Chapter 2

Methodology

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Chapter 2
Methodology

1. IEEJ–NE Model

We conducted an analysis using an optimum technology selection model (the Institute of Energy Economics, Japan [IEEJ]–<New Earth> [NE] model) developed by Otsuki et al. (2019) and encompassing the entire energy system. The analysis covers the 10 ASEAN countries from 2017 to 2060,[1] with representative years 2017, 2030, 2040, 2050, and 2060. We consider energy-related CO_2.

The IEEJ-NE model is formulated as a linear programming model. Like the market allocation (MARKAL) model developed by the Energy Technology Systems Analysis Program (ESTAP) of the International Energy Agency (IEA), the IEEJ-NE model takes the cost and performance of each energy technology as input values and yields a single combination of the scale and operational patterns of individual energy technologies to be introduced. Doing so minimises the total cost of the energy system when various constraints such as CO_2 emissions and power supply–demand balance are given. The model covers the energy conversion and end-use sectors (industry, transport, households, and commercial), and incorporates more than 350 technologies into them. The model evaluates combinations of the technologies by giving factors such as capital costs, fuel costs, and CO_2 emissions to each technology. The model includes low-carbon technologies such as solar photovoltaic (PV) power generation, onshore and offshore wind power generation, hydrogen (H_2)-fired power generation, ammonia (NH_3)-fired power generation, and negative-emission technologies such as direct air capture with carbon storage (DACCS) and bioenergy with carbon capture and storage (BECCS) (Table 2.1). The IEEJ-NE model shows the entire energy system, starting from energy imports, secondary energy conversion, intraregional energy trade, CO_2 capture and storage (CCS), and final consumption. The model assumes various types of energy to be consumed (Figure 2.1).

[1] Brunei Darussalam, Cambodia, Indonesia, Laos, Malaysia, Myanmar, Philippines, Singapore, Thailand, and Viet Nam.

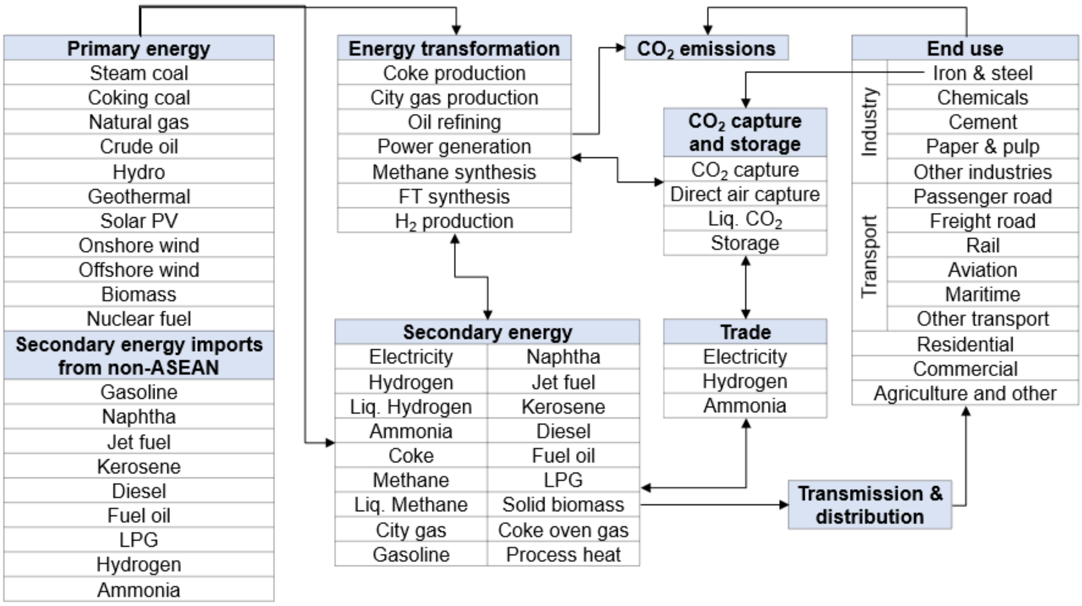
Modelling of the end-use sectors is based on data from the ERIA outlook, the IEA energy balance table, and the IEEJ outlook. However, some sectors are not simulated because data were unavailable (Figure 2.2).

