ERIA Research Project Report FY2025 No. 33

Decarbonisation of ASEAN Energy Systems: Optimum Technology Selection Model Analysis up to 2060

Updated 2025

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Preface

The Economic Research Institute for ASEAN and East Asia (ERIA), in collaboration with the Institute of Energy Economics, Japan (IEEJ), has been undertaking research on long-term decarbonisation pathways for the energy systems of the Association of Southeast Asian Nations (ASEAN) using quantitative modelling approaches. This report builds on earlier studies, further refining the analytical framework to support ASEAN Member States in pursuing carbon neutrality under evolving economic, technological, and policy conditions.

Since 2021, ERIA and IEEJ have continuously enhanced their carbon neutrality scenario analysis, assessing decarbonisation options in the context of socio-economic trends, resource availability, and technical feasibility. The modelling framework has been applied across ASEAN, incorporating energy efficiency improvements, electrification, expansion of renewable energy, and emerging technologies such as hydrogen, ammonia, and carbon capture, utilisation, and storage (CCUS). The 2025 update reflects revised macroeconomic and energy demand assumptions, updated technology cost estimates, and more detailed assessments of renewable energy potential.

A major addition to this report is the inclusion of a detailed country-specific analysis for Viet Nam. This case study provides more granular insights into national decarbonisation pathways and highlights how country-specific system constraints, infrastructure conditions, and policy contexts influence technology deployment and system costs within the broader ASEAN framework.

ERIA hopes that this report will serve as a useful reference for policymakers, researchers, and industry stakeholders engaged in shaping ASEAN's energy transition. ERIA remains committed to delivering rigorous, policy-relevant research that supports sustainable economic development, environmental sustainability, and long-term energy security in the region.

Acknowledgements

The Economic Research Institute for ASEAN and East Asia (ERIA) expresses its sincere appreciation to the Institute of Energy Economics, Japan (IEEJ) and Associate Professor Takashi Otsuki of Yokohama National University for their valuable collaboration on this relevant and important project, 'Preparation of Carbon-Neutral Road Map for ASEAN Countries'. This collaboration was made possible through the sophisticated optimisation model – the IEEJ–New Earth_ASEAN model – formulated based on the New Earth Global model. Special thanks are extended to the Natural Resources and Fuel Department, Agency of Natural Resources and Energy, Ministry of Economy, Trade and Industry, Japan for facilitating discussions between ERIA, the IEEJ, and Association of Southeast Asian Nations countries, enabling the presentation of model results and the exchange of information on future energy plans.

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Contents

List of Figures

List of Tables

List of Abbreviations and Acronyms

ASEAN	Association of Southeast Asian Nations
BECCS	bioenergy with carbon capture and storage
BEV	battery electric vehicle
BL	baseline
CAPEX	capital expenditure
CO_2	carbon dioxide
COVID-19	coronavirus disease
CCS	carbon capture and storage
CN	carbon neutral
DAC	direct air capture
DACCS	direct air capture with carbon storage
ERIA	Economic Research Institute for ASEAN and East Asia
GDP	gross domestic product
GHG	greenhouse gas
GW	gigawatt
H_2	hydrogen
IEA	International Energy Agency
IEEJ	Institute of Energy Economics, Japan
IEEJ-NE	IEEJ-New Earth
Lao PDR	Lao People's Democratic Republic
Mtoe	million tonnes of oil equivalent
NH_3	ammonia
Nm^3	normal cubic metre
O&M	operation and maintenance
OPEX	operational expenditure
PV	photovoltaic
t	tonne
UN	United Nations

Chapter 1

Background

The Association of Southeast Asian Nations (ASEAN) Member States have set ambitious medium- to long-term greenhouse gas (GHG) emission reduction targets, in a manner similar to that of other countries that have announced their ambitions to achieve carbon neutrality. To identify pathways for achieving these goals, ASEAN countries have been collaborating with developed countries over the past few years to develop road maps towards decarbonisation. When formulating these road maps, it is important to consider the unique characteristics of Asian countries, such as significant economic growth, high dependence on fossil fuels, and limited wind resources. Additionally, Russia's invasion of Ukraine continues to have a negative impact on fuel-switching from coal to natural gas in the region, due to relatively high natural gas prices.

As in the previous year, this study

(i) aims to quantitatively describe the energy transition pathway necessary to realise carbon neutrality in ASEAN countries through model analysis;

(ii) provides information to formulate energy policies in each country and seek support from developed countries; and

(iii) suggests strategies to minimise the additional costs of transforming the energy supply–demand structure by using a cost-optimal technology selection model to evaluate combinations of energy technologies.

This study employs a single model covering 10 ASEAN countries. During the analysis of the model, discussions were held with ASEAN governments regarding their energy policies and actual situations. The discussions considered the assumptions used in the analysis and guided the prioritisation of technologies for introduction. The study serves as a second opinion to support ASEAN countries in developing their road maps for the energy transition towards carbon neutrality.

This marks the fourth year of the study. In the first year, the focus was on developing the energy technology model and assessing the technology pathway for the ASEAN region. In the second year, the study centred on country-specific analyses for selected countries, and in the third year, the study updated the analysis. In the current year, the study continues to update the analysis for the ASEAN region and countries and focuses on comparing the results with other published road maps to extract implications for the region.

Chapter 2

Analytical Framework

1.1. Institute of Energy Economics, Japan–New Earth Model

The analysis presented in this study was conducted using the Institute of Energy Economics, Japan (IEEJ)-New Earth (NE) model, an optimal technology model developed by Otsuki et al. (2022, 2019) that encompasses the entire energy system. The base model with full equations is open to the public on Zenodo. The model covers all 10 Association of Southeast Asian Nations (ASEAN) countries[1] from 2017 to 2070, using 2017, 2030, 2040, 2050, 2060, and 2070 as representative years. The study focuses on energy-related carbon dioxide (CO_2) emissions.

The IEEJ-NE model is formulated as a linear programming model. Like the market allocation model developed under the Energy Technology Systems Analysis Program of the International Energy Agency (IEA), it incorporates the cost and performance of individual energy technologies as input values. The model identifies a single, cost-minimising combination of technology scale and operational patterns across ASEAN, subject to constraints such as CO_2 emissions and supply–demand balance. It covers both energy conversion and end-use sectors (industry, transport, residential, and commercial) and incorporates more than 350 technologies. Evaluation criteria include capital costs, fuel costs, and CO_2 emissions. This model minimises the total energy system cost for the ASEAN region as a whole, rather than for each individual country.

The model encompasses a wide range of technologies, including low-carbon options such as solar photovoltaic (PV), onshore and offshore wind power, hydrogen (H_2), and 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 0.1). The model comprehensively represents the energy system, from primary energy production and imports to secondary energy conversion, intraregional energy trade, CO_2 capture and storage (CCS), and final energy consumption. It also accounts for sector-specific consumption of various energy types (Figure 0.1).

Modelling of the end-use sectors draws on data from the Economic Research Institute for

[1] Brunei Darussalam, Cambodia, Indonesia, the Lao People's Democratic Republic, Malaysia, Myanmar, the Philippines, Singapore, Thailand, and Viet Nam.

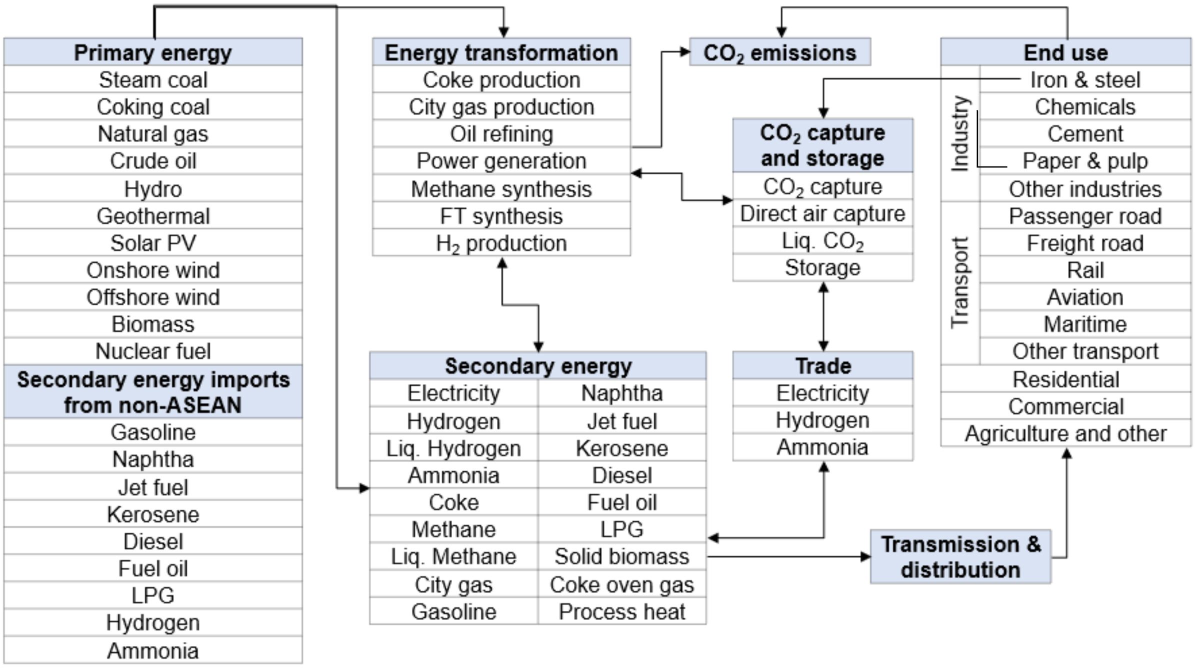
ASEAN and East Asia (ERIA) outlook, IEA energy balance tables, and the IEEJ outlook. However, some sectors could not be fully simulated due to data limitations in the public domain (Figure 0.2).

Table 0.1. Selected Clean Technologies in the Model

Category	Technologies
Renewables	Ground-mounted solar PV, rooftop solar PV, onshore wind, bottom-fixed offshore wind, floating offshore wind, hydropower, geothermal, biomass
Nuclear	Large-scale reactor, small modular reactor
CO_2 capture, utilisation, and storage	Capture: Chemical absorption, physical absorption, direct air capture
	Utilisation: Methane synthesis, FT liquid fuel synthesis
	Storage: Geological storage
H_2	Supply: Electrolysis, coal gasification, methane reforming, H_2 separation from NH_3, H_2 trade amongst ASEAN countries, 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 (new builds and retrofit), 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

ASEAN = Association of Southeast Asian Nations, CCS = carbon capture and storage, CO_2 = carbon dioxide, FT = Fischer-Tropsch, H_2 = hydrogen, NH_3 = ammonia, PV = photovoltaic.
Source: Author.

Figure 0.1. Modelled Energy System



CO_2 = carbon dioxide, H_2 = hydrogen, FT = Fischer-Tropsch, liq. = liquid, LPG = liquefied petroleum gas, PV = photovoltaic.
Source: Author.

Figure 0.2. Data Availability for Modelled End-use Sectors

		BRN	KHM	IDN	LAO	MYS	MMR	PHL	SGP	THA	VNM
Industry	Iron and Steel			✓		✓	✓	✓		✓	✓
	Cement			✓				✓		✓	✓
	Chemicals	✓		✓		✓	✓	✓	✓	✓	✓
	Paper and pulp			✓			✓	✓		✓	✓
	Other industries	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Transport	Passenger LDV	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
	Bus and truck	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
	Rail			✓		✓	✓	✓	✓	✓	✓
	Aviation			✓		✓	✓	✓		✓	✓
	Navigation			✓		✓	✓	✓	✓	✓	✓
	Other transport	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Residential and 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 assumptions regarding the manufacturing processes for iron and steel production in each country are based on data from the World Steel Association (2019). Cement sector assumptions, such as efficiency factors per country, are based on data from the Global Cement and Concrete Association (2019).
Source: Author.

Within the model, the total cost – expressed as the sum of fixed costs, fuel costs, and variable costs, such as operation and maintenance (O&M) – is minimised using the objective function indicated in equation (1):

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

Where:

Fix: fixed cost (annualised capital cost + fixed O&M cost)

Fuel: fuel cost

Variable: variable O&M cost

R: discount coefficient (discount rate is 8%)

Subscript *y* = year, *r* = region, *i* = technology

The model operates under typical constraints, including CO_2 emission limits for the representative years, hourly power supply–demand balance, maximum capacity of each power source, and load curve requirements (see Otsuki et al. [2022, 2019]). To ensure reliability during periods of low solar and wind generation, the model requires support from storage discharge (e.g. lithium-ion batteries), H_2-/NH_3-fired power generation, or thermal power with CCS.

Power supply and demand are represented in 4-hour intervals to capture fluctuations in renewable output and the required balancing mechanisms. One year is divided into 2,190 time slices (4-hour resolution).

The model explicitly simulates co-firing technologies in both existing and new thermal power plants. These include coal co-firing with biomass (20%, 40%, 60%, 80%, and 100%) and NH_3 (20%, 40%, 60%, 80%, and 100%), and gas co-firing with H_2 (20%, 40%, 60%, 80%, and 100%). Technologies modelled include coal-fired power, integrated coal gasification combined cycle, gas-fired and gas-combined cycle generation, oil-fired power, solar PV (ground-mounted and rooftop), onshore and offshore wind power (bottom-fixed and floating), biomass-fired power, hydropower, geothermal power, nuclear (large-scale and SMRs), new H_2- and NH_3-fired power generation, pumped hydro and lithium-ion battery storage, and H_2 storage tanks.

The model simulates both domestic production and international imports of H_2 and NH_3. H_2 is assumed to be used for power generation, fuel synthesis, industry, and transport, whilst NH_3 is used only for power generation.

Negative-emission technologies are incorporated, specifically DACCS and BECCS. Direct air capture (DAC) extracts CO_2 directly from the atmosphere. The captured CO_2 can either be stored in deep geological formations, achieving negative emissions, or combined with H_2 to produce synthetic fuels through carbon recycling. As of 2023, 17 DAC plants operate worldwide, capturing less than 10,000 tonnes of CO_2 per year (IEA, 2023a). Although DAC is energy intensive and currently costly, it is expected to become more competitive as carbon prices rise in pursuit of carbon neutrality.

1.1.1. Case settings

As well as Endo et al. (2025),[2] this study analyses the carbon neutral (CN)2050/2060 case, which reflects the nationally declared carbon neutral targets and considers carbon sinks in Brunei Darussalam, Cambodia, Indonesia, Malaysia, Myanmar, Thailand, and Viet Nam. These assumptions were developed through discussions with each country (Table 0.2).

Table 0.2. Assumed Carbon Neutral Target Years and Carbon Sinks in CN2050/2060

Country	Carbon Neutral Target Year	Energy-related CO_2 Emission Reduction Target from 2017	Assumed Natural Carbon Sink (LULUCF) in the Target Year
Brunei Darussalam	2050	-50% (3.5 Mt)	Information from Brunei Darussalam (-4.4 Mt)
Cambodia	2050	+37% (26.0 Mt)	2050 target of the LTS4CN scenario in the LTS (-50.2 Mt)
Indonesia	2060	-50% (245.5 Mt)	2050 target of the LCCP scenario in the LTS (-300 Mt)
Lao PDR	2050	-100%	-
Malaysia	2050	-22% (164.0 Mt)[a]	2016 value of the inventory (-241Mt)
Myanmar	2060	-60% (12.0 Mt)	2040 target of the unconditional NDC (-13 Mt)
Philippines	2060	-100%	-
Singapore	2050	-100%	-
Thailand	2050	-61% (95.5 Mt)[b]	2050 target of the Carbon Neutrality Pathway in the LTS (-120 Mt)
Viet Nam	2050	-54% (88.8 Mt)[c]	2030 target of the unconditional NDC (-59 Mt)

CO_2 = carbon dioxide; Lao PDR = Lao People's Democratic Republic; LULUCF = land use, land-use change, and forestry; LTS = long-term strategy; LTS4CN = long-term strategy for carbon neutrality; LCCP = low-carbon scenario compatible with Paris Agreement target; Mt = million tonnes; NDC = nationally determined contribution.

[2] ERIA Research Project FY2025 No. 05 (ERIA, 2025).

Note: '–' indicates countries excluded from consideration due to lack of available data.
[a] Consistent with the National Energy Transition Roadmap (Ministry of Economy, 2023).
[b] Consistent with the LT-LEDS (Office of Natural Resources and Environmental Policy and Planning, 2022).
[c] Consistent with the National Strategy on Climate Change by 2050 (Government of Viet Nam, 2022).
Source: Author.

1.2. Key assumptions

1.2.1. Gross domestic product

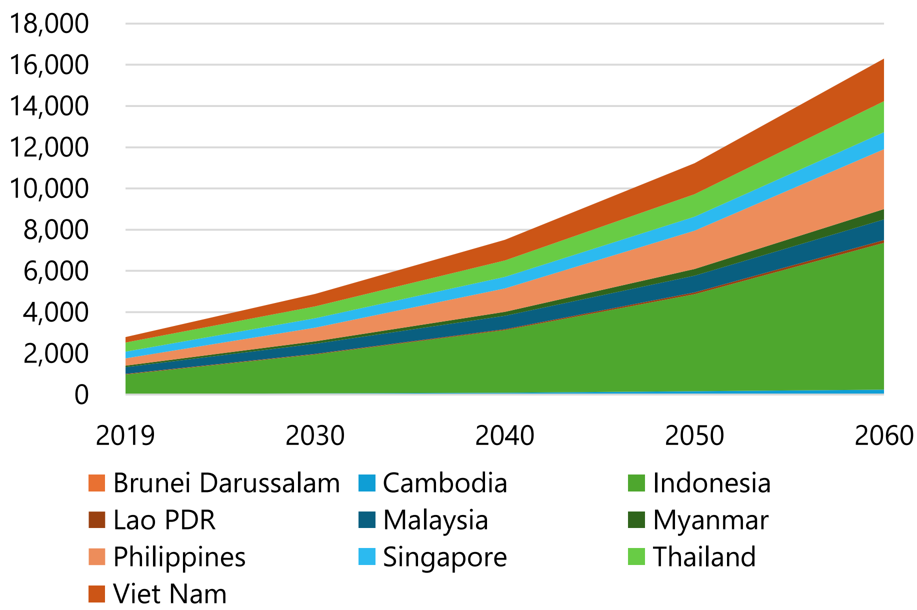
The GDP assumption mainly relies on the ERIA outlook (ERIA, 2023), which projects an annual growth rate of 4.1%. For short-term growth rates, the International Monetary Fund (2024) projections are referenced. In general, these projections are lower than those presented in the previous outlook (ERIA, 2021), which anticipated a growth rate of 4.2% (Figure 0.3). The revision reflects the prolonged impact of the coronavirus disease (COVID-19) pandemic, the ongoing Ukrainian crisis, and the resulting global inflation, all of which have a negative impact on the GDP assumption. GDP projections for this study were updated based on the latest ERIA Energy Outlook (forthcoming) (see Section 3.2).

Table 0.3. Gross Domestic Product Assumption (US$ million)

	2019	2030	2040	2050	2060
Brunei Darussalam	13	18	22	27	28
Cambodia	21	41	75	134	209
Indonesia	950	1,898	3,033	4,711	7,123
Lao PDR	16	27	48	83	129
Malaysia	333	483	642	817	1,001
Myanmar	69	118	201	327	511
Philippines	351	667	1,134	1,847	2,899
Singapore	334	451	560	683	830
Thailand	432	582	797	1,093	1,500
Viet Nam	273	594	991	1,503	2,073

GDP = gross domestic product, Lao PDR = Lao People's Democratic Republic.
Note: Constant 2015 prices.
Sources: Estimated from Economic Research Institute for ASEAN and East Asia (2023) and International Monetary Fund (2024).

Figure 0.3. Gross Domestic Product Assumption (US$ million)



Lao PDR = Lao People's Democratic Republic.
Sources: Estimated from Economic Research Institute for ASEAN and East Asia (2023) and International Monetary Fund (2024).

1.2.2. Population

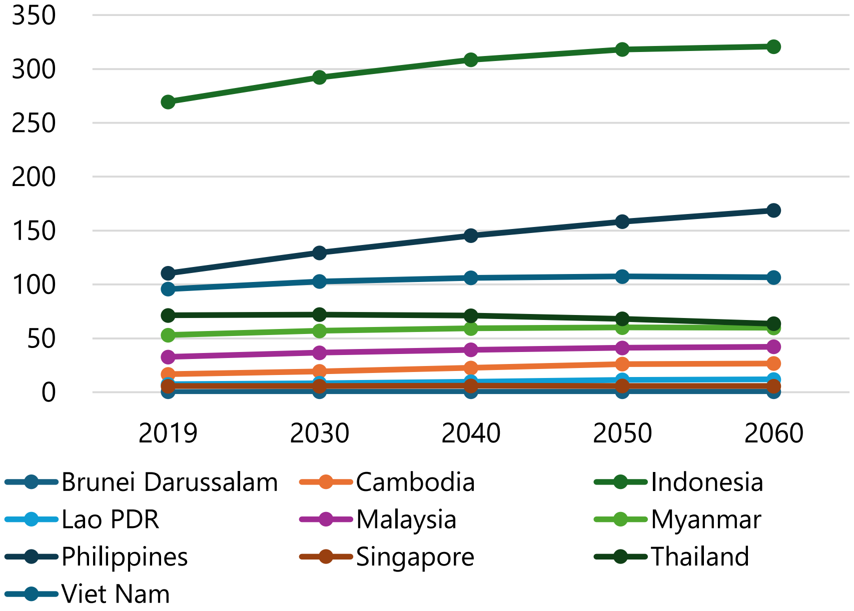
The population assumption is based on United Nations (2024), which provides population projections up to the year 2100 for all countries. In consideration of varying perspectives, this analysis adopts the 'medium variant' scenario to represent moderate demographic trends (Figure 0.4).

Table 0.4. Population Assumption (thousand)

	2019	2030	2040	2050	2060
Brunei Darussalam	438	474	494	501	492
Cambodia	16,730	19,420	22,540	26,160	26,746
Indonesia	269,583	292,212	308,678	318,249	320,809
Lao PDR	7,300	8,400	9,800	11,400	11,877
Malaysia	32,804	36,727	39,382	41,180	42,237
Myanmar	53,040	57,033	59,261	60,120	59,845
Philippines	110,381	129,508	145,313	158,406	168,748
Singapore	5,704	5,740	5,895	5,839	5,669
Thailand	71,308	72,109	71,062	68,113	63,648
Viet Nam	95,777	102,870	106,193	107,415	106,622

Lao PDR = Lao People's Democratic Republic.
Source: United Nations (2024).

Figure 0.4. Population Assumption (million)

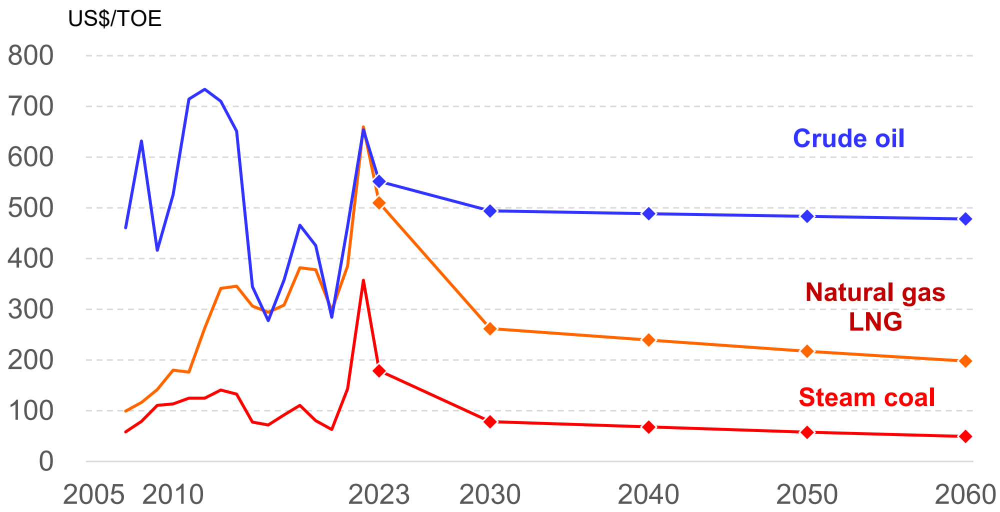


Lao PDR = Lao People's Democratic Republic.
Source: United Nations (2024).

1.2.3. Fossil fuel prices

A common pricing structure is assumed for both domestic and imported fossil fuels. Future prices for coal and natural gas are estimated using historical data from ASEAN and projected figures for Japan, based on the Stated Policies Scenario (STEPS) in the IEA's *World Energy Outlook 2023* (IEA, 2023b). Crude oil prices are estimated in the same way, using international market prices (Figure 0.5).

Figure 0.5. Future Fossil Fuel Prices in ASEAN



ASEAN = Association of Southeast Asian Nations, LNG = liquefied natural gas, TOE = tonne of oil equivalent.
Note: 2017 real prices. Historical coal and natural gas prices are based on Indonesian data.
Source: Author, based on the Stated Policies Scenario of the International Energy Agency (2023b).

1.2.4. Grid connections amongst ASEAN countries

ASEAN countries initiated the ASEAN Power Grid concept in 2007, which has since facilitated the construction and operation of multiple cross-border interconnectors. By 2021, the total transmission capacity had reached 5.7 gigawatts (GW). Further expansion of regional power grids remains a priority for ASEAN Member States. In this study, the upper limits for the interconnection capacities listed in Table 0.5 were assumed based on the ASEAN Power Grid concept (IEA, 2019a; 2022) and feedback received from individual countries.

Table 0.5. Upper Limits for the Grid Capacity Assumptions After 2040

Node 1	Node 2	Capacity (GW)
Brunei Darussalam	Sabah	0.4
Brunei Darussalam	Sarawak	0.4
Malaysia	Lao PDR	3
Malaysia	Thailand	2.32
Malaysia	Viet Nam	0.2
Java	Sumatra	24.6
Java	Kalimantan	16.8
Java	Maluku	16.2
Sumatra	Kalimantan	4.9
Sumatra	Malaysia	0.6
Kalimantan	Sulawesi	7.3
Kalimantan	Sarawak	0.23
Lao PDR	Thailand	25
Lao PDR	Viet Nam	5
Malaysia	Sarawak	1.6
Malaysia	Singapore	1.05
Malaysia	Thailand	0.78
Sabah	Philippines	0.5
Myanmar	Thailand	14.859

GW = gigawatt, Lao PDR = Lao People's democratic Republic.
Source: Author.

1.2.5. Hydrogen and ammonia imports from non-ASEAN countries

In this model, H_2 and NH_3 may be produced domestically or imported from outside ASEAN. The maximum permissible imports of H_2 and NH_3 from non-ASEAN countries are assumed to account for up to 15% of the total baseline primary energy supply in 2040, rising to 30% after 2050.

The assumed import prices of H_2 and NH_3, inclusive of international transport costs, are presented in Table 0.6. These prices are based on Japan's long-term targets (Ministerial Council on Renewable Energy, Hydrogen and Related Issues, 2023).

In this study, we use the estimates provided by Endo et al. (2024), based on the bottom-up approach proposed by Otsuki and Shibata (2022). These estimates calculate the costs of both green and blue hydrogen, taking into account future prices of renewable energy, fossil fuels, and CCS. The lower of the two is then adopted as the assumed import price for hydrogen and ammonia. For hydrogen, blue hydrogen is projected to be more cost-effective than green hydrogen, with its cost expected to remain constant beyond 2030. In contrast, the cost of ammonia is assumed to decline over time, reflecting reductions in the cost of production and storage facilities.

Table 0.6. Maximum Volume and Prices for Imported Hydrogen and Ammonia

	2030	2040	2050	2060
Maximum volume of H_2 and NH_3 imports (% of total primary energy in the baseline, except Brunei Darussalam and Indonesia)	-	15%	30%	30%
Import H_2 prices (US cents per Nm^3-H_2)	39.3	39.3	39.3	39.3
Import NH_3 prices (US cents per Nm^3-H_2)	20.1	19.7	19.3	18.5

H_2 = hydrogen, NH_3 = ammonia, Nm_3 = normal cubic metre.
Note: 2017 real prices. Maximum volume of imports is 0% for Brunei Darussalam, 5% in 2040, and 7.5% after 2050 for Indonesia.
Source: Author, based on the Ministerial Council on Renewable Energy, Hydrogen and Related Issues (2023) for prices.

1.2.6. Solar and wind resources

The upper limit of solar and wind energy capacity is estimated using geographic information system (GIS) data originally developed by Obane (2025), incorporating information on building, land use (500-metre [m] grid meshes), and marine use (1-kilometre grid meshes) data. Figure 0.6 shows the schematic design of the GIS data. Building-mounted PV is assumed to be installed on all rooftops, whilst ground-mounted PV is considered for deployment on weed-covered and bare land, excluding protected areas. To avoid land-use conflicts with onshore wind turbines, ground-mounted PV is allocated only for areas where the average annual wind speed at a height of 100 m is less than 5.0 m per second. Conversely, onshore wind installations are limited to areas with average wind speeds of 5.0 m per second or above. Table 0.7 shows the regional upper limits for the capacity of solar and wind energy systems.

Offshore wind power is assumed to be installed in areas with an average annual wind speed of 7.0 m per second or more at a height of 200 m, excluding protected areas and locations where vessel traffic equipped with automatic identification systems averages fewer than 100 vessels per day. Bottom-fixed wind turbines are installed in waters shallower than 60 m, whilst floating wind turbines are installed in deeper waters. Capital expenditure is assumed to increase with water depth.

Figure 0.6. Schematic Design of Geographic Information System Data

(A) Buildings | (B) Land-use data (500-metre grid mesh) | (C) Marine-use data (1-kilometre grid mesh)

Source: Author.

Table 0.7. Upper Limits of Solar PV and Onshore Wind (gigawatts)

Country		Ground-mounted PV	Building-mounted PV	Onshore Wind
Brunei Darussalam		0.4	2.3	0.0
Cambodia		33.1	35.3	3.6
Indonesia	Java	12.5	334.3	0.5
	Kalimantan	120.8	34.5	0.8
	Maluku・Papua	112.1	26.1	8.5
	Sulawesi・Nusa Tenggara	13.4	41.1	0.3
	Sumatra	84.1	111.1	0.1
Lao PDR		46.4	18.4	5.3
Malaysia	Peninsula	10.5	91.6	0.1
	Borneo	22.1	18.9	0.0
Myanmar		116.9	15.7	4.7
Philippines		5.6	102.4	1.2
Singapore		0.3	3.1	0.0
Thailand		39.1	299.8	4.8
Viet Nam		56.0	226.3	10.5

Total	673.3	1,360.8	40.4

Lao PDR = Lao People's Democratic Republic.
Source: Obane (2025).

Table 0.8. Upper Limits of Offshore Wind (gigawatts)

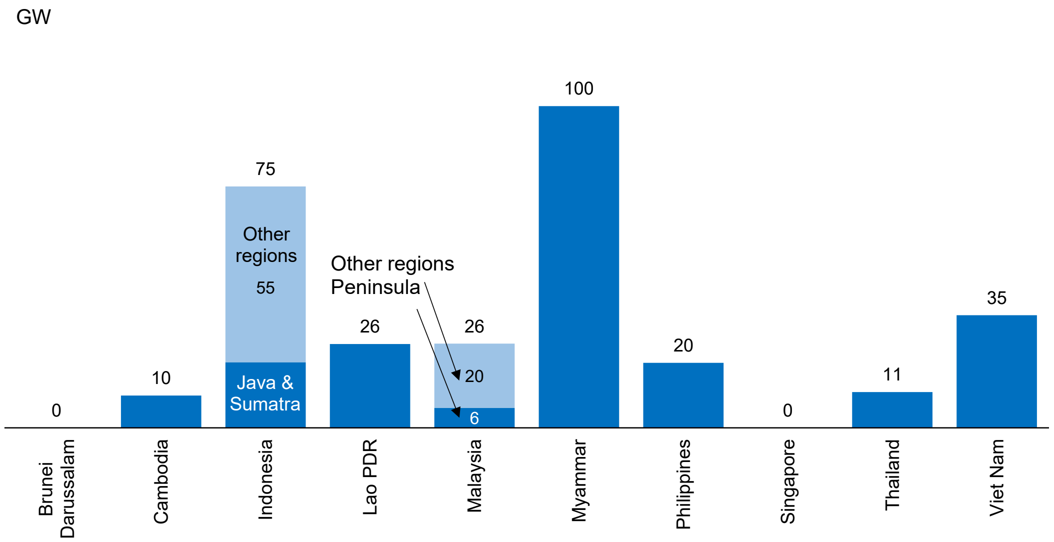
Country		Water Depth					
		0–15 m	15–30 m	30–60 m	60–100 m	100–200 m	> 200 m
Cambodia		0.6	0.2	0.2	0.0	0.0	0.0
Indonesia	Java	0.2	0.4	0.4	0.4	0.9	2.5
	Kalimantan	0.0	0.0	0.0	0.0	0.0	0.0
	Maluku・Papua	114.6	98.7	98.2	2.1	0.2	17.9
	Sulawesi・Nusa Tenggara	1.8	1.0	1.2	0.3	0.4	0.9
	Sumatra	0.1	0.6	0.2	0.1	0.1	0.2
Philippines		20.1	15.0	31.5	36.3	42.9	627.4
Viet Nam		35.4	150.6	199.2	57.6	82.9	161.1
Total		172.7	266.5	330.8	96.7	127.5	810

Source: Obane (2025).

1.2.7. Hydro, geothermal, and biomass resources

The upper limit for hydropower capacity across ASEAN is estimated at 304 GW based on data from PwC (2018) and country-specific contributions provided by ASEAN Member States (Figure 0.7).

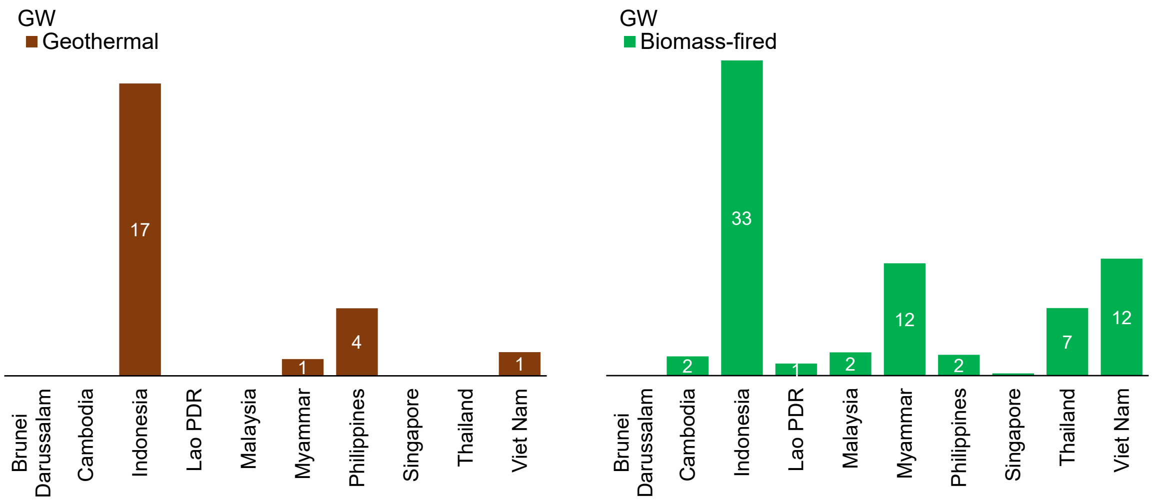
Figure 0.7. Upper Limits of Hydropower Capacity



GW = gigawatt, Lao PDR = Lao People's Democratic Republic.
Source: Author.

The upper limits for geothermal and biomass-fired power generation capacities in ASEAN are estimated to be 24 GW and 71 GW, respectively. Indonesia, in particular, demonstrates relatively high potential for both types of power generation (Figure 0.8).

Figure 0.8. Upper Limits of Geothermal and Biomass Power Capacity



GW = gigawatt, Lao PDR = Lao People's Democratic Republic.
Source: Author.

1.2.8. Annual CO_2 storage capacity

The assumed annual CO_2 storage capacities are shown in Table 0.10 The annual storage capacity is set at 0.3% of the cumulative CO_2 storage potential in 2040, increasing to 0.6%

by 2050. This assumption ensures the sustainability of CO_2 storage capacity beyond 2050. Whilst accurately estimating CO_2 storage potential remains challenging, the IEA (2021) reports that ASEAN countries possess abundant potential, with a combined cumulative capacity of 133.4 gigatonnes of CO_2 across six countries: Brunei Darussalam, Indonesia, Malaysia, the Philippines, Thailand, and Viet Nam. This study also considers the possibility of cross-border CO_2 imports and exports amongst ASEAN countries.

Table 0.9. Cumulative Carbon Dioxide Storage Potential
(gigatonnes of carbon dioxide)

	Depleted Oil/Gas Fields, Enhanced Oil Recovery	Aquifers	Total
Brunei Darussalam	0.6	-	0.6
Indonesia	-	8.4	8.4
Malaysia	-	80	80
Philippines	0.3	22	22.3
Thailand	1.4	8.9	10.3
Viet Nam	1.4	10.4	11.8

Source: IEA (2021).

Table 0.10. Annual Carbon Dioxide Storage Capacity (share of cumulative potential)

	2040	2050	2060
Low	0.2%	0.4%	0.6%
Medium (adopted)	0.3%	0.6%	0.9%
High	0.4%	0.8%	1.2%

Source: Author.

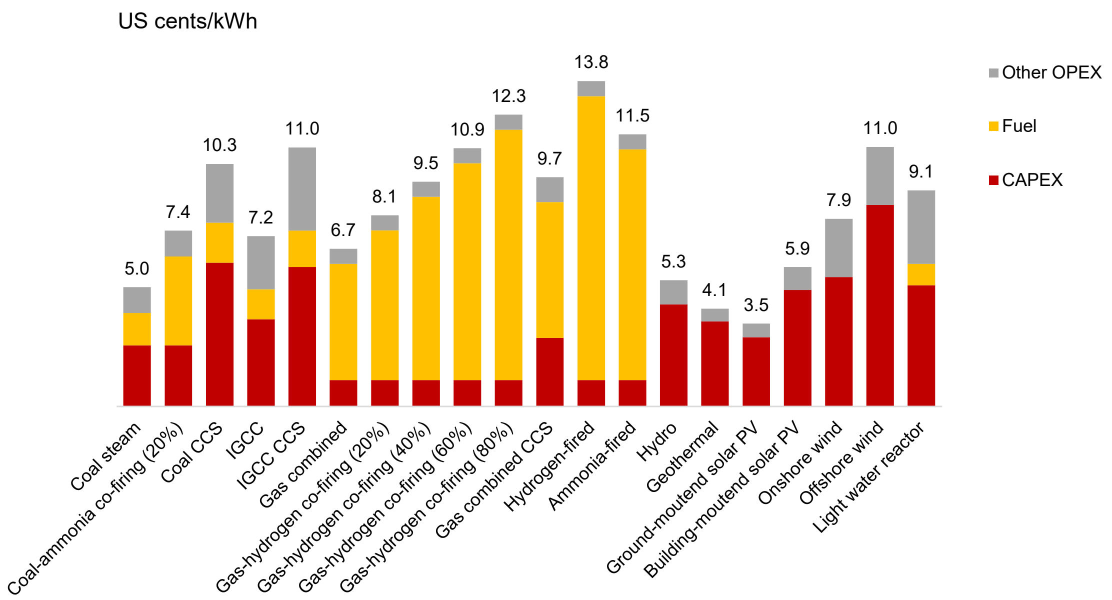
1.2.9. Supply potential of biofuels for vehicles

In transport, the model considers the expanded use of biofuels as well as the electrification of vehicles. The biofuel supply potential is assumed to increase in proportion to the demand for road transport throughout the study period.

1.2.10. Power generation technologies

Parameters for power generation technologies were sourced from publicly available reports, such as those by the Danish Energy Agency (2021), and supplemented with data provided by ASEAN countries (Figure 0.9). The capacity factors of various power generation technologies and the required storage battery capacity are determined endogenously within the model.

Figure 0.9. Levelised Cost of Electricity in 2050 for Indonesia



CAPEX = capital expenditure, CCS = carbon capture and storage, H_2 = hydrogen, IGCC = integrated coal gasification combined cycle, kWh = kilowatt-hour, Nm^3 = normal cubic metre, OPEX = operational expenditure, PV = photovoltaic.

Note: H_2 price: US$0.20/$Nm^3$-$H_2$; ammonia price: US$0.16/Nm^3-H_2; capacity factors: 40% for hydropower, 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).

1.2.11. Capital cost and energy consumption of direct air capture

DAC requires enormous amounts of energy, both electrical power for the fans that extract CO_2 from the atmosphere, and heat for desorbing CO_2 from the sorbent material. As a result, the cost of energy is a key factor in DAC's overall cost.

Given the uncertainty surrounding the technological progress of DAC, three cases have been prepared (Table 0.1111). In the low case, capital expenditure and energy consumption are based on Fasihi et al. (2019), showing significant anticipated reductions in capture costs. The high case assumes no further improvements beyond 2020. The mid case takes the average values of the low case and high case scenarios. This study adopts the mid case in its modelling.

Table 0.11. Assumed Technological Specifications of Direct Air Capture

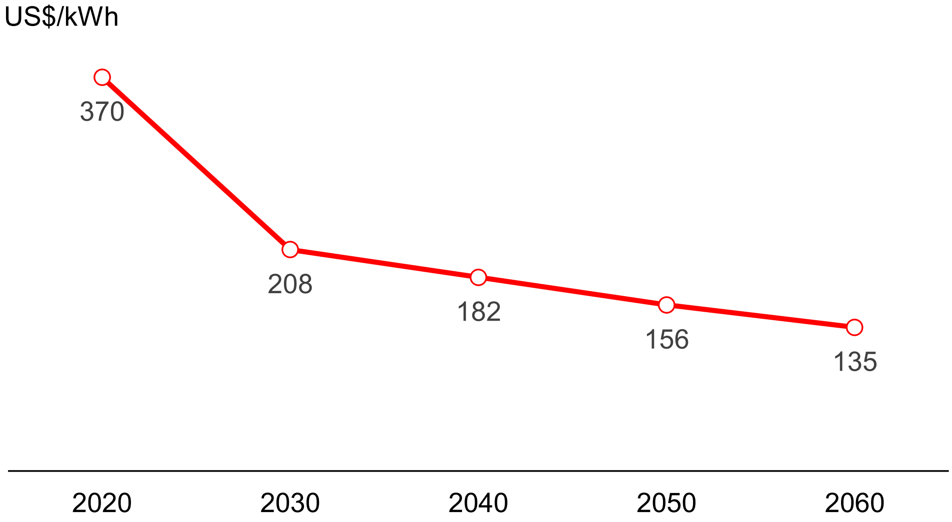
	Case	2020	2030	2040	2050	2060
Capital cost ($US\$/[tCO_2/year]$)	Low	906	420	294	247	226
	Mid	906	663	600	576	566
	High	906	906	906	906	906
Electricity input (kWh/tCO_2)	Low	1,535	1,458	1,385	1,316	1,283
	Mid	1,535	1,497	1,460	1,426	1,409
	High	1,535	1,535	1,535	1,535	1,535
Capturing cost ($US\$/tCO_2$)	Low	276	203	178	165	159
	Mid	276	240	227	221	218
	High	276	276	276	276	276

kWh = kilowatt-hour, tCO_2 = tonne of carbon dioxide.
Note: 2017 real prices. The low case is based on Fasihi et al. (2019). Electricity cost is assumed to be US$0.1 per kWh for capture cost estimation.
Source: Author.

1.2.12. Energy storage technologies

The model includes pumped hydro storage, batteries, and compressed H_2 tanks as energy storage technologies. The required capacities for batteries and compressed H_2 tanks are determined endogenously within the simulation. The manufacturing cost of lithium-ion batteries is expected to decline substantially. Future cost reductions are based on projections by the National Renewable Energy Laboratory of the United States (US) (Figure 0.10).

Figure 0.10. Assumed Lithium-ion Battery Cost



kWh = kilowatt-hour.
Note: 2017 real prices.
Source: Author, based on Cole and Frazier (2020).

Chapter 3

Major Updates to the Model

1.3. Adding new technologies to the model

1.3.1. Overview: Technology Perspective List

To enhance the comprehensiveness of the technologies included in the energy model used in this project, we verified whether technologies that play a significant role in decarbonisation, as outlined in ERIA's (2025) 'Technology List and Perspectives for Transition Finance in Asia' (TLP), were incorporated in the model framework in this study. We then attempted to supplement the model with any missing technologies.

The TLP is a comprehensive list compiled by ERIA that presents the characteristics, costs, and implementation prospects of technologies for decarbonising energy systems. A comprehensive survey of the technical specifications for the 'Deep Dive' technology list was conducted, with the objective of incorporating the most significant technologies into the IEEJ-NE model. As of April 2025, the second version of the TLP (Phase 2-1) provides detailed information on deep-dive technologies in the power, upstream, and end-use/industry sectors. Technologies in the midstream and downstream sectors are expected to be added to the TLP in the future. The TLP also covers other sectors, such as agriculture and waste. However, as these technologies reduce GHGs other than energy-related CO_2, they fall outside the scope of this energy transition study.

Table 0.1 provides a list of the deep-dive technologies in the TLP. Most technologies on the deep-dive list are significant in terms of energy supply or demand and are already explicitly considered or partially considered in the NE model as combinations of multiple technologies. In the context of this cycle's project, we examined the feasibility of adding technologies that were not included in the NE model. The technologies were assessed based on the following criteria:

- The potential impact on energy-related CO_2 emissions
- The feasibility of incorporating them into the IEEJ-NE model framework
- Data availability and alignment with model structure

As a result, these technologies can be classified into two categories:

Newly added technologies: Technologies that contribute to reducing energy-related CO_2 emissions to a certain extent, and for which the reduction effects can be quantified. Specifically, fuel combustion cogeneration, fuel cell cogeneration, ammonia/biofuel-fuelled ships, and carbon capture (in the chemical sector) fall into this category.

Technologies that cannot be included: Technologies that contribute to reducing GHG emissions other than energy-related CO_2 fall outside the scope of this project, which focuses on energy system analysis. Additionally, systems such as home energy management systems, for which the costs and energy-saving effects are difficult to quantify, are also excluded.

Table 0.1. Deep-dive Technologies in the Technology Perspective List

	Sector	Subsector	Technology	Status in IEEJ-NE Model	Update in this Project	Comments
1	Power		CCGT(coal avoidance, higher efficiency)	**Already included**		
2	Power		Waste-to-energy power plant	Partially included		
3	Power		Biomass co-firing	**Already included**		
4	Power		Low-carbon ammonia co-firing	**Already included**		
5	Power		Low-carbon hydrogen co-firing	**Already included**		
6	Upstream		Leak detection and repair for fugitive emission	Not included		Outside of scope; GHGs other than CO_2 from energy
7	Upstream		Process electrification in gas production and processing	**Already included**		
8	Power		CCUS in coal/gas power plant	**Already included**		
9	Upstream		Blue Hydrogen and blue ammonia	**Already included**		
10	Upstream		CCUS in gas processing	Not included		Outside of scope; GHGs other than CO_2 from energy
11	End use	Building	Heat oumps	**Already included**		
12	End use	Building	Fuel combustion cogeneration	Not included	Newly added	
13	End use	Building	Fuel cell cogeneration	Partially included	Newly added	
14	End use	Building	HEMS	Not included		
15	End use	Transport	HFCV	**Already included**		
16	End use	Transport	BEV/PHEV	**Already included**		
17	End use	Transport	HEV	**Already included**		
18	End use	Transport	Flex fuel vehicles	Not included		Not familiar with NE model; Bio-fuel vehicles and gasoline ICVs are already included.
19	End use	Transport	LNG-fuelled Ship	**Already included**		
20	End use	Transport	Ammonia/biofuel-fuelled ship	Not included	Newly added	
21	End use	Cement	Carbon mineralisation	Not included		Outside of scope; GHGs other than CO_2 from energy
22	End use	Cement	NSP kiln	Partially included		Included in "high efficiency tech".
23	End use	Chemical	Chemical production using captured CO_2	**Already included**		
24	End use	Steel	Electric arc furnace (EAF)	**Already included**		
25	End use	Steel	Direct reduced iron (DRI)	**Already included**		
26	End use	Ind. cross-cut.	Carbon capture	Partially included	Newly added	CCS with Steel, cement and power are already included
27	End use	Ind. cross-cut.	Lower emission fuel fuelled equipment	**Already included**		
28	End use	Ind. cross-cut.	Large-scale industrial heat pump	**Already included**		
29	End use	Ind. cross-cut.	Waste heat recovery	Partially included		Included in "high efficiency tech".
30	End use	Ind. cross-cut.	Electric heating	**Already included**		
31	End use	Ind. cross-cut.	Small-scale once through boiler	Partially included		

BEV = battery electric vehicle, CCGT = combined cycle gas turbine, CCUS = carbon capture utilisation and storage, HEMS = home energy management system, HEV = hybrid electric vehicle, HFCV = hydrogen fuel cell vehicle, LNG = liquefied natural gas, NSP = new suspension preheater, PHEV = plug-in hybrid electric vehicle.

Source: 'Technology', 'Sector', and 'Subsector' are from ERIA (2025).

1.3.2. Ammonia/biofuel-fuelled ships

These ship types were added as new activity categories. The capital costs were assumed to be comparable to conventional vessels, based on Fayas et al. (2024), whilst fuel costs are determined endogenously within the model.

1.3.3. CCS in the chemical subsector

CO_2 capture and storage in the steel and cement sectors has already been included in the NE model as a CCS option for the industrial sector. For this project, CCS in the chemical industry has been newly added. There are two types of CCS in the chemical industry: CCS accompanying chemical processes and CCS accompanying the thermal utilisation of fossil fuels in chemical furnaces. However, since CO_2 emissions from chemical processes are not energy-related CO_2, they fall outside the scope of this study's analytical framework. Therefore, only CCS with thermal utilisation has been implemented. CCS requires additional energy consumption and capital investment. Referring to IEA (2019b), Danish Energy Agency (2021), and Hughes and Zoelle (2022), we established the values shown in Table 3.2.

Table 0.2. Assumptions on CCS in the Chemical Sector

	Unit	Assumption
Energy consumption	GJ/t-CO_2	2.60
Capital cost (2030)	US$/(TOE/year)	1,171
Capital cost (2050)	US$/(TOE/year)	920
Operating period	Year	15
O&M cost	% of capital cost/year	5.0

Source: Author, based on IEA (2019b), Danish Energy Agency (2021), Hughes and Zoelle (2022).

Furthermore, considering that CCS may not be installable in all facilities, we set the upper limit for CCS-installable demand at 55% of chemical furnace demand. This figure is based on the combined share of ammonia, methanol, and high-value-added products (30% + 13% + 16%) for which CO_2 recovery is feasible, as noted in IEA (2019b), multiplied by the proportion of large-scale factories in the manufacturing industry in 2019 (93%; BPS Statistics Indonesia [2024]).

1.3.4. Cogeneration

Currently, gas boilers and turbines are the mainstream technologies used for cogeneration. Additionally, fuel cells are expected to be utilised in the future. In this analysis, cogeneration using gas turbines and fuel cells are considered as technical options.

Gas turbine cogeneration systems have been newly added to the model, based on comprehensive parameters from USEPA (2017). The assumptions concerning fuel cells have been updated to reflect the latest projections from the Ministry of Economy, Trade and Industry, Japan (2025), which include future cost assessments. Both surveys are referenced in the TLP and can be regarded as consistent with its framework.

Table 0.3. Assumptions on Cogeneration

	Unit	Gas Turbine	Fuel Cell
Fuel	-	Natural gas	Hydrogen/natural gas
Heat efficiency	-	39.0%	50.1%
Power efficiency	-	29.8%	40.2%
Capital cost	US$/(TOE/year)	2,132	4,965
Operating period	Year	30	15
O&M cost	% of capital cost/year	2.7%	1.0%

Sources: USEPA (2017) and Ministry of Economy, Trade and Industry, Japan (2024).

1.4. GDP and energy service demand

GDP projections were updated based on the latest ERIA Energy Outlook (forthcoming), and energy service demand was also updated based on the updated GDP statistics. The GDP projections for 2050 are shown in Table 0.4, with a downward revision of 2.5% for ASEAN as a whole, but the direction and magnitude of the revisions vary by country. With regard to service demand in the industrial sector, service demand other than energy-intensive materials was newly estimated based on the economic assumptions by ERIA (forthcoming). This resulted in an upward revision of service demand in 'other industries' compared to the previous assumption.

Table 0.4. Updates to GDP in 2050 (US$ billion, 2015)

Country	Previous	Updated	Change
Brunei Darussalam	27	25	-4.8%
Cambodia	134	134	0.0%
Indonesia	4,711	4,801	1.9%
Lao PDR	83	84	2.0%
Malaysia	817	819	0.2%
Myanmar	327	276	-15.5%
Philippines	1,847	1,680	-9.0%
Singapore	683	811	18.7%
Thailand	1,093	800	-26.8%
Viet Nam	1,503	1,517	1.0%
ASEAN	**11,224**	**10,948**	**-2.5%**

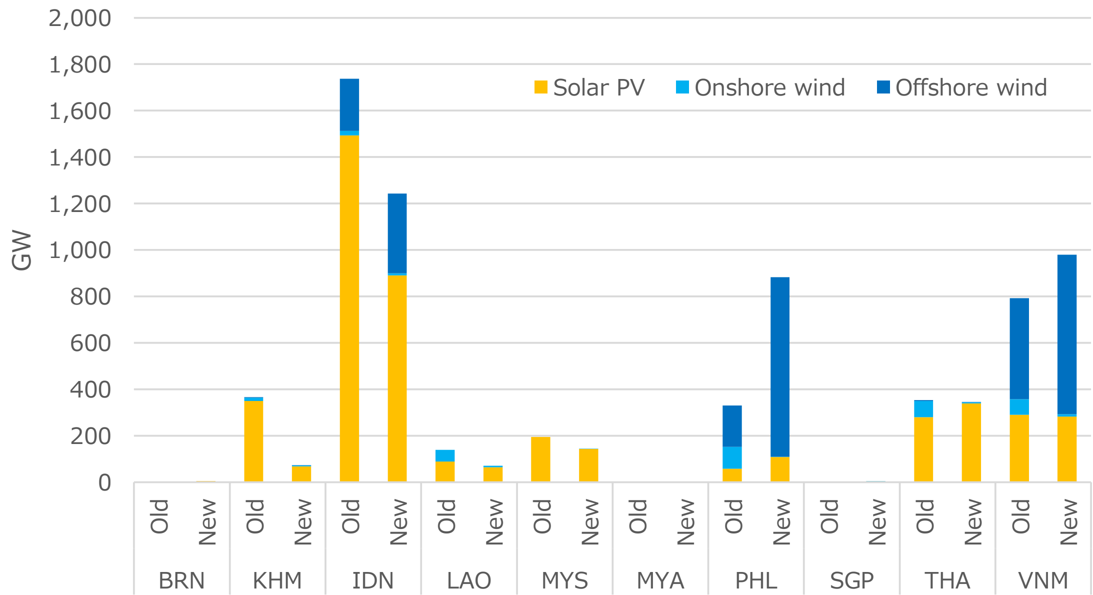
Sources: ERIA (2023; forthcoming).

1.5. Solar PV and wind

1.5.1. Upper limits of solar PV and wind

The upper limits for solar PV and wind power have been comprehensively updated using newly compiled, more detailed GIS land-use data, as explained in Section 2.2.6. As shown in Figure 0.1, compared to the previous estimates, solar PV has decreased in Indonesia, whilst offshore wind power has increased in the Philippines and Viet Nam. Indonesia, Malaysia, and Viet Nam have been divided into multiple regions to estimate their potential. In the context of offshore wind power, the consideration of variable wind conditions according to proximity to the coastline has resulted in the categorisation of the study area into six distinct water depth grades: 0–15 m, 15–30 m, 30–60 m, 60–100 m, 100–200 m, and >200 m. The study design incorporates the delineation of fixed-bottom systems for depths up to 60 m and floating systems for depths beyond 60 m. Furthermore, solar PV was newly distinguished between ground-mounted and building-mounted systems.

Figure 0.1. Updates to the Upper Limits of Variable Renewable Energy



BRN = Brunei Darussalam, IDN = Indonesia, KHM = Cambodia, LAO = Lao People's Democratic Republic, MYA = Myanmar, MYS = Malaysia, PHL = Philippines, SGP = Singapore, THA = Thailand, VNM = Viet Nam.
Source: Author.

1.5.2. Capacity factor for solar PV and wind

In the updated analysis, we developed 4-hourly capacity factor curves for solar and wind power generation. These curves incorporated power output profiles based on solar radiation and wind speed at each node and were reflected in the model assumption. In this study, the annual average solar irradiance and wind speed were calculated for each node. For each case, the mesh cell with the closest irradiance or wind speed was selected, and the corresponding capacity factor curve was estimated for that mesh. One-hourly capacity factor data were obtained from an open database (Renewables.ninja) for each representative location of the node. The detailed settings are as follows. A 1-year period from 00:00 local time on 1 January 2023 was extracted for this analysis. The key assumptions used for extracting data included a system loss of 10%, a tilt angle of 20 degrees, an azimuth angle of 180 degrees (facing south) for solar PV, and a hub height of 60 m with the turbine model Vestas V80 2000 for wind power. The obtained 1-hourly capacity factor data was smoothed by calculating 4-hourly averages and then used as input data for the model assumptions.

1.6. Direct air capture

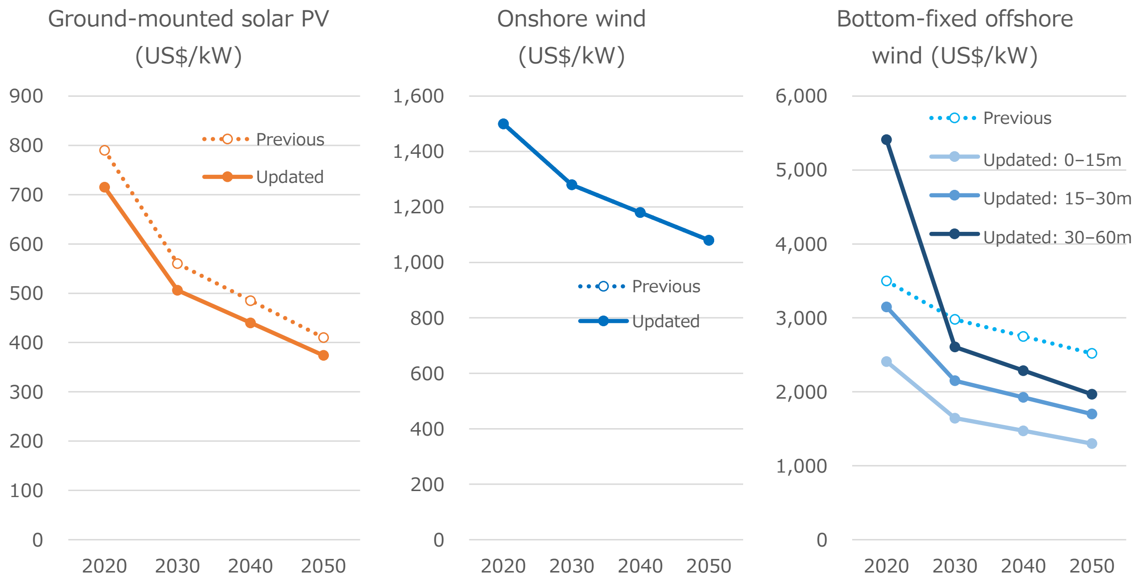
Compared to previous assumptions, CO_2 capturing costs after 2050, when DAC is expected to be introduced largely, are projected to decrease slightly but remain largely unchanged. For further details of updated assumptions, refer to Section 2.2.11.

1.7. Power generation technologies

1.7.1. Solar PV and wind power

Previously, power generation costs for Viet Nam were assumed to be equivalent to those for Indonesia (Danish Energy Agency, 2021). However, these values have now been updated based on Viet Nam's power generation technology catalogue (Danish Energy Agency, 2023). Bottom-fixed offshore wind power in Viet Nam was divided into three grades according to water depth (0–15 m, 15–30 m, 30–60 m). A comparison of capital expenditure (CAPEX) and the previous estimates is shown in Figure 3.2. Whilst ground-mounted solar PV and onshore wind power remain largely unchanged, floating offshore wind power has been revised downward. Additionally, building-mounted solar PV was newly considered in this analysis for all countries.

Figure 0.2. Updates to the Capital Cost of Variable Renewable Energy for Viet Nam



Sources: Danish Energy Agency (2021; 2023). Grade division of bottom-fixed offshore wind was conducted by the author.

1.7.2. Nuclear power

The lifetimes and capital costs of light water reactors in Indonesia and Viet Nam were revised with reference to Viet Nam's power generation technology catalogue (Danish Energy Agency, 2023) (Table 3.5). Whilst only light water reactors had been considered as nuclear power generation technology in the previous analysis, small modular reactors (SMRs) were newly considered in this analysis. SMRs are assumed to have higher load following capabilities than light water reactors.

Table 0.5. Updates to the Lifetimes and Capital Cost of Nuclear Power for Indonesia and Viet Nam

Item	Lifetime (years)		Capital cost (US$/kW)			
			2030	2040	2050	2060
Light water reactors	Previous	40	2,650	2,650	2,650	2,650
	Updated	60	4,800	4,625	4,450	4,450
Small modular reactors	-	60	4,900	4,700	4,500	4,500

Source: Danish Energy Agency (2023).

1.7.3. Thermal power

In the previous model, the co-firing ratio of coal-fired power plants was limited to 20% for both biomass and ammonia. In the revised model, this constraint has been relaxed by introducing a set of options allowing for gradual increases in the co-firing ratio (20%, 40%, 60%, 80%, and 100%). The technical parameters for co-firing technologies, including additional capital costs and efficiency penalties, were adopted from Viet Nam's power generation technology catalogue (Danish Energy Agency, 2023). Regarding the upper limit on biomass energy for power generation, the previously assumed capacity-based cap for 100% biomass-firing power plants was converted to the energy-based cap for both dedicated and co-firing. In addition, whilst the previous model assumed that CO_2 capture technology could be applied to coal- and gas-fired power plants even when co-firing with hydrogen or ammonia, this option has been removed as it seems to be an unrealistic option.

In addition, as retrofit technology for natural gas-fired power plants, we have newly considered 100% ammonia firing in addition to the previously assumed hydrogen co-firing and dedicated hydrogen firing. The 100% ammonia-fired power generation system considered here is an ammonia decomposition gas turbine combined cycle system that decomposes ammonia into H_2 and N_2 and burns it in a hydrogen combustion chamber. Although the technology is currently under development and shares similarities with hydrogen-fired gas turbines, it is believed that retrofitting natural gas-fired gas turbines to ammonia-fired gas turbines can be achieved by only adding combustion chambers and fuel supply systems (Mitsubishi Heavy Industries, 2023). Although the retrofit costs are unknown at this moment, based on the specifications of hydrogen co-firing technology in Viet Nam's power generation technology catalogue, an additional cost equivalent to 25% of the CAPEX for natural gas-fired power plants is assumed.

1.8. Other assumptions about Viet Nam

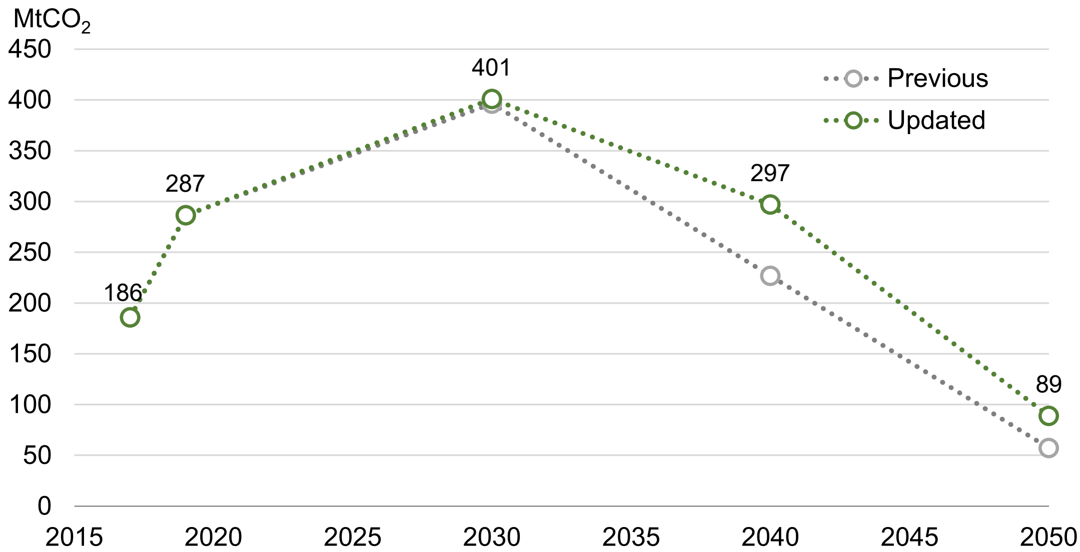
1.8.1. Regional division

Taking into account the uneven distribution of renewable energy resources and energy demand, Viet Nam was divided into six regions instead of the previous one region (see Section 5.1.1). With this regional division, interregional transmission lines were explicitly assumed, and the country's energy service demand was allocated to each region based on regional population, GDP, and transportation volume. The upper limits for VRE were set for each region using GIS analysis.

1.8.2. Emission constraints

Energy-related CO_2 emission constraints for Viet Nam were revised to reflect the National Strategy on Climate Change by 2050 (Government of Viet Nam, 2022) (Figure 3.3).

Figure 0.3. Energy-related Carbon Dioxide Emission Constraints for Viet Nam



CO_2 = carbon dioxide, $MtCO_2$ = million tonnes of carbon dioxide.
Source: Government of Viet Nam (2022).

1.8.3. Upper limit of nuclear power

In contrast, whilst the preceding analysis made no assumptions regarding the introduction of nuclear power generation in Viet Nam, this analysis sets an upper limit based on the former government plans (see Section 5.1.1).

Chapter 4

Results for ASEAN

1.9. Results

This chapter presents the results for ASEAN, compared with those from the previous year's report (Endo et al., 2025). Country-specific results can be found in the Appendix.

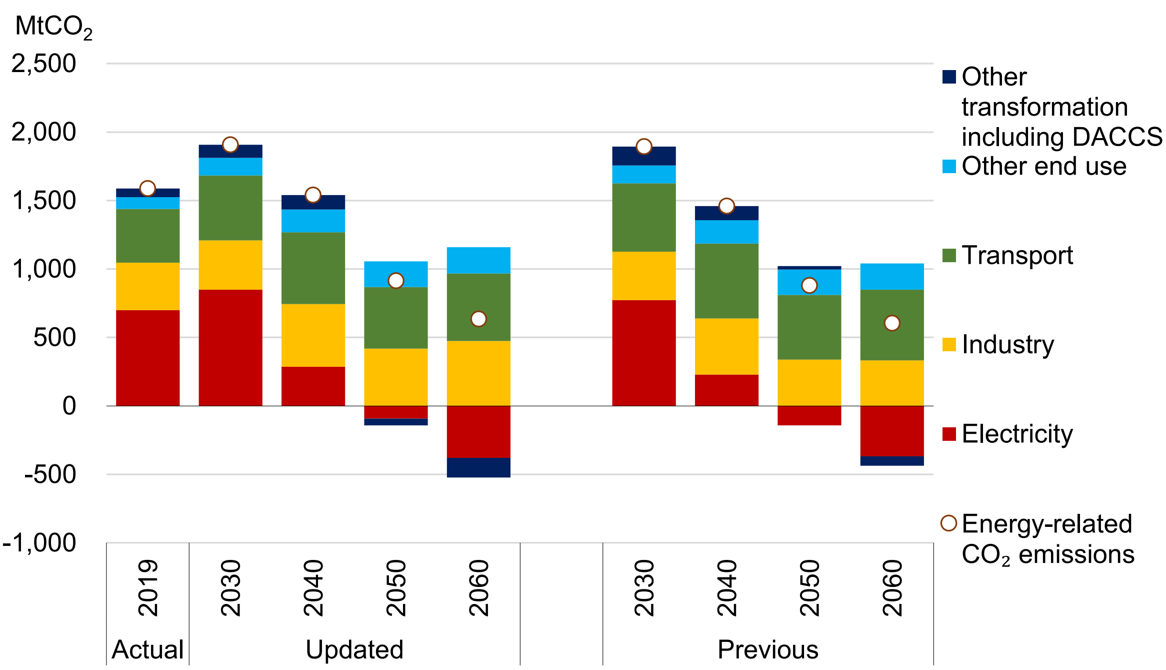
CO_2 emissions from the power sector decrease significantly from 2040 onwards (Figure 4.1). After 2050, the emissions from the power sector are negative through the deployment of BECCS, offsetting some residual emissions from sectors with higher abatement costs, such as high-temperature industrial heat and heavy-duty vehicles. Emissions from the end-use sector also decrease significantly until 2050. The persistence of energy-related CO_2 emissions by 2060 is due to emission reduction targets being set on a country-by-country basis, taking into account carbon sinks, including emissions from land use, land-use change, and the forestry sector. Compared with previous results, the deployment of negative emission technologies, such as BECCS and DACCS, after 2050 has increased. Emissions from the end-use sector have increased accordingly. This is mainly due to an upward revision in energy service demand in other industries and the price of imported hydrogen.

Final energy consumption in 2060 is projected to be 2.5 times higher than in 2019 (Figure 4.3). The energy mix shows an increase in electricity and natural gas use and a decrease in oil consumption. Electricity's share reaches 34% by 2060. The demand for natural gas increases, mainly in the industrial sector, whilst electricity demand increases across the industrial, residential and commercial, and transport sectors. The decline in oil consumption is primarily due to the electrification of passenger vehicles (Figure 4.7). In comparison to previous results, total final energy consumption in 2060 has increased by 6.0%, and natural gas consumption in 2060 has been revised upward by 17%. This increase reflects upward revisions in energy service demand in other industries and additional assumptions on CCS in the chemical industry. Due to a significant increase in imported hydrogen prices, the final consumption of hydrogen has decreased.

Electricity generation is projected to increase significantly more than final energy consumption, reaching 5.7 times the 2019 level by 2060 (Figure 4.4). Renewable energy, mainly solar PV, is expected to expand rapidly after 2030, reaching a 62% share by 2060. Following the installation of more than 1 terawatt (TW) of variable renewable energy capacity by 2050, representing a 64% share, significant battery storage will be deployed in combination with low-carbon thermal fuel-fired power plants to address the intermittency of variable renewable energy (Figure 4.6). The amount of electricity from thermal power generation increases towards 2060, with low-carbon thermal generation achieved mainly through CO_2 capture in coal- and natural gas-fired plants, biomass co-firing in coal-fired plants, and ammonia-fired power plants (Figure 4.4 and Figure 4.5). BECCS as a negative emission source grows after 2040. Compared with previous results, total electricity generation in 2060 has increased by 11.8%. This increase is attributed to increased final consumption in the end-use sector and DACCS. This increased electricity demand is met by various technologies, including solar PV, offshore wind, and 100% ammonia-fired power. Electricity generation from offshore wind has increased due to a decline in its capital cost. Regarding hydrogen and ammonia, net ammonia imports have increased in line with the rise in dedicated ammonia-fired power generation (Figure 4.8).

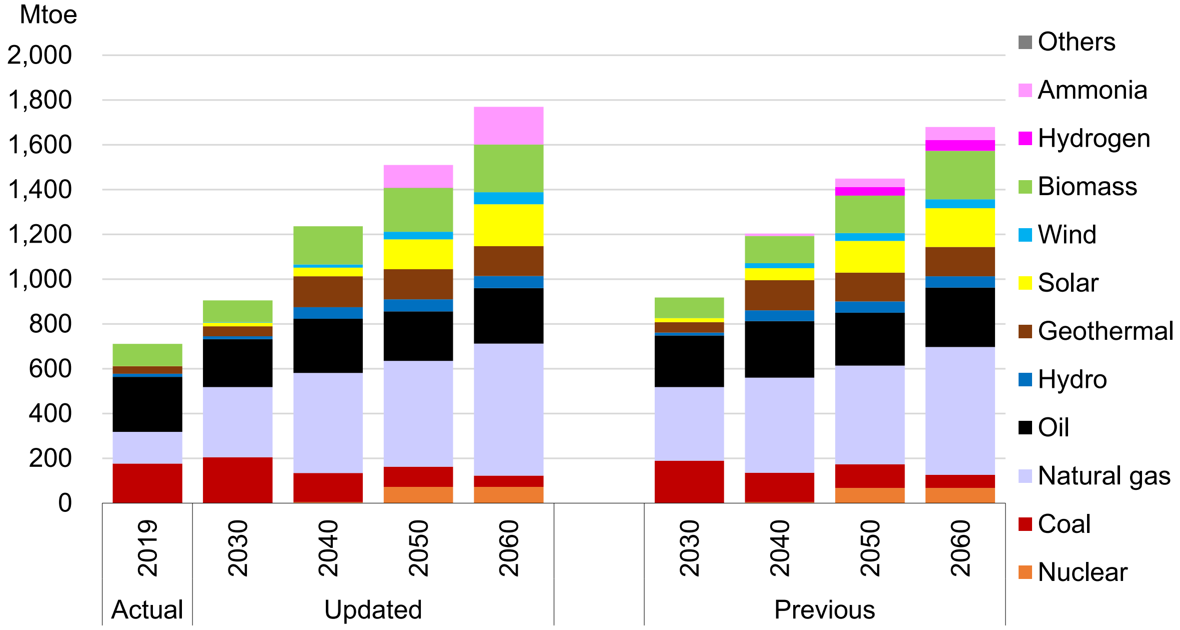
Primary energy supply (Figure 4.2) reflects these changes in final energy consumption and power generation. CO_2 emissions from fossil fuels are reduced through CCS (Figure 4.9). Initially, CO_2 capture facilities are installed in coal-fired power plants, later expanding to gas- and biomass-fired plants. These facilities play a role in blast furnaces, cement kilns, and chemical plants. Finally, energy system costs increase because of decarbonisation efforts. By 2060, the marginal abatement cost of CO_2 will reach US$281 per tonne of CO_2 (Figure 4.10), whilst the marginal cost of electricity rises to US$10.5 per kWh, which is 2.1 times the base year model estimate (Figure 4.11).

Figure 0.1. Carbon Dioxide Emissions by Sector



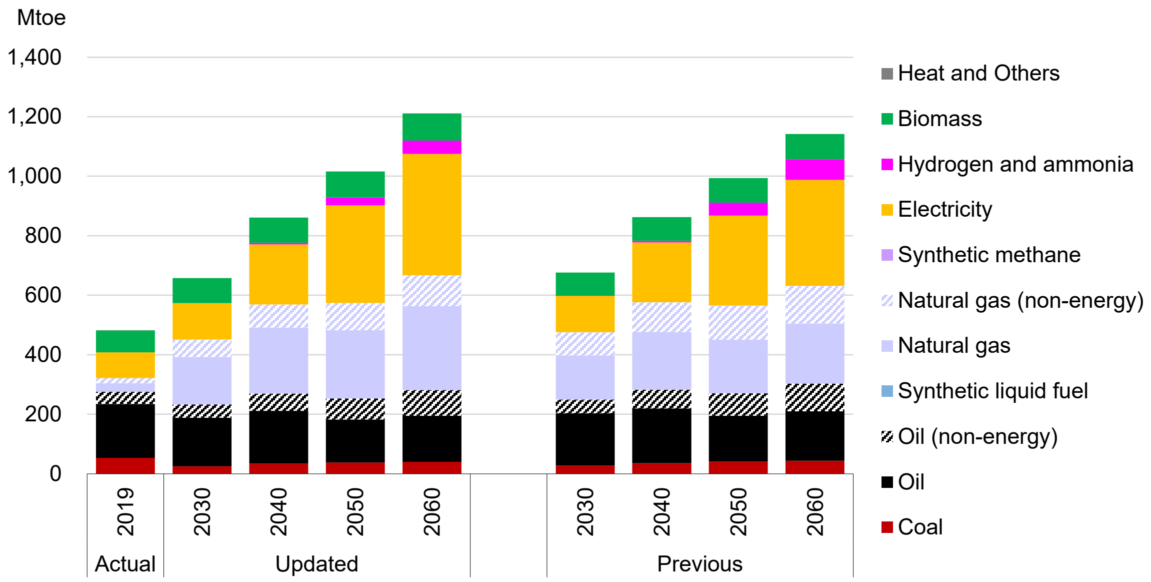
DACCS = direct air carbon capture and storage, $MtCO_2$ = million tonnes of carbon dioxide.
Source: Author.

Figure 0.2. Primary Energy Supply by Source



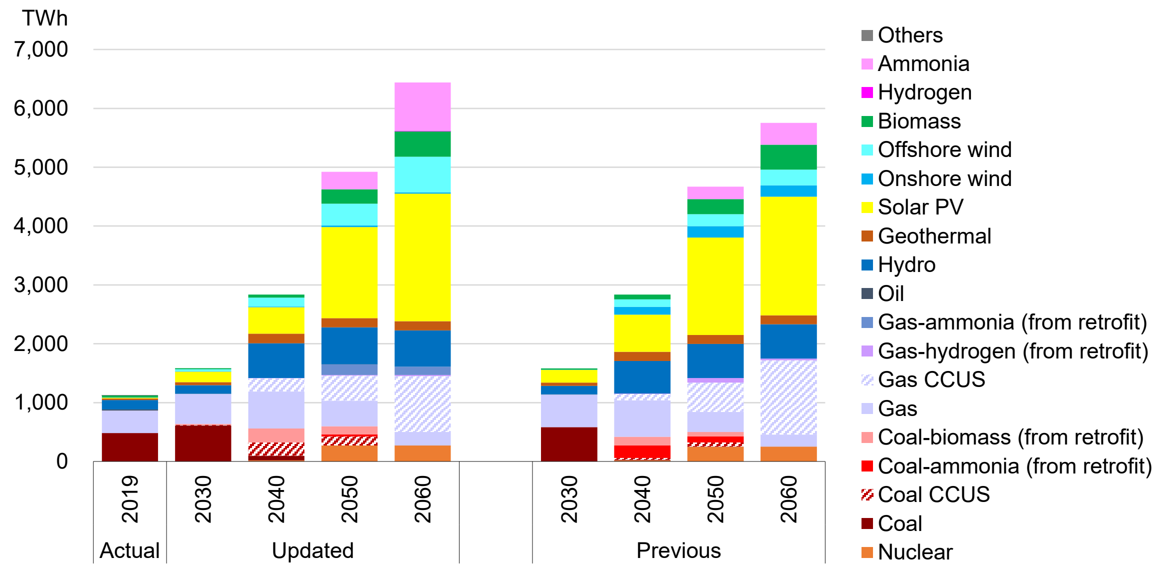
Mtoe = million tonnes of oil equivalent.
Source: Author.

Figure 0.3. Final Energy Consumption by Source



Mtoe = million tonnes of oil equivalent.
Source: Author.

