydrogen-fired, Ammonia-fired, Coal CHP, Gas CHP$\}$. Endogenous variables: $xk_{k,n,y}$: installed capacity of technology k [kW], $mxp_{k,d,n,y}$: maximum output of technology k in day d [kWh/hour]. Exogenous variables: RU_k: maximum ramp-up rate [%/hour], RD_k: maximum ramp-down rate [%/hour], AF_k: availability factor of technology k [%], DSS_k: share of daily start and stop of technology k [%], MIN_k: minimum output ratio of technology k [%].

The model explicitly considers energy balances and the technical performance of electricity storage technologies. Eq.6 ensures that stored electricity is balanced at all times in pumped hydro and Li-ion battery systems. Similar constraints are also formulated for the energy balance in thermal and hydrogen storage technologies. Eq.7 and Eq.8 are capacity constraints for pumped hydro and Li-ion battery; stored electricity should be below the energy capacity (kWh capacity as shown in Eq.7), and charge and discharge electricity are constrained by the power capacity (kW capacity in Eq.8). Eq.9 and Eq.10 indicate the ratio between energy and power capacities of pumped hydro and Li-ion battery systems.

$$se_{k,d,t+1,n,Y} = (1 - LOS_k) \cdot se_{k,d,t,n,Y} + \left(\sqrt{SEF_k} \cdot cha_{k,d,t,n,Y} - 1 \Big/ \sqrt{SEF_k} \cdot dis_{k,d,t,n,Y}\right) \;\; (for\ k \in S) \tag{6}$$

$$se_{k,d,t,n,Y} \leq AF_k \cdot ks1_{k,n,Y} \;\; (for\ k \in S) \tag{7}$$

$$cha_{k,d,t,n,Y} + dis_{k,d,t,n,Y} \leq AF_k \cdot ks2_{k,n,Y} \;\; (for\ k \in S) \tag{8}$$

$$ks1_{k,n,Y} = ENE_k \cdot ks2_{k,n,Y} \;\; (for\ k \in \{\text{Pumped hydro}\}) \tag{9}$$

$$ks2_{k,n,Y} = CRate_k \cdot ks1_{k,n,Y} \;\; (for\ k \in \{\text{Li-ion battery}\}) \tag{10}$$

Where Endogenous variable: $se_{k,d,t,n,y}$: stored energy in technology k [kWh], $ks1_{k,n,y}$: energy capacity of electricity storage technology k [kWh], $ks2_{k,n,y}$: power capacity of electricity storage technology k [kW]. Exogenous variables: LOS_k: self-discharge loss [%/hour], SEF_k: cycle efficiency [%], ENE_k: kW to kWh ratio for pumped hydro (6 h), Crate: C-rate of battery (2 for Li-ion battery).

Computational costs would be of interest to energy modelers. The NE_Global-R model has 510 million variables and 540 million constraints. Compared to existing global energy system models [10,42], the size of the NE_Global-R is larger by a factor of 10–100. Without international power grid interconnections (subsections 2.3 and 3.1–3.5), calculating a representative year takes about 20 h using a server with CPU Intel Xeon Platinum 8362 (2.80 GHz). Therefore, it takes about 100 h to calculate all the representative years. We use the solver CPLEX, and optimization algorithm is the interior-point method. The random-access memory (RAM) requirement is about 500GB. With international power grid interconnections (subsection 3.6), calculating a representative year takes about 96 h with the server. The RAM requirement is about 750GB.

2.2. Key assumptions

The NE_Global-R is a data-intensive model that requires large amounts of assumptions, including final demand, primary energy resources, geological CO_2 storage capacity, and techno-economic parameters (such as cost and efficiency) of technologies. We obtained the data from various referenced sources [43–52,53–63,64–72]. Most assumptions are prepared for all nodes at each representative year. Due to space constraints, this subsection only describes key assumptions, such as hourly profiles of electricity load and VRE output, and potential of renewable energy resources. Other important assumptions are presented in Appendix A (Tables 5, 13). See the Data Availability section for model codes and input data.

Hourly electricity load curves ($LDC_{d,t,n}$ in Eq.1) in the following countries are obtained from actual system operation data or estimated information in peer-reviewed journal papers: Australia, Brazil, Canada, China, Indonesia, Japan, Republic of Korea, Malaysia, Mexico, New Zealand, Peru, Philippines, Russia, Singapore, United States, Viet Nam, and countries in the ENTSO-E (European Network of Transmission System Operators for Electricity) region. These countries are represented by 47 city nodes (out of 75) in the model. For the rest of the city nodes, we constructed hourly load curves referring to typical daily load curve data in each season or month [42]. Hourly power output profiles for solar PV, CSP, onshore wind, and offshore wind are extracted from Pfenninger & Staffell [54] and Staffell & Pfenninger [55], which are based on weather data from global reanalysis models and satellite observations [56,57]. Hourly output profiles for solar PV at all nodes assume dual-axis tracking.

The resources of large and small hydro, amounting to a total of 47 PWh/year globally, are obtained from the high spatial resolution assessments in Hoes et al. [51]. The resources of solar PV, CSP, onshore wind, fixed-bottom offshore wind, and floating offshore wind are estimated by the authors using geographical information system data, such as solar irradiation [73], wind speed [74], land cover [75], slope [76], bathymetry [77], and environmentally protected area [78]. We referred to the estimation methods in [79]. The estimated global resource of solar PV is 390 PWh/year; CSP, 17 PWh/year; onshore wind, 453 PWh/year; fixed-bottom offshore wind, 96 PWh/year; and floating offshore wind, 101 PWh/year. Our estimates consider potential land use competition among VRE developments; onshore wind development is assumed to be prioritized in areas with good wind speed and solar irradiation. In the areas suitable both for solar PV and CSP, we assume half of the area is for solar PV and the rest for CSP development. For offshore wind resources, sea areas less than 200 km to shore with a depth of up to 1000 m are included. These estimated results are comparable or in the same order of magnitude compared to existing studies; for example, the global technical solar PV resource is estimated to be 613 PWh/year in [80], onshore wind resource with 20%+ capacity factor is estimated to be 458 PWh/year in [81], and offshore wind is estimated at 157–330 PWh/year in [82–84]. As for sustainable biomass resources, existing studies present a wide range of estimates about its availability for energy use, although there appears to be a broad consensus that up to 100EJ per year could be produced sustainably without serious difficulties and the long-term potential could be as much as 200EJ per year [85]. Based on this information, global sustainable resources are assumed to be 3583 Mtoe/year (150 EJ/year) in this study. Costs for hydro, solar PV, CSP, and onshore and offshore wind power are based on IEA [61], and biomass on NEDO [58,59].

2.3. Case settings

We examine three cases with different climate policy and technology assumptions, as shown in Table 2. The *NoReg* case does not assume any carbon policies, and no upper limits are considered for global energy-related CO_2 emissions. In contrast, the global energy system in the other two cases reach net zero emissions by 2050. Both cases follow the emissions pathway projected in the Net Zero Emission by 2050 (NZE) Scenario in IEA [3], which would be compatible with a 50% probability of limiting the average global temperature rise to 1.5 °C. The *FullTech* case is designed to explore the cost-effective net zero system in which all the modeled technologies can be installed based on cost minimization. Here, it should be noted that nuclear power generation capacity at each node in this analysis is subject to upper limit constraints–a total of 800GW globally in 2050, considering nuclear development policies and regulations in each country. This global upper bound is almost equivalent to the High case in the long-term projection published by the International Atomic Energy Agency (792GW in 2050) [86]. The *RE100* case investigates an energy system based on 100% renewable energy sources; all nuclear power plants are assumed to be phased-out by 2050, and CO_2 storage options are excluded. These three cases do not consider international power grid interconnections due to high computational costs, although domestic power grid extensions and international transportation of other energy carriers—renewable-based hydrogen, ammonia, methanol, and synthetic methane—are still available. To investigate the impacts of international power grid interconnections, we performed a sensitivity analysis in subsection 3.6.

3. Results and discussion

This section discusses the salient characteristics of the optimization results, including final energy consumption, power generation, and CO_2 abatement cost in net zero energy systems. Although the model presents the results at each node, this paper focuses on global results due to space constraints.

3.1. End-use energy transition

Fig. 3 shows the global final energy consumption under each of the cases. Like many existing studies [4], our results imply that accelerated end-use electrification contributes to the cost-effective strategy for net zero emissions. Electricity consumption increases even in the *NoReg* case, driven by economic developments and modern lifestyle needs in emerging countries. Yet, it grows more strongly in the *FullTech* and *RE100* cases due to the accelerated deployment of plug-in hybrid and electric vehicles in the passenger road transport sector, and heat pumps in the industry and buildings sectors. Electricity becomes the main source of final energy by 2050 in the latter two cases, with its share rising from 18% in 2015 to 41% and 54% in 2050, respectively, which are much higher than the level in the *NoReg* case (32%).

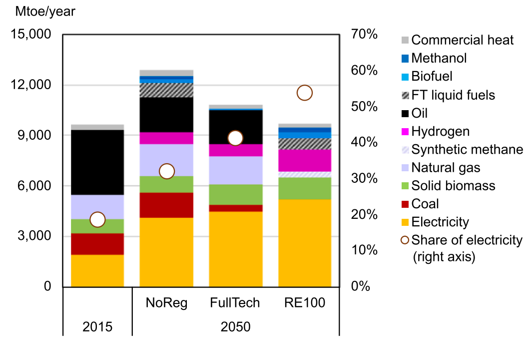


Fig. 3. Global final energy consumption
Note: FT = Fischer-Tropsch. Hydrogen and hydrogen-based fuels, such as FT liquid fuels, in the *NoReg* case are produced from unabated coal (see Fig. 22).

The cost-optimal mix of final energy in net zero system varies by case. Oil and natural gas (e.g., for trucks and heat demand, respectively) remain in 2050 in the *FullTech* case, while final consumption in the *RE100* case completely shifts to net zero emission energy carriers, including electricity, hydrogen, bioenergy, and synthetic fuels. The *RE100* case also features strengthened energy savings. These different trends between two net zero cases are due to the availability of negative emission technologies (NETs). In the *FullTech* case, biomass-fired power generation with CCS and direct air capture with CO_2 storage are largely installed, together storing 13GtCO_2/year in 2050 globally and offsetting residual CO_2 emissions from the end-use sectors. On the other hand, the *RE100* case needs to decarbonize final energy without using NETs; therefore, energy savings and zero emission energy carriers, including synthetic fuels, become critical. The cost-optimal level of end-use decarbonization would partially depend on the technical and economic viability of NETs.

3.2. Variable renewables in power generation

Fig. 4 depicts global power generation in 2050 in each case. Coal-fired continues to dominate the global power generation without carbon policies (the *NoReg* case), whereas low-carbon electricity reaches almost 100% in the latter two cases. In the *FullTech* case, a wide range of technologies, including CCUS-equipped gas-fired and biomass-fired, VRE, as well as nuclear, contribute to reducing CO_2 emissions. The cost-optimal share of VRE in global power generation is estimated to be 57%. This cost-effective share of VRE is within the range of existing studies (68% in IEA [3], 45–68% in the four illustrative scenarios of SR15 [5–8], 54%–74% in NGFS [9]). Even with the improved representation of the intermittency and system integration costs of VRE, our analysis confirmed the increasing importance of VRE in net zero energy

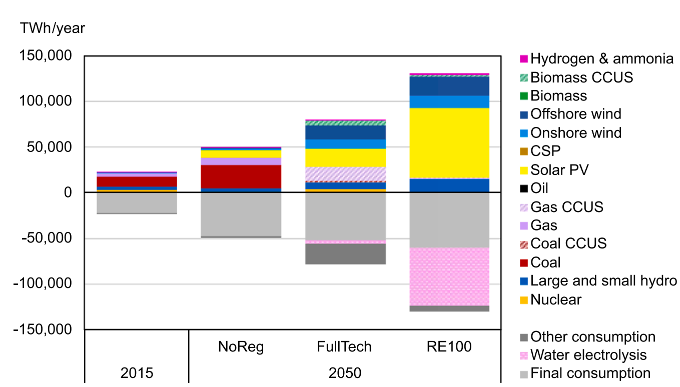


Fig. 4. Global power supply and demand balance
Note: CCUS = carbon capture, utilization, and storage.

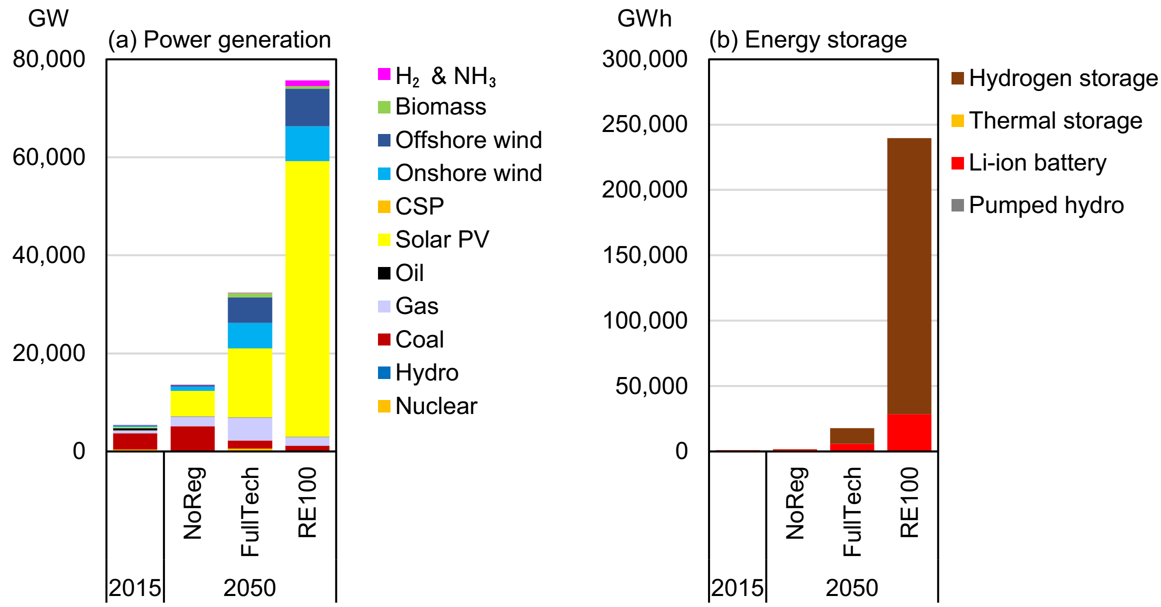


Fig. 5. Global installed capacity
Note: "H_2" and "NH_3" indicate hydrogen and ammonia, respectively.

systems.

The results also highlight that VRE penetration and optimal technology choice vary by country and region, reflecting local resource endowments. For example, VRE contributes to relatively higher shares (62%–71%) in the United States, China, and India, while gas-fired and biomass-fired hold the majority share in regions with abundant CO_2 storage and biomass resource potentials, such as the Middle East, Southeast Asia, Sub-Sahara, and Other Americas (see Fig. 20). Nuclear power generation appears to be cost-effective particularly in Asian countries, such as China, India, and Japan. These results imply that there would be no silver bullet technologies for the world; combining technological options suitable for local energy situations would be key to decarbonizing power generation efficiently.

VRE plays a more critical role in the *RE100* case, contributing to 85% of global power generation in 2050 (Fig. 4). Total generated electricity is estimated to grow drastically, reaching 130PWh/year in 2050, which is 65% higher than the *FullTech* case. This is largely for water electrolysis to produce hydrogen and hydrogen-based synthetic fuels for decarbonizing final energy consumption. Electrolyzers consume about half of the generated electricity (see the negative values in Fig. 4), implying that the electricity supply and demand structure may change significantly in an energy system with 100% renewable energy. End-use sectors are the main electricity consumer in the current energy system, while water electrolysis becomes one of the main consuming sectors.

From capacity viewpoints, the accelerated deployment of VRE and energy storage technologies is necessary to realize net zero energy systems—both in the *FullTech* and *RE100* cases. In the *FullTech* case, global VRE capacity is projected to increase from 633 GW in 2015 to 24,480 GW by 2050 (panel (a) in Fig. 5). To reach this level of VRE capacity, annual net capacity additions need to be 680 GW/year from 2015 to 2050. This is more than fourfold compared to recent development trends (154 GW/year between 2015 and 2020 [53]). To maintain grid flexibility, the global capacity of Li-ion battery storage systems reaches 5,090 GWh (or 5,090 GW) in 2050 (panel (b) in Fig. 5). This is more than 300-fold from the actual installed capacity as of the end of 2020 (about 17 GW) [87]. Even stronger installations of VRE and energy storage are projected in the *RE100* case. Global VRE capacity is estimated to be 71, 050 GW, with an average annual net capacity addition of 2010 GW/year. Total energy storage capacity reaches a total of 239,660 GWh not only to maintain grid flexibility but also to balance hydrogen supply and demand. Hydrogen partially serves as a long-duration electricity storage technology (e.g., storing energy longer than a week). A significant scale-up of VRE and energy storage technology supply chain is a prerequisite especially in the *RE100* case.

3.3. Power system operation in net zero energy systems: Japan and selected regions

Detailed temporal resolution enables the model to illustrate hourly power system operation. Fig. 6 depicts hourly electricity balances in the net zero cases in Japan as an example. In the *FullTech* case, a wide range of low-carbon options, including nuclear, renewables, and CCUS equipped coal-fired and gas combined cycle, contribute to Japan's power supply. The variable output of solar PV is managed mainly by ramping operation of dispatchable power plants (such as coal- and gas-fired), energy storage using pumped hydro and batteries, and curtailment. Among these integration options, dispatchable power plants and curtailment play an important role in managing the seasonality of solar irradiation, e.g., coal-fired and gas combined cycle covers the low solar output in the winter and curtailment manages excess electricity in spring (panel (a) in Fig. 6). Combining these integration measures would be crucial for accommodating solar PV in Japan's energy system cost-effectively.

In contrast, solar PV and offshore wind become the main source of electricity in Japan in the *RE100* case (panel (b) in Fig. 6). Installed solar PV and offshore wind capacities reach 551 GW and 288 GW by 2050, respectively, which are more than double the *FullTech* case (207 GW and 99 GW). This massive introduction of solar PV and offshore wind ensures the electricity supply even in a season with high electricity demand, like winter. In addition, these VRE sources are utilized to produce hydrogen for decarbonizing the end-use sectors. System operation in a week in January (panel (b) in Fig. 6) illustrates that most electricity from solar PV and offshore wind turbines is effectively utilized; excess generation is charged into storage technologies (pumped hydro and Li-ion battery) or input into water electrolysis. On the other hand, a large amount of curtailment appears in May due to high solar irradiation and moderate electricity demand. Curtailed electricity in Japan amounts to 79 TWh/year in 2050 in the *RE100* case, equivalent to about 8% of the country's total electricity output in 2019 (1037 TWh/year). Managing the seasonality of VRE would become a more critical agenda for power system

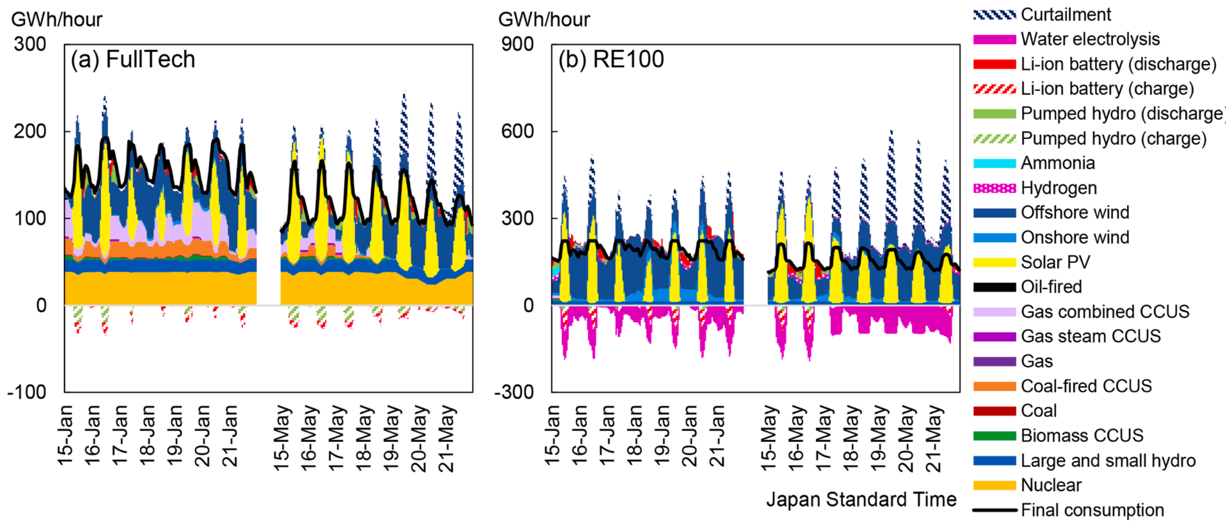


Fig. 6. Hourly power dispatch in Japan, selected weeks, 2050.

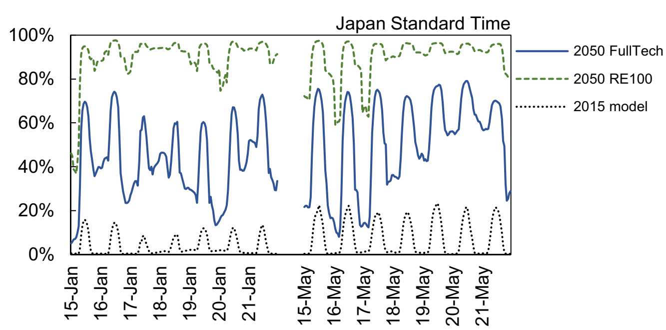


Fig. 7. Hourly share of non-synchronous power in Japan, selected weeks, 2050.

operation in Japan in the *RE100* case.

The *RE100* case also implies that the system non-synchronous penetration (SNSP)—defined as the share of VRE and net charge of Li-ion battery in this study—significantly rises. Fig. 7 illustrates Japan's hourly SNSP in the same weeks as Fig. 6. SNSP increases from 2015 to 2050, even in the *FullTech* case. It reaches 78% during the daytime due to solar PV, while it sharply declines to around 20%–40% in the evening as nuclear and fossil fuels with CCUS become the main generators. In contrast, hourly SNSP remains at a very high level (between 80% to 98%) in the *RE100* case. Grid operational and technological measures would be crucial to realize such a high SNSP in the *RE100* case. For example, several power grid operators have been relaxing the operational constraints; one of the most advanced cases is Ireland's transmission operator (EirGrid) which plans to run on 75% VRE and targets 95% by 2030 [16]. From technological viewpoints, virtual inertia produced by smart inverters [88] would also be important to accommodate a very high SNSP.

Fig. 8 illustrates hourly power system operation in a week in January and May in the United States, China, Russia, and four European countries (aggregated results of France, Germany, Italy, and the United Kingdom).

In the *FullTech* case, like in Japan, various power generation technologies—VRE as well as CCUS-equipped thermal power plants (gas combined cycle, coal-fired, or biomass-fired)—appear cost-effective in each country (see panels (a), (c), (e), (g) in Fig. 8). Ramping operation of these thermal power plants, battery storage systems, and curtailment are estimated to be the main flexibility options (see Fig. 25 for the total curtailed electricity in the world). In Russia, CCUS-equipped thermal power plants serve not only as a flexibility option but also as the primary source of electricity during the winter season, covering the low VRE output (panels (e) in Fig. 8). Maintaining a certain level of dispatchable low-carbon power sources would be crucial to ensure electricity balances in Russia. The load curves in the United States and four European countries show a sharp increase during daytime (panels (c) and (g) in Fig. 8). These are due to the flexible charging of battery electric vehicles (e.g., all the passenger light-duty vehicles are estimated to be electrified by 2050 in the United States). Demand-side flexibility resources would also play an important role in integrating VRE cost-effectively.

Nuclear power generation contributes as a stable low-carbon power source in China and Russia in the *FullTech* case (panels (a) and (e) in Fig. 8), while its contribution is modest in the United States and four European countries (panels (c) and (g)). Yet, care should be taken when interpreting the results of the United States and European countries, as some recent policy and regulatory updates—such as subsequent license renewal in the United States [89] and new nuclear policies (including lifetime extension of existing reactors and new reactor installations) announced by the President of France since November 2021 [90]—are not incorporated in this study. The contribution of nuclear (especially existing reactors) may be underestimated in these countries, given these policy developments.