Table 2.1. Selected Low-carbon Technologies in the Model

Renewables	Solar photovoltaic, onshore wind, offshore wind, hydro, geothermal, biomass
Nuclear	Light water reactor
CO_2 capture, utilisation, and storage	CO_2 capture: Chemical absorption, physical absorption, direct air capture CO_2 utilisation: Methane synthesis, FT liquid fuel synthesis CO_2 storage: Geological storage
H_2	Supply: Electrolysis, coal gasification, methane reforming, H_2 separation from NH_3, H_2 trade amongst Association of Southeast Asian Nations (ASEAN) countries, H_2 imports from non-ASEAN countries Consumption: H_2 turbine, natural gas–H_2 co-firing, fuel cell electric vehicle, H_2-based direct reduced iron–electric arc furnace, fuel cell ship, H_2 aviation, H_2 heat for industries, fuel synthesis (methane, FT liquid fuel, NH_3)
NH_3	Supply: NH_3 synthesis, NH_3 trade amongst ASEAN countries, NH_3 imports from non-ASEAN countries Consumption: NH_3 turbine, coal–NH_3 co-firing, H_2 separation
Negative-emission technologies	Direct air capture with CCS (direct air CCS), biomass-fired power generation with CCS (bioenergy with carbon capture and storage)

CCS = CO_2 capture and storage, CO_2 = carbon dioxide, FT = Fischer-Tropsch, H_2 = hydrogen, NH_3 = ammonia.
Source: Author.

Figure 2.1. Modelled Energy System



CO_2 = carbon dioxide, H2 = hydrogen, FT = Fischer-Tropsch, liq. = liquid, LPG = liquefied petroleum gas, PV = photovoltaic.
Source: Author.

Figure 2.2 Data Availability for Modelled End-use Sectors

		BRN	KHM	IDN	LAO	MYS	MMR	PHL	SGP	THA	VNM
Industry	Iron&Steel			✓				✓		✓	✓
	Cement			✓				✓		✓	✓
	Chemicals	✓		✓		✓	✓	✓	✓	✓	✓
	Paper & Pulp			✓			✓	✓		✓	✓
	Other industries	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Transport	Passenger LDV	✓		✓		✓	✓	✓	✓	✓	✓
	Bus & Truck	✓		✓		✓	✓	✓	✓	✓	✓
	Rail					✓	✓	✓	✓	✓	
	Aviation			✓		✓	✓	✓		✓	✓
	Navigation			✓		✓	✓	✓	✓	✓	✓
	Other transport	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Residential & commercial		✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Agriculture and other		✓	✓	✓	✓	✓	✓	✓	✓	✓	✓

BRN = Brunei Darussalam, KHM = Cambodia, IDN = Indonesia, LAO = Lao People's Democratic Republic, LDV = light-duty vehicle, MYS = Malaysia, MMR = Myanmar, PHL = Philippines, SGP = Singapore, THA = Thailand, VNM = Viet Nam.
Note: The manufacturing processes of iron and steel for each country are based on World Steel Association (2019). The assumptions on cement, such as efficiency for each country, are based on Global Cement and Concrete Association (2019).
Source: Author.

In the model, the total cost expressed as the sum of fixed costs, fuel costs, and variable costs, such as operation and maintenance (O&M) cost for technologies, is minimised using an objective function indicated in equation (1).

$$\boldsymbol{min\,TotalCost} = \sum_{\boldsymbol{y}}\sum_{\boldsymbol{r}}\sum_{\boldsymbol{i}}\left(\boldsymbol{Fix_{y,r,i}} + \boldsymbol{Fuel_{y,r,i}} + \boldsymbol{Variable_{y,r,i}}\right)\cdot \boldsymbol{r} \qquad (\mathbf{1})$$

Fix: fixed cost (sum of the capital cost and the fixed O&M cost); ***Fuel***: fuel cost; ***Variable***: O&M cost; ***r***: discount coefficient (discount rate is 8%); Subscript *y*, *r,* and *i* stand for year, region (country), and technology.

