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Technical Report

Background to

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Foreword

The analyses described in this report are part of Development Engagement 1 (DE1): "Capacity Development for long-range energy sector planning with Electricity and Renewable Energy Agency of Viet Nam", currently being conducted under the Energy Partnership Programme between Viet Nam and Denmark (DEPP III), a cooperation between the Danish Energy Agency (DEA), the Electricity and Renewable Energy Authority of Viet Nam (EREA) and the Vietnamese Ministry of Industry and Trade (MOIT).

This Technical Report serves as a background report to the Energy Outlook Report for Viet Nam – Pathways to Net-Zero (EOR-NZ), which analyses a range of energy scenarios to guide decision-makers and energy and power system planners to achieve a sustainable green transition of the energy system in a cost-efficient way. The EOR-NZ builds on the work carried out in the previous editions of the bi-annual report: the EOR 2017 (EREA and DEA, 2017), the EOR 2019 (EREA and DEA, 2019) and EOR 2021 (EREA and DEA, 2022).

Supporting this study is the Vietnamese Technology Catalogue for Power Generation 2023 (EREA and DEA, 2023) and the Vietnamese Technology Catalogue for RE fuels, Storage and PtX (EREA and DEA, 2023).

The document lays out key assumptions, modelling set-up and results of two main scenarios and a range of sensitivity scenarios. The scenarios are optimised in a modelling framework comprising two energy models: TIMES (encompassing supply, conversion, and end-use sectors) and Balmorel (representing the power sector in high technical, temporal, and geographical detail). Furthermore, the power grid model PSS/E has been applied to strengthen the conclusions regarding the power grid.

This report is written by Ea Energy Analyses (Ea), Energy Modelling Lab (EML), E4SMA, and Institute of Energy (IE) in close cooperation with EREA, DEA and many national stakeholders.

1 Introduction

Vietnamese energy landscape

At the end of 2021, the Glasgow Climate Treaty was launched at the 26th Conference of the Parties to the United Nations Framework Convention on Climate Change (COP26) with the consensus of nearly 200 member countries. The Treaty reaffirmed the maintenance of the goal in the 2015 Paris Agreement to limit global temperature rise to 1.5oC by 2100. Also at the Conference, the Prime Minister of Viet Nam made a pledge that Viet Nam will strongly develop and deploy measures to reduce greenhouse gas emissions based on domestic resources, along with the cooperation and support of the international community towards the goal of achieving a net emission level of "zero" by 2050.

According to statistics, Vietnam's total emissions due to energy processes in 2021 is 248.5 million tons of CO_2 equivalent, and is expected to continue to increase in the period to 2030. Therefore, the goal of limiting emissions and achieving net-zero in 2050 will be a big challenge for the entire Vietnamese energy industry in the coming years. In order to realise the net-zero goal, the Prime Minister issued Decision No. 888/QD-TTg dated July 25, 2022 approving a project on tasks and solutions to implement the results of COP 26 conference. Accordingly, the study of EOR-NZ is one of the tasks given in the above decision.

During the last decades, Viet Nam has experienced economic growth, industrial development, urbanisation, increased transport demand, improved energy access, and rising living standards, all of which are major drivers for growing energy consumption. In 2020 and 2021, while Viet Nam still achieved economic growth, the rate of growth was significantly lower than what is expected following the trend of the previous years, due to the disruption from the COVID-19 pandemic.

For the period 2011-2019, average economic growth (measured on GDP) was 5.95%/year. In the five-year period from 2011 to 2015, the average growth rate decreased sharply compared to the previous periods, reaching only 5.9%/year. In the period 2016-2019, the growth rate recovered, reaching a much higher level, of 6.78%/year on average. In 2020 and 2021, because of the COVID-19 pandemic, Viet Nam economic growth rate was only 2.91% (GSO, 2020) and 2.58% (GSO, 2021), respectively.

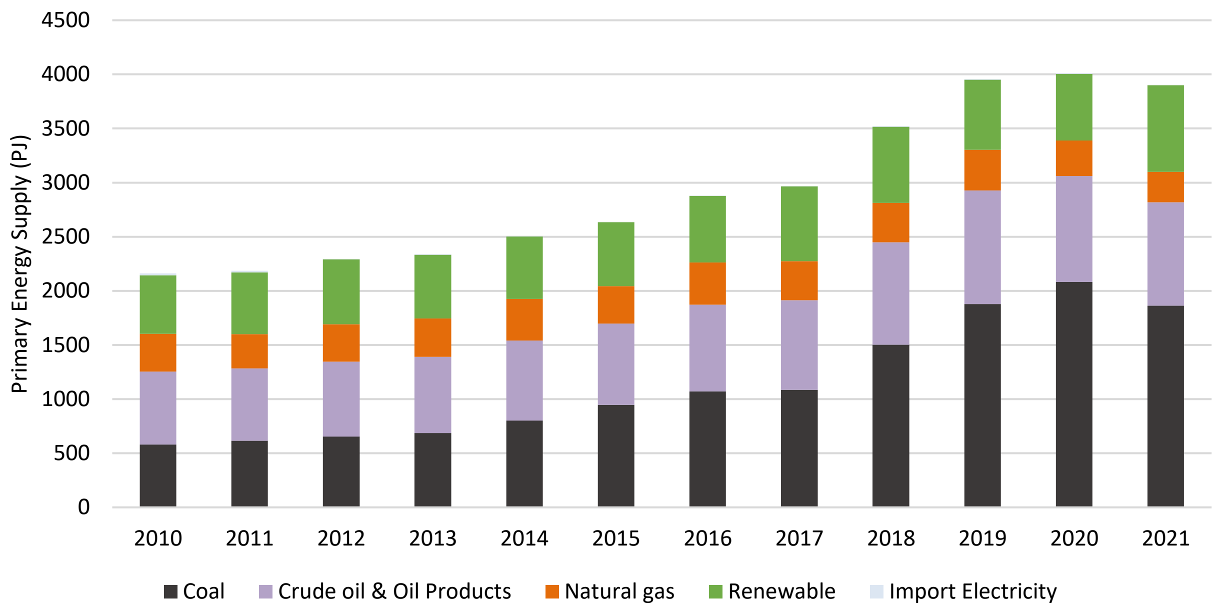


Figure 1: Historical total primary energy supply (TPES) of Viet Nam.

In 2020, Viet Nam's Total Primary Energy Supply (TPES) was 4009 PJ, an increase of 1.3% compared to 2019 (Figure 1). This is significantly lower than the average growth rate of 7% annually in the 2010-2019 period. In 2020, the COVID-19 pandemic significantly hampered economic growth, which had been the main driver for TPES growth in the preceding period.

The share of renewable energy, including hydropower, in the total energy supply was 25.1% in 2010, 22.4% in 2015 and 16.4% in 2019. In 2020 renewable energy decreased, accounting for only 15.3% of TPES despite the near two-fold increase in solar energy compared to 2019. On the other hand, hydropower grew at a rate of 11.9% annually in the period 2010-2020.

The most significant development concerns coal. In 2010, coal accounted for only 26.8% of the fuel supply and increased steadily in the few years after. However, after 2015, the share of coal increased significantly, to account for 52% of the total energy supply in 2020.

In 2019, domestic energy production reached 2219 PJ. Domestic coal accounted for the largest portion with 40.2%, lower than in 2010 (45.6%). The second largest volume of domestically produced fuel is crude oil, accounting for 17% of the total commercial energy production. The share of crude oil has continuously decreased since its peak in 2014.

Energy exports have decreased in recent years, while imports have increased. The exported energy in 2020 was only 322 PJ, 2.8 times less than 2010. Meanwhile, the amount of imported energy, after a few years of decline due to the fall in domestic demand, has increased sharply since 2015, which is also the first year that Viet Nam officially became a net energy importer. In terms of volume, imported energy was 2260 PJ in 2020, an increase of 67% compared to 2018. For the whole period of 2015-2020, imported energy growth

was 15.8%/year. Overall, the share of net energy imports in TPES shows a trend of general increase, going from 8.4% in 2015 to 48% in 2020 (VNEEP, 2021).
Especially, due to the COVID-19 pandemic, in 2021 Viet Nam's Total Primary Energy Supply (TPES) was 3904 PJ, a decrease of 2.6% compared to 2020.

Vietnamese power sector

Viet Nam's electricity consumption in recent years has regularly grown at a high level to meet the needs of socio-economic development. In the period 2010-2022, national electricity sale of electricity increased more than 2.5 times, from 85.7 billion kWh in 2010 to 242.3 billion kWh in 2022 with an average growth rate of about 9.2%/year. In the years 2020-2021, due to the impact of the COVID-19 pandemic, the growth rate of national electricity sale slowed down, each year increasing only about 3-4%. In 2022, Viet Nam's economy entered the post-pandemic recovery phase, with electricity demand increasing by 7.5% compared to 2021. Similar to electricity, also the peak power demand grew rapidly with an average rate of about 9.9%/year in the period 2011-2022, from more than 16 GW in 2011 to over 45.4 GW in 2022. The growth rate of peak demand is higher than electricity demand, showing that the electricity consumption in peak hours is increasing more than in other hours.

In the period 2011-2022, the total installed capacity of power generation sources in the system has increased more than 3 times, from about 23 GW in 2011 to 81 GW in 2022, with an average growth rate of about 12%/year. The growth rate of installed capacity has been higher than the power demand due to the high growth of renewable energy sources (wind and solar) in the recent period. Before 2019, Viet Nam's electricity sources were mostly traditional power plants such as coal thermal power, gas thermal power and hydropower.

From 2019 onwards, due to the Government's mechanisms to encourage renewable energy development, solar and wind power sources have developed significantly. By the end of 2022, Viet Nam's power system had over 16 GW of solar power (including rooftop solar power) and 5 GW of wind power; the ratio of solar and wind power sources went from almost 0% in 2018 to 21% and 5% in 2022, respectively. The proportion of hydropower sources (including small hydropower plants) tends to gradually decrease because hydropower potential has been almost fully exploited, with hydropower accounting for about 28% of the national power installed capacity in 2022. Meanwhile, from 2015 onwards, coal thermal power has steadily accounted for over 30%. Gas turbine power sources have not been added in the past 10 years, so the capacity ratio decreased from 32% in 2011 to 9% in 2022.

National electricity production grew on average by 8.9%/year, from 108 TWh in 2011 to nearly 271 TWh in 2022. In 2020, coal thermal power output accounted for 50%, hydropower accounted for 30%, gas thermal power accounted for 14%, renewable energy and other sources accounted for 5%. By 2022, due to the strong development of wind power and solar power, and due to rising coal prices, the proportion of electricity produced by coal-fired power was only 39%, hydropower accounted for 35%, gas-fired power accounted for 11%, and wind power and solar power accounted for 13%.
Up to 2022, the power system of Viet Nam has grown dramatically, ranking 20th in the world and the second in ASEAN, based on electricity generation (Energy Institute, 2023). The Prime Minister of Viet Nam approved

Viet Nam Power Development Plan for the period 2021-2030 with a vision until 2050 (PDP8) in Decision No. 500/QD-TTg dated 15th May 2023.

According to PDP8, electricity generation will reach 567 TWh in 2030 and about 1224-1378 TWh in 2050. PDP8 has oriented the development of the electricity industry with the goal of ensuring the implementation of the Prime Minister's net-zero commitment by 2050 announced at COP26, specifically as follows:

- Viet Nam will strongly develop renewable energy sources for electricity production, reaching a rate of about 31%-39% by 2030, or up to 47% in 2030 if supported from developed countries. In 2050, the proportion of renewable energy will reach 70%.
- Viet Nam's power system will limit CO_2 emissions from electricity production to about 204-254 million tons in 2030 and about 30 million tons in 2050.
- Coal and natural gas thermal power plants will be following the energy transition roadmap:
    - Coal power plants will switch fuel to biomass or ammonia after 20 years of operation and stop operating after 40 years of life, if they do not switch fuel.
    - Prioritise maximum use of domestic gas for electricity generation. In case domestic gas production declines, additional imports of natural gas or LNG will be required.
    - Limit the development of power sources using LNG, if there are alternatives to reduce dependence on imported fuel. Power plants using LNG will implement a fuel conversion roadmap to hydrogen, when the technology is commercial and price-competitive.

In addition to PDP8 and the commitments made at COP26, the Prime Minister confirmed Viet Nam's participation in the international JETP, which sets the following goals for 2030: the aim is to reach peak emissions of no more than 170 million tons of CO_2 from the power sector in 2030; limit coal power capacity to 30.2 GW, and reach 47% RE share in electricity generation. Fulfilment of these goals is dependent on support from international partners.

To implement the roadmap to achieve the net-zero target as committed, Viet Nam's power sector is facing a number of challenges (as well as opportunities), specifically as follows:

1) Challenges in solving the legal issues, compensation costs and social issues when ceasing the operation of coal and gas thermal power projects.
2) PDP8 proposes to convert fuel for coal and gas thermal power plants to biomass, ammonia and hydrogen in order to implement the net-zero commitment. However, currently fuel conversion options for coal and gas thermal power plants are still being researched around the world and have not yet been commercialised, so there is a high risk in terms of their technical and economic feasibility.
3) The theoretical potential of renewable energy is large, but the technical potential is limited in the short term due to land use. Regarding land availability, RE power sources compete with land use in other sectors. Wind and solar resources are not uniform across regions in Viet Nam. The demand for electricity is forecasted to grow strongly in the Northern region, where renewable energy potential and economic efficiency is lower than in other regions. While the South and Central regions have better solar and wind resources, the potential is limited by the ability to expand the transmis-

sion grid, or by shifting future demand to these regions. Developing renewable energy sources, including hydropower, can ensure electricity supply, but it may still be necessary to have reserves for dry years and years/periods with low wind and solar power.

4) The potential for developing nuclear power and carbon storage is limited:
   - There has not been a consensus of the National Assembly on the issue of developing nuclear power sources.
   - Ability of CO_2 storage has great theoretical potential, but technical feasibility studies have not been undertaken yet. According to an assessment in a study of ADB, Viet Nam only has technical potential to store about 900 million tons of CO_2 in exploited oil and gas fields in the Southeast region (Asian Development Bank (ADB), 2013).
5) Other challenges include difficulties in mobilising investment capital, implementing ability for the renovation of the old power grid system and developing smart power grids to integrate renewable energy sources. The ability to further expand the inter-regional transmission grid from the South to the North is limited, due to limited land availability and the investments needed for the construction of the required 1000-1500 km long transmission lines.
6) Electricity prices, power sector policies and mechanisms, and electricity market design have not yet been adjusted to appropriately develop renewable energy sources and operate a highly integrated power system with renewable energy sources. For example, there has not yet been effective ancillary services market to encourage the development of backup and flexible sources for system security and integration of renewable energy sources. Moreover, there has been no change in electricity tariffs for coal and gas power plants to encourage flexible operation of thermal power plants.

Purpose and scope

This Technical Report serves as a background report to the Energy Outlook Report for Viet Nam – Pathways to Net-Zero and is part of the Energy Partnership Programme between Viet Nam and Denmark (DEPP III), which aims to support Viet Nam's green transition of the energy system. The analysis covers different energy scenarios for the period from 2019 to 2050 and focuses on the power sector, as well as the end-use sectors covering agriculture, industry, residential, commercial, and transport. This report lays out key assumptions, modelling set-up and results of two main scenarios and a range of sensitivity scenarios to provide further technical background information to the EOR-NZ report.

The analysis reported in this document is based on simulation results from three energy models: TIMES, Balmorel and PSS/E. Both TIMES and Balmorel are least-cost optimisation models. The TIMES model optimises all energy sectors with a wide scope, allowing for analysis of electrification of other sectors, sector coupling and allocation of resources between sectors. The Balmorel model performs a more detailed optimisation of the power system only and is ideally suited to assess integration of variable renewables, need for transmission expansions and flexibility in terms of batteries. The PSS/E model is used to investigate the Vietnamese grid and assess future grid reinforcement needs.

2 Modelling framework

The TIMES model

TIMES model generator: principles and coverage

The TIMES (The Integrated MARKAL-EFOM System) model generator serves as a crucial component within the IEA-ETSAP's methodology (IEA-ETSAP, 2024) for energy scenarios, facilitating in-depth analyses of energy and environmental factors. The entire source code is openly available under the GPL3 license, accessible for free on GitHub (GitHub TIMES, 2024). Developed by integrating two distinct yet complementary approaches - technical engineering and economic modelling - the TIMES model generator is a collaborative effort involving 21 countries, the EU, and support from the private sector, ensuring ongoing methodological advancements.

Functioning as a techno-economic model, TIMES enables comprehensive analyses of national energy systems, offering a technology-rich foundation for projecting energy dynamics across an extended timeframe. Typically applied to scrutinise entire energy system, the model relies on statistical data and assumptions, including estimates for end-use energy service demands (e.g. car road travel, residential lighting, steam heat requirements in the paper industry, etc.) and details on the existing energy equipment stock in all sectors. Users are also responsible for providing information on current and future technologies, along with present and prospective primary energy sources and their potentials.

Utilising these inputs, the TIMES model strives to optimise technology investment and operation concurrently, aiming to deliver energy services at the minimum global cost. However, it is important to acknowledge certain modelling limitations associated with TIMES. These include assumptions of perfect foresight, ideal market conditions, and a modelling perspective from the vantage point of a central planner.

TIMES-Vietnam

The EOR21 introduced a Net-Zero scenario aligned with Viet Nam's commitment to achieve net-zero emissions by 2050 (EREA and DEA, 2022). The EOR-NZ aims to assist Vietnamese authorities in planning a cost-effective pathway to meet the net-zero target. Achieving this requires significant enhancements to the existing modelling toolbox. Hence, the TIMES-Vietnam energy system model (based on the software set-up, as in Figure 2) has been completely re-built and deployed within this project. The model development includes the establishment of local expertise to ensure effective application and stewardship of the methodology in the long term. Additionally, the TIMES-Vietnam model has been previously adapted to facilitate scenario analysis for the EOR19 and EOR21, and now for EOR-NZ.

The TIMES-Vietnam model encompasses the entire spectrum of the energy system, spanning from primary energy resources to power plants and other fuel processing facilities, and finally reaching various demand services across the demand sectors.

Primary energy sources, including domestic and imported fossil fuels, electricity, and diverse domestic renewable energy sources, are harnessed to meet the nation's energy demands. Power plants and fuel production and processing facilities, both fossil and renewable, transform these primary energy sources into final energy carriers, such as electricity, oil products, natural gas, bio-, or electro fuels, which, in turn, are utilised in the demand sectors. The model encompasses both existing and potential future plants categorised by fuel and technology type, each characterised by parameters such as existing capacity or investment cost, operating costs, efficiency, and other techno-economic attributes. Final energy carriers are consumed by demand-specific end-use devices (e.g. electricity in residential lamps for lighting), meeting the energy service demands within each sector.

The model covers five demand sectors: Agriculture, Commercial, Industry, Residential, and Transport. Each sector is defined by a specific array of technologies and end-use devices delivering services such as illustrated in Table 2. Both existing and potential new end-use technologies are characterised by parameters such as existing capacity or investment cost, operating costs, efficiency, and other performance metrics. More details on the model structure and coverage, among others, can be found in the User Manual of the TIMES-Vietnam Model.

Projections for energy service demands are determined by forecasting the base year energy demands, derived from the 2019 energy balance provided by Viet Nam Institute of Energy (IE) as part of the calibration process (VNEEP, 2021). These projections align with sector-specific macroeconomic drivers as shown in Table 1 comprising GDP growth, GDP per capita growth, and population growth rates.

Table 1: Demand drivers by sector.

Sector	Driver for demand projections	Service demands
Agriculture	Population growth rate	Aggregated agriculture demand [PJ]
Industry	GDP growth rate	See Table 2
Residential	GDP per capita growth rate	See Table 3
Services	GDP growth rate	See Table 3
Transport: Cars and motorcycles	GDP per capita growth rate	See Table 4
Transport: Other	GDP growth rate	See Table 4

Table 2: Industry sub-sector demand types.

Sub-sectors demand	Code	Unit
Iron and steel	IIS	Mt
Non-metallic minerals		
Cement	ICM	Mt
Other non-metallic	INM	PJ
Chemicals		
Ammonia	IAM	Mt
Other chemicals	ICH	PJ
Extractive Industry	IEX	PJ
Pulp and paper	IPP	PJ
Textile and leather	ITL	PJ
Wood products	IWP	PJ
Food, beverage, tobacco processing	IFB	PJ
Material construction	IMC	PJ
Manufacturing of machinery and equipment	IME	PJ
Motor vehicles manufacturing	IMV	PJ
Other industries	IOI	PJ

Table 3: Residential and services demand types.

Sector	Demand	Code	Unit
Residential (rural/urban), Services	Thermal uses	TH	PJ
	Air conditioning	AC	PJ
	Cooking	CK	PJ
	Lighting	LIG	Mill. units
	Electric Appliances	EAP	PJ
	Other uses	OTH	PJ
Services	Street lighting	SLIG	Mill. units

Table 4: Transport demand types.

Sub-sector	Demand	Code	Unit[1]
Passengers	Cars	TCAR	Bpkm
	Light commercial passenger vehicles	TLPV	Bpkm
	Motorbikes	TMOT	Bpkm
	Buses	TBUS	Bpkm
	Rail	TRAP	Bpkm
	Navigation	TNAP	Bpkm
	Aviation	TAVP	Bpkm
Freight	Light-commercial freight vehicles	TLCV	Btkm
	Heavy-duty trucks	THDT	Btkm
	Rail	TRAF	Btkm
	Navigation	TNAF	Btkm
	Aviation	TAVF	Btkm

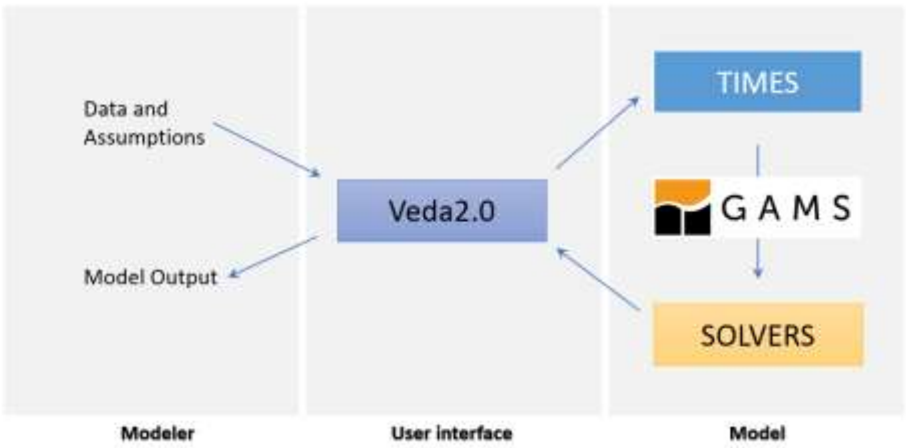


Figure 2: Overview of the VEDA system for the TIMES modelling framework as applied for TIMES-Vietnam (IEA-ETSAP Veda, 2024).

The main settings in terms of temporal and spatial resolution, as well as the broad economic drivers are listed below.

- Annual GDP growth rate: 6,5%
- General real discount rate: 10%
- Base year for discounting: 2019
- Currency: Million USD
- Periods and model horizon:
    - The model consists of 7 milestone years (2019, 2022, 2025, 2030, 2035, 2040, 2045, 2050).

[1] [Bpkm]: Billion passenger-kilometers, [Btkm]: Billion tonne-kilometers

    - The base-year is 2019, due to data availability and the absence of unusual pandemic-related influences on the statistics.
- Time-slice aggregation: in total the model consists of 48 time-slices to represent variations within the modelled periods.
    - 4 seasons, representing 3 consecutive months of the year (accounting for dry, wet, and intermediate seasonality):
        - January to March
        - April to June
        - July to September
        - October to December
    - Each season comprises 12 blocks of hours as shown in Table 5
- Regions: the model is set-up as a single-region model with supply, transformation, and demand in the same region. Transmission constraints are applied on an aggregated level, e.g. grid efficiency, or delivery costs among sectors for selected commodities. Trade with neighbouring countries is modelled through import of commodities with exogenous fuel price projections. Export options are not considered.

Table 5: Time-slice aggregation overview, TIMES.

Block	Start hour of day	End hour of day	Length [hours]
B01	0	7	8
B02	8	9	2
B03	10	10	1
B04	11	11	1
B05	12	12	1
B06	13	13	1
B07	14	14	1
B08	15	15	1
B09	16	16	1
B10	17	19	3
B11	20	21	2
B12	22	23	2

The Balmorel model

The power system analyses for the Vietnamese system are carried out with the Balmorel model. Like TIMES, Balmorel is a least-cost optimisation model, but with a focus on the power (and district heating) sector. The model optimises both the dispatch of generation units and the capacities of future investments in generation and transmission. Balmorel uses a detailed technical representation of the existing power system, as well as a catalogue of well-defined investment options for generation and transmission.

All existing and committed generation plants are represented on an individual basis. Investment options are available as generic technologies. Among others, these are coal and gas turbines, wind turbines, solar cells, biomass plants, small hydro plants, storage/batteries, and nuclear reactors.

The Balmorel model can either be run with a full hourly time granularity or with time aggregation to reduce complexity and thereby computation time when performing investment and dispatch optimisations simultaneously. Dispatch optimisations with fixed investments in future capacities (based on a previous investment optimisation run) can then be made to analyse the hour-by-hour balancing of power system when large shares of variable renewable energy (VRE) are integrated in the power system.

Balmorel – Viet Nam

The Vietnamese Balmorel model contains input data on the Vietnamese electricity system on a regional level: the map in Figure 3 illustrates the existing interconnected power system in Viet Nam, as of 2022. The country is represented by seven transmission regions, for which the electricity balance between supply and demand needs to be met. The transmission regions are connected by transmission lines with fixed existing capacity in the base year. In total, eight lines connect the transmission regions, allowing for flow exchange between regions to meet the electricity balance.

In addition, three transmission lines connect individual power plants in China and Laos to the Vietnamese grid. Plants in neighbouring countries which deliver power to Viet Nam are limited to existing and planned capacities and optimised interconnections between neighbouring power grids are not included.

As mentioned, the Balmorel model can be run with full hourly resolution or with aggregated time steps to save computational time. The current analysis represents each year by 624 time-slices per year, utilising 26 aggregated seasons, representing half monthly periods each. Each of these seasons is modelled with 24 time-steps, which are aggregated in a logical way, grouping all hours of the week with a similar character (e.g. peak load, solar peak, low demand in weekends and nights etc.). The grouping of the time-steps is shown in Table 6.

Table 6: Schematic representation of how weekly time steps are aggregated in Balmorel.

	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
1	24	1	1	1	1	1	24
2	24	1	1	1	1	1	24
3	24	1	1	1	1	1	24
4	24	1	1	1	1	1	24
5	24	1	1	1	1	1	24
6	24	1	1	1	1	1	24
7	2	2	2	2	2	2	2
8	2	2	2	2	2	2	2
9	3	3	3	3	3	3	21
10	3	3	3	3	3	3	21
11	4	4	4	4	4	4	22
12	4	4	4	4	4	4	22
13	5	6	7	8	9	6	10
14	5	6	7	8	9	6	10
15	11	11	11	11	11	11	21
16	11	11	11	11	11	11	21

17	12	13	14	15	16	13	17
18	12	13	14	15	16	13	17
19	18	18	18	18	18	18	23
20	18	18	18	18	18	18	23
21	19	19	19	19	19	19	19
22	19	19	19	19	19	19	19
23	20	20	20	20	20	20	20
24	20	20	20	20	20	20	20

Balmorel is a free-of-charge, open-source model and has been adapted and continuously updated for Viet Nam during a series of activities over the last 9 years. For more information about the model and examples for published studies, see (Ea Energy Analyses, 2024) and more at (Danish Energy Agency, 2024) and at (DEPP3, 2024). For a simplified online demonstration model, see (Danish Energy Agency, 2024).

Figure 3: Transmission regions of Viet Nam, connected neighbouring power plants and the current interconnectors in GW (2022).

Power-to-X modelling

Compared to previous versions (e.g. EOR21), the Balmorel model has been further developed to simulate renewable fuels production, storage, and distribution.

The demand of hydrogen for end-use sectors as found by the TIMES model is provided as input to Balmorel. The Balmorel model then finds the optimal capacity of electrolysers, ammonia synthesis, hydrogen pipelines, hydrogen storage, ammonia storage and transport. Moreover, Balmorel calculates the optimal hydrogen demand required for the power system, utilised generating electricity from hydrogen or ammonia (X-to-Power). Hydrogen and ammonia can be utilised in the power sector by refurbishment of existing plants or installing new capacity of plants that can co-firing with natural gas and ammonia or coal and hydrogen. A schematic representation of the supply chain as represented in Balmorel, including the link to TIMES, is shown in Figure 4.

Figure 4: Schematic representation of how the Power-to-X modelling works between TIMES and Balmorel. The models (TIMES or Balmorel) responsible for determining the different types of hydrogen and ammonia demand is indicated.

Balmorel-Vietnam models hydrogen as being produced by the power grid through electrolysis (i.e. yellow hydrogen) and does not consider any imports from other sources (international or non-grid based electrolysis). Under the Net-Zero scenarios, it is expected that most of the hydrogen production will be green hydrogen, due to the high proportions of power from wind and solar in the long term until 2050 and the availability of storages for flexibility.

Modelling of co-firing

The Balmorel model can allow multiple fuels to be used for one technology. The practical implementation consists of including two technologies, one main technology (e.g. a natural gas turbine), whose capacity is output by the model in the results and an additional technology whose capacity is solely virtual and determined in relation to the capacity of the main technology. Additional equations govern the share of generation, fuel use or capacity both technologies get allocated.

In Balmorel-Vietnam, the co-firing functionality is implemented in the following occasions:

- Existing or committed technologies using coal or LNG can implement CCS, thus enabling the use of fossil fuels with fewer emissions.
- Existing or committed technologies using coal or LNG can be refurbished to be able to co-fire with ammonia or biomass (coal power plants) or hydrogen (LNG plants).
- Model-based investments can be made in cofiring technologies (coal + ammonia, coal + biomass or LNG + hydrogen).

- Ammonia synthesis is modelled as a cofiring technology where input fuels are hydrogen and electricity. The ratio between the two fuels is carefully set to match the technology catalogue (EREA and DEA, 2023).

Reserve modelling

Balmorel was developed with the functionality to comply with reserve requirements given to the model. It is important to note that the Balmorel model does not optimise the amount of reserve capacity, but rather, it can optimise which units should supply the reserve service when given the amount as an input.
Two types of reserve requirements were implemented in Balmorel-Vietnam: operating reserve and strategic reserve.
The operating reserve is modelled as different services (spinning reserve, regulating reserve, flexibility reserve and absolute reserve) that need to be determined on hourly basis. The required reserve level is calculated based on the demand, wind and solar generation levels or entered as a fixed number. This reserve is meant to support the system when forecast errors result in a loss of generation or an increase in demand.
The strategic reserve models the planning reserve requirement for long-term dry years with low hydro, as well as a year with low wind and solar power compared to a normal year. The strategic reserve capacity is kept aside in the model and cannot be used for generation of electricity.

The PSS/E model

The model PSS/E (Power System Simulator for Engineering) belongs to Power Technology Inc Company of Siemens Group. It is a program to simulate, analyse and optimise operational features of the power system, as well as power system planning.

The PSS/E model is widely used in Viet Nam for making short-term operation analyses and long-term grid planning. Its main functions in grid planning are load flow, short circuit calculation, Active power – voltage (P-V) curve and Reactive power – voltage (Q-V) curve analysis, and dynamic stability simulation. Additionally, N-1 and N-2 criteria analyses of the grid can be performed through a PSS/E simulation to analyse where these criteria are violated.
The PSS/E model was first used in National Load Dispatching Center (NLDC-A0) in early 1990s. Then, Institute of Energy (under EVN at that time) used PSS/E for grid design of the National Power Development Plan (PDP) 4 (1995), PDP5 (2000), PDP6 (2005), PDP7 (2010) and PDP7 Revised (2015).
Currently NLDC (A0) and its subsidiary (Regional Load Dispatching Center – A1,2,3) are using PSS/E V33-34 for making their operation planning: Weekly, Monthly and Yearly Planning. The version of PSS/E used in this study was used for Long-term Grid Planning in PDP8.

PSS/E – Viet Nam

A detailed model of the Vietnamese power grid has been used to test grid-related assumptions from the Balmorel power system analyses. The 500 kV and 220 kV national power grids for the years 2025 and 2030 are represented in the model; the 110 kV and lower voltage level power grid will be equivalent to the 220 kV nodes. The model has around 800 nodes and 1700 branches of lines for the system in 2030, including all plants (detailed at unit level), loads, transformers, shunts, Flexible Alternating Current Transmission System (FACTSs), branches of lines.

The PSS/E model is used to calculate and check the power flow on the power system, identifying nodes with voltage or transmission capacity exceeding the allowed limit. For checking N-1 faults, the study uses a calculation module written in Python to check all N-1 fault cases on the 500 kV and 220 kV grid in all snapshots. It only scans N-1 incidents of line branches and transmission transformers, excluding generator set incidents and busbar incidents. The calculation program classifies N-1 incidents depending on the level of overload on the elements of the transmission grid: (i) Serious incidents (overload < 10%); (ii) Extremely serious incidents (overload 10%-20%); (iii) Emergency incidents (overload > 20%).

There are 8760 hours of generation dispatching mix in one year, corresponding to 8760 time steps of load (with approximate hourly accuracy). Therefore, in theory, it would be necessary to observe 8760 hours of power grid simulations in a year to test the ability of the grid to respond to generation dispatching and load at the same time. However, not all 8760 grid operation modes are critical. In grid simulation, it is often only some of most critical operation modes that are interesting to analyse to reduce the calculated volume. If the most critical operation modes are satisfied, the grid can respond well to the remaining operation cases. The Balmorel model has calculated power dispatch in 2025 and 2030 at hourly level (i.e. for the full 8760 h in each year), and a number of typical snapshots to be considered for grid operation analyses have been selected.

The relevant operation snapshots for the simulation of the load flow in the power system are as follows:

- Highest generation (HG)
- Lowest generation (LG)
- Highest residual demand (HRD)
- Lowest residual demand (LRD)
- Maximum total interconnected transmission capacity (HF)
- Minimum total interconnected transmission capacity (LF)
- Highest wind and solar curtailment (HC)

Combined modelling suite and soft linking

Integrating the capabilities of three distinct energy system models - TIMES, Balmorel, and PSS/E - enables leveraging their complementary strengths. Table 7 provides a summary of the primary purposes and key characteristics of these three models.

Given its comprehensive approach, the TIMES model stands out by modelling all energy sectors, making it particularly well-suited for analysing resource or emission allocations across different sectors. Moreover, TIMES thrives in modelling the electrification of various end-use sectors such as industry and transportation.

The Balmorel model, with its optimisation focus on the power sector, boasts heightened temporal and geographical resolution. This makes it the optimal choice for scrutinising the evolution of power generation and transmission capacities in the future. It is also adept at assessing the impact of system flexibility, including demand response and storage, along with the integration of variable renewable energy sources.

Conversely, the PSS/E model analyses the power grid at high level of detail. The model can e.g. assess load flow and voltages, as well as test the N-1 criteria to evaluate the grid's robustness.

Table 7: Main purpose and key characteristics of the three models in the modelling suite for EOR: TIMES, Balmorel and PSS/E.

	TIMES	Balmorel	PSS/E
Purpose	Investment optimisation Cost-optimal allocation of: • Resources • Emissions • Electrification	Cost optimised power system build-out and dispatch: • Power generation and transmission system • Demand response and storages • Integration of VRE • Conversion (P2X) technologies and fuel pipelines	Analyse power grid: • Check load level and voltage of intra-regional grid • Propose necessary intra-regional grid • Calculate inter-regional power loss
Sectors	Supply, Power, Agriculture, Commercial, Industry, Residential, Transport	Power sector	Power sector
Temporal resolution	48 time-slices: 4 seasons, 12 hours	624 time-slices: 26 seasons, 24 hours	Up to hourly resolution
Geographical resolution	1 region for all sectors	7 regions	500kV – 220kV power system of Viet Nam
Foresight	Full foresight until 2050	Myopic – one year at a time	Snapshot

To assure consistent scenarios across the three models, the input data is aligned (see Chapter 3). Additionally, the three models are soft linked, meaning that the results from one model are implemented as input to the next. Figure 5 illustrates the soft links between the models. Several iterations were made to arrive at the final scenario results presented in this report.

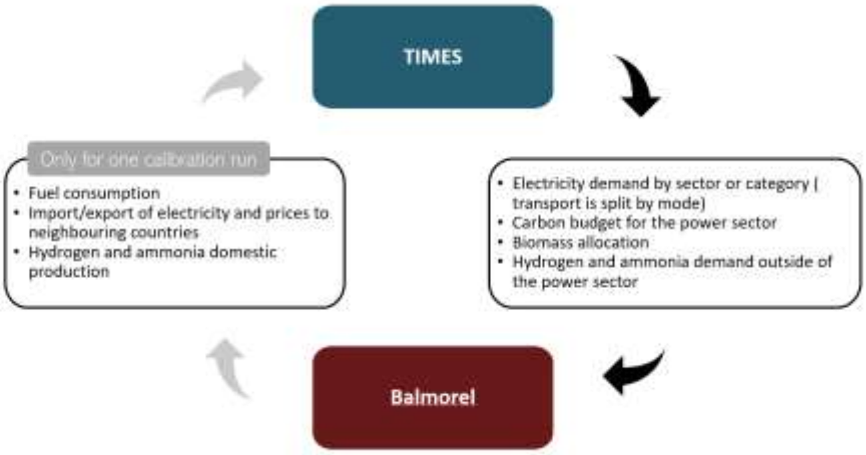


Figure 5: Modelling suite for EOR-NZ, and soft linking between TIMES and Balmorel. Grey arrows indicate linking performed for calibration runs only, black arrows indicate linking performed for all scenario runs.

Linking TIMES and Balmorel

Regarding the integration between TIMES and Balmorel, TIMES provides essential input to Balmorel, particularly in guiding the allocation of domestic biomass resources and defining the carbon emissions budget for the power sector. These constraints serve as upper bounds within the Balmorel model. Furthermore, the TIMES model plays a pivotal role in establishing the overall annual power demand for each sector, as well as demands for hydrogen and ammonia.

It is noteworthy that TIMES, in its hydrogen projections, does not encompass hydrogen usage specific to the power sector and ammonia production. Similarly, the transferred ammonia demand provided by TIMES excludes the ammonia consumption within the power sector (see Figure 6). The linking process is performed once per scenario.

A calibration of the power sector in the TIMES model is made based on the results of the Balmorel model, to ensure that the two models are calibrated and that the TIMES model can benefit from the model detailed power sector modelling in the Balmorel model.

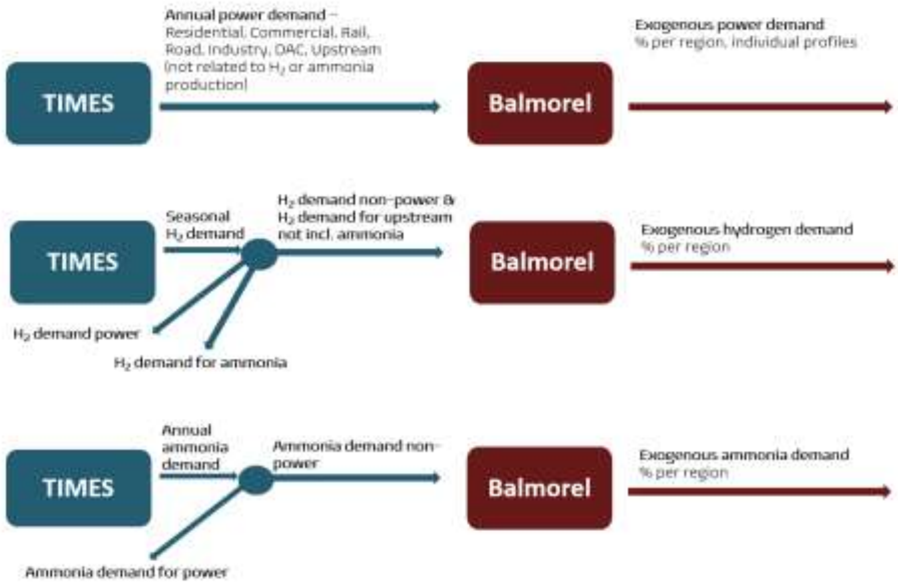


Figure 6: Linking of demands from TIMES to Balmorel.

Linking Balmorel and PSS/E

The results from Balmorel model will provide two important inputs to the PSS/E model, as follows:

- The installed generation capacity and installed transmission capacity between regions in each year considered. The power plants in each region and the inter-regional transmission system in PSS/E will be built based on this input from Balmorel.
- The generation dispatch snapshots: Balmorel optimises the hourly output power of each power plant in each region and the loading level of the transmission lines. This is called "snapshot", which is transferred to the PSS/E model. The most critical snapshots are selected to be simulated in grid operation, to check the response of the transmission system.

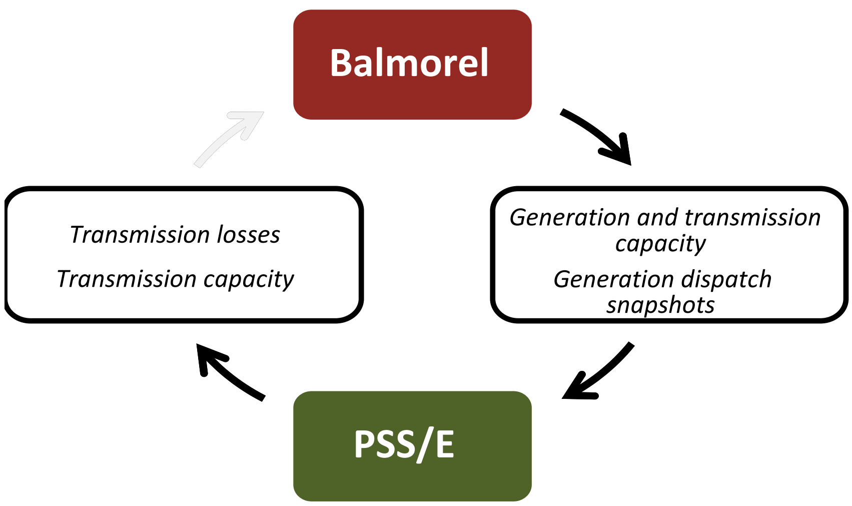


Figure 7: Linking between the Balmorel and PSS/E model. Grey linking arrow has not been performed in this EOR.

On the other hand, PSS/E can provide input about inter-regional transmission capacity as well as transmission losses. Based on a more thorough and complete analysis of the transmission grid (including intra-regional grid) as output of PSS/E, the Balmorel results are evaluated. More details on the study in PSS/E can be found in the report "Grid modelling of Net-Zero scenario". The linking process of Balmorel and PSS/E is represented in Figure 7.

3 Key input data

Data flow in the modelling framework

The data requirements for the three models in the modelling suite are extensive. The three models in the modelling suite have separate requirements for model input. As explained in the previous section, the models are soft linked, meaning that one model uses the output of another model as its input. Besides these soft-link inputs, the models also require a lot of external inputs. As illustrated in Figure 8, some of the main types of input data are shared by two or all three of the models. In this case, data consistency between the models was ensured as much as possible.

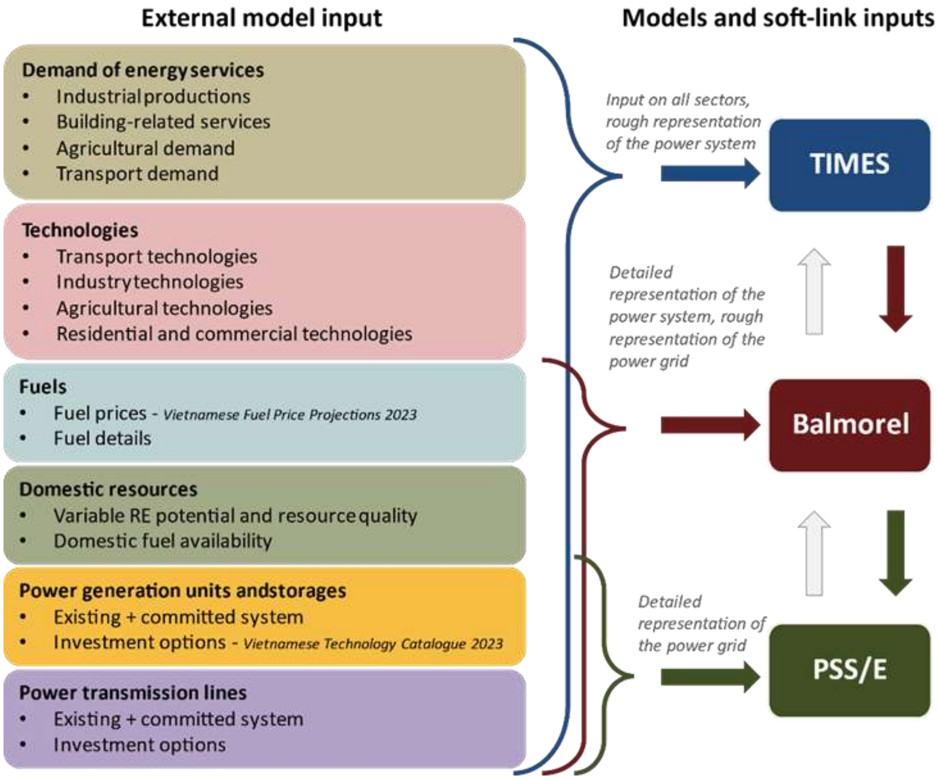


Figure 8: Key input data to the three models, TIMES, Balmorel and PSS/E. Soft linking input is seen in detail in Figure 5, Figure 6 and Figure 7. The coloured arrows indicate soft-linking performed for each scenario run, the grey arrows indicate calibration link (Balmorel to TIMES) and potential linking (PSS/E to Balmorel) as executed in the previous EOR (EREA and DEA, 2022)

External model input to TIMES and Balmorel

Demands for energy services

The primary demand drivers include GDP growth, population growth and sectoral shares, the latter referring to the proportion of each sector within the overall GDP. The applied GDP growth rate is 6.5% for main scenarios and the real GDP is seen in Figure 9. The sectoral shares for main scenarios are presented in Table 89. The population can be seen in Figure 10.

There are secondary drivers for each demand sector, such as the elasticity of energy use to GDP growth, industrial production projections, market penetration rates for space cooling, refrigeration, and electric appliances.

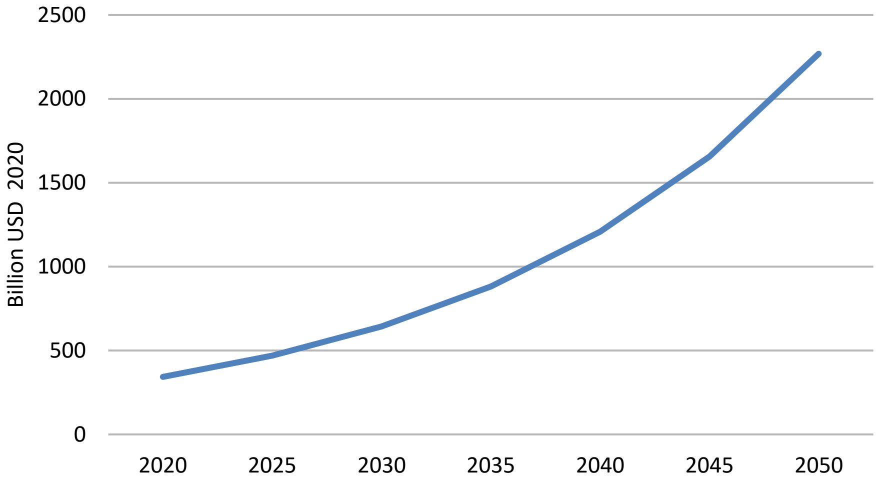


Figure 9: Assumed real GDP for Viet Nam until 2050.

Table 89: Main assumptions on sectoral shares for base scenarios, where data for 2019 and 2020 represent historical values from statistics.

	Industry	Commercial	Agricultural	Tax & Subsidy
2019	35.9%	43.2%	11.3%	9.6%
2020	36.4%	42.9%	11.3%	9.4%
2025	38.2%	43.9%	9.5%	8.3%
2030	40.0%	45.0%	7.8%	7.2%
2035	40.0%	46.3%	7.6%	6.2%
2040	40.0%	47.5%	7.4%	5.1%
2045	40.0%	48.8%	7.2%	4.1%
2050	40.0%	50.0%	7.0%	3.0%

Table 89 outlines the main assumptions (Vietnam Gov, 2022) regarding the sectoral shares in different sectors over the years. In 2019, the industrial sector accounted for 35.9%, the commercial sector for 43.2%, agriculture for 11.3%, and tax & subsidy for 9.6%. The share of industry sector increases to 40% in 2030 and kept constant until 2050. From 2030 to 2050, the commercial sector is anticipated to rise to 50% by 2050. Agriculture is expected to experience a gradual decline, reaching 7% in 2050.

Table 10: Main assumptions on sectoral shares for the Green Growth scenario

	Industry	Commercial	Agricultural	Tax & Subsidy
2019	35.9%	43.2%	11.3%	9.6%
2020	36.4%	42.9%	11.3%	9.4%
2025	38.2%	43.9%	9.5%	8.3%
2030	40.0%	45.0%	7.8%	7.2%
2035	37.5%	48.8%	7.6%	6.2%
2040	35.0%	52.5%	7.4%	5.1%
2045	32.5%	56.3%	7.2%	4.1%
2050	30.0%	60.0%	7.0%	3.0%

Table 10 outlines the main assumptions (Vietnam Gov, 2022) regarding the sectoral shares in different sectors over the years for the Green Growth (GG) scenario. The difference compared to the base scenarios is the share of the commercial sector in 2050, which stands at 60% instead of 50%, and the share of industry for the GG scenario is 30% in 2050, instead of 40%.

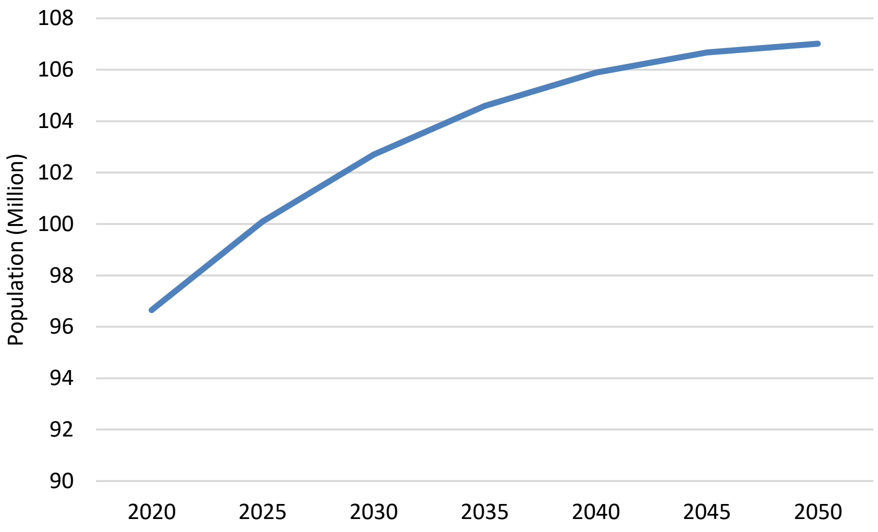


Figure 10: Assumption on population development in Viet Nam until 2050.

The population data from 2019 to 2050 indicates a steady increase in the overall population. In 2019, the population stood at 95.78 million. The projection for the future shows a consistent upward trend, with the population reaching 107.01 million by the year 2050 (World Bank, 2019).

Energy service demand projection

The major driver for demands in all sectors is the GDP and sectoral GDP growth. Other important drivers for the different sectors include population, urbanisation, sectoral development plans etc.

Below is the description of demand projections for the Baseline scenario.

Industry

The demand projection for the iron and steel and cement subsectors is expressed in terms of production tonnage, which is derived from the Vietnam Cleaner Production Centre's projections (Vietnam Cleaner Production Centre, 2021). For other subsectors, demand is projected based on sub-sector growth rates and elasticity factors, as in EOR21.

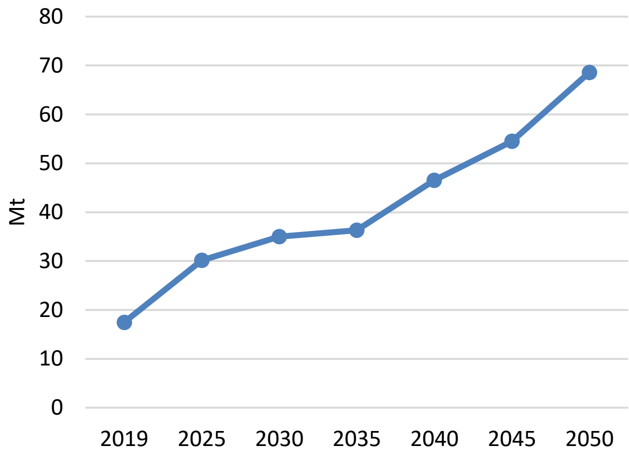


Figure 11: Projections for Iron and Steel production.

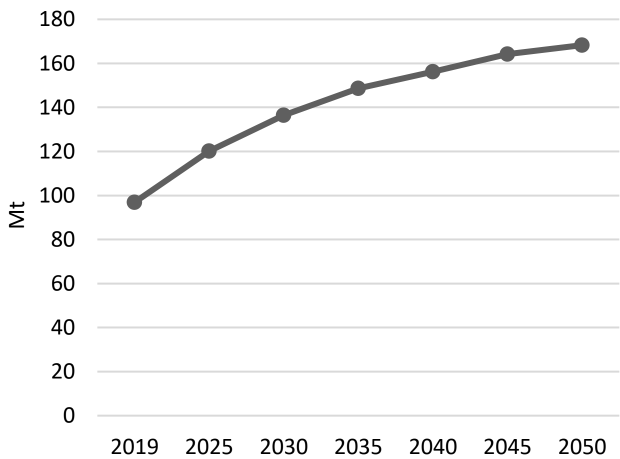


Figure 12: Projection for cement production.

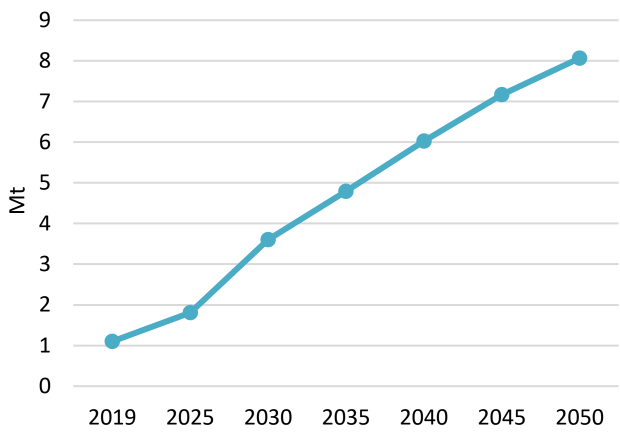


Figure 13: Projection for ammonia production.

The iron & steel industry is expected to have a production growth rate of about 9.5% per year in the 2019-2025 period (Figure 11), followed by a period of slower growth at a rate of 1.9% per year until 2035. After this, the growth rate is projected to increase, achieving about 4.3% per year in the period leading up to 2050. In 2050, the production is forecasted to be 68.6 Mt, up from 17.5 Mt in 2019 (Vietnam Cleaner Production Centre, 2021).

The production of the cement industry is high in volume; however, the growth rate for the demand gradually decreases in the period 2019-2050 (Figure 12). Starting from 96.92 Mt in 2019, demand is projected to reach 168.27 Mt in 2050 (Vietnam Cleaner Production Centre, 2021).

The ammonia industry is predicted to experience production growth at a rate around 8.6% per year in the 2019-2025 period (Figure 13). This is followed by the 2025-2030 period with expected growth rate at about 14.8% per year. After this, from 2030 to 2050, the expected growth rate slows down to 4.1% per year. Demand is expected to be 8.07 Mt in 2050, an increase from 1.10 Mt in 2019.

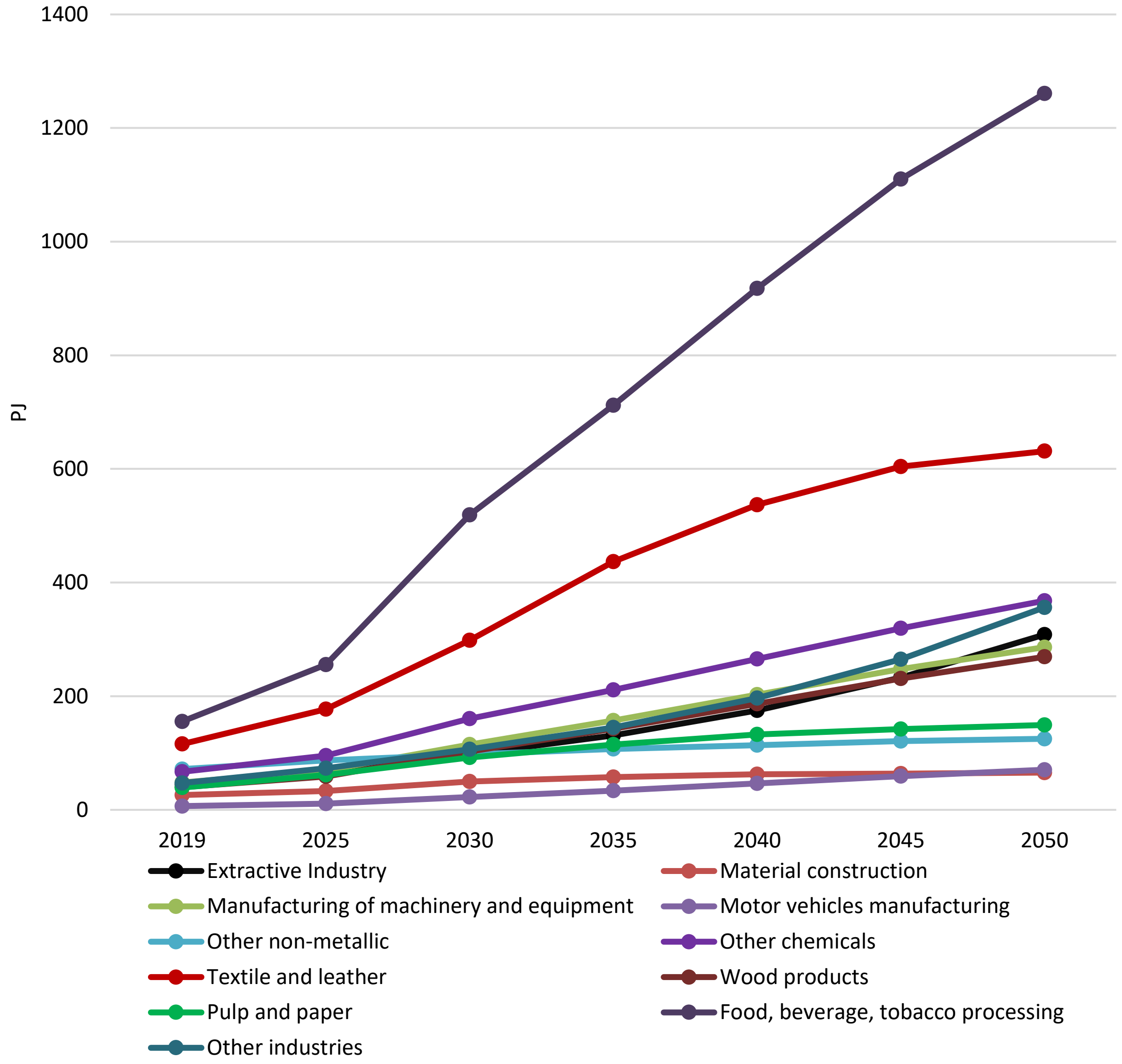


Figure 14: Projections for sub-sectoral demands in industry for Baseline scenario.

In general, predictions for energy service demand for industries exhibit a trend of growth throughout the period of 2019-2050. Growth rates for the demand in the 2025-2030 period are higher than those of the previous period for most industries; however, after 2030, growth rates gradually decrease (Figure 14).

Transportation

In the transportation sector, demand drivers are considered to vary based on the mode of transport. For private cars and motorbikes, demand is projected using the elasticity and GDP per capita growth rate. The demand for light commercial vehicles, buses, and trucks is estimated using the elasticity and overall GDP growth rate.

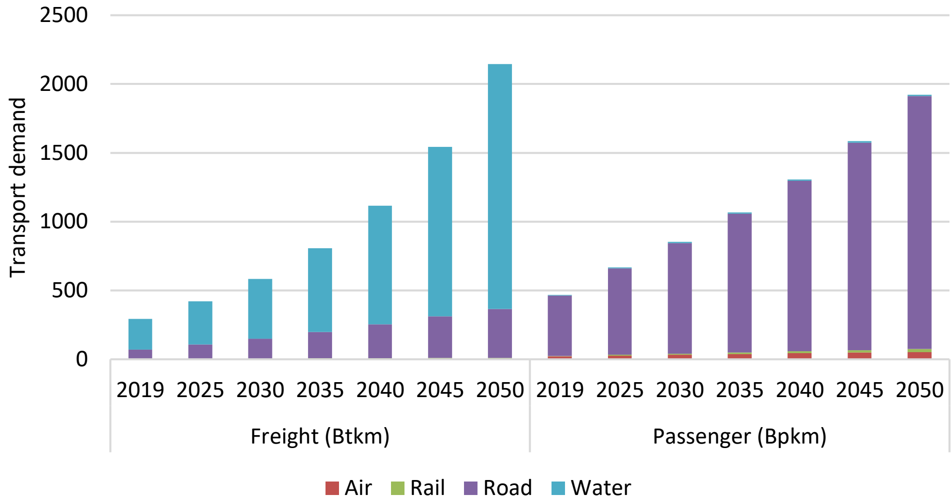


Figure 15: Freight and Passenger Transport demand for Baseline scenario.

For freight transport, most of the demand is served by navigation/water transport (*Figure 15*). From 2019 to 2050, demand for water transport is expected to continue increasing in volume, while maintaining its position as the mode of freight transportation with the largest share. From 222.5 Btkm in 2019, accounting for 76% of total demand for freight transport, demand for water transport is projected to reach 1775.8 Btkm in 2050, accounting for 83% of total freight transport demand at that time. This translates to a growth rate of around 7% per year in the 2019-2050 period.

Road transport holds the second largest share of freight transport demand. In 2019, it was at 66.8 Btkm, accounting for 23% of total freight transport demand. Road transport demand is expected to increase, reaching 142.4 Btkm and accounting for 24% of demand for freight transport in 2030. After this, while the volume of demand for road transport is expected to continue increasing, estimated to reach 356.8 Btkm in 2050, its share in freight transport demand is reduced, down to 16% in 2050.

Both air and rail transport are projected to grow in demand; however, these two modes only account for a minor portion of the demand for freight transport. The growth rate for demand for rail transport is estimated to be 2.4% per year, and for air transport, the estimated rate is 6% per year.

For passenger transport, most of the demand is served by road transport, which in 2019 accounted for 94% of total passenger transport demand (Figure 15). The total demand of this mode is expected to steadily grow in the period 2019-2050 at a rate of around 4.7% per year, from 438.8 Bpkm in 2019 to 1007.5 Bpkm in 2035 and 1837.3 Bpkm in 2050. By this, passenger road transport demand accounts for 95% of total passenger transport demand in 2035 and 2050. Air transport for passengers is projected to grow in demand at a rate of around 3% per year, achieving 52.3 Bpkm in 2050 from 20.7 Bpkm in 2019. Demand for water transport is expected to grow at the rate of 2.4% per year, reaching 11.0 Bpkm in 2050, from 5.3 Bpkm in 2019.

Rail transport for passengers, accounting for the smallest share as of today, is predicted to have the highest growth rate among the four modes. Starting at 4.1 Bpkm in 2019, it is projected to grow to 22.1 Bpkm in 2050.

The projections are based on the base assumptions from the Baseline scenario. The Net-Zero scenarios assume a share of modal shift from private to public transport, as well as from navigation to rail for freight (as further detailed in Chapter 4).

Agriculture, commercial and residential sectors

The demand in the agriculture sector and commercial sector is linked to GDP growth rate and elasticities, as assumed in the TIMES model for EOR21. The main driver used to project the demand of the residential sector is GDP per capita growth rate.

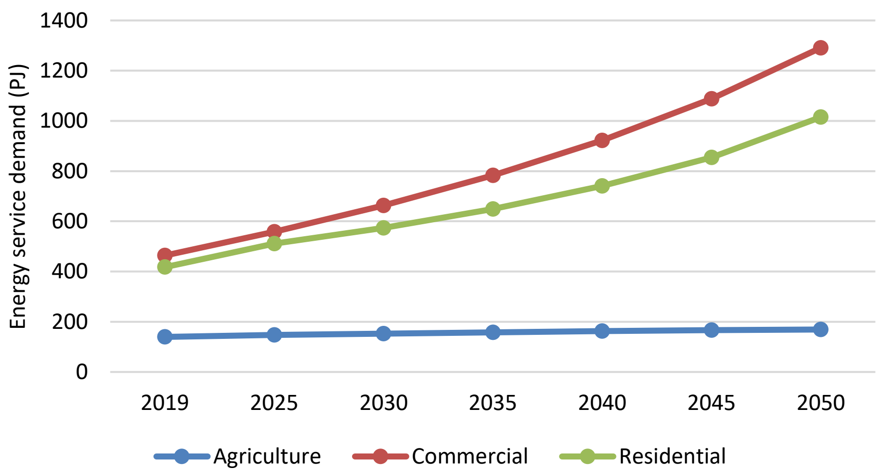


Figure 16: Energy service demand projection of Agriculture, Commercial and Residential sectors.

Demand for energy from the agriculture, commercial and residential sectors is expected to grow in the period 2019-2050, with a growth rate of around 0.6% per year for agriculture, 3.4% per year for commercial and 2.9% per year for residential sector (Figure 16). In the year 2050, energy demand for the agriculture, commercial, and residential sectors is projected to be 169.2 PJ, 1290.9 PJ and 1014.8 PJ respectively.

Air pollution costs

The air pollution emissions of NO_x, SO_2, and PM2.5 are included in all scenarios and for all sectors alongside their externality costs for Viet Nam, which are included in the objective function of the model. Thus, the emissions come at a cost that the model will try to avoid, as much as it is cost-efficient. The emission factors are derived depending on the type of sector, technology, and fuel type from the following source (Aarhus University, 2024).

For the sectors agriculture, industry, residential, services, and upstream the emissions for stationary combustion technologies are deployed, while for transport the data for mobile sources is used. Emissions factors for the power sector are implemented in both TIMES and Balmorel.

Table 11 shows the applied air pollution costs in the base-year 2019 for each sector and pollutant. The transport sector has a finer resolution to capture the differences between land-based transport modes and aviation and shipping.

Table 11: Air pollution costs for the year 2019 by sector and pollutant [Million USD per kg] (Brandt et al, 2021)

Sector	SO_2	NO_X	PM2.5
	Million USD per kg in 2020		
Agriculture	3.29	7.68	21.96
Industry	2.71	6.63	8.46
Power	2.66	5.81	6.05
Residential	7.39	14.07	40.87
Services	7.39	14.07	40.87
Upstream	2.66	5.81	6.05
Land transport, incl. rail	3.29	7.68	21.96
Domestic aviation	14.18	21.60	72.68
Domestic shipping	2.22	2.00	3.80

The air pollution costs are assumed to have a higher impact, hence, higher costs for society, depending on the GDP PPP (purchasing power parity) and thus, are adjusted based on its projection. In Table 12Table 6, the applied scaling factors are laid out for each model period. The cost factors are multiplied by the scaling factor to get the future air pollution costs.

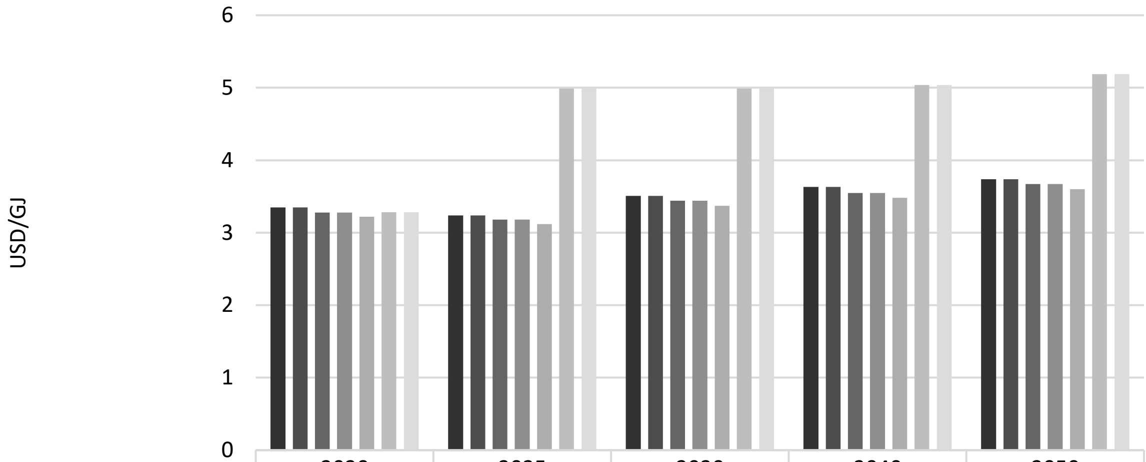
Table 12: Scaling factors for air pollution costs per period.

Year	Scaling factor
2016	1.00
2020	1.25
2025	1.76
2030	2.47
2035	3.54
2040	5.09
2045	7.30
2050	10.49

Fuel prices

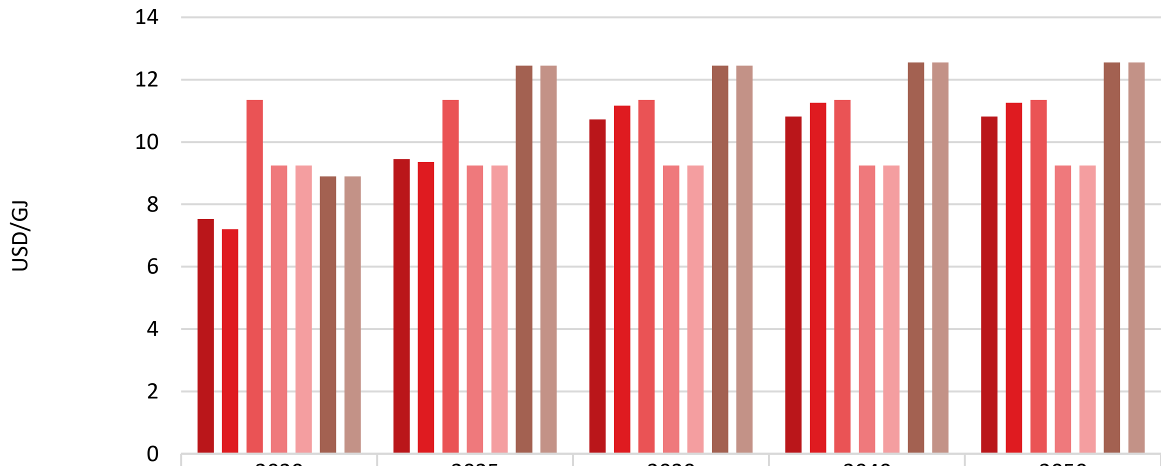
As a net importer of fuel, Viet Nam is directly exposed to international fuel prices. Thus, projections of future prices are an important input to least-cost optimisation and analyses of the Vietnamese energy system. Figure 17 - Figure 20 show historical fuel prices as well as the fuel price projections used in the models. The detailed study and methodology used for fuel prices and price projections is outlined in a separate report (EREA and DEA, 2021).

For imported coal and LNG, transport cost add-ons - differentiated across regions - are added to the fuel prices to reflect, e.g., differences in distance to harbours. Fuel prices of all fuels, without add-ons, used in the Balmorel model are shown in Figure 17 - Figure 20.



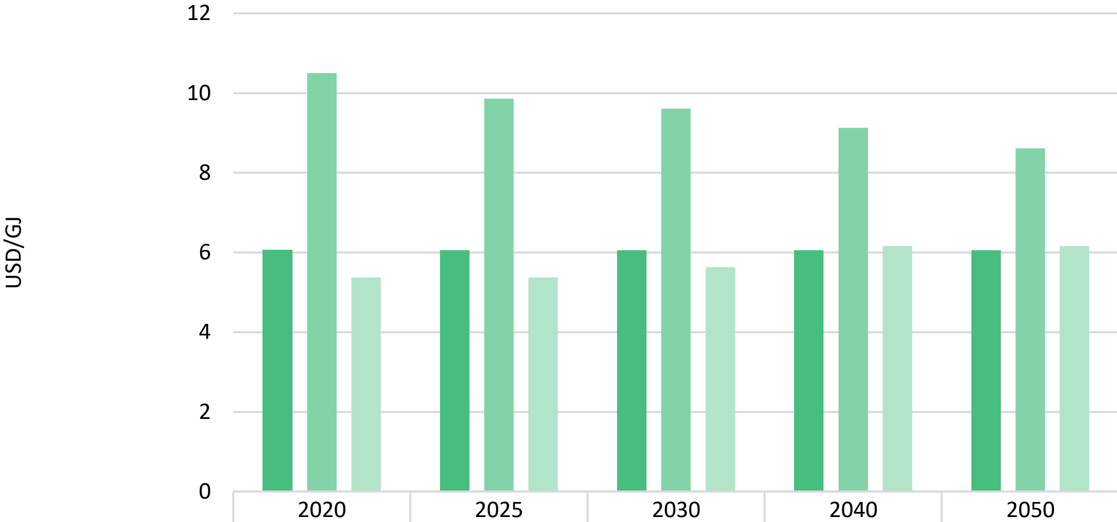
	2020	2025	2030	2040	2050
Dom. Coal (4b-5)	3,35	3,24	3,51	3,63	3,74
Dom. Coal CCS (4b-5)	3,35	3,24	3,51	3,63	3,74
Dom. Coal (6)	3,28	3,18	3,44	3,55	3,67
Dom. Coal CCS (6)	3,28	3,18	3,44	3,55	3,67
Dom. Coal (7)	3,22	3,12	3,37	3,48	3,60
Imp. coal	3,28	4,99	4,99	5,04	5,19
Imp coal CCS	3,28	4,99	4,99	5,04	5,19

Figure 17: Coal price projections in Viet Nam. Different coal types are included, where Coal 7 has the lowest caloric value and coal 6 has slightly higher quality and coal 4b-5 has the highest quality.



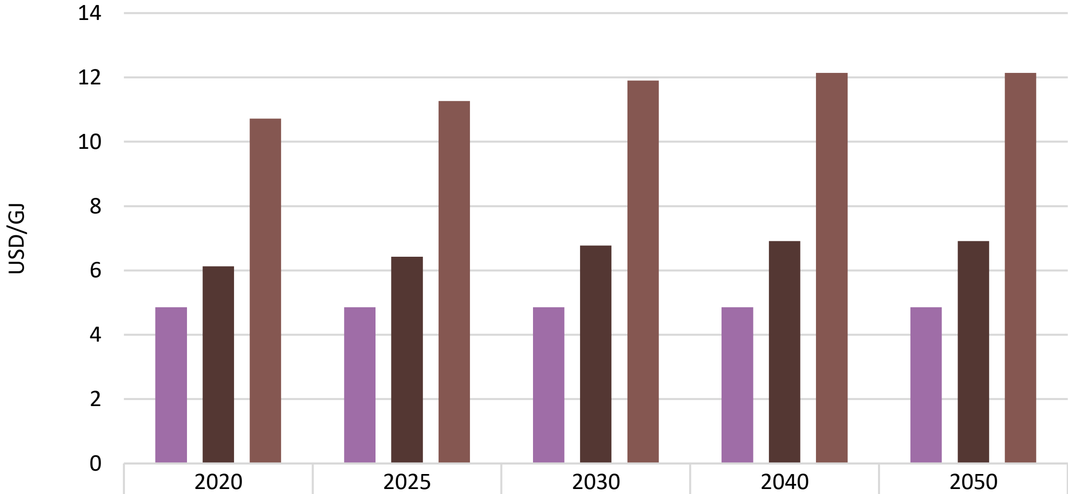
	2020	2025	2030	2040	2050
NG (East)	7,53	9,45	10,73	10,82	10,82
NG (West)	7,20	9,36	11,17	11,26	11,26
NG (Block B)	11,35	11,35	11,35	11,35	11,35
NG (CVX)	9,25	9,25	9,25	9,25	9,25
NG (Ken Bau)	9,25	9,25	9,25	9,25	9,25
LNG	8,90	12,45	12,45	12,56	12,56
LNG (CCS)	8,90	12,45	12,45	12,56	12,56

Figure 18: Natural gas price projections in Viet Nam.



	2020	2025	2030	2040	2050
Wood	6,06	6,06	6,06	6,06	6,06
Biogas	10,50	9,86	9,62	9,13	8,61
Non-wood biomass	5,37	5,37	5,63	6,16	6,16

Figure 19: Biomass price projections in Viet Nam.



	2020	2025	2030	2040	2050
Nuclear	4,86	4,86	4,86	4,86	4,86
Fuel oil	6,12	6,43	6,78	6,91	6,91
Light oil	10,72	11,27	11,90	12,14	12,14

Figure 20: Prices for oil products and uranium in Viet Nam

Investment options for the power sector

In the Vietnamese Technology Catalogue for Power Generation 2023 (EREA and DEA, 2023), international and Vietnamese investment costs for coal and natural gas-based generation plants, as well as wind and solar power and other technologies, have been compared, along with a projection of the development of expected investment costs for 2020, 2030 and 2050. For more information, please refer to the Vietnamese Technology Catalogue that includes 2 volumes: Power Generation, and Renewable Fuel (including Power to

X) and Energy Storage (EREA and DEA, 2023). The catalogue also contains information about hydro, tidal, wave, biomass, biogas, waste, geothermal, internal combustion engine, pumped hydro, nuclear, electrolyser, and storage. In addition to investment costs, operation and maintenance costs (variable and fixed O&M), technology efficiencies, as well as many other technical parameters are described.

The techno-economic information from the Vietnamese Technology Catalogue 2023 has been implemented in the modelling framework, both for Balmorel and TIMES. Small differences exist between the Technology Catalogue and the Balmorel modelling investment costs because the interest during construction (IDC) is added based on discount rate and the construction time of the power plant in the model input. Interest during construction is of importance when comparing technologies costs to each other. Plants with a shorter construction time pay less IDC compared to plants with a longer construction time. The investment costs in the technology catalogue are given as overnight costs and therefore do not consider IDC.
The IDC for technologies is calculated as:

$$IDC = a \times \frac{(1+i)^t - 1}{i \times t} \times \left(1 + \frac{i}{2}\right) - a$$

Where *a* indicates invested capital, *i* indicates interest rate and *t* indicates construction time.

With respect to solar PV power, land costs are also included in the investment costs. Based on the average compensation cost in rural areas for land for perennial crops in 2020 (about 2.75 USD/m^2), the growth rate of land prices in the future will follow the population growth rate. Although floating PV does not occupy land, thus no land-use costs are considered, the capital costs are higher than utility scale PV (about 15%).

End-of-life processing costs of solar panel and chemical in battery are also put in the model. The disposal cost of solar PV is about 20 kUSD/MW up to 2030, after 2030 about 10 kUSD/MW (IRENA, 2016). The cost of disposing of lithium-ion about 30 kUSD/MW up to 2030, after 2030 about 20 kUSD/MW (Battery University, 2017).

The back-end cost of the nuclear fuel cycle (spent fuel removal, disposal and storage) of 2.33 USD/MWh is added in Variable O&M cost, and the front-end cost of the nuclear fuel cycle (mining, enrichment, conditioning) of 7 USD/MWh is the fuel price of nuclear (NEA OECD, 2020).

Power generation technology investment options, costs, efficiency and technical lifetimes are presented in Table 13 - Table 17.

Table 13: Thermal power generation technology investment options.

Technology type	Available	CAPEX incl. IDC kUSD (2019)/MW	Fixed O&M kUSD (2019)/MW	Variable O&M USD (2019)/MWh$_{el}$	Efficiency %	Technical lifetime Years
Coal subcritical	2020 - 2029	1,622	32.64	2.46	36%	30
	2030 - 2049	1,608	31.57	2.25	36%	30
	2050	1,568	30.50	2.14	36%	30
Coal supercritical	2020 - 2029	1,789	39.60	0.78	37%	30
	2030 - 2049	1,698	38.50	0.12	38%	30
	2050	1,674	37.20	0.12	39%	30
Coal ultra-supercritical	2020 - 2029	2,027	61.10	0.12	42%	30
	2030 - 2049	1,893	59.40	0.12	43%	30
	2050	1,880	57.50	0.11	44%	30
Coal AUSC	2035 - 2049	1,925	70.48	0.12	50%	30
	2050	1,800	72.80	0.11	50%	30
Coal CCS	2020 - 2029	4,307	83.10	4.00	29%	30
	2030 - 2049	3,885	80.60	3.25	30%	30
	2050	3,409	78.10	3.14	31%	30
SteamTur-Super-NH3	2020 - 2029	2,270	39.64	0.78	36%	30
	2030 - 2049	2,121	37.89	0.12	37%	30
	2050	2,110	37.24	0.12	38%	30
Nuclear – PWR	2020 - 2029	7,370	127	4.73	33%	60
	2030 - 2049	6,680	122	4.63	38%	60
	2050	6,190	113	4.53	45%	80
Nuclear – SMR	2020 - 2029	6,640	114	4.61	33%	60
	2030 - 2049	5,760	110	4.52	38%	60
	2050	5,260	102	4.42	45%	80
CCGT - LNG	2020 - 2029	875	29.35	0.45	52%	25
	2030 - 2049	789	28.50	0.13	59%	25
	2050	778	27.60	0.12	60%	25
CCGT – H2	2020 - 2029	1065	30.82	0.45	52%	25
	2030 - 2049	979	29.93	0.13	59%	25
	2050	979	29.93	0.12	60%	25
CCGT- CCS- LNG	2020 - 2029	2,643	37.9	1.70	44%	25
	2030 - 2049	2,543	37.5	1.33	50%	25
	2050	2,443	36.4	1.30	50%	25
SCGT	2020 - 2029	665	18.75	4.23	33%	25
	2030 - 2049	642	17.89	4.04	35%	25
	2050	608	17.31	3.85	39%	25
RICE	2020-2050	633	10.0	6.5	49%	25
Geothermal	2020 - 2029	5,236	20.80	0.38	10%	30
	2030 - 2049	4,843	19.20	0.36	11%	30
	2050	4,424	17.60	0.33	12%	30
Biomass	2020 - 2029	1,990	49.50	3.16	31%	25
	2030 - 2049	1,831	45.50	2.91	31%	25
	2050	1,598	39.60	2.53	31%	25
MSW	2020 - 2029	6,404	253.40	25.10	28%	25
	2030 - 2049	5,947	233.70	24.31	29%	25
	2050	5,278	201.20	23.48	29%	25

Table 14: Renewable power generation technology investment options. Offshore wind costs are further differentiated over the specific sites modelled (average costs are shown in the table). Solar PV costs include the end-of-life processing cost

Technology type	Available	CAPEX incl. IDC kUSD (2019) /MW	Fixed O&M kUSD (2019) /MW	Variable O&M USD (2019) /MWh_{el}	Technical life-time Years
Small hydro	2020 - 2029	1,528	41.90	0.50	50
	2030-2049	1,528	39.80	0.48	50
	2050	1,528	37.30	0.45	50
Onshore Wind	2020 - 2024	1,625	42.48	-	27
	2025 - 2029	1,506	42.48	-	27
	2030 - 2039	1,387	38.48	-	30
	2040 - 2049	1,279	38.48	-	30
	2050	1,170	32.70	-	30
Near shore Wind	2020 - 2024	2,287	55.00	-	27
	2025 - 2029	2,001	47.50	-	27
	2030 - 2039	1,670	40.00	-	30
	2040 - 2049	1,558	36.00	-	30
	2050	1,452	32.20	-	30
Wind offshore (fixed base)	2020 - 2024	3,702	111.16	-	25
	2025 - 2029	3,115	98.61	-	28
	2030 - 2039	2,459	86.05	-	30
	2040 - 2049	2,201	78.07	-	30
	2050	1,944	70.10	-	30
Wind offshore (floating base)	2020 - 2024	6,464	155.00	-	25
	2025 - 2029	4,660	140.00	-	28
	2030 - 2039	3,031	125.00	-	30
	2040 - 2049	2,659	95.00	-	30
	2050	2,306	66.50	-	30
Solar PV (Utility scale)	2020 - 2024	880	15.50	-	35
	2025 - 2029	759	12.75	-	35
	2030 - 2039	633	10.00	-	40
	2040 - 2049	556	9.00	-	40
	2050	479	8.00	-	40
Solar PV (Rooftop)	2020 - 2024	1,027	14.80	-	35
	2025 - 2029	880	12.40	-	35
	2030 - 2039	730	10.00	-	40
	2040 - 2049	632	9.00	-	40
	2050	534	8.00	-	40
Solar PV (Floating)	2020 - 2024	1,026	15.50	-	35
	2025 - 2029	894	12.75	-	35
	2030 - 2039	733	10.00	-	40
	2040 - 2049	645	9.00	-	40
	2050	548	8.00	-	40
Tidal	2020 - 2029	7,227	70.80	-	25
	2030 - 2049	6,714	62.50	-	25
	2050	6,335	35.70	-	30

Table 15: Synthetic fuel production technology investment options (In 2023 Balmorel model, H2 and NH3 are produced by electricity grid).

	Available	Inverter CAPEX incl. IDC kUSD (2019) /MW	Fixed O&M kUSD (2019) /MW	Variable O&M USD (2019) /MWh_{el}	Efficiency %	Technical lifetime Years
Electrolyser	2020 - 2029	1,051	40.06	-	58%	20
	2030 - 2039	738	28.12	-	66%	25
	2040-2049	596	22.73	-	68%	28
	2050	455	17.34	-	71%	30
Hydrogen storage	2020 - 2029	70	0.72	-	88%	25
	2030 - 2039	55	0.60	-	89%	30
	2040-2049	33	0.60	-	90%	30
	2050	26	0.48	-	90%	30
NH3 Synthesis from electricity	2020 - 2029	1,491	40.19	0.02	82%	30
	2030 - 2039	1,220	32.87	0.02	82%	30
	2040-2049	992	26.74	0.02	82%	30
	2050	765	20.61	0.02	82%	30
NH3_storage	2020-2050	70	0.72	0%	88%	25

Table 16: Storage investment options (disposal cost included). The battery is a Li-ion battery. Battery investments can be independently optimised in storage volume (MWh) and inverter (=charging/discharging) capacity (MW).

	Available	Volume CAPEX incl. IDC kUSD (2019) /MWh	Inverter CAPEX incl. IDC kUSD (2019) /MW	Fixed O&M kUSD (2019) /MW	Variable O&M USD (2019) /MWhel	Efficiency %	Technical lifetime Years
Battery	2020 - 2029	270	590	0.62	2.30	91%	20
	2030 - 2049	160	270	0.31	2.07	92%	25
	2050	90	160	0.16	1.84	92%	30
Vanadium flow battery	2020 - 2029		2,795	0.01	0.51	78%	20
	2030 - 2049		2,587	0.004	0.51	78%	20
	2050		1,843	0.003	0.51	78%	20
CAES	2020 - 2029	468	1,222	0.001	1.40	60%	40
	2030 - 2049	468	1,222	0.001	1.40	70%	40
	2050	460	1,203	0.001	1.40	72%	40
Flywheels	2020 - 2029	1724	1,803	0.00006	0.30	98%	20
	2030 - 2049	1640	1,687	0.00006	0.30	98%	25
	2050	1024	1,062	0.00006	0.30	98%	25

Table 17: Specific pumped hydro projects. Pumped hydro project can only be invested in with a fixed ratio between storage volume (MWh) and pump/turbine capacity (MW). Ratio indicated in the table per project. Efficiency is assumed 80%. The costs indicated are the total investment cost for the full pumped hydro system including storage volume, pump and turbine. The two CAPEX columns indicate this total cost per MWh storage on the one hand and per MW pump/turbine capacity.

	Region	Total CAPEX incl. IDC kUSD (2019) /MWh	Total CAPEX incl. IDC kUSD (2019) /MWh	Maximum Turbine /Pump capacity MW	Maximum Reservoir capacity MWh	Volume to output ratio MWh/MW
Moc Chau PSPP	North	106	736	900	6,178	6.9
Phu Yen East PSPP	North	121	930	1,200	8,984	7.5
Phu Yen West PSPP	North	105	945	1,000	8,502	8.5

Chau Thon PSPP	North Central	106	954	1,000	8,502	8.5
Don Duong PSPP	Highland	125	963	1,200	8,956	7.5
Ninh Son PSPP	Highland	114	882	1,200	8,948	7.5
Ham Thuan Bac PSPP	South Central	117	909	1,200	8,948	7.5
Bac Ai PSPP	South Central	106	776	1,200	9,247	7.7
Phuoc Hoa PSPP	South Central	109	840	1,200	9,247	7.7

The model is also able to optimise the transmission capacity between different regions. The investment rate of the transmission lines is taken from the PDP8.
Investment costs for each of the transmission line (USD (2019)/MW/km) are as follows:

- 500kV HVAC line: 1000 USD (2019)/MW/km
- 800kV HVDC line from Center Central to North (600 km): 570-865 USD (2019)/MW/km (depending on transmitted capacity 3GW-6GW)
- 800kV HVDC line from South Central to North (1200 km): 480-590 USD (2019)/MW/km (depending on transmitted capacity 3 GW-6 GW)

The investment cost estimates are based on the distance between regions, which are displayed in Table 18. No limitations are placed on the size of investments in transmission.

Table 18: Voltage levels, lengths, and investment costs for electricity transmission lines

	Connection Voltage kV	Length km	Investment cost kUSD (2019)/MW
North - North Central	500	330	332
North Central - Centre Central	500	450	452
Centre Central - Highland	500	200	201
Centre Central - South Central	500	420	422
Highland - South East	500	300	302
South Central - South East	500	250	251
Highland - South Central	500	300	301
South East – South West	500	300	301
HVDC line from South Central to North	+/-800	1200	673
HVDC line from Center Central to North	+/-800	600	342

Hydrogen pipeline is based on data from the European Hydrogen Backbone Values (Danish Energy Agency, 2022). The investment costs of hydrogen pipelines are given in Table 19.

Table 19: Lengths, and investment costs for each hydrogen pipelines

	Length (km)	Investment cost (kUSD (2019)/MW)	FO&M cost (kUSD (2019)/MW)
North - North Central	256	72	0.96
North Central - Centre Central	319	90	1.19
Centre Central - Highland	273	77	1.02
Centre Central - South Central	349	98	1.30
Highland - South East	131	37	0.49
South Central - South East	336	95	1.25
Highland - South Central	340	96	1.27
South East – South West	162	46	0.60
South Central - North	879	247	3.27

Investment options for end-use technologies

The TIMES-Vietnam model explores the diverse investment opportunities available in end-use technologies including advanced and improved technologies to enhance energy efficiency and reduce emissions. The investment information of new technologies is expressed in term of investment (CAPEX) and operation (OPEX) cost.

Industry sector

Excluding the iron and steel and cement subsectors, all other industry sub-sectors are described by 23 generic processes, that produce high/low temperature heat, machine drive, and other energy services

The cost of explicit processes in the iron and steel subsector is presented in Table 20 (Netherlands Organisation for Applied Scientific Research (TNO), 2020).

Table 20: Cost of explicit processes in iron and steel subsector.

Type of process	Investment cost (CAPEX)	Operation cost (OPEX)
	MUSD/Mt steel	MUSD/Mt steel
Blast Furnace with Basic Oxygen Furnace	529	122
Blast Furnace with Basic Oxygen Furnace with CCS	552	127
Natural Gas based Direct Reduction with Electric Arc Furnace	529	132
Natural Gas based Direct Reduction with Electric Arc Furnace with Carbon Capture and storage	564	130
Hydrogen based Direct Reduction with Electric Arc Furnace	529	85
Oxygen-rich smelt reduction with CCUS	467	79
Scrap to Electric Arc Furnace	233	35
Ulcolysis	1,587	238
Ulcowin	1,676	251

The investment cost and fixed operation cost of selected processes are presented in Table 21. The full data is presented in the Appendix A.

Table 21: Cost of other generic processes in iron and steel subsector.

	Investment costs (CAPEX) MUSD/GW				Fixed Operation cost (OPEX) MUSD/GW-yr				Variable Operation cost (OPEX) MUSD/GW-PJ			
Year	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
IND Iron and steel technology: High temperature heat using Electricity - Heat Pump	1,132.87	1,012.72	949.26	910.25	1.05	0.94	0.87	0.78	0.54	0.51	0.51	0.48
IND Iron and steel technology: High temperature heat using Natural gas, Synthetic natural gas, Natural gas H2 blend - Boiler	59.11	49.26	49.26	49.26	2.17	2.06	1.95	1.84	0.33	0.30	0.30	0.30
IND Iron and steel technology: Low temperature heat using Electricity - Boiler	791.05	704.36	650.18	628.50	2.17	2.17	2.17	2.17	0.54	0.51	0.50	0.48
IND Iron and steel technology: Low temperature heat using Electricity - Heat Pump	75.85	65.02	65.02	65.02	1.16	1.11	1.05	1.00	0.15	0.15	0.12	0.12

IND Iron and steel technology: Machine drive using Electricity – Machinery	734.26	652.02	623.68	595.34	36.71	32.60	31.18	29.77	0.30	0.30	0.30	0.30
IND Iron and steel technology: Other services using Electricity - Other	734.26	652.02	623.68	595.34	36.71	32.60	31.18	29.77	0.30	0.30	0.30	0.30

The investment cost and fixed operation cost of cement subsector processes are presented in Table 22.

Table 22: Cost of processes in cement subsector.

Type of process	Investment cost (CAPEX)	Operation Cost (OPEX)
Clinker	MUSD/Mt clinker	MUS/Mt clinker
Dry process -BAT	259.5	13.0
Dry process with post-combustion CCS	321.2	16.1
Dry process with oxy fuel CCS	549.9	27.5
Dry process Hydrogen	259.8	13.0
Dry process Hydrogen with CCS	321.5	16.1
Grinding	$MUSD/Mt_{cement}$	
Grinding	56.0	5.6
Grinding	115.6	11.6
Grinding	127.7	12.8

Investment cost and fixed operation cost of ammonia subsector processes are presented in Table 23.

Table 23: Cost of processes in Ammonia subsector

Type of process	Year	Investment cost (CAPEX)	Operation Cost (OPEX)
		MUSD/Mt	MUSD/Mt
Steam Methane Reforming BAT	2020	798.14	19.95
Autothermal Reforming	2020	798.14	19.95
Coal Gasification BAT	2020	1,918.18	95.91
Steam Methane Reforming with CCS	2020	1,159.72	28.99
Autothermal Reforming with CCS	2020	1,159.72	28.99
Coal Gasification with CCS	2020	2,478.20	123.91
Electrolysis	2020	1,023.03	15.35
	2030	780.50	11.71
	2050	507.10	7.61
Biomass Gasification	2020	5,573.73	278.69
Naptha Partial Oxidation	2020	1,088.83	27.22
Ammonia synthesis unit (Haber-Bosch)	2020	86.20	2.15

Investment cost and fixed operation cost of selected processes in other subsectors (chemical, paper, vehicle manufacturing) are presented in Table 24.

Table 24: Cost of processes in the remaining industry subsectors

Technology	Investment Cost (CAPEX)				Fixed operation Cost (OPEX)			
	MUSD/GW				MUSD/GW-yr			
Year	2020	2030	2040	2050	2020	2030	2040	2050
High temperature heat using Electricity - Heat Pump	1,132.87	1,012.72	949.26	910.25	1.05	0.94	0.87	0.78
High temperature heat using Natural gas,Synthetic natural gas,Natural gas H2 blend - Boiler	59.11	49.26	49.26	49.26	2.17	2.06	1.95	1.84
Low temperature heat using Electricity - Boiler	791.05	704.36	650.18	628.50	2.17	2.17	2.17	2.17
Low temperature heat using Electricity - Heat Pump	75.85	65.02	65.02	65.02	1.16	1.11	1.05	1.00
Machine drive using Electricity - Machinery	734.26	652.02	623.68	595.34	36.71	32.60	31.18	29.77
Other services using Electricity - Other	734.26	652.02	623.68	595.34	36.71	32.60	31.18	29.77

Transport sector

The transport sector is divided into four subsectors including road, rail, waterway, and airway (European commission). The road subsector includes various types of vehicles, such as cars, light commercial passenger vehicles, light-commercial freight vehicles, heavy-duty trucks, motorbikes, and busses. Table 25 illustrates the investment cost and operation cost of selected technologies. The full data is presented in the Appendix A.

Table 25: Cost of road technologies

Mode	Type	Investment cost (CAPEX)	Operation Cost (OPEX)
		kUSD/vehicle	kUSD/vehicle
Cars	Internal Combustion Engine CAR Natural gas - New Improved	24.5	0.7
Cars	Hybrid CAR Natural gas - New Ordinary	27.6	0.8
Cars	Internal Combustion Engine CAR Methanol (H2 derived) (TRA) - New Ordinary	33.2	1.0
Cars	Battery Electric CAR Electricity - New Advanced	27.9	0.3
Buses	Hybrid BUS Natural gas - New Improved	408.5	12.3
Buses	Battery Electric BUS Electricity - New Advanced	392.4	3.9
Motorbikes	Battery Electric MOT Electricity - New Improved	3.8	0.0
Light commercial passenger vehicles	Plug-in Hybrid LPV Natural gas - New Ordinary	32.6	1.0
Light-commercial freight vehicles	Internal Combustion Engine LCV Natural gas - New Advanced	24.2	0.7
Heavy-duty trucks	Internal Combustion Engine HDT Natural gas - New Advanced	112.8	3.4

Table 26 illustrates the cost of non-road technologies, including three modes, i.e. rail, water, air.

Table 26: Cost of non-road technologies

Sub-sector	Mode	Fuel	Investment cost (CAPEX)	Operation Cost (OPEX)
			MUSD/vehicle	MUSD/vehicle
Rail	Passenger	Diesel & Renewable diesel	10.98	0.33
Rail	Passenger	Electricity	15.01	0.45
Rail	Passenger	Gaseous hydrogen	15.05	0.45
Rail	Freight	Diesel & Renewable diesel	11.54	0.35
Rail	Freight	Electricity	15.15	0.45
Rail	Freight	Gaseous hydrogen	16.19	0.49
Air	Passenger	Jet fuel & Renewable jet fuel	140.15	4.20
Air	Passenger	Hybrid Jet fuel & Renewable jet fuel	152.93	4.59
Air	Passenger	Electricity	236.81	7.10
Air	Passenger	Gaseous hydrogen	182.4	5.47
Air	Freight	Jet fuel & Renewable jet fuel	140.15	4.20
Air	Freight	Hybrid Jet fuel & Renewable jet fuel	152.93	4.59
Air	Freight	Electricity	236.81	7.10
Air	Freight	Gaseous hydrogen	182.4	5.47
Water	Passenger	Diesel & Renewable diesel	9.69	0.29
Water	Passenger	Electricity	15.83	0.47
Water	Passenger	Gaseous hydrogen	12.55	0.38
Water	Passenger	Methanol (H2 derived)	12.6	0.38
Water	Passenger	Ammonia	12.6	0.38
Water	Freight	Heavy fuel oil	10.9	0.33
Water	Freight	Diesel & Renewable diesel	10.9	0.33
Water	Freight	Electricity	21.4	0.64
Water	Freight	LNG & Synthetic natural gas	10.9	0.33
Water	Freight	Gaseous hydrogen	20.8	0.62
Water	Freight	Methanol (H2 derived)	14.17	0.43
Water	Freight	Ammonia	14.17	0.43

Residential sector

The residential sector's technologies include stove, air conditioning, lighting, and other appliances. Table 27 illustrates the investment cost and operation cost of selected technologies. The full data is presented in the Appendix A.

Table 27: Cost of technologies in Residential Sector

Technology	Unit	Investment cost
Wood Stove Advanced	USD/kW	592
Heat Pump Air Improved	USD/kW	811
Air conditioning Advanced	USD/kW	343
Cooking system Ordinary	USD/kW	182
Lighting system Advanced	USD/unit	9
Other Appliance	USD/kW	535

Service sector

Technologies in the service sector include stove, air conditioning, lighting and other appliances. Table 28 illustrates the investment cost and operation cost of selected technologies. The full data is presented in the Appendix A.

Table 28: Cost of Technologies in Service sector

	Investment cost
Technology	USD21/kW
Wood Stove Advanced	594
Coal Stove	399
Heat Pump Air Advanced	736
H2 boiler	162
Air conditioning Advanced	182
Street lights Advanced	111
Office lighting Advanced	22
Cooking system Ordinary	190
Electric Appliance Advanced	24

RE and potentials

Land solar PV

PDP8 has calculated the potential of land solar PV based on the land use planning of the provinces approved since 2015. Accordingly, the remaining unused land area is quite large. However, at present, the land use planning of the provinces and the country has been recalculated, increasing the area of forest land. As a result, the area of unused land has decreased. It is therefore necessary to recalculate land solar PV potential. Base sources for calculating potential include:

- Resolution No. 39/2021/QH15 dated 13/11/2021 of the National Assembly on the national land use planning
- Decision No. 326/QD-TTg dated 9/03/2022 of the Prime Minister on allocation of national land use planning targets.

- Map of land use planning of provinces in 2030.
- Topographic maps of the provinces are taken from GEBCO Gridded Bathymetry.

Calculation methodology:

- The scale of the existing land solar power source and the planned addition capacity is located in the energy land area that will be separated.
- The potential scale of land solar power for further construction will be calculated on the remaining land area by 2030 in the land use planning of the provinces.
- Overlapping the land use planning maps of the provinces on the topographic map of GEBCO to calculate the available area for the installation of ground solar power in the remaining land area. The available area for ground solar PV installation will have an average slope of 30% or less.
- Potential for new land solar PV construction (MW) = Available land area for ground solar power installation (ha) x Land use coefficient (1.1 MW/ha)
- Total potential of solar land includes existing land solar and potential for new land solar PV.

Based on the land use planning by Resolution No. 39/2021/QH15, the total technical potential of utility scale ground solar is about 136 GW. The EOR-NZ considers another case with the ability to increase land for energy and the development of technology, so that the potential is assumed to be double the potential following Resolution No. 39/2021/QH15. Land solar PV potential in Balmorel is modelled for each of the 64 provinces. The resulting potentials per region are shown in Figure 21.

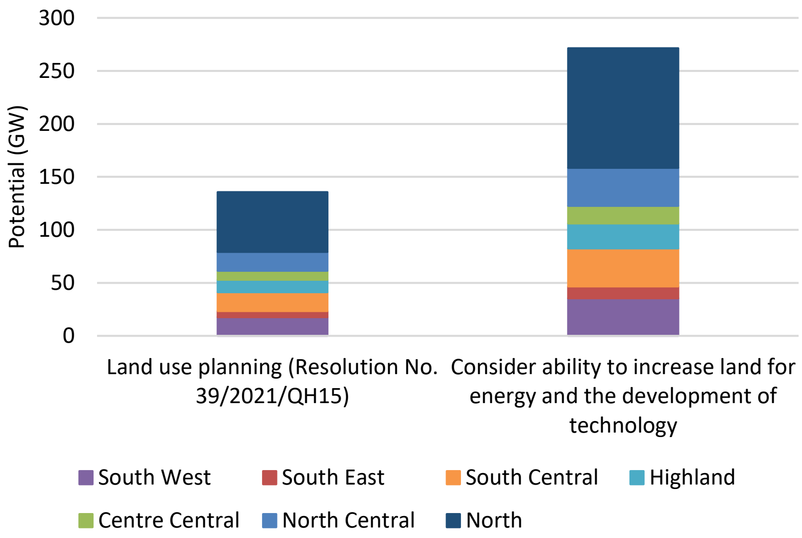


Figure 21: Solar PV potential implemented in Balmorel.

Rooftop and floating PV

The potential of rooftop solar power in PDP8 is only calculated for the potential of installation on residential roofs, not including the potential for installation on roofs of public buildings and industrial parks. However, the rooftop solar power potential for the EOR-NZ is greater as it includes the potential on public buildings and industrial parks.

The EOR-NZ calculates the potential for rooftop solar including residential roofs, roofs of public buildings and industrial parks as follow:

- Solar power potential of industrial park roof (MW) = Industrial park land area (ha) x roof area coefficient (0.275) x use coefficient (1 MW/ha)
- Potential of rooftop solar power at public facilities = (Land area for construction of educational and training institutions (ha) + Land area for construction of cultural facilities (ha) + Land area for construction of medical facilities (ha)) x Roof area coefficient (0.25) x use coefficient (1 MW/ha).

Floating solar PV is based on the potential given in PDP8, as seen in Figure 22.

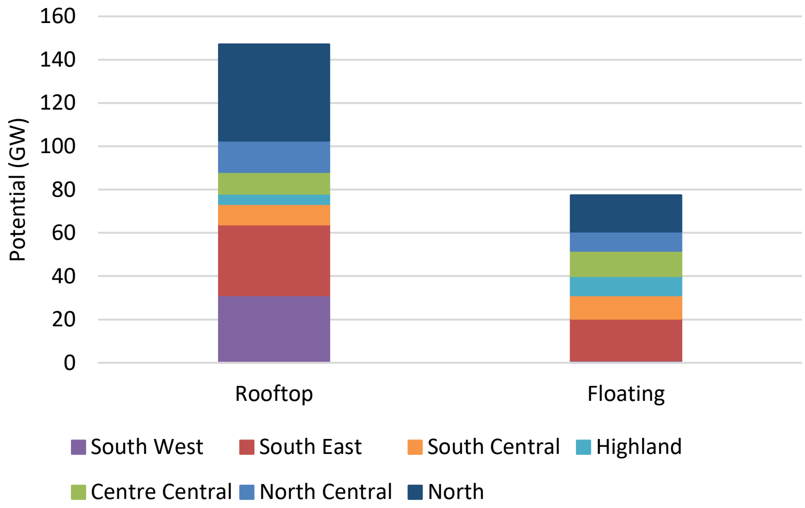


Figure 22: Solar PV potential implemented in Balmorel for Rooftop and Floating PV.

Onshore wind

An hourly wind profile for a normal year has been computed for low (4.5 – 5.5 m/s), medium (5.5 – 6 m/s) and high (6+ m/s) windspeeds for each of the seven regions based on hourly wind speed data provided by the Technical University of Denmark - Department for Wind Power. The technical potential of onshore wind is based on PDP8 with total capacity of about 217 GW (North 13 GW, North Central 11 GW, Center Central 11 GW, Highland 74 GW, South Central 35 GW, South East 5 GW, South West 68 GW). Corresponding potentials are shown in Figure 23.

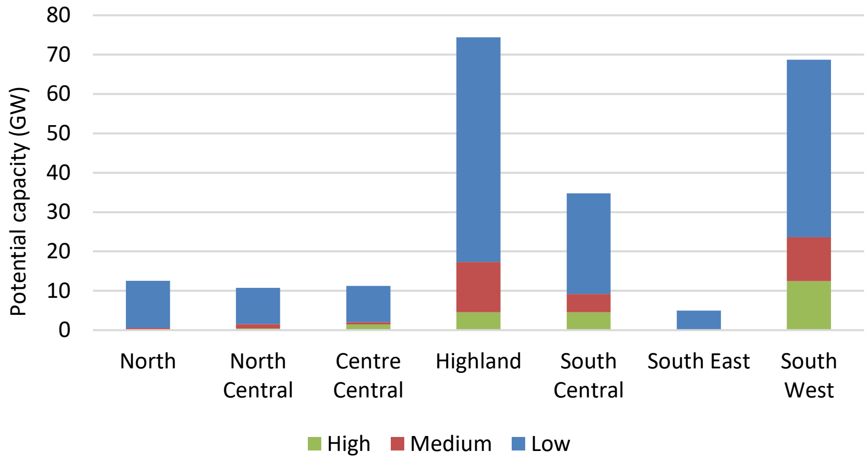


Figure 23: Onshore wind potentials by windspeed and region.

Offshore wind

The EOR-NZ updated the potential of offshore wind according to a study from the World Bank with total technical potential of offshore wind reaching about 600 GW, as in Figure 24. This potential is distributed as follows: about 66 GW in North, 70 GW in North Central, 79 GW in Center Central, 210 GW in South Central, 174 GW in South with the distance far from the shore of about 200 km.

Balmorel-Vietnam only simulates about 218 GW potential of offshore wind with the following assumptions: distance to the shore below 150 km; more than 6 nautical miles from shore; outside the maritime channel and with average wind speed higher than 7 m/s at a height of 100 m. Based on these assumptions, the potential stands at 101 GW with fixed base and 117 GW with floating base, which are distributed by regions as in Figure 25.

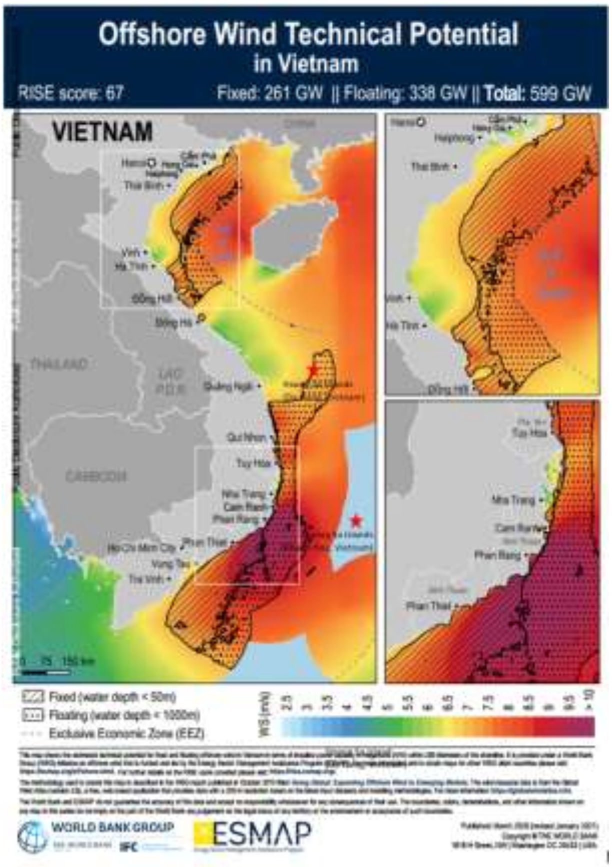


Figure 24: Offshore wind technical potential regions (WB and ESMAP, 2021).

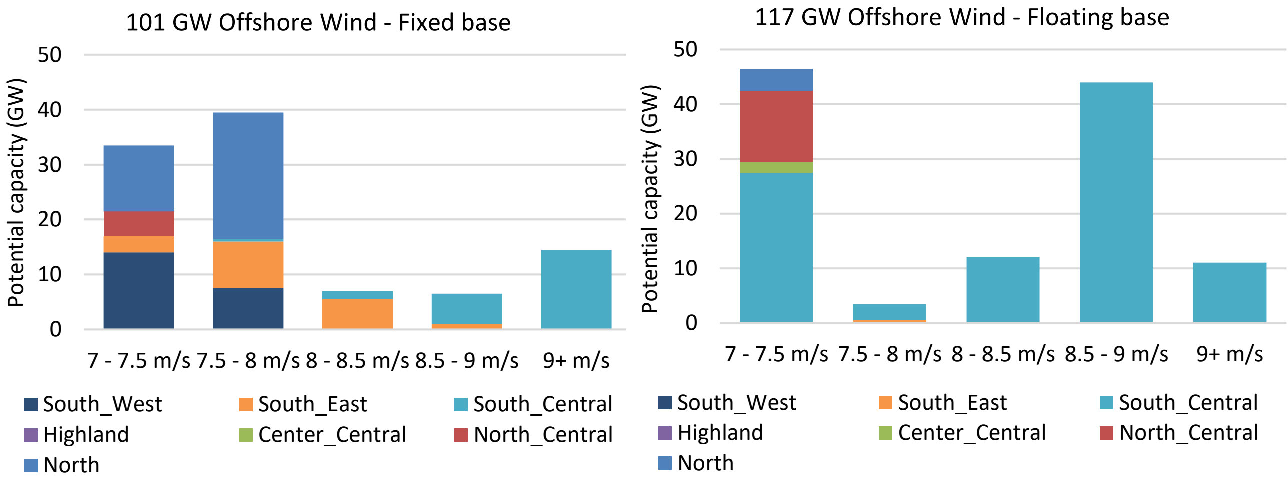


Figure 25: Offshore wind potential implemented in Balmorel (218 GW - Potential of offshore wind with distance to the shore below 150 km, more than 6 nautical miles from shore, outside the maritime channel, average wind speed is higher 7 m/s at height 100 m)

Nearshore wind

Based on PDP8, nearshore wind projects are registered for construction in the South West region. These projects are located in areas with lower seabed depth (less than 20 m) and not far from shore (less than 40 km), with wind speeds around 6.5 m/s. The investment costs range between those for onshore and offshore wind projects. These projects can be classified into the high wind power type but have higher investment costs and are considered as nearshore wind. The EOR-NZ uses nearshore wind potential from PDP8 with 14 GW in South West regions, 0.7 GW and 1.7 GW potentials in the North and North Central regions, respectively.

Biomass and waste potentials

The increased collection rates and consumption of municipal solid waste (MSW) has been estimated exogenously and was forced in as a minimum consumption for all scenarios. Based on a study of World Bank, minimum waste incineration will be 168 PJ by 2030 and 204 PJ by 2050, as the benefits of electricity generation from MSW incineration under the given costs are not sufficient in itself to warrant the investments in MSW incineration plants (The World Bank , 2018). However, MSW collection and incineration entails other benefits for society, especially related to waste management, which are not included in the optimisation.

Viet Nam has a great potential for biomass energy, as it is an agricultural country with a large amount of biomass residues from crops, livestock, forestry, and industrial activities.

The potential for energy use of biomass in TIMES was calculated based on several assumptions:

- The potential of wood was calculated by the export quantity of wood chips and wood pellets
- The potential of crop residues was calculated by the volume of crop residues and agriculture processing by-products.

Based on the General Statistics Office data, in 2020, the country's total by-product volume exceeded 156.8 million tons, which is equivalent to 1827 PJ. This includes:

- 88.9 million tons (or 56.7%) from post-harvest crop residues and agricultural processing by-products of the cultivation sector.
- 61.4 million tons (or 39.1%) of manure from livestock and poultry within the livestock sector.
- 5.5 million tons (or 3.5%) from the forestry sector.
- Nearly 1 million tons (or 10.6%) from the fisheries sector.

Besides, the theoretical potential for biomass showed that in 2050 Viet Nam could reach 3700 PJ (Vietnam Energy Development Support Centre, 2018). Based on this data and with assumptions on collection rate of each type of biomass, the potential used in the TIMES model is shown in Table 29.

Table 29: Technical potential of biomass (PJ)

Type of biomass	2020	2025	2030	2035	2040	2045	2050
Wood	239.2	279.9	325.9	363.4	405.3	449.2	498.1
Crop residues	193.6	261.2	334.9	413.6	497.3	586	770.6
Manure	26	61.7	103.3	152.6	211.1	280.3	366
Other	4.2	10.9	18.1	28.3	38	51.5	83.7
Total	463	613.7	782.2	957.9	1151.6	1367	1719

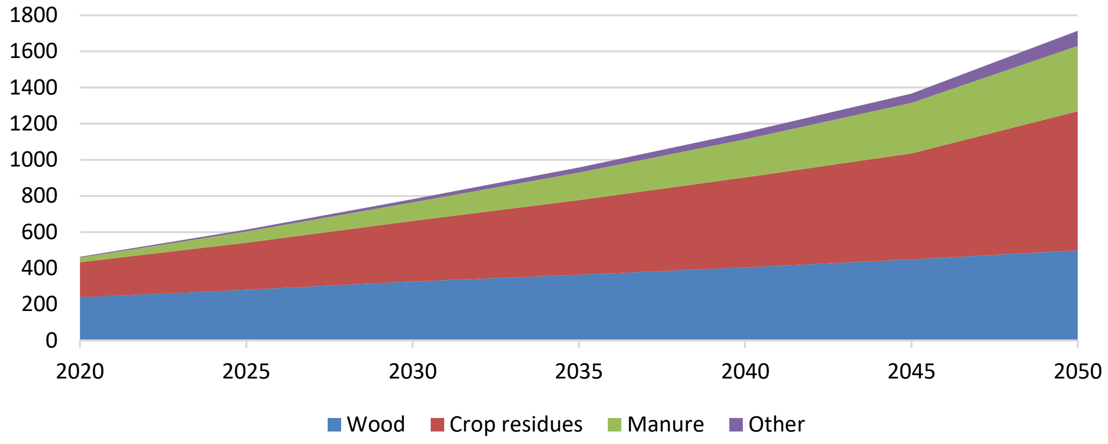


Figure 26: Technical potential of biomass (PJ)

In terms of the waste potential for energy (both for power and for other energy purposes), the estimated rate of waste emissions by capita and collection rate is 85.5% (The World Bank , 2018).

Table 30: Projection of waste energy potential

Year of waste deposited	Waste generation per capita (kg/person/day)	Population (millions of people)	Mass of Domestic Solid Waste deposited	Waste generation (million ton)	Energy potential (PJ)
2015	0.560	92.2	13.8	16.1	161.1
2020	0.600	96.6	17.9	20.9	208.8
2025	0.640	100.1	19.8	23.1	230.6
2030	0.680	102.7	21.5	25.1	251.4
2035	0.713	104.6	23.0	26.8	268.3
2040	0.745	105.9	24.3	28.4	284.0
2045	0.778	106.7	25.6	29.9	298.6
2050	0.810	107.0	26.7	31.2	312.0

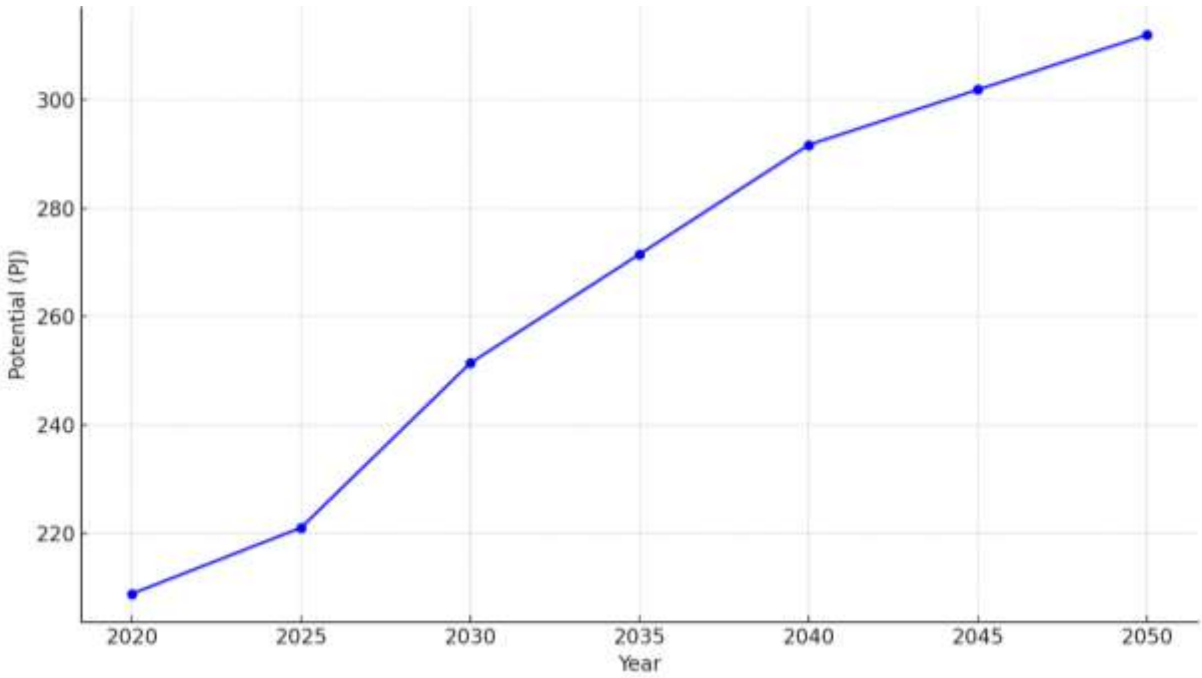


Figure 27: Potential of Waste for Energy Production in Viet Nam

Figure 27 illustrates the hypothetical potential of waste for energy production in Viet Nam, expressed in Petajoules (PJ), from 2020 to 2050. It shows a clear upward trend, indicating an increasing potential for energy production from waste over the years.

Hydro power

Total potential of large hydro (with a capacity higher than 30 MW) is about 21 GW (existing installed capacity about 18 GW and committed capacity about 3 GW). Besides that, the EOR-NZ is modelled 3.8 GW of potential for expanding hydro power plant (not expanding reservoir).

Existing installed capacity of small hydro is about 4 GW. The potential for additional small run-of-river hydro is 10 GW. Total small run-of-river potential by regions is shown in Figure 28. Full load hours for all run-of-river hydro are assumed to be 2950 h.

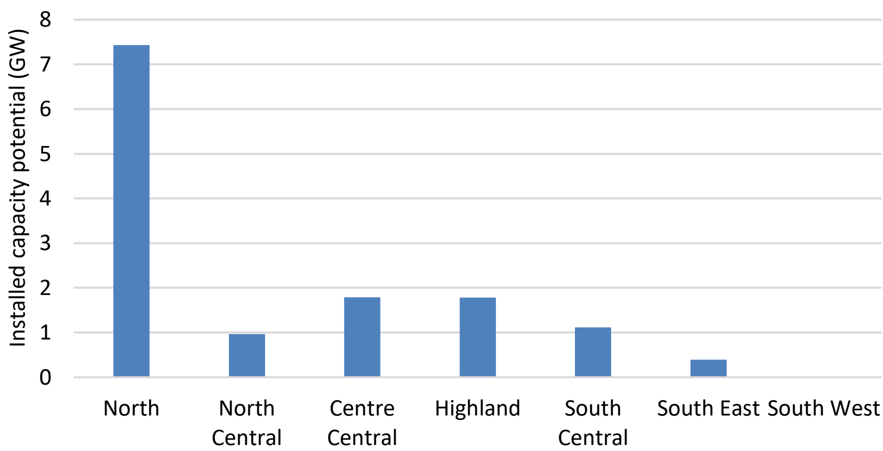


Figure 28: Total small run-of-river hydro potential capacity by regions.

Potential for construction of the pumped storage hydro will be taken from PDP8 (the installed capacity is registered by provinces). Based on that, total potential of pumped storage hydro about 25.9 GW (in which 10.9 GW in North, 1 GW in North Central, 2.2 GW in Center Central, 2.4 GW in Highland and 9.4 GW in South Central).

Other RE

About 0.46 GW of geothermal potential and 2.3 GW tidal power are based on the assessment potential of PDP8 that are also simulated in Balmorel model as candidate for capacity expansion.

Nuclear

According to Decision No 906/QD-TTg, 17/6/2010, approving the development planning orientation for large nuclear power plant in Viet Nam in the period to 2030, 8 potential sites are available in the Balmorel model for conventional PWR nuclear power plants (North Central – 1 site in Ha Tinh, Center Central – 2 sites in Quang Ngai, South Central – 5 sites in Binh Dinh, Phu Yen, Ninh Thuan). Each location has the capacity for 4 to 6 nuclear power units with total capacity about 4 GW – 6 GW for each site. EOR-NZ does not limit the potential for SMR nuclear. SMR nuclear can be invested in 6 regions near the coastline (except the Highland).

Committed and decommissioning generation capacity

Committed capacity

Some projects of coal fired power plants and gas fired power plants are under construction and will be committed in the model.

The coal power plant projects, which are committed in the period 2024-2030 are: An Khanh – Bac Giang (650 MW), Na Duong II (110 MW), Quang Trach I (1,200 MW), Van Phong I (1,320 MW), Long Phu I (1,200 MW). Total installed capacity of coal fired power plants in 2030 will be about 30.5 GW (including existing and committed projects). No new model investments in conventional coal power plants are allowed, only exogenous increase in coal capacities until 2030.

The domestic gas power plants projects are committed with about 3.8 GW using CVX gas and 3.8 GW using Block B gas. CCGTs using LNG projects are committed with 10.4 GW in period 2021-2030 (in Baseline scenario). The committed capacity in other scenarios is mentioned in the scenario description.

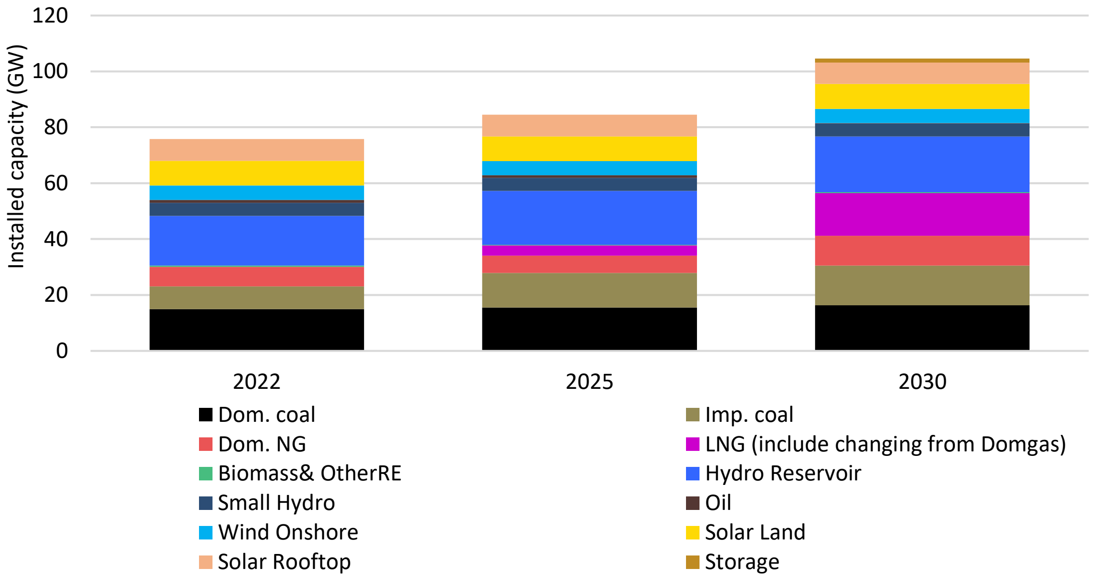


Figure 29: Existing and committed installed capacity in Baseline scenario.

BOT power plants (Build-Operate-Transfer) are modelled with a minimum amount of FLHs of 6,000 for 20 operation years in Baseline scenario, but this policy will be removed from 2030 in the Net-Zero scenario.

Decommissioning

The Balmorel-Vietnam model is currently simulating existing power plants to be decommissioned at the end of their economic life (coal thermal power after 30 years of operation, gas thermal power after 25 years, wind power plants after 30 years, solar power plants after 35-40 years, hydropower after 50 years). Therefore, in the period to 2050, about 18 GW of existing coal-fired power plants and 7 GW of CCGT will stop operating. The decommissioning of these thermal power plants in the Balmorel model does not consider any cost for decommissioning.

In addition, the ability to decommission coal and gas thermal power plants before the end of lifetime is simulated in Net-Zero scenario and its variations. The model optimises plants decommissioning by evaluating the plants value for the power system operation against its fixed operating and maintenance costs. When the value of the plant is too low, it is decommissioned before the end of its lifetime. It should be noted that no costs related to early-decommissioning are considered in the optimisation. It is furthermore important to mention that even in the Baseline scenario, where decommissioning of capacity is not optimised, a system can be found where some power plants produce too little to be practically feasible. The main difference here is that the capacity will still be seen in the capacity overview.

As for all technologies, there are costs associated with decommissioning, which can also include social costs such as retraining and reallocation of local mining jobs in the case of coal power. However, those costs and benefits are not included in the model optimisations.

Transmission system

For the transmission grid, input from the grid model PSS/E was used to find the current net transfer capacity (NTC) of the eight transmission lines between the seven regions (Figure 30). The committed inter-regional transmission capacity in period 2021-2030 is based on PDP8. These capacities are based on a detailed representation of the Vietnamese transmission grid and include N-1 considerations.

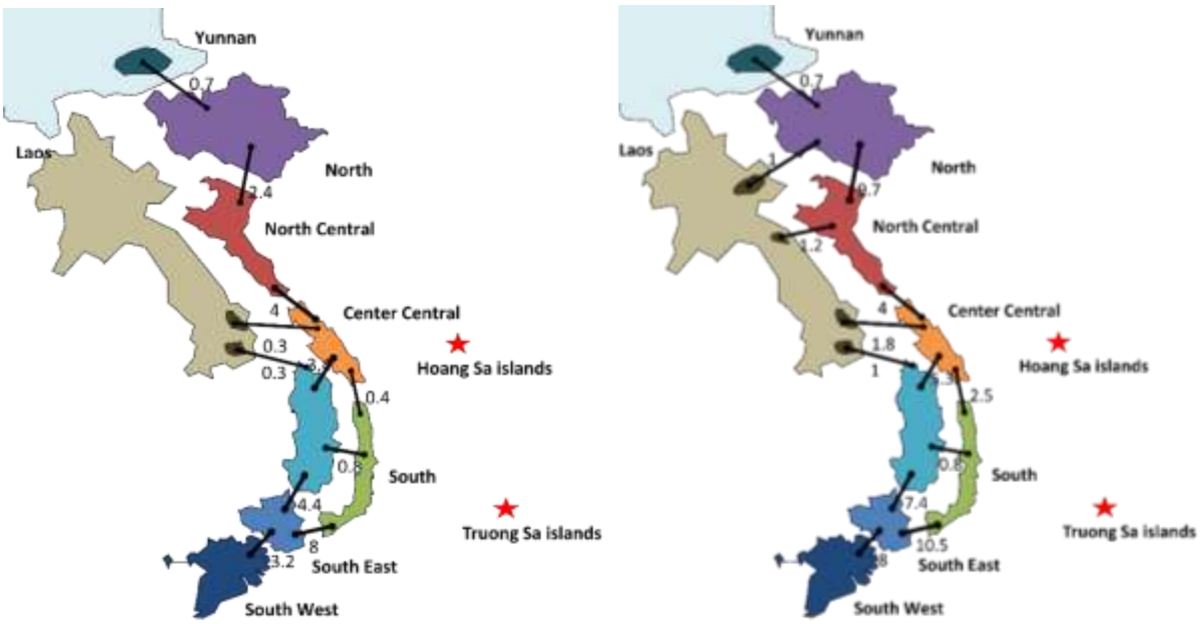


Figure 30: Transmission regions and the exogenous interconnectors in Viet Nam (2020, left, and 2030, right)

Table 31: Transmission capacity between regions in 2020 and in 2030

From	To	2020 (MW)	2030 (MW)
North	North Central	2,400	9,650
North Central	Center Central	3,500	4,000
Center Central	Highland	2,000	5,300
	South Central	400	2,500
Highland	South Central	800	800
	South East	4,400	7,400
South Central	South East	8,000	10,500
South East	South West	3,200	8,020

Losses on transmission lines between regions are calculated according to Table 32. These losses are shown as percentage and are derived based on transmission line load of 80% for each line.

Table 32: Losses on transmission flow between regions.

From	To	Losses on flow
North Central	North	3.2%
Center Central	North Central	3.6%
Highland	Center Central	2.5%
South Central	Center Central	3.8%
South Central	Highland	2.4%
South East	Highland	3.5%
South East	South Central	3.0%
South West	South Central	3.0%
South East	South West	3.2%
Center Central	North	6.0%

External input data to PSS/E

To build the PSS/E case file, the key data inputs include power sources, load at nodes, the transmission system include transmission lines and substations at different voltage levels. An overview of those key input data is given below, detail descriptions can be found in the respective PSS/E report ("Grid modelling of Net-Zero scenario").

Power sources

- Large power sources

Balmorel defines the large power sources as individual candidates up to the plant or unit size. The major power sources in the Balmorel model are updated based on the current power sources and detailed list of projects in Decision No. 500/QD-TTg dated May 15, 2023, approving PDP8. Power plants have clear locations, and nodes can be easily and accurately identified in the PSS/E model. The study will review the major power sources proposed to be developed according to the results of the Balmorel model and attached to the corresponding nodes in PSS/E.

- Renewable energy sources

To determine the location of renewable energy projects such as onshore/near-shore wind power, solar power, biomass and waste power, and small hydropower in the planning stage is usually difficult. The Balmorel results only show the total capacity size of each type of renewable energy source for each of the 7 regions. For the PSS/E study, the relative locations of these types of sources will be determined according to regional clusters and allocate them to 220 kV nodes according to appropriate provinces in the power grid. This assumption still ensures accuracy in assessing the operation of the transmission grid because each area with favourable characteristics for developing renewable energy sources will have some power gathering substations, so to be connected to the national power system.

Load

The PSS/E model receives load from Balmorel in 7 regions. The load is assigned to nodes in each region following the same ratio as in PDP8. In each snapshot, the total load of region will be scaled up or down to match the snapshot input data.

The transmission system

The inter-regional transmission system will be built based on installed transmission capacity between region from Balmorel. The Balmorel model does not consider the local transmission network so the internal power grid in each region will be taken from draft PDP8. Other assumptions:

- Power factor at load nodes ($Cos\varphi$): The voltage on the grid depends very much on the power factor $Cos\varphi$ at load node. $Cos\varphi$ usually ranges from 0.9 to 1.0. The lower the $Cos\varphi$, the more reactive power the load consumes. This can lead to the lower voltage. Since the power grid simulated in this project only represents equivalent electrical load at 220 kV nodes, it is assumed that $Cos\varphi = 0.98$ – i.e., the average compared to the present (0.95 - 1.0).
- Generator terminal voltage: Traditional generators and modern inverters for wind and solar power can act as voltage control elements on the grid, by controlling the amount of emitting reactive power. However, the output voltage of the generators cannot be set too high or too low and must meet the requirements of the Grid code. In the grid simulation, it is assumed that the terminal voltage of generators varies within +/- 5% of the rated voltage.
- Limitation capacity of transmission lines: In this project, the thermal limit of transmission line is used (except for lines over 300 km using the limit capacity according to the condition of power system stability). Limitation capacity of an interface is taken from Total Transfer Capacity (TTC) calculation result.
- Limit capacity of 500/220 kV transformers: It is set according to the rated power of the transformer.
- Resistor, resistance of line and transformer parameters (R0, X0, B0): Typical parameters on the current transmission grid are used.

4 Energy scenarios

Main scenarios

The EOR-NZ focusses on the following two main scenarios:

- **Baseline scenario (BSL)**
  The BSL serves as the benchmark, encompassing current policies along with those decided for the medium term. It considers existing policies, e.g., transport and energy efficiency policies, as well as the commissioning of new plants that have been contracted until 2030.
- **Net-Zero scenario (NZ)**
  The NZ outlines a prospective Vietnamese energy system that aims to achieve decarbonisation in its energy sector by 2050. This involves accounting for the anticipated absorption of emissions from LULUCF[2], and assuming a high solar potential.

The scenarios are executed within the EOR modelling framework explained in Chapter 2. The execution involves initial runs with the TIMES model, conducted prior to the subsequent runs of the Balmorel model. Following the TIMES runs, the outputs related to the power sector are transferred to the Balmorel model as exogenous model input.

TIMES

The constraints employed in the TIMES-Vietnam model are presented in Table 33. In the following sections the restrictions will be more thoroughly described.

[2] Land Use, Land-Use Change and Forestry (https://unfccc.int/topics/land-use/workstreams/land-use--land-use-change-and-forestry-lulucf)

Table 33: Comparison of main scenario restrictions for TIMES-Vietnam, excluding constraints for the power sector, which are described in the Balmorel comparison.

Scenario	CO_2 emission pathway	Green transport target	Transport modal shift	Electrification of rail	Energy efficiency (EE) targets	Air pollution costs optimization
BSL	2030: 613,6 Mt in 2030 (678,4 Mt (BAU[3]) minus 64,8 Mt (NDCs[4]))[1] After 2030 model is unconstrained.	Short-term electrification and green transport targets[3]: 2030: 100% of new taxis 2025: 100% of new buses	No modal shift implemented	No targets implemented	Max. market share of advanced technologies in 2050: Residential: 75% Services: 50% Industry[4]: Min. EE improvement in 2030	**Included**
NZ	2030: 457 Mt linear interpolation 2050: 121 Mt (incl. 20 Mt for industry process emissions)[2]	**= BSL**	**Freight on rail:** 2030: 5% Linear interpolation 2050: 35% **Passenger on rail:** 2030 to 2050: 11%[3]	**Freight:** 2030:72% 2040: 94% 2050: 96% **Passenger:** 2030: 21% 2040: 51% 2050: 57%	No targets implemented	**= BSL**

[1] *Viet Nam NDCs updated in 2022*
[2] Prime Ministers Decision-896-QD-TTg
[3] Prime Ministers Dec No. 876 QD-TTg
[4] VNEEP (Viet Nam National Energy Efficiency Program)

CO_2 emissions pathways

In the earlier years, no targets are applied. The Baseline scenario sets a trajectory with only the 2030 target at 613.6 Mt, derived from Business as Usual (BaU), as reported in the National Climate Change Strategy, minus Nationally Determined Contributions (NDCs). For NZ, a more ambitious plan was established with emissions projected at 457 Mt in 2030, following a linear interpolation down to 121 Mt as outlined in Prime Minister's Decision-896-QD-TTg. This trajectory encompasses a specific industry process emission target of 20 Mt by the year 2050. The sectoral pathway for industry process emissions is not adding to the overall emissions but is fulfilled simultaneously. The total NZ emissions minus the optimised industry process emissions yields the emission limit for the Vietnamese energy system, as modelled in TIMES. The sectoral allocation of the emissions budget is a core model result and subject to cross-sectoral cost-optimisation.

Green transport target

In relation to the CO_2 emissions from the transport sector for BSL and NZ, both scenarios are exogenously forced to meet the short-term targets set in the Prime Ministers Dec No. 876 QD-TT for the years 2025 and 2030. This entails that all new busses and taxis must either run on electricity or on fossil free fuels from the respective years onwards. This underscores a commitment to immediate action and compliance with established benchmarks. Beyond 2030, no additional explicit decarbonisation constraints are applied in either BSL or NZ scenarios, allowing the model the freedom to optimise and allocate decarbonisation efforts efficiently across various energy sectors.

[3] Business as usual scenario
[4] Nationally Determined Contributions

Transport modal shift

In the context of freight transport, a modal shift assumption has been implemented in all Net-Zero scenarios, reflecting the introduction of a North-South high-speed railway system catering to freight transport. The assumption posits that 5% of freight transport in 2030 will be serviced by this system, which equals an increase by a factor of 5 compared to the default projection at the expense of other freight modes, such as shipping, aviation, trucks, and vans. This shift progressively increasing to 35% by 2050, equals to an increase by factor of 100 compared to freight transported by rail in the Baseline scenario Notably, only electric trains are considered for meeting this demand.

Table 34: Freight demand shift to rail [Million ton-km]

	Mode	2030	2035	2040	2045	2050
		Million ton-km				
Freight demand before shift	Total	613.2	891.1	1292.8	1879.5	2750.7
	Rail	6.2	7.2	8.2	8.9	9.4
	Trucks	143.7	203	273.3	350.7	428.8
	Vans	6.7	8.7	10.3	11.1	10.8
	Aviation	456.3	671.5	1,000.2	1,507.8	2,300.4
	Shipping	0.39	0.56	0.78	1.06	1.42
Share of total freight demand after shift	Rail	5%	15%	25%	30%	35%
Freight demand after shift	Rail	30.7	133.7	323.2	563.9	962.8
	Trucks	137.9	174	206.3	246.7	279.7
	Vans	6.4	7.5	7.8	7.8	7
	Aviation	437.9	575.5	754.9	1,060.5	1,500.4
	Shipping	0.4	0.5	0.6	0.8	0.9

As for passenger transport, an assumption regarding a transition to metro and urban railway systems in the five major metropolitan areas of Viet Nam, i.e., Hà Nội, Hải Phòng, Đà Nẵng, Hồ Chí Minh City, and Cần Thơ has been incorporated, facilitating the shift of demands from cars and motorbikes to metro services. Metro and urban railway systems are included in the Rail mode. The assumptions outlined in Table 35 assert that a steady 11% of all motorbikes in these 5 cities will transition to metro and urban railway usage between 2030 and 2050.

Table 35: Share of passenger demand shift to public transport [%]

City	Mio. passenger-km in 2019	Share of whole country	Modal shifts to public transport by 2030
Hà Nội	16,882.7	11.2%	45%
Hải Phòng	2,839.1	1.9%	10%
Đà Nẵng	1,361.5	0.9%	25%
Hồ Chí Minh City	28,949.2	19.3%	25%
Cần Thơ	5,906.8	3.9%	20%

Table 36 shows the effect of the shift upon the involved modes of transport. The total demand is not affected by the shift. While the projected passenger demand grows significantly over time, the modal shift to rail remains constant at 11%. This leads to an increase in rail demand by a factor of 8.5 in 2030 down to a factor of 5 in 2050.

Table 36: Passenger demand shift to rail [Million passenger-km]

	Mode	2030	2035	2040	2045	2050
		Million passenger-km				
Passenger demand before shift	Total	666.47	835.47	1,003.54	1,155.6	1,277.95
	Cars	154.40	212.60	284.57	369.53	464.87
	Motorcycles	503.35	610.62	702.38	764.39	785.78
	Rail	8.73	12.25	16.59	21.67	27.30
Share of total passenger demand after shift	Rail	11%	11%	11%	11%	11%
Passenger demand after shift	Cars	139.11	191.86	257.29	334.87	422.39
	Motorcycles	453.52	551.05	635.06	692.69	713.97
	Rail	73.84	92.57	111.19	128.03	141.59

Electrification of rail

Electrification of rail in freight and passenger transport is implemented in the Net-Zero scenario. The objectives entail achieving a minimum electrification rate, determined by service demand, commencing in 2030 and progressively intensifying up to 2050, as shown in Table 37.

Table 37: Minimum electrification rates for rail transport demand by type of mode and period [%]

Mode	2030	2035	2040	2045	2050
Freight	72%	91%	94%	95%	96%
Passenger	21%	31%	51%	53%	57%

Energy efficiency targets

In the context of BSL, energy efficiency (EE) targets are incorporated into the model sectors: residential (RR: rural and RU: urban), services, and industry. Within the first two sectors, the scope encompasses applications such as air conditioning, electrical appliances, lighting, and heating. The demand technologies available for investment in these applications are categorised into three energy efficiency levels: ordinary, improved, and advanced, where advanced signifies the highest efficiency. The penetration level in meeting various end-use demands by category is constrained, with annual shares progressively increasing, as illustrated in Table 38.

Table 38: Market shares of EE technologies in Residential and Services sectors per period [%].

Sector	EE category	2025	2030	2050
Residential	Ordinary	100%	100%	100%
	Improved	60%	80%	100%
	Advanced	45%	60%	75%
Services	Ordinary	100%	100%	100%
	Improved	60%	80%	100%
	Advanced	30%	40%	50%

Regarding the industry sector, a distinctive strategy has been employed, drawing from the data by VNEEP. In this context, a mandatory enhancement in energy efficiency is stipulated for each sub-sector by 2030.

This improvement is determined by analysing the base-year's energy consumption and demand output, alongside the expected percentage decrease in the energy intensity of each sub-sector by 2030. Table 39 depicts the minimum EE improvement by industry sub-sector.

Table 39: Minimum energy efficiency improvements by industry sub-sector in 2030 [%].

Industry sub-sector	Minimum EE improvement in 2030
Ammonia	0%
Other chemicals	0%
Cement	14%
Extractive Industry	0%
Food, beverage, tobacco processing	15%
Iron and steel	23%
Material construction	60%
Manufacturing of machinery and equipment	0%
Motor vehicles manufacturing	0%
Other non-metallic	0%
Other industries	0%
Pulp and paper	29%
Textile and leather	10%
Wood products	0%

Balmorel

This section describes the set-up for core scenarios and relevant constraints, as applied in the power system model Balmorel-Vietnam.

Power demand, e-fuels demand, biomass and MSW consumption for power sector, and CO_2 emission limitation for the power sector are provided as input from TIMES to Balmorel for each scenario. For the BSL, the CO_2 emission limit from the TIMES model only applies until 2030, after 2030 there is no constraint on CO_2 emissions limitation.

For all scenarios, the maximum LNG fuel use is set based on the Viet Nam Energy Master Plan (EMP) starting from 2030, equivalent to 18.2 billion m^3/year, corresponding to 180.99 TWh/year or equally 651.56 PJ/year.

In the Baseline scenario, decommissioning of power plants before economic lifetime is not allowed, while in the Net-Zero scenario, decommissioning of power plants is allowed at any point during the plant lifetime based on economic optimisation. However, part of the costs for decommissioning, including e.g. principal and interest of investment cost, social costs and benefits like re-training and reallocation of jobs, are not accounted for in the modelling.

In the Baseline scenario, coal and gas power plants with BOT investment form will be set with minimum FLHs to 6,000 hours/year for 20 years of operation. In the Net-Zero scenario, constraints on minimum FLHs for all technologies are lifted starting from 2030. Moreover, the minimum fuel use for all fuel-based plants on take-or-pay contracts are also lifted starting from 2030 in all scenarios.

Key differences in data inputs between the Baseline scenario and Net-Zero scenario as set in the Balmorel model are described Table 40.

Table 40: Key differences in data inputs between the Baseline scenario and Net-Zero scenario in the Balmorel model.

Scenarios	Baseline	Net-Zero
Committed CCGT using LNG (GW) in 2030	10.4	2.8
Maximum installed capacity of solar in 2030 (GW)	21	81
Maximum installed capacity of onshore wind in 2030 (GW)	22	217
Maximum installed capacity of offshore wind in 2030 (GW)	6	218
Total potential of land solar PV (GW)	136	271
Flexibility assumptions in 2030 for Industry, upstream, EV (% of average demand that is flexible)	4%, 10%, 10%	8%, 20%, 20%
Flexibility assumptions in 2050 of Industry, upstream, EV (% of average demand that is flexible)	8%, 20%, 20%	16%, 40%, 40%

In the Baseline scenario, the l installed capacity of solar and wind in 2030 is limited based on the PDP8 does allow for higher investments compared to PDP8. The total potential of solar PV is assigned on a yearly basis, with a linear increase over time reaching the total potential as described in Chapter 3.

The core scenarios, variations and sensitivity analyses, except the NZ-reserve scenario, do not include additional reserve requirements with regard to unplanned outage of generation, transmission lines as well as forecasting errors.

Main variations and sensitivity analyses

The main variations of the NZ core scenario are:

- **Net-Zero+ (NZ+)**
  The Net-Zero+ variation outlines a future energy system that achieves net-zero energy-related carbon emissions in 2050, i.e. with a target of 0 Mt CO_2eq in 2050 from all energy sectors (excluding industry process emissions).
- **Green Growth (GG)**
  The Green Growth variation focuses on a system, where the GDP contributions by sector shift away from energy intensive industries to the services sector, while overall maintaining the same national productivity. The industry share of 40% by 2050 in NZ is reduced to 30%. The commercial share of 50% in NZ is increased to 60%.
- **Green Transport (GT)**
  The Green Transport scenario aligns with the overarching emission targets of NZ. This scenario focuses on the green transition of the transport sector towards 2050. The scenario maintains the same assumptions for the power sector as in the Baseline scenario, while including also the net-zero target by 2050 for the whole energy system, in addition to the specific target of decarbonization of the transport sector by 2050.

The additional sensitivities based on either the main scenarios (as indicated in the naming) that have been performed in both TIMES and Balmorel are:

- **NZ – Lower discount rate (NZ-L DR, 6.3% per year)**

The sensitivity NZ – Lower discount rate investigates the possible effects on investments when lowering the general discount rate by 3.3 pp from 10% to 6.3% in the settings of the NZ main scenario.

- **NZ – High GDP (NZ-GDP+)**

  The sensitivity NZ – High GDP investigates the possible effects on the future energy system with the GDP growth rate increased to 7% (2020 – 2030) and 7.5% (2031 – 2050).

The initial runs with TIMES are followed by runs with Balmorel. Power sector specific scenario output, i.e. power demand, e-fuel demand, CO_2 emission limit and bioenergy use in the power sector, are provided from TIMES to Balmorel. The remaining sensitivities were exclusively run in Balmorel without prior linking of the power sector results from TIMES.

The constraints employed in the TIMES-Vietnam and Balmorel-Vietnam models related to the main variations and sensitivities are presented in the following overview of Table 41. In the following sections, the restrictions will be more thoroughly described.

Table 41: Main variations and sensitivity restrictions.

Scenario name and ID	Type	Assumption	Scenario reference
Net-Zero+ (NZ+)	Main variation	The CO_{2e} energy related emission target of 101 Mt in 2050 in NZ is reduced to 0 Mt. The linear reduction from 2030 to 2050 has been adjusted accordingly.	NZ
Green Growth (GG)	Main variation	The industry share of 40% by 2050 in NZ is reduced to 30%. The commercial share of 50% in NZ is increased to 60%	NZ
Green Transport (GT)	Main variation	In addition to the CO_{2e} emission trajectory, a separate trajectory for the transport sector is added, reducing the transport emissions from the NZ 2030 level to 1 Mt in 2050. Potential of RE and committed capacity is same with Baseline scenario.	BSL + CO2 target from NZ
Lower discount rate (NZ-L DR)	Sensitivity	Reducing the discount rate by 3.3 pp from 10% to 6.3% compared to NZ.	NZ
High GDP (NZ-GDP+)	Sensitivity	The GDP growth rate of 6.5% during 2020 – 2050 in NZ is increased to 7% (2020 – 2030) and 7.5% (2031 – 2050)	NZ
High fuel price (BSL-H Fuel)	Sensitivity	Fuel prices increase by 25% for all imported and domestic fuels (excluding nuclear) from 2030.	BSL
Low fuel price (BSL-L Fuel)	Sensitivity	Fuel prices decrease by 25% for all imported and domestic fuels (excluding nuclear) from 2030.	BSL
BSL - Improved energy efficiency	BSL-EE+	Increased level of energy efficient technologies available in residential and services sectors.	BSL
High fuel price (BSL-H Fuel)	Sensitivity	Fuel prices increase by 25% for all imported and domestic fuels (excluding nuclear) from 2030.	BSL
Low fuel price (BSL-L Fuel)	Sensitivity	Fuel prices decrease by 25% for all imported and domestic fuels (excluding nuclear) from 2030.	BSL
BSL - Improved energy efficiency	BSL-EE+	Increased level of energy efficient technologies available in residential and services sectors.	BSL

The assumptions for the sensitivity scenarios performed in Balmorel are included in Table 42.

Table 42: Sensitivity scenarios in power sector.

Scenario	Abbreviation	Assumption	Scenario reference
NZ - Reserves	NZ-Res	Reserve requirement is calculated for NZ scenario. Operating reserve and planning reserve requirement is simulated to calculate enough capacity to meet reliability criteria of Viet Nam power system.	NZ
NZ - High Battery cost	NZ-HC BESS	Sensitivity scenarios are calculated on NZ scenario with high investment cost of battery, low investment cost of battery and high investment cost of solar PV. The investment cost is based on the higher or lower investment cost of each technology in Viet Nam Technology Catalogue 2023.	NZ
NZ - Low Battery cost	NZ-LC BESS		NZ
NZ - High Solar cost	NZ-HC PV		NZ
NZ - High Nuclear cost	NZ-HC Nuc		NZ
NZ –high LNG price 50%	NZ-H50-LNG	Sensitivity scenarios with an increase in LNG fuel prices by +50% and +100%, respectively.	NZ
NZ –high LNG price 100%	NZ-H100-LNG		NZ

Seven scenarios have been chosen only to run with the Balmorel model, as the effect of these parameters mainly will affect the power sector: NZ – Reserves, NZ - High Battery cost, NZ - Low Battery cost, NZ - High Nuclear cost, NZ - High Solar cost, NZ – High LNG price 50%, NZ – High LNG price 100%.
Five sensitivity scenarios have been performed by running both the TIMES and Balmorel models, namely: NZ - Lower discount rate, NZ - High GDP, BSL - High fuel price, BSL - Low fuel price, BSL - Improved energy efficiency, where the results on power demand, use of biofuels, demand of e-fuels and CO_2 limitation target for power generation are transferred from TIMES to Balmorel.

The uncertain input parameters, varied in the sensitivity scenarios NZ - High Battery cost, NZ - Low Battery cost, NZ - High Nuclear cost, NZ - High Solar cost are described below.
In Vietnamese technology catalogue (EREA and DEA, 2023), an uncertainty range for the cost of each technology is forecasted. In the sensitivity scenarios, those projected higher or lower investment costs are used to investigate the impact on the power system development. A comparison of the costs is shown in Figure 31-Figure 33.

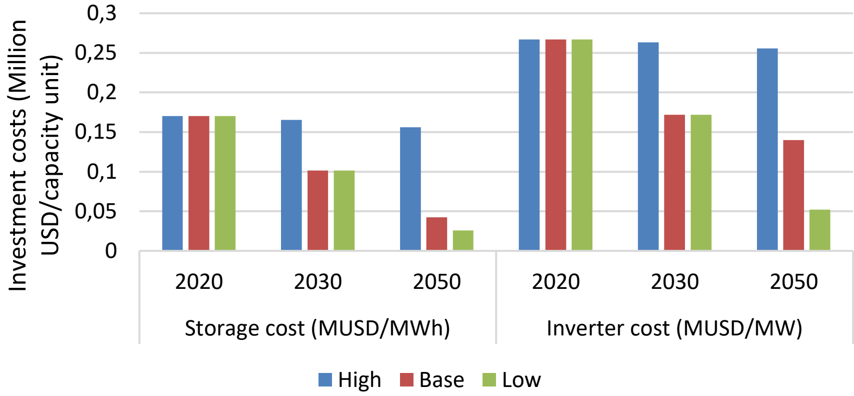


Figure 31: Battery investment cost projection in Vietnamese Technology Catalogue (EREA and DEA, 2023).

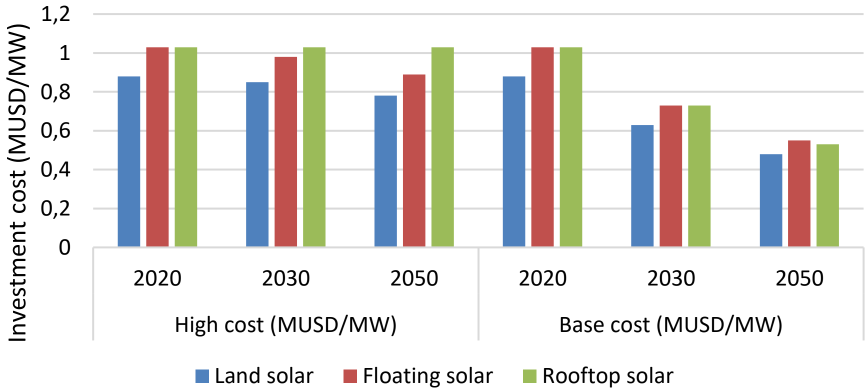


Figure 32: Solar investment cost projection (including IDC) in Vietnamese Technology Catalogue (EREA and DEA, 2023).

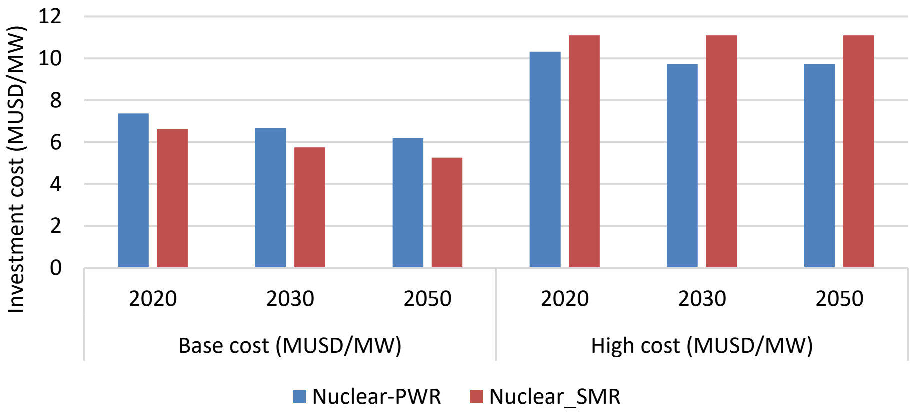


Figure 33: Nuclear investment cost projection (including IDC) in Vietnamese Technology Catalogue (EREA and DEA, 2023).

5 Modelling results – Main scenarios

The modelling results of the main scenarios are structured into three sections: 1) Energy system results comprising combined results from both Balmorel and TIMES and end-use sector results from TIMES only, incl. a comparison to EMP results; 2) Linked data between TIMES and Balmorel; 3) Power system results from Balmorel only.

Energy system results

The energy system results are split into combined results from both models, TIMES and Balmorel, on the one hand. Herein the Power sector results from TIMES are neglected at the expense of the Balmorel power system results. On the other hand, this section delves into the results of the end-use sector modelled in TIMES.

Combined results from Balmorel and TIMES

GHG *emissions*

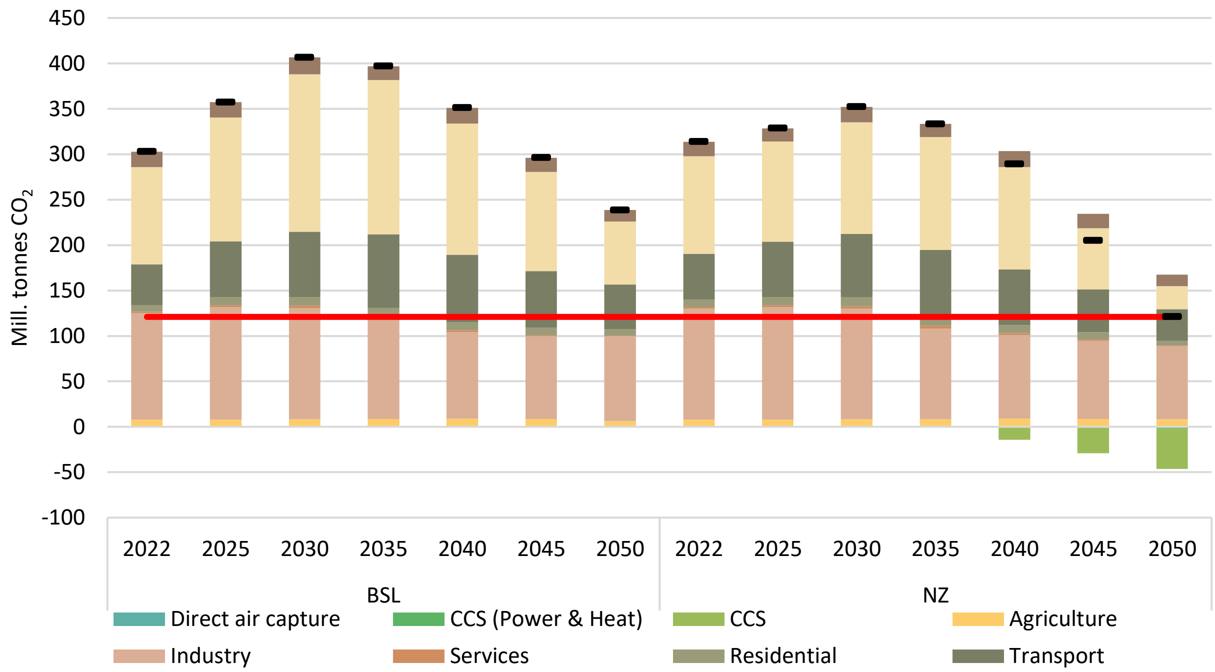


Figure 34 shows the total CO_2e emissions in both main scenarios, BSL and NZ, by sector. The negative CCS and Direct air capture values are displayed separately for the captured carbon. The part of the captured carbon that is used to produce fuels and not permanently stored underground is added to the upstream or industry sector (TIMES) or the power sector (Balmorel). This is done to illustrate the total captured amount. Emissions in BSL increase until 2035, where they peak and afterwards reduce to a similar level of 2022. This reduction is due to the cost-effectiveness of renewable energy as well as air pollution costs (see section below). In NZ, the emissions only increase until 2030 and are then further reduced compared to BSL because of the emission limit. The target of 121 Mt energy and process related emissions in 2050 is met (as indicated by the red line). By 2040, CCS emerges in NZ, which is becoming the cheapest decarbonisation solution towards the end of the model horizon. Decarbonisation efforts in NZ in transport and power & heat sectors are going hand in hand, while industry emissions remain constant in both scenarios.

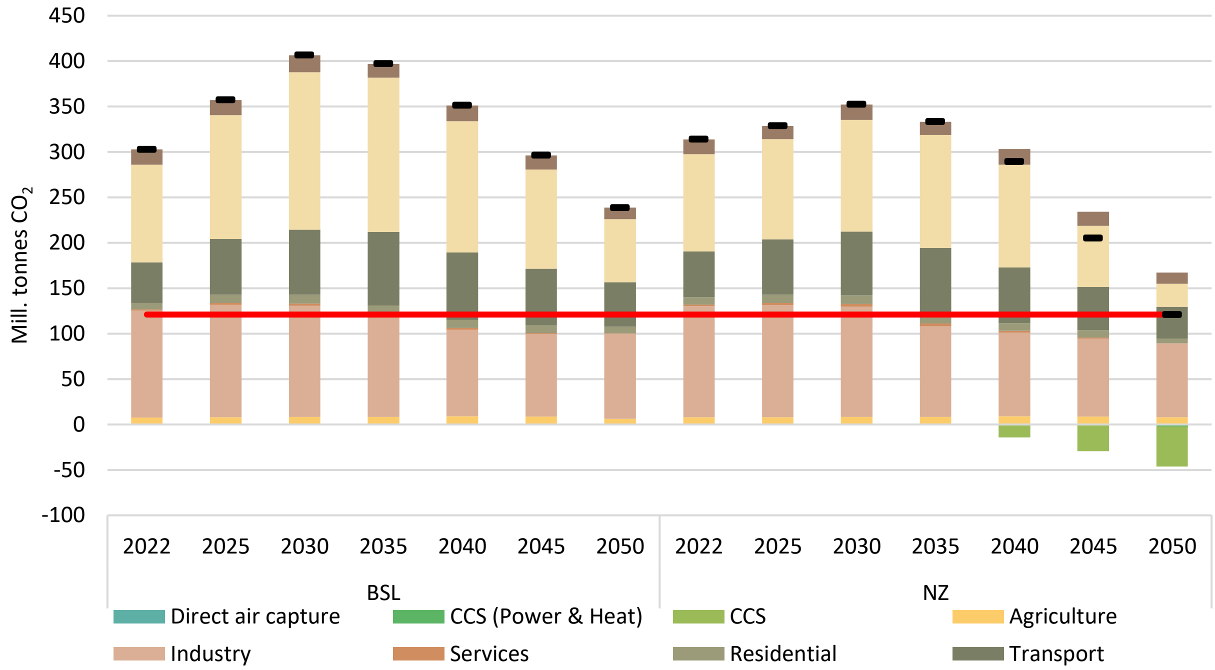


Figure 34: CO_2e emissions by sector in main scenarios, TIMES & Balmorel [Mt CO_{2e}]

Air pollution

The emission of the air pollutants NO_x, SO_2, and $PM_{2.5}$ by sector are shown in Figure 35 and Figure 36 for BSL and NZ respectively. The highest emissions fall on transport NO_X, power and heat, and industry. Transport is the main emitter of NO_x, while SO_2, and $PM_{2.5}$ are associated with power and heat. The development of the overall air pollution is proportional to the CO_2 emissions. However, when looking at the distribution amongst the pollutants, it shows that emission mainly reduce for SO_2 in industry and in power and heat more equally. Transport air pollution remains at a high level Where the high levels of NO_X are related to the similar NO_x pollution from e-fuels as from fossil fuels.

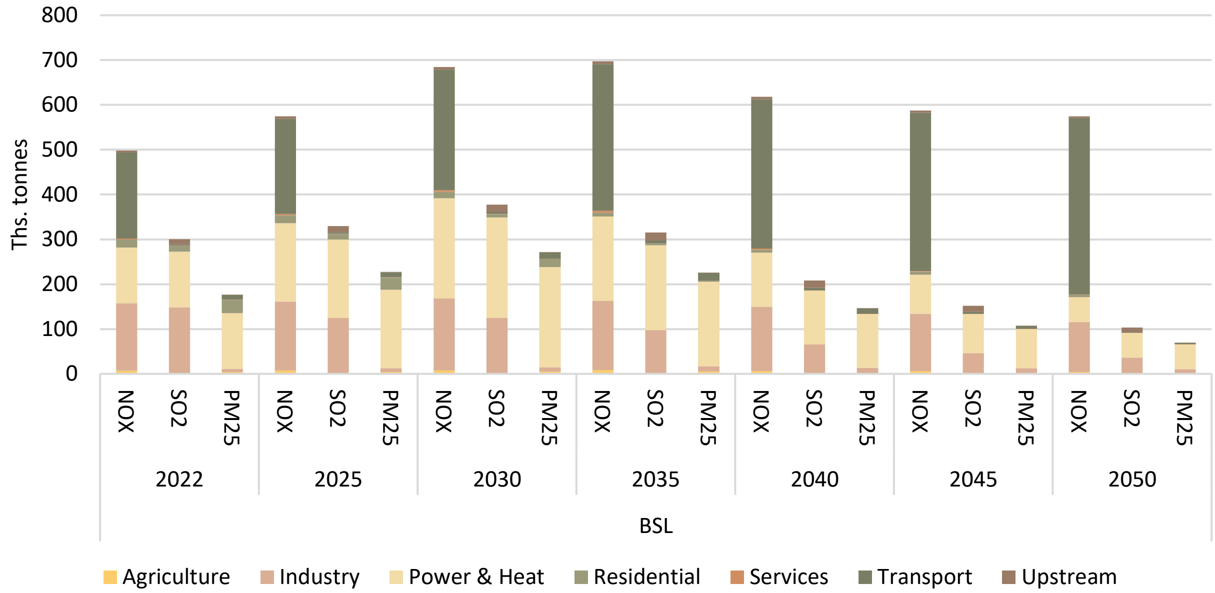


Figure 35: Air pollution by sector in BSL scenario, TIMES & Balmorel [Ths. Tonnes]

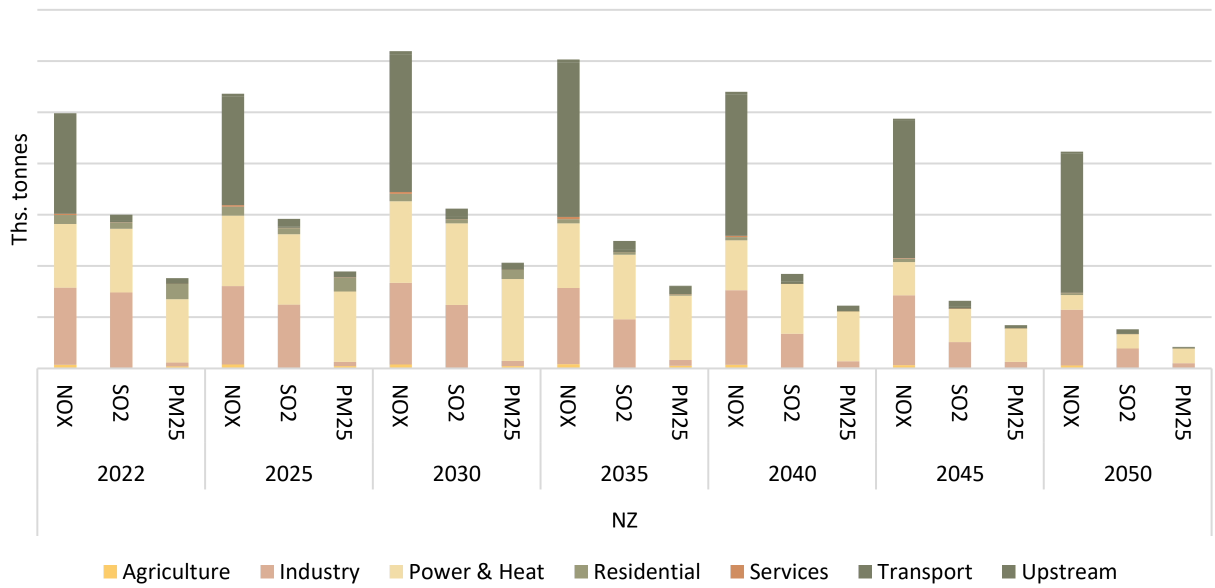


Figure 36: Air pollution by sector in NZ scenario, TIMES & Balmorel [Ths. Tonnes]

Total primary energy supply

The total final energy supply (TPES) is laid out in Figure 37 by aggregated fuel types and for both main scenarios BSL and NZ. In 2022, TPES amounts to 6 EJ and more than doubles by 2050 in both scenarios. In the future years, the TPES will be lower in NZ due to higher electrification rates and higher penetration of energy efficiency measures. In both scenarios, coal and oil commodities are phased out, while natural gas and variable renewable energy (VRE) sources increase. In NZ, natural gas decreases again after 2040. Solar holds the largest share of VRE, and the biomass potential is exploited in both scenarios.

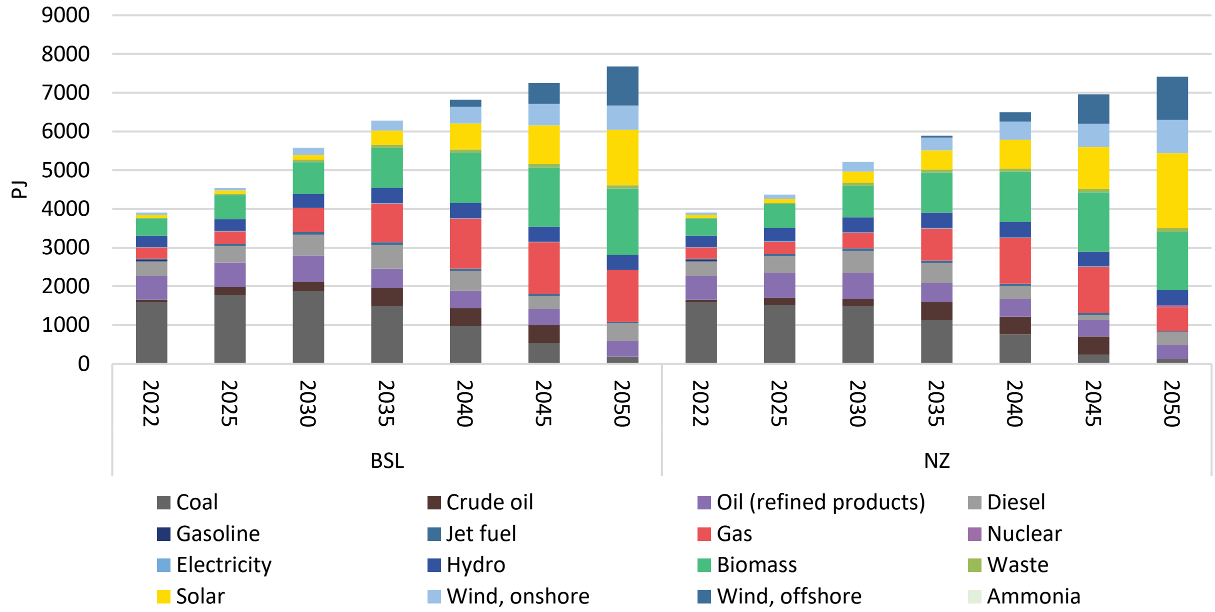


Figure 37: TPES by fuel type in main scenarios, TIMES & Balmorel [PJ]

Total system costs

Figure 38 shows the total system costs for both BSL and NZ by type of cost. The costs shown are undiscounted and annualised. The large share of CAPEX relates to the extensive vehicle stock in the transport sector. The total levels between BSL and NZ are similar in 2050, but in the earlier years, NZ is cheaper, due to a more optimistic solar potential. Further, the distribution shows that NZ is reducing fuel and air pollution costs at the expense of CAPEX and fixed O&M costs. The role of variable O&M costs is neglectable.

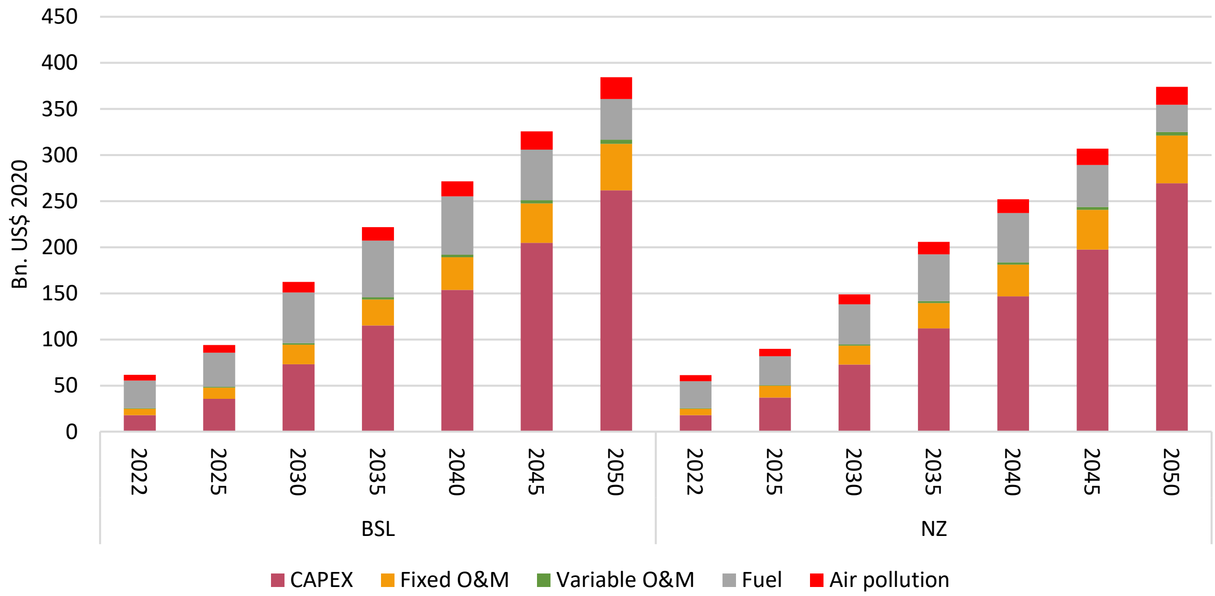


Figure 38: Total system costs by cost type in main scenarios, TIMES & Balmorel [Bn. USD (2020)]

End-Use sector results from TIMES

Total Final Energy Consumption

The total final energy consumption (TFEC) represents the necessary energy to supply the end-use service demands in the five different end-use sectors: agriculture, industry, residential, services, and transport. In both main scenarios, BSL and NZ, a significant increase in TFEC can be observed; it more than doubles. Figure 39 shows TFEC by fuel type. It becomes evident that electrification plays a major role in both scenarios, taking up more than 50% share of TFEC in 2050. The electrification in NZ is slightly more pronounced, at the expense of diesel and biomass consumption. The latter is needed to produce RE-fuels for the transport sector. The fade-out of fossil gasoline happens until 2045, regardless of the scenario. Towards 2050, the demand for RE-fuels in NZ to decarbonize the transport sector increases, which reduces the consumption of gas.

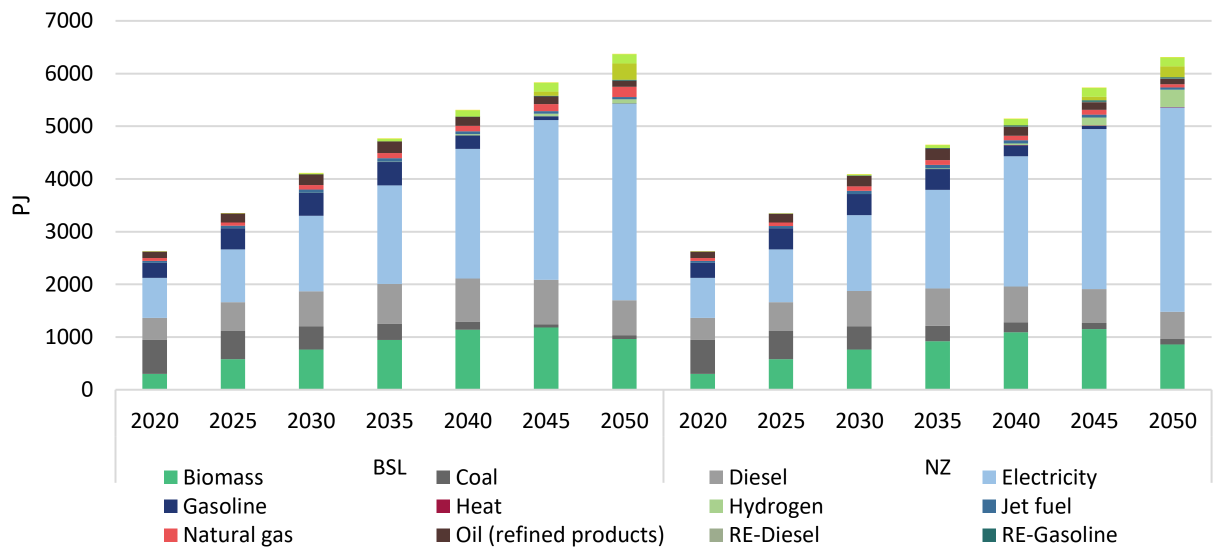


Figure 39: TFEC by fuel type in main scenarios, TIMES [PJ]

Delving into the sectoral split of TFEC, Figure 40 shows that the split remains rather constant throughout the model time horizon. However, the speed with which demand increases is highest in the industry sector. Industry has the highest fuel demand, followed by transport, and residential. Services and agriculture only play a minor role.

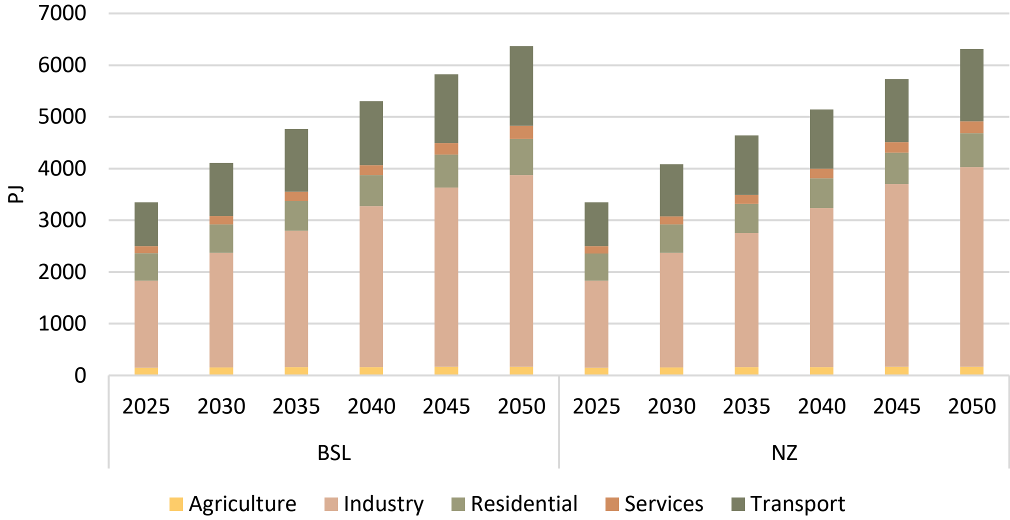


Figure 40: TFEC by end-use sector in main scenarios, TIMES [PJ]

Hydrogen consumption

The direct end-use consumption of hydrogen is shown in Figure 41. Hydrogen emerges in final consumption in 2030 and grows significantly to 64 and 70 PJ by 2050 in BSL and NZ respectively. In BSL, the transport sector is the main consumer of hydrogen, while in NZ the industrial sector consumes the largest amounts of hydrogen by 2045 with 103 PJ; and growing by an additional 150 PJ in 2050.

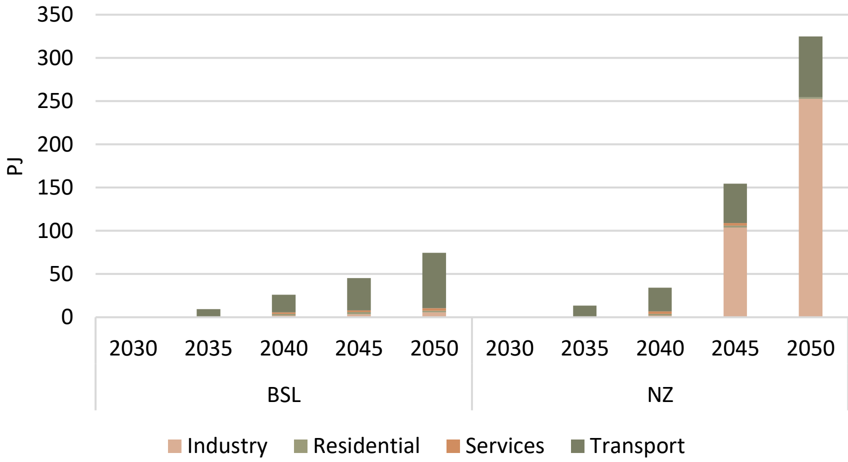


Figure 41: Final H_2 consumption by sector, TIMES [PJ]

Agriculture

The development of fuel demand in the agriculture sector is displayed in Figure 42. It shows a moderate increase in energy demand of 18% between 2022 and 2050. The electrification rate is increasing in both scenarios, but stronger in BSL. In NZ, the system-wide electricity demand is higher and thus, there is stronger competition between the sectors for electricity. As agriculture is modelled only as one aggregated demand process with a single efficiency, electrification does not lead to less overall consumption. This results in the same final energy demand for BSL and NZ, regardless of the fuel composition.

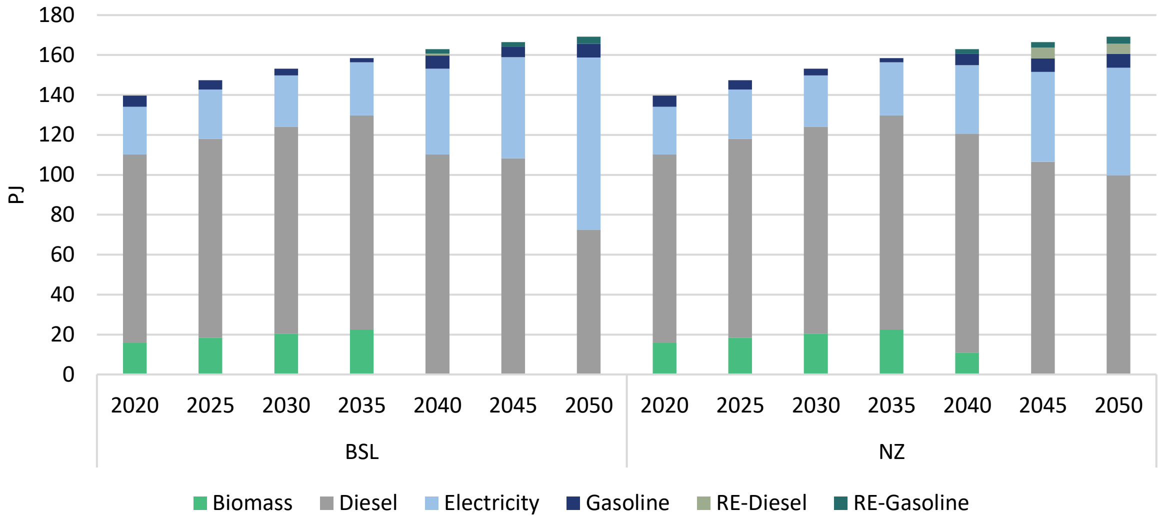


Figure 42: Final energy consumption in Agriculture, TIMES [PJ]

Industry

As illustrated in the TFEC (Figure 40), the industry sector holds the largest final energy consumption in both main scenarios. In both BSL and NZ, energy consumption more than doubles and electrification becomes the main fuel choice, reaching more than 50% by 2040 and onwards (Figure 43). Coal is phased out and replaced by biomass and natural gas. NZ sees slightly more penetration of RE-fuels in 2050 and a bit less biomass consumption.

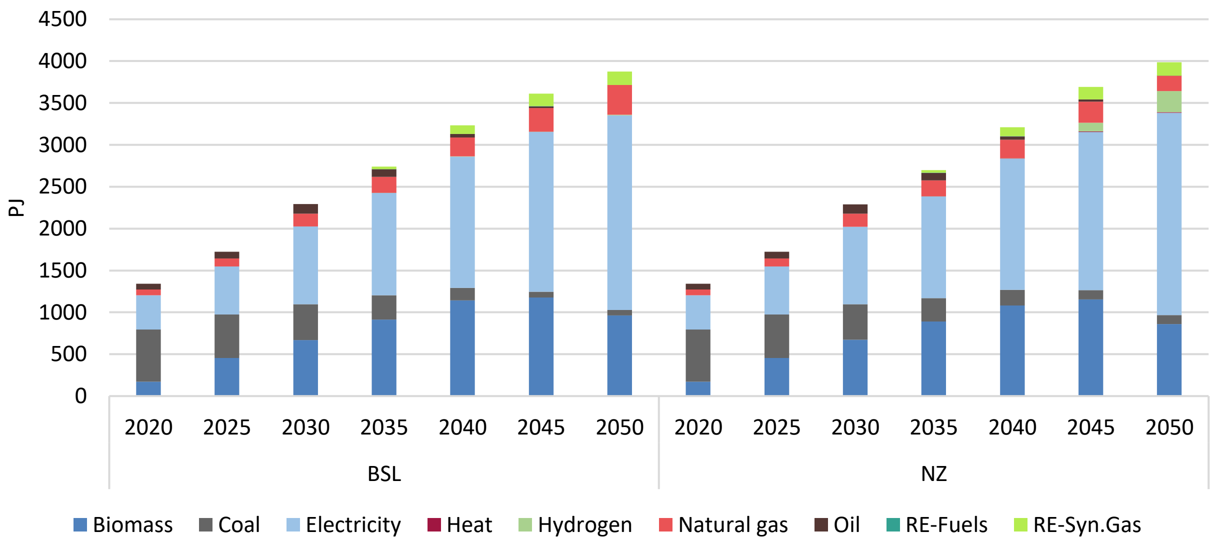


Figure 43: Final energy consumption in Industry by fuel type, TIMES [PJ]

Residential

In the residential sector, it becomes apparent that NZ compared to BSL has overall lower energy consumption post 2030, as BSL is subject to restrictions on the market share of improved and advanced technologies (see Table 38).

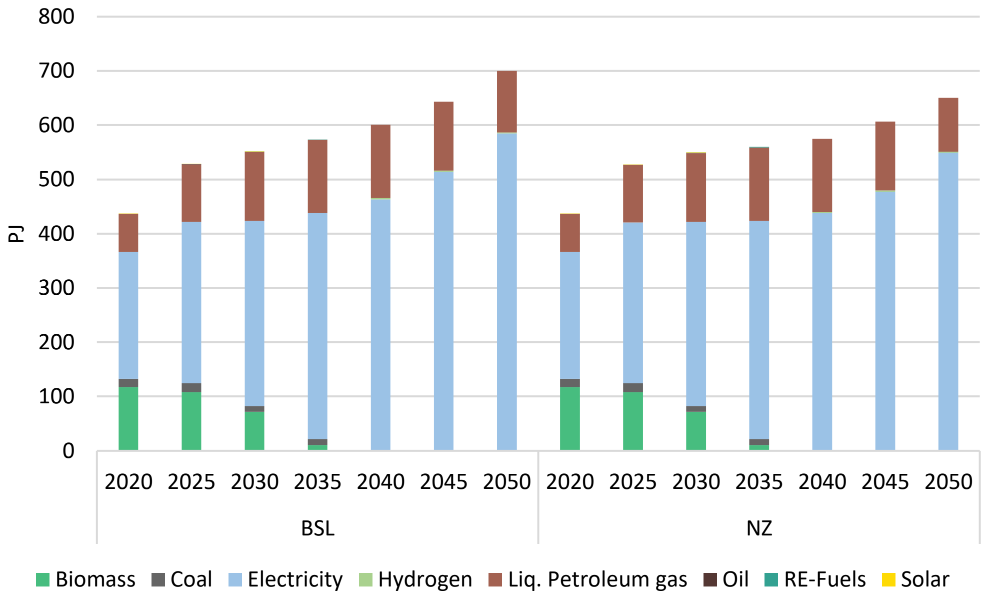


Figure 44: Final energy consumption in Residential, TIMES [PJ]

Services

Analog to the residential sector, the services sector (Figure 45) shows no major differences between BSL and NZ in terms of fuel composition, but only in the total consumption. The latter is lower in NZ due to efficiency build-out constraints set in BSL (see Table 38). Electrification remains the main fuel choice and increases its contribution by 2050, after a small decrease due to penetration of LPG (Liq. Petroleum gas) and renewable synthetic natural gas (RE-Syn. Gas) in the medium term. The roles of direct solar, biomass, and coal are neglectable.

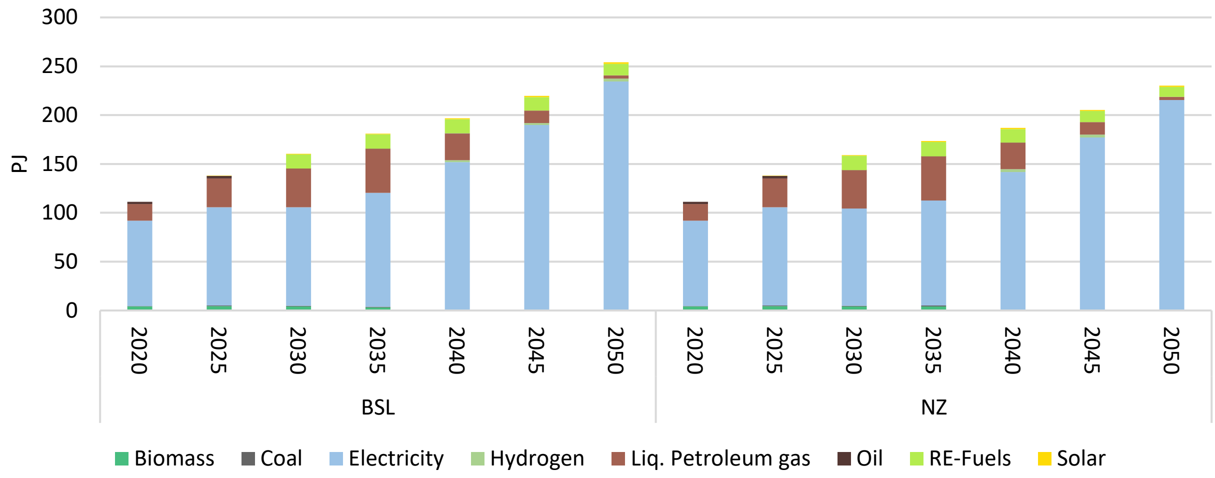


Figure 45: Final energy consumption in Services, TIMES [PJ]

Transport

The final energy consumption for the transport sector in BSL and NZ by fuel type is shown in Figure 46. In 2022, diesel and gasoline are the dominating commodities. The renewable gasoline part is in the fuel mix due to a policy directive regarding minimum blending levels. Post 2025, electricity is emerging and first replacing gasoline and afterwards diesel, becoming the major commodity. Besides, renewable methanol is penetrating in the later years. It is mainly consumed in navigation and its driver is air pollution cost in BSL, while the carbon constraint additionally drives the consumption of renewable methanol in NZ. However, the level in NZ is lower, due to the cross-sectoral competition for biomass, which is used to produce methanol. Besides, the modal shift of freight and passenger demand to rail also adds to the reduced demand for methanol, while increasing electricity needs, due to electrification targets (see Table 34 -Table 37).

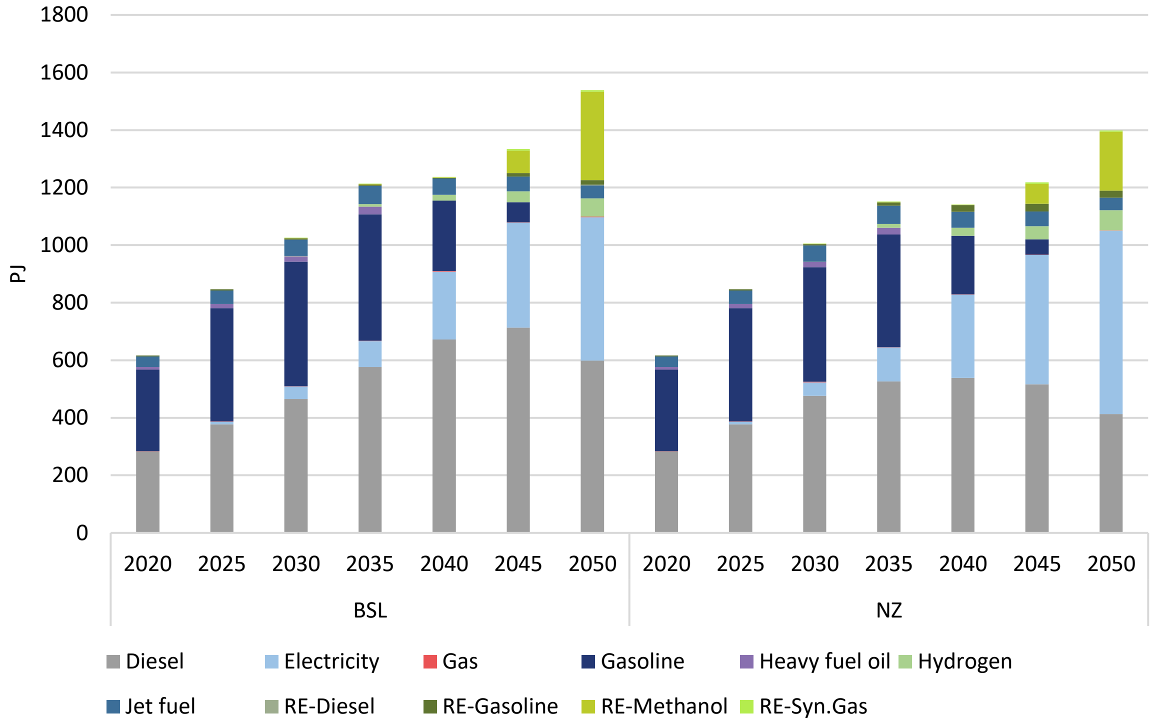


Figure 46: Final energy consumption in Transport, TIMES [PJ]

Figure 47 illustrates that electricity is the main future option for reduction of costs, air pollutants and for decarbonisation of the road transport. The latter is only taking effect in NZ. The only road transport modes that continue to consume diesel are trucks and buses. All other modes (see Table 4) move to 100% electrification by 2050. Busses reach 80% electrification and trucks 17%.

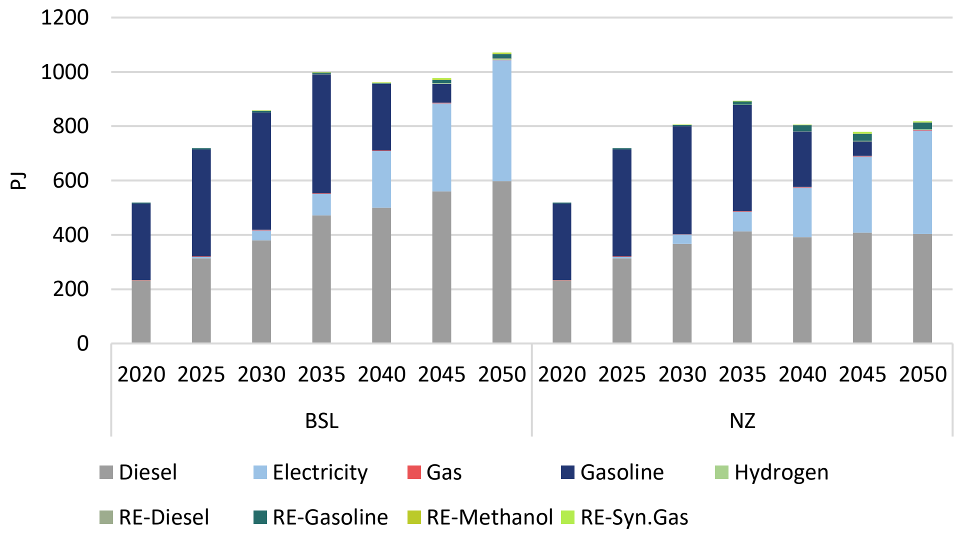


Figure 47: Road transport fuel consumption, TIMES [PJ]

It is expected that the share of rail transport (both freight and passenger) will increase significantly in the future. This expectation has been implemented only in NZ (and NZ variations and sensitivities). Figure 48 indicates how this shift will affect the fuel demand. In BSL, the main fuel in the early years is diesel, which is subsequently replaced by electricity and some hydrogen and renewable diesel. Compared to NZ, the levels are almost neglectable. In NZ, the shift takes effect from 2030 and is mainly increasing the diesel consumption, which is afterwards reduced, and electricity takes over. Also, hydrogen is shown to be to some extent a feasible solution.

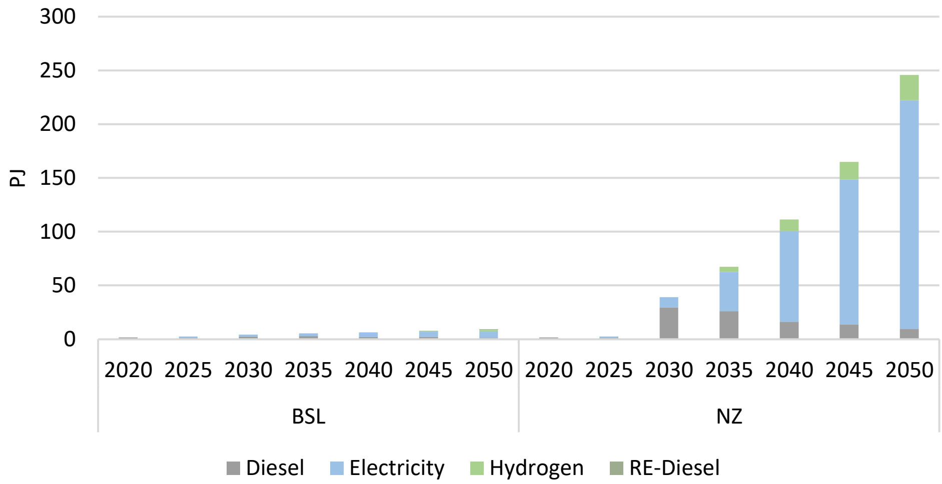


Figure 48: Rail transport fuel consumption

The consumption of aviation fuel presented in Figure 49 shows no major differences between BSL and NZ. In both scenarios, jet fuel is being replaced by hydrogen and electricity, to the maximum assumed service demand shares (20% and 30% respectively) due to technological limitations. Hydrogen and electricity show high cost-effectiveness but are likely to operate only on the short haul.

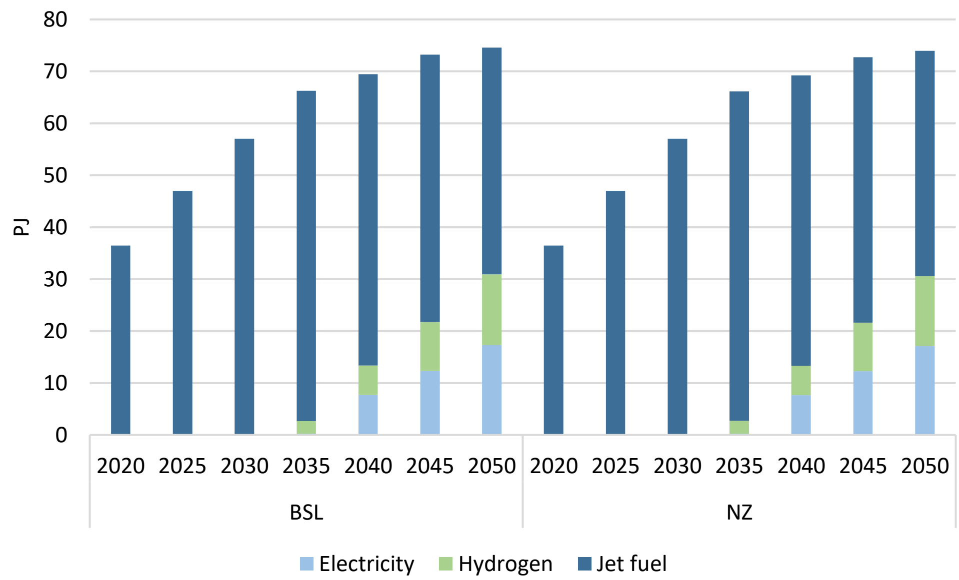


Figure 49: Aviation fuel consumption, TIMES [PJ]

As previously mentioned, and as illustrated in Figure 50 (renewable) methanol becomes the future fuel choice for navigation, accompanied by small levels of hydrogen. NZ has lower levels per period due to modal shift to rail, but the fuel composition and developments follow similar trends. Among fossil fuels, diesel dominates the sub-sector until 2040, together with heavy fuel oil. Afterwards, renewable fuels take over. This is again mainly due to air pollution costs in BSL and the additional carbon constraint in NZ.

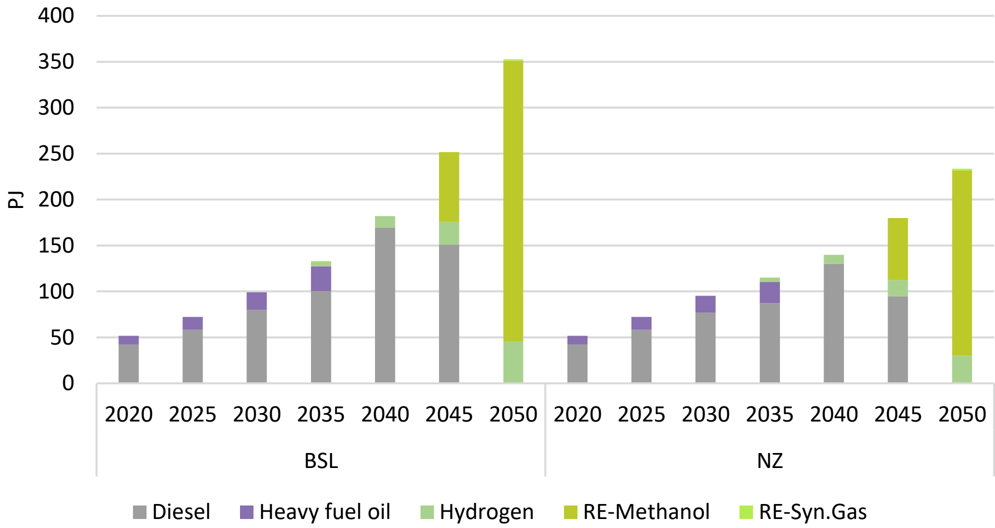


Figure 50: Navigation fuel consumption, TIMES [PJ]

Linked data between TIMES and Balmorel

In this section the data provided by the TIMES model to feed into the Balmorel model, as described in chapter 2 is laid out. Note that the linking has been done for all main variations and sensitivities as described in chapter 4. In total, four sets of results from TIMES are soft linked, including two sets of data that constrain the power sector itself, i.e., the allocated carbon budget in Table 43 and the biomass and waste availability in Table 44. The remaining two sets of data regard the supply of power and e-fuels by the power sector to the other sectors, i.e., final electricity demand in Table 45 and final hydrogen and ammonia demand in Table 46.

Table 43 depicts the carbon budget for the power sector as allocated by the TIMES model runs and is implemented as maximum limits of CO_2eq emissions allowed in each model year, ensuring that the total emissions from both models are in line with the overall target for the energy system. In Baseline, emission allowances are only given from TIMES to Balmorel for 2030, while in NZ emission limits are given for all modelling years from TIMES to Balmorel. In both main scenarios, the emissions in the power sector decrease towards 2050 compared to 2020. This shows that decarbonisation in the power sector is a possible feasible solution and even cost-effective in the BSL scenario. However, the reduction is stronger in the NZ scenario due to the overall target in 2050.

Table 43: Soft linking of carbon budget for power sector from TIMES to Balmorel [Mt CO_2-eq.].

Scenario	2030	2035 Mt	2040	2045	2050
BSL	173	-	-	-	-
NZ	123	124	113	67	23

The allocation of biomass and waste, as calculated in TIMES, is shown in Table 44. Regarding biomass, the allocated amounts provided as input from TIMES to Balmorel are rather small, as the biomass is used to alarge extent in the end-use sectors. In BSL, only in 2025 some biomass is available for power generation, while in NZ there is also availability in 2050.

Table 44: Soft linking of biomass and waste allocation for power sector from TIMES to Balmorel [PJ]

Scenario	Sector	2022	2025	2030	2035	2040	2045	2050
					PJ			
BSL	MSW[1]	17	33	70	75	80	84	90
	Non-woody Biomass[2]	0	2.4	0	0	0	0	0
	Wood	0	1.8	0	0	0	0	0
NZ	MSW[1]	17	33	70	75	80	84	90
	Non-woody Biomass[2]	0	2.1	0	0	0	0	5.7
	Wood	0	1.6	0	0	0	0	3.5

[1]*Municipal solid waste*

[2]*Includes Rice husk, Straw, Bagasse, Manure, and Others*

Table 45 shows the electricity demand by sector or category and model period for both main scenarios. It excludes any potential consumption by the sector itself. In Balmorel, these annual demands are combined with demand profiles, which the model must serve. It becomes apparent that the need for electricity increases from BSL to NZ, especially in industry, and transport sectors, due to higher electrification and a modal shift of transport service demands to electric rail, and the introduction of carbon reduction targets post 2030. In contrast, power demand reduces in residential and services, due to less constraints on the build-out of high efficiency technologies.

Table 45: Soft linking of electricity demand excl. power sector from TIMES to Balmorel [TWh]

Scenario	Sector or category	2022	2025	2030	2035	2040	2045	2050
					TWh			
BSL	Residential	80	89	101	123	138	153	174
	Services	35	37	38	42	57	71	95
	EVs[1]	1	2	12	27	65	103	142
	Rail	0	0	1	1	3	5	7
	Industry	138	172	277	364	466	572	688
	DAC[2]	0	0	0	0	0	0	0
	Upstream	0	0	0.1	0.2	0.5	0.7	0.8
NZ	Residential	80	89	101	117	131	142	167
	Services	35	37	37	40	51	65	80
	EVs[1]	1	2	11	25	57	89	121
	Rail	0	0	3	11	27	44	68
	Industry	138	172	277	363	465	563	712
	DAC[2]	0	0	0	0	0	0	0
	Upstream	0	0	0.1	0.3	0.7	0.9	0.9

[1] *Electric vehicles*

[2] *Direct air capture*

The fourth set of data comprises hydrogen and ammonia demands for consumption outside of the power sector (Table 46), both for further production of renewable fuels or direct utilisation. In both scenarios, the demand for ammonia is zero, while hydrogen emerges in 2030 and thereafter rapidly increases to its maximum in 2050. Hydrogen proves to have a more pronounced role in the NZ scenario, where the demand exceeds by more than a factor of 4 of the level reached in BSL by 2050. The main consumers are the clinker production in industry, non-road transport, and the production of renewable jet fuel. There is no ammonia demand reported due to the high costs. If, e.g., the CO_2 targets become stricter or transport needs to fully decarbonise by 2050, then ammonia is likely to become part of the model solution, as seen in the NZ+ scenario described later in Figure 83.

Table 46: Soft linking of hydrogen and ammonia supply by the power sector from TIMES to Balmorel [TWh]

Sector		2022	2025	2030	2035	2040	2045	2050
					TWh			
BSL	Hydrogen	0	0	0.4	9.4	25.2	45.0	74.6
	Ammonia	0	0	0	0	0	0	0
NZ	Hydrogen	0	0	0.4	13.4	32.7	153.0	324.9
	Ammonia	0	0	0	0	0	0	0

Power system results

With the starting point in the results of the TIMES simulations, through the inputs described in the previous section, the Balmorel model subsequently simulates the power sector for the 2 main scenarios in greater detail.

Power generation mix

Figure 51 shows the installed power capacity for the two core scenarios. While in the year 2030, some differences between the BSL and NZ scenarios can be found, with more solar power and slightly reduced thermal capacity installed in the NZ scenario, however by 2040 and 2050 larger differences can be found. By 2050, utility scale solar doubles in capacity in the NZ scenario compared to the BSL scenario. Wind capacity increases of about 35% and battery capacity increases to balance the system in the NZ 2050 scenario.

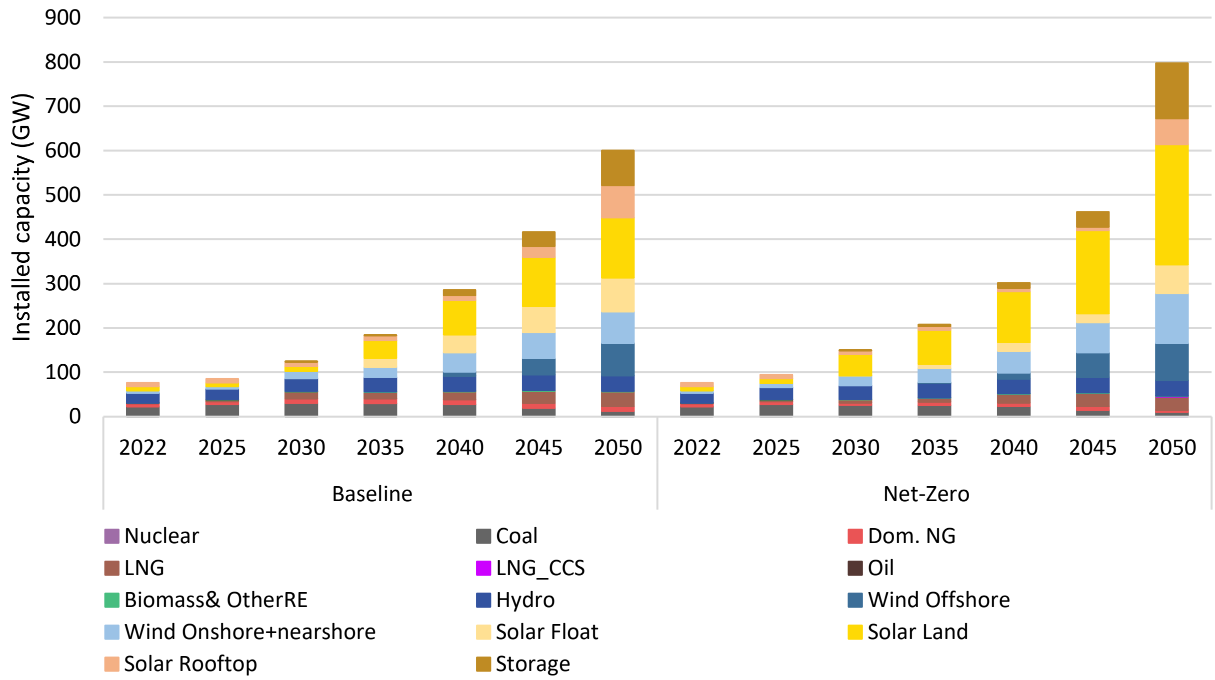


Figure 51: Installed power capacity of the two core scenarios. Fixed import from neighbouring countries is not included in figure (Import from China 0.7 GW; Import from Laos 0.6 GW in 2022, 3.4GW in 2025, 5 GW after 2025).

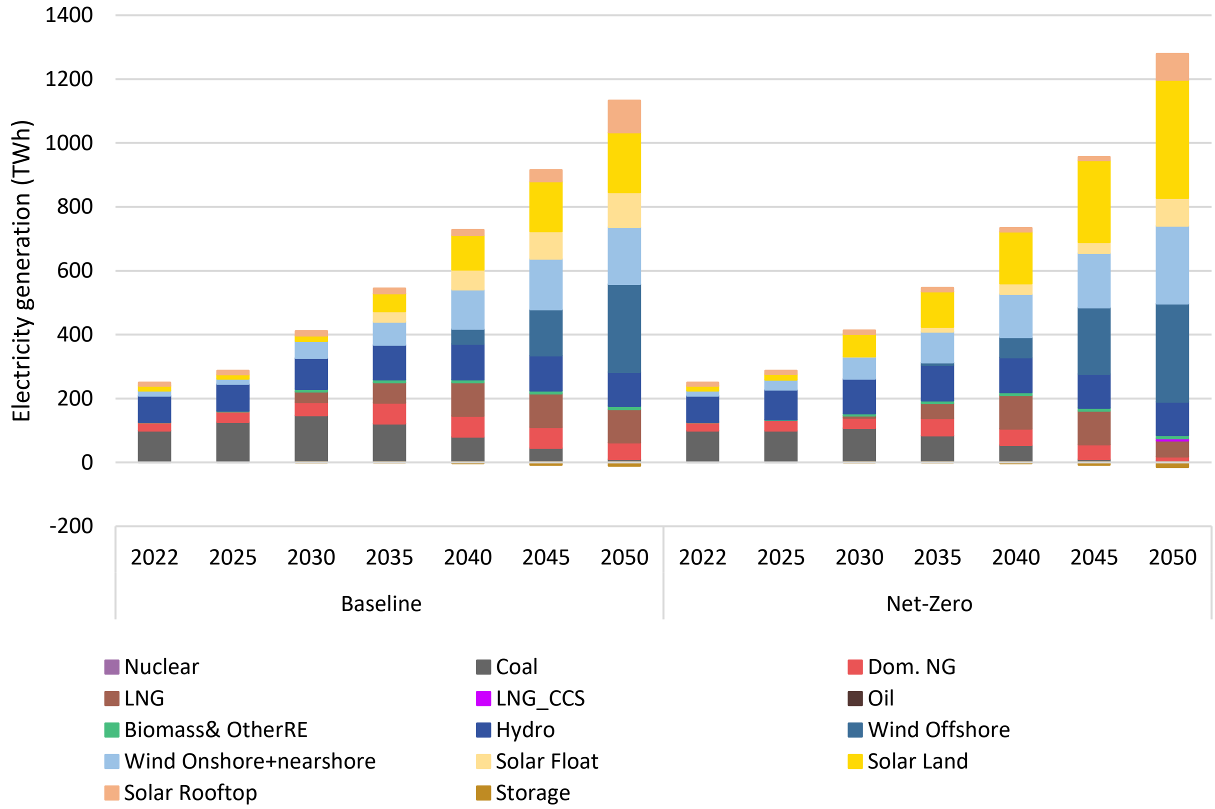


Figure 52: Electricity generation for the two core scenarios. Fixed import from neighbouring countries is not included in figure (Import from China 1.4 TWh; Import from Laos 2.1TWh in 2022, 10.9TWh in 2025 and 16.8 TWh from 2030).

In the core scenarios, generation from coal will gradually reduce after 2030 and achieve almost zero in 2050 even in BSL which does not have CO_2 limitation. Renewable energy (solar and wind) is more competitive than coal due to gradually lower investment costs of RE and the additional cost of emissions from coal and gas power plants.

In addition, simulating hydrogen and ammonia produced from electricity grid causes the price of hydrogen and ammonia to be quite high in the future due to increasing electricity prices, so the use of hydrogen and ammonia for electricity production will not appear in either scenario. Co-firing of coal and biomass is also not appearing in core scenarios.

In 2030, because the CO_2 emission limit set for the scenarios follows the limit from the TIMES model and the electricity demand from the TIMES model is much lower than PDP8 (about 430 TWh while PDP8 is 567 TWh), there is no additional capacity of LNG thermal power plants beside committed capacity. After 2035, more LNG capacity will develop to replace coal, although not considering reserves. In 2050, LNG (includes CCGT, SCGT, RICE) will have about 33 GW in Baseline scenario, 30 GW in Net-Zero scenario.

Nuclear (SMR technology) and LNG-CCS will appear from 2050 because of net-zero condition (CO_2 limitation only 23 tons/year in 2050). In the NZ scenario, SMR nuclear will appear about 1 GW and LNG-CCS about 1 GW in 2050 while they do not appear at all in BSL scenario.

The Baseline (BSL) scenario shows significant RE generation, which in all years lies above the REDS target, indicating that investments in RE generation are attractive from a socio-economic perspective. RE shares of 44% and 85% found in 2030 and 2050 respectively in the baseline scenario.

The Net-Zero scenario, following a lower emission trajectory assumes the land solar power potential to be twice as large compared to BSL. Along with that, NZ allows for the decommissioning of all generation plants at any time (with decommissioning costs not accounted for in the modelling). Thus, the capacity of coal and gas power sources will decrease, when compared to the BSL scenario, and at the same time, renewable energy sources (especially solar power) increase. The NZ scenario will decommission about 4.4 GW of imported coal and 5.5 GW of domestic gas before 2030. The proportion of renewable energy in the electricity production structure is consistently greater than BSL scenario, with approximately 62% in 2030 and 94% in 2050.

Wind and solar generation

As shown in Figure 51, wind and solar power become the key technologies in both scenarios with total capacities, as 82% and 88% of the total power system generation capacities (excluding storage) is either wind or solar power in the BSL and NZ scenario, respectively. In 2030, the installed RE capacity is limited to the PDP8 in the BSL, but the NZ scenario reaches 48 GW of land-based solar capacity in 2030. A continuous growth in land-based solar is observed in both scenarios, reaching the full potential allowed (137 GW in BSL and 271 GW in NZ) in 2050. Solar floating is deployed from 2035 and is becoming a vital part of the solar production with 65-76 GW by 2050 in the two main scenarios. Further reaches rooftop solar 59-73 GW of capacity. Due to higher costs of rooftop solar, land and floating solar is preferred in the cost-optimized model results.

Similar as for solar power, a continuous growth in onshore wind power from today towards 2050 is seen, where the BSL scenario reaches 71 GW of onshore wind installed in 2050 and the NZ scenario requires additionally 41 GW more compared to the BSL. Offshore wind appears from 2035 in the NZ scenario and first in 2040 in the BSL scenario, due to comparatively higher costs in the coming decade, but high investments are observed even in the BSL scenario from 2040 onwards. 73 GW of offshore wind is given in 2050 in BSL scenario and 84 GW in the NZ scenario.

Storages

Both main scenarios show considerable wind and solar generation in future years and a declining role for thermal generation in the electricity mix.

One measure for integrating variable renewable energy is the use of power storages such as batteries and pumped hydro. In Balmorel, investments can be made in specific, fully defined pumped hydro projects or in lithium-ion batteries, vanadium flow batteries, flywheels which can be optimised independently in storage volume and inverter capacity. Table 47 shows the resulting sizes of both batteries and pumped hydro for three scenarios with increasing wind and solar generation.

Table 47: Storage and loading/generation capacity of batteries and pumped hydro, along with the C-ratio (storage volume divided by the generation capacity) for the core scenarios.

		Batteries			Pumped hydro		
		Inverter capacity (GW)	Storage volume (GWh)	C-ratio	Pump/Turbine Capacity (GW)	Storage volume (GWh)	C-ratio
2035	BSL	0.0	0.0	-	1.1	9.2	8.66
	NZ	1.5	3.1	2.09	2.0	16.3	8.18
2040	BSL	4.1	8.0	1.95	7.0	52.7	7.56
	NZ	1.5	3.2	2.19	9.2	71.2	7.70
2045	BSL	6.3	28.6	4.50	25.0	192.1	7.68
	NZ	7.4	30.1	4.09	26.0	199.5	7.68
2050	BSL	53.0	259.2	4.89	25.0	192.1	7.68
	NZ	98.0	593.3	6.06	26.0	199.5	7.68

Increasing levels of wind and especially solar power require more storage for balancing. The optimised C-ratio of the batteries indicates that the power system requires relatively little storage volume compared to inverter capacity in circumstances of lower solar power penetration levels, only needing to cover for the balancing of the system in few hours. However, when the total solar and wind generation increases, more storage is needed to move generation over longer periods of time. At this stage, pumped hydro with a fixed large storage volume per turbine capacity also becomes more attractive.

Because of limitations for pumped storage capacity potential, almost the entire potential of pumped storage will be utilised from 2045 and batteries capacity will expand extensively in 2050 with an increased C-ratio (5-6 hours) to allow further integration of solar and wind.

Transmission

As wind and solar resources are highly location-dependent, capacity build-out is larger in some regions than in others. This can be seen in Figure 53, where the generation is shown for the NZ scenario for 2050. South Central produces the majority of the offshore wind generation, the Southeast region and North region have large solar production and the South West region is dominated by onshore wind generation. The graph also shows that wind and solar power is not necessarily produced or available where it is needed and thus, needs to be transmitted to the demand centres.

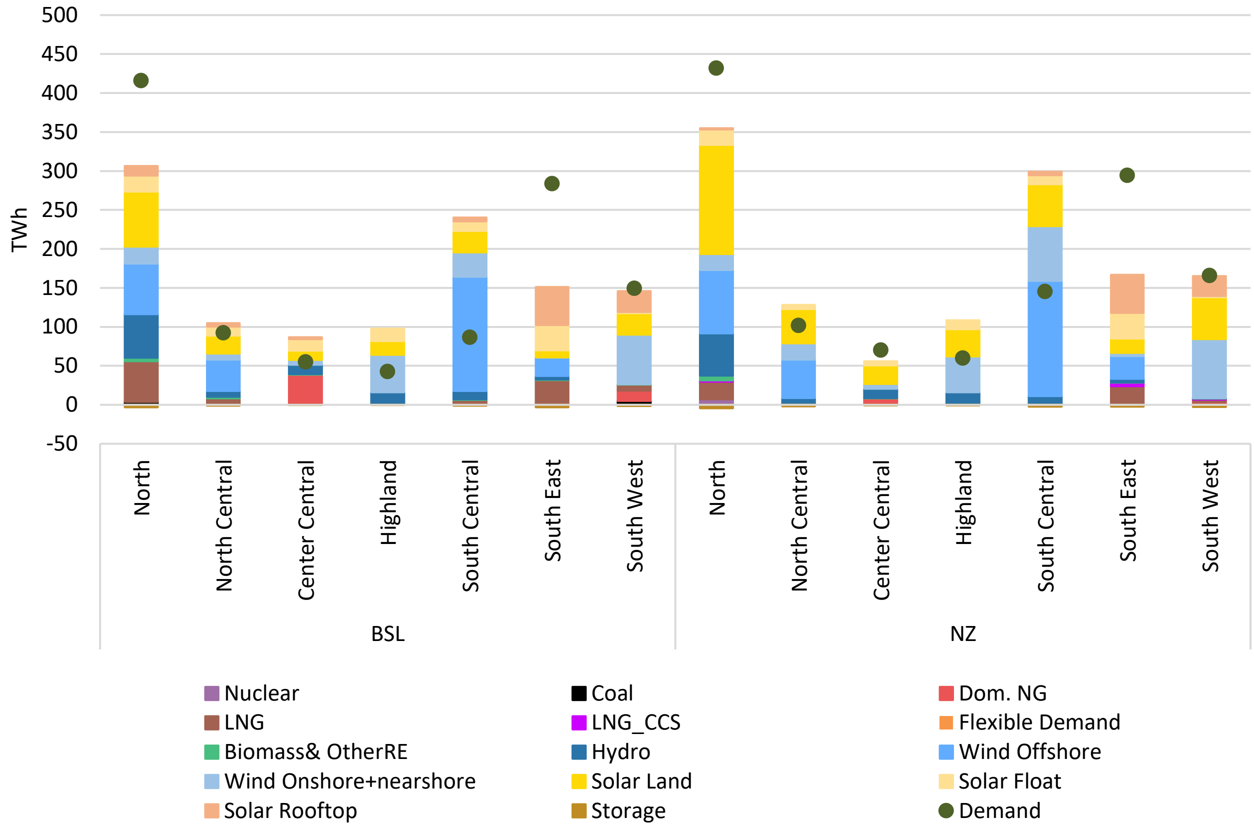


Figure 53: Annual generation and demand in the BSL and NZ scenarios for 2050 shown per region.

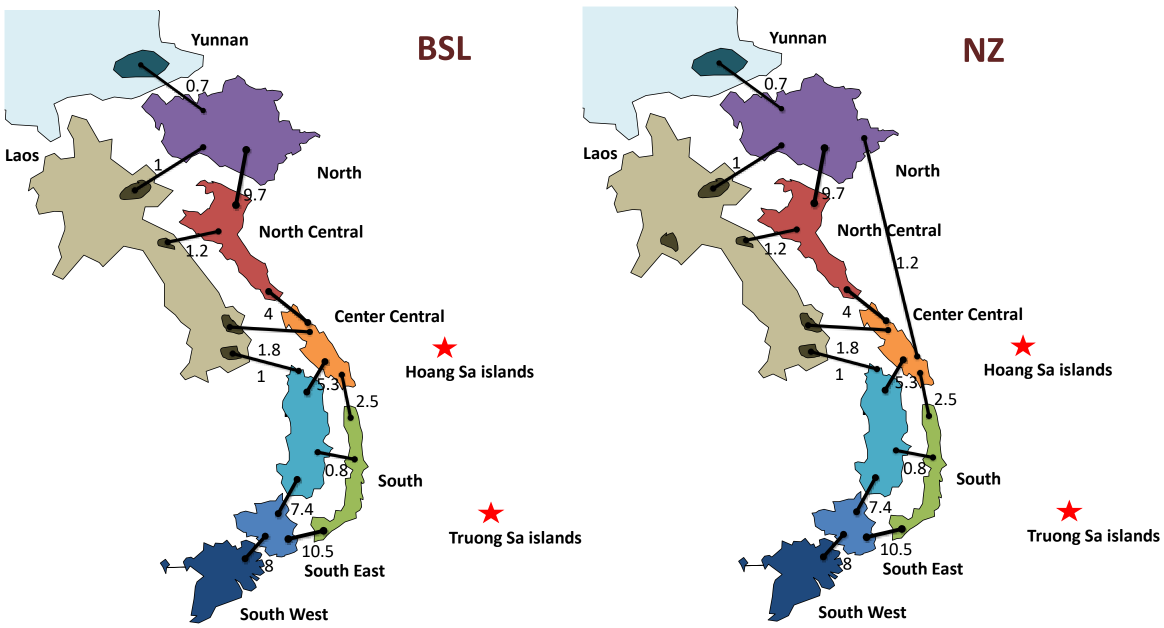


Figure 54: Transmission capacity (GW) between regions in 2030 for both core scenarios.

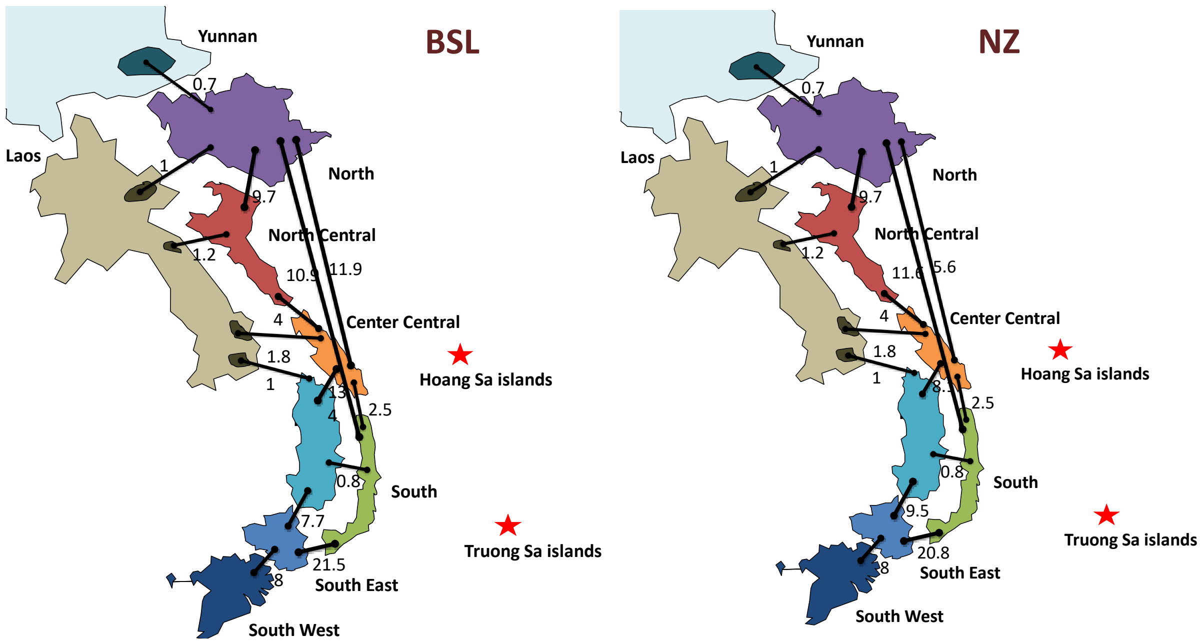


Figure 55: Transmission capacity (GW) between regions in 2050 for both core scenarios. Lines from Center Central to North and South Central to North are HVDC lines.

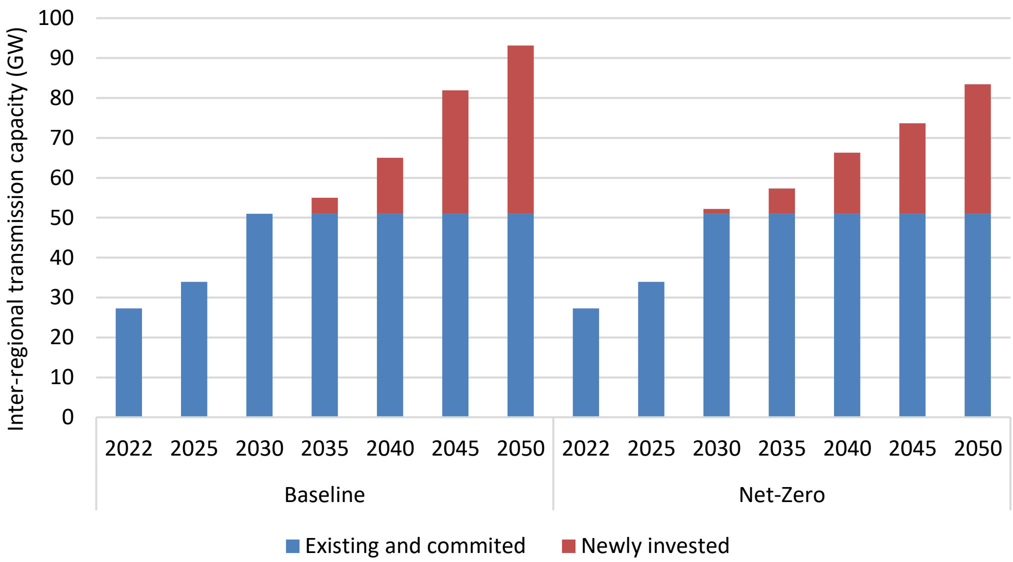


Figure 56: Total inter-regional transmission capacity (GW) of core scenarios

The Balmorel result show that both the North region and the South East region import large amounts of electricity from South Central and Highlands. To accommodate the transmission from the South of Viet Nam to the Northern regions, large investments in cross-country HVDC lines are seen.

Total inter-regional transmission capacity in NZ scenario is slightly lower than BSL scenario because the NZ scenario has a higher potential of solar land than BSL (especially in North) and can be implemented in all regions with similar quality and nuclear appears in the North reducing the need of transmission.

Hydrogen pipelines appear for the hydrogen demand of other sector (especially transport and industry).

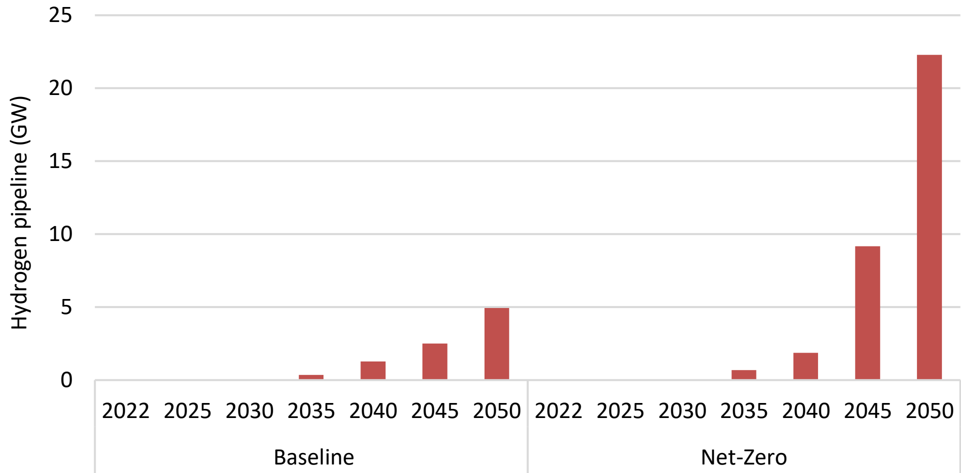


Figure 57: Total hydrogen pipeline capacity (GW) between regions for all core scenarios).

As the hydrogen demand is much higher in the NZ scenario vs the BSL scenario, the North, North Central, South East have high hydrogen demand coinciding with a lower potential of wind and solar. Therefore, hydrogen will be transmitted from South West, South Central, Highland to the South East, and from South Central, Highland, Center Central to North Central, North.

Full load hours (FLHs) of coal-fired power plants and gas-fired power plants

In BSL scenario, coal and gas power plants with BOT investment are implemented in the model with minimum FLHs of 6000 hours/year for 20 operation years. But in NZ scenario, minimum FLHs of all technologies are removed from 2030. Besides that, the minimum fuel use of all fuel based on take or pay contract also are removed from 2030 in all scenarios. In the results, coal power plants will reduce the FLHs from 4000-5000 hours/year in 2030 to 0-800 hours/year in 2050. Coal power plants nearly have no generation in 2050 although without CO_2 limitation in BSL scenario. In Baseline, full load hours of gas power plants are higher than the Net Zero scenario after 2040.

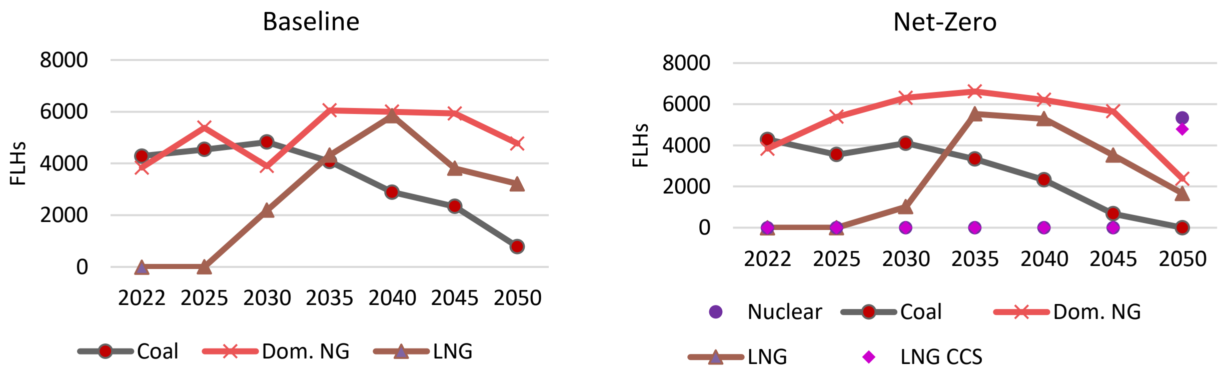


Figure 58: Full load hours of coal and gas fired power plants for all core scenarios.

Emissions and pollutants

CO_2 emissions

One of the key drivers for the green transition as underlying assumption of the net-zero scenarios is the goal to limit climate change by reducing carbon emissions. To achieve this transition, direct CO_2 limits are modelled in the net-zero scenarios, based on TIMES output results. For the baseline scenario, a CO_2 limit is set until the year 2030, after which no restrictions on CO_2 emissions are imposed.

Figure 59 shows carbon emissions in the power system for the different scenarios. Although no CO_2 limitation are modelled after 2030, the BSL scenario still reaches the carbon emission's peak of the power sector in 2030 at 173 million tons. The NZ scenario has lower carbon emissions as compared to JETP requirements, with only 123 million tons in 2030 and 124 million tons in 2035 in NZ scenario compare with 170 million tons in 2030 of JETP requirement). This result occurs mainly because NZ scenario allows early shut down of coal and gas thermal power plants, with a decommission of 4.4 GW of imported coal and 5.6 GW of domestic gas, and 7 GW of LNG committed capacity lower than BSL scenario in 2030.

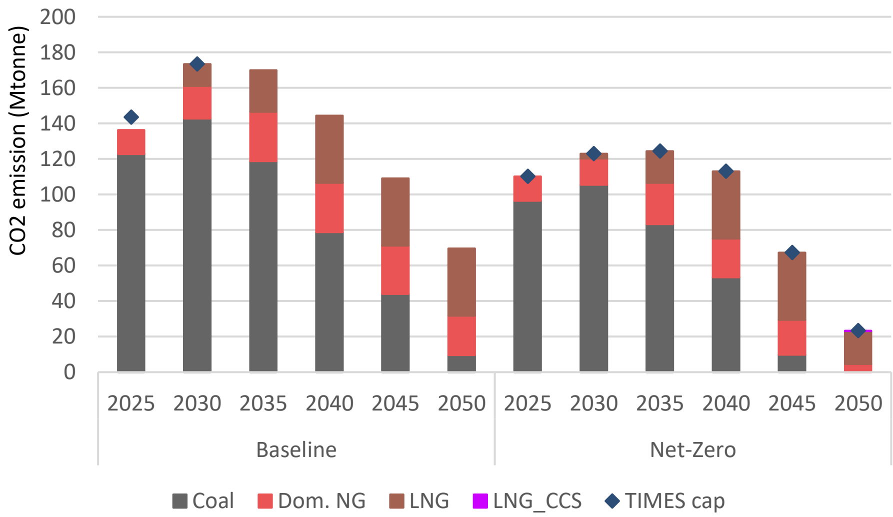


Figure 59: CO_2 emissions of the power system for the core scenarios and the limitation from TIMES.

Pollution

Apart from CO_2 emissions and the related global consequences, monitoring and reducing the emissions of pollutants in Viet Nam is also very relevant to ensure its inhabitants health and reduce the health costs incurred because of pollution.

The scenarios in the EOR-NZ all consider pollution costs in the model's optimisation function.

The results of pollutant emissions can be seen in Figure 60. Along with the process of reducing CO_2 emissions, pollutant emissions also decrease according to the same trend as CO_2 emissions, with peak emissions reached in 2030 in BSL scenario (total about 318 thousand tons), decreasing to less than 67 thousand tons in 2050 in BSL scenario. NZ scenario will have lower air pollution than BSL scenario, with peak emission in 2025 with 255 thousand tons and only 30 thousand tons in 2050.

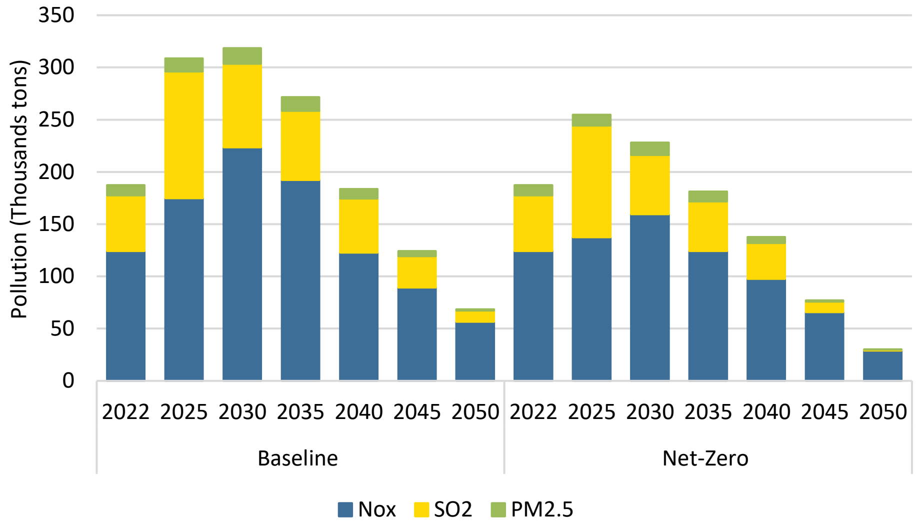


Figure 60 : Air Pollutant emissions in the power sector for the core scenarios.

Power system costs

Figure 61 shows the power system cost by each component in both core scenarios. The capital costs in the graph represent annualised costs for model optimised investments. In 2050, the capital cost will occupy about 72-80% of the total power system cost in both core scenarios. The power system cost in the NZ scenario in 2050 is about 22% higher than the BSL scenario. Compared to the BSL, the NZ scenario has a higher share of capital costs, due to the extra investments in solar and batteries, which are capital intensive. Conversely, the fuel costs and variable O&M share reduces.

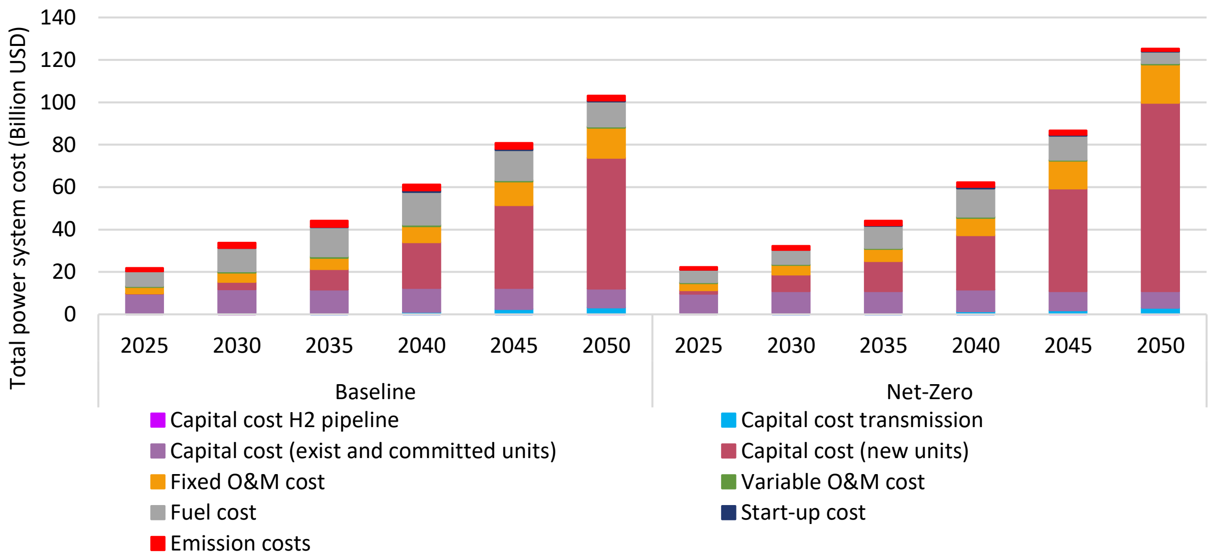


Figure 61: Annualised system cost of power system for the core scenarios (not discounted, @USD2019).

The average electricity production cost will increase from 7.3 cents/kWh in 2022 to 7.6-7.9 cents/kWh in 2030 and to 9.2-9.8 cents/kWh in 2050.

The average cost of producing hydrogen from the power grid will reach 37-38 USD/GJ in 2030 and increase to 47-50 USD/GJ in 2045, achieve 37 USD/GJ in 2050.

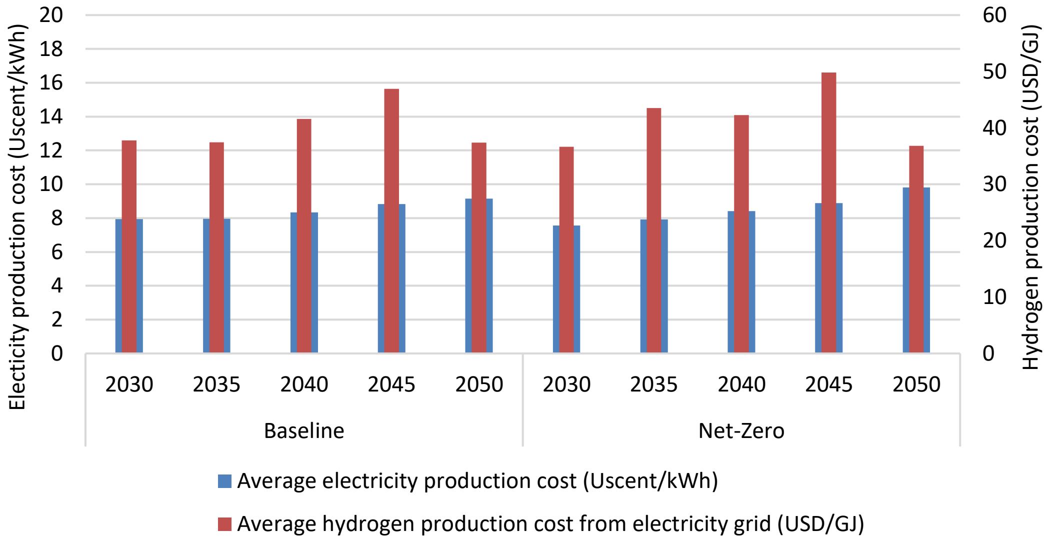


Figure 62: Average electricity production cost and hydrogen production cost from Balmorel model (not discounted, @USD2019).

6 Modelling results – Main variations and sensitivity analyses

Energy system results

Combined results from Balmorel and TIMES

GHG emissions

GHG emissions peak in 2030 for all Net-Zero scenario variations (Figure 63), as is the case for the Baseline scenario. GHG emissions are drastically reduced in the NZ+ scenario, reaching 20.0 Mt CO_2e by 2050, corresponding to solely industrial process-related emissions. In the GG scenario, there is a progressive reduction in net emissions, reaching 115.9 Mt CO_2e in 2050.

Among the Net-Zero scenario variations, the net emissions are highest in the Green Transport scenario in the period 2030-2045, due to the lower decarbonization of the power and industry sectors. Emissions from the industrial sectors are indeed highest in 2050 for the GT scenario, at 87.6 Mt CO_2eq compared to 81.0 Mt CO_2eq for the NZ scenario. On the other hand, transport emissions peak Peaks at 70.6 Mt CO_2eq in 2030 for the GT scenario, while peaking in 2035 for all other NZ variations. Transport emissions reach 1 Mt CO_2eq in 2050 in the GT scenario based on the set target for decarbonization of the transport sector, while reaching 34.8 and 3.7 Mt CO_2e in 2050, for NZ and NZ+ scenarios, respectively.

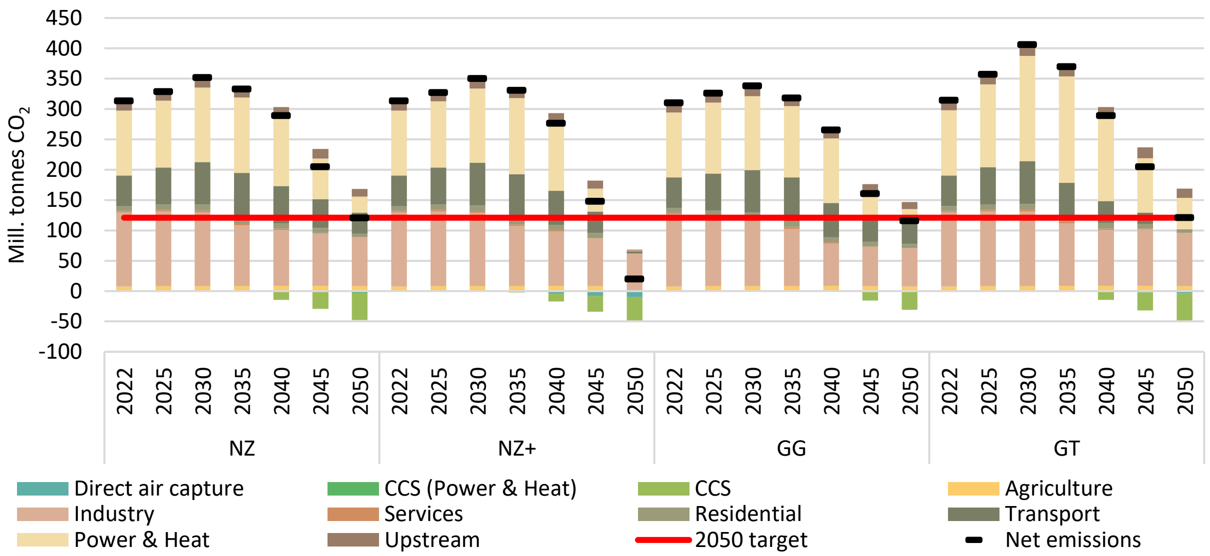


Figure 63: GHG emissions by sectors for main variation scenarios.

Air pollution

Figure 64 describes the emissions for various pollutants (NO_X, SO_2, $PM_{2.5}$) across the different sectors for the main Net-Zero scenario variations over the period 2022-2050. NO_x emissions are the highest among the analysed air pollutants, with the transport sector being the main emitter across scenarios over the time horizon Moreover, all scenarios have similar pollution emission levels, except for the NZ+ scenario, where the emissions of the various pollutants (NO_X, SO_2, PM25) are lower compared to the other scenarios in 2050, due to the phase-out of a large part of fossil fuel consumption across sectors, based on the net-zero target. The higher air pollution emissions in the GT scenario in 2030 are related to the larger fossil fuel use in the power sector, compared to other NZ scenario variations.

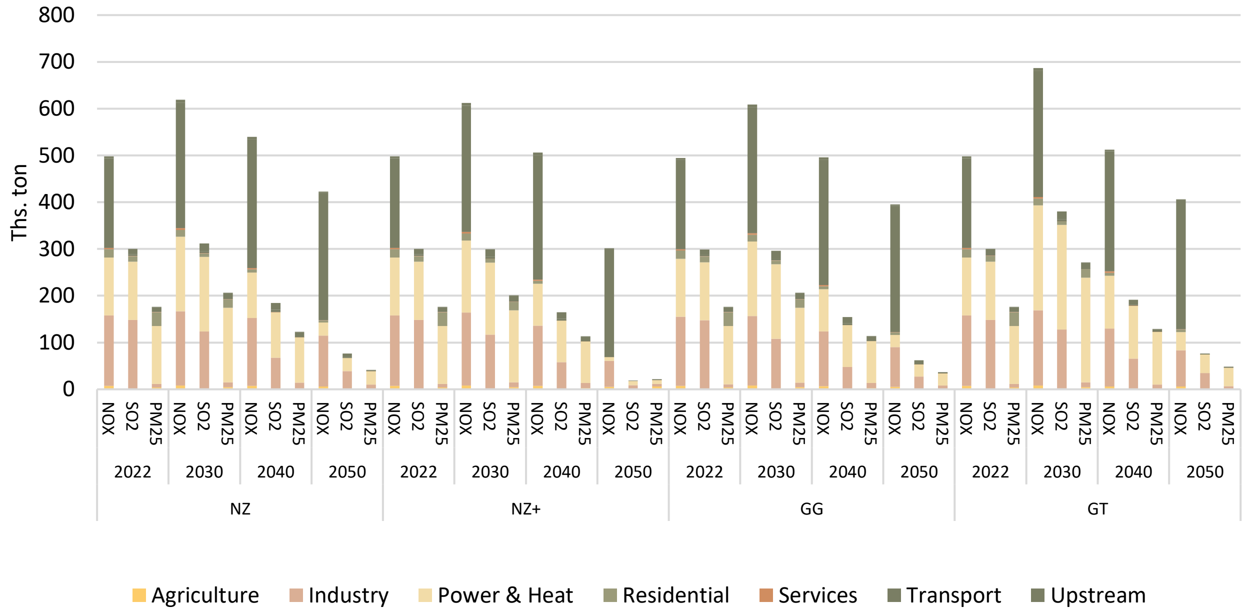


Figure 64: Air pollution by sector in variation *scenarios, TIMES & Balmorel [Ths. Tonnes]*

Total primary energy supply

In 2050, the total primary energy supply (TPES) in NZ+ and GT scenarios is higher compared to the NZ scenario. To meet the net-zero target, nuclear appears in NZ+, starting from 2040 and reaching 1409 PJ in 2050. In the NZ and GT scenarios, nuclear appears only in 2050. The share of renewable energy increases in the NZ+ scenario by 2050, reaching 81% in 2050, compared to 79% in NZ. In GG, due to the assumed change in GDP sectoral shares from high energy-intensive industrial sectors to lower energy-intensive sectors (services), the TPES is lower compared to the NZ scenario.

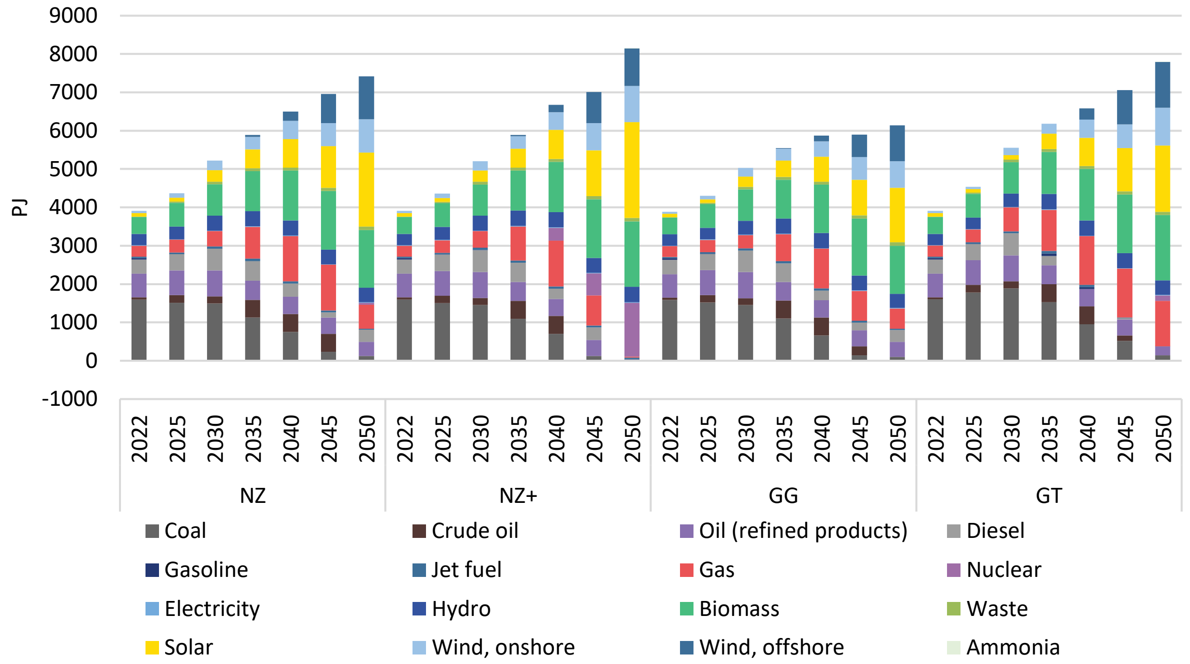


Figure 65: Total primary energy supply by fuels for main variation scenarios.

Carbon capture, storage, and utilisation

Figure 66 presents the implementation of Carbon Capture and Storage (CCS) technologies and Direct Air Capture (DAC) in various sectors across the NZ scenario variations.

CCS is implemented starting from 2040, in order to reach the net-zero target, with around 50 Mt CO_2eq captured by CCS (mainly in industry) in 2050 for the NZ scenario. In comparison, CCS presents the lowest level of investment in the GG scenario, with 30.7 Mt CO_2eq captured in 2050, while in the GT and NZ+ scenarios both direct air capture and CCS are invested in, leading to 3.7 Mt CO_2eq in direct air capture and 44.2 Mt CO_2eq in CCS by 2050 (GT scenario).

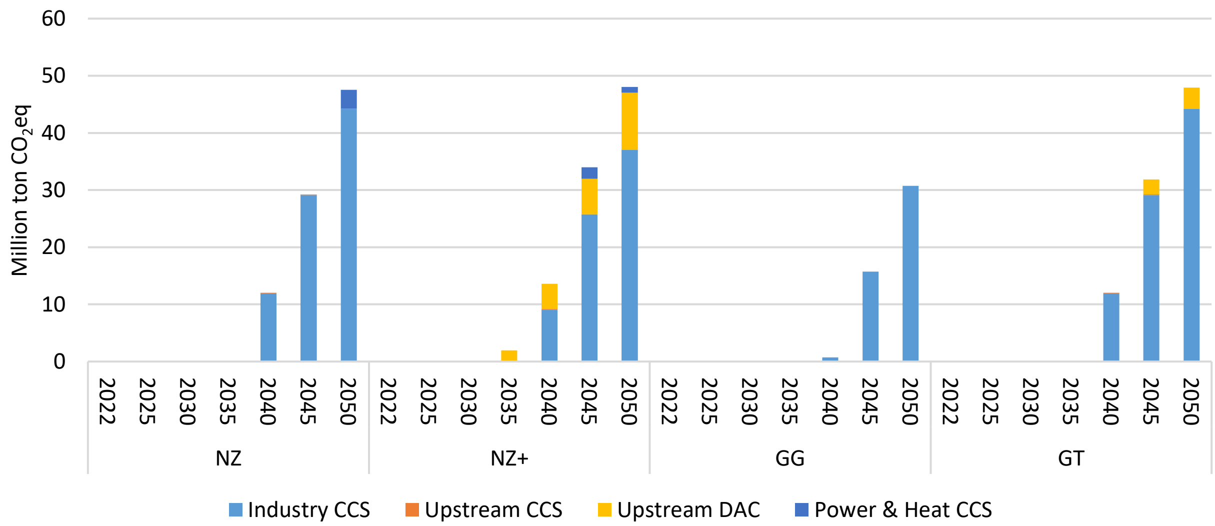


Figure 66: Carbon capture, storage and utilisation for main variation scenarios

Total system costs

The total system cost for the NZ+ scenario is higher compared to the NZ scenario, because of the stricter constraint on GHG emission reduction by 2050, with consequent increase in CAPEX (Figure 70). In the GT scenario, investment in green technologies in the transport sector also results in higher CAPEX. In the GG scenario, the decrease in the total system costs results from the assumed changes in the economic structure, with a shift from industry-based to more services-based economy.

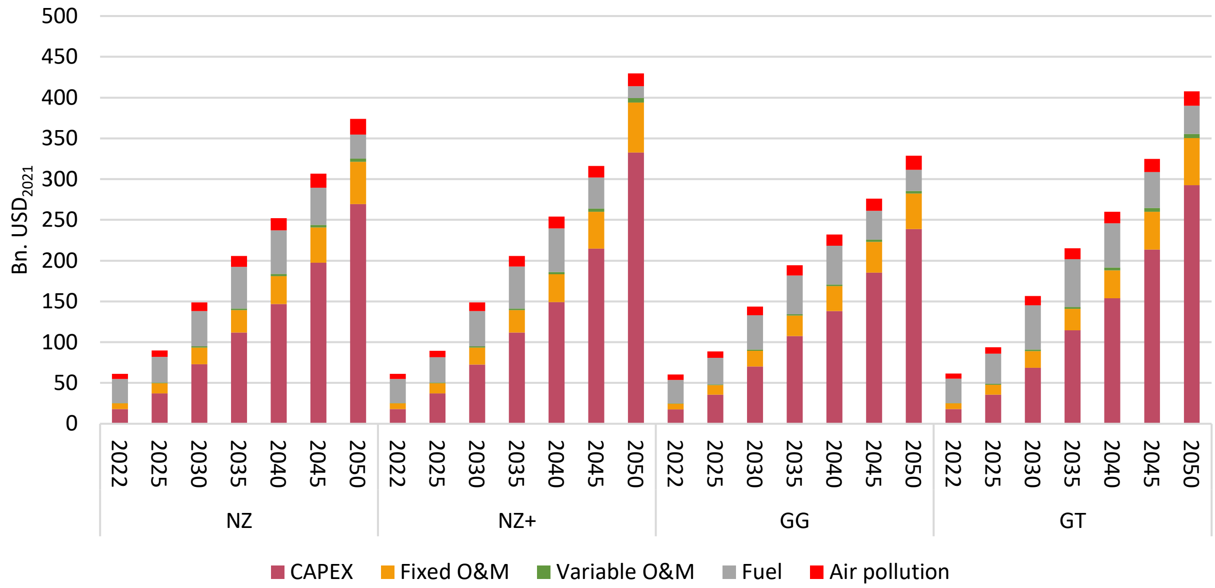


Figure 67: Total system costs divided in CAPEX, fixed and variable O&M, fuel costs and air pollution costs for main variation scenarios.

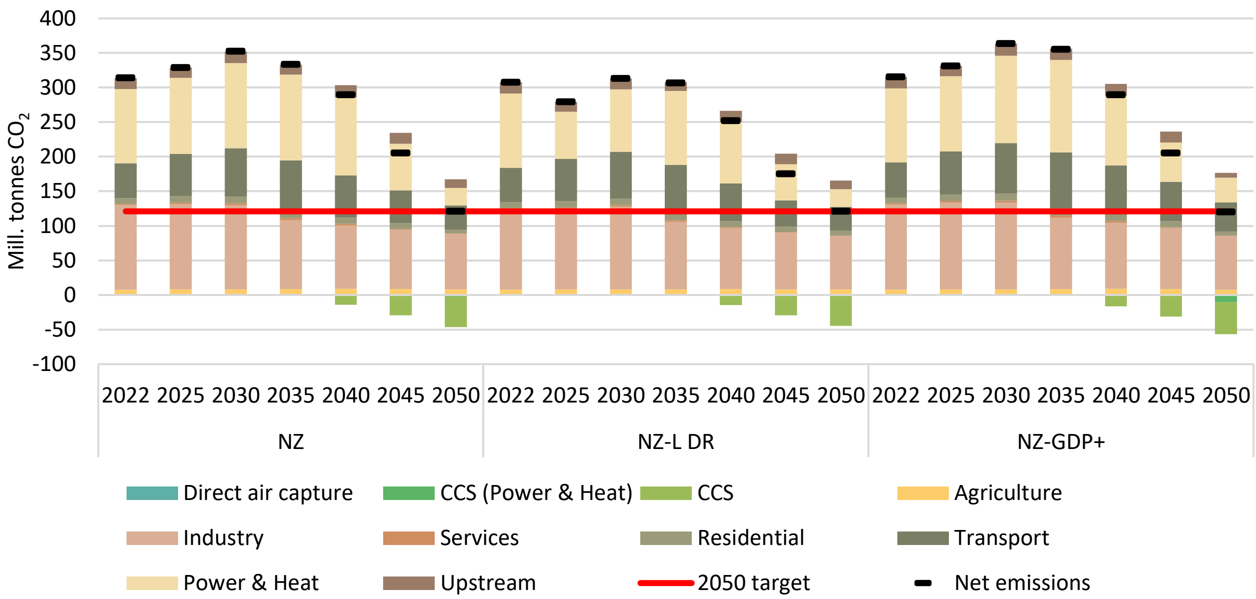


Figure 68: Carbon emissions by sectors for sensitivity scenarios.

The total primary energy supply increases by 7% in 2030 and 23% in 2050 the NZ-GDP+ scenario compared to NZ (Figure 69). This is in order, to fulfil the higher energy demand corresponding to the higher economic growth.

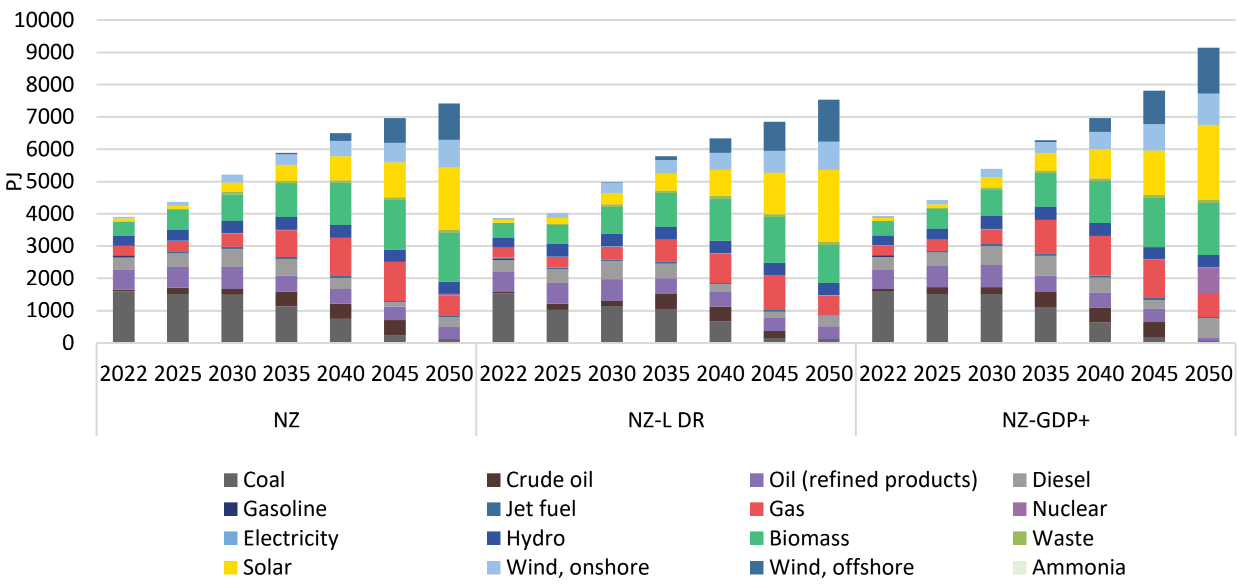


Figure 69: Total primary energy supply by fuels for sensitivity scenarios.

With a lower discount rate, the total system cost will reduce, with the largest reductions to be found in the future years compared to the recent years (Figure 70). In the NZ-GDP+ scenario, as a consequence of increasing the GDP growth rate by 1%, the total system cost increases by 5.6% in 2030, 12.7% in 2040, 25.6% in 2050, compared to the NZ scenario. The increase rate of CAPEX is higher compared to the increase rate of the total system cost, corresponding to 6.2% in 2030, 16.7% in 2040, 26.1% in 2050.

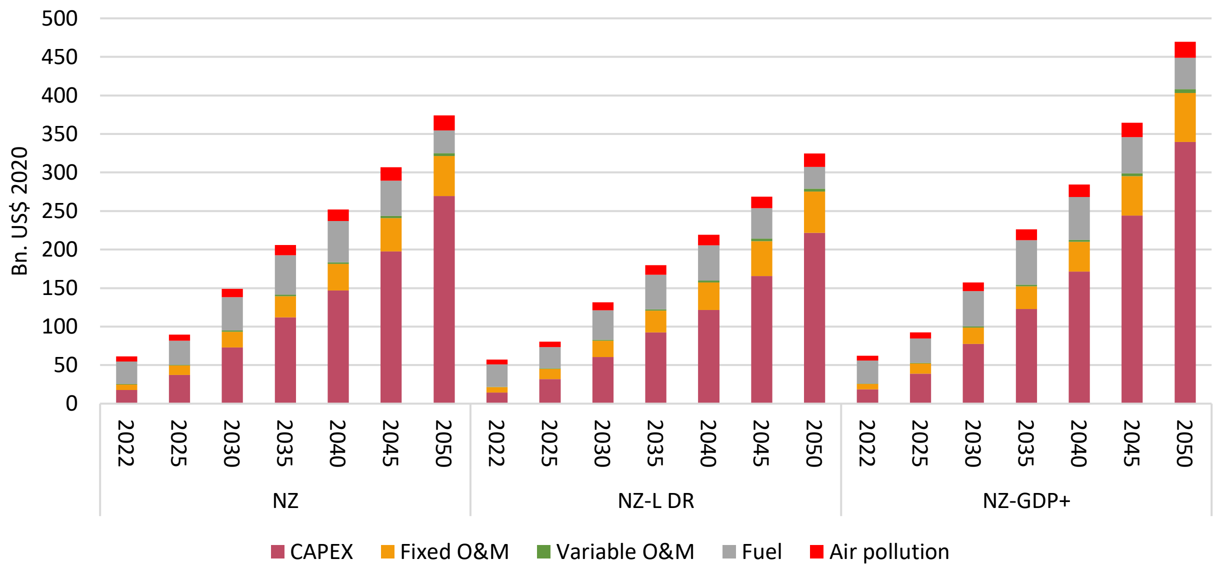


Figure 70: Total system costs divided in CAPEX, fixed and variable O&M, fuel and air pollution for sensitivity scenarios

End-Use sector results from TIMES

Final energy consumption

Figure 71 presents the TFEC by fuel for the NZ scenario variations. In the NZ+ scenario, due to the tight constraint on emissions, the share of renewable energy increases over time.

In the GG scenario, the TFEC reduces by 4% in 2030, 11% in 2040, 17% in 2050 compared to NZ, because of the assumed change in the economic structure. The share of energy consumed in industry reduces, reaching 52% in 2050, as compared to 61% in the NZ scenario. In the GT scenario, the TFEC reduces compared to BSL, highest at 7% in 2040. The consumption of electricity is increased from 3% to 8%, while the consumption of RE-diesel and RE-gasoline increases by 3 to 4 times, as a result of the green transport policies.

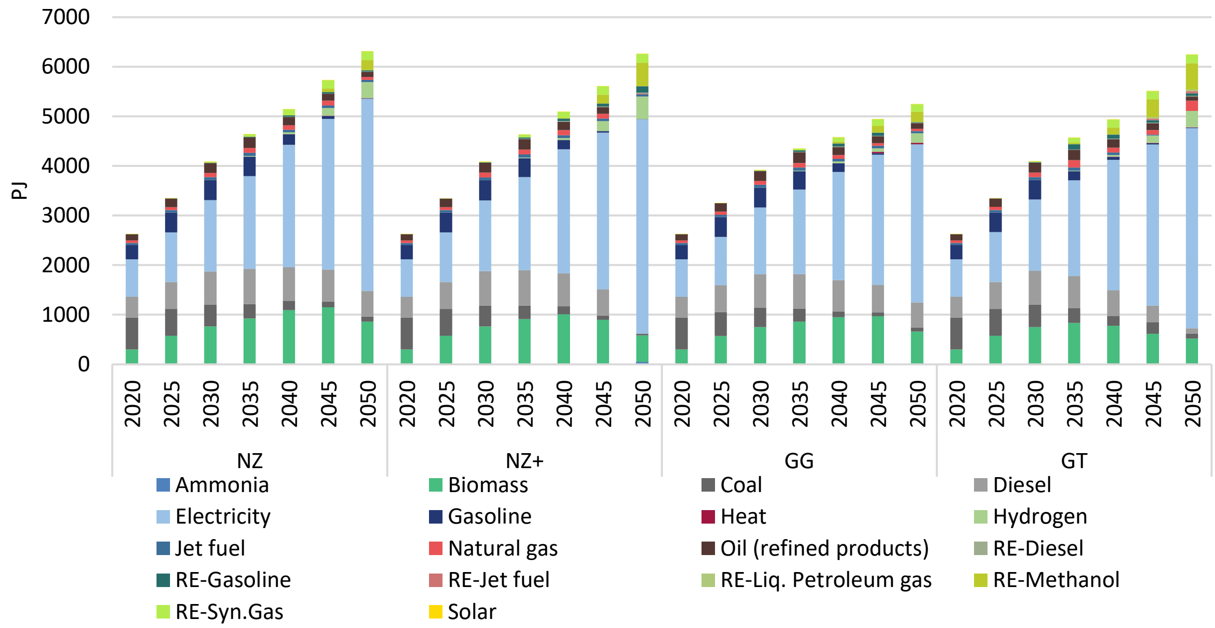


Figure 71: TFEC by fuel type in Net-Zero main variation scenarios, TIMES [PJ]

Hydrogen consumption

Figure 72 presents the hydrogen consumption by end-use sectors for the NZ scenario variations. Lower hydrogen is required in the GG scenario compared to NZ in 2045-2050, while it can be seen that hydrogen is used also in agriculture in the NZ+ scenario in 2050, to comply with the more ambitious emission reduction target.

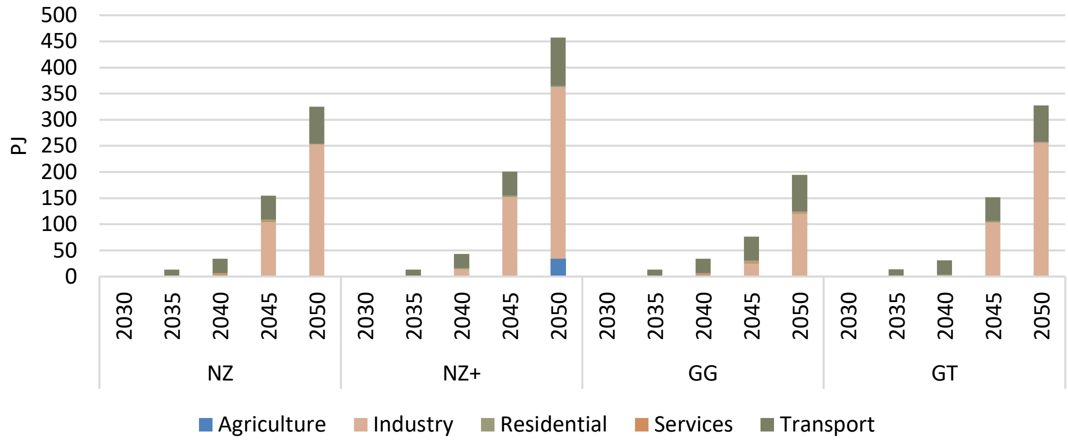


Figure 72: Final H_2 consumption by sector, TIMES [PJ]

Agriculture

Figure 73 presents the final energy consumption in the agriculture sector for the NZ scenario variations. In the NZ+ scenario, no diesel or gasoline are used in 2050, which are replaced by only renewable energy, hydrogen and ammonia. In the GG scenario, a higher level of electrification is observed starting from 2045. In the GT scenario, biomass consumption is discontinued starting from 2040, which is 5 year earlier compared to the NZ scenario.

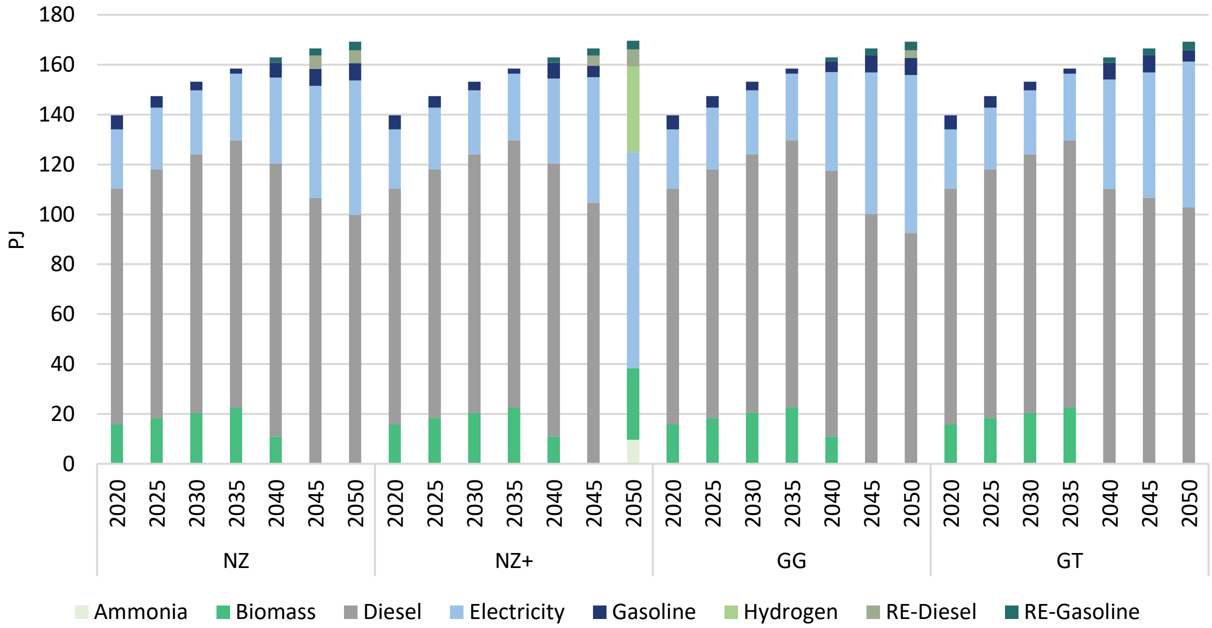


Figure 73: Final energy consumption in Agriculture, TIMES [PJ]

Industry

Figure 74 shows the final energy consumption in the industry sector by fuel type in the NZ scenario variations. The energy consumption in NZ+, GG and GT scenarios is lower compared to NZ and BSL scenarios, especially true for the GG scenario. The use of electricity increases particularly in NZ+ in the later years, when natural gas and other fossil fuels are completely phased out. As previously observed, energy demand is lower for the industry sector in the GG scenario.

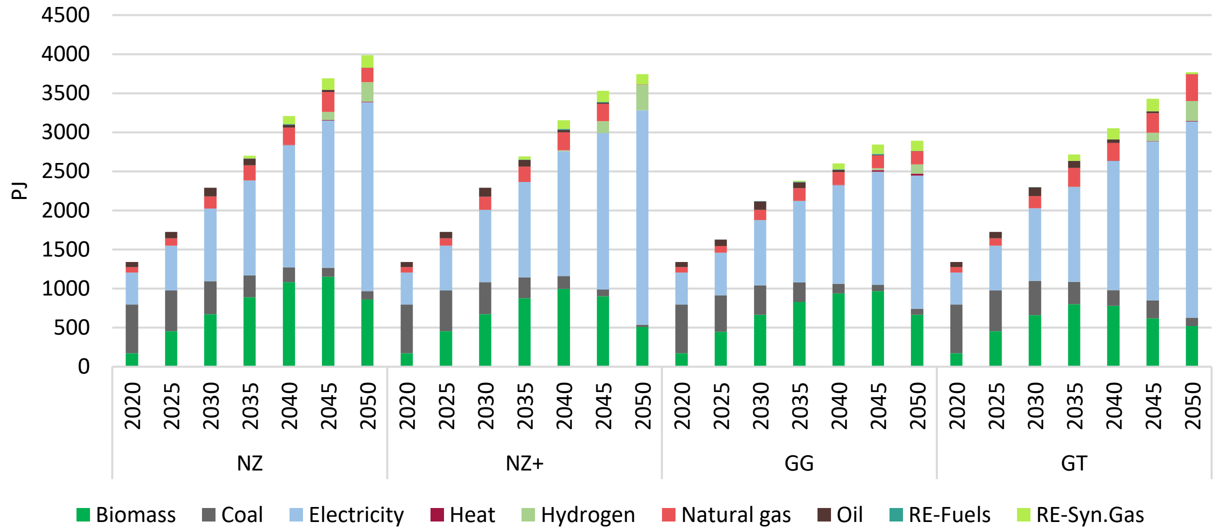


Figure 74: Final energy consumption in industry by fuel type of variation scenarios, TIMES [PJ]

Residential

Figure 75 presents the final energy consumption in the residential sector for the NZ scenario variations. In the NZ+ scenario, electricity accounts for 99.6% in 2050, while in the GT scenario, apart from electricity as key fuel, RE-Liquid Petroleum gas also appears from 2045, and accounts for 4.4% of the final energy consumption in 2050.

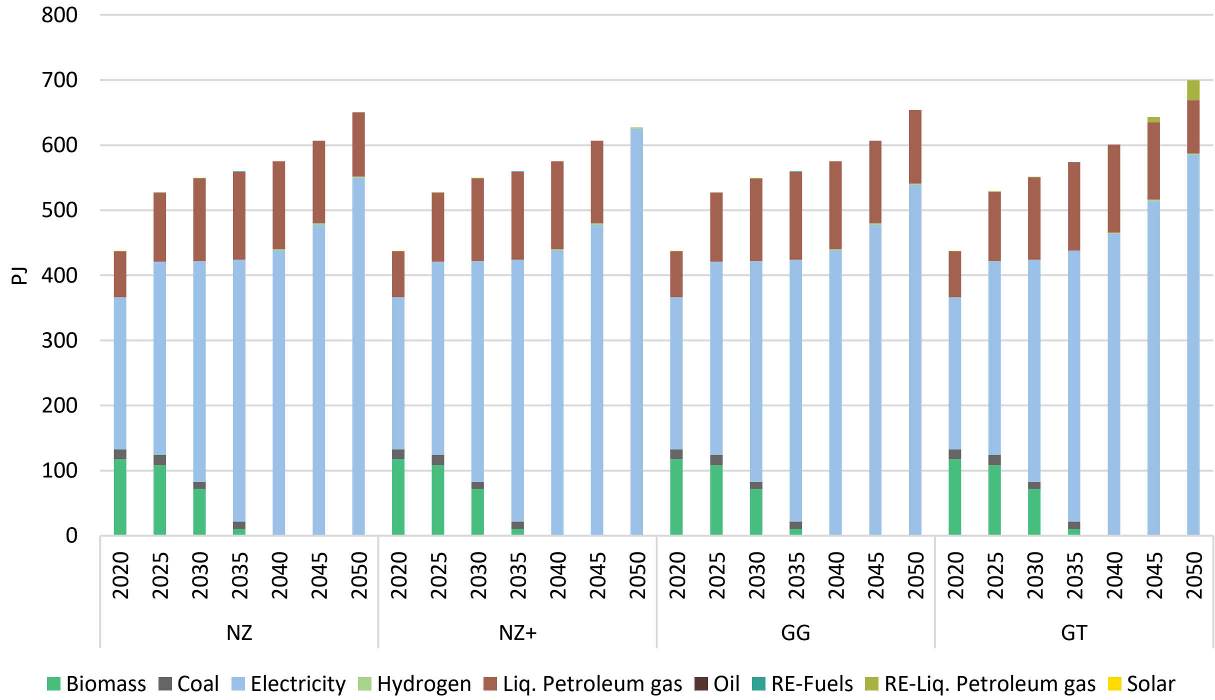


Figure 75: Final energy consumption in Residential, of variation scenarios TIMES [PJ]

Service

Figure 76 presents the final energy consumption in the service sector for the NZ scenario variations. Due to the sectoral structure change from industry to service sector, the FEC in the GG scenario increases by 4.6%, 7.5% and 11.6% in 2040, 2045, 2050 respectively compared to the NZ scenario. The share of electricity in the NZ+ scenario increases compared to the NZ scenario, reaching 98% in 2050.

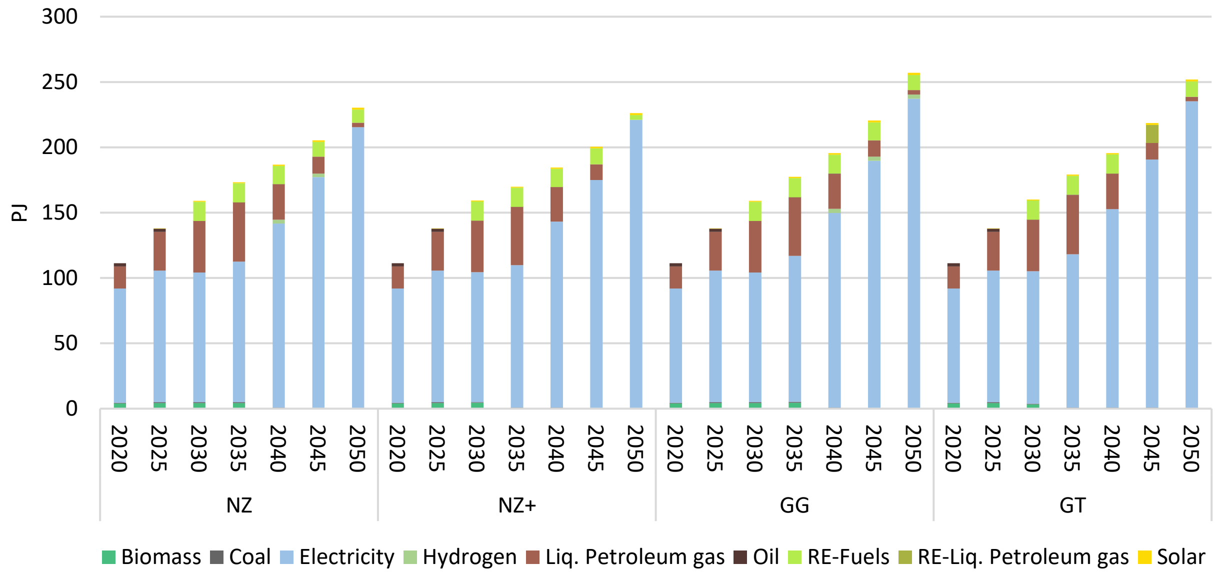


Figure 76: Final energy consumption in services of variation scenarios, TIMES [PJ]

Transport

The final energy consumption by fuel type for the transport sector in the NZ scenario variations is shown in Figure 77. While there are no large variations between NZ and GG scenarios, both NZ+ and GT scenarios require a higher degree of electrification and use of RE-fuels by 2050, with diesel and other oil products progressively phased out. RE-fuels are needed to decarbonize freight trucks, aviation and navigation segment and cover a larger use of RE-methanol, as well as shares of ammonia and RE-jet fuel for the NZ+ and GT scenarios respectively in 2050 (Figure 78, Figure 79 and Figure 80).

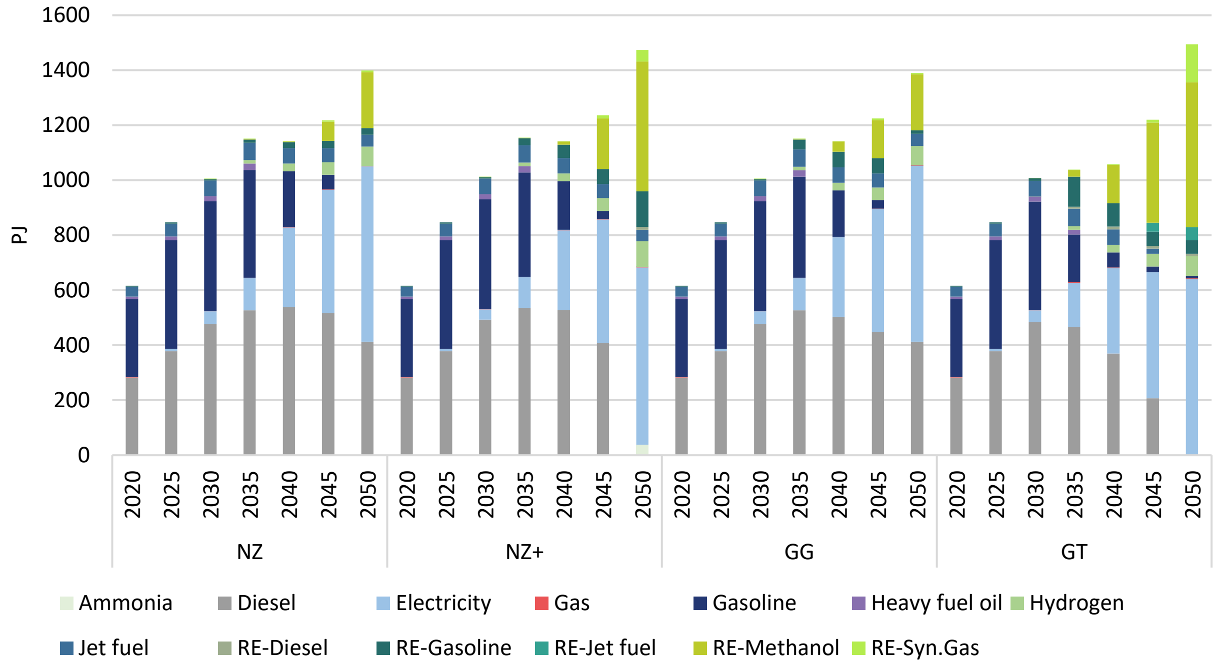


Figure 77: Final energy consumption in transport of variation scenarios, TIMES [PJ]

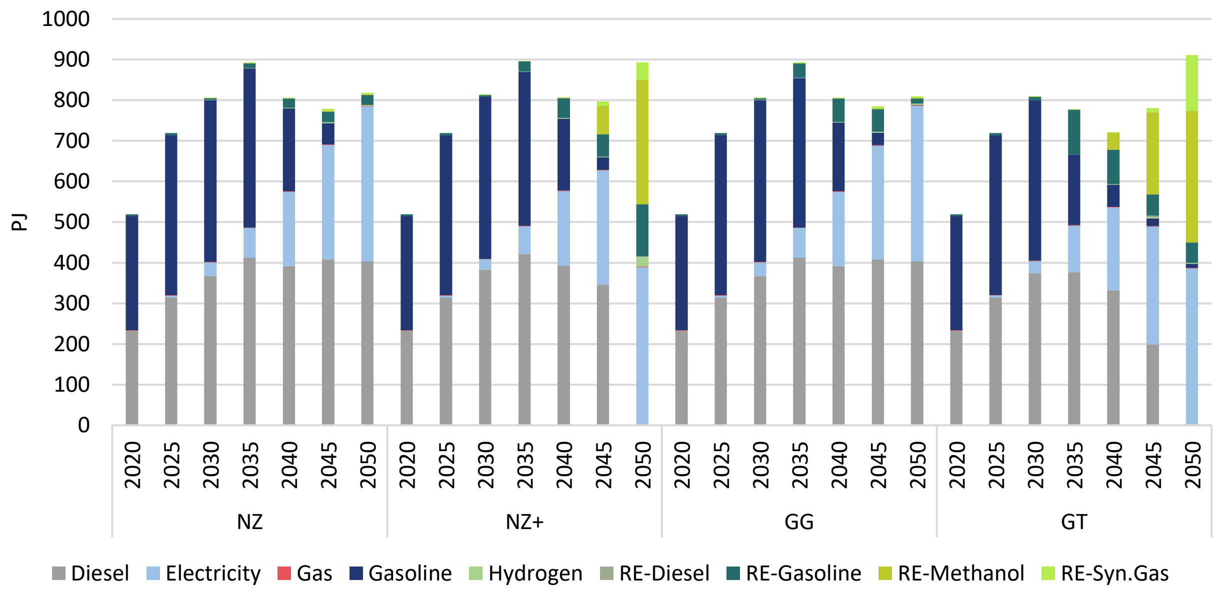


Figure 78: Road transport fuel consumption of variation scenarios, TIMES [PJ]

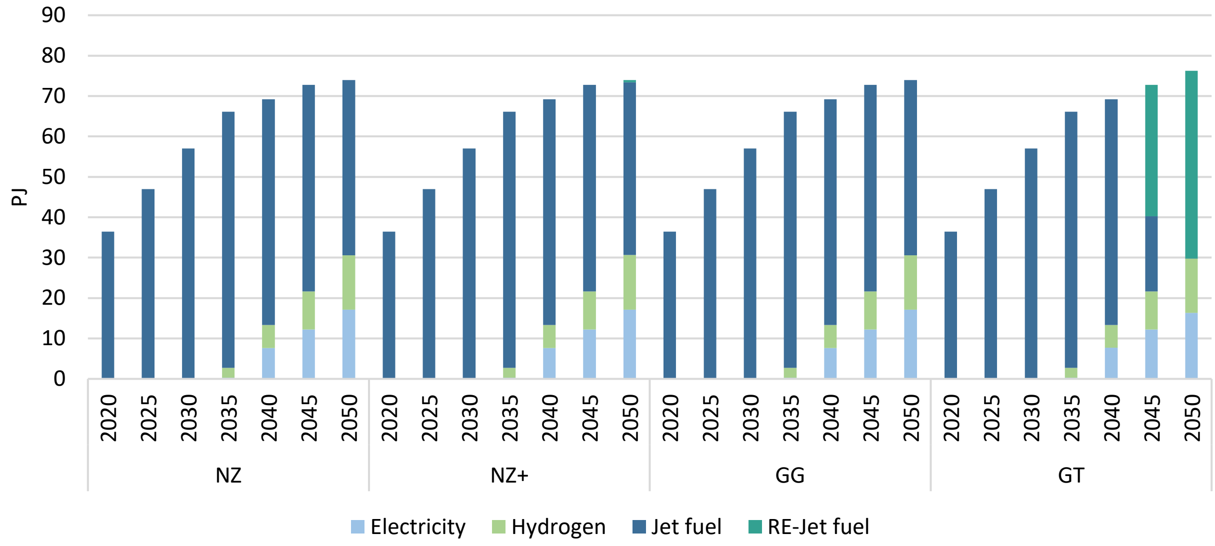


Figure 79: Aviation fuel consumption of variation scenarios, TIMES [PJ]

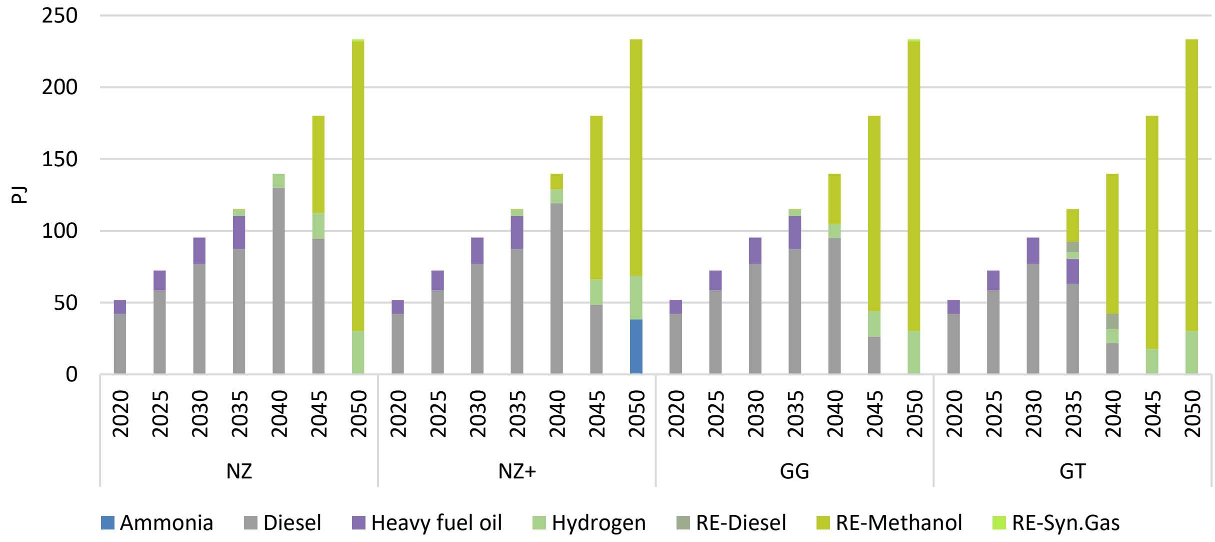


Figure 80: Navigation fuel consumption of variation scenarios, TIMES [PJ]

Power system results

Net-Zero main variation scenarios

The input parameters from the TIMES model for main variation scenarios (Net-Zero+, Green Growth, Green Transport) include: power demand, e-fuel demand, biomass allocation and CO_2 emissions.

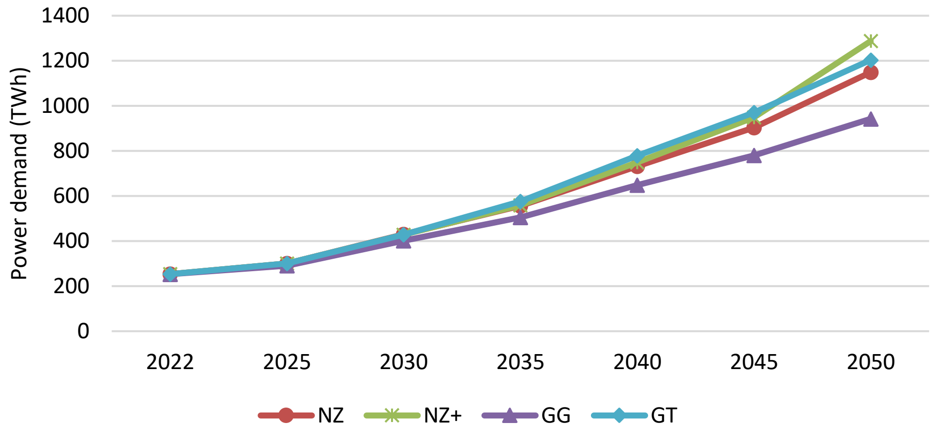


Figure 81: Power demand from TIMES for main variation scenarios.

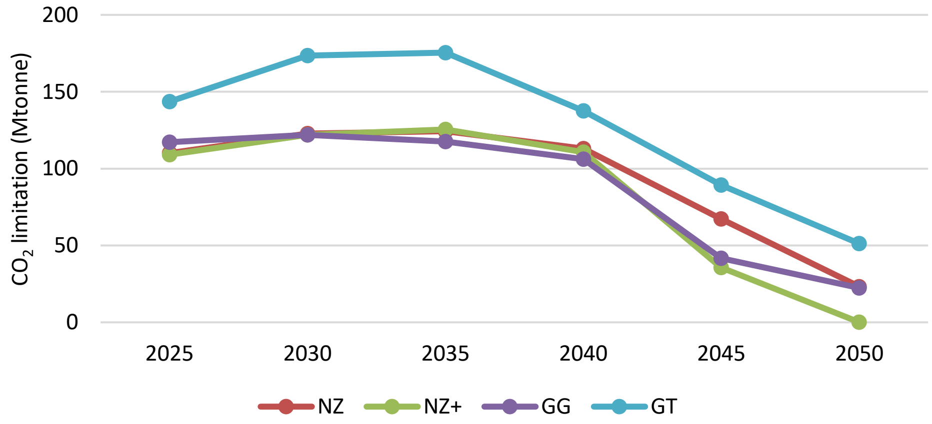


Figure 82: CO_2 limitation from TIMES for main variation scenarios.

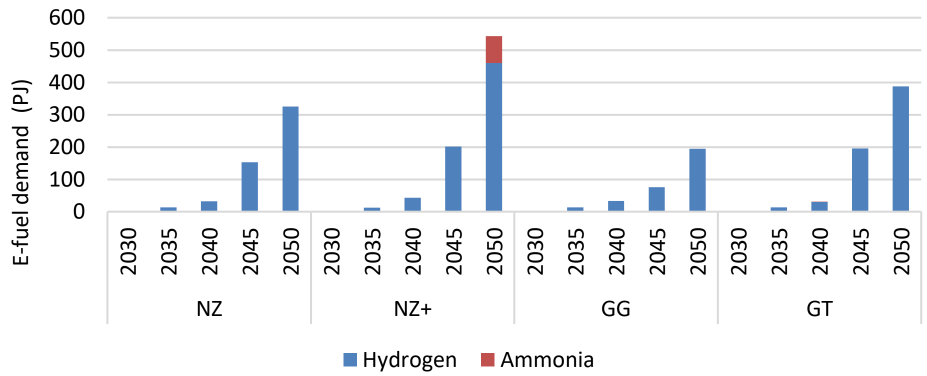


Figure 83: E-fuel demand from TIMES for main variation scenarios.

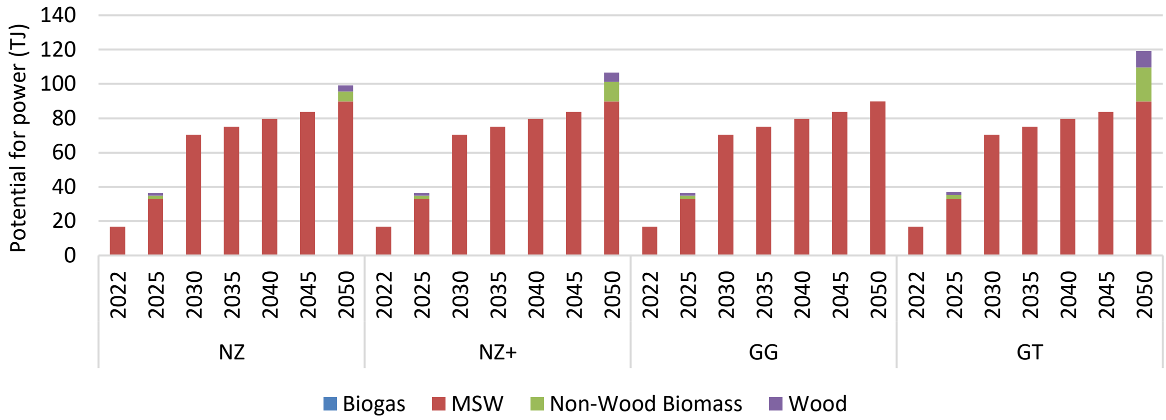


Figure 84: Potential of Biofuel for power sector from TIMES for main variation scenarios.

Based on input data from TIMES, Net-Zero+ scenario has the highest electricity demand and e-fuel demand while the lowest ones in the Green Growth scenario.

The results of Balmorel model for main variation scenarios are shown in Figure 85 - Figure 89.

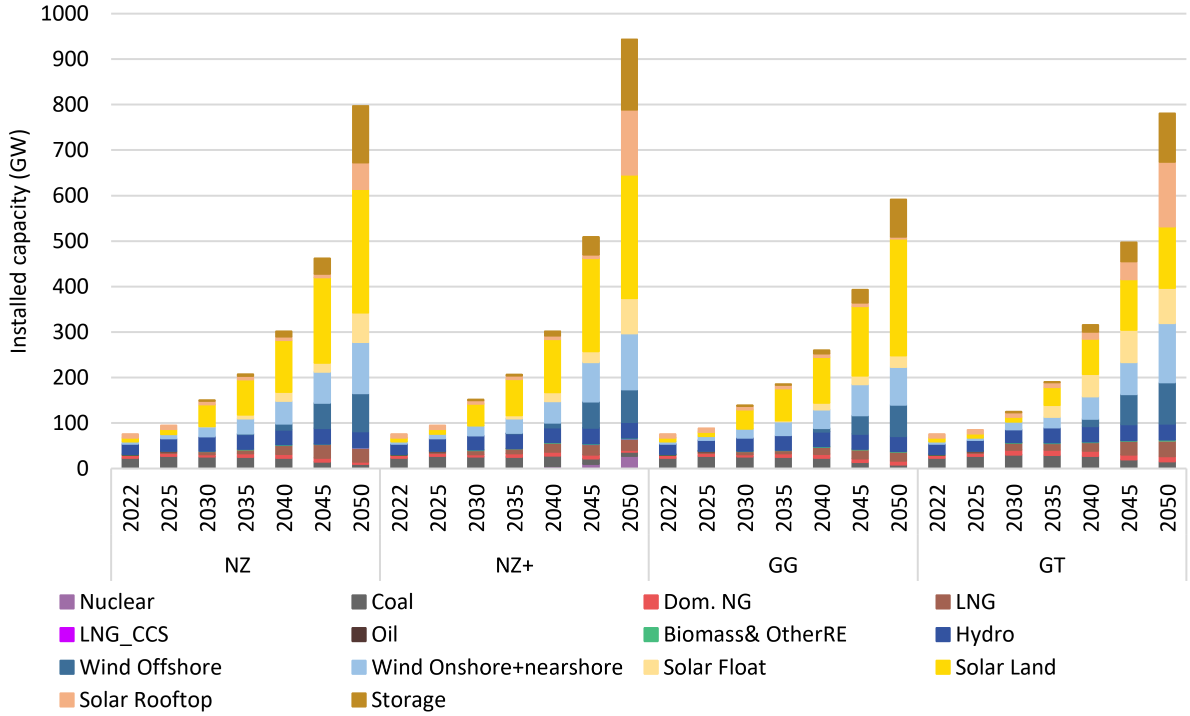


Figure 85: The installed capacity of main variation scenarios comparing with the NZ scenario. *Fixed import from neighbouring countries is not included in figure.*

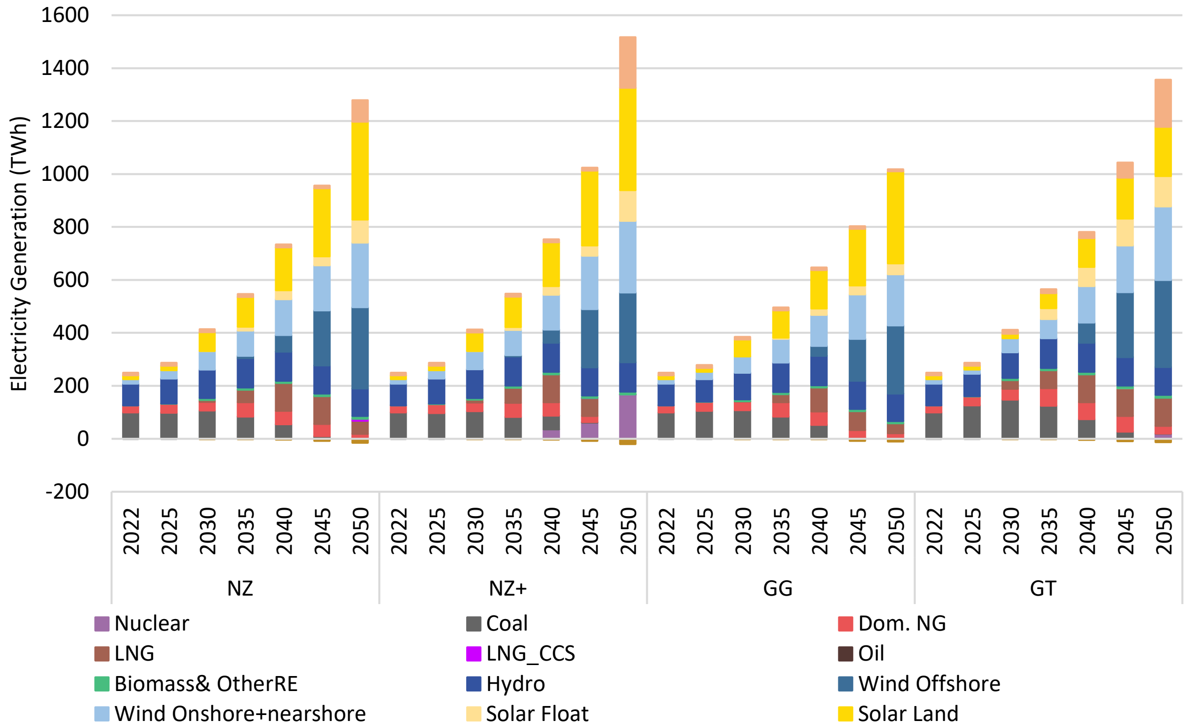


Figure 86: The electricity generation of main variation scenarios comparing with the NZ scenario. Fixed import from neighbouring countries is not included in the figure.

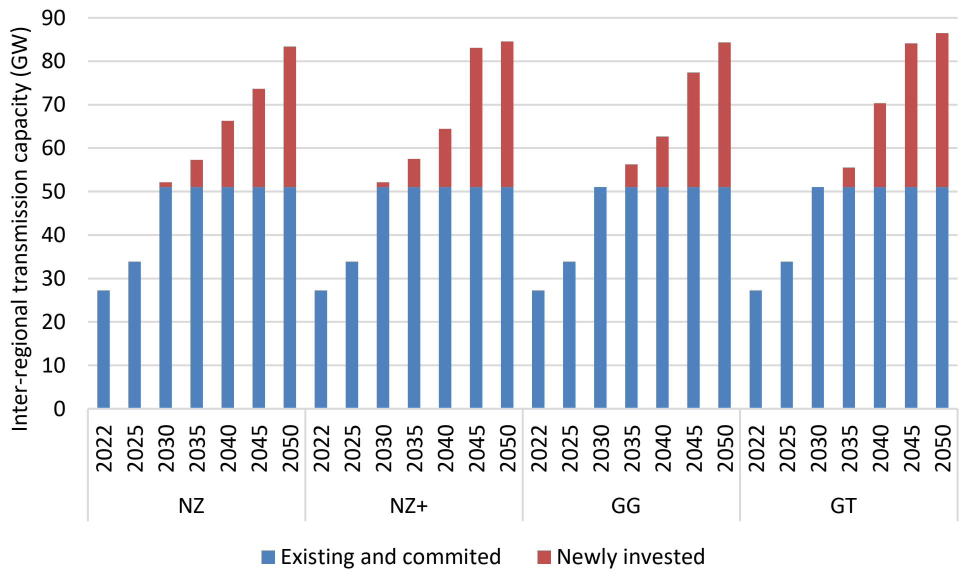


Figure 87: The inter-regional transmission capacity of main variation scenarios comparing with the NZ scenario.

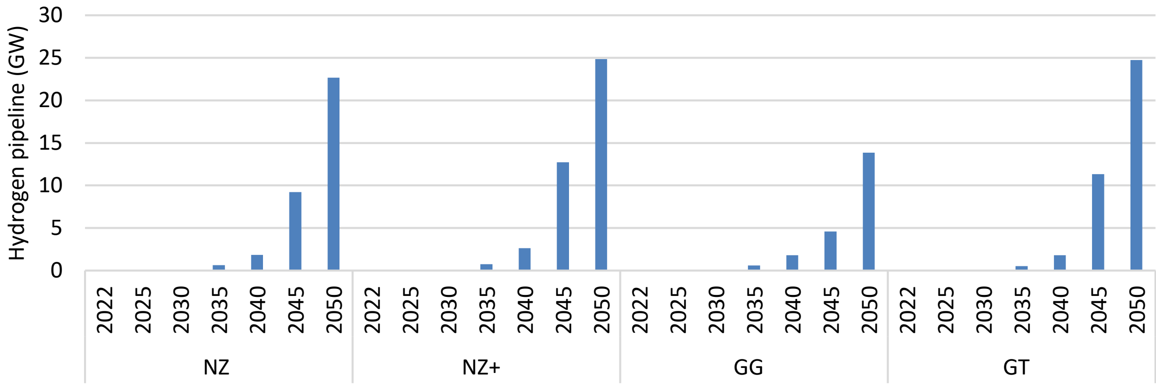


Figure 88: The hydrogen pipeline capacity of main variation scenarios comparing with the NZ scenario.

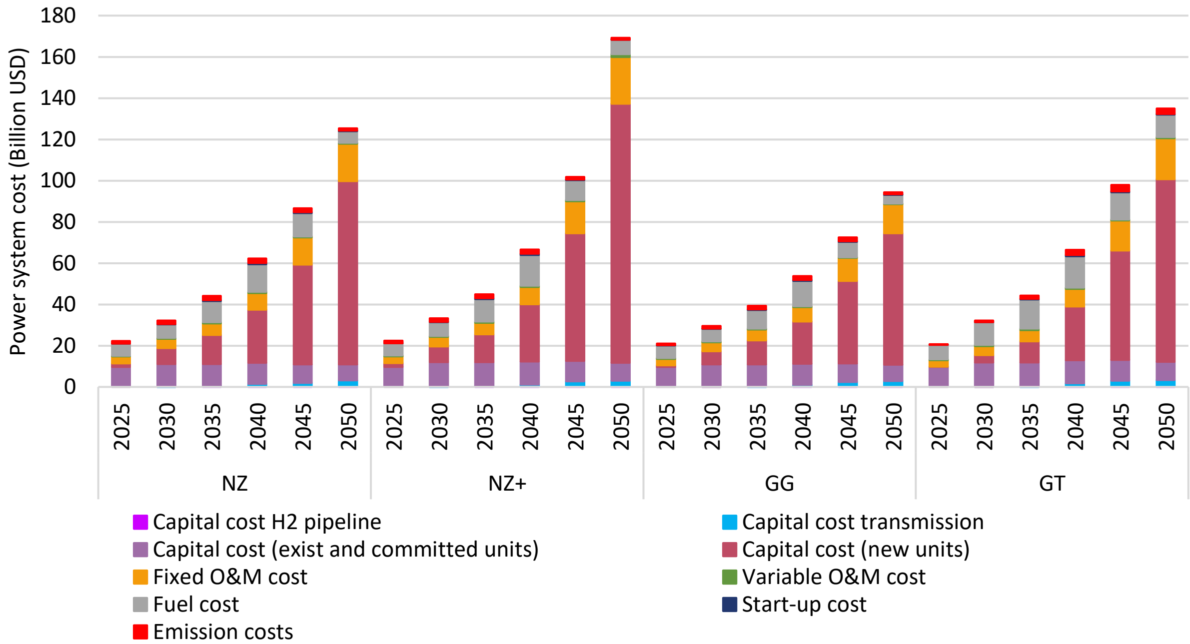


Figure 89: Power system cost of main variation scenarios comparing with the NZ scenario.

Up to 2045 the NZ+ scenario has power demand and a CO_2 emission limit are close to that of the NZ scenario. However, by 2050, the NZ+ scenario has a higher demand of about 179 TWh more and an energy related CO_2 emission decrease to zero. Thus, the power source capacity will mainly change in 2045 and 2050. In 2050, the NZ+ scenario includes 27.5 GW of nuclear power, an increase of 26 GW when compared to the NZ scenario. In further comparison with NZ scenario, in 2050 the NZ+ scenario saw an increase of 11 GW onshore wind, 97 GW solar PV and 30 GW storage source while also depicting a decrease of 7 GW LNG and 12 GW offshore wind. Renewable energy share of NZ+ is lower than NZ in 2050 due to the development of nuclear which replaces LNG and offshore wind. However, this scenario develops the whole potential of solar PV in 2050. The total cost of the electricity system of NZ+ in 2050 will increase by 35% compared to NZ scenario.

With the GG scenario, the power demand will be lower than the NZ scenario (in 2050, the difference is about 207 TWh). The CO_2 emission limit is also lower than Net-Zero, but not too large. Therefore, LNG, wind, solar PV and battery power sources tend to decrease compared to the NZ scenario since 2030. In 2050, nuclear does not appear in the GG scenario, while LNG decreases by 11 GW, offshore wind decreases by 15 GW, onshore wind decreases by 29 GW, solar PV reduce with 109 GW and storage reduces with 42 GW. The renewable energy share of GG is nearly equal with NZ. Due to reducing the size of the power source from lower load demand, the total cost of the electricity system will decrease compared to the NZ scenario (about 25% in 2050).

The GT scenario has higher power demand than NZ scenario, in 2050, the demand is about 54 TWh higher, due to the transport sector's switch to electricity. CO_2 emission limitation of GT is higher than NZ scenarios in all periods of 2025-2050 (about 28-50 million tons/year). In 2030, renewable energy sources development in GT are limited according to the development scale of PDP VIII as the Baseline scenarios, so solar power does not grow more than 21GW. In 2050, the capacity of nuclear, coal and gas power sources in GT scenario is higher than NZ scenario (an increase 2GW of nuclear, 3.8 GW of coal, 6 GW of domestic gas, 4.6 GW of LNG). The increase of thermal power capacity in GT due to this scenario do not permit decommission at any time as NZ scenario, thermal power plants only stop operating at the end of their economic life. The proportion of renewable energy (including hydropower) in GT scenario will reach 88% in 2050, lower than NZ scenario. Because potential of land solar PV in GT scenario is equal with BSL and only half of the NZ, so in GT scenario the installed capacity of wind increases with 24 GW, roof top solar PV and floating solar PV increase 95 GW comparing with NZ scenario. At the same time, all potential of solar PV also will be used in 2050 in the GT scenario. The total electric system cost of the GT scenario will increase with about 8% by 2050 compared to the NZ scenario.

Sensitivity scenarios

These sensitivity scenarios are calculated by the TIMES and Balmorel model: NZ-L DR, NZ-GDP+, BSL-H Fuel, BSL-L Fuel, BSL-EE+. The input data linking from TIMES for these scenarios are shown in Figure 90 - Figure 93.

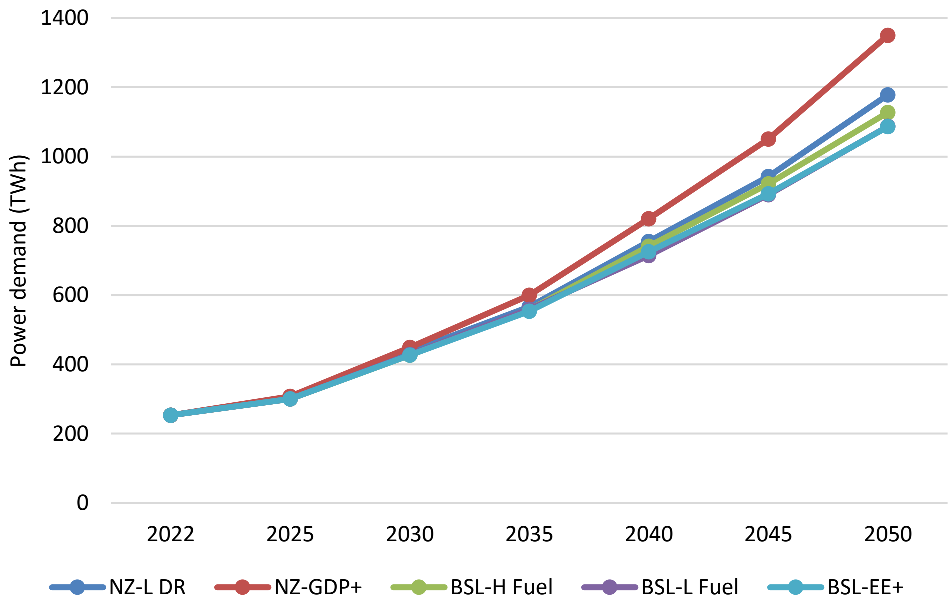


Figure 90: Power demand from TIMES for sensitivity scenarios.

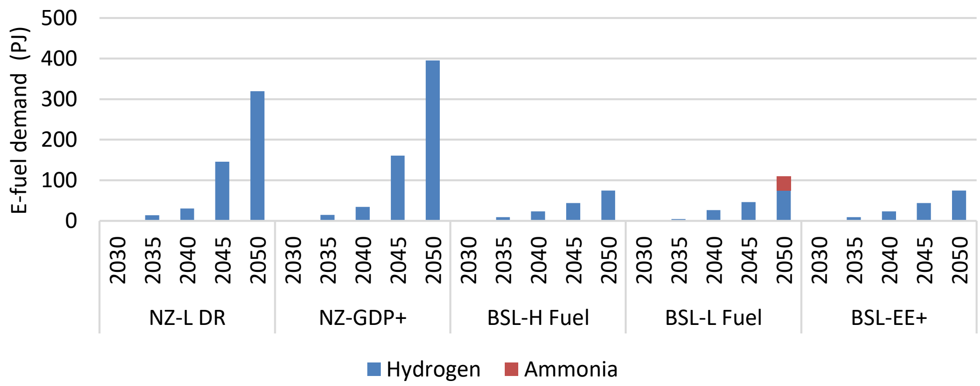


Figure 91: E-fuel demand from TIMES for sensitivity scenarios.

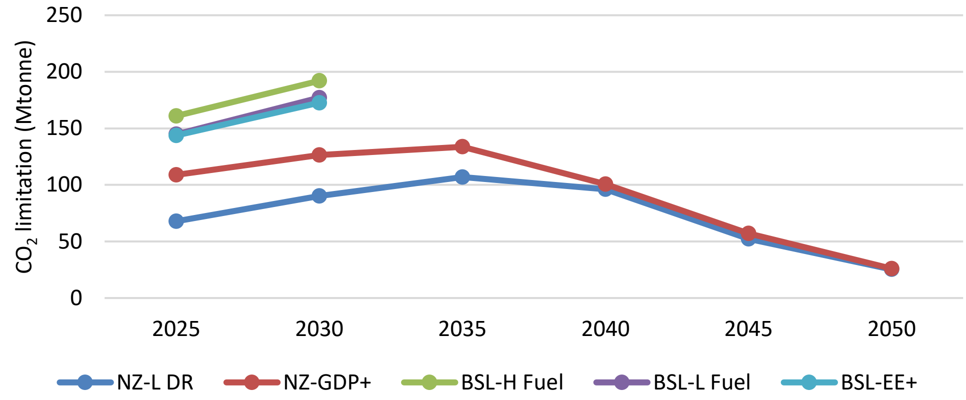


Figure 92: CO_2 limitation from TIMES for sensitivity scenarios.

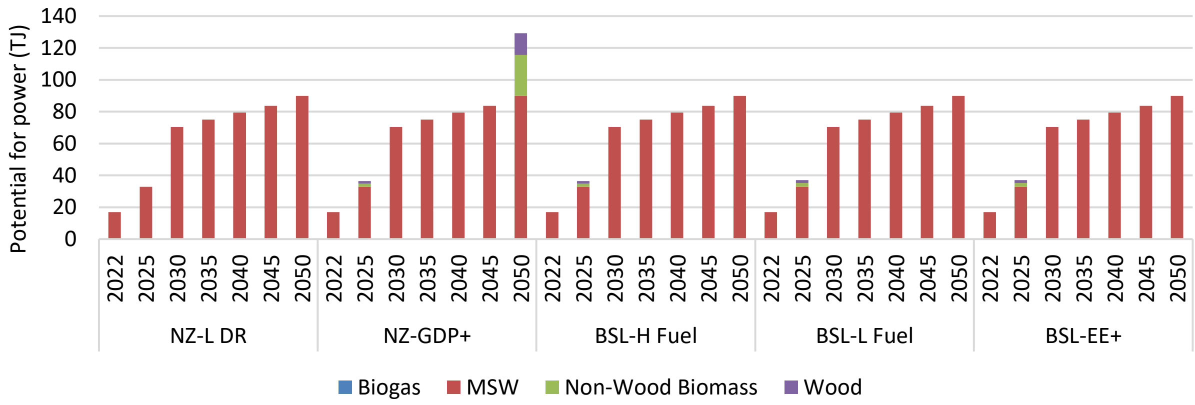


Figure 93: Potential of Biofuel for power sector from TIMES for sensitivity scenarios.

Comparing with NZ scenario, NZ-L DR scenario has higher power demand and lower e-fuel demand but the difference is not much (about 29 TWh of power demand in 2050). While the NZ-GDP+ scenario has a much higher power demand and e-fuel demand than NZ scenario (higher than about 201 TWh and 70 TJ in 2050). CO_2 limitations in NZ-GDP+ is not much different compared with the NZ scenario. While NZ-L DR has CO2 limitation in 2025-2045much lower than NZ scenario but in 2050 it is a little higher than NZ scenario.

The sensitivity scenarios of the Baseline scenario have input data from TIMES which are not much different with Baseline scenario. BSL-H Fuel has higher demand while BSL-L Fuel and BSL-EE+ have lower demand.

The Balmorel results for the NZ-GDP+ and NZ-L DR scenarios are shown in Figure 94 - Figure 97.

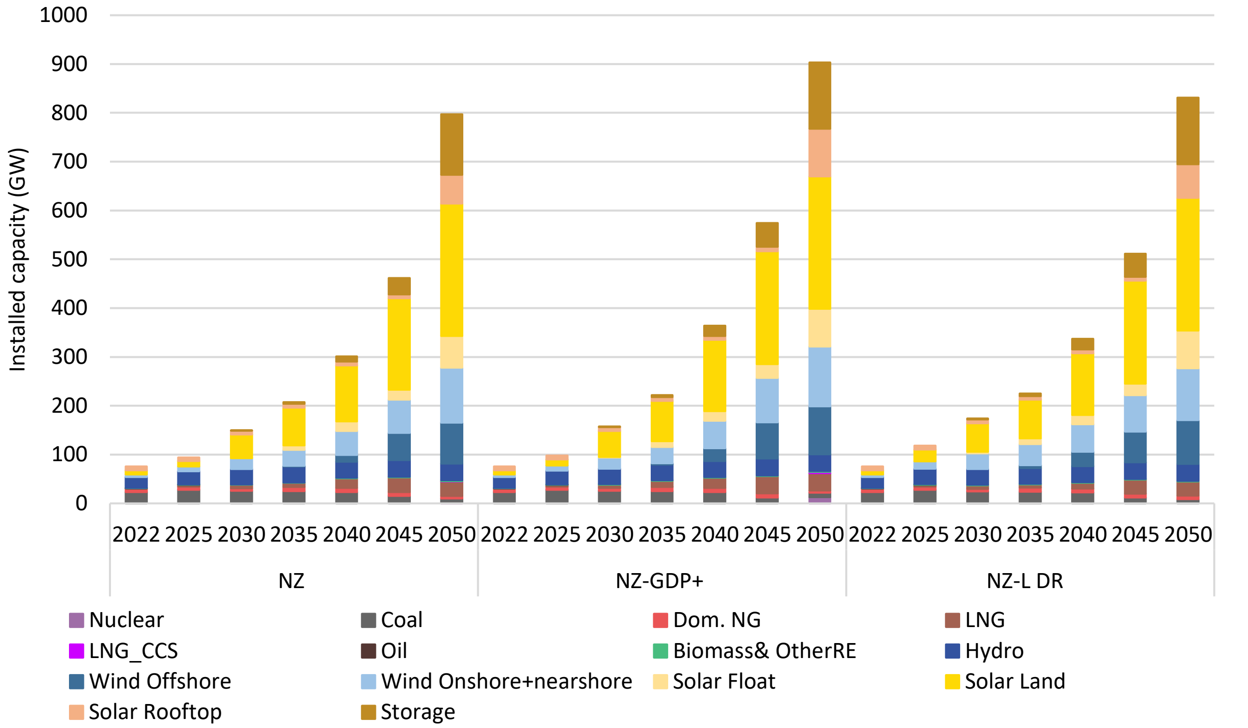


Figure 94: The installed capacity of NZ-GDP+ and NZ-L DR scenarios comparing with NZ scenario. Fixed import from neighbouring *countries is not included in the figure.*

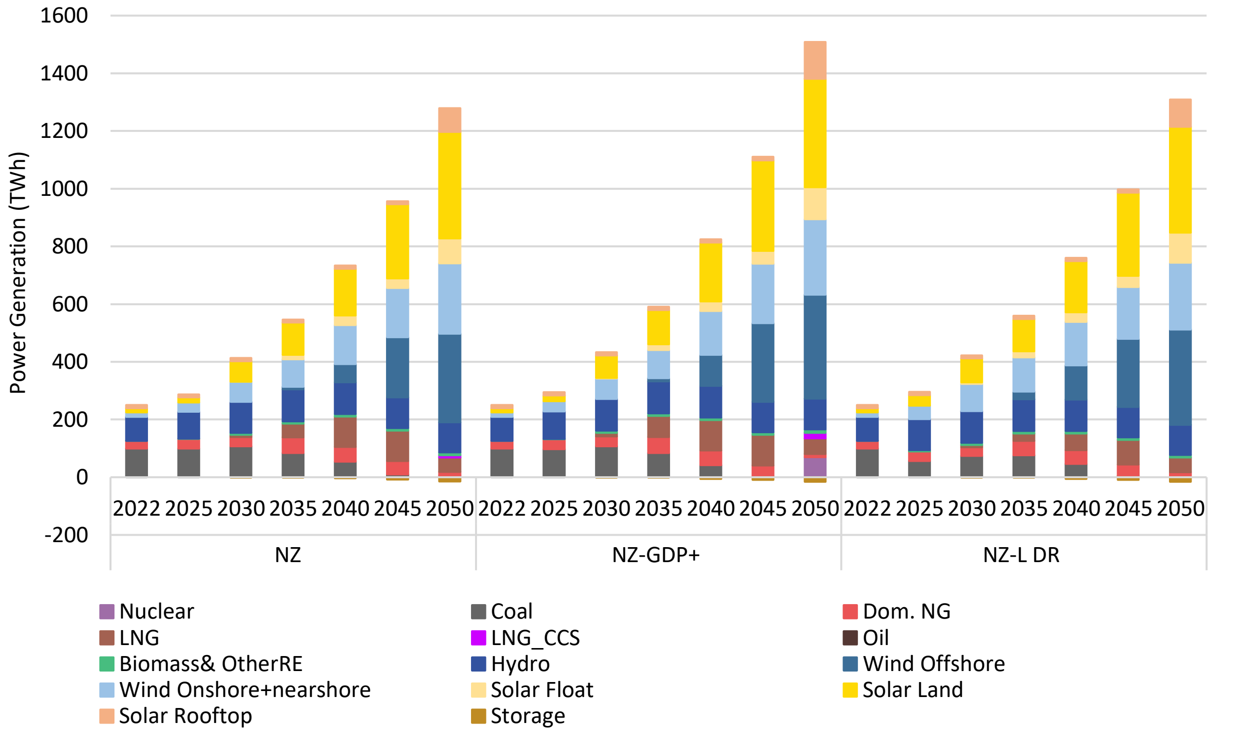


Figure 95: The generation of NZ-GDP+ and NZ-L DR scenarios comparing with the NZ scenario. Fixed import from neighbouring countries is not included in the figure.

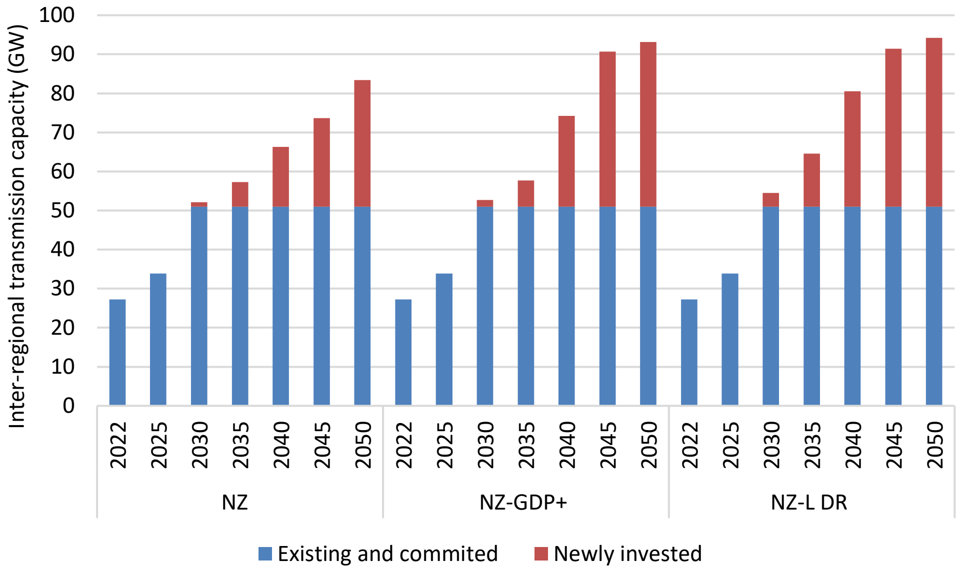


Figure 96: The inter-regional transmission capacity of NZ-GDP+ and NZ-L DR scenarios comparing with the NZ scenario.

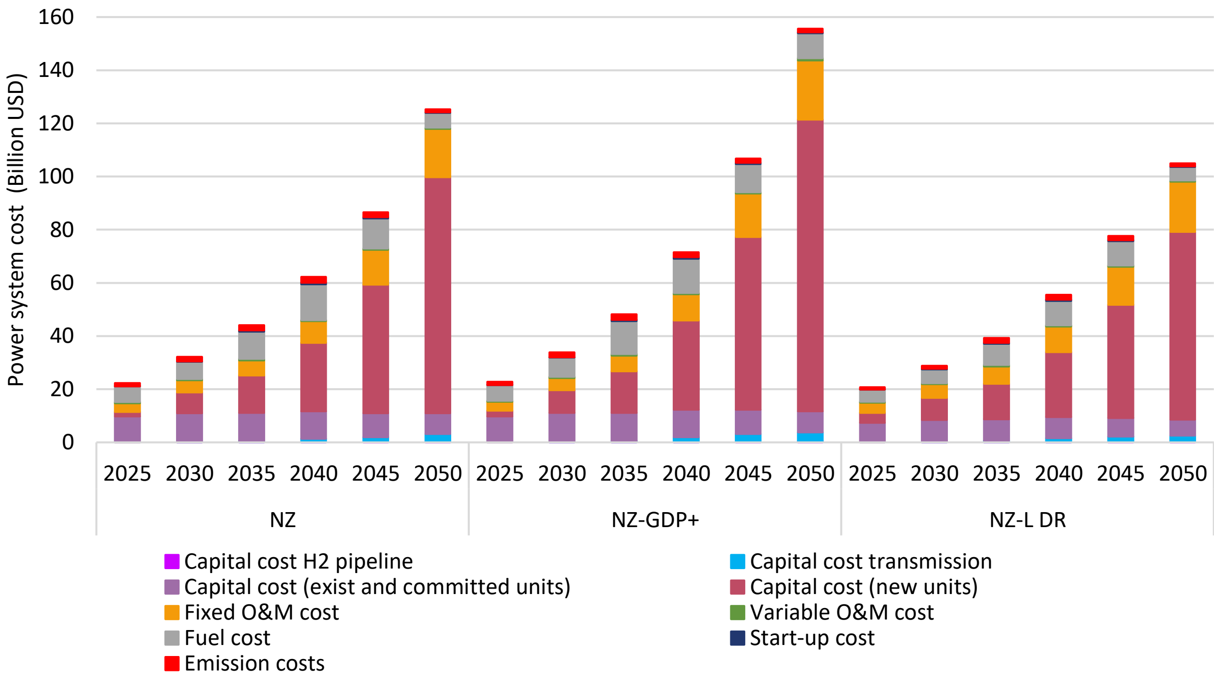


Figure 97: Power system cost of NZ-GDP+ and NZ-L DR scenarios comparing with the NZ scenario.

The NZ-GDP+ scenario has higher power demand than the NZ scenario, so the installed capacity of NZ-GDP+ are always higher than the NZ. The LNG source will be higher than the NZ scenario from 2035, wind, solar PV and battery power sources still tend to increase compared to NZ. In 2050, compared to the NZ scenario, nuclear increases by 11 GW, LNG increases 6 GW and LNG-CCS increases 1 GW. Furthermore, offshore wind increases by 15 GW , onshore wind increases by 10 GW, solar PV increases with 51 GW and storage increases by 12 GW. The total electric system cost of the NZ-GDP+ scenario will increase about 24% by 2050 compared to the NZ scenario.

In NZ-L DR scenario, with a lower interest rates (6.3%/year), the investment cost of power technology will be lower (especially the renewable energy sources) than NZ scenario. According to the results of TIMES, the CO_2 emissions limit in 2025-2045 are much lower than NZ but it is a little higher in 2050. Therefore, the size of the power source will change in the direction of increasing wind power, solar power and battery. In 2050, nuclear nearly does not appear in NZ-L DR, but the offshore wind will increase by 6 GW, solar PV increases 23 GW and storage increases 12 GW, but the onshore wind decreases 6 GW. The total cost of the whole power system in NZ-L DR scenario will decrease compared to the NZ scenario (about 16% in 2050).

The Balmorel results for the BSL-EE+, BSL-L Fuel, BSL-H Fuel scenarios are shown in Figure 98 - Figure 100.

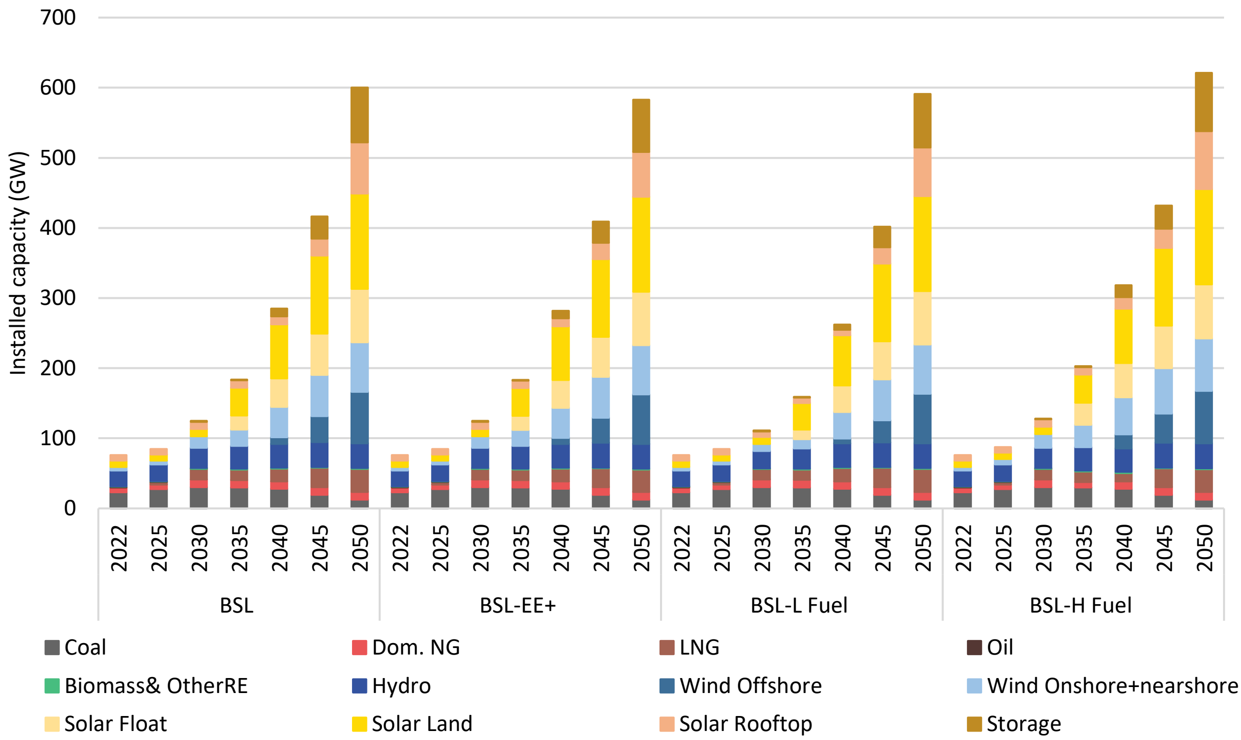


Figure 98: The installed power generation and storage capacity of BSL sensitivity scenarios comparing with BSL scenario. Fixed import from neighbouring countries is not included in figure.

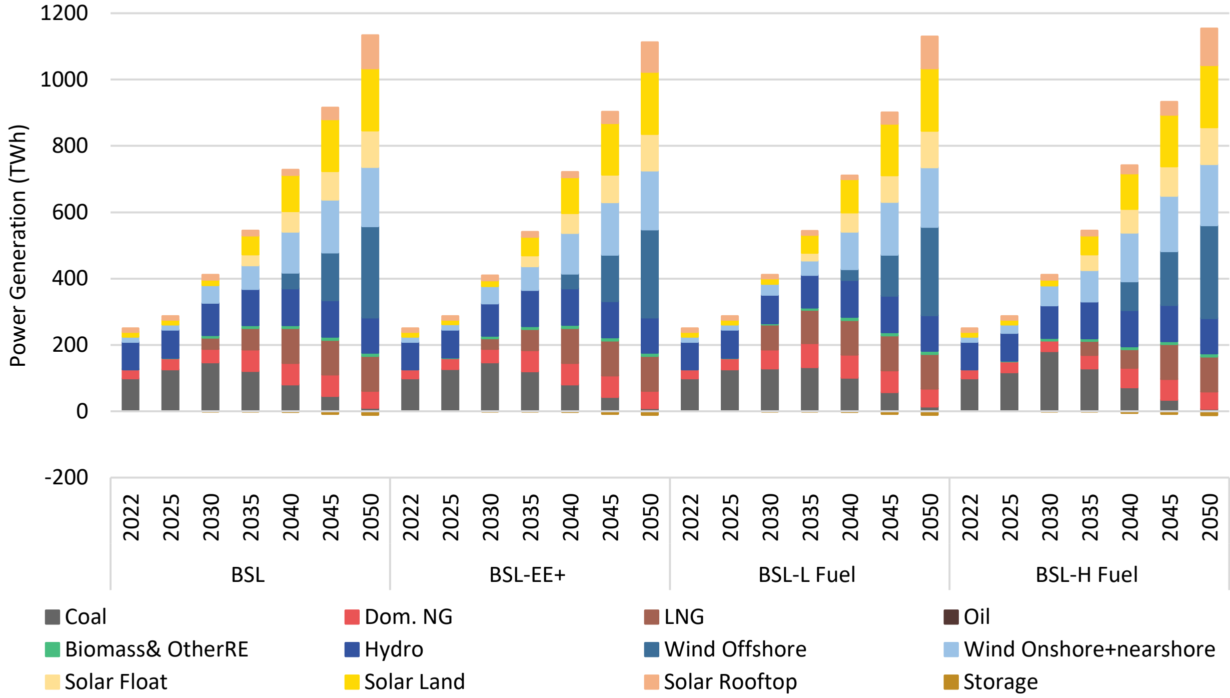


Figure 99: The power generation of BSL sensitivity scenarios comparing with BSL scenario. Fixed import from neighbouring countries is not included in the figure.

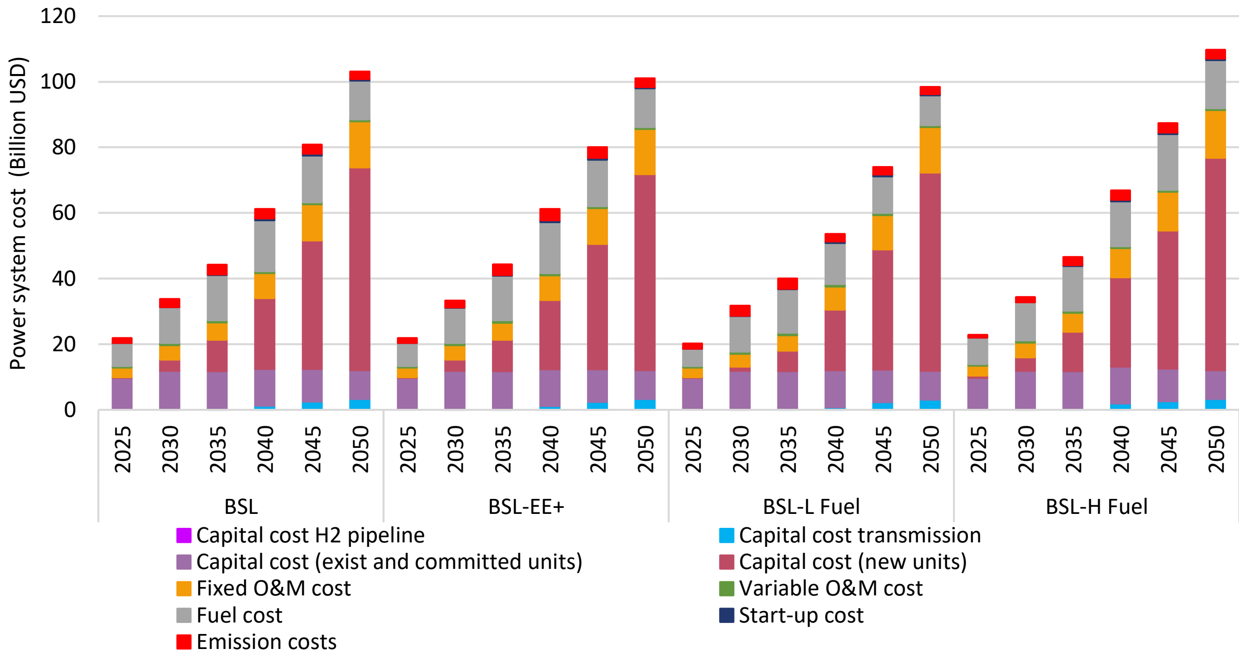


Figure 100: The power system cost of BSL sensitivity scenarios comparing with BSL scenario.

In BSL-EE+ scenario, the power demand is lower than in the BSL scenario but not much different, so the total installed capacity is lower than BSL. In 2050, the capacity of wind in BSL-EE+ will decrease by 3GW, solar PV decreases 9GW and storage capacity decreases by 4 GW compared to BSL. The total cost of BSL-EE+ scenario will decrease about 2% comparing with BSL scenario.

In the BSL-H Fuel scenario, the installed capacity of coal and gas in 2050 is nearly equal with the BSL scenario but the generation of coal and gas will reduce from 2025-2050. To replace coal and gas generation, wind, solar PV and battery power sources will increase in capacity and electricity output. In 2050, offshore wind will increase by 2 GW, onshore wind will increase by 4 GW, solar power will increase by 11 GW, and battery storage will increase by 5 GW. Total power system costs of BSL-H Fuel in 2050 will increase by about 6% compared to the BSL scenario.

In the BSL-L Fuel scenario, the installed capacity of coal and gas are nearly equal with the BSL scenario, but the generation of coal and gas will be higher in 2030-2050. While wind, solar and battery storage installed capacity will decrease from 2030 compared to BSL scenario. In 2050, offshore wind power will decrease by 3 GW, solar PV power will decrease by 4 GW, and batteries will decrease by 2 GW. Total power system costs of BSL-L Fuel in 2050 will decrease by about 5% compared to the BSL scenario. Lower fossil fuel prices do not have much of an impact on the structure of power sources and power system costs.

NZ-Reserve scenario

Reserve capacity in the power system includes operating reserve and planning reserve. Operating reserve will be considered to withstand unforeseen system load fluctuations, renewable energy resources fluctuations and sudden power outages of largest unit and transmission line. Planning reserves are provisions for hydrological changes (dry years with low hydro, low wind, low solar…) and temperature increases that cause increases in electricity load.

Operating reserve is not only relevant for outages, but also for deviations in forecast of e.g. wind and solar generation and power demand. Operating reserve for spinning, regulation, and flexibility of solar and wind can be determined hour by hour and can depend on factors of wind generation, solar generation and power demand that are forecasted in each hour. Operating reserve for outage will be the sum of outages for the largest generator unit (N-1) and additional outage (N-2) e.g.: loss of additional transmission line or another large generator unit.

Table 48: Operating reserve in US power system (NREL, 2018)

Product	Load requirement	Wind requirement	PV requirement	Absolute	Time scale
Spinning	3% of load				10 min
Regulation	1% of load	0.5% of wind generation	0.3% of PV capacity during daytime hours		5 min
Flexibility		10% of wind generation	4% of PV capacity during daytime hours		60 min
Benchmark outage				Exact capacity	60 min

In Viet Nam, the National Load Dispatch Center (NLDC) decides the reserve capacity for fluctuation of variable renewable energy (solar and wind) about 5% capacity of solar and wind by regions. So EOR-NZ suggests that the reserve for solar and wind in regulation reserve should comprise about 0.5% of the capacity, and in flexibility reserve of about 5% capacity of solar and wind, following the reserve for load requirements as the US power system (3% of load for spinning and 1% of load for regulation).

In long-term planning, planning reserve capacity will ensure the reliability for the power mix to withstand dry years, where the capacity and generation energy of hydro power plants will be reduced, or in years where energy generation from solar and wind is reduced. Besides that, the reserve for temperature variation in planning reserve capacity based on the climate change scenario in future.

In Viet Nam, hydrological data of hydro reservoir at a probability of 90% (P90) will reduce the energy by 25-30% and 30-35% by max capacity compared with probability 50% (P50). With run-of-river hydro, it can be even zero energy in a dry season of a dry year. Thus the power system needs to reserve at least 30% installed capacity of hydro for dry year and dry season.

Solar power at P90 will reduce 3-5% compared to P50, wind power at P90 will reduce 15-20% compared with P50. So, planning reserve capacity should add 15% of wind capacity for the year with probability of 90% of wind. Planning reserves for solar power reduction in P90 balance out with operation reserve for solar and therefore not necessary to add more.

According to some studies on the change in electrical load capacity according to temperature, it is shown that when the temperature increases by 1°C, the load increases by 2%. Thus, the reserve for temperature variation in the long-term will be about 2% of peak load minus the flexible demand.

Based on the result about the peak load by regions, the installed capacity of solar and wind and the installed capacity of hydro in future from Balmorel model of each scenario, the primary estimating reserve capacity (exclude the operating reserve for demand, solar and wind requirement) in the future for NZ scenario are shown in Table 49.

Table 49: Primary estimated the reserve capacity for Net-Zero scenario (exclude the operating reserve for demand, solar and wind requirement)

No		Year	2022	2025	2030	2035	2040	2045	2050
1	-	Total peak load of 7 regions (GW)	43	51	73	94	124	159	220
	-	Flexible demand (GW)	0.5	1.3	2.8	5.4	9.3	15.5	22.5
	-	Total capacity of hydro (GW)	23	27	31	32	33	34	34
	-	Total capacity of wind (GW)	5	10	22	34	63	124	196
2	Reserve capacity for outage of large unit (N-1)		2.6	3.3	5.0	5.0	5.0	5.0	5.0
3	Reserve capacity for additional outage (N-2)		2	3	4	5	6	6	7
4	Reserve capacity for low hydro and low wind year (at probability 90%)		8	10	13	15	19	29	40
5	Reserve capacity for temperature variation (2% of (Peak load-flexible demand))		0.8	1.0	1.4	1.8	2.3	2.9	3.9
I	Absolute operating reserve capacity (GW) for N-1, N-2		4.6	6.3	9.0	10.0	11.0	11.0	12.0
II	Planning reserve capacity (GW)		8.4	10.5	14.1	16.6	21.6	31.7	43.7

There are two types of reserve calculations in Balmorel model (operating reserve and planning reserve). Operating reserves include reserve for N-1, N-2 outage, and reserve for fluctuation of demand, solar and wind (calculate by percentage of forecasted capacity in each hour), operating reserve will be calculated by operating reserve add-on function. Planning reserve (for year of low hydro and low wind with increasing temperature) will be calculated by strategic-reserve add-on function. Balmorel can choose the optimal capacity mix meeting with reserve requirement with least cost.

Table 50: Comparing the total installed capacity with and without consideration reserve in Net-Zero scenario (not included Import from China 0.7 GW and Import from Laos 0.6 GW in 2022, 3.4 GW in 2025, 5 GW after 2025)

		Total installed capacity without solar and wind (GW)		Total installed capacity (GW)	
Year	Pmax (GW)	Net-Zero	Net-Zero with reserve	Net-Zero	Net-Zero with reserve
2022	43	54	54	76	76
2025	51	66	69	94	96
2030	73	72	86	150	161
2035	94	79	106	207	220
2040	124	96	133	301	337
2045	159	122	175	462	511
2050	220	206	268	797	847

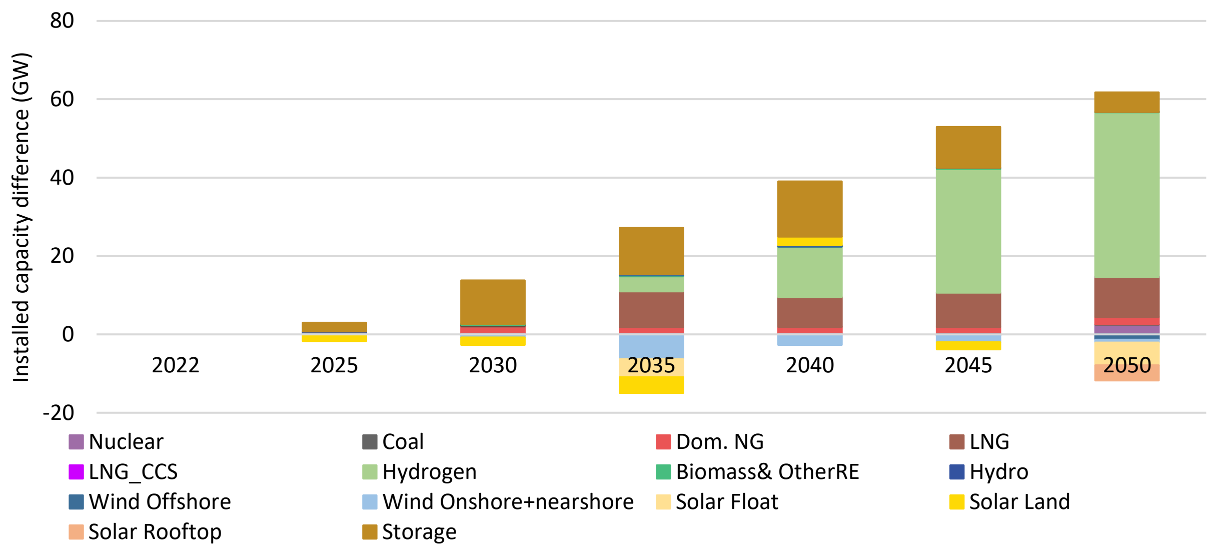


Figure 101: The installed capacity difference of NZ-reserve scenario comparing with the Net-Zero scenario.

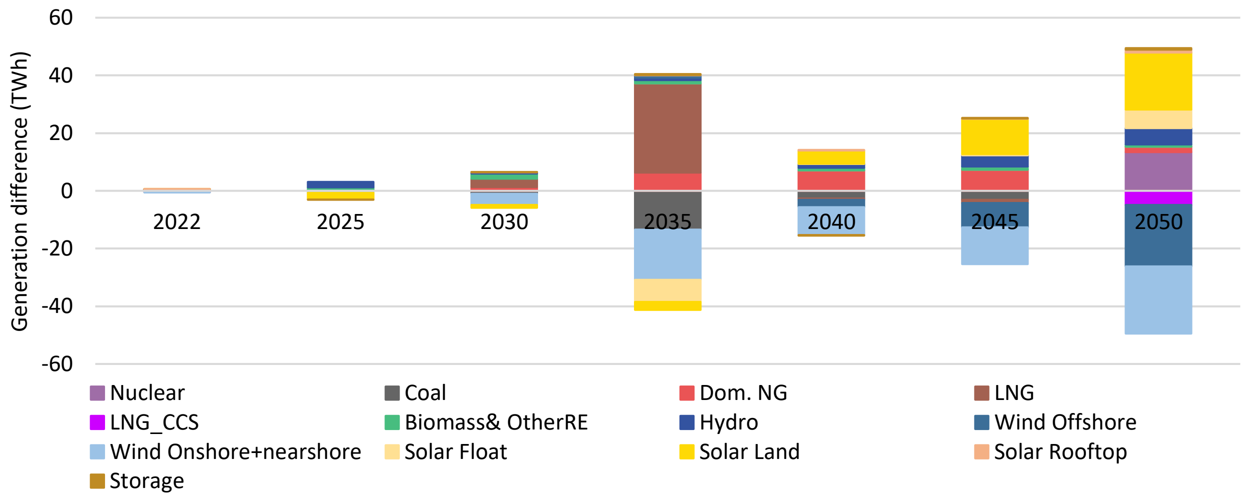


Figure 102: The generation difference of NZ-reserve scenario comparing with the Net-Zero scenario.

The installed power capacity structure in 2022 already ensures reserve capacity for the system, so the model does not increase the size of the power source for capacity reserve.

Compared to the case of not considering capacity reserve, calculation results from the model show that: When considering capacity reserve, LNG flex thermal, hydrogen flex thermal and storage will mainly increase in scale to meet the reserve. Hydrogen and LNG will develop with higher installed capacity for reserve capacity requirements, but nearly no generation energy in normal situation or normal year. This is because in long-term calculations, fluctuations over time are not carefully considered (only calculated for about 624 timesteps/year and only calculated for the normal hydrology year). Hydrogen and LNG will be used when outages occur in the power system, or in dry years with lower hydro power and years with lower solar and wind power. Besides that, the storage from fly wheel technology is added to supply more spinning reserve. Small capacity of solar and wind power will be reduced but not significant. In 2050, nuclear will develop by 13 GW comparing with NZ scenario.

Calculating additional reserve capacity will increase system costs by 1-4%/year in the period 2025-2050 compared to the case of not considering reserve. In 2050, total system cost will increase about 3% comparing with cases not considering planning reserve.

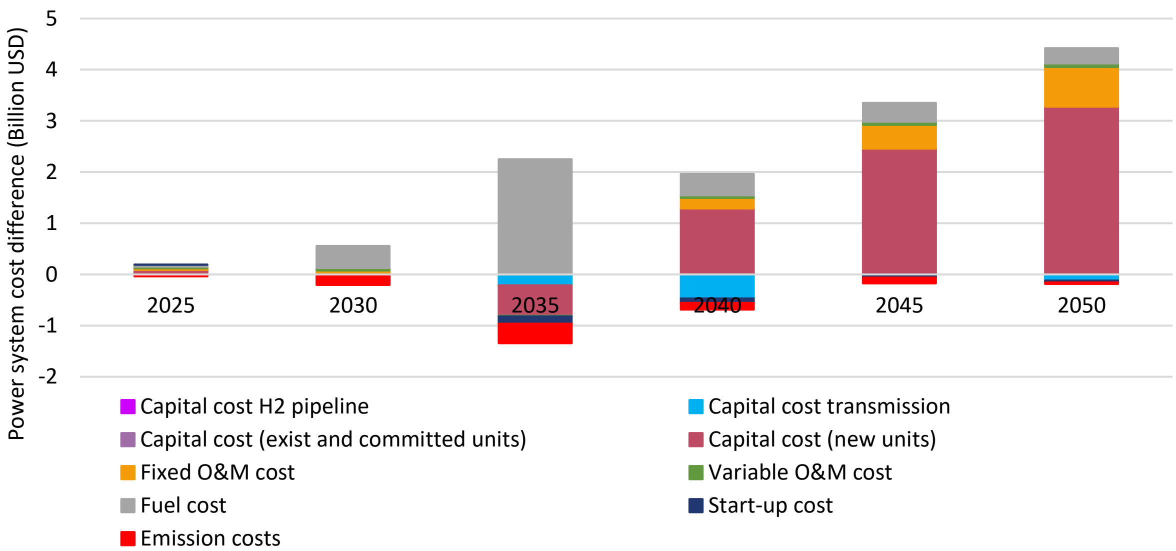


Figure 103: The total power system cost difference of NZ-reserve scenario comparing with the Net-Zero scenario.

NZ technology cost sensitivity scenarios

These scenarios will be calculated by Balmorel model for NZ scenario with lowest and highest technology investment cost which are forecasted in the Technology Catalogue 2023. These sensitivities include: NZ - High Solar cost (NZ-HC PV); NZ - High Battery cost (NZ-HC BESS); NZ - Low Battery cost (NZ-LC BESS); NZ - High Nuclear cost (NZ-HC Nuc).

The installed capacity, generation, power system cost of technology cost sensitivity scenarios comparing with the NZ scenario can be seen in the following figures:

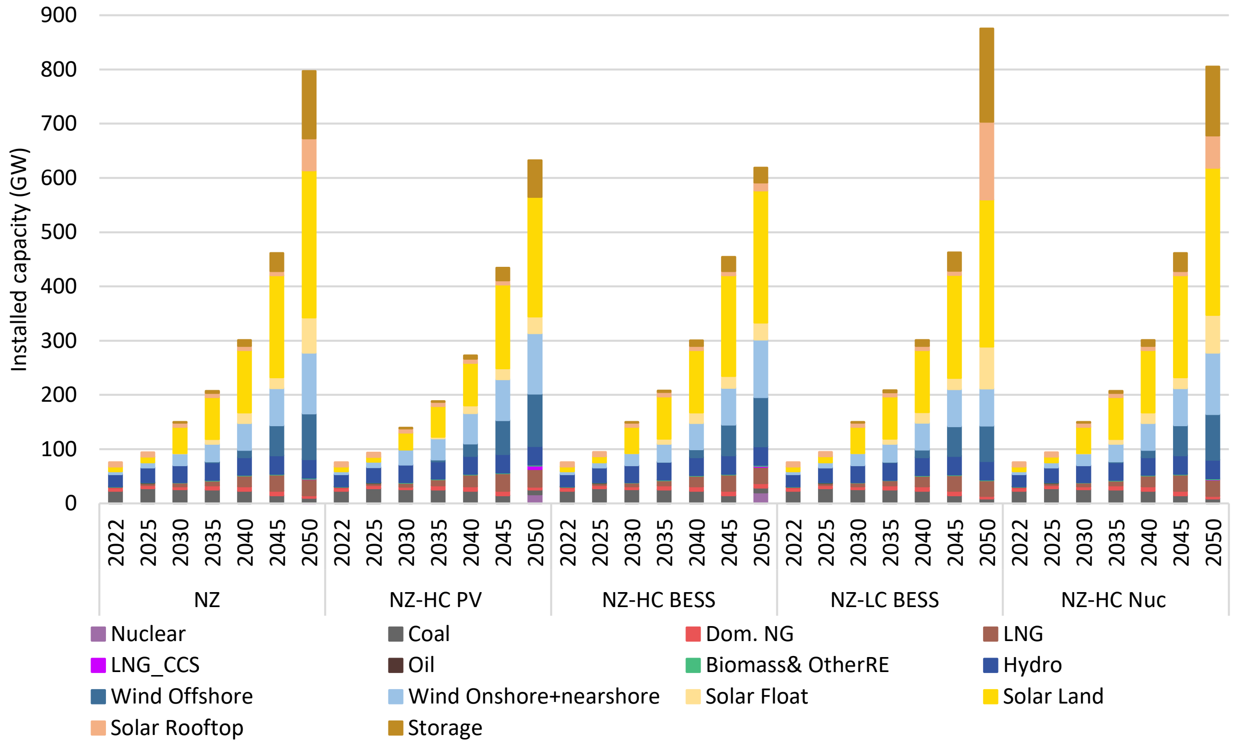


Figure 104: The installed capacity of technology cost sensitivity scenarios comparing with the NZ scenario. Fixed import from neighbouring countries is not included in the figure.

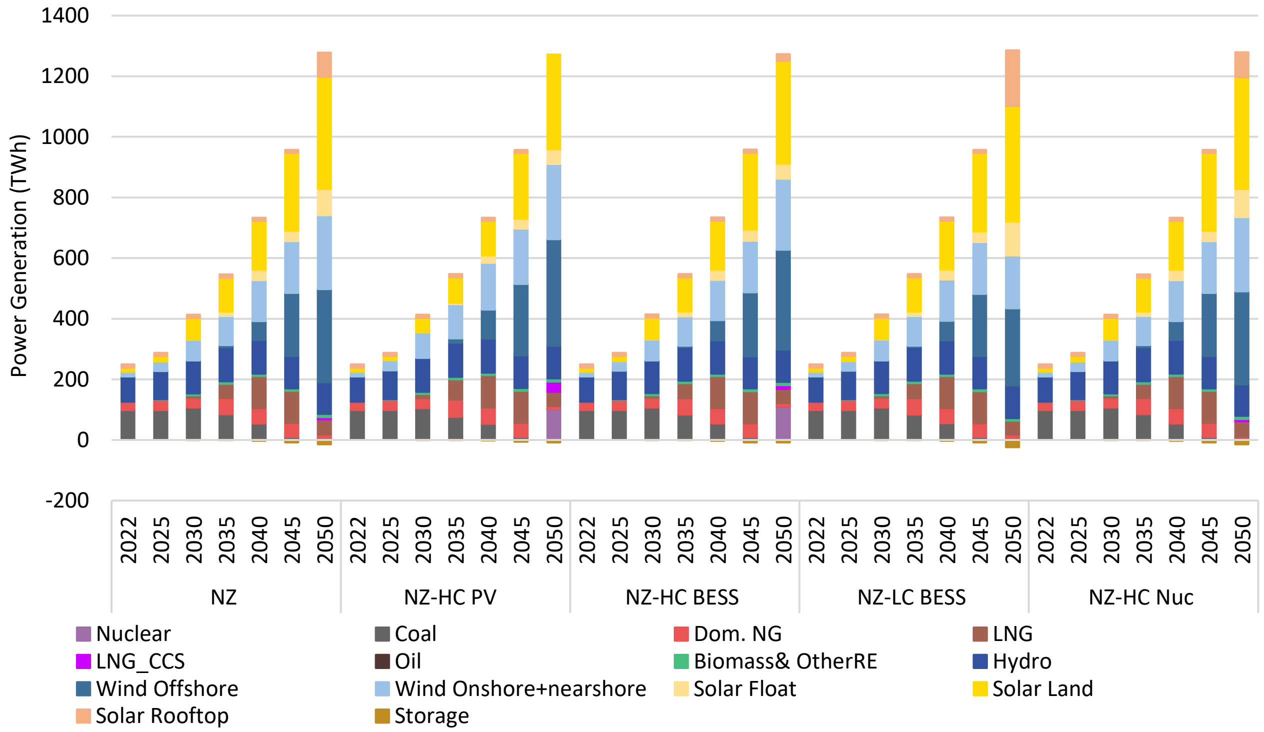


Figure 105: The generation of technology cost sensitivity scenarios comparing with the NZ scenario. Fixed import from neighbouring countries is not included in the figure.

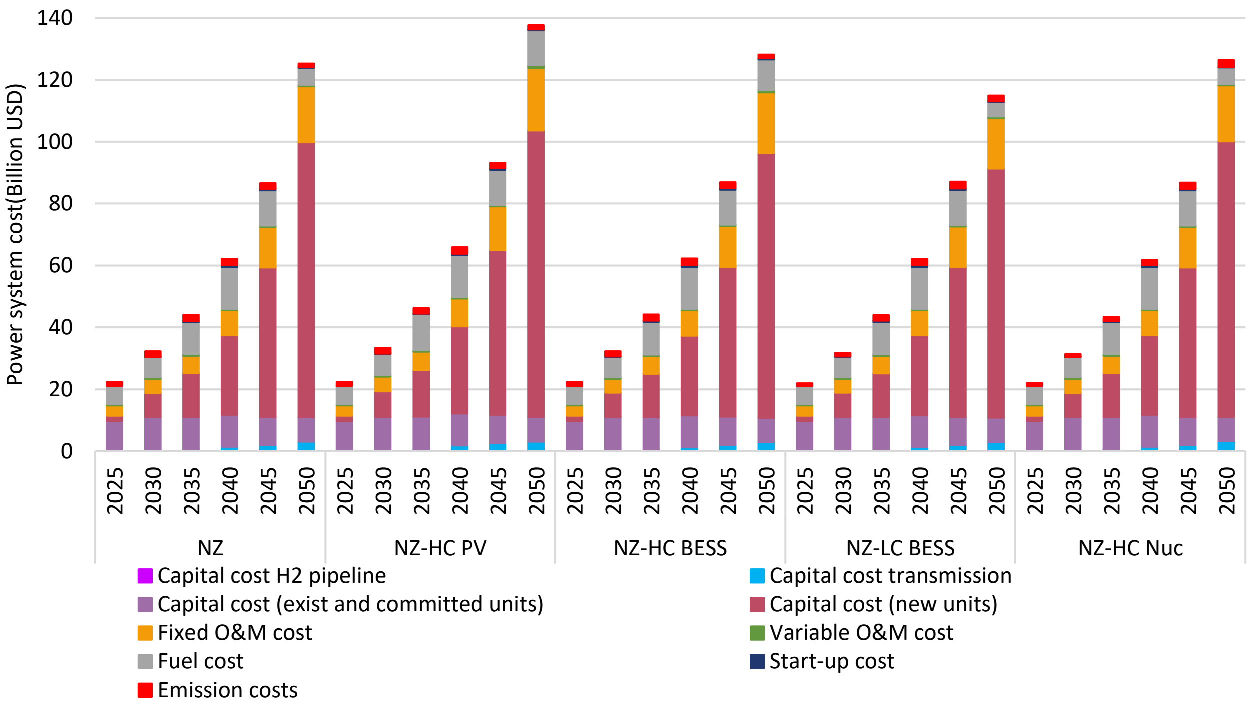


Figure 106: The power system cost of technology cost sensitivity scenarios comparing with the NZ scenario.

In the NZ-HC PV scenario, when the investment and O&M costs of solar PV are high as upper limit in the technology catalogue 2023, the scale of power sources will change from 2025 towards reducing capacity of solar power sources and batteries, and increasing capacity of nuclear, LNG sources, wind power sources. In 2050, compared to the NZ scenario, nuclear will increase 16 GW, LNG will increase by 2 GW, LNG-CCS increase with 6 GW, increase offshore wind by 13 GW. While NZ-HC PV scenario will reduce solar PV by 144 GW and reduce battery by 57 GW compared to NZ scenario. The power system cost in 2050 of NZ-HC PV scenario will increase 10% compared to NZ scenario.

In the NZ-HC BESS scenario, when the investment and O&M costs of batteries are high following the upper limit in the technology catalogue 2023, the scale of power sources will change mainly from 2045 towards increasing capacity of nuclear, LNG sources, offshore wind power sources, and reducing capacity of onshore wind, solar power sources and batteries. In 2050, compared to the NZ scenario, NZ-HC BESS scenario will increase with 19 GW of nuclear, 4 GW of domestic gas and LNG-CCS, 7 GW of offshore wind, while this scenario decreases onshore wind by 7 GW, reduces solar PV by 105 GW, and reduces battery by 97 GW. The power system cost in 2050 of NZ-HC BESS scenario will increase 2% compared to NZ scenario.

In the NZ-LC BESS scenario, when the investment and O&M costs of batteries are low following the lower limit in the Technology Catalogue 2023, the scale of power sources will change in 2050 towards reducing capacity of LNG (-1 GW), LNG-CCS (-1 GW), offshore wind (-18 GW), onshore wind (-44 GW), but increasing capacity of solar power sources (+97 GW) and batteries (+48 GW). Nuclear will not appear in NZ-LC BESS. The power system cost in 2050 of NZ-LC BESS scenario will decrease 8% compared to NZ scenario.

In the NZ-HC Nuc scenario, when the investment cost of nuclear is high as higher limit in the technology catalogue 2023 (CAPEX (not include IDC) achieving about 7000 USD/kW for PWR and 9450 USD/kW for

SMR), the scale of power sources will change from 2050 with reducing capacity of nuclear, increasing capacity of wind power, solar and batteries. In 2050, compared to the NZ scenario, nuclear will not appear, onshore wind increases by 1 GW, solar PV increases by 6 GW, and battery by 3 GW. The power system cost in 2050 of NZ-HC Nuc scenario will increase 1% compared to NZ scenario. Thus, if we do not build nuclear but instead develop more LNG, wind, solar and batteries, the system cost will not increase much.

NZ LNG fuel cost sensitivity scenarios

The main results of the two sensitivity analyses on the NZ scenario with increased LNG fuel costs by 50% and 100%, respectively, calculated in the Balmorel model, are shown below. The results are given in absolute difference compared to the NZ scenario.

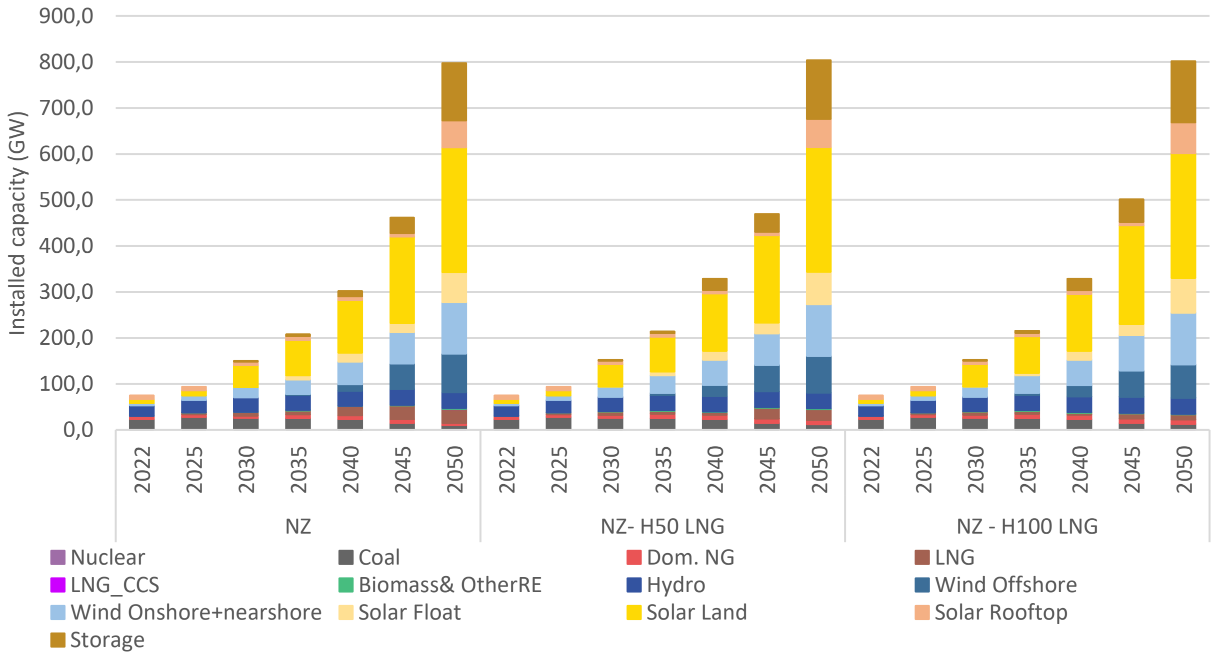


Figure 107: Installed capacity of the NZ scenario and LNG price sensitivity scenarios .

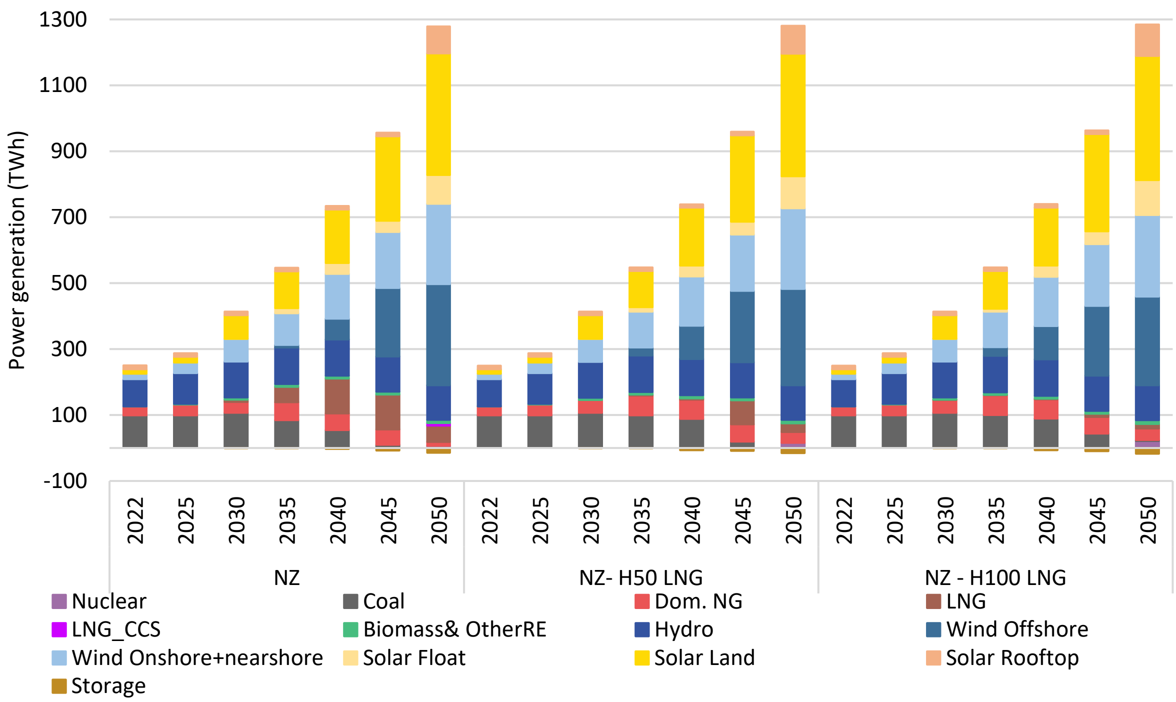


Figure 108: Power generation by technology of the NZ scenario and LNG price sensitivity scenarios.

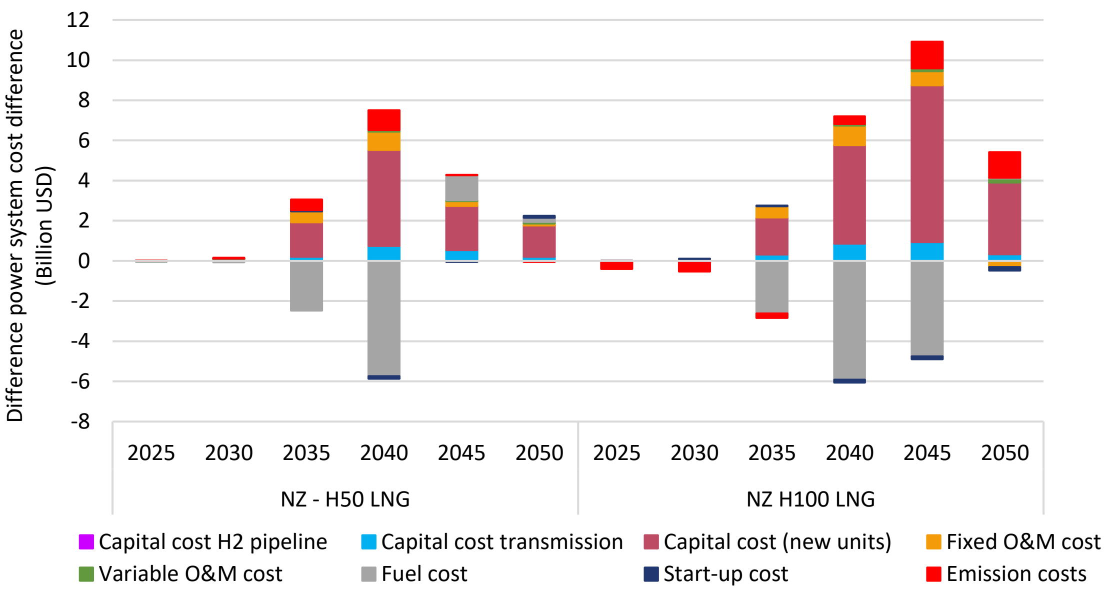


Figure 109: difference in power system costs of LNG price sensitivity scenarios compared to NZ scenario.

The increased LNG fuel price reduces the attractiveness of LNG investments and consequently, lower and later LNG investments can be observed in the sensitivities. LNG capacity stays below 8 GW until 2040 in the sensitivity scenarios, and first in 2045 additional investments occur, reaching 24 GW in the NZ - H50 LNG scenario, thus 6 GW less than in NZ, and only 11 GW in the NZ H100 LNG scenario compared to the NZ scenario. Further, no LNG with CCS is installed in the two sensitivities. The reduced capacity is replaced by a mix of a slightly faster build-out of wind power capacity, both onshore and offshore wind with more investments in 2035-2040, some more solar power in combination with battery storage from 2040, but by 2050, the total difference in solar capacity compared to the NZ scenario is only 8 and 19 GW, respectively. Instead, additional nuclear power of 1.7 and 2.5 GW more compared to NZ scenario is installed in 2050 as well 5 GW more domestic natural gas in the NZ - H100 LNG sensitivity.

As a result of the increased prices and reduced LNG capacity, LNG is less present in the power mix, with a maximum annual generation of 73 TWh in the NZ - H50 LNG sensitivity, and only 14 in the NZ - H100 LNG sensitivity, corresponding to a maximum annual fuel use of 453 PJ and 93 PJ, respectively, compared to up to over 100 TWh or 650 PJ in the NZ scenario. In 2050, the absolute difference is lower with 23 TWh and 36 TWh in the NZ - H50 LNG and NZ - H100 LNG, respectively. More wind and solar, but also more coal power is part of the power mix from between 2035-2045 in both sensitivities. In 2050, a mix of solar, domestic natural gas and nuclear power replaces the expensive LNG.

Total power system costs are higher from 2035 onwards. While fuel costs are reduced in the medium term, in 2050, fuel costs are at a similar level as a result of an increase use of other fuels and the high price of the LNG used. The majority of the cost can be traced back to the need of higher investment needs (capital costs), but also emission costs increase driven by the increased use of coal instead of LNG. The relative annual increase in power system cost is between 1-5% for the NZ-H50 LNG sensitivity and between 2-7% for the NZ-H100 LNG sensitivity.

7 Key findings

Table 51 Key metrics for main EOR-NZ scenarios, both for the whole energy system and for the power sector.

			System costs (in-dexed)	Net CO2eq emissions	Captured CO2eq emissions	RE share	W&S share	Electricity demand	Hydrogen demand	Ammonia demand
			BSL = 1	Mt	Mt	%	%	TWh	PJ	PJ
All energy sectors	2030	BSL	1	407	0	28%	5%			
		NZ	0.92	352	0	35%	10%			
		GG	0.89	338	0	35%	10%			
		NZ+	0.92	351	0	35%	10%			
		GT	0.97	406	0	28%	5%			
	2050	BSL	1	239	0	68%	40%			
		NZ	0.97	121	46	79%	53%			
		GG	0.86	116	31	78%	50%			
		NZ+	1.12	20	47	81%	54%			
		GT	1.06	121	48	78%	50%			
Power sector	2030	BSL	1	173	0	28%	12%	425	0.40	0
		NZ	0.95	123	0	44%	24%	426	0.40	0
		GG	0.86	122	0	42%	22%	398	0.40	0
		NZ+	0.96	122	0	43%	23%	425	0.40	0
		GT	1	173	0	28%	12%	425	0.40	0
	2050	BSL	1	70	0	77%	66%	1,127	75	0
		NZ	1.25	23	2	90%	79%	1,271	325	0
		GG	0.93	22	0	91%	78%	1,013	194	0
		NZ+	1.72	0	0	78%	67%	1,504	460	83
		GT	1.34	51	0	82%	71%	1,350	388	0

Key findings in the end-use sectors

Net-zero ambition in Viet Nam is technically and economically viable and provides multiple benefits

The report finds that the net-zero goal is technically feasible and economically viable, as demonstrated in the Net-Zero scenario. The scenario achieves the target by high electrification rate of the end-use sectors, energy efficiency measures and high shares of renewable generation in the power sector. The electrification happens both as direct electrification (mainly in the transport sector) and indirect electrification through green hydrogen (industrial sector and transport sector). Energy efficiency is important, across all end-use sectors. The power sector capacity increases in the Net-Zero scenario compared to the Baseline scenario to serve the higher electricity needs. Furthermore, the CO_2 budget results in an increase in renewable generation in the Net-Zero Scenario: 62% in 2030 and 94% in 2050. Despite the increase in costs in the power sector, the total system costs for the Net-Zero scenario are also slightly lower than the Baseline scenario due to the assumed modal shift in the transport sector towards rail, where the required infrastructure costs are not included, increased solar availability and less restricted build-out of renewables, which in turn allows for higher electrification and reduced fuel needs in the end-use sectors.

Adopting the net-zero goal provides multiple benefits, such as improved air quality and lower air pollution costs, higher energy security with regard to reduced import dependencies on fossil fuels, lower costs and low carbon emissions.

Impact of the economic structure on reaching the net-zero target

A lower share of energy-intensive industries will help achieve green growth. The Green Growth scenario highlights a pathway to reach more cost-effectively the net-zero target, through green growth by restructuring the economy and prioritizing service sector growth, reducing energy-intensive industries. This development helps reduce total energy demand down to 6.1 EJ in 2050 (compared to 7.4 EJ in the NZ scenario), thereby saving investments in the energy system, while still achieving economic growth and fulfilling climate goals. As a result, the total system cost (2022-2050) for the energy system is reduced by 13% in GG compared to NZ scenario.

Transformation of the transport sector

High share of electrification of light duty vehicles and rail transport is cost-optimal in all scenarios: the electrification level, across all transport segments, drastically moves from a current 0.4% of the fuel mix in 2022 to covering 44% of the energy needs in transport in 2050 in NZ scenario; even in the Baseline scenario, with no targets on GHG emission reduction, electrification rates increase to 32% in 2050. The use of synthetic fuels in transport sector can be observed only for heavy-duty transport, for freight trucks, airplanes and ships. Energy consumption to supply the future transport needs grows by a factor of 2.3-2.5 compared to current levels depending on the scenario, with savings to be harnessed both through increased electrification especially of the light segments, but also in other modes through modal shift in the later years, as well as energy efficiency gains considering the uptake of more advanced vehicle technologies.

The development of the industry sector

Heavy industrial sub-sectors such as iron, steel and cement represent a large share of the total energy consumption of the industrial sector in Viet Nam today. However, their share on the total industrial energy consumption can shift from the current 42% to 23-25% in 2050. By then, electricity could make up 58-73% of final energy consumption in industry, depending on the scenario, thereby substituting coal use.

The role of renewable fuels in the Vietnamese energy system

Renewable fuels, such as hydrogen, methanol and ammonia, can play a significant role in an ambitious climate strategy in the hard to abate sectors such as the transport and the industrial sectors, especially starting from 2035-2040. In the Net-Zero scenario a hydrogen demand of 325 PJ is found of which 78% is for industrial use and 22% is used in transport. Production of hydrogen through electrolysis, while incurring energy losses, allows pushing the burden of CO_2 abatement to the power sector, with its high potential for renewable integration. More ambitious scenarios see even higher hydrogen demand up to 460 PJ in the NZ+ scenario. Due to its higher cost and higher round-trip losses compared to batteries, RE fuels play a very limited role in the power sector.

Economic viability of the different pathways

Net-zero implementation can follow different paths, even when assuming the same GDP growth projections. Power demand and power system costs would be at the lowest if the economic structure is changed towards a Green Growth (GG), achieving a decrease of 25% of power system cost compared to the base economic projections (NZ). The NZ+ scenario, which corresponds to the complete decarbonisation of all sectors by 2050, corresponds to the highest power demand and power system cost, reaching an increase of

35% of the cost of the power system in 2050 compared to the NZ scenario. The power system cost of the GT scenario, which represents the economic development towards a green transportation system, is characterised by an increase of 8% of the power system cost compared to the NZ scenario. It is necessary to remember that the GT scenario does not include the decommissioning of coal and gas thermal power plants before their economic lifetime, and at the same time, the land solar power potential in the GT scenario is equal to the potential assumed in the Baseline scenario , which is half of the potential applied in the NZ scenario.

Comparing CO_2 emissions

The peak CO_2 emissions for the power sector are achieved in 2030-2035, and the highest value of 173-175 million tons/year in the Baseline and GT scenarios, while only 122-125 million tons/year reached in the NZ, GG, NZ+ scenarios. It must be highlighted that the power demand in 2030 in each scenario is equal to 75% of the power demand in PDP8 (while this corresponds to about 70% for the GG scenario).

The CO_2 emissions' reduction in 2050 was achieved with different end values in the various scenarios. For the Baseline scenario, the lowest emissions in 2050 consists of 70 million tons/year for the power sector, while in the GT scenario 51 million tons/year are achieved, 22 and 23 million tons/year in the NZ and GG scenario respectively and 0 million tons/year in the NZ+ scenario.

The development of renewable energy

Due to the reduced cost of wind power, solar power and battery storage in the future, those technologies become competitive with coal-fired power sources. The analysis shows that onshore wind, offshore wind and particularly solar are part of the least-cost power system even in the Baseline scenario. Although there are no restrictions on CO_2 emissions in the Baseline after 2030, the full load hours of coal thermal power plants will gradually decrease after 2030 and only reach about 800 hours/year in 2050. In the NZ scenario, coal almost does not generate from 2045.

The renewable energy (including large hydro) share stands at 44% in 2030 and increase to 85-88% in 2050 in the Baseline and GT scenarios. In the NZ, NZ+ and GG scenarios, the RE share reaches about 60-62% in 2030 and increases to 89-94% in 2050. In 2050, the land solar power develops to its full potential in most scenarios (except for the GG scenario), especially in the NZ+ and GT scenarios, in which the full potential of solar power is exploited, resulting in a capacity (floating solar, land solar, rooftop solar) of 492 GW in NZ+ and 355 GW in GT. Other renewable energy sources are not being used at their full potentials in all the scenarios, however onshore wind power reaches 112 GW in NZ scenario and offshore wind power capacities of 84 GW can be seen in the NZ scenario.

The role of storage

To balance the power system, pumped storage hydro and battery will develop mainly from 2040. Pumped hydro storage develops almost at full potential from 2045, and battery storage follows with a development characterised by high C-ratio (storage hours about 5-7 hours) in 2050.

Batteries come out of the analysis as a robust technology in Viet Nam's power system, where the Net-zero scenario sees about 124 GW of batteries, whereas even more ambitious scenarios have capacities beyond that. The extent of the role of batteries is sensitive to its investment costs, where a reduction of 25% in battery costs results in an increase of 38% in capacity. This set-up is attractive for solar generation and results in 25% additional solar PV capacity, at the expense of onshore wind. Conversely, a cost increase in batteries results in less batteries, less solar PV, and some additional nuclear capacity.

Gas and CCS technologies

The capacity of gas power sources (CCGT, SCGT, RICE) using LNG continues to grow along with the demand growth, and to compensate for the decreasing share of coal-fired power capacity. However, the full load hours decrease gradually after 2035-2040 and only reach about 3000 hours/year in 2050 in the Baseline scenario. To ensuring reliability of the power system (reserve requirements in system operation), the installed capacity of power sources using LNG and hydrogen increases after 2030 compared to the main scenario. The gas power sources that are increased to ensure reserve requirements for the system are mainly the flexible technologies (SCGT and RICE).

The solution of installing additional CCS for coal and gas power plants is still an expensive solution in the future. Therefore, only very small amount of new CCGT is selected to install CCS by 2050 in the NZ and NZ+ scenarios.

Transmission capacity

Large transmission capacity investments can be observed across all scenarios in order to allow the distribution of renewable energies, especially towards the demand centers in the North region and South Central region. Interregional transmission capacities reach 81-90 GW in 2050, whereof 17 GW (NZ) and up to 23 GW (BSL) are HVDC lines towards the North region from South Central and Central Central in the NZ scenario.

Hydrogen and ammonia production for electricity generation

Producing hydrogen from the power grid is a solution that results in a high cost of hydrogen and ammonia production, and therefore not suitable for electricity production. In addition, most of existing power plants have low efficiency and poor flexibility. Therefore, renovating existing coal and gas power plants to co-fire or 100% fire ammonia, hydrogen or biomass is not selected in the EOR-NZ.

Development of nuclear energy in Viet Nam

Nuclear power (SMR technology) is developed in the NZ, NZ+ and GT scenarios, with capacities that vary from 1.3 to 28 GW in 2050, and located mainly in the North (NZ, GT), and in both the North and the South in the NZ+ scenario. The analysis shows only a small role for nuclear capacity in the NZ scenario with 1.3 GW. This is due to the abundancy of variable renewable resources, the high capital cost of nuclear, as well as its difficulty to integrate renewables. Only when renewable resources are exhausted (NZ+) or when they are difficult to integrate in the system (NZ-HC BESS), a distinct role for nuclear as dispatchable carbon-neutral generator emerges. The appearance of nuclear in the power system has a significant effect on the system costs.

Reserve capacities in Viet Nam

Reserve capacity is important to ensure a safe and reliable system operation. When considering capacity reserve (NZ-Reserves sensitivity), the share of LNG flex thermal, hydrogen flex thermal and fly wheel storage increases to meet the reserve requirements. Hydrogen and LNG develop with higher installed capacity to comply with the reserve capacity requirements, showing nearly no energy generation in a normal year (NZ-Res). Additional reserve capacity increases the system costs by 1-4%/year in the period 2025-2050.

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Appendix A

Investment cost information for various sectors

Industry sector

Table 52: Cost of generic processes in iron and steel subsector (Danish Energy Agency, 2022)

Technology	Investment Cost (CAPEX) (MUSD/GW)				Fixed operation Cost (MUSD/GW-yr)				Variable cost (MUSD/PJ)			
Years	2020	2030	2040	2050	2020	2030	2040	2050	2020	2030	2040	2050
IND Iron and steel technology: High temperature heat using Electricity - Heat Pump	1.132,87	1.012,72	949,26	910,25	1,05	0,94	0,87	0,78	0,54	0,51	0,51	0,48
IND Iron and steel technology: High temperature heat using Natural gas,Synthetic natu-ral gas,Natural gas H2 blend - Boiler	59,11	49,26	49,26	49,26	2,17	2,06	1,95	1,84	0,33	0,30	0,30	0,30
IND Iron and steel technology: High temperature heat using Natural gas,Synthetic natu-ral gas,Natural gas H2 blend - Condens-ing Boiler	65,02	54,18	54,18	54,18	2,17	2,06	1,95	1,84	0,33	0,30	0,30	0,30
IND Iron and steel technology: High temperature heat using LPG,Renewa-ble LPG - Boiler	59,11	49,26	49,26	49,26	2,17	2,06	1,95	1,84	0,33	0,30	0,30	0,30
IND Iron and steel technology: High temperature heat using Oil,Renewable liquid fuels - Boiler	59,60	50,47	48,33	47,73	1,95	1,84	1,73	1,63	0,30	0,27	0,27	0,27
IND Iron and steel technology: High temperature heat using Coal - Boiler	541,81	504,71	483,30	477,29	36,52	35,33	34,24	33,16	0,57	0,58	0,58	0,58
IND Iron and steel technology: High temperature heat using Biomass - Boiler	669,88	640,33	610,77	581,22	40,09	38,90	37,71	36,52	0,84	0,85	0,86	0,86
IND Iron and steel technology: High temperature heat using Biomass - Con-densing Boiler	736,87	704,36	671,85	639,34	40,09	38,90	37,71	36,52	0,84	0,85	0,86	0,86
IND Iron and steel technology: High temperature heat using Hydrogen - Boiler	285,59	137,08	137,08	137,08	4,33	4,66	4,66	4,66	0,40	0,36	0,36	0,36
IND Iron and steel technology: High temperature heat using Coal - Boiler w. CCS	1.191,99	1.110,37	1.063,26	1.050,04	80,34	77,72	75,33	72,95	1,26	1,27	1,28	1,28

IND Iron and steel technology: High temperature heat using Natural gas,Synthetic natural gas,Natural gas H2 blend - Boiler w. CCS	177,32	147,77	147,77	147,77	6,50	6,18	5,85	5,53	0,99	0,90	0,90	0,90
IND Iron and steel technology: Low temperature heat using Electricity - Boiler	791,05	704,36	650,18	628,50	2,17	2,17	2,17	2,17	0,54	0,51	0,50	0,48
IND Iron and steel technology: Low temperature heat using Electricity - Heat Pump	75,85	65,02	65,02	65,02	1,16	1,11	1,05	1,00	0,15	0,15	0,12	0,12
IND Iron and steel technology: Low temperature heat using Natural gas,Synthetic natural gas,Natural gas H2 blend - Boiler	736,87	704,36	671,85	639,34	40,09	38,90	37,71	36,52	0,84	0,85	0,86	0,86
IND Iron and steel technology: Low temperature heat using Natural gas,Synthetic natural gas,Natural gas H2 blend - Condensing Boiler	734,26	652,02	623,68	595,34	36,71	32,60	31,18	29,77	0,30	0,30	0,30	0,30
IND Iron and steel technology: Low temperature heat using LPG,Renewable LPG - Boiler	734,26	652,02	623,68	595,34	36,71	32,60	31,18	29,77	0,30	0,30	0,30	0,30
IND Iron and steel technology: Low temperature heat using Heat,Geothermal - Heat Pump	606.83	552.65	520.14	498.47	2.17	2.17	2.17	2.17	0.08	0.08	0.07	0.07
IND Iron and steel technology: Low temperature heat using Oil,Renewable liquid fuels - Boiler	47.68	40.38	38.66	38.18	1.95	1.84	1.73	1.63	0.30	0.27	0.27	0.27
IND Iron and steel technology: Low temperature heat using Coal - Boiler	541.81	541.81	541.81	541.81	36.52	35.33	34.24	33.16	0.57	0.58	0.58	0.58
IND Iron and steel technology: Low temperature heat using Biomass - Boiler	669.88	640.33	610.77	581.22	40.09	38.90	37.71	36.52	0.84	0.85	0.86	0.86
IND Iron and steel technology: Low temperature heat using Biomass - Condensing Boiler	736.87	704.36	671.85	639.34	40.09	38.90	37.71	36.52	0.84	0.85	0.86	0.86
IND Iron and steel technology: Machine drive using Electricity - Machinery	734.26	652.02	623.68	595.34	36.71	32.60	31.18	29.77	0.30	0.30	0.30	0.30
IND Iron and steel technology: Other services using Electricity - Other	734.26	652.02	623.68	595.34	36.71	32.60	31.18	29.77	0.30	0.30	0.30	0.30

Transport sector

Table 53: Cost of road technologies

Mode	Fuel	Type	Investment Cost (CAPEX)	Operation Cost (OPEX)
			kUSD/vehicle	kUSD/vehicle
Cars	Gasoline & Renewable gasoline	Internal Combustion Engine CAR Natural gas - New Ordinary	24.1	0.7
Cars	Gasoline & Renewable gasoline	Internal Combustion Engine CAR Natural gas - New Improved	24.5	0.7
Cars	Gasoline & Renewable gasoline	Internal Combustion Engine CAR Natural gas - New Advanced	25.3	0.8
Cars	Gasoline & Renewable gasoline	Hybrid CAR Natural gas - New Ordinary	27.6	0.8
Cars	Gasoline & Renewable gasoline	Hybrid CAR Natural gas - New Improved	26.6	0.8
Cars	Gasoline & Renewable gasoline	Hybrid CAR Natural gas - New Advanced	26.8	0.8
Cars	Gasoline & Electricity	Plug-in Hybrid CAR Natural gas - New Ordinary	33.5	1.0
Cars	Gasoline & Electricity	Plug-in Hybrid CAR Natural gas - New Improved	28.6	0.9
Cars	Gasoline & Electricity	Plug-in Hybrid CAR Natural gas - New Advanced	27.2	0.8
Cars	Diesel & Renewable diesel	Internal Combustion Engine CAR Biomass - New Ordinary	27.6	0.8
Cars	Diesel & Renewable diesel	Internal Combustion Engine CAR Biomass - New Improved	28.8	0.9
Cars	Diesel & Renewable diesel	Internal Combustion Engine CAR Biomass - New Advanced	29.7	0.9
Cars	Diesel & Renewable diesel	Hybrid CAR Biomass - New Ordinary	27.6	0.8
Cars	Diesel & Renewable diesel	Hybrid CAR Biomass - New Improved	30.5	0.9
Cars	Diesel & Renewable diesel	Hybrid CAR Biomass - New Advanced	30.8	0.9
Cars	Diesel & Electricity	Plug-in Hybrid CAR Biomass - New Ordinary	36.8	1.1
Cars	Diesel & Electricity	Plug-in Hybrid CAR Biomass - New Improved	32.1	1.0
Cars	Diesel & Electricity	Plug-in Hybrid CAR Biomass - New Advanced	30.9	0.9
Cars	Electricity	Battery Electric CAR Electricity - New Ordinary	36.0	0.4
Cars	Electricity	Battery Electric CAR Electricity - New Improved	29.1	0.3
Cars	Electricity	Battery Electric CAR Electricity - New Advanced	27.9	0.3
Cars	Gaseous hydrogen	Fuel Cell CAR Gaseous hydrogen - New Ordinary	64.4	0.6
Cars	Gaseous hydrogen	Fuel Cell CAR Gaseous hydrogen - New Improved	45.8	0.5
Cars	Gaseous hydrogen	Fuel Cell CAR Gaseous hydrogen - New Advanced	38.4	0.4
Cars	Natural gas & Synthetic natural gas	Internal Combustion Engine CAR Natural gas - New Ordinary	24.1	0.7
Cars	Natural gas & Synthetic natural gas	Internal Combustion Engine CAR Natural gas - New Improved	24.5	0.7

Cars	Natural gas & Synthetic natural gas	Internal Combustion Engine CAR Natural gas - New Advanced	25.3	0.8
Cars	Liquefied petroleum gas	Internal Combustion Engine CAR Liquefied petroleum gas - New Ordinary	24.1	0.7
Cars	Liquefied petroleum gas	Internal Combustion Engine CAR Liquefied petroleum gas - New Improved	24.5	0.7
Cars	Liquefied petroleum gas	Internal Combustion Engine CAR Liquefied petroleum gas - New Advanced	25.3	0.8
Cars	Methanol (H2 derived) (TRA)	Internal Combustion Engine CAR Methanol (H2 derived) (TRA) - New Ordinary	33.2	1.0
Buses	Gasoline & Renewable gasoline	Internal Combustion Engine BUS Natural gas - New Ordinary	372.2	11.2
Buses	Gasoline & Renewable gasoline	Internal Combustion Engine BUS Natural gas - New Improved	374.5	11.2
Buses	Gasoline & Renewable gasoline	Internal Combustion Engine BUS Natural gas - New Advanced	376.4	11.3
Buses	Gasoline & Renewable gasoline	Hybrid BUS Natural gas - New Ordinary	406.0	12.2
Buses	Gasoline & Renewable gasoline	Hybrid BUS Natural gas - New Improved	408.5	12.3
Buses	Gasoline & Renewable gasoline	Hybrid BUS Natural gas - New Advanced	410.4	12.3
Buses	Diesel & Renewable diesel	Internal Combustion Engine BUS Biomass - New Ordinary	372.2	11.2
Buses	Diesel & Renewable diesel	Internal Combustion Engine BUS Biomass - New Improved	374.5	11.2
Buses	Diesel & Renewable diesel	Internal Combustion Engine BUS Biomass - New Advanced	376.4	11.3
Buses	Diesel & Renewable diesel	Hybrid BUS Biomass - New Ordinary	406.0	12.2
Buses	Diesel & Renewable diesel	Hybrid BUS Biomass - New Improved	408.5	12.3
Buses	Diesel & Renewable diesel	Hybrid BUS Biomass - New Advanced	410.4	12.3
Buses	Electricity	Battery Electric BUS Electricity - New Ordinary	553.9	5.5
Buses	Electricity	Battery Electric BUS Electricity - New Improved	411.7	4.1
Buses	Electricity	Battery Electric BUS Electricity - New Advanced	392.4	3.9
Buses	Gaseous hydrogen	Fuel Cell BUS Gaseous hydrogen - New Ordinary	814.1	8.1
Buses	Gaseous hydrogen	Fuel Cell BUS Gaseous hydrogen - New Improved	526.5	5.3
Buses	Gaseous hydrogen	Fuel Cell BUS Gaseous hydrogen - New Advanced	447.7	4.5
Buses	Natural gas & Synthetic natural gas	Internal Combustion Engine BUS Natural gas - New Ordinary	318.0	9.5
Buses	Natural gas & Synthetic natural gas	Internal Combustion Engine BUS Natural gas - New Improved	320.2	9.6
Buses	Natural gas & Synthetic natural gas	Internal Combustion Engine BUS Natural gas - New Advanced	322.5	9.7
Buses	Liquefied petroleum gas	Internal Combustion Engine BUS Liquefied petroleum gas - New Ordinary	310.6	9.3
Buses	Liquefied petroleum gas	Internal Combustion Engine BUS Liquefied petroleum gas - New Improved	312.8	9.4
Buses	Liquefied petroleum gas	Internal Combustion Engine BUS Liquefied petroleum gas - New Advanced	315.1	9.5

Buses	Methanol (H2 derived) (TRA)	Internal Combustion Engine BUS Methanol (H2 derived) (TRA) - New Ordinary	446.7	13.4
Motorbikes	Gasoline & Renewable gasoline	Internal Combustion Engine MOT Natural gas - New Ordinary	2.3	0.1
Motorbikes	Gasoline & Renewable gasoline	Internal Combustion Engine MOT Natural gas - New Improved	2.4	0.1
Motorbikes	Gasoline & Renewable gasoline	Internal Combustion Engine MOT Natural gas - New Advanced	2.4	0.1
Motorbikes	Electricity	Battery Electric MOT Electricity - New Ordinary	5.5	0.1
Motorbikes	Electricity	Battery Electric MOT Electricity - New Improved	3.8	0.0
Motorbikes	Electricity	Battery Electric MOT Electricity - New Advanced	3.4	0.0
Light commercial passenger vehicles	Gasoline & Renewable gasoline	Internal Combustion Engine LPV Natural gas - New Ordinary	22.0	0.7
Light commercial passenger vehicles	Gasoline & Renewable gasoline	Internal Combustion Engine LPV Natural gas - New Improved	22.7	0.7
Light commercial passenger vehicles	Gasoline & Renewable gasoline	Internal Combustion Engine LPV Natural gas - New Advanced	24.2	0.7
Light commercial passenger vehicles	Gasoline & Renewable gasoline	Hybrid LPV Natural gas - New Ordinary	25.9	0.8
Light commercial passenger vehicles	Gasoline & Renewable gasoline	Hybrid LPV Natural gas - New Improved	24.7	0.7
Light commercial passenger vehicles	Gasoline & Renewable gasoline	Hybrid LPV Natural gas - New Advanced	25.0	0.8
Light commercial passenger vehicles	Gasoline & Electricity	Plug-in Hybrid LPV Natural gas - New Ordinary	32.6	1.0
Light commercial passenger vehicles	Gasoline & Electricity	Plug-in Hybrid LPV Natural gas - New Improved	26.5	0.8
Light commercial passenger vehicles	Gasoline & Electricity	Plug-in Hybrid LPV Natural gas - New Advanced	25.0	0.7
Light commercial passenger vehicles	Diesel & Renewable diesel	Internal Combustion Engine LPV Biomass - New Ordinary	26.8	0.8
Light commercial passenger vehicles	Diesel & Renewable diesel	Internal Combustion Engine LPV Biomass - New Improved	28.7	0.9
Light commercial passenger vehicles	Diesel & Renewable diesel	Internal Combustion Engine LPV Biomass - New Advanced	31.3	0.9
Light commercial passenger vehicles	Diesel & Renewable diesel	Hybrid LPV Biomass - New Ordinary	31.1	0.9
Light commercial passenger vehicles	Diesel & Renewable diesel	Hybrid LPV Biomass - New Improved	29.8	0.9
Light commercial passenger vehicles	Diesel & Renewable diesel	Hybrid LPV Biomass - New Advanced	30.0	0.9
Light commercial passenger vehicles	Diesel & Electricity	Plug-in Hybrid LPV Biomass - New Ordinary	36.9	1.1
Light commercial passenger vehicles	Diesel & Electricity	Plug-in Hybrid LPV Biomass - New Improved	31.2	0.9
Light commercial passenger vehicles	Diesel & Electricity	Plug-in Hybrid LPV Biomass - New Advanced	29.9	0.9
Light commercial passenger vehicles	Electricity	Battery Electric LPV Electricity - New Ordinary	27.8	0.3
Light commercial passenger vehicles	Electricity	Battery Electric LPV Electricity - New Improved	26.2	0.3
Light commercial passenger vehicles	Electricity	Battery Electric LPV Electricity - New Advanced	25.6	0.3
Light commercial passenger vehicles	Gaseous hydrogen	Fuel Cell LPV Gaseous hydrogen - New Ordinary	57.8	0.6

Light commercial passenger vehicles	Gaseous hydrogen	Fuel Cell LPV Gaseous hydrogen - New Improved	43.2	0.4
Light commercial passenger vehicles	Gaseous hydrogen	Fuel Cell LPV Gaseous hydrogen - New Advanced	36.3	0.4
Light commercial passenger vehicles	Natural gas & Synthetic natural gas	Internal Combustion Engine LPV Natural gas - New Ordinary	20.7	0.6
Light commercial passenger vehicles	Natural gas & Synthetic natural gas	Internal Combustion Engine LPV Natural gas - New Improved	21.3	0.6
Light commercial passenger vehicles	Natural gas & Synthetic natural gas	Internal Combustion Engine LPV Natural gas - New Advanced	22.6	0.7
Light commercial passenger vehicles	Liquefied petroleum gas	Internal Combustion Engine LPV Liquefied petroleum gas - New Ordinary	20.1	0.6
Light commercial passenger vehicles	Liquefied petroleum gas	Internal Combustion Engine LPV Liquefied petroleum gas - New Improved	20.7	0.6
Light commercial passenger vehicles	Liquefied petroleum gas	Internal Combustion Engine LPV Liquefied petroleum gas - New Advanced	22.0	0.7
Light commercial passenger vehicles	Methanol (H2 derived) (TRA)	Internal Combustion Engine LPV Methanol (H2 derived) (TRA) - New Ordinary	32.1	1.0
Light-commercial freight vehicles	Gasoline & Renewable gasoline	Internal Combustion Engine LCV Natural gas - New Ordinary	22.0	0.7
Light-commercial freight vehicles	Gasoline & Renewable gasoline	Internal Combustion Engine LCV Natural gas - New Improved	22.7	0.7
Light-commercial freight vehicles	Gasoline & Renewable gasoline	Internal Combustion Engine LCV Natural gas - New Advanced	24.2	0.7
Light-commercial freight vehicles	Gasoline & Renewable gasoline	Hybrid LCV Natural gas - New Ordinary	25.9	0.8
Light-commercial freight vehicles	Gasoline & Renewable gasoline	Hybrid LCV Natural gas - New Improved	24.7	0.7
Light-commercial freight vehicles	Gasoline & Renewable gasoline	Hybrid LCV Natural gas - New Advanced	25.0	0.8
Light-commercial freight vehicles	Gasoline & Renewable gasoline	Plug-in Hybrid LCV Natural gas - New Ordinary	32.6	1.0
Light-commercial freight vehicles	Gasoline & Renewable gasoline	Plug-in Hybrid LCV Natural gas - New Improved	26.5	0.8
Light-commercial freight vehicles	Gasoline & Renewable gasoline	Plug-in Hybrid LCV Natural gas - New Advanced	25.0	0.7
Light-commercial freight vehicles	Diesel & Renewable diesel	Internal Combustion Engine LCV Biomass - New Ordinary	26.8	0.8
Light-commercial freight vehicles	Diesel & Renewable diesel	Internal Combustion Engine LCV Biomass - New Improved	28.7	0.9
Light-commercial freight vehicles	Diesel & Renewable diesel	Internal Combustion Engine LCV Biomass - New Advanced	31.3	0.9
Light-commercial freight vehicles	Diesel & Renewable diesel	Hybrid LCV Biomass - New Ordinary	31.1	0.9
Light-commercial freight vehicles	Diesel & Renewable diesel	Hybrid LCV Biomass - New Improved	29.8	0.9
Light-commercial freight vehicles	Diesel & Renewable diesel	Hybrid LCV Biomass - New Advanced	30.0	0.9
Light-commercial freight vehicles	Diesel & Renewable diesel	Plug-in Hybrid LCV Biomass - New Ordinary	36.9	1.1
Light-commercial freight vehicles	Diesel & Renewable diesel	Plug-in Hybrid LCV Biomass - New Improved	31.2	0.9
Light-commercial freight vehicles	Diesel & Renewable diesel	Plug-in Hybrid LCV Biomass - New Advanced	29.9	0.9
Light-commercial freight vehicles	Electricity	Battery Electric LCV Electricity - New Ordinary	27.8	0.3
Light-commercial freight vehicles	Electricity	Battery Electric LCV Electricity - New Improved	26.2	0.3

Light-commercial freight vehicles	Electricity	Battery Electric LCV Electricity - New Advanced	25.6	0.3
Light-commercial freight vehicles	Gaseous hydrogen	Fuel Cell LCV Gaseous hydrogen - New Ordinary	57.8	0.6
Light-commercial freight vehicles	Gaseous hydrogen	Fuel Cell LCV Gaseous hydrogen - New Improved	43.2	0.4
Light-commercial freight vehicles	Gaseous hydrogen	Fuel Cell LCV Gaseous hydrogen - New Advanced	36.3	0.4
Light-commercial freight vehicles	Natural gas & Synthetic natural gas	Internal Combustion Engine LCV Natural gas - New Ordinary	20.7	0.6
Light-commercial freight vehicles	Natural gas & Synthetic natural gas	Internal Combustion Engine LCV Natural gas - New Improved	21.3	0.6
Light-commercial freight vehicles	Natural gas & Synthetic natural gas	Internal Combustion Engine LCV Natural gas - New Advanced	22.6	0.7
Light-commercial freight vehicles	Liquefied petroleum gas	Internal Combustion Engine LCV Liquefied petroleum gas - New Ordinary	20.1	0.6
Light-commercial freight vehicles	Liquefied petroleum gas	Internal Combustion Engine LCV Liquefied petroleum gas - New Improved	20.7	0.6
Light-commercial freight vehicles	Liquefied petroleum gas	Internal Combustion Engine LCV Liquefied petroleum gas - New Advanced	22.0	0.7
Light-commercial freight vehicles	Methanol (H2 derived) (TRA)	Internal Combustion Engine LCV Methanol - New Ordinary	32.1	1.0
Heavy-duty trucks	Gasoline & Renewable gasoline	Internal Combustion Engine HDT Natural gas - New Ordinary	114.4	3.4
Heavy-duty trucks	Gasoline & Renewable gasoline	Internal Combustion Engine HDT Natural gas - New Improved	112.9	3.4
Heavy-duty trucks	Gasoline & Renewable gasoline	Internal Combustion Engine HDT Natural gas - New Advanced	112.8	3.4
Heavy-duty trucks	Gasoline & Renewable gasoline	Hybrid HDT Natural gas - New Ordinary	129.5	3.9
Heavy-duty trucks	Gasoline & Renewable gasoline	Hybrid HDT Natural gas - New Improved	125.0	3.8
Heavy-duty trucks	Gasoline & Renewable gasoline	Hybrid HDT Natural gas - New Advanced	124.1	3.7
Heavy-duty trucks	Diesel & Renewable diesel	Internal Combustion Engine HDT Biomass - New Ordinary	131.2	3.9
Heavy-duty trucks	Diesel & Renewable diesel	Internal Combustion Engine HDT Biomass - New Improved	131.6	3.9
Heavy-duty trucks	Diesel & Renewable diesel	Internal Combustion Engine HDT Biomass - New Advanced	132.1	4.0
Heavy-duty trucks	Diesel & Renewable diesel	Hybrid HDT Biomass - New Ordinary	148.6	4.5
Heavy-duty trucks	Diesel & Renewable diesel	Hybrid HDT Biomass - New Improved	143.5	4.3
Heavy-duty trucks	Diesel & Renewable diesel	Hybrid HDT Biomass - New Advanced	142.6	4.3
Heavy-duty trucks	Electricity	Battery Electric HDT Electricity - New Ordinary	245.9	2.5
Heavy-duty trucks	Electricity	Battery Electric HDT Electricity - New Improved	180.2	1.8
Heavy-duty trucks	Electricity	Battery Electric HDT Electricity - New Advanced	165.9	1.7
Heavy-duty trucks	Gaseous hydrogen	Fuel Cell HDT Gaseous hydrogen - New Ordinary	446.9	4.5
Heavy-duty trucks	Gaseous hydrogen	Fuel Cell HDT Gaseous hydrogen - New Improved	267.5	2.7
Heavy-duty trucks	Gaseous hydrogen	Fuel Cell HDT Gaseous hydrogen - New Advanced	205.0	2.0

Heavy-duty trucks	Natural gas & Synthetic natural gas	Internal Combustion Engine HDT Natural gas - New Ordinary	143.2	4.3
Heavy-duty trucks	Natural gas & Synthetic natural gas	Internal Combustion Engine HDT Natural gas - New Improved	143.5	4.3
Heavy-duty trucks	Natural gas & Synthetic natural gas	Internal Combustion Engine HDT Natural gas - New Advanced	143.9	4.3
Heavy-duty trucks	Liquefied petroleum gas	Internal Combustion Engine HDT Liquefied petroleum gas - New Ordinary	121.7	3.7
Heavy-duty trucks	Liquefied petroleum gas	Internal Combustion Engine HDT Liquefied petroleum gas - New Improved	143.5	4.3
Heavy-duty trucks	Liquefied petroleum gas	Internal Combustion Engine HDT Liquefied petroleum gas - New Advanced	143.9	4.3
Heavy-duty trucks	Methanol (H2 derived) (TRA)	Internal Combustion Engine HDT Methanol (H2 derived) (TRA) - New Ordinary	178.3	5.3

Residential sector

Table 54: Cost of technologies in the residential sector

Service	Fuel	Technology	Year	Unit	Investment cost
Thermal uses	Biomass	Wood Stove (Ord.)	2020	USD/kW	398
Thermal uses	Biomass	Wood Stove (Imp.)	2030	USD/kW	457
			2050	USD/kW	428
Thermal uses	Biomass	Wood Stove (Adv.)	2030	USD/kW	592
			2050	USD/kW	573
Thermal uses	Coal	Stove	2020	USD/kW	398
Thermal uses	Electricity	Heat Pump Air (Ord.)	2020	USD/kW	762
Thermal uses	Electricity	Heat Pump Air (Imp.)	2030	USD/kW	811
			2050	USD/kW	654
Thermal uses	Electricity	Heat Pump Air (Adv.)	2030	USD/kW	1,049
			2050	USD/kW	1,000
Thermal uses	Electricity	Heat Pump Wat. (Ord.)	2020	USD/kW	1,006
Thermal uses	Electricity	Heat Pump Wat. (Imp.)	2030	USD/kW	1,072
			2050	USD/kW	932
Thermal uses	Electricity	Heat Pump Wat. (Adv.)	2020	USD/kW	1,386
			2020	USD/kW	1,250
Thermal uses	Electricity	Electr. Resist. (Ord.)	2020	USD/kW	59
			2030	USD/kW	73
			2050	USD/kW	67
Thermal uses	Natural gas	Boiler (Ord.)	2020	USD/kW	152

Thermal uses	Natural gas	Boiler cond. (Ord.)	2020	USD/kW	172
Thermal uses	Natural gas	Boiler (Imp.)	2030	USD/kW	175
			2050	USD/kW	173
Thermal uses	Natural gas	Boiler cond. (Imp.)	2030	USD/kW	218
			2050	USD/kW	204
Thermal uses	Natural gas	Heat Pump (Ord.)	2020	USD/kW	1,142
Thermal uses	Natural gas	Heat Pump (Imp.)	2030	USD/kW	1,159
			2050	USD/kW	915
Thermal uses	Natural gas	Heat Pump (Adv.)	2030	USD/kW	1,468
			2050	USD/kW	1,300
Thermal uses	Geothermal	Heat Pump (Ord.)	2020	USD/kW	1,646
Thermal uses	Geothermal	Heat Pump (Imp.)	2030	USD/kW	1,754
			2050	USD/kW	1,524
Thermal uses	Geothermal	Heat Pump (Adv.)	2030	USD/kW	2,268
			2050	USD/kW	1,722
Thermal uses	Heat	District Heat (Ord.)	2020	USD/kW	88
Thermal uses	Heat	District Heat (Imp.)	2030	USD/kW	104
			2050	USD/kW	97
Thermal uses	LPG	Boiler	2020	USD/kW	157
Thermal uses	Oil	Boiler (Ord.)	2020	USD/kW	157
Thermal uses	Oil	Boiler cond. (Ord.)	2020	USD/kW	195
Thermal uses	Oil	Boiler cond. (Imp.)	2030	USD/kW	224
			2050	USD/kW	210
Thermal uses	Solar	Thermal (Ord.)	2020	USD/kW	1,214
			2030	USD/kW	1,342
			2050	USD/kW	1,049
Thermal uses	Hydrogen	H2 boiler	2040	USD/kW	204
Air conditioning	Electricity	Air conditioning (Ord.)	2020	USD/kW	190
Air conditioning	Electricity	Air conditioning (Imp.)	2030	USD/kW	254
			2050	USD/kW	243
Air conditioning	Electricity	Air conditioning (Adv.)	2030	USD/kW	343
			2050	USD/kW	337
Cooking	Electricity	Cooking system (Ord.)	2020	USD/kW	182
Cooking	Natural gas	Cooking system (Ord.)	2020	USD/kW	190
Cooking	LPG	Cooking system (Ord.)	2020	USD/kW	190
Cooking	Coal	Cooking system (Ord.)	2020	USD/kW	190
Cooking	Oil,Renewable liquid fuels	Cooking system (Ord.)	2020	USD/kW	190
Cooking	Biomass	Cooking system (Ord.)	2020	USD/kW	190
Lighting	Electricity	Lighting system (Ord.)	2020	USD/unit	4

Lighting	Electricity	Lighting system (Imp.)	2030	USD/unit	5
			2050	USD/unit	4
Lighting	Electricity	Lighting system (Adv.)	2030	USD/unit	9
			2050	USD/unit	9
Electric Appli-ances	Electricity	Appl. (Ord.)	2020	USD/kW	535
Electric Appli-ances	Electricity	Appl. (Imp.)	2030	USD/kW	622
			2050	USD/kW	603
Electric Appli-ances	Electricity	Appl. (Adv.)	2030	USD/kW	784
			2050	USD/kW	773

Service sector

Table 55: Cost of technologies in the service sector

Service	Fuel	Technology	Year	Investment cost
				USD/kW
Thermal uses	Biomass	Wood Stove (Ord.)	2020	399
Thermal uses	Biomass	Wood Stove (Imp.)	2030	458
			2050	430
Thermal uses	Biomass	Wood Stove (Adv.)	2030	594
			2050	574
Thermal uses	Coal	Coal Stove	2020	399
Thermal uses	Electricity	Heat Pump Air (Ord.)	2020	534
Thermal uses	Electricity	Heat Pump Air (Imp.)	2030	569
			2050	458
Thermal uses	Electricity	Heat Pump Air (Adv.)	2030	736
			2050	652
Thermal uses	Electricity	Heat Pump Wat. (Ord.)	2020	706
Thermal uses	Electricity	Heat Pump Wat. (Imp.)	2030	752
			2050	654
Thermal uses	Electricity	Heat Pump Wat. (Adv.)	2030	973
			2050	814
Thermal uses	Natural gas,Biogas	Boiler (Ord.)	2020	115
Thermal uses	Natural gas,Biogas	Boiler cond. (Ord.)	2020	152
			2030	174
			2050	162
Thermal uses	Electricity	Ground Heat Pump (Ord.)	2020	1,155
Thermal uses	Electricity	Ground Heat Pump (Imp.)	2030	1,231
			2050	1,070
Thermal uses	Electricity	Ground Heat Pump (Adv.)	2030	1,592
			2050	1,122

Thermal uses	Heat	District Heat (Ord.)	2020	71
Thermal uses	Heat	District Heat (Imp.)	2030	76
			2050	90
Thermal uses	LPG	Boiler	2020	157
Thermal uses	Oil, Renewable liquid fuels	Boiler (Ord.)	2020	157
Thermal uses	Oil, Renewable liquid fuels	Boiler cond. (Ord.)	2020	195
Thermal uses	Oil, Renewable liquid fuels	Boiler cond. (Imp.)	2030	224
			2050	210
Thermal uses	Solar	Thermal (Ord.)	2020	1,217
			2030	1,346
			2050	1,052
Thermal uses	Hydrogen	H2 boiler	2040	162
Air conditioning	Electricity	Air conditioning (Ord.)	2020	133
Air conditioning	Electricity	Air conditioning (Imp.)	2030	172
			2050	156
Air conditioning	Electricity	Air conditioning (Adv.)	2030	223
			2050	220
Air conditioning	Natural gas,Biogas	Air conditioning (Ord.)	2020	562
Air conditioning	Natural gas,Biogas	Air conditioning (Imp.)	2030	510
			2050	342
Air conditioning	Natural gas,Biogas	Air conditioning (Adv.)	2030	559
Air conditioning	Heat	Air conditioning (Ord.)	2020	151
Air conditioning	Heat	Air conditioning (Imp.)	2030	159
			2050	147
Air conditioning	Heat	Air conditioning (Adv.)	2030	182
		…	2050	150
Street lighting	Electricity	Street lights (Ord.)	2020	44
Street lighting	Electricity	Street lights (Imp.)	2030	60
			2050	60
Street lighting	Electricity	Street lights (Adv.)	2030	111
		…	2050	109
Lighting	Electricity	Office lighting (Ord.)	2020	9
Lighting	Electricity	Office lighting (Imp.)	2030	12
			2050	12
Lighting	Electricity	Office lighting (Adv.)	2030	22
		…	2050	22
Cooking	Biomass	Cooking system (Ord.)	2020	190
Cooking	Natural gas,Biogas	Cooking system (Ord.)	2020	190
Cooking	Electricity	Cooking system (Ord.)	2020	182
Cooking	LPG	Cooking system (Ord.)	2020	190
Cooking	Oil, Renewable liquid fuels	Cooking system (Ord.)	2020	190
		….		0
Electric Appliances	Electricity	Appl.(Ord.)	2020	18

Electric Appliances	Electricity	Appl.(Imp.)	2030	17
			2050	15
Electric Appliances	Electricity	Appl.(Adv.)	2030	24
		…	2050	22

Appendix B

Sensitivity scenarios for Net-Zero

Final energy consumption

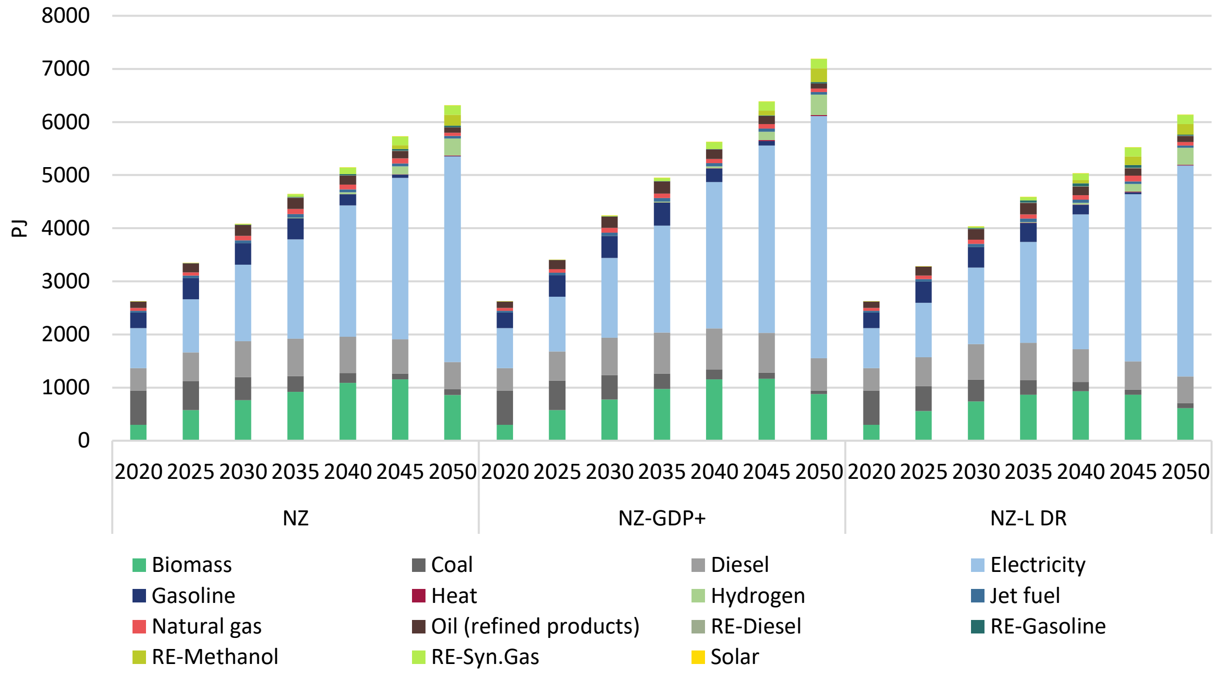

Figure 110: TFEC by fuel type in sensitivity scenarios, TIMES [PJ]

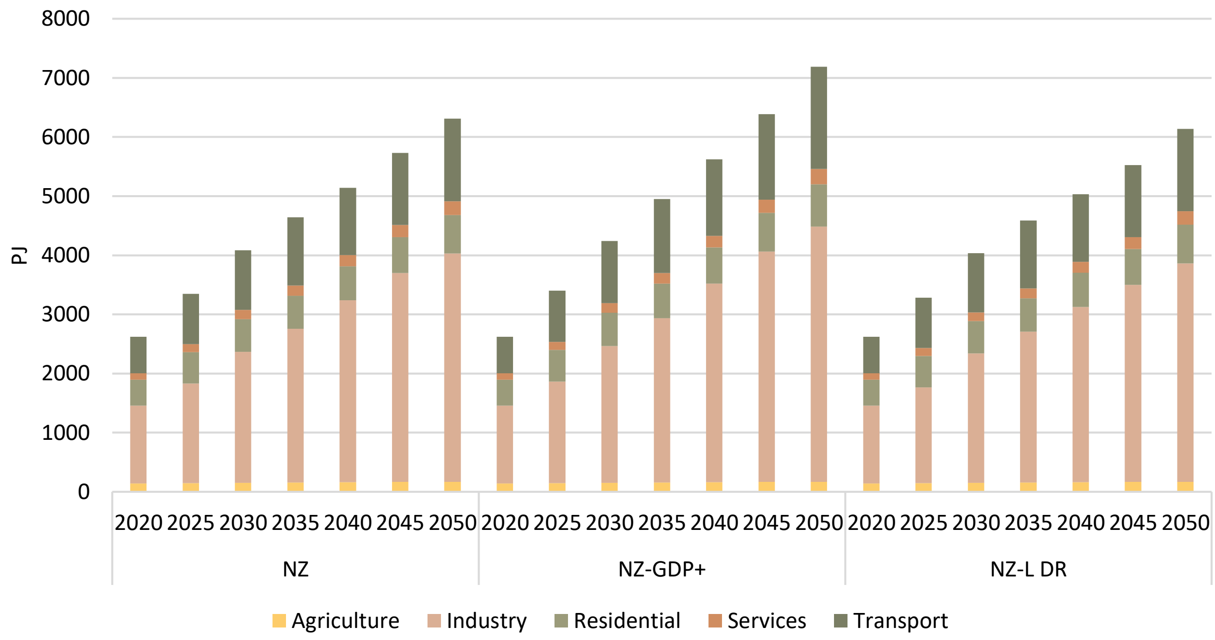

Figure 111: TFEC by end-use sector in sensitivity scenarios, TIMES [PJ]

Hydrogen consumption

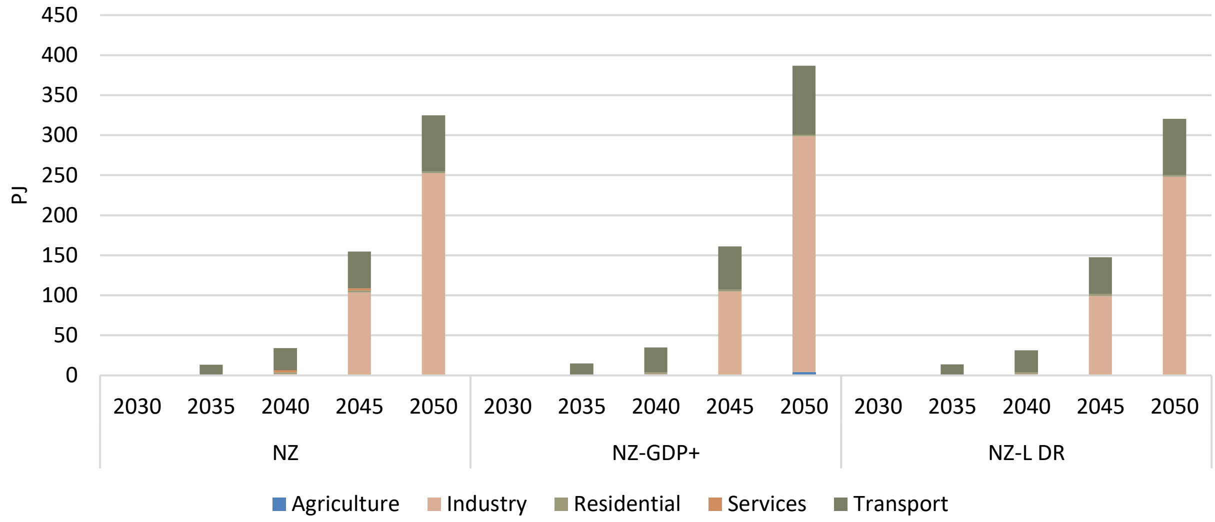

Figure 112: Final H_2 consumption by sector, TIMES [PJ]

Agriculture

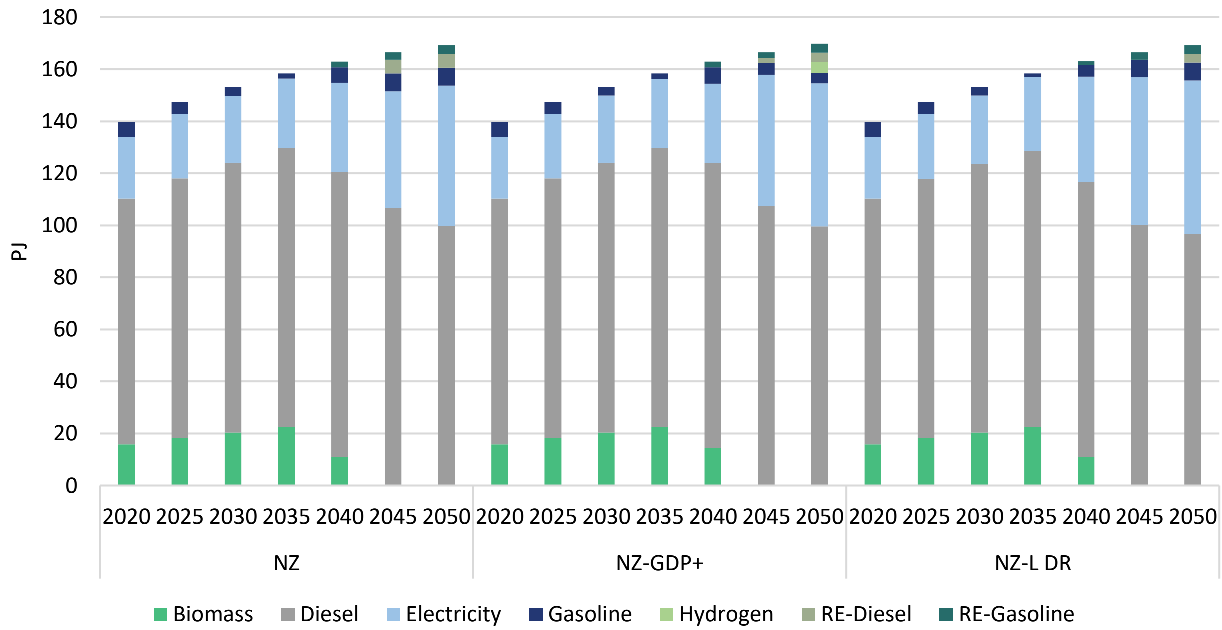

Figure 113: Final energy consumption in Agriculture, TIMES [PJ]

Industry

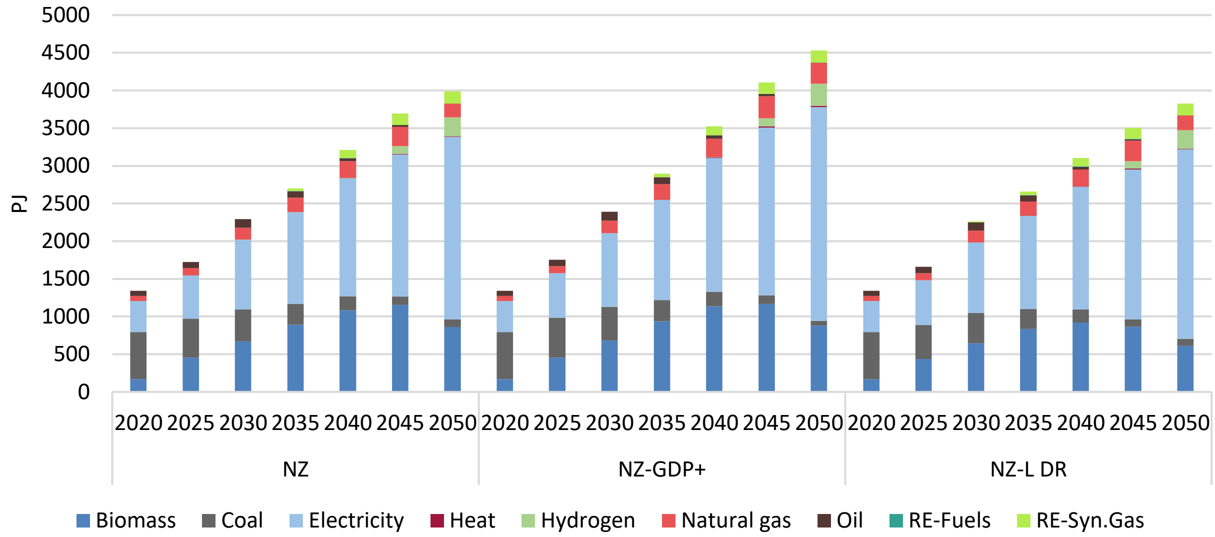

Figure 114: Final energy consumption in Industry by fuel type, TIMES [PJ]

Residential

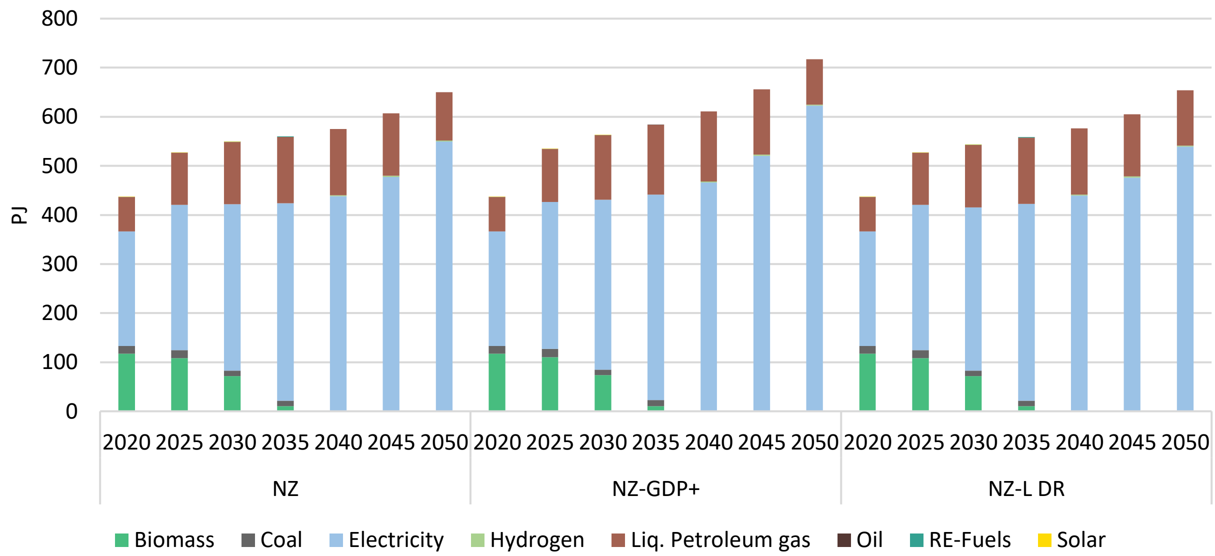

Figure 115: Final energy consumption in Residential, TIMES [PJ]

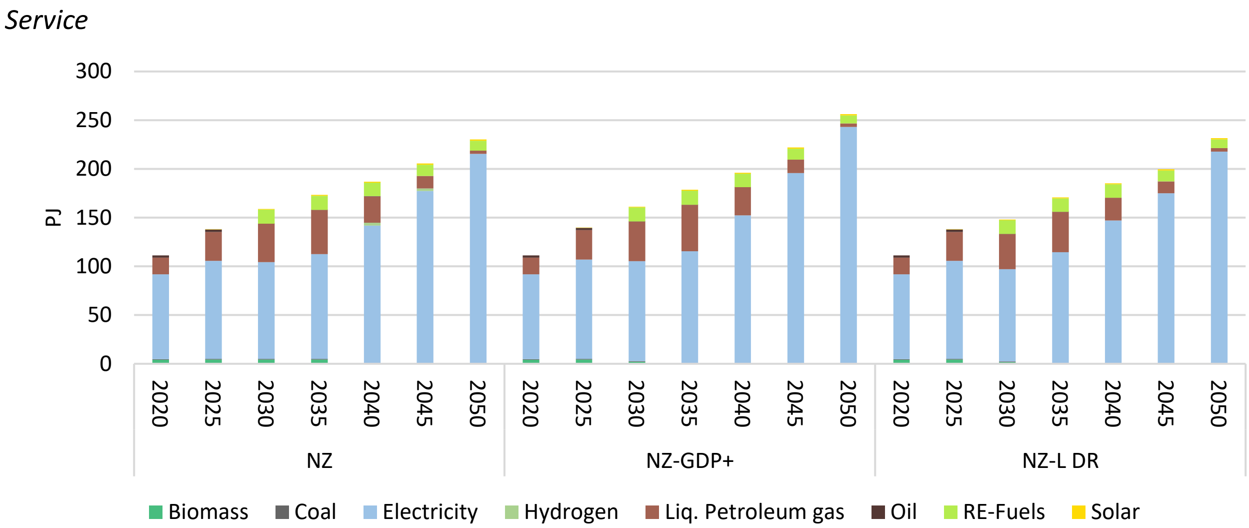

Figure 116: Final energy consumption in Services, TIMES [PJ]

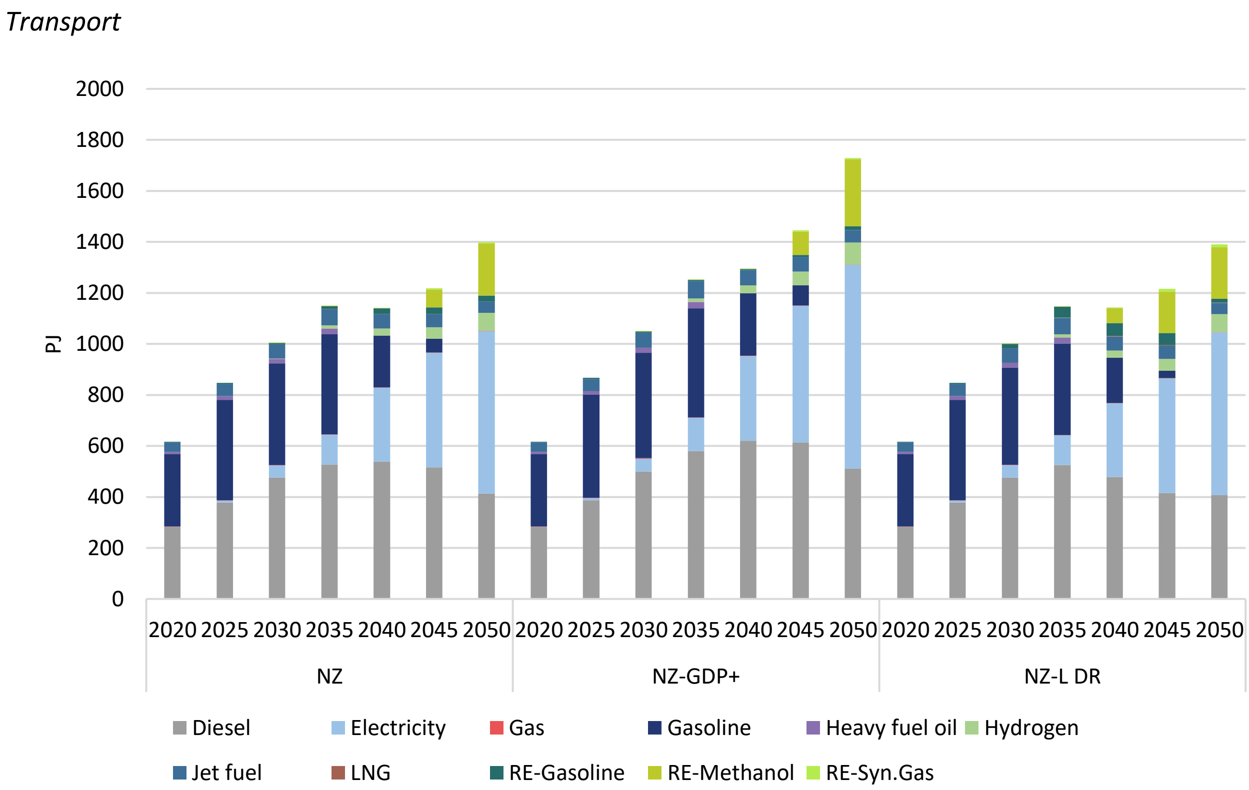

Figure 117: Final energy consumption in Transport, TIMES [PJ]

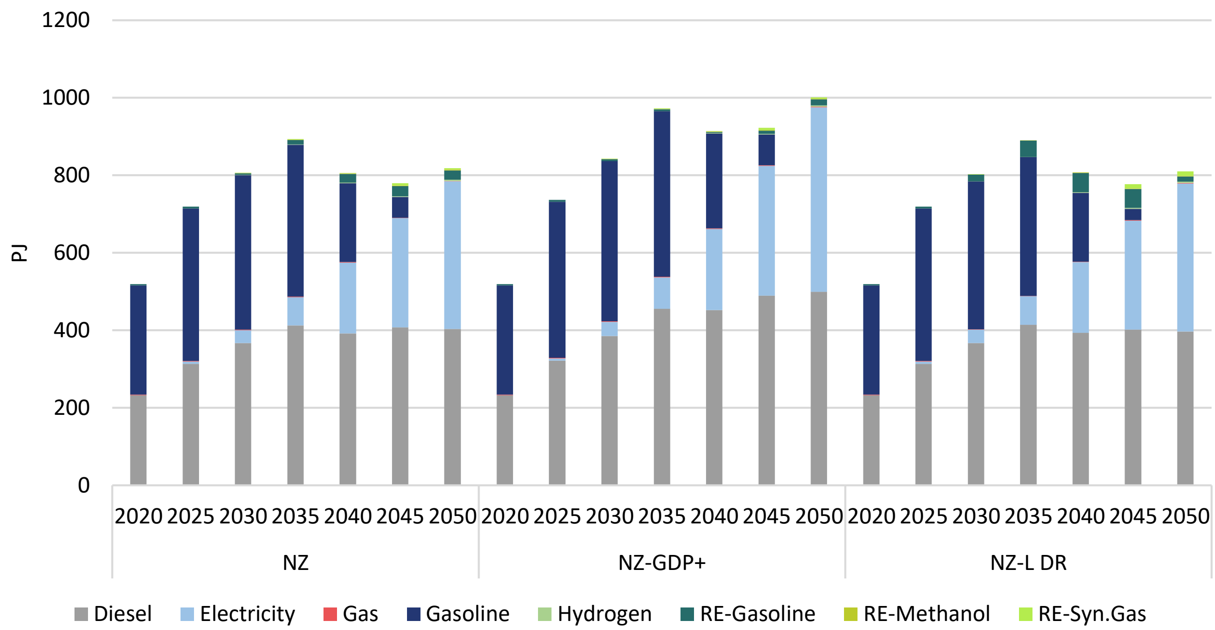

Figure 118: Road transport fuel consumption, TIMES [PJ]

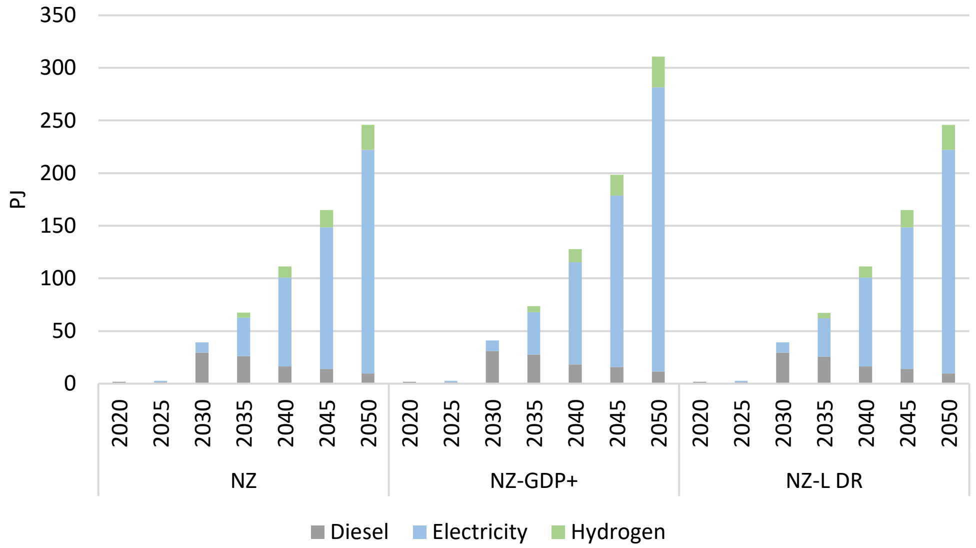

Figure 119: Rail transport fuel consumption

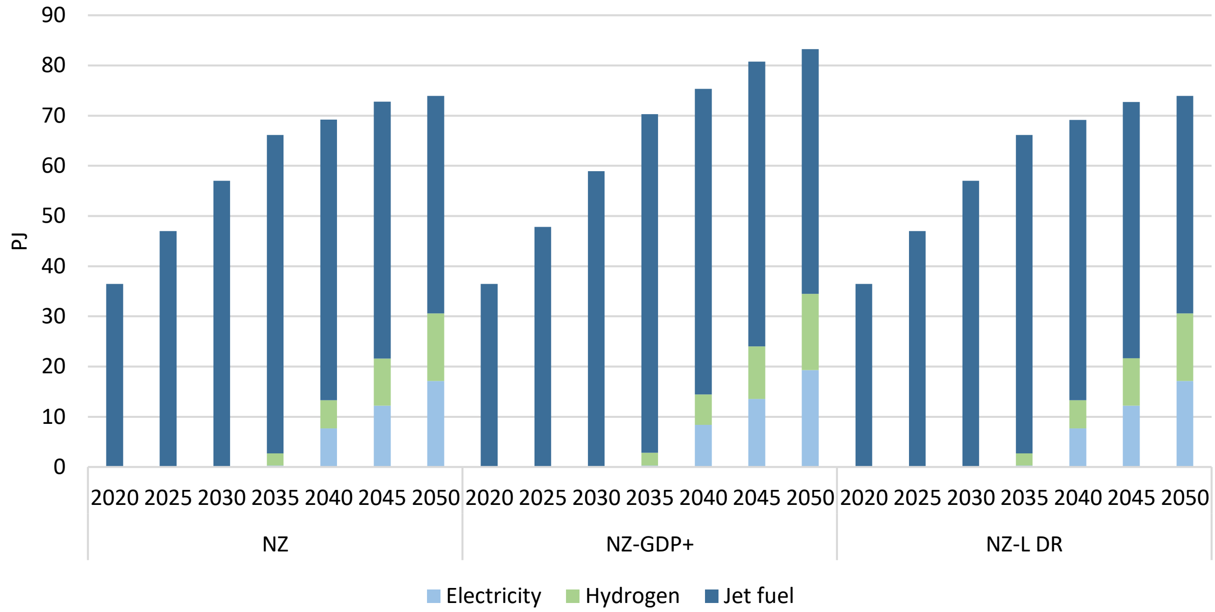

Figure 120: Aviation fuel consumption, TIMES [PJ]

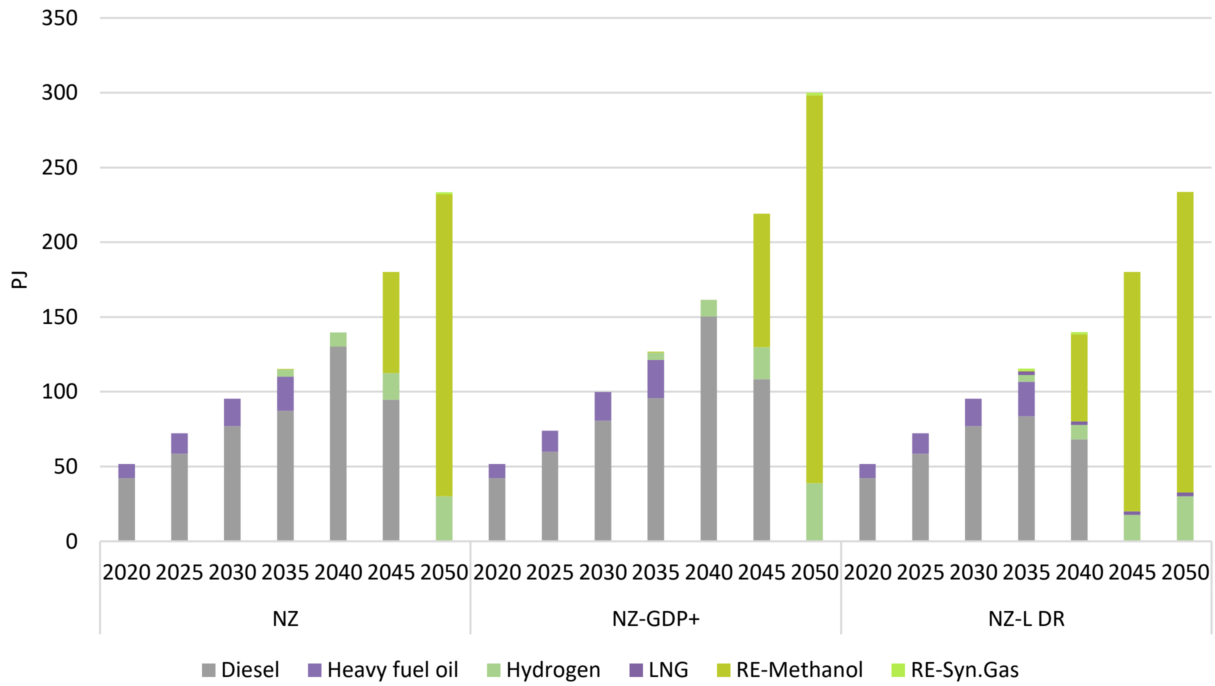

Figure 121: Navigation fuel consumption, TIMES [PJ]

Appendix C

Levelized costs of energy (LCOE)

Figure 122 presents the LCOE of the key power generation technologies for the year 2030 and 2050. LCOE includes capital, O&M, fuel and pollution costs and has been calculated for three different levels of full load hours (FLHs) for each technology with the following assumptions:

- The Balmorel model input data as described in this report, is used for investment costs (including IDC), fixed and variable O&M costs, as well as the power plants' efficiencies.
- The same fuel cost assumptions as used in the EOR-NZ study are applied.
- Pollution costs are included in the LCOE calculation, and present the result of the sum of SO_2, NOx and $PM_{2.5}$ emissions costs. The same cost assumptions as used in this study are applied, taking into consideration the specific characteristics of the power plants technologies.
- An annuity factor based on the discount rate of 10% as used in the EOR-NZ study and a period of 20 years is applied.
- The FLHs, both average, high and low values, are assumed partly based on average values from the model (for RE technologies) and from general average use, which are listed in Table 56.

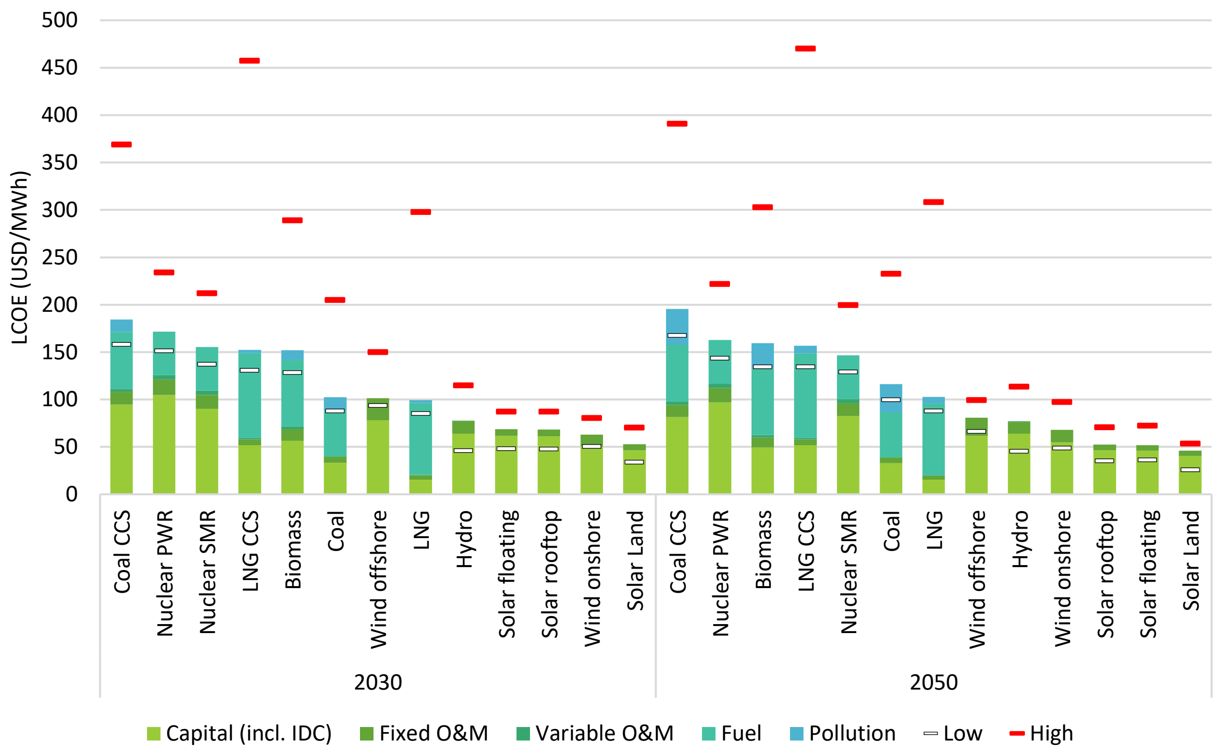

Figure 122: LCOE values for the various technologies. "Low" and "High" indicate the LCOE result with low and high FLH assumptions.

Table 56: Full load hours assumed for LCOE calculation

Year	Technologies	FLHs	Low FLHs	High FLH
2030	Nuclear PWR	7.500	5.500	8.500
	Nuclear SMR	7.500	5.500	8.500
	Coal	6.000	3.000	7.000
	Coal CCS	6.000	3.000	7.000
	LNG	6.000	2.000	7.000
	LNG CCS	6.000	2.000	7.000
	Biomass	3.800	2.000	4.500
	Hydro	2.950	2.000	5.000
	Solar Land	1.600	1.200	2.500
	Solar rooftop	1.400	1.100	2.000
	Solar floating	1.400	1.100	2.000
	Wind onshore	3.200	2.500	4.000
	Wind offshore	3.700	2.500	4.000
2050	Nuclear PWR	7.500	5.500	8.500
	Nuclear SMR	7.500	5.500	8.500
	Coal	6.000	3.000	7.000
	Coal CCS	6.000	3.000	7.000
	LNG	6.000	2.000	7.000
	LNG CCS	6.000	2.000	7.000
	Biomass	3.800	2.000	4.500
	Hydro	2.950	2.000	5.000
	Solar Land	1.400	1.200	2.500
	Solar rooftop	1.350	1.000	2.000
	Solar floating	1.400	1.000	2.000
	Wind onshore	2.500	1.750	3.500
	Wind offshore	3.700	3.000	4.500