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

Updated 2023

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Preface

In 2021–2022, the Economic Research Institute for ASEAN and East Asia (ERIA), in collaboration with the Institute of Energy and Economics, Japan (IEEJ), prepared the *Decarbonisation of ASEAN Energy Systems: Optimum Technology Selection Model Analysis up to 2060* report for the Association of Southeast Asian Nations (ASEAN) region. The report showed the energy transition pathways for ASEAN, including (a) the promotion of energy efficiency and electrification in the final energy consumption sector and (b) shifting from fossil fuel power generation to renewable power sources in the early stages and new energy technologies, such as hydrogen/fuel ammonia and carbon capture, utilisation, and storage in the later stages. In addition, the report suggested the necessity of negative emissions technologies, such as direct air capture with carbon capture and storage (DACCS) and bioenergy with carbon capture and storage (BECCS), after 2040 and forest carbon offsets from 2030.

In 2022–2023, to support ASEAN Member States in the establishment of their carbon-neutral pathways, ERIA and the IEEJ refined the Carbon Neutral Roadmap model that was developed in 2021–2022 to meet their national circumstances, such as economic development level, available energy resources, and potential for renewable energy and carbon dioxide (CO_2) storage. Applying this model, the carbon neutral roadmaps for Thailand, Brunei Darussalam, Malaysia, and the Philippines were produced (Indonesia and Viet Nam were done in 2021–2022) and the results were presented to the countries for comments and suggestions. ERIA/IEEJ reflected the comments and suggestions in each country model. All countries expressed that the model results were useful for preparing their national carbon-neutral pathways and noted their appreciation to ERIA/IEEJ.

On the other hand, the International Energy Agency (IEA) conducted a comparative study between its Announced Pledge Scenario (APS) of the *World Energy Outlook 2022* and the *Carbon Neutral Roadmap* for ASEAN prepared by ERIA/IEEJ and published the comparative report, *Decarbonization Pathways for Southeast Asia*. According to the report, the major difference between them is the economic growth assumption. The IEA assumption is lower than that of ERIA/IEEJ, and consequently, the IEA's future energy demand is also lower than that of ERIA/IEEJ. Thus, the IEA considered that aggressive Energy Efficiency and Conservation and renewable energy would have key roles in achieving carbon neutrality. On the other hand, ERIA/IEEJ considered that the continuous use of fossil fuels with hydrogen or CCS would be important.

ERIA/IEEJ wants to expand this approach beyond ASEAN, such as to South Asia, including India, so ERIA/IEEJ conducted a preparatory study for applying a cost minimum model to India, which consisted of studies on the current energy demand situation and power generation, the power development plan (PDP), renewable energy potential, CO_2 storage potential, and so on.

ERIA hopes this report will become a good reference for the six ASEAN countries to prepare their national plans for carbon neutral pathways and roadmaps to implement the promotion of EEC, electrification, and renewable energy, and increase knowledge of hydrogen/fuel ammonia and CCUS with support from the international society.

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List of Abbreviations and Acronyms

ASEAN	Association of Southeast Asian Nations
BECCS	bioenergy with carbon capture and storage
BEV	battery electric vehicle
CO_2	carbon dioxide
CCS	carbon dioxide capture and storage
CDR	carbon dioxide removal
DAC	direct air capture
DACCS	direct air capture with carbon storage
ERIA	Economic Research Institute for ASEAN and East Asia
FCEV	fuel cell electric vehicle
GDP	gross domestic product
GHG	greenhouse gas
GIS	geographic information system
GW	gigawatt
H_2	hydrogen
IEA	International Energy Agency
IEEJ	Institute of Energy Economics, Japan
IEEJ-NE	IEEJ-New Earth
LULUCF	land use, land-use change, and forestry
MAC	marginal carbon dioxide abatement cost
$MtCO_2$	million tonnes of carbon dioxide
Mtoe	million tonnes of oil equivalent
NH_3	ammonia
Nm^3	normal cubic metre
PV	photovoltaic
t	tonne
VRE	variable renewable energy

Glossary

Baseline	A case with no CO_2 emission target
CCSInov	A case of technological innovation that considers cost reduction of DAC and larger CO_2 storage capacity
CN2050/2060	A case of net-zero CO_2 emissions in 2050 or 2060 that considers carbon sinks
Combo	A case of technological innovation that considers all assumptions mentioned
DemInov	A case of technological innovation that considers the cost reduction of advanced end-use technologies
H_2Inov	A case of technological innovation that considers the cost reduction of technologies related to the supply and demand of H_2
PowInov_PHL	A case of technological innovation for the Philippines, which considers the cost reduction of lithium-ion batteries and expansion of the international power grid
PowInov_THA	A case of technological innovation for Thailand, which considers the cost reduction of lithium-ion batteries and expansion of the international power grid

Chapter 1
Background

Many countries have announced highly ambitious medium- to long-term greenhouse gas (GHG) emission reduction targets. The decarbonisation movement is expected to spread across not only developed countries but also many other countries, including Association of Southeast Asian Nations (ASEAN) Member States, which have presented or are expected to present ambitious GHG emission reduction targets, including carbon-neutral declarations. Asian countries are still highly dependent on fossil fuels and, unlike Europe, are not blessed with abundant wind resources. At the same time, Russia's invasion of Ukraine has dramatically increased natural gas prices, making it difficult to reduce carbon dioxide (CO_2) emissions, particularly in the electricity sector, by fuel switching from coal to natural gas in the region. Accelerating decarbonisation whilst maintaining economic growth is not straightforward.

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 how to minimise the additional costs of transforming the energy supply–demand structure by using a cost-optimal technology selection model, which evaluates combinations of energy technologies.

This study uses a single model covering 10 ASEAN countries. In analysing the model, we discussed energy policies and the actual situations with the ASEAN governments and, on that basis, considered the assumptions for the analysis and priorities of technologies to be introduced. The study is merely a second opinion to support ASEAN countries as they develop their own road maps for energy transition towards carbon neutrality. We will review our assumptions and reflect the latest data in the model analysis when the expected cost reduction of each technology is updated by international organisations and research institutes.

Chapter 2
Methodology

2.1. IEEJ–NE model

We conducted an analysis using an optimum technology selection model (the Institute of Energy Economics, Japan [IEEJ]–<New Earth> [NE] model) developed by Otsuki et al. (2022, 2019) encompassing the entire energy system. The analysis covers the 10 ASEAN countries from 2017 to 2060,[1] with representative years 2017, 2030, 2040, 2050, and 2060. We considered energy-related CO_2.

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

The modelling of the end-use sectors is based on data from the ERIA outlook, the IEA energy balance table, and the IEEJ outlook. However, some sectors were not simulated due to a lack of data in the public domain (Figure 2.2).

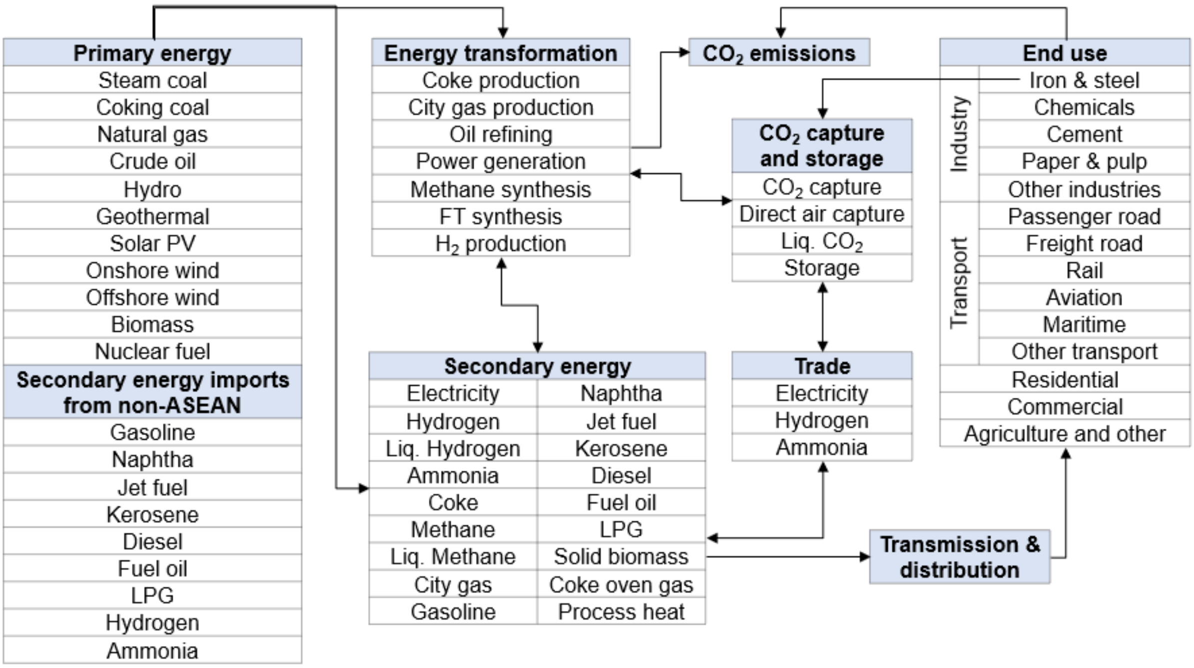
[1] Brunei Darussalam, Cambodia, Indonesia, the Lao PDR, Malaysia, Myanmar, the Philippines, Singapore, Thailand, and Viet Nam.

Table 2.1. Selected Clean Technologies in the Model

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

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

Figure 2.1. Modelled Energy System



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

Figure 2.2. Data Availability for Modelled End-use Sectors

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

BRN = Brunei Darussalam, KHM = Cambodia, IDN = Indonesia, LAO = Lao People's Democratic Republic, LDV = light-duty vehicle, MYS = Malaysia, MMR = Myanmar, PHL = Philippines, SGP = Singapore, THA = Thailand, VNM = Viet Nam.

Note: The manufacturing processes for iron and steel for each country are based on the World Steel Association (2019). The assumptions on cement, such as the efficiency for each country, are based on Global Cement and Concrete Association (2019).

Source: Author.

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

$$\boldsymbol{min\ TotalCost} = \sum_{y}\sum_{r}\sum_{i}\left(\boldsymbol{Fix}_{y,r,i} + \boldsymbol{Fuel}_{y,r,i} + \boldsymbol{Variable}_{y,r,i}\right)\cdot \boldsymbol{R}_{y} \qquad (1)$$

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

Typical constraints include the CO_2 emissions in representative years, the power supply–demand balance at each time slice, the upper limit on the introducible amount of each power source, and the load curve (see Otsuki et al. [2022, 2019]). To balance the supply and demand of electricity even when solar PV and wind power plants are not operating, electricity must be discharged from storage batteries, H_2-/NH_3-fired power generation, or other thermal power generation operated with CCS.

In the model, the power supply–demand is divided by a 4-hour time resolution to express the fluctuation of renewable energy output and the necessary amount of absorption means. One year for power supply–demand was split into 2,190 time slices (4-hour resolutions).

The model explicitly simulates co-firing thermal power generation at existing and new power plants, that is, co-firing coal and NH_3 and co-firing gas and H_2. The modelled technologies are as follows: coal-fired power generation; co-firing coal and biomass (20%); co-firing coal and NH_3 (20%); integrated coal gasification combined cycle (IGCC); gas-fired power generation; gas combined (cycle power generation); co-firing gas and H_2 (H_2: 20%, 40%, 60%, 80%); oil-fired power generation; hydropower; geothermal; solar PV; onshore and offshore wind power; biomass-fired; nuclear power; H_2-fired (available after 2050); NH_3-fired (available after 2050); pumped hydropower; lithium-ion battery; and H_2 tank.

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

Table 2.2. Supply and Demand of Hydrogen and Ammonia

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

FCEV = fuel cell electric vehicle, H_2 = hydrogen, NH_3 = ammonia.
Note: H_2 heat is assumed in the iron and steel and chemical industries.
Source: Author.

The model considers negative-emission technologies, namely DACCS and BECCS. Direct air capture (DAC) enables capturing CO_2 directly from the atmosphere. The captured CO_2 is either permanently stored in deep geological formations (negative emissions) or used to manufacture synthetic fuels by combining it with H_2 (carbon recycling). Seventeen DAC plants operate all over the world and capture less than 10,000 tonnes of CO_2 per year (IEA, 2023a). DAC requires a large amount of energy, and its cost is extremely high, at US$600 per tonne of carbon dioxide (tCO_2). With high carbon prices aiming to achieve carbon neutrality, however, DAC may be cost-competitive. Table 2.3 lists the cost assumptions for DAC in the model.

Table 2.3. Cost Assumptions for Direct Air Capture in 2050

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

MWh = megawatt-hour, O&M = operation and maintenance, tCO_2 = tonnes of carbon dioxide.
Note: Total capturing cost depends on the electricity price. In this table, the capturing cost is assumed to be US$0.1 per kilowatt-hour.
Source: Author.

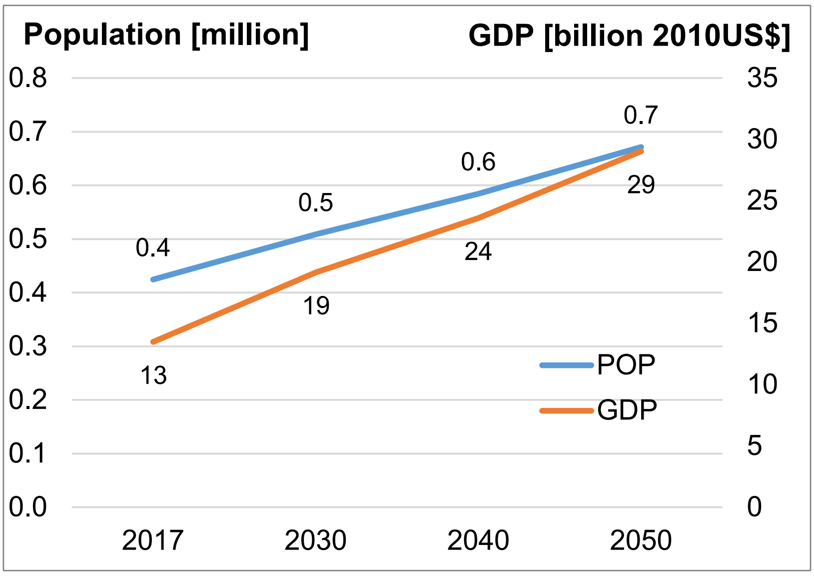
2.2. Preconditions

2.2.1. Key Assumptions

(a) Economic indicators

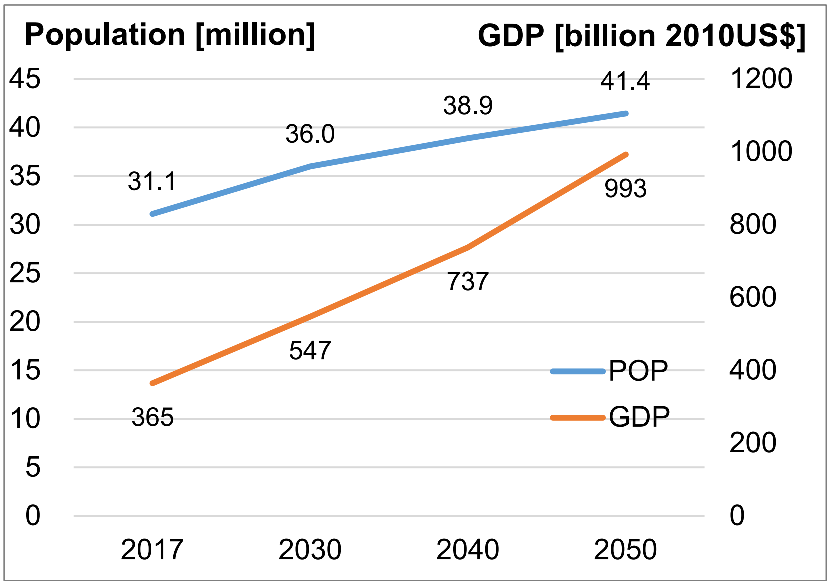
ASEAN countries expect economic growth in the coming decades. The major economic indicators, such as population and gross domestic product (GDP), are based on the ERIA outlook (ERIA, 2021) (Figure 2.3–Figure 2.6).

Figure 2.3. Population and GDP for Brunei Darussalam



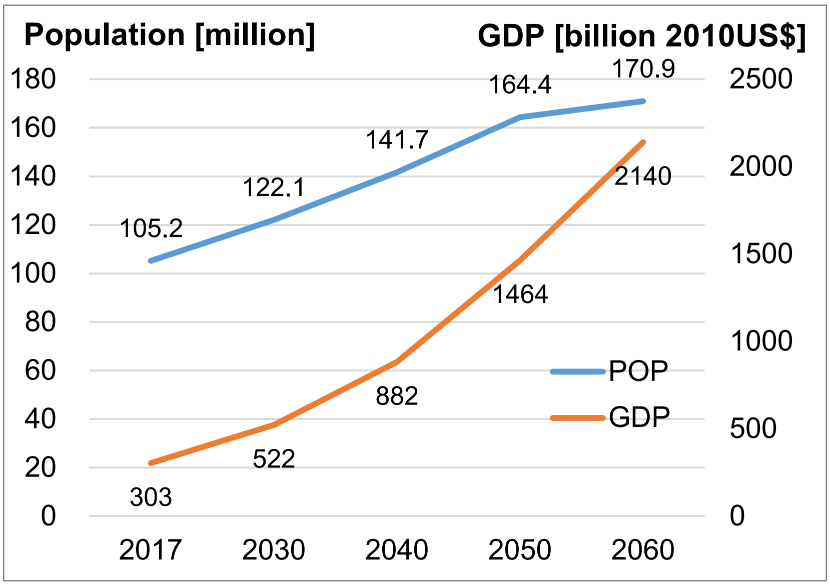
Source: Based on ERIA (2021).

Figure 2.4. Population and GDP for Malaysia



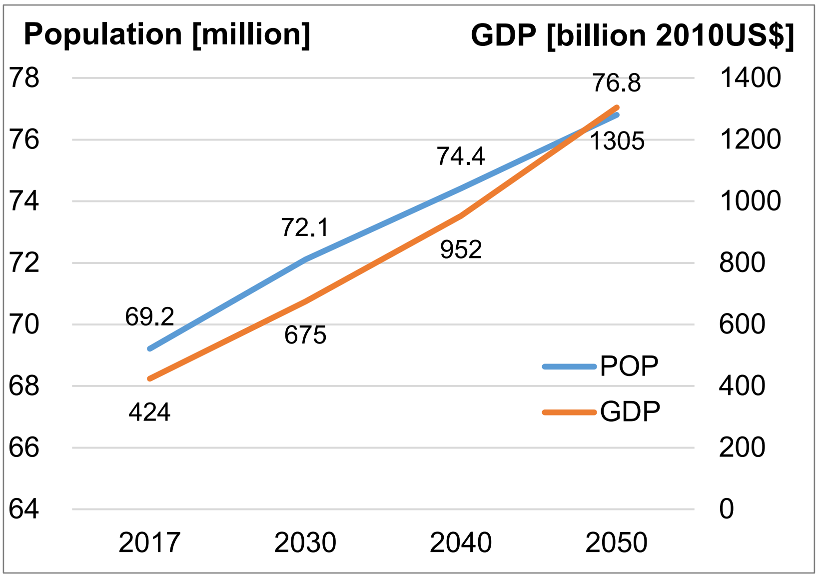
Source: Based on ERIA (2021).

Figure 2.5. Population and GDP for the Philippines



Source: Based on ERIA (2021).

Figure 2.6. Population and GDP for Thailand

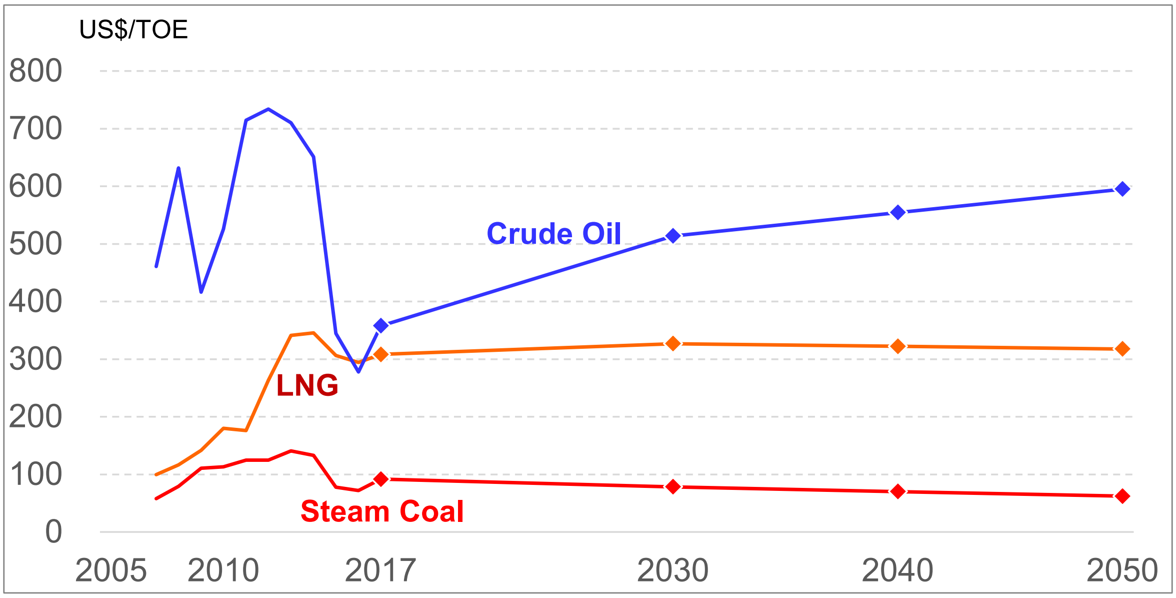


Source: Based on ERIA (2021).

(b) Fuel prices

Following the Russian invasion of Ukraine, fossil fuel prices have increased dramatically since 2022. This study assumes future fossil fuel prices in ASEAN based on the Stated Policies Scenario (STEPS) of the IEA (2022), which reflects the current energy circumstances (Figure 2.7).

Figure 2.7. Future Fossil Fuel Prices in ASEAN



LNG = liquified natural gas, toe = tonne of oil equivalent.
Source: Estimated by the Institute of Energy Economics, Japan, based on the Stated Policies Scenario of the IEA (2022).

(c) Grid connections amongst ASEAN countries

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

(d) Hydrogen and ammonia imports from non-ASEAN countries

The maximum amounts of H_2 and NH_3 imports from outside ASEAN are assumed to be up to 203 million tonnes of oil equivalent (Mtoe) per year in 2040, 540 Mtoe in 2050, and 638 Mtoe in 2060. The upper limit of imports after 2050 is equivalent to 30%[2] of the total Baseline primary energy supply. This study assumes a maximum amount of H_2 and NH_3 imports for the selected countries as shown in Table 2.4.

Table 2.4. Maximum Amount of H_2 and NH_3 Imports

(Mtoe/year)	2040	2050	2060
Brunei Darussalam	0	0	0
Malaysia	28	67	77
Philippines	18	49	60
Thailand	36	84	90

H_2 = hydrogen, NH_3 = ammonia.
Source: Author.

H_2 import prices are assumed to be US$0.30 per normal cubic metre (Nm^3)-H_2 in 2030, US$0.20 in 2050, and US$0.175 in 2060, based on the Government of Japan's long-term H_2 supply chain target[3]. NH_3 import prices are assumed to be US$0.18 per Nm^3-H_2 in 2030 and US$0.16 in 2050 and 2060, respectively, based on Japan's targets. Under these price assumptions, domestic green H_2 is more expensive than imported H_2/NH_3. However, it should be noted that the order of prices depends on the import price assumptions.

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

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[2] Note that 0% and 8% are assumed for Brunei Darussalam and Indonesia, respectively.
[3] These prices are for blue or green hydrogen, covering the transporting cost.

(e) Annual CO_2 storage capacity

In this study, the annual CO_2 storage potential was estimated to be up to 687 million tonnes of carbon dioxide ($MtCO_2$) per year in 2040, 1,138 $MtCO_2$ per year in 2050, and 1,610 $MtCO_2$ per year in 2060. The annual capacity is equivalent to 0.5% of the cumulative CO_2 storage potential of each country in 2040, 0.8% in 2050, and 1.1% in 2060. It is difficult to accurately estimate the CO_2 storage potential. However, the IEA (2021) estimates that ASEAN countries have abundant CO_2 storage potential and the total cumulative potential of the six countries (Brunei Darussalam, Indonesia, Malaysia, the Philippines, Thailand and Viet Nam) is estimated to be 133.4 $GtCO_2$ (Table 2.5). Imports and exports of captured CO_2 amongst ASEAN countries are also considered in this study.

Table 2.5. Cumulative CO_2 Storage Potential for Selected Countries

($GtCO_2$)	Depleted oil/gas fields, Enhanced oil recovery, etc.	Aquifers	Total
Brunei Darussalam	0.6	-	0.6
Malaysia	-	80	80
Philippines	0.3	22	22.3
Thailand	1.4	8.9	10.3

Source: IEA (2021).

(f) Supply potential of biofuels for vehicles

For the transport sector, the model considers expanding the use of biofuels as well as electrifying automobiles. The biofuel supply potential in the study is assumed to increase in proportion with the demand for road transport. This study assumes the biofuel supply capacity for the selected countries as shown in Table 2.6.

Table 2.6. Biofuel Supply Capacity for Selected Countries

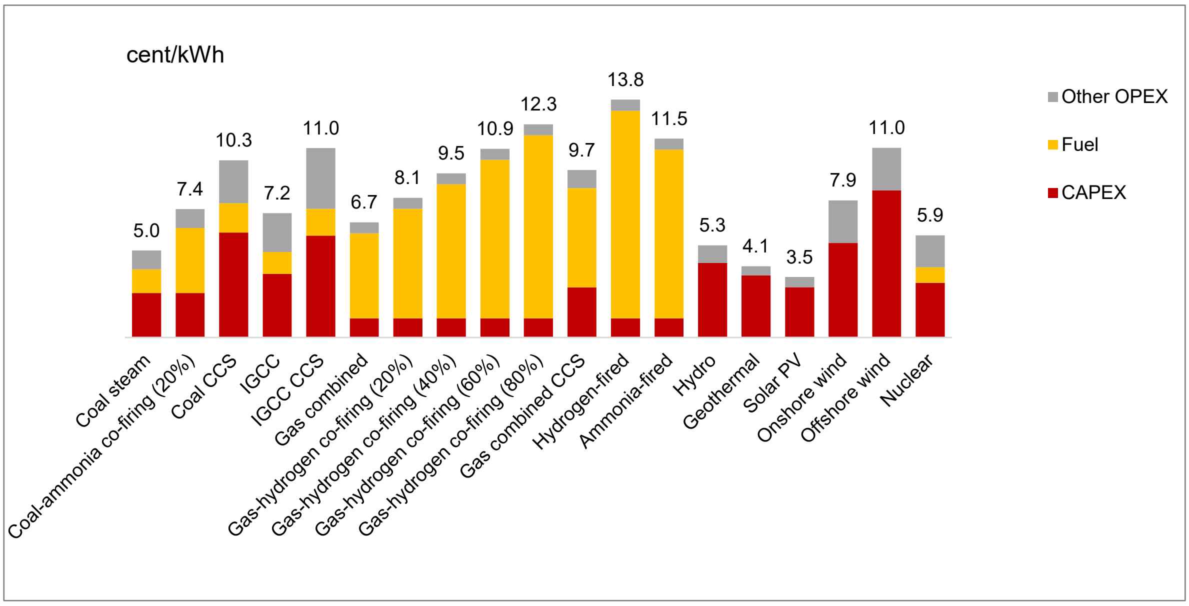
(Mtoe/year)	2040	2050	2060
Brunei Darussalam	0	0	0
Malaysia	1.3	1.9	2.3
Philippines	1.5	2.1	2.6
Thailand	4.6	6.0	6.5

Source: Author.

(g) Levelised cost of electricity

Power generation costs are estimated based on publicly available reports, such as by the Danish Energy Agency (2021), and information obtained by ASEAN countries. The capacity factor of different types of power generation and the required storage battery capacity are determined endogenously.

Figure 2.8. Power Generation Costs in 2050 for Brunei Darussalam and Malaysia

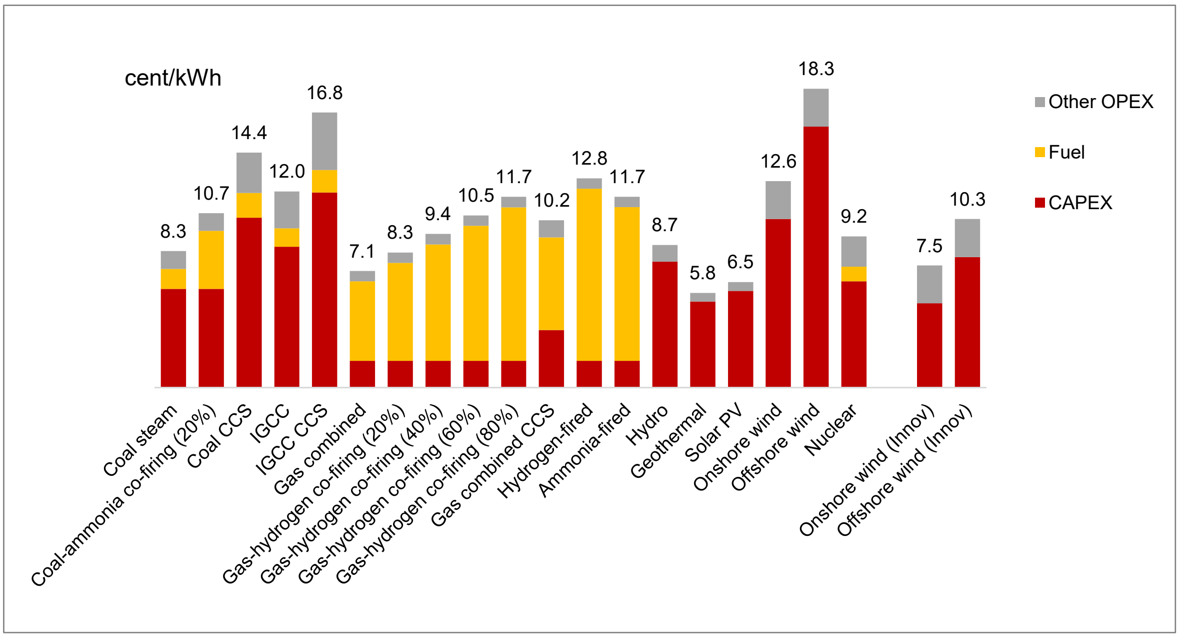


CAPEX = capital expenditure, CCS = carbon dioxide capture and storage, H_2 = hydrogen, IGCC = integrated coal gasification combined cycle, Nm^3 = normal cubic metre, OPEX = operating expenditure, PV = photovoltaic.

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

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

Figure 2.9. Power Generation Costs in 2050 for the Philippines

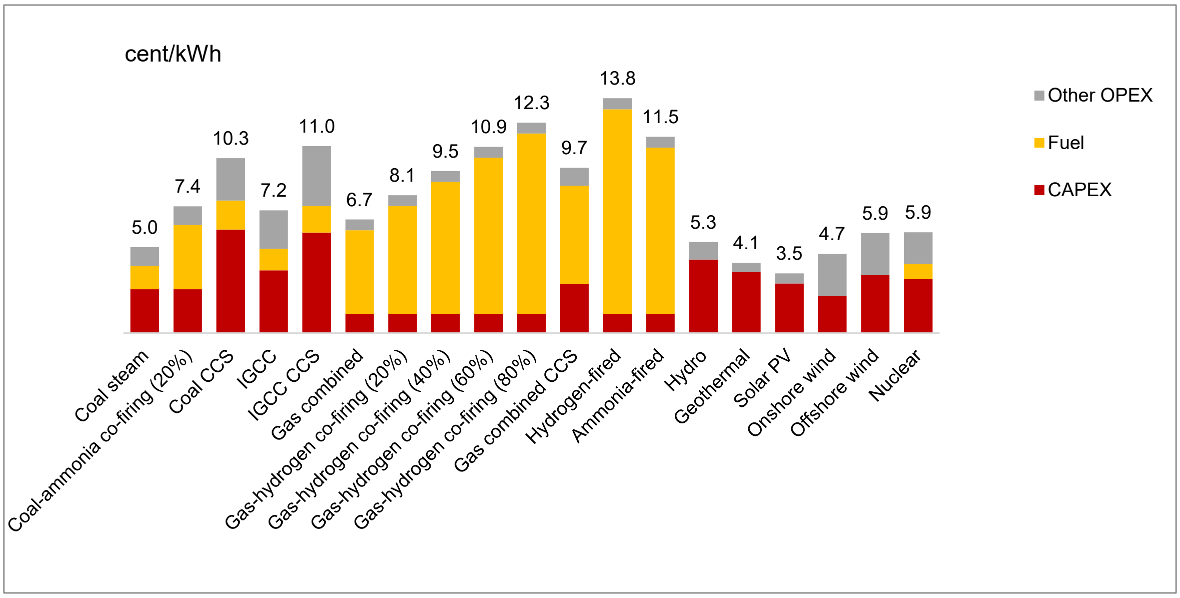


CAPEX = capital expenditure, CCS = carbon dioxide capture and storage, H_2 = hydrogen, IGCC = integrated coal gasification combined cycle, innov = innovation, Nm^3 = normal cubic metre, OPEX = operating expenditure, PV = photovoltaic.

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

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

Figure 2.10. Power Generation Costs in 2050 for Thailand



CAPEX = capital expenditure, CCS = carbon dioxide capture and storage, H2 = hydrogen, IGCC = integrated coal gasification combined cycle, Nm3 = normal cubic metre, OPEX = operating expenditure, PV = photovoltaic.

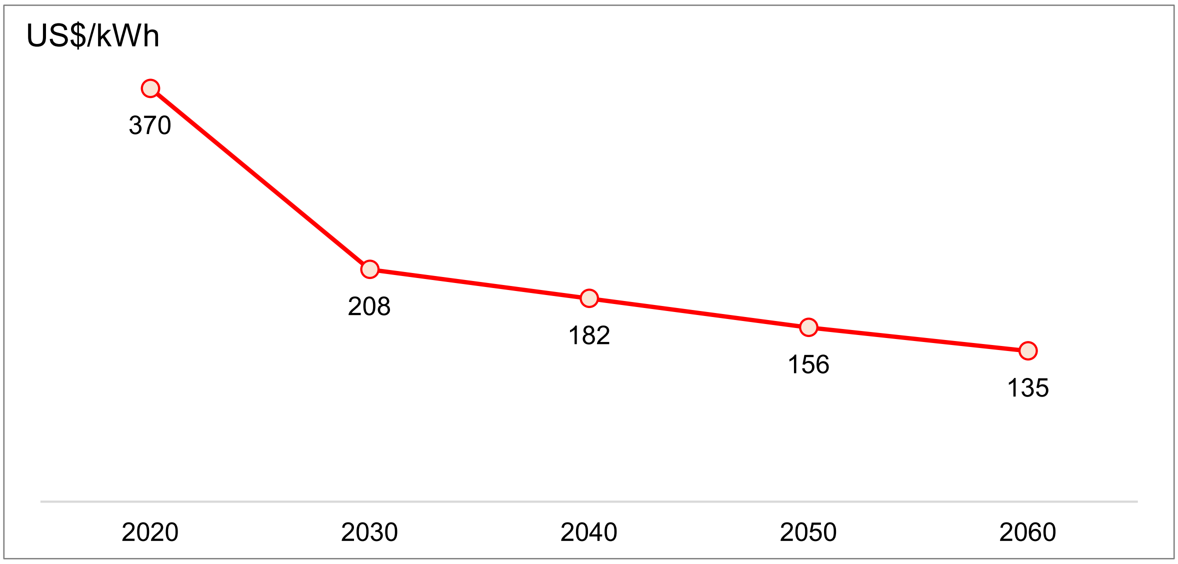
Note: H2 price: US$0.20/$Nm^3$-$H_2$; ammonia price: US$0.16/Nm^3-H_2; capacity factor: 40% for hydro, 80% for geothermal, 15% for solar PV, 20% for onshore wind, 30% for offshore wind, 80% for nuclear, 60% for the rest of the technologies.

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

(h) Energy storage technologies

The model assumes pumped hydro storage, lithium-ion batteries, and compressed H_2 tanks as energy storage technologies. The amounts required for lithium-ion batteries and compressed H_2 tanks were determined endogenously in the model simulation. The manufacturing cost of lithium-ion batteries is expected to decline substantially. The future cost reduction is assumed based on a cost forecast estimated by the National Renewable Energy Laboratory of the United States (Figure 2.11).

Figure 2.11. Assumed Lithium-ion Battery Cost

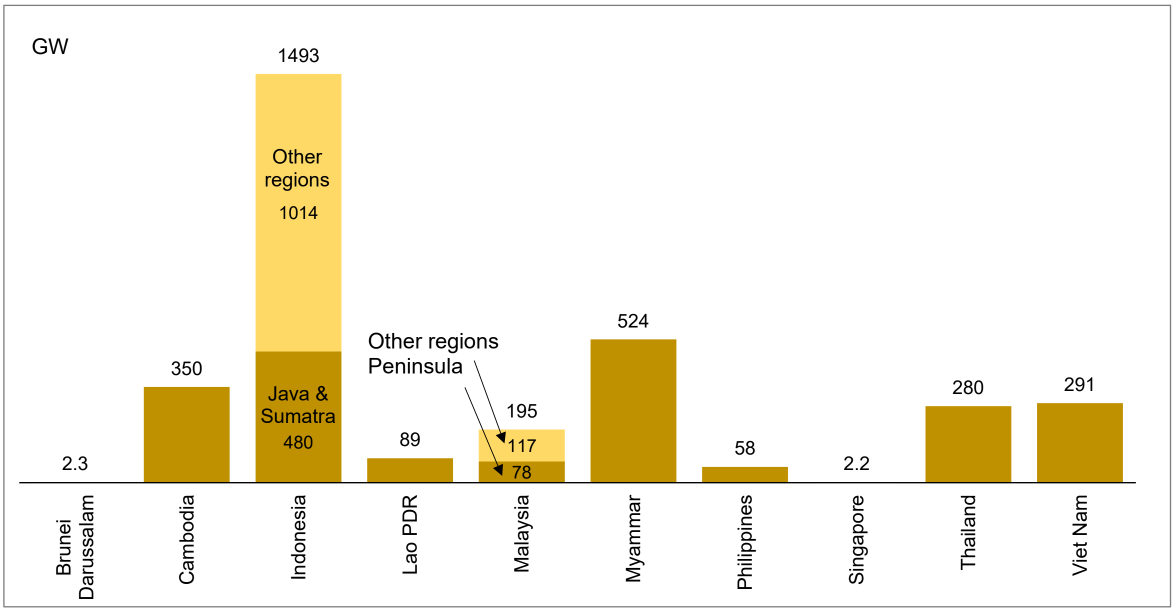


kWh = kilowatt-hour.
Note: Values are 2019 US$.
Source: Cole and Frazier (2020).

(i) Upper limit of solar photovoltaic capacity

This study estimates the upper limit of solar PV power generation capacity as 3,284 GW for all of ASEAN based on geographic information system (GIS) data and information from each country (Figure 2.12). The capacity of solar PV power generation in Indonesia, an archipelago, is divided into 'Java and Sumatra' and 'other regions', given the regional imbalances between electricity demand and renewable energy sources. Solar PV power generation in 'other regions' was assumed to be used for H_2 production. The capacity in Malaysia is divided into 'peninsula' and 'other regions', given its geographical characteristics.

Figure 2.12. Upper Limits of Solar Photovoltaic Capacity

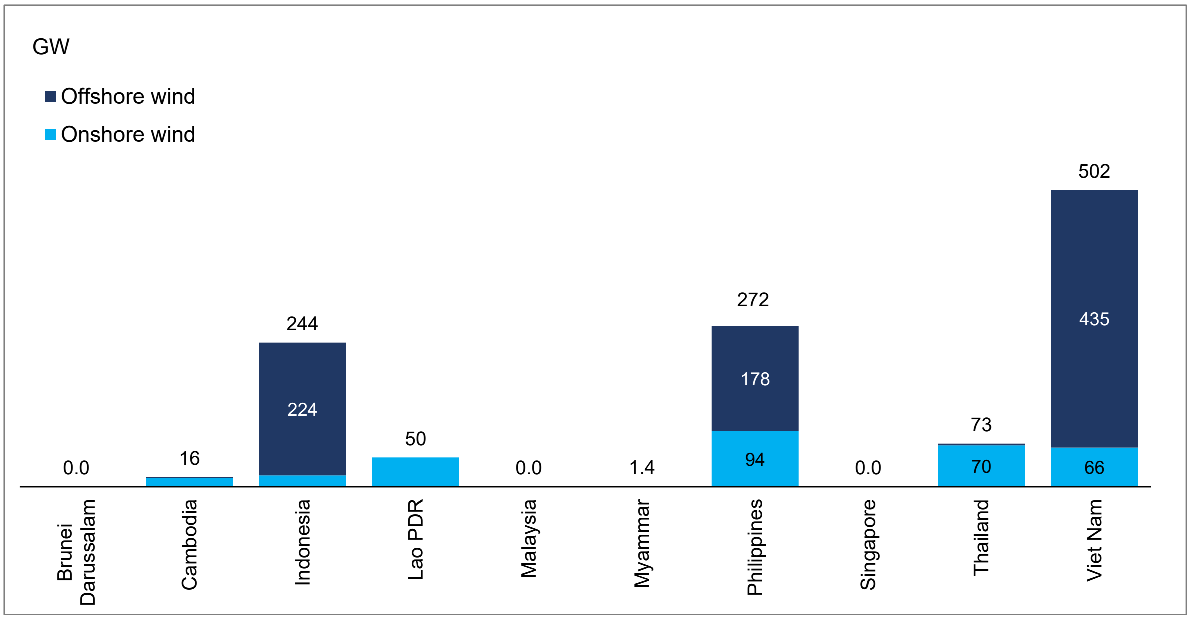


Source: Author.

(j) Upper limit of wind power capacity

The upper limit of wind power generation capacity, which is divided into onshore and offshore, is estimated based on GIS data and information from each country. The upper limit of capacity is assumed to be 315 GW for onshore wind and 843 GW for offshore wind (Figure 2.13). The available capacity of onshore and offshore wind power generation in Indonesia is divided into 'Java and Sumatra' and 'other regions' to consider the regional imbalances between electricity demand and resources. Wind power generation in 'other regions' is assumed to be used for H_2 production.

Figure 2.13. Upper Limits of Wind Power Capacity

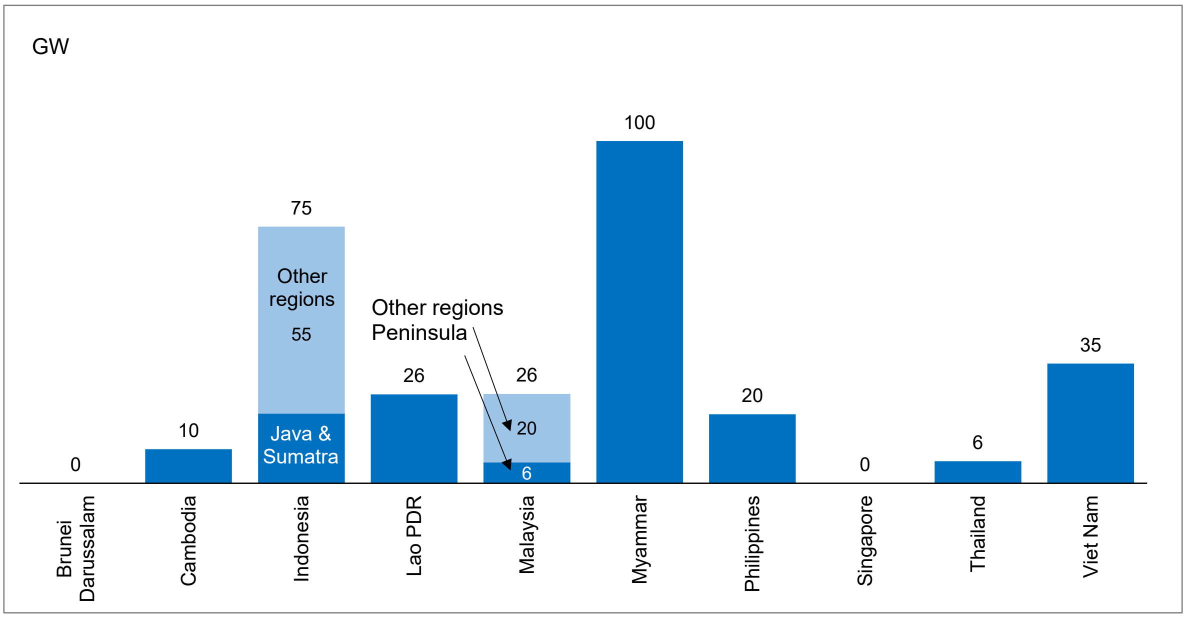


GW = gigawatt.
Source: Author.

(k) Upper limit of hydropower capacity

The upper limit of hydropower generation capacity is assumed to be 299 GW in the entire ASEAN region based on data from sources such as PwC (2018) and information provided by ASEAN countries (Figure 2.14). The capacity of hydropower generation in Indonesia and Malaysia is divided into 'Java and Sumatra' for Indonesia and 'Peninsula' for Malaysia, and 'other regions' given the regional imbalance between electricity demand and resources. Hydropower generation in 'other regions' is assumed to be for H_2 production.

Figure 2.14. Upper Limit of Hydropower Capacity

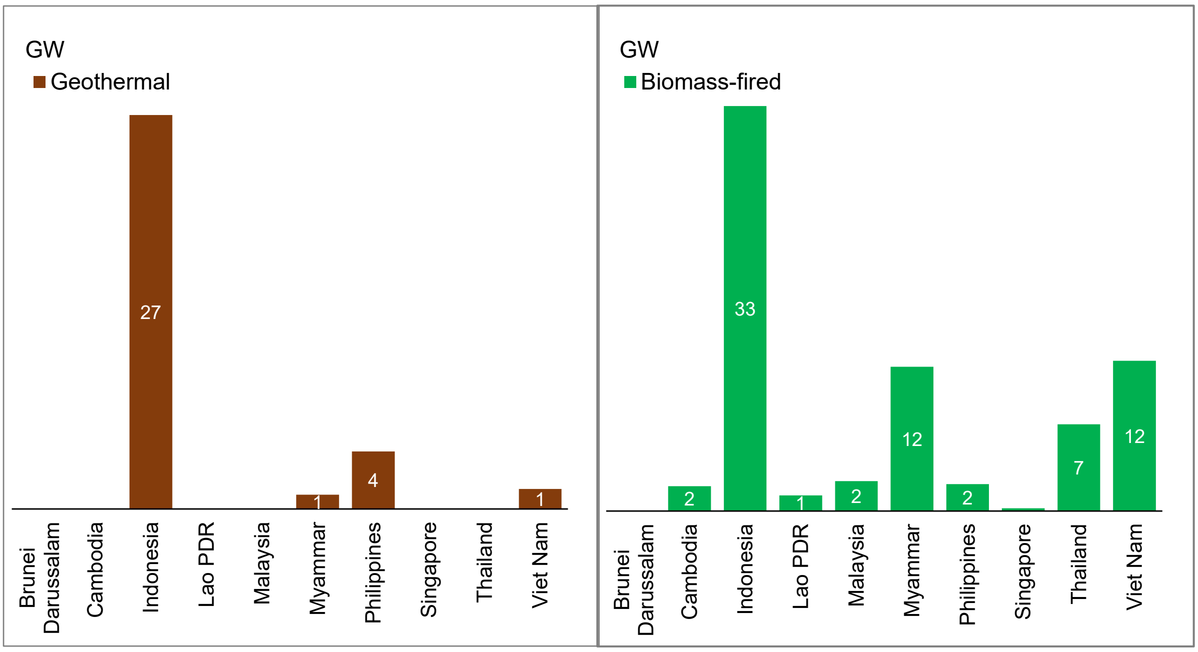


GW = gigawatt.
Source: Author.

(l) Upper limit of geothermal and biomass power capacity

The upper limits for geothermal power and biomass-fired power generation capacity in the region are estimated to be 34 GW and 71 GW, respectively. As shown in Figure 2.15, Indonesia has a relatively high potential for both types of power generation.

Figure 2.15. Upper Limit of Geothermal and Biomass Power Capacity



GW = gigawatt.
Source: Author.

2.2.2. Case Settings

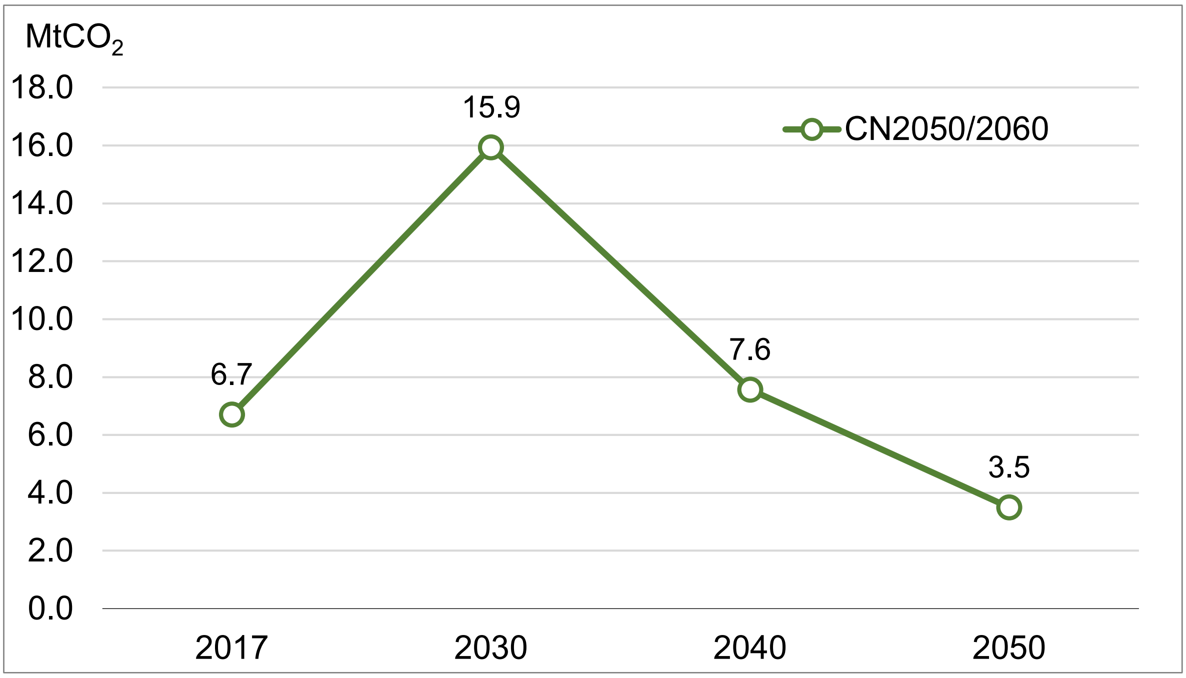
Based on the previous report[4], this study analyses the following two cases, and shows some sensitivity analysis for selected countries:

Baseline case; does not set a CO_2 emissions target.

CN2050/2060 case; reflects nationally declared carbon-neutral targets and considers carbon sinks in Brunei Darussalam, Indonesia, Malaysia, Myanmar, Thailand, and Viet Nam based on discussions with each country.

Energy-related CO_2 emissions constraints in CN2050/2060 for Brunei Darussalam, Malaysia, the Philippines, and Thailand are set as shown in Figure 2.16 to Figure 2.19 based on discussions with each country. CN2050/2060 reflects nationally declared carbon-neutral target years and considers carbon sinks in Brunei Darussalam, Indonesia, Malaysia, Myanmar, Thailand, and Viet Nam based on discussions with each country (Table 2.7). When an energy-related CO_2 emission reduction target with a carbon sink becomes less than 50%, its target is capped at 50%.

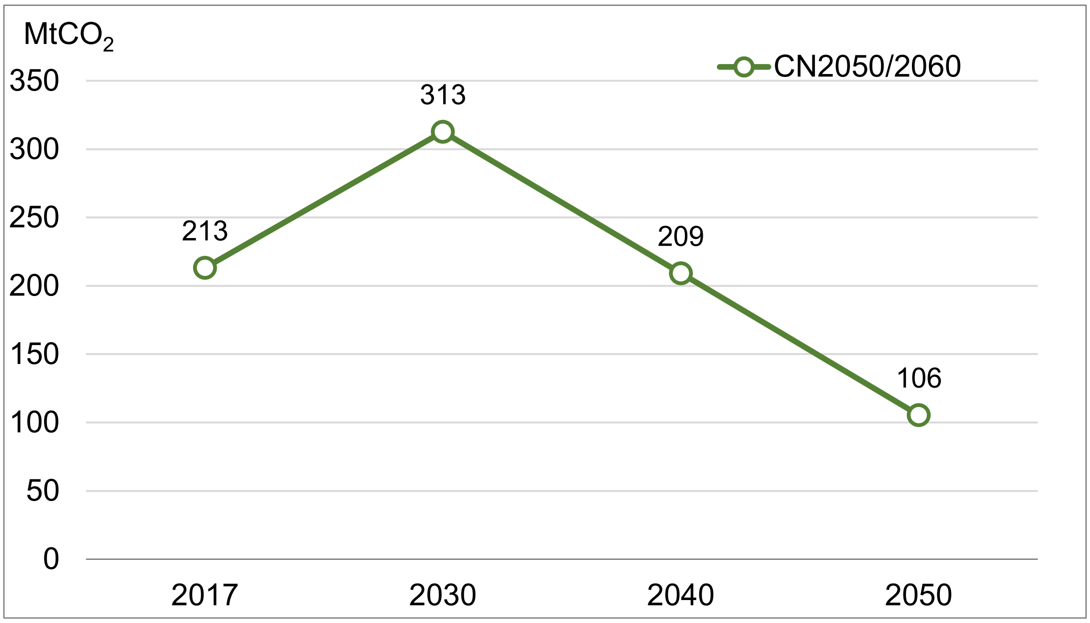
Figure 2.16. Energy-related Carbon Dioxide Emissions Constraints in Brunei Darussalam



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

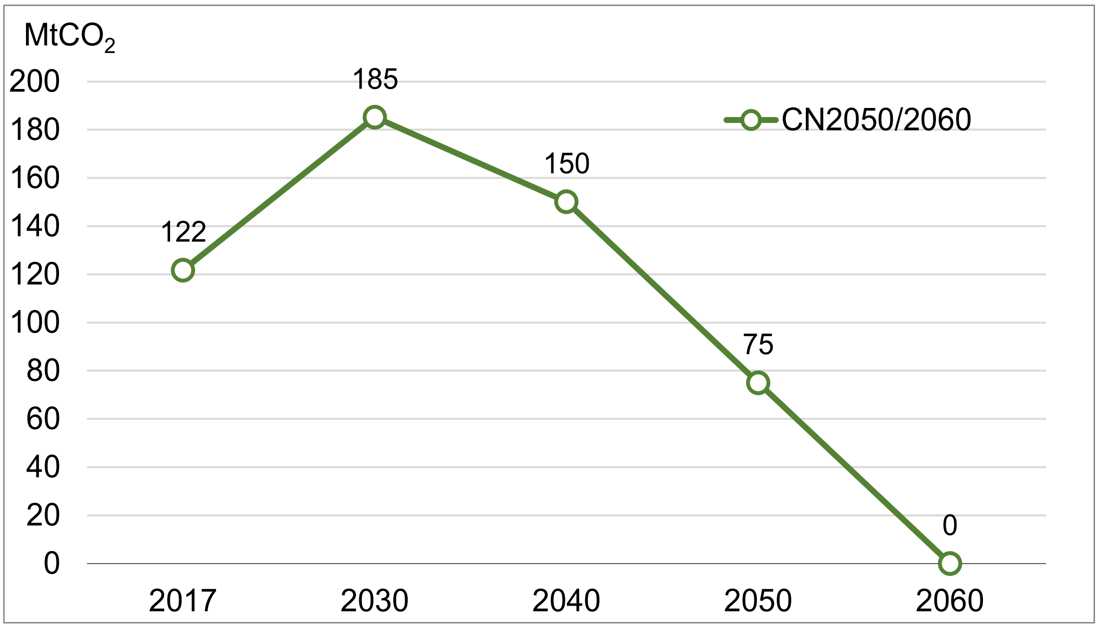
[4] ERIA Research Project 2022 No. 05.

Figure 2.17. Energy-related Carbon Dioxide Emissions Constraints in Malaysia



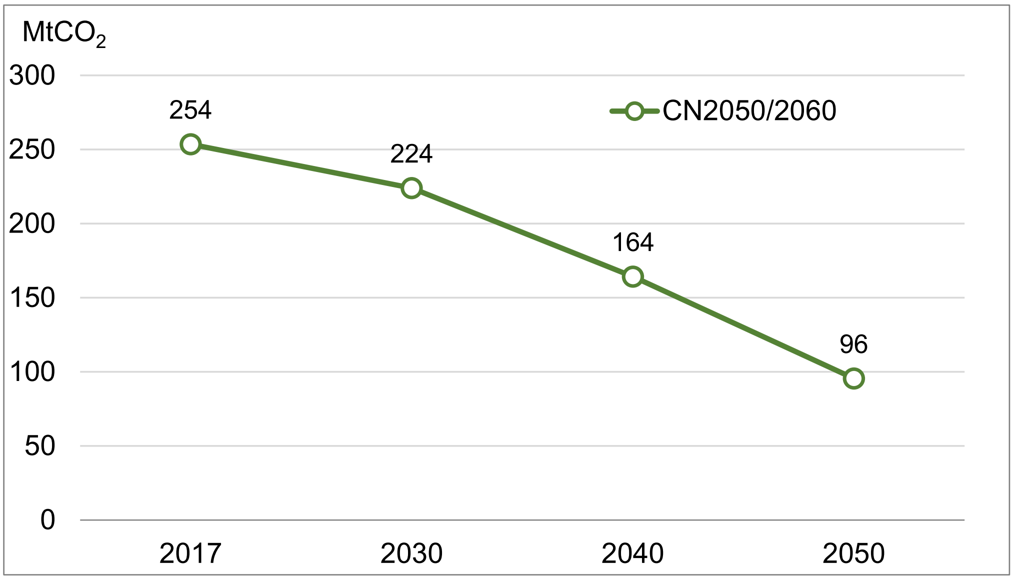
$MtCO_2$ = million tonnes of carbon dioxide.
Source: Author.

Figure 2.18. Energy-related Carbon Dioxide Emissions Constraints in the Philippines



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

Figure 2.19. Energy-related Carbon Dioxide Emissions Constraints in Thailand



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

Table 2.7. Assumed Carbon Neutrality Target Years and Carbon Sinks in CN2050/2060

Country	CN Target Year	Energy-related CO_2 Emission Reduction Target from 2017	Assumed Natural Carbon Sink (LULUCF) in the Target Year
Brunei Darussalam	2050	50%	Information from Brunei (-4.4Mt)
Cambodia	2050	100%	-
Indonesia	2060	50%	2050 target of the LCCP scenario in the LTS (-300Mt)
Lao PDR	2050	100%	-
Malaysia	2050	50%	2016 value of the inventory (-241Mt)
Myanmar	2060	60%	2040 target of the unconditional NDC (-13Mt)
Philippines	2060	100%	-
Singapore	2050	100%	-
Thailand	2050	50%	2050 target of the Carbon Neutrality Pathway in the LTS (-120Mt)
Viet Nam	2050	70%	2030 target of the unconditional NDC (-59Mt)

Notes: LULUCF = land use, land-use change, and forestry, LTS = long-term strategy, LCCP = low-carbon scenario compatible with Paris Agreement target, NDC = nationally determined contribution.
Source: Author.