Typical constraints include CO_2 emissions in representative years, power supply–demand balance at each time slice, upper limit on the introducible amount of each power source, and load following (see Otsuki et al. [2019]). To balance supply and demand of electricity even when solar PV and wind power plants are not operating, electricity must be discharged from storage batteries and H_2- and NH_3-fired power generation or other thermal power generation operated with CCS.

In the model, the power supply–demand is divided by time to express the fluctuation of renewable energy and the system integration cost. One year for power supply–demand is split into 2,190 time slices (4-hour resolution). The model explicitly simulates co-firing thermal power generation at existing and new power plants, that is, co-firing coal and NH_3 and co-firing gas and H_2. The modelled technologies are as follows: coal-fired power generation; co-firing coal and NH_3 (20%); integrated coal gasification combined cycle (IGCC); gas-fired power generation; gas combined (cycle power generation); co-firing gas and H_2 (H_2: 20%, 40%, 60%, 80%); hydropower; geothermal; solar PV; onshore and offshore wind power; biomass-fired; nuclear power; H_2-fired; NH_3-fired; pumped hydropower; lithium-ion battery; and H_2 tank.

For supply–demand of H_2 and NH_3, the model simulates production of H_2 and NH_3 in ASEAN countries and imports from outside ASEAN. Some countries consider domestic production of H_2. The model assumes that H_2 can be used for power generation, fuel synthesis, industry, and transport, whilst NH_3 is used only for power generation.

Table 2.2. Supply and Demand of Hydrogen and Ammonia

H_2 supply	Coal gasification, methane reforming, water electrolysis, H_2 trade amongst ASEAN countries, H_2 imports from outside ASEAN, H_2 separation from NH_3
H_2 consumption	Gas–H_2 co-firing, H_2-fired, methane synthesis, Fischer-Tropsch synthesis, NH_3 synthesis, H_2-based direct reduced iron–electric arc furnace, H_2 heat (industry), FCEV (light-duty vehicle), FCEV (bus and truck), H_2 ship, H_2 aviation
NH_3 supply	NH_3 synthesis, NH_3 trade amongst ASEAN, NH_3 imports from outside ASEAN
NH_3 consumption	Coal–NH_3 co-firing, NH_3-fired

FCEV = fuel cell electric vehicle, H2 = hydrogen, NH3 = ammonia.
Note: H_2 heat is assumed in iron and steel and chemical industries.
Source: Author.

The model considers DACCS and BECCS negative-emission technologies. Direct air capture (DAC) enables capturing CO_2 directly from the atmosphere, and the captured CO_2 is either permanently stored in deep geological formation (negative emission) or used to manufacture synthetic fuels by combining it with H_2 (carbon recycle). Fifteen DAC plants are operating all over the world and capturing more than 9,000 tons of CO_2 per year (IEA, 2020). However, DAC requires a large amount of energy, and the cost is extremely high at US$600 per tonnes of carbon dioxide (tCO_2). With high carbon prices aiming to achieve carbon neutrality, however, DAC may be cost-competitive. The cost assumptions for DAC in the model are in Table 2.3.

Table 2.3. Cost Assumptions for Direct Air Pressure in 2050

Item	Value	Unit
Capital cost	694	US$/($tCO_2$/year)
O&M cost	35	US$/$tCO_2$
Electricity consumption	1.5	MWh/tCO_2
Capturing cost	253	US$/$tCO_2$

MWh = megawatt-hour, O&M = operation and maintenance, tCO_2 = tonne of carbon dioxide.
Note: Electricity price is assumed to be US$0.1 per killowatt-hour for capturing cost.
Source: Author.

2. Preconditions

2.1. Case Settings

The Paris Agreement sets the goal of 'holding the increase in the global average temperature to well below 2°C above pre-industrial levels, and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels' (UN, 2015). The IEA states that to achieve the 1.5°C target, global carbon neutrality must be achieved by 2050. The IEA estimates that even under the scenario of achieving net-zero emissions for the entire world in 2050, some CO_2 emissions from developing countries will remain.