The *RE100* case requires a more radical power system operation due to the massive introduction of VRE. A significant amount of battery storage and curtailment, as well as ramping operation of water electrolysis, become necessary to ensure electricity balances in each country. For example, hourly electricity inputs into energy storage and water electrolysis reach 6300 GWh/hour in China and 430 GWh/hour in the four European countries during the two weeks illustrated in Fig. 8. These levels are much larger than the current annual peak load in each country (about 1200 GWh/hour in China in 2021 [91] and 250 GWh/hour in the four European countries in the same year [92]). In addition to these flexibility options, dispatchable thermal power plants—fueled by biomass or synthetic methane gas—are operated during January as backup generators in Russia and four European countries (panels (f) and (h) in Fig. 8). These results imply that dispatchable power plants would be necessary even in a system with very high penetration in some countries. As for SNSP, these countries and regions show higher shares in the *RE100* case (Fig. 9). SNSP particularly increases in China and the United States, reaching above 90% frequently during the weeks; power system inertia and reliability can be crucial agendas in the *RE100* case in both countries.

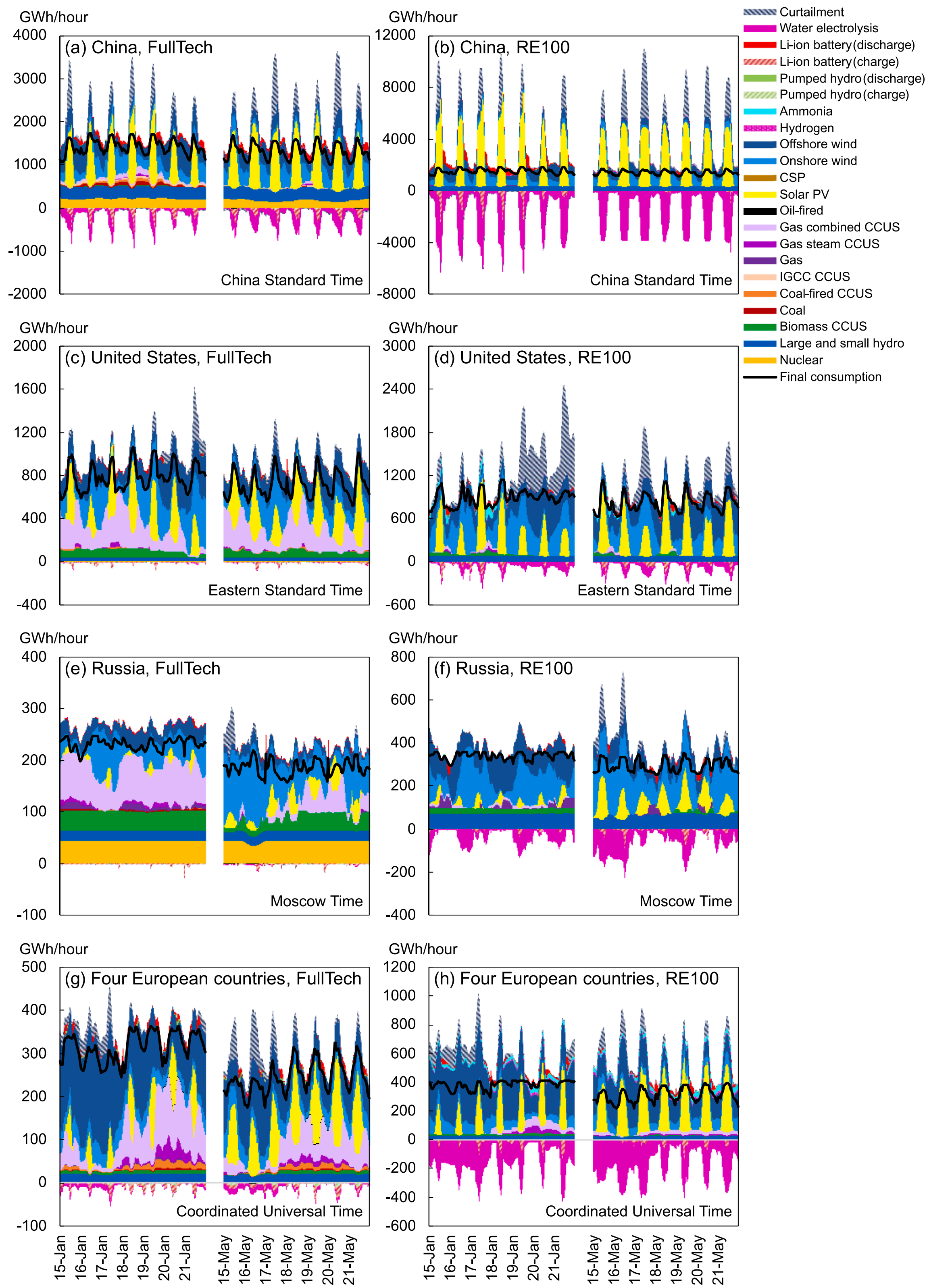


Fig. 8. Hourly power dispatch in China, the United States, Russia, and four European countries, selected weeks, 2050. Four European countries include France, Germany, Italy, and the United Kingdom.

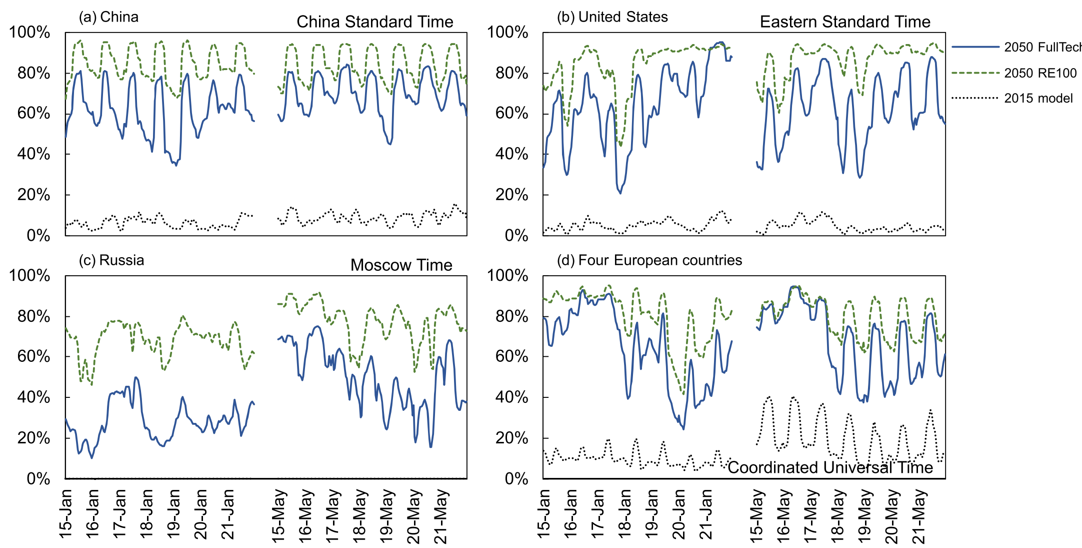


Fig. 9. Hourly share of non-synchronous power in China, the United States, Russia, and four European countries, selected weeks, 2050.

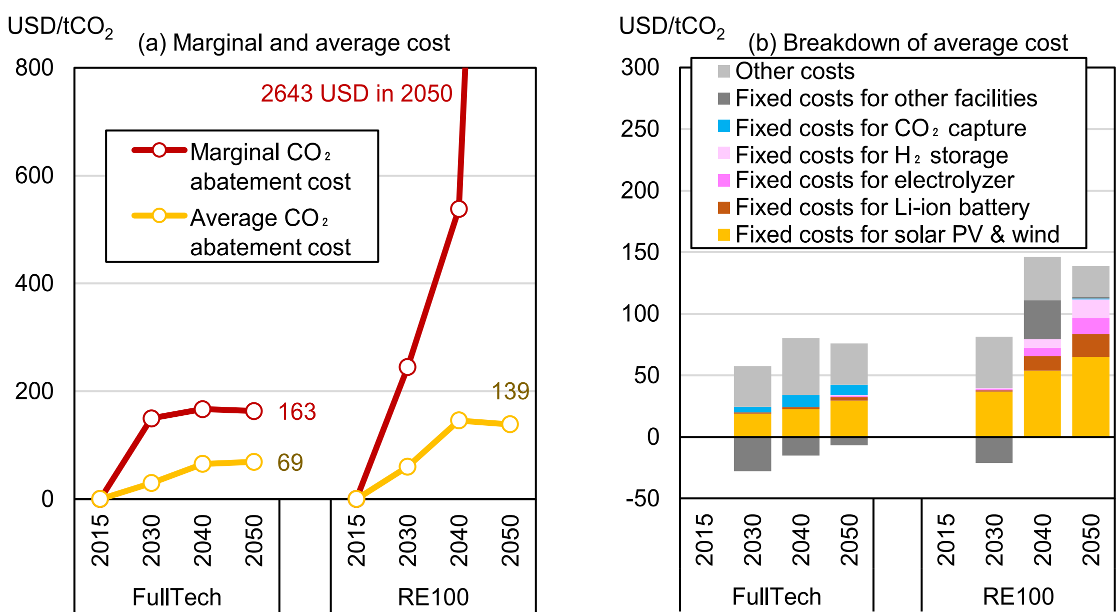


Fig. 10. Costs for realizing net zero energy systems.

Table 3
Capital cost assumptions for solar PV, Li-ion battery, and water electrolyzer in 2050 in the *RE100+* and *RE100++* cases.

	RE100 case	RE100+ case	RE100++ case
Solar PV	261–1016 USD/kW	130–508 USD/kW	65–254 USD/kW
Li-ion battery	300 USD/kWh	150 USD/kWh	75 USD/kWh
Water electrolyzer	450 USD/kW	225 USD/kW	113 USD/kW

Note: Cost assumptions for solar PV vary by region. The ranges indicate the lowest and highest values.

3.4. CO_2 abatement cost

Fig. 10(a) illustrates average and marginal CO_2 abatement costs for the entire world, and Fig. 10(b) shows the breakdown of average CO_2 abatement costs. Both figures are described in USD 2015. The average CO_2 abatement cost is estimated by dividing mitigation costs by reduced CO_2 emissions, as shown in Eq.**11**. In contrast, marginal CO_2 abatement cost (MAC) represents the mitigation cost at the margin, or the cost of reducing one more unit of CO_2 emissions. MAC indicates the theoretical level of the global carbon price needed to achieve a net zero energy system.

$$AAC_{c,y} = \left(C_{c,y} - C_{NoReg,y}\right) / \left(E_{NoReg,y} - E_{c,y}\right) \tag{11}$$

Where c: case index, y: year index, $ACC_{c,y}$: average CO_2 abatement cost in year y in case c, $C_{c,y}$: annual system cost in year y in case c [USD], $E_{c,y}$: CO_2 emissions in year y in case c [tCO_2].

Costs for realizing net zero energy systems are largely curbed in the *FullTech* case compared to the *RE100* case. The average abatement cost in the *FullTech* case is estimated to be 69 USD/tCO_2 in 2050, about half of the *RE100* case (139 USD/tCO_2). Combining various mitigation options suitable for local energy situations—renewables, CCS, and nuclear—is critical to reducing CO_2 emissions cost-effectively. In the *RE100* case, capital costs for VRE, batteries, and water electrolyzer push up the average abatement cost despite large cost reductions assumed for these

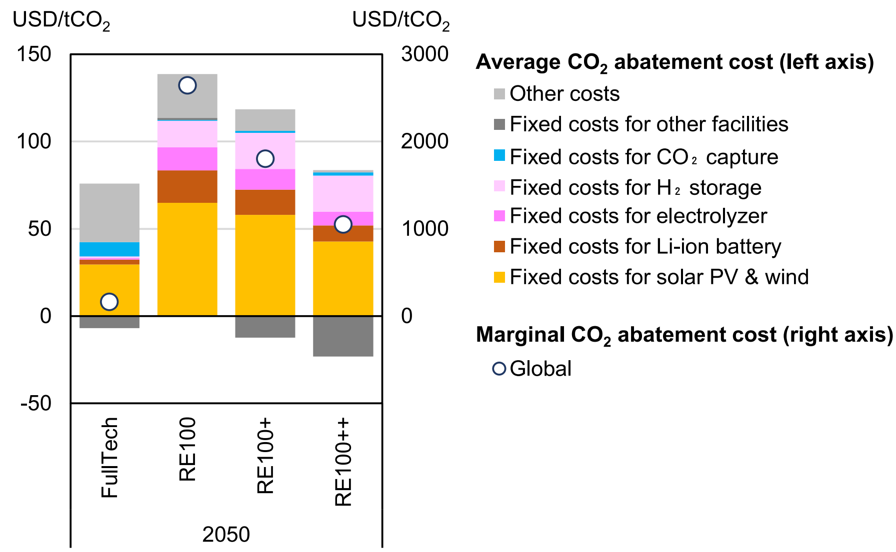


Fig. 11. Average and marginal CO_2 abatement costs in 2050 in the *FullTech, RE100,* and two cost reduction cases.

Table 4
Assumptions for interregional electricity high-voltage lines in the *RE100* and *RE100Grid* cases.

	RE100 case	RE100Grid case
Domestic power grid interconnections	Cost-optimized	Cost-optimized
International power grid interconnections	Not allowed	Cost-optimized in 2040 and 2050

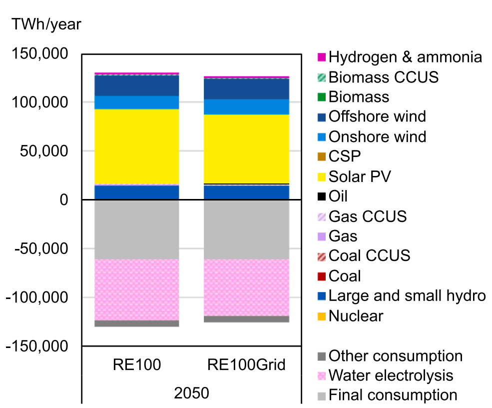


Fig. 12. Global power supply and demand balance in the *RE100Grid* case.

technologies (e.g., capital costs for solar PV, Li-ion battery, and water electrolyzer decline by 50%, 70%, and 75%, respectively, from 2015 to 2050. For the assumptions in 2050, see Tables 6–8). Further cost reductions for these technologies are necessary for the *RE100* case to be the most cost-effective. To investigate the impacts of accelerated cost reduction of VRE, Li-ion battery, and water electrolyzer, we conducted a sensitivity analysis in subsection 3.5.

The MAC, or carbon price, is substantially different between the two net zero cases. The MAC is estimated to be 163 USD/tCO_2 in 2050 in the *FullTech* case, while it increases sharply in the *RE100* case, reaching 538 USD/tCO_2 in 2040 and 2643 USD/tCO_2 in 2050. For comparison, IPCC SR15 [4] reported that the estimated carbon price in 2050 ranges from 113 to 14,300 USD2010/tCO_2 (123–15,580 USD2015/tCO_2) for below-1.5 °C and 1.5 °C pathways. Our estimates for the two net zero cases are within this range. In the *FullTech* case, the average and marginal abatement costs show a saturating trend, as direct air capture with CO_2 storage serves as a backstopping technology (see Table 9 for economic assumptions). In contrast, the high MAC in the latter case is due to mitigation costs in high-latitude regions, such as Northern Europe, Canada, and Russia. Solar PV output in these countries largely varies by season (e.g., very low output in winter due to short sunshine duration), which can hardly satisfy electricity and heat demand in that season. Therefore, these regions and countries rely heavily on offshore wind power, although its output also presents significant seasonal variation [54,55]. Excess power generation and seasonal storage facilities are necessary for ensuring energy supply and demand balances, resulting in a relatively high marginal cost in the regions.

3.5. Sensitivity analysis of solar PV, battery, and water electrolysis cost assumptions

Fig. 10 suggested that the average CO_2 abatement cost of a 100% renewable-based system is about double the *FullTech* case. The figure also indicated that VRE, Li-ion battery, and water electrolyzer are the major cost factors. However, the unit cost of these technologies has fallen drastically over the last decade [11,93], and future cost reductions may be further accelerated, reaching lower costs than what is assumed in Tables 6–8. Therefore, this subsection performs two additional cases (the *RE100+* and *RE100++* cases) with a focus on cost assumptions for solar PV, Li-ion battery, and water electrolyzer to investigate their effects on the economics of a 100% renewable-based system. In the *RE100+* case, capital costs for these technologies in 2050 are reduced by half from the default settings (Table 3). The *RE100++* case assumes an additional 50% reduction from the *RE100+* case (or 75% reductions from the *RE100* case). For comparison, the assumed solar PV cost for the IEA's "Net Zero Emission by 2050″ Scenario [3] is between the *RE100* and *RE100+* cases. Other assumptions in these additional cases are the same as in the *RE100* case.

Fig. 11 illustrates the average and marginal CO_2 abatement costs of the sensitivity cases. The results indicate the improved economics of a 100% renewable-based system under low capital costs of solar PV, battery, and water electrolyzer. The average CO_2 abatement cost in 2050 is estimated to be 106 USD/tCO_2 in the *RE100+* case and further declines to 60 USD/tCO_2 with accelerated cost reductions of solar PV and battery systems (*RE100++* case). The level in the *RE100++* case is lower than the *FullTech* case (69 USD/tCO_2), implying that an energy system based on 100% renewable energy can be cost-effective if such cost reductions are realized.

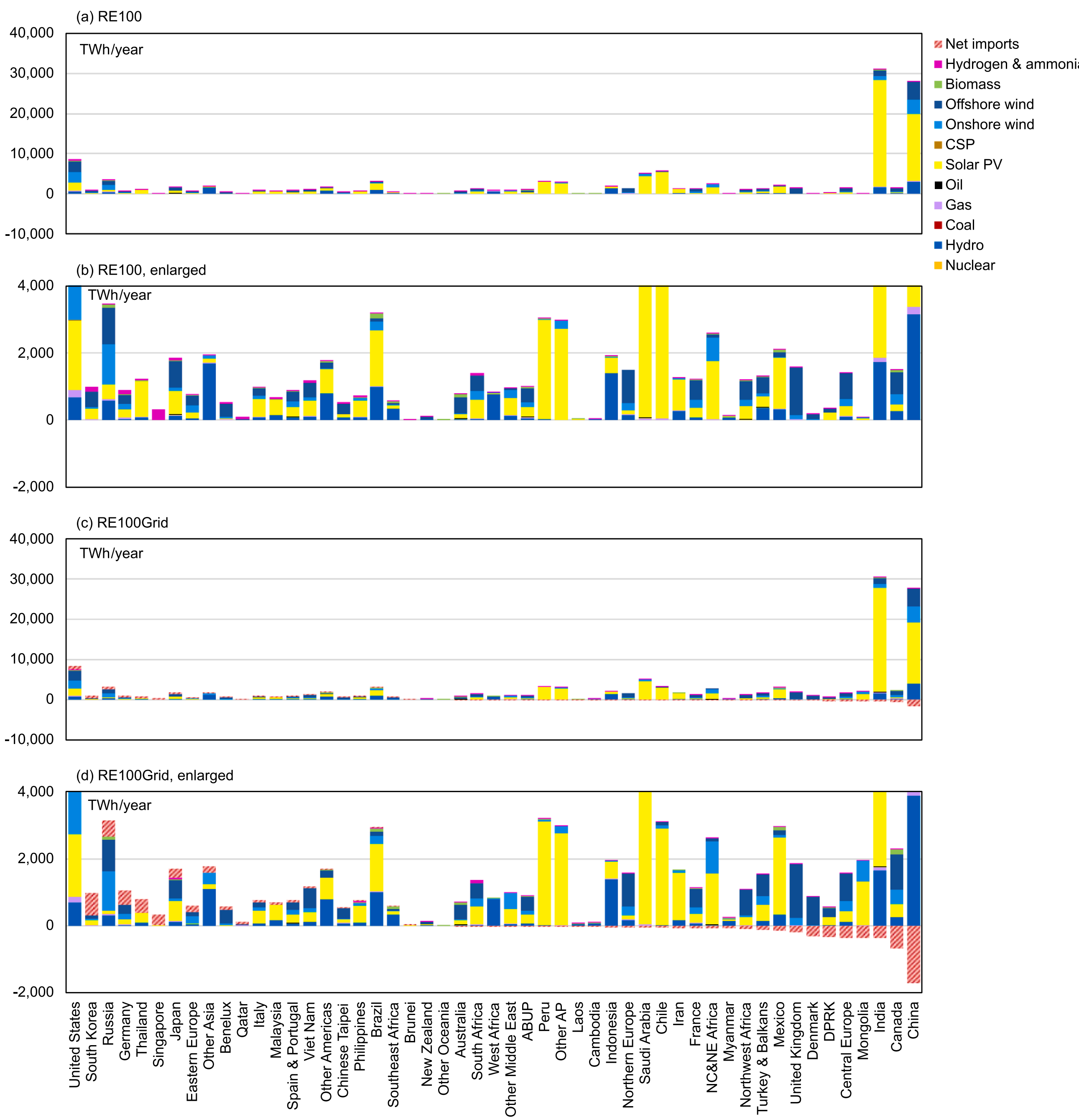


Fig. 13. Region- and country-level power generation in 2050 in the *RE100* and *RE100Grid* cases
Note: "Coal", "Gas", and "Biomass" include coal with CCUS, gas with CCUS, and biomass with CCUS, respectively. DPRK= the Democratic People's Republic of Korea, ABUP=Argentina, Bolivia, Uruguay, and Paraguay, AP= Arabian Peninsula, NC&NE=Northcentral and northeast.

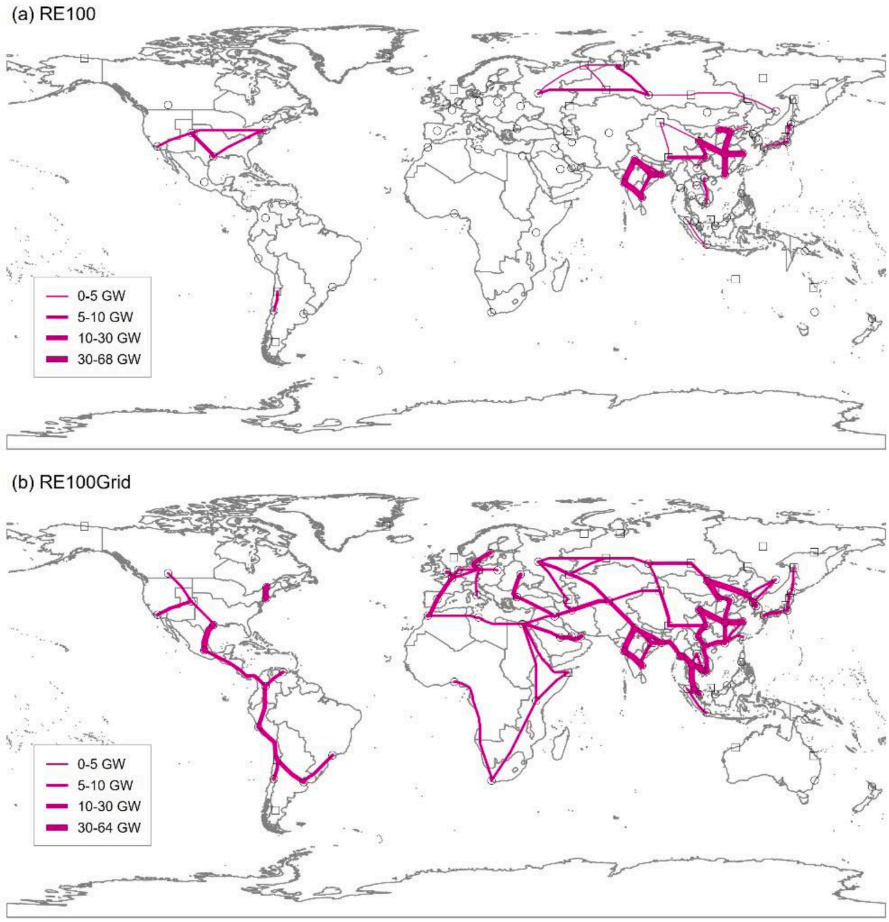


Fig. 14. Interregional high-voltage electricity transmission capacity in 2050 in the *RE100* and *RE100Grid* cases.

However, these sensitivity cases still pose some economic challenges. In both cases, the global marginal CO_2 abatement cost remains relatively high in 2050 (1052 USD/tCO_2 in the *RE100++* case). Even though solar PV, battery, and water electrolysis systems become more economical and the average abatement cost can be reduced, the "last one mile" of CO_2 emissions reduction can be costly. The IPCC WG3 AR6 pointed out that "it will be challenging to supply the entire energy system with renewable energy" (Executive Summary, Chapter 6). We believe that our results are broadly consistent with this argument.

3.6. Sensitivity analysis of international power grid interconnections

The optimization results in subsections 3.1–3.5 do not consider international electricity transmissions. However, as mentioned in subsection 2.1, international power grids may play an important role in integrating VRE and realizing a net zero energy system cost-effectively. Therefore, this subsection performs an additional analysis (the *RE100Grid* case) which endogenously considers international power grid extensions for realizing a 100% renewable-based system (Table 4). International grid extensions are included after 2040. High-voltage electricity transmission routes expressed in Fig. 18(b) are cost-optimized in this case. To investigate the maximum benefits achievable by international power grids, this case does not impose any upper bounds for electricity imports in each region or country.

Fig. 12 illustrates the global electricity supply and demand balance in 2050 in the *RE100* and *RE100Grid* cases. Global power generation does not significantly change between the two cases. International power grids encourage the integration of spatially imbalanced wind resources, yet solar PV remains the largest power generation technology. The modest impacts would be because global electricity demand is dominated by China and India, where abundant renewable resources are available at relatively low-cost. These two countries account for about half of the global electricity generation in both cases (Fig. 13). They could be large electricity importers and affect the global electricity flow if their domestic renewable energy resources were sparse and expensive compared to neighboring countries. However, according to our GIS-based estimates, abundant renewable energy resources are available in these two countries—98 PWh/year of solar PV, 32 PWh/year of onshore wind, and 8 PWh/year of offshore wind power, which suffice their domestic electricity needs (56 PWh/year in 2050 in the *RE100Grid* case). In addition, this study assumes that their VRE costs will achieve one of the lowest levels in the world by 2050—e.g., capital costs for solar PV in 2050 are 261 USD/kW in India and 308 USD/kW in China—with reference to IEA [61]. Although there are some exceptions (like renewable power exports from Mongolia to northern China), domestic renewable resources are economically attractive in these two largest markets, resulting in modest changes from the *RE100* to *RE100Grid* cases.

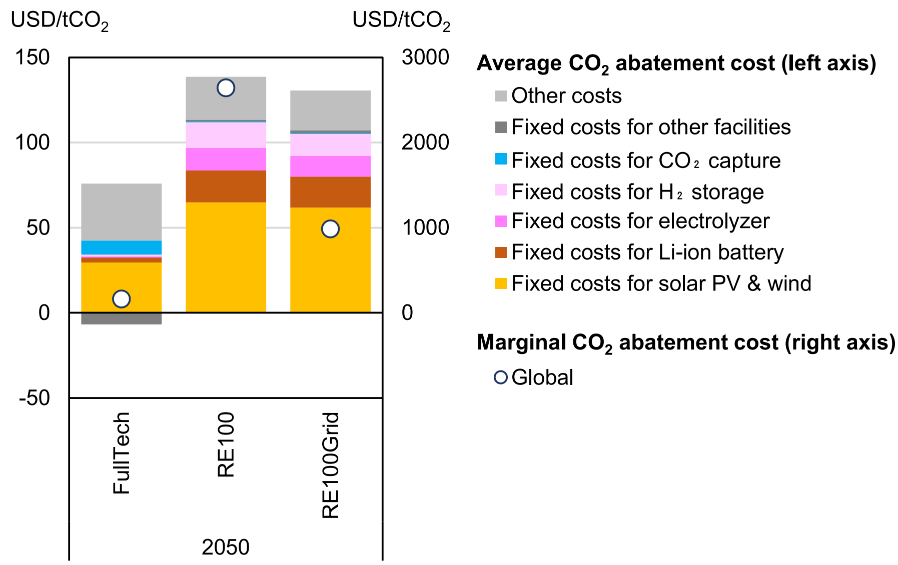


Fig. 15. Average and marginal CO_2 abatement costs in 2050 in the *RE100Grid* case.

However, it should be highlighted that international electricity interconnections have significant impacts on the power generation mix at a local level (Fig. 13). Low-cost domestic renewable resources encourage China to be the largest net exporter in the world, transmitting electricity to neighboring countries such as South Korea and Viet Nam (Fig. 14). Net exported electricity from China in 2050 amounts to 1700 TWh/year, equivalent to the sum of total power generation in France, Germany, Italy, and the United Kingdom in 2019. Such large-scale transmissions drastically change the power generation mix in importing countries. Net imports account for 68% of the power supply in 2050 in South Korea, replacing domestic VRE and hydrogen-fired power generation (see panels (b) and (d) in Fig. 13). In northern Viet Nam, the share of net imports reaches 56% in 2050. Fig. 13(d) indicates that net imports are modest in Viet Nam as a whole; this is because southern Viet Nam exports offshore wind power to Thailand, offsetting net imports in northern Viet Nam. Although energy security aspects (such as dependency on foreign countries) need to be carefully discussed before implementation, international power grids can be a cost-effective option for these countries to realize a 100% renewable-based energy system.

International electricity transmission also appears cost-effective in other regions, including the Americas, South Asia, Southeast Asia, and Europe. In the Americas, the United States becomes the largest importer in absolute terms; net imports amount to 680 TWh/year, about 8% of the country's power generation mix in 2050. In South Asia, India becomes a net exporter, transmitting low-cost solar PV to central Asia (included in the Other Asia node in this model) and Southeast Asia. Singapore and Thailand are estimated to be prospective importers; these two countries import not only from India but also from other countries in Greater Mekong Subregion, such as Cambodia, Laos, Myanmar, and southern Viet Nam. International power trade meets almost all (94%) of the electricity needs in Singapore and half (51%) in Thailand in 2050. Imported electricity has replaced hydrogen-fired—fueled by imported hydrogen—in Singapore and domestic solar PV in Thailand (see panels (b) and (d) in Fig. 13). In Europe, international interconnections appear cost-effective among western and northern European countries (Figs. 13, 14). Germany becomes the main importer, receiving electricity from Denmark, France, and northern Europe. The share of net imports in Germany is estimated to be 41%, replacing domestic solar PV and hydrogen-fired power generation. Figs. 13 and 14 also indicate that importing electricity (mostly offshore wind) from northwest Africa can be economically attractive for western European countries.

Fig. 15 illustrates the CO_2 abatement costs in the *RE100* and *RE100Grid* cases. International electricity transmissions improve the economic viability of a 100% renewable-based energy system; in particular, global marginal CO_2 abatement cost sharply declines from 2643 USD/tCO_2 in the *RE100* case to 985 USD/tCO_2 in the *RE100Grid* case. As pointed out in subsection 3.4, the marginal abatement cost in the *RE100* case was due to the costs of compensating VRE's seasonality in high-latitude regions. International power grids enable these regions to procure renewable electricity in low VRE output seasons cost-effectively, curbing the marginal costs. However, the results also suggest that the mitigation costs of the *RE100Grid* are still higher than the *FullTech* case. International interconnections may be insufficient to change the cost structure drastically; combining various conditions, such as the cost reduction of VRE (subsection 3.5) and international interconnections, would be necessary for the *RE100* case to be more affordable in terms of average and marginal abatement costs.

3.7. Limitations of this study

As is often the case with existing energy system analyses, our study has potential limitations due to model boundaries and granularity. This last subsection highlights methodological limitations to deepen understanding of the optimization results, particularly the *FullTech* and *RE100* cases.

The *FullTech* case suggested that combining low-carbon technologies, including CCS and nuclear power, contributes to reducing mitigation costs; however, the social, technological, and institutional uncertainties—which are not fully incorporated into the model—can be barriers to the deployment of CCS and nuclear power in the real world. As for CCS, the siting process of CO_2 storage can be hampered by *Not-in-my-backyard* perceptions of the local community (e.g., a Japanese survey is available in Ref [94]). Technological maturity of CO_2 capture and storage technologies in the future is uncertain, which can be a barrier. In particular, direct air capture (DAC) with CO_2 storage serves as a backstopping technology in the *FullTech* case, although the technology readiness level of DAC is still evaluated at the "large prototype" stage [95]. In addition, long-term monitoring and verification framework must be developed technically and institutionally to ensure the performance of the geologic CO_2 storage. Regarding nuclear power, fission reactors face public acceptance issues when installing new power plants and final disposal facilities for high-level radioactive waste [96]. From Japan's experiences, nuclear power generation is estimated to be cost-competitive, even considering accident risk costs such as Fukushima Daiichi Nuclear Power Station's decommissioning, compensation, radiation decontamination, interim storage of radioactive wastes, and various administrative costs [97,98]; however, reputation and financial risks are severe for nuclear reactor owners and operators. In the longer term, uranium supply may constrain the operation of nuclear fission reactors because the resource depletes unless breeding reactors and nuclear fuel cycles are commercially established [99].

A comprehensive assessment would also be needed to investigate the feasibility of the *RE100* case from the following three perspectives. The first is about area requirements and their environmental and social impacts. The area required for VRE deployment is estimated to be 2.8 million km^2 in 2050 in the *RE100* case. Although this is relatively modest (2.2%) compared to the total land area in the world, the area requirements can have significant impacts on a country basis (see Fig. 21). For example, in Japan, the land area for VRE is estimated to be 20 thousand km^2 in the *FullTech* case, and it grows to 61 thousand km^2 in the *RE100* case. The area requirement in the *RE100* case is about 16% relative to Japan's total land area, or almost equivalent to three-quarters of the size of Hokkaido—the second largest island in the country. This extensive land use may significantly impact the local environment (e.g., vegetation and wildlife) and social acceptance (e.g., the fishery industry). Assumptions for these estimates are as follows: the land area of the world is 147 million km^2; that of Japan is 378 thousand km^2; the space required for solar PV, onshore wind turbines, and offshore wind turbines is 15 km^2/GW, 100 km^2/GW and 167 km^2/GW, respectively [100]. The second is about power grid operation. Our perfect-foresight model does not consider the prediction errors of weather conditions. In addition, stability requirements (e.g., system inertia and voltages) are not incorporated. As illustrated in subsection 3.3, the hourly share of VRE power generation reaches a very high level in the *RE100* case. This system can be more susceptible to prediction errors and contingency events. The third concerns the material balance of critical minerals, such as lithium, nickel, and cobalt, for Li-ion batteries. Resource availability and market price dynamics of these minerals may constrain battery storage installation. Comprehensive assessments of these perspectives—land use (like [101]), power grid stability, and critical mineral constraints—would be needed in future studies.

Model limitations regarding technological granularity should also be highlighted for interpreting the *RE100* case; some system integration measures are not included in our study. For example, this study considers only four storage technologies—existing pumped hydro, Li-ion battery, hydrogen storage, and thermal storage (molten salt storage) for CSP. Other prospective storage technologies, such as underground hydrogen storage, sodium-sulfur battery, redox flow battery, other thermal storage technologies, and seasonal storage of hydrogen-based synthetic fuels, may contribute to integrating VRE more cost-effectively. In addition, this analysis considers the flexible charging of electric vehicles as a demand response (DR) technology, but other DR options—the vehicle-to-grid, flexible operation of heat pumps in buildings, and flexible energy management of industrial equipment—are missing. We believe that the robustness of the economic implications from the *RE100* case is confirmed by the sensitivity analysis in subsection 3.5, where significant cost reductions of solar PV and some flexibility measures are assumed; however, this model limitation should be addressed in future work.

4. Conclusion and future work

This study newly developed a temporally disaggregated global energy system model to assess the cost-effective energy mix, with a focus on VRE, for net zero energy systems by 2050. VRE in this model includes solar PV, onshore wind, fixed-bottom offshore wind, and floating offshore wind turbines. Electricity and hydrogen balances are modeled on an hourly basis for a total of 100 regions in the world. This detailed temporal resolution enables the model to explicitly incorporate the costs for integrating VRE. Our model is one of the largest energy system models in the world, formulated as a linear programming problem with 510 million variables and 540 million constraints. We examined two net zero cases—one is a cost-optimal case (*FullTech*) and the other is a 100% renewables case (*RE100*)—as shown in Table 2. These optimization results provide the following notable findings regarding the economic viability of net zero systems.

First, there would be no "silver bullet" for realizing net zero emissions. The *FullTech* case indicated that combining various technical options suitable for local energy situations is critical to reducing global CO_2 emissions cost-effectively. Not only VRE but also CCS-equipped gas-fired and biomass-fired are projected to largely contribute to decarbonizing power supply. Cost-optimal share of VRE is estimated to be 57% in global power generation in 2050. Although its global share is modest, nuclear can serve as a major power source, particularly in Asia (such as China, India, and Japan). On the demand side, energy efficiency and electrification need to be implemented first in the cost-effective scenario, while fossil fuels are estimated to remain for heating and transport. Offsetting these CO_2 emissions by negative emission technologies (NETs, such as direct air capture and biomass coupled with CCS) plays a crucial role in achieving net zero emissions and curbing mitigation costs. Future energy policies need to support the optimal deployment of these various mitigation options, including fossil fuels combined with NETs. There are long-term uncertainties regarding energy demand, resource potential, and technology costs. Mitigation strategies with diversified technological options would help manage the risks associated with these uncertainties.

Second, a 100% renewable-based global energy system poses economic challenges. The average CO_2 abatement cost in 2050 in the *RE100* case is estimated to be double that of the *FullTech* case due to large investment costs for VRE and battery technologies. The marginal abatement cost also increases significantly in the *RE100* case; the cost burden needs to be carefully recognized by energy policymakers. The robustness of this argument is confirmed by sensitivity analyses of cost assumptions and international power grids. These analyses indicate that 1) significant cost reduction of solar PV, battery systems, and water electrolyzer would be necessary for a 100% renewable-based system to be the most cost-effective, and 2) mitigation costs of a 100% renewable-based system are still higher than the *FullTech* case, even with international electricity transmissions. Another interesting finding is the level of VRE deployment. Installed VRE capacity grows by a factor of two from 2015 to 2050 in a 100% renewable-based system. This is because of accelerated end-use electrification and the deployment of large-scale water electrolysis for producing hydrogen and hydrogen-based fuels. A vast amount of energy storage technologies becomes necessary to manage the variability of VRE-based electricity and hydrogen. Expanding the supply chain of VRE and energy storage technologies is crucial for realizing such a level of deployment.

Turning to priorities for future work, we need to enhance the model's capabilities and conduct additional analyses in at least four ways. The first would be improved modeling of VRE and integration measures. Detailed modeling of solar PV technologies, such as ground-mounted, rooftop, wall-mounted, and floating solar panels, would better reflect technical and siting characteristics for massive PV deployment. Prospective VRE integration measures and critical mineral constraints need to be modeled, as mentioned in subsection 3.7. Also, modeling of sub-hourly variability enables the model to validate the technical feasibility of power grid operation and assess the role of short-term flexibility measures. The second would be about modeling the end-use sector. The industry and buildings in the model are described in an aggregated manner. Explicit representations of energy service demand and end-use technologies are necessary to estimate the potential and costs for end-use transition in detail. The third point is energy security and geopolitical considerations. Cost-optimization models generally assume an ideal situation where all stakeholders (e.g., countries, energy producers, and energy consumers) fully cooperate toward the most cost-effective pathway, regardless of their interests and actual policies. Reflecting energy security policies, such as upper bounds for energy imports, would be an interesting research agenda. In addition, describing each stakeholder's interests and non-cooperative situation, for example, by multi-agent simulation approaches, would help to understand the cost of net-zero emissions. The last point is about regional or country-level energy and climate policies. To focus on the optimal pathway for the whole world, this study only constrained global CO_2 emissions; regional and country-level climate goals, including the target year of net zero emissions in each country, are not incorporated. Future work needs to reflect local policies to explore their energy and economic implications, such as energy mix and marginal and average abatement costs.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Model code and input files are available for non-commercial use in Ref. [102], although proprietary data (such as hourly electricity load curve in some countries) are replaced by dummy data.

Acknowledgement

The paper is supported by JSPS KAKENHI Grant Number JP20H02679, JP22H00572 and JP23K13696, by the Environment Research and Technology Development Fund 2–2104 of the Environmental Restoration and Conservation Agency, and by MEXT Innovative Nuclear Research and Development Program Grant Number JPMXD0220354480.

Appendix A

A.1. Model code and selected assumptions

Model code is available for non-commercial use in Ref [102], and key socioeconomic assumptions are summarized in Table 5 [43].

This model assumes fossil fuel resources and their production costs at each node (Fig. 16). We referred to regional production cost information [45,49,50], proven reserves [44,47], and undiscovered resource estimates [48]. Fossil fuel resources at each node are further divided into several grades to reflect production cost variations due to resource location (onshore or offshore) and resource quality (such as resource existence probability in USGS [48]). Coal is described by four grades (two for high-grade coal and the rest for low-grade coal), natural gas by seven grades, and crude oil by seven grades. Production costs vary by node and grade. Fig. 16 does not include the costs for interregional transportation. Economic assumptions for energy and CO_2 trade for the whole world are illustrated in Fig. 17 [58,59,64,68–70]. These costs are assumed to be constant during the analysis period. Interregional transportation routes are illustrated in Fig. 18.

Techno-economic assumptions for energy conversion technologies, such as power generation, energy storage, and hydrogen production, are summarized in Tables 6, –8 [30,60–65,71]. Assumptions for CCS technologies are provided in Tables 9, 10 [58,59,66,67,72]. Energy distribution and end-use technologies are provided in Tables 11–13. End-use energy choice is optimized considering the costs and vintages of energy distribution infrastructure and consumption technologies, such as vehicles in road transport and aggregated "energy distribution and consumption" technologies in the other end-use sectors. Costs for energy distribution are estimated by subtracting energy production or importing costs from delivered end-use energy prices [103]. Vehicle costs are estimated by authors in [34] by referring to actual vehicle prices and future cost projections for vehicle components (such as battery packs for BEV). Economic assumptions for the "energy distribution and consumption" technologies (Table 13) include the estimated costs for

Table 5
Key socioeconomic assumptions for the world.

	2015	2030	2050
Population (million)	7336	8497	9710
Global GDP (billion USD)	81,780	125,627	208,538
Road passenger travel (trillion person-km)	19.3	26.1	37.4
Road freight travel (trillion ton-km)	10.5	16.4	26.6

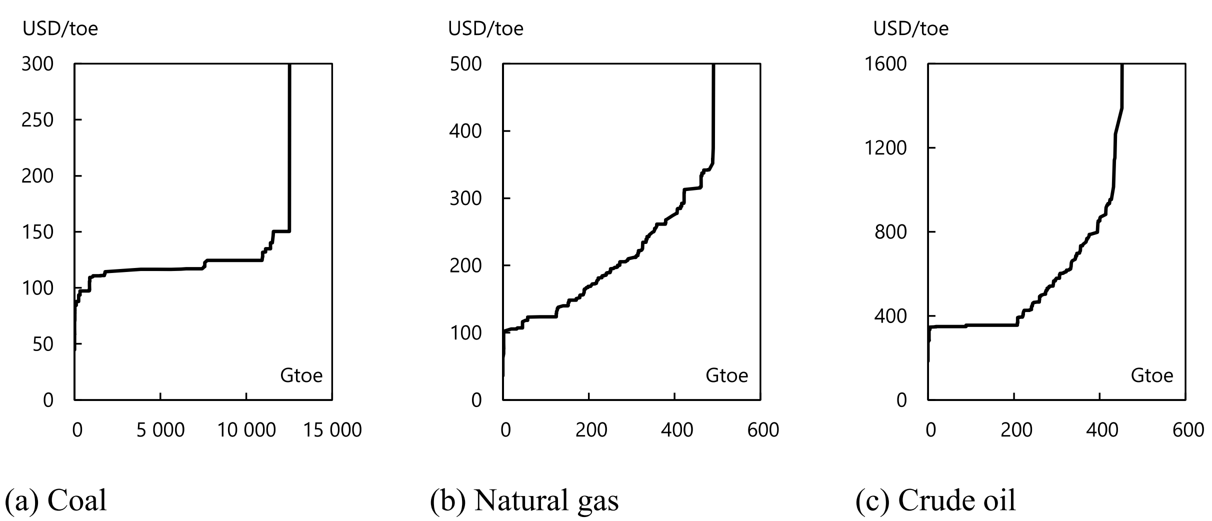


Fig. 16. Globally aggregated production cost curve of coal, natural gas, and crude oil.

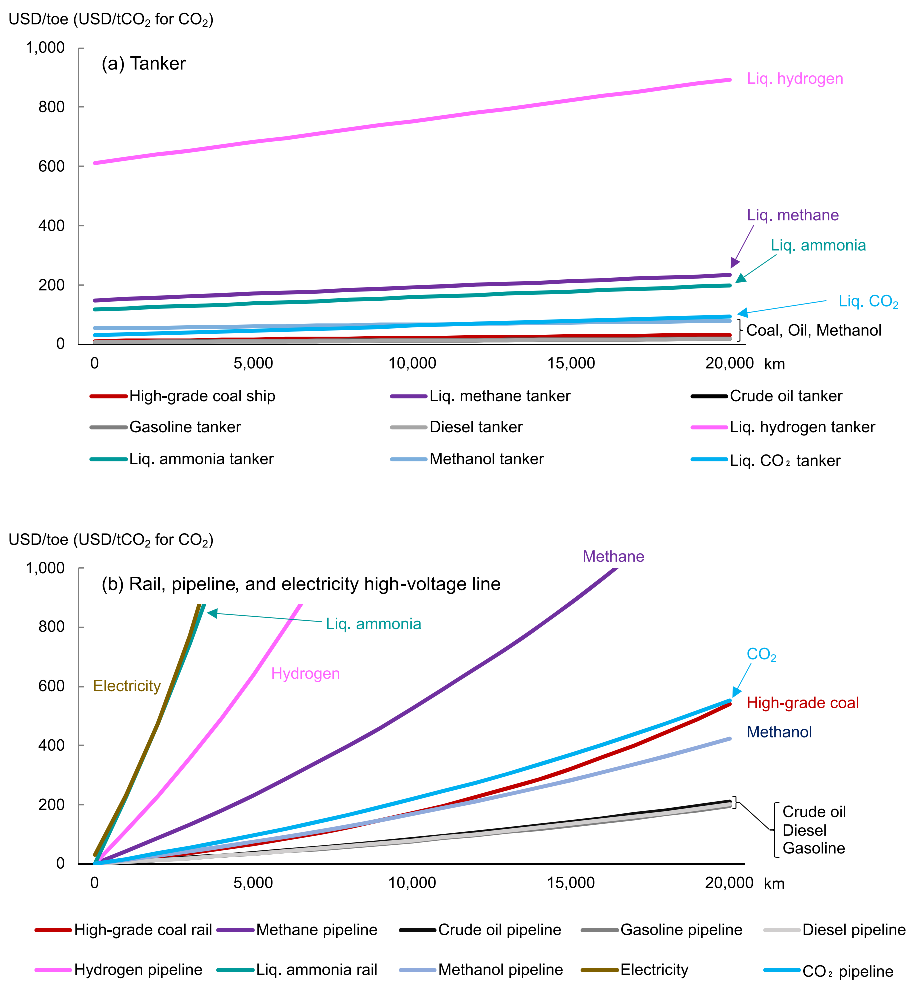
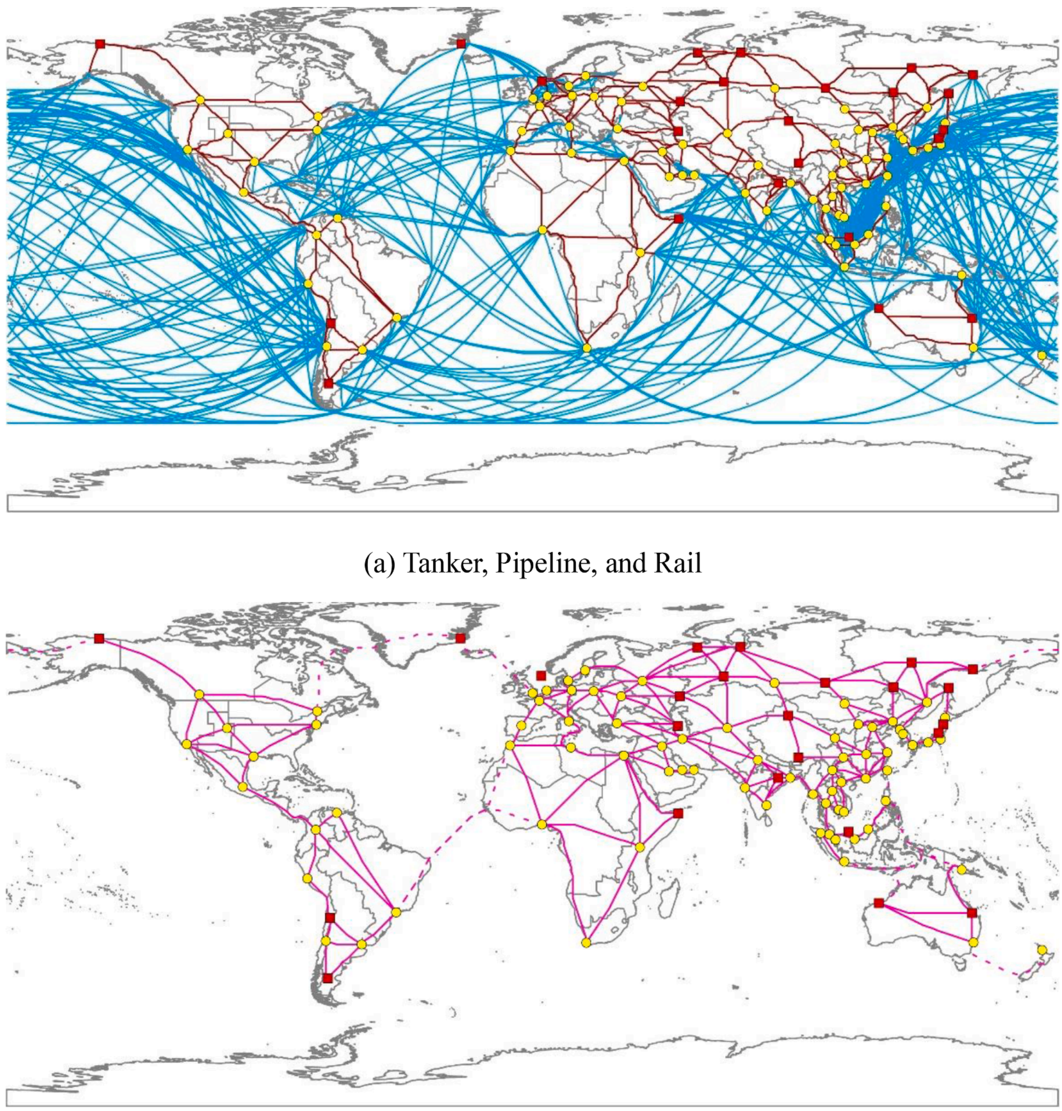


Fig. 17. Cost assumptions for interregional energy and CO_2 transportation.
Note: Liq. = Liquefied.



(a) Tanker, Pipeline, and Rail

(b) Electricity transmission

Fig. 18. International transportation routes
Note: Red lines in panel (a) are for pipeline and rail transportation, and light blue is for maritime transportation. Electricity transmission routes expressed in solid lines in panel (b) are cost-optimized in subsection 3.6. Dotted lines in panel (b) are formulated but excluded even in subsection 3.6 to reduce computational costs.

Table 6
Assumptions for power generation and heat production technologies for 2050.

	Capital cost [USD/kW]	Efficiency [LHV%]	Maximum ramp-up rate [% per hour]	Maximum ramp-down rate [% per hour]	Share of DSS [%]	Minimum output rate [%]	Availability factor [%]
Coal-fired	720–2400	32–42	26	31	0	30	85
IGCC	1107–3690	41–45	26	31	0	30	85
Gas steam	616–1100	34–49	44	31	30	30	85
Gas combined	616–1100	56–59	44	31	30	30	85
Oil-fired	1900	37	44	31	70	30	85
Nuclear	2000–6600	–	2	2	0	80	87
Large hydro	2925–4936	–	–	–	–	–	40
Small hydro	5850–9872	–	–	–	–	–	40
Solar PV	261–1016	–	–	–	–	–	Hourly profile
Onshore wind	932–2656	–	–	–	–	–	Hourly profile
Fixed-bottom offshore wind	1193–2106	–	–	–	–	–	Hourly profile
Floating offshore wind	1789–3159	–	–	–	–	–	Hourly profile
Concentrating solar power (receiver)	921–1267	–	–	–	–	–	Hourly profile
Concentrating solar power (turbine)	616–1100	40	44	31	30	30	90
Biomass	1500–2344	35	26	31	0	30	85
Hydrogen-fired	616–1100	56–59	44	31	30	30	85
Ammonia-fired	616–1100	56–59	44	31	30	30	85
Coal CHP	975–3250	80	26	31	0	30	85
Gas CHP	644–1150	80	44	31	40	20	85
Coal boiler	224	85	–	–	–	–	90
Gas boiler	150	85	–	–	–	–	90
Oil boiler	150	85	–	–	–	–	90
Biomass boiler	224	85	–	–	–	–	90

Note: Capital costs and efficiency vary by region. The ranges in the table indicate the lowest and highest values. Heat production from CHP plants and boilers (coal, gas, oil, and biomass) are for district heating.

Table 7
Assumed cost for energy storage technologies in 2050.

		Capital cost	C-rate	kW to kWh ratio	Efficiency [%]	Self-discharge loss [% per hour]	Availability factor [%]
Pumped hydro		920–1553 USD/kW	–	6	70 (cycle efficiency)	0.01	90
Li-ion battery		300 USD/kWh	2	–	85 (cycle efficiency)	0.1	90
Thermal storage for CSP (molten salt)		20 USD/kWh	–	–	–	0.2	90
Hydrogen storage	Compressor	700 USD/kW	–	–	90	–	90
	Tank	15 USD/kWh	–	–	–	0.01	90

Table 8
Assumed capital cost for hydrogen production technologies in 2050.

	Capital cost	Efficiency [%]
Coal gasification	814 USD/(toe/year)	64
Methane reforming	996 USD/(toe/year)	78
Oil gasification	694 USD/(toe/year)	76
Electrolyzer	450 USD/kW	74

Table 9
Assumptions for CO_2 capture technologies in 2050.

	Capital cost [USD/(tCO_2/year)]	Required electricity [MWh/tCO_2]	Solvent costs for post-combustion capture [USD/tCO_2]
Post-combustion CO_2 capture at coal-fired	80	0.30	4.4
Pre-combustion CO_2 capture at IGCC	85	0.27	–
Post-combustion CO_2 capture at gas steam and gas combined	112	0.42	4.4
Post-combustion CO_2 capture at biomass-fired	67	0.25	4.4
Pre-combustion CO_2 capture at hydrogen production plants	85	0.27	–
Direct air capture (fueled by hydrogen and electricity)	166	Hydrogen: 1.45 Electricity: 0.37	–
Direct air capture (electrified)	185	1.54	–

Table 10
Assumptions for CO_2 storage technologies.

	Storage cost in 2050 [USD/tCO_2]	Required electricity in 2050 [MWh/tCO_2]	Potential [GtCO_2]
Enhanced oil recovery	195–303	0.07	27
Enhanced coalbed methane	27–142	0.07	136
Depleted gas well	9–59	0.07	Max. 1060
Aquifer	5–38	0.07	1833

Table 11
Economic assumptions for energy distribution for the road transport sector in 2050.

	Annualized capital cost
Methane distribution	38–400 USD/(toe/yr)
Hydrogen distribution	38–400 USD/(toe/yr)
Gasoline distribution	40–709 USD/(toe/yr)
Diesel distribution	40–709 USD/(toe/yr)
Biofuel distribution	40–709 USD/(toe/yr)
Electricity distribution	5–56 USD/(MWh/yr)

Table 12
Economic assumptions for vehicles for 2050.

		Vehicle cost [thousand USD/vehicle]	Efficiency [thousand passenger-km/toe for LDV or thousand ton-km/toe for truck]
Passenger light-duty vehicle	Gasoline ICEV	21	23–26
	Gasoline HEV	23	46–52
	Gasoline PHEV	23	56–62
	Diesel ICEV	21	29–33
	Diesel HEV	23	49–55
	Biofuel ICEV	27	23–26
	Biofuel HEV	29	46–52
	CMG ICEV	25	25–29
	CMG HEV	27	51–57
	FCEV	45	41–46
	BEV	24	65–73
Truck	Diesel ICEV	65	21
	Diesel HEV	70	32
	Biofuel ICEV	73	21
	Biofuel HEV	74	32
	CMG ICEV	72	24
	CMG HEV	77	35
	FCEV	146	37
	BEV	114	60

Table 13
Assumptions for energy distribution and consumption technologies in end-use sectors (except for road transport) for 2050.

	Annualized capital cost
Coal distribution and consumption	239–321 USD/(toe/yr)
Solid biomass distribution and consumption	239–321 USD/(toe/yr)
Methane distribution and consumption	188–550 USD/(toe/yr)
Hydrogen distribution and consumption	188–550 USD/(toe/yr)
Diesel distribution and consumption	189–859 USD/(toe/yr)
Other oil product distribution and consumption	189–859 USD/(toe/yr)
Biofuel distribution and consumption	189–859 USD/(toe/yr)
Methanol distribution and consumption	189–859 USD/(toe/yr)
Electricity distribution and consumption	5–56 USD/(MWh/yr)
Heat pump for fuel switch	241 USD/(toe/yr)

energy distribution and list prices of end-use heating equipment (such as boiler).

A.2. Supplemental results

Fig. 19 illustrates global primary energy supply, Fig. 20 depicts country-level and regional power generation, Fig. 21 summarizes area requirement for VRE, Fig. 22 is about global hydrogen supply and demand balance, and Fig. 23 is about global vehicle stock. Key global results of the *RE100+*, *RE100++*, and *RE100Grid* cases are presented in Fig. 24. Fig. 25 illustrates the total curtailed electricity of hydro, solar, and wind power plants in all six cases. The figure also depicts the curtailment rate, estimated by dividing the curtailed electricity by the total potential output.

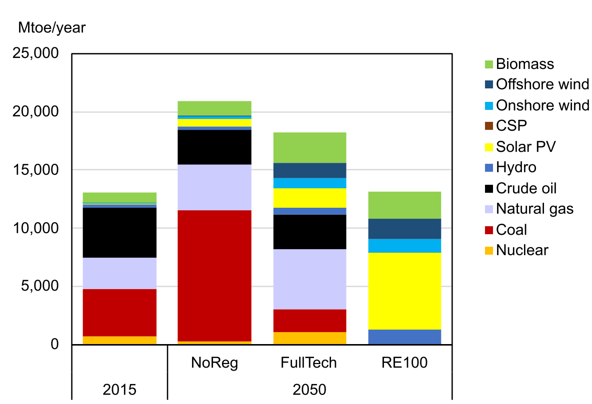


Fig. 19. Global primary energy supply.

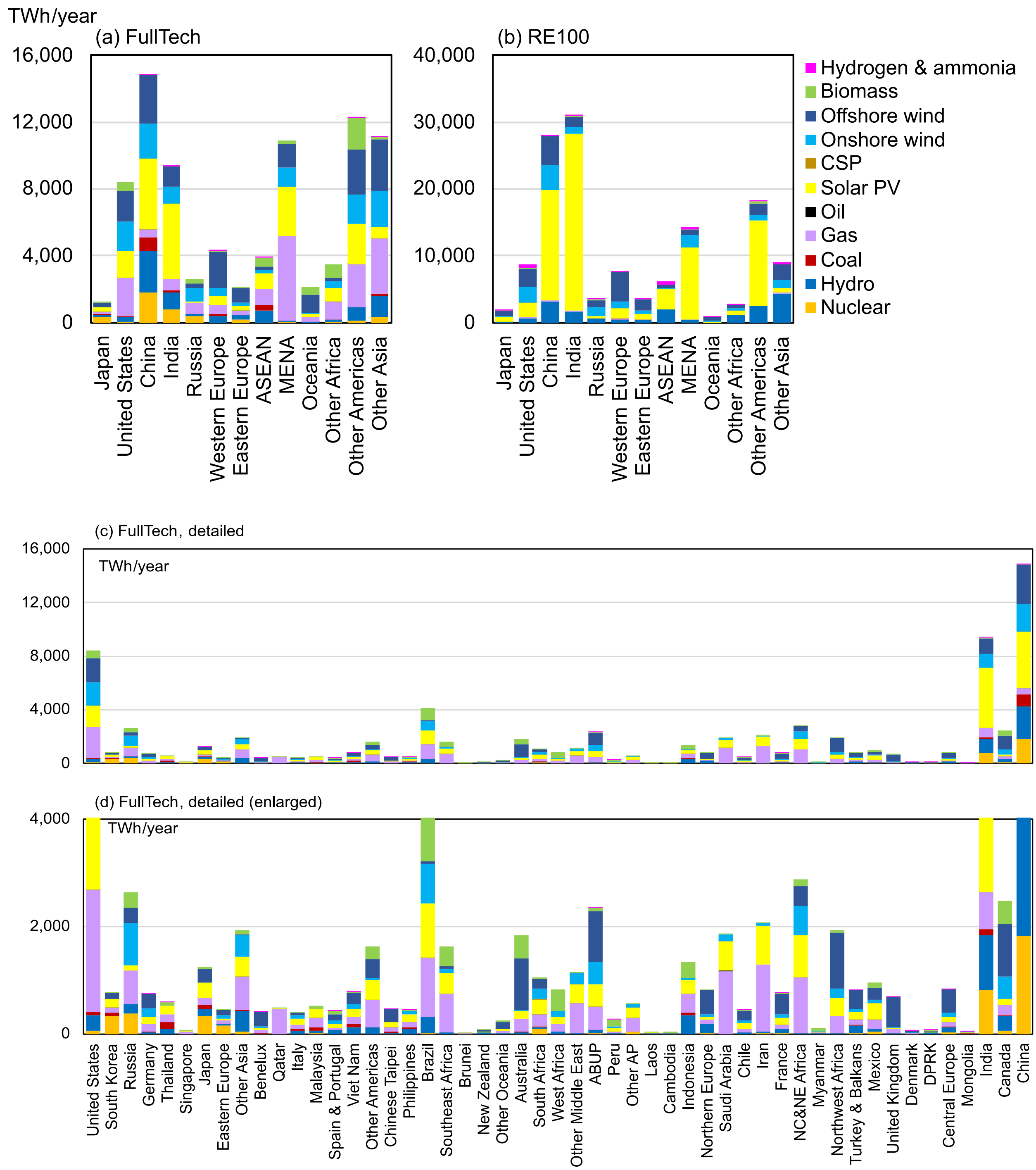


Fig. 20. Country-level and region-level power generation
Note: "Coal", "Gas", and "Biomass" include coal with CCUS, gas with CCUS, and biomass with CCUS, respectively. MENA = Middle East and North Africa, DPRK= the Democratic People's Republic of Korea, ABUP=Argentina, Bolivia, Uruguay, and Paraguay, AP= Arabian Peninsula, NC&NE=Northcentral and northeast.

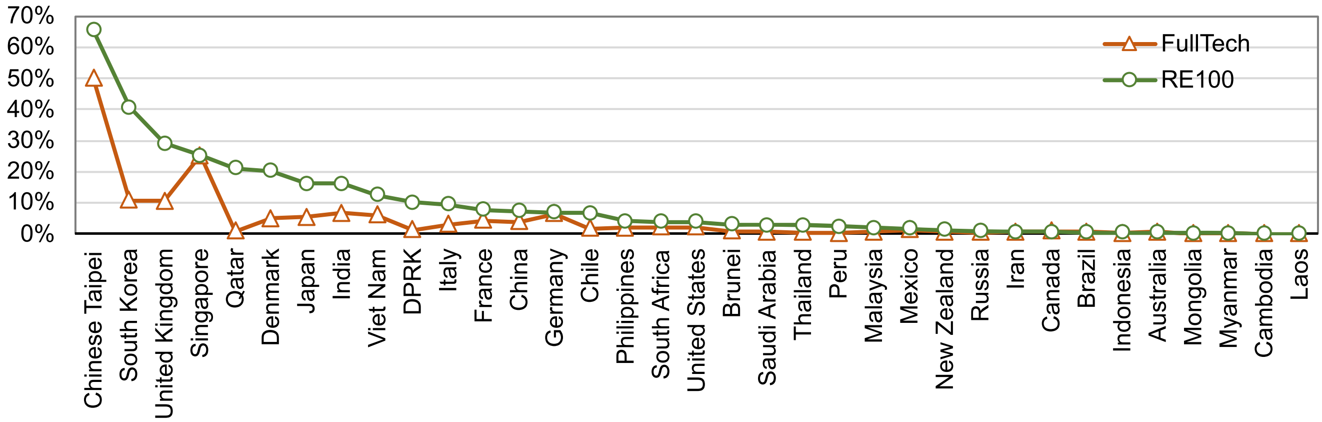


Fig. 21. Area requirement for VRE (ratio to total land area in each country or economy).

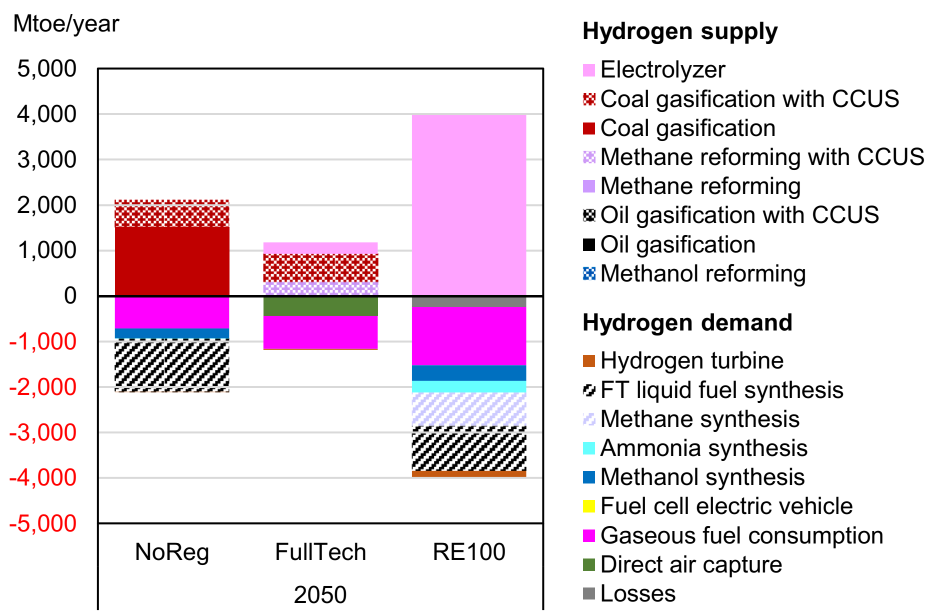


Fig. 22. Global hydrogen supply and demand balance.

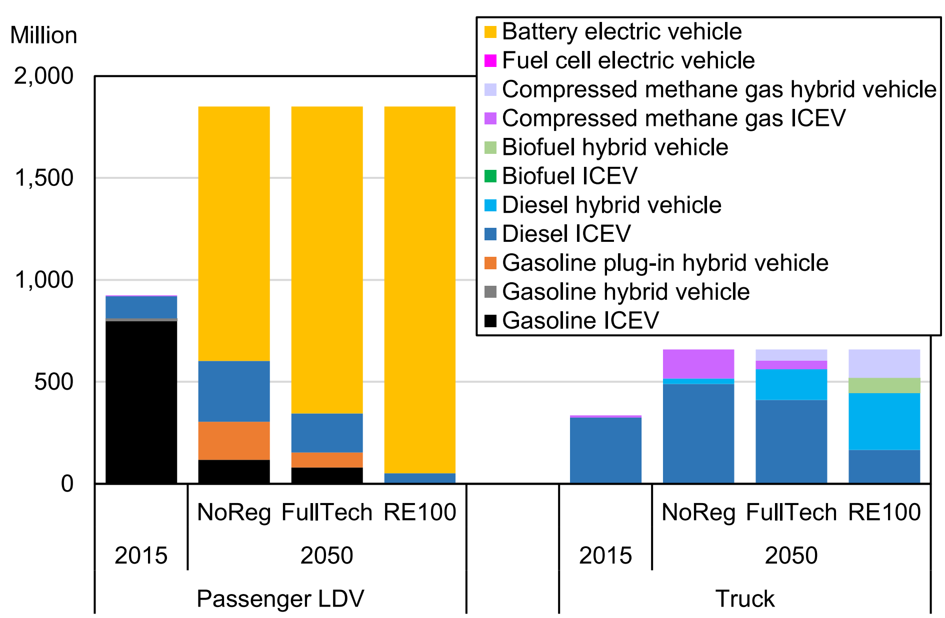


Fig. 23. Global vehicle stock
Note: ICEV=Internal Combustion Engine Vehicle, LDV=Light-duty vehicle.

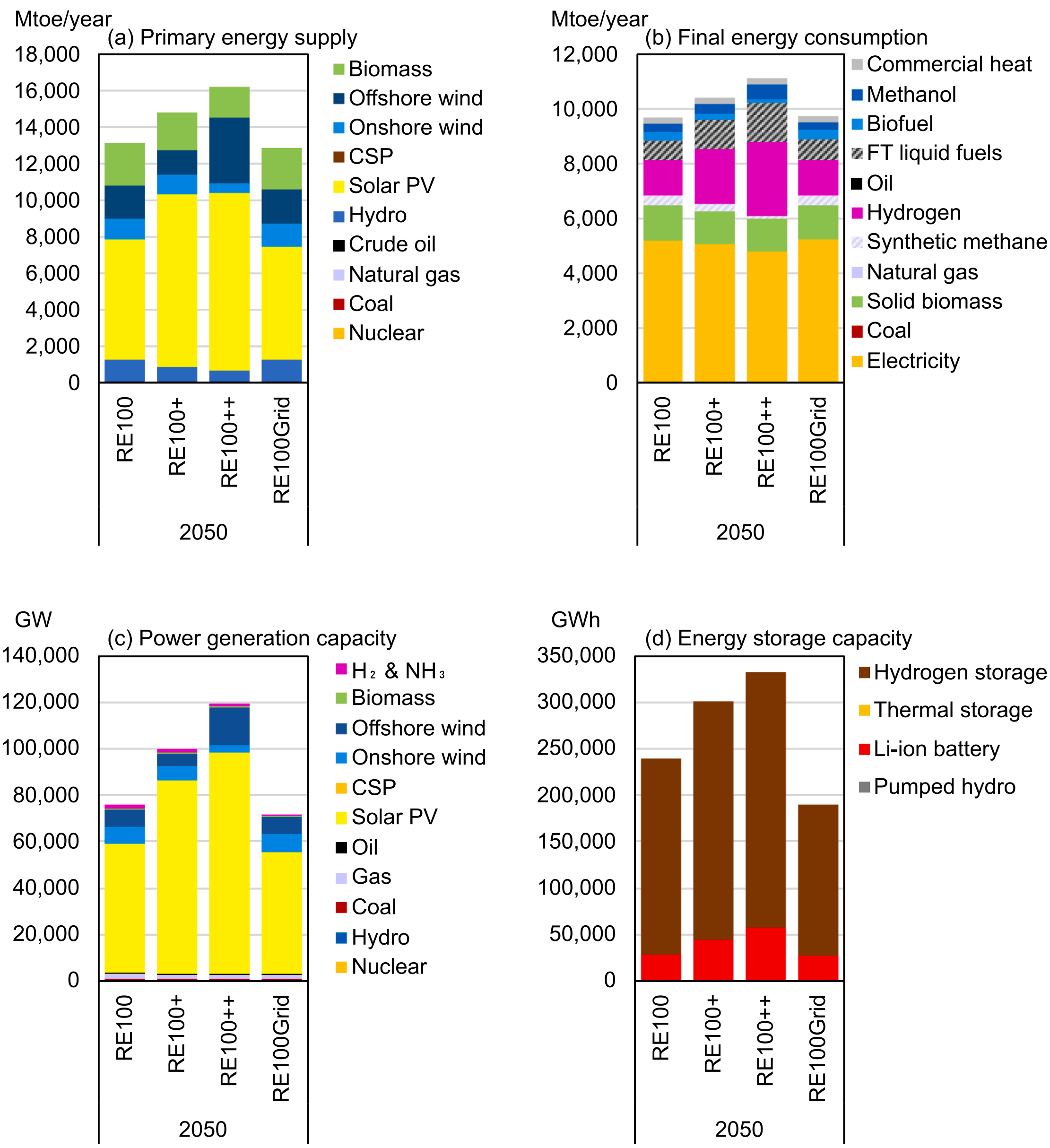


Fig. 24. Key global results of the *RE100+*, *RE100++*, and *RE100Grid* cases
Note: "H_2" and "NH_3" indicate hydrogen and ammonia, respectively.

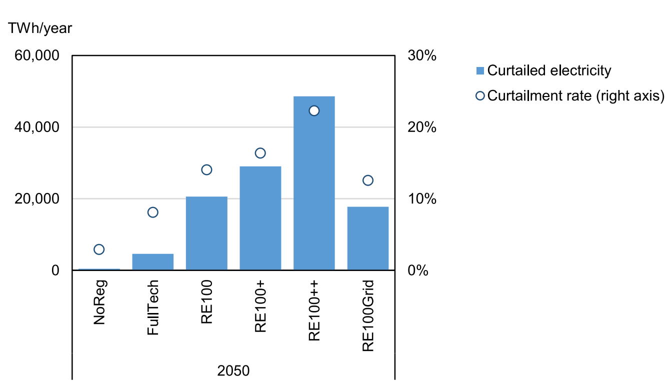


Fig. 25. Curtailment in the world in all six cases.

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