Chapter 3

Results for Selected Countries

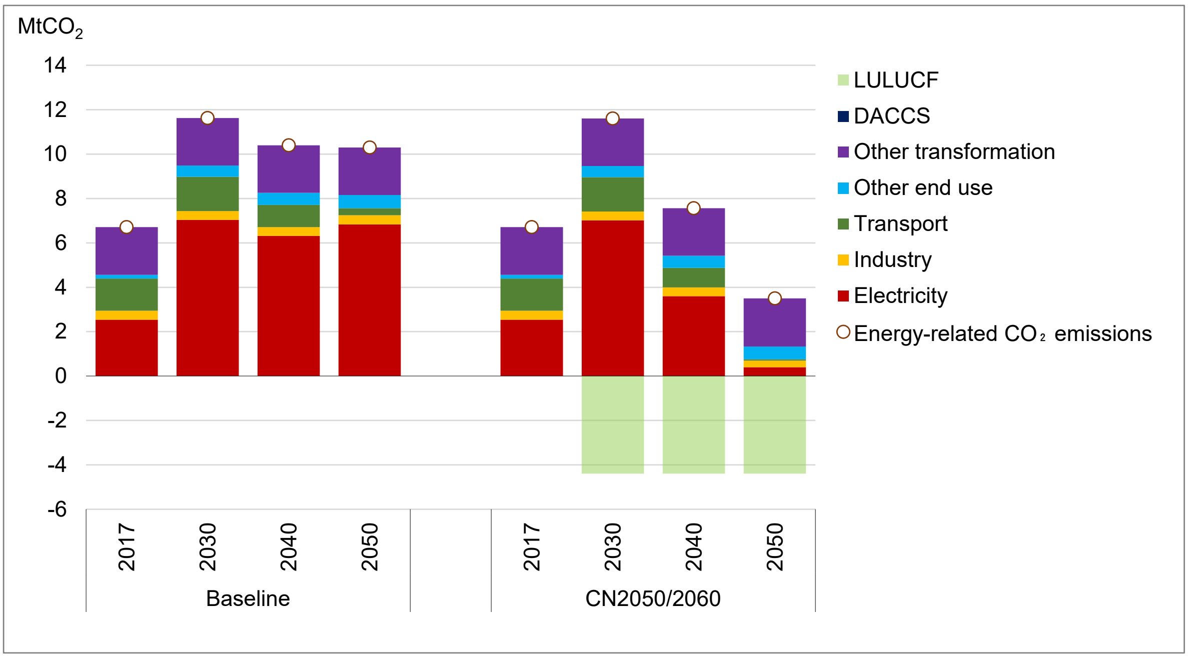
This section describes the results for the four selected countries. It should be noted that the following results for each country are a part of the ASEAN-wide optimisation results.

3.1. Brunei Darussalam

3.1.1. Sectoral CO_2 Emissions

Figure 3.1 shows the sector-wise CO_2 emissions for the Baseline and CN2050/2060. In the Baseline, CO_2 emissions increased mainly in the electricity sector. In CN2050/2060, CO_2 emissions from the electricity and transport sectors were largely reduced. Land Use, Land-Use Change, and Forestry (LULUCF) offset the residual emissions, mostly from other transformation sectors, including captive consumption in the oil and gas sectors, in 2050.

Figure 3.1. Sector-wise Energy-related Carbon Dioxide Emissions in Brunei Darussalam (CN2050/2060)

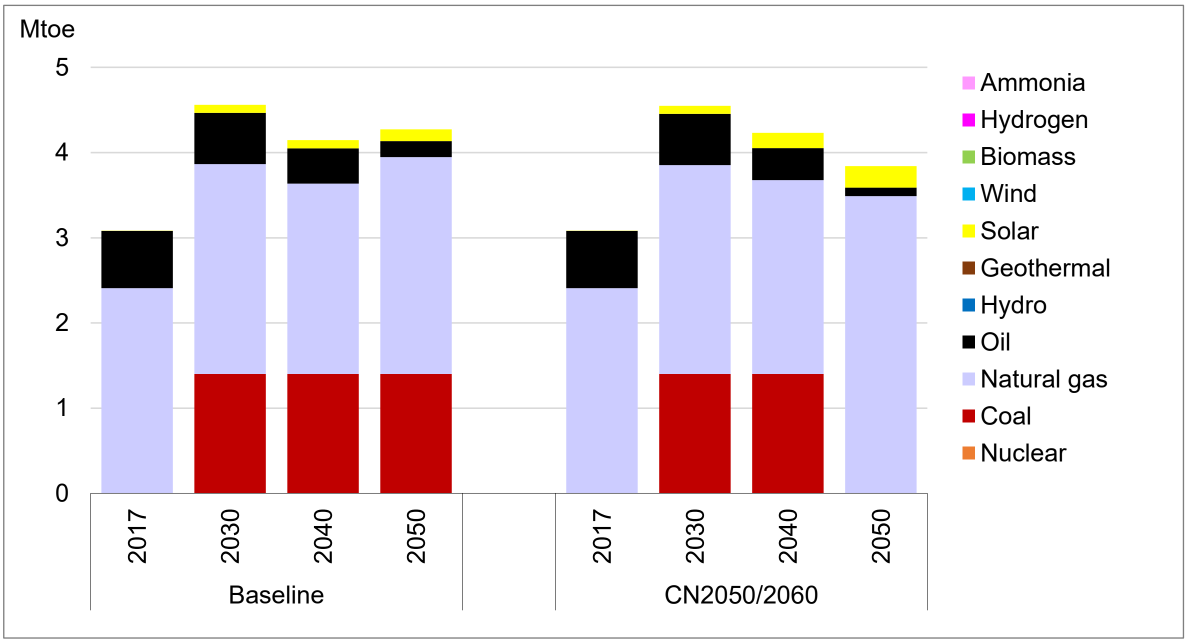


CO_2 = carbon dioxide; DACCS = direct air capture with carbon storage; LULUCF = land use, land-use change, and forestry; $MtCO_2$ = million tonnes of carbon dioxide.
Note: LULUCF emissions in 2017 are not available.
Source: Author.

3.1.2. Primary Energy Supply

Figure 3.2 shows the primary energy supply in the Baseline and CN2050/2060. The primary energy supply in 2050 increased to approximately 1.3 times the 2017 level in the Baseline and about 1.4 times in CN2050/2060, respectively. Even in CN2050/2060, the primary energy supply from natural gas continued to be a major energy source, accounting for 91% of the total primary energy supply. On the other hand, the share of oil decreased significantly in both the Baseline and CN2050/2060 owing to the electrification of the transport sector.

Figure 3.2. Primary Energy Supply in Brunei Darussalam (CN2050/2060)

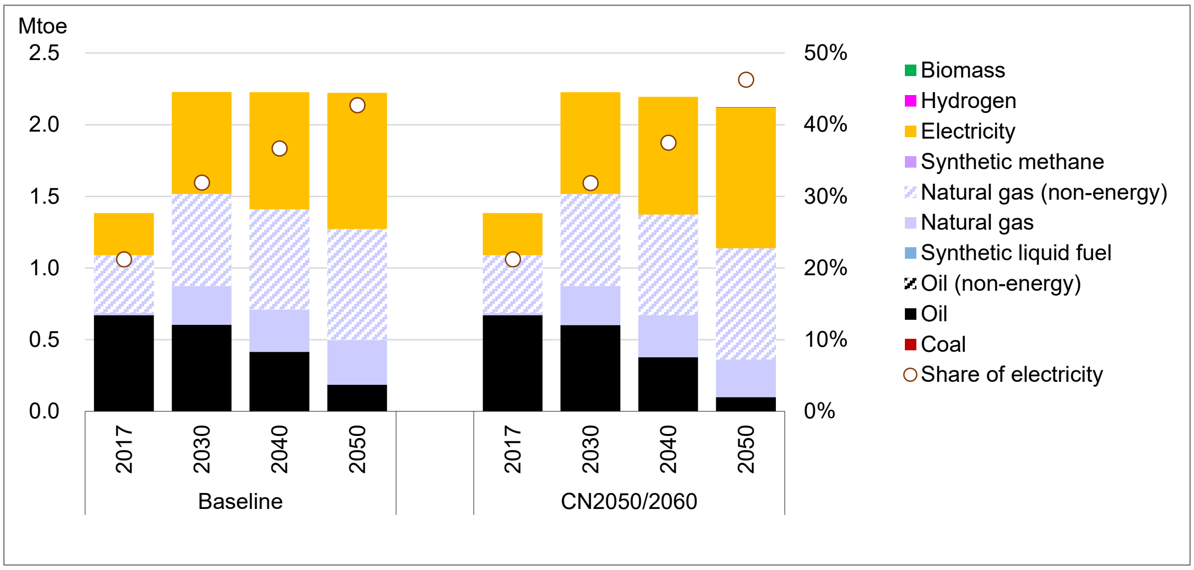


Mtoe = million tonnes of oil equivalent.
Source: Author.

3.1.3. Final Energy Consumption

Figure 3.3 shows final energy consumption in the Baseline and CN2050/2060. In CN2050/2060, final energy consumption in 2050 was 5% lower than in the Baseline due to improved energy efficiency, but at the same time, energy demand, especially in the industry sector, continued to grow in both cases. The share of electricity increases to 46% in CN2050/2060 by 2050. This suggests that electrification is an important strategy to decarbonise end-use sectors.

Figure 3.3. Final Energy Consumption in Brunei Darussalam (CN2050/2060)

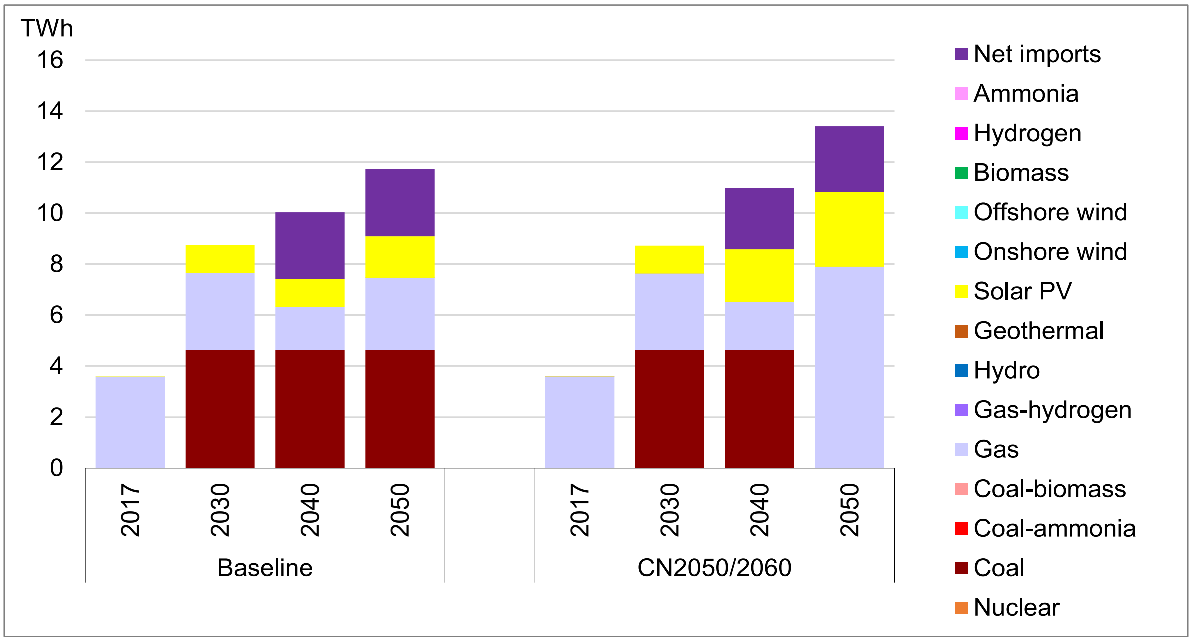


Mtoe = million tonnes of oil equivalent.
Source: Author.

3.1.4. Power Generation

Figure 3.4 shows the power generation in the Baseline and CN2050/2060. In the Baseline, coal-fired and natural gas-fired power generation accounted for almost 64% of the electricity mix in 2050. In CN200/2060, natural gas-fired power generation continued to be a major power source, accounting for 59% in 2050. The share of renewables rose to 41% in 2050 owing to the increased deployment of solar PV and the import of hydropower from Sarawak.

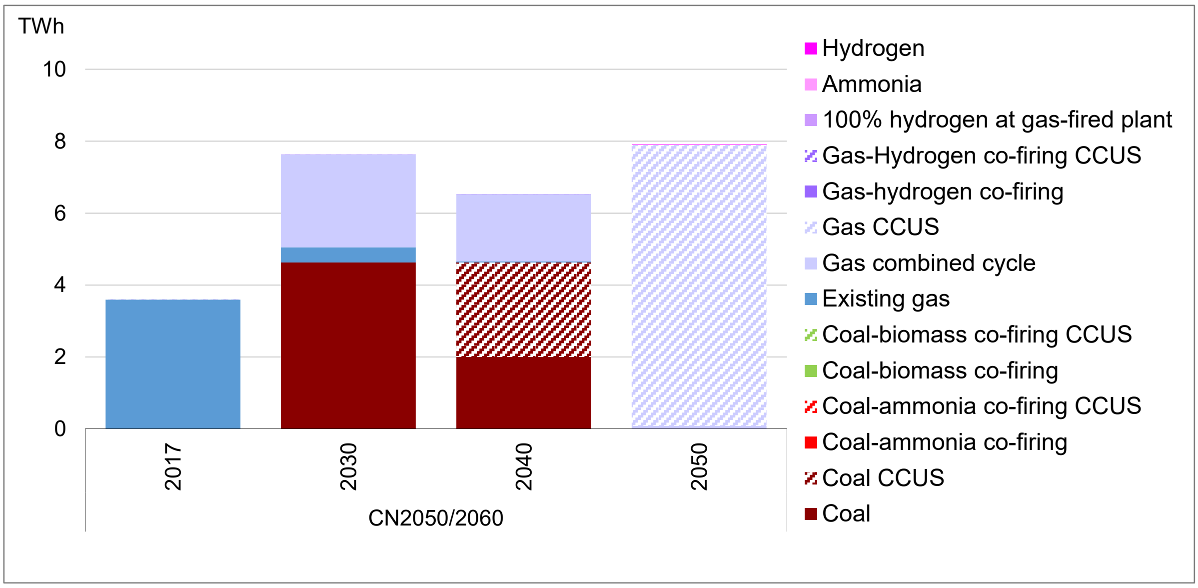
Figure 3.4. Power Generation in Brunei Darussalam (CN2050/2060)



PV = photovoltaic, TWh = terawatt-hour.
Source: Author.

Figure 3.5 shows the transition of thermal power generation (coal, natural gas, NH_3, and H_2) in total electricity generation. Gas combined cycle technology in the near-to-medium term, and CO_2 capture and storage (CCS) technologies in the medium-to-long term are expected to reduce CO_2 emissions from thermal power generation. Nearly 100% of thermal power generation shifts to gas-fired power with CCS by 2050.

Figure 3.5. Generated Electricity from Coal, Gas, Ammonia, and Hydrogen in Brunei Darussalam (CN2050/2060)

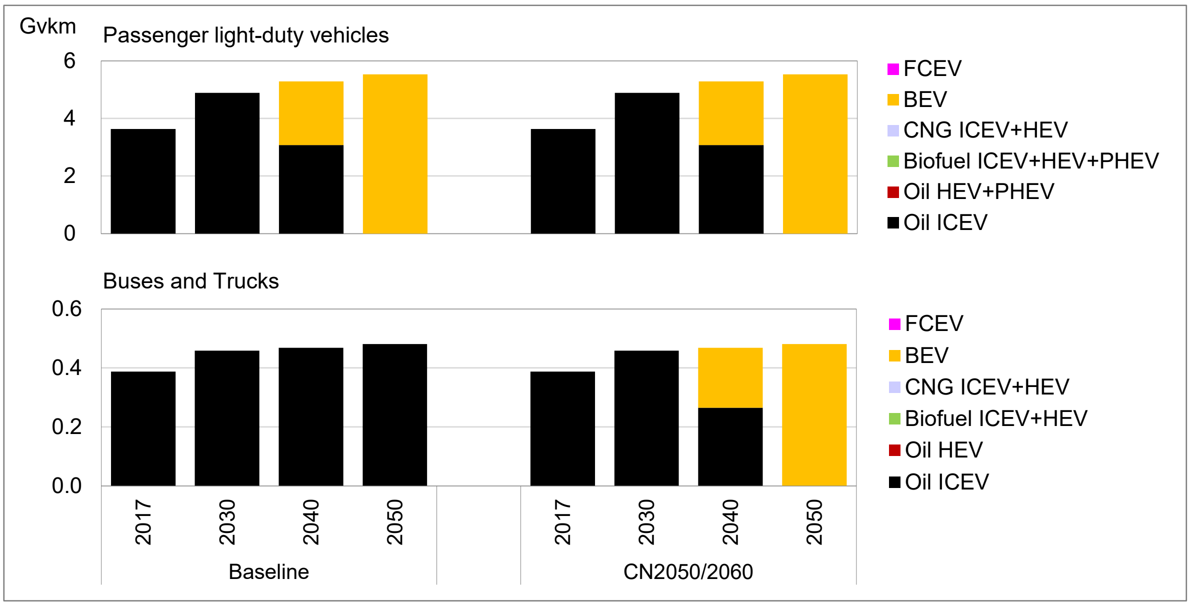


CCUS = carbon dioxide capture, utilisation, and storage; TWh = terawatt-hour.
Source: Author.

3.1.5. Road Transport

Figure 3.6, which shows the travel distance of passenger light-duty vehicles in the upper graph and that of buses and trucks in the bottom graph, shows that all vehicles are electrified by 2050 in CN2050/2060. Under our assumptions of rising crude oil prices, even in the Baseline, all passenger light-duty vehicles as well as buses and trucks shift to BEVs by 2050.

Figure 3.6. Travel Distance by Vehicle Technology in Brunei Darussalam (CN2050/2060)

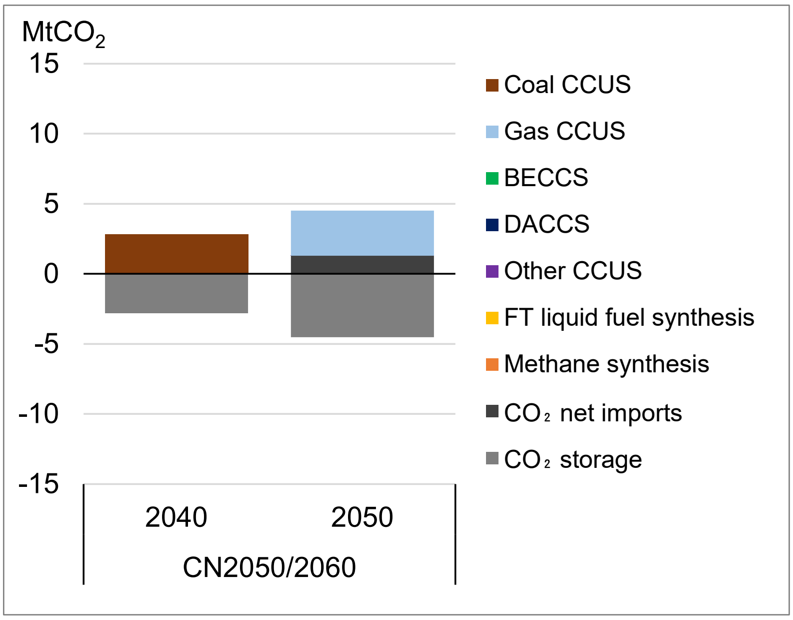


BEV = battery electric vehicle, CNG = compressed natural gas, FCEV = fuel cell electric vehicle, HEV = hybrid electric vehicle, ICEV = internal combustion engine vehicle, Gvkm = 10^9 vehicle-km, PHEV = plug-in hybrid electric vehicle.
Note: Biofuel includes bioethanol and biodiesel mixed with petroleum fuel.
Source: Author.

3.1.6. CCUS

Captured CO_2 from coal and gas-fired power plants is stored underground (CCS). CO_2 is captured at coal-fired power plants in 2040 and at gas-fired power plants in 2050, and all captured CO_2 is stored. Annual CO_2 storage capacity in Brunei is sufficient to import CO_2 from other ASEAN countries, in addition to the country's own captured CO_2. In CN2050/2060, the amount of H_2 and NH_3 used in Brunei is almost negligible.

Figure 3.7. CCUS Balance in Brunei Darussalam



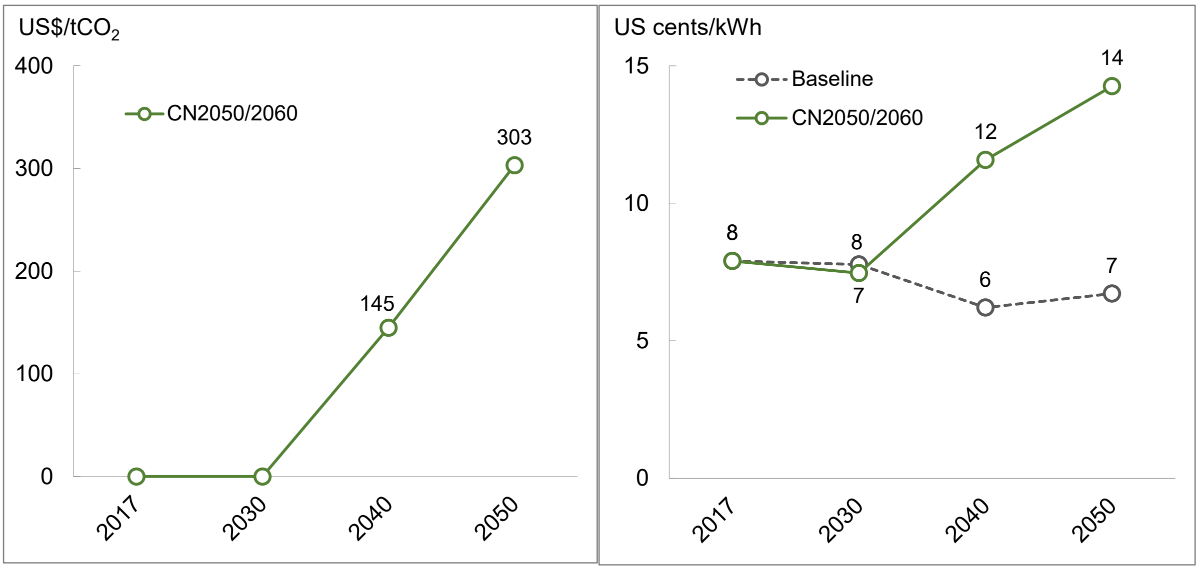
CCUS = carbon dioxide capture, utilisation, and storage, DRI-EAF = direct reduced iron–electric arc furnace, FT = Fischer-Tropsch.
Source: Author.

3.1.7. Costs for Reducing Carbon Dioxide

The marginal CO_2 abatement cost (MAC) is the cost required for the entire energy system to marginally reduce 1 tonne of CO_2, as yielded by the model simulation (see Enkvist et al. [2007]), which shows the difficulty of decarbonisation. Figure 3.8 shows the MAC for Brunei Darussalam. The MAC rose to US$303/t$CO_2$ in 2050, however, it is well below that of other ASEAN countries because of the consideration of the natural carbon sink in the country.

In this study, electricity prices are shown as the average marginal costs for 2,190 time slices (4-hour resolution). Typically, the marginal cost of each time slice is determined as the highest fuel price of the power plant operated. Figure 3.8 also shows the marginal cost of electricity generation for CN2050/2060. The electricity price is estimated to increase twofold in CN2050/2060 compared to the Baseline and increase to 14 cents/kWh in 2050.

Figure 3.8. Marginal Carbon Dioxide Abatement Cost (Left) and Marginal Cost of Electricity (Right) for CN2050/2060, Brunei Darussalam



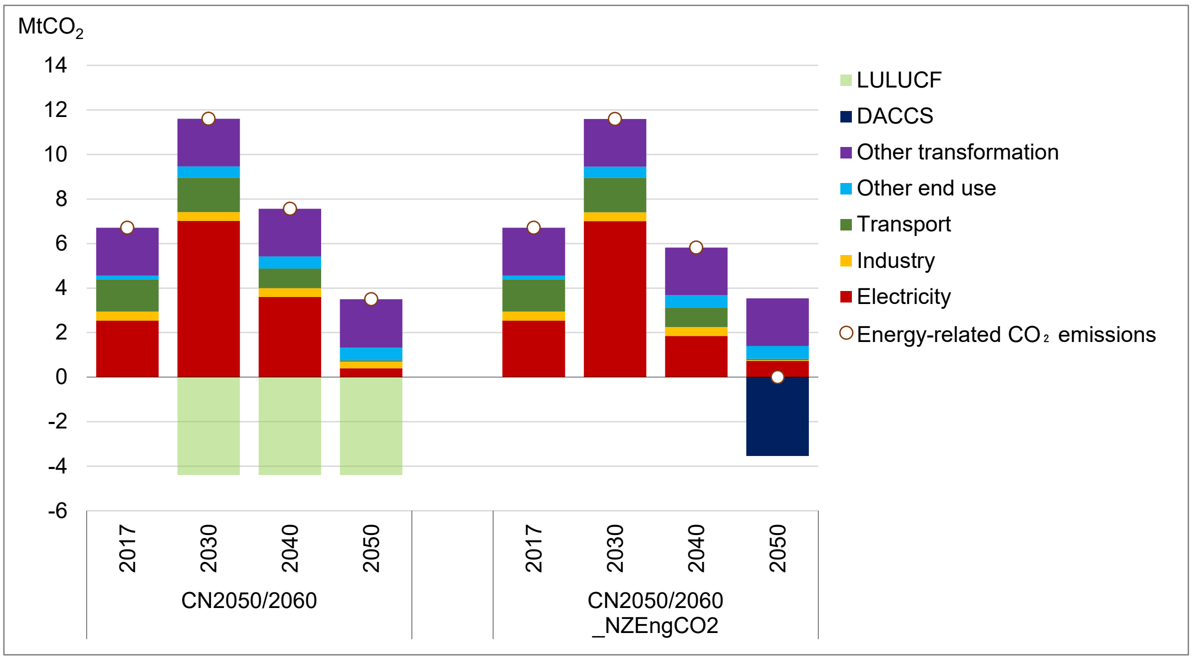
CO_2 = carbon dioxide, kWh = kilowatt-hour, MAC = marginal CO_2 abatement cost, tCO_2 = tonnes of carbon dioxide.
Source: Author.

3.1.8. Sensitivity Analysis 1: 100% Reduction in Energy-related CO_2

Emission constraints in the CN2050/2060 case, which reduce energy-related CO_2 emissions by 50% compared to 2017, were based on the assumption that residual emissions are offset by a carbon sink of 4.4 $MtCO_2$. However, other GHG emissions were not negligible, such as fugitive emissions from the oil and gas sector, which are currently around 2 $MtCO_2e$. According to the IEA's analysis, methane leakage from the oil and gas sector is estimated to be reduced by measures with low or even negative costs. Although these low-hanging fruits should be prioritised, there is uncertainty in the outlook for GHG emissions other than energy-related CO_2, which is outside the scope of this study. To address this uncertainty, this sensitivity analysis considered a 100% reduction in energy-related CO_2 emissions by 2050 for Brunei Darussalam (CN2050/2060_NZEngCO2).

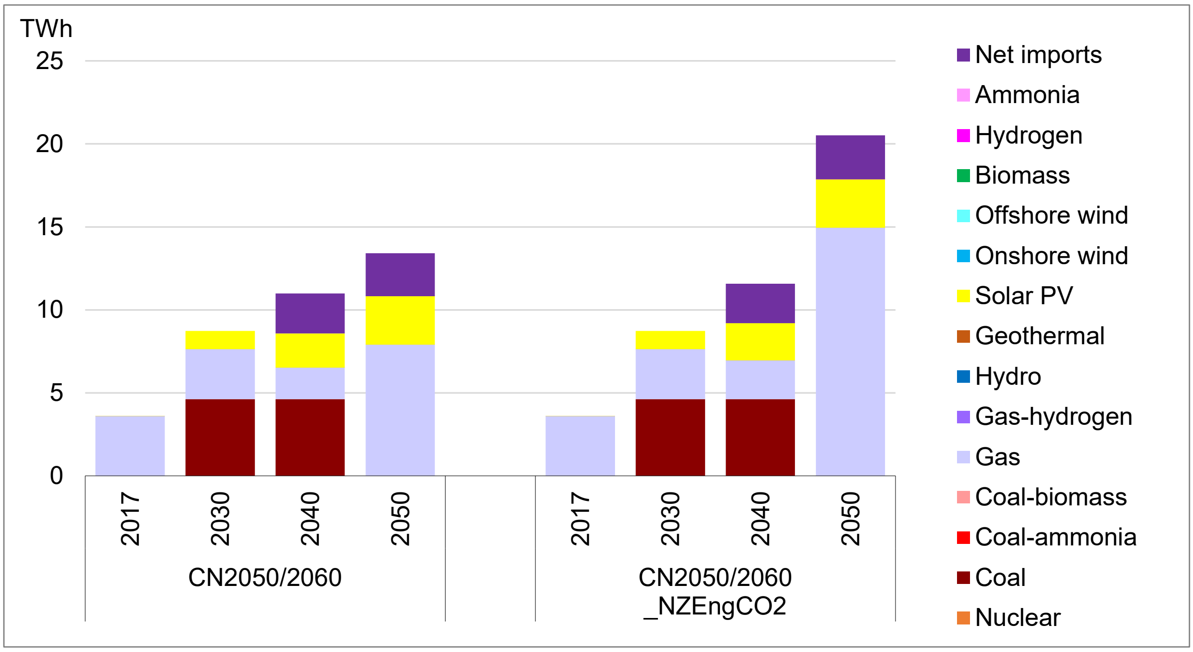
The results are presented in Figure 3.9 to Figure 3.12. In the CN2050/2060_NZEngCO2 case, DACCS is introduced in 2050, and electricity input to DAC requires an increase in power generation. Since solar PV reaches the upper limit of deployment, gas-fired with CCUS covers this increase. The amount of CO_2 captured increases significantly, exceeding the upper limit of annual storage capacity in Brunei Darussalam. This results in captured CO_2 being exported to other countries, such as Malaysia. In 2050, the marginal cost for reducing CO_2 and generating electricity rises by approximately US$150 and 4 cents, respectively, compared to the 50% reduction case.

Figure 3.9. Sector-wise Energy-related Carbon Dioxide Emissions in Brunei Darussalam (Sensitivity Analysis 1)



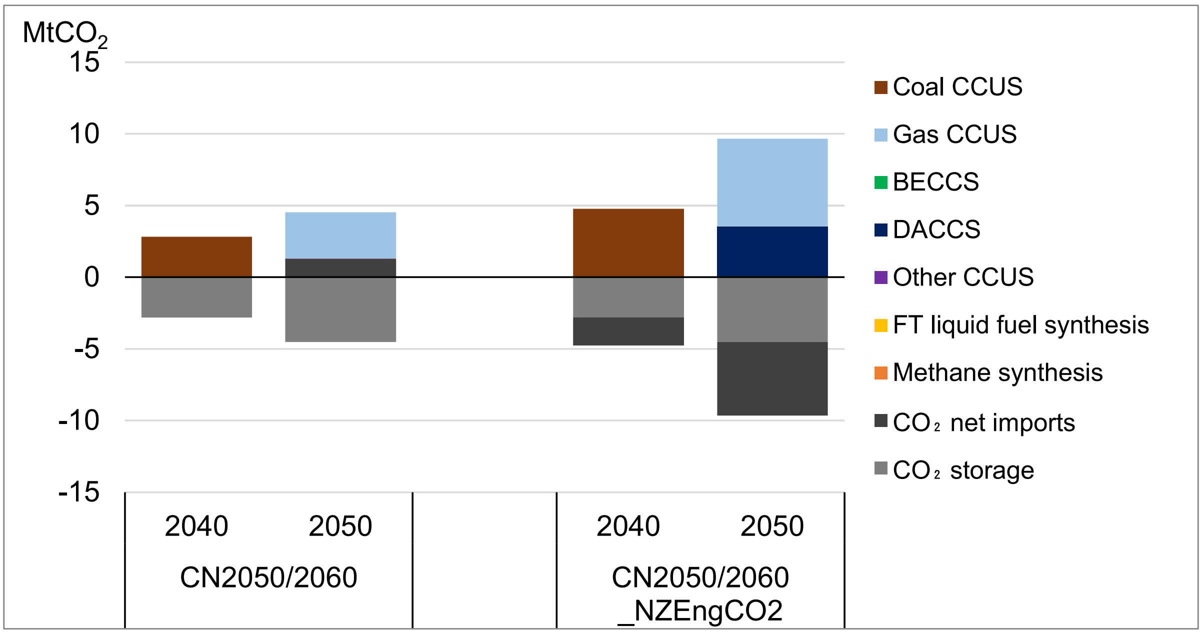
CO_2 = carbon dioxide; DACCS = direct air capture with carbon storage; LULUCF = land use, land-use change, and forestry; $MtCO_2$ = million tonnes of carbon dioxide.
Note: LULUCF emissions in 2017 are not available.
Source: Author.

Figure 3.10. Power Generation in Brunei Darussalam (Sensitivity Analysis 1)



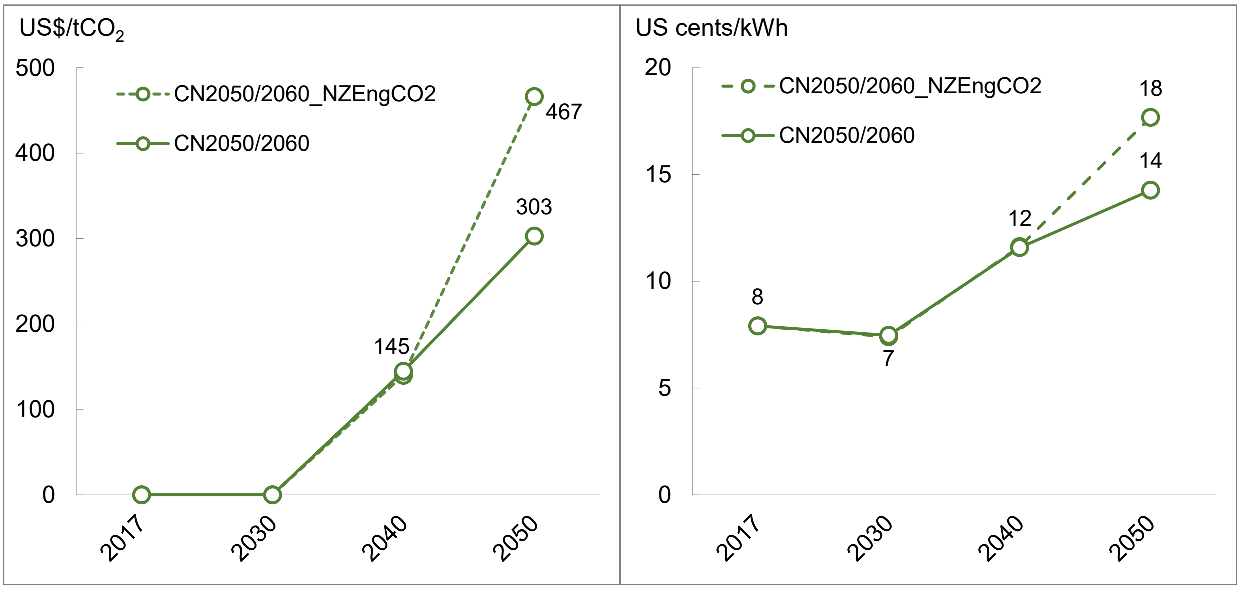
PV = photovoltaic, TWh = terawatt-hour.
Source: Author.

Figure 3.11. CCUS Balance in Brunei Darussalam (Sensitivity Analysis 1)



CCUS = carbon dioxide capture, utilisation, and storage, DRI-EAF = direct reduced iron-electric arc furnace, FT = Fischer-Tropsch.
Source: Author.

Figure 3.12. Marginal Carbon Dioxide Abatement Cost (Left) and Marginal Cost of Electricity (Right) for Sensitivity Analysis 1, Brunei Darussalam



CO_2 = carbon dioxide, kWh = kilowatt-hour, MAC = marginal CO_2 abatement cost, tCO_2 = tonnes of carbon dioxide.
Source: Author.

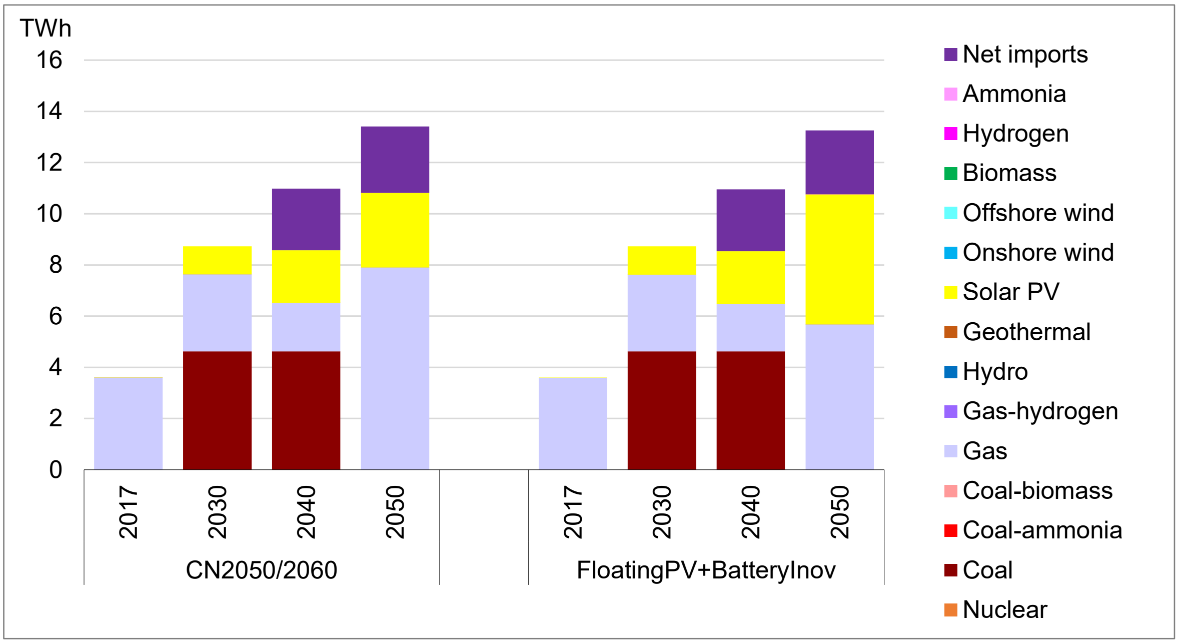
3.1.9. Sensitivity Analysis 2: Technological Innovation in Floating Solar PV and Batteries

This sensitivity analysis considers floating solar PV as an additional technology, as well as a reduction in battery costs (FloatingPV+BatteryInov). The quantitative assumptions were as follows:

- Floating solar PV: 1.7 GW for the upper limit. +25% for the capital cost compared to ground-mounted solar PV
- Cost reduction of Li-ion battery: 25% in 2040 and 50% after 2050, from the reference level
- Cost reduction of BEVs: 50% in and after 2040, as the difference from existing technologies

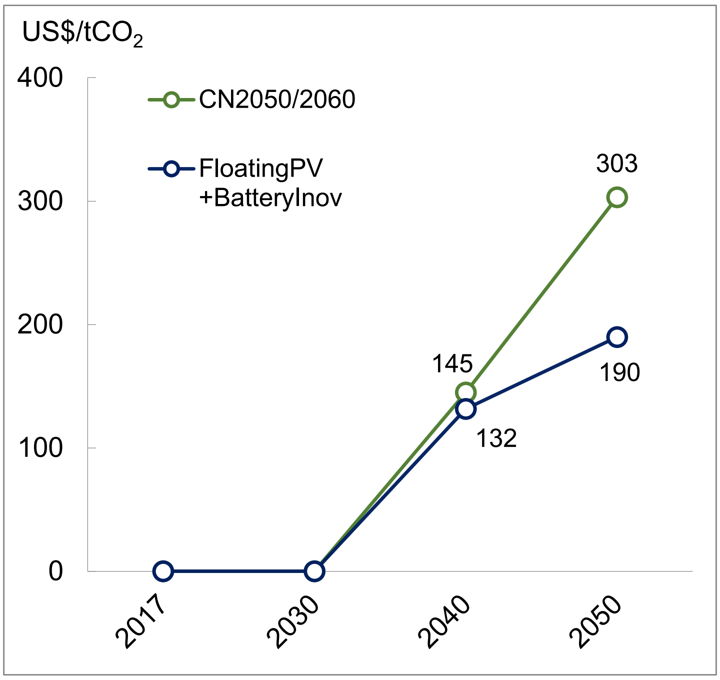
The results are shown in Figure 3.13 and Figure 3.14, respectively. In this case, more solar PV is installed and its share reaches as much as 38% in 2050. It should be highlighted that technological innovation in floating solar PV and batteries also brings about a large reduction in the marginal abatement costs of CO_2.

Figure 3.13. Power Generation in Brunei Darussalam (Sensitivity Analysis 2)



PV = photovoltaic, TWh = terawatt-hour.
Source: Author.

Figure 3.14. Marginal Carbon Dioxide Abatement Cost for Sensitivity Analysis 2, Brunei Darussalam



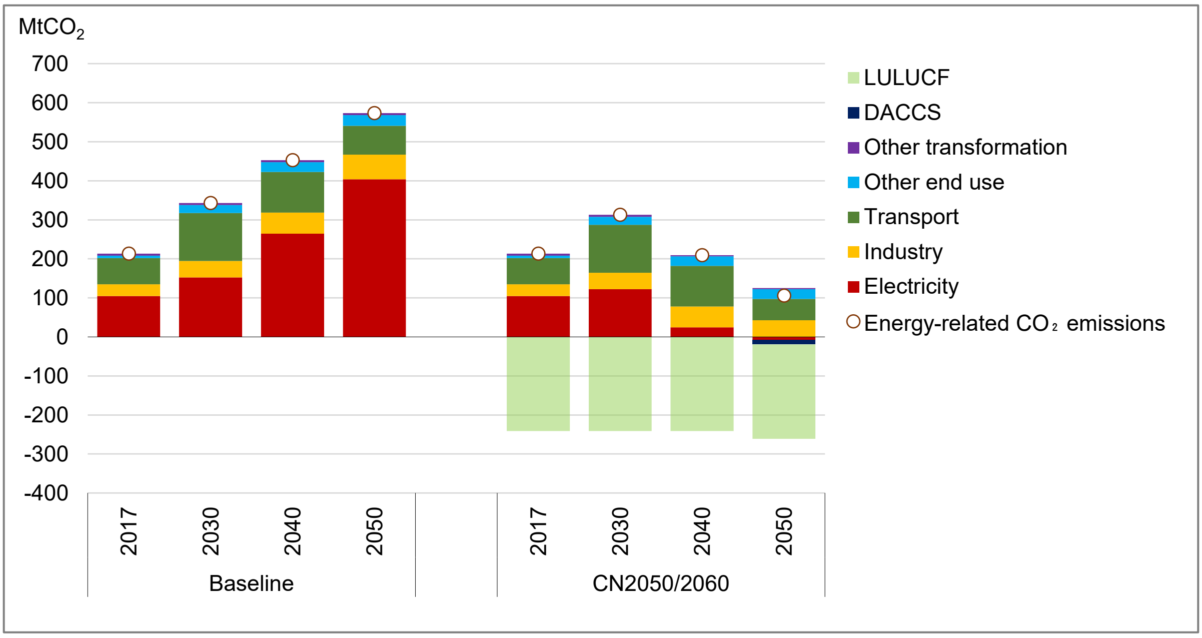
CO_2 = carbon dioxide, MAC = marginal CO_2 abatement cost, tCO_2 = tonnes of carbon dioxide.
Source: Author.

3.2. Malaysia

3.2.1. Sectoral Carbon Dioxide Emissions

Figure 3.15 shows the sector-wise CO_2 emissions in the Baseline and CN2050/2060. In the Baseline, CO_2 emissions increased mainly in the electricity sector, whilst, in CN2050/2060, CO_2 emissions were largely reduced in the electricity sector. According to the current emission inventory of 2016, LULUCF could fully offset the energy-related CO_2 emissions.

Figure 3.15. Sector-wise Energy-related Carbon Dioxide Emissions in Malaysia (CN2050/2060)

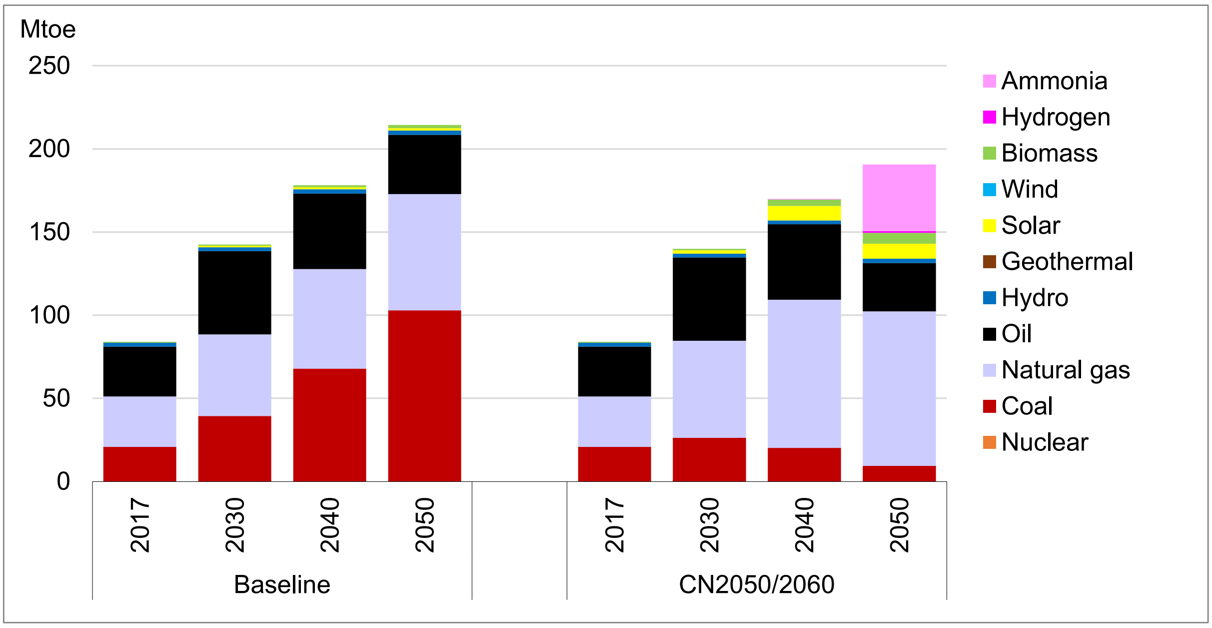


CO_2 = carbon dioxide; DACCS = direct air capture with carbon storage; LULUCF = land use, land-use change, and forestry; $MtCO_2$ = million tonnes of carbon dioxide.
Source: Author.

3.2.2. Primary Energy Supply

Figure 3.16 shows the primary energy supply in the Baseline and CN2050/2060. The primary energy supply in 2050 increases by approximately 2.9 times the 2017 level in the Baseline, and by approximately 2.7 times in CN2050/2060. In CN2050/2060, the primary energy supply from natural gas accounted for 49% of the primary energy supply in 2050. Imported H_2 and NH_3, mainly NH_3, are introduced in 2050 for ammonia-fired power generation, accounting for 22% of the primary energy supply as total H_2 and NH_3.

Figure 3.16. Primary Energy Supply in Malaysia (CN2050/2060)

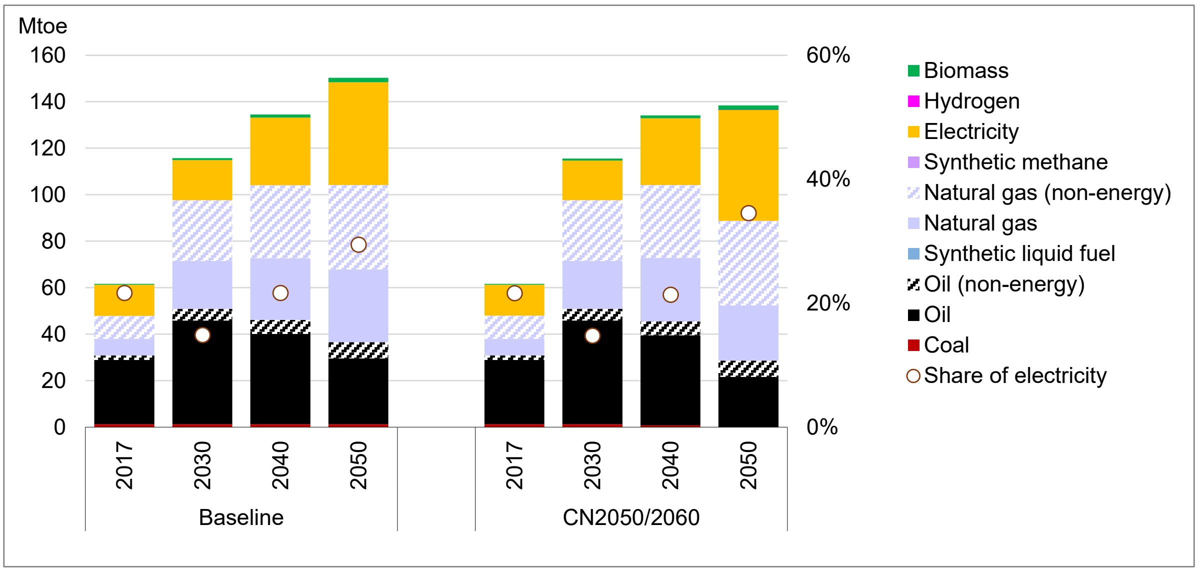


Mtoe = million tonnes of oil equivalent.
Source: Author.

3.2.3. Final Energy Consumption

Figure 3.17 shows final energy consumption in the Baseline and CN2050/2060. In CN2050/2060, final energy consumption is reduced by 8% in 2050. In CN2050/2060, the share of electricity increases to 35% in 2050; however, oil and gas consumption remains in the transport and industry sectors.

Figure 3.17. Final Energy Consumption in Malaysia (CN2050/2060)

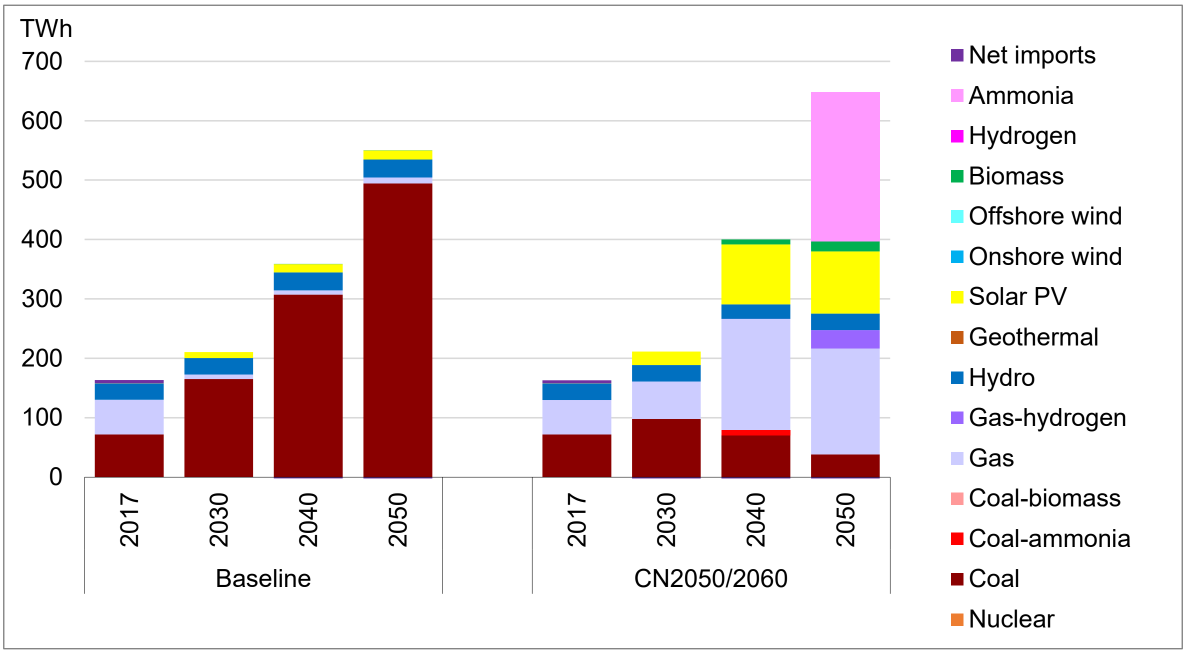


Mtoe = million tonnes of oil equivalent.
Source: Author.

3.2.4. Power Generation

Figure 3.18 shows the power generation in the Baseline and CN2050/2060. In the Baseline, coal-fired power generation accounted for 91% of the electricity mix in 2050. In CN2050/2060, gas-fired power generation (almost all with CCS) and solar PV expand instead of coal-fired power generation until 2040, with gas-fired power generation accounting for 28% and solar PV for 16% in 2050. The share of renewables including solar PV is 23% in 2050, and solar PV capacity installed in Peninsular Malaysia peaks in 2050 (78GW). Based on our price assumptions, ammonia-fired power generation is fuelled by imported NH_3, which is more cost-effective than domestic green hydrogen. Solar PV and hydropower are not installed for hydrogen production in East Malaysia.

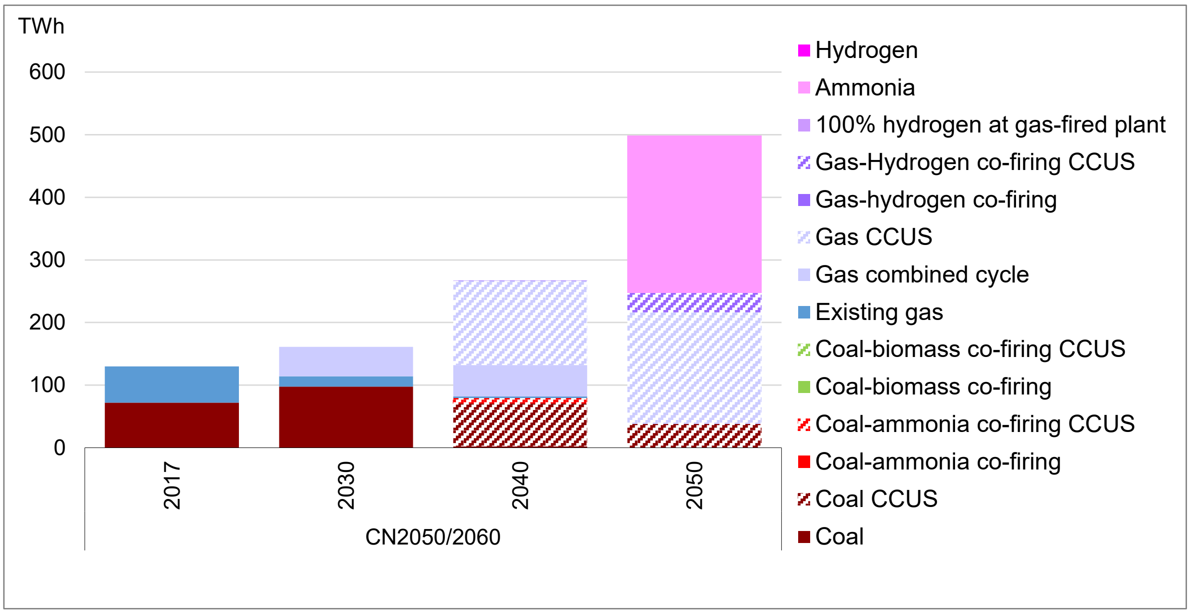
Figure 3.18. Power Generation in Malaysia (CN2050/2060)



PV = photovoltaic, TWh = terawatt-hour.
Source: Author.

Figure 3.19 shows the transition of thermal power generation (coal, natural gas, NH_3, and H_2) in total electricity generation. In the near term, efficient gas-fired (gas combined cycle) power generation plays a critical role in Malaysia's power mix. In 2040, CCS technology is preferentially introduced for coal and natural gas-fired power plants. In the long term, all fossil fuel-fired power plants need to be equipped with CCS by 2050 and the share of ammonia-fired power generation increases to 39% of total power generation.

Figure 3.19. Generated Electricity from Coal, Gas, Ammonia, and Hydrogen in Malaysia (CN2050/2060)

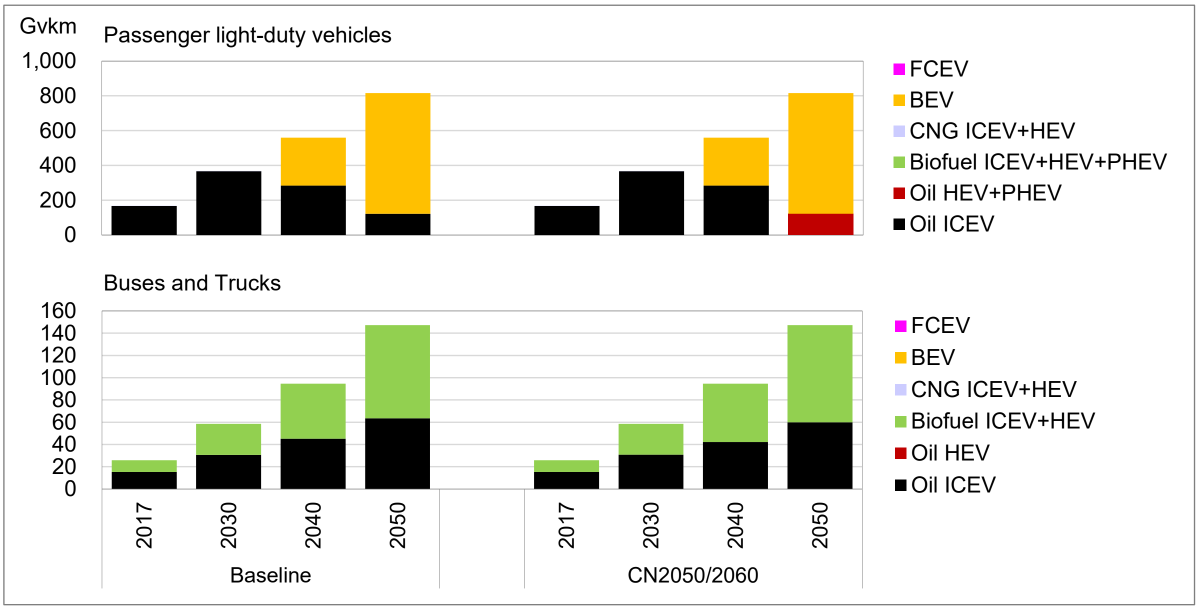


CCUS = carbon dioxide capture, utilisation, and storage, TWh = terawatt-hour.
Source: Author.

3.2.5. Road Transport

Figure 3.20, which shows the travel distance of passenger light-duty vehicles in the upper graph and that of buses and trucks in the bottom graph, demonstrates that oil continues to be used in short- and long-distance transportation in both the Baseline and CN2050/2060. In both cases, passenger light-duty vehicles are mostly electrified by 2050, whilst buses and trucks are not, due to their higher initial costs. Biofuel supply potential is not considered in detail in this analysis. The upper limit of biofuel supply is simply assumed to grow in proportion with road transport demand.

Figure 3.20. Travel Distance by Vehicle Technology in Malaysia (CN2050/2060)



BEV = battery electric vehicle, CNG = compressed natural gas, FCEV = fuel cell electric vehicle, Gvkm = 10^9 vehicle-km, HEV = hybrid electric vehicle, ICEV = internal combustion engine vehicle, PHEV = plug-in hybrid electric vehicle.

Note: Biofuel includes bioethanol and biodiesel mixed with petroleum fuel.

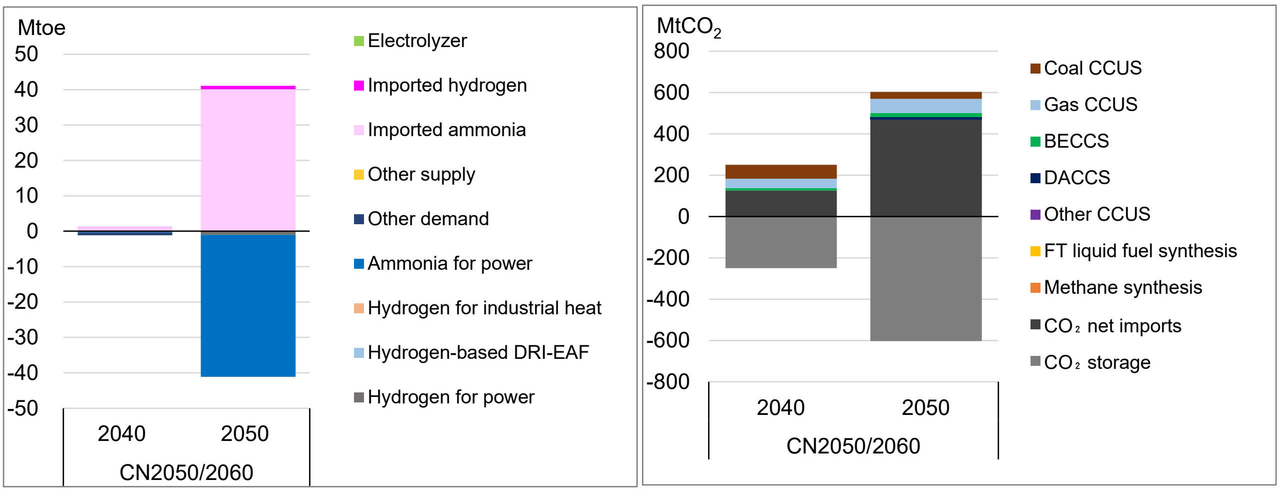
Source: Author.

3.2.6. Hydrogen and CCUS

According to the results, H_2 and NH_3 are supplied from abroad and are consumed mainly in power plants. The direct use of electricity from renewable energy sources is more cost-effective than producing green H_2 to meet electricity demand. Therefore, the optimisation model tends not to select domestic green H_2-fired power generation to realise the minimum cost. Based on our price assumptions, NH_3 is supplied only from abroad.

Given its large CCS potential, Malaysia is expected to import CO_2 from neighbouring countries. The amount of CO_2 stored in 2050 is 603 $MtCO_2$, which is equivalent to 0.8% of Malaysia's cumulative CCS capacity (80 $GtCO_2$).

Figure 3.21. Supply and Demand Balance of H_2 (Left) and the CCUS Balance (Right) in Malaysia



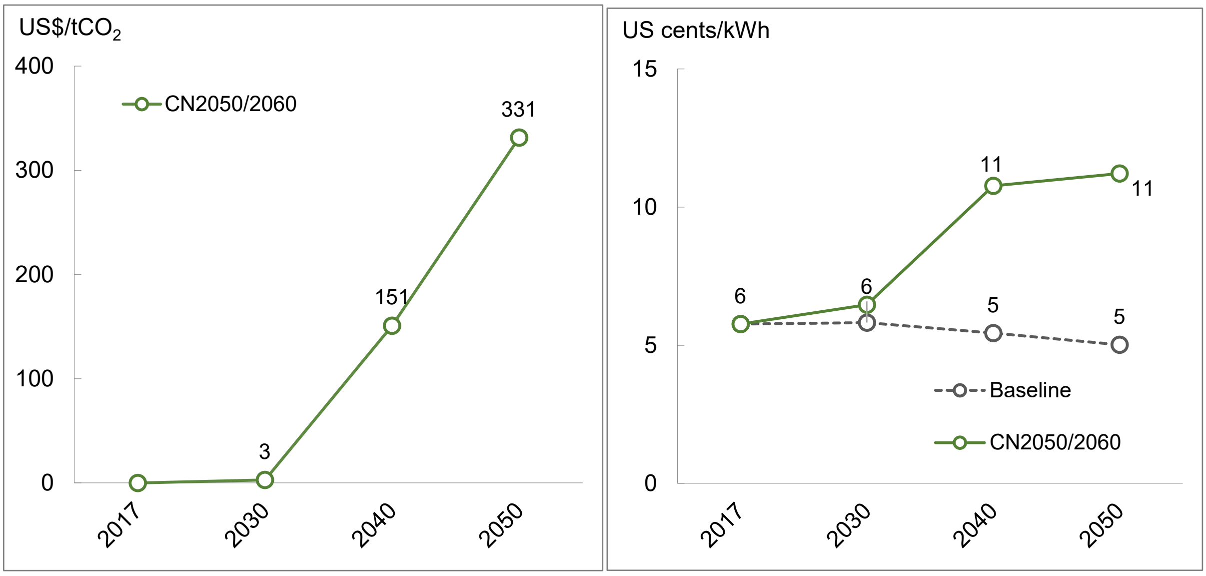
CCUS = carbon dioxide capture, utilisation, and storage, DRI-EAF = direct reduced iron–electric arc furnace, FT = Fischer-Tropsch.
Source: Author.

3.2.7. Costs for Reducing Carbon Dioxide

Figure 3.22 shows the MAC and the marginal cost of electricity in Malaysia. In CN2050/2060, the MAC rises to US$331/t$CO_2$ in 2050 towards carbon neutrality, which is 2.5 times higher than one of the current most expensive carbon prices in the world (US$130/t$CO_2$[5]). The marginal cost of electricity (11 cents/kWh) is about twice the current cost. Ammonia-fired power generation or gas-fired with CCS are the main determinants.

[5] Carbon tax in Sweden as of 2022.

Figure 3.22. Marginal Carbon Dioxide Abatement Cost (Left) and Marginal Cost of Electricity (Right) for CN2050/2060 in Malaysia



CO_2 = carbon dioxide, kWh = kilowatt-hour, MAC = marginal CO_2 abatement cost, tCO_2 = tonnes of carbon dioxide.

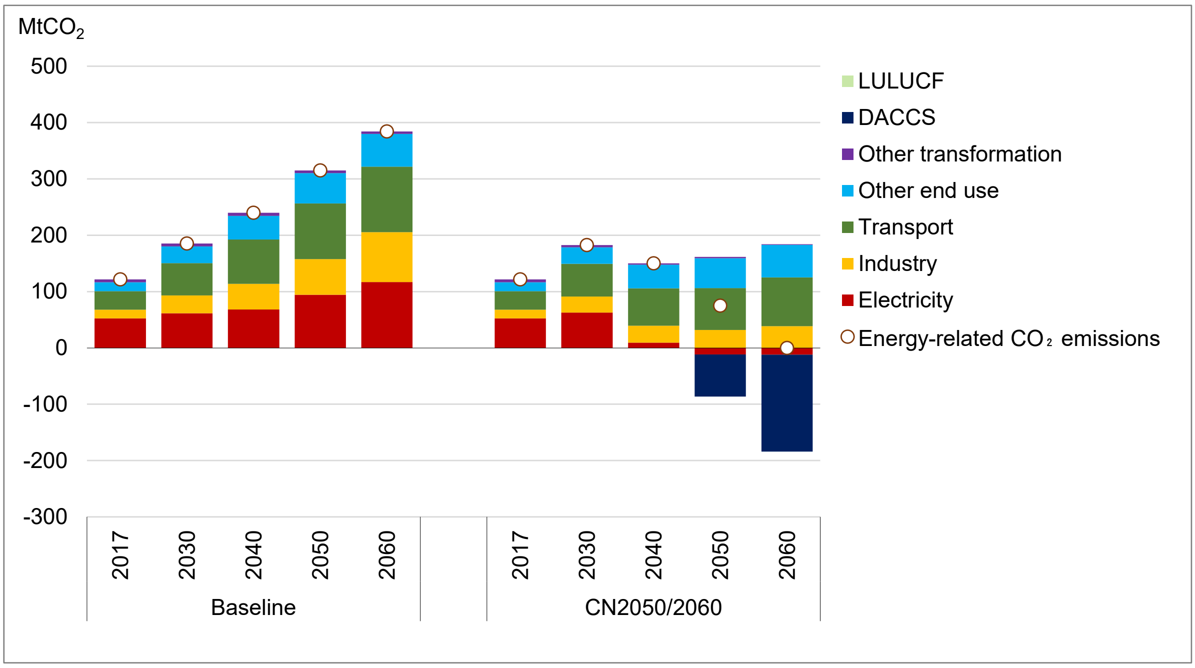
Source: Author.

3.3. Philippines

3.3.1. Sectoral Carbon Dioxide Emissions

Figure 3.23 shows the sector-wise CO_2 emissions in the Baseline and CN2050/2060. In the Baseline, CO_2 emissions increase mainly in electricity and transport with the growth of final energy consumption. In CN2050/2060, CO_2 emissions from transport, particularly buses and trucks, remain the same, whilst the power sector is fully decarbonised by 2050 because the costs of alternative vehicles, specifically battery electric vehicles and fuel cell vehicles, are high. End-use CO_2 emissions after 2050 are offset not only through decarbonisation of the power sector but also through a combination of negative-emission technologies, such as BECCS and DACCS.

Figure 3.23. Sector-wise Energy-related Carbon Dioxide Emissions in the Philippines (CN2050/2060)

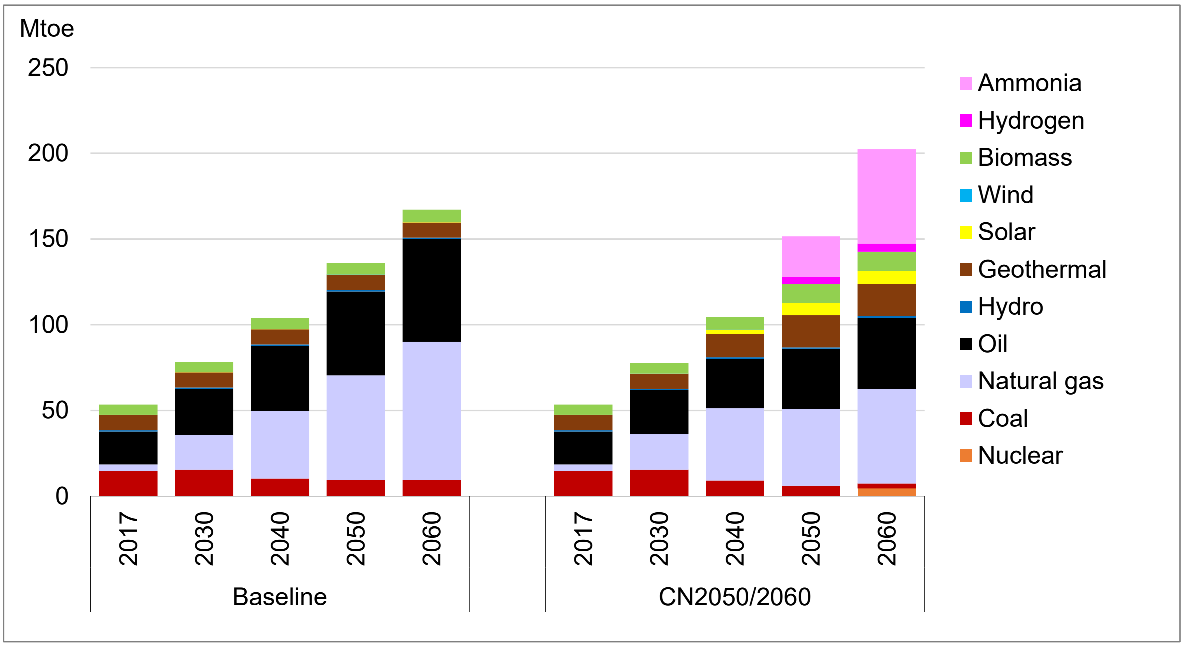


CO_2 = carbon dioxide, DACCS = direct air capture with carbon storage, LULUCF = land use, land-use change, and forestry; $MtCO_2$ = million tonnes of carbon dioxide.
Source: Author.

3.3.2. Primary Energy Supply

Figure 3.24 shows the primary energy supply in the Baseline and CN2050/2060. The primary energy supply in 2060 substantially increases to approximately 3.1 times the 2017 level in the Baseline and to approximately 3.8 times in CN2050/2060. In the Baseline, the primary energy supply from fossil fuels such as natural gas and oil continues to increase in 2060. Even in CN2050/2060, fossil fuels account for about half of the primary energy supply. However, promoting decarbonisation towards carbon neutrality requires a broad range of technologies, such as renewable energy, nuclear, CCS, and H_2 and NH_3 imports. In CN2050/2060, the share of these technologies rises to 43% of the primary energy supply in 2050 and 51% in 2060. The share of H_2 and NH_3 imports increases to 29%, and renewables account for 19% in 2060.

Figure 3.24. Primary Energy Supply in the Philippines (CN2050/2060)

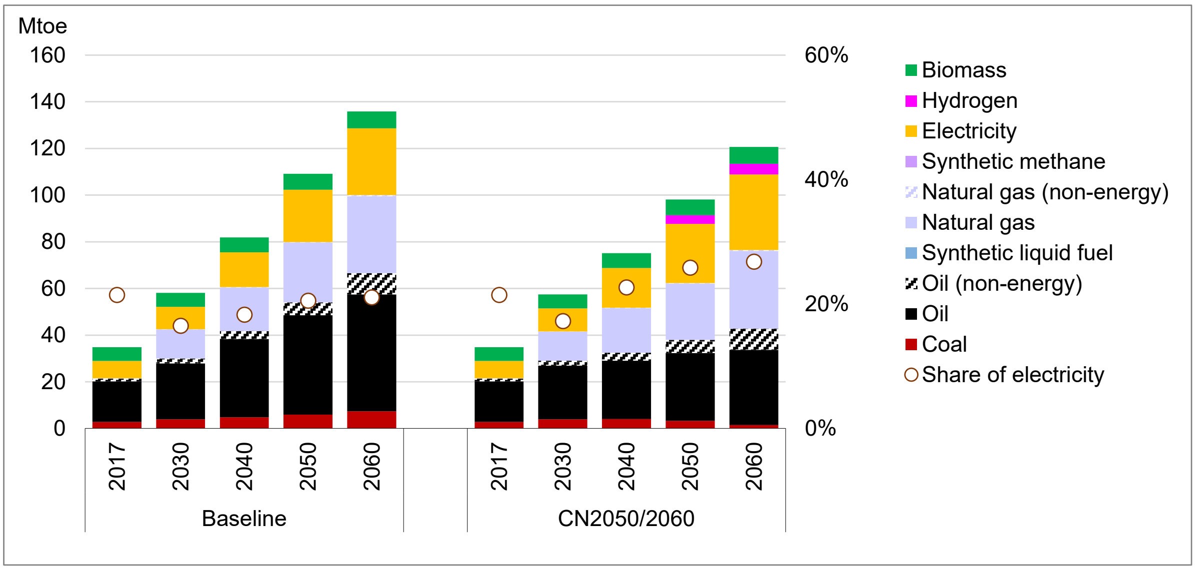


Mtoe = million tonnes of oil equivalent.
Source: Author.

3.3.3. Final Energy Consumption

Figure 3.25 shows final energy consumption in the Baseline and CN2050/2060. In CN2050/2060, final energy consumption in 2060 decreases by 11% compared with the Baseline, driven by accelerated energy savings and electrification. In CN2050/2060, the share of electricity increases to 27% by 2060. The changes suggest that advancing energy efficiency and electrification is a core strategy to decarbonise end-use sectors.

Figure 3.25. Final Energy Consumption in the Philippines (CN2050/2060)

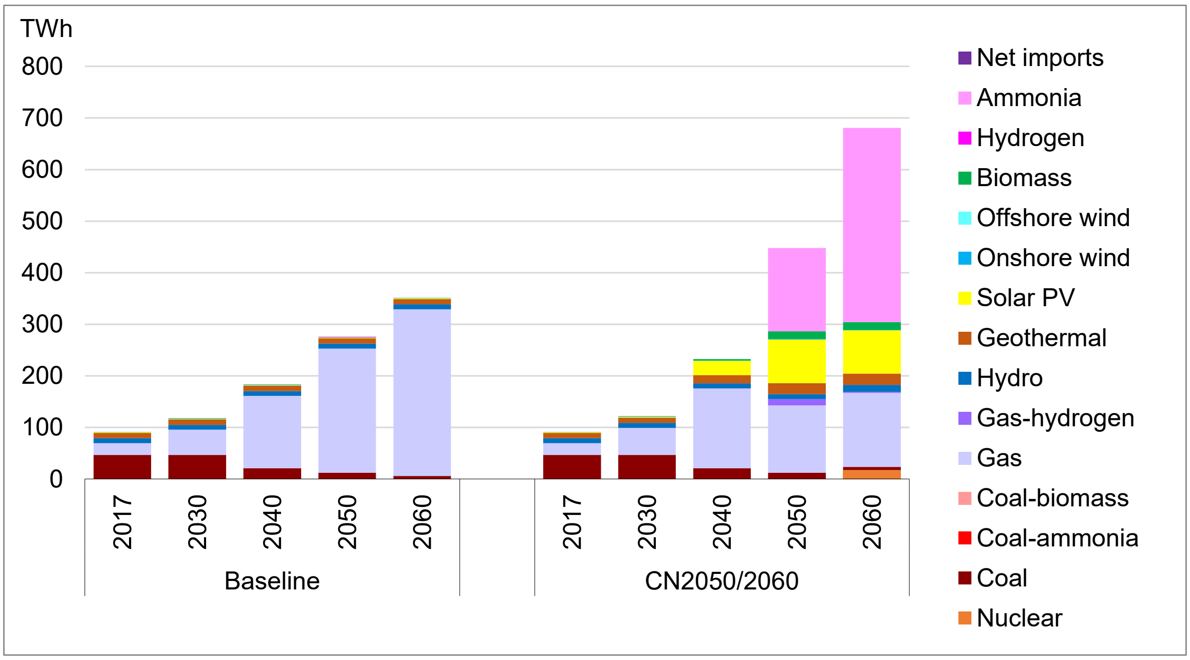


Mtoe = million tonnes of oil equivalent.
Source: Author.

3.3.4. Power Generation

Figure 3.26 shows power generation in the Baseline and CN2050/2060. In the Baseline, natural gas-fired power generation accounts for most of the electricity mix in 2060. In CN2050/2060, NH_3-fired power generation is a major power source, accounting for 55% in 2060. The share of natural gas-fired power generation is 21%, followed by renewables, which account for 20%.

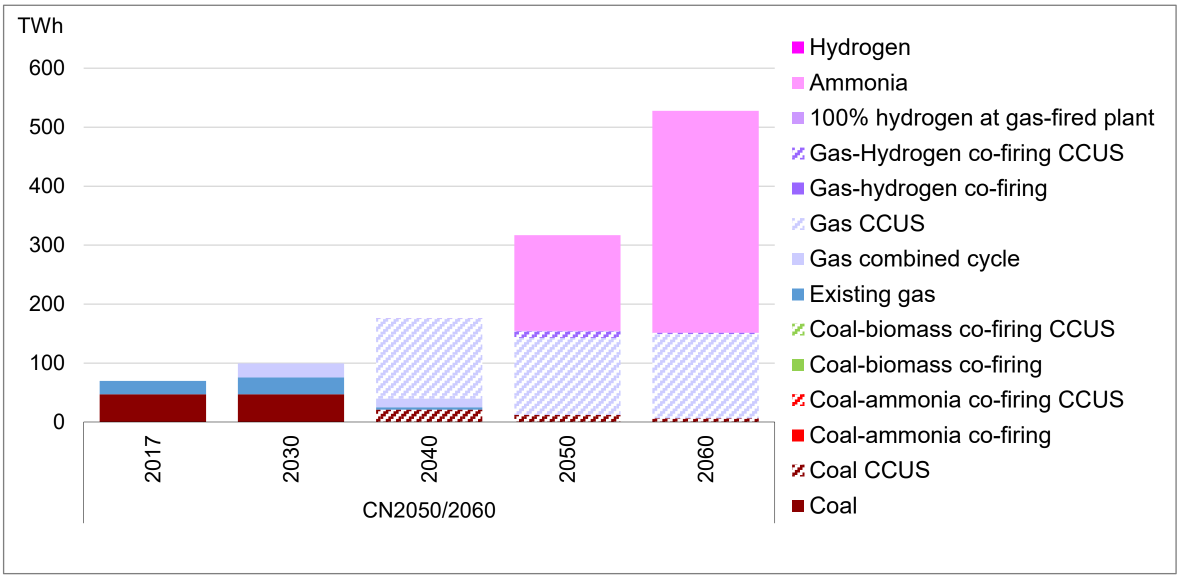
Figure 3.26. Power Generation in the Philippines (CN2050/2060)



PV = photovoltaic, TWh = terawatt-hour.
Source: Author.

Figure 3.27 shows the transition of thermal power generation (coal, natural gas, NH_3, and H_2) in total electricity generation. In the near term, for example, up to 2030, highly efficient gas-fired power generation and gas combined cycle technology are estimated to contribute to curbing CO_2 emissions from power generation. In the medium-to-long term, gas-fired power generation with CO_2 capture, utilisation, and storage (CCUS), co-firing with NH_3 or H_2, and 100% NH_3-fired power generation are the candidates. From 2040 to 2050, gas-fired power generation with CCUS and 100% NH_3-fired power generation are expected to be pursued, and 71% of thermal power generation shifts to 100% NH_3-fired power generation by 2060.

Figure 3.27. Generated Electricity from Coal, Gas, Ammonia, and Hydrogen in the Philippines (CN2050/2060)

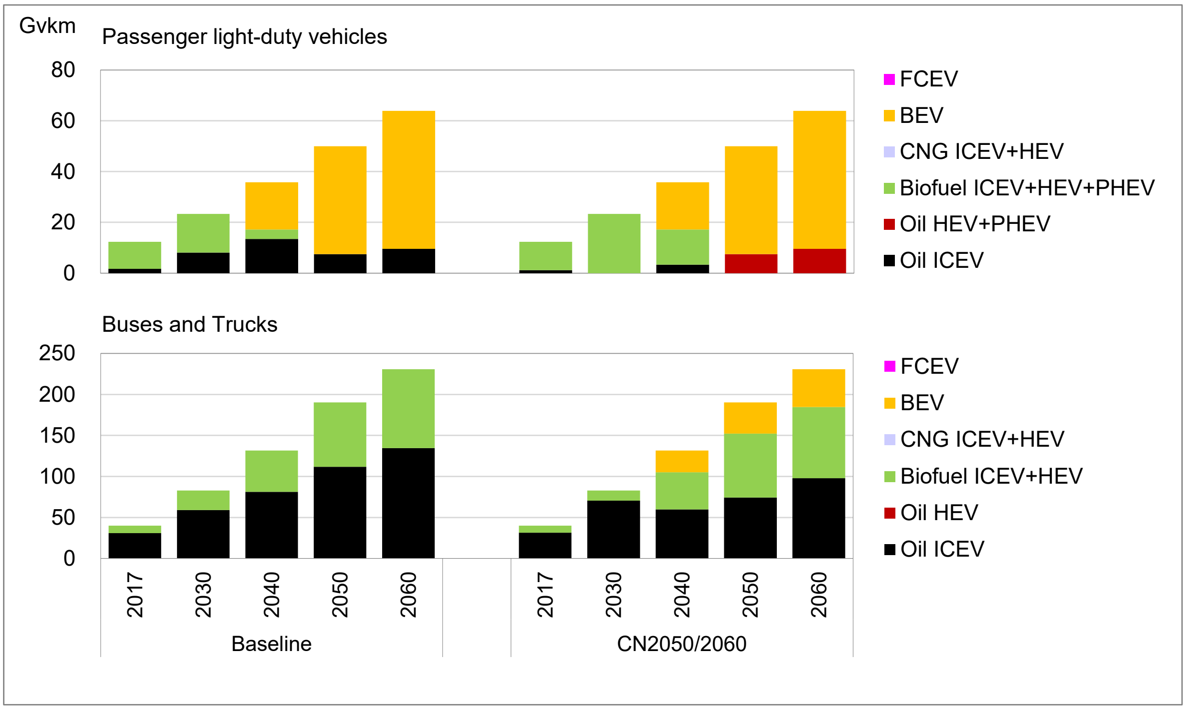


CCUS = carbon dioxide capture, utilisation, and storage, TWh = terawatt-hour.
Source: Author.

3.3.5. Road Transport

Transport contributes greatly to the growth of final energy consumption in the Baseline. Figure 3.28, which shows the travel distance of passenger light-duty vehicles in the upper graph and that of buses and trucks in the bottom graph, demonstrates that the use of oil continues in short- and long-distance transportation in the Baseline. In contrast, a major share of passenger vehicles are electrified by 2050 in CN2050/2060. However, the electrification of buses and trucks is limited due to the upper-bound assumption, i.e. a maximum share of 20% of all vehicles. The current fossil fuel price assumption provides incentives to promote the use of biofuels in internal combustion engines and hybrid vehicles. Biofuel and oil are expected to be the primary fuel sources for buses and trucks in 2060, and the residual emissions are offset by DACCS.

Figure 3.28. Travel Distance by Vehicle Technology in the Philippines (CN2050/2060)



BEV = battery electric vehicle, CNG = compressed natural gas, FCEV = fuel cell electric vehicle, Gvkm = 10^9 vehicle-km, HEV = hybrid electric vehicle, ICEV = internal combustion engine vehicle, PHEV = plug-in hybrid electric vehicle.

Note: Biofuel includes bioethanol and biodiesel mixed with petroleum fuel.

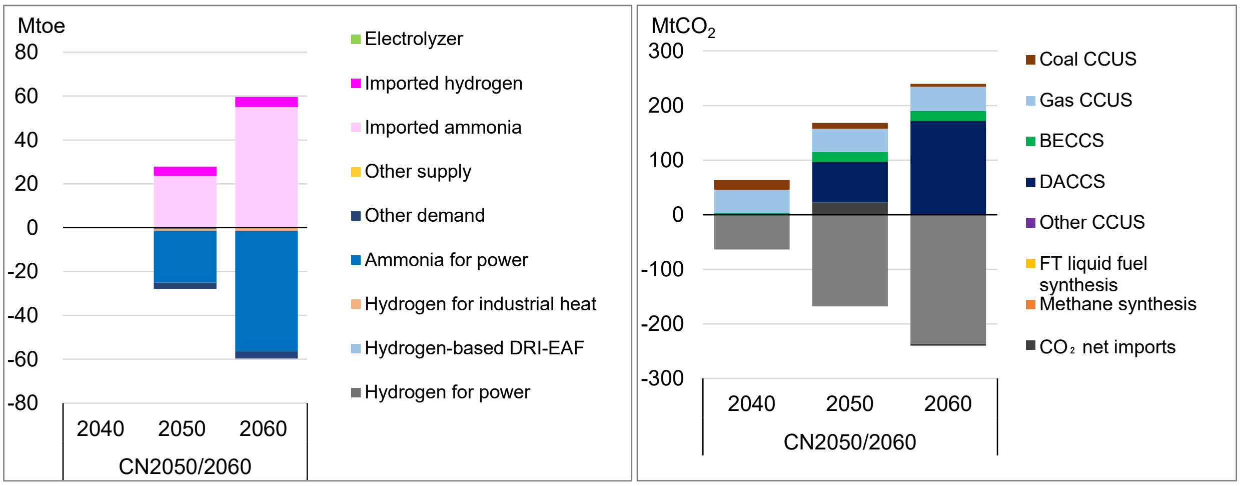
Source: Author.

3.3.6. Hydrogen and CCUS

As discussed in Section 3.2.6, H_2 and NH_3 are supplied from abroad and are consumed in power plants. Thus, the main opportunity for domestic green H_2 will be consumption for transportation, such as fuel cell vehicles and ships, and for thermal demand, such as heat for furnaces. As discussed in Section 2.2.1 (d), the feasibility of producing green H_2 depends on its cost. If a country has renewable energy potential in remote areas without transmission lines, power generation from domestic green NH_3/H_2 may be feasible, which will also contribute to the energy security of the country. Currently, the model does not consider the installation of renewables in remote areas in the Philippines.

Captured CO_2 from power plants and DAC is stored underground (CCS). The amount of CO_2 stored in 2060 is 242 $MtCO_2$, equivalent to 1.1% of the cumulative CCS capacity in the Philippines (22.3 $GtCO_2$).

Figure 3.29. Supply and Demand Balance of H_2 (Left) and the CCUS Balance (Right)

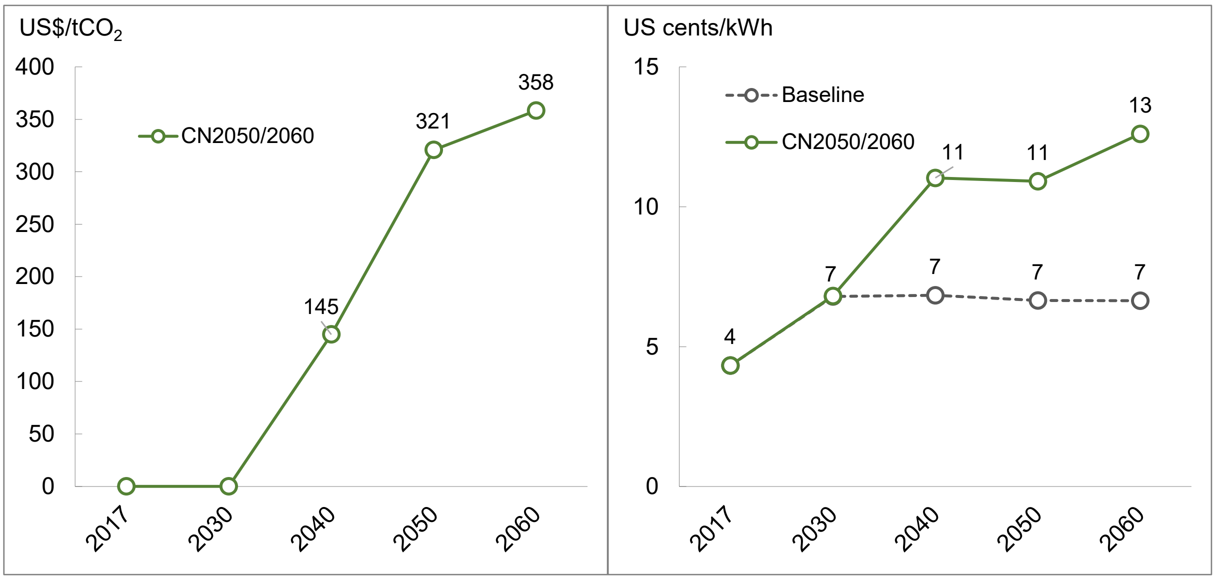


CCUS = carbon dioxide capture, utilisation, and storage, DRI-EAF = direct reduced iron–electric arc furnace, FT = Fischer-Tropsch.
Source: Author.

3.3.7. Costs for Reducing Carbon Dioxide

Figure 3.30 shows the MAC and the marginal cost of electricity in the Philippines. In CN2050/2060, the MAC rises to US$358/$tCO_2$ in 2060, implying an economic challenge to decarbonisation. The electricity price is estimated to increase two-fold in CN2050/2060 compared to the Baseline.

Figure 3.30. Marginal Carbon Dioxide Abatement Cost (Left) and Marginal Cost of Electricity (Right) for CN2050/2060 in the Philippines



CO_2 = carbon dioxide, kWh = kilowatt-hour, MAC = marginal CO_2 abatement cost, tCO_2 = tonnes of carbon dioxide.
Source: Author.

3.3.8. Sensitivity Analysis 1: Technological Innovation

In this sensitivity analysis, five cases of technological innovation were set to analyse the impact of the innovation on mitigation costs (MAC). Table 3.1 shows the assumptions of the cases.

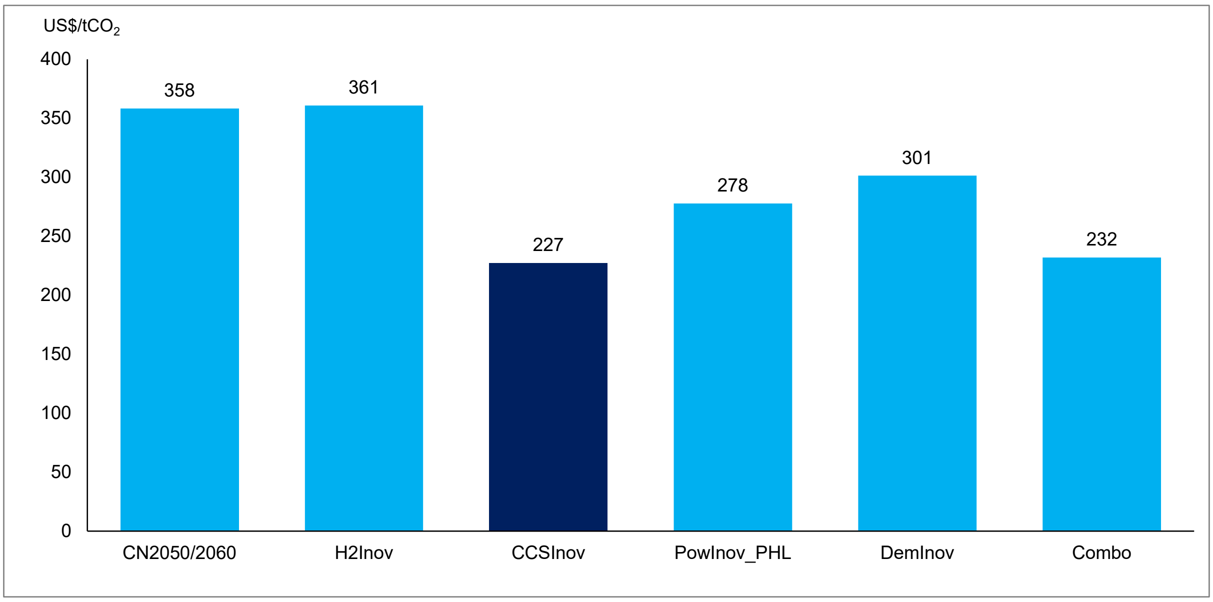
Table 3.1. Key Technology Assumptions for Technological Innovation Cases for the Philippines

Case	Net-zero Year	Key Technology Assumptions
CN2050/2060	2060	• Reference technology cost • International power grid extension constrained by planned ASEAN power grid capacity • Annual CO_2 storage up to 1.1% of cumulative potential in 2060
PowInov_PHL	2060	• Cost reduction of lithium-ion batteries, wind turbines (-25% in 2040 and -50% after 2050, from the reference level) and international grid extension • No upper limit for international power grid extension • Large-scale electricity exports from Myanmar to Thailand
CCSInov	2060	• Cost reduction of direct air capture (-25% in 2040 and -50% after 2050) • Additional CO_2 storage capacity (+1% of potential. The added capacity is for the exclusive use of the country with the resource.)
H_2Inov	2060	• Cost reduction of coal gasification, methane reforming and electrolyser (-25% in 2040 and -50% after 2050) • Cost reduction of H_2 consumption: H_2-based DRI-EAF and fuel cell ships (-25% in 2040 and -50% after 2050), FCEVs (comparable to hybrid electric vehicle price in 2060)
DemInov	2060	• Cost reduction of advanced end-use technologies (-50% in and after 2040)
Combo	2060	• Combined assumptions of the four innovation cases mentioned above

ASEAN = Association of Southeast Asian Nations, CO_2 = carbon dioxide, DRI-EAF = direct reduced iron–electric arc furnace, FCEV = fuel cell electric vehicle, $GtCO_2$ = gigatonnes of carbon dioxide, H_2 = hydrogen.
Source: Author.

Figure 3.31 shows the MAC for each case in 2060. A comparison of CN2050/2060 with the technological innovation cases shows that energy cooperation in the region, such as reducing the cost of each technology through innovation, significantly reduces the marginal costs. The MAC for CCSInnov is about 37% lower than that for CN2050/2060, indicating that reducing the cost of DAC and expanding CO_2 storage contribute to the MAC reduction. Research and development and international collaboration are essential for achieving carbon neutrality. Technological innovation, including research and development and international cooperation, are particularly important for achieving carbon neutrality. Therefore, rather than promoting individual efforts, all countries should pursue international cooperation to accelerate innovation leading to cost reductions.

Figure 3.31. Marginal Abatement Cost of CO_2 in 2060

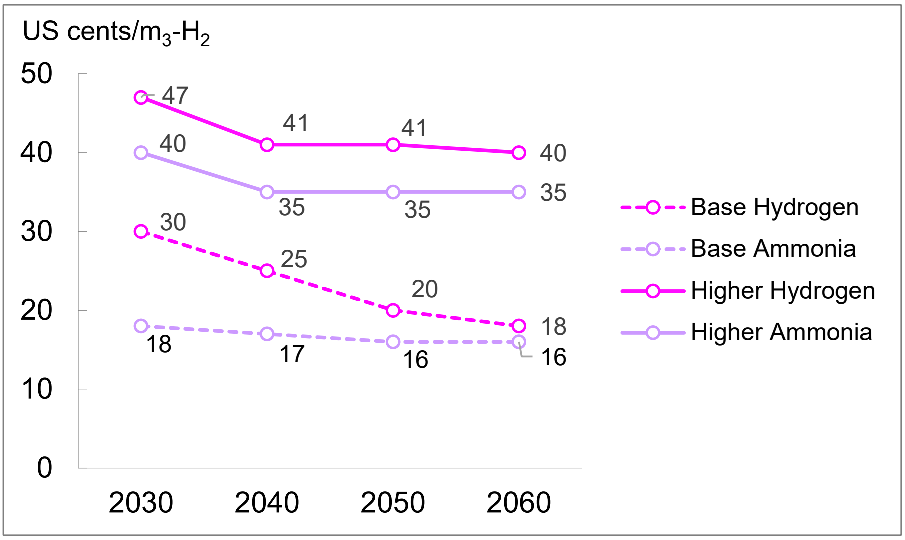


Source: Author.

3.3.9. Sensitivity Analysis 2: Higher H_2 and NH_3 Prices

This sensitivity analysis was set to analyse the impact of higher H_2 and NH_3 prices on the energy mix. The prices of H_2 and NH_3 are assumed as shown in Figure 3.32 based on the IEA (2022b).

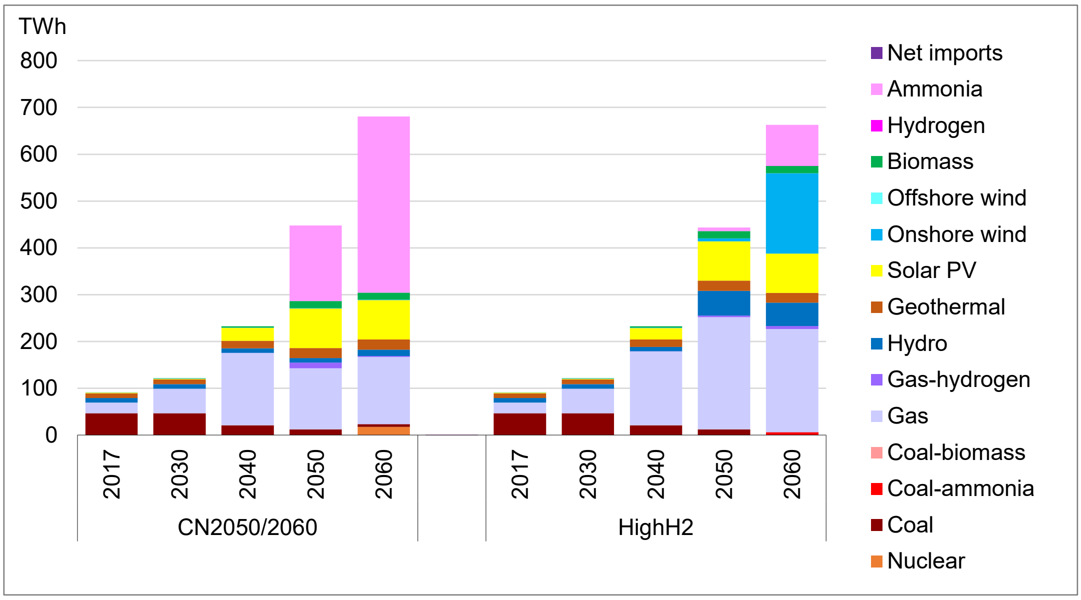
Figure 3.32. Assumed H_2 and NH_3 Prices (Sensitivity Analysis 2)



Source: Author.

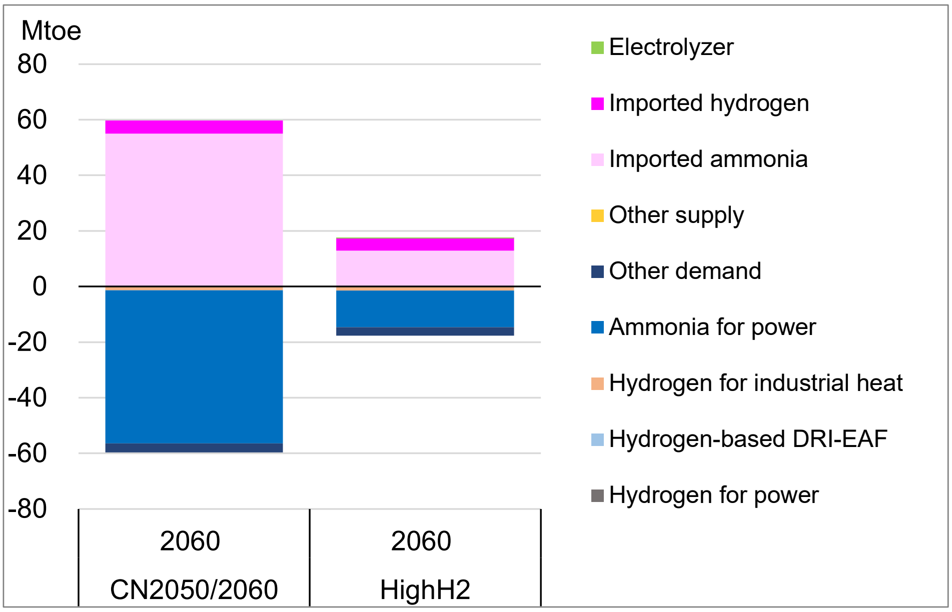
The main difference between the two cases is the power generation mix. The higher price assumptions lead to a significant increase in renewables, especially onshore wind and hydropower, instead of NH_3-fired power generation. The marginal cost of electricity in Sensitivity Analysis 2 increases by 64% in 2050 and by 53% in 2060, compared to CN2050/2060. As shown in Figure 3.34, the higher prices reduce the amount of imported H_2 and NH_3, but a certain amount of imported NH_3 is consumed in power generation.

Figure 3.33. Power Generation in the Philippines (Sensitivity Analysis 2)



TWh = terawatt-hour.
Source: Author.

Figure 3.34. Balance of H_2 in the Philippines (Sensitivity Analysis 2)



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

3.3.10. Sensitivity Analysis 3: Impact of Nuclear Power

This sensitivity analysis was carried out to evaluate the impact of nuclear power on the energy supply and cost in the Philippines. Based on the Philippines' DOE target of 2,500 MW of nuclear power capacity by 2032, HighNuclear assumes further development of nuclear power after 2040 and a longer operating period. HighNuclear also assumes higher H_2 and NH_3 prices as set in Sensitivity Analysis 2.

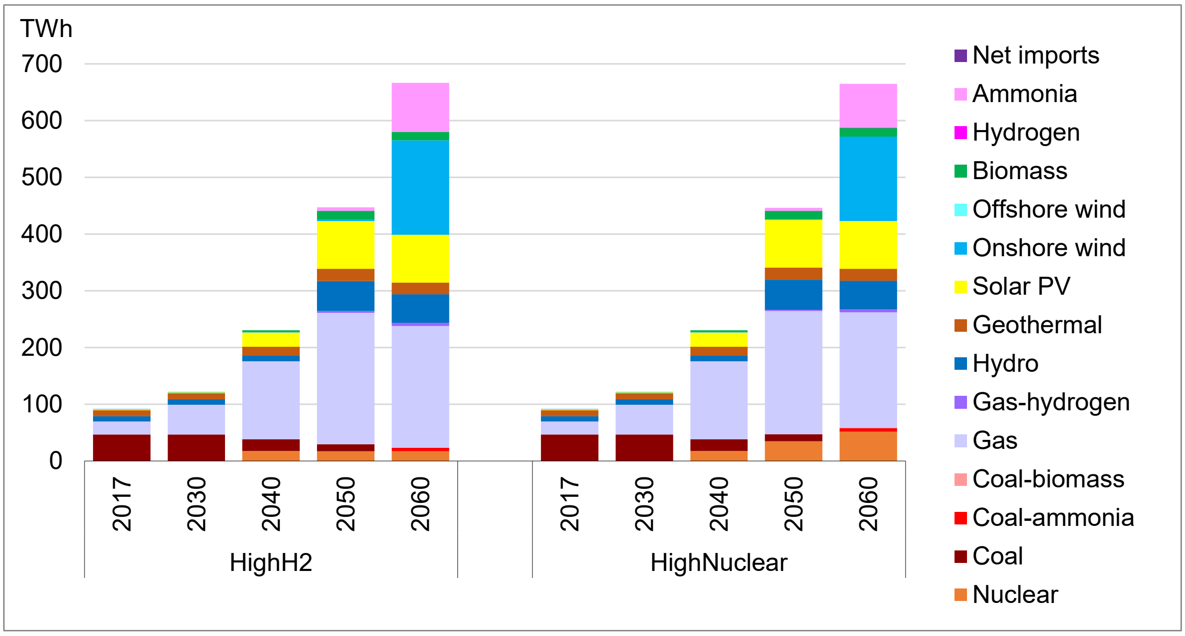
Table 3.2. Assumptions for Nuclear Power in the Philippines

	Year	CN2050/2060	HighNuclear
Upper limit of capacity (MW)	~2030	0	0
	2040	2,500	2,500
	2050	2,500	5,000
	2060	2,500	7,500
Capital cost (US$/kW])		5,433	5,433
Operating period [years]		40	60

kW = kilowatt, MW = megawatt.
Note: Based on DOE information.
Source: Author.

Figure 3.35 shows the power generation in HighH2 and HighNuclear. In HighNuclear, nuclear power accounts for approximately 8% of the total generation after 2040, reducing onshore wind and ammonia-fired power. Whilst electricity demand is projected to grow significantly, other forms of generation are still needed to meet the demand. Natural gas-fired power generation remains the dominant source of electricity in 2060, although its share declines slightly to 49% when comparing the two cases. Renewables also play a key role after 2040.

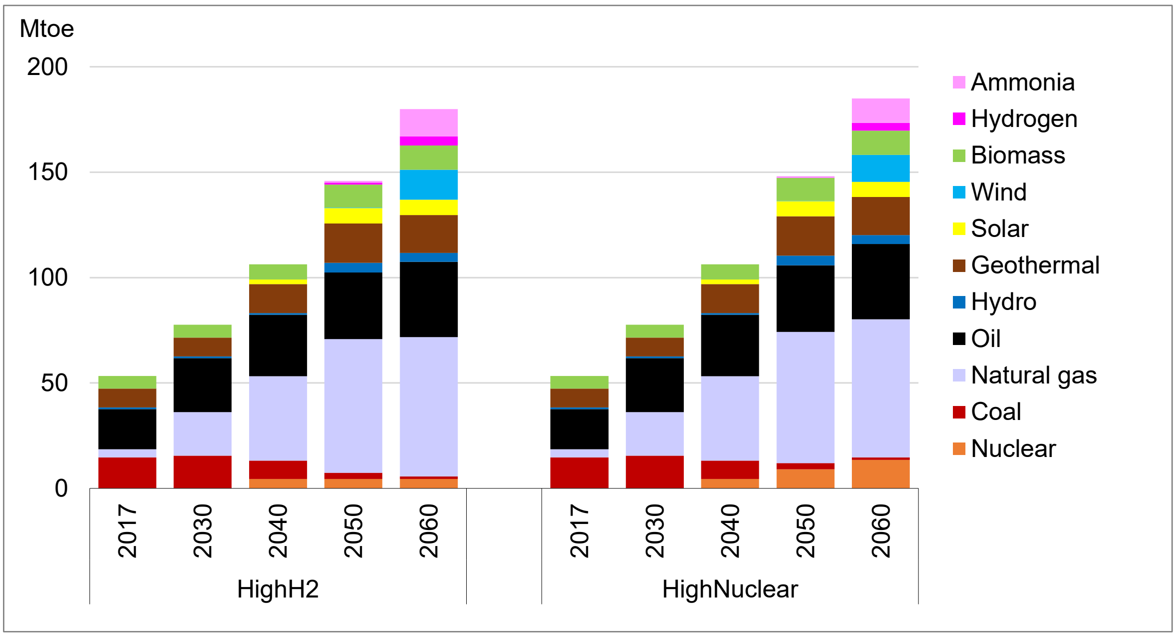
Figure 3.35. Power Generation in the Philippines (Sensitivity Analysis 3)



TWh = terawatt-hour.
Source: Author.

In terms of the primary energy supply, the introduction of nuclear power combined with higher H_2/NH_3 prices could reduce the imports of ammonia. Figure 3.36 shows the primary energy supply in HighH2 and HighNuclear. The share of imported H_2 and NH_3 decreases to 8% in 2060.

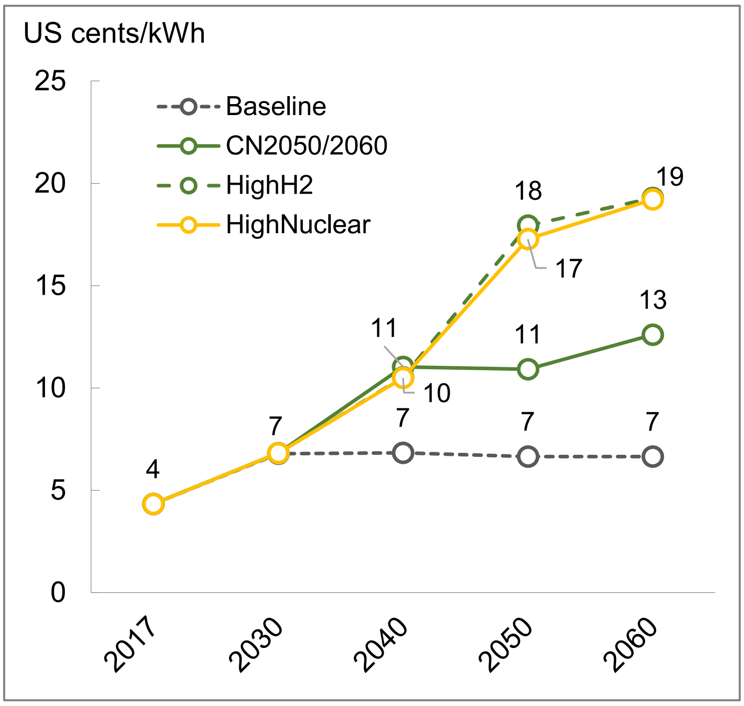
Figure 3.36. Primary Energy Supply in the Philippines (Sensitivity Analysis 3)



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

Figure 3.37 shows the marginal cost of electricity in four cases, including HighNuclear. Compared to CN2050/2060, the marginal cost of electricity in HighH2 and HighNuclear in 2060 increases by 53% and 52%, respectively, due to the higher H_2 and NH_3 price assumptions. Since both cases have the same assumptions except for nuclear power, the marginal cost of electricity in HighNuclear is slightly lower than that in HighH2. This indicates that nuclear power contributes to reducing the marginal cost of electricity.

Figure 3.37. Marginal Cost of Electricity in the Philippines (Sensitivity Analysis 3)



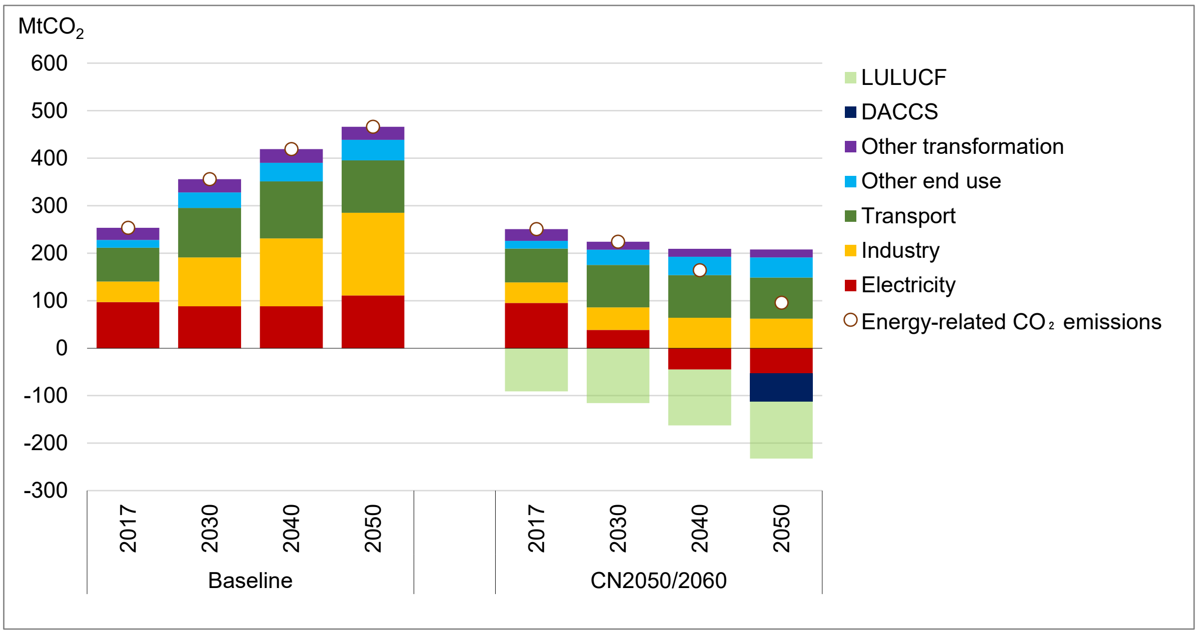
kWh = kilowatt-hour.
Source: Author.

3.4. Thailand

3.4.1. Sectoral Carbon Dioxide Emissions

Figure 3.38 shows the sector-wise CO_2 emissions in the Baseline and CN2050/2060. In the Baseline, CO_2 emissions increase in the electricity and industry sectors. In CN2050/2060, CO_2 emissions from electricity are fully decarbonised by 2040. LULUCF, BECCS, and DACCS offset the residual emissions, mostly from the transport and industry sectors, in 2050.

Figure 3.38. Sector-wise Energy-related Carbon Dioxide Emissions in Thailand (CN2050/2060)

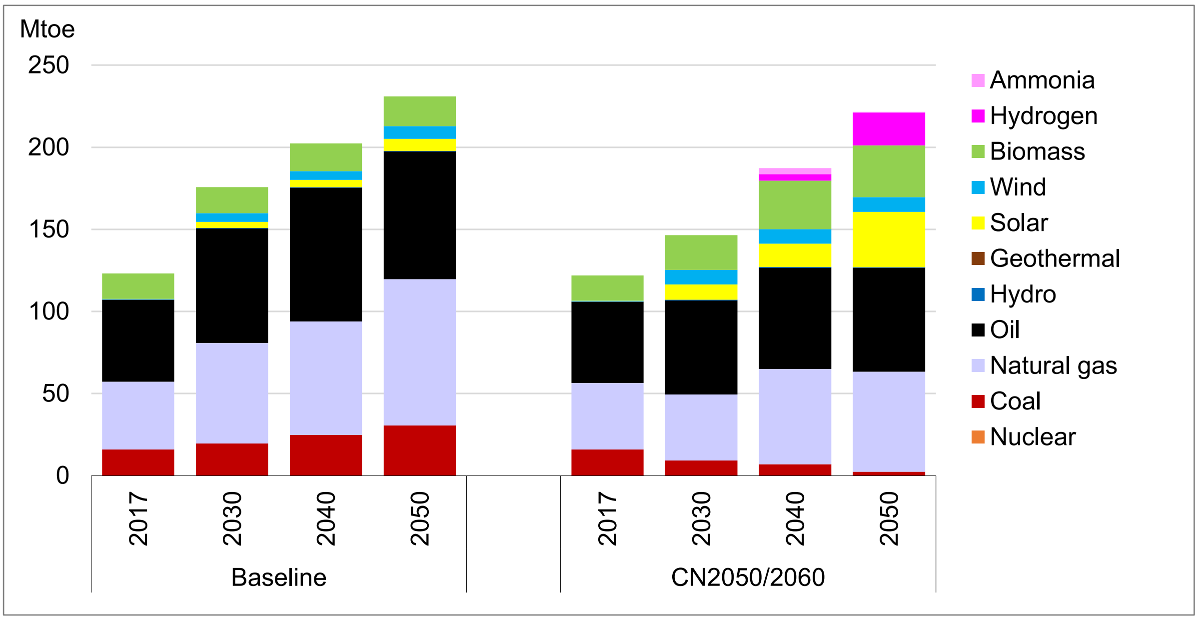


CO_2 = carbon dioxide; DACCS = direct air capture with carbon storage; LULUCF = land use, land-use change, and forestry; $MtCO_2$ = million tonnes of carbon dioxide.
Source: Author.

3.4.2. Primary Energy Supply

Figure 3.39 shows the primary energy supply in the Baseline and CN2050/2060. The primary energy supply in 2050 increases to approximately 1.9 times the 2017 level in the Baseline, and to 1.8 times in CN2050/2060. In the Baseline, the primary energy supply from fossil fuels, such as coal, natural gas, and oil, accounts for 85% of the primary energy supply. In CN2050/2060, fossil fuels continue to play a role, but the share of solar PV and wind increases to 19% of the primary energy supply.

Figure 3.39. Primary Energy Supply in Thailand (CN2050/2060)

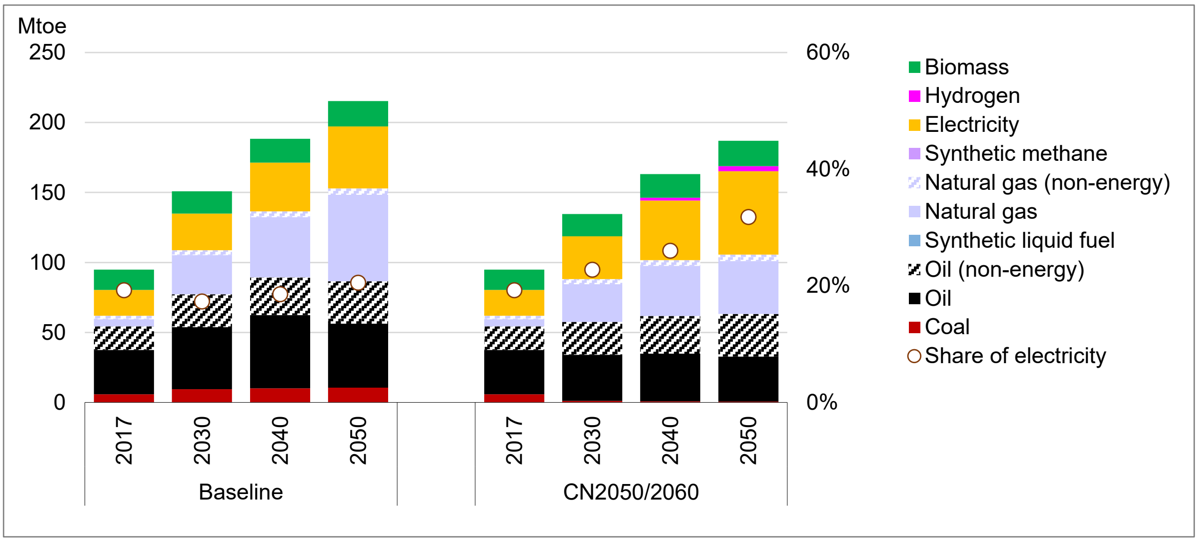


Mtoe = million tonnes of oil equivalent.
Source: Author.

3.4.3. Final Energy Consumption

Figure 3.40 shows the final energy consumption in the Baseline and CN2050/2060. In CN2050/2060, the final energy consumption decreases by 13% in 2050 compared to the Baseline. In CN2050/2060, the share of electricity increases to 32% in 2050, however, oil and gas consumption remains in the transport and industry sectors.

Figure 3.40. Final Energy Consumption in Thailand (CN2050/2060)

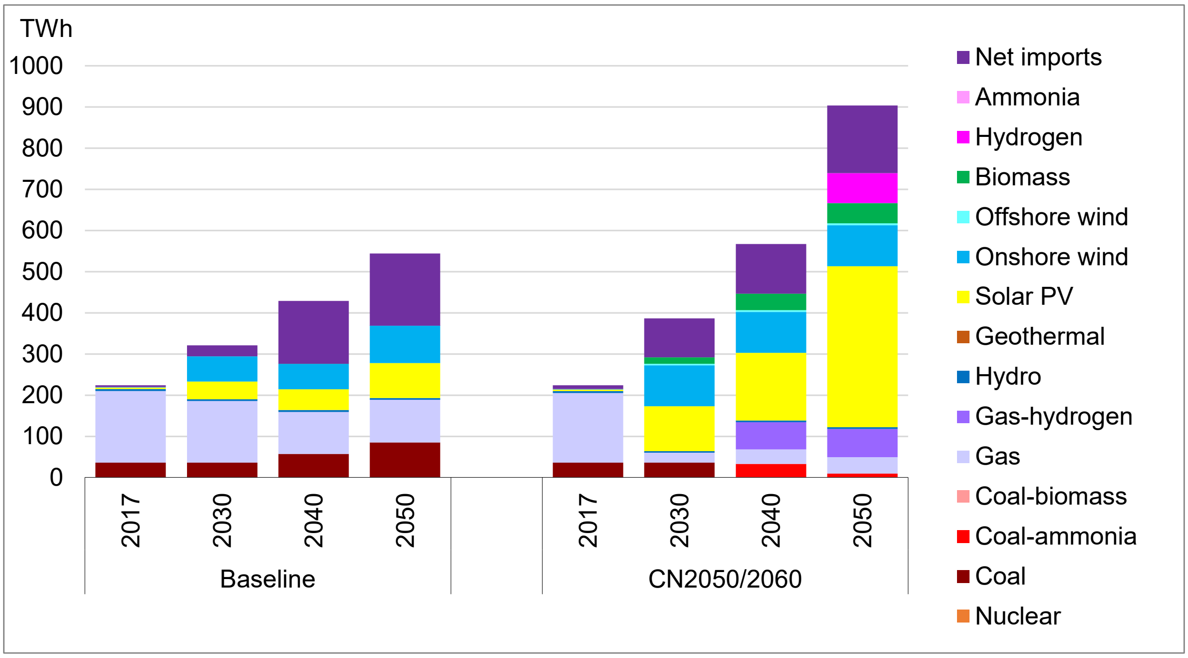


Mtoe = million tonnes of oil equivalent.
Source: Author.

3.4.4. Power Generation

Figure 3.41 shows the power generation in the Baseline and in CN2050/2060. In the Baseline, coal and natural gas-fired power generation account for 35% of the electricity mix in 2050. In CN2050/2060, solar PV plays an important role in generated electricity, accounting for 43% in 2050, and the share of renewables increases to 61%.[6] Solar PV and wind expand dramatically, and the share of natural gas-fired power generation decreases in CN2050/2060. However, thermal power plants, such as natural gas-fired, natural gas co-firing with H_2, and 100% H_2-fired plants, also contribute to maintaining the balance between electricity supply and demand. Imported electricity, mainly from the Lao PDR, is also an important source of electricity for Thailand.

Figure 3.41. Power Generation in Thailand (CN2050/2060)

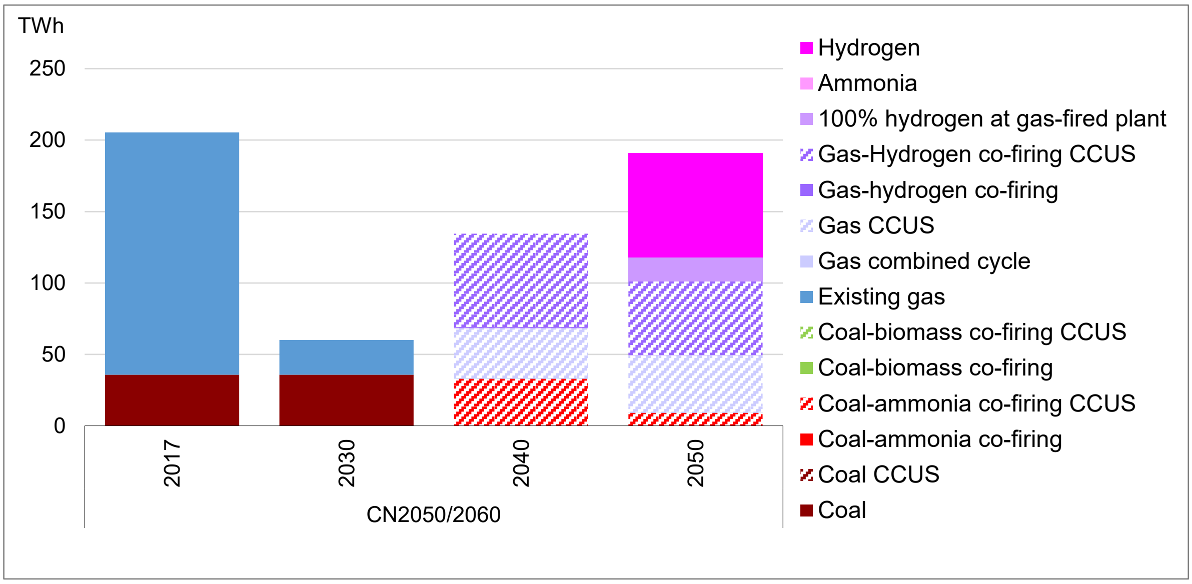


PV = photovoltaic, TWh = terawatt-hour.
Source: Author.

Figure 3.42 shows the transition of thermal power generation (coal, natural gas, NH_3, and H_2) in total electricity generation. In the medium term, gas-fired power generation and co-firing power plants with H_2 or NH3 should be equipped with CCUS. The share of H_2-fired power generation is expected to reach 8% in 2050.

[6] Net imports are not counted as renewables here.

Figure 3.42. Generated Electricity from Coal, Gas, Ammonia, and Hydrogen in Thailand (CN2050/2060)

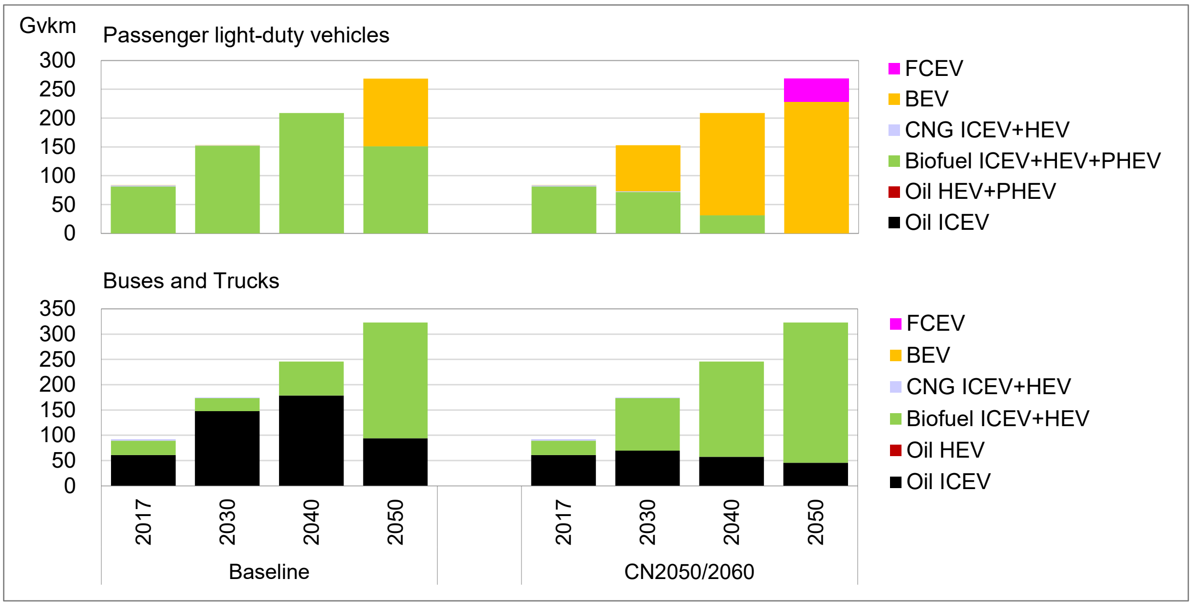


CCUS = carbon dioxide capture, utilisation, and storage; TWh = terawatt-hour.
Source: Author.

3.4.5. Road Transport

Figure 3.43 shows the travel distance of passenger light-duty vehicles in the upper graph and that of buses and trucks in the bottom graph. Thailand's targets on the share of zero-emission vehicle sales, 50% by 2030 and 100% after 2040, are reflected. As a result, nearly half of the passenger light-duty vehicles shift to BEVs by 2030, increasing to 85% by 2040. Imported H_2 is used for FCEVs in 2050. The use of oil remains for buses and trucks, however, the current fossil fuel price assumption provides incentives to promote the use of biofuels in internal combustion engines and hybrid vehicles.

Figure 3.43. Travel Distance by Vehicle Technology in Thailand (CN2050/2060)



BEV = battery electric vehicle, CNG = compressed natural gas, FCEV = fuel cell electric vehicle, Gvkm = 10^9 vehicle-km, HEV = hybrid electric vehicle, ICEV = internal combustion engine vehicle, PHEV = plug-in hybrid electric vehicle.

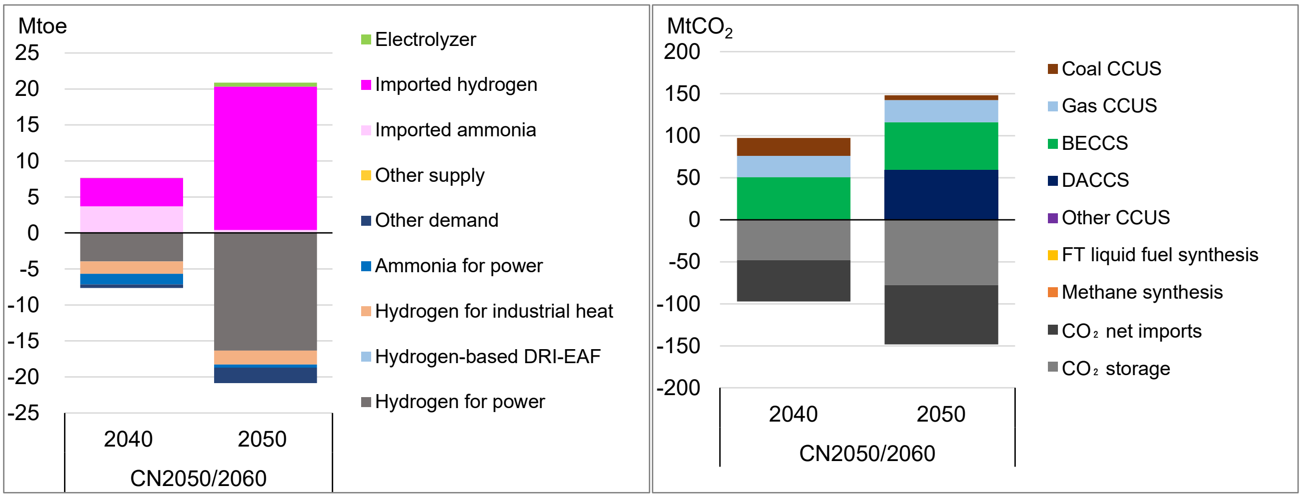
Note: Biofuel includes bioethanol and biodiesel mixed with petroleum fuel.

Source: Author.

3.4.6. Hydrogen and CCUS

As discussed in the previous chapters, H_2 and NH_3 are supplied from abroad and are mainly consumed in power plants in this study. Based on our price assumptions on H_2 and NH_3, domestic green H_2 is more expensive than imported H_2/NH_3. A small amount of green H_2 is supplied within the country in 2050, however, most of the H_2 and NH_3 are imported from abroad and used for mainly power generation. The amount of CO_2 stored in 2050 is 78 $MtCO_2$, which was equivalent to 0.8% of the cumulative CCS capacity in Thailand (10.3 $GtCO_2$).

Figure 3.44. Supply and Demand Balance of H_2 (Left) and CCUS Balance (Right) in Thailand

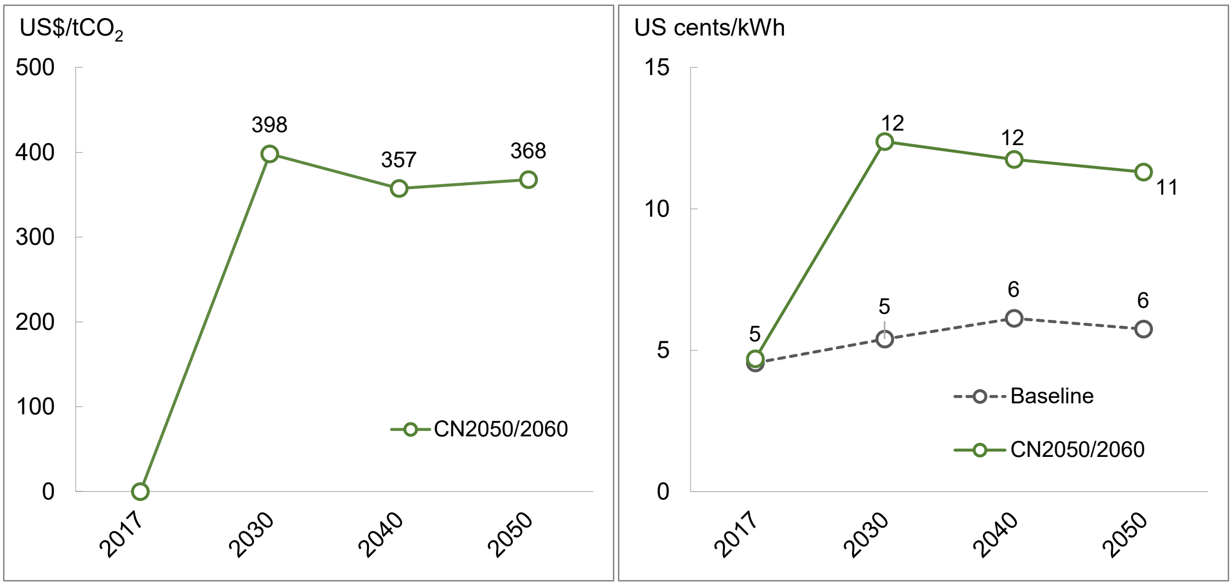


CCUS = carbon dioxide capture, utilisation, and storage, DRI-EAF = direct reduced iron–electric arc furnace, FT = Fischer-Tropsch, Mtoe = million tonnes of oil equivalent.
Source: Author.

3.4.7. Costs for Reducing Carbon Dioxide

Figure 3.45 shows the MAC and the marginal cost of electricity in Thailand. In CN2050/2060, the MAC rises to US$368/t$CO_2$ and the marginal cost of electricity increases to 11 cents/kWh in 2050. The stringent emission constraints lead to steeper increases in both the MAC and the electricity price in the medium term. The marginal cost of electricity mainly reflects the cost of H_2 in 2050.

Figure 3.45. Marginal Carbon Dioxide Abatement Cost (Left) and Marginal Cost of Electricity (Right) for CN2050/2060 in Thailand



CO_2 = carbon dioxide, kWh = kilowatt-hour, MAC = marginal CO_2 abatement cost, tCO_2 = tonnes of carbon dioxide.
Source: Author.

3.4.8. Sensitivity Analysis: Technological Innovation

This sensitivity analysis was carried out to evaluate the impact of the innovation cases on mitigation costs (MAC). The assumptions of the cases are set out in detail in Table 3.3.

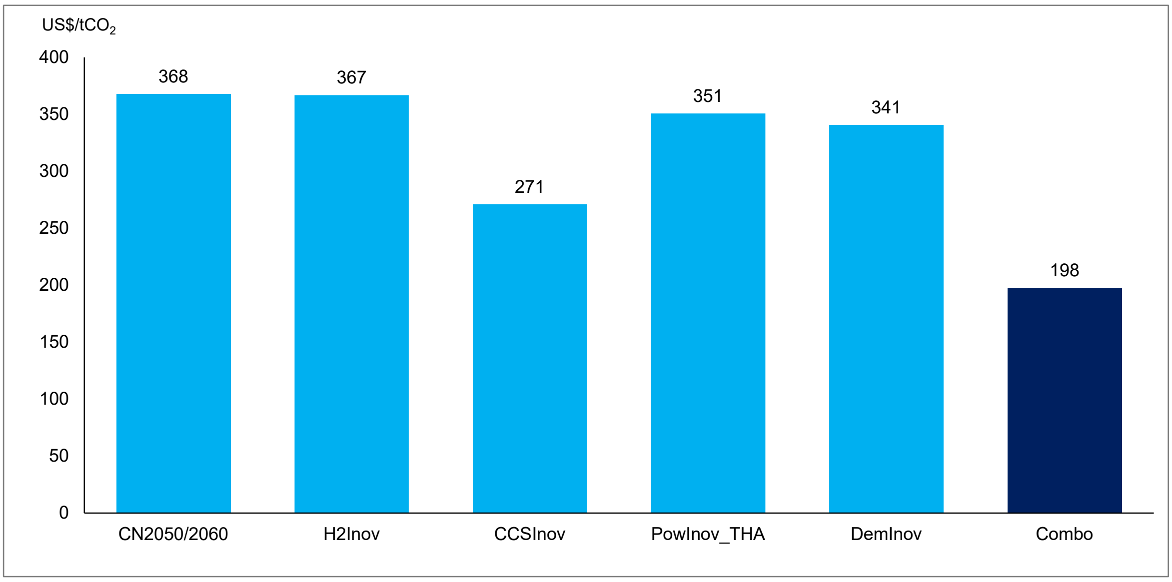
Table 3.3. Key Technology Assumptions for the Technological Innovation Cases for Thailand

Case	Net-zero Year	Key Technology Assumptions
CN2050/2060	2050	• Reference technology cost • International power grid extension constrained by planned ASEAN power grid capacity • Annual CO_2 storage up to 0.8% of cumulative potential in 2050
PowInov_THA	2050	• Cost reduction of lithium-ion batteries (-25% in 2040 and -50% after 2050, from the reference level) and international grid extension
CCSInov	2050	• Cost reduction of direct air capture (-25% in 2040 and -50% after 2050) • Additional CO_2 storage capacity (+1% of potential. The added capacity is for the exclusive use of the country with the resource.)
H_2Inov	2050	• Cost reduction of coal gasification, methane reforming and electrolyser (-25% in 2040 and -50% after 2050) • Cost reduction of H_2 consumption: H_2 based DRI-EAF and fuel cell ships (-25% in 2040 and -50% after 2050), FCEVs (comparable to hybrid electric vehicle price in 2060)
DemInov	2050	• Cost reduction of advanced end-use technologies (-50% in and after 2040)
Combo	2050	• Combined assumptions of the four innovation cases mentioned above

ASEAN = Association of Southeast Asian Nations, CO_2 = carbon dioxide, DRI-EAF = direct reduced iron–electric arc furnace, FCEV = fuel cell electric vehicle, $GtCO_2$ = gigatonnes of carbon dioxide, H_2 = hydrogen.
Source: Author.

Figure 3.46 shows the marginal CO_2 abatement costs for each case in 2050. It illustrates that reducing the cost of each technology through innovation significantly reduces the marginal costs. The MAC for Combo was approximately 46% lower than that for CN2050/2060. The cost reduction of expanding CO_2 storage by CCS contributes to the reduction of the MAC.

Figure 3.46. Marginal Abatement Cost of CO_2 in 2050 for Thailand



Source: Author.

3.4.9. Capacity Building Programme for Thailand

For this year, preparatory work for the capacity building programme, e.g. the development of a draft training programme, was conducted. Further development and arrangements will be made when the interest of the Thai government becomes clear.

3.5. Conclusions: Results for Selected Countries

Using an optimal technology selection model, this study estimated the cost-optimal deployment of energy technologies to achieve carbon neutrality in ASEAN countries up to 2050 and 2060. The results of the analyses indicate the following three points: (1) decarbonisation of power sources, (2) acceleration of energy savings and electrification, and (3) international cooperation to reduce the cost of technologies.

First, power sources should be decarbonised by combining multiple technologies, not only VRE but also other carbon-free technologies, to contribute to carbon neutrality. Considering the location of electricity demand and the reinforcement of the domestic grid, it is important to consider the cost-efficient deployment of renewables. For *Brunei Darussalam*, even if solar PV is fully installed on rooftops and bare land, zero-emission thermal power, such as coal-fired or gas-fired with CCS, is needed. In this regard, CCS-related technologies are crucial for Brunei to achieve carbon neutrality. The development of a power interconnection line with Sarawak is another important option for Brunei to utilise the abundant renewable resources in the region.

For *Malaysia*, the potential of renewables is relatively limited according to our assumptions. However, abundant CO_2 storage potential and its development in Malaysia are key to ASEAN's carbon neutrality. Malaysia is expected to import CO_2 from neighbouring countries for storage.

For *the Philippines*, the country has a huge potential for wind power. Therefore, cost reductions in wind turbines will lead to the expansion of both onshore and offshore wind energy, contributing to the improvement of self-sufficiency. In addition to the use of imported NH_3, highly efficient gas-fired power generation with CCS will play a critical role, even under high fuel price assumptions.

For *Thailand*, the share of solar PV and wind increases based on our fossil fuel price assumptions, but 'decarbonised' thermal power plants also contribute to maintaining the balance between electricity supply and demand whilst addressing climate change.

Second, energy-saving and electrification are key to CO_2 abatement in end-use sectors. Whilst energy demand in these countries is expected to grow steadily, progress in end-use energy efficiency and electrification is crucial for deeper decarbonisation. For all the selected countries, accelerated electrification should be realised, especially in the transport and industry sectors, hand in hand with low-carbonisation of the power supply. Currently, oil accounts for most of the energy consumed in the transport sector, and the increasing dependence on oil imports is recognised as an energy security risk. In these countries, promoting electrification, improving fuel efficiency, and using alternative fuels in the transport sector, will not only contribute to decarbonisation but also to ensuring energy security.

Third, cost reduction and international cooperation are key to making carbon neutrality affordable. More expensive decarbonisation technologies need to be introduced at the final stage. To develop and deploy still-expensive decarbonisation technologies, costs must be reduced through technological innovation and economies of scale. Research and development of low-carbon technologies in cooperation with developed countries is important to achieve carbon neutrality in the long term. As shown in the sensitivity analysis of the technological innovation for Thailand, reducing the cost of direct air capture and expanding CO_2 storage could reduce the MAC the most amongst other options. Regional imbalances exist in the resources and energy demand in the ASEAN region. These could be partially adjusted by strengthening resource-sharing within ASEAN, such as the international power grid and imports/exports of captured CO_2, which appear in the results of the power generation mix or CCUS balances in selected countries. For the effective reduction of GHG emissions, efforts should be made not only in the energy-related CO_2 sector but also in other sectors. Based on the results from Brunei Darussalam, enhancing natural carbon sinks could help offset energy-related CO_2 emissions in a relatively affordable way. International cooperation to accelerate reforestation and afforestation should be strengthened in the coming decades.

3.6. Comparison between the IEA and IEEJ

In addition to this study, various organisations, such as the IEA, have also formulated decarbonisation roadmaps for ASEAN. A comparative analysis of these scenarios can provide important information for policy makers referring to roadmaps 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 2022 by the IEA. This comparison has already been published by the IEA (2023b) as the report, *Decarbonization Pathways for Southeast Asia*. Although the comparison in this section reflects updates to the ERIA/IEEJ analysis after the publication of the IEA report, the results are not significantly different from the report. Therefore, please refer to the report for more details. The figures and tables presented in this section were prepared by the author using only publicly available data for the IEA's scenario.

3.6.1. Compared Scenarios

Table 3.4 shows the compared 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 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 easy to understand because it has a single clear criterion of value or cost minimisation. Since ERIA/IEEJ focuses on ASEAN, it also has the advantage of dividing ASEAN into 10 countries and having a high temporal resolution for electricity supply and demand balances.

Table 3.4. Outline of Compared Scenarios

	IEA APS	ERIA/IEEJ
Scenario	IEA World Energy Outlook 2022 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
Time period	Up to 2050	2017–2060
Methodology	Hybrid model with an econometric model (WEM) and a bottom-up technology model (ETP)	Liner programming model for cost minimisation

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

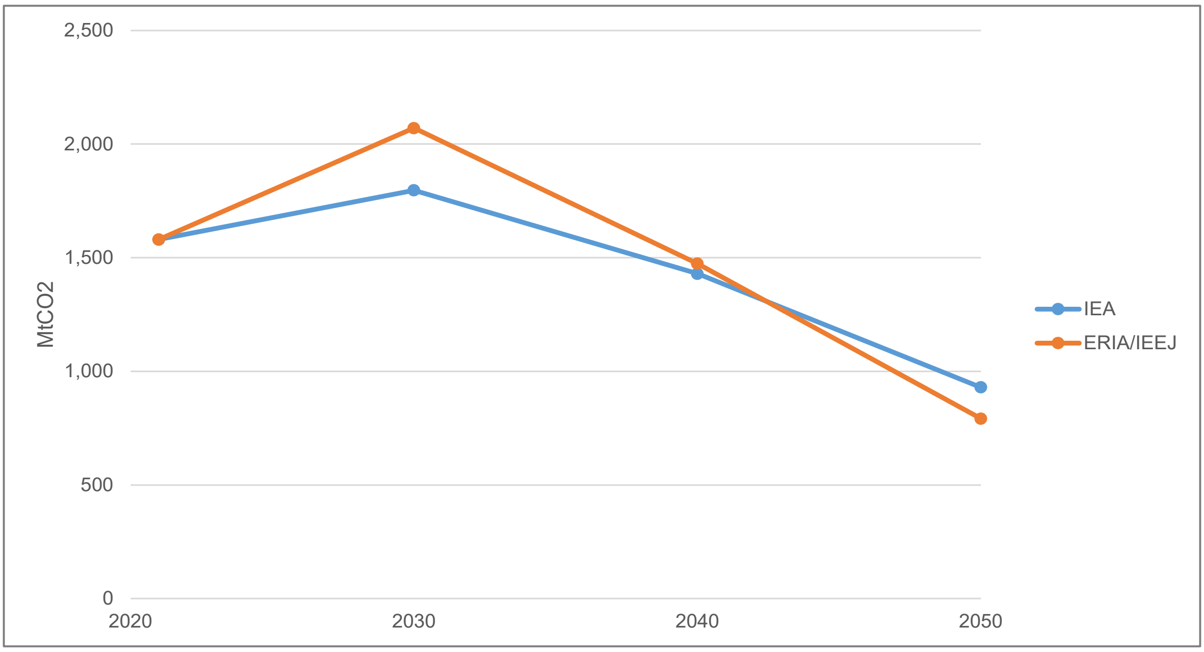
3.6.2. Population and GDP

ERIA/IEEJ assumed a 4.5% larger population in 2050 than the IEA. The difference in the GDP assumption, on the other hand, was even greater, with the IEA forecasting an average annual growth rate of 3.8% from 2020 to 2050, whilst the ERIA/IEEJ forecasted 4.6% (IEA, 2023b). The IEA's assumption was based on the historical trend of slowing GDP growth as countries get richer, whilst the ERIA/IEEJ assumption referred to ERIA's Energy Outlook, which reflects the ASEAN countries' vision of economic growth. The difference in GDP assumption is likely to have a significant impact on the outlook for energy demand in the region.

3.6.3. CO_2 Emissions

Figure 3.47 shows a comparison of total energy-related CO_2 emissions. Although emissions in 2030 are smaller for the IEA and those in 2050 are smaller for ERIA/IEEJ, the two have roughly similar emission paths. However, a closer look shows that even in the long term, whilst the IEA hardly expects any energy-related carbon dioxide removal (CDR), such as BECCS and DACCS (IEA, 2023b), ERIA/IEEJ expects a large introduction (approximately 0.7 Gt) as a result of cost minimisation. Both scenarios consider the offsetting of residual emissions by natural carbon sinks, such as forests, as well, although the IEA's assumed scale of carbon sinks, e.g. in Indonesia, appears to be smaller.

Figure 3.47. Comparison of Total Energy-related CO_2 Emissions in ASEAN

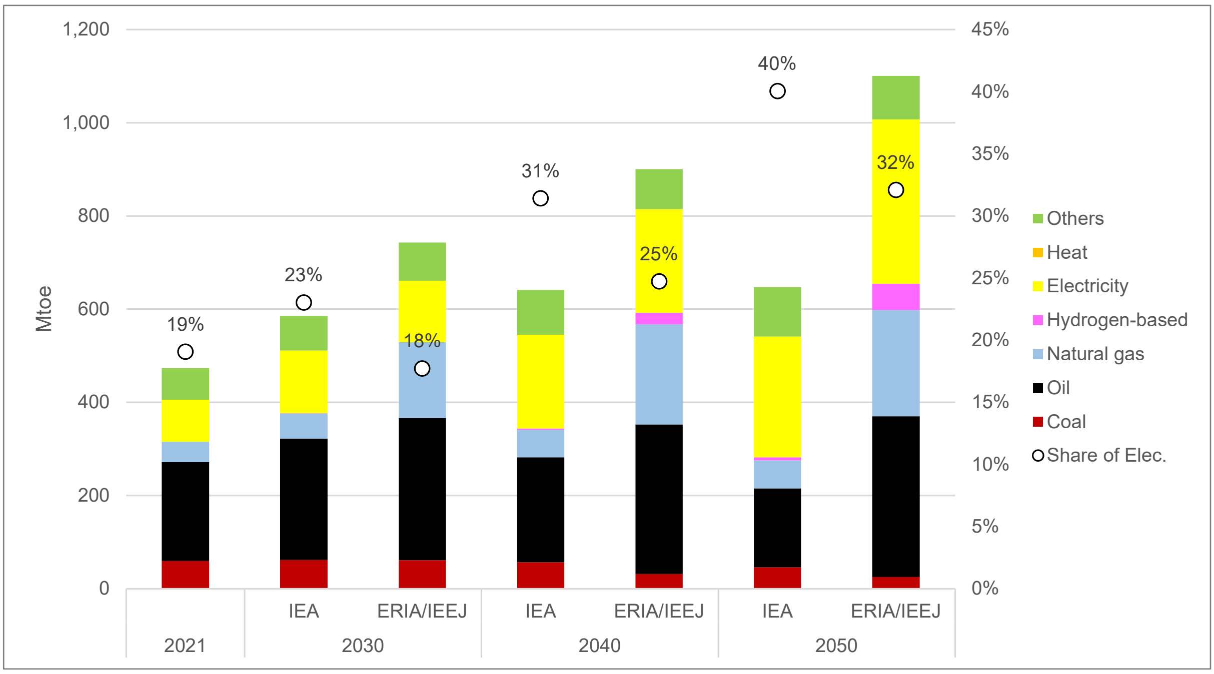


Source: Author; IEA (2022).

3.6.4. Final Energy Consumption

As shown in Figure 3.48, the total final energy consumption in 2050 reaches 1.7 times higher for ERIA/IEEJ than for the IEA. This difference primarily reflects differences in energy demand (particularly in the transport sector) 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 (IEA, 2023).

Figure 3.48. Comparison of Final Energy Consumption in ASEAN

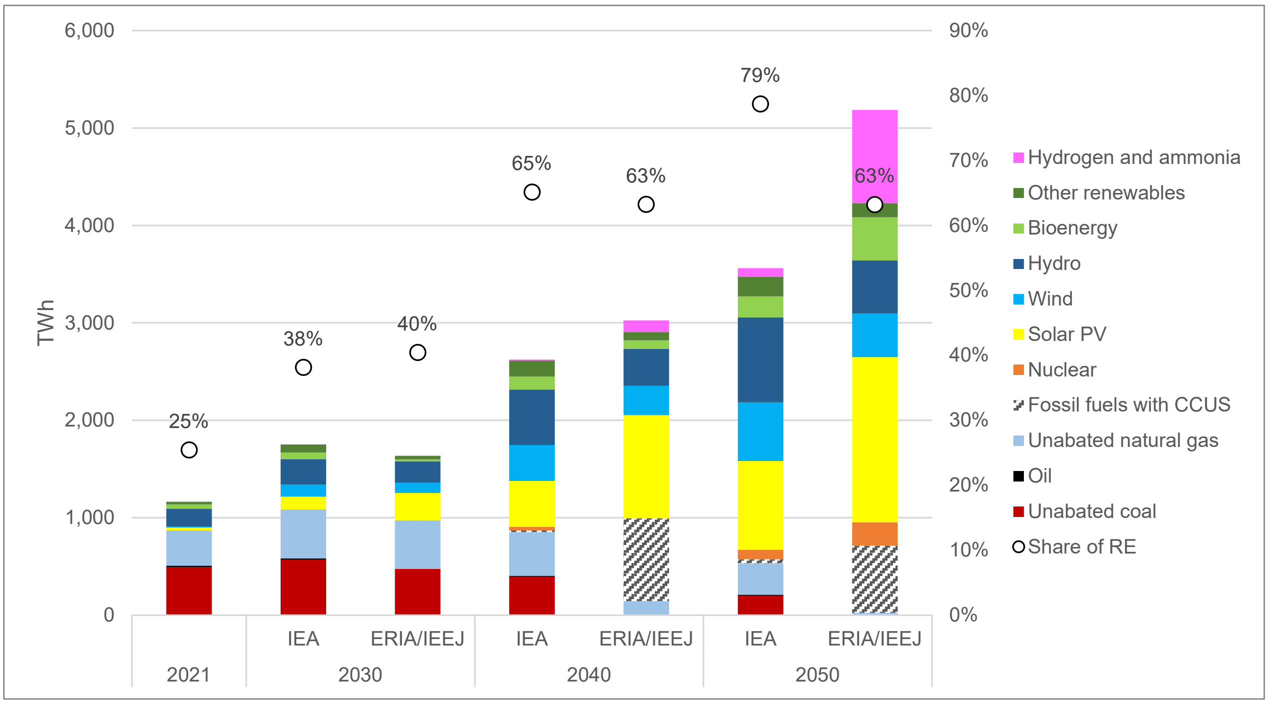


Source: Author; IEA (2022).

3.6.5. Power Generation

As shown in Figure 3.49, the total power generation for ERIA/IEEJ reaches 1.5 times that for the IEA in 2050. This reflects not only the growth in final energy demand but also the electricity input to DACs. Although the share of renewables is larger for the IEA, the absolute volume of renewable power generation is larger for ERIA/IEEJ in 2050. For ERIA/IEEJ, in addition to gas/coal-fired power with CCUS, hydrogen/ammonia single-fired power is also introduced. For the IEA, on the other hand, the introduction of these power sources is limited.

Figure 3.49. Comparison of Power Generation in ASEAN



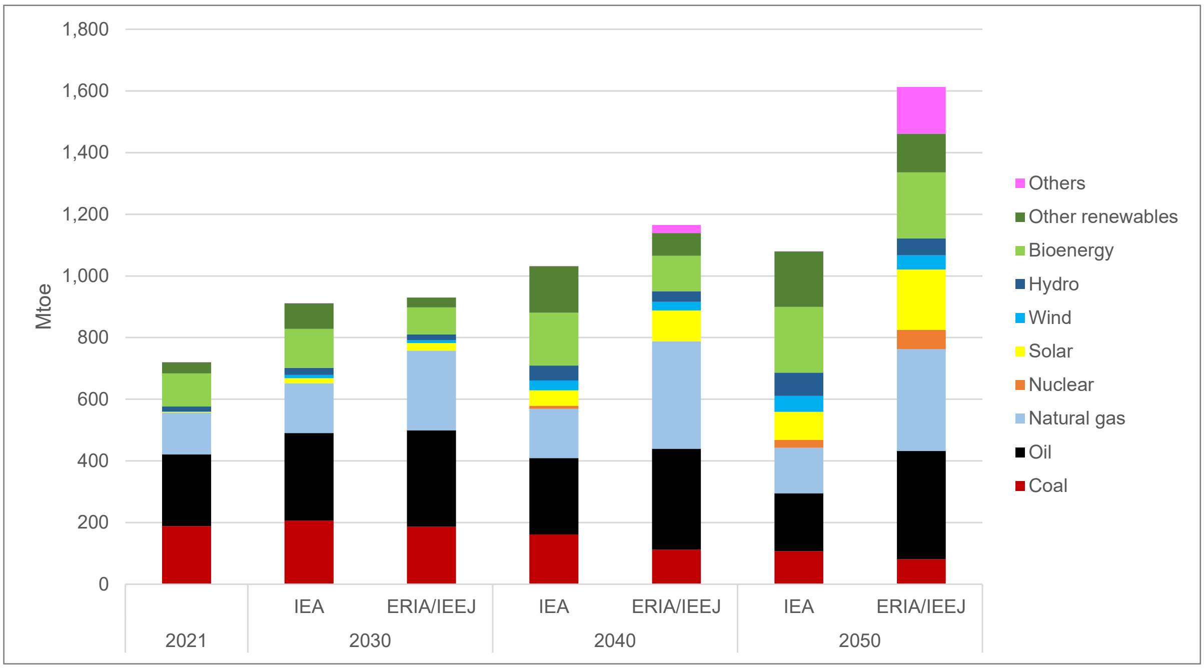
CCUS = carbon dioxide capture, utilisation, and storage, PV = photovoltaic, RE = renewable energy, TWh = terawatt-hour.

Source: Author; IEA (2022).

3.6.6. Primary Energy Supply

As shown in Figure 3.50, the supply of natural gas expands rapidly for the ERIA/IEEJ, especially in the transitional period, such as 2030 and 2040, but is almost flat for the IEA, showing a significant difference. Whilst oil peaks at around 2030 in the IEA, it continues to grow in the ERIA/IEEJ, reflecting increasing demand for heavy-duty vehicles that are difficult to electrify. In the ERIA/IEEJ, 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 are also important options.

Figure 3.50. Comparison of Primary Energy Supply in ASEAN



Mtoe = million tonnes of oil equivalent.
Source: Author; IEA (2022).

3.7. Conclusions: Comparison between the IEA and IEEJ

The biggest differences between the IEA (APS) and the ERIA/IEEJ scenarios come from the assumptions on future economic growth and the outlook for progress in energy efficiency. Compared to ERIA/IEEJ, the IEA expects less economic growth and more improvement in energy efficiency and draws a roadmap mainly relying on electrification and a shift to renewables in power generation. On the other hand, in order to respond to robust economic growth and the resulting energy demand, the ERIA/IEEJ scenario needs to expand the use of fossil fuels (especially gas) in the near-to-medium term, in addition to the maximum deployment of renewables beyond the IEA. Simultaneously, hydrogen/ammonia, fossil fuels with CCS, CDR such as DACCS and BECCS, and natural carbon sinks are introduced to decarbonise fossil fuels and achieve net zero.

When discussing the roadmap towards net zero, attention tends to focus on the ratio of renewables, but it is important to consider how the amount of energy demand is anticipated. The energy mix to be pursued depends on this.

There is uncertainty regarding the future economic growth of developing countries. Given that it takes many years to develop an energy infrastructure, it is necessary to consider a roadmap that takes this uncertainty into consideration.

Chapter 4

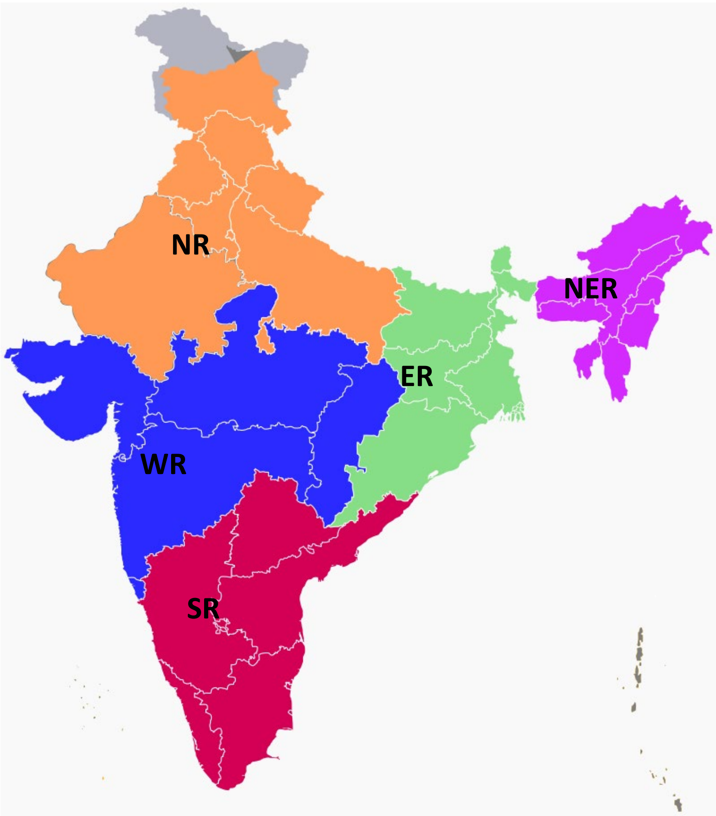
Preparation for Analysis on India

For this year, data collection was started in order to develop a model for India. This chapter presents some of the data collected.

4.1. Regional Classification

As shown in Figure 4.1 and Table 4.1, India's national grid is divided into five regions. Table 4.2 shows the mapping between the 28 states and 8 union territories of India and the 5 regions.

Figure 4.1. The Five Regional Power Grids in India



Source: Wikipedia, National Grid (India), modified by authors.

Table 4.1. The Five Regional Power Grids in India

Code	Name	Population (2020, millions)	Gross domestic product (2019, million 2011 lakh)
NR	Northern	430	391
ER	Eastern	310	186
WR	Western	304	429
NER	North Eastern	275	434
SR	Southern	51	38
	Total	1,371	1,478

Source: Unique Identification Authority of India (2021); Reserve Bank of India (2022).

Table 4.2. Mapping of States and Regions

#	State	Region	Area	Population (2020)	Gross Domestic Product (2019, 2011 lakh)
1	Andaman and Nicobar Islands	SR	8,249	417,036	719,844
2	Andhra Pradesh	SR	160,205	53,903,393	66,884,789
3	Arunachal Pradesh	NER	83,743	1,570,458	1,791,640
4	Assam	NER	78,550	35,607,039	23,784,428
5	Bihar	ER	94,163	124,799,926	40,964,460
6	Chandigarh	NR	114	1,158,473	3,123,451
7	Chhattisgarh	WR	135,194	29,436,231	24,987,503
8	Dadra and Nagar Haveli and Daman and Diu	WR	603	615,724	-
9	Delhi	NR	1,490	18,710,922	61,384,270
10	Goa	WR	3,702	1,586,250	5,309,957
11	Gujarat	WR	196,024	63,872,399	126,895,663
12	Haryana	NR	44,212	28,204,692	55,970,500
13	Himachal Pradesh	NR	55,673	7,451,955	12,228,389
14	Jammu and Kashmir	NR	42,241	13,606,320	11,904,290
15	Jharkhand	ER	74,677	38,593,948	23,839,543
16	Karnataka	SR	191,791	67,562,686	114,378,127
17	Kerala	SR	38,863	35,699,443	56,863,552
18	Ladakh	NR	59,146	289,023	-

#	State	Region	Area	Population (2020)	Gross Domestic Product (2019, 2011 lakh)
19	Lakshadweep	SR	32	73,183	-
20	Madhya Pradesh	WR	308,252	85,358,965	58,040,617
21	Maharashtra	WR	307,713	123,144,223	213,406,502
22	Manipur	NER	22,347	3,091,545	2,067,301
23	Meghalaya	NER	22,720	3,366,710	2,518,959
24	Mizoram	NER	21,081	1,239,244	1,803,361
25	Nagaland	NER	16,579	2,249,695	1,812,084
26	Odisha	ER	155,820	46,356,334	41,237,480
27	Puducherry	SR	492	1,413,542	2,500,937
28	Punjab	NR	50,362	30,141,373	41,357,818
29	Rajasthan	NR	342,269	81,032,689	68,871,434
30	Sikkim	ER	7,096	690,251	1,970,017
31	Tamil Nadu	SR	130,058	77,841,267	127,855,872
32	Telangana	SR	114,840	38,510,982	64,859,504
33	Tripura	NER	10,492	4,169,794	4,020,713
34	Uttar Pradesh	NR	243,286	237,882,725	116,681,747
35	Uttarakhand	NR	53,483	11,250,858	19,971,848
36	West Bengal	ER	88,752	99,609,303	78,442,406

Source: Wikipedia, States and Union Territories of India; Unique Identification Authority of India (2021); Reserve Bank of India (2022).

4.2. Fossil Fuel Prices

Table 4.3 shows fossil fuel prices as of 2019. For natural gas and steam coal, domestic prices are much cheaper than imported ones.

Table 4.3. Fossil Fuel Prices in India as of 2019

Category	Fuel	Value	Unit	Category	Fuel	Value	Unit
Import	Crude oil	63	US$/bbl	Retail	Gasoline	75.45	INR/L
	Natural gas	11	US$/Mbtu		Diesel	68.22	INR/L
	Steam coal	68	US$/tonne		LPG	49.99	INR/kg
Domestic	Crude oil	65	US$/bbl		Kerosine	25.75	INR/L
	Natural gas	3.69	US$/Mbtu		Jet	65.22	INR/L
	Steam coal	16	US$/tonne				

Bbl = barrel, kg = kilogramme, L = litre, LPG = liquefied petroleum gas, Mbtu = million British thermal units.
Note: 2019 prices. The domestic steam coal price represents the weighted average of the gradewide pit head price applicable to power utility.
Source: IEA (2021); Ministry of Petroleum and Natural Gas (2021); Ministry of Coal (2021).

4.3. Energy Service Demand

Table 4.4 shows the regional crude steel production as of 2019, and Table 4.5 shows the transport-related indicators as of 2019. India's total crude steel production is 109 Mt, of which 45% is basic oxygen furnace (BOF) steel. The number of registered vehicles is 295 million.

Table 4.4. Regional Crude Steel Production as of 2019 (kt)

Region	BOF	EAF	IF	Total
NR	0	856	7,063	7,920
ER	28,784	9,061	7,920	45,766
WR	4,497	15,908	11,261	31,666
SR	15,292	2,541	5,754	23,587
NER	0	0	200	200
Total	48,573	28,366	32,198	109,139

BOF = basic oxygen furnace, EAF = electric arc furnace, IF = induction furnace.
Source: Ministry of Mines, Indian Bureau of Mines (2022).

Table 4.5. Regional Transport-related Indicators as of 2019

Region	Railway Route (km)	Registered Vehicles (thousand units)
NR	19,878	88,225
ER	13,143	27,719
WR	17,319	83,790
SR	14,283	89,923
NER	2,792	6,114
Total	67,415	295,772

Source: Reserve Bank of India (2020), Ministry of Road Transport & Highways, Transport Research Wing (2021).

4.4. Power Sector

4.4.1. Installed Capacity

Table 4.6 shows the regional installed power generation capacity as of 2019. The total installed capacity in India is 435 GW.

Table 4.6. Regional Installed Capacity as of 2019 (MW)

Grid	Coal	Diesel	Hydro	Natural Gas	Nuclear
NR	49,175	5,380	19,023	6,997	1,620
ER	48,032	938	5,862	805	-
WR	104,672	3,417	7,416	16,514	1,840
SR	51,418	6,578	11,838	7,416	3,320
NER	967	95	1,452	2,201	-
Total	254,264	16,408	45,591	33,933	6,780

Grid	Bagasse Cogeneration	Small Hydro	Solar	Waste	Wind	Total
NR	2,465	1,550	5,823	61	4,300	96,394
ER	463.4	295.2	659.8	-	-	57,055
WR	2,886	609	6,169	28	13,387	156,938
SR	3,289	1,853	15,491	49	17,939	119,191
NER	14	286	64	-	-	5,079
Total	9,117	4,594	28,207	138	35,626	434,658

Source: NITI Aayog, India Energy Dashboards.

4.4.2. Technology Cost

Table 4.7 shows the costs of power generation technology for India. According to the IEA's 'Levelised Cost of Electricity Calculator', the LCOE is estimated to be the lowest for solar (35.60 US$/MWh) and onshore wind (35.91 US$/MWh) amongst other technologies shown in Table 18 under default assumptions.

Table 4.7. Costs of Power Generation Technology in India

Technology	Overnight Costs (US$/kW)	O&M (US$/MWh)
Coal-fired (ultra-supercritical, pithead)	1,148	8.53
Coal-fired (ultra-supercritical, load centred)	1,111	38.65
Hydropower	2,449	11.65
Solar PV (utility scale)	629	3.67 (at 7% DR)
Wind power (onshore wind)	877	3.72
Biomass	833	2.24
Nuclear (light water reactor)	2,778	23.84
Li-ion battery	826	12.57
Pumped storage	563	10.71

DR = discount rate, kW = kilowatt, MWh = megawatt-hour, O&M = operation and maintenance.
Note: 2018 prices.
Source: IEA and OECD/NEA (2020).

4.5. Resource Potential

4.5.1. Renewables

Table 4.8 shows regional renewable potential for power generation. India has a potential of 1,489 GW.

Table 4.8. Regional Renewables Potential (GW)

Grid	Solar	Wind	Small Hydro	Biomass	Bagasse cogenera-tion	Waste	Total
NR	336.3	128.8	8.0	7.4	1.9	0.5	482.9
ER	66.4	14.3	1.7	1.4	0.3	0.3	84.4
WR	180.9	256.5	2.9	4.7	1.6	0.5	447.1
SR	107.3	295.4	5.5	3.8	1.2	0.3	413.5
NER	57.4	0.5	3.0	0.3	-	-	61.2
Total	748.3	695.5	21.1	17.6	5.0	1.6	1,489.1

Source: NITI Aayog, India Energy Dashboards.

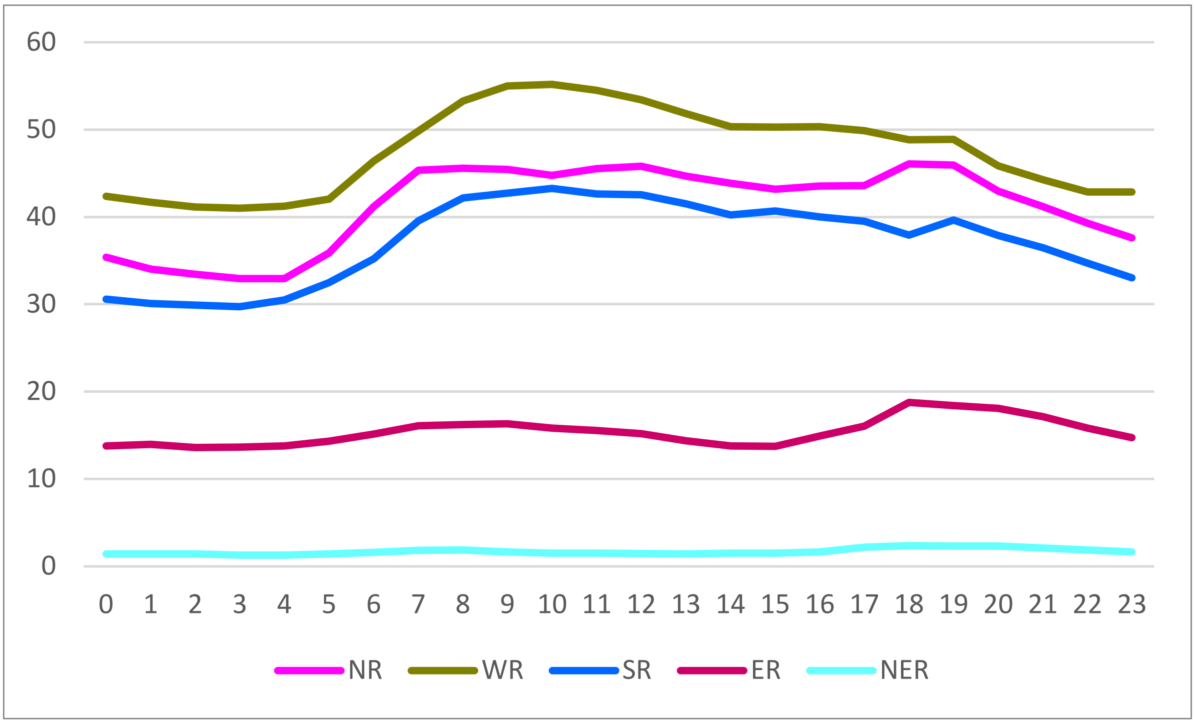
4.5.2. CO_2 Storage

The Global CCS Institute (2016) evaluated the total CO_2 storage potential of India at 47–143 $GtCO_2$. The prospective basins include Cambay, Cauvery, Krishna-Godavari, and Mumbai.

4.6. Load Curve

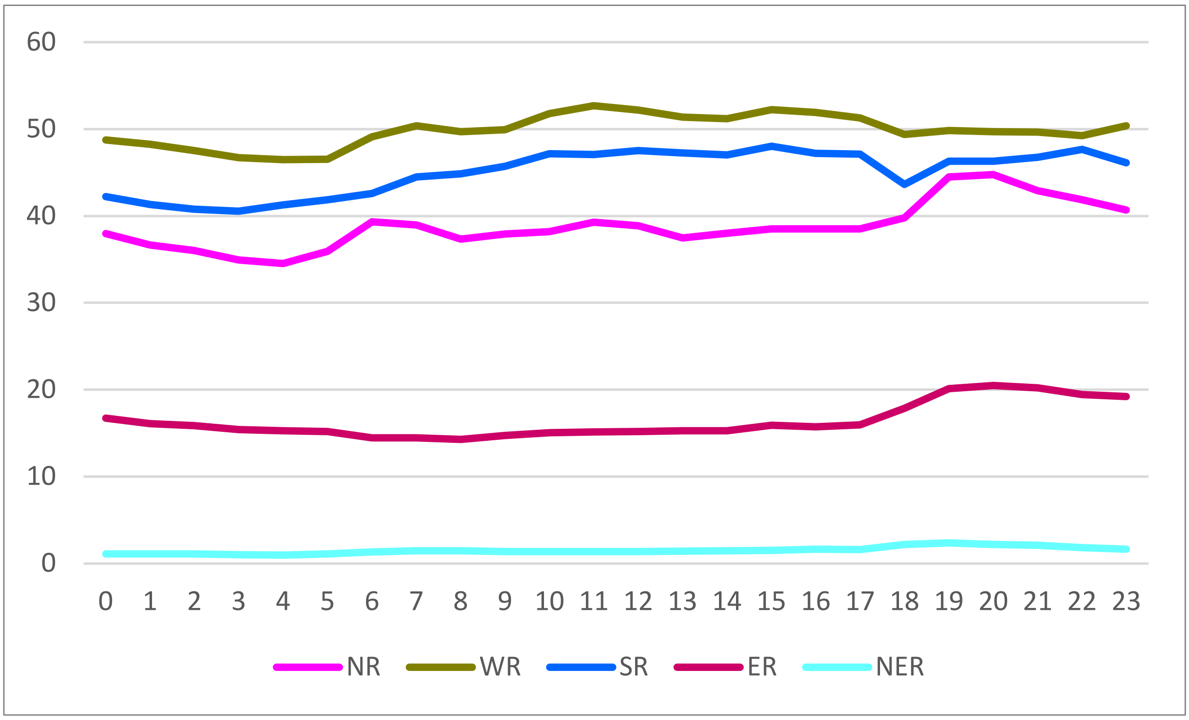
Figure 4.2–Figure 4.5 show the regional daily electricity demand. Each month shows the day with the highest electricity demand across India. The peak load reached 60–70 GW in the Northern region in July.

Figure 4.2. Regional Hourly Electricity Demand, 18 January 2019 (GW)



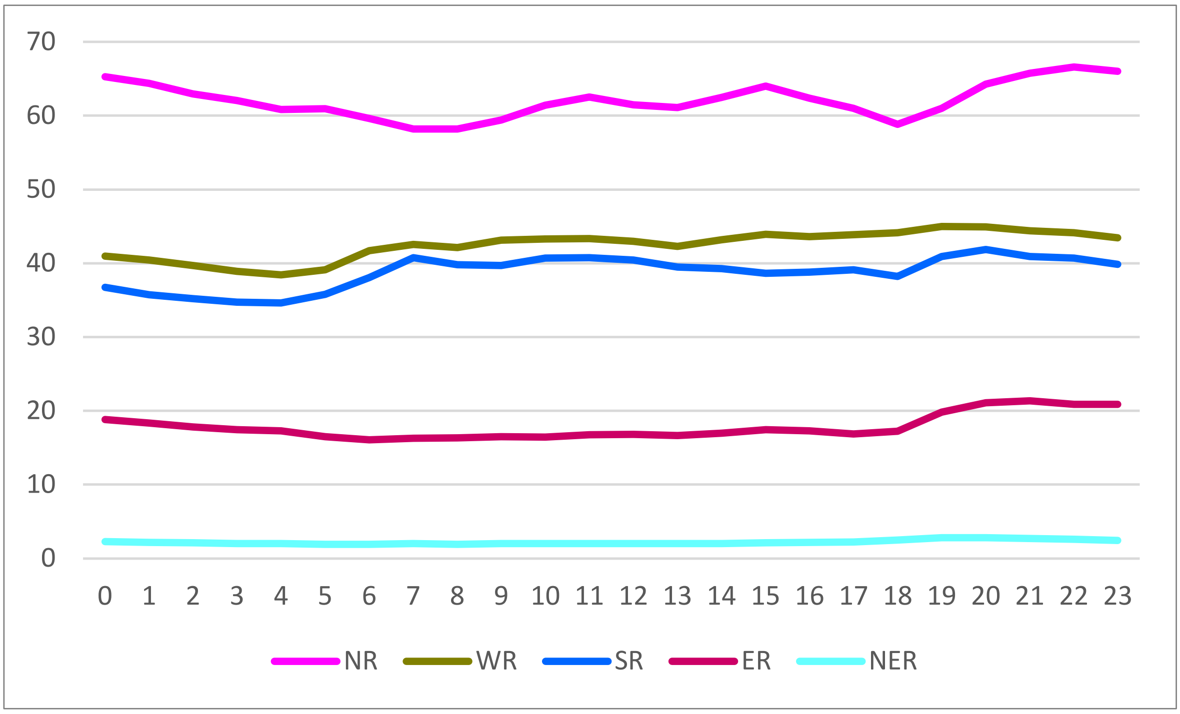
Source: Power System Operation Corporation Ltd., National Load Despatch Centre (2019).

Figure 4.3. Regional Hourly Electricity Demand, 29 April 2019 (GW)



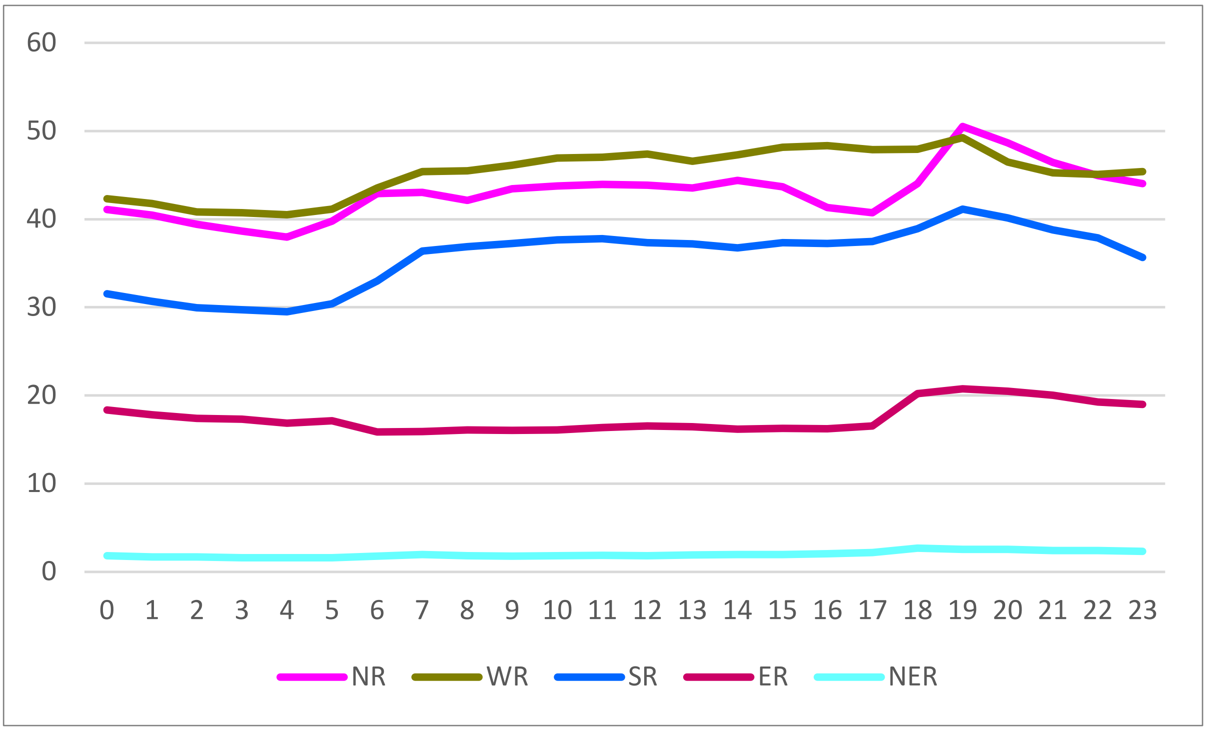
Source: Power System Operation Corporation Ltd., National Load Despatch Centre (2019).

Figure 4.4. Regional Hourly Electricity Demand, 3 July 2019 (GW)



Source: Power System Operation Corporation Ltd., National Load Despatch Centre (2019).

Figure 4.5. Regional Hourly Electricity Demand, 14 October 2019 (GW)



Source: Power System Operation Corporation Ltd., National Load Despatch Centre (2019).

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