Based on those global circumstances, this study analyses five cases:

(i) Baseline does not set any CO_2 emissions target.

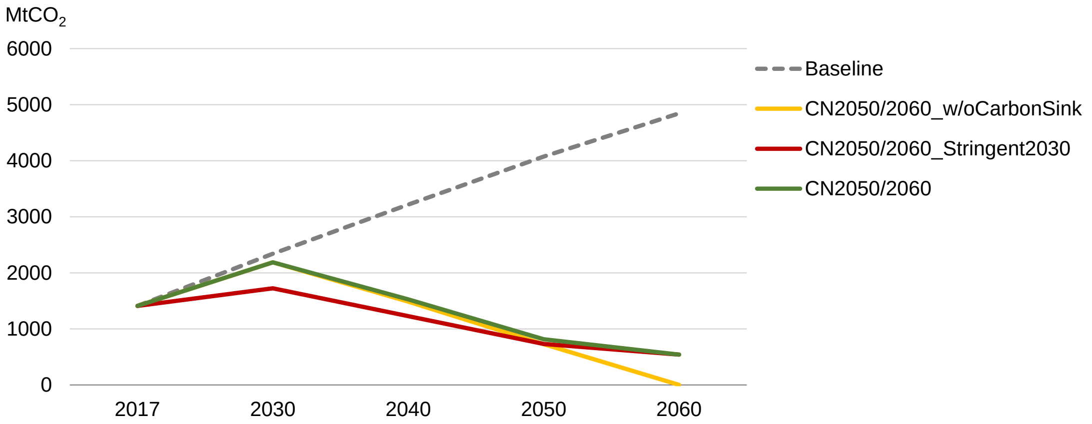
(ii) CN2050/2060 reflects nationally declared carbon-neutral target years and considers carbon sinks in Indonesia, Malaysia, Myanmar, Thailand, and Viet Nam based on discussions with each country.

(iii) CN2050/2060_Innovation cases, where five cases describe the impacts of technological innovation as sensitivity analysis of (ii).

(iv) CN2050/2060_Stringent2030 tightens emission constraints in 2030 of CN2050/2060 to the same level as the IEA sustainable development scenario. Case (iv) shows the results as sensitivity analysis of case (ii).

(v) CN2050/2060_w/oCarbonSink assumes that energy-related CO_2 emissions become net zero by 2060 and does not consider carbon sinks. The case assumes that the year net-zero emissions are achieved in ASEAN varies by country, based on the World Bank's classification by income level. Brunei Darussalam and Singapore are assumed to achieve net-zero emissions by 2050 and other countries by 2060. We initially assumed CN2050/2060_w/oCarbonSink, discussed it with ASEAN countries based on the initial results, and developed CN2050/2060 to reflect each country's comments.

Figure 2.3. Energy-related Carbon Dioxide Emissions in ASEAN



$MtCO_2$ = million tonnes of carbon dioxide.
Source: Author.

2.2. Key Assumptions

(a) Grid Connections amongst ASEAN Countries

ASEAN countries launched the ASEAN Power Grid in 2007, and since then, interconnectors amongst them have been constructed and operated. As of 2021, total transmission capacity was 5.7 gigawatts (GW). Countries are planning to continue to expand the international power grids. The study imposes a constraint of 55 GW in total based on the planned capacity and comments from each country.

(b) Hydrogen and Ammonia Imports from non-ASEAN Countries

The maximum amounts of H_2 and NH_3 imports from outside ASEAN are assumed to be up to 203 million tonnes of oil equivalent (Mtoe) per year in 2040, 540 Mtoe in 2050, and 638 Mtoe in 2060. An upper limit on imports after 2050 is equivalent to 30% of the total Baseline primary energy supply. H_2 prices are assumed at US$0.30 per normal cubic meter (Nm^3)–H_2

in 2030, US$0.20 in 2050, and US$0.175 in 2060, based on the Government of Japan's long-term H_2 supply chain target[2]. NH_3 prices are assumed to be US$0.18 per Nm^3–H_2 in 2030 and US$0.16 in 2050 and 2060, based on IEA (2020).

The study does not specify the production method of imported H_2, either green H_2 using electrolysers with electricity from renewable energy, or blue H_2 from fossil fuels tied with CCS. Specific H_2-exporting countries are not identified either. However, given the geographical transport distances and the potential for clean H_2 production, Australia, India, and Middle Eastern countries are regarded as candidates.

(c) Annual CO_2 Storage Capacity

In the study, the annual CO_2 storage potential is estimated at up to 687 million tonnes of carbon dioxide ($MtCO_2$) per year in 2040, 1,138 $MtCO_2$ per year in 2050, and 1,610 $MtCO_2$ per year in 2060. This potential for 2050 is equivalent to 25% of CO_2 emissions in Baseline and 30% in 2060. It is difficult to accurately estimate CO_2 storage potential. However, even if only relatively feasible options such as storage in depleted oil fields or gas fields and enhanced oil recovery in mature oil fields are considered, the potential of ASEAN countries is high (Global CCS Institute, 2016).[3]

(d) Supply Potential of Biofuels for Vehicles

As transport decarbonises, the model considers expanding the use of biofuels as well as electrifying automobiles. Biofuel supply potential in the study is assumed to increase in proportion to demand for road transport.

(e) Levelised Cost of Electricity

Power generation costs are estimated by IEEJ based on publicly available reports such as Danish Energy Agency (2021) for Indonesia and information obtained by ASEAN countries. Figure 2.4 shows the power generation costs in 2050 in Indonesia. The capacity factor of each power generation and the required storage capacity of batteries are endogenously determined.

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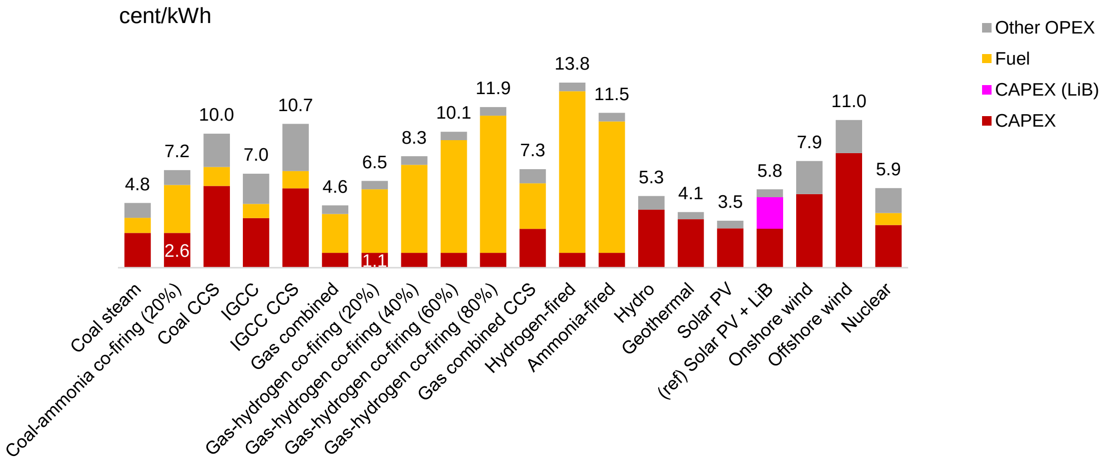
[2] These prices are for blue or green hydrogen, covering transport cost.

[3] The cumulative potential of five countries combined (Indonesia, Malaysia, Philippines, Thailand, and Viet Nam) is estimated to be 75 $GtCO_2$ according to GCCSI (2016).

Figure 2.4. Power Generation Cost in 2050 (Indonesia)



CAPEX = capital expenditure, CCS = carbon dioxide capture and storage H_2 = hydrogen, IGCC = integrated coal gasification combined cycle, LiB = lithium-ion battery, Nm^3 = normal cubic meter, OPEX = operating expenditure, PV = photovoltaic, ref = reference.

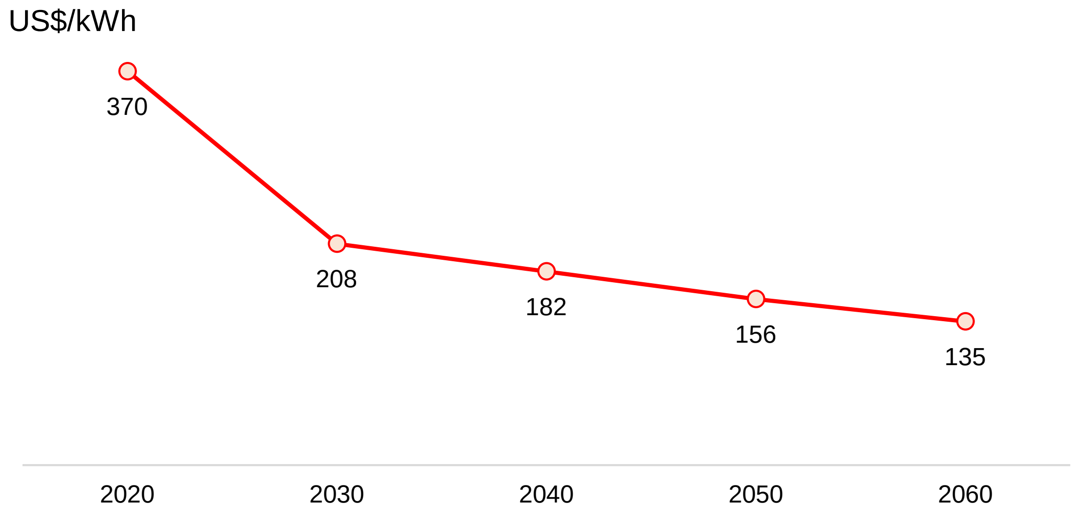
Note: H_2 price: US\$0.20/Nm^3–H_2; ammonia price: US\$0.16/Nm^3–H_2; capacity factor: 40% for hydro, 80% for geothermal, 15% for solar PV, 20% for onshore wind, 30% for offshore wind, 80% for nuclear, 60% for the rest of the technologies.

Source: Estimated by the Institute of Energy Economics, Japan, based on Danish Energy Agency (2021) and information provided by Indonesia.

(f) Energy Storage Technologies

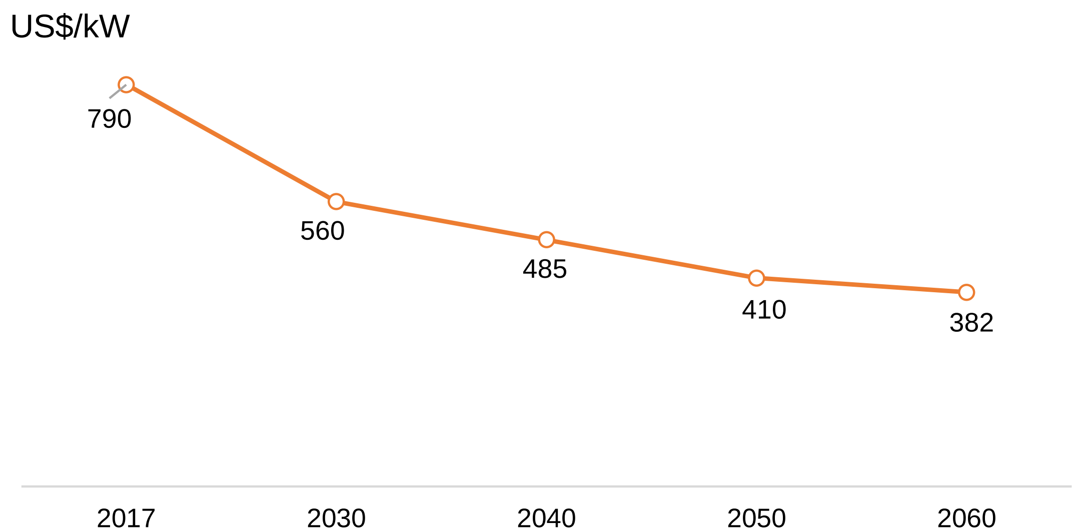
The model simulates pumped hydro storage, lithium-ion batteries, and compressed H_2 tanks as energy storage technologies. The required amounts for lithium-ion batteries and compressed H_2 tanks are endogenously determined. The production cost of lithium-ion batteries is expected to substantially decline. Future cost reduction in the study is based on a cost forecast by the National Renewable Energy Laboratory of the United States.

Figure 2.5. Assumed Lithium-ion Battery Cost



kWh = kilowatt-hour.
Note: 2019 US$.
Source: National Renewable Energy Laboratory (2020).

Figure 2.6. Assumed Capital Cost of Solar Photovoltaic Generation

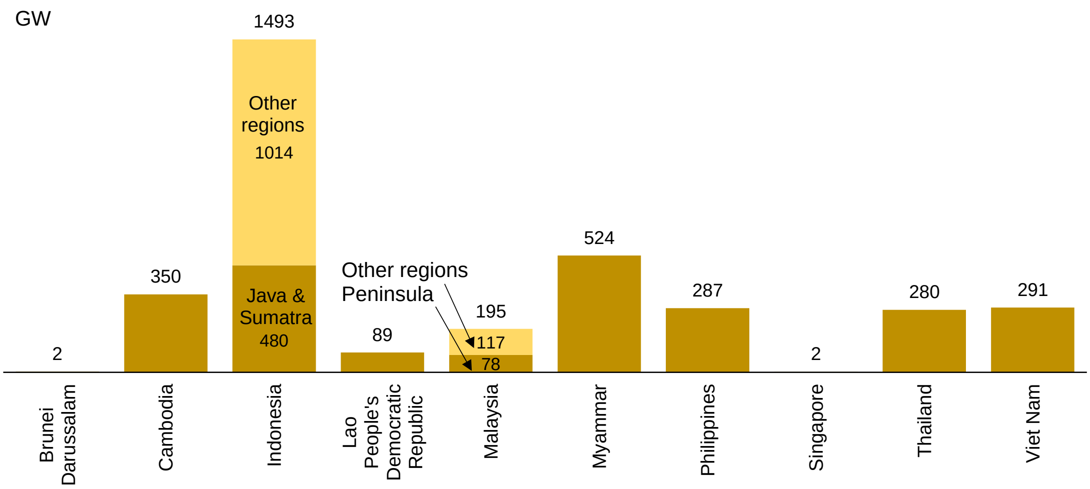


kW = kilowatt.
Note: 2019 US$.
Source: Estimated by the Institute of Energy Economics, Japan, based on Danish Energy Agency (2021).

(g) Solar Photovoltaic Potential

IEEJ estimates the potential of solar PV power generation based on geographic information system (GIS) data to be 3,513 GW for the entire ASEAN. The potential of solar PV power generation in Indonesia, an archipelago, is divided into 'Java and Sumatra' and 'other regions' given the regional imbalance between electricity demand and renewable energy sources. Solar PV power generation in 'other regions' is assumed to be used for H_2 production. The potential in Malaysia is divided into 'peninsula' and 'other regions' given its geographical characteristics.

Figure 2.7. Solar Photovoltaic Potential

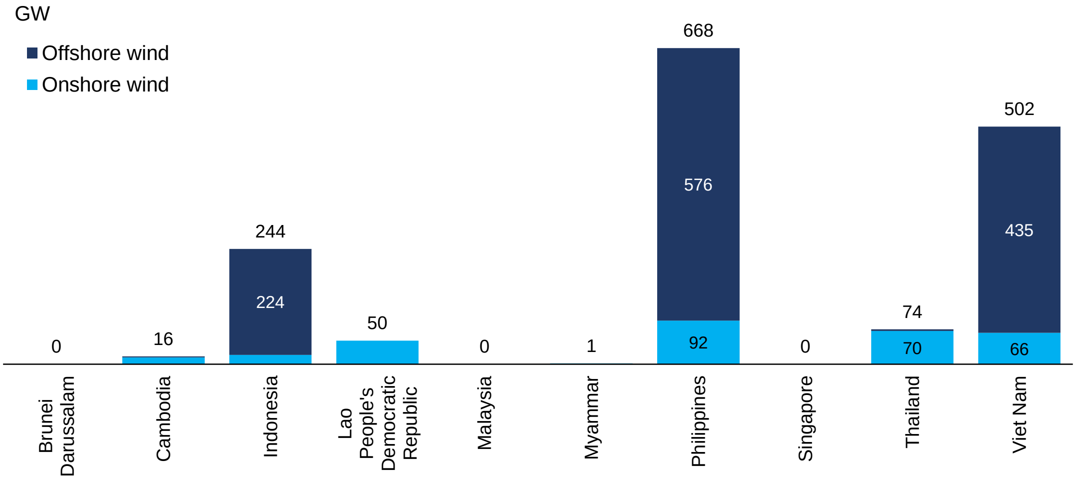


Source: Author.

(h) Wind Power Potential

The potential of wind power generation, which is divided into onshore and offshore, is estimated by IEEJ based on GIS data. The potential of onshore wind power generation in the entire ASEAN is assumed to be 313 GW and offshore 1,241 GW. The potential of onshore and offshore wind power generation in Indonesia is divided into 'Java and Sumatra' and 'other regions' to consider the regional imbalance between electricity demand and resources. Wind power generation in 'other regions' is assumed to be used for H_2 production.

Figure 2.8. Wind Power Potential

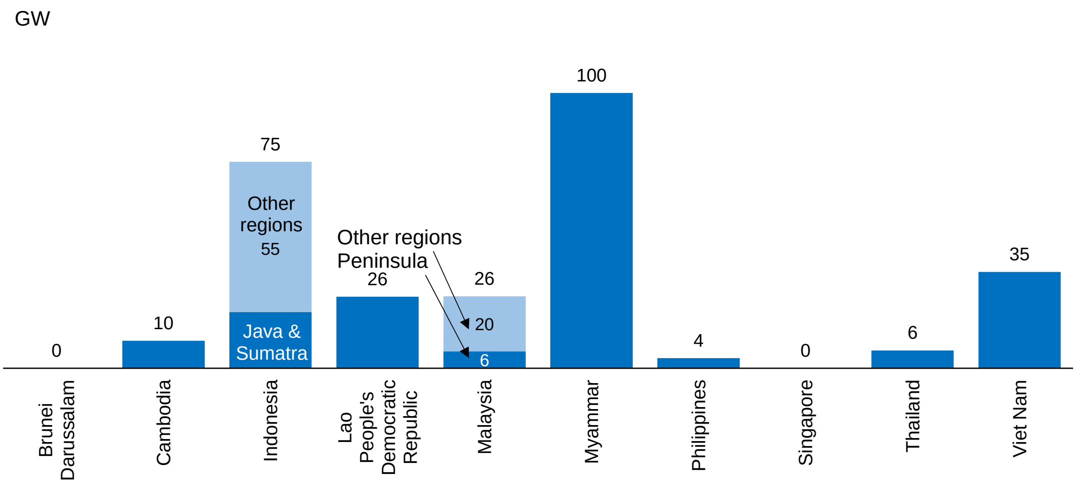


GW = gigawatt.
Source: Author.

(i) Hydropower Potential

The potential of hydropower generation is assumed to be 282 GW in the entire ASEAN based on data from sources such as PricewaterhouseCoopers (2018). The potential of hydropower generation in Indonesia is divided into 'Java and Sumatra' and 'other regions' given the regional imbalance between electricity demand and resources, and hydropower generation in 'other regions' is assumed to be for H_2 production. Potential in Malaysia is divided into 'peninsula' and 'other regions'.

Figure 2.9. Hydropower Potential



GW = gigawatt.
Source: Author.