Figure 0.4. Power Generation by Technology

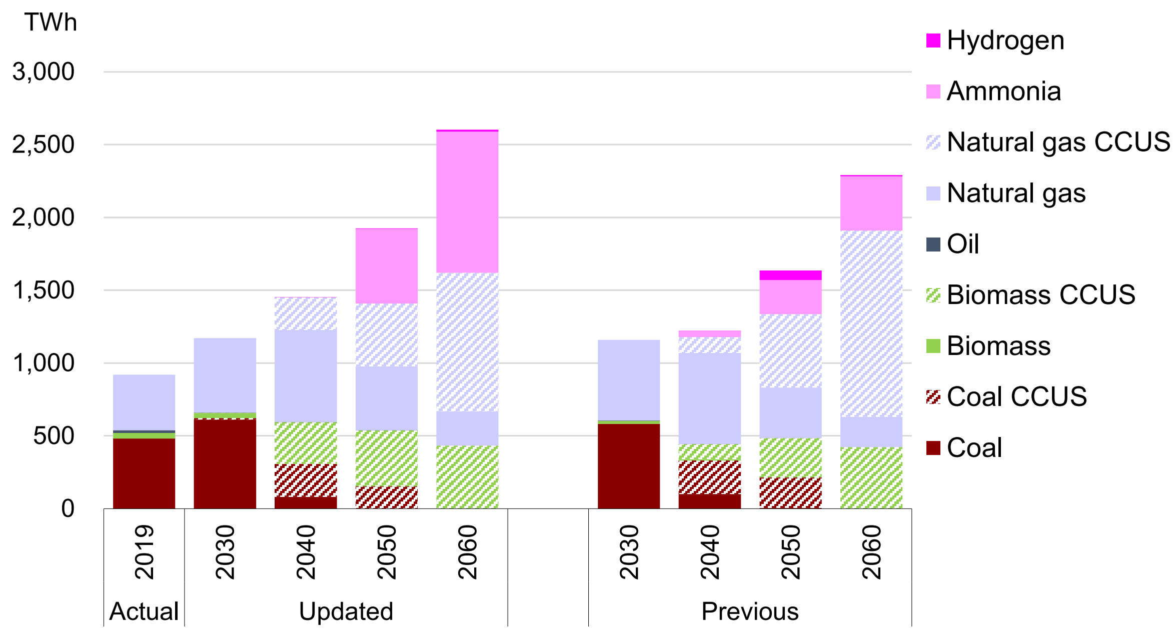


PV = photovoltaic, TWh = terawatt hour.

Note: 'Gas-ammonia' and 'coal-ammonia' means ammonia co-firing power retrofitted from natural gas or coal power plants, respectively. For both, the updated model selected a 100% co-firing ratio, effectively resulting in dedicated firing. 'Ammonia' refers to newly constructed 100% ammonia-fired power generation.

Source: Author.

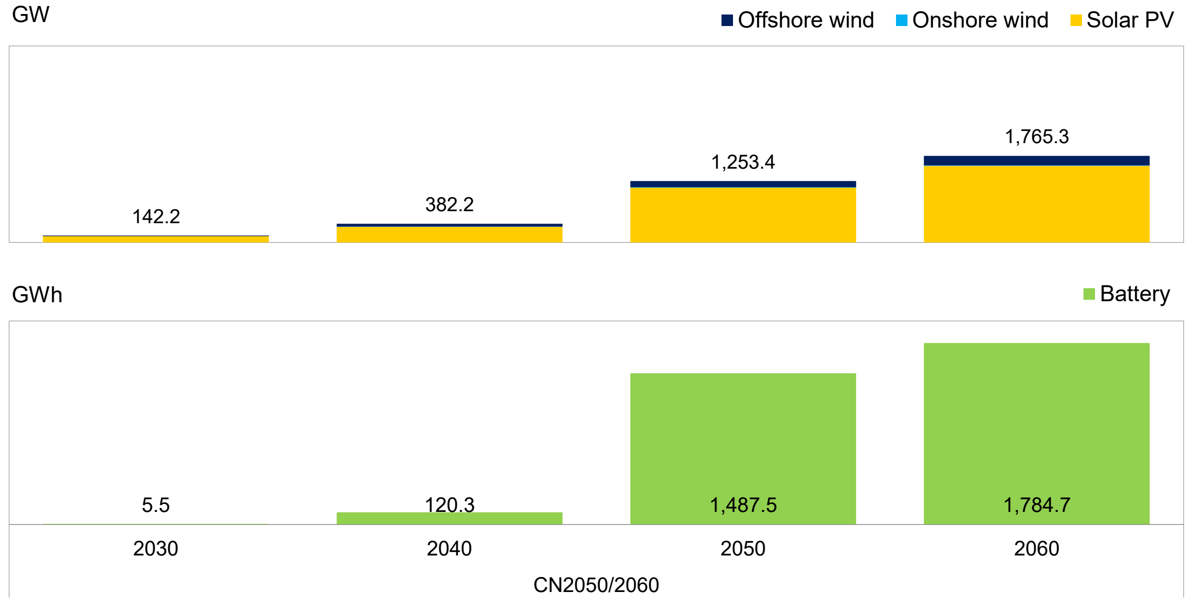
Figure 0.5. Thermal Power Generation by Source



CCUS = carbon capture, utilisation, and storage, TWh = terawatt hour.

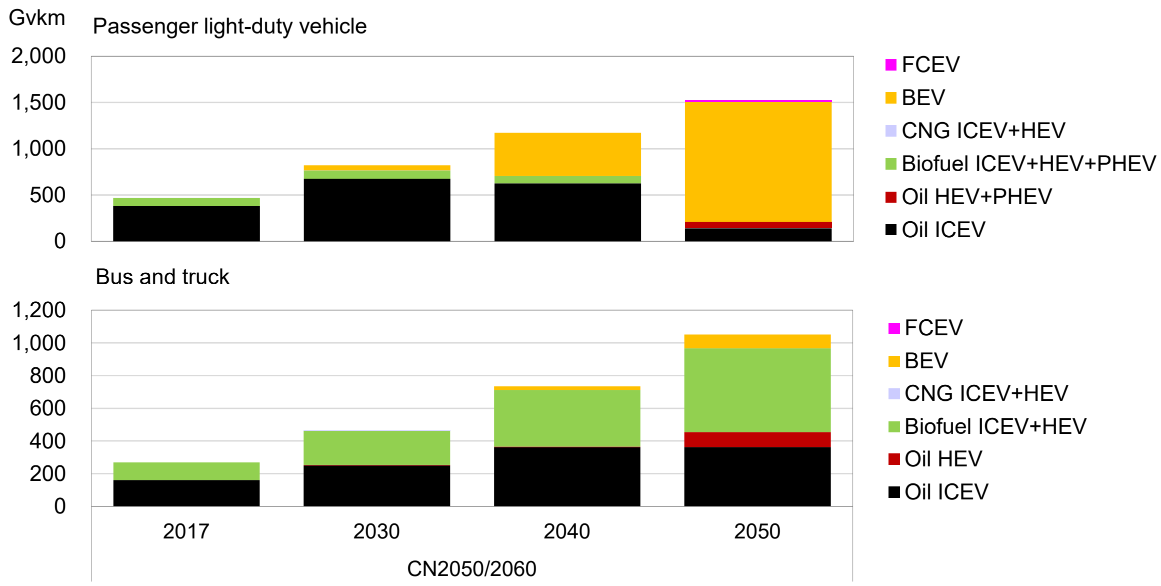
Source: Author.

Figure 0.6. Installed Capacity of Variable Renewable Energy and Battery



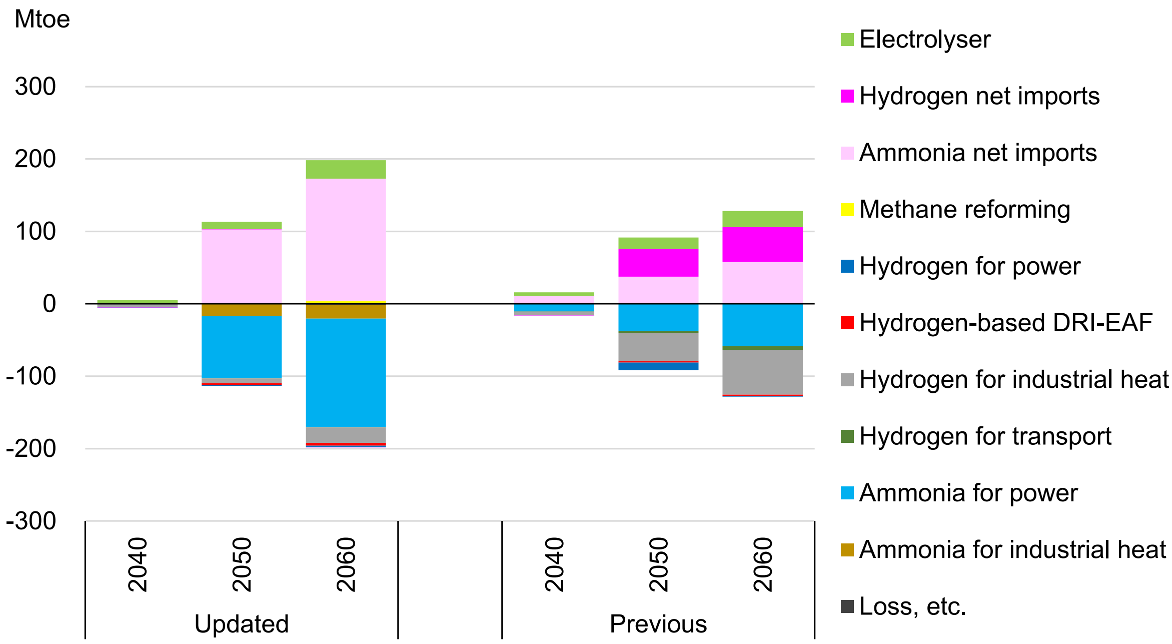
GW = gigawatt, GWh = gigawatt hour, PV = photovoltaic.
Source: Author.

Figure 0.7. Road Transport Demand



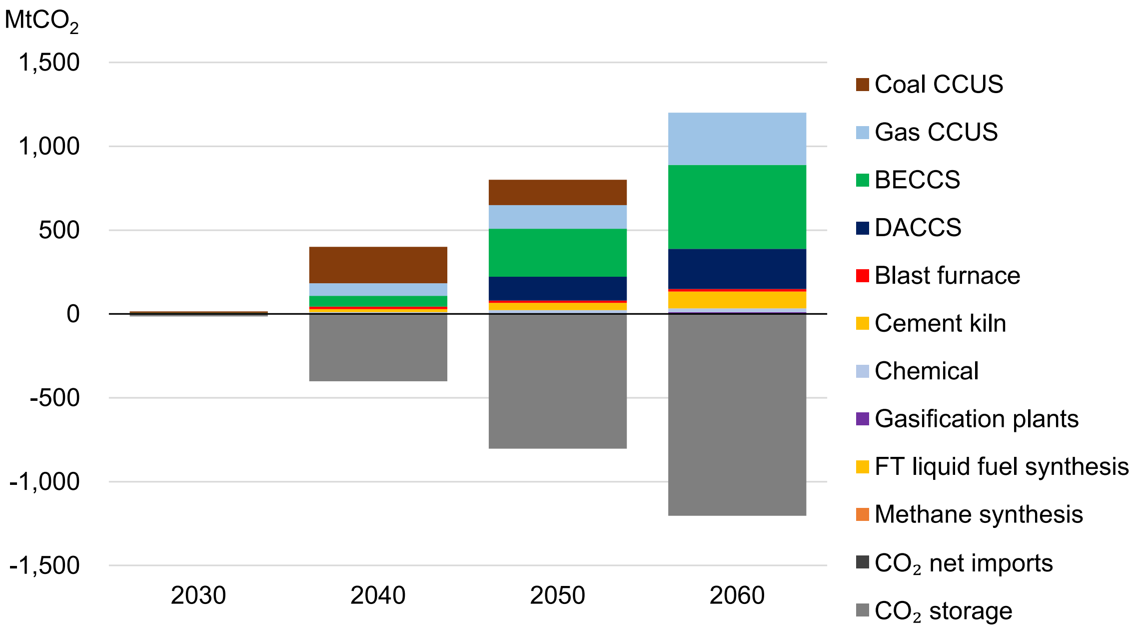
BEV = battery electric vehicle, CNG = compressed natural gas, FCEV = fuel cell electric vehicle, HEV = hybrid electric vehicle, ICEV = internal combustion engine, Gvkm = giga vehicle-kilometre, PHEV = plug-in hybrid electric vehicle.
Source: Author.

Figure 0.8. Supply and Demand of Hydrogen and Ammonia



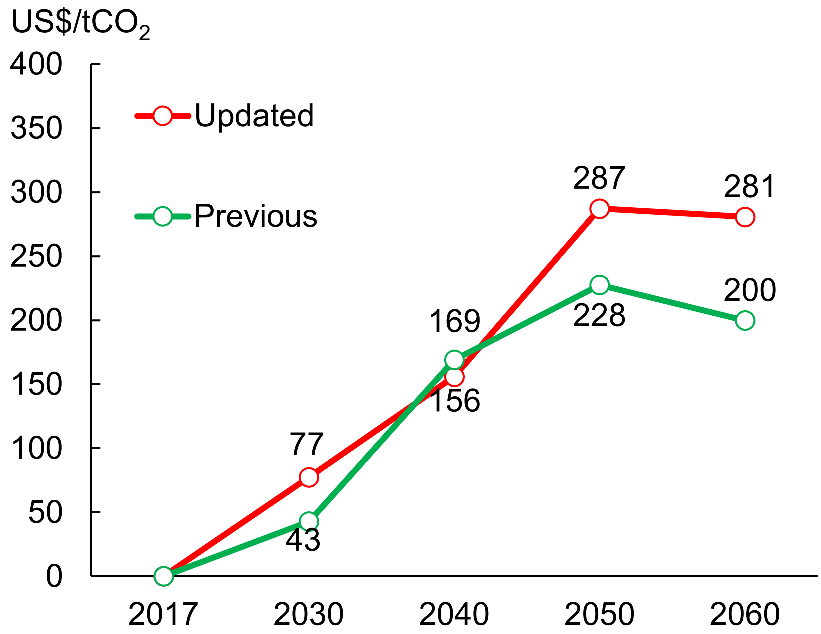
DRI-EAF = direct reduced iron–electric arc furnace, Mtoe = million tonnes of oil equivalent.
Source: Author.

Figure 0.9. Supply and Demand of Captured CO_2



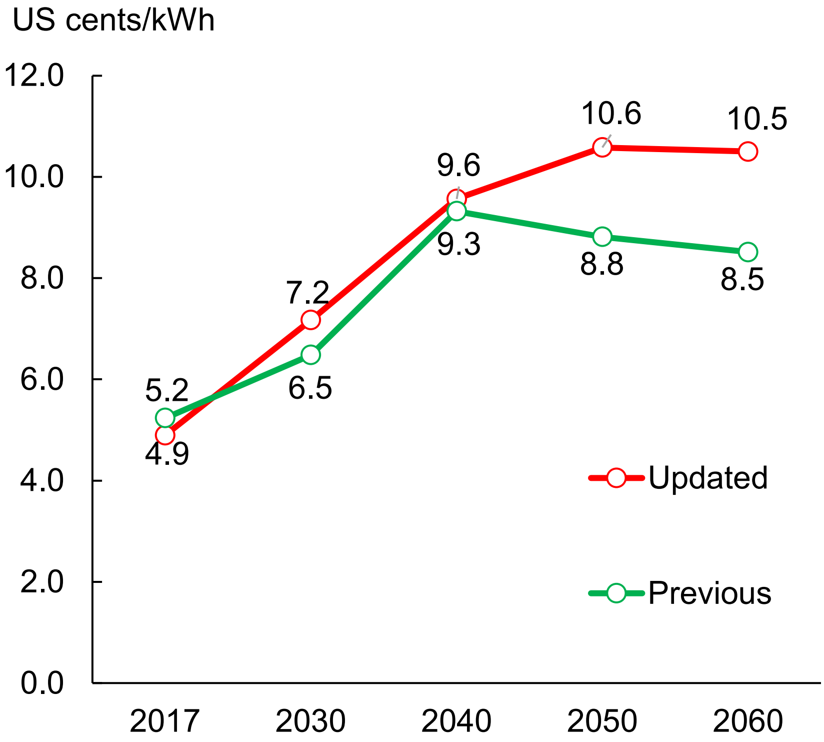
BECCS = bioenergy with carbon capture and storage; CCUS = carbon capture, utilisation, and storage; CO_2 = carbon dioxide; DACCS = direct air carbon capture and storage; FT = Fischer–Tropsch; $MtCO_2$ = million tonnes of carbon dioxide.
Source: Author.

Figure 0.10. Marginal Abatement Cost of Carbon Dioxide



CO_2 = carbon dioxide, tCO_2 = total carbon dioxide.
Source: Author.

Figure 0.11. Marginal Cost of Electricity



kWh = kilowatt-hour.
Source: Author.

1.10. Conclusions

This study incorporates major updates to the IEEJ-NE_ASEAN model, developed since 2021. These updates include a reassessment of energy service demand. Whilst certain differences from previous results are evident – such as increased total energy consumption, including electricity demand, which is met by various technologies including solar PV, offshore wind, and ammonia-fired power – the main implications for ASEAN remain consistent throughout this study:

- Energy savings and electrification in end-use sectors, combined with a low-carbon power supply, are core strategies for decarbonising ASEAN energy systems.
- During transition periods, various low-carbon technologies can effectively reduce CO_2 emissions. In the power sector, strategies such as fuel switching from coal to natural gas, deploying more efficient turbines, co-firing with biomass, ammonia, and hydrogen, as well as fossil-fuel-fired power generation with CCS, can support progress towards deep decarbonisation.
- The simulation results imply significant economic challenges associated with decarbonisation.

In addition, the analysis highlights four further implications. First, the expansion of variable renewable energy in power generation must be supported by maintaining a certain level of thermal power generation and installing substantial battery capacity and hydrogen storage tanks to ensure supply flexibility.

Second, natural gas emerges as a key energy source, with its consumption continuing to grow during the transition period and over the long term. Its share in the primary energy supply is projected to increase from 20% in 2019 to 33% in 2060, becoming the largest component of the energy mix. The use of natural gas is expected to expand in the industrial and power sectors.

Third, CCS technologies and thermal power plants for ammonia or hydrogen fuels are essential. As shown in the assumptions, the installed capacity of coal-fired power plants in ASEAN is expected to increase by 2030. Expanding coal-fired power plants with CCS offers a viable strategy for reducing CO_2 emissions whilst effectively utilising existing facilities. Furthermore, CCS is considered a cost-effective option for coal- and gas-fired power plants and so-called 'hard-to-abate' sectors, such as blast furnaces, cement kilns, and chemical plants. Moreover, for deeper decarbonisation towards net-zero emissions, CCS will be a prerequisite for negative emission technologies, such as BECCS and DACCS.

1.11. Comparison with other outlooks

In addition to this study, various organisations, such as the IEA, have also formulated decarbonisation road maps for ASEAN. A comparative analysis of these scenarios can provide important information for policymakers referring to road maps in an uncertain future.

In this section, we conduct a comparative analysis of the CN2050/2060 case by ERIA/IEEJ and the Announced Pledges Scenario (APS) from the *World Energy Outlook 2024* by the IEA. For the former versions of these scenarios, a comparison has already been conducted by the IEA (2023c). The comparison in this section reflects updates to both IEA and ERIA/IEEJ analyses.

Table 4.1 shows the comparison of the two scenarios. Both the IEA APS and the ERIA/IEEJ are backcast-type analyses, since they assume the achievement of carbon-neutral pledges. However, the methodologies employed in these two scenarios are different. ERIA/IEEJ adopts a cost minimisation approach using a linear programming model, whilst the IEA adopts a hybrid approach with an econometric model and a bottom-up technology model. The IEA's approach has the advantage of being able to keep overall consistency since it balances global energy supply and demand, taking into account past trends. On the other hand, ERIA/IEEJ's approach is characterised by its simplicity, as it employs a single clear criterion of value or cost minimisation. Since ERIA/IEEJ focuses on ASEAN, it also has the advantage of dividing ASEAN into 21 regions and having a high temporal resolution for electricity supply and demand balances.

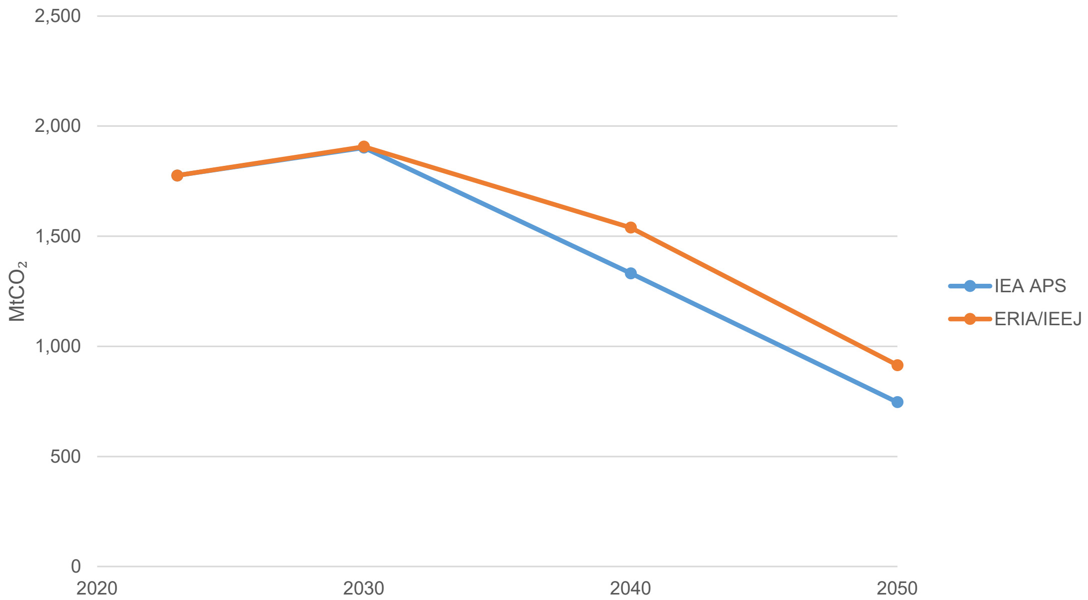
Table 0.1. Outline of the Compared Scenarios

	IEA APS	ERIA/IEEJ
Scenario	IEA World Energy Outlook 2024 Announced Pledges Scenario	IEEJ-NE_ASEAN CN2050/2060
Policy targets by countries	Carbon neutral pledged, nationally determined contributions, sectoral targets	Carbon neutral pledges (carbon neutral by 2060 for the entire ASEAN)
Regional division for ASEAN	Indonesia, other ASEAN	Each of the 10 ASEAN countries, divided into 21 regions
Time period	Up to 2050	Up to 2060
Methodology	Hybrid model with an econometric model (World Energy Model) and a bottom-up technology model (Energy Technology Perspectives model)	Linear programming model for cost minimisation

ASEAN = Association of Southeast Asian Nations, APS = Announced Pledges Scenario.
Source: Author.

Figure 4.12 shows a comparison of the total energy-related CO_2 emissions. Although emissions after 2040 are smaller for the IEA APS, the two have roughly similar emission paths, so it is still meaningful to compare the scenarios. However, a closer look shows that even in the long term, whilst the IEA expects a small amount of energy-related carbon dioxide removal, such as BECCS and DACCS, ERIA/IEEJ expects a large introduction driven by cost minimisation. Both scenarios consider the offsetting of residual emissions by natural carbon sinks, such as forests. However, the IEA's assumed scale of carbon sinks, e.g. in Indonesia, appears to be smaller.

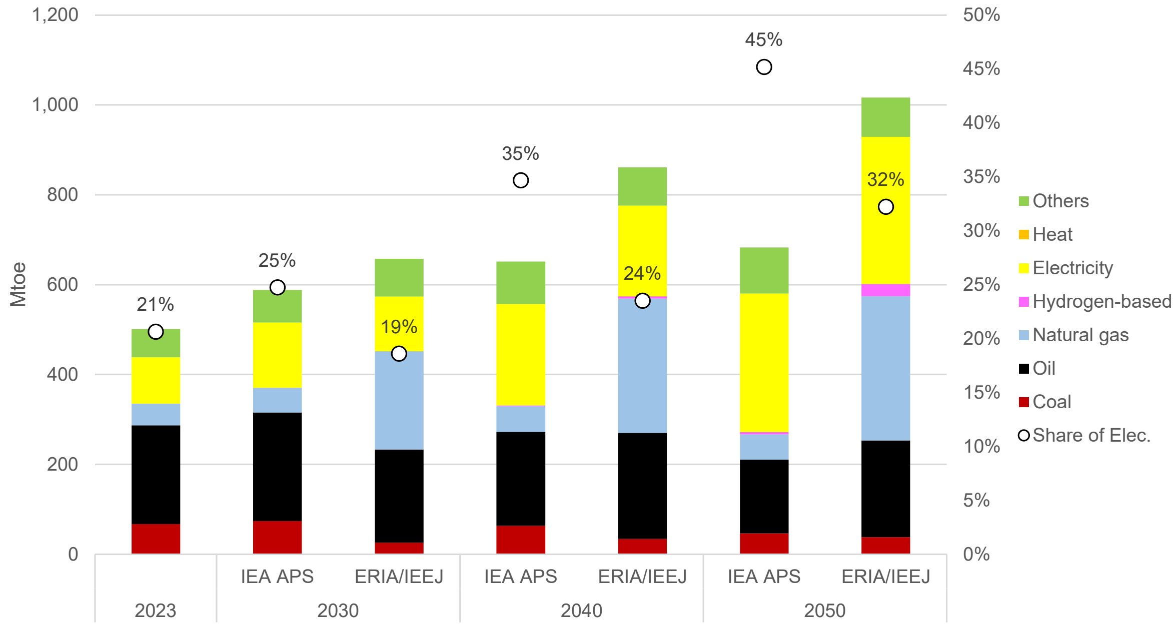
Figure 0.12. Comparison of Total Energy-related Carbon Dioxide Emissions in ASEAN



MtCO2 = million tonnes of carbon dioxide.
Source: Author; IEA (2024).

As shown in Figure 4.13, the total final energy consumption in 2050 reaches 1.5 times higher for ERIA/IEEJ than for the IEA. This gap was already found in the previous comparative study (IEA, 2023c), and according to the previous analysis, this difference primarily reflects differences in energy demand resulting from assumptions of economic growth. Second, the IEA also expects a greater improvement in energy efficiency, measured by dividing total final energy consumption by GDP. These points appear to be still effective for the latest comparison. The gap in total demand is mainly met by natural gas in the ERIA/IEEJ scenario, leading to a significant gap in natural gas demand. In the ERIA/IEEJ scenario, natural gas (including non-energy use) is demanded mainly by the industrial sector. Our cost-optimal analysis shows that end-use emissions from natural gas are partly recovered by CCS technology in the chemical sector, and the rest is offset by negative emissions technologies.

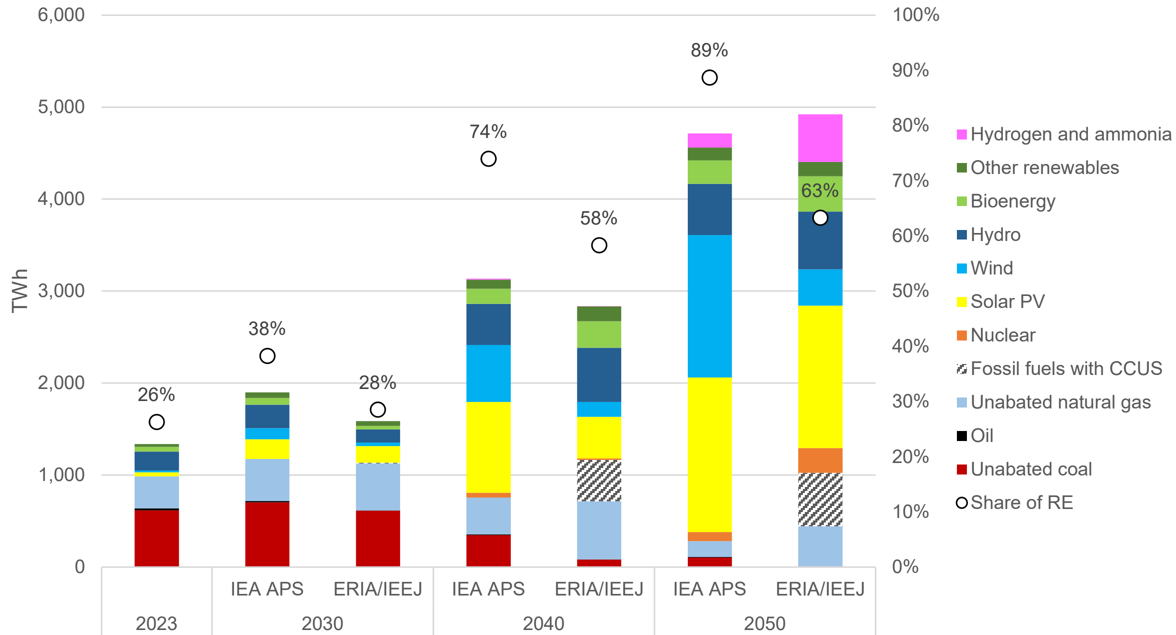
Figure 0.13. Comparison of Final Energy Consumption in ASEAN



Mtoe = million tonnes of oil equivalent.
Source: Author; IEA (2024).

Although the final energy consumption in the IEA APS is much smaller than that of ERIA/IEEJ, total power generation is similar to ERIA/IEEJ in 2050, or even greater in 2030 and 2040 (Figure 4.14). This is led by a more rapid and deeper electrification in the IEA APS. In terms of the power generation composition, although the expansion of renewables, especially VREs, is essential in both scenarios, both the share and absolute amount of renewable energy are greater in the IEA APS, reaching almost 90%. In the ERIA/IEEJ scenario, natural gas, ammonia, and nuclear power play more important roles, even in 2050, contributing to the best mix of the power system. The largest discrepancy between the IEA and this study appears in wind power generation after 2040, which is supposed to result from installation constraints on onshore wind (e.g. limited to bare land) and the depth-dependent CAPEX assumptions for offshore wind.

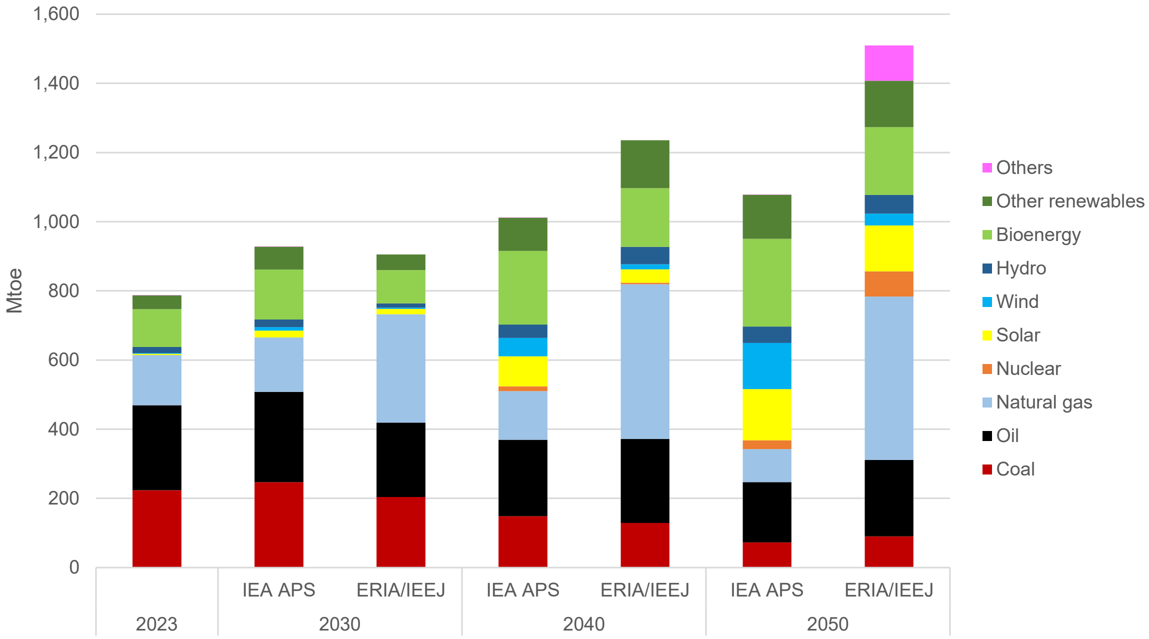
Figure 0.14. Comparison of Power Generation in ASEAN



CCUS = carbon capture, utilisation, and storage, PV = photovoltaic, RE = renewable energy, TWh = terawatt-hour.
Source: Author; IEA (2024).

As shown in Figure 4.15, the supply of natural gas expands rapidly for the ERIA/IEEJ scenario, especially in the transitional period, such as 2030 and 2040, but is almost flat by 2030 and even decreases after 2030 for the IEA scenario, showing a significant difference. In the ERIA/IEEJ scenario, fossil fuels continue to be important energy sources alongside the massive deployment of renewables to meet the strong energy demand as a result of rapid economic growth. In the long term, hydrogen and ammonia (included in 'other' in Figure 4.15) are also important options.

Figure 0.15. Comparison of Primary Energy Supply in ASEAN



Mtoe = million tonnes of oil equivalent.
Source: Author; IEA (2024).

Chapter 5

Country-specific Analysis: Viet Nam

1.12. Viet Nam

1.12.1. Key assumptions[3]

(a) Regional division and transmission network

Viet Nam's main transmission lines (500 kilovolts) run from north to south, connecting major power plants across the country. In the model, Viet Nam is divided into six nodes – north, north central, central central, central highlands, south central, and south – to account for the uneven distribution of renewable energy resources, energy service demands, and existing facilities (Table 0.1. Assumed Distance and Capacity of Transmission Lines

		Distance (km)	Capacity (MW)	
			Existing	Upper Limit
Domestic	N – NC	250	2,200	-
	NC – CC	350	1400	-
	CC – CH	350	2,000	-
	CC – SC	350	400	-
	CH – S	400	4,000	-
	SC – S	650	2,500	-
Intl.	Cambodia – S	100	200	200
	Lao PDR – NC	100	860	5,000

CC = central central, CH = central highlands, intl. = international, km = kilometre, MW = megawatt, N = north, NC = north central, S = south, SC = south central.
Note: Existing capacity of domestic lines is based on Vietnam Electricity (2020) and National Power Transmission Corporation.
Source: Author.

[3] The assumptions regarding the import prices of H_2 and NH_3 are not aligned with the ASEAN assumptions, as evidenced in Table 2.5. The assumptions for Viet Nam are consistent with the targets set by the Japanese government, as outlined in Endo et al. (2025).

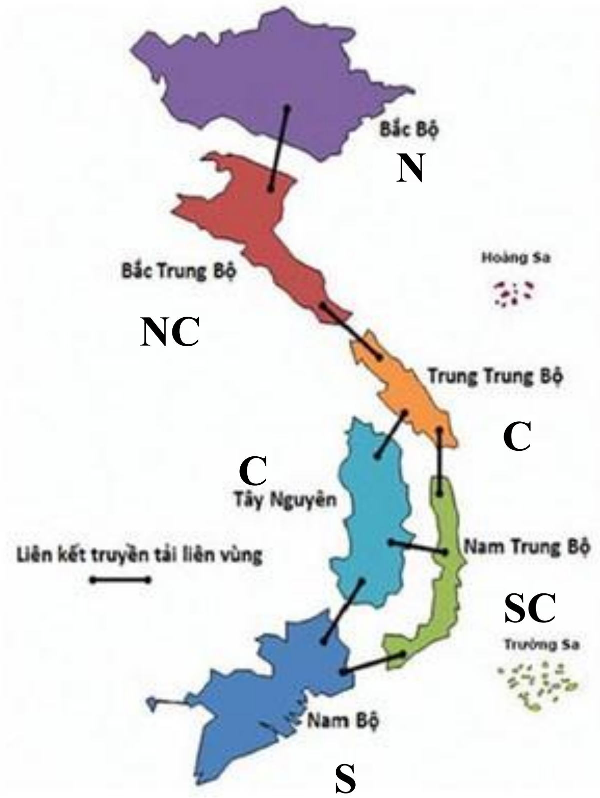
Figure 0.1). The expansion of transmission lines between regions is determined endogenously within the model. This study imposes upper limits on the capacity of international interconnections with the Lao PDR and Cambodia, based on planned infrastructure developments. Conversely, no upper limit is assumed for the capacity of domestic transmission lines within Viet Nam.

Table 0.1. Assumed Distance and Capacity of Transmission Lines

		Distance (km)	Capacity (MW)	
			Existing	Upper Limit
Domestic	N – NC	250	2,200	-
	NC – CC	350	1400	-
	CC – CH	350	2,000	-
	CC – SC	350	400	-
	CH – S	400	4,000	-
	SC – S	650	2,500	-
Intl.	Cambodia – S	100	200	200
	Lao PDR – NC	100	860	5,000

CC = central central, CH = central highlands, intl. = international, km = kilometre, MW = megawatt, N = north, NC = north central, S = south, SC = south central.
Note: Existing capacity of domestic lines is based on Vietnam Electricity (2020) and National Power Transmission Corporation.
Source: Author.

Figure 0.1. Regional Divisions in the Model



CC = central central, CH = central highlands, N = north, NC = north central, S = south, SC = south central.
Source: Author's additions to Vietnam Electricity (2020).

(b) Energy service demand

Table 0.2 shows the economic indicators and energy service demand for Viet Nam.

Table 0.2. Energy Service Demand for Both the Baseline and Carbon Neutral Scenarios

Item	Unit	2019	2030	2040	2050
Population	Millions	96	103	106	107
GDP	Billion US$ (2015)	315	572	977	1,517
	Annual growth rate, %	-	5.6% (2019–2030)	5.5% (2030–2040)	4.5% (2040–2050)
Crude steel production	Million tonnes	19	34	49	61
Cement production	Million tonnes	97	157	220	258
Passenger cars	Billion vehicle-km	15	66	94	106

Buses and trucks	Billion vehicle-km	22	56	97	144
Data centres	TWh	-	1.4	5.8	19.7

GDP = gross domestic product, km = kilometre, TWh = terawatt-hour.
Note: Electricity demand from data centres is estimated by dividing the global demand forecast (JST, 2022) by the number of data centres currently operating in the country (Data Center Map).
Source: Author.

(c) Solar and wind resources

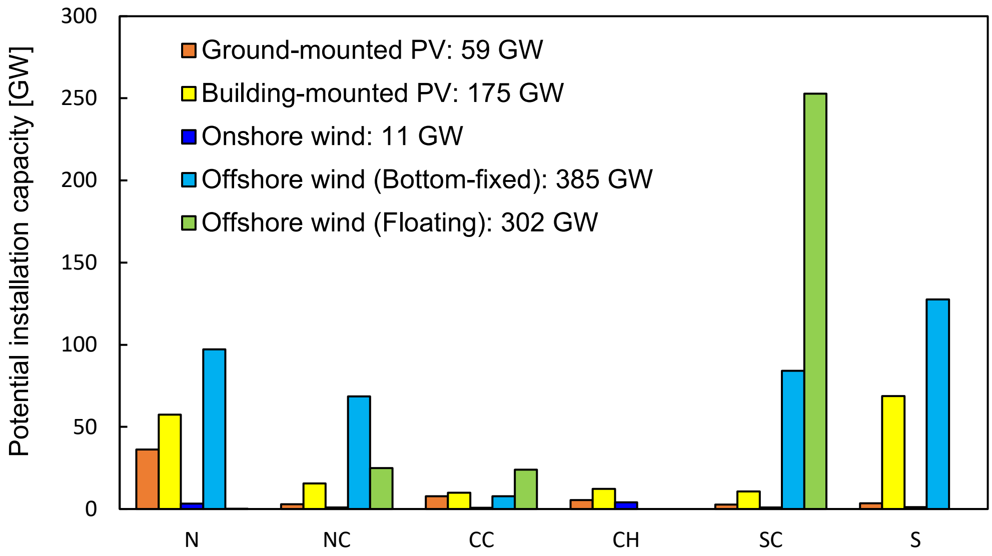
Figure 0.2 summarises the estimated upper limits of solar and wind energy resources. In Viet Nam, areas suitable for solar and wind power energy are mostly concentrated in the northern and south-central regions.

For both PV and wind power, the grid cell (mesh) with the closest average global horizontal irradiance or average annual wind speed was selected from the available areas. Corresponding 4-hourly irradiance and wind data for 2023 were obtained from Renewables.ninja (Pfenninger, S. and I. Staffell) at the latitude and longitude of the selected mesh.

Table 0.3 summarises the annual capacity factors for PV and onshore wind, estimated using hourly data from Renewables.ninja. The onshore wind capacity factor is highest in the central-central and south-central regions, remains around 10% in the north, and falls below 10% in the central highlands. In contrast, capacity factors for PV exhibit less regional variation. The highest PV capacity factor is assumed in the north, and the lowest in the central-central region.

Figure 0.3 shows the annual capacity factors of offshore wind. Capacity factors are not shown for grades with no suitable offshore wind turbine installation locations, such as those with insufficient wind resources. Overall, offshore wind capacity factors are higher in the south-central and southern regions than in other areas.

Figure 0.2. Estimated Upper Limits of Solar and Wind Energy Capacity by Region



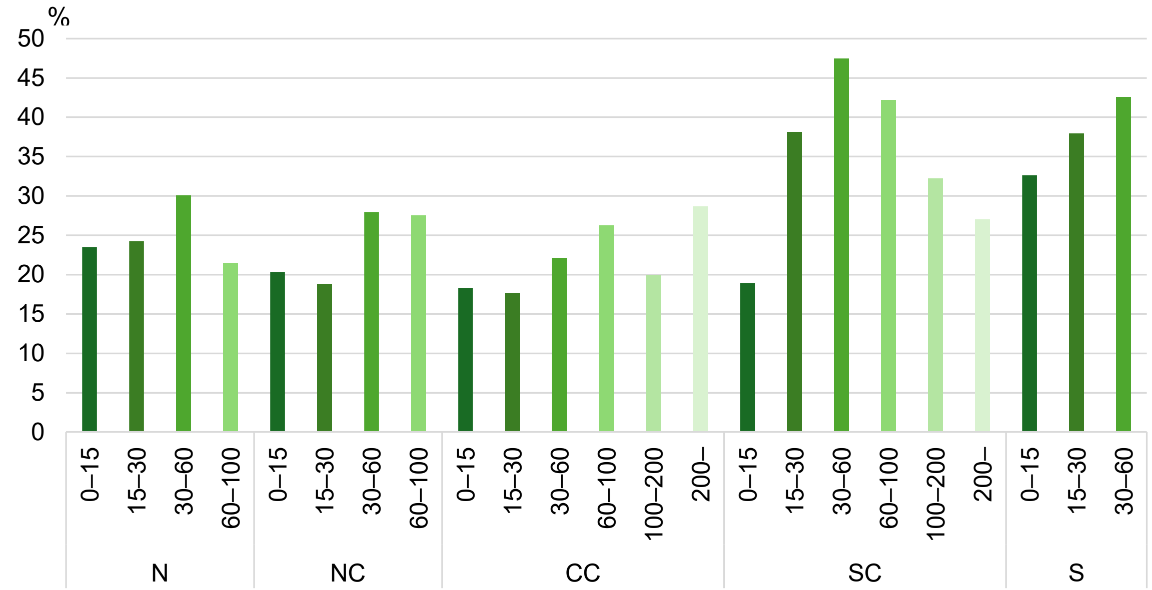
CC = central central, CH = central highlands, GW = gigawatt, N = north, NC = north central, PV =photovoltaic, S = south, SC = south central.
Source: Author.

Table 0.3. Capacity Factors of Solar Photovoltaic and Onshore Wind by Region

Region	Capacity Factor (%)	
	Solar PV	Onshore Wind
N	17.7	10.1
NC	15.5	13.6
CC	15.1	18.1
CH	16.8	8.1
SC	16.3	16.0
S	16.0	14.5

CC = central central, CH = central highlands, N = north, NC = north central, PV = photovoltaic, S = south, SC = south central.
Note: Capacity factors are based on data from Renewables.ninja.
Source: Author.

Figure 0.3. Capacity Factors of Offshore Wind by Region and Water Depth



CC = central central, N = north, NC = north central, S = south, SC = south central.
Note: Capacity factors are based on data from Renewables.ninja. The numbers on the horizontal axis represent water depth. Categories without bars indicate areas where no offshore wind resources are assumed.
Source: Author.

(d) Hydro, geothermal, and biomass resources

The upper limits of hydro, geothermal, and biomass power generation capacity are based on various literature sources (Table 0.4). In this study, biomass energy use in end-use sectors is assumed to remain fixed at the 2017 level.

Table 0.4. Upper Limits of Hydro, Geothermal, and Biomass Power by Region

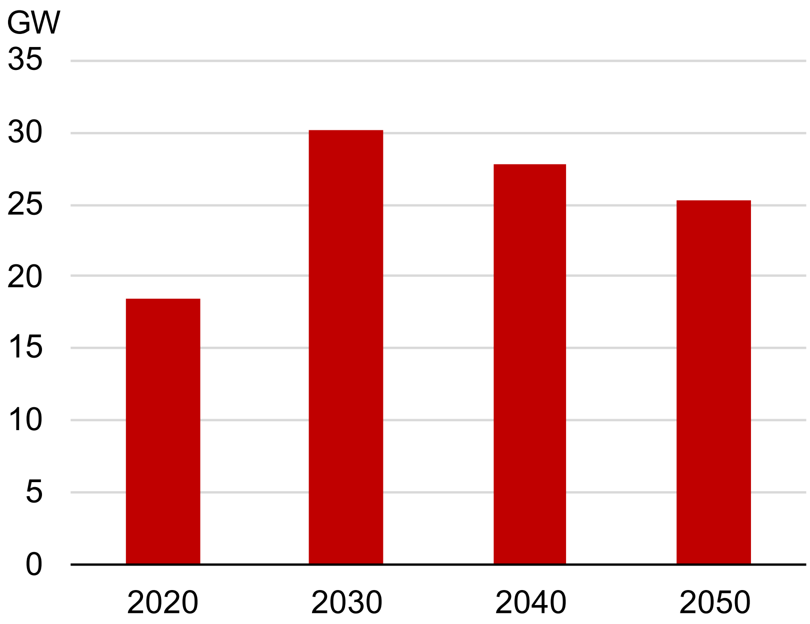
		N	NC	CC	CH	SC	S	Total
Hydropower	GW	17.5	1.9	3.3	8.0	2.8	1.5	35.0
Geothermal power	GW	0.5	0.2	0.1	0.2	0.1	0.3	1.4
Biomass for power	Mtoe	3.3	1.2	0.7	1.5	0.8	1.8	9.3

CC = central central, CH = central highlands, GW = gigawatt, Mtoe = million tonnes of oil equivalent, N = north, NC = north central, S = south, SC = south central.
Note: The total hydropower potential is assumed based on Vietnam Electricity (2019), geothermal on Asian Development Bank (2017), and biomass on Asian Development Bank (2015) and Vietnam Briefing (2018). Regional potentials are estimated by downscaling national totals using existing capacity (for hydro) or land area (for geothermal and biomass). Biomass potential for power includes input for co-firing.
Source: Author.

(e) Existing coal-fired power capacity and operation

In the CN scenario, existing coal-fired power generation is treated as exogenous in both capacity and operation. The coal-fired power capacity is fixed based on the outlook provided in the Power Development Plan VIII (Government of Viet Nam, 2023) (Figure 0.4). These plants are assumed to operate until 2050 to avoid becoming stranded assets. Emissions from coal-fired power generation can be reduced by capturing CO_2 or through co-firing with biomass or ammonia. Co-firing options are prepared at various ratios: 20%, 40%, 60%, 80%, and 100%.

Figure 0.4. Assumed Coal-fired Power Capacity



GW = gigawatt.
Note: For 2050, the lower projection value from the Government of Viet Nam (2023) is used.
Source: Author.

(f) Nuclear power capacity

The upper limit of nuclear power plant capacity is determined based on the previous government's plan (Figure 0.5). This plan identified eight potential sites for the construction of new nuclear power plants, including in Ninh Thuan province in the south and several sites in the central region. This study assumes the deployment of nuclear power capacity in both the southern and the central regions, in line with the potential sites identified. Specifically, it is assumed that eight units – equivalent to the previous Ninh Thuan 1 and 2 projects – will become operational in Ninh Thuan Province by 2050, along with two additional reactors in the central region. In November 2024, the National Assembly approved plans to resume the Ninh Thuan nuclear power project, and the prime minister has expressed expectations for its accelerated completion. Accordingly, the first unit is assumed to become operational around 2030.

Figure 0.5. Potential Site and Assumed Upper Limit of Nuclear Power Capacity

Year	Upper Limit (GW)	
	CC	SC
2030	-	1.2
2040	-	5.0
2050	3.0	10.0

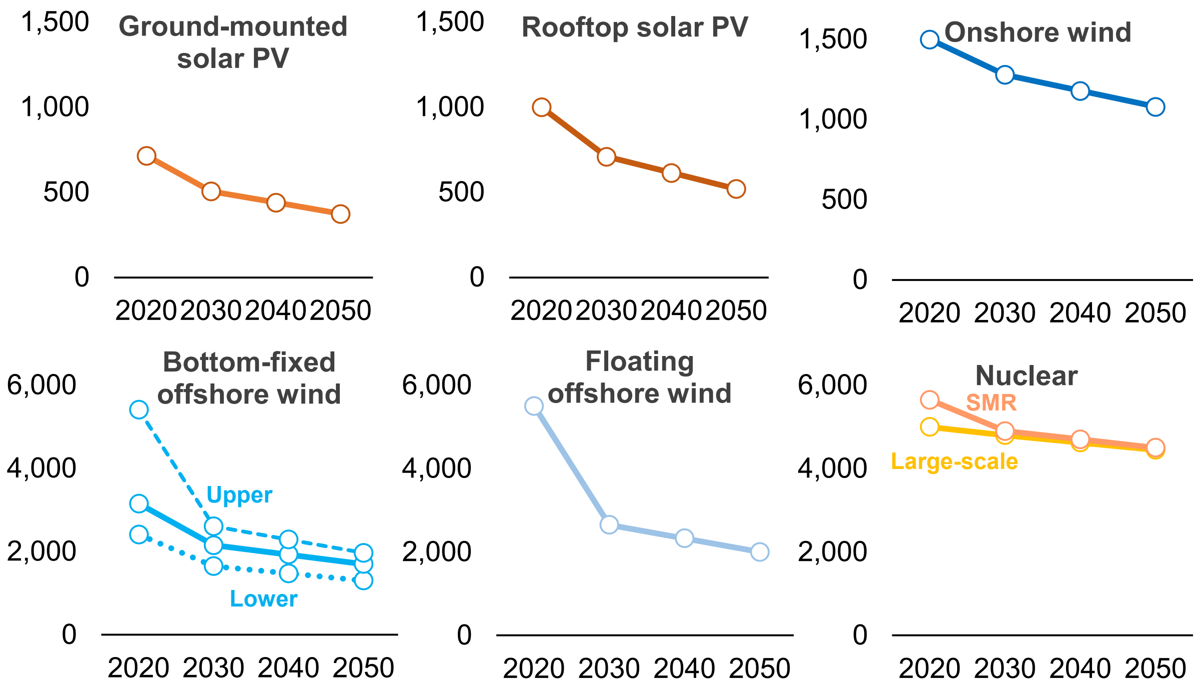
Source: Author's additions to Le (2011) (left), and author (right).

(g) Power generation technology cost

Capital costs for power generation technologies are based on the Viet Nam technology catalogue for power generation (Institute of Energy, Energy Analyses and Danish Energy Agency, 2023) (Figure 0.6). To reflect the range of actual costs, the capital costs of bottom-fixed offshore wind turbines are divided into three grades, according to bathymetry (0–15 m, 15–30 m, and 30–60 m). Current costs are determined based on project surveys (Japan Ship Technology Research Association, 2024).

The levelised cost of electricity (LCOE) for the various technologies in the SC region in 2050 is shown in Figure 0.7. Estimates are based on assumptions of fuel prices, technical specifications, and capacity factors. Coal- and gas-fired power plants equipped with CCS are shown to have lower LCOE than those using H_2 or NH_3 co-firing or dedicated firing. Offshore wind shows lower LCOE than nuclear.

Figure 0.6. Capital Costs of Solar Photovoltaic, Wind Power, and Nuclear Power (US$/kW)

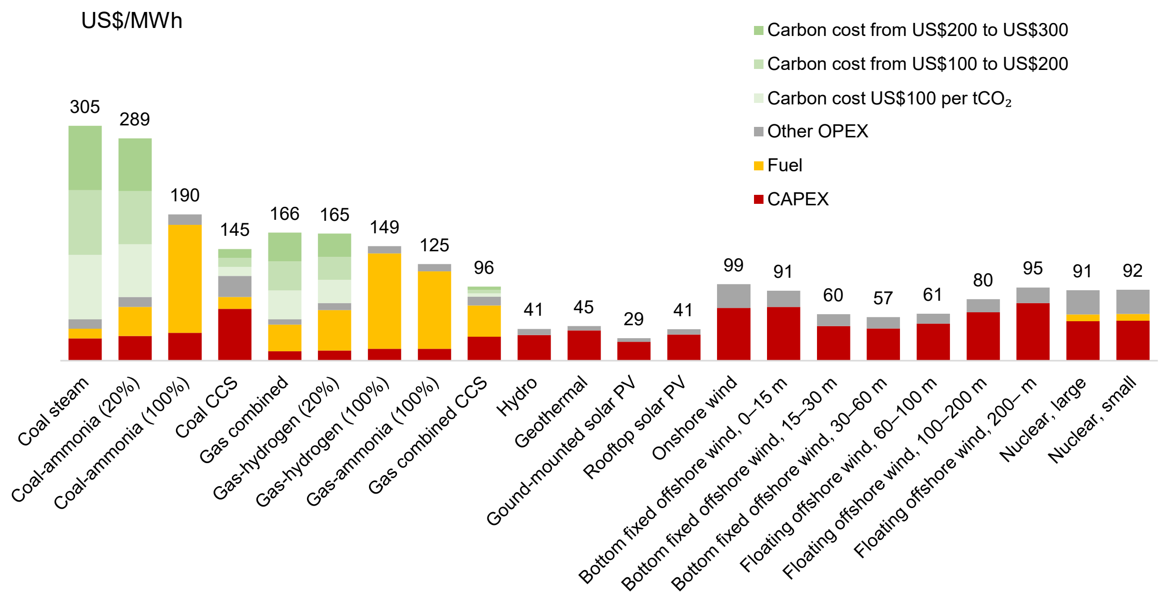


kw = kilowatt, PV = photovoltaic, SMR = small modular reactor.

Note: Prices are 2017 real prices. For bottom-fixed offshore wind, three different capital costs were assumed depending on the water depth.

Source: Author, based on Institute of Energy, Energy Analyses and Danish Energy Agency (2023) and Japan Ship Technology Research Association (2024).

Figure 0.7. Estimated Levelised Cost of Electricity (South Central, 2050)



CAPEX = capital expenditure, CCS = carbon capture and storage, m = metre, MWh = megawatt-hour, OPEX = operational expenditure, PV = photovoltaic.

Note: Prices are 2017 real prices. A discount rate of 8% is applied. All levelised cost of electricity values

represent new-build construction. 'Gas-ammonia' refers to 100% ammonia-firing in retrofitted natural gas turbines. Capacity factors assumed: 60% for thermal, 42% for hydro, 80% for geothermal, 16% for solar PV, 16% for onshore wind, 19%–47% for bottom-fixed offshore wind, 27%–42% for floating offshore wind, and 80% for nuclear. See Section 2.2.3 for fuel prices and Section 5.1.1 (c) for variable renewable energy capacity factors.
Source: Author.

1.12.2. Results

(a) Key energy-related indicators

The main results of the model analysis for energy and emissions are shown in Figure 0.8 through Figure 0.20. The following section outlines these results, proceeding from downstream to upstream across the energy system. The analysis focuses primarily on the carbon neutral (CN) and baseline (BL) scenarios for comparison.

Under the BL scenario, which imposes no emission constraints and allows the expanded use of coal, energy-related CO_2 emissions increase significantly through to 2050 (Figure 0.8). By contrast, the CN scenario limits total emissions to meet reduction targets, particularly achieving substantial early reductions in the electricity sector ahead of the end-use sectors. By 2050, negative emissions technologies, such as BECCS and DACCS, will become cost competitive, offsetting residual emissions from hard-to-abate sectors such as high-temperature industrial processes and heavy-duty transport. The industrial sector also sees notable emission reductions compared with the BL scenario.

In the BL scenario, final energy consumption is estimated to be 3.8 times higher in 2050 than in 2019, driven by robust economic growth. Conversely, under the CN scenario, final energy consumption in 2050 is 9.4% lower than in the BL scenario, owing to advancements in energy efficiency and increased electrification (Figure 0.9). However, the extent of additional energy savings in the CN scenario appears minimal in this cost-minimisation model, as energy-efficient technologies are also adopted in the BL scenario when deemed cost-effective, even in the absence of emission constraints. Concerning the energy mix, electricity consumption increases whilst coal consumption decreases in the CN scenario. Oil consumption remains relatively stable, as the road transport sector exhibits minor differences between the CN and BL scenarios (Figure 0.10). Passenger vehicles will largely shift to battery electric vehicles (BEVs) by 2050, even under the BL scenario. In contrast, buses and trucks begin partially shifting to BEVs after 2040 in the CN scenario.

Electricity demand also increases to accommodate electrolysis and DAC by 2050, alongside rising industrial usage (Figure 0.11). The share of electricity losses increases after 2040, partly due to periods of low demand during which offshore wind-generated electricity is not fully utilised. Gaseous fuels are primarily consumed by industrial boilers and furnaces. Natural gas, excluding non-energy uses, increases significantly from 2030 to 2040 before transitioning to H_2 in 2050. In the CN scenario, the remaining coal consumption – mainly for blast furnaces and cement kilns – declines significantly following CCS deployment after 2040.

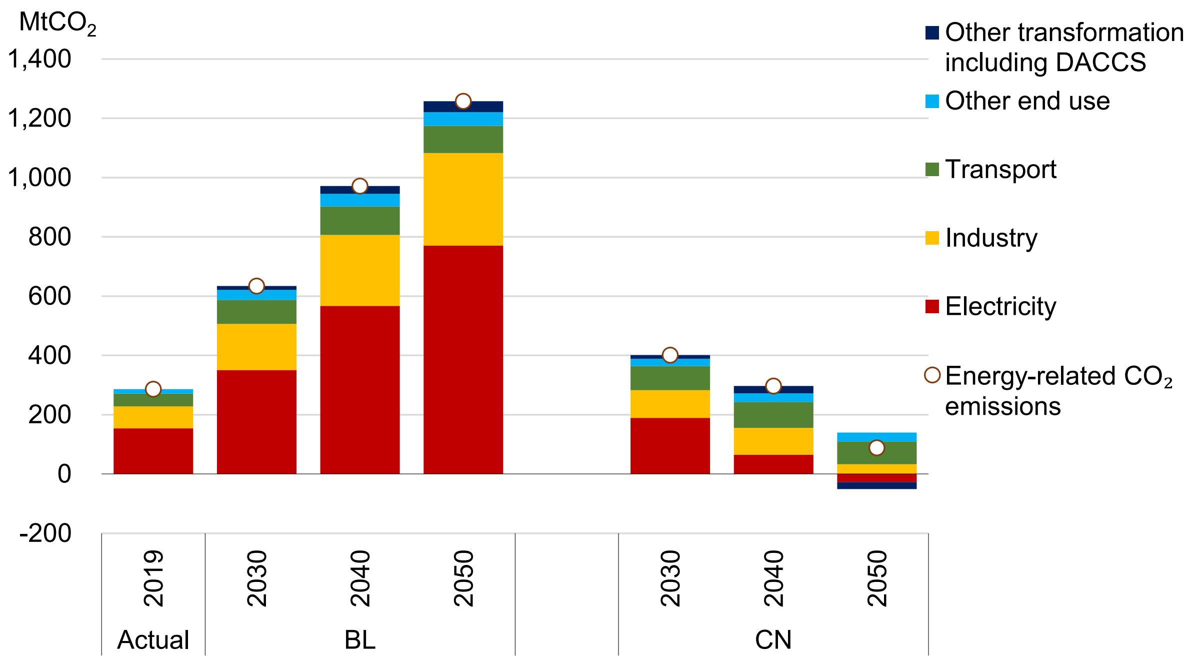
Power generation increases at a much faster pace than total final energy consumption, reaching 5.5 times its 2019 level by 2050 under the CN scenario (Figure 0.12). After 2040, renewables – especially offshore wind and solar PV – dominate the power mix. Gas-fired generation increases from 2030 to 2040, shifting completely to clean thermal power by 2050 (Figure 0.13), with retrofitting of gas plants to ammonia firing or newly installed ammonia firing. Coal-fired power, the capacity and operation of which are assumed exogenously, is decarbonised by equipping all plants with CCS after 2040. Biomass power also adopts CCS (BECCS) after 2040. In the CN scenario, nuclear power is not selected due to the greater cost competitiveness of wind power (Figure 0.14).

Substantial infrastructure investment is required to manage the mass deployment of solar PV and offshore wind. Due to the geographical mismatch between electricity demand and variable renewable energy (VRE) resources, the SC region is projected to become a net electricity exporter by 2050 (Figure 0.15). To achieve this electricity flow, interregional transmission capacity must expand significantly, reaching 5.0 times the 2020 level by 2050 (Figure 0.16). In addition to thermal generation, battery storage is introduced to enhance grid flexibility in response to increasing VRE penetration. Battery storage capacity is projected to reach 188 gigawatt-hours by 2050 (Figure 0.17).

H_2 and NH_3 are mainly supplied through inexpensive imports, with H_2 used in industry and NH_3 in power generation (Figure 0.18). CO_2 is captured from coal-fired power plants, blast furnaces, cement kilns, biomass-fired power plants, and DAC systems (Figure 0.19). Due to limited domestic storage, captured CO_2 is exported to neighbouring ASEAN countries. CCU was not selected for this study due to its high cost.

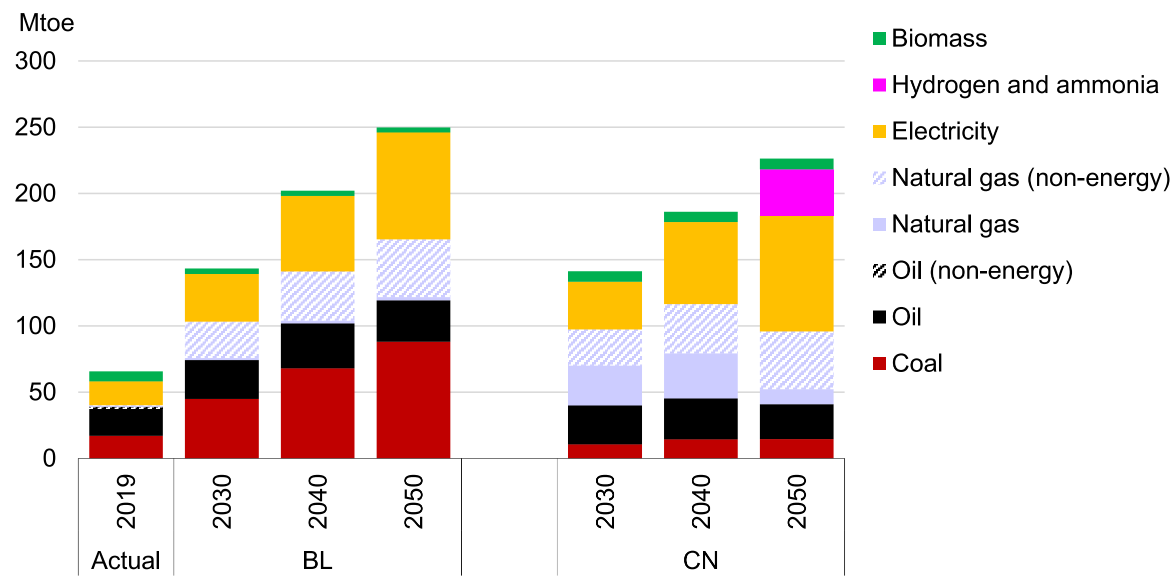
Primary energy supply patterns reflect the changes in final energy consumption and power generation (Figure 0.20). In the CN scenario, the total primary energy supply is much smaller than in the BL scenario due to energy savings and the assumption that solar, wind, and hydro have a conversion efficiency of 100%. The notable increase in natural gas usage in 2030 and 2040 is driven by industrial and power generation demand, including non-energy applications.

Figure 0.8. Sector Energy-related Carbon Dioxide Emissions



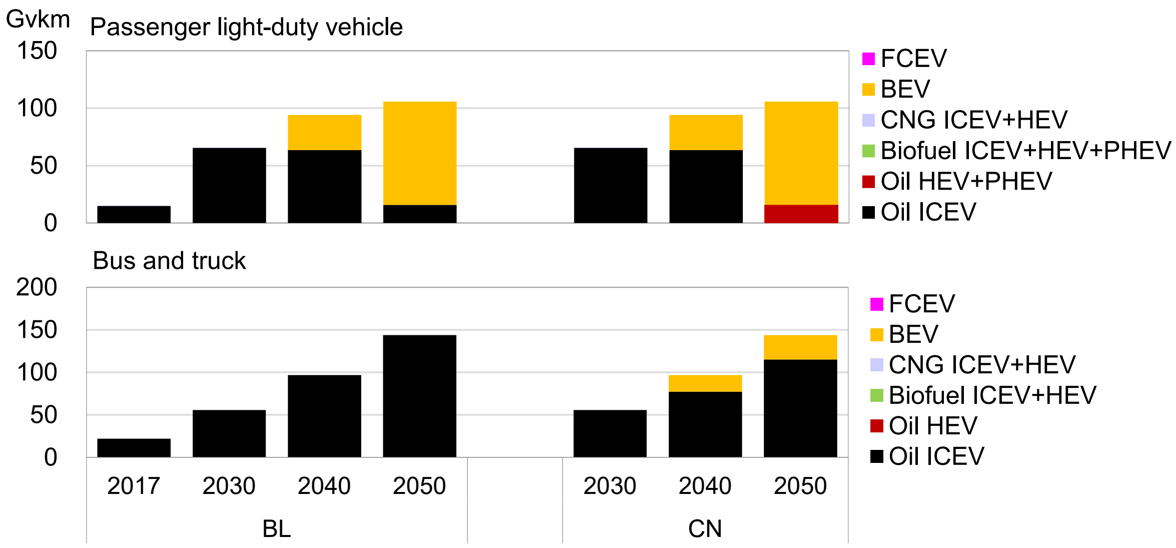
BL = baseline, CN = carbon neutral, DACCS = direct air capture with carbon storage, $MtCO_2$ = million tonnes of carbon dioxide.
Source: Author.

Figure 0.9. Final Energy Consumption



BL = baseline, CN = carbon neutral, Mtoe = million tonnes of oil equivalent.
Source: Author.

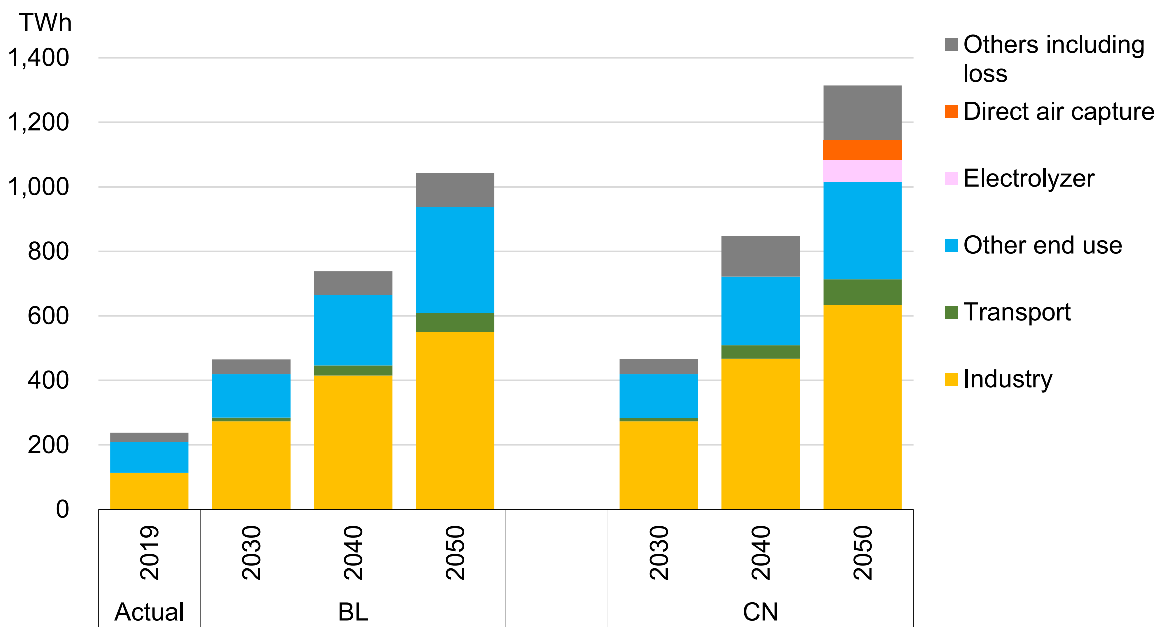
Figure 0.10. Travel Distance by Vehicle Technology



BEV = battery electric vehicle, BL = baseline, CN = carbon neutral, CNG ICEV = compressed natural gas internal combustion engine vehicle, FCEV = fuel cell electric vehicle, Gvkm = giga vehicle-kilometre, HEV = hybrid electric vehicle, PHEV = plug-in electric vehicle.

Source: Author.

Figure 0.11. Electricity Demand

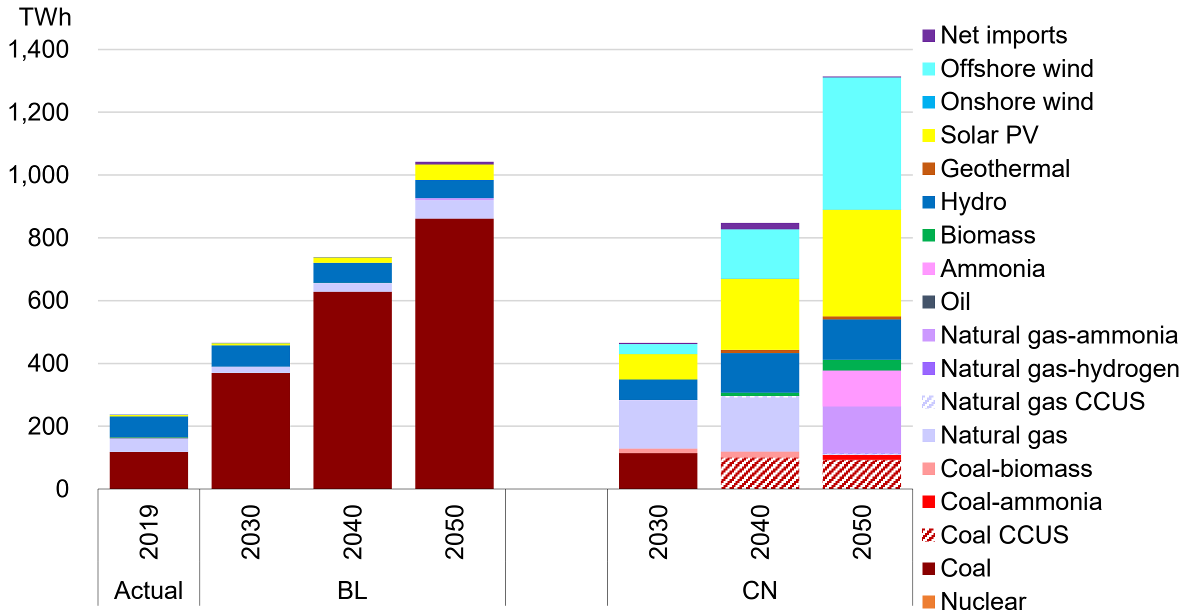


BL = baseline, CN = carbon neutral, TWh = terawatt-hour.

Note: 'Others including loss' is calculated by subtracting the electricity demands of industry, transport, other end-use sectors, electrolysers, and direct air capture from total power generation.

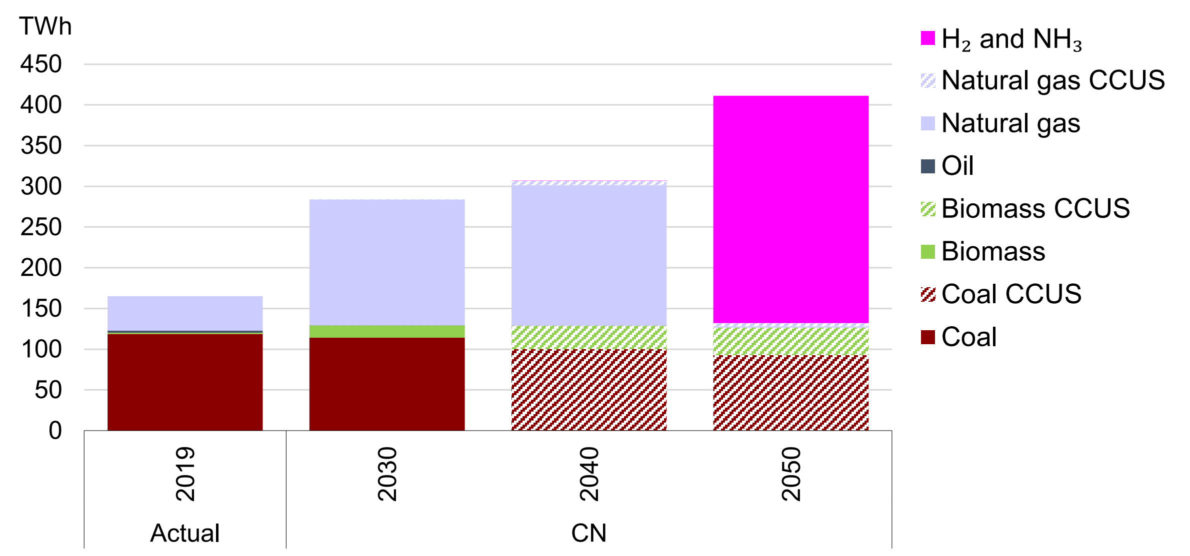
Source: Author.

Figure 0.12. Power Generation by Technology



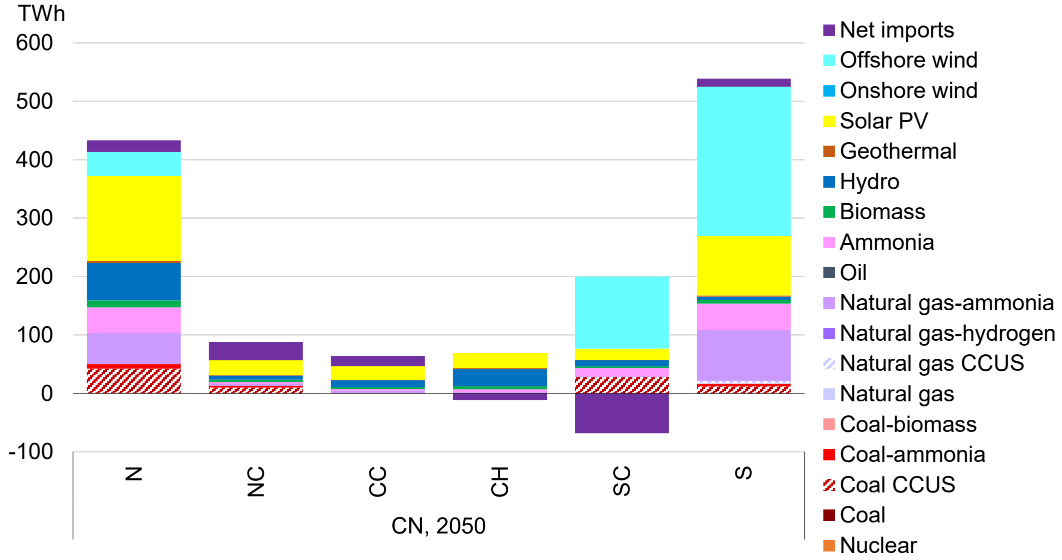
BL = baseline, CCUS = carbon capture, utilisation, and storage, CN = carbon neutral, PV = photovoltaic, TWh = terawatt-hour.
Note: Includes curtailed electricity from variable renewable energy sources. 'Natural gas-ammonia' refers to 100% ammonia firing in retrofitted natural gas turbines.
Source: Author.

Figure 0.13. Thermal Power Generation by Energy Source



CCUS = carbon capture, utilisation, and storage; CN = carbon neutral; H_2 = hydrogen; NH_3 = ammonia; TWh = terawatt-hour.
Source: Author.

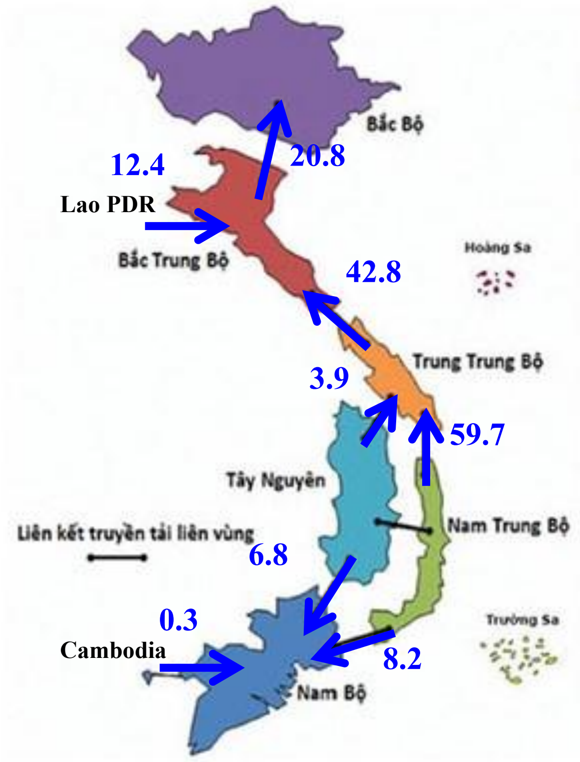
Figure 0.14. Regional Power Generation by Technology in 2050



CC = central central, CCUS = carbon capture, utilisation, and storage, CH = central highlands, CN = carbon neutral, N = north, NC = north central, PV = photovoltaic, S = south, SC = south central, TWh = terawatt-hour.
Note: Includes curtailed electricity from variable renewable energy sources. 'Natural gas-ammonia' refers to 100% ammonia firing in retrofitted natural gas turbines.
Source: Author.

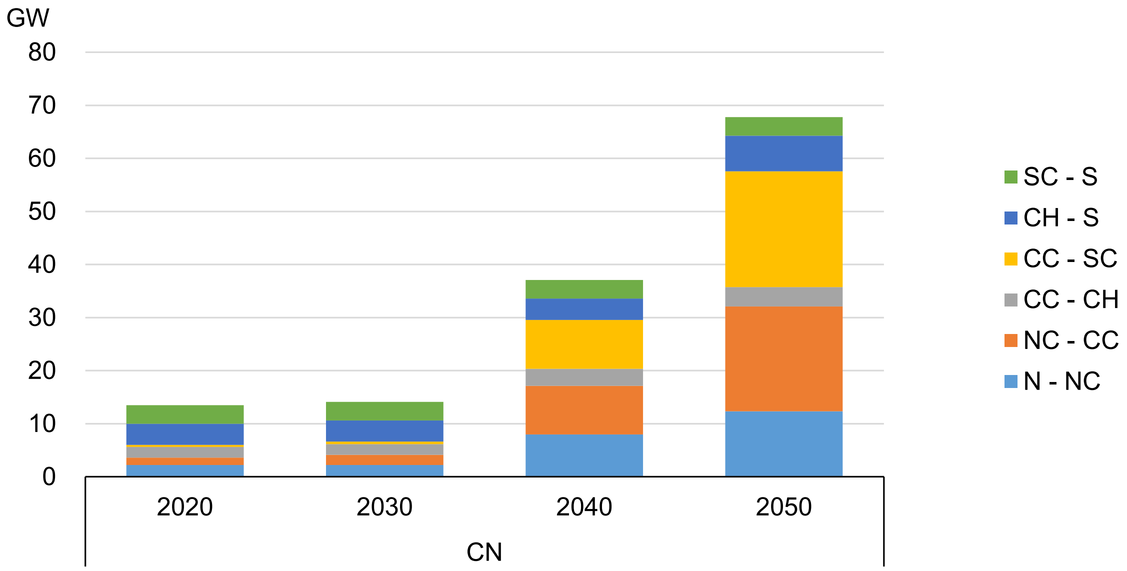
Figure 0.15. Annual Net Electricity Flows in 2050 (TWh)

Carbon neutral



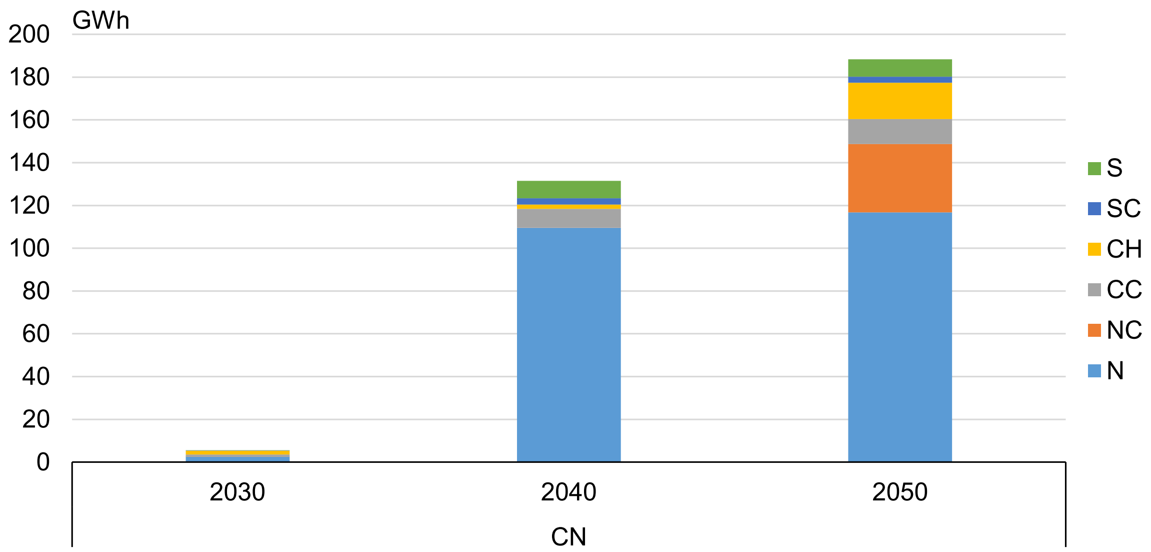
Note: Includes electricity losses during transport.
Source: Author, based on Vietnam Electricity (2020).

Figure 0.16. Transmission Line Capacity



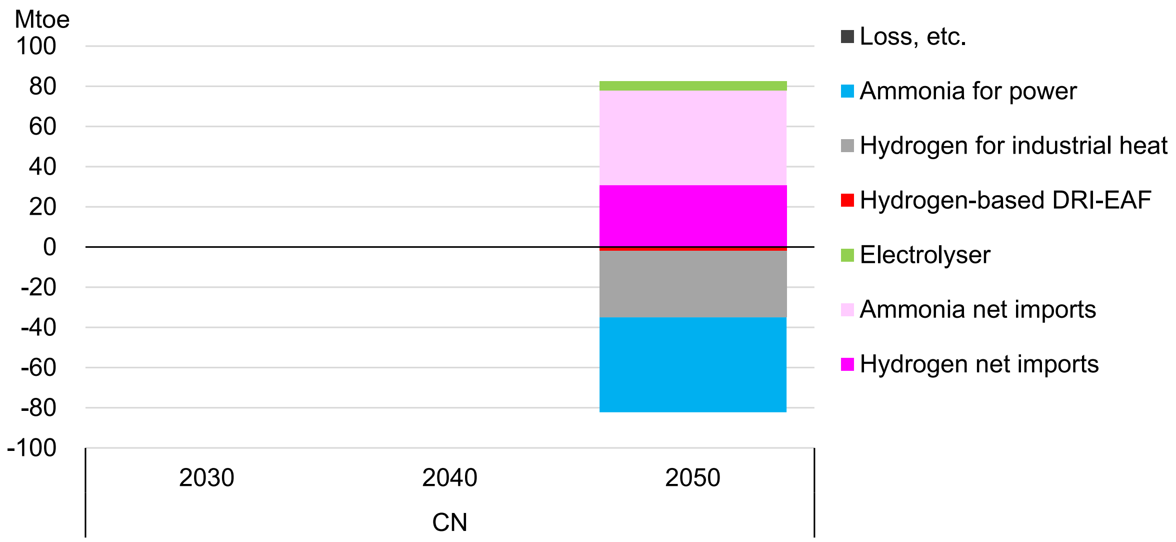
CC = central central, CH = central highlands, CN = carbon neutral, GW = gigawatt, N = north, NC = north central, S = south, SC = south central.
Source: Author.

Figure 0.17. Installed Battery Storage Capacity



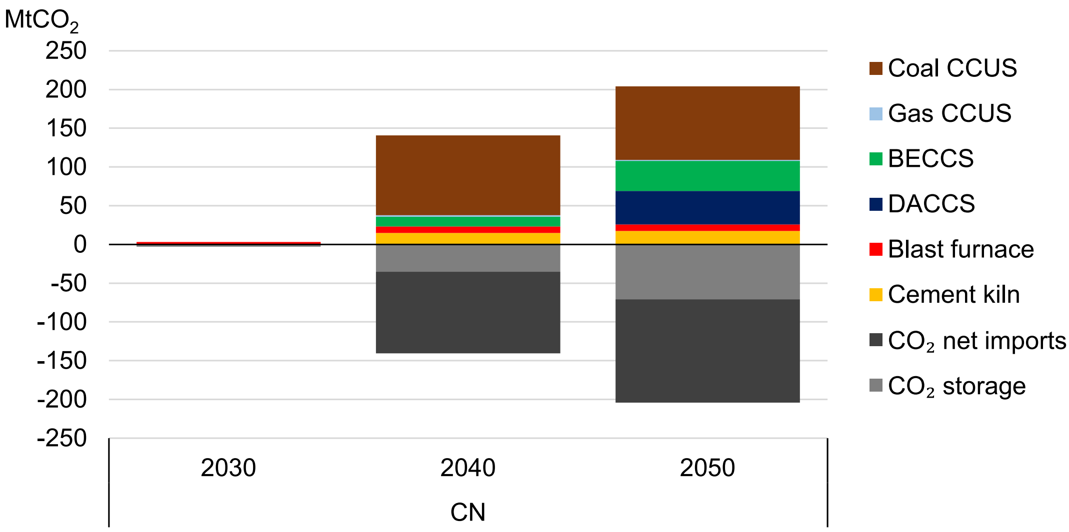
CC = central central, CH = central highlands, CN = carbon neutral, GWh = gigawatt-hour, N = north, NC = north central, S = south, SC = south central.
Source: Author.

Figure 0.18. Supply and Demand of Hydrogen and Ammonia



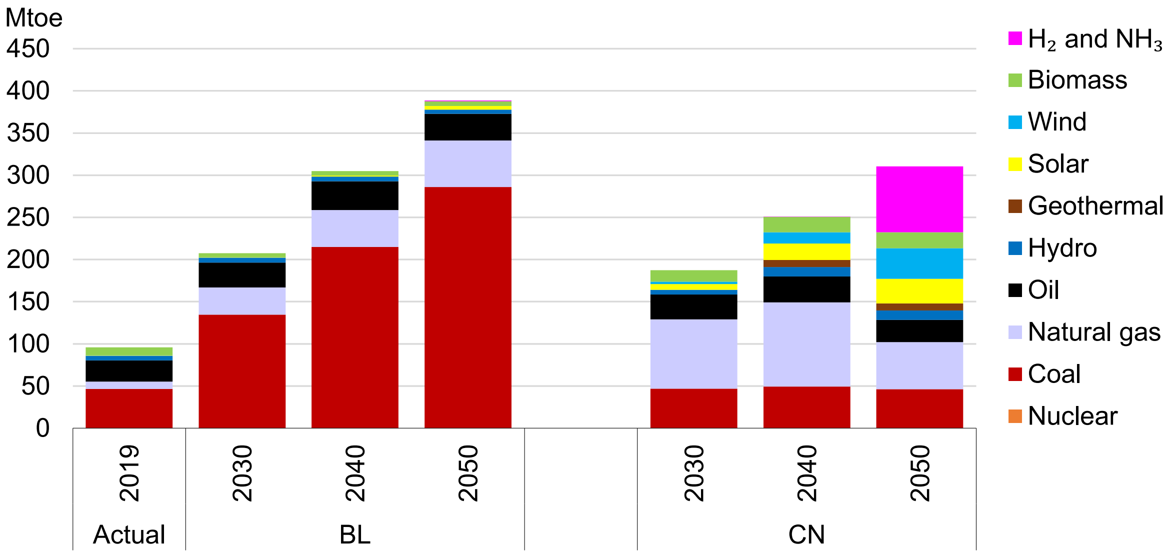
CN = carbon neutral, DRI-EAF = direct reduced iron-electric arc furnace, Mtoe = million tonnes of oil equivalent.
Source: Author.

Figure 0.19. Supply and Demand of Captured Carbon Dioxide



BECCS = bioenergy with carbon capture and storage, CCUS = carbon capture, utilisation, and storage, CN = carbon neutral, CO_2 = carbon dioxide, DACCS = direct air capture with carbon storage, GDP = gross domestic product, $MtCO_2$ = million tonnes of carbon dioxide.
Source: Author.

Figure 0.20. Primary Energy Supply



BL = baseline, CN = carbon neutral, H_2 = hydrogen, Mtoe = million tonnes of oil equivalent, NH_3 = ammonia.
Source: Author.

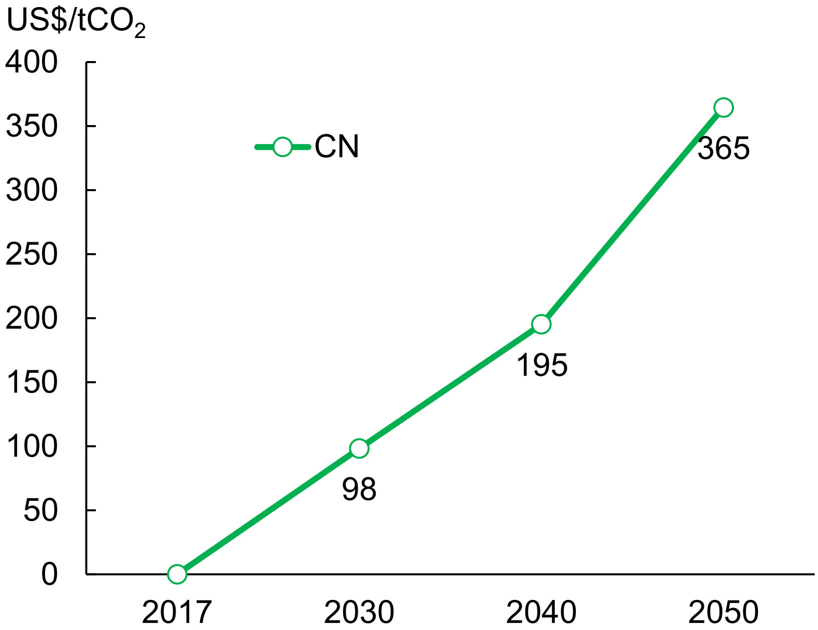
(b) Financial indicators

The marginal abatement cost (MAC) is defined as the cost of reducing an additional tonne of CO_2, and may be interpreted as the theoretical carbon price within the model. In the CN scenario, MAC increases almost linearly, reaching US$365 by 2050 (Figure 0.21), which is higher than the emissions allowance price of US$61 in the European Union Emissions Trading Scheme as of 1 April 2024 (World Bank, 2025).

Marginal electricity costs increase through to 2040, followed by a modest decline in 2050 under the CN scenario (Figure 0.22). Compared with the BL scenario, which relies on low-cost coal-fired power, the marginal electricity cost in 2040 rises by a factor of 2.3. This analysis defines the marginal electricity cost as the average across 2,190 time slots, with each slot's marginal cost reflecting the variable cost of the power source supplying the last kilowatt-hour. The decline in marginal electricity cost in 2050 is primarily due to a lower ammonia fuel price and the inclusion of CO_2 costs – on top of fuel costs – for unabated natural gas-fired power generation in 2040.

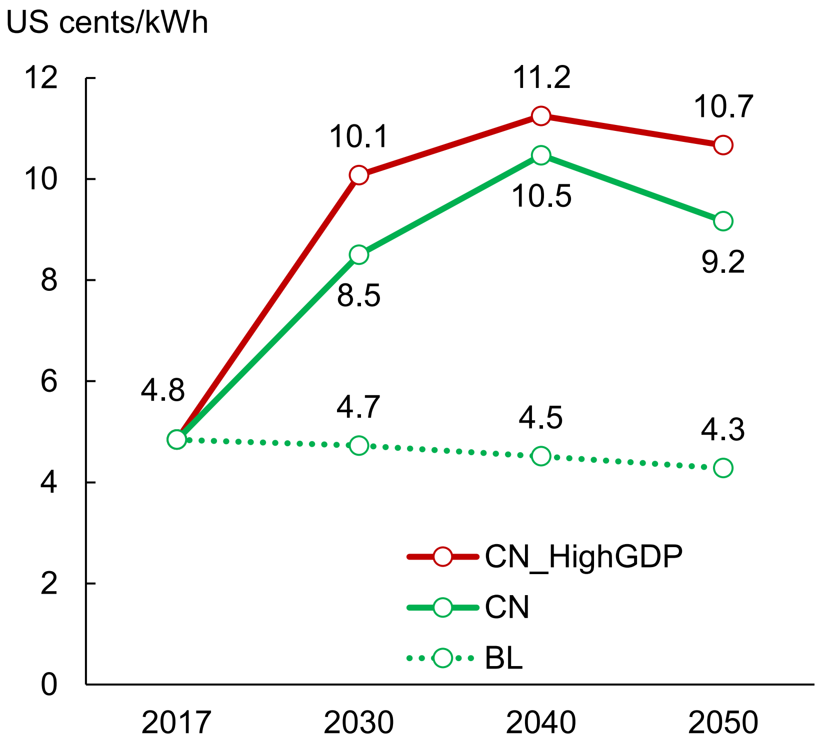
Concerning total cost – represented by the model's objective function – the annual additional costs relative to the BL scenario, expressed as a share of GDP, also rise almost linearly, peaking at 7.2% of GDP in 2050 (Figure 0.23). In that year, fixed costs for VRE and fuel costs for imported H_2 and NH_3 account for a significant share.

Figure 0.21. Marginal Abatement Cost of Carbon Dioxide



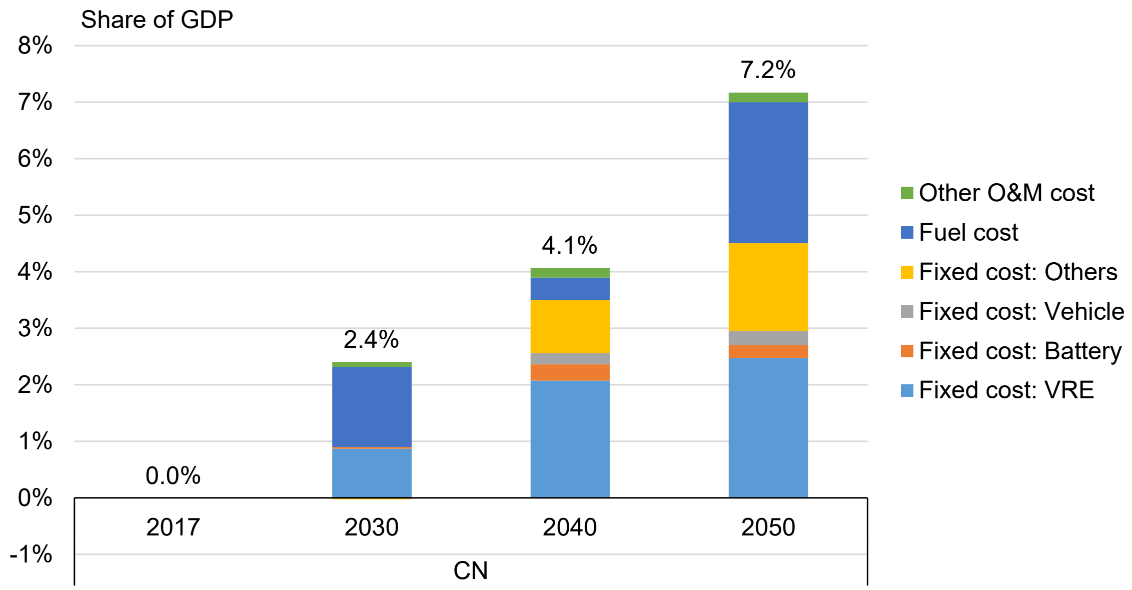
CN = carbon neutral, tCO_2 = tonne of carbon dioxide.
Note: Prices are 2017 real prices.
Source: Author.

Figure 0.22. Marginal Electricity Cost



BL = baseline, CN = carbon neutral, GDP = gross domestic product, kWh = kilowatt-hour.
Note: Prices are 2017 real prices.
Source: Author.

Figure 0.23. Additional Annual Costs from the Baseline



BL = baseline, CN = carbon neutral, GDP = gross domestic product, O&M = operation and maintenance, VRE = variable renewable energy.
Note: Based on 2017 real prices.
Source: Author.

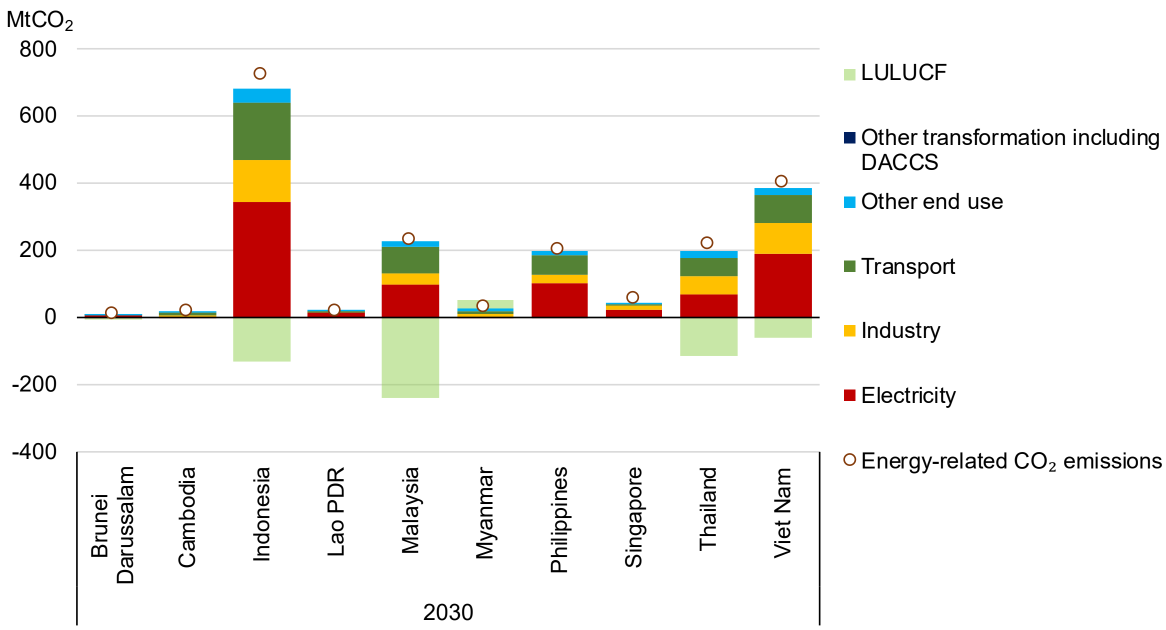
Appendix

This appendix provides a comparative analysis of ASEAN member countries across the various indicators and presents only the CN scenario.

A-1. Carbon dioxide emissions by sector for each country

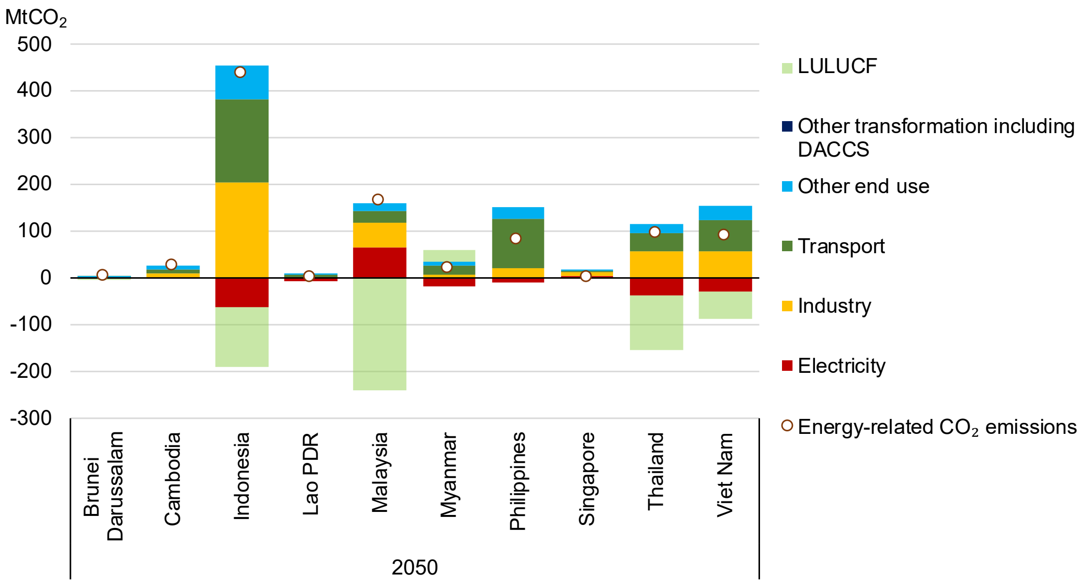
This section presents the results for ASEAN countries, showing comparisons of the CO_2 emissions by sector in 2030, 2050, and 2060. In 2030, the electricity sector accounts for a large part of each country's CO_2 emissions, accounting for approximately half of all emissions in Brunei Darussalam, Indonesia, the Lao PDR, the Philippines, Singapore, and Viet Nam. However, emissions from the electricity sector are estimated to turn negative after 2050. Emissions from end-use sectors will still exist in 2050 and 2060, but will be offset by BECCS and DACCS.

Figure A-1. Carbon Dioxide Emissions by Sector, 2030



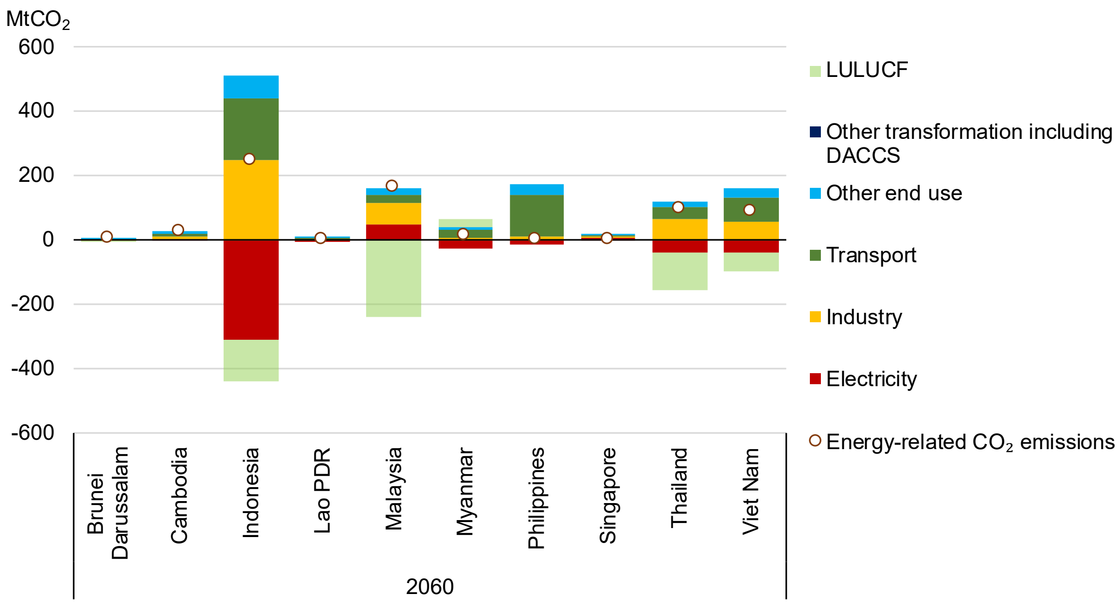
CO_2 = carbon dioxide, DACCS = direct air carbon capture and storage, Lao PDR = Lao People's Democratic Republic, LULUCF = land use, land-use change, and forestry, $MtCO_2$ = million tonnes of carbon dioxide.
Source: Author.

Figure A-2. Carbon Dioxide Emissions by Sector, 2050



CO_2 = carbon dioxide, DACCS = direct air carbon capture and storage, Lao PDR = Lao People's Democratic Republic, LULUCF = land use, land-use change, and forestry, $MtCO_2$ = million tonnes of carbon dioxide.
Source: Author.

Figure A-3. Carbon Dioxide Emissions by Sector, 2060

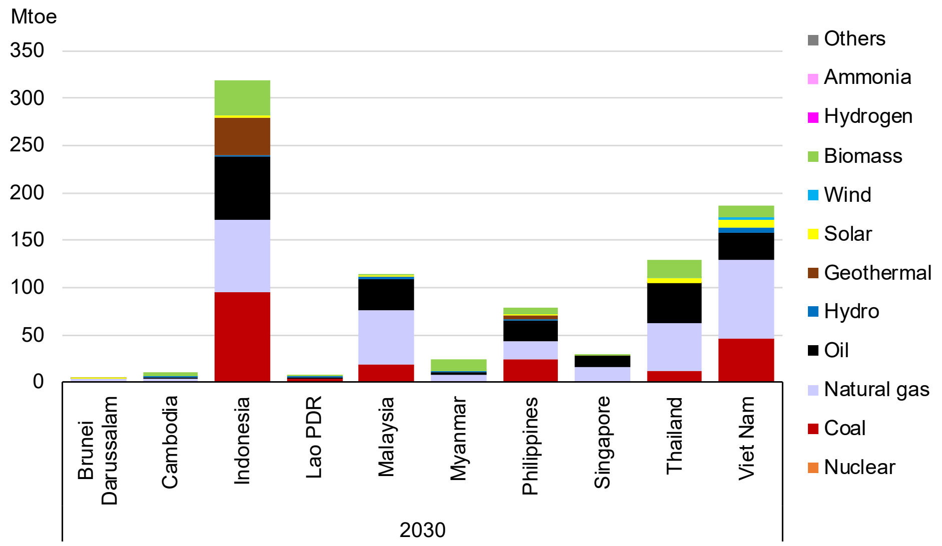


CO_2 = carbon dioxide, DACCS = direct air carbon capture and storage, Lao PDR = Lao People's Democratic Republic, LULUCF = land use, land-use change, and forestry, $MtCO_2$ = million tonnes of carbon dioxide.
Source: Author.

A-2. Primary energy supply by source for each country

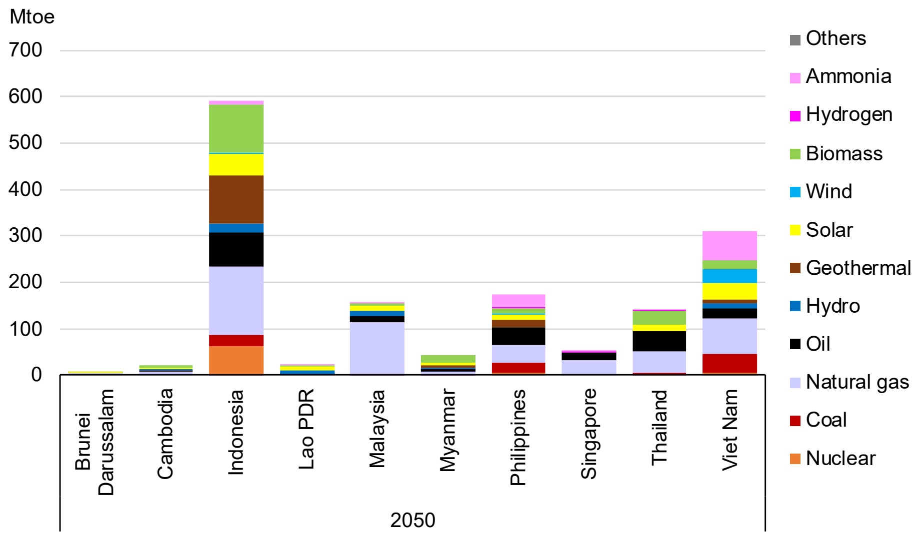
In terms of the primary energy supply across individual countries, the primary energy supply in 2050 is expected to be nearly double that in 2030, except for Brunei Darussalam and Thailand, where overall energy supply levels are expected to remain relatively stable. Coal, natural gas, and oil will each supply approximately 20% to 30% of total energy supply. A comparison of primary energy supply estimations for 2030 and 2050 indicates a substantial reduction in coal and oil, highlighting a shift towards cleaner energy sources.

Figure A-4. Primary Energy Supply by Source, 2030



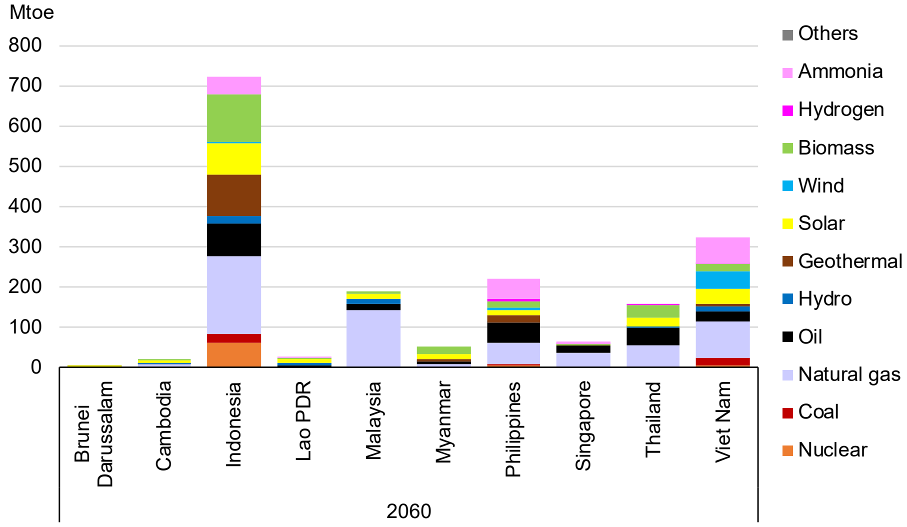
Lao PDR = Lao People's Democratic Republic, Mtoe = million tonnes of oil equivalent.
Source: Author.

Figure A-5. Primary Energy Supply by Source, 2050



Lao PDR = Lao People's Democratic Republic, Mtoe = million tonnes of oil equivalent.
Source: Author.

Figure A-6. Primary Energy Supply by Source, 2060

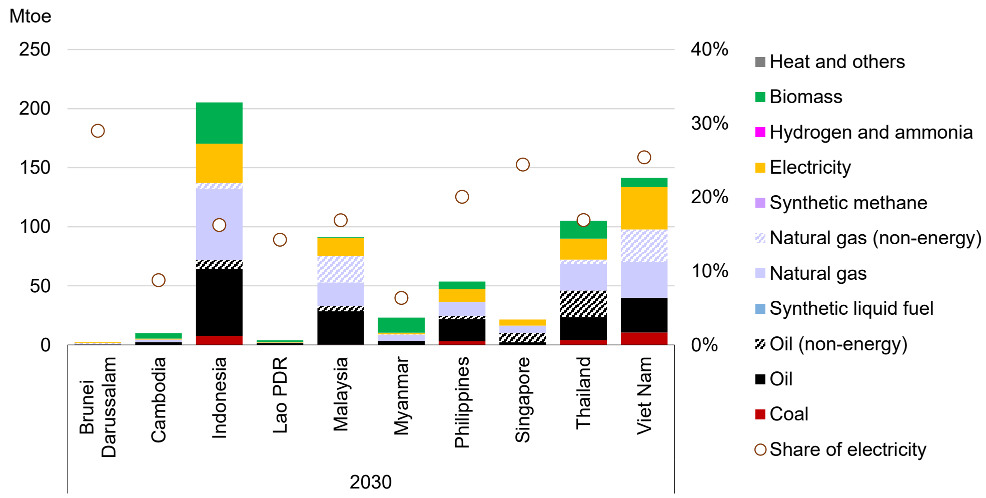


Lao PDR = Lao People's Democratic Republic, Mtoe = million tonnes of oil equivalent.
Source: Author.

A-3. Final energy consumption by source for each country

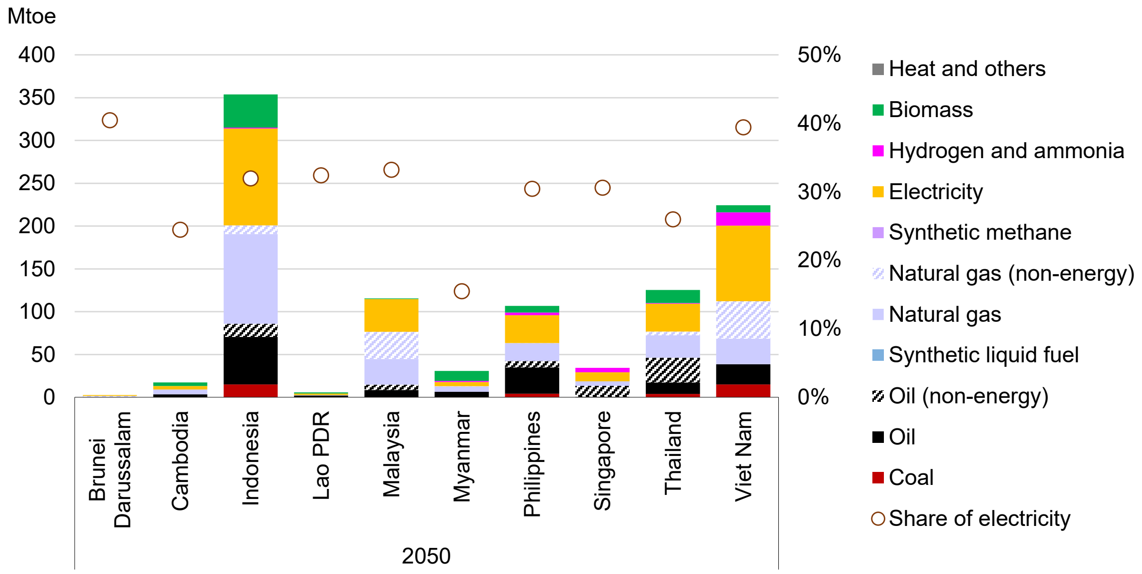
Electricity consumption is estimated to increase significantly across the region. In particular, sharp growth is observed in Cambodia, Indonesia, the Lao PDR, and Myanmar, where demand in 2050 is estimated to exceed three times the levels recorded in 2030. This substantial change is primarily driven by advancements in electrification and improvements in energy efficiency. Natural gas consumption is also anticipated to expand, serving as a transitional energy source that supports the shift towards lower-carbon energy systems whilst maintaining energy security and system flexibility.

Figure A-7. Final Energy Consumption by Source, 2030



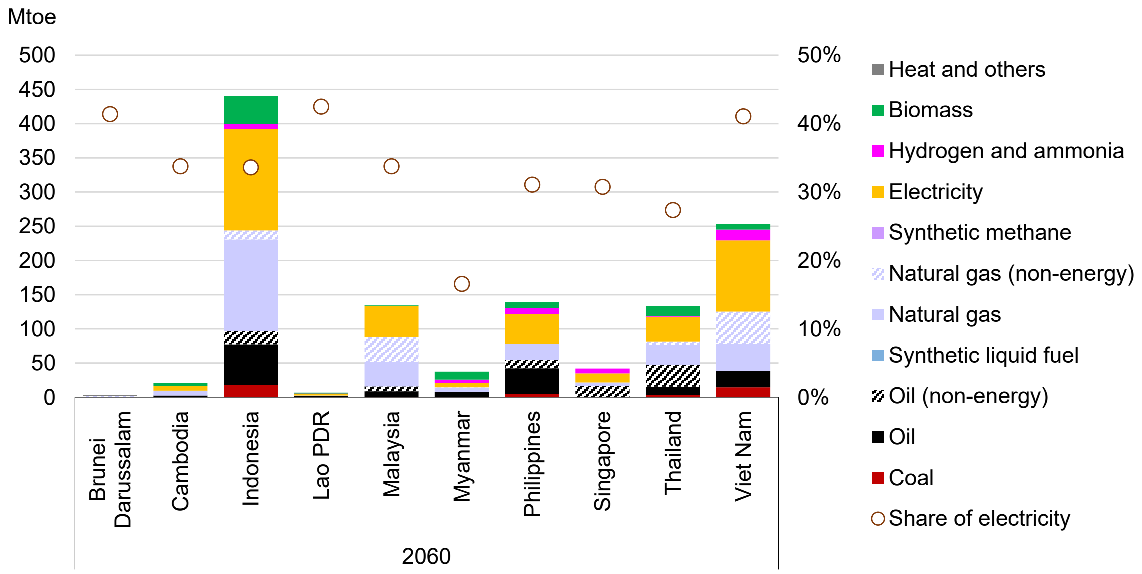
Lao PDR = Lao People's Democratic Republic, Mtoe = million tonnes of oil equivalent.
Source: Author.

Figure A-8. Final Energy Consumption by Source, 2050



Lao PDR = Lao People's Democratic Republic, Mtoe = million tonnes of oil equivalent.
Source: Author.

Figure A-9. Final Energy Consumption by Source, 2060

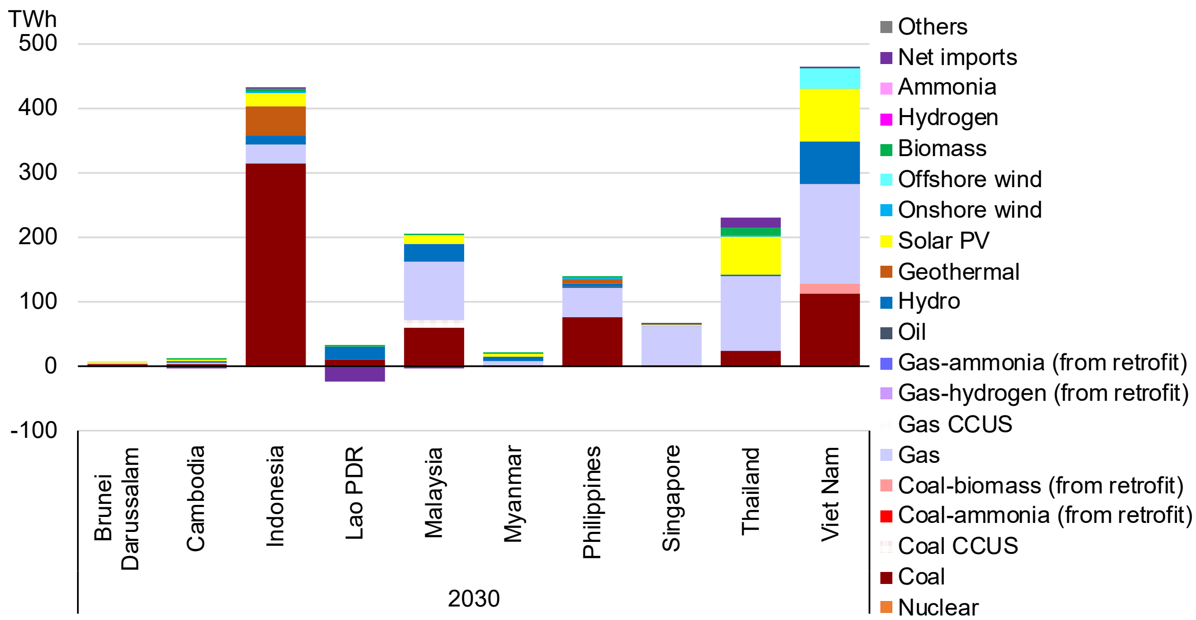


Lao PDR = Lao People's Democratic Republic, Mtoe = million tonnes of oil equivalent.
Source: Author.

A-4. Power generation by technology for each country

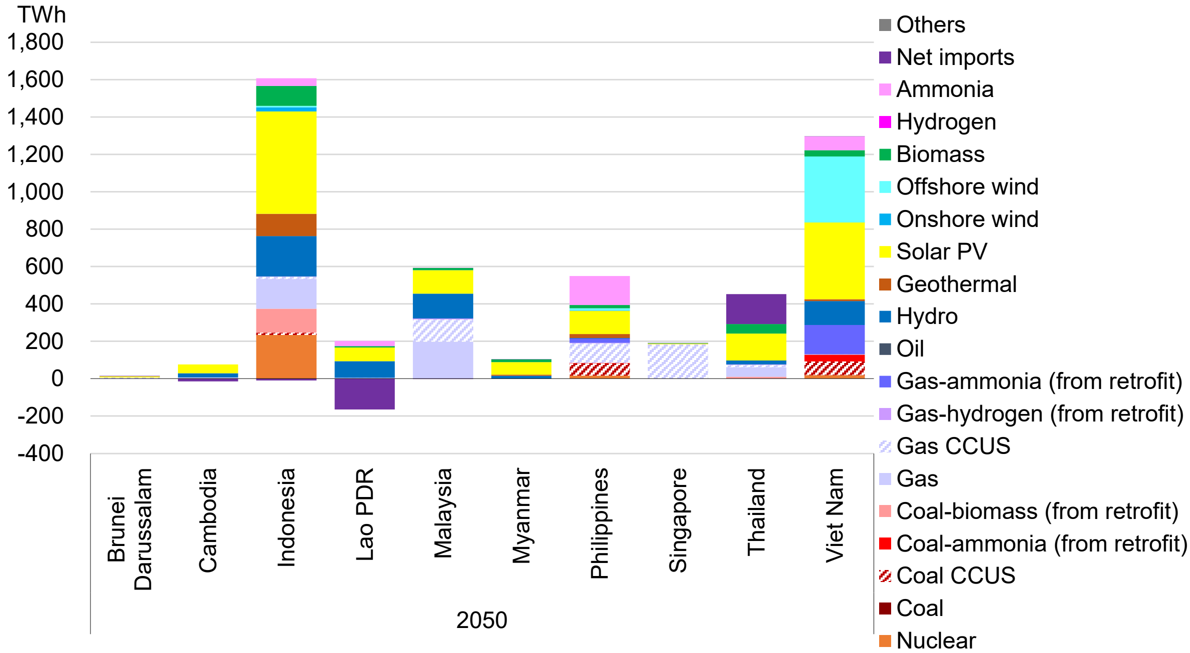
As of 2030, coal-fired power generation remains a significant component of the energy mix. In particular, Indonesia utilises coal for 73% of all generation. By contrast, a substantial phase-out of coal is estimated by 2050. Concurrently, the share of renewable energy continues to expand, with notable growth in solar PV and hydropower. By 2060, offshore wind power is expected to become a prominent and advanced energy source, particularly in the Philippines and Viet Nam. Furthermore, Gas-ammonia co-firing is expected to expand in some countries along with the retrofitting of gas-fired power plants.

Figure A-10. Power Generation by Technology, 2030



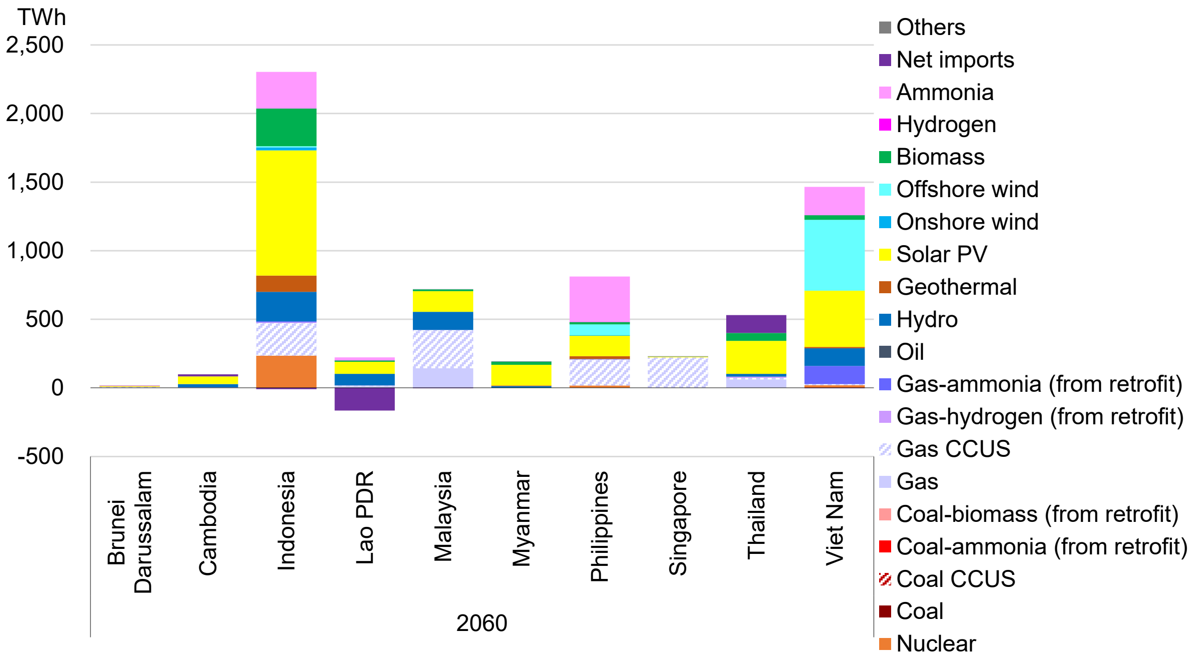
CCUS = carbon capture, utilisation, and storage, Lao PDR = Lao People's Democratic Republic, TWh = terawatt hour, PV = photovoltaic.
Source: Author.

Figure A-11. Power Generation by Technology, 2050



CCUS = carbon capture, utilisation, and storage, Lao PDR = Lao People's Democratic Republic, TWh = terawatt hour, PV = photovoltaic.
Source: Author.

Figure A-12. Power Generation by Technology, 2060

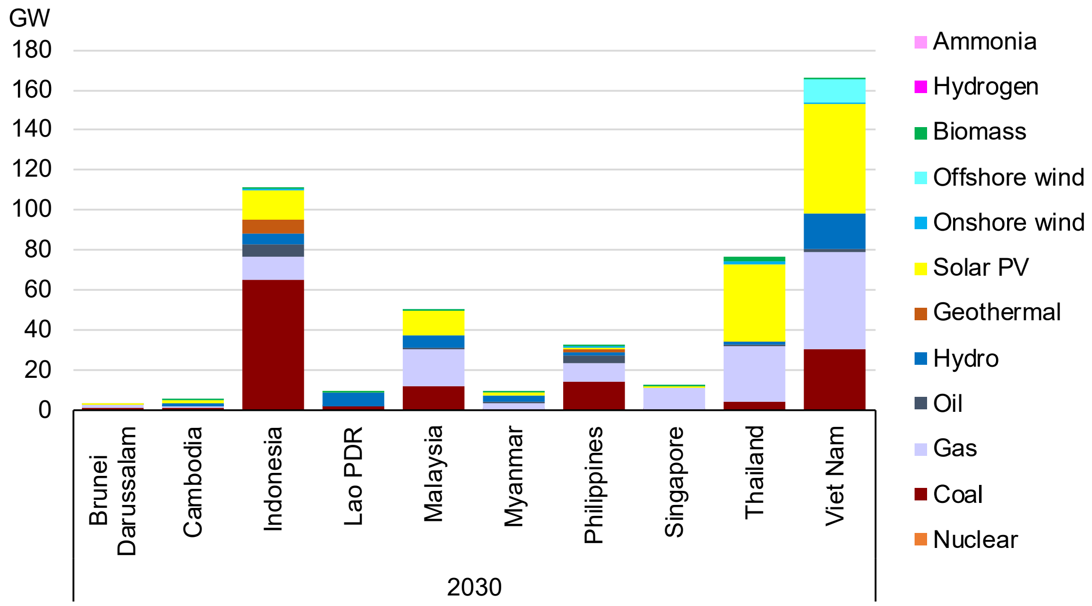


CCUS = carbon capture, utilisation, and storage, Lao PDR = Lao People's Democratic Republic, TWh = terawatt hour, PV = photovoltaic.
Source: Author.

A-5. Power generation capacity for each country

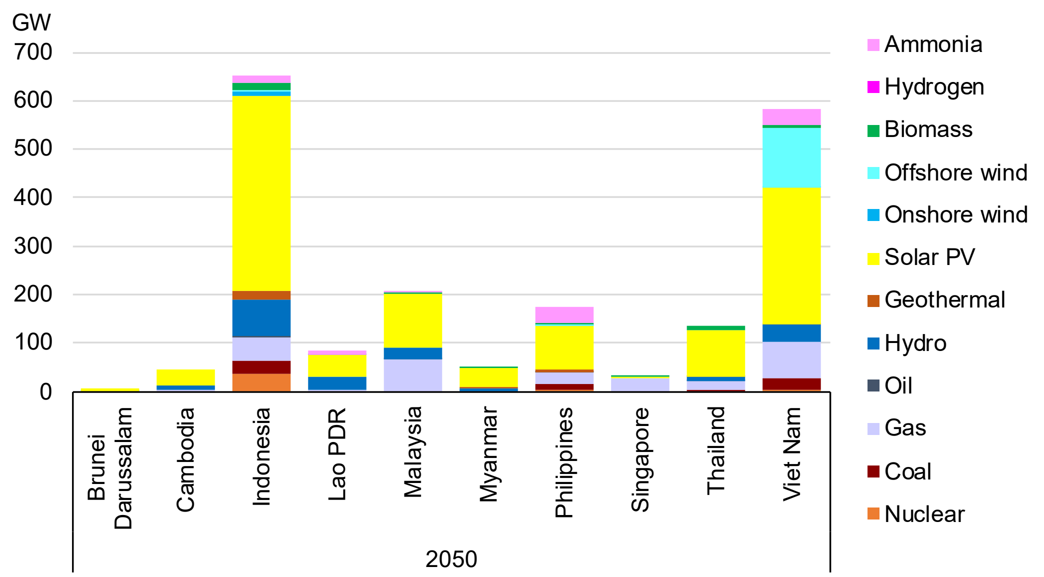
Power generation capacity exhibits the same trend as power generation by technology.

Figure A-13. Power Generation Capacity, 2030



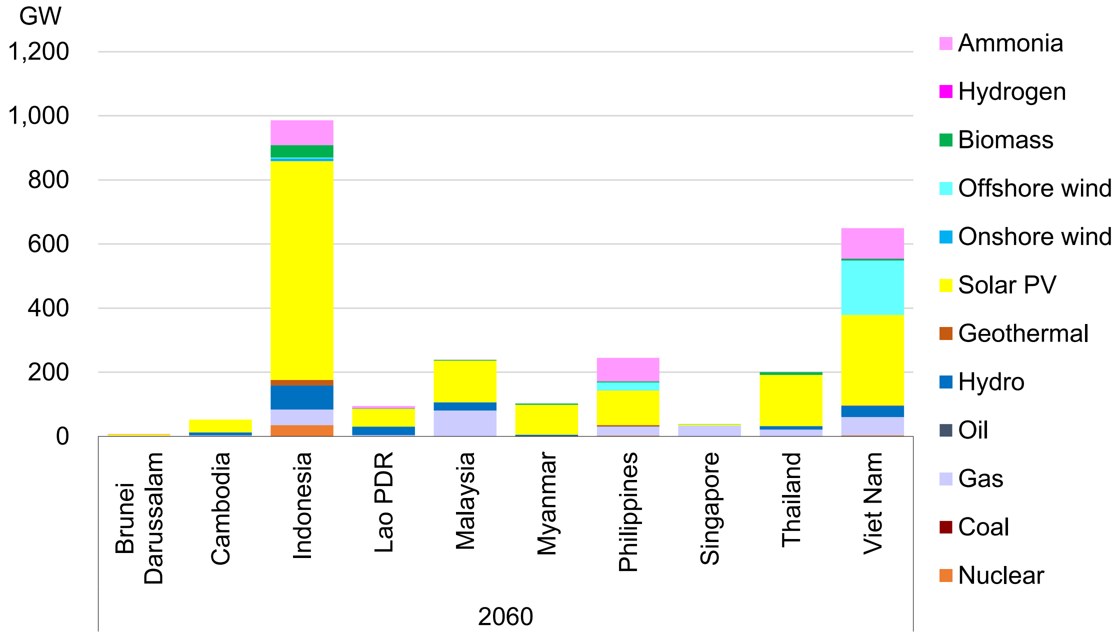
GW = gigawatt, Lao PDR = Lao People's Democratic Republic, PV = photovoltaic.
Source: Author.

Figure A-14. Power Generation Capacity, 2050



GW = gigawatt, Lao PDR = Lao People's Democratic Republic, PV = photovoltaic.
Source: Author.

Figure A-15. Power Generation Capacity, 2060



GW = gigawatt, Lao PDR = Lao People's Democratic Republic, PV = photovoltaic.
Source: Author.

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