Asia-Pacific
Economic Cooperation



APEC Energy Demand and Supply Outlook

9th Edition 2025

Volume 2

APERC
Asia Pacific Energy Research Centre

Asia-Pacific
Economic Cooperation

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APEC Energy Working Group

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The terms used in this document are for purposes of this report and do not imply the "political status" of any APEC member economy.

Foreword

The first *APEC Energy Demand and Supply Outlook* was published in 1998, when the Asia Pacific Energy Research Centre (APERC) was just two years old. Since then, the *Outlook* has continued to evolve, providing projections and analysis through periods of unprecedented growth and numerous changes in the energy sector across the Asia-Pacific Economic Cooperation (APEC) region.

Today, the global energy system is undergoing profound changes as individual economies address the energy trilemma and strive to balance energy security, affordability, and sustainability. The *APEC Energy Demand and Supply Outlook, 9th Edition* underscores the fact that energy policy decisions made by APEC economies will have far-reaching implications for the individual economies, the APEC region, and the world.

The primary aim of the *Outlook* is to support APEC economies in achieving their individual and collective energy goals. It also serves as a valuable reference for those seeking to better understand recent and prospective energy developments within the APEC region.

This edition is comprised of two volumes: **Volume 1** highlights key trends and insights for the APEC region as a whole. **Volume 2** presents detailed energy outlooks for each of the 21 APEC economies. The analysis is anchored in two scenarios designed to explore the opportunities and challenges across the diverse energy systems of the APEC member economies. The **Reference Scenario (REF)** offers a projection based on historical trends and APERC's assumptions about the continuation of those trends in each APEC economy, while acknowledging technical constraints. The REF Scenario provides baseline results to compare with the **Target Scenario (TGT)** projections, which explore a hypothetical pathway where each economy achieves energy-related policy targets, assuming implementation regardless of cost-effectiveness.

Reflecting the shifting global energy landscape, this edition of the Outlook sharpened its focus on three key energy issues: 1) The costs associated with decarbonisation of the power and hydrogen sectors of each APEC economy; 2) The effects of increased variable renewable energy (VRE) sources, such as solar and wind, on electric grid reliability; and 3) The increased electricity requirements of data centres, including artificial intelligence (AI) workloads. We hope these enhanced analyses provide stakeholders with useful insights into critical issues that will shape the future of energy in the APEC region.

For its base year, the *Outlook* utilises data submitted by APEC economies to APEC's Expert Group on Energy Data and Analysis (EGEDA).

This 9th Edition of the *Outlook* is the result of three years of planning, rigorous analysis, and collaboration by the APERC research team, under the leadership of Senior Vice President Glen E. Sweetnam. It also reflects the valuable contributions of experts across APEC's 21 member economies and beyond.

It is my pleasure to present this edition of the *APEC Energy Demand and Supply Outlook*.



Dr. Kazutomo IRIE
Chairman & President, Asia Pacific Energy Research Centre (APERC)

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The development of the *APEC Energy Demand and Supply Outlook, 9th Edition*, would not have been possible without the valuable contributions of numerous individuals and organisations across APEC's 21 member economies and beyond. We extend our sincere gratitude to all those whose support made this edition possible, particularly the participants of the APERC Annual Conference and the individuals and organisations acknowledged below.

We would like to express our deep appreciation to the Ministry of Economy, Trade and Industry of Japan for its generous sponsorship and financial support of this project.

We would also like to express our gratitude to members of the APEC Secretariat, the APEC Energy Working Group (EWG), the APEC Expert Group on Energy Data and Analysis (EGEDA), the APERC Advisory Board, along with numerous government officials, for their valuable insights and feedback throughout preparation of this report.

Please note that the *Outlook* is an independent study conducted by APERC and does not necessarily reflect the views of APEC member economies.

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Introduction

Overview of Volume 2

The *APEC Energy Demand and Supply Outlook, 9th Edition* was developed with the recognition that each APEC member economy must address the energy trilemma: What government policies and programs will provide the best balance of energy security, sustainability, and affordability?

To that end, this *Outlook* provides a projection through 2060 of four key parameters:

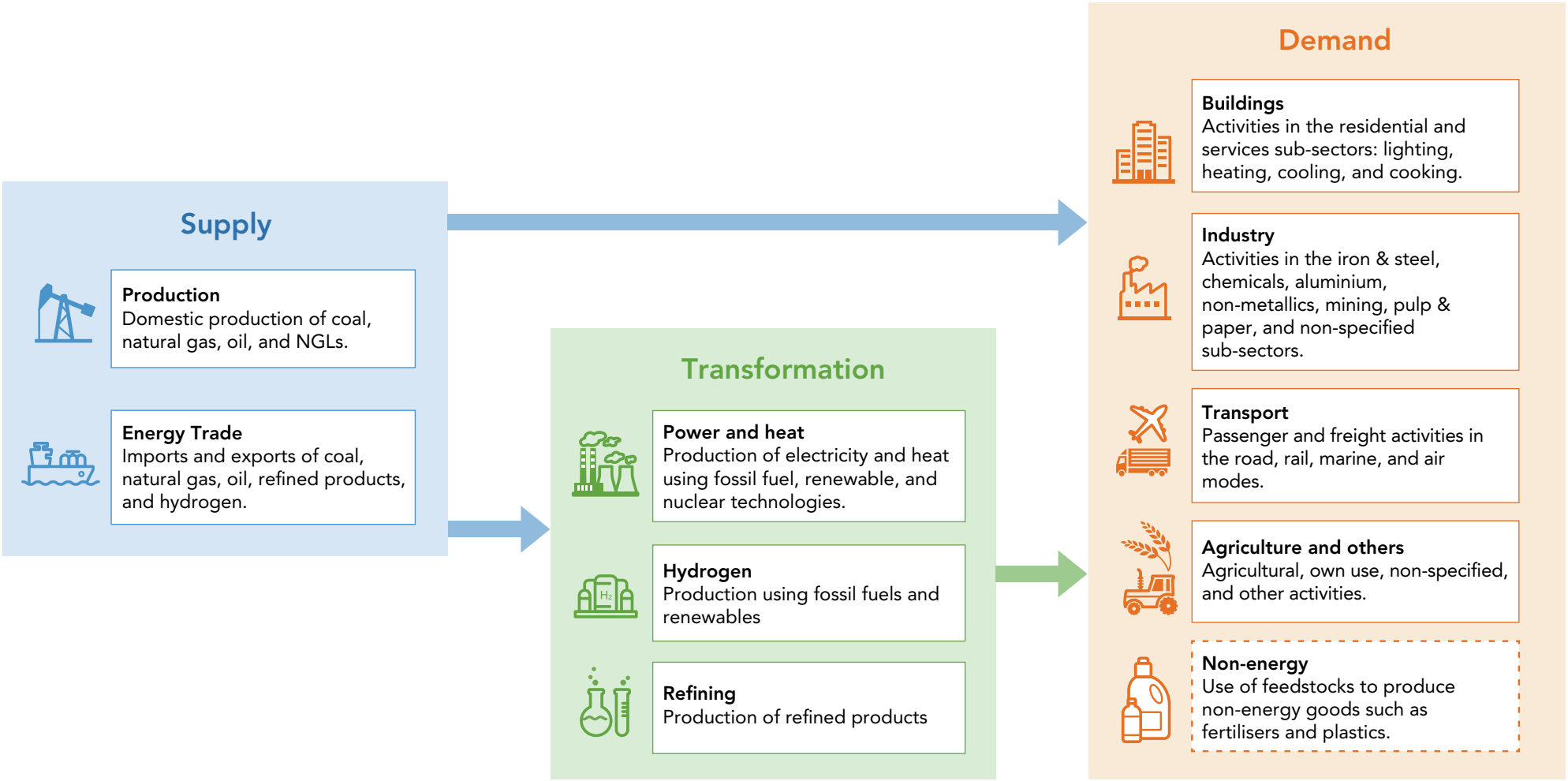
1. CO_2 emissions as one measure of environmental sustainability
2. Energy import dependence as one component of energy security
3. Electric grid reliability as a dimension of energy security
4. Total costs in the power and hydrogen sectors as a proxy for affordability.

Volume 2 of the *Outlook* provides a separate chapter for each economy organised as follows:

i. Summary table of key results
ii. Key takeaways: four key parameters
iii. Economy profile and key energy initiatives
iv. Sankey (energy flow) diagrams
v. Scenarios and assumptions
vi. Demographic and macroeconomic assumptions
vii. Energy demand projections
viii. Power generation, capacity, and reliability
ix. Energy supply projections
x. Costs in power and hydrogen sectors
xi. CO_2 emissions

It is our hope that these economy-specific projections of energy demand and supply, as well as forward-looking estimates of the four key parameters, will assist each APEC member economy as it develops its strategy to effectively navigate the energy trilemma.

Components of the APEC Energy System



Summary – Key Results for the APEC Region

	Reference			Target		
	2022	2060	% Change	2022	2060	% Change
Macroeconomic						
Population (million)	2,974.6	2821.9	-5%	2,974.6	2,821.9	-5%
GDP (billion 2017 USD, PPP)	75,411	177,430	135%	75,411	177,430	135%
Energy Demand						
Agriculture & fisheries (PJ)	4,685	5,272	13%	4,685	4,251	-9%
Buildings (PJ)	56,161	74,562	33%	56,158	63,307	13%
Industry (PJ)	82,128	93,767	14%	82,128	86,039	5%
Non-energy (PJ)	30,253	43,522	44%	30,253	38,970	29%
Transport (PJ)	59,620	59,359	0%	59,623	35,962	-40%
Modern renewables share of TFEC (%)	11	28	155%	11	46	318%
Energy intensity of TFEC (PJ/GDP, billion USD)	2.8	1.4	-50%	2.8	1.1	-61%
Electricity						
Generation (TWh)	18,971	32,690	72%	18,971	37,193	96%
Renewables share of generation (%)	26	55	115%	26	64	146%
Generation capacity (GW)	5,426	14,915	175%	5,426	19,008	250%
Total Primary Energy Supply (TPES)						
Coal & coal products (PJ)	129,237	57,100	-56%	129,240	33,736	-74%
Natural gas (PJ)	86,184	136,572	58%	86,276	90,548	5%
Petroleum liquids (PJ)	98,863	91,902	-7%	98,860	45,853	-54%
Low-carbon & waste energy (PJ)	52,787	139,699	165%	52,787	221,948	320%
CO_2 intensity of energy supply ($MtCO_2/PJ$)	0.055	0.037	-33%	0.055	0.019	-65%
Net CO_2 Emissions (million tonnes)	20,198	15,725	-22%	20,204	6,699	-67%

The term "modern renewables" refers to all renewable energy sources excluding solid biomass in the buildings sector. The term "low-carbon & waste energy" includes all bioenergy, waste-derived energy, renewables, nuclear, and hydrogen-based fuels. Total primary energy supply (TPES) numbers include international bunkers. Net emissions are calculated as gross energy sector combustion CO_2 minus CO_2 captured and stored through carbon capture and storage (CCS).
Historical energy balance data is provided by the Expert Group on Energy Data and Analysis (EGEDA) for 2000 through to 2022. Unless otherwise stated, the base year is 2022, with the exception of Russia, which uses 2021. Projections continue to 2060.



1. Australia

Summary

	Reference			Target		
	2022	2060	% Change	2022	2060	% Change
Macroeconomic						
Population (million)	26	39.5	52%	26	39.5	52%
GDP (billion 2017 USD, PPP)	1,373	3,101	126%	1,373	3,101	126%
Energy Demand						
Agriculture & fisheries (PJ)	104	107	3%	104	88	-15%
Buildings (PJ)	782	968	24%	782	758	-3%
Industry (PJ)	950	1,066	12%	950	1,178	24%
Non-energy (PJ)	202	178	-12%	202	159	-21%
Transport (PJ)	1,271	1,048	-18%	1,271	817	-36%
Modern renewables share of TFEC (%)	12	50	317%	12	75.5	529%
Energy intensity of TFEC (PJ/GDP, billion USD)	2.3	1	-57%	2.3	0.9	-61%
Electricity						
Generation (TWh)	271	504	86%	271	607	124%
Renewables share of generation (%)	30.8	90.8	195%	30.8	97.6	217%
Generation capacity (GW)	101	300	198%	101	388	286%
Total Primary Energy Supply (TPES)						
Coal & coal products (PJ)	1,567	116	-93%	1,567	9	-99%
Natural gas (PJ)	1,442	1,259	-13%	1,442	706	-51%
Petroleum liquids (PJ)	1,807	1,251	-31%	1,807	533	-71%
Low-carbon & waste energy (PJ)	510	1,954	283%	510	4,236	730%
CO_2 intensity of energy supply ($MtCO_2/PJ$)	0.07	0.03	-57%	0.07	0.01	-86%
Net CO_2 Emissions (million tonnes)	352	152	-57%	352	68	-81%

Note: In this publication, the term "modern renewables" refers to all renewable energy sources excluding solid biomass in the buildings sector. The term "low-carbon & waste energy" includes all bioenergy, waste-derived energy, renewables, nuclear, and hydrogen-based fuels. Total primary energy supply (TPES) numbers include international bunkers. Net emissions are calculated as gross energy sector combustion CO_2 minus CO_2 captured and stored through carbon capture and storage (CCS).

Key Takeaways

Emissions

- Australia's combustible CO_2 emissions peaked in 2011 and have since declined due to the reduction in coal-fired power generation, renewable generation uptake, and multi-sectoral efficiency measures.
- Emission reductions across both scenarios are strongly influenced by the power sector, particularly the retirement of coal-fired power plants. A more aggressive coal phase-out schedule in the Target scenario (TGT) results in a greater overall emissions decline when compared with the Reference scenario (REF).
- By 2050, in TGT, combustible emissions decline by 71% compared to 2022 levels. This trajectory positions Australia to make strong progress towards its 2022 Nationally Determined Contribution (NDC) ambitions of reducing greenhouse gas emissions by 43% below 2005 levels by 2030 and achieving net-zero emissions by 2050.

Energy Import Dependence

- Australia is a net exporter of coal (both metallurgical and thermal), as well as natural gas, ensuring its self-reliance in these two resources.
- Low-carbon fuels, such as hydrogen, are assumed to be exported in TGT as Australia scales up its green hydrogen production sector.
- However, Australia remains import dependent for petroleum products and crude oil given its declining oil reserves and limited refining capacity. Such dependence raises potential energy security issues especially when geo-political turbulence results in disruptions of global supply.
- Despite being a net-exporter of gas, gas supply shortfalls are expected in southern states over the projection period due to pipeline constraints from northern gas producing states, high gas usage in the winter season, market dynamics, and declining output from southern gas fields, necessitating some imports in order to meet domestic demand.

Figure 1-1. Net CO_2 emissions (million tonnes)

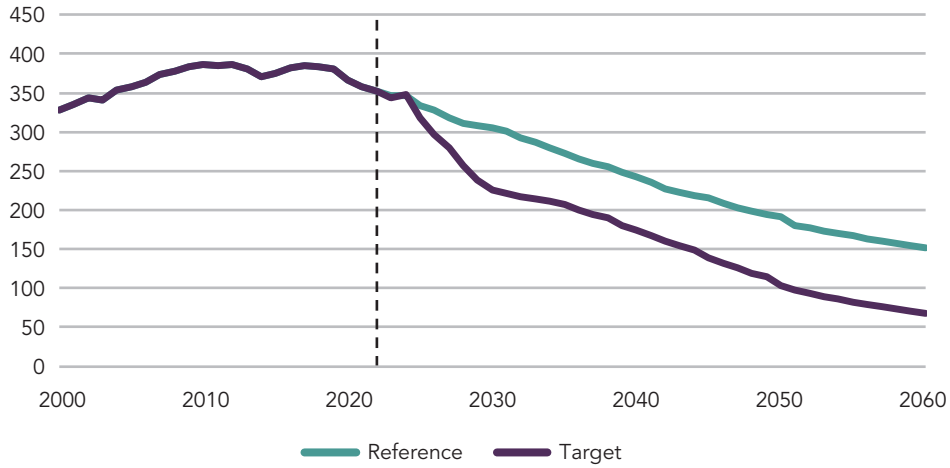
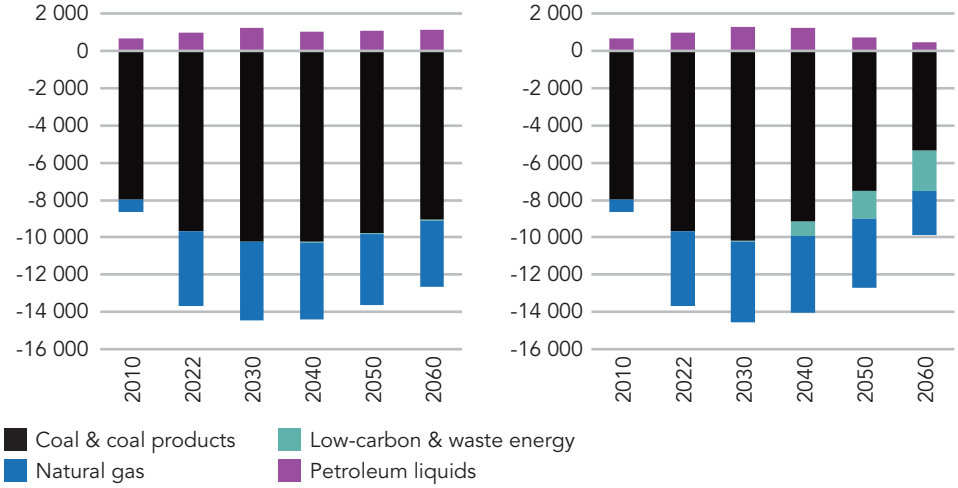


Figure 1-2. Net imports in REF & TGT (PJ)



Note: In Figure 1-2, net imports refer to total imports minus exports and international bunkers.

Key Takeaways

Grid Reliability

- Electric grid reliability requires a near-instantaneous balance between power supply and demand, requiring adequate dispatchable power sources, which include batteries.
- Figure 1-3 shows the dispatchable power that is necessary in the periods of maximum and minimum dependence across all power grids in Australia. Reductions in baseload coal generation and increased solar penetration see reduced need for intraday dispatchable power. Dependence on dispatchable power increases in the evening with both storage and gas needing to ramp up to meet evening demand. The gap between the maximum dispatchable power and peak load is assumed to be met by variable renewable energy (VRE), with system stability assumed under perfect conditions (sufficient VRE with fully charged storage).
- The power system will need to be managed carefully to ensure reliability when operating with a high level of renewables as peak demand grows.

Cost

- Australia's transformation of its electric grids through to 2060 will involve costs. In TGT, total costs are estimated to be USD 1.25 trillion, USD 274 billion higher than in REF. Total costs consider total capital, fixed, and variable costs in the power sector, costs for green hydrogen production for domestic use, transmission for VRE, and electric vehicle (EV) chargers.
- The added expenses in TGT are driven primarily by Australia's renewable energy ambitions to expand its wind, solar, and dispatchable storage capacity. Costs for additional transmission needed to accommodate more VRE capacity further increase costs in TGT relative to REF.
- In line with Australia's ambitions to grow its green hydrogen sector, green hydrogen production costs for domestic use are considered inclusive of the VRE required for electrolysis (on top of the VRE needed in the power sector). This further drives costs in TGT (relative to REF) as hydrogen production and use in REF is assumed to be relatively minimal.

Figure 1-3. Peak load and maximum and minimum dependence on dispatched power (GW)

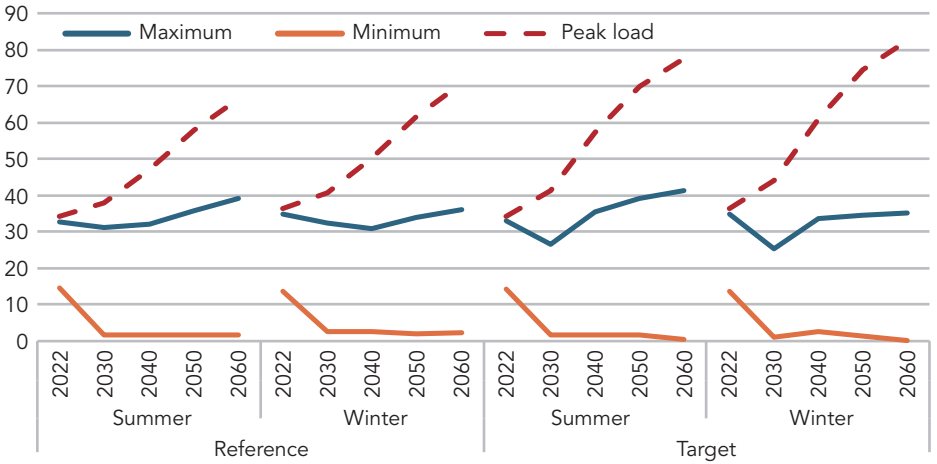
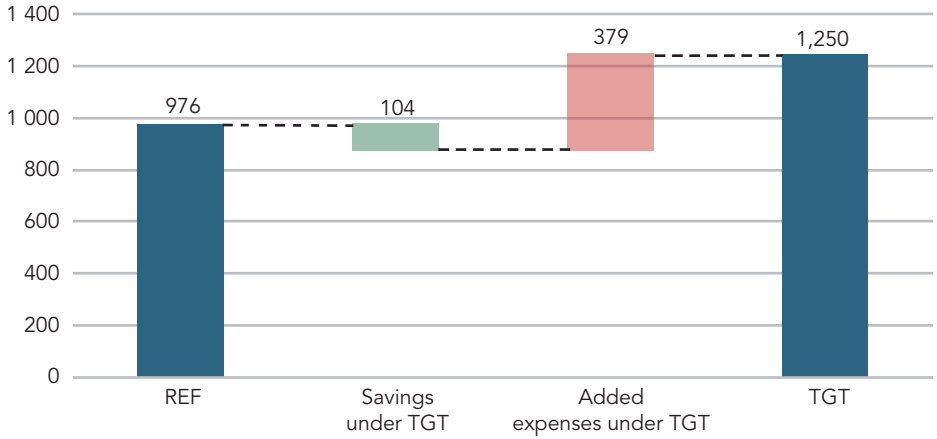


Figure 1-4. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



*Actual costs will differ from estimated costs in the *Outlook* for a variety of reasons including changing commodity prices, manufacturing costs and unforeseen technical advances. All costs are in 2023 real terms.

About Australia

Overview

Geographical and Economic Landscape

Australia features one of the lowest population densities in the world, filled with vast arid interiors, extensive deserts, tropical rainforests to the north, and temperate regions in the southeast and southwest. The economy is resource-rich and service-driven with mining, finance, and education sectors driving GDP growth. Australia is blessed with an abundance of energy resources such as coal, gas, precious metals, wind, and solar, and plays a vital role in global energy trade.

Energy Supply and Consumption

Australia's total final consumption in 2022 was 3,309 PJ, with the transport and industry sectors accounting for the largest shares at 38% and 29%, respectively. Given its abundance of energy resources, Australia has relied on domestically sourced coal and gas which historically dominated energy supply. However, renewables are playing an increasingly prominent role with their usage expected to grow as Australia moves to phase-out ageing coal plants.

Economic growth has driven a steady increase in electricity demand. Between 2000 and 2022, electricity generation increased by 29%, from 209 TWh to 271 TWh. With a growing focus on carbon neutrality, coal-fired power generation capacity will be reduced over time, being replaced by wind and solar energy, with gas playing an important role in providing firming capacity.

Energy Security Challenges and Strategies

While a largely energy exporting economy, Australia still faces potential energy security challenges. Its renewable energy expansion coupled with coal closures has prompted initiatives to enhance grid infrastructure and increase investment in electricity storage. In addition, gas supply constraints in the east coast market may necessitate imports from overseas.

Key Energy Initiatives

Nationally Determined Contribution (NDC) under the Paris Agreement

In 2022, Australia pledged to reduce greenhouse gas emission by 43% below 2005 levels by 2030 and to achieve net-zero emissions by 2050. Australia is expected to update its NDC by the end of 2025 including setting a 2035 emissions target which may further influence its emissions trajectory.

82% Renewable Electricity Target

In December 2022, Australia announced a goal for 82% of on-grid electricity generation (covering the NEM, SWIS, NWIS, DKIS, Mt Isa electric grids) to be derived from renewable sources by 2030.

Capacity Investment Scheme (CIS)

A revenue underwriting scheme to accelerate investment in renewable energy generation and low-emission dispatchable capacity, such as wind, solar, and storage. By 2030, an additional 40 GW of capacity of these technologies will be constructed.

Safeguard Mechanism

Australia has legislated limits on the greenhouse gas emissions of its largest industrial facilities, with these limits becoming more stringent over time.

New Vehicle Efficiency Standard (NVES)

Introduced in May 2024, a new fuel efficiency standard will be applied to new cars sold in the Australian market after January 2025, with each new vehicle having a set average CO_2 target that will be lowered over time.

The National Electric Vehicle Strategy

In April 2023, Australia enacted this strategy to increase the uptake of electric vehicles (EVs) by promoting increased supply, and establishing resources, systems, and infrastructure to enable rapid EV uptake and encourage EV demand.

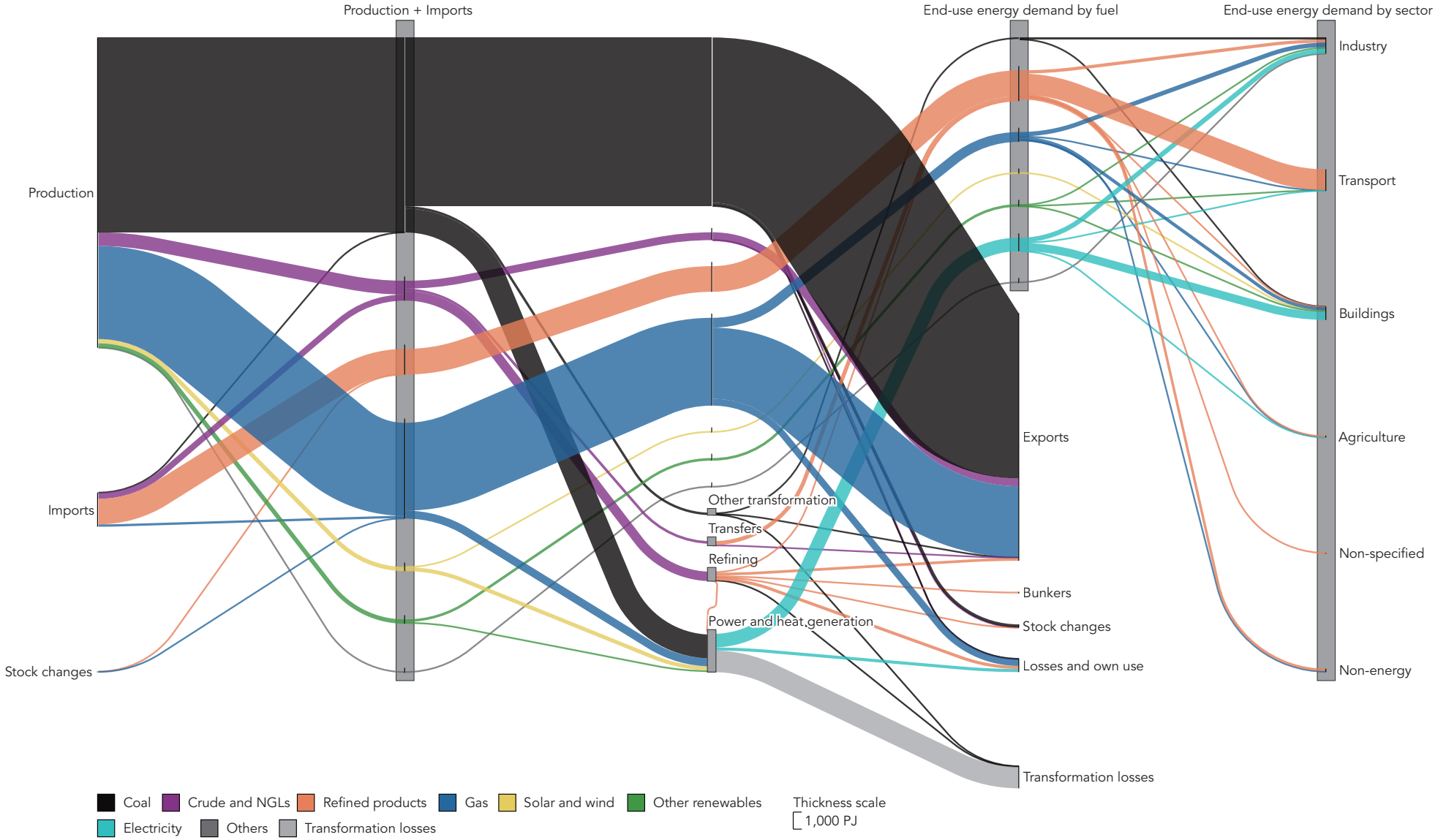
Future Made In Australia (FMIA), National Interest Framework

Australia aims to prioritise industries for investment that will make a significant contribution to achieving its net-zero ambitions, including renewable hydrogen, critical minerals processing, green metals, and increased reliance on decarbonised energy in the manufacturing sector.

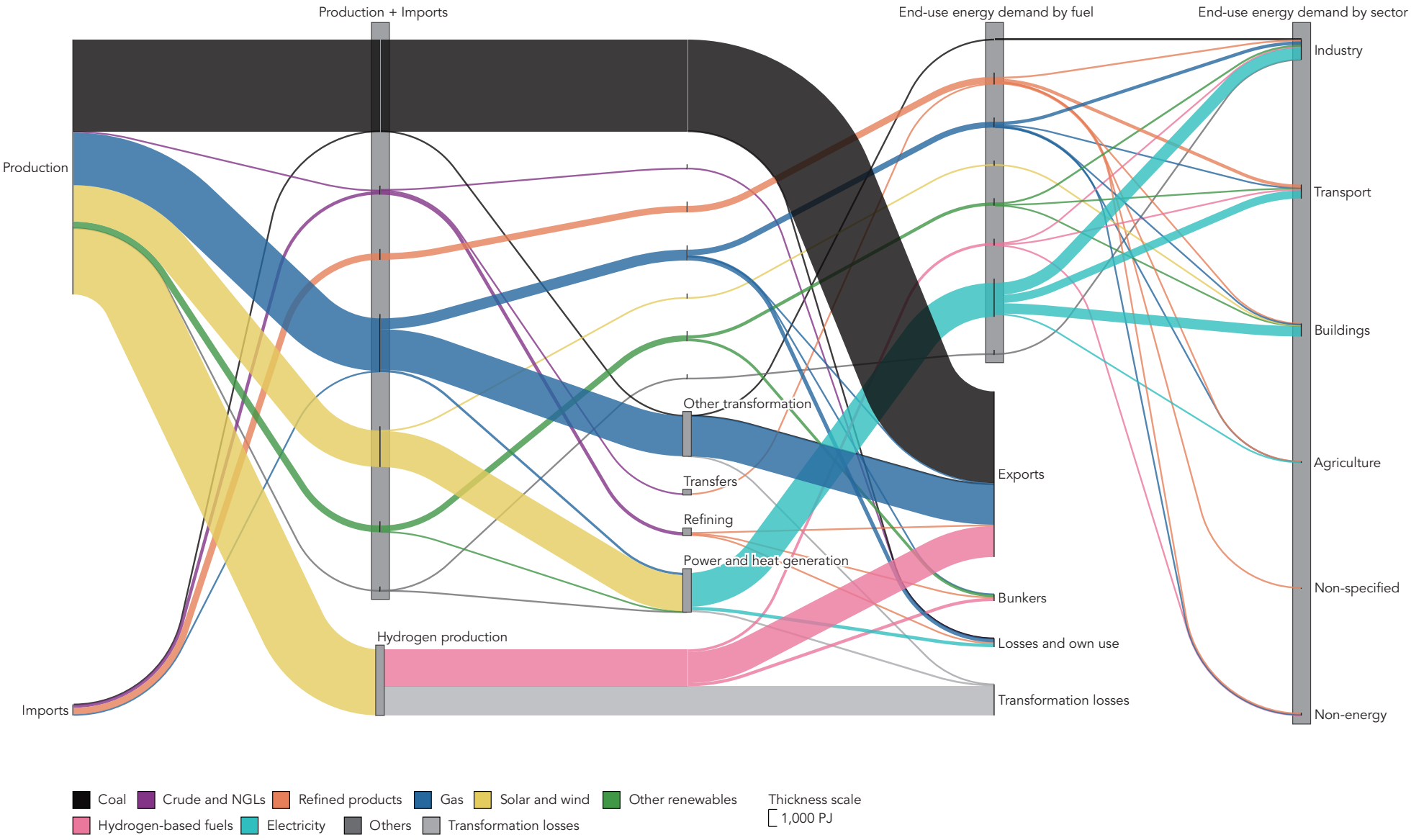
National Hydrogen Strategy

In September 2024, Australia unveiled an updated framework to guide Australia's production, use, and export of hydrogen to position itself as a global hydrogen leader focusing specifically on accelerating the growth of the renewable hydrogen industry.

Energy Flow (2022)



Energy Flow (2060, Target Scenario)



Scenarios and Assumptions

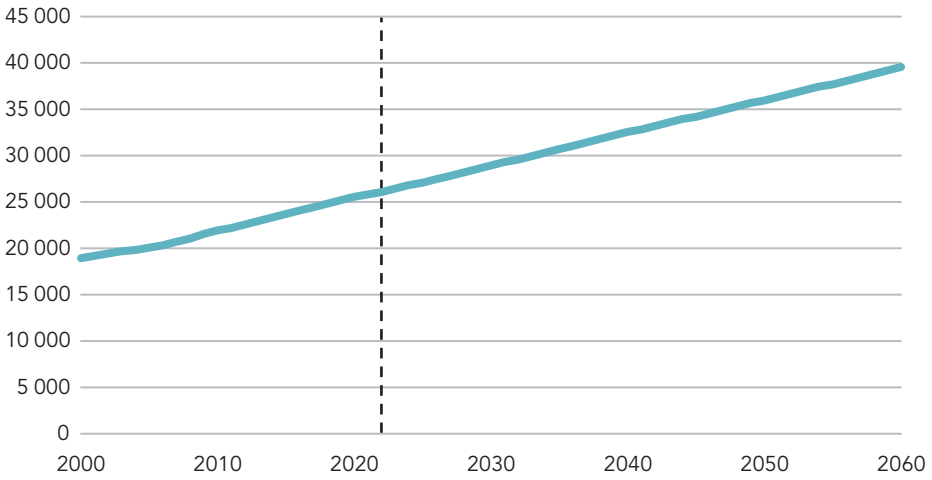
In *The Outlook*, APERC analyses energy demand, transformation, and supply, as well as emissions. The **Reference Scenario (REF)** offers a projection based on historical trends, recent developments, and APERC's assumptions about the continuation of those trends in each APEC economy, while acknowledging technical restraints. The REF Scenario offers a baseline to compare with the **Target Scenario (TGT)** projections, which explores a hypothetical pathway where each economy achieves energy-related policy targets, assuming implementation regardless of cost-effectiveness. When implementation details are lacking, assumptions are inferred from the targets themselves or emissions-related goals.

	Reference	Target
General	• Population: 2023 Intergenerational Report by the Treasury Department Australia; GDP: APERC model and IMF.	• Population: 2023 Intergenerational Report by the Treasury Department Australia; GDP: APERC model and IMF.
Buildings	• Energy efficiency standards and building thermal insulation measures are implemented. Commercial Building Disclosure Program promotes energy efficiency in commercial buildings. • AI data centres expand under both the REF and TGT scenarios.	• Stricter efficiency standards for new buildings and improved retrofits lead to higher energy savings. • Higher proportion of electrification than in REF. Faster shift from gas to electricity for heating and cooking in line with domestic state policies.
Industry	• Robust growth is assumed for the industry sector due to a growing population and economy, particularly in minerals mining. • Electricity use expands modestly, while fossil fuel use slightly declines, but still accounts for 50% of consumption in 2060.	• Increased electrification, energy efficiency, recycling, and low-carbon fuel use compared to REF. • Larger energy demand growth due to higher global demand for metals for renewable energy infrastructure. • More hydrogen usage in industry compared to REF, especially in steel.
Transport	• NVES "Option A" assumed with emissions reduction targets of 34% and 14% for passenger and light commercial vehicles by 2029. • ICE vehicles steadily decline, with a shift toward electrification by 2060 coupled with PHEV uptake. • Private vehicle ownership is at the same level in both scenarios.	• NVES "Option B" assumed with emissions reduction targets of 61% and 62% for passenger and light commercial vehicles by 2029. • BEV sales share for light vehicles reaches 50% by 2030 and 100% by 2060. • Some uptake of PHEV, but use is overshadowed by EV usage. • Greater usage of hydrogen-based fuels in the transport sector, but EV usage still dominates.
Power	• Existing coal-fired power phased out by 2050. Natural gas plays a flexible backup role to support grid stability in both scenarios. • Snowy Hydro 2 assumed operational by 2029 in both scenarios.	• Existing coal-fired power plants phased out by 2040. • 82% domestic target for renewables and capacity additions from the Capacity Investment Scheme are implemented by 2030.
Supply	• Gradual reduction of fossil fuel supply by 2060. • Metallurgical coal supply assumed robust in both scenarios.	• Gas and coal supply declines at a faster rate due to greater decarbonisation efforts amongst APEC economies resulting in a projected lower global demand for these commodities.
Emissions	• Nationally Determined Contributions are not incorporated in REF.	• 43% emissions reduction by 2030 from 2005 and net-zero emissions by 2050 are used as a guide for combustible emissions reductions.

Note: The base year is 2022. Macro-economic assumptions are constant across scenarios. Historical energy balances are from EGEDA submissions for 2022.

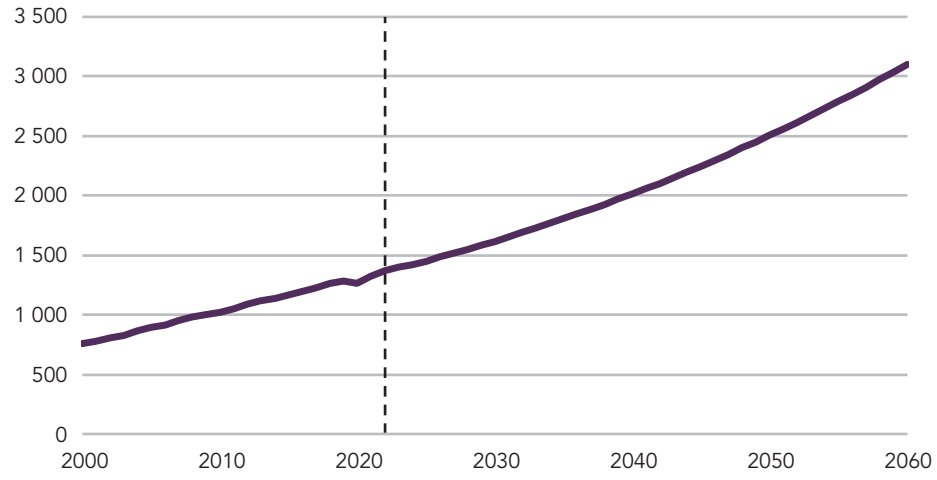
Demographic and Macroeconomic Assumptions

Figure 1-5. Population (thousands)



- Australia's population is projected to reach well over 37 million by 2060 and reflects a continuation in the large increases in net overseas migration since the early 2000s. Projections are based on the 2023 Intergenerational Report by the Department of the Treasury which offers higher estimates than UN Department of Economic and Social Affairs projections.
- In line with the increase in population, the number of households is projected to increase from 10 million in 2021 to between 13.3 and 13.9 million by 2046.
- The projected growth in population and households is expected to place further strain on the economy's electric grids, presenting challenges for meeting electricity demand while advancing grid decarbonisation.
- Australia has one of the lowest population densities in the world, averaging around 3.5 people per km², with a large proportion of the land being uninhabitable. Population densities are highest around coastal areas, with major population centres being the cities of Sydney, Melbourne, and Brisbane.

Figure 1-6. Real GDP (billion 2017 USD, PPP)



- Australia's GDP is projected to show a consistent upward trend through 2060. After a small contraction caused by the COVID-19 pandemic, real GDP growth rate stabilised at a consistent 2-3%.
- From 2025, Australia's economy is expected to grow at a steady rate of 2.3%, driven by assumed strong population growth through migration and the growth of key sectors, namely mining. By 2060, real GDP is expected to reach approximately USD 3 trillion (PPP).
- Industrial activity is expected to grow through 2060, with growth driven mainly by the mining and precious metal subsectors. Global demand is expected to rise for these resources as the world shifts towards renewable technologies with Australia being well positioned to be a key global supplier, underpinned by government support and policies such as FMIA.

End-use Energy Demand

Figure 1-7. Energy demand by sector in REF & TGT (PJ)

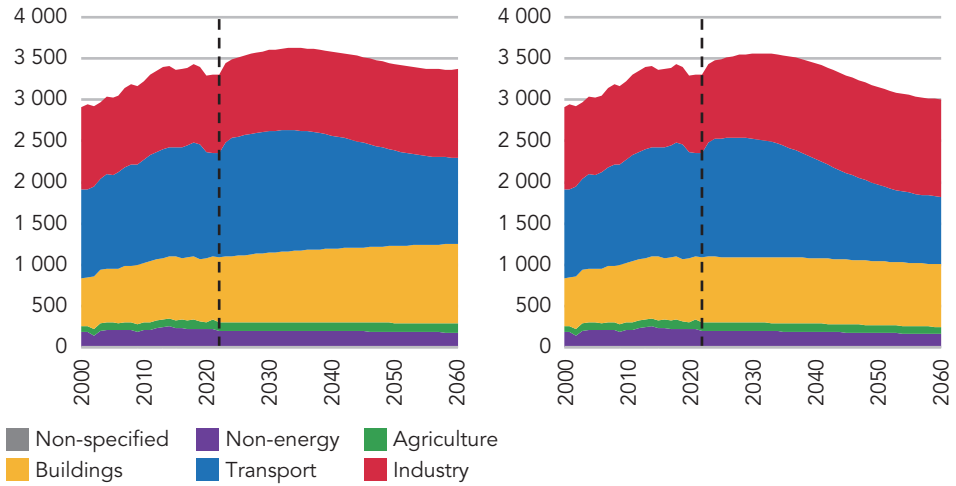
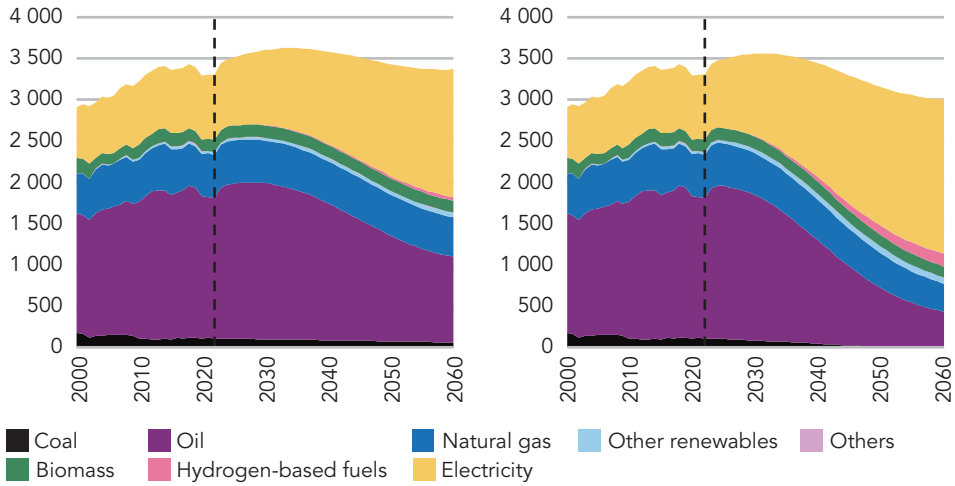


Figure 1-8. Energy demand by fuel in REF & TGT (PJ)



- Australia's total end-use energy demand is projected to peak at nearly 3,600 PJ around 2035 in the REF scenario. Demand then slightly declines to 3,369 PJ by 2060, reflecting a -0.28% annual decrease.
- In contrast, the TGT scenario demand peaks earlier—in 2030—and declines by 16% to 3,002 PJ by 2060, resulting in an overall 10% reduction from 2022 levels due to accelerated efficiency gains and electrification.
- Transport energy usage declines in both scenarios as fuel efficiency standards come into effect with a higher uptake of energy efficient EVs.
- Building demand increases in REF in line with a growing population. Higher efficiency gains in TGT explain the decline in demand in this scenario despite having the same population growth trajectory as REF.
- Industry demand grows in TGT due to the growth in mineral mining and metals processing needed to meet global demand for precious minerals as economies seek to decarbonise and build renewable energy assets. Demand growth stabilises in the 2040s as efficiency gains come into effect.

- Fossil fuels have historically dominated end-use energy demand. In 2022, they accounted for 71% of total demand, led by oil (50%), gas (15%), and coal (3%), while electricity made up 24%. In REF, the share of fossil fuels declines to 46% by 2060. Electricity's share gradually rises to 46%, reflecting moderate electrification across the industry, transport, and building sectors.
- In contrast, the TGT scenario projects a sharper reduction in fossil fuel use, with total energy demand also decreasing. Fossil fuels decrease to 26% of final demand with electricity making up 62% of final demand as electrification increases across the industry, transport, and building sectors. Greater assumed efficiency gains results in lower demand compared to REF by 2060.
- Gas demand in TGT falls but still plays a role in industrial heat applications in sectors such as ceramics, textiles, paper, metal fabrication, as well as continuing to play a role as a chemical feedstock.
- Hydrogen-based fuels increase in the transport sector, especially in the use of fuel cell trucks. Greater hydrogen adoption also occurs in industrial processes, most notably in steel production.

Buildings Energy Demand

Figure 1-9. Buildings energy demand by fuel in REF & TGT (PJ)

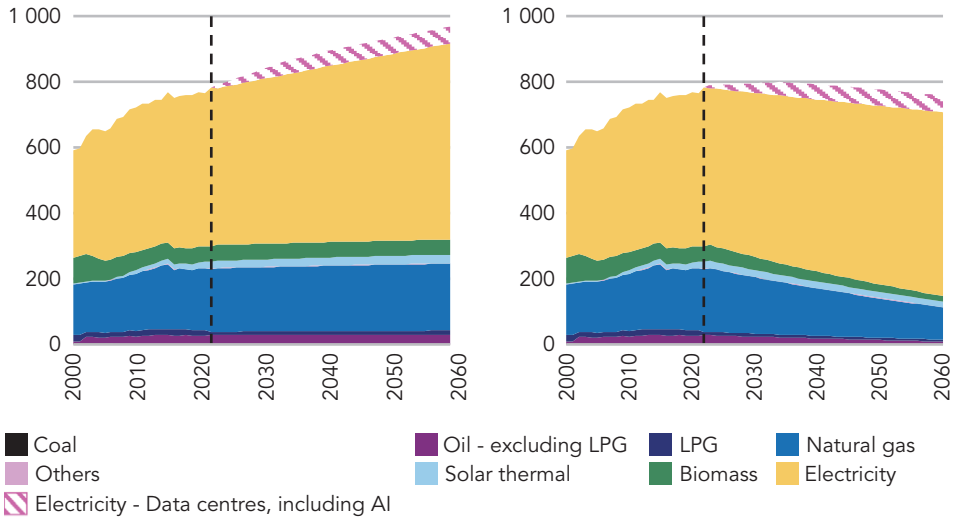
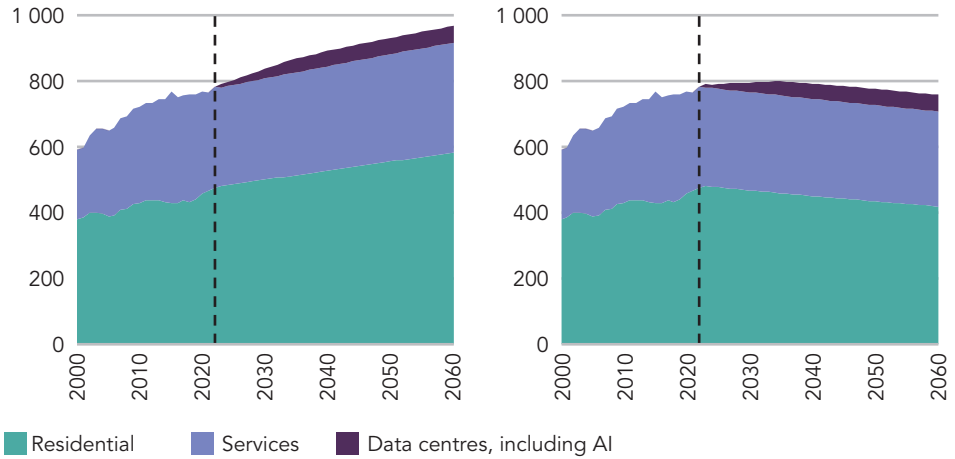


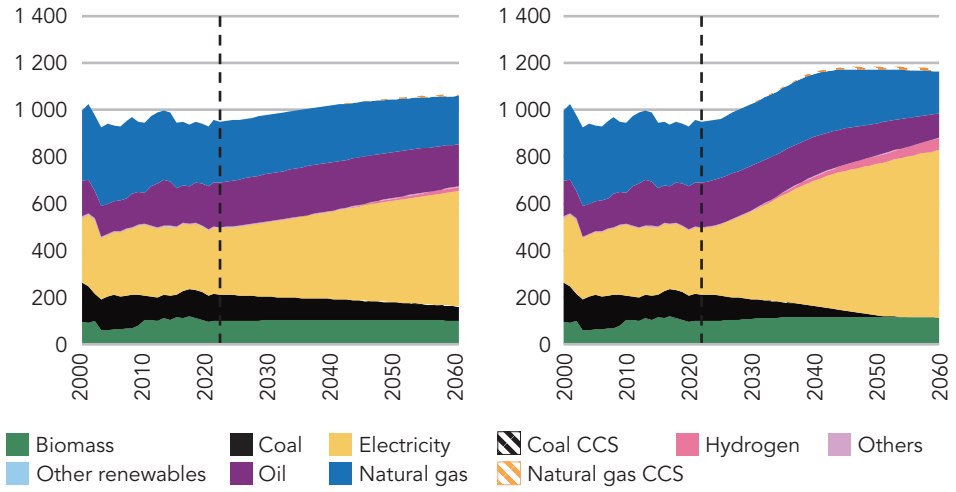
Figure 1-10. Buildings energy demand by sector in REF & TGT (PJ)



- REF building demand will continue growing in line with population growth, increasing from 782 PJ to 967 PJ from 2022 to 2060. While some efficiency gains are assumed, it is insufficient to offset this increase in demand with residential energy demand increasing by 22% during the projection period.
- In TGT, due to greater assumed efficiency gains in the residential sector such as improved insulation, heating, and cooling efficiency and more energy efficient appliances, residential energy demand declines by 12% despite increased housing demand from population growth.
- While some fuel switching is assumed in REF, the overall increase in demand for housing (and new gas connections) offsets this, contributing to the 6% increase in gas demand from 2022 to 2060.
- Higher fuel switching from gas to electricity is assumed in TGT due to rising gas prices, improved efficiency of electrical appliances (such as induction cooking), and shifting consumer preferences to lower emissions. The growing use of rooftop solar and behind-the-meter batteries for domestic use further encourages greater electrification.
- While solar-thermal systems will grow modestly, their growth will be outstripped by consumer preferences for electric heat-pump water heaters.
- Government policies such as Victoria's Gas Substitution Roadmap, which phases out gas connections for new residential and commercial buildings, will promote switching away from gas towards electrification.
- Electricity required for data centre and AI usage will expand significantly and grow rapidly as Australia invests more heavily into the underlying physical and digital infrastructure. Projections were made based on available industry consensus/development and APERC acknowledges this projection may be higher/lower than what transpires.
- In REF, the services sector energy demand will increase with a growing economy, partially limited by efficiency gains from policies such as more stringent energy ratings, smart controls, and automation of HVAC and lighting appliances. In REF, services demand increased by 9% during the projection period, but decreased overall in TGT by 6% due to greater assumed efficiency gains.

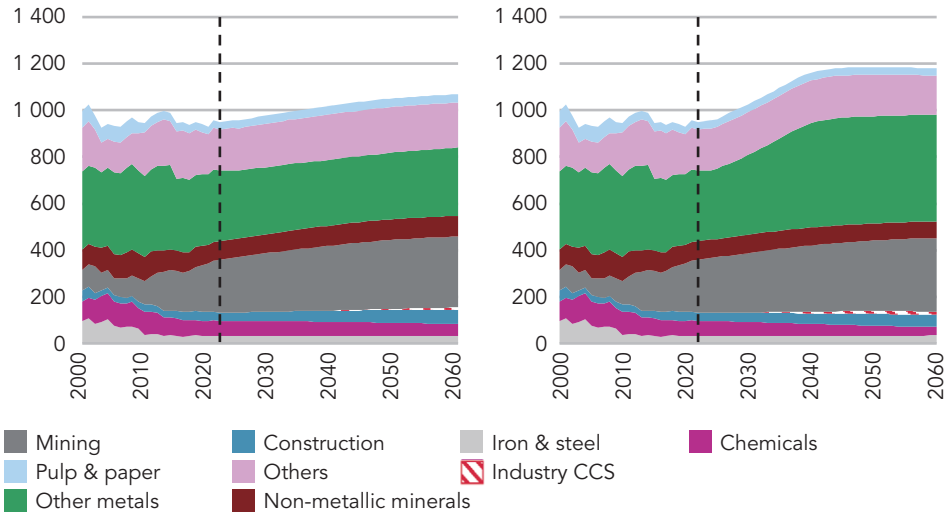
Industry Energy Demand

Figure 1-11. Industry energy demand by fuel in REF & TGT (PJ)



- Australia's industry energy demand is expected to grow due to a growing population and economy and an assumed trend of onshoring. Energy demand eventually tapers off in TGT around 2040 due to greater efficiency gains. However, the near tripling of electricity in TGT will place additional pressure on the power grid to expand and deliver electricity.
- Industry electrification will increase in both scenarios, making inroads in most industrial subsectors such as mining, metals, construction, and limiting the growth of combustibles. More ambitious decarbonisation efforts from industry in TGT will lead to even greater electrification.
- Hydrogen use is more prominent in TGT, where coal is replaced by hydrogen-based steel production and hydrogen blends with/or replaces fossil fuels in cement kilns, glass and ceramics manufacturing, non-ferrous metal smelting, and alumina refining.
- Carbon capture and storage (CCS) is deployed in the chemicals and cement sectors in REF and marginally more in TGT, but its deployment is limited due to concerns over cost.

Figure 1-12. Industry energy demand by sector in REF & TGT (PJ)



- Construction accounts for a small share of demand though it is assumed to increase in line with population growth in both scenarios.
- By sector, minerals mining and other metals continue to grow in energy usage in both scenarios as global decarbonisation efforts require more key minerals such as copper, aluminium, and lithium (other metals) for green energy infrastructure, materials which Australia is well placed to supply.
- Demand growth is larger in TGT (even with higher efficiency gains), particularly for processing other metals, in line with more ambitious global renewable build-outs requiring more inputs and an assumed onshoring trend of metals processing (for economic and geopolitical reasons).
- This trend will be bolstered by government initiatives such as the Critical Minerals Strategy 2023, which seeks to capitalise on Australia's established industry and expertise, renewable energy potential, land availability, and proximity to key markets. The continuation of this trend will require collaboration with international partners in shifting supply chains onshore.

Non-energy Demand

Figure 1-13. Non-energy demand in REF (PJ)

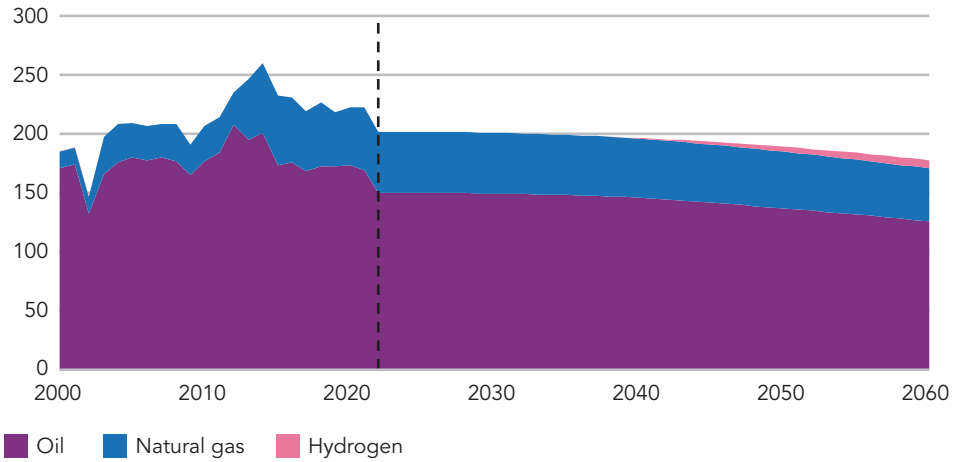
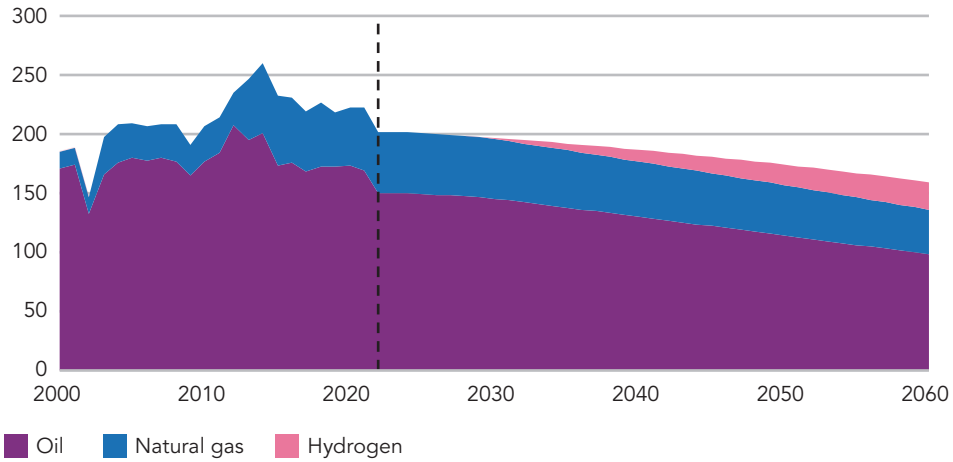


Figure 1-14. Non-energy demand in TGT (PJ)



- Australia's non-energy use of oil and gas is expected to decline in both scenarios. In REF, demand for both fuels declines marginally, by 16%, from 2022 to 2060, while in TGT, demand declines by 32% as decarbonisation efforts intensify and efficiency gains take hold.
- Oil in Australia is used as a feedstock in industries such as petrochemicals, industrial lubricants, cement, and asphalt production, amongst others. It accounted for the majority (150 PJ or 75%) of non-energy demand in 2022, a trend that is expected to continue in both scenarios.
- A combination of fuel switching to alternative feedstocks, particularly in petrochemicals, as well as material efficiency, circular economy policies, and carbon pricing all contribute to reduced oil use as a feedstock. Oil use declines to 125 PJ in 2060 in REF and more rapidly in TGT to 98 PJ as efforts to decarbonise industrial sectors accelerate.
- Gas makes up a smaller portion of non-energy demand, at 25% in 2022. Gas demand declines overtime in both scenarios due to factors such as gas price volatility, efficiency gains, and fuel switching to green hydrogen (especially in ammonia production). TGT demand declines faster in line with stronger decarbonisation efforts and greater feedstock switching occurring from grey to green hydrogen.
- While no green hydrogen is currently used in the non-energy sector, this sector is expected to expand in line with growing private interest and government initiatives.
- Hydrogen use increases more rapidly under TGT as production of green electrolytic hydrogen ramps up in line with domestic targets. Hydrogen use increases to 23 PJ in 2060, allowing green hydrogen to be used as a key alternative feedstock for chemical production (namely methanol and ammonia), further reducing gas demand over time.

Transport Energy Demand

Figure 1-15. Domestic transport energy demand in REF (PJ)

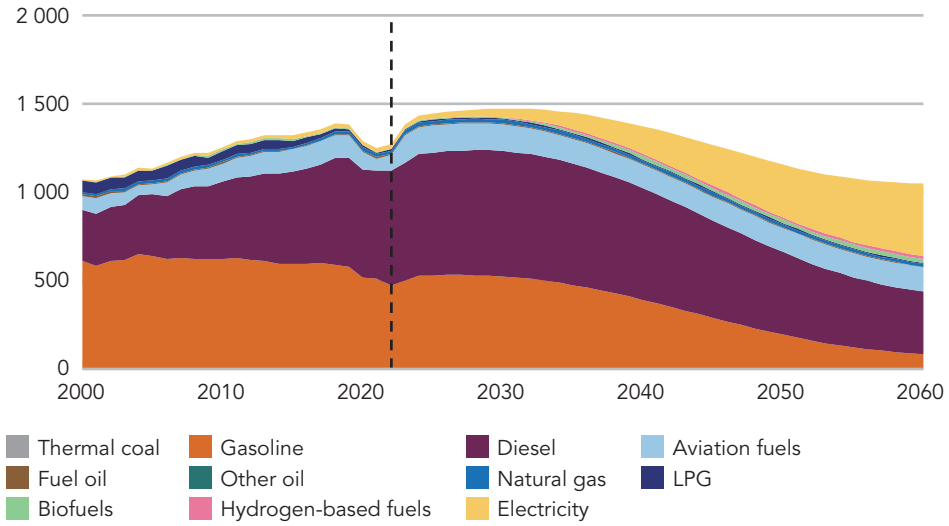
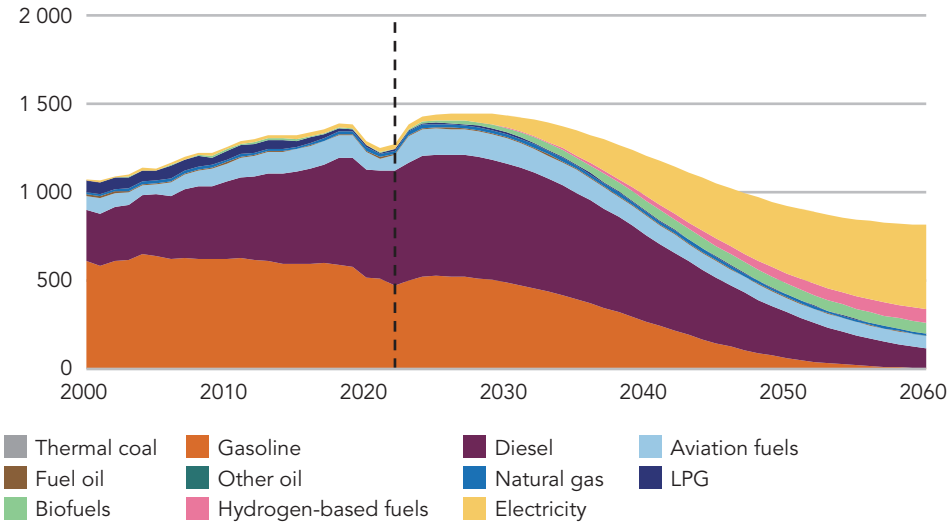


Figure 1-16. Domestic transport energy demand in TGT (PJ)



- Given its large landmass, road transport dominates Australian transport energy demand, representing 83% of demand in 2022. Both scenarios assume a roughly 1.5 times increase in passenger and freight activity from 2022 to 2060 due to an increasing population and GDP.
- While conventional fuels dominate initially, their dominance falls in REF and more so in TGT. The driving factor behind this is the New Vehicle Efficiency Standards (NVES) CO_2 target for new vehicles. In REF, a mix of plug-in hybrid electric vehicle (PHEV) adoption, battery electric vehicle (BEV) uptake, and internal combustion engine (ICE) efficiency improvements are assumed to meet the least strict CO_2 targets. In TGT, a stricter NVES target is assumed, which prompts the need for 100% passenger BEV sales by 2060 with little room for less effective solutions such PHEV/ICE efficiency improvements.
- In TGT, the decline in conventional fuels accelerates. Gasoline is phased out by 2060, while diesel accounts for 13% of total transport demand and electricity comprises 50%. BEVs are adopted more rapidly as battery technology improves and becomes more cost effective, with BEV sales reaching 100% by 2060. Electrification also expands to non-passenger vehicles, including trucks and trains.
- Hydrogen based fuels become more prominent in TGT, growing to 92 PJ by 2060. Although high costs associated with hydrogen production, storage, transportation, and refuelling may limit passenger vehicle uptake, FCEVs are expected to remain persistent in trucks, accounting for 30% of truck sales, however BEVs continue to dominate at 60%.
- In TGT, biofuel blends gain prominence, with liquid biofuels replacing 10% of gasoline and diesel and 30% of jet fuels. Developments in Sustainable Aviation Fuels (SAFs) lead to e-fuels replacing 15% of jet fuels by 2060.
- Increased transport electrification will assist with bolstering Australia's fuel security by reducing fuel imports, though at the added cost of developing EV supporting infrastructure (EV chargers, stations, and renewable energy).

Other Transport Data

Figure 1-17. Transport vehicle stocks in REF & TGT (millions)

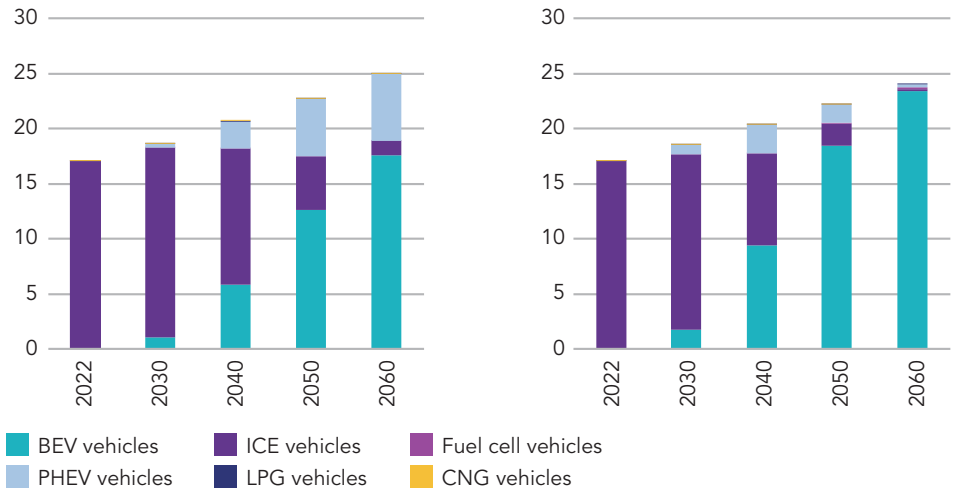
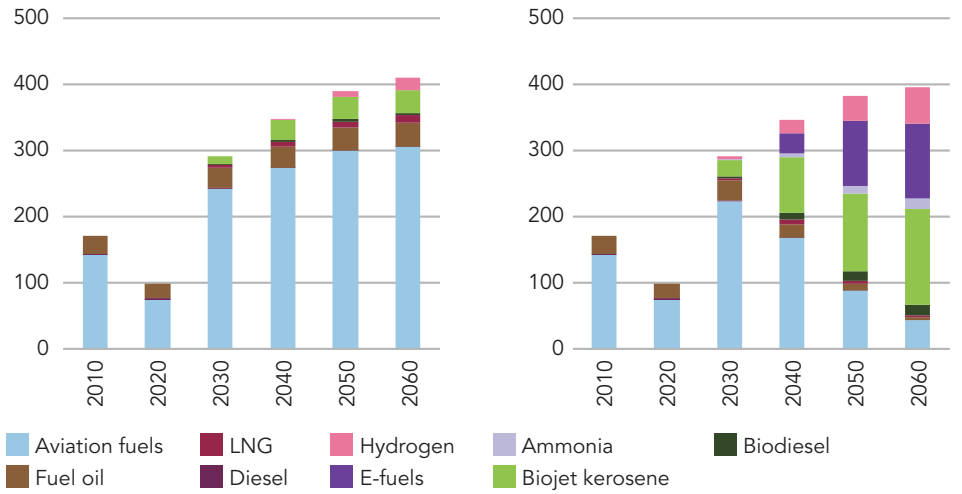
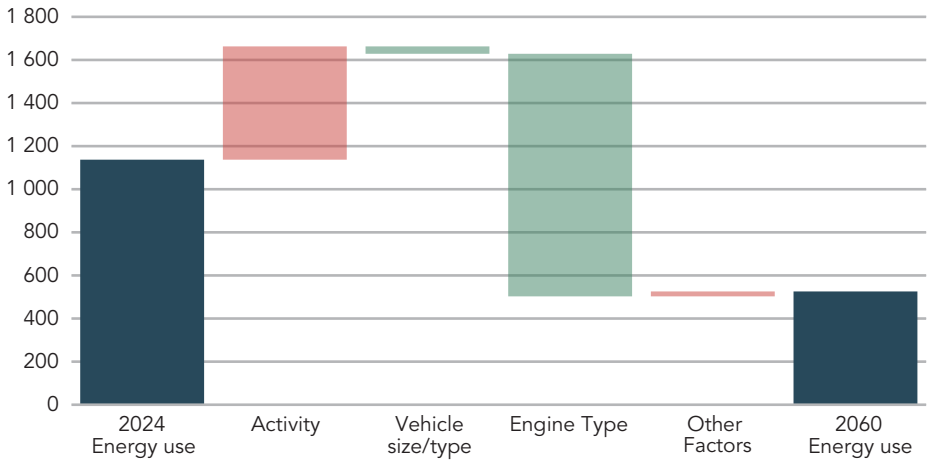


Figure 1-18. International bunker energy demand for shipping and aviation in REF & TGT (PJ)



- With transport accounting for 38% of Total Final Consumption in 2022, transport stock composition is an important factor in Australia's decarbonisation efforts. In REF, growth in BEVs, together with PHEVs, replaces the majority of ICE vehicles. In TGT, ICE vehicles are fully replaced by BEVs as advances in battery technology and cost reductions shift consumer preferences away from PHEVs.
- In TGT, bunker fuels (used for international transport) begin shifting to lower-emissions alternatives, most notably hydrogen-based fuels. This is based on decarbonisation targets set by international transport bodies.
- Between 2022 and 2060, assuming all other factors remain constant, energy use would increase by roughly 400 PJ due to growth in passenger and freight tonne-kilometres. However, widespread adoption of BEVs replacing ICE vehicles offsets this increase, resulting in overall transport energy use declining by approximately half by 2060.

Figure 1-19. Components of the change in road energy use in TGT (PJ)



Note: Information on the different drivers in the transport energy decomposition can be found in the *Outlook*'s annex.

Electricity Generation

Figure 1-20. Electricity generation by fuel in REF (TWh)

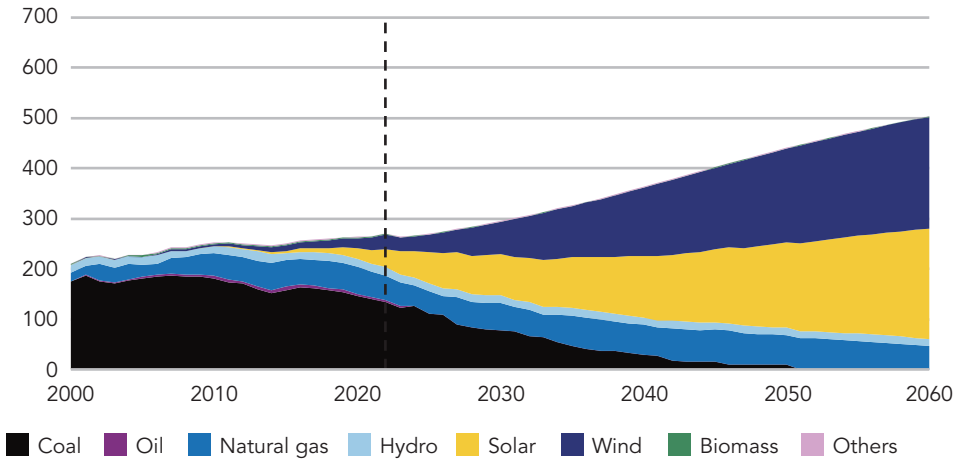
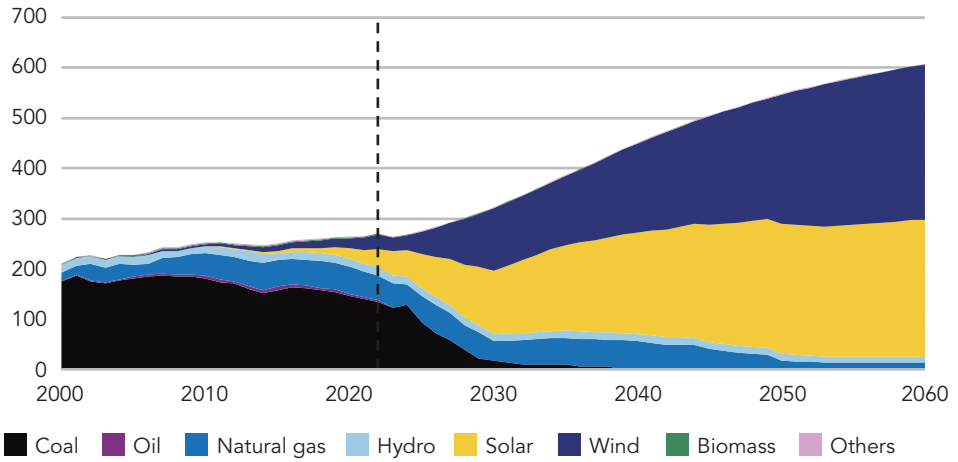


Figure 1-21. Electricity generation by fuel in TGT (TWh)



- Total electricity generation is projected to nearly double by 2060 in REF, and nearly triple in TGT, as electrification in industry, buildings, and transport drives electricity demand upward.
- In REF, the fuel mix shifts towards renewables as coal usage declines due to coal plant closures. Renewable generation, mostly wind and solar, becomes dominant as Australia takes advantage of its abundant renewable energy resources.
- With coal generation declining and renewable electricity generation increasing, more gas generation is required to provide stability to the grid. Gas generation increases by 20% from 2022 to 2050 before declining gradually as storage solutions proliferate, being relegated to providing firming capacity instead.

- In TGT, renewable generation grows earlier and considerably more as coal plants exit earlier. Renewable generation expands to make up at least 82% of total electricity generation by 2030, meeting the government's core 2030 target.
- However, to reach the 2030 target and ensure that the dual goals of sustainability and reliability are met, progress will need to be made to address regulatory challenges, secure social licenses, expand transmission and distribution infrastructure, and invest in batteries.
- Gas usage will continue at roughly the same level in TGT to provide generation against the backdrop of coal plant closures. While gas generation decreases past 2045 as long duration storage grows, it will still play an important role in the 2050s to help manage outlier weather periods, dunkelflaute events, and to meet a peak load that progressively increases over time.

Note: Figures 1-20 and 1-21 do not include electricity generation for hydrogen production.

Generation Capacity

Figure 1-22. Generation capacity by fuel in REF (GW)

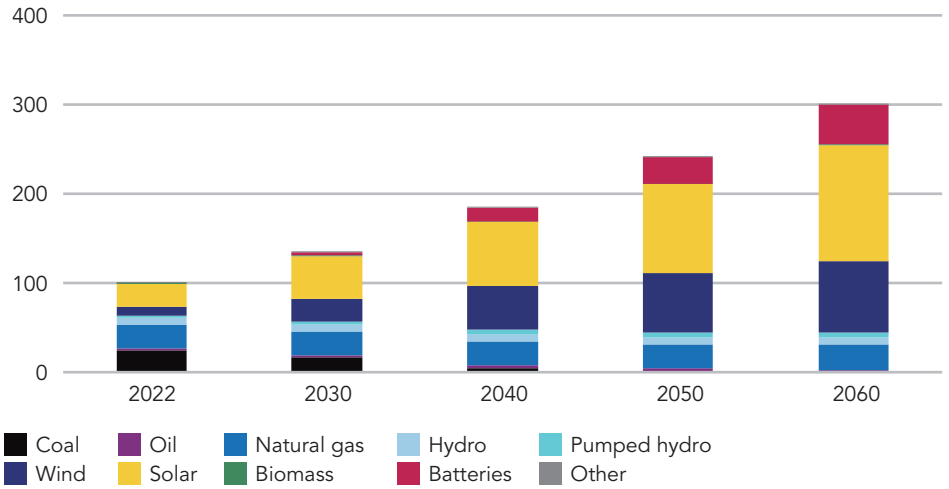
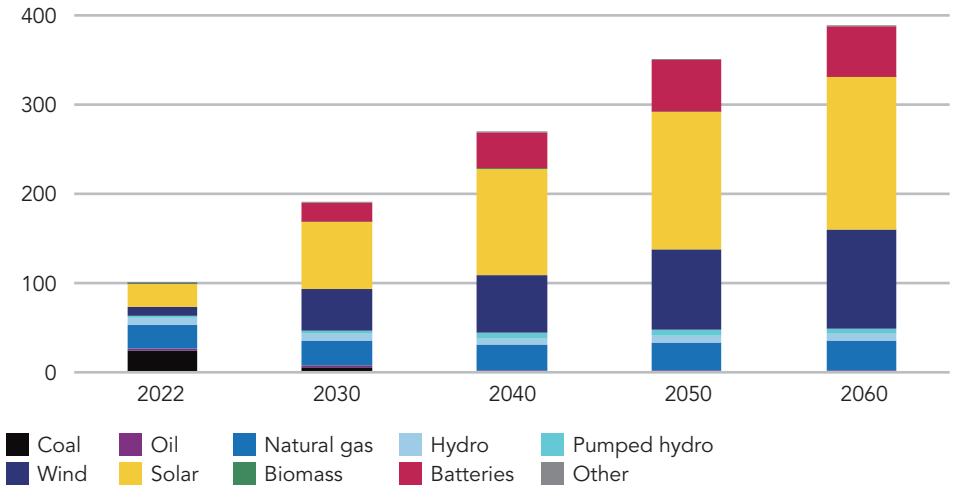


Figure 1-23. Generation capacity by fuel in TGT (GW)



- Leveraging its abundant solar resources and its cost competitiveness, solar capacity (both utility and rooftop) becomes dominant in both scenarios. By 2060, 130 GW and 171 GW of solar capacity is installed in REF and TGT, respectively. Wind capacity also grows significantly, reaching 80 GW and 111 GW in REF and TGT, respectively.
- Offshore wind capacity reaches 9 GW in both scenarios by 2040, meeting Victoria's offshore wind targets. Further development is expected in other states such as New South Wales, Western Australia, and Tasmania with 23 GW of offshore wind built in TGT by 2060.
- Coal plants have been closing since 2000 due to falling reliability, economic competition from renewables (particularly rooftop PV eroding intraday profits), and emissions reductions policies and pledges. In REF, coal closures follow publicly announced closures with just under 2 GW of capacity left by 2050. In TGT, closures accelerate as greater renewable uptake puts further economic pressure on coal plants to retire with all coal phased out by 2040.
- To maintain grid stability amid coal exits and a renewable-dominated grid, gas capacity is expected to increase by around 1.5 GW in REF and 6 GW in TGT. Despite gas generation declining overall, additional gas capacity will be needed to provide firming during the morning and evening demand peaks as peak loads rise over time.
- Storage capacity grows significantly in TGT, reaching nearly 60 GW by 2060 with a large portion of this being behind-the-meter household batteries operating under Virtual Power Plants (VPP). Both scenarios assume the Snowy Hydro 2.0 project is operational by 2030, providing 2.2 GW of capacity worth of long duration storage.
- Despite recent political discourse around nuclear power, APERC sees nuclear capacity as unlikely in either scenario, given the cost competitiveness of renewables, limited domestic industry knowledge, legislative prohibitions, and current unfavourable public sentiment (especially around waste storage).

Note: Figures 1-22 and 1-23 do not include electricity capacity for hydrogen production.

Grid Reliability

Figure 1-24. Total generation capacity and peak load (GW)

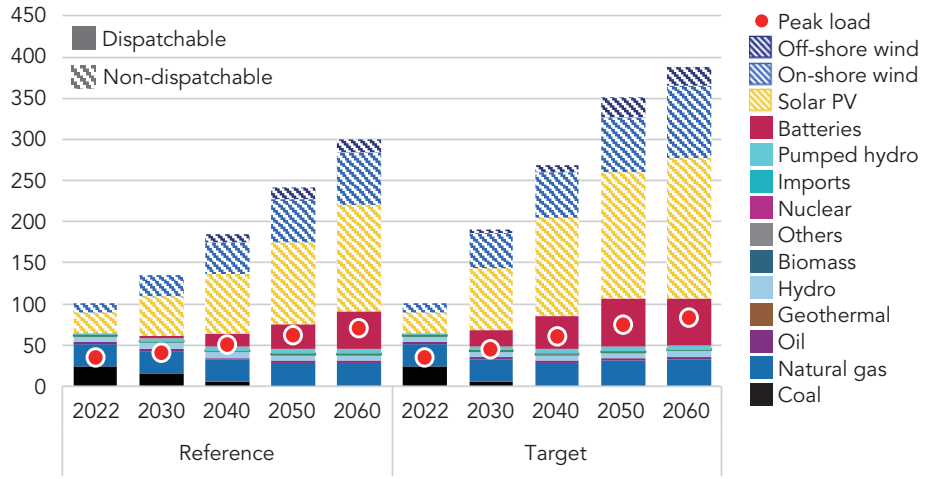
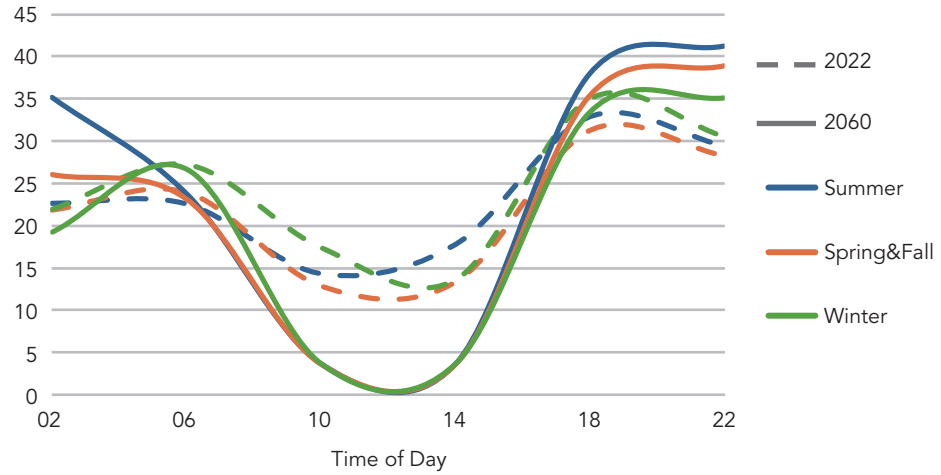


Figure 1-25. Power from dispatchable sources in TGT (GW)



- In REF, the peak electricity load doubles from 35.7 GW to 70.8 GW in REF from 2020 to 2060 and to 82.5 GW in TGT due to higher electricity demands.
- Higher adoption of solar PV and wind increases the challenge of lower load factors, resulting in more capacity needing to be built to meet peak load due to the intermittency of these energy sources. In REF, over 200 GW of VRE capacity is installed, increasing to nearly 300 GW in TGT.
- A key assumption made in the modelling is that the power system will have sufficient dispatchable generation capacity including batteries to satisfy peak loads when paired with VRE. This assumes that batteries are fully charged, during periods of peak demand. However, the presence of extreme weather events, solar and wind droughts (dunkelflaute events), and omni-system failures, such as what occurred Broken Hill in 2024, may lead to reliability risks.
- As more wind and solar are added to the grid, dispatchable plants operate less often, reducing their efficiency and increasing the cost per unit of energy they produce and hence total system costs overall.
- Increased reliance on wind and solar generation will increase the variability of the generation required from dispatchable power sources.
- As solar PV capacity grows, this will displace the need for dispatchable power during the day, leading to a pronounced dip that can be seen in 2060 for all seasons. However, a ramping up of power must occur from noon onwards to meet the demand of the evening peak as solar output falls.
- Summer requires the most dispatchable power as hot weather necessitates air conditioner and HVAC usage. Solar capacity factors are strongest in summer and when combined with storage solutions, more dispatchable power becomes available in the morning and evening peaks.
- The actual variability will be different than this total since the variability will be spread across the entire economy and individual days will differ from the seasonal averages. The variability may present challenges for the Australian Energy Market Operator and could require additional capital, maintenance and operating costs to ensure grid reliability.

Coal and Biomass

Figure 1-26. Coal and biomass consumption by sector in REF & TGT (PJ)

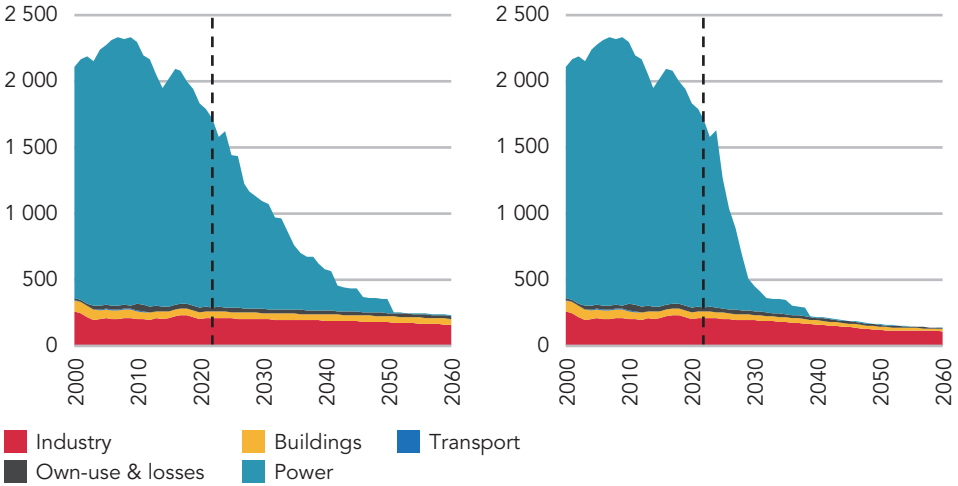
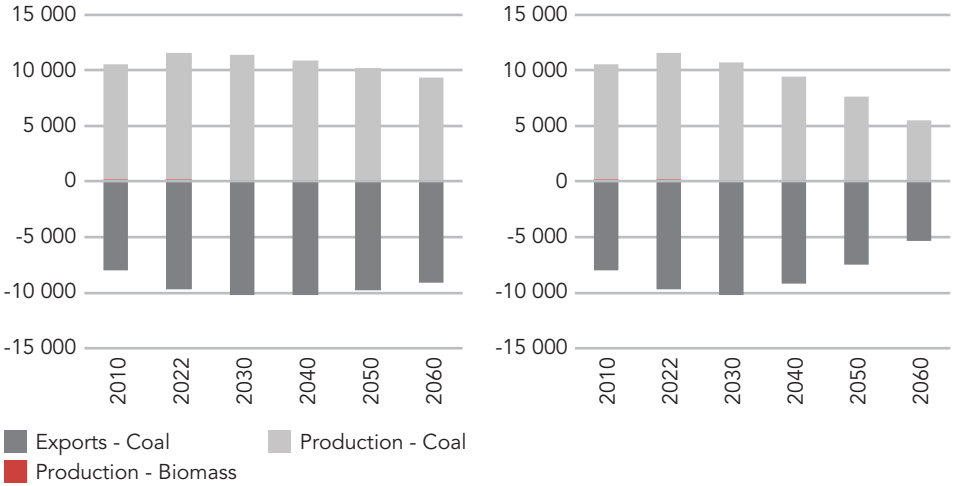


Figure 1-27. Coal and biomass production, imports, and exports in REF & TGT (PJ)



- Coal consumption has been steadily declining since its 2009 peak, driven primarily by coal-fired power plant closures, with this trend set to continue as the electricity grid transitions to renewables.
- The power sector is still the dominant consumer of coal, accounting for 83% of total use in 2022. The reduction in coal-fired generation brought on by voluntary closures by coal operators drives coal's major decline. By 2050, coal consumption in the power sector is largely phased out in REF and even earlier in TGT—in 2040—as coal plants retire earlier.
- Coal use in the industrial and building sectors continues in both scenarios. While coal is still used in iron, steel, and cement production, its use declines in TGT due to the increased use of green steel and alternative fuels in iron and steel production, and increased electrification in the cement industry.
- As one of the world's leading coal producers, Australia is a dominant global exporter and is expected to remain so going forward. Coal exports will increase slightly in 2030, as declining domestic use of thermal coal makes additional volumes available for international markets.
- Overall coal exports will decline by 12% from 2030 to 2060 in REF and will decline by 47% in TGT during the same period. This will primarily be driven by falling thermal coal demand globally as Australia's trading partners transition away from thermal coal-based power generation.
- Coal exports persist in both scenarios due to the continued demand for metallurgical coal in global iron and steel production. This is because metallurgical coal serves as a key ingredient in transforming iron ore into steel, which is difficult to substitute for other fuels. However, metallurgical coal exports will be tempered by the growing use of recycled and green steel in Australia's export markets, such as in the People's Republic of China.

Natural Gas and Biogas

Figure 1-28. Natural gas and biogas consumption by sector in REF & TGT (PJ)

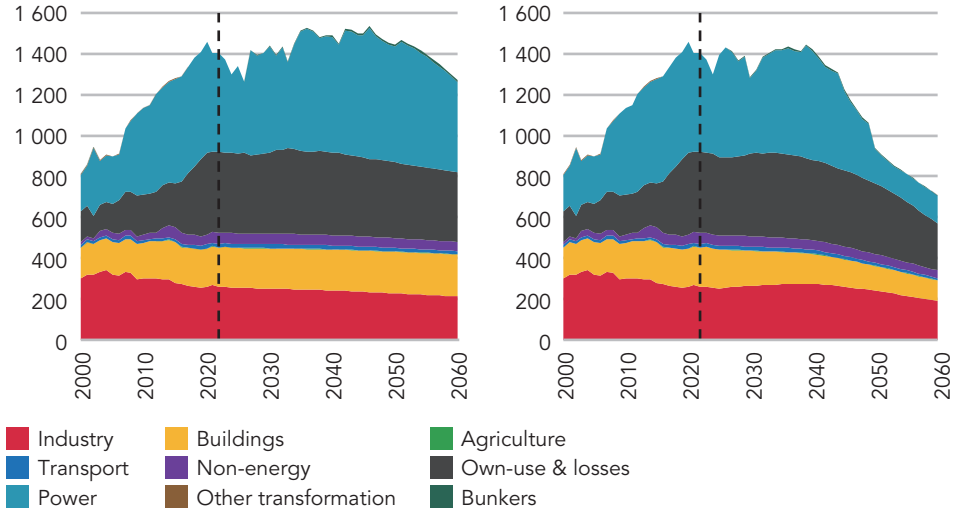
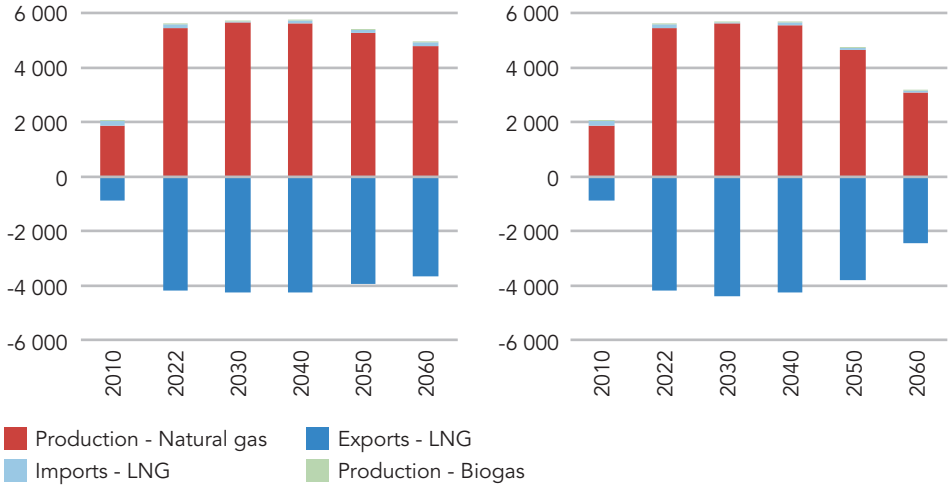


Figure 1-29. Natural gas and biogas production, imports, and exports in REF & TGT (PJ)



- Natural gas provides fuel for core industries in Australia, namely power, buildings, and industry. Total consumption peaks at around 1400-1500 PJ in the 2040s before gradually declining in both scenarios.
- Gas demand grows in the power sector to 2040 due to its role in providing firming capacity in electric grids transitioning to renewables. In TGT, gas usage grows in the late 2020s to compensate for earlier coal exits but falls faster post-2040 compared to REF as renewable and storage deployments accelerate. Gas demand for buildings remains generally constant under REF but declines under TGT as more fuel switching from gas to electricity occurs.
- In TGT, fuel switching from coal to gas in the industrial sector experiences small increases in gas use before falling post-2050 as higher renewable and alternative fuel adoption occurs in line with decarbonisation objectives.

- Australia, being one of the world's top gas producers, continues to produce and simultaneously export most of its gas. Production declines slightly in REF after 2050 due to declining domestic demand and international demand as APEC economies aim to decarbonise their electric grids.
- The decline in gas production is steeper in TGT as domestic gas usage (particularly in the power sector) and export demand declines even more. Gas exports decline sharply post-2040 based on projected decreases in gas demand from Australia's trading partners as they progress towards their net-zero objectives.
- Small levels of LNG imports in both scenarios occur to meet domestic demand in the more populous southern states due to difficulties in moving gas from northern producing regions, declining southern reserves, and high winter consumption. The recent construction of the Port Kembla import terminal will help address these supply gaps.

Note: Historical data for LNG is based on JODI gas data.

Petroleum Liquids

Figure 1-30. Crude oil, NGLs, and other hydrocarbon production, imports, and exports in REF & TGT (PJ)

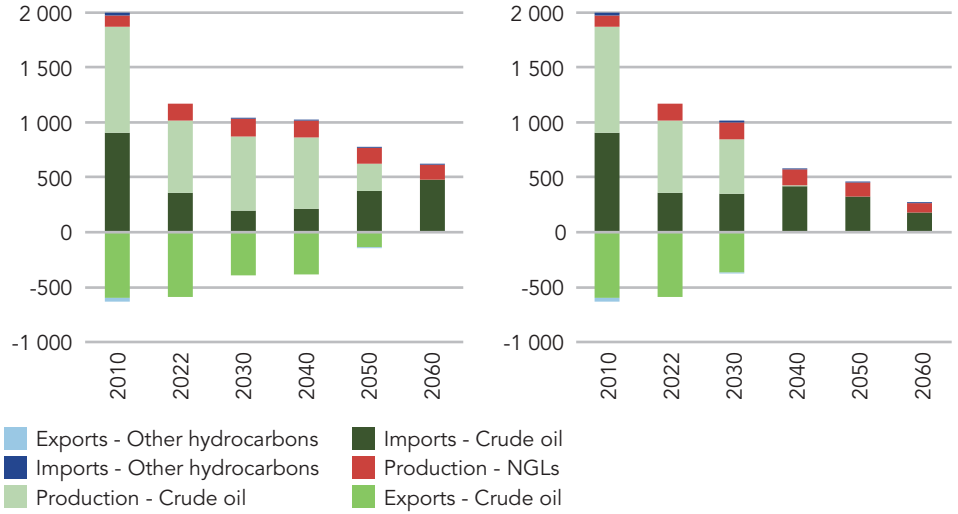
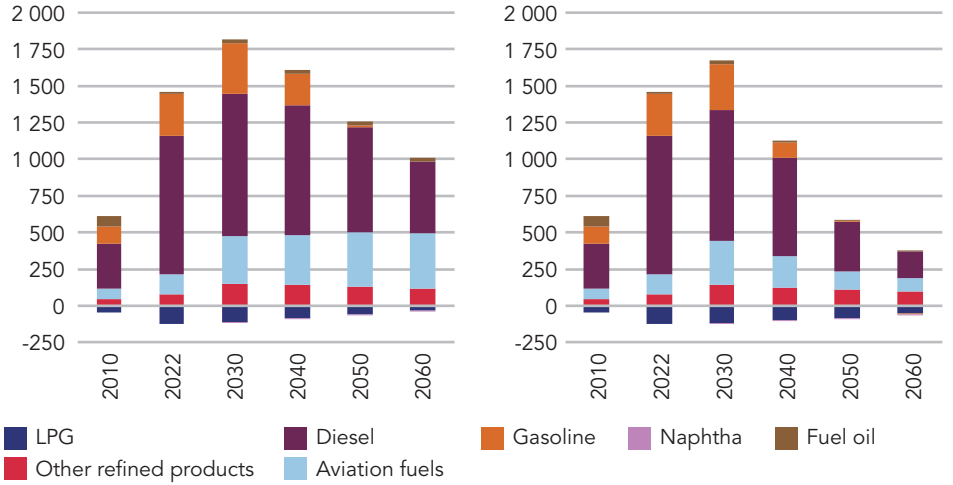


Figure 1-31. Net imports of refined products in REF & TGT (PJ)



- Most of Australia's crude oil production is exported as domestic refineries are not well-suited to refine domestic grades. In REF, crude oil production remains relatively low, peaking at around 700 PJ by 2040 before declining as proven and contingent reserves of crude oil are exhausted.
- Production is expected to decline faster in TGT as greater decarbonisation efforts place further downward pressure on domestic demand for refined petroleum products and lead to a reduced willingness to explore contingent crude oil reserves.
- Imports of crude oil will continue to supply Australia's remaining refineries for industrial and transport fuel production. In REF, crude oil imports are projected to increase in the 2050s as reserves run dry. In TGT, imports will displace domestic production earlier as reserves are exhausted faster. A growing share of imports will necessitate expanded import infrastructure (tankers, storage, and pipelines) to maintain fuel security.
- With the greater focus on decarbonisation and fuel switching in the transport and industrial sectors in TGT, the reliance on crude oil imports will decline past 2050 as refinery production decreases, with one refinery expected to close during the projection period.
- Imports of refined petroleum products are currently dominated by diesel, gasoline, and aviation fuels given Australia's limited domestic refining capacity to produce products for its transport and industrial sectors.
- However, diesel and gasoline net imports decline overtime as Australia's transport and industry sectors decarbonise and shift away from fossil fuel usage and towards electrification and alternative fuels. This decline is more rapid in TGT as decarbonisation efforts intensify in these sectors.
- In REF, importation of aviation fuels steadily increases as a growing population bolsters demand. However, imports decline in TGT as the aviation industry embraces trends such as improved efficiency, sustainable aviation fuels, and hydrogen blending.

Note: In Figure 1-31, net imports are presented without deducting bunkers.

Refining

Figure 1-32. Refined products and low-carbon fuels outputs in REF & TGT (PJ)

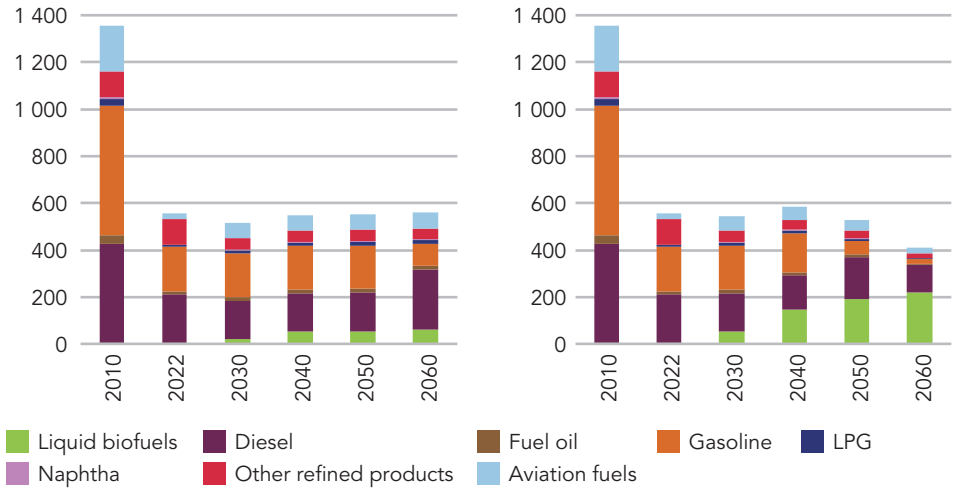
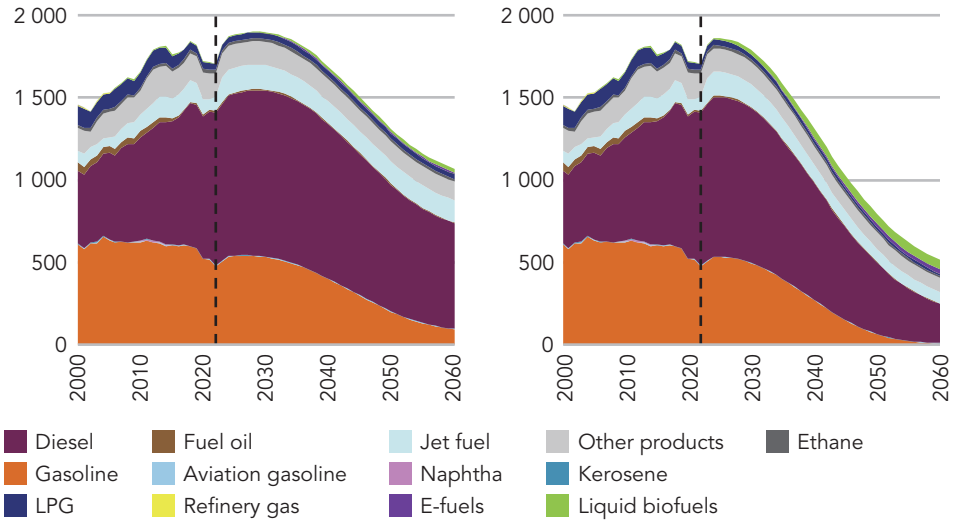


Figure 1-33. Refined products and low-carbon fuels demand in REF & TGT (PJ)



- Australia's refineries have steadily decreased from eight to two since 2000, with a current crude distillation capacity of 240 kb/d, relatively low compared to other economies. Australia's oil refineries are small, ageing, face high labour costs, and operate with comparatively low efficiency. In REF, government support, driven by concerns over energy independence, is expected to keep both refineries operational. In TGT, stronger decarbonisation efforts and reduced petroleum product demand lead to a decline in total non-biofuel production over time, with one refinery closing in 2050.
- Transport accounts for the majority of refined petroleum product demand, particularly diesel. In REF, total refined product consumption peaks at 1,900 PJ in 2030 before gradually declining. In TGT, the peak occurs earlier, in the late 2020s, followed by a sharper decline. Gasoline is phased out by 2060 due to rapid EV adoption, while diesel demand falls by 75% from its peak in 2027 but remains in the transport and industrial sectors, in areas where electrification may not always be feasible.
- In REF, diesel and gasoline output remain stable until 2050 as existing refineries continue operating in line with government support. As domestic gasoline consumption declines with reduced ICE vehicle use, refineries may shift production toward diesel to maintain domestic fuel security.
- In TGT, refinery fuel switching occurs earlier, around 2040, as domestic gasoline use decreases. Overall diesel production still declines due to early transport sector decarbonisation and the closure of a refinery. Production of liquid biofuels outside the petroleum refining sector rises to meet growing biofuel demand in transport and bunkering.
- In TGT, with one refinery closed, total refinery output drops to 190 PJ by 2060 (excluding biofuel production), compared with around 500 PJ of projected consumption. Imports are expected to account for approximately 60% of total refined product demand in 2060.

Hydrogen-based Fuels in the Target Scenario

Figure 1-34. Hydrogen-based fuels demand by sector [left]; Hydrogen-based fuels demand by fuel [right] (PJ)

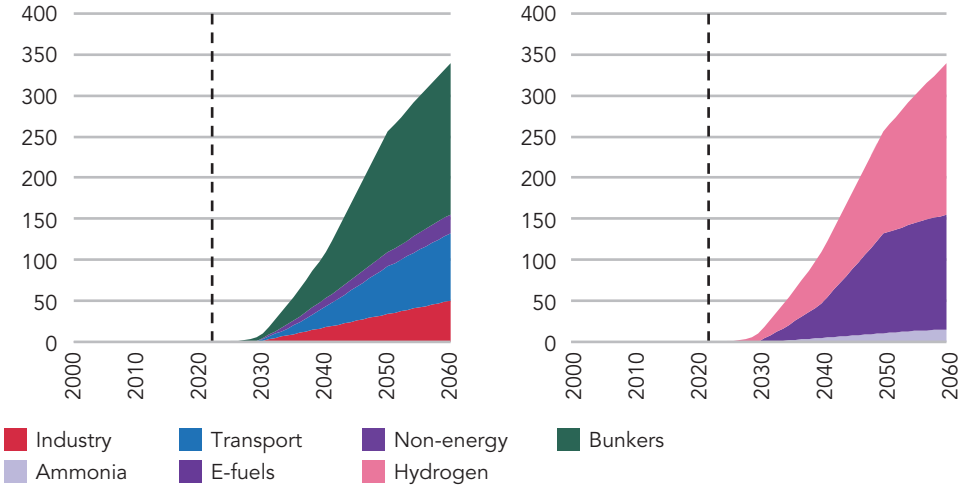
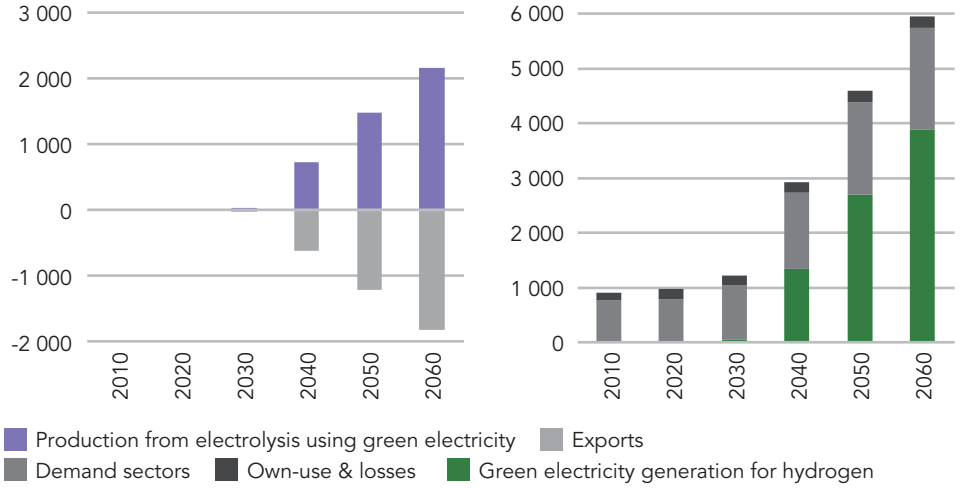


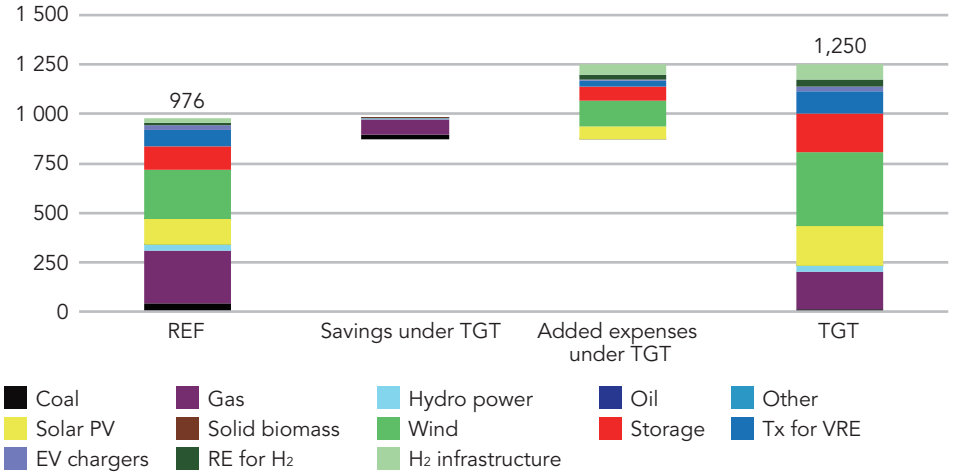
Figure 1-35. Hydrogen-based fuels production methods and supply [left]; Electricity for electrolysis vs other sectors (PJ) [right]



- Hydrogen-based fuels are projected to play a growing role in decarbonising the transport sector with the increased adoption of hydrogen fuel cells for trucks, buses, and trains, and hydrogen-derived synthetic fuels in aviation such as e-kerosene. Approximately half of hydrogen-based fuels are used for international bunkering, primarily in aviation and, to a lesser extent, shipping, with e-fuels in particular driving demand in the aviation sector.
- Hydrogen use is expected to increase in the industrial sector, supporting the decarbonisation of steel production through technologies such as direct-reduced iron, and providing energy for industrial heating and alumina refining (amongst many other applications).
- The non-energy sector will increase its use of hydrogen-based fuels, using them as a feedstock for producing chemicals such as ammonia, e-fuels, and methanol.
- Australia's green hydrogen production and exports are driven by the National Hydrogen Strategy 2024 which aims to produce 15 million tonnes of renewable hydrogen per year by 2050. These aspirations are further embedded in the FMIA strategy, identifying green hydrogen as a priority sector and positioning Australia as a global export leader.
- In particular, the volume of Australia's hydrogen exports is estimated to be sufficient to meet up to 25% of APEC's projected hydrogen import demand.
- Of the 1,480 PJ of hydrogen produced by electrolysis, 1,222 PJ is exported by 2050 (as ammonia). To achieve this production level, Australia will need 2,700 PJ of green electricity generation by 2050, roughly 1.6 times the amount required for its non-hydrogen demand sectors. This will require substantial investments in renewable generation and hydrogen infrastructure (e.g., electrolysers, refuelling stations, ports) while ensuring its nascent green hydrogen industry reaches commercial levels by the 2030s.

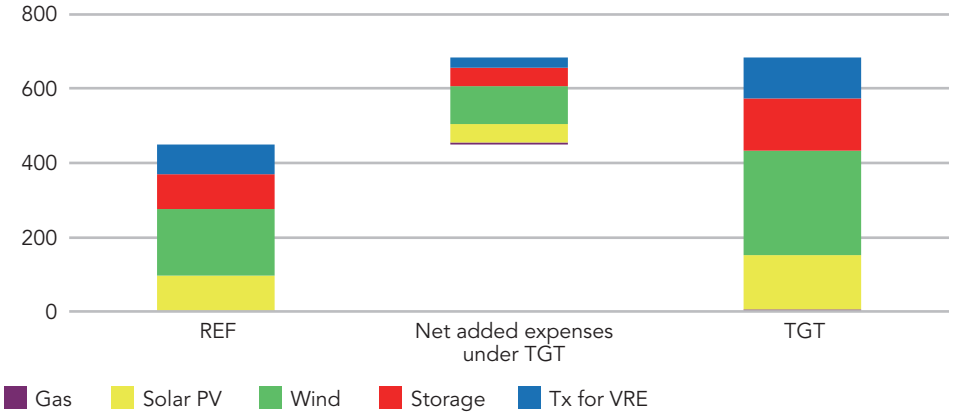
Costs

Figure 1-36. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



Note: Tx for VRE is only transmission infrastructure to connect variable renewable capacity to the grid. EV chargers do not cover the cost of associated infrastructure or EV vehicles. Hydrogen costs do not cover costs for bunkering.

Figure 1-37. Total capital investment (CAPEX) from 2025 to 2060 in the power sector (billion USD, undiscounted)

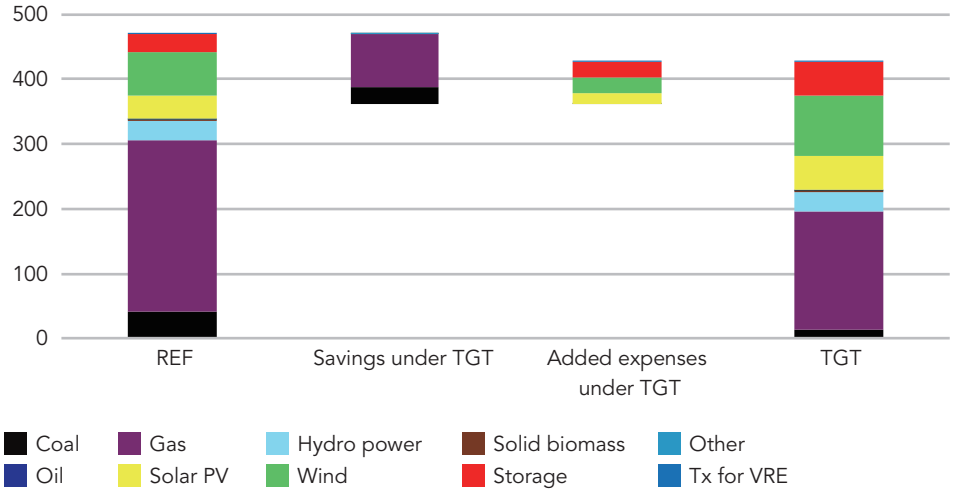


Note: Figure 1-37 only covers power and VRE transmission sector investments. Hydrogen and EV capital investments are not included.

- The transformation of Australia's electric grids will involve expenditures, with total costs rising in both scenarios from 2025 to 2060. Total costs consider the total capital, fixed, and variable costs in the power sector, costs for green hydrogen production for domestic use, transmission for VRE, and EV charger deployment.
- In REF, total costs reach an estimated USD 976 billion, with fuel costs for gas-fired generators representing the largest expense. In TGT, reductions in coal and gas use save an estimated USD 103 billion, but these savings are offset by higher investments in wind, solar, and energy storage. Increased spending on transmission will also be needed to connect new VRE capacity to demand centres.
- A growing green hydrogen producing sector is assumed, with an estimated USD 112 billion spent on renewable energy capacity, electrolyser plants, and associated logistics to produce green hydrogen for transport, industry and non-energy use. To note, the cost of producing hydrogen for exports is not included as cost recovery is assumed from Australia's future trading partners. Increased hydrogen usage for transport in TGT is expected to offset conventional fuel consumption, yielding an estimated USD 33 billion in savings (not shown in Figure 1-36).
- EV charger deployment costs are projected to rise with increased EV adoption, especially in TGT. An estimated USD 21 billion and USD 27 billion will be needed in the REF and TGT scenarios, respectively.
- Total capex in the power sector reaches USD 683 billion in TGT, up from USD 450 billion in REF. Australia's decarbonisation ambitions for its power grid (such as the 82% target) will require large investments in wind and solar, storage deployment, and transmission to accommodate the added VRE.
- Wind investment (both onshore and offshore) is the largest cost, comprising 41% of total investment in TGT. Combined wind and solar investment will be an estimated USD 426 billion with an estimated USD 110 billion needed for transmission to accommodate the added VRE in TGT.
- In TGT, an estimated USD 141 billion will be spent on storage to ensure energy reliability during morning and evening demand peaks. To note, this includes cost estimates of behind-the-meter storage.

Costs

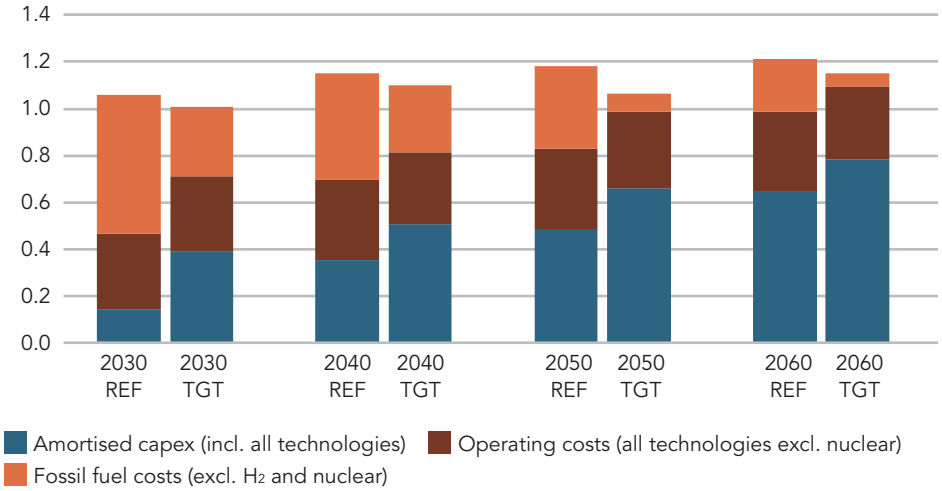
Figure 1-38. Total operating costs from 2025 to 2060 in the power sector (billion USD, undiscounted)



Note: Figure 1-38 only covers power and VRE transmission sector costs. It does not include operating costs associated with hydrogen production and EV charger costs.

- Total operating costs for the Australian power sector are projected to be 10% lower in TGT compared to REF. These costs incorporate variable fuel and non-fuel expenditures and fixed costs for the power sector, as well as fixed costs for transmission infrastructure to 2060.
- In REF, the highest operating costs are the fuel costs for coal and gas-fired power generation. While some of these costs are reduced in TGT due to more intense decarbonisation of Australia's electric grids, there are some added operational expenses associated with deploying low-emission technologies, namely wind, solar, and the associated storage required, which partially offset TGT savings. On balance, operating costs decline in TGT.
- The modest reduction in operating costs in TGT highlights the importance of policies that facilitate capital deployment. The Capacity Investment Scheme, which will underwrite 26 GW of renewables capacity and 14 GW of low-emission dispatchable capacity, is one such scheme that aims to divert capital towards necessary renewable projects as coal capacity progressively exits.

Figure 1-39. Cost of generating electricity relative to 2025 (2025 cost = 1.0) in the power sector



Note: Based on our assumptions about future capital and operating costs, Figure 1-39 shows cost compositions over time relative to 2025. It should not be considered an estimate of electricity tariffs and excludes market mechanisms that are too difficult to estimate.

- Figure 1-39 shows the relative cost of generating electricity in selected years indexed to the base year of 2025 in REF and in TGT, with the cost rising slightly in both scenarios overtime. In REF, fossil fuel costs as a share of total costs decline (due to declining thermal generation), but this is outweighed by an increase in capital amortisation costs as more renewables are added to the system, leading to an overall increase in the generation costs.
- Amortised capex grows larger in TGT, reflecting higher renewable investment. However, as fossil fuel costs decline more when compared to REF (due to more aggressive coal closures), the overall increase in TGT costs (relative to 2025) ends up being lower than that of REF overtime.
- To note, Figure 1-39 estimates the cost of electricity generation only and does not reflect the consumer cost of electricity which includes difficult-to-project market mechanisms that will add to the cost of electricity supply. In the case of Australia, these will include network charges, green and environmental government schemes, retail costs and margins.

CO_2 Emissions

Figure 1-40. CO_2 emissions in REF (million tonnes)

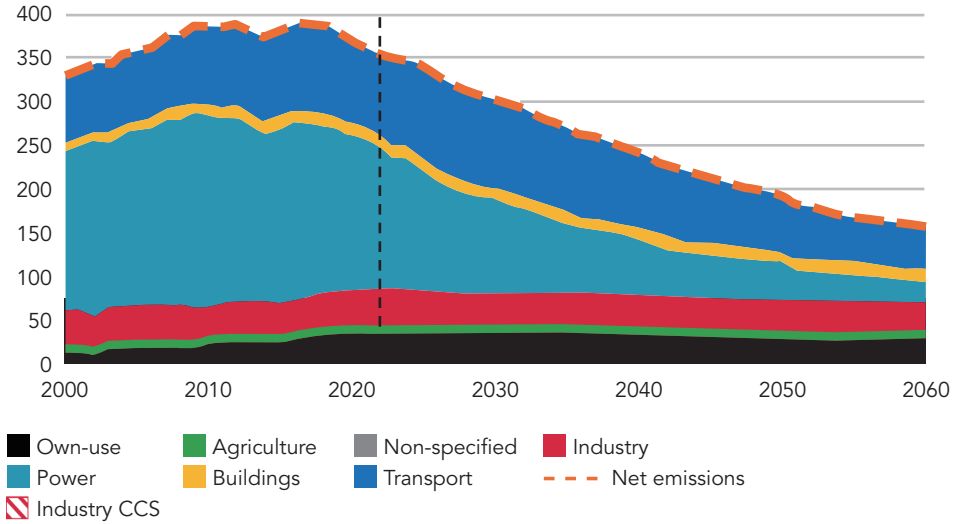
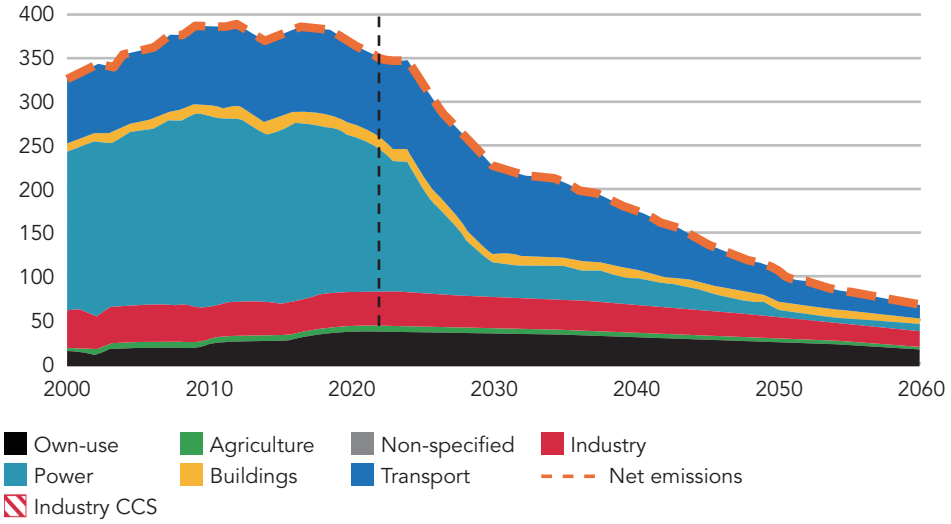
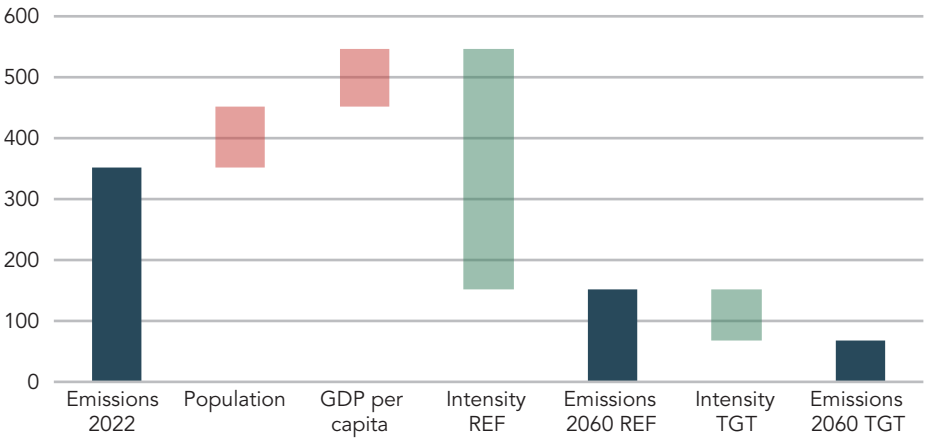


Figure 1-41. CO_2 emissions in TGT (million tonnes)



- Combustible CO_2 emissions decline in both scenarios as a result of Australia's decarbonisation efforts and policies. In TGT, Australia's net-zero 2050 target and its NDC drive an 81% decline in combustible emissions by 2060 relative to 2022. Achieving the net-zero target will require offsetting the remaining combustible emissions through carbon sinks and credits. To note, Australia's updated 2025 NDC and associated 2035 emissions target was not considered in either scenario, given the recency of the announcement.
- Emission declines are mostly driven by decarbonisation in the power sector. Emissions fall more sharply in TGT due to earlier coal closures and higher renewable adoption. The electrification of the transport sector is also a strong contributor in reducing emissions. Industrial emissions persist due to hard to abate industrial processes.
- Australia's population and economic activity growth (GDP per capita) would have led to a potential doubling of emissions if emission intensity remained the same. However, emission intensity improvements (from renewables adoption and efficiency improvements) help reduce emissions by half with additional intensity improvements in TGT lowering emissions further.

Figure 1-42. CO_2 emissions components (million tonnes)



Note: All values represent energy sector combustion CO_2 emissions. Biogenic CO_2 is treated as zero at the point of combustion. Emissions reductions from CCS are comparatively small and do not register in Figures 1-40 and 1-41.

Useful Links

APEC Energy Overview – https://aperc.or.jp/reports/energy_overview.php

APEC Energy Statistics 2022 – https://www.egeda.ewg.apec.org/egeda/general/info/pdf/APEC_Energy_Statistics_2022.pdf

APEC Expert Group on Energy Data and Analysis (EGEDA) – https://www.egeda.ewg.apec.org/

Australian Energy Market Operator (AEMO) – AEMO | Australian Energy Market Operator

Australian Energy Regulator – Australian Energy Regulator (AER)

Australian Energy Statistics – Australian Energy Statistics | energy.gov.au

Clean Energy Council – Renewable energy in Australia | Clean Energy Council

Clean Energy Regulator – Promoting biodiversity, emissions reduction and renewable energy uptake | Clean Energy Regulator

CSIRO – Commonwealth Scientific and Industrial Research Organisation – Commonwealth Scientific and Industrial Research Organisation, Australian Government - CSIRO

Department of Climate Change, Energy, the Environment and Water – Home – DCCEEW

Energy Institute Statistical Review of World Energy – https://www.energyinst.org/statistical-review

Geoscience Australia – Geoscience Australia

Grattan Institute – Home – Grattan Institute

World Bank Open Data – https://data.worldbank.org/



2. Brunei Darussalam

Summary

	Reference			Target		
	2022	2060	% Change	2022	2060	% Change
Macroeconomic						
Population (million)	0.4	0.5	10%	0.4	0.5	10%
GDP (billion 2017 USD, PPP)	27	46	68%	27	46	68%
Energy Demand						
Buildings (PJ)	13	15	16%	13	14	8%
Industry (PJ)	6	19	206%	6	16	167%
Non-energy (PJ)	0.2	57	28,200%	0.2	57	28,200%
Transport (PJ)	17	16	-6%	17	8	-53%
Modern renewables share of TFEC (%)	0.03	12	39,900%	0.03	20	66,567%
Energy intensity of TFEC (PJ/GDP, billion USD)	1.3	1.1	-15%	1.3	0.83	-36%
Electricity						
Generation (TWh)	6	11	103%	6	9	62%
Renewables share of generation (%)	0.09	20.3	22,456%	0.09	25.3	28,011%
Generation capacity (GW)	1.2	3.4	177%	1.2	3.4	177%
Total Primary Energy Supply (TPES)						
Coal & coal products (PJ)	28	93	226%	28	0	-100%
Natural gas (PJ)	130	195	50%	130	222	71%
Petroleum liquids (PJ)	43	50	17%	43	37	-12%
Low-carbon & waste energy (PJ)	0	9	46,663%	0	9	46,663%
CO_2 intensity of energy supply ($MtCO_2/PJ$)	0.046	0.045	-2%	0.046	0.027	-41%
Net CO_2 Emissions (million tonnes)	9	16	71%	9	8	-18%

Note: In this publication, the term "modern renewables" refers to all renewable energy sources excluding solid biomass in the buildings sector. The term "low-carbon & waste energy" includes all bioenergy, waste-derived energy, renewables, nuclear, and hydrogen-based fuels. Total primary energy supply (TPES) numbers include international bunkers. Net emissions are calculated as gross energy sector combustion CO_2 minus CO_2 captured and stored through carbon capture and storage (CCS).

Key Takeaways

Emissions

- Brunei Darussalam's CO_2 emissions are projected to have a 1.8-fold increase, from 9.2 million tonnes in 2022 to 16.5 million tonnes in 2027 in both REF and TGT, as phase 2 of the Pulau Muara Besar (PMB) refinery and petrochemical complex necessitates increased use of coal.
- Although emissions are expected to stabilise beyond 2027 and reach 15.7 million tonnes in 2060 in REF, TGT will see a greater emissions reduction throughout the outlook period. Consequently, emissions in 2060 in TGT are expected to reach 7.6 million tonnes, which is on par with 2019 levels.
- Emissions reduction efforts in Brunei Darussalam are contingent upon effective execution of its Brunei Darussalam National Climate Change Policy (BNCCP), including increasing the total share of renewable energy to at least 30% of the economy's total capacity in the power generation mix, electrification of the transport sector, and carbon pricing. In addition, coal-to-gas switching in the refining and petrochemical complex could potentially bring down overall emissions.

Energy Import Dependence

- Brunei Darussalam is expected to remain a net energy exporter through 2060 in both scenarios, with the refinery and petrochemical complex playing a role in increasing refined and petrochemical products exports, in addition to continually being an LNG exporter.
- The scale of the refining and petrochemical complex requires importation of crude oil to supplement crude oil produced domestically. Consequently, there is risk to crude oil security due to import dependence as well as declining domestic production.
- Should the world follow a net-zero trajectory through 2060, Brunei Darussalam's status as a net energy exporter could be affected due to declining fossil fuel demand and stricter carbon regulations.

Figure 2-1. Net CO_2 emissions (million tonnes)

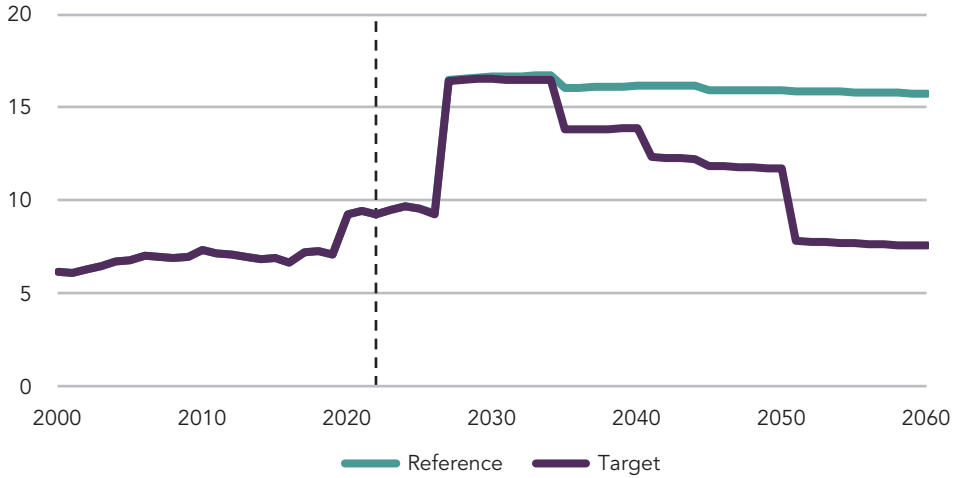
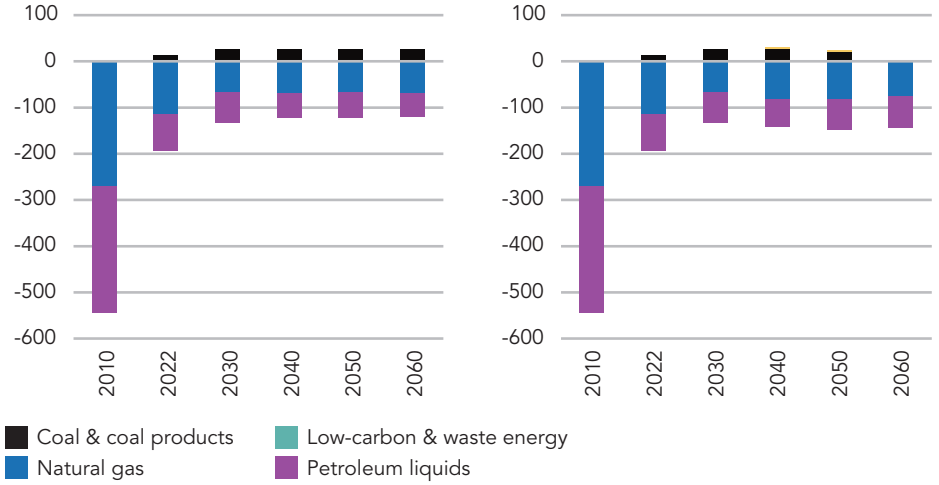


Figure 2-2. Net imports share of TPES in REF & TGT (%)



Note: In Figure 2-2, net imports refer to total imports minus exports and international bunkers.

Key Takeaways

Grid Reliability

- Brunei Darussalam's current power system is highly dispatchable and therefore reliable, given heavy reliance on fossil fuels, with a tiny fraction from solar.
- Figure 2-3 illustrates the grid's dependence on dispatchable power in the 4-hour period of maximum dependence and 4-hour period of minimum dependence. In 2022, the difference between maximum and minimum was relatively small, allowing operators to produce power at a constant rate. The dashed line shows the system's peak load in each year.
- The growth in electricity demand in both REF and TGT necessitates the continuous operation of gas-fired power plants to provide grid stability and reliability, particularly when non-dispatchable generation (solar) is intermittent.

Cost

- Brunei Darussalam's power sector will require substantial expenditures. Total costs from 2025 to 2060 are estimated to be between USD 29 billion to USD 28 billion in REF and TGT, respectively.
- Total costs consider the capital, fixed, and variable costs in the power sector, costs for electricity imports, transmission for variable renewable electricity, and electric vehicle chargers.
- The cost increase in TGT is driven by the importation of hydroelectricity imports from Malaysia. Meanwhile, the coal-to-gas switch at the PMB refinery and petrochemical complex yields cost savings in TGT with a decline in coal use.

Figure 2-3. Peak load and maximum and minimum dependence on dispatched power (GW)

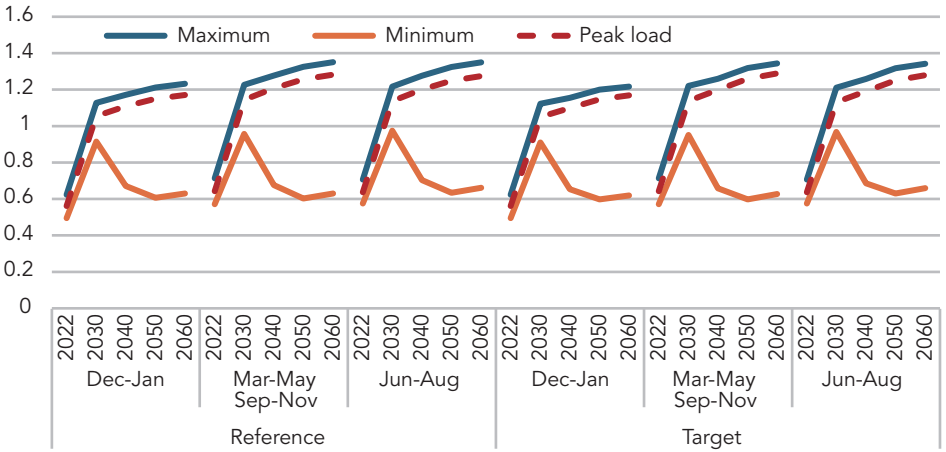
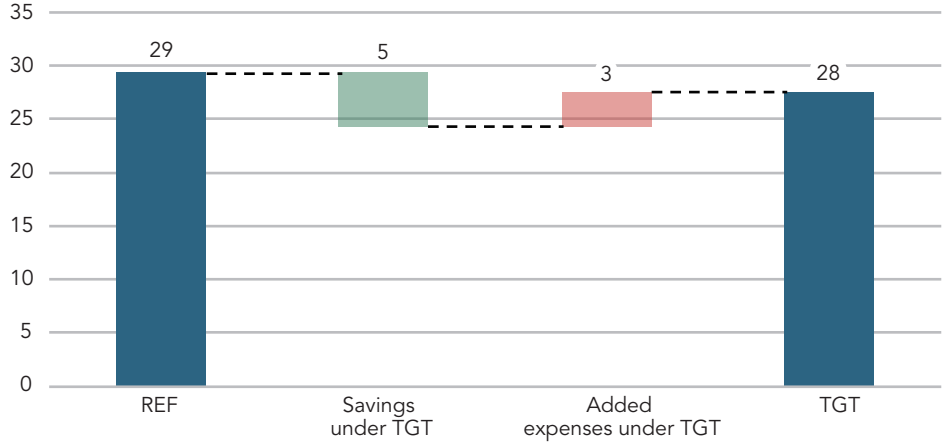


Figure 2-4. Costs in the power sector, 2025 to 2060 (billion USD, undiscounted)



*Actual costs will differ from estimated costs in the *Outlook* for a variety of reasons including changing commodity prices, manufacturing costs, and unforeseen technical advances. All costs are in 2023 real terms.

About Brunei Darussalam

Overview

Geographical and Economic Landscape

Brunei Darussalam is a tiny economy that spans 5,765 square kilometres. It is situated on the northwest coast of Borneo Island – the world's third largest island. The Malaysian state of Sarawak surrounds Brunei Darussalam on three sides. The remaining border has a coastline with a length of about 168 km along the South China Sea, and the coastal areas are generally low-lying of up to 12 meters below sea level.

The economic landscape of Brunei Darussalam is linked to the oil and gas sector, which accounts for more than half of the economy's GDP. Consequently, Brunei Darussalam has encountered significant challenges in recent years amid volatile global energy prices. In addition, as the world is transitioning towards the possibility of carbon neutrality by 2050, Brunei Darussalam must continue to advance its energy sector diversification efforts to strengthen resilience and competitiveness in a low-carbon future.

Energy Supply and Consumption

Brunei Darussalam's energy supply amounted to 201 PJ in 2022, an increase of over 16% from 2021 levels. This was primarily driven by imports of crude oil to meet the domestic refinery needs. Meanwhile, oil and gas production declined in 2022 due to unscheduled maintenance and rejuvenation activities. In terms of shares, gas remained the dominant fuel, accounting for 65% of the total energy supply, followed by coal and oil at 21% and 14%, respectively.

Total final consumption remained stable at 35 PJ in 2022 from 2021 levels. Transport and industry sectors registered the largest yearly increases of 4.7% and 3.7% respectively, while commercial and residential sectors experienced declines of over 11% and 3%, respectively.

Energy Security Challenges and Strategies

Despite being one of APEC's main net energy exporters, Brunei Darussalam continues to revitalise its upstream oil and gas activities for its long-term energy security and sustainability. For instance, the economy recently announced the first licensing for its two offshore oil and gas blocks after more than a decade. Brunei Darussalam is also committed to increase total share of renewable energy to at least 30% of total capacity in the power generation mix.

Key Energy Initiatives

Paris Agreement Commitment

Brunei Darussalam aims to achieve net zero emissions by 2050, with an NDC target of reducing GHG emissions by 20% relative to business-as-usual levels by 2030.

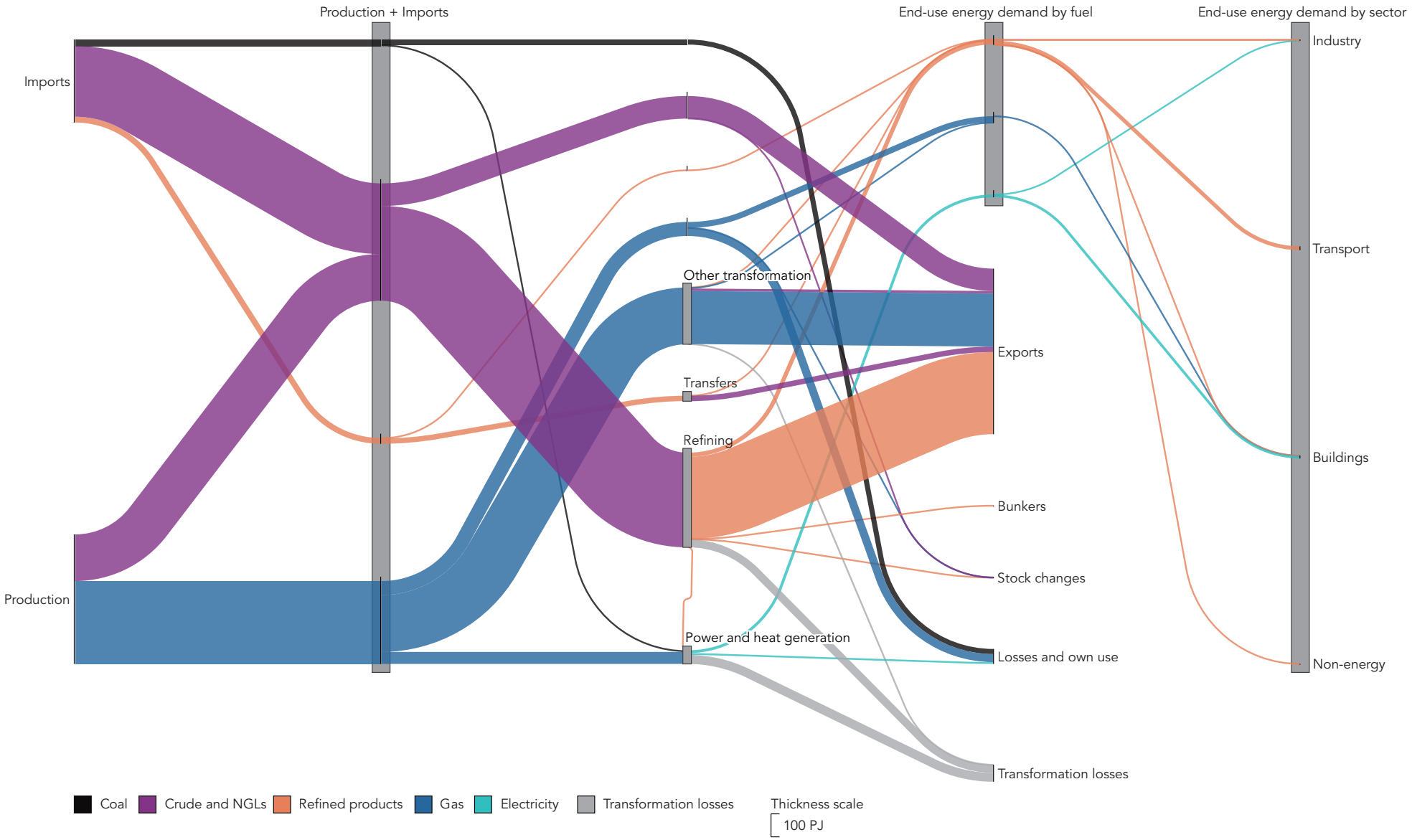
Brunei Darussalam National Climate Change Policy (BNCCP)

This policy was established to pave the way for Brunei Darussalam's low-carbon and climate-resilient pathways for a sustainable economy, through the adoption of ten key strategies: industrial emissions, forest cover, electric vehicles, renewable energy, power management, carbon pricing, waste management, climate resilience & adaptation, carbon inventory, awareness & education.

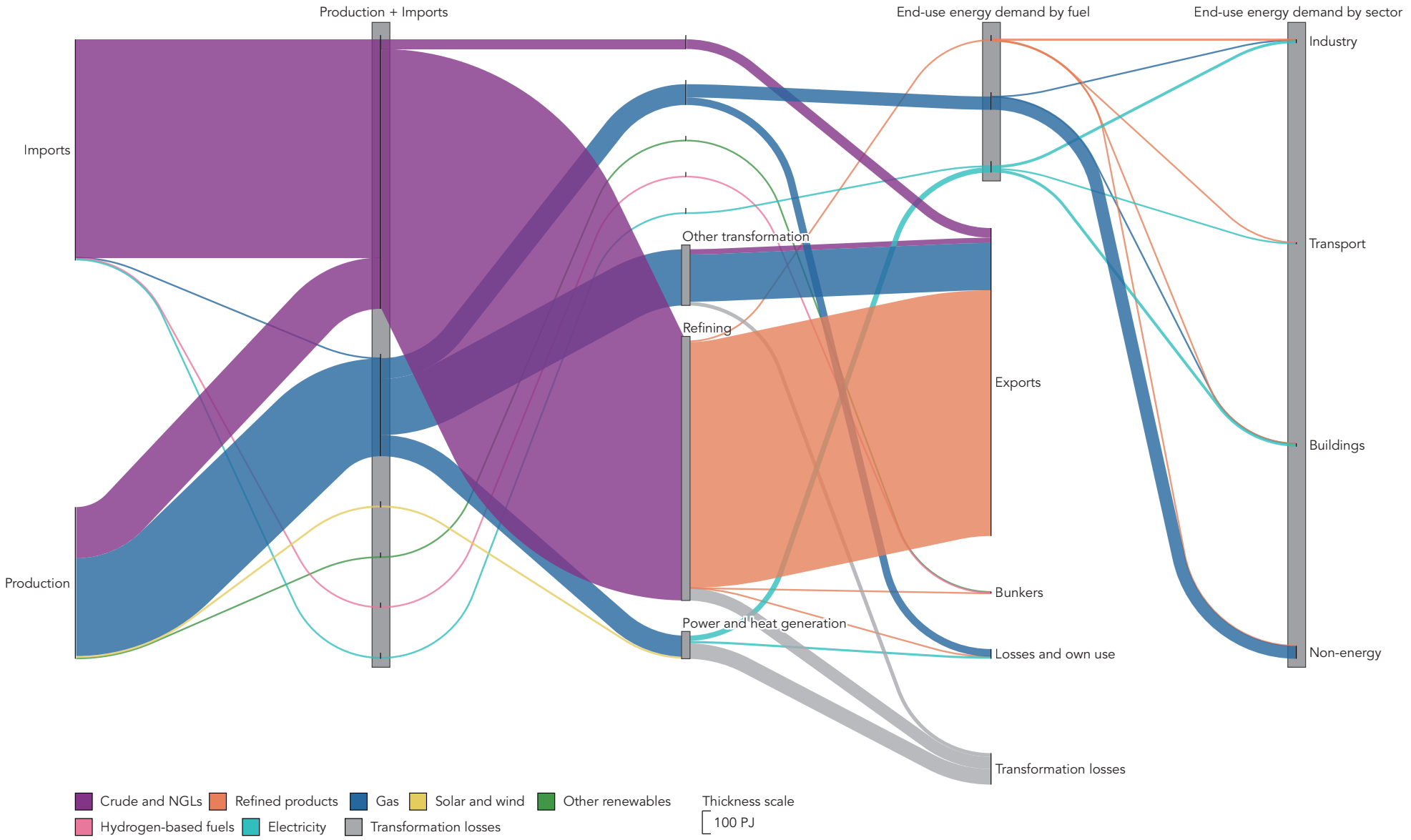
Chapter 233 Energy Efficiency (Standards and Labelling) Act, 2021

The Department of Energy at the Prime Minister's Office introduced this Act in 2021, in line with its energy efficiency and conservation initiatives. The Act requires manufacturers, suppliers, wholesalers and retailers in Brunei Darussalam to import and sell appliances that meet the minimum energy performance standards.

Energy Flow (2022)



Energy Flow (2060, Target Scenario)



Scenarios and Assumptions

In *The Outlook*, APERC analyses energy demand, transformation, and supply, as well as emissions. The **Reference Scenario (REF)** offers a projection based on historical trends, recent developments, and APERC's assumptions about the continuation of those trends in each APEC economy, while acknowledging technical restraints. The REF Scenario offers a baseline to compare with the **Target Scenario (TGT)** projections, which explores a hypothetical pathway where each economy achieves energy-related policy targets, assuming implementation regardless of cost-effectiveness. When implementation details are lacking, assumptions are inferred from the targets themselves or emissions-related goals.

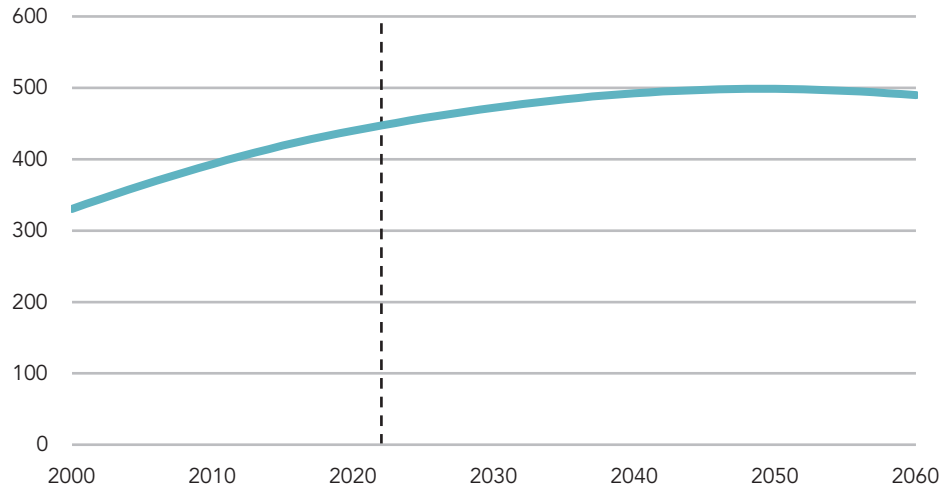
	Reference	Target
General	• Population: UN medium; GDP: APERC model and IMF	• Population: UN medium; GDP: APERC model and IMF
Buildings	• Appliances in households and commercial and public buildings are regulated under the Chapter 233 Energy Efficiency (Standards and Labelling) Act, 2021. • Expansion of AI and data centres.	• Appliances in households and commercial and public buildings are regulated under the Chapter 233 Energy Efficiency (Standards and Labelling) Act, 2021. • Energy efficiency measures are assumed to be enhanced. • Expansion of AI and data centres.
Industry	• The refinery and petrochemical complex, methanol plant, and a fertiliser industry dominate electricity consumption. • Natural gas feedstock of about 0.05 trillion cubic feet annually for fertiliser production at the fertiliser industry (non-energy sector).	• The refinery and petrochemical complex, methanol plant, and a fertiliser industry dominate electricity consumption. • Natural gas feedstock of about 0.05 trillion cubic feet annually for fertiliser production at the fertiliser industry (non-energy sector). • Energy efficiency measures are assumed to be enhanced.
Transport	• Battery electric vehicles (BEVs) are assumed to achieve the following: - Passenger vehicles and light commercial vehicles reach a 30% sales share and a 20% stock share by 2050. - Heavy trucks reach a 20% sales share and an 11% stock share by 2050. • Plug-in hybrid electric vehicles (PHEVs) are assumed to achieve the following: - Passenger vehicles reach a 23% sales share and a 15% stock share by 2050. - Light commercial vehicles reach a 30% sales share and an 18% stock share by 2050.	• BEVs are assumed to achieve the following: - Passenger vehicles and light commercial vehicles reach a 67% sales share by 2035, and then a 100% sales share by 2050. This results in a 78% stock share by 2050. - Heavy trucks reach a 40% sales share and a 22% stock share by 2050. • Plug-in hybrid electric vehicles (PHEVs) are assumed to achieve the minimal sales share and stock share, given increased stock and sales shares of BEVs.
Power	• The Pulau Muara Besar (PMB) refinery and petrochemical complex coal power plant to be expanded by 2027, as per its phase 2 operation. • Solar PV generation capacity to reach over 1,000 MW by 2060.	• The PMB refinery and petrochemical complex coal power plant to be expanded by 2027, as per its phase 2 operation. • The PMB refinery and petrochemical complex to gradually displace coal with natural gas for its electricity generation from 2040 onwards • Solar PV generation capacity to reach over 1,000 MW by 2060. • Brunei Darussalam to import 100 MW of hydropower from 2035 onwards.

	Reference	Target
Supply	• Refinery and petrochemical complex to increase its coal and crude oil imports for meeting its phase 2 requirements over the outlook period. • Oil and gas production reaches 300,000 barrels of oil equivalent per day over the outlook period.	• Refinery and petrochemical complex to increase its coal and crude oil imports for meeting its phase 2 requirements, but coal imports to gradually decline from 2040 onwards to zero by 2050. • Oil and gas production reaches 300,000 barrels of oil equivalent per day over the outlook period.
Emissions	• Only considers CO_2 emissions from fuel combustion. • Guided by Brunei Darussalam's first NDC and Brunei Darussalam National Climate Change Policy (BNCCP).	• Only considers CO_2 emissions from fuel combustion. • Guided by Brunei Darussalam's first NDC and Brunei Darussalam National Climate Change Policy (BNCCP).

Note: The base year is 2022. Macro-economic assumptions are constant across scenarios. Historical energy balances are from EGEDA submissions for 2022.

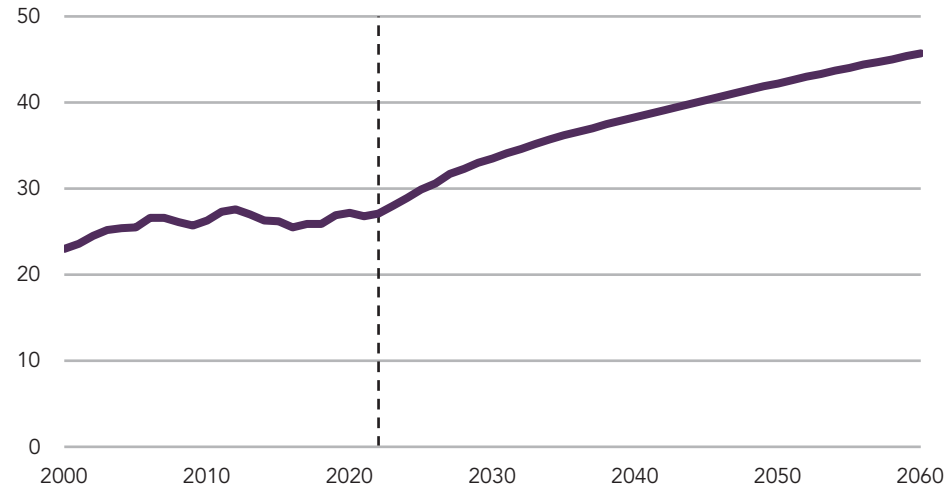
Demographic and Macroeconomic Assumptions

Figure 2-5. Population (thousands)



- Brunei Darussalam's population is expected to continue growing at a rate of 0.25% per annum until 2060, by which the economy will have around 489,700 people.
- However, the population aged above 65 in Brunei Darussalam will rise by over 13% by 2035, which will drive a societal transformation, potentially influencing financial markets, social welfare, healthcare, as well as future energy demand.

Figure 2-6. Real GDP projections (billion 2017 USD, PPP)



- The IMF projects Brunei Darussalam's GDP to reach USD 31.66 billion in 2027. Beyond 2027, its GDP is expected to grow further, eventually reaching over USD 45.60 billion in 2060.
- It is assumed that much of the growth in Brunei Darussalam's GDP will be driven by the domestic PMB refinery and petrochemical complex. Phase 1 of the complex has been a success, contributing over BND 4.5 billion to the economy's GDP. Further expansion of the complex, which will include phase 2, will significantly increase Brunei Darussalam's GDP through increased petrochemical product export volumes.

End-use Energy Demand

Figure 2-7. Energy demand by sector in REF & TGT (PJ)

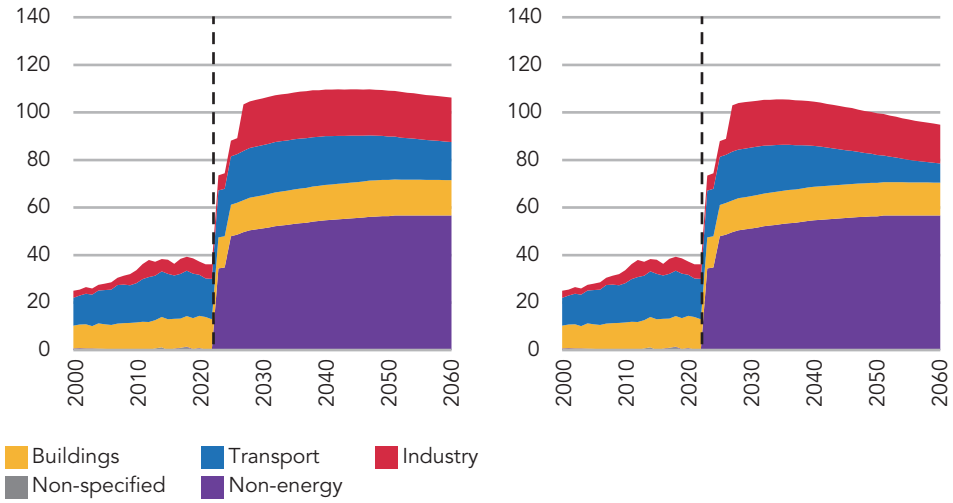
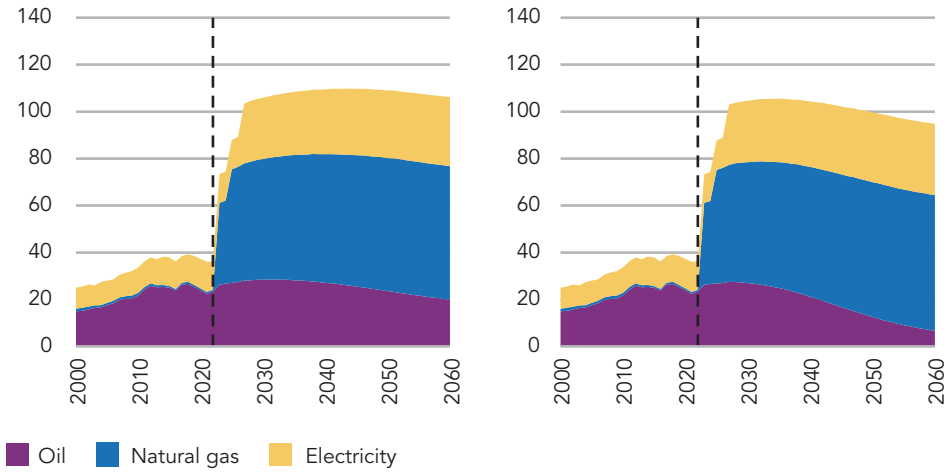


Figure 2-8. Energy demand by fuel in REF & TGT (PJ)



- Brunei Darussalam's total sectoral energy demand is expected to almost triple by 2060 from 2022 levels in both the REF and TGT scenarios.
- In REF, the largest growth is projected to come from the non-energy sector, reflecting the expansion of downstream facilities. As a result, the non-energy sector is expected to account for over half of the economy's energy demand mix by 2060. The industry sector is also projected to more than triple throughout the outlook period. The transport sector will see a decline of 6% in 2060 in REF.
- Similar growth of demand is expected in the non-energy sector in TGT. The notable difference is in the transport sector's energy demand, which is expected to decrease by 35% in 2060 from 2022 levels. The industry and buildings sectors are expected to grow at a slower rate than in REF.
- The expansion of downstream facilities in Brunei Darussalam involves greater use of natural gas as feedstock. Hence, gas is expected to account for over 50% of the total demand throughout the outlook period in both the REF and TGT scenarios.
- In addition, electricity is expected to increase by 2.4-fold in 2060 in both scenarios, reflecting its importance in supporting the downstream sector. Share-wise, electricity is projected to contribute to almost 30% in 2060 in both scenarios.
- The utilisation of oil is expected to decline by 10% in REF and 54% in TGT, as Brunei Darussalam's transport sector undergoes improvement in vehicle efficiency, as well as electrification.

Buildings Energy Demand

Figure 2-9. Buildings energy demand by fuel in REF & TGT (PJ)

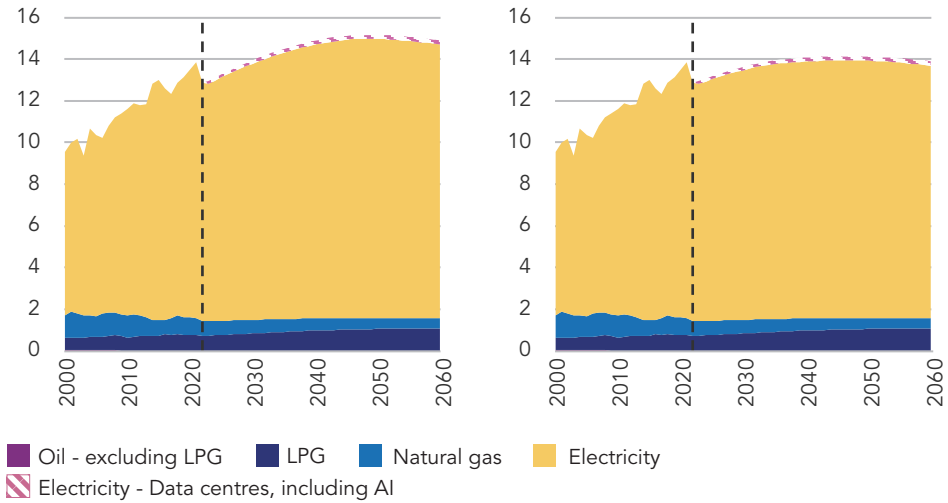
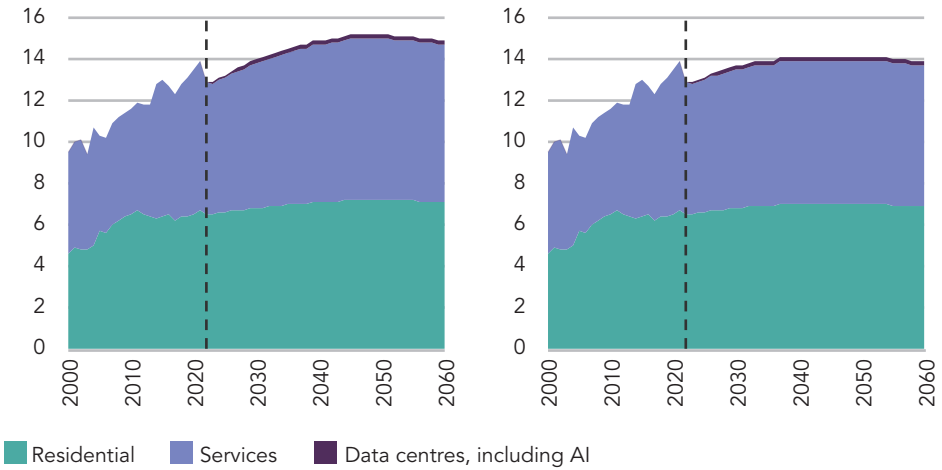


Figure 2-10. Buildings energy demand by sector in REF & TGT (PJ)



- Brunei Darussalam's residential and commercial buildings have been highly electrified, given their excellent access to the electricity grid. The persisting shares of oil and gas are small as those fuels are only utilised for cooking purposes.
- Overall buildings energy demand is expected to increase by 16% between 2022 and 2060 in REF. Increasing population and economic growth will lead to a growth of 17% in electricity demand, while LPG demand also expands by 1.6-fold.
- In TGT, enhanced enforcement of the Energy Efficiency (Standards and Labelling) Order 2021 on buildings is assumed to slow the growth of buildings energy demand to 9%, with the corresponding electricity demand increasing by only 8%.
- In REF, services energy demand is expected to contribute highly to the overall increase in 2060, which is in tandem with Brunei Darussalam's economic growth. Conversely, residential energy demand only grows by 9%.
- Services energy demand is projected to grow by only 6% in TGT, based on the assumption that the Energy Efficiency (Standards and Labelling) Order 2021 is enforced on services buildings (including government and commercial establishments). The Order is assumed to affect residential buildings too, with its energy demand in TGT expected to grow by 6% over the outlook period.
- The use of data centres and the application of artificial intelligence (AI) will be important in meeting the economy's increasing digital needs, as outlined in the Ministry of Finance and Economy (MOFE)'s Economic Blueprint. In this light, the energy demand of data centres and AI is expected to account for over 1% of the total buildings' energy demand in 2060 in both scenarios.

Industry Energy and Non-energy Demand

Figure 2-11. Industry & non-energy demand by fuel in REF & TGT (PJ)

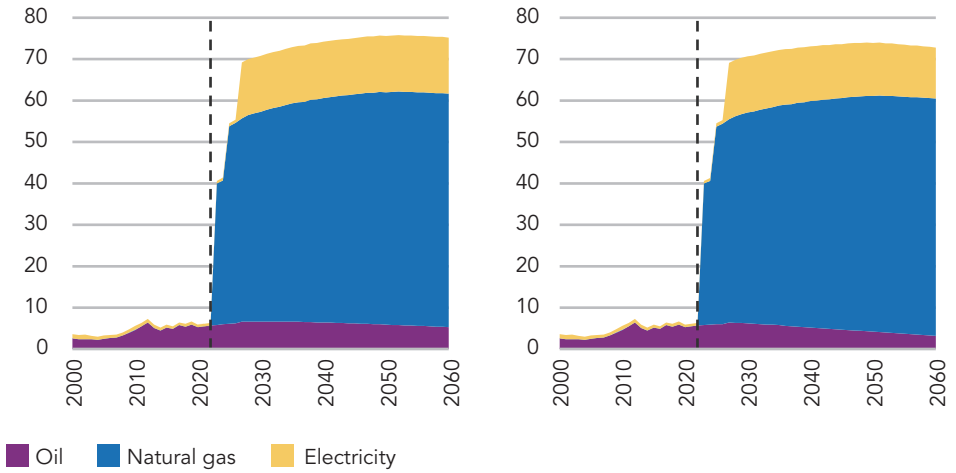
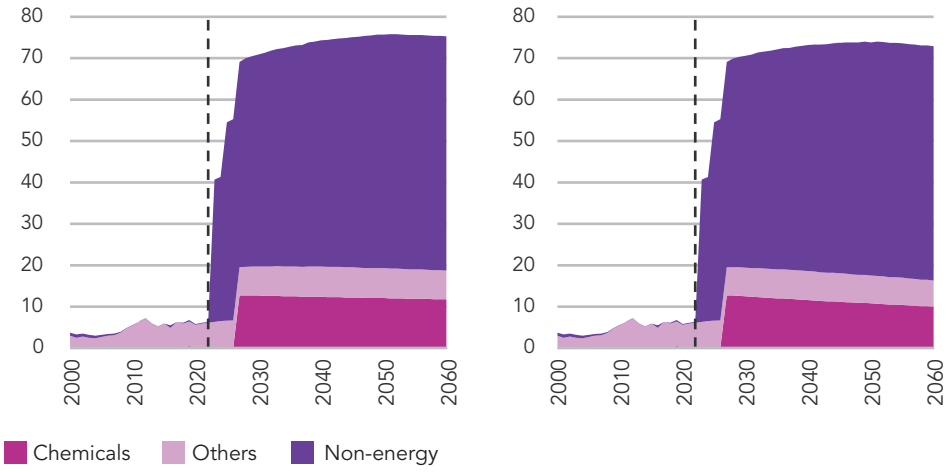


Figure 2-12. Industry & non-energy demand by sector in REF & TGT (PJ)



- Within the industry and non-energy sectors of Brunei Darussalam, gas and electricity are expected to increase the most throughout the outlook period.
- The establishment and operation of the Brunei Fertilizer Industry, which is one of the largest fertiliser plants in Southeast Asia, is expected to increase gas demand to over 56 PJ in 2060 in both REF and TGT. The Brunei Fertilizer Industry manufactures ammonia using gas as the feedstock and then converts it into urea, which has a production capacity of 1.3 million tonnes per year.
- The sheer size of the fertiliser industry in Brunei Darussalam will lead gas to be the most dominant commodity within industry and non-energy sectors, accounting for over 70% of the total demand in 2060 in REF and TGT.

Transport Energy Demand

Figure 2-13. Domestic transport energy demand in REF (PJ)

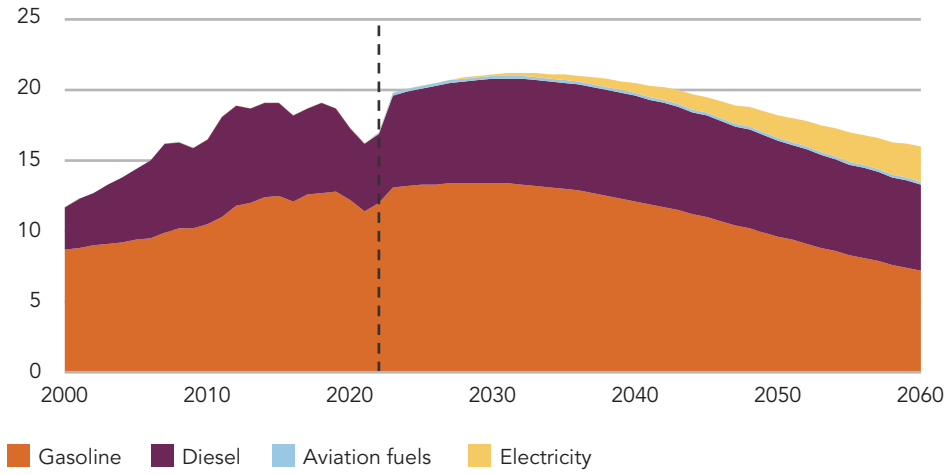
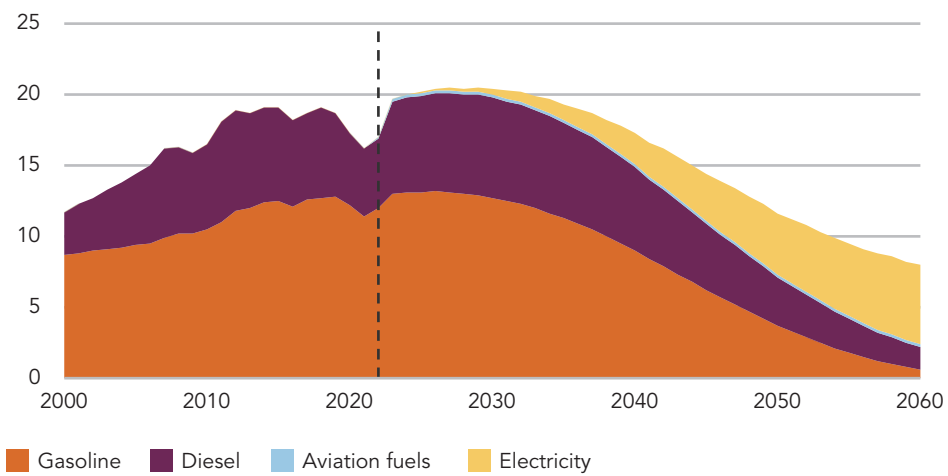


Figure 2-14. Domestic transport energy demand in TGT (PJ)



- Brunei Darussalam's transport sector has been dominated by gasoline and diesel, with the former constituting the major portion. While these trends are set to continue beyond 2020, electricity is expected to enter the demand mix in both REF and TGT.
- In addition, given the high rate of private vehicle ownership, passenger activity tracks population growth and therefore energy demand reaches a peak in the 2050s. On the other hand, freight activity is tied to GDP growth and is expected to continue increasing throughout the projection period.
- In REF, demand is projected to decline by 6% in 2060 from 2022 levels, with gasoline demand falling by 40%. On the other hand, the demand for diesel is expected to remain strong.
- In REF, the adoption of battery electric vehicles and plug-in hybrid electric vehicles is expected to increase electricity's share of total demand to 16% by 2060. As a result, the share of gasoline is projected to fall to 45% from 2022 levels of 71%.
- A greater decline in energy demand is anticipated in TGT than in REF, driven by a higher level of adoption of electric vehicles, which are roughly three times more efficient than conventional vehicles. Overall energy demand is projected to decline by 53% during the same period, with gasoline and diesel demands falling by 95% and 67%, respectively.
- Due to higher uptake of battery electric vehicles and plug-in hybrid electric vehicles, the share of electricity will rise to 70%. Consequently, gasoline and diesel shares are expected to settle at just 8% and 20%, respectively.
- Electric vehicles are one of the key components of Brunei Darussalam's decarbonisation strategy. However, the dominance of conventional vehicles, whose fuels are heavily subsidised, may limit the growth of electric vehicles.

Other Transport Data

Figure 2-15. Transport vehicle stocks in REF & TGT (millions)

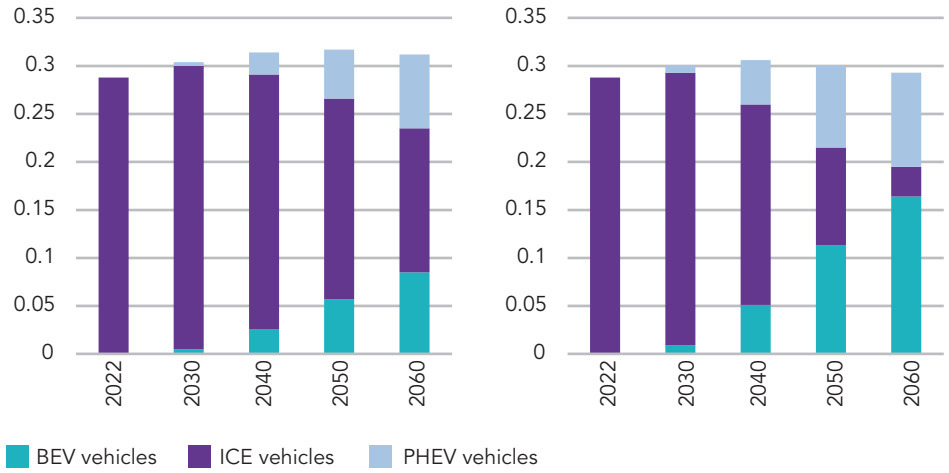
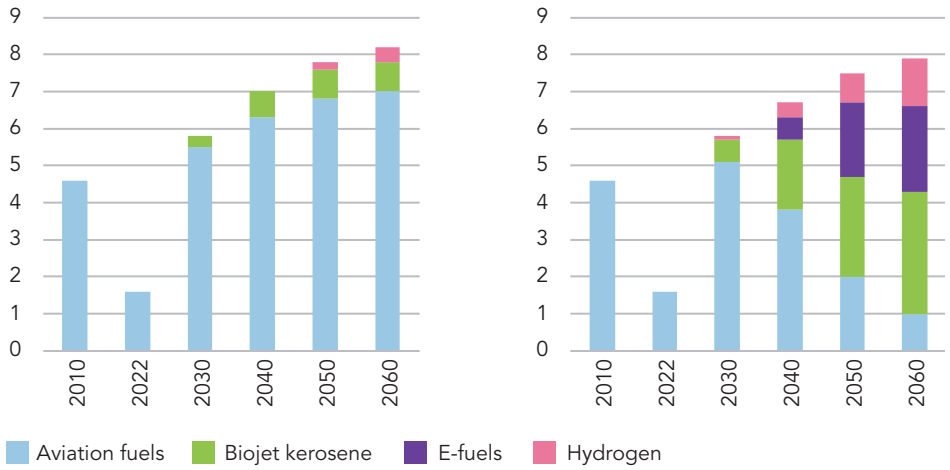
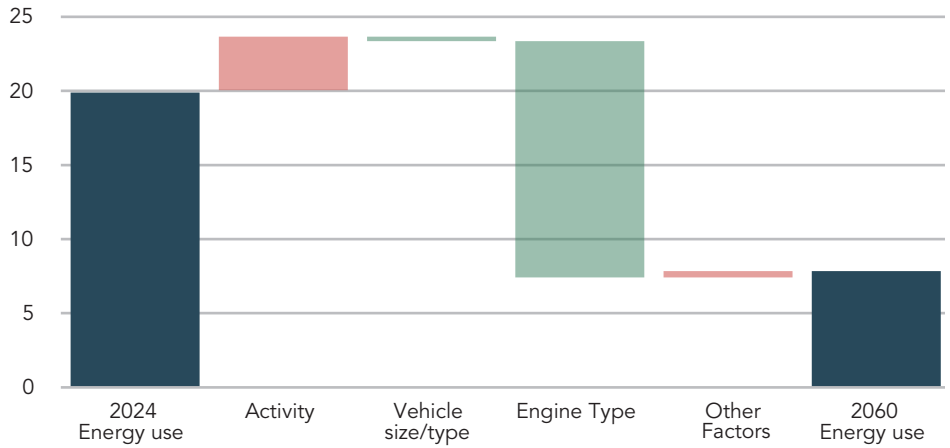


Figure 2-16. International bunker energy demand for aviation in REF & TGT (PJ)



- Brunei Darussalam is projected to see a considerable shift in its transport stocks from internal combustion engines to plug-in hybrid electric vehicles (PHEVs) and battery electric vehicles (BEVs) in both scenarios. In REF, BEVs and PHEVs stock shares reach over 27% and 25% respectively by 2060. In TGT, it is expected that PHEVs and BEVs will collectively account for almost 90% of the total transport stocks by 2060.
- A similar shift is expected in international aviation bunkers energy demand. In REF, kerosene jet fuel is expected to remain dominant, while in TGT, biojet kerosene, e-fuels, and hydrogen take the lead. This is in line with commitments by Royal Brunei Airlines, the sole domestic carrier, to reduce its carbon footprint by investing in fuel-efficient aircrafts and utilising sustainable aviation fuel.
- The main driver of the projected reduction in energy demand is the shift in vehicle engine types, despite growth in freight and passenger activity driven by population and economic expansion.

Figure 2-17. Components of the change in road energy use in TGT (PJ)



Note: Information on the different drivers in the transport energy decomposition can be found in the *Outlook*'s annex.

Electricity Generation

Figure 2-18. Electricity generation by fuel in REF (TWh)

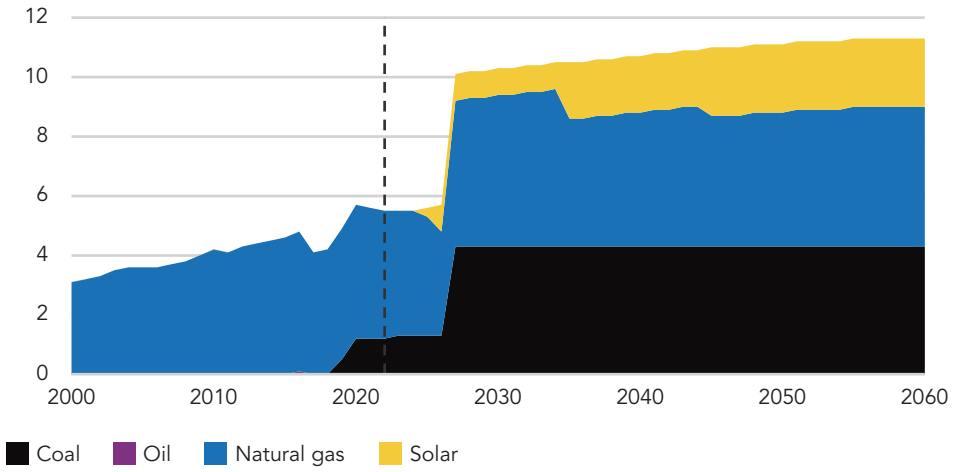
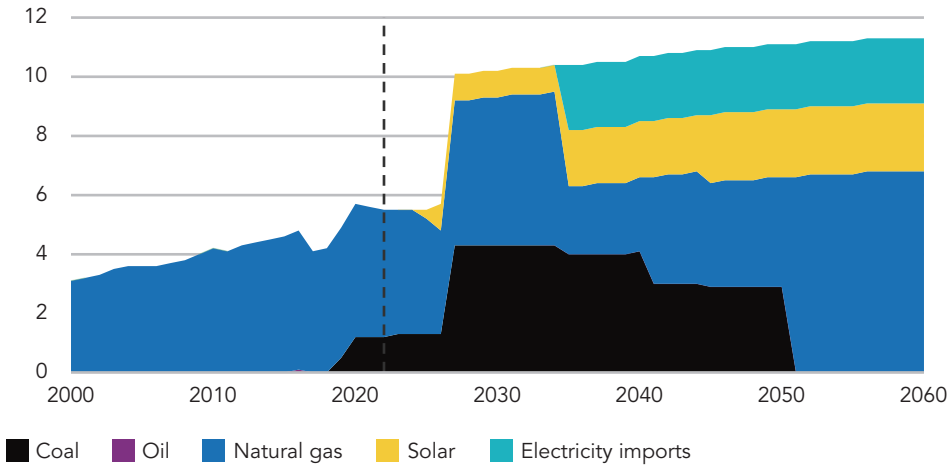


Figure 2-19. Electricity generation by fuel in TGT (TWh)



- Natural gas is an important source of baseload electricity for Brunei Darussalam, and is expected to remain vital throughout the outlook period in both REF and TGT.
- In line with the expansion of the existing PMB refinery and petrochemical complex in 2027, electricity from coal generation is projected to increase substantially, reaching over 4 TWh in REF. In TGT, coal is expected gradually decline until it is phased out in 2050, as the complex switches from coal to gas for its electricity generation.
- New solar PV projects are expected to increase electricity generation from solar to 2.3 TWh in 2060 in both scenarios. In REF and TGT, this is expected to account for 20% and 21% of the total electricity generation mix, respectively, in 2060.
- The notable difference between REF and TGT is the potential for renewable energy electricity imports from nearby economies through an interconnection in the TGT scenario beginning 2035. This will contribute to approximately 16% of the total electricity generation mix in TGT in 2060.

Note: Figures 2-18 and 2-19 do not include electricity generation for hydrogen production.

Generation Capacity

Figure 2-20. Generation capacity by fuel in REF (GW)

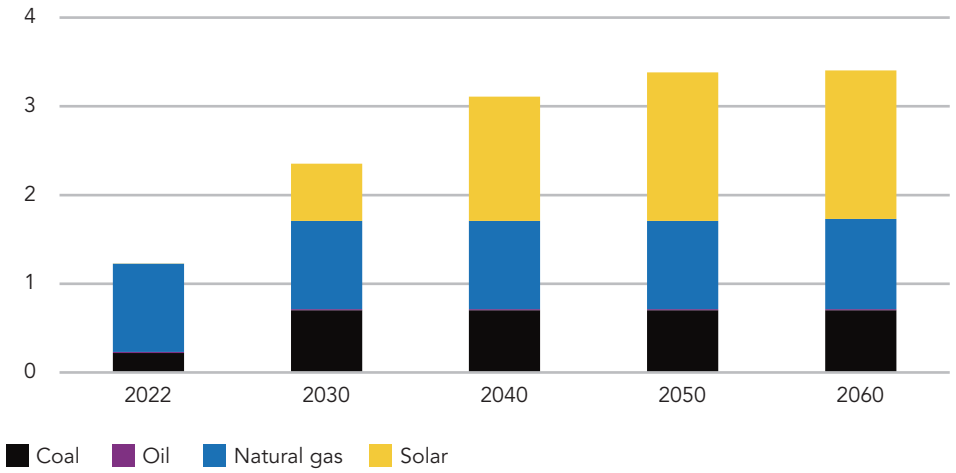
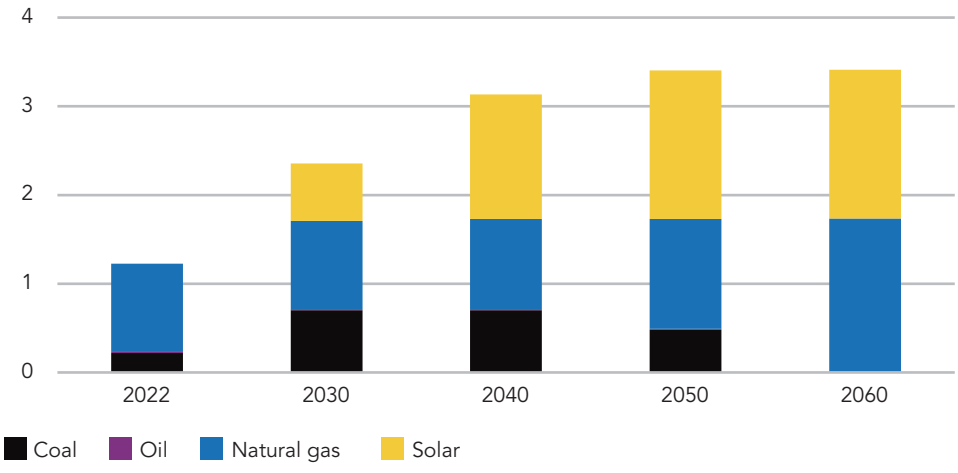


Figure 2-21. Generation capacity by fuel in TGT (GW)



- Brunei Darussalam's total installed capacity is expected to almost double in 2060 from 2022 levels, reaching 3.4 GW by 2060 in REF.
- New projects will substantially increase Brunei Darussalam's solar PV capacity to over 1.6 GW in 2060 in both scenarios. Consequently, solar is expected to be the most dominant capacity in 2060, accounting for nearly half of the total installed capacity in both REF and TGT.
- These solar PV projects include, among others, the 30 MW utility-scale solar plant on a remediated landfill in Kampong Belimbing, Mukim Kota Batu. In addition, PMB recently launched their solar project at its refinery and petrochemical complex. Over three phases, PMB will install a total capacity of 476 MW in various areas within the complex.
- PMB has been using 220 MW of coal-fired power capacity to supply electricity to phase 1 of its refinery and petrochemical complex. An additional 482 MW of coal-fired capacity is expected to be operational for phase 2 in REF. In TGT, coal capacity is expected to gradually decrease until it is phased out in 2050, paving the way for the potential use of natural gas as an alternative for the complex's electricity supply.

Note: Figures 2-20 and 2-21 do not include generation capacity for hydrogen production.

Grid Reliability

Figure 2-22. Total generation capacity and peak load (GW)

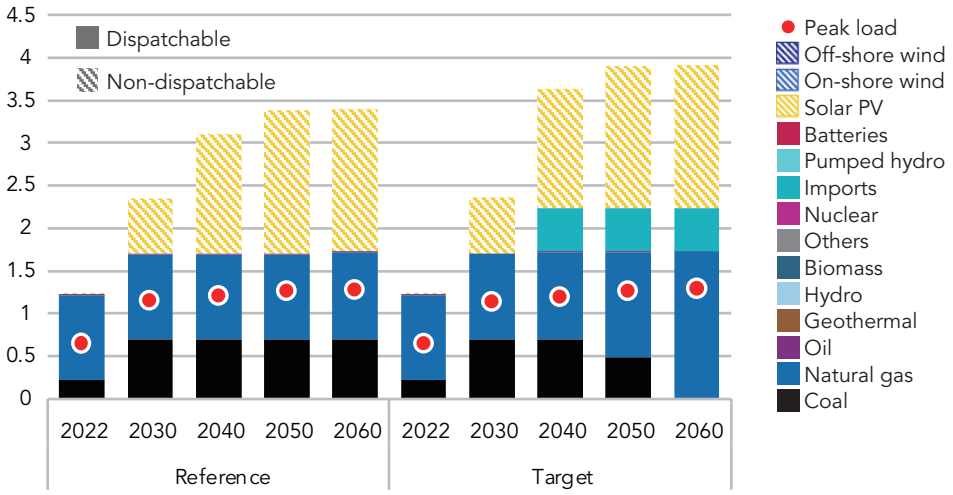
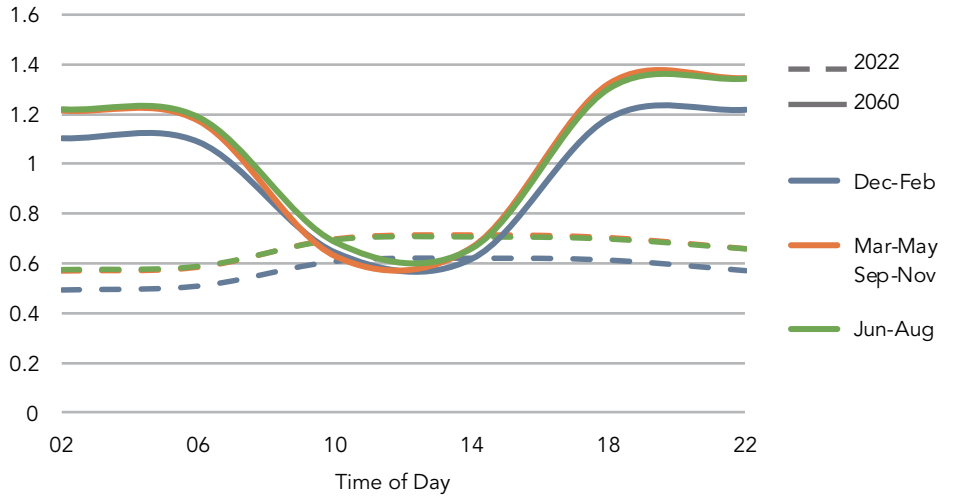


Figure 2-23. Power from dispatchable sources in TGT (GW)



- Brunei Darussalam's peak loads in both scenarios are expected to reach over 1.28 GW in 2060. These are attributable to the growth in electricity demand across the end-use sectors.
- The current power system is highly dispatchable and therefore reliable, given heavy reliance on fossil fuels, with a tiny fraction from solar. By 2060, almost half of total installed capacity will be of non-dispatchable type (solar).
- Although currently operating at a maximum voltage capacity of 66 kV, Brunei Darussalam's transmission lines are capable of operating at 132 kV and 275 kV. Such capacities can accommodate and handle future load growths.
- In REF, the peak load in 2060 can still be covered by dispatchable generation (coal and gas), even when the solar generation is at its lowest level. In TGT, hydropower imports will supplement gas-fired generation in meeting the peak load.
- Given the uniform climate in Brunei Darussalam, variations in seasonal demands are minimal, which is reflected in the pattern of dispatched electricity generation. However, as solar power peaks around midday, excess electricity is expected to be produced, which needs to be curtailed to avoid grid overload.
- The generation from gas-fired plants needs to be ramped from about 600 MW from midday to 1,300 MW in the evening on a typical day. The steep ramping of generation requires gas power plants to respond quickly, which can be challenging for system operators in terms of cost and maintenance.

Coal

Figure 2-24. Coal consumption by sector in REF & TGT (PJ)

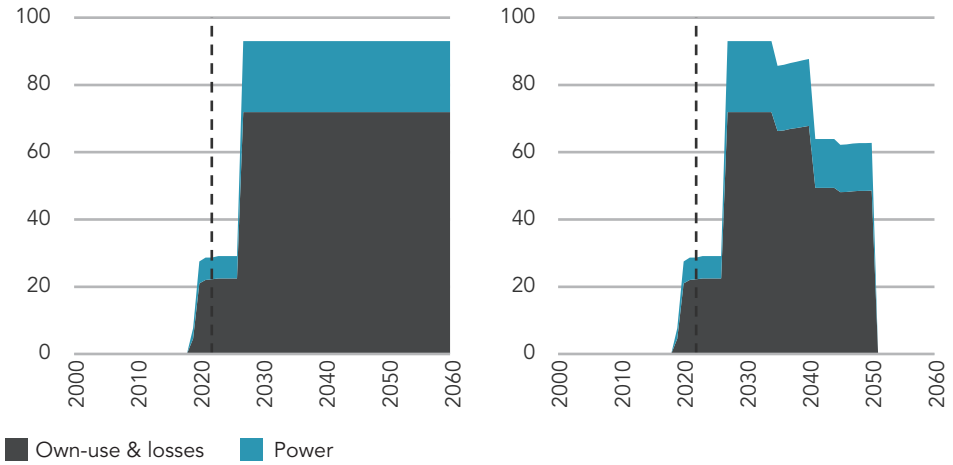


Figure 2-25. Coal imports in REF & TGT (PJ)



- Coal has been used solely to support the PMB refinery and petrochemical complex since its commencement in late 2019. The complex utilises a combined heat and power (CHP) plant to simultaneously provide electricity and heat, the latter of which is considered as own use, for the operation of the refinery.
- Majority of the CHP output comprises of heat. As of 2022, heat constituted about 77% of the total output, with electricity only about 23% of the total. Going forward, it is assumed that the CHP plant produces heat and electricity with the same ratio.
- As the refinery and petrochemical complex expands, the demand for coal is expected to grow three-fold by 2060 from 2022 levels in REF, with the assumption that the refinery and petrochemical complex still relies on coal for electricity and heat.
- In TGT, there is a potential for the refinery and petrochemical complex to utilise CHP with gas as an alternative to coal. The pledge committed by Brunei Darussalam on the Global Coal to Clean Power Transition during COP26 in Glasgow, United Kingdom, could signal the first few steps in transition away from coal to gas and other low-emission fuels.
- Given that Brunei Darussalam does not produce coal domestically, the economy will continue to import coal to meet the complex's requirements throughout the outlook period in both scenarios.

Natural Gas

Figure 2-26. Natural gas consumption by sector in REF & TGT (PJ)

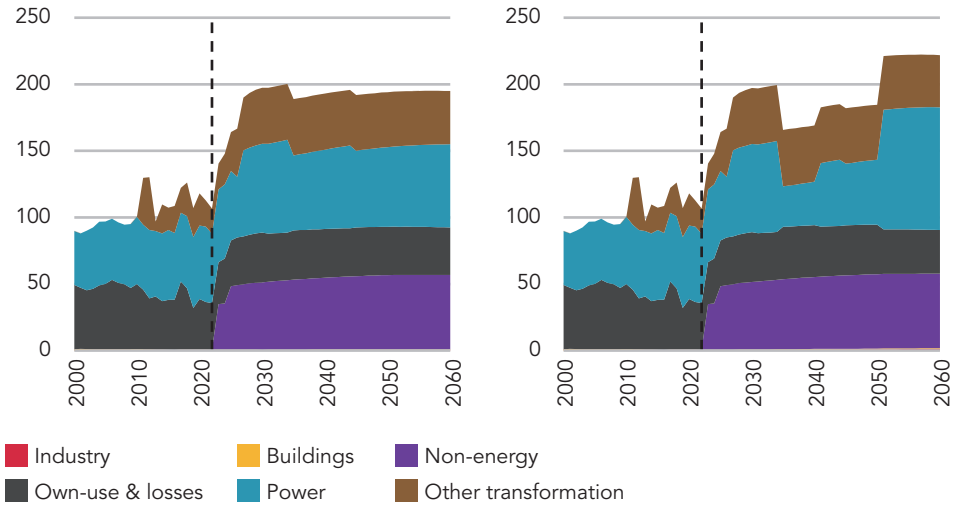
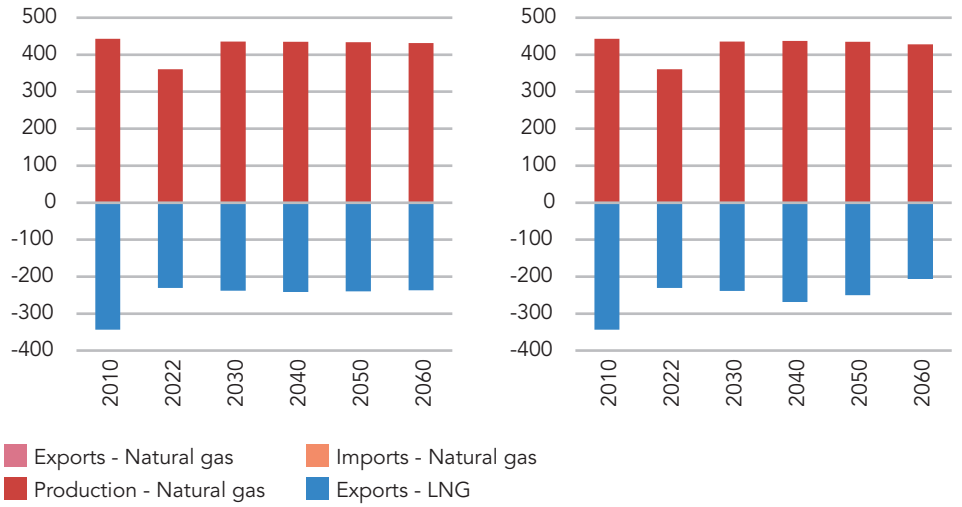


Figure 2-27. Natural gas production, imports, and exports in REF & TGT (PJ)



- Nearly half of the total natural gas consumption in Brunei Darussalam in 2022 was for the power sector. Furthermore, about 33% of the total consumption was utilised for own uses, particularly during the liquefaction of natural gas and during the extraction of oil and gas.
- Since its commencement in 2010, Brunei Methanol Company (BMC) has been using natural gas to produce methanol at 850,000 tonnes annually. This contributed about 18% of the total consumption in 2022 (represented by "Other transformation" in Figure 2-26).
- The Brunei Fertilizer Industries (BFI), which manufactures urea from feedstock natural gas, is projected to increase the share of the non-energy sector's natural gas consumption throughout the outlook period. In REF and TGT, this will contribute to 29% and 25% respectively by 2060.
- Consequently, non-energy sector is expected to become the second largest user of natural gas in Brunei Darussalam by 2060 in both scenarios, with the power sector still maintaining its dominance.
- The higher level of natural gas consumption in the power sector in TGT compared to REF between 2050 and 2060 is assumed to be driven by the coal-to-gas switch at PMB refinery and petrochemical complex.
- Domestic natural gas production is projected to increase in both REF and TGT, as part of Brunei Darussalam's aim to increase and maintain its oil and gas production at 300,000 barrels of oil equivalent per day throughout the outlook period. In addition, while the growth in LNG exports is expected to be stronger in REF, the growth is less in TGT, in line with increased domestic demand for natural gas in PMB refinery and petrochemical complex.

Petroleum Liquids

Figure 2-28. Crude oil, NGLs, and other hydrocarbon production, imports and exports in REF & TGT (PJ)

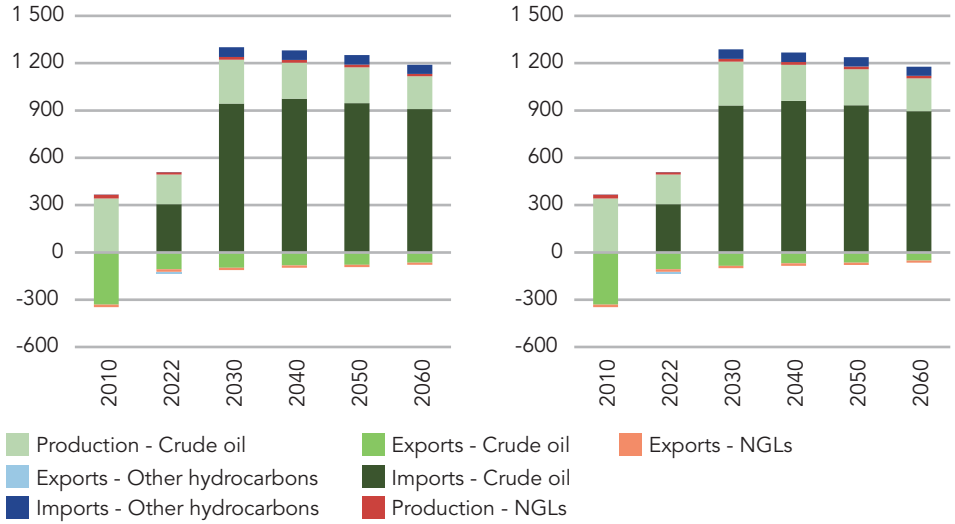
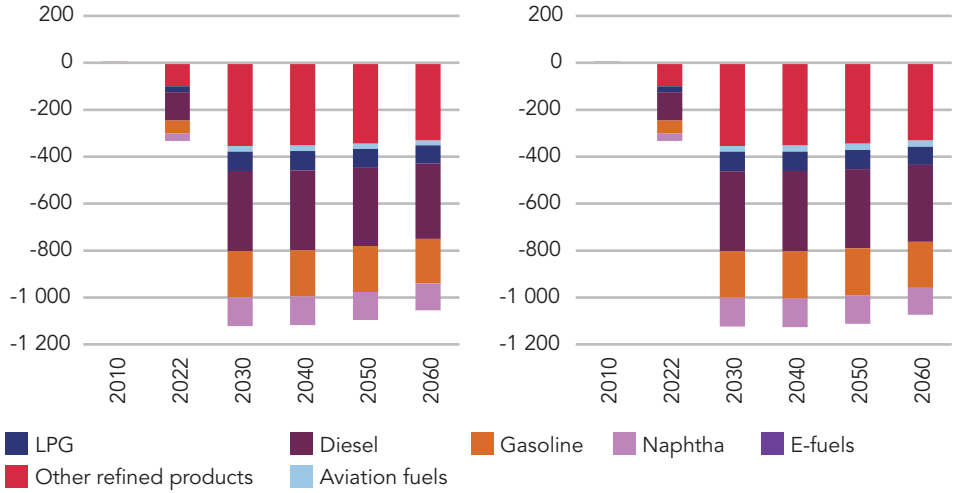


Figure 2-29. Net imports of refined products in REF & TGT (PJ)



- Since the establishment and operation of the PMB phase 1 refinery and petrochemical complex in late 2019, Brunei Darussalam has been importing crude oil to supplement its limited domestic crude oil. In 2022, over 60% of the total inland crude oil supply was from imports, with the remaining percentage from domestic crude.
- The combination of phase 1 and phase 2 of the complex will lead crude oil imports to almost triple by 2060 from 2022 levels in both REF and TGT. Thus, crude oil imports will account for over 80% of the total inland crude supply in 2060.
- The crude oil production trend is expected to be similar in both REF and TGT, in line with the domestic target mentioned in the previous page. However, the natural decline of oilfields implies declining production throughout the outlook period. In line with it, crude oil export trends are expected to decline too.
- The significant size of the refinery and petrochemical complex, coupled with low domestic demand, enables the PMB refinery and petrochemical complex to export substantial volumes of petroleum products. This makes Brunei Darussalam a net exporter of all petroleum products.
- Substantial exports of these petroleum products are expected to remain in place in REF and even in TGT, with the assumption of strong regional demand for petroleum products over the outlook period.
- Other refined products, i.e. petrochemical products, are projected to be the largest exported product over the outlook period. This is in line with PMB's phase 2 expansion to include additional key petrochemical products such as ethylene, polyethylene, butadiene and polypropylene, which serve as the main raw materials for downstream industries.

Note: In Figure 2-29, net imports are presented without deducting bunkers.

Refining

Figure 2-30. Refining outputs in REF & TGT (PJ)

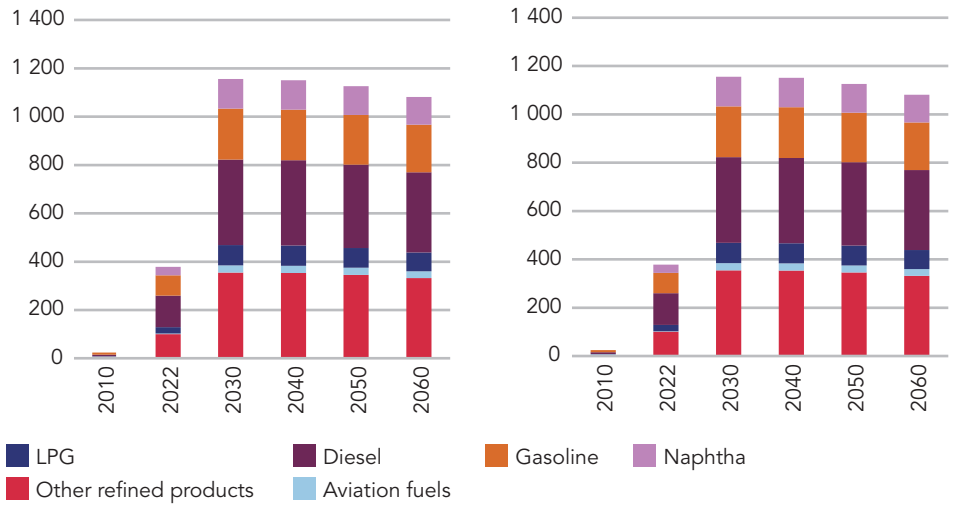
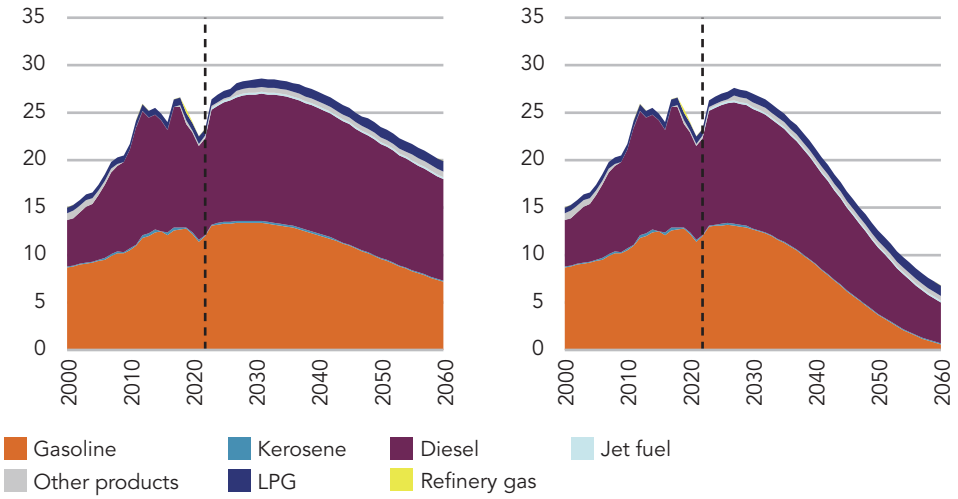


Figure 2-31. Refined products demand in REF & TGT (PJ)

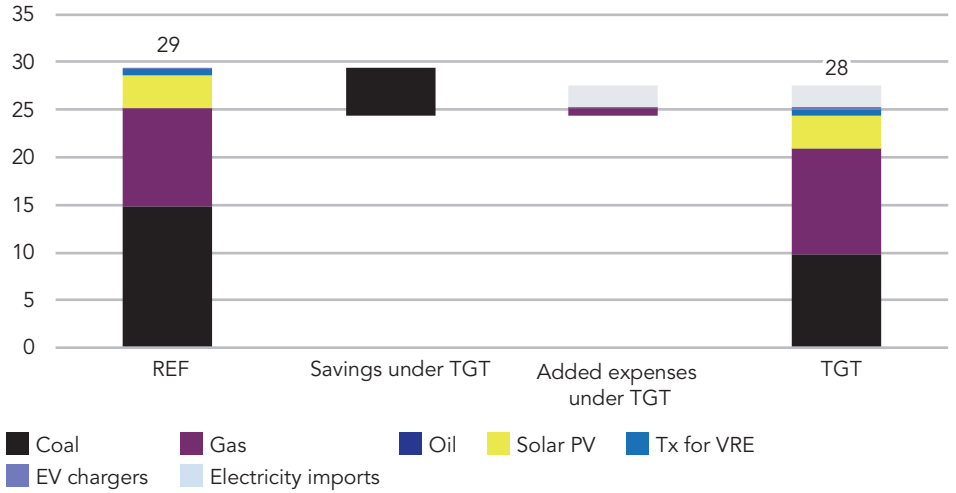


- The PMB refinery and petrochemical complex is a major upgrade to the previous refinery owned by Brunei Shell. Brunei Shell refinery used to be the sole refiner in Brunei Darussalam with a capacity of 12,000 barrels per day.
- Since its decommissioning in 2020, the significantly larger PMB refinery and petrochemical complex has become the main supplier of refined products. In addition, the refined outputs are more diversified, given that the complex can yield high-value petrochemical products such as benzene and paraxylene.
- As of 2022, other refined products (including petrochemical products) and diesel constituted the two largest outputs of the PMB refinery and petrochemical complex. Assuming the same output yield ratio, this trend is expected to continue developing over the outlook period in both REF and TGT.

- Brunei Darussalam's low population is a significant factor that contributes to the low overall demand for refined products.
- Gasoline and diesel have historically been the dominant fuels for transportation, and this trend is expected to continue over the outlook period in both REF and TGT.
- In REF, overall refined products demand is expected to decline by 15% in 2060 from 2022 levels, with a significant reduction of 40% in gasoline demand during the same period. This is partly due to the adoption of plug-in hybrid and battery electric vehicles that displace conventional gasoline vehicles.
- In TGT, there will be a more substantial reduction of 71% during the same period. The enhanced penetration of plug-in hybrid and battery electric vehicles in the domestic market is expected to decrease gasoline and diesel demand by 95% and 58%, respectively, between 2022 and 2060.

Costs

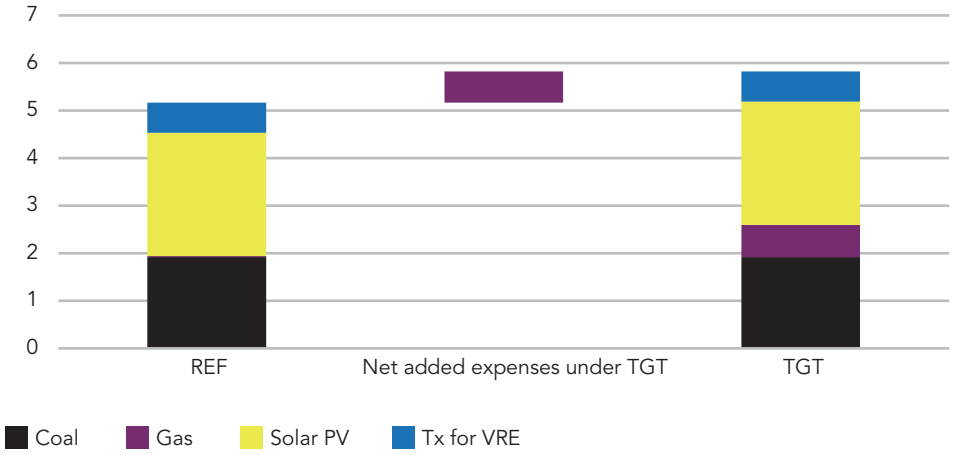
Figure 2-32. Costs in the power sector, 2025 to 2060 (billion USD, undiscounted)



Note: Tx for VRE is only transmission infrastructure to connect variable renewable capacity to the grid. EV chargers do not cover the cost of associated infrastructure or EV vehicles. H_2 costs for bunkering are not included here which is assumed to be sole use of H_2 imports for the economy.

- Brunei Darussalam's power sector will involve significant costs. Figure 2-32 considers total capital, fixed, and variable costs in the power sector, hydropower imports, transmission for new variable renewable electricity, and electric vehicle chargers.
- In REF, total costs will reach an estimated USD 29 billion, noting the uncertainty of future estimates. Costs in TGT fall to USD 28 billion as greater electricity imports partially offset the reduction in coal generation costs. Coal and gas will account for most of the total estimated cost, due to investments in the new coal-fired power plant for the PMB refinery and petrochemical complex, and new gas power plants.
- The gradual phase out of the coal-fired power plant at the PMB refinery and petrochemical complex in TGT is estimated to yield cost savings of USD 5.1 billion. At the same time, there is an additional USD 2.3 billion worth of hydropower imports over the projection period partially offsetting this saving

Figure 2-33. Total capital investment (CAPEX) from 2025 to 2060 in the power sector (billion USD, undiscounted)

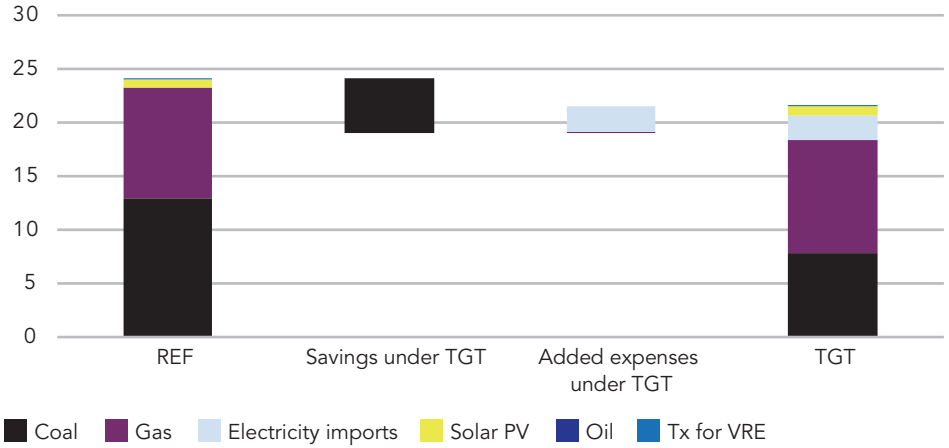


Note: Figure 2-33 only covers power and VRE transmission sector investments. Hydrogen and EV capital investments are not included.

- The total capital investment alone is estimated at USD 5.2 billion in REF, with investment in new solar PV projects accounting for over half of the total, equivalent to USD 2.6 billion.
- In TGT, the levels of investment in coal and solar are similar to those in REF, given unchanged installed capacities in both scenarios. The only distinction is the investment of new gas-fired power plant at the PMB refinery and petrochemical complex to replace the coal-fired power plant. An additional USD 0.7 billion of capital costs are estimated to be required to displace the coal-fired power plant with gas-fired power at the complex.
- Consequently, the total capital investment in TGT is expected to be USD 5.8 billion – about 12% higher than in REF.

Costs

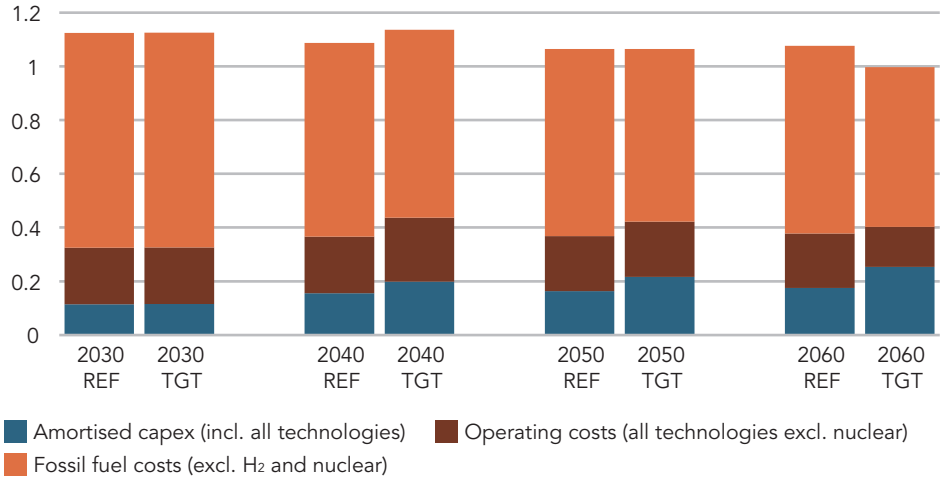
Figure 2-34. Total operating costs from 2025 to 2060 in the power sector (billion USD, undiscounted)



Note: Figure 2-34 only covers power and VRE transmission sector costs. It does not include operating costs associated with hydrogen use and EV charger costs. Costs for electricity imports are included here.

- Total operating costs are expected to exceed total capital investments in both REF and TGT. The higher operating costs reflect the fuel expenditures of variable fossil fuels (coal and gas), which account for most of the total costs.
- In REF, total operating costs are projected to reach USD 24 billion by 2060. Coal is expected to account for majority of the operating costs, at USD 13 billion, largely attributable to its imports at an assumed price of USD 4 million per PJ (or approximately USD 90 per tonne). The total operating cost of gas is estimated at USD 10 billion, assuming that gas is priced at USD 4 million per PJ (approximately USD 4.2 per MMBTu).
- In TGT, the phasing out of the coal-fired power plant in the PMB refinery and petrochemical complex means there will be total cost savings of USD 5 billion. Even with the additional costs of electricity imports, total operational costs in TGT are lower than in REF, as additional costs associated with importing hydropower are estimated at USD 2.3 billion.

Figure 2-35. Cost of generating electricity relative to 2025 (2025 cost = 1.0) in the power sector



Note: Based on our assumptions about future capital and operating costs, Figure 2-35 shows cost compositions over time relative to 2025. It should not be considered an estimate of electricity tariffs and excludes market mechanisms that are too difficult to estimate.

- The cost of generating electricity in Brunei Darussalam indexed to 2025 slightly reduces over the projection period in TGT. To note, this figure does not reflect the consumer cost of electricity which includes market mechanisms that are challenging to quantify.
- The reduction in electricity generation costs is primarily due to reduced operating costs (fuel and non-fuel) per MWh of electricity generated and the uptake of solar PV. As the PMB refinery is phased out, generation costs will decrease eventually in TGT. To note, as electricity imports are not counted as part of electricity generation, costs in TGT will be relatively lower as a result since a portion of generation is replaced by imports.
- Amortised capital expenditures are expected to rise in both scenarios, given investments in new solar PV capacities, as well as investments in a gas-fired power plant to displace the coal-fired power plant in PMB refinery and petrochemical complex in TGT.

CO_2 Emissions

Figure 2-36. CO_2 emissions in REF (million tonnes)

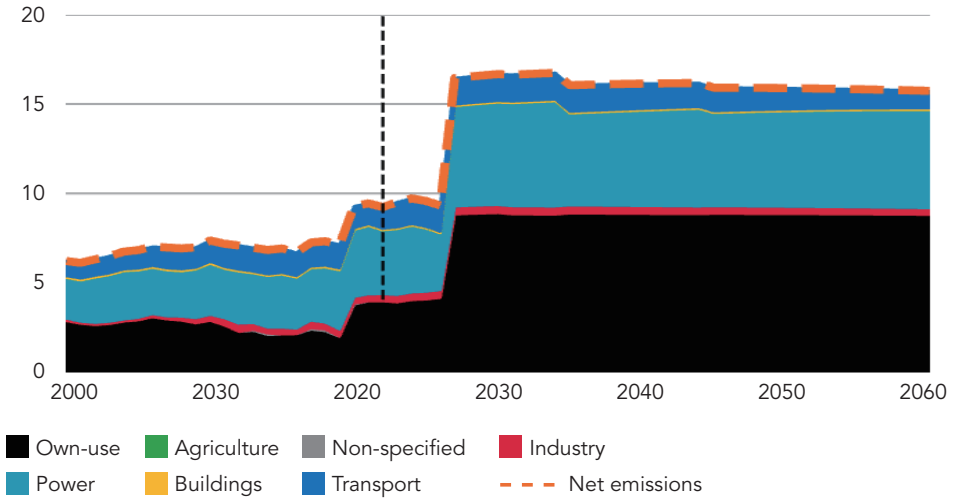
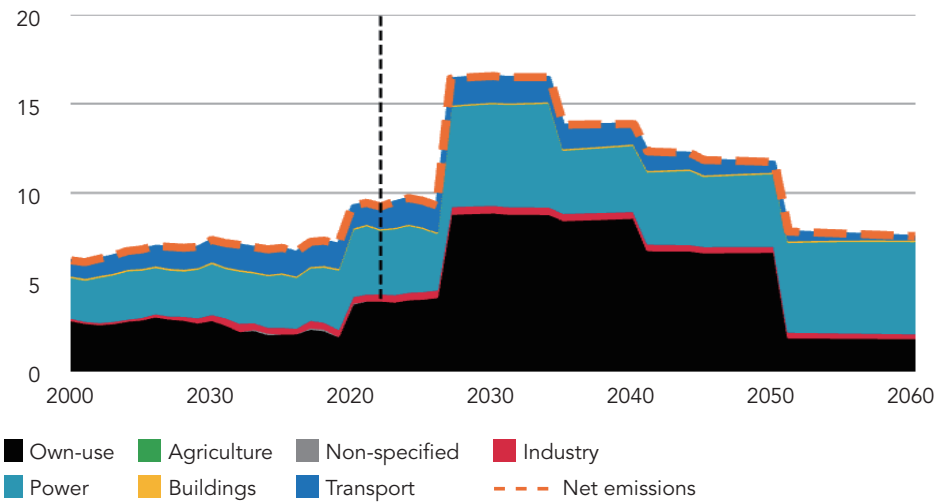
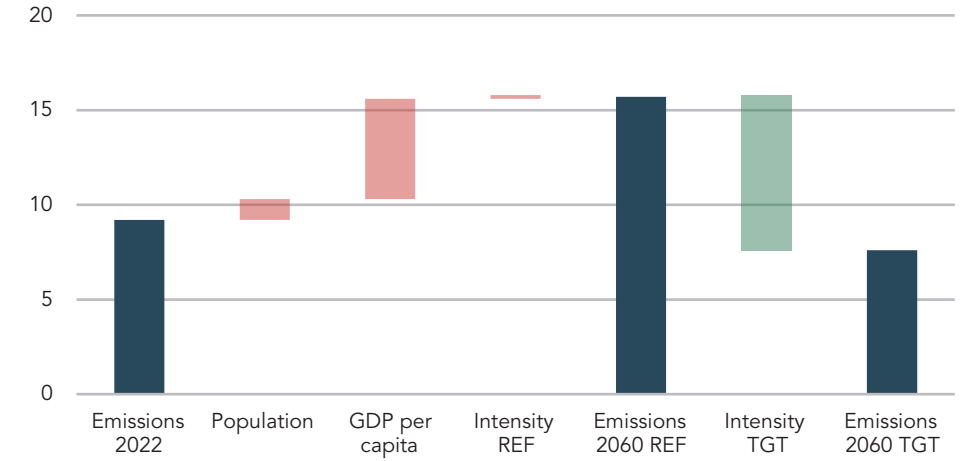


Figure 2-37. CO_2 emissions in TGT (million tonnes)



- Gross CO_2 emissions are projected to nearly double 2022 levels in REF, reaching 15.7 million tonnes by 2060. This substantial growth is attributable to the utilisation of coal in the refinery and petrochemical complex in generating useful electricity for the day-to-day operations, as well as generating electricity for the complex's own use. Coal is expected to account for more than half of the total emissions in 2060.
- In TGT, there will be a greater emissions reduction throughout the outlook period. Consequently, emissions in 2060 are expected to reach 7.8 million tonnes, which is on par with 2019 levels. The largest reductions are expected from coal, driven by the phase-out of coal use in the refinery and petrochemical complex.
- The transport sector is also expected to contribute substantially to the emissions reduction, given the significant adoption of battery electric and plug-in hybrid vehicles, thereby reducing the number of gasoline and diesel-powered vehicles.
- Changes in emissions from 2022 to 2060 are largely influenced by improvements in energy and carbon intensities, which help offset the impacts of population and economic growth. In the TGT scenario, continued intensity improvements, underpinned by stronger decarbonisation efforts, are essential for accelerating emissions reductions.

Figure 2-38. CO_2 emissions components (million tonnes)



Note: All values represent energy sector combustion CO_2 emissions. Biogenic CO_2 is treated as zero at the point of combustion.

Useful Links

APEC Expert Group on Energy Data and Analysis (EGEDA) – https://www.egeda.ewg.apec.org/

APEC Energy Statistics 2022 – https://www.egeda.ewg.apec.org/egeda/general/info/pdf/APEC_Energy_Statistics_2022.pdf

APEC Energy Overview – https://aperc.or.jp/reports/energy_overview.php

Brunei Darussalam National Council on Climate Change (BNCCC) – https://climatechange.gov.bn

Brunei Fertilizer Industries (BFI) – https://www.bfi.com.bn

Brunei Shell Petroleum (BSP) – https://www.bsp.com.bn

Department of Energy, the Prime Minister's Office – https://www.energy.gov.bn

Department of Economic Planning and Statistics, Ministry of Finance and Economy – https://deps.mofe.gov.bn

Hengyi Industries – https://www.hengyi-industries.com

Petroleum Authority of Brunei Darussalam (PABD) – https://www.pa.gov.bn



3. Canada

Summary

	Reference			Target		
	2022	2060	% Change	2022	2060	% Change
Macroeconomic						
Population (million)	38.3	52.6	37%	38.3	52.6	37%
GDP (billion 2017 USD, PPP)	1,904	3,751	97%	1,904	3,751	97%
Energy Demand						
Agriculture & fisheries (PJ)	316	380	20%	316	317	0%
Buildings (PJ)	2,519	2,994	19%	2,519	1,955	-22%
Industry (PJ)	1,944	2,240	15%	1,944	2,148	11%
Non-energy (PJ)	1,013	1,669	65%	1,013	1,494	47%
Transport (PJ)	2,480	1,702	-31%	2,480	1,234	-50%
Modern renewable share of TFEC (%)	23	36	57%	23	56	143%
Energy intensity of TFEC (PJ/GDP, billion USD)	3.8	2.0	-47%	3.8	1.5	-61%
Electricity						
Generation (TWh)	651	1,159	78%	651	1,278	96%
Renewables share of generation (%)	69	66	-4%	69	71	3%
Generation capacity (GW)	153	334	118%	153	390	155%
Total Primary Energy Supply (TPES)						
Coal & coal products (PJ)	316	57	-82%	316	7	-98%
Natural gas (PJ)	5,140	7,435	45%	5,140	3,545	-31%
Petroleum liquids (PJ)	4,114	2,982	-28%	4,114	1,642	-60%
Low-carbon & waste energy (PJ)	3,057	4,029	32%	3,057	7,862	157%
CO_2 intensity of energy supply ($MtCO_2/PJ$)	0.041	0.037	-10%	0.041	0.018	-56%
Net CO_2 Emissions (million tonnes)	515	526	2%	515	183	-65%

Note: In this publication, the term "modern renewables" refers to all renewable energy sources excluding solid biomass in the buildings sector. The term "low-carbon & waste energy" includes all bioenergy, waste-derived energy, renewables, nuclear, and hydrogen-based fuels. Total primary energy supply (TPES) numbers include international bunkers. Net emissions are calculated as gross energy sector combustion CO_2 minus CO_2 captured and stored through carbon capture and storage (CCS).

Key Takeaways

Emissions

- In the Reference scenario (REF), gross emissions remain relatively flat. Emissions from transportation decline as zero-emission vehicles are adopted, but this progress is offset by rising emissions from a power grid that remains reliant on unabated gas power.
- In the Target scenario (TGT), gross emissions fall by 65% from 2022, with deeper reductions than in REF driven largely by power sector decarbonisation through increased renewable and nuclear capacity, implementation of carbon capture and storage, and higher electric vehicle adoption. Emission decreases additionally come from the buildings, industrial, own use, and agriculture sectors.
- This highlights the need for economy-wide emissions reductions combined with solutions tailored to the unique challenges of each sector. It also underscores the critical role of decarbonising the power sector as energy demand increasingly shifts to electricity.

Energy Import Dependence

- Because Canada is a net energy exporter, it generally considers itself to be a contributor of reliable energy supply, rather than being significantly affected by traditional energy security disruptions.
- Exporting gas, crude oil, and petroleum products in a decarbonising global economy presents challenges. While the *Outlook* assumes Canada will retain its status as an energy exporter, sustaining exports at this level may require efforts to diversify export markets and adapt to evolving demand.
- Canada's natural gas exports increase in both scenarios as new LNG export terminals come online on the west coast. This added capacity positions Canada to serve as a reliable LNG supplier to APEC member economies.

Figure 3-1. Net CO_2 emissions (million tonnes)

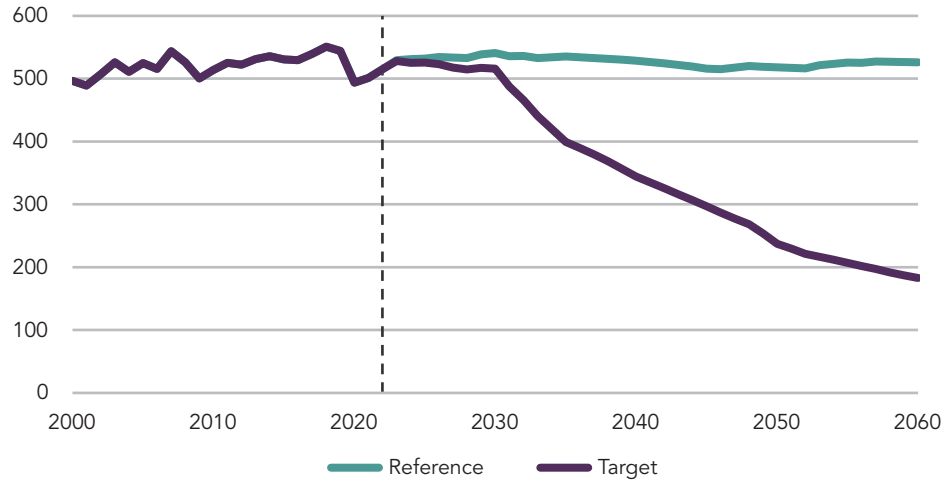
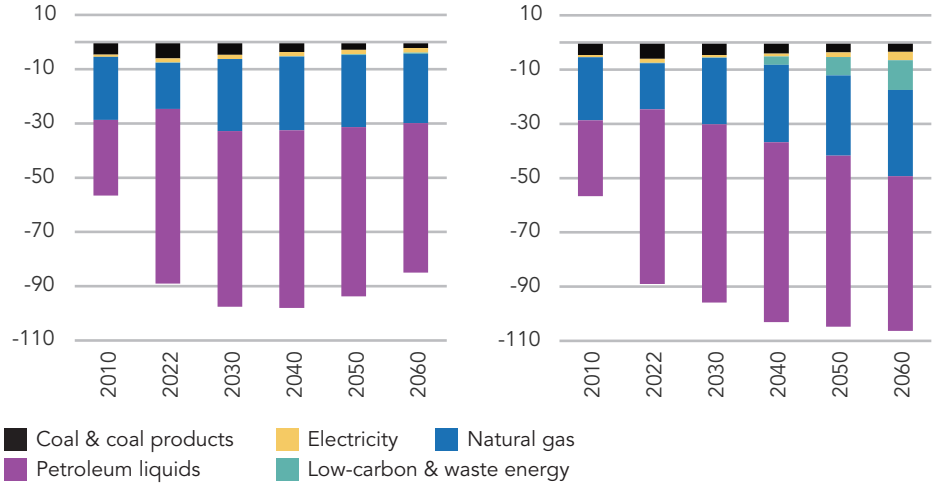


Figure 3-2. Net imports share of TPES in REF & TGT (%)



Note: In Figure 3-2, net imports refer to total imports minus exports and international bunkers.

Key Takeaways

Grid Reliability

- Electric grid reliability requires a near-instantaneous balance between power supply and demand at all times. Maintaining this balance requires adequate dispatchable power sources, which can include batteries.
- Figure 3-3 shows grid dependence on dispatchable power in the 4-hour period of maximum dependence and 4-hour period of minimum dependence. The widening gap between maximum and minimum output suggests dispatchable generators will need greater flexibility over time.
- In both REF and TGT, total electricity consumption is projected to rise. As a result, Canada is expected to require an increased amount of total power capacity, including more dispatchable capacity for those periods when variable renewable energy sources, such as wind and solar, are not producing at their maximum level.

Cost

- Major costs are estimated for each scenario through to 2060. In TGT, total costs are an estimated USD 1,845 billion, USD 547 billion higher than in REF. Costs considered include total capital, fixed, and variable costs in the power sector, costs for blue and green hydrogen production for domestic use, transmission for VRE, and electric vehicle chargers.
- In REF, costs are largely accumulated from operating costs for hydro and gas power generation, as well as capital investments in solar, wind, and related transmission infrastructure.
- In TGT, fossil fuel savings are outweighed by higher capital costs expenses. Of added expenses, 21% stem from hydrogen infrastructure and renewables for hydrogen, and 38% from nuclear. While nuclear and carbon capture equipped gas replace unabated gas as baseload in TGT, there is a negligible change in operating costs between scenarios.

Figure 3-3. Peak load and maximum and minimum dependence on dispatched power (GW)

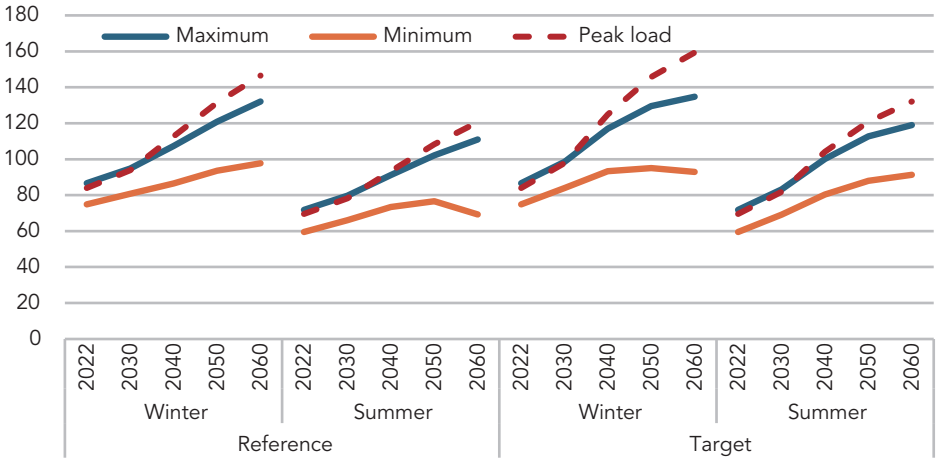
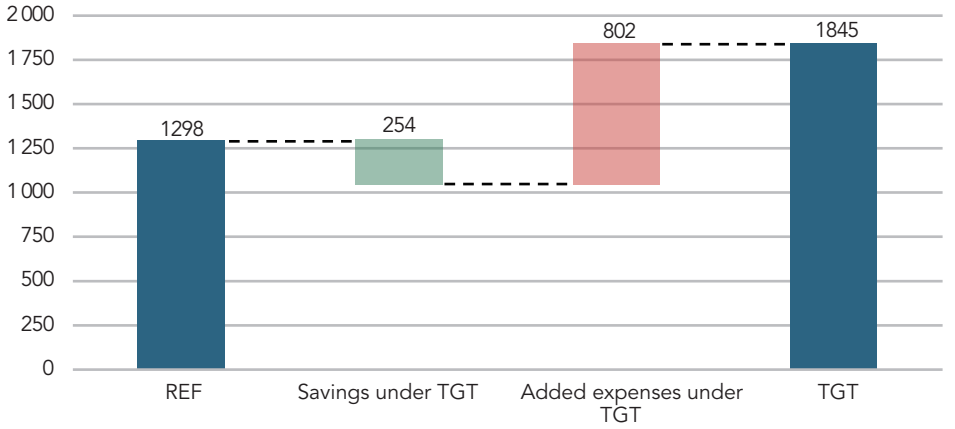


Figure 3-4. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



*Actual costs will differ from estimated costs in the *Outlook* for a variety of reasons including changing commodity prices, manufacturing costs, and unforeseen technical advances. All costs are in 2023 real terms.

About Canada

Overview

Geographical and Economic Landscape

Canada is home to a diverse energy landscape, influenced by varied geography, climate, and economic drivers. This diversity necessitates a tailored approach to energy generation among its provinces and territories. While the federal government oversees emissions and federal policy, provinces and territories manage natural resources and intraprovincial energy distribution. Energy is a key driver to Canada's economy, contributing on average around 10% to total GDP over the past several years.

Energy Supply and Consumption

Canada's energy production exceeds its domestic supply requirements, freeing up parts of its energy production for international export markets. Canada is a top five producer of crude oil, gas, and hydro, a top six exporter of crude oil, natural gas, and electricity, the 13th largest producer of biofuels, the second largest exporter of wood pellets, and the second largest producer and exporter of uranium. In recent years, Canada has made significant progress towards positioning itself as a secure supplier of LNG to the APEC region, with export projects beginning operations in 2025 and beyond.

Canada is the second highest per capita energy user and fourth highest per capita GHG emitter in APEC. This is partly due to its vast area and varied climate, which features cold winters and hot summers that drive substantial demand for both space heating and cooling. In addition, the sparse dispersion of Canada's population, reliance on individual vehicle transportation, and abundance of cheap energy are also contributors.

Energy Security Challenges and Strategies

Because Canada is a net energy exporter, it generally considers itself to be a contributor of reliable energy supply, though its deep integration with U.S. energy markets and infrastructure may create vulnerabilities. In addition, higher energy prices are challenging affordability for Canadians. Provinces across the economy are providing relief via tax cuts, subsidies, and retail price caps on the end-user prices for oil products, natural gas, and electricity.

Key Energy Initiatives

Canada Net Zero Emissions Accountability Act

The Act sets legal requirements on the Government of Canada to plan, report, and course correct on the path to net zero emissions by 2050. Under this Act, the 2030 Emissions Reduction Plan was released setting a target to reduce emissions by 40-45% below 2005 levels by 2030. Building on the 2030 target, the 2035 target aims to reach 45-50% below 2005 levels by 2035.

Clean Electricity Regulations

The regulations outline a set of rules for transitioning Canada's electricity grid to net zero by 2050 and will come into force in 2035. The regulations set technology-neutral emissions performance standards and include flexibility so that provinces and utilities can maintain reliable and affordable electricity.

Clean Fuel Regulations

The Clean Fuel Regulations, in force since July 2023, are enacted under the government's criminal law head of power through the Canadian Environmental Protection Act. The regulations target a 15% reduction in the lifecycle carbon intensity of liquid fossil fuels by 2030, relative to 2016 levels.

Canada Green Buildings Strategy

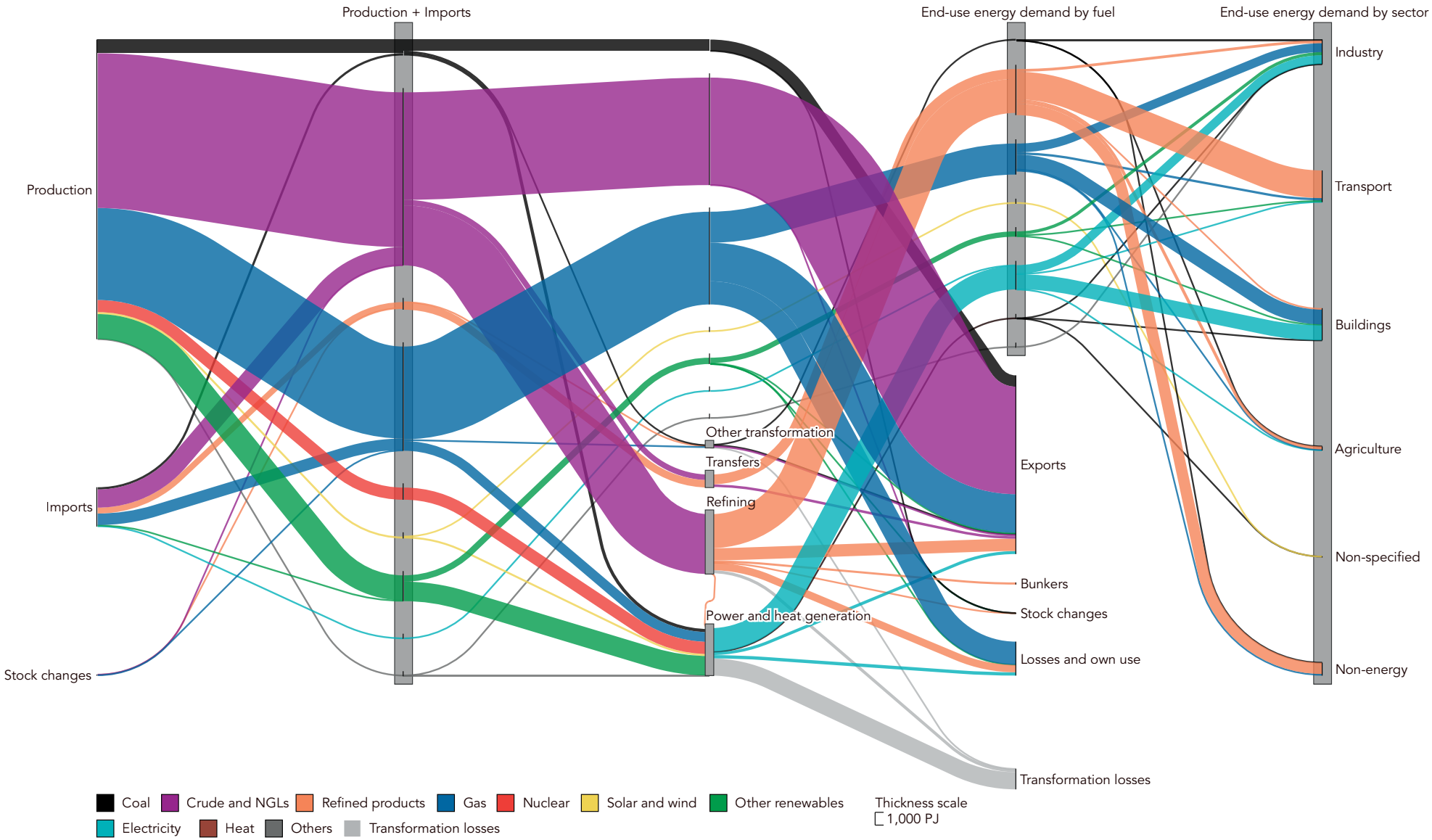
The strategy focuses on steps to lower home energy bills and reduce building emissions by supporting energy-efficient retrofits and the adoption of better building codes to build new homes with net zero in mind, as well as by promoting home energy labelling.

Zero-Emission Vehicles (ZEV)

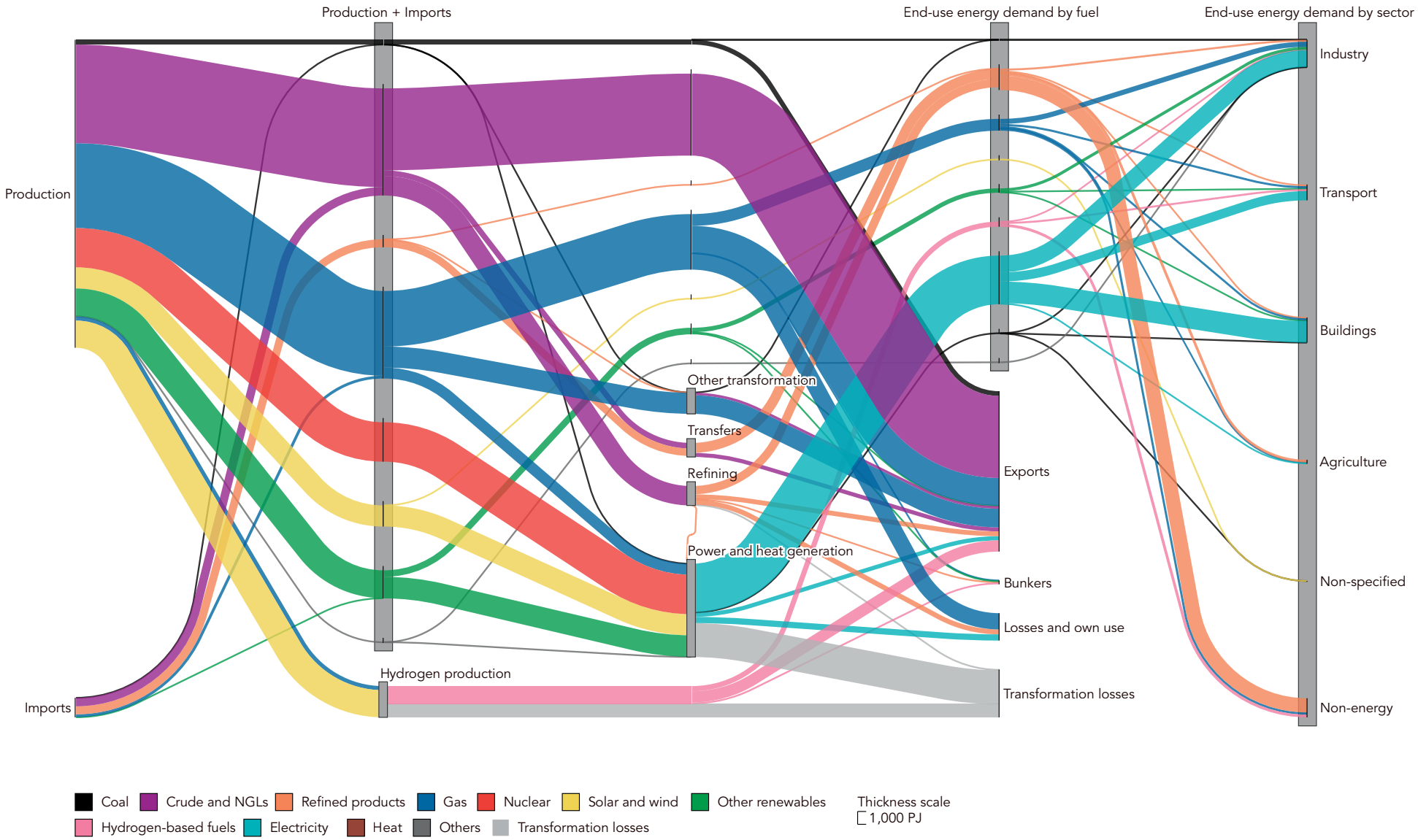
To electrify transport, Canada implemented a regulated light-duty ZEV sales targets (20% by 2026, 60% by 2030, 100% by 2035). Multiple funding streams are also available to support the deployment of ZEV infrastructure.

A multitude of additional policies, regulations, and supports exist and can be found through Government of Canada and provincial government websites.

Energy Flow (2022)



Energy Flow (2060, Target Scenario)



Scenarios and Assumptions

In *The Outlook*, APERC analyses energy demand, transformation, and supply, as well as emissions. The **Reference Scenario (REF)** offers a projection based on historical trends, recent developments, and APERC's assumptions about the continuation of those trends in each APEC economy, while acknowledging technical restraints. The REF Scenario offers a baseline to compare with the **Target Scenario (TGT)** projections, which explores a hypothetical pathway where each economy achieves energy-related policy targets, assuming implementation regardless of cost-effectiveness. When implementation details are lacking, assumptions are inferred from the targets themselves or emissions-related goals.

	Reference	Target
General	• Population: UNDESA High; GDP: IMF and APERC model.	• Population: UNDESA High; GDP: IMF and APERC model.
Agriculture	• Agriculture energy demand follows the projections of harvested area and crop yield. • Oil, in particular diesel, remains dominant throughout the projection period. Electrification remains marginal.	• Agriculture energy demand follows the projections of harvested area and crop yield. • Energy efficiency is incorporated, which sees energy demand declining by 2060. • Fuel switching occurs, i.e. the share of oil declines with increasing electrification.
Buildings	• Moderate building envelope improvements and equipment efficiency gains are considered. • Electrification is incorporated but not in line with net zero buildings by 2050. • The use of oil derivatives, such as heating oil and kerosene, are restricted to isolated areas. • AI and data centres expand under both the REF and TGT scenarios.	• Stricter building envelope improvements and net-zero ready buildings codes considered. • Greater equipment efficiency gains and stronger appliance standards reflected. • Higher rates of fuel switching than in REF to increase electrification. • Increased retrofits of existing building stock are considered. • The use of oil derivatives, such as heating oil and kerosene, are restricted to isolated areas.
Industry	• Industrial activity is assumed to be robust in the coming decades due to a reversal in offshoring trends, and a concerted effort for industrial output to support economic growth. • Hydrogen and gas with CCS are incorporated from 2040. • Electrification makes inroads in most subsectors.	• General energy efficiency improvements, but the improvement is dependent on subsector and energy potential of industrial processes. • Hydrogen and gas with CCS are incorporated from 2030, scaling faster than in REF. • Electrification makes greater inroads in most industrial subsectors.
Transport	• Implementation of Canada's Light Duty Vehicle Sales Mandate with a greater share of plug-in hybrid EVs (PHEVs) than in TGT. • Battery EV (BEV) sales share for passenger and light commercial vehicles increases to 90% by around 2060. There is a 42% sales share for PHEVs in 2035, and this falls thereafter. • BEV sales share for heavy trucks increases to 25% by around 2060 such that there is a 20% stock share in 2060.	• Implementation of Canada's Light Duty Vehicle Sales Mandate and the Heavy Duty and Freight Sales Mandate is considered. • BEV sales share for passenger and light commercial vehicles increases to 100% by around 2040. There is a 10% sales share for plug-in hybrid EVs (PHEVs) in 2030, and this falls thereafter. • BEV sales share for heavy trucks increases to 60% by 2040, and fuel cell EV (FCEV) sales share for heavy trucks reaches 40% by 2040.

	Reference	Target
Transport	• Biogasoline (including renewable gasoline and ethanol) and biodiesel (including renewable diesel) level off at 7% blending by volume in 2030. Biojet levels off at 10% blending by volume in 2050. E-fuels rise in use to replace 1% of all refined fuels by 2035 and remain at that level thereafter. • Some efficiency improvement is lost to the continued growth in the shares of heavier SUVs and pickup trucks.	• Biogasoline (including renewable gasoline and ethanol), biodiesel (including renewable diesel), and biojet slowly grow to 25% mixing by volume in 2060. E-fuels rise in use to replace 3% of all refined fuels by 2060. • Some efficiency improvement is lost to the continued growth in the shares of heavier SUVs and pickup trucks. • Diesel use in rail transport starts being phased out in favour of electrification.
Power	• A net zero grid is not achieved, and gas generation increases with increased power demand. • Nuclear and hydro power capacity do not expand. • Moderate batteries installation accompanying solar PV. • Coal-fired power plants gradually decommissioned by 2030. • CCS is not incorporated.	• Nuclear and hydro power capacity expand. No technical distinction is made between conventional nuclear and small modular reactors. • Battery storage is incorporated to a greater degree. • Coal-fired power plants gradually decommissioned by 2030. • CCS is incorporated in the late 2030s.
Supply	• Thermal coal export ban implemented by 2030. • As a metallurgical export-oriented economy, the production of metallurgical coal and coal products is assumed to follow the global demand trends. • Natural gas production follows domestic demand and expected exports based on planned terminals. • Oil production remains near peak levels following its peak in the 2030s. Crude oil export trends follow production trends.	• Thermal coal export ban implemented by 2030. • As a metallurgical export-oriented economy, the production of metallurgical coal and coal products assumed to follow the global demand trends. • Natural gas production follows domestic demand and expected export based on planned terminals. Liquefaction capacity stops growing in 2030 as decarbonisation efforts in other economies limit LNG demand growth. • Crude oil production decreases steadily from its peak in the 2030s. Crude oil export trends follow production trends.
Refining	• Refinery capacity is assumed to decline slightly from 1,954 kb/d in 2022 to 1,353 kb/d in 2060. • Refinery utilisation rate is assumed to remain at about 90%. • Refinery output yield ratios of diesel and jet fuel are assumed to increase in medium and longer terms against the decline of gasoline to align with changes in consumption.	• Refinery capacity is reduced to 755 kb/d by 2060 but maintain the high 90% utilisation rate. • Refinery output yield ratios are same as in REF with a greater decline in jet fuel and diesel.
Emissions	• CO_2 emissions are calculated at post consumption based on IPCC emission factors.	• CO_2 emissions are calculated at post consumption based on IPCC emission factors.

Note: The base year is 2022. Macro-economic assumptions are constant across scenarios. Historical energy balances are from EGEDA submissions for 2022.

Demographic and Macroeconomic Assumptions

Figure 3-5. Population (thousands)

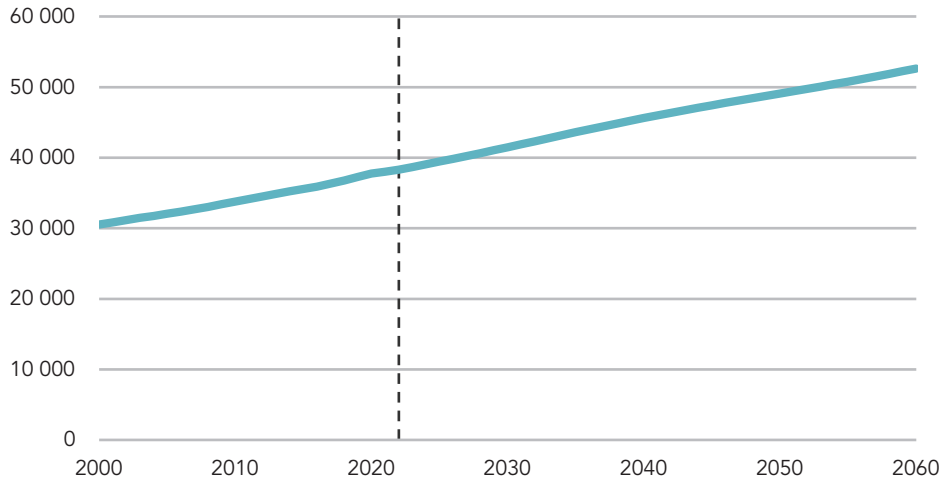
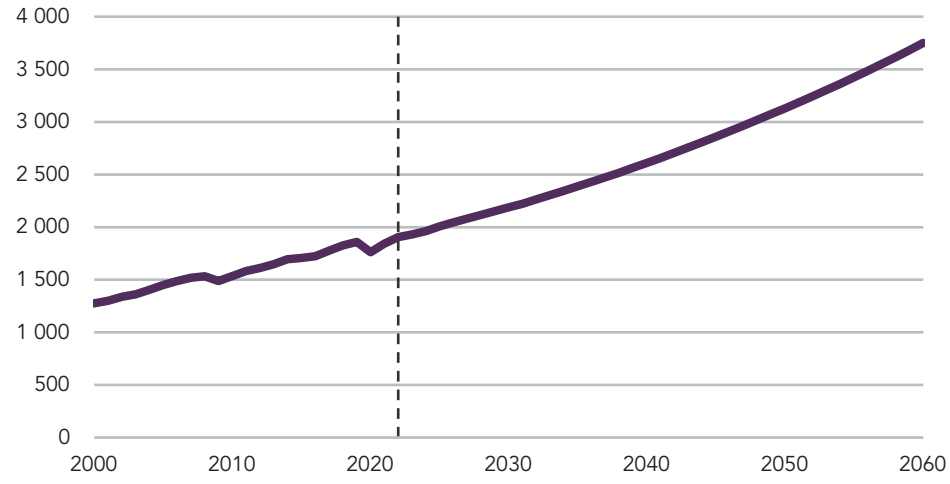


Figure 3-6. Real GDP (billion 2017 USD, PPP)



- Population assumptions are taken externally from the United Nations Department of Economic and Social Affairs (UNDESA) World Population Prospects 2022 projection. For the *Outlook*, the UNDESA High projection is used for Canada. In this projection, population reaches 49 million by 2050 and approaches nearly 53 million by 2060.
- Although Canada's birth rate is at its lowest level since 2000, the UNDESA High projection was selected based on assumptions that population growth would be sustained through immigration. However, future contributions from immigration will depend on domestic policies and global dynamics.
- Over 80% of Canada's population lives in census metropolitan areas. While the absolute number of people living in urban areas has steadily increased since the early 2000s, the share of the total population living in these areas has grown by only about three percentage points.
- As a simplifying assumption, the macroeconomic projections are the same in both scenarios. However, as a producer-exporter of energy, a contraction of fossil fuel markets in the future could impact Canada's growth trajectory. Nevertheless, the evolution of the Canadian and global economy in a market focused on reducing greenhouse gas emissions is uncertain. Canada could offset declining fossil fuel revenues by expanding other sectors, including low-emission energy technologies such as hydrogen and carbon capture and storage.
- The structural evolution of Canada's economy follows historical trends through to 2060. From 2000 to 2022, real economic growth averaged approximately 1.8% annually, and this growth rate is projected to continue at around 1.8% per year from 2023 to 2060.
- Consequently, it is assumed that GDP per capita then increases at approximately 0.95% per year from 2023 to 2060.

End-use Energy Demand

Figure 3-7. Energy demand by sector in REF & TGT (PJ)

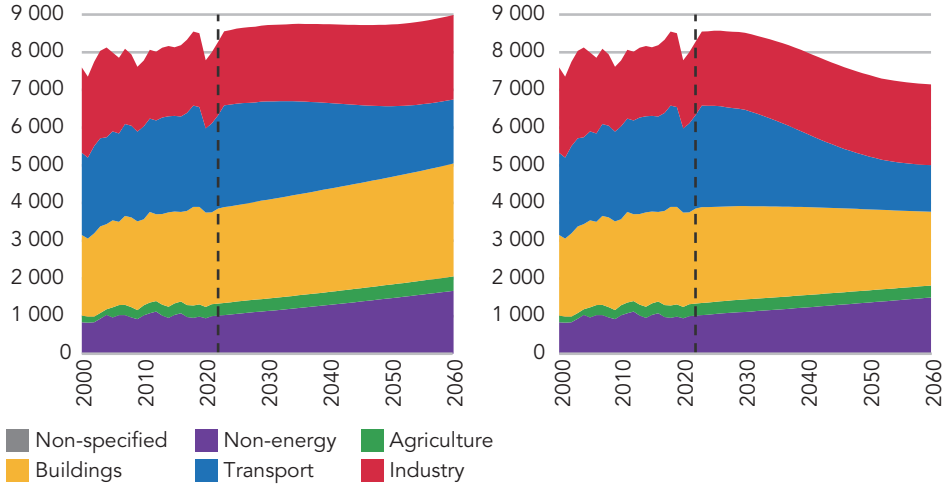
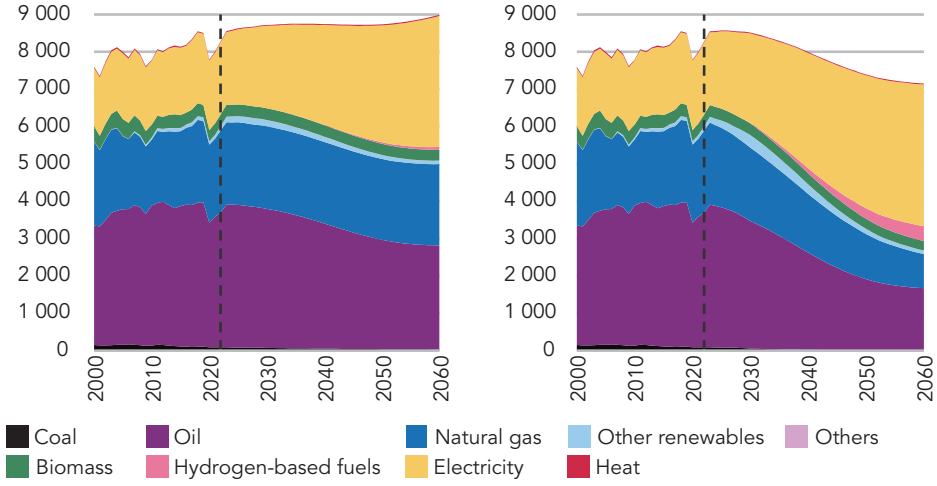


Figure 3-8. Energy demand by fuel in REF & TGT (PJ)



- Despite growing population and GDP, Canada's end-use energy demand is expected to remain relatively steady into the future under REF. This reflects Canada's existing efforts to curb energy consumption through zero emission vehicle adoption, energy efficiency measures, and electrification.
- Total final energy consumption is 20% lower in TGT than in REF in 2060. In TGT, stricter energy policies are assumed and are influenced by a net zero pathway that cause Canada's end-use energy demand to decrease steadily after 2025.
- Notable differences in energy demand by sector between REF and TGT arise from the transport and buildings sectors. Electrification options in both sectors present clear pathways to reduce energy use from efficiency gains compared to other sectors like industry, where electrification is more difficult.
- In REF, the buildings sector remains the largest energy-using sector, while growth in industrial activity increases energy consumption above that of transport. In TGT, industry overtakes buildings by 2050 to become the top energy consumer.
- The share of electricity in final energy use reaches about 40% in 2060 in REF compared to 60% in TGT. Despite this increase in the share of electricity in TGT, oil and gas remain part of the energy mix to meet ongoing demands in thermally intensive industrial processes that currently lack viable alternatives, as well as for non-energy uses.
- In both scenarios, electricity generation increases significantly compared to historical levels. Meeting this rising demand while progressing toward a net-zero economy will require both deep decarbonisation of the grid and infrastructure capable of supporting higher shares of non-emitting electricity.

Buildings Energy Demand

Figure 3-9. Buildings energy demand by fuel in REF & TGT (PJ)

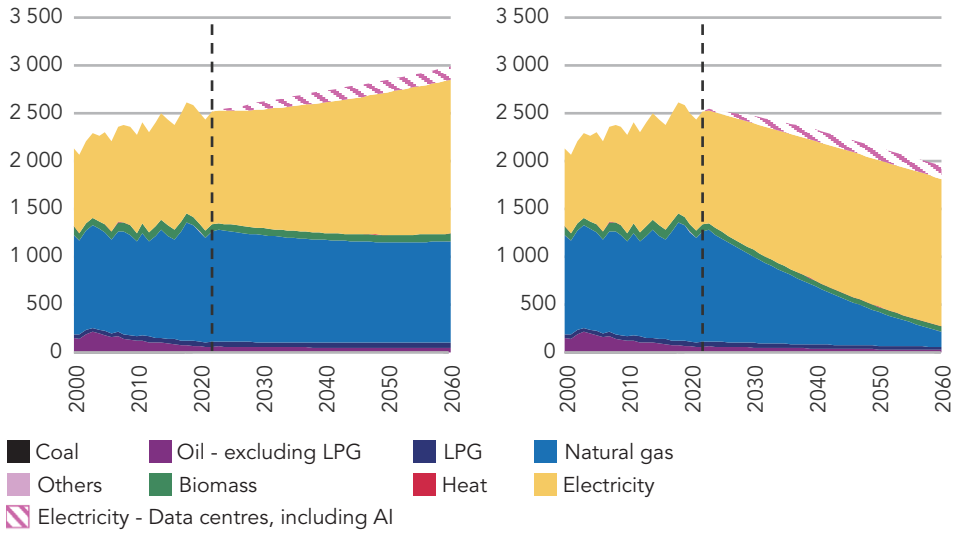
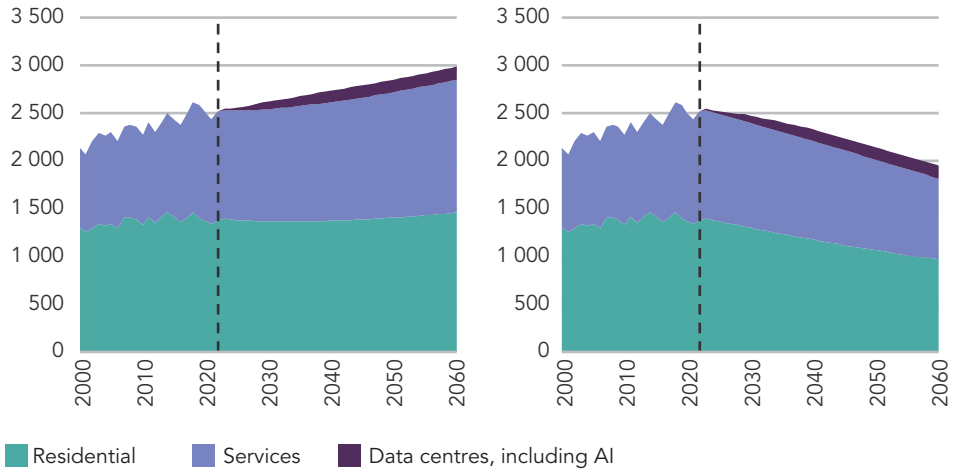


Figure 3-10. Buildings energy demand by sector in REF & TGT (PJ)



- The buildings sector accounted for the highest energy demand in Canada in 2022 and remains the largest demand sector through 2060 in REF. In TGT by 2060, buildings is overtaken by industry as the largest demand sector but remains a close second. High energy demand in buildings is driven in part by Canada's varied climate, characterized by cold winters and hot summers, which generates substantial demand for both space heating and cooling.
- As the population of Canada grows, demand for additional buildings is assumed to increase. In REF, while energy demand generally follows historical patterns, efficiency improvements partially offset the rise in energy use caused by population growth.
- In both scenarios, the share of electricity rises as electrification policies and incentives drive the adoption of heat pumps over gas heating, reduce the use of gas boilers in new buildings, and support retrofits, while also encouraging a shift away from gas-based cooking.
- In TGT, energy demand is assumed to decline relative to REF, driven by deeper electrification and fuel switching, updated building codes, and stricter efficiency standards for new and existing buildings, guided by the Canada Green Buildings Strategy.
- About 80% of buildings expected in 2030 already exist, making retrofits critical for emissions reductions. Policy support, affordability, and consumer awareness may be key to reducing energy use.
- Data centre electricity use is assumed to be the same in REF and TGT. Data centres are disaggregated only in the projection period, and their future energy demand remains highly uncertain due to the rapid evolution of digital technologies and AI. The rapid growth in additional electricity demand has the potential to place significant strain on local power systems unless there is adequate infrastructure planning to incorporate this emerging demand source.

Industry Energy and Non-energy Demand

Figure 3-11. Industry & non-energy demand by fuel in REF & TGT (PJ)

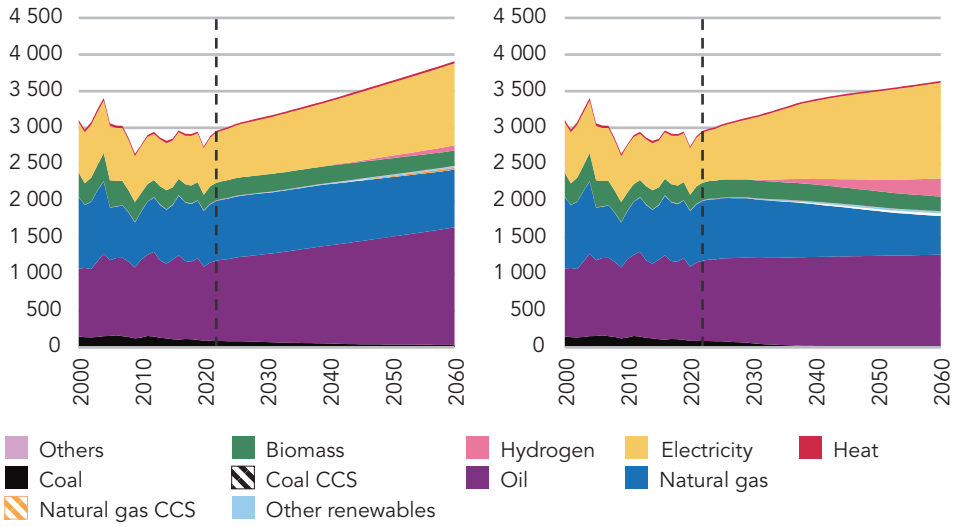
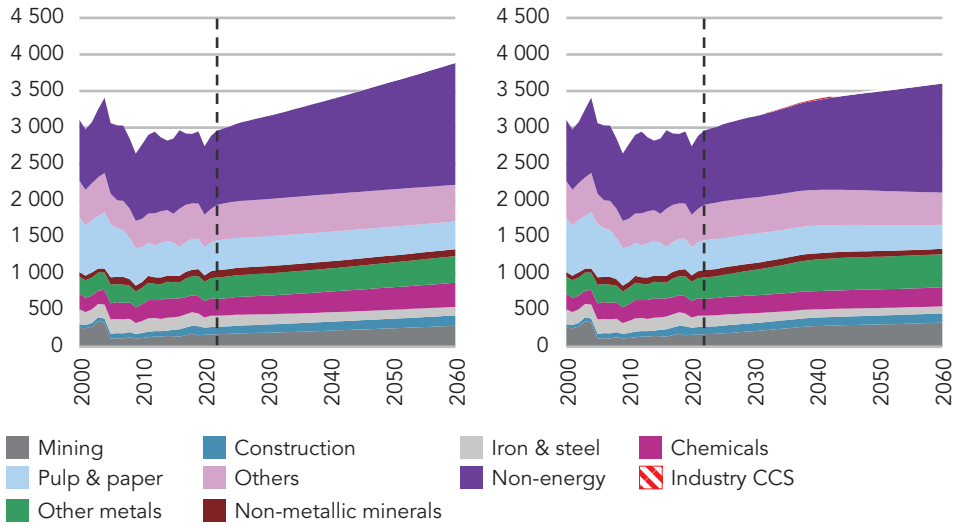


Figure 3-12. Industry & non-energy demand by sector in REF & TGT (PJ)



- Canada's services-based economy is expected to experience robust industrial activity in the coming decades, driven by onshoring as well as by economic and population growth. As the analysis is fuel-based, pricing and emissions-related policies are considered implicitly through their assumed effects on fuel consumption.
- The industrial sector remains a key challenge for economy-wide decarbonisation due to high-temperature heat requirements and persistent oil and gas use in non-energy applications. While electricity makes greater inroads in TGT than in REF, its use is currently limited to low- and medium-temperature processes and cannot displace fuel used for high-temperature processes or feedstock demand. Innovation to reduce reliance on oil and gas could support Canada in meeting its decarbonisation targets.
- Starting in 2030 in TGT, hydrogen use increases in iron and steel, replacing coking coal and providing a source of heat, and in chemicals as a feedstock.
- In both scenarios, increases in industrial production are supported in part through increased electrification. Lower efficiency improvements in REF compared to TGT keep the total energy demand growing in REF to 2060. In TGT, greater recycling and reduced end-use demand for materials, due to assumed innovations in end-use products, result in less production and activity in steel, cement, and chemicals.
- In contrast to lower activity in the aforementioned industrial sectors, TGT assumes a significant rise in minerals mining and metals processing through the early 2040s to support higher global demand for critical minerals and materials needed for low carbon technologies. However, compounding efficiency improvements over the projection period offset this growth, resulting in lower overall industrial energy use in TGT than REF in 2060.

Transport Energy Demand

Figure 3-13. Domestic transport energy demand in REF (PJ)

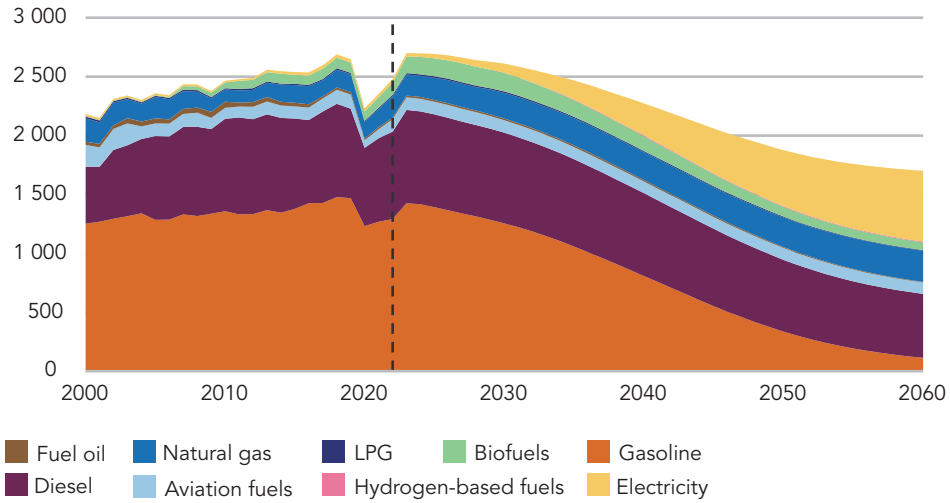
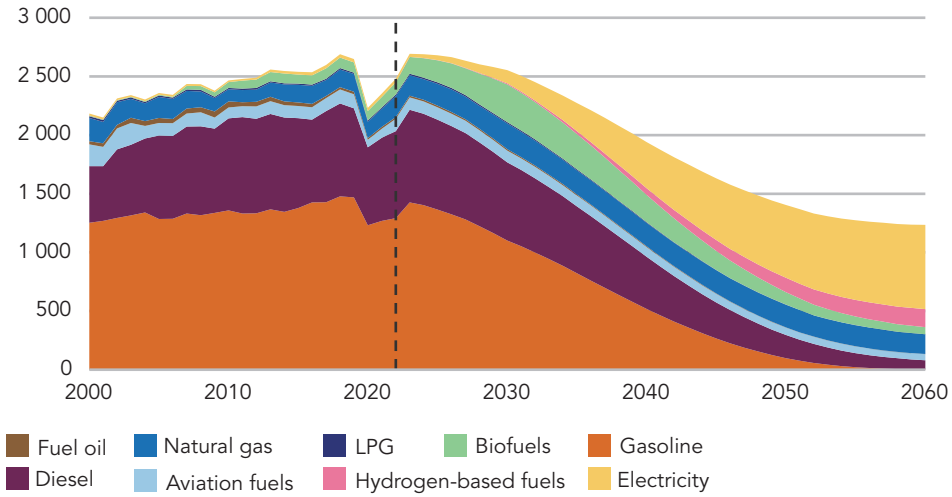


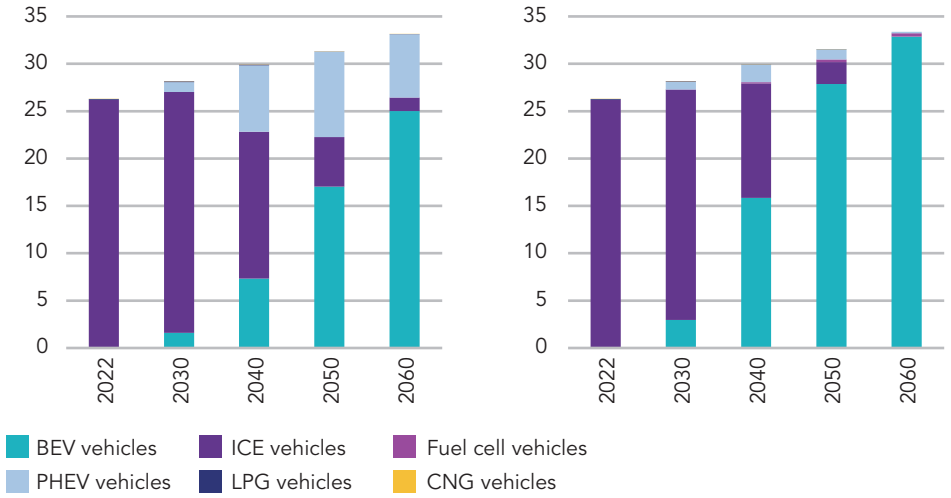
Figure 3-14. Domestic transport energy demand in TGT (PJ)



- Both REF and TGT assume that Canada meets its target of 100% zero-emission vehicle (ZEV) sales for new light-duty vehicles (LDVs) by 2035, though through different stock compositions in each scenario.
- The scenarios also differ in the assumed pace of heavy freight vehicle decarbonisation. In REF, ZEVs surpass internal combustion engine (ICE) vehicles by 2050. In contrast, the TGT scenario incorporates a more rapid decline in ICE vehicles, with ZEVs overtaking ICE vehicles by the late 2030s. In TGT, a significant amount of heavy vehicle ZEVs are fuel cell EVs powered by hydrogen.
- In TGT, faster and more widespread adoption of ZEVs leads to a more rapid decline in gasoline and diesel consumption compared with REF. In REF, diesel continues to be primarily used in freight transport, and gasoline use remains higher partly due to reliance on plug-in hybrid electric vehicles (PHEVs).
- In TGT, emissions intensity of transport fuels declines as biofuel blending in domestic jet fuel, gasoline, and diesel gradually increases to 25% by 2060. Despite expected technological progress, these low-carbon alternatives are likely to remain significantly more expensive than fossil fuels.
- APERC's analysis compares two pathways for Canada's LDV sales mandate. Both pathways reduce emissions, but higher BEV adoption provides stronger support for achieving Canada's 2050 emissions targets. Additional reductions could be achieved by advancing decarbonisation in heavy freight transport through electrification and the use of hydrogen-based fuels.
- Since the majority of Canada's transport energy demand originates from road transport, the higher efficiency of ZEVs reduces total transport energy use in both scenarios while increasing electricity use. Supporting transport sector decarbonisation will necessitate electricity systems capable of accommodating this additional load.

Other Transport Data

Figure 3-15. Transport vehicle stocks in REF & TGT (millions)



- Canada's ZEV definition provides flexibility for consumers in selecting vehicle options to meet mandate targets. However, higher BEV adoption in TGT leads to faster decarbonisation than a mix of BEVs and PHEVs in REF. Additionally, in REF, uncertainty remains as some PHEV users may rely more on gasoline and charge less frequently, potentially reducing expected energy savings.
- In TGT, bunkers (energy for international transport) transition to lower-emissions fuels based on targets aligned with the stated goals of international transport organisations.
- Although several factors influence energy use, the anticipated primary driver of energy reduction is the shift from internal combustion engines to electricity-dependent vehicles. At the same time, population and economic growth lead to increased freight and passenger activity, partially offsetting expected energy reductions from a shift in engine type.

Figure 3-16. International bunker energy demand for shipping and aviation in REF & TGT (PJ)

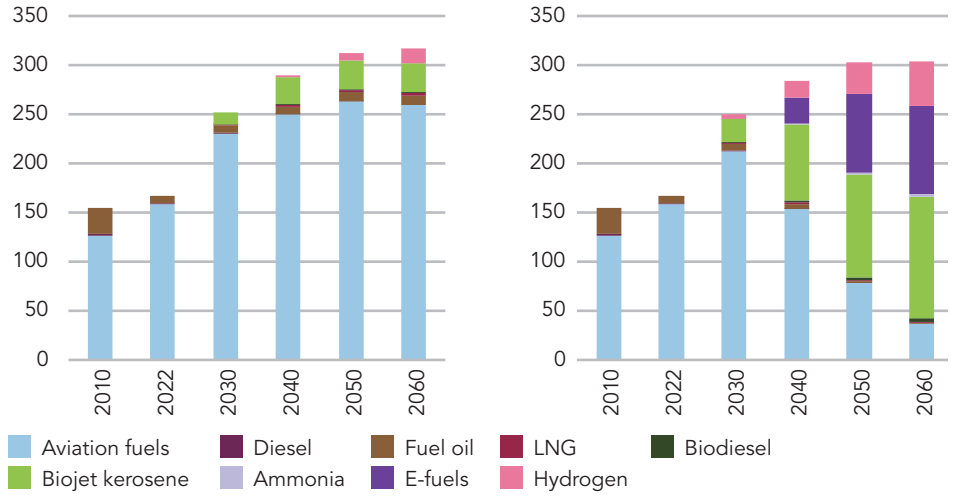
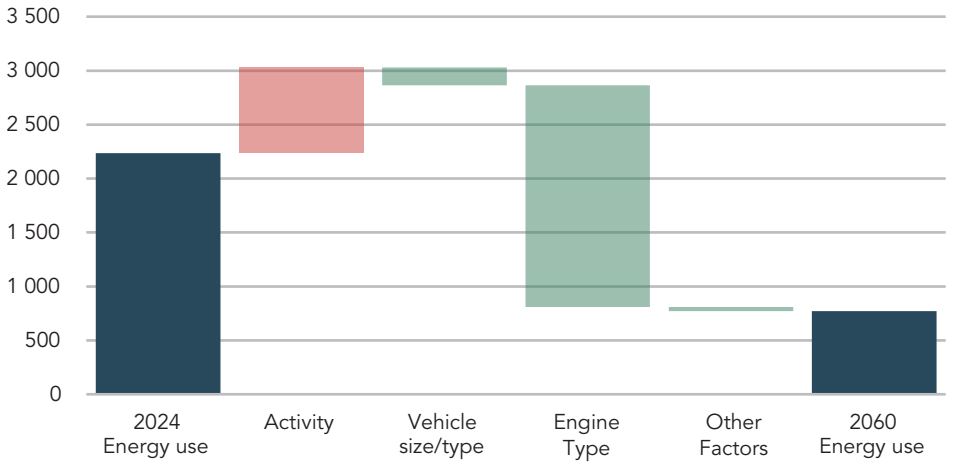


Figure 3-17. Components of the change in road energy use in TGT (PJ)



Note: Information on the different drivers in the transport energy decomposition can be found in the *Outlook*'s annex.

Electricity Generation

Figure 3-18. Electricity generation by fuel in REF (TWh)

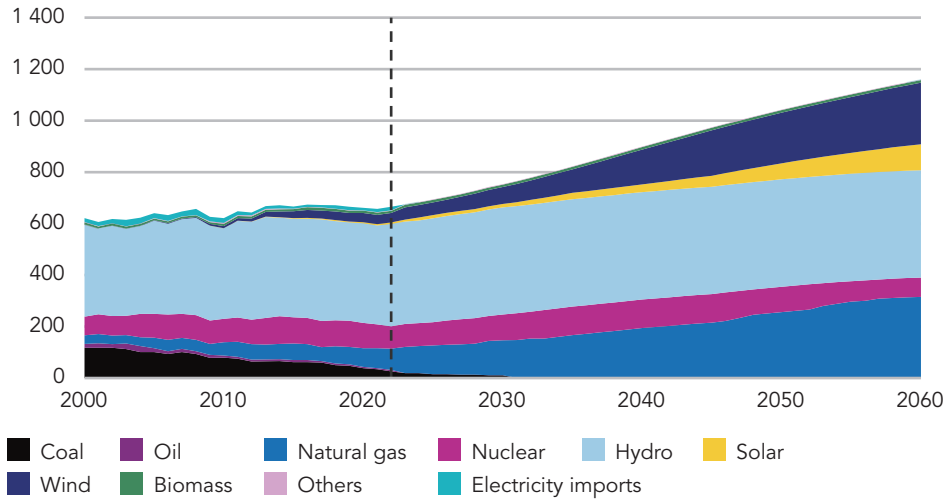
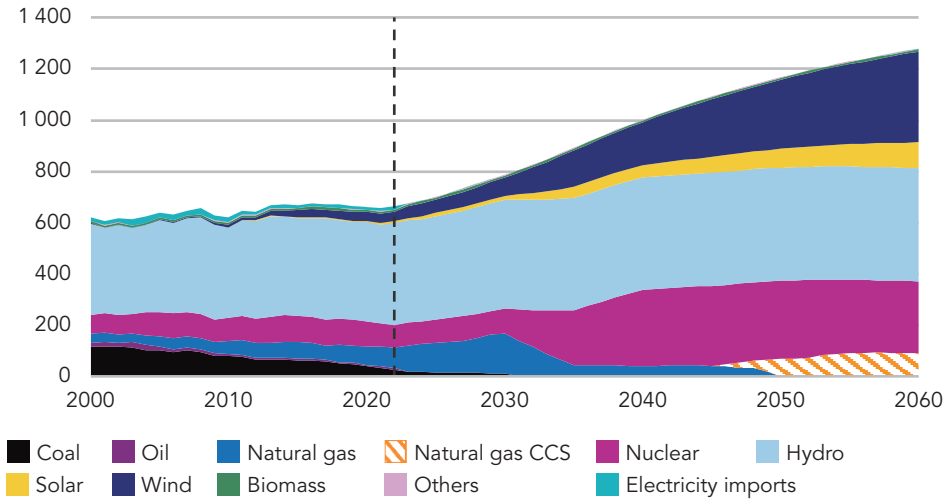


Figure 3-19. Electricity generation by fuel in TGT (TWh)



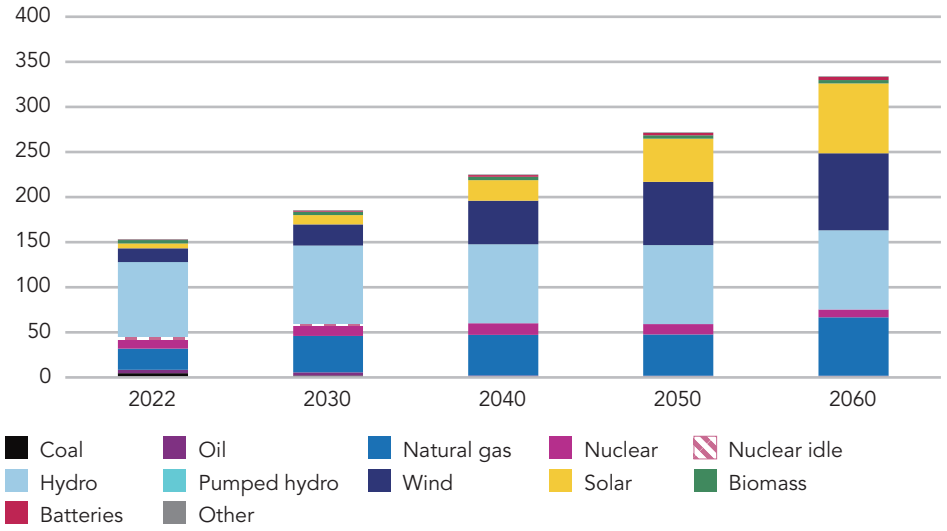
- In both scenarios, the assumptions used in the *Outlook* result in a significant increase in electricity demand over the projection period. This contrasts with the relatively unchanged demand during the previous two decades. By 2060, total electricity demand is projected to be approximately 10% higher in TGT than in REF.
- Both scenarios assume greater integration of non-dispatchable renewable energy, based on assumed continued technological advancement and declining infrastructure costs. In REF, non-dispatchable sources account for approximately 30% of total generation by 2060, and 36% in TGT.
- As electricity demand rises, the share of generation supplied by hydro declines in both scenarios due to long development timelines and regulatory barriers. In REF, increased gas generation reduces the share of non-emitting electricity from 82% in 2022 to about 73% in 2060. In TGT, nuclear expansion offsets a temporary increase in gas generation around 2030 when new nuclear plants are expected to come online, adhering to the scenario parameter requiring net zero grid emissions by 2050. Emissions are discussed in more depth in the "Gross CO_2 Emissions" section of this chapter.

- Canada's Clean Electricity Regulations emissions targets for gas power generation are reflected in TGT, while REF assumes no CCS in the power sector. In TGT, the reduction in gas generation results partly from these regulatory limits and partly from the addition of new nuclear capacity. As new nuclear plants come online and provide sufficient baseload power, there is less incentive to invest in carbon capture and storage (CCS) technology for gas plants. Moreover, gas plants equipped with CCS cannot operate flexibly without compromising the effectiveness of the carbon capture process, making them less suitable as a flexible resource when nuclear already meets baseload demand.
- Policy and lower-cost alternatives phase out coal generation by 2030 in both scenarios.

Note: Figures 3-18 and 3-19 do not include electricity generation for hydrogen production.

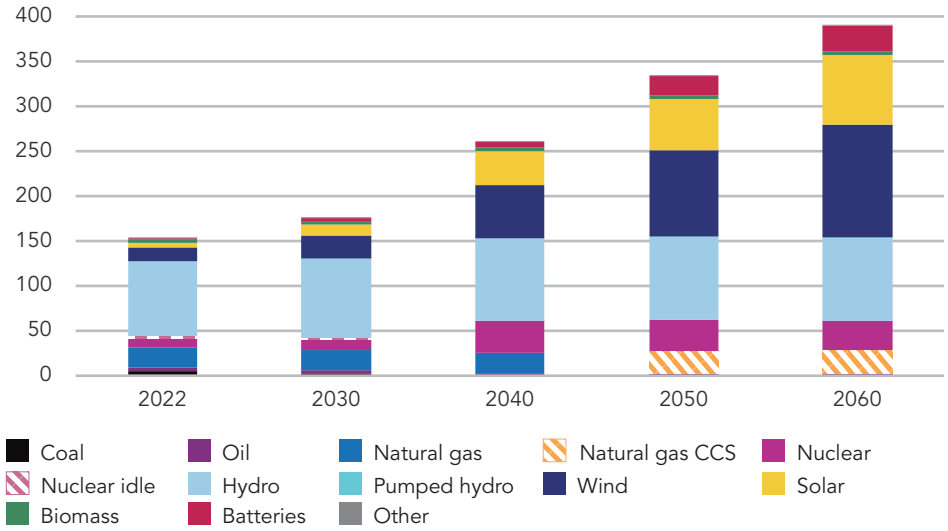
Generation Capacity

Figure 3-20. Generation capacity by fuel in REF (GW)



- While total electricity generation increases by less than a factor of two in both REF and TGT by 2060, total installed capacity increases approximately 2.2 times in REF and approximately 2.5 times in TGT.
- Average annual capacity factors of 15% for solar and 32% for wind are assumed in both scenarios. Because solar uses a lower capacity factor in the APERC model compared with other models, the *Outlook* implements more solar capacity to achieve comparable generation. Wind capacity is consistent with other models, but the lower capacity factor in the *Outlook* results in relatively less wind generation.
- In REF, by 2060, wind and solar comprise approximately 30% of electricity generated annually, but account for nearly half of total installed capacity in 2060 and the majority of added capacity since 2022.
- In TGT, by 2060, wind and solar provide approximately 35% of electricity generated annually but wind, solar, and batteries account for about 60% of total capacity and about 90% of added capacity since 2022. Additionally, nuclear emerges by partially replacing gas as baseload capacity in TGT.

Figure 3-21. Generation capacity by fuel TGT (GW)



- REF incorporates existing nuclear plants, including those undergoing refurbishments, assuming a 70-year lifespan, as well as moderate levels of added capacity through small modular reactors (SMRs). In TGT, an additional 24 GW of installed nuclear is incorporated by 2060, likely requiring a combination of SMR and CANDU technologies.
- In both scenarios, installed capacity must increase substantially to meet growing electricity demand. As the grid evolves, building suitable infrastructure and addressing technical challenges from integrating a high share of renewables into a system designed for centralised, dispatchable power will be essential.
- Oil capacity falls significantly in both scenarios but remains as a back-up and to power remote communities.

Note: Figures 3-20 and 3-21 do not include generation capacity for hydrogen production.

Grid Reliability

Figure 3-22. Total generation capacity and peak load (GW)

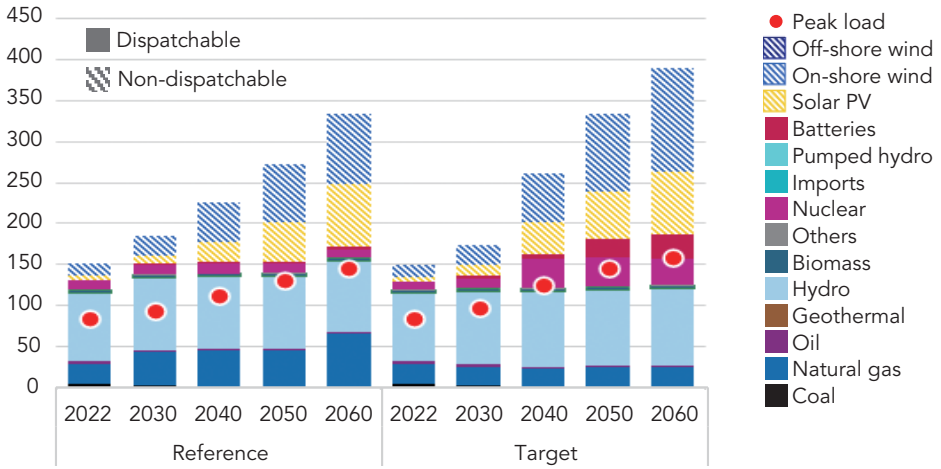
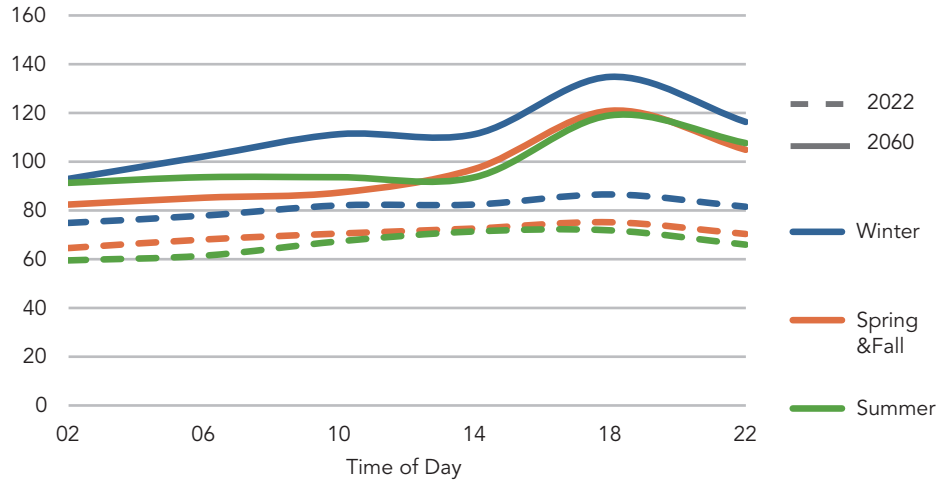


Figure 3-23. Power from dispatchable sources in TGT (GW)



- In REF, the peak electricity load grows by 74%, from 84 GW in 2022 to 146 GW in 2060. In TGT, due to greater electrification, peak load grows by 89% to 159 GW by 2060.
- The intermittent nature of wind and solar leads to lower load factors, meaning total system generation capacity must expand faster than peak load in order to integrate these sources.
- In REF, total capacity grows by 118% from 153 GW to 334 GW. In TGT, it needs to grow by 155% to 390 GW.
- Grid reliability requires that power systems have enough dispatchable generation capacity, including batteries, to meet peak load in those periods when wind and solar generation are minimal or nil.
- Increased reliance on wind and solar generation will increase the variability of the generation required from dispatchable power sources. Additionally, as wind and solar capacity increases, the load factor for dispatchable sources declines, which increases total system cost.

- In 2022, generation from dispatchable sources remained relatively constant throughout the day. By 2060, generation from dispatchable sources will need to fluctuate by approximately 28 GW on an average summer day, 39 GW on an average spring and fall day, and 43 GW on an average winter day.
- Winter requires the most dispatchable power, as electricity demand peaks during this season. Although wind availability is typically higher in winter, reduced solar output and increased demand drive greater reliance on dispatchable sources.
- In general, the fluctuations of dispatchable power in Canada are not as large as some other economies due to high hydro and nuclear capacities and relatively small shares of electricity generated by wind and solar. However, actual variability may differ from modelled totals due to regional differences in solar and wind resource availability across Canada. Additionally, individual days with greater variability could exceed seasonal averages.

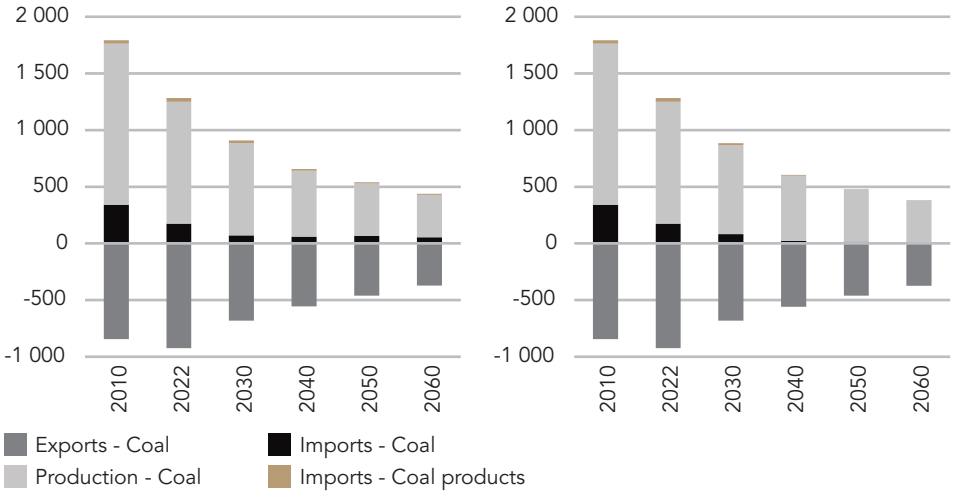
Coal

Figure 3-24. Coal consumption by sector in REF & TGT (PJ)



- In both scenarios, coal use falls significantly. The industrial sector dominates the remaining coal consumption out to 2060, with most of this persisting coal use in the form of metallurgical coal, primarily for coking coal in steel production.
- In TGT, metallurgical coal use declines more rapidly than in REF, driven by factors including increased hydrogen adoption in industry, a larger shift in steelmaking from coking coal furnaces to electric arc furnaces for scrap steel and iron ore processing, and improvements in industrial energy efficiency.
- Demand for coal in the power sector has declined significantly over the past two decades, reflecting efforts to decarbonise the grid and improve air quality. Coal is phased out of electricity generation by 2030 in both scenarios following Canada's policy to phase out unabated coal-fired electricity generation.
- Coal use in the buildings sector was fully phased out by 2018.

Figure 3-25. Coal production, imports, and exports in REF & TGT (PJ)



- Thermal coal production declines as domestic demand falls and a thermal coal export ban begins in 2030. Metallurgical coal production also steadily declines because of lower domestic demand. While exports decrease, international demand supports some ongoing production. By 2060, exports fall to about 45% of 2022 levels in REF and 44% in TGT.
- In REF, modest coal imports persist through 2060 due to industrial and non-energy sector needs, despite overall declining demand. In TGT, imports fall to near zero as domestic demand declines further.
- Thermal coal production falls faster in TGT than REF, driven by greater fuel switching, from coal to biomass, electricity, and natural gas.
- In TGT, increased hydrogen-based steelmaking reduces metallurgical coal demand. However, since Canada's metallurgical coal sector is export-oriented, production remains similar in both scenarios.

Natural Gas

Figure 3-26. Natural gas consumption by sector in REF & TGT (PJ)

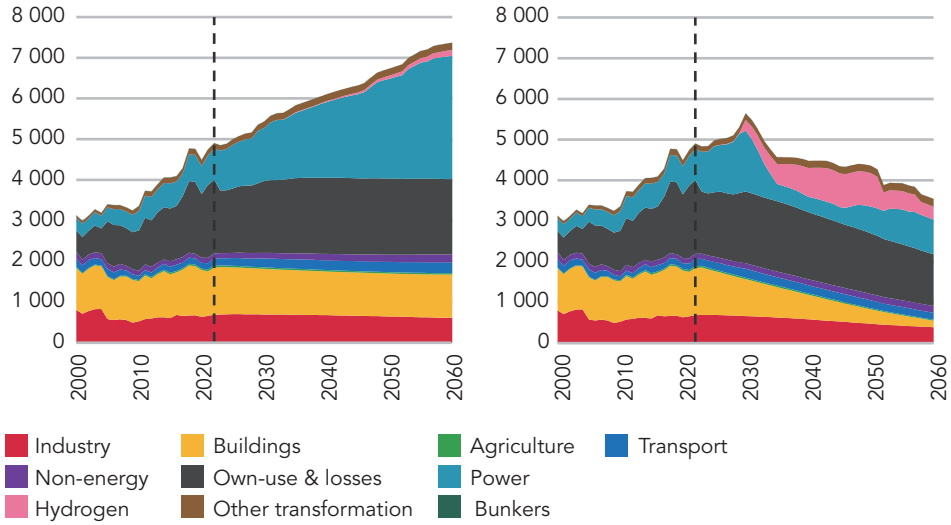
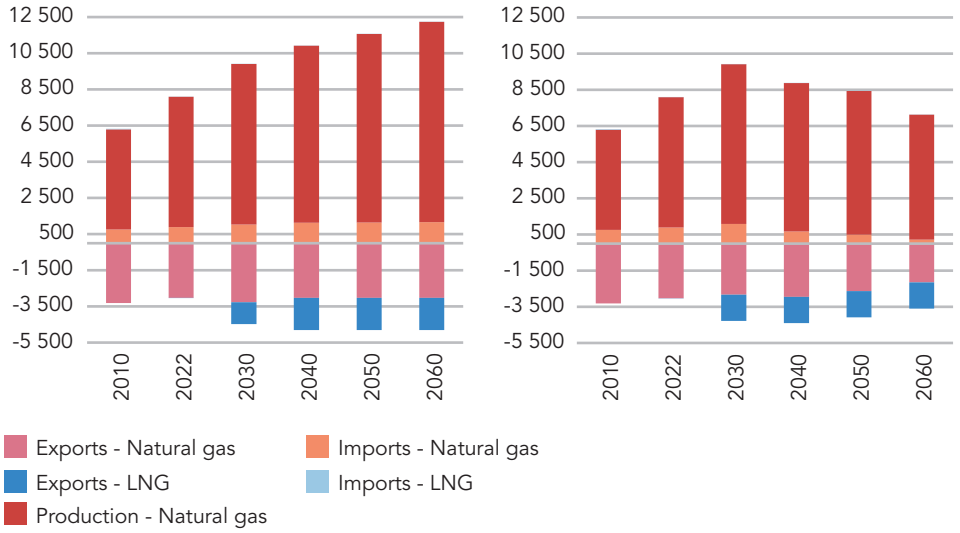


Figure 3-27. Natural gas production, imports, and exports in REF & TGT (PJ)



- Natural gas demand grew over the past two decades, serving as a key fuel for baseload power generation. In REF, its role continues, and demand increases over the projection period. In TGT, an increase in nuclear generation in the early 2030s reduces gas generation, though it rises again in the latter years to meet growing electricity demand and support baseload supply.
- Canada views low-carbon hydrogen as a way to maintain its energy exporter role. Hydrogen production via natural gas with CCS currently holds a cost advantage over renewable-based alternatives, driving hydrogen-related domestic gas use in TGT.
- Natural gas has historically played a major role in buildings for heating, cooling, and cooking. In TGT, stronger decarbonisation policies and broader electrification reduce gas demand in the buildings sector.
- Canada's natural gas production depends on natural gas prices as well as domestic and export demand. In REF, pipeline exports to the United States are expected to remain near 2022 levels. In TGT, pipeline exports to the United States are assumed to decline as U.S. gas demand peaks around the 2030s and is met with domestic production. Similarly, imports from the United States decrease as Canadian gas demand peaks around 2030, with trade continuing only in regions where domestic supply is insufficient and importing offers a cost advantage.
- Historically, most exports flowed to the United States via pipelines. While that is expected to continue, starting in 2025, new LNG export terminals will position Canada as a strategic LNG supplier to APEC economies and drive export growth.
- Competition from established LNG producers, like the United States and Qatar, may challenge new entrants' market share, though successful large-scale export chains could boost exports and production beyond that expected in the *Outlook*. LNG export demand may stem from activities like LNG-to-power projects in Southeast Asia and AI data centre power demand, among others.

Note: Historical data for LNG is based on JODI gas data.

Petroleum Liquids

Figure 3-28. Crude oil, NGLs, and other hydrocarbons production, imports, and exports in REF & TGT (PJ)

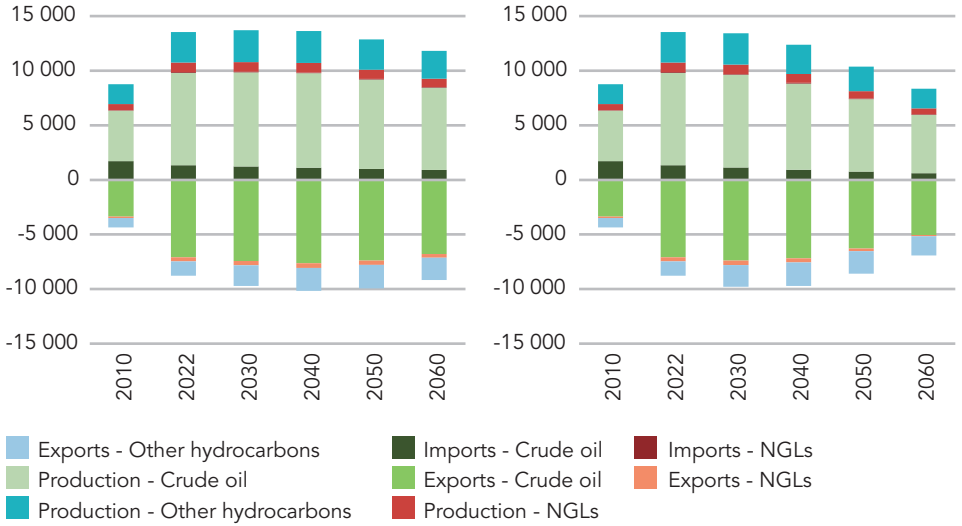
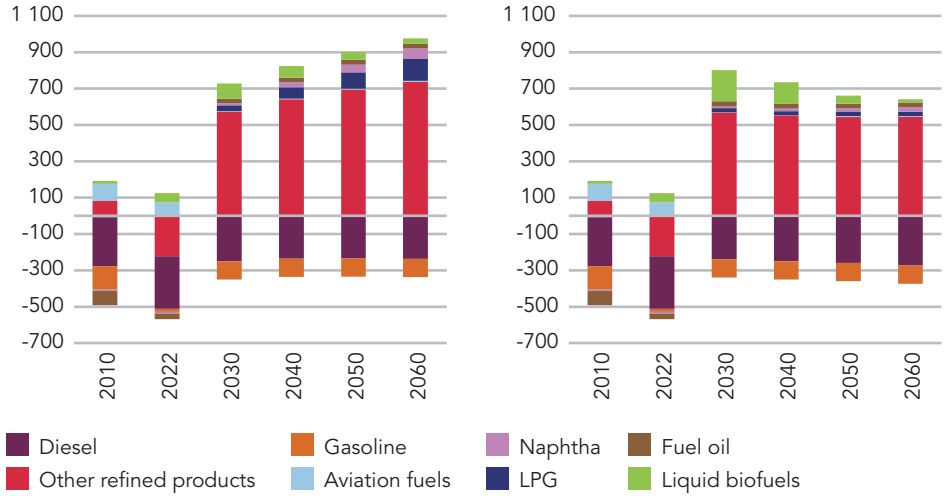


Figure 3-29. Net imports of refined products and low-carbon fuels in REF & TGT (PJ)



- Canadian crude oil production is projected to peak around 2030 in both scenarios. In REF, production plateaus and then declines only slightly by 2060. In TGT, oil production undergoes a sharper decline to 2060.
- In REF, production continues in order to maximise returns on ongoing and planned resource development, but long-term growth is expected to be constrained by diminishing reserves and a slowdown in new investment.
- In TGT, production falls more quickly in response to assumptions about faster global and domestic transitions away from crude oil, including reduced refinery demand in major markets such as the United States.
- Crude oil exports increase early in the projection period in both scenarios, but gradually decline through to 2060, with the decline more pronounced in TGT. Since most Canadian crude currently goes to the United States, securing access to alternative markets may help maintain export volumes.

- Despite being a net crude oil exporter, Canada imports over one-third of the crude it refines domestically. This is mainly because refineries in Eastern Canada are not connected by pipeline to Western Canada where the vast majority of Canada's crude oil is produced.
- In REF, crude imports decline slightly over time, while TGT shows a more pronounced decrease, reflecting assumptions of greater reductions in domestic refining capacity.
- Canada remains a net exporter of diesel, gasoline, and fuel oil in both scenarios. However, to sustain export levels amid global shifts toward decarbonising transport, Canada may seek to diversify its export markets.
- In TGT, imports account for approximately half of liquid biofuel consumption in 2030. However, as domestic production increases and demand declines in the latter years of the projection period, imports correspondingly decrease.

Note: In Figure 3-29, net imports are presented without deducting bunkers.

Refining

Figure 3-30. Refining outputs in REF & TGT (PJ)

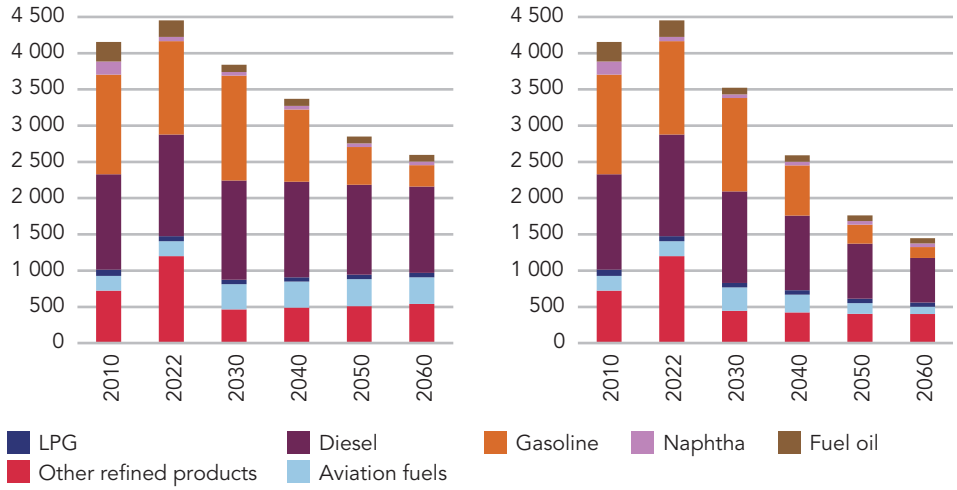
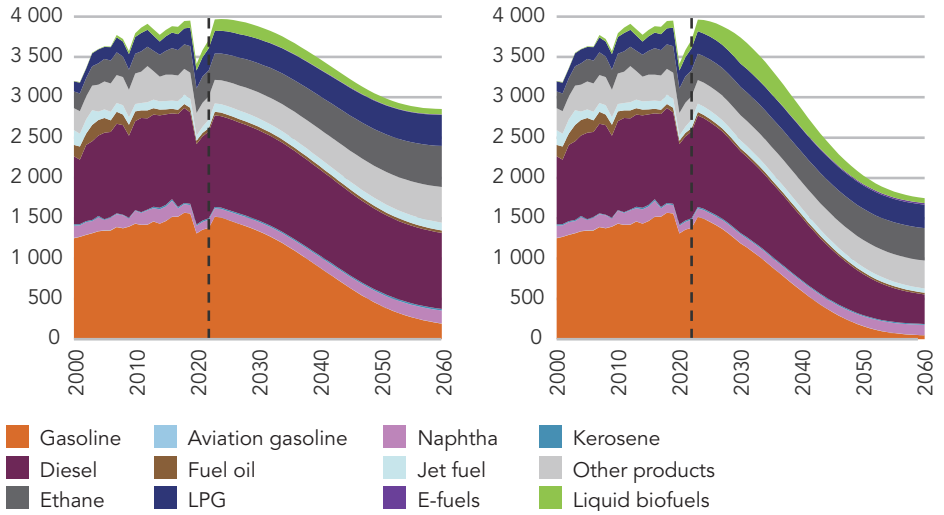


Figure 3-31. Refined products and low-carbon fuels demand in REF & TGT (PJ)



- Historically, a large portion of refined products demand in Canada came from the transport sector. With the push for electrification of the sector, domestic demand for refined products decreases in both scenarios.
- Gasoline and diesel production are projected to decrease in both scenarios. In REF, gasoline output falls as internal combustion engine vehicles are gradually replaced by zero-emission vehicles. In TGT, the decline in gasoline is more pronounced due to higher adoption of electric vehicles over plug-in hybrids. Additionally, diesel production declines further, reflecting assumptions that diesel vehicles will increasingly adopt alternative fuels to reduce diesel consumption.
- Existing refinery capacity exceeds projected demand, and it is assumed that technological advancements will enable refineries to adjust their product output ratios. For example, it is assumed that refineries will be readily able to reduce motor gasoline production in favour of other petroleum products, including diesel and jet fuel, to sustain operations.
- Despite this, an approximately 25% reduction in refining capacity is assumed by 2060 in REF, while in TGT, it is assumed that there will be an approximately 55% capacity reduction. Both scenarios implement a steady capacity decrease designed to maintain an average utilisation rate of 90%.
- Pipeline interconnections among Canadian upgraders, domestic refineries, and U.S. refineries provide operational flexibility. This integrated network enables the refining sector to adapt production in response to shifting demand and consumption patterns, which may be crucial for maintaining the competitiveness of Canadian refineries in the future.

Bioenergy and Waste

Figure 3-32. Bioenergy and waste demand by sector in REF & TGT (PJ)

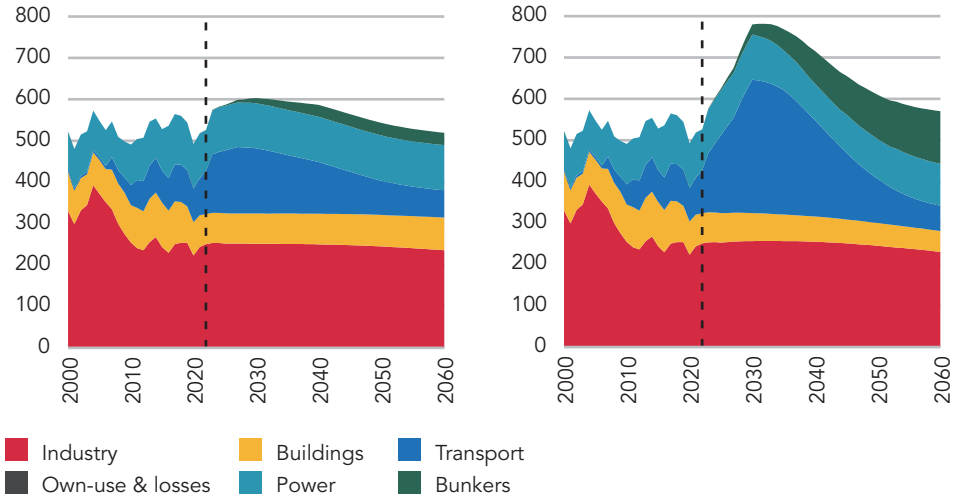
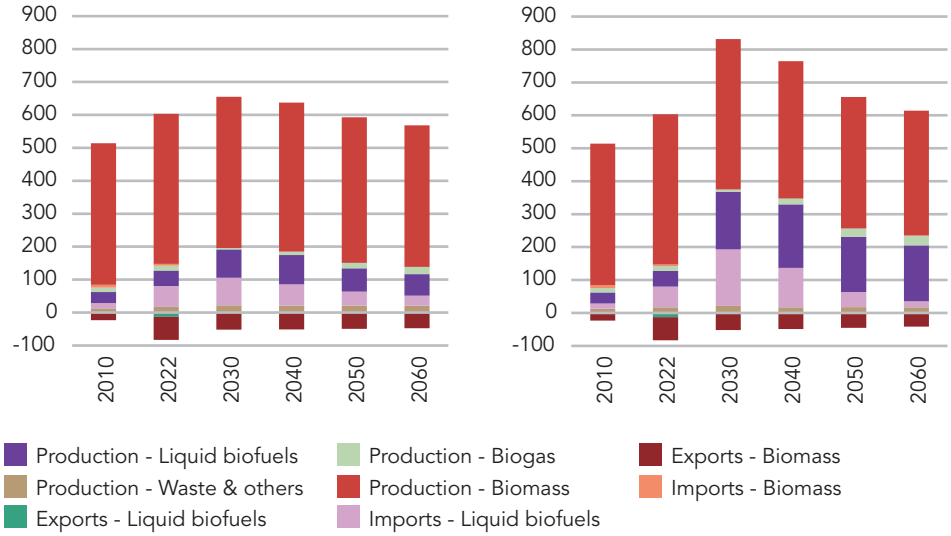


Figure 3-33. Bioenergy and waste production, imports, and exports in REF & TGT (PJ)



- Domestic bioenergy use in Canada's manufacturing industry is primarily in the form of solid biomass for use in the pulp and paper, as well as wood and wood products subsectors. For exports, solid biofuels such as wood pellets are primarily produced from waste.
- In both scenarios, greater biofuel blending in transport raises demand, with even higher rates in TGT driving stronger growth. As electric vehicle uptake grows, liquid biofuel demand in transport eventually declines.
- Canada currently relies on liquid biofuel imports to meet domestic demand, with approximately 50% of liquid biofuels being imported. In 2023, about 60% of ethanol blended into gasoline to meet clean fuel targets was imported.
- Canada's liquid bioenergy production is almost entirely for domestic use and is assumed to follow domestic demand trends through the projection period.
- In both scenarios, Canada reduces its import reliance on biodiesel and biogasoline as demand declines, while also increasing domestic feedstock use to expand biofuel production under policies such as the Clean Fuel Regulations. In addition, Canada could potentially utilise domestic feedstocks to produce biocarbon products to replace fossil fuels use in industry.
- Nonetheless, liquid biofuel imports are expected to rise in the near term before decreasing below 2022 levels by 2060. In REF, imports supply 32% of total liquid biofuel consumption in 2060. In TGT, this value is expected to be much lower, at 10%, based on assumptions of lower demand and enhanced production supports compared to REF.
- In REF, biojet kerosene production is expected to reach over 17 PJ (0.52 billion litres) by 2030, below the C-SAF Roadmap target of 1 billion litres. In contrast, production reaches 34 PJ (1.01 billion litres) by 2030 in TGT, reaching the goal.

Hydrogen-based Fuels in the Target Scenario

Figure 3-34. Hydrogen-based fuels demand by sector [left]; Hydrogen-based fuels demand by fuel [right] (PJ)

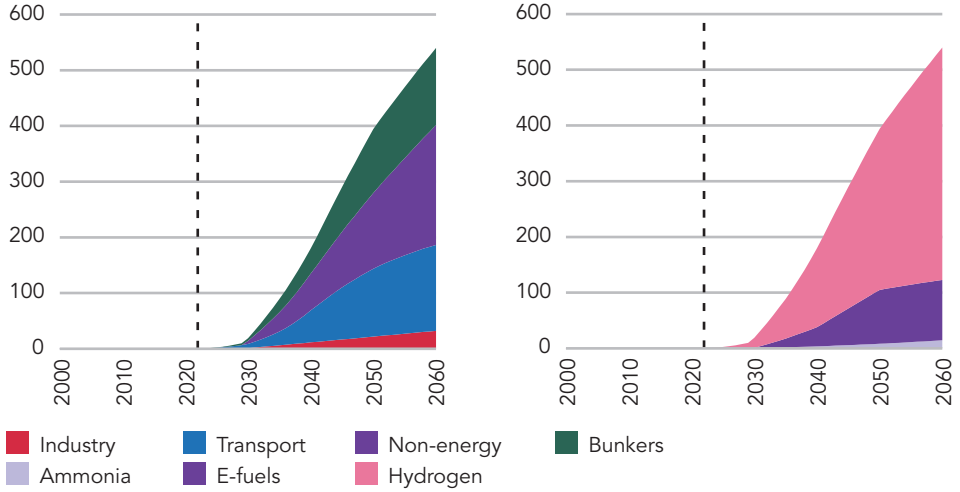
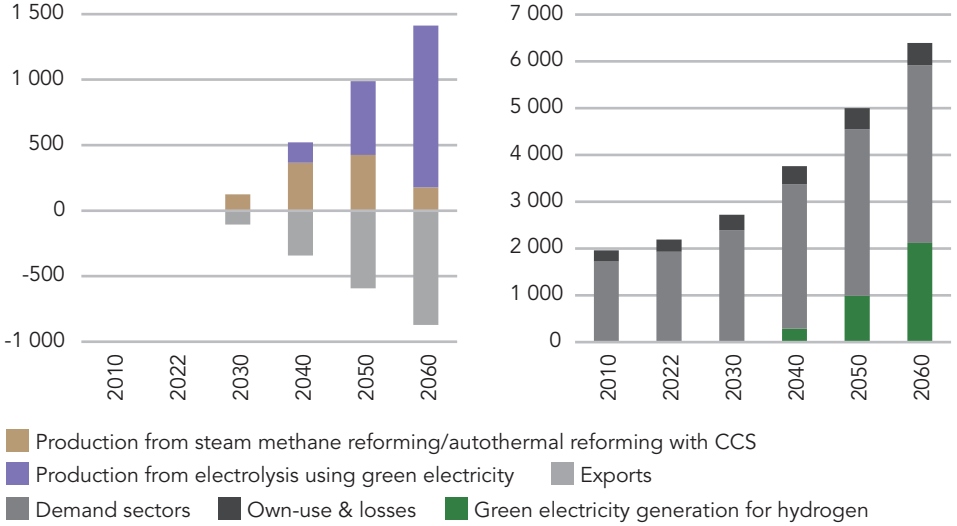


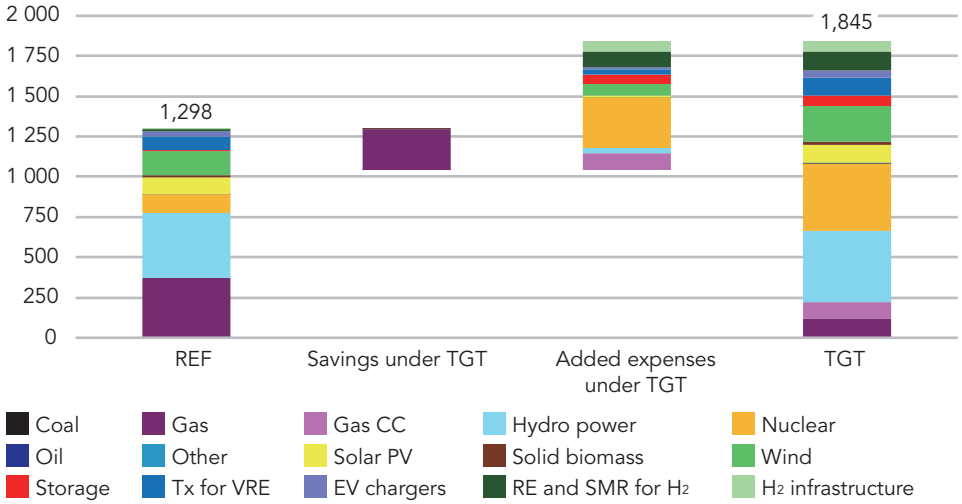
Figure 3-35. Hydrogen-based fuels production methods and supply [left]; Electricity for electrolysis vs. other sectors [right] (PJ)



- Canada aims to become a major producer and exporter of low-carbon hydrogen. As outlined in the Hydrogen Strategy, hydrogen is viewed as a pathway to maintaining Canada's role as a leading energy exporter and this is incorporated in the TGT scenario.
- Hydrogen in Canada is not used widely across demand sectors. In 2060, about 30% is expected to be used in the transport sector and 5% directly in industry. The remaining 65% would be for non-energy and bunkers.
- Early hydrogen production is expected to rely heavily on natural gas through steam methane reforming with CCS, which holds an initial cost advantage over green hydrogen production.
- In REF, overall hydrogen production is assumed to be significantly lower (approximately 10 PJ in 2040), with no exports and all supply coming from natural gas with CCS.
- High exports in the TGT scenario reflect assumptions of stronger import demand from economies with significant expectations for hydrogen use.
- Green hydrogen from electrolysis is assumed to scale up later in the projection period. High costs and electricity supply constraints could limit earlier deployment. By 2060, green electricity for hydrogen production could account for around 33% of total electricity demand, imposing a large demand on power generation. This renewable electricity generation is assumed to be dedicated to hydrogen production and is not included in the renewable generation shown in the power sector model.
- Given the assumption of low natural gas prices (USD 3.5/MMBTU), green hydrogen may require additional support beyond existing tax credits to transition from natural gas in hydrogen production. For modelling purposes, a carbon price ranging from USD 170/tCO_2 to USD 450/tCO_2 was assumed.

Costs

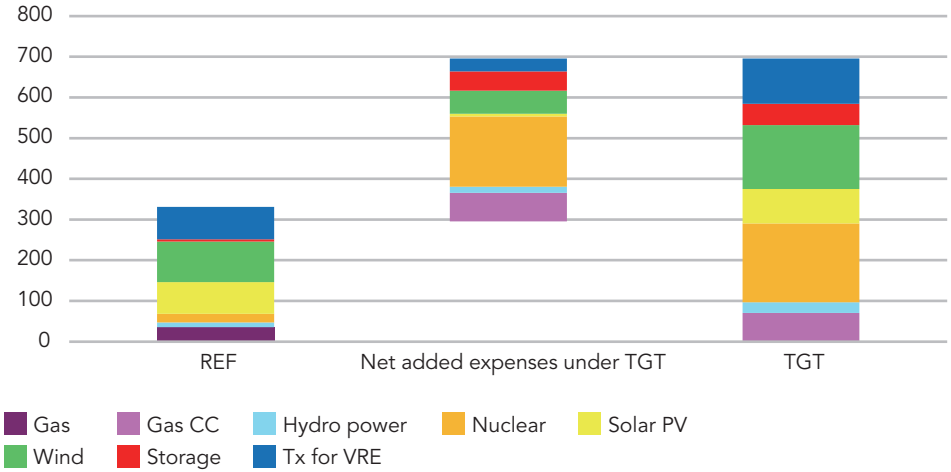
Figure 3-36. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



Note: Tx for VRE is only transmission infrastructure to connect variable renewable capacity to the grid. EV chargers do not cover the cost of associated infrastructure or EV vehicles. SMR is Steam Methane Reforming used to produce blue hydrogen.

- The power and hydrogen sectors will require significant expenditures and investment in Canada, with total costs rising substantially in both scenarios from 2025 to 2060. The total capital, fixed, and variable costs in the power sector are considered, as well as costs for green and blue hydrogen production for domestic use, transmission for variable renewable electricity, and electric vehicle chargers.
- In REF, total costs are driven by operating expenditures for hydro and gas generation. Costs also arise from capital investments in wind, solar PV, VRE transmission infrastructure, and nuclear power operating costs.
- In TGT, hydrogen producing infrastructure costs and costs for renewables and steam methane reforming for hydrogen production comprise 10% of accumulated costs by 2060, and 21% of added expenses. This considers green and blue hydrogen production for the transport, industrial, and non-energy sectors, but not hydrogen for export or bunkers. Increased hydrogen usage in transport in TGT will offset conventional fuel consumption, estimating to save USD 90 billion (not shown in Figure 3-36).

Figure 3-37. Total capital investment (CAPEX) from 2025 to 2060 in the power sector (billion USD, undiscounted)

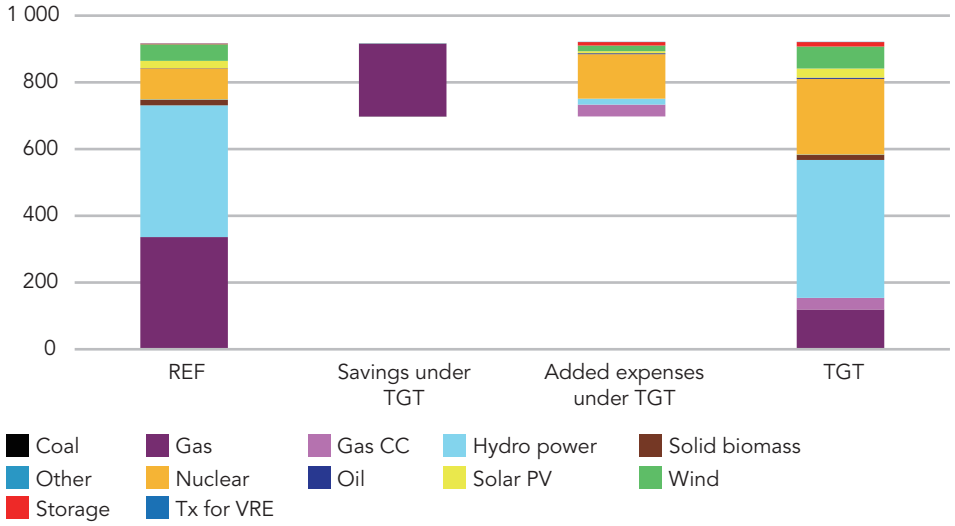


Note: Figure 3-37 only covers power and VRE transmission sector investments. Hydrogen and EV capital investments are not included.

- Nuclear power accounts for 23% of total costs and 38% of added expenses in TGT. Nuclear costs are primarily driven by capital and fixed costs.
- While reduced natural gas use in TGT results in total cost savings, these are offset by substantial new investments, primarily in nuclear power.
- Figure 3-37 shows the capital costs required in both scenarios. Significant capital investment is required for nuclear in TGT. To this end, the federal government currently offers several funding options, including the Enabling SMRs Program and the Electricity Predevelopment Program.
- Carbon capture infrastructure for gas-fired power also contributes notably to added expenses (approximately 18% of the added capital investment in TGT).
- In both scenarios, investment in transmission infrastructure is needed to meet evolving power system requirements and connect added VRE to demand centres, with higher spending in TGT to accommodate more VRE.

Costs

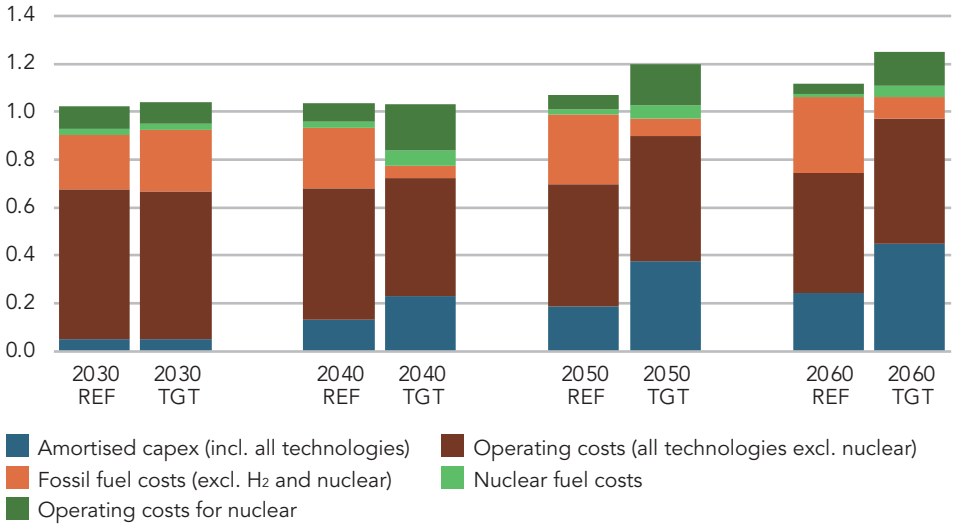
Figure 3-38. Total operating costs from 2025 to 2060 in the power sector (billion USD, undiscounted)



Note: Figure 3-38 only covers power and VRE transmission sector costs. It does not include operating costs associated with hydrogen production and EV charger costs.

- Total operating costs for the Canadian power sector are projected to be roughly the same in both scenarios. These costs incorporate variable fuel and non-fuel expenditures, fixed costs for the power sector, and for transmission infrastructure to 2060.
- Despite substantial differences in total costs and capital investment between the two scenarios, total operating costs remain similar, as higher fixed costs for nuclear in TGT largely offset the savings in gas operating costs.
- The negligible change in total operating costs between REF and TGT suggests that, despite significant shifts in the energy mix, the total costs of running the system may remain relatively steady. This would imply that policy may be well suited to reducing barriers to capital deployment rather than providing operating subsidies.
- Figure 3-39 shows the relative cost of generating electricity in selected years indexed to the base year of 2025 for each scenario.

Figure 3-39. Cost of generating electricity relative to 2025 (2025 cost = 1.0) in the power sector



Note: Based on our assumptions about future capital and operating costs, Figure 3-39 shows cost compositions over time relative to 2025. It should not be considered an estimate of electricity tariffs and excludes market mechanisms that are too difficult to estimate.

- In REF, the cost of generating electricity remains relatively steady, within the range of expected uncertainty around factors like CAPEX and variable costs.
- In TGT, the cost of generating electricity begins to rise more noticeably in the 2050s, reaching just over 1.2 times the 2025 level by 2060. This increase reflects the adoption of higher-cost technologies, such as CC-equipped gas, nuclear, and greater investments in renewables compared to REF, which drives up amortised capital costs, especially in the last decade.
- Notably, new nuclear capacity in TGT primarily comes online in the 2030s. Although the new capacity increases capex (due to large capital requirements) and nuclear operating costs, the reduction in fossil fuel expenditure means that up until 2040, generation costs are similar in both scenarios.

CO_2 Emissions

Figure 3-40. CO_2 emissions in REF (million tonnes)

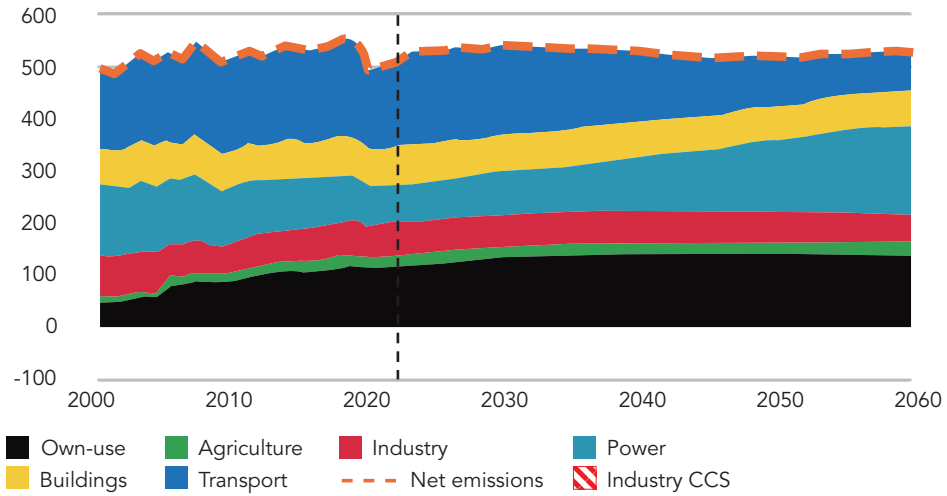
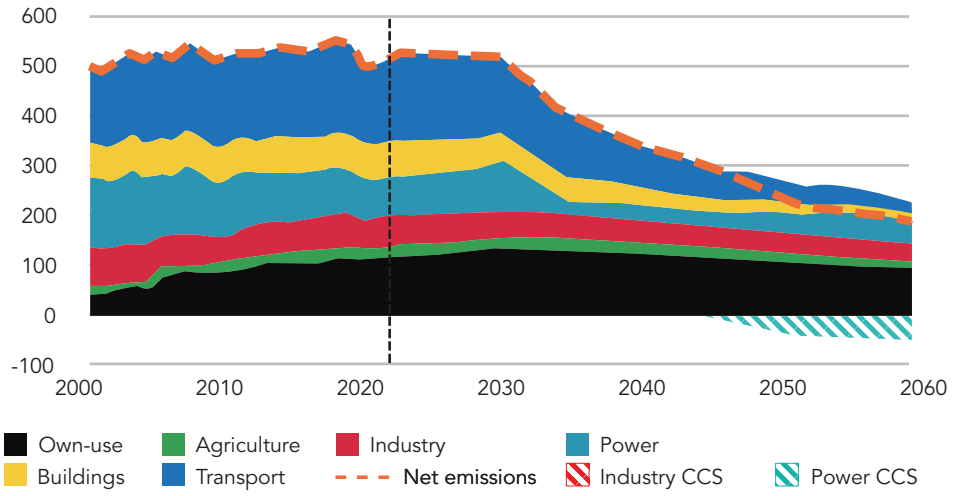
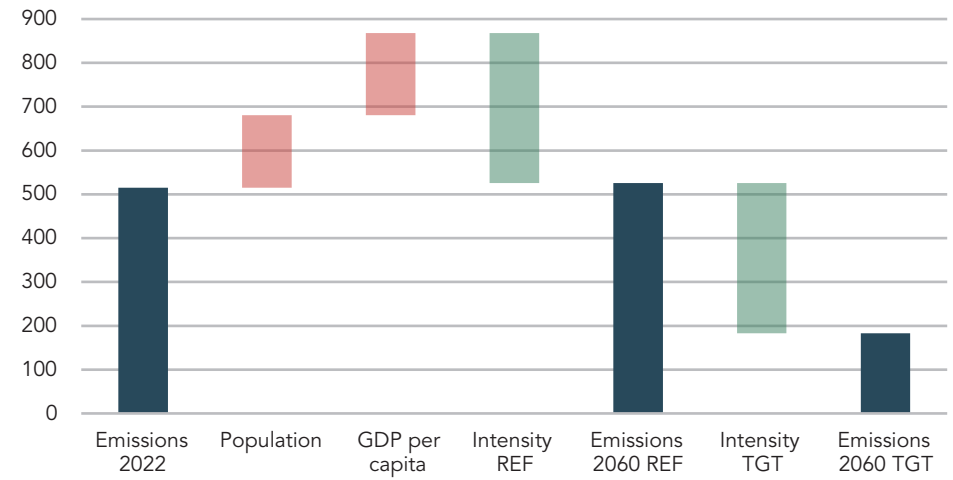


Figure 3-41. CO_2 emissions in TGT (million tonnes)



- In REF, emissions initially decline but rebound slightly as rising electricity demand results in increased gas-fired generation without CCS. Reductions in transport emissions are partially offset by this growth in power sector emissions, underscoring the importance of an economy-wide approach and the continued decarbonisation of Canada's electricity system.
- In TGT, emissions are 65% lower than in REF by 2060. The largest share of remaining emissions comes from own use, primarily resulting from the energy required for oil and gas extraction, refining, and LNG liquefaction.
- Emissions reductions from 2022 to 2060 are largely driven by improvements in energy and carbon intensity, which help mitigate the impacts of population growth and rising GDP per capita. In TGT, these efficiency gains are key to achieving the additional reductions needed to make progress toward emissions targets, highlighting their critical role of emission strategies.

Figure 3-42. CO_2 emissions components 2022-2060 (million tonnes)



Note: All values represent energy sector combustion CO_2 emissions. Biogenic CO_2 is treated as zero at the point of combustion.

Useful Links

APEC Expert Group on Energy Data and Analysis (EGEDA) – https://www.egeda.ewg.apec.org/

APEC Energy Statistics 2022 – https://www.egeda.ewg.apec.org/egeda/general/info/pdf/APEC_Energy_Statistics_2022.pdf

APEC Energy Overview – https://aperc.or.jp/reports/energy_overview.php

Atomic Energy of Canada Ltd – www.aecl.ca

Canada Gazette – www.gazette.gc.ca/

Canadian Centre for Energy Information – https://energy-information.canada.ca/en

Canada Energy Regulator – https://www.cer-rec.gc.ca/index-eng.html

Canadian Nuclear Laboratories – www.cnl.ca

Canadian Nuclear Safety Commission – http://nuclearsafety.gc.ca

Environment and Climate Change Canada – www.ec.gc.ca

Innovation, Science and Economic Development Canada – https://ised-isde.canada.ca/site/ised/en

Natural Resources Canada – https://natural-resources.canada.ca/home

Statistics Canada – www.statcan.ca

Transport Canada – www.tc.gc.ca



4. Chile

Summary

	Reference			Target		
	2022	2060	% Change	2022	2060	% Change
Macroeconomic						
Population (million)	19.6	22.8	16%	19.6	22.8	16%
GDP (billion 2017 USD, PPP)	489	970	98%	489	970	98%
Energy Demand						
Agriculture & fisheries (PJ)	28	51	83%	28	47	65%
Buildings (PJ)	314	391	24%	314	302	-4%
Industry (PJ)	464	691	49%	464	697	50%
Non-energy (PJ)	6	8	46%	6	7	30%
Transport (PJ)	414	461	11%	414	242	-42%
Modern renewables share of TFEC (%)	20	49	145%	20	75	275%
Energy intensity of TFEC (PJ/GDP, billion USD)	2.5	1.6	-34%	2.5	1.3	-47%
Electricity						
Generation (TWh)	91	193	113%	91	252	178%
Renewables share of generation (%)	55	99.8	81%	55	99.8	81%
Generation capacity (GW)	30	115	287%	30	141	375%
Total Primary Energy Supply (TPES)						
Coal & coal products (PJ)	227	9	-96%	227	2	-99%
Natural gas (PJ)	235	120	-49%	235	129	-45%
Petroleum liquids (PJ)	690	663	-4%	690	172	-75%
Low-carbon & waste energy (PJ)	527	923	75%	527	1,623	208%
CO_2 intensity of energy supply ($MtCO_2/PJ$)	0.050	0.031	-38%	0.050	0.009	-82%
Net CO_2 Emissions (million tonnes)	84	54	-37%	84	18	-79%

Note: In this publication, the term "modern renewables" refers to all renewable energy sources excluding solid biomass in the buildings sector. The term "low-carbon & waste energy" includes all bioenergy, waste-derived energy, renewables, nuclear, and hydrogen-based fuels. Total primary energy supply (TPES) numbers include international bunkers. Net emissions are calculated as gross energy sector combustion CO_2 minus CO_2 captured and stored through carbon capture and storage (CCS).

Key Takeaways

Emissions

- Chile's CO_2 emissions from the energy sector (not considering other greenhouse gases) are close to peak and are projected to decline steadily through 2060 in both the Reference (REF) and Target (TGT) scenarios, driven by the decarbonisation of the power sector.
- In REF, CO_2 emissions fall to 54 $MtCO_2$ by 2060, a 37% reduction from the 2022 level of 84 $MtCO_2$. In TGT, CO_2 emissions fall to 18 $MtCO_2$, representing a 79% reduction from 2022 levels. The 37 $MtCO_2$ gap between the scenarios is equivalent to the annual emissions from approximately 8 GW of coal-fired power capacity operating at a 50% capacity factor.
- The power sector plays a critical role in decarbonisation. In TGT, emissions from electricity generation decline by 91% by 2060, while total electricity output increases by 83%. This outcome is driven by the ambitious adoption of variable renewable energy in power generation, supported by battery storage.

Energy Import Dependence

- Chile remains a net energy importer in both REF and TGT, although its dependence on imported oil and petroleum products is significantly lower in TGT. Oil imports account for 40% of Total Primary Energy Supply (TPES) in 2022. This share declines to 38% by 2060 in REF and drops to just 13% in TGT.
- Beginning in 2040 in TGT, Chile is projected to begin exporting of low-carbon energy, primarily green ammonia derived from renewable hydrogen. Additionally, imports of refined oil products are phased out by 2050. From that point onward, the remaining domestic demand for oil products is met entirely by locally refined crude oil.

Figure 4-1. Net CO_2 emissions (million tonnes)

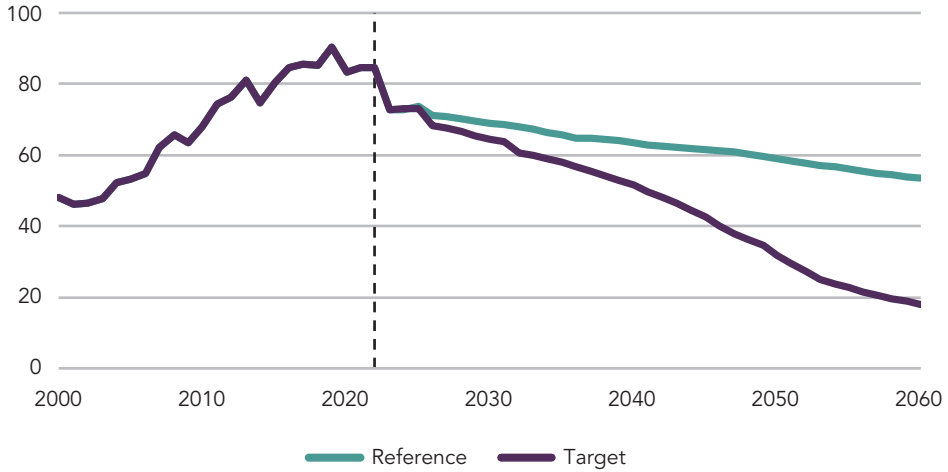
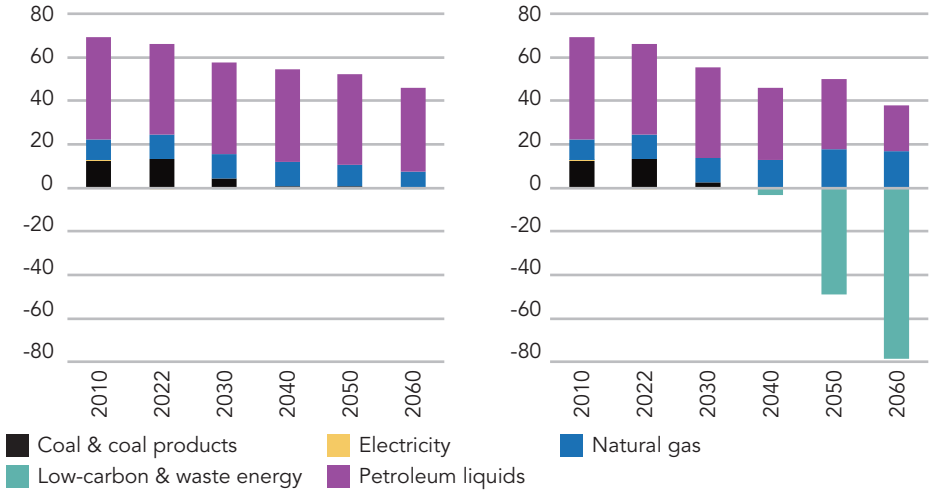


Figure 4-2. Net imports share of TPES in REF & TGT (%)



Note: In Figure 4-2, net imports refer to total imports minus exports and international bunkers.

Key Takeaways

Grid Reliability

- Maintaining grid reliability during the ambitious expansion of variable renewable energy (e.g., solar and wind) requires the retention of dispatchable generation—mainly natural gas, large hydropower, and energy storage.
- A key challenge facing the Chilean electric grid is the increasing gap between minimum and maximum dependence on dispatchable power on an average day in June through August. This gap highlights the importance of dispatchable power for grid reliability as the share of variable renewable energy (VRE) sources increases. Even though dispatchable power is much less needed on an average day in December through February it must be maintained to be used in other parts of the year.
- The cost of maintaining dispatchable power even though it is not needed throughout the year is one reason the cost of electricity rises as the share of VRE increases.

Cost

- Chile will face substantial costs in its energy transition. Under TGT, total costs are projected to reach USD 439 billion, 29% higher than in REF (USD 340 billion). Estimated costs consider the total capital, fixed and operating costs in the power sector, green hydrogen production costs dedicated for domestic demand, transmission for VRE and electric vehicle chargers.
- These costs are primarily driven by the rapid expansion of low-emission power generation such as solar PV and solar CSP, and wind energy. Investments in storage, EV chargers, and transmission also grow significantly under TGT to support a more electrified and decentralised energy system.
- Electricity generation costs rise steadily towards the end of the projection period in both scenarios as amortised capital expenses rise in line with greater renewable deployment.

Figure 4-3. Peak load and maximum and minimum dependence on dispatched power (GW)

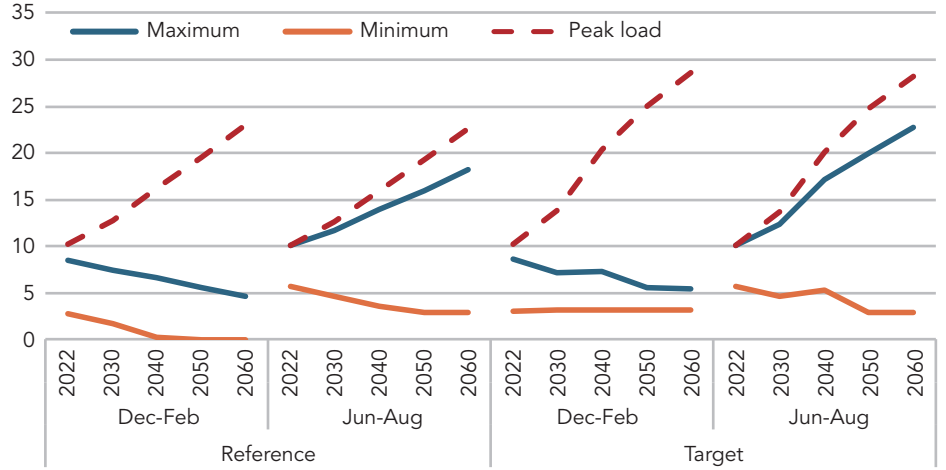
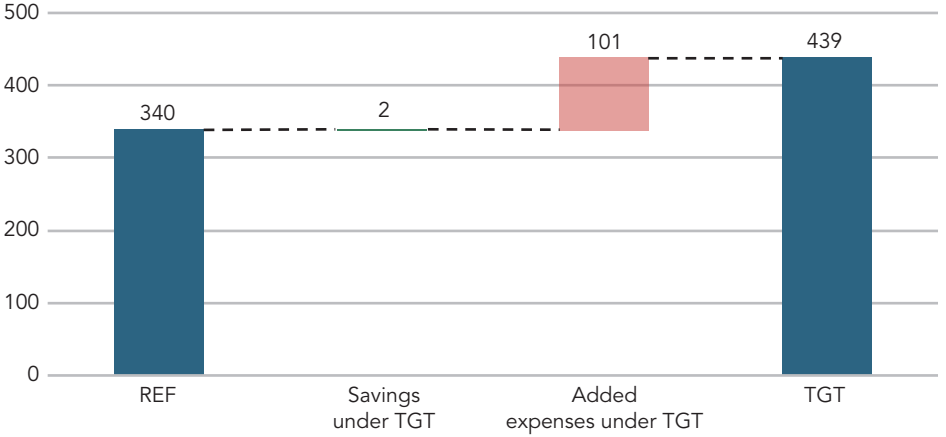


Figure 4-4. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



*Actual costs will differ from estimated costs in the *Outlook* for a variety of reasons including changing commodity prices, manufacturing costs, and unforeseen technical advances. All costs are in 2023 real terms.

About Chile

Overview

Geographical and Economic Landscape

Chile, one of the longest and narrowest economies in the world, stretches from Antarctica in the south to the Atacama Desert in the north. Bordered by Argentina; Bolivia; Peru; and the Pacific Ocean, Chile covers 756,092 km², averaging 175 km in width and 6,435 km of coastline.

Chile is among South America's fastest-growing economies, with an average annual growth rate of 3.2% from 2000 to 2020. In 2020, GDP fell by 5.8% to USD 445.9 billion (2017 USD PPP) and per capita GDP dropped by 6.6% to USD 23,325 due to the COVID-19 pandemic. In APEC, Chile ranks 16th by GDP, 13th by GDP per capita, and 15th by population. It plays a key role in the global energy transition as a major copper and lithium producer.

Energy Supply and Consumption

In 2022, total energy supply reached 1,678 PJ, with 69% from imports—mainly fossil fuels. Domestic production covered the remaining 31%.

Final energy demand rose by 10% to 1,220 PJ, surpassing pre-pandemic levels. Oil demand grew by 5%, reaching 663 PJ; renewable energy increased by 38%, reaching 186 PJ; and electricity rose by 5.5%, reaching 290 PJ. Coal and natural gas use declined slightly, to 19 PJ and 9.7 PJ, respectively.

Energy Security Challenges and Strategies

In 2024, supply disruptions highlighted vulnerabilities in Chile's transmission and distribution system. The issuance of Law No. 21.721 aims to provide a robust framework to strengthen the electricity system and support Chile's energy transition. The law promotes competition and the development of electricity transmission projects. These initiatives may mitigate the impact of severe weather events by ensuring a more reliable electricity system.

Key Energy Initiatives

Net-zero Emissions by 2050

Chile aims for carbon neutrality by 2050. Its updated NDC goals include an unconditional 30% GHG reduction by 2030 (vs. 2016) and a conditional 45% reduction with international support.

Decarbonisation

Chile has committed to phase out coal-fired power generation by 2040, with ongoing evaluation of advancing this target to 2035. Additionally, Chile's 2022 e-mobility strategy targets 100% zero-emission public transport by 2040 and 100% electric light duty vehicles sales by 2035.

Ensuring Energy Security and Energy Efficiency

Chile launched the Energy Agenda 2022-2026. The Agenda promotes equitable access and a clean, secure, and resilient energy system. Law 21.305 Energy Efficiency mandates a five-year energy efficiency plan and large energy consumer regulation.

Expansion of Renewable Energy

Energy Policy 2050 raises the renewables target to 80% of electricity by 2030, with 100% zero-emission energy by 2050.

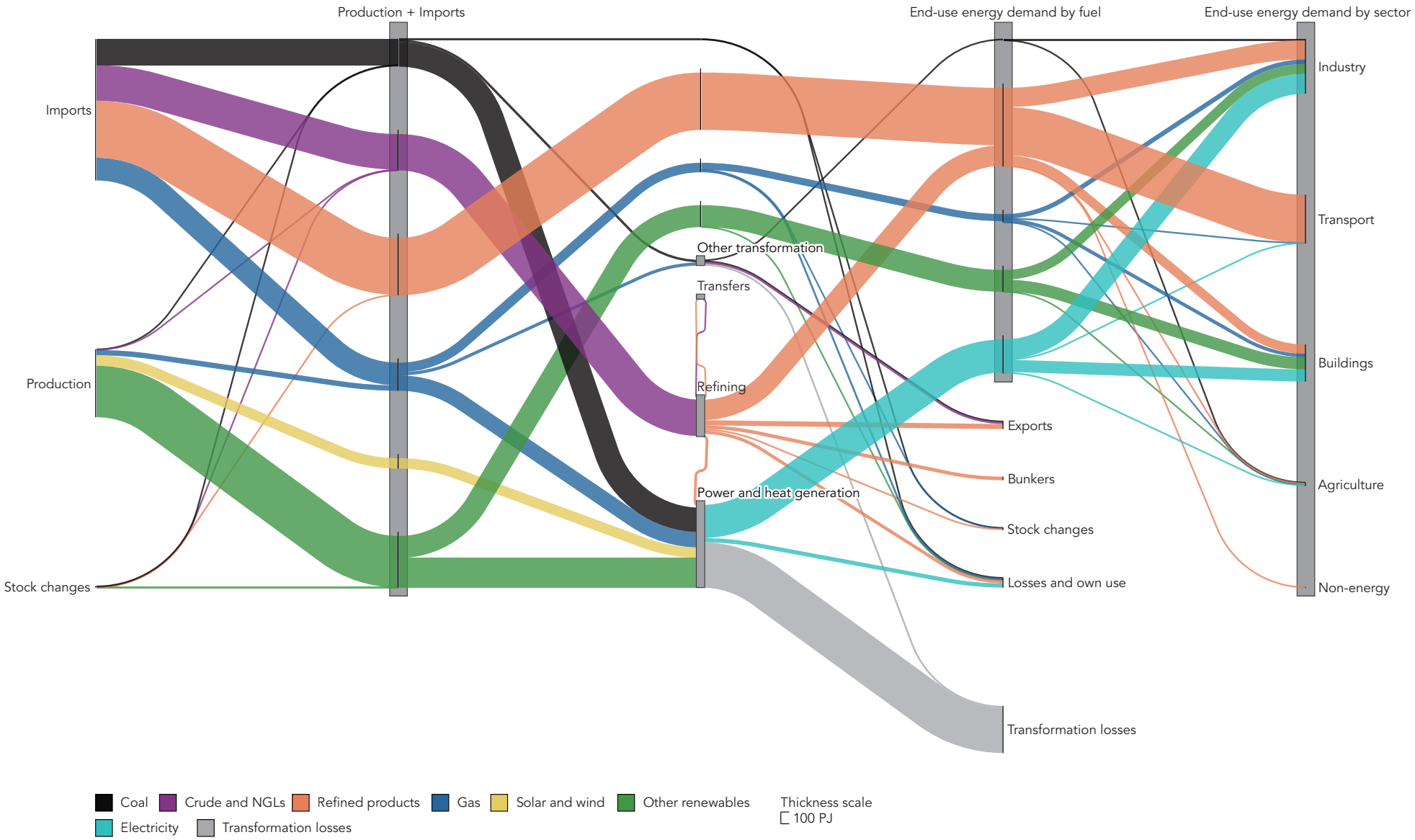
Hydrogen Economy Strategy

Chile's 2020 Hydrogen Strategy, updated with a 2024 action plan, outlines a roadmap for scaling sustainable hydrogen and derivatives through 2030, leveraging the Chile's abundant renewable energy resources.

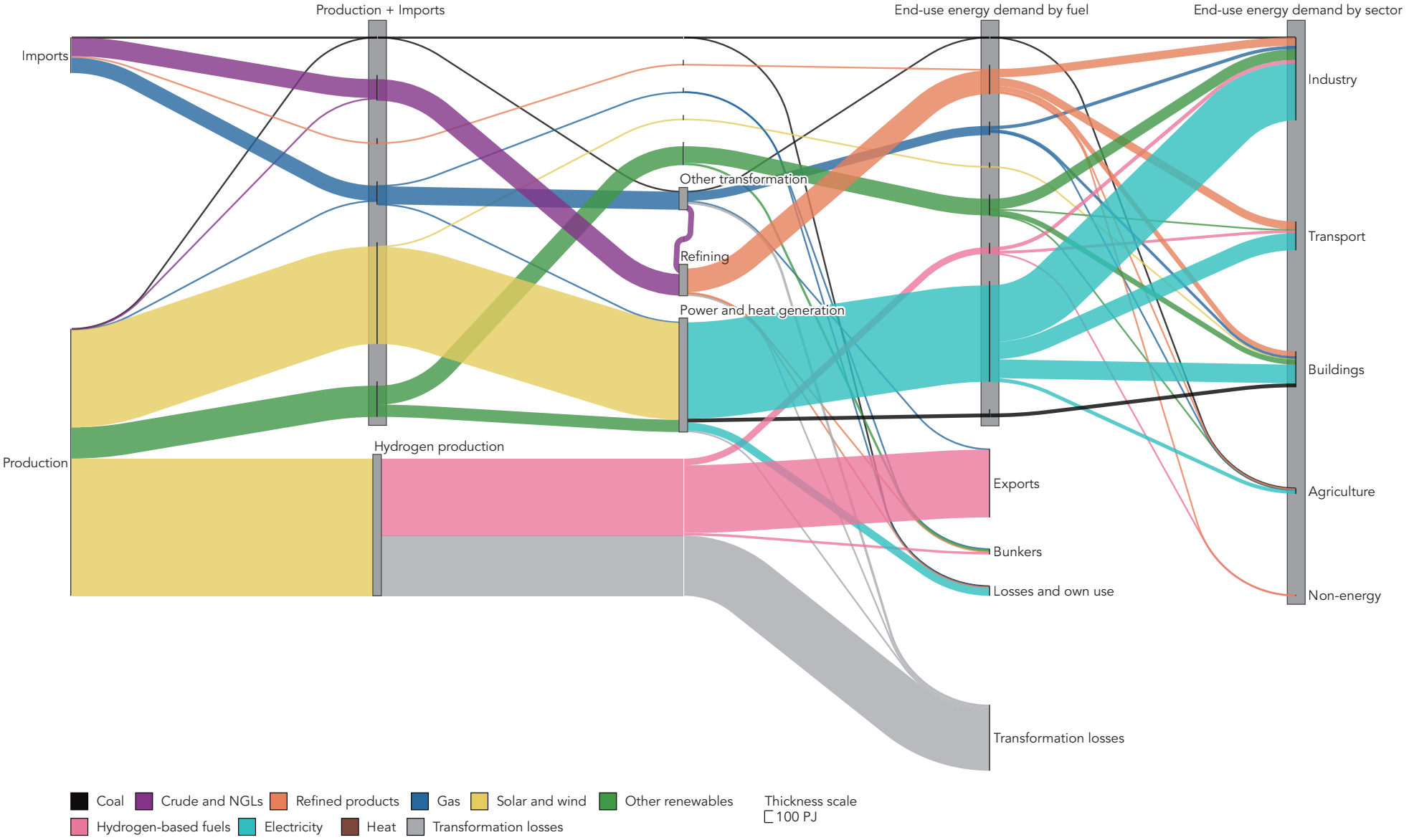
Climate Change Framework Law

Law 21.455 mandates the elaboration of sectorial mitigation and adaptation plans which establishes a binding sectorial emission budget.

Energy Flow (2022)



Energy Flow (2060, Target Scenario)



Scenarios and Assumptions

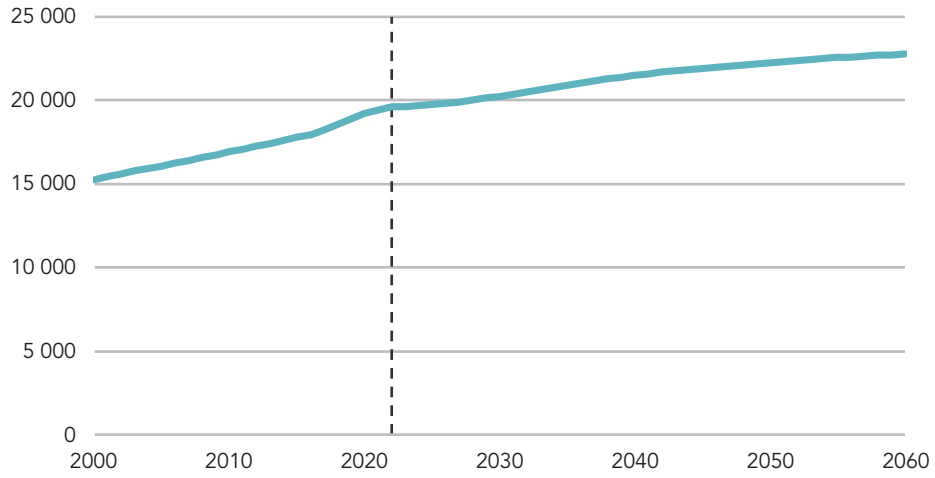
In *The Outlook*, APERC analyses energy demand, transformation, and supply, as well as emissions. The **Reference Scenario (REF)** offers a projection based on historical trends, recent developments, and APERC's assumptions about the continuation of those trends in each APEC economy, while acknowledging technical restraints. The REF Scenario offers a baseline to compare with the **Target Scenario (TGT)** projections, which explores a hypothetical pathway where each economy achieves energy-related policy targets, assuming implementation regardless of cost-effectiveness. When implementation details are lacking, assumptions are inferred from the targets themselves or emissions-related goals.

	Reference	Target
General	• Population: UN medium; GDP: APERC model and IMF	• Population: UN medium; GDP: APERC model and IMF
Buildings	• Traditional biomass is reduced following historical trends, assuming fuel switching to LPG. • Modest electrification in residential and services sectors.	• Stricter efficiency standards for buildings. • Accelerated electrification for heating, cooking, and building systems. • AI and data centre growth is the same in both scenarios.
Industry	• Key manufacturing sectors sustain strong output. • Electricity grows modestly.	• Greater electrification and efficiency. • Hydrogen use for mining, steel and chemical industries expands from the 2030s, scaling faster than in REF.
Transport	• ICE vehicles steadily decline, shifting toward electrification. • Lower emission vehicles (EV, FECV, HEV) grow to represent 10% of the vehicle stock by 2030, 30% by 2050, and 38% by 2060.	• BEVs rapidly grow to 50% of the passenger vehicle stock by 2040 and fully replace ICE vehicles by 2060. • In TGT, the share of low-emission vehicles increases more rapidly, reaching 15% by 2030, 85% by 2050, and 98% by 2060.
Power	• Renewables target 70% of electricity generation by 2030. • Coal is phased out by 2040. • Adoption of energy storage technologies, such as batteries, is primarily determined by cost considerations.	• Energy Policy 2050 raises the renewables target to 80% of electricity generation by 2030, with 100% zero-emission energy by 2050. • Electricity used for hydrogen production is supplied by dedicated renewable energy power plants.
Supply	• No additional fossil fuel reserves are developed. • Refinery capacity is not expanded.	• No additional fossil fuel reserves are developed. • Refinery capacity is not expanded.
Emissions	• While the NDC targets were taken into account, the simulation was not explicitly constrained to achieve them.	• While the NDC targets were taken into account, the simulation was not explicitly constrained to achieve them.

Note: The base year is 2022. Macro-economic assumptions are constant across scenarios. Historical energy balances are from EGEDA submissions for 2022.

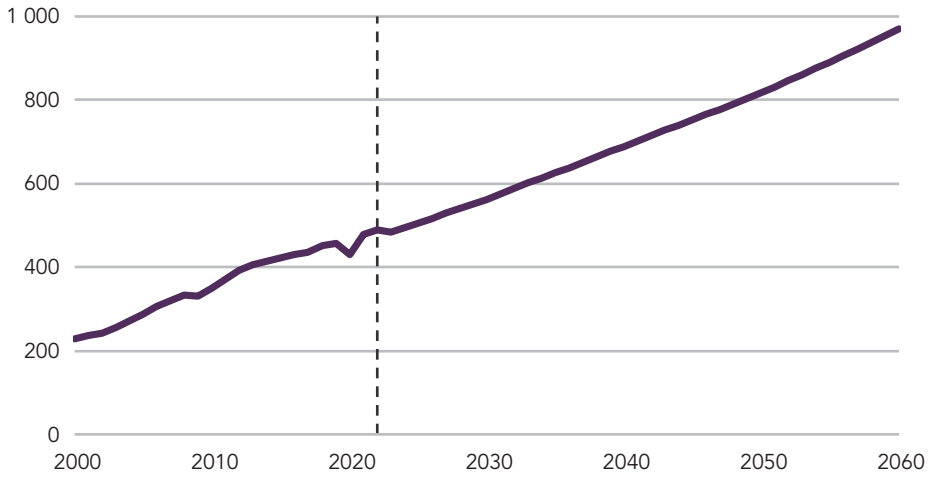
Demographic and Macroeconomic Assumptions

Figure 4-5. Population (thousands)



- Population is expected to surpass 21 million by the early 2040s and 23 million by 2060. While Chile's population continues to grow, the pace is expected to decelerate, with an average annual growth rate of just 0.4% from 2022 to 2060.
- Chile is undergoing a demographic transition period, as its population ages, so demands for services is expected to rise.

Figure 4-6. Real GDP (billion 2017 USD, PPP)



- Real GDP projections follow a two-phase structure. From 2021 to 2027, growth rates align with the IMF's World Economic Outlook (October 2022). Beyond 2027, projections are based on APERC's long-term macroeconomic model, which employs the Solow-Swan growth framework. Without major technological or productivity breakthroughs, economic growth is projected to decelerate gradually as labour force growth slows.
- Average annual real GDP growth is projected at 1.80% (2021–2030), 2.01% (2031–2040), 1.71% (2041–2050), and 1.73% (2051–2060). Chile's real GDP in expected to increase 98% by 2060, compared to 2020 levels.
- As population growth slows and aging accelerates, GDP per capita becomes a more relevant measure of economic progress. Projections suggest that GDP per capita will increase significantly—rising from approximately USD 22,000 in 2020 to over USD 42,000 by 2060—reflecting rising productivity and living standards.

End-use Energy Demand

Figure 4-7. Energy demand by sector in REF & TGT (PJ)

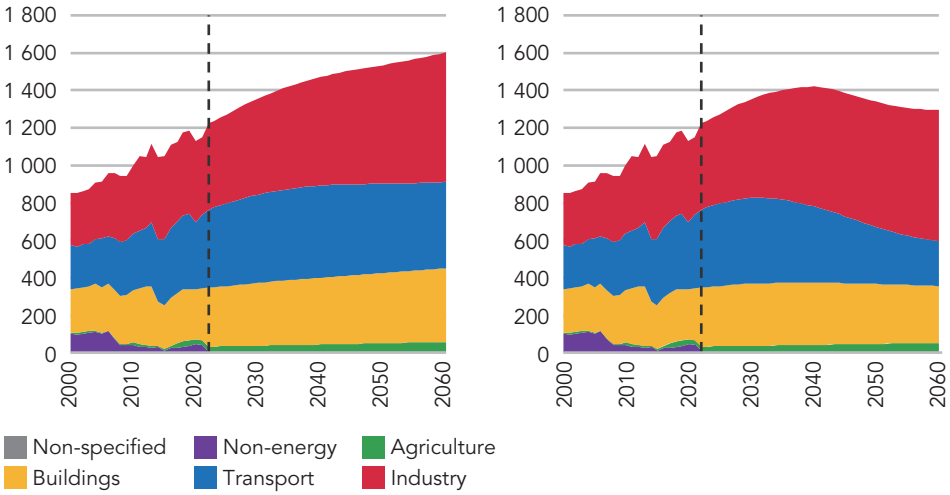
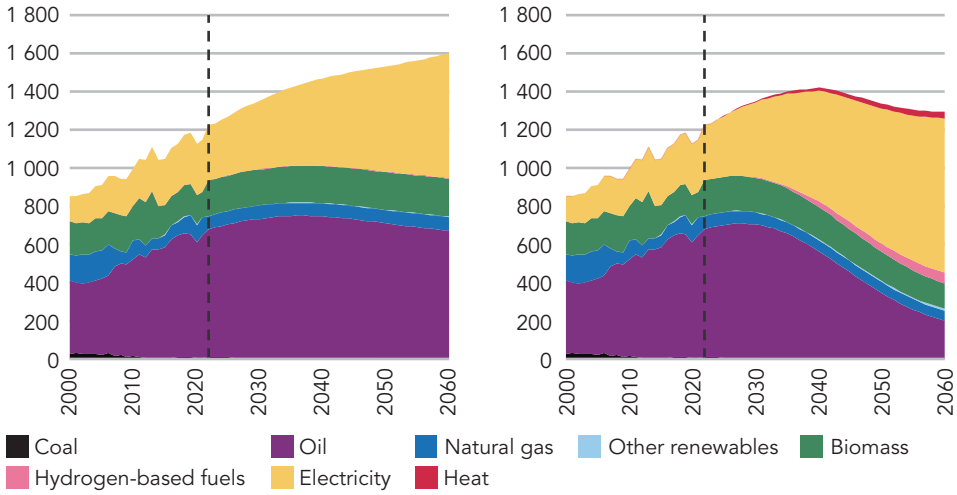


Figure 4-8. Energy demand by fuel in REF & TGT (PJ)



- Due to population and economic growth, Chile is expected to experience sustained energy demand growth in REF, although the growth rate gradually slows. Total final energy consumption (TFC) rises from 1,226 PJ in 2022 to 1,603 PJ by 2060, an increase of 30%. In contrast in TGT, more ambitious energy policies that improve energy efficiency, reduce fossil fuel use, and promote electrification, resulting in energy demand peaking at 1,420 PJ around 2040 and then declining to 1,295 PJ by 2060.
- In REF, transport energy demand grows until 2038, peaking at 490 PJ before slightly declining to 460 PJ by 2060. Building sector demand increases continuously, reaching 390 PJ by 2060. The decline in energy demand in TGT is mainly driven by reductions in the transport and buildings sectors. In TGT, transport demand peaks earlier at 455 PJ around 2030, then drops sharply to 240 PJ by 2060. Building energy use peaks at 330 PJ in the mid-2030s and steadily declines to 300 PJ by 2060.
- Since Chile imports almost all its oil supply, reducing domestic consumption by electrification of transport and industry leveraging Chile's abundant renewable energy potential will lower imports volume. In REF, oil demand peaks at 740 PJ by the late 2030s, then gradually declines to 670 PJ by 2060. In TGT, oil demand grows until the early 2030s but then falls to 200 PJ by 2060.
- Similarly, Chile imports almost all its natural gas demand. In REF, domestic demand remains stable at 70 PJ, while in TGT it peaks early and then gradually declines. This lower natural gas demand in TGT reduces reliance on imported natural gas and reduces pressure on gas and LNG import infrastructure.
- Coal is nearly eliminated in both scenarios, with a faster phase-out in TGT.
- Hydrogen is adopted across multiple sectors, especially in TGT, reaching 56 PJ by 2060, mainly for hard-to-electrify industrial and transport applications.
- TGT also deploys district heating systems in the buildings sector, improving energy efficiency and reducing emissions.

Buildings Energy Demand

Figure 4-9. Buildings energy demand by fuel in REF & TGT (PJ)

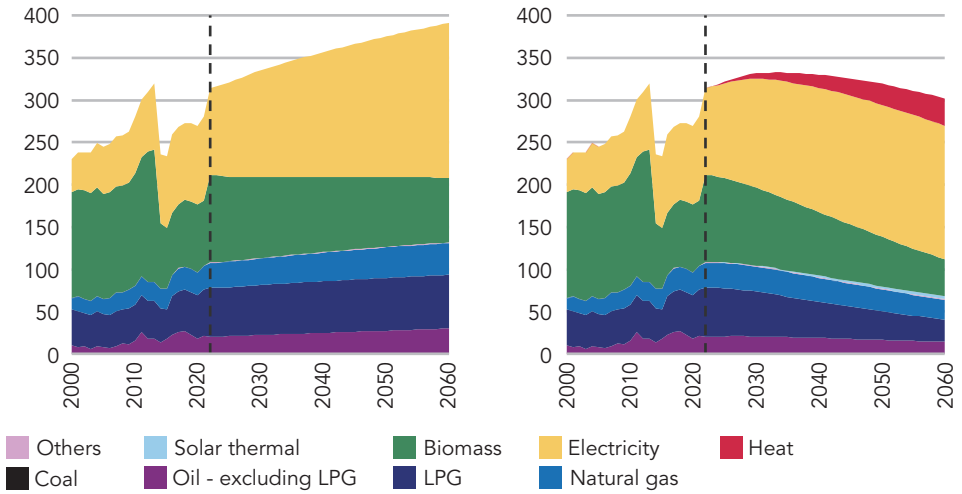
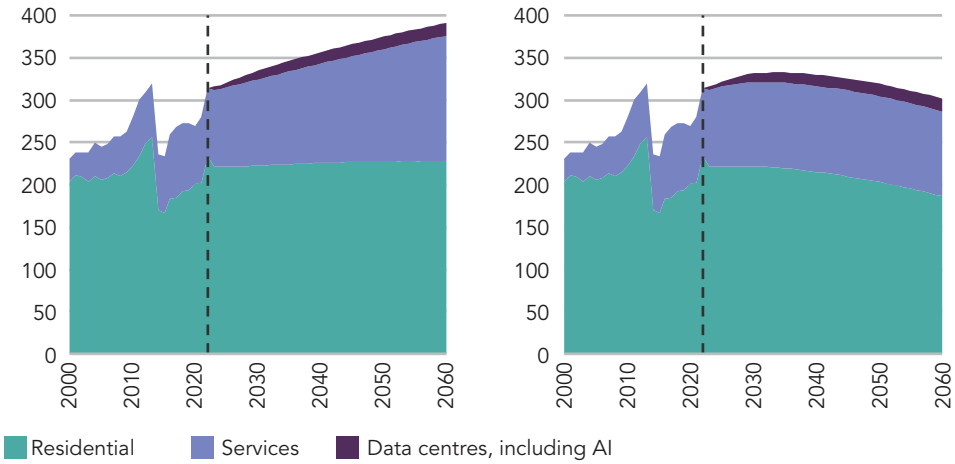


Figure 4-10. Buildings energy demand by sector in REF & TGT (PJ)



- Chile's buildings sector energy use is projected to increase steadily from 314 PJ in 2022 to 391 PJ by 2060 in REF. In contrast, in TGT, demand peaks at 330 PJ around 2030, then declines gradually to 301 PJ by 2060 due to more ambitious energy efficiency measures and electrification.
- Biomass consumption declines in both scenarios, but at different rates. In REF, it falls gradually from 102 PJ in 2022 to 76 PJ by 2060, reflecting a shift toward improved biomass use, particularly in southern Chile. In TGT, biomass demand drops more sharply, reaching 44 PJ by 2050, as building demand electrification accelerates.
- In REF, LPG and other oil products (excluding natural gas), increase from 78 PJ in 2022 to 93 PJ by 2060, mainly driven by growth in the commercial sector. In TGT, both fuels decline significantly, reaching 41 PJ in 2060, reflecting efforts to reduce fossil fuel reliance. LPG and oil products are mainly used for cooking, water heating, and space heating.
- The residential sector remains the largest energy consumer in both scenarios. However, the services/commercial sector shows the most significant growth in demand under REF. Residential consumption rises modestly and stabilises around 227 PJ by 2060, supported by efficiency improvements and slowing population growth. Meanwhile, commercial energy use increases from 81 PJ in 2022 to 149 PJ by 2060.
- Electricity demand from data centres and AI infrastructure is projected to rise from 3.6 PJ in 2023 to 15.5 PJ in 2060 in both scenarios. While modest relative to total demand, this demand is equivalent to the annual electricity consumption of 2.2 million households in Chile, highlighting its growing significance.
- Although limited in overall scale, the TGT scenario includes the deployment of district heating systems specially in southern Chile.

Industry Energy and Non-energy Demand

Figure 4-11. Industry & non-energy demand by fuel in REF & TGT (PJ)

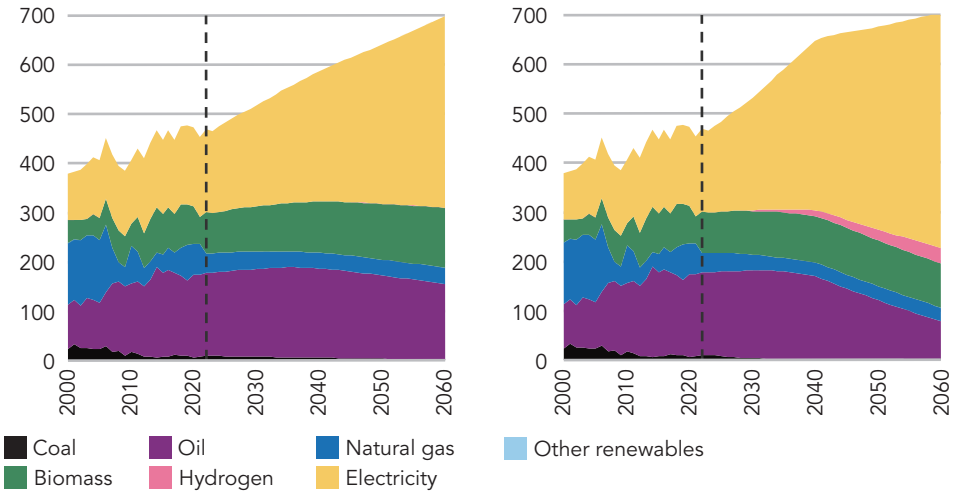
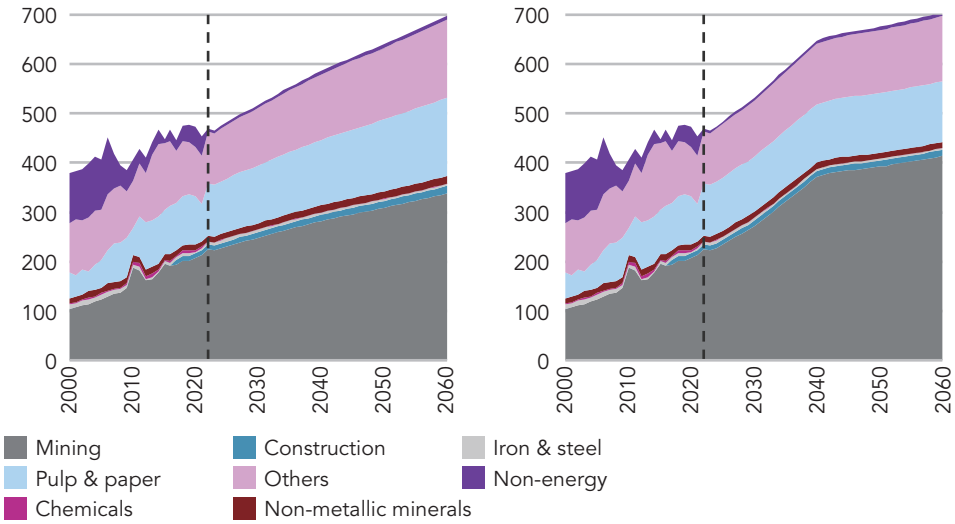


Figure 4-12. Industry & non-energy demand by sector in REF & TGT (PJ)



- Key strategies to manage industrial energy demand include enhancing energy efficiency and substituting fossil fuels with electricity in selected processes.
- Chile's industrial and non-energy demand is the largest demand sector. Demand is projected to increase in both REF and TGT, reaching approximately 700 PJ by 2060. Despite gains in energy efficiency and shifts in the fuel mix, the rise in demand in the TGT scenario is driven by expanding mining activity due to increase of critical minerals exports.

- Electricity becomes increasingly prominent in the industrial sector, rising from 169 PJ in 2022 to 389 PJ by 2060 in REF, and further to 477 PJ by 2060 in TGT. The shift highlights the role of electrification in industrial decarbonisation. Meanwhile, the share of fossil fuels declines steadily: oil and petroleum product demand peaks around 179 PJ in the early 2030s, then gradually declines to 152 PJ by 2060 in REF, while in TGT, it falls more sharply to 77 PJ. Coal demand also drops significantly, reaching 3 PJ in REF and nearly phased out at 0.8 PJ in TGT by 2060. Natural gas use stabilises in both scenarios, plateauing at around 32 PJ in REF and 29 PJ in TGT, suggesting its continued but limited role as an important industrial fuel and feedstock.
- Low-carbon hydrogen emerges as a decarbonisation tool for hard-to-electrify industrial applications in TGT. Its adoption increases after 2030, reaching 32 PJ by 2060. This reflects policy-driven efforts to decarbonise energy-intensive sectors such as mining, where hydrogen can replace fossil fuels in haul trucks, loaders, generators, and other machinery, supporting the broader decarbonisation of industrial production.

Transport Energy Demand

Figure 4-13. Domestic transport energy demand in REF (PJ)

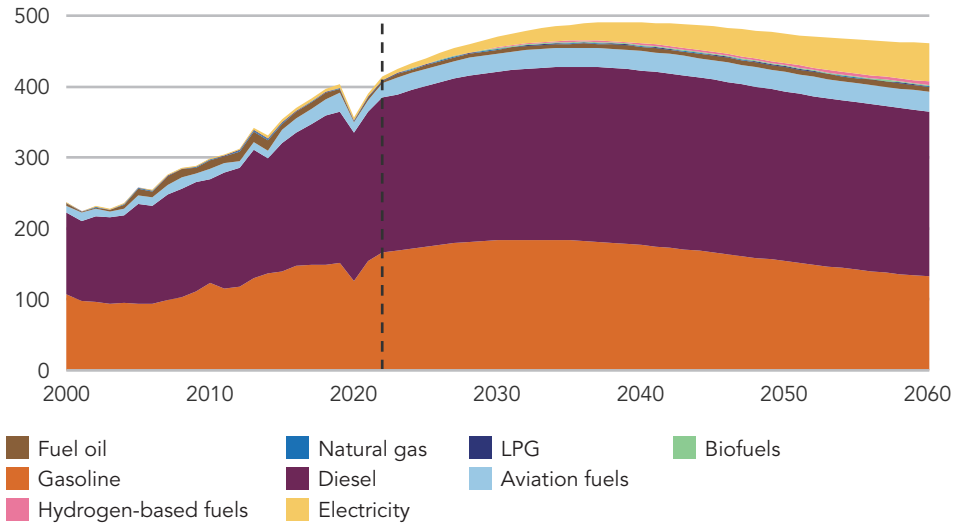
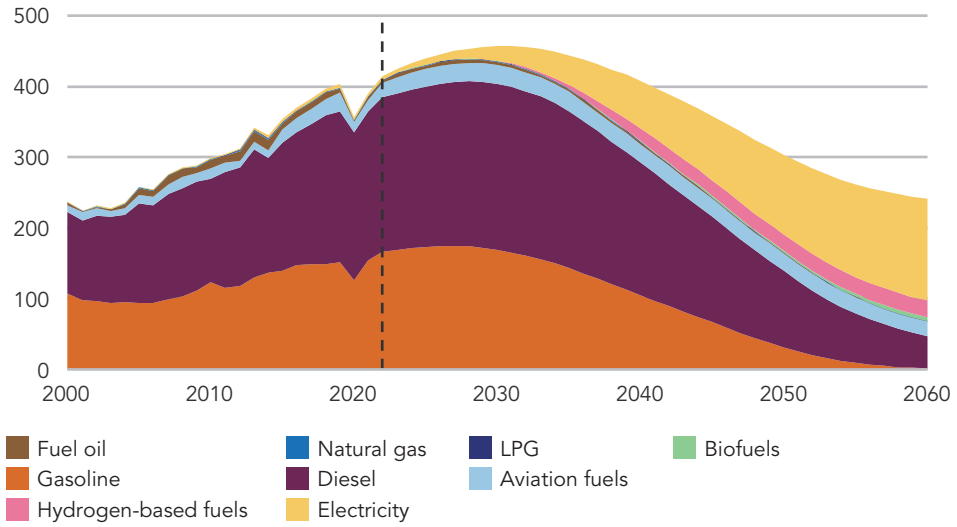


Figure 4-14. Domestic transport energy demand in TGT (PJ)



- In REF, Chile's transport sector remains heavily reliant on imported fossil fuels. Total transport energy demand increases from 413 PJ in 2022 to a peak of around 490 PJ by 2040, before gradually declining to 461 PJ by 2060. In contrast in TGT, energy demand peaks at 457 PJ in 2030 and then declines steadily to 242 PJ in 2060. This trend is driven by moderate modal shifts, such as increased adoption of public transportation, along with the deployment of more efficient vehicles, including electric vehicles (EVs).
- Gasoline, associated with light vehicles, and diesel, associated with heavy-duty vehicles, remain the dominant fuels throughout the REF projection period. In REF, gasoline demand peaks near 2030 at approximately 183 PJ and then declines to 132 PJ by 2060 as EV adoption expands, although growth decelerates over time. Diesel demand peaks around 2040 at 246 PJ and declines to 233 PJ by 2060.
- Electricity consumption in REF increases moderately, as a result of EV adoption, and reaches 54 PJ by 2060. Biofuels and hydrogen contribute to the lower-carbon fuel mix for transport. In TGT, transport electrification is driven by increased adoption of EVs. This is most evident in gasoline demand in TGT, which peaks around 2030 and is nearly phased out by 2060.
- Electrification of diesel-fuelled transport proves more challenging because it is mainly for long-distance heavy-duty transport. Although diesel demand declines significantly, it remains part of the fuel mix, with an estimated 46 PJ consumed in 2060.
- Electricity becomes the most relevant transport fuel in the TGT scenario. By 2060, it supplies approximately 60% of total transport energy demand, reaching 144 PJ. Hydrogen also enters the mix, accounting for 2% of demand—about 5 PJ—equivalent to nearly 290,000 fuel cell electric vehicles (FCEVs) on the road.

Other Transport Data

Figure 4-15. Transport vehicle stocks in REF & TGT (millions)

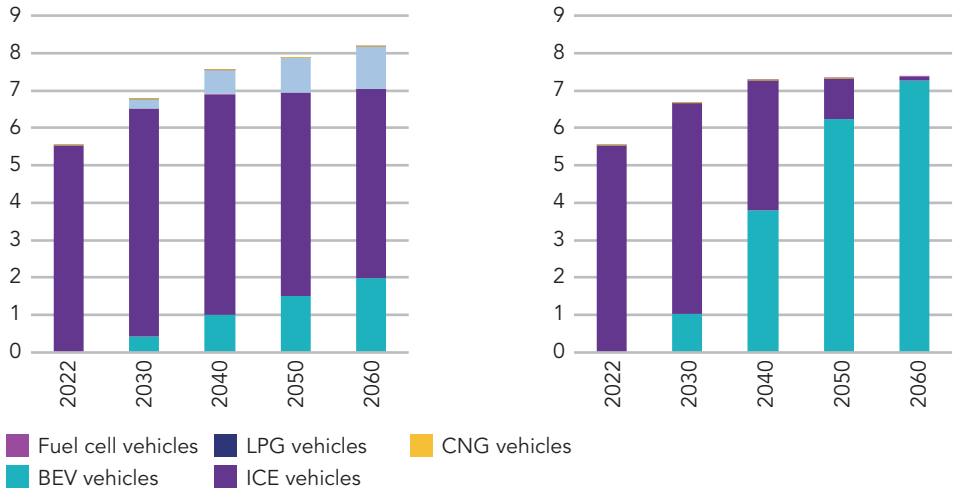
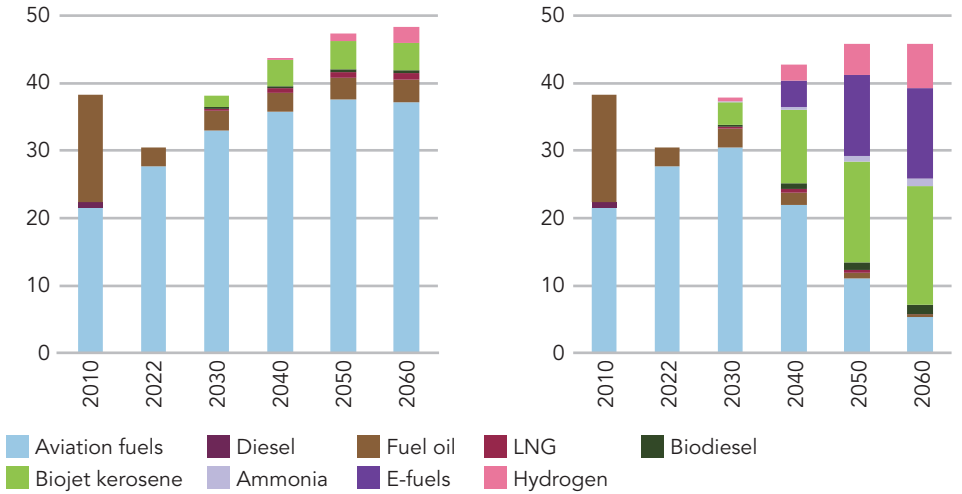
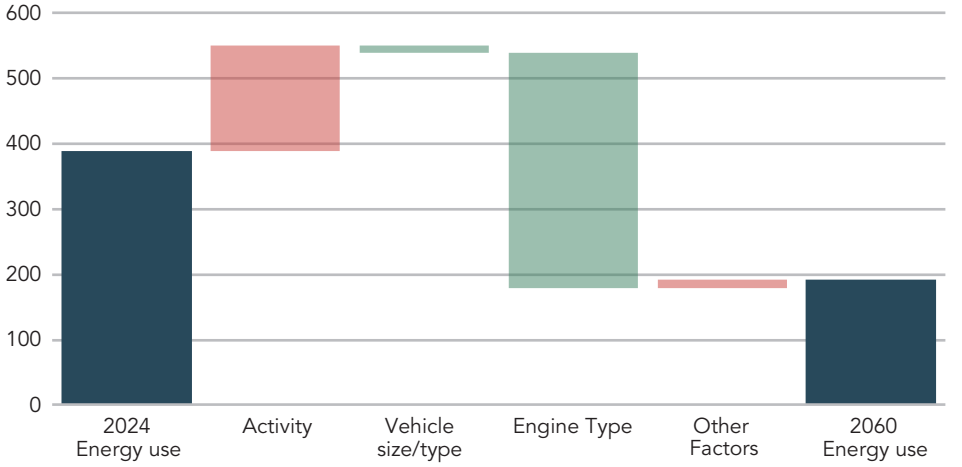


Figure 4-16. International bunker energy demand for shipping and aviation in REF & TGT (PJ)



- Figure 4-15 highlights the impact of market and technology shifts on the decarbonisation of Chile's transport sector. Battery electric vehicles (BEVs), plug-in hybrid electric vehicles (PHEVs), and fuel cell electric vehicles (FCEVs), which are marginal in 2022 under the REF scenario, grow to represent 10% of the vehicle stock by 2030, 30% by 2050, and 38% by 2060. In TGT, their share increases more rapidly, reaching 15% by 2030, 85% by 2050, and 98% by 2060.
- In TGT, there is broader adoption of hydrogen and hydrogen-based fuels, including ammonia, e-fuels, and biojet kerosene bunkers. This scenario assumes that international regulations will require stricter emissions controls for international travel and shipping.
- Figure 4-17 further illustrates that changes in engine technology are the primary driver of reduced energy consumption in the TGT scenario. This is largely due to the widespread adoption of electrified vehicles in Chile, with a smaller but growing role for hydrogen-powered transport.

Figure 4-17. Components of the change in road energy use in TGT (PJ)



Note: Information on the different drivers in the transport energy decomposition can be found in the *Outlook*'s annex.

Electricity Generation

Figure 4-18. Electricity generation by fuel in REF (TWh)

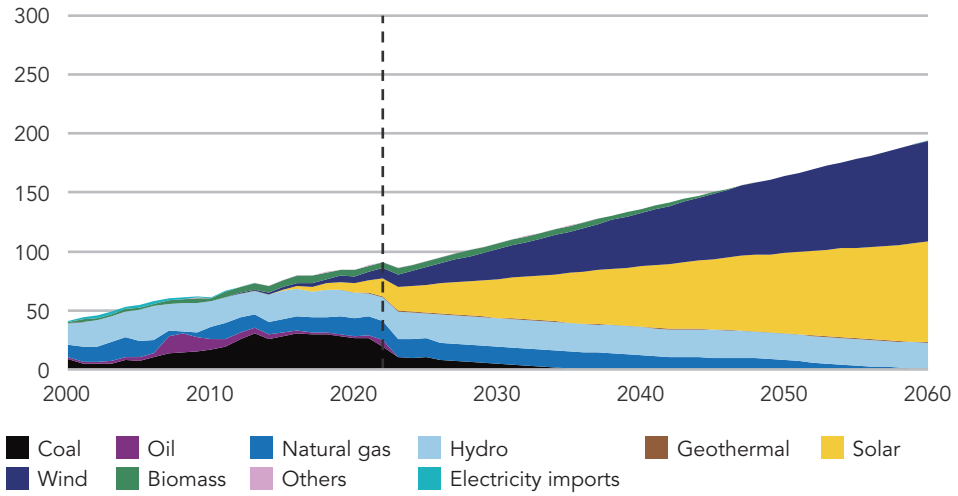
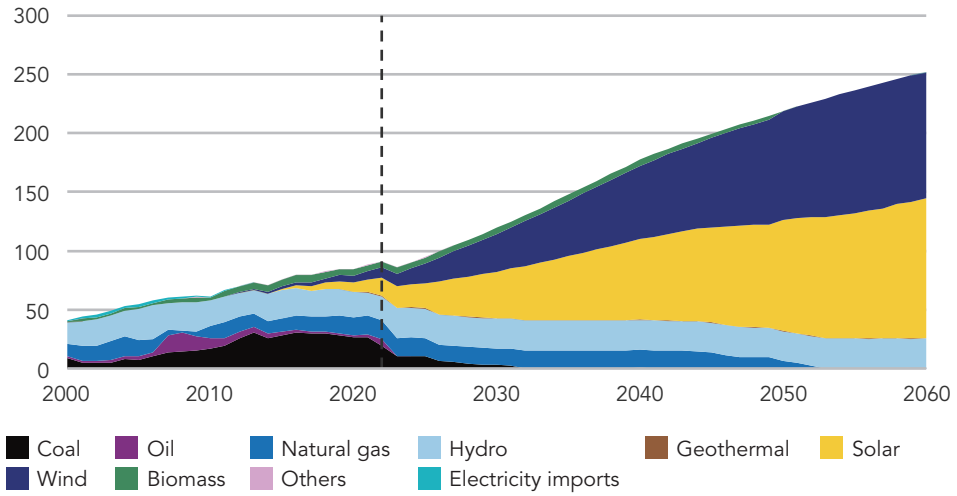


Figure 4-19. Electricity generation by fuel in TGT (TWh)



- Chile's electricity mix has shifted over the past two decades, with the fossil fuel share falling from around 50% in the early 2000s to under 30% by 2024. This reflects Chile's commitment to phasing out coal in power generation by 2040 and scaling up its renewable resources.
- In REF, renewables are projected to supply 60% of electricity by 2030 and 80% by 2050. To meet these targets, solar generation must increase by 63% by 2030 and 240% by 2050, and wind by 119% and 490%, respectively, relative to 2022 levels.
- Coal-fired generation is nearly phased out with its share dropping from 31% to just 2%, primarily due to regulatory measures and plant closures.

- TGT assumes all coal power plants will be closed by 2031, based on negotiated agreements with generators to accelerate plant retirement schedules. A small amount of natural gas generation, around 0.3 TWh, is maintained beyond 2050 to serve small-scale self-producers who lack access to the main electricity grid. Excluding these isolated cases, the main electricity system can be considered 100% powered by zero-emission sources, in line with the 2022 update of the National Energy Policy.
- In TGT, solar generation increases by 135% by 2030 and 445% by 2050, while wind generation increases by 261% and 937% respectively, compared to 2022 levels. These higher levels of variable renewable energy (VRE) deployment create greater grid integration challenges than those projected in REF, requiring enhanced flexibility resources for frequency regulation, voltage support, and renewable energy balancing.

Note: Figures 4-18 and 4-19 do not include electricity generation for hydrogen production.

Generation Capacity

Figure 4-20. Generation capacity by fuel in REF (GW)

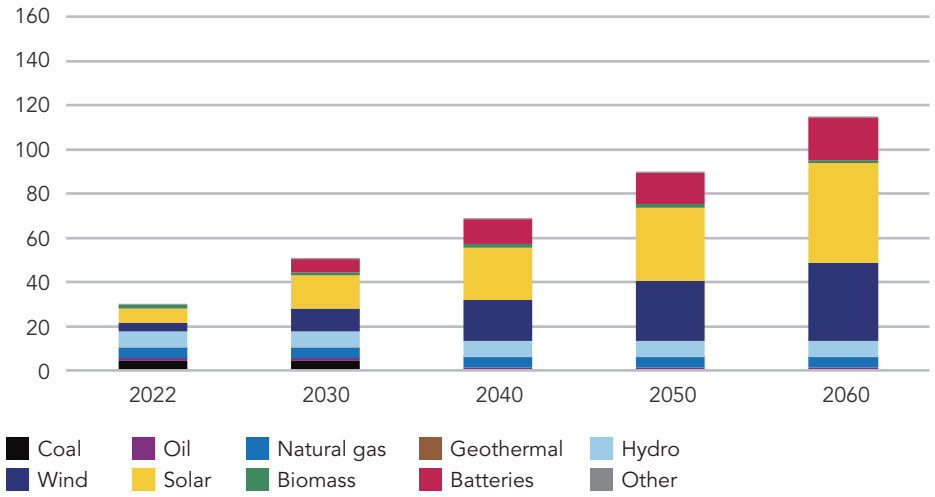
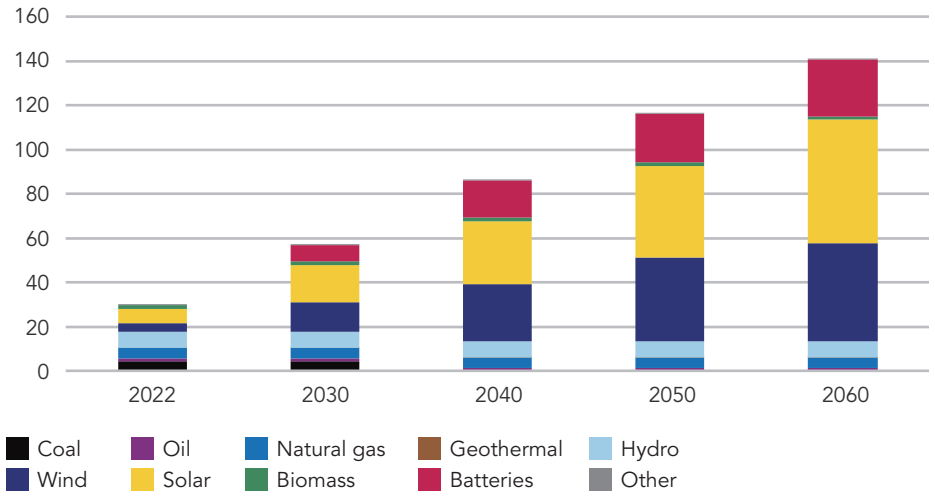


Figure 4-21. Generation capacity by fuel in TGT (GW)



- Expanding variable renewable energy without corresponding investments in transmission and storage infrastructure can significantly increase curtailment, creating a critical bottleneck in the power system. In REF, solar capacity is expected to grow to 15 GW by 2030 and to 33 GW by 2050, while wind capacity rises to 10 GW by 2030 and to 27 GW by 2050. Existing and planned transmission projects—such as the 3 GW Kimal–Lo Aguirre HVDC line that is under development—can help mitigate some of the resulting pressure. However, the pace of transmission development may be insufficient to keep up with the growth in renewable generation. To enhance system reliability and reduce curtailment, energy storage deployment is required, with capacity projected to reach 6 GW by 2030 and 14 GW by 2050.

- In line with the coal phase-out plan, no coal-fired capacity remains after 2040. However, the system retains approximately 1.5 GW of oil-fired capacity and 4.5 GW of natural gas capacity to provide peaking support for grid reliability.
- In TGT, solar capacity is expected to grow from 17 GW in 2030 to 41 GW by 2050, while wind capacity increases from 13 GW to 38 GW over the same period. Energy storage capacity also rises, reaching 7 GW by 2030 and 22 GW by 2050.
- In TGT, all coal-fired power plants are fully retired by 2030, and oil and gas-fired peaking capacity is maintained at the same levels as in REF to maintain reserve capacity.

Note: Figures 4-20 and 4-21 do not include generation capacity for hydrogen production.

Grid Reliability

Figure 4-22. Total generation capacity and peak load (GW)

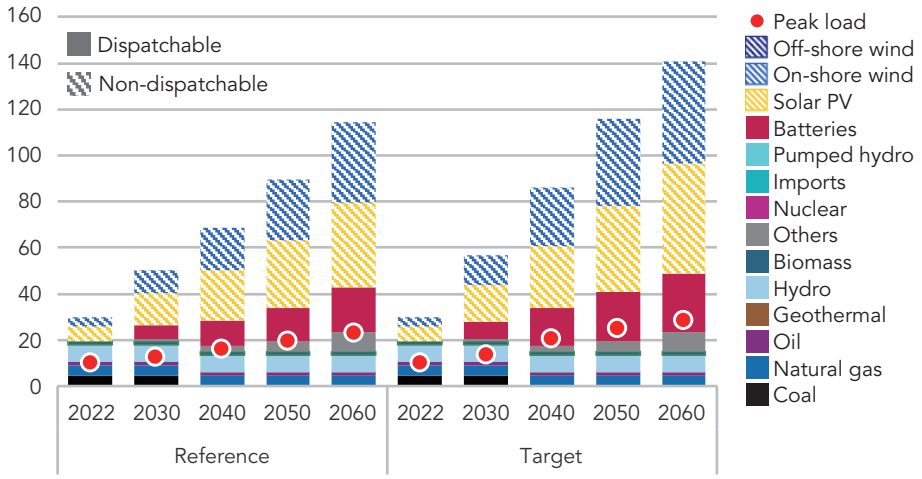
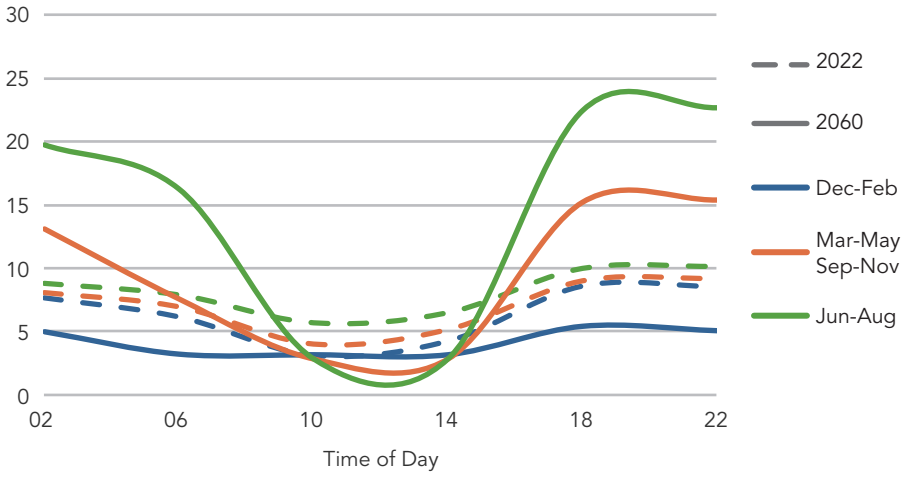


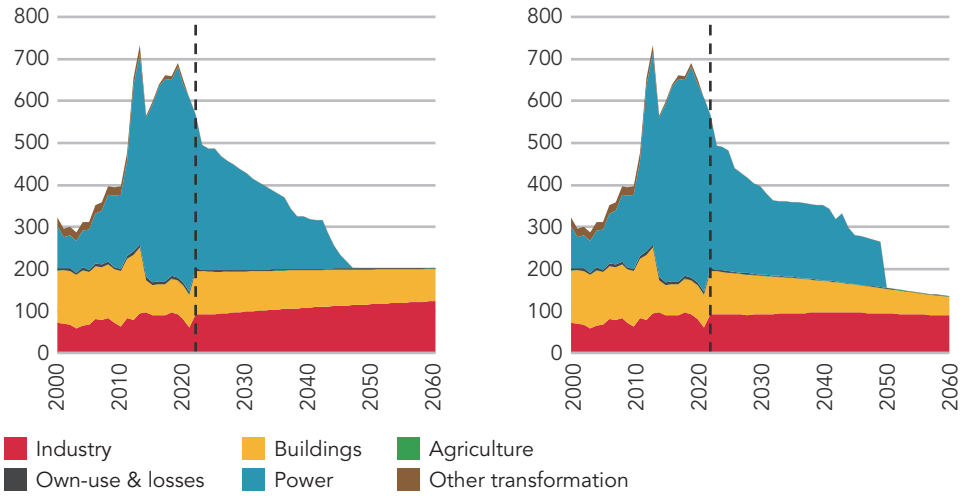
Figure 4-23. Power from dispatchable sources in TGT (GW)



- Chile's electricity grid will require significant expansion of energy storage to support the growing share of VRE and to maintain system reliability. This need arises as the growth of hydropower is assumed to be limited by social, environmental, and regulatory constraints, while Chile's decarbonisation vison limits the construction of new natural gas capacity, emphasising gas as a transitional fuel while prioritising renewable energy and storage technologies.
- The installed capacity-to-peak demand ratio increases from 2.6 in 2020 to 4.7 by 2060 in REF and 4.6 in TGT, reflecting the need for excess capacity to manage VRE variability. In TGT, existing natural gas plants provide backup power and reserve margins to ensure grid reliability when wind and solar resources are low. Both scenarios require substantial energy storage investments, increasing both generation and system balancing costs.
- A key challenge for Chile is the geographic concentration of solar generation in the north and wind generation in the south. This regional disparity poses difficulties for long-distance electricity transmission and for maintaining grid reliability across the economy.
- As shown in Figure 4-23, on an average day between June and August in 2060—when solar output is highest—the system is expected to require over 20 GW of dispatchable power ramp-up between noon and 6:00 pm. Such conditions create a significant flexibility challenge. As the share of VRE increases, this issue is expected to intensify, underscoring the urgent need for investments in grid flexibility, storage infrastructure, and dispatchable back-up generation.

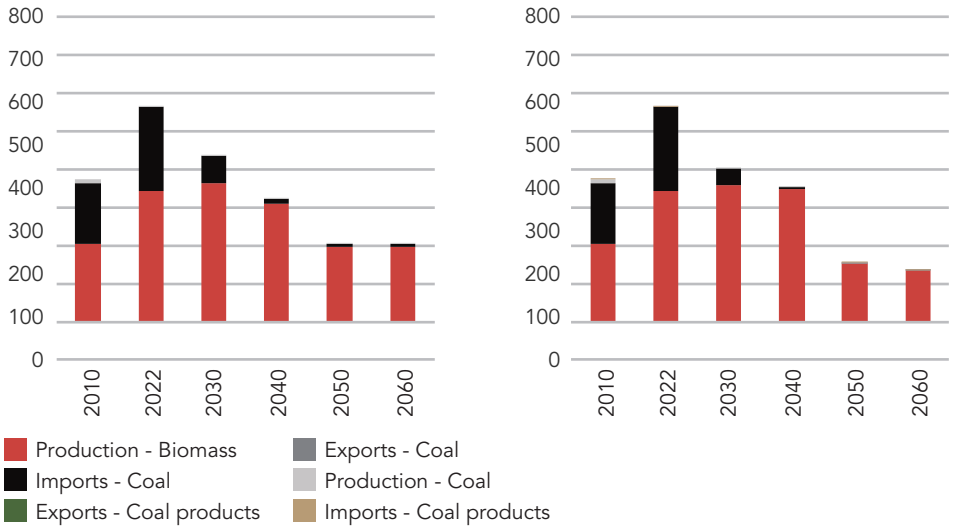
Coal and Biomass

Figure 4-24. Coal and biomass consumption by sector in REF & TGT (PJ)



- Chile's coal supply remains almost entirely dependent on imports, which accounted for nearly all coal consumption in 2022, primarily for power generation. In the REF scenario, coal imports decline by 97%, from 222 PJ in 2022 to just 8 PJ by 2060. The TGT scenario further reduces Chile's reliance on imported coal, virtually eliminating imports by 2060 and thereby increasing Chile's energy security. The phase-out of coal in the power sector is the main driver of this trend, with residual coal use by 2060 limited largely to industrial applications.

Figure 4-25. Coal and biomass production, imports, and exports in REF & TGT (PJ)



- Chile remains self-sufficient in biomass production in both scenarios. However, declining industrial demand drives significant production reduction. In REF, output decreases by 43% by 2060 relative to 2022 levels, while in TGT, the decline is deeper, with output falling by 61% relative to 2022.

Natural Gas

Figure 4-26. Natural gas consumption by sector in REF & TGT (PJ)

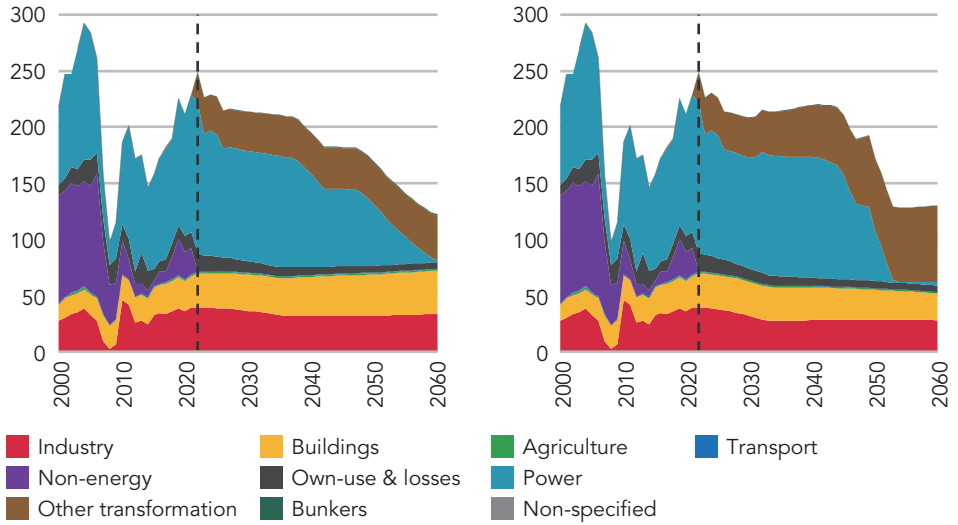
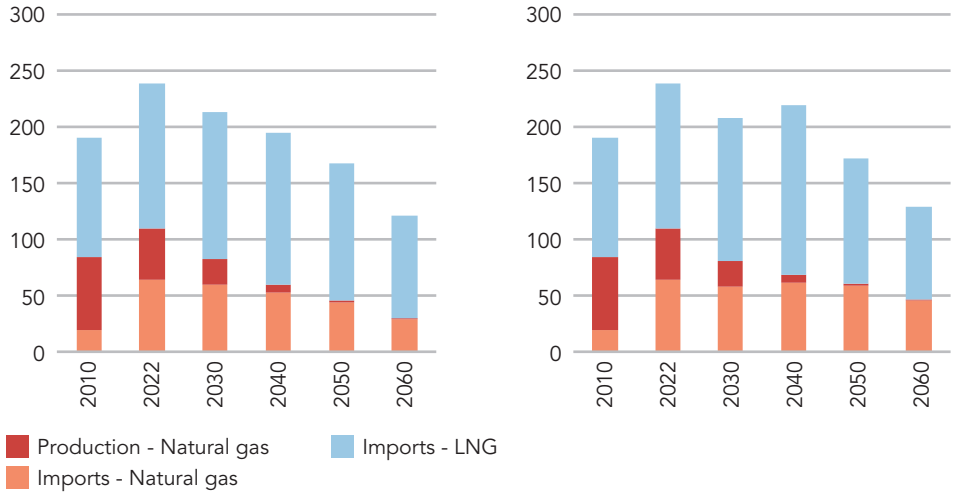


Figure 4-27. Natural gas production, imports, and exports in REF & TGT (PJ)



- The primary drivers of the overall decline in natural gas demand observed in both scenarios are the reduced use of natural gas in the power sector and a more moderate decline in the industrial and buildings sectors. Demand in the TGT scenario is slightly higher between 2040 and 2050, as natural gas is also utilised to support the greater integration of variable renewable energy under higher overall electricity demand.
- Chile relies heavily on natural gas imports, mainly LNG, to meet domestic gas demand. LNG terminals in Quinteros and Mejillones are expected to continue to operate at high-capacity factors through the 2030s and 2040s given the projected domestic natural gas demand in both scenarios, and outputs are expected to gradually decline after 2050.
- Strategic natural gas storage capacity—closely tied to LNG import infrastructure—is currently estimated at 11.4 PJ. Given that average daily demand is projected at 0.6 PJ/day in the scenarios, this corresponds to roughly 19 days of supply, significantly below the internationally recommended 90-day threshold for energy security. Without additional investments in storage infrastructure, this security benchmark is only projected to be met by the late 2050s as gas use declines.

Note: Historical data for LNG is based on JODI gas data.

Petroleum Liquids

Figure 4-28. Crude oil, NGLs, and other hydrocarbons production, imports, and exports in REF & TGT (PJ)

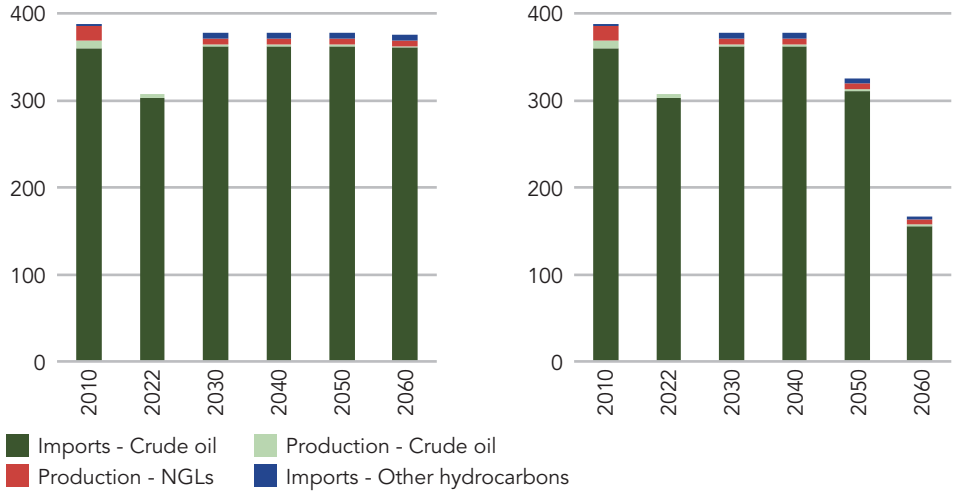
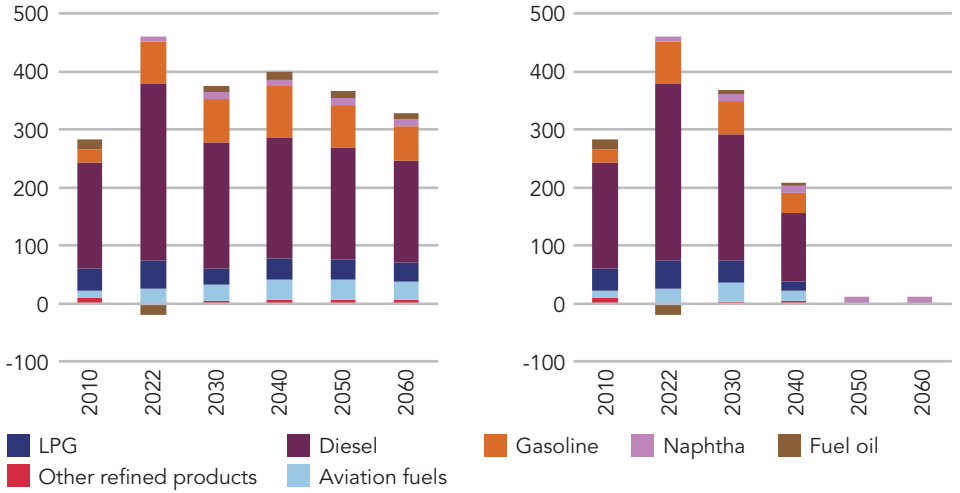


Figure 4-29. Net imports of refined products in REF & TGT (PJ)



- To meet domestic fossil fuel demand, Chile heavily relies on imports of oil and oil products, with import dependency remaining above 95% in both scenarios through 2060. Although demand declines in both REF and TGT, it remains higher than domestic production. In REF, crude oil imports are projected to remain around 360 PJ per year to maintain an 80% refinery utilisation rate and maintain domestically refined products. The decreasing demand for oil products in REF contributes to a gradual reduction in imports of refined products such as diesel and gasoline.
- In TGT, the demand for oil products is even lower due to lower consumption mainly in transport. As a result, crude oil imports begin to decline after 2035, reaching 156 PJ by 2060. In parallel, imports of refined oil products become marginal by 2050, as domestic refineries outputs can meet domestic demand.
- Domestic oil production is expected to remain at historical levels in the short term. However, in REF, production begins to decline after 2040 due to static or depleting reserves. In TGT, domestic production decreases in line with the overall reduction in consumption.
- The growing role of hydrogen and hydrogen-based fuels contributes to the reduction in aviation fuel imports. Additionally, increased electrification of cooking and water heating significantly reduces liquefied petroleum gas (LPG) imports.
- Although Chile has the potential to develop new fossil fuel reserves, it has not increased its proven reserves, consistent with its policy direction to transition away from fossil fuels and toward alternative energy sources such as hydrogen and renewable electricity.

Note: In Figure 4-29, net imports are presented without deducting bunkers.

Refining

Figure 4-30. Refining outputs in REF & TGT (PJ)

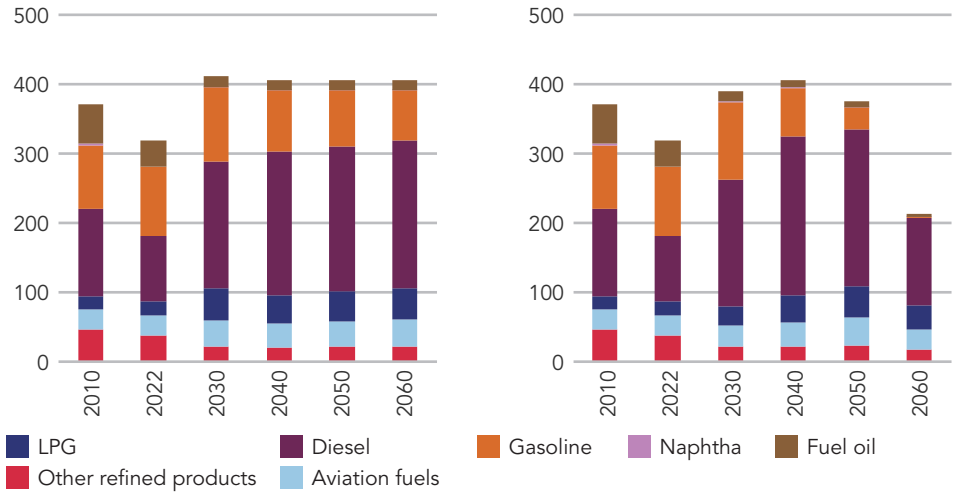
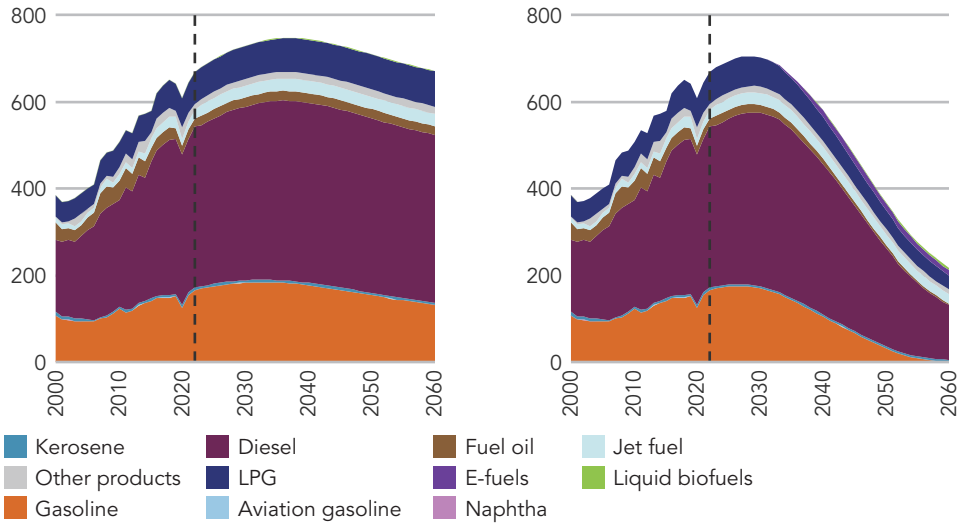


Figure 4-31. Refined products and low-carbon fuels demand in REF & TGT (PJ)



- Chile's current refinery capacity is estimated at 236,000 barrels per day. Diesel and gasoline are currently the main outputs of domestic refineries, but the projected decline in oil product demand may require adjustments to output configurations to better align with changing demand patterns. For instance, in TGT, refineries are projected to increase diesel output relative to gasoline by 2040 to optimise capacity utilisation, as domestic production meets only a portion of diesel demand. In both scenarios, the refinery utilisation rate is assumed to remain at 80% in the long term, with output gradually declining after 2050.
- In REF, gasoline output decreases from approximately 100 PJ to 72 PJ by 2060. In TGT, gasoline output drops dramatically to just 1.4 PJ. In contrast, diesel output remains relatively stable in REF, reaching around 210 PJ by 2060, while in TGT it declines to about 126 PJ.
- These shifts in the refined product mix will require technical and capital adjustments in refinery operations. Refineries currently optimised for gasoline production may become underutilised, necessitating a transition toward configurations that is optimised for maximum diesel production. This may involve investments in hydrocracking, hydrotreating, or residue upgrading units, as well as reevaluating the economic viability of units like catalytic reformers and isomerisation systems associated with gasoline production.
- In TGT, there are no imports of refined oil products after 2050, so the remaining demand is met by domestically refined products.

Hydrogen-based Fuels in the Target Scenario

Figure 4-32. Hydrogen-based fuels production methods and supply [left]; Inputs for hydrogen production [right] (PJ)

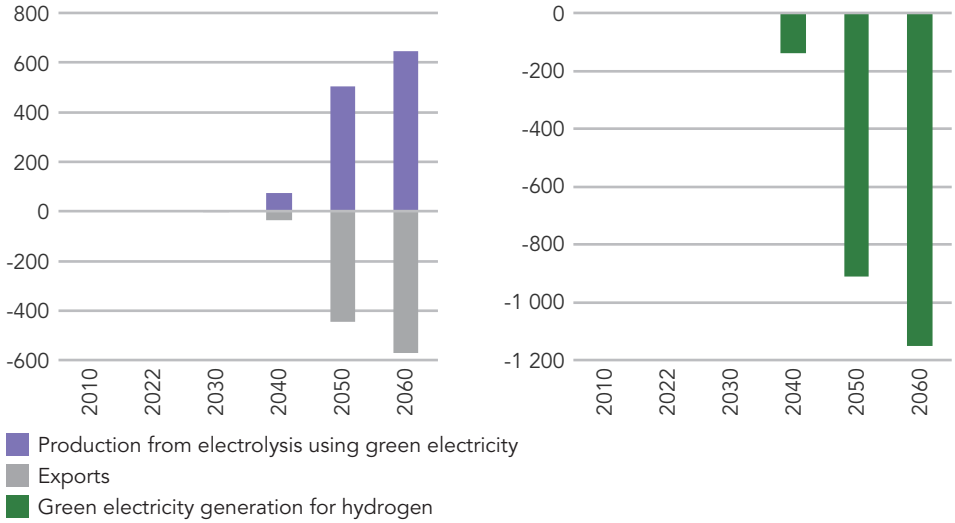
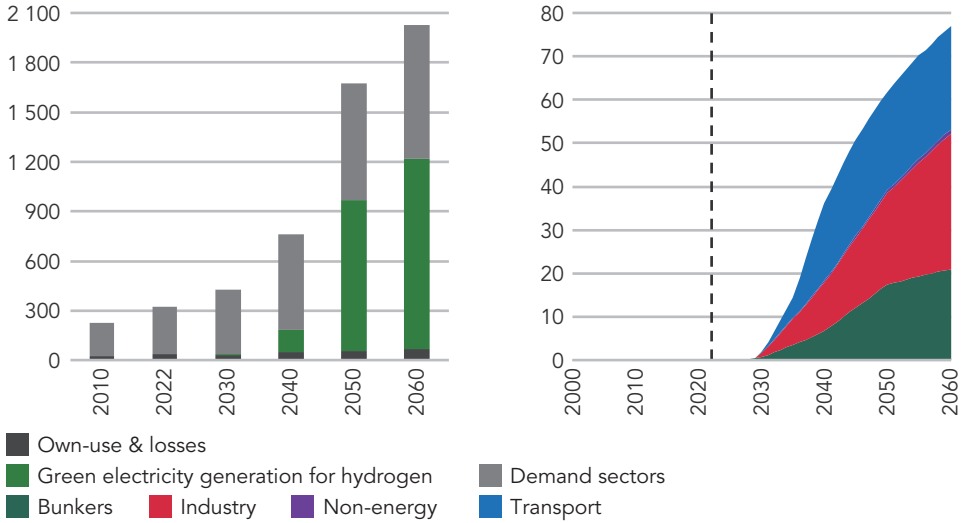


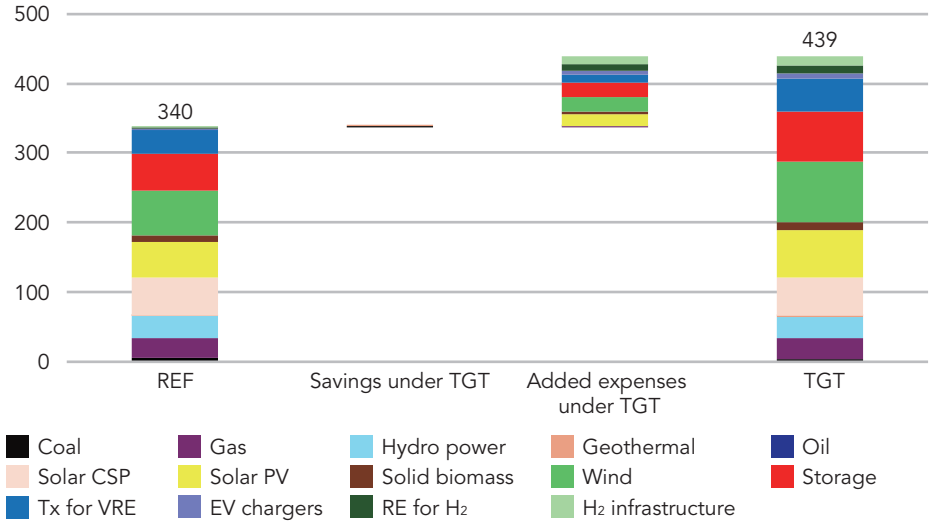
Figure 4-33. Electricity for electrolysis vs other sectors [left]; Hydrogen-based fuels demand by sector [right] (PJ)



- Chile is actively promoting the development of a green hydrogen economy, leveraging its abundant renewable energy resources. Chile's National Green Hydrogen Strategy envisions hydrogen production exclusively through electrolysis powered by renewable electricity. Under the TGT scenario, ammonia exports derived from green hydrogen are projected to reach 2 million tonnes by 2040, 24 million tonnes by 250, and 30 million tonnes by 2060. This level of exports corresponds to roughly 8% of estimated hydrogen imports demand in APEC.
- Domestically, hydrogen demand is expected to reach 77 PJ by 2060. The industrial sector is the main consumer, accounting for 31 PJ, where hydrogen replaces fossil fuels in processes such as mining and on-site transport of materials. The transport sector follows with 24 PJ, and international bunkering and shipping fuels contribute significantly to demand, assuming continued alignment with stricter international emissions regulations.
- To meet TGT hydrogen production, electrolysis will require approximately 1,152 PJ of electricity by 2060, which implies a 132% increase in renewable electricity generation beyond baseline projections. This electricity requires additional capacity of 61 GW of solar and 39 GW of wind power plants. To meet hydrogen demand under the TGT scenario, 3,600 MW of electrolyser capacity, 22,000 MW of ammonia production capacity, and 750 MW of e-fuel production capacity are required.

Costs

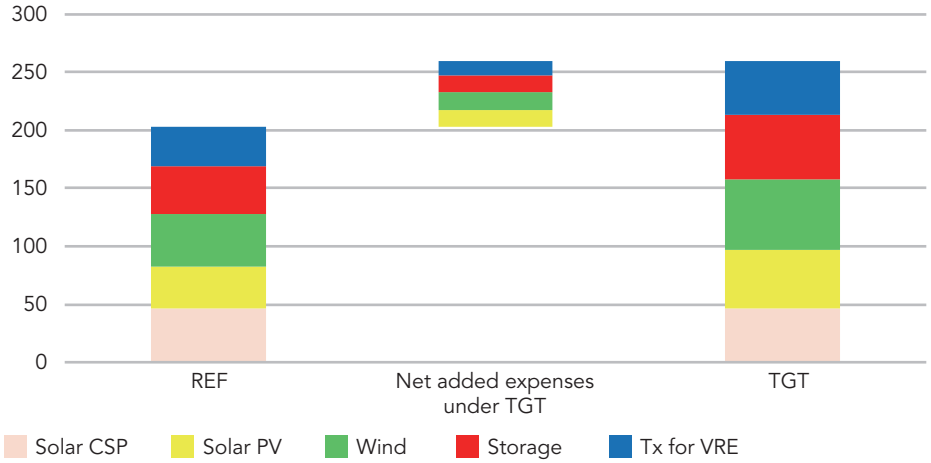
Figure 4-34. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



Note: Tx for VRE is only transmission infrastructure to connect variable renewable capacity to the grid. EV chargers do not cover the cost of associated infrastructure or EV vehicles. Hydrogen costs do not cover costs for bunkering.

- Significant costs will be incurred in Chile's decarbonisation efforts. From 2025 to 2060, total costs rise significantly in both scenarios, including the total capital, fixed and variable costs of power generation, costs for green hydrogen production, EV charger deployment, and transmission for added VRE.
- In REF, total costs reach an estimated USD 340 billion, primarily driven by investments in renewable energy capacity and energy storage solutions. In the TGT scenario, total costs rise to USD 439 billion. Although fossil fuel spending, particularly for coal, declines slightly in TGT, savings are small given the already low use of coal in both scenarios. These savings are offset by significantly higher investments in clean energy technologies such as new solar PV, wind, storage, transmission and expenditure on green hydrogen production for use in industry and transport. The cost for hydrogen production dedicated for exports was not considered as cost recovery is assumed.

Figure 4-35. Total capital investment (CAPEX) from 2025 to 2060 in the power sector (billion USD, undiscounted)

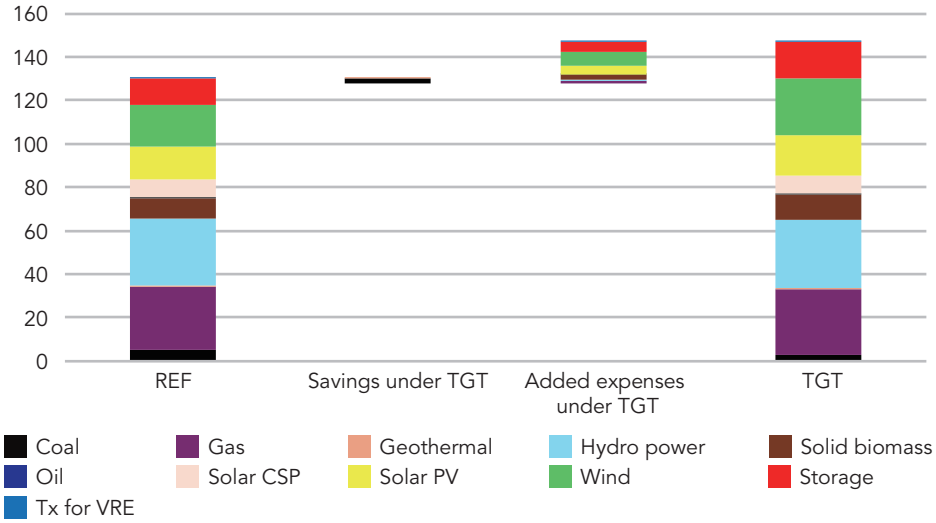


Note: Figure 4-35 only covers power and VRE transmission sector investments. Hydrogen and EV costs are not covered.

- Increased hydrogen usage for transport in TGT will offset conventional fuel consumption, estimating to save USD 13 billion (not shown in Figure 4-34).
- Total capital investment for Chile's power sector is an estimated USD 260 billion in TGT, up from USD 203 billion in REF. This rise is driven by renewable capacity additions (in particular solar PV and wind capacity), expanded transmission capacity, and storage deployment to accommodate a growing share of variable renewables.
- Investment in energy storage also increases to support dispatchable supply and ensure its availability during peak demand periods These results emphasise the importance of timely and strategic investment to ensure grid stability and support a reliable and affordable energy transition.

Costs

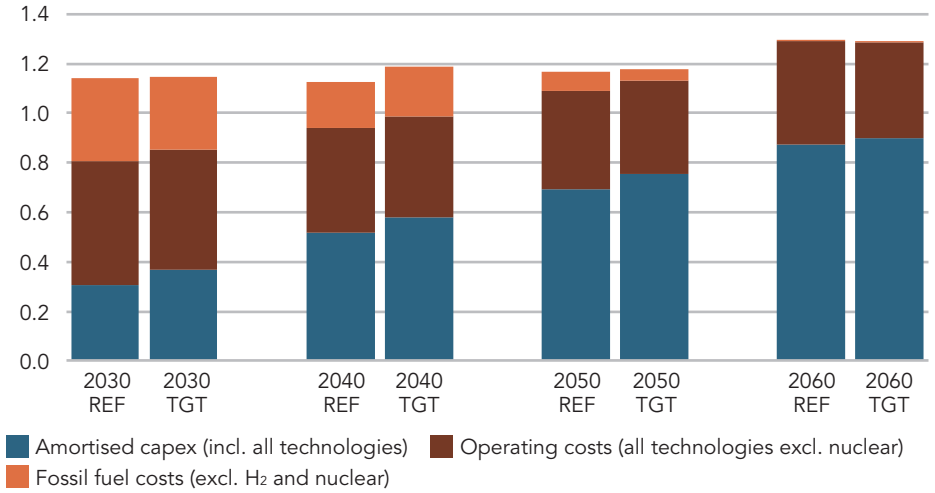
Figure 4-36. Total operating costs from 2025 to 2060 in the power sector (billion USD, undiscounted)



Note: Figure 4-36 covers power and VRE transmission sector costs. It does not include operating costs associated with hydrogen production and EV charger costs.

- Chile's total operating costs for the power sector are projected to be an estimated USD 147 billion under the TGT scenario, compared to USD 130 billion in REF. The largest cost items are variable fuel expenditures, with coal and gas-fired generation together being the largest cost component in both scenarios due to their role in ensuring system reliability, especially up until 2050 (before usage starts to decline as storage grows in prominence).
- However, the bulk of total costs will come from the operational costs involved in managing the renewable build out and existing hydro power plants.
- These projections highlight the sustained operational burden of a decarbonised pathway. Effective fuel management, especially for fuel inputs, will be essential to maintaining economic efficiency while supporting Chile's energy transition to low emissions energy sources.

Figure 4-37. Cost of generating electricity relative to 2025 (2025 cost = 1.0) in the power sector



Note: Based on our assumptions about future capital and operating costs, Figure 4-37 shows cost compositions over time relative to 2025. It should not be considered an estimate of electricity tariffs and excludes market mechanisms that are too difficult to estimate.

- Chile's electricity generation cost, indexed to 2025 (Figure 4-37) is relatively stable in both REF and TGT, although a 25% increase is expected toward the end of the projection period. The decrease in the share of fossil fuel expenditure is more than offset by the increased share of amortised capital costs (CAPEX) resulting in overall cost increases over time. Amortised capital costs (CAPEX) rise steadily in both scenarios due to a rise in investment in renewables. which become the dominant cost component in both scenarios.
- The cost structure of Chile's generation costs will reflect a decarbonised grid, where electricity generation is sourced entirely from renewables by 2060.
- To note, Figure 4-37 estimates the cost of electricity generation only and does not include difficult-to-project market mechanisms such as network, fees, local taxes, retail fees that could become significant in an electric grid based on a low share of fossil fuel.

CO_2 Emissions

Figure 4-38. CO_2 emissions in REF (million tonnes)

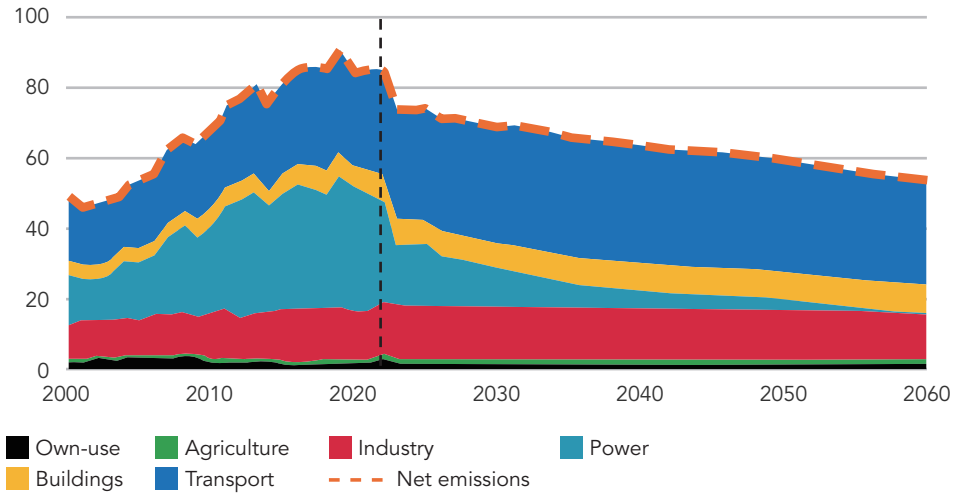
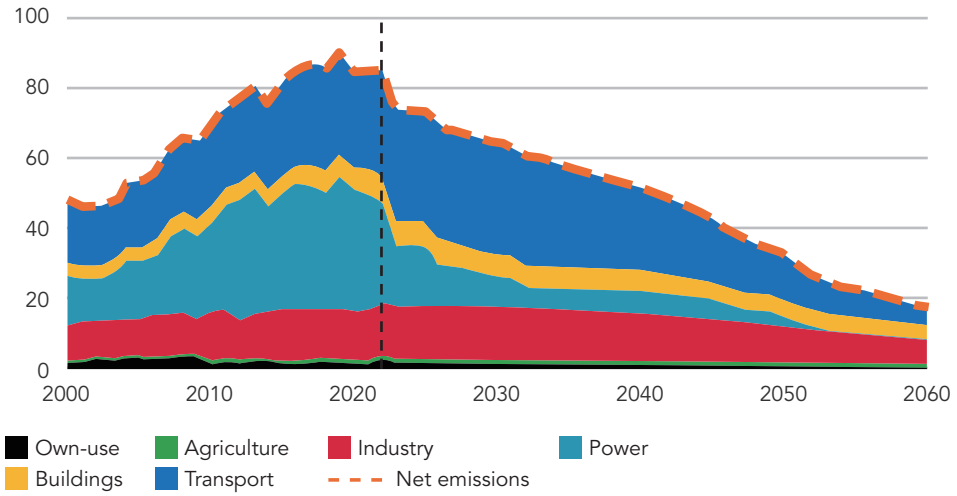
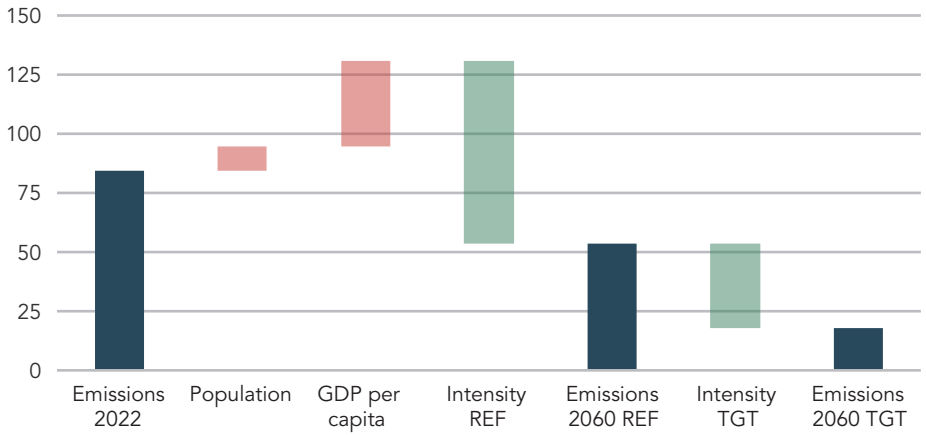


Figure 4-39. CO_2 emissions in TGT (million tonnes)



- CO_2 emissions are projected to decline by 2060 in both the REF and TGT scenarios, reflecting Chile's various decarbonisation efforts. However, the reductions fall short of achieving carbon neutrality, highlighting the need for additional mitigation measures.
- Emissions reductions are primarily driven by energy efficiency improvements and electrification across the industry, buildings, and transport sectors. The power sector plays a critical role, particularly in the TGT scenario, where accelerated deployment of low-emission generation enables deeper cuts.
- As shown in Figure 4-40, emissions changes from 2022 to 2060 are largely influenced by improvements in energy and carbon intensity, which help offset the upward impacts from economic growth. In the TGT scenario, these improvements are more pronounced, supported by policy measures and technology adoption.

Figure 4-40. CO_2 emissions components (million tonnes)



Note: All values represent energy sector combustion CO_2 emissions. Biogenic CO_2 is treated as zero at the point of combustion.

Useful Links

APEC Expert Group on Energy Data and Analysis (EGEDA) – https://www.egeda.ewg.apec.org/

APEC Energy Statistics 2022 – https://www.egeda.ewg.apec.org/egeda/general/info/pdf/APEC_Energy_Statistics_2022.pdf

APEC Energy Overview – https://aperc.or.jp/reports/energy_overview.php

Department of Economic and Social Affairs of the United Nations (UNDESA) Population Division – https://www.un.org/development/desa/pd/data-landing-page

Energy Balance – http://energiaabierta.cl/visualizaciones/balance-de-energia/

Energy Institute Statistical Review of World Energy – https://www.energyinst.org/statistical-review

International Monetary Fund/World Economic Outlook Database – https://www.imf.org/en/Publications/WEO/weo-database/2022/October

Ministry of Energy – https://energia.gob.cl/

Ministry of Energy-Planificación Energética de Largo Plazo – https://energia.gob.cl/pelp

World Bank Open Data – https://data.worldbank.org/



5. China

Summary

	Reference			Target		
	2022	2060	% Change	2022	2060	% Change
Macroeconomic						
Population (million)	1,425.9	1,080.6	-24%	1,425.9	1,080.6	-24%
GDP (billion 2017 USD, PPP)	25,558	70,074	174%	25,558	70,074	174%
Energy Demand						
Agriculture & fisheries (PJ)	2,090	2,007	-4%	2,090	1,787	-14%
Buildings (PJ)	14,451	22,509	56%	14,451	18,390	27%
Industry (PJ)	46,527	38,316	-18%	46,527	35,516	-24%
Non-energy (PJ)	12,662	16,064	27%	12,662	14,374	14%
Transport (PJ)	12,641	11,941	-6%	12,641	8,668	-31%
Modern renewables share of TFEC (%)	11	37	236%	11	52	373%
Energy intensity of TFEC (PJ/GDP, billion USD)	3.2	1.2	-63%	3.2	1.0	-69%
Electricity						
Generation (TWh)	8,849	13,468	52%	8,849	13,903	57%
Renewables share of generation (%)	30	67	123%	30	72	140%
Generation capacity (GW)	2,666	7,998	200%	2,666	8,765	229%
Total Primary Energy Supply (TPES)						
Coal & coal products (PJ)	95,068	31,535	-67%	95,068	17,679	-81%
Natural gas (PJ)	13,584	26,386	94%	13,584	18,420	36%
Petroleum liquids (PJ)	28,770	21,555	-25%	28,770	14,952	-48%
Low-carbon & waste energy (PJ)	16,998	68,228	301%	16,998	81,050	377%
CO_2 intensity of energy supply ($MtCO_2/PJ$)	0.062	0.031	-50%	0.062	0.018	-71%
Net CO_2 Emissions (million tonnes)	9,599	4,473	-53%	9,599	2,303	-76%

Note: In this publication, the term "modern renewables" refers to all renewable energy sources excluding solid biomass in the buildings sector. The term "low-carbon & waste energy" includes all bioenergy, waste-derived energy, renewables, nuclear, and hydrogen-based fuels. Total primary energy supply (TPES) numbers include international bunkers. Net emissions are calculated as gross energy sector combustion CO_2 minus CO_2 captured and stored through carbon capture and storage (CCS).

Key Takeaways

Emissions

- China's energy sector is poised for substantial gross CO_2 emissions reductions, driven by improved energy intensity, end-use electrification, fossil fuel displacement by renewables and nuclear, and carbon capture and storage (CCS) deployment.
- With its robust commitment to decarbonisation, China's 2030 carbon peak target is anticipated to be realised ahead of schedule in both scenarios.
- As 100% post-combustion carbon capture is technically and economically unfeasible with current technologies, achieving China's 2060 net-zero goal will require additional carbon sink measures across energy and non-energy sectors.

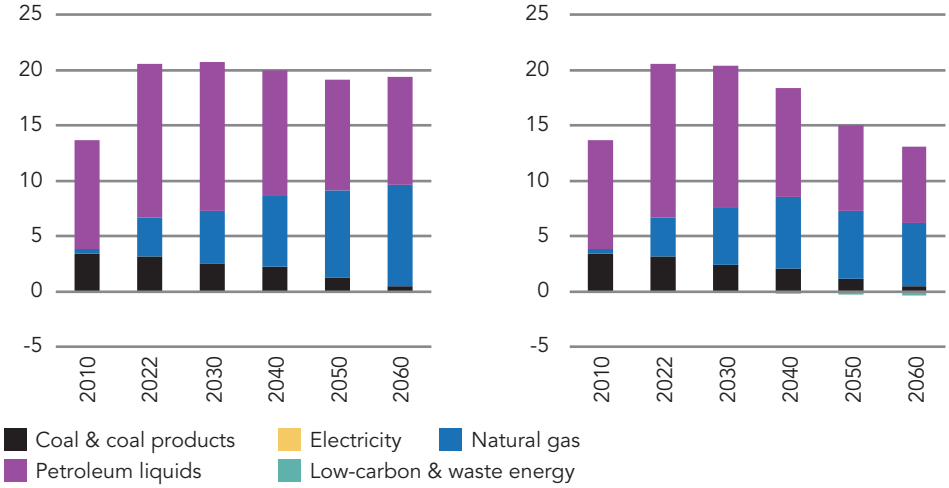
Figure 5-1. Net CO_2 emissions (million tonnes)



Energy Import Dependence

- Safeguarding energy security is the prerequisite for building China's modern energy system. The share of domestic supply within TPES is projected to remain above 78%. Coal has been and will continue to be the ballast of China's energy supply in the medium term. As primary energy supply diversifies, renewables and nuclear will play increasingly important roles as the key pillars of energy supply.
- China is expected to continuously improve domestic exploration and overseas investment in crude oil and natural gas resources, while also optimising its refineries' product structure, to mitigate import dependency. As total consumption decreases, crude oil and petroleum product imports will experience a steady decline.
- The share of natural gas imports differs noticeably between the two scenarios. In the Reference scenario (REF), gas supply continues to grow, primarily driven by demand for flexible and comparatively low-carbon dispatchable power. In the Target Scenario (TGT), alternative fuels and storage technologies are expected to offset gas demand.

Figure 5-2. Net imports share of TPES in REF & TGT (%)



Note: In Figure 5-2, net imports refer to total imports minus exports and international bunkers.

Key Takeaways

Grid Reliability

- Increasing electricity demand, higher penetration of intermittent renewable power, and the integration of diverse end-users with new load behaviours all pose significant challenges to grid stability and operation.
- In China, peak load from the demand-side, typically in summer, is projected to grow over 60%. To compensate for variable output of solar PV and wind, dispatchable power sources will be required to participate in more extensive load following operations, as shown in the expanding difference between max and min power.
- To address these challenges, China is employing a systematic approach to enhance grid reliability, including improving the flexibility of coal and hydro power plants, building baseload nuclear, increasing gas power and storage capacity, enhancing intelligent grid operations, and promoting electricity market reform.

Cost

- The total costs for the power and hydrogen sectors from 2025 to 2060 are estimated to be USD 5.1 trillion higher overall in TGT compared to REF, marking an 18% growth. The total costs consider the total capital, fixed, and variable costs in the power sector, costs for heat generation, costs for green hydrogen production, transmission for variable renewable electricity, and electric vehicle chargers.
- The cost of generating electricity from China's wind and solar PV projects has achieved remarkable reductions, driven by rapid technological advancements and industrial capacity ramp-up. However, investors face increased uncertainty regarding risks and returns. Various incentives are essential for the sustainable growth of renewables capacity.
- Investments in securing grid reliability will further raise the overall cost for power supply. These higher costs could be mitigated by an effective cost-sharing mechanism.

Figure 5-3. Peak load and maximum and minimum dependence on dispatched power (GW)

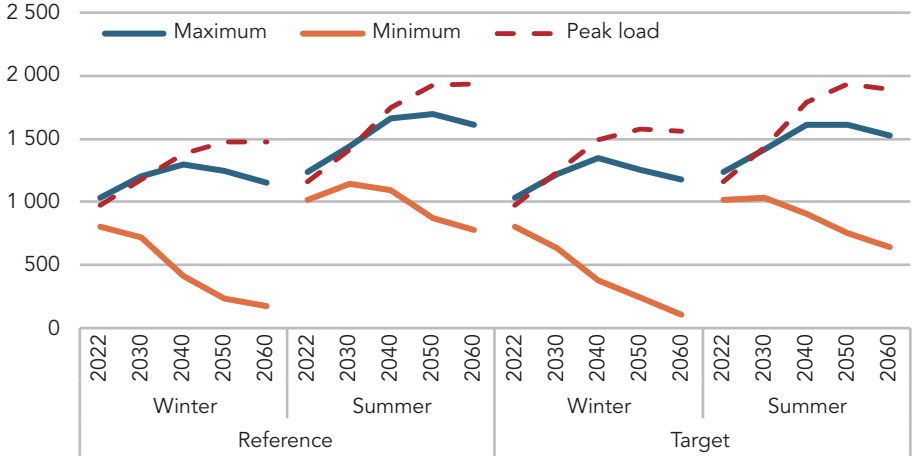
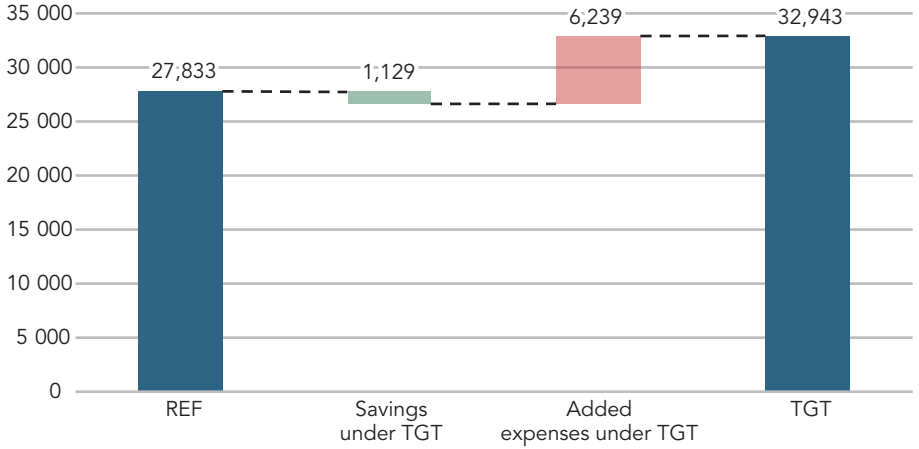


Figure 5-4. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



*Actual costs will differ from estimated costs in the *Outlook* for a variety of reasons including changing commodity prices, manufacturing costs and unforeseen technical advances. All costs are in 2023 real terms.

About China

Overview

Geographical and Economic Landscape

The People's Republic of China is located in eastern Asia, on the west coast of the Pacific Ocean. It has a land area of approximately 9.6 million square kilometres with diverse landscapes consisting of mountains, plateaus, basins, and plains. The majority of that land area is in the north temperate zone.

As of 2022, China has a population of 1.4 billion and a real GDP of USD 17.96 trillion, making it the second-largest economy in the world.

Energy Supply and Consumption

China is the largest energy producer and consumer in the world. Its energy supply mix is steadily transitioning from fossil fuels towards low-carbon alternatives. In 2022, coal, oil, and gas represented 62%, 19%, and 8.8% of the total primary energy supply, respectively, while renewables consisted of 7.7%. China is self-sufficient regarding coal production, but its oil and natural gas supply relies heavily on imports.

China's final energy consumption is steadily increasing and shifting towards electrification. The industry sector, including non-energy, occupies almost half of the total final consumption. Coal dominates the power sector, and hydro is the largest source of renewable electricity. Meanwhile, China is leading the world in solar PV, wind, and nuclear capacity expansion. China's new energy vehicle (including electric vehicles, hybrid electric vehicles, fuel cell electric vehicles, etc.) output and sales are also topping the global rankings.

Energy Security Challenges and Strategies

The evolving global landscape and heightened market uncertainties present risks to energy supply chains and resource access. The transition in electricity generation and load profile also challenges the security of power supply.

China is enhancing the stability and security of its energy supply chain through three key approaches: strengthening strategic security by improving domestic production and diversifying import channels, elevating the operational safety levels of energy infrastructure, and enhancing emergency response capabilities.

Key Energy Initiatives

Decarbonisation Commitment

China has announced peaking carbon dioxide emissions by 2030 and achieving carbon neutrality by 2060. The government prioritises energy conservation and efficiency improvement, while strictly limiting fossil fuel consumption, promoting non-fossil energy sources, and deepening market reform.

New Energy Security Strategy

In 2014, President Xi Jinping proposed the "New Energy Security Strategy" aimed at revolutionising consumption, supply, technology, and institutions, while strengthening all-around international cooperation.

Expansion of Renewable Energy

China has set ambitious targets to raise renewable energy consumption by 30% by 2025 from 2023 levels, and by another 36% by 2030 from 2025 levels.

Constructing a New Power System

To support the energy transition, China aims to construct a new power system that is safe, efficient, clean, low-carbon, resilient, flexible, and intelligent.

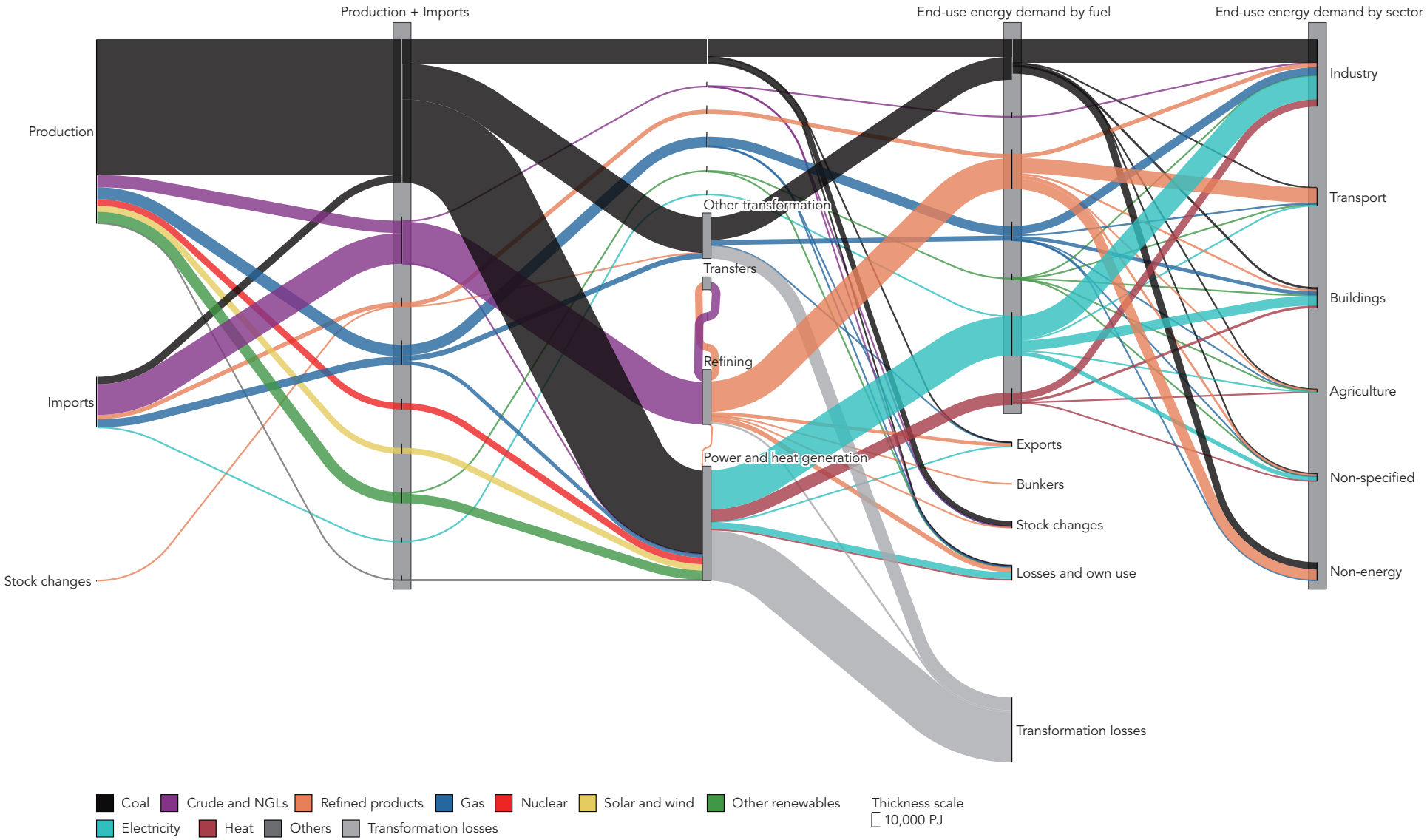
Clean and Efficient Coal Utilisation

China attaches great importance in the role of coal as the ballast of its energy supply. Coordinated measures have been taken to realise energy-savings and carbon-reducing transformation of remaining coal-fired power units, increase their flexible load regulation capabilities, and upgrade their heat supply capacity.

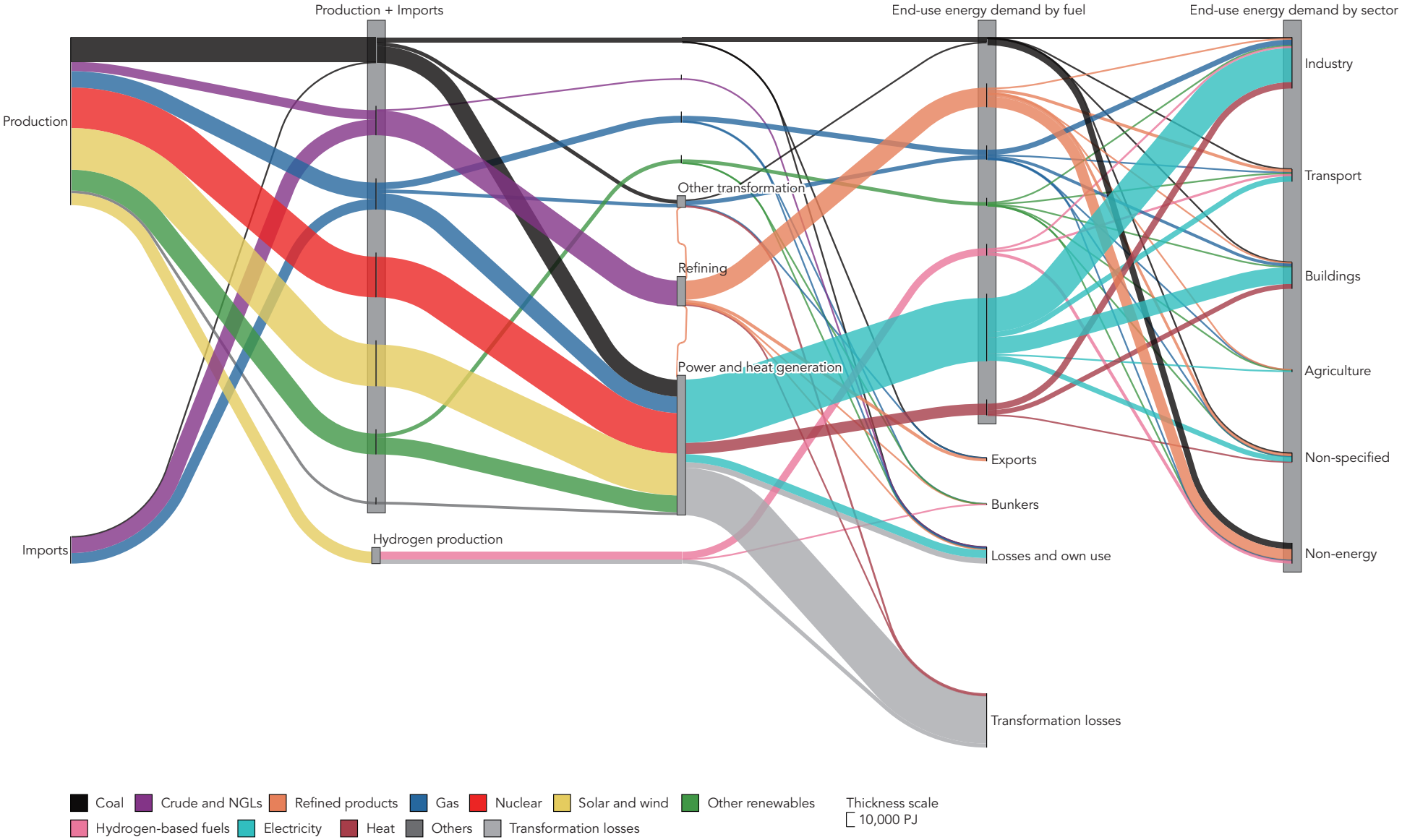
Active, Safe, and Orderly Development of Nuclear Power

China maintains a steady pace in constructing on coastal nuclear power projects on the premise of ensuring safety.

Energy Flow (2022)



Energy Flow (2060, Target Scenario)



Scenarios and Assumptions

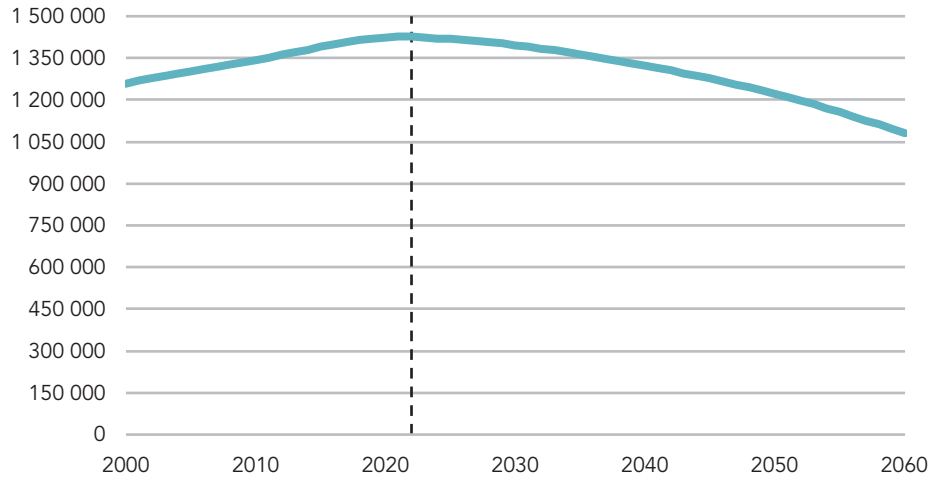
In *The Outlook*, APERC analyses energy demand, transformation, and supply, as well as emissions. The **Reference Scenario (REF)** offers a projection based on historical trends, recent developments, and APERC's assumptions about the continuation of those trends in each APEC economy, while acknowledging technical restraints. The REF Scenario offers a baseline to compare with the **Target Scenario (TGT)** projections, which explores a hypothetical pathway where each economy achieves energy-related policy targets, assuming implementation regardless of cost-effectiveness. When implementation details are lacking, assumptions are inferred from the targets themselves or emissions-related goals.

	Reference	Target
General	• Population: UN DESA 'low' scenario • GDP: APERC model and IMF	• Population: UN DESA 'low' scenario • GDP: APERC model and IMF
Buildings	• Households' access to cleaner cooking and district heating increases, and energy efficiency increases. • Coal is not completely phased out in isolated rural areas.	• Faster electrification and additional energy efficiency gains. • Coal is phased out by 2050 in the commercial/services sector. • Same data centre energy demand as the Reference scenario.
Industry	• Industrial activity remains robust. • Electrification continues, and coal consumption declines. • Hydrogen-based steelmaking deployed in the 2040s, CCS deployed in heavy industry in the 2040s.	• Enhanced energy efficiency improvements. • Higher demand for critical minerals leads to increased activity in mineral mining and metals processing. • Earlier deployment of green hydrogen and CCS.
Transport	• Steady growth of EV, FCEV, and LNG truck sales share. • Freight gradually switches from road to rail and ships. • Mixing rate of biofuel in liquid fuel levels off at 5%.	• Faster phase-out of ICE vehicles. • Deeper penetration of BEV and FCEV for heavy trucks. • Faster decrease in passenger activity. • Faster adoption of hydrogen-based fuels and biofuels.
Power	• Coal power peaks around 2030 before declining. • Wind and solar power continue to grow at a similar pace. • Pumped hydro capacity reaches 120 GW in 2030, and 160 GW in the 2040s.	• Faster decrease of coal power and increase of renewables. • Higher share of gas power to provide flexibility to the grid. • Nuclear and hydro remain the same as REF. • CCS deployed in the 2040s.
Supply	• Coal production follows demand trends, declining over the projection period. • Coal imports account for less than 10% of the coal consumption, declining over the projection period. • Domestic natural gas production capacity and pipeline import capacity increase to 330 bcm and 150 bcm. • Methane produced from coal and biomass reach 630 PJ and 440 PJ. • Exports are assumed to remain at current levels.	• Coal production declines at a higher pace than in REF. • Coal imports account for less than 10% of the coal consumption, declining over the projection period. • Domestic natural gas production peaks at around 330 bcm/yr and then follows the demand trends. Pipeline import capacity is the same as REF. • Higher biogas production. • Exports are assumed to remain at current levels.
Emissions	• Realising the 2030 carbon peaking target. • Falls short of the 2060 net-zero goal.	

Note: The base year is 2022. Macro-economic assumptions are constant across scenarios. Historical energy balances are from EGEDA submissions for 2022.

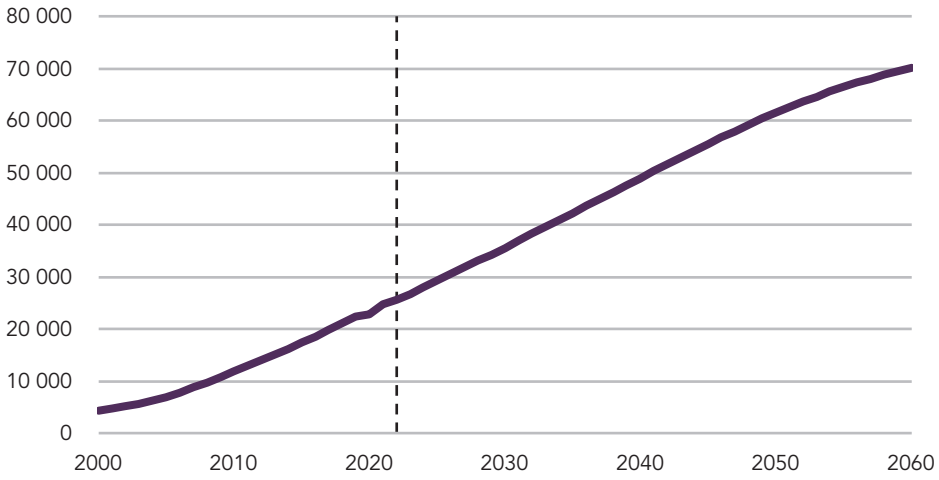
Demographic and Macroeconomic Assumptions

Figure 5-5. Population (thousands)



- China's population is assumed to follow the UN DESA 'low' projection, falling from over 1.4 billion to under 1.1 billion by 2060.
- China's labour force and total population will remain stable at high levels during the next decade (which will be crucial for the energy transition), despite the overall trends of population aging and decline.
- While urbanisation persists in China, its rate of expansion is decelerating. The continued growth of the urban population, in conjunction with decreasing household sizes and increasing living standards, will sustain robust growth in energy demand.

Figure 5-6. Real GDP (billion 2017 USD, PPP)



- Real GDP is expected to grow at a Compound Annual Growth Rate of about 2.7% and reach USD 70 trillion (2017 USD purchase power parity [PPP] basis) in 2060.
- China's strong emphasis on the real economy and its industry powerhouse strategy will enable the economy to maintain its leading industrial status in the long term. While services have become the primary driver of China's economic growth, the share of industrial added value in GDP will remain significant over an extended period.
- It is projected that China's per capita GDP will exceed USD 30,000 by 2035, reaching the level of a moderately developed economy. By then, China will have the largest middle class in the world and form the largest unified market.

End-use Energy Demand

Figure 5-7. Energy demand by sector in REF & TGT (PJ)

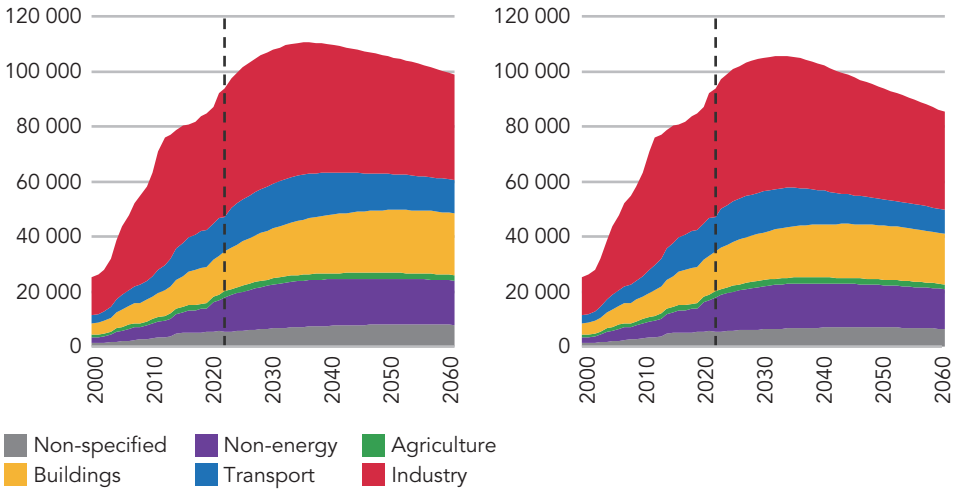
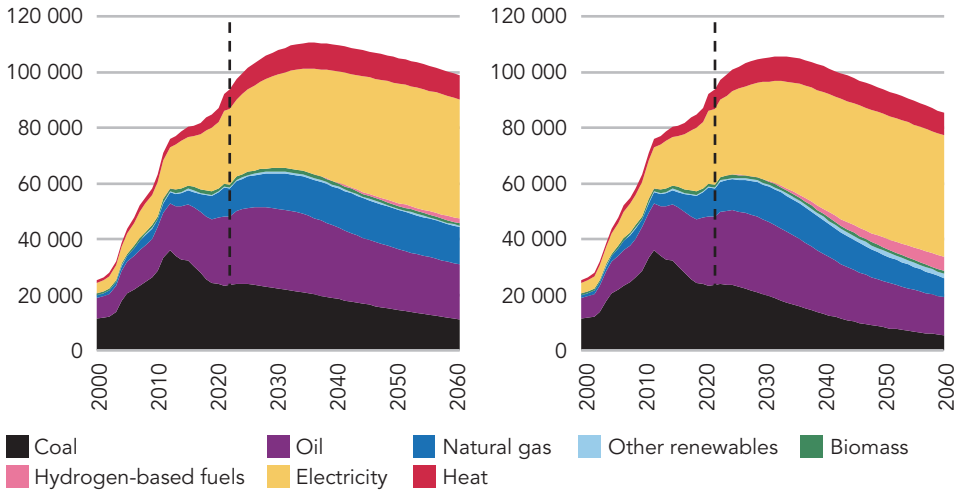


Figure 5-8. Energy demand by fuel in REF & TGT (PJ)



- In REF, China's Total Final Consumption (TFC, including energy and non-energy demand) is projected to increase by 18% from 2022 and peak at more than 110,400 PJ in the late 2030s before gradually declining to around 99,000 PJ by 2060. In TGT, TFC is expected to plateau sooner in 2032 at around 105,600 PJ and decline to under 86,000 PJ in 2060, reducing overall energy intensity by almost 14% compared with REF.
- Over the projection period, industry's share in end-use demand will decrease from the current level of 50% to around 40% under both scenarios. In contrast, the share of non-energy slightly increases from 14% to more than 16%, reflecting the robust demand for China's manufacturing products.
- Buildings become the fastest growing sector, contributing to 15% of TFC in 2022 and around 22% in 2060. The share of transport decreases from 14% to 12% in REF and to 10% in TGT. Agriculture remains stable at 2%.
- The electrification of end-use energy consumption is one of the key strategies for China's energy transition. By 2060, the share of electricity in TFC is projected to reach 44% in REF and exceed 50% in TGT, while the combined share of fossil fuels declines from 62% in 2022 to 45% and 31%, respectively.
- In REF, gas (including natural gas and gas works gas) will replace coal as the second largest end-use energy source with lower emissions and higher efficiency. However, to further promote decarbonisation in TGT, it will also be phased down after peaking in the 2030s.
- Hydrogen-based fuel will play an important role in TGT and constitute up to 6% of TFC. Other renewables, including biogas, are almost quadrupled compared to REF.
- With non-energy excluded, fossil fuels would only account for less than 20% of Total Final Energy Consumption in TGT by 2060.

Buildings Energy Demand

Figure 5-9. Buildings energy demand by fuel in REF & TGT (PJ)

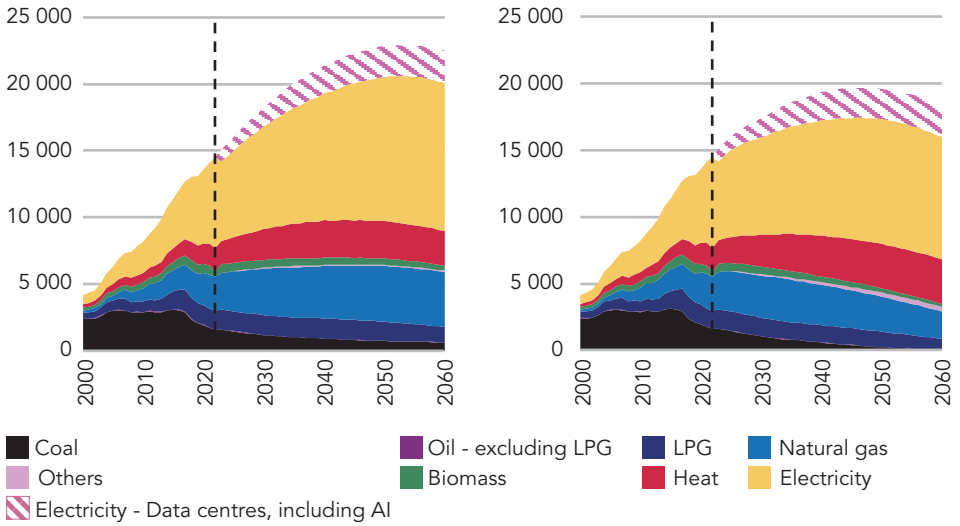
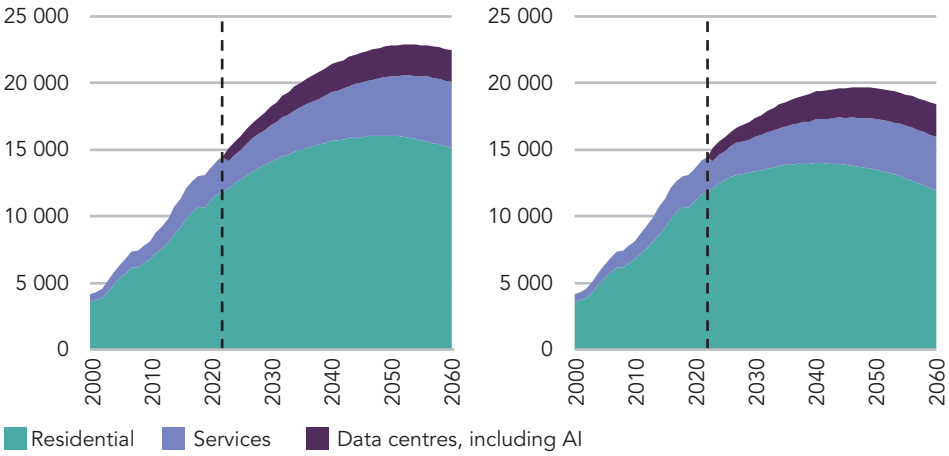


Figure 5-10. Buildings energy demand by sector in REF & TGT (PJ)



- Buildings are the fastest-growing and latest-peaking sector in energy demand, driven by improved living standards and expanding commercial activities. Energy consumption in the buildings sector will plateau in the 2040s under both scenarios with a decrease in TGT from around 2050.
- In TGT, there will be a complete coal phase-out and faster gas replacement with electricity and heat in buildings. By 2060, the combined fossil fuel share will drop from 38% to 26% in REF and further shrink to 16% in TGT.
- By 2060, electricity will constitute 60% of the sector's energy consumption under REF and 63% in TGT, a substantial increase from 47% in the 2022 base year.
- In northern China, where heating is required in winter, centralised heat supply is more efficient and cost-effective than individual boilers in urban areas. While gas remains a vital, affordable fuel for cooking and distributed heating, biogas (under "others") and heat pumps are promising low-carbon alternatives for rural regions.
- Residential energy demand is projected to decline after peaking in the 2040s due to the population decreasing and enhanced energy efficiency. Conversely, the service sector's energy consumption will grow throughout the projection period, consistent with its increasing economic output.
- Implementing new building energy efficiency standards, retrofitting old buildings for insulation, and optimising energy management are crucial for energy conservation and emissions reduction. These measures are assumed to be applied to a greater extent in TGT.
- As one of the leading economies in cloud computing and AI investment, China is expected to keep expanding its data centre capacity. The power demand from this application is projected at 2,400 PJ by 2060, contributing to around 20% and 30% of power demand growth in REF and TGT, respectively. Uncertainties persist regarding power usage effectiveness, GPU consumption, and computational model design with ongoing innovation.

Industry Energy and Non-energy Demand

Figure 5-11. Industry & non-energy demand by fuel in REF & TGT (PJ)

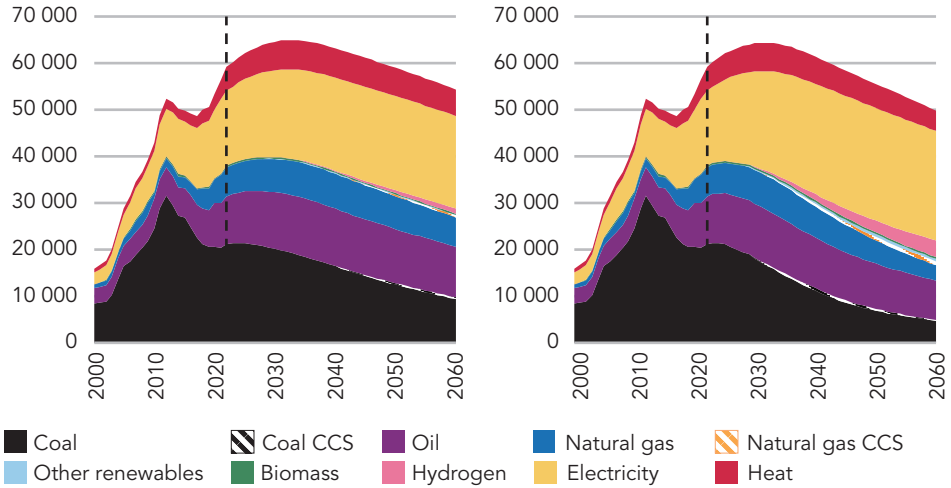
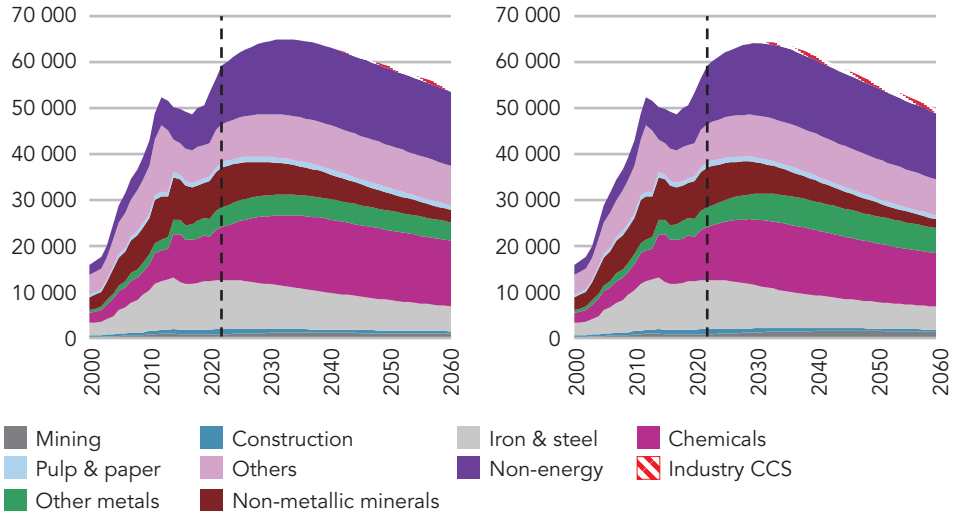


Figure 5-12. Industry & non-energy demand by sector in REF & TGT (PJ)

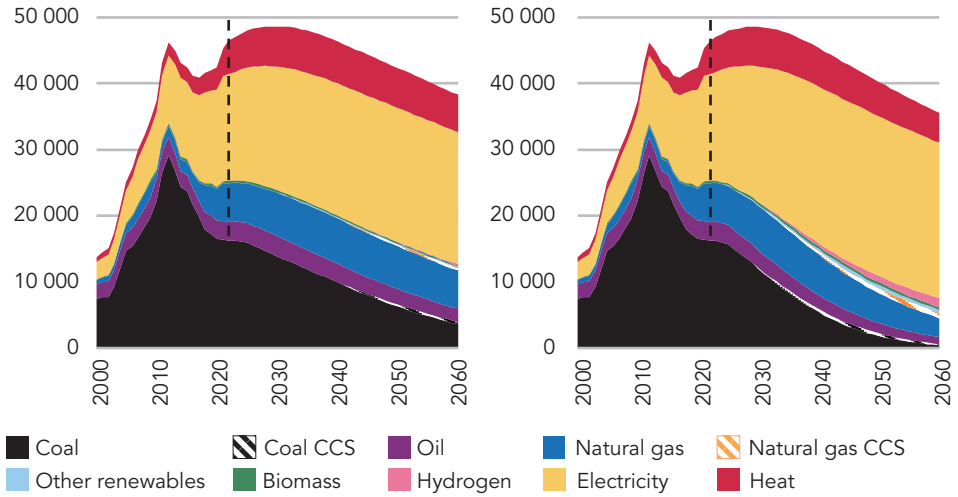


- The industry sector forms the bedrock of China's economy, currently accounting for nearly half of its end-use energy consumption. This sector is poised to maintain its significance in the coming decades, undergoing a crucial transformation towards high-end, intelligent, and green operations.
- Total demand of this sector is expected to continue its upward trajectory until the early 2030s, followed by a gradual decline as industrial activities moderate and efficiency gains take hold. Compared to REF, industrial demand will achieve a greater reduction from the peak through faster energy-saving upgrades and a deeper transition of the fuel mix in TGT.
- Driven by the electrification of industrial equipment and processes, the share of electricity demand is expected to rise by 10 percentage points under REF, while accounting for nearly half of the sector's total demand in TGT.

- Efforts are underway to encourage low-carbon hydrogen as a replacement for conventional hydrogen supply, which is presently dominated by coal and natural gas transformation. To note, the by-product hydrogen was not included in final demand.
- Steel and cement (non-metallic minerals) production is expected to decline significantly in the coming decades, as vast infrastructure and property construction recede as key economic drivers.
- Conversely, other manufacturing subsectors will continue to increase their output. Within this sector, chemicals are set to become the largest energy-consuming subsector during the latter half of the projection period.
- Non-energy demand currently constitutes 21% of the industry sector's total demand. Since most of this demand serves as manufacturing feedstock, it will gain increased prominence, reaching 30% by 2060.

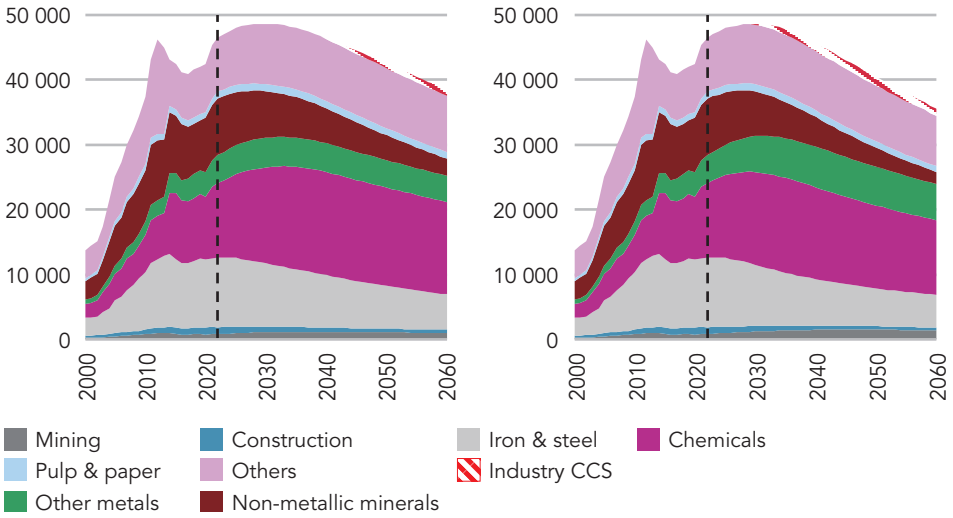
Industry Energy Demand

Figure 5-13. Industry energy demand by fuel in REF & TGT (PJ)



- In REF, the shares of electricity and heat in final energy consumption (non-energy excluded) are projected to increase from 35% and 11% in 2022 to 53% and 15% in 2060, respectively. Coal demand is anticipated to continue its downward trend since 2012, decreasing from 35% in 2022 to 10% in 2060. Oil demand is also set to halve during the same period. Gas, as a cleaner alternative, is projected to increase until 2040 before stabilising.
- In TGT, coal is anticipated to be nearly completely phased out, oil consumption will decline by three-quarters, and gas consumption will decrease by 40%. Electricity and heat are collectively expected to fulfill almost 80% of this sector's final energy demand. This requires increased investment in the research and development of emerging technologies, such as electric furnaces, microwaves, and plasma, alongside faster equipment upgrades.
- Green hydrogen is utilised to meet high-temperature heat demands from the 2030s in TGT and later in REF from the 2040s.

Figure 5-14. Industry energy demand by sector in REF & TGT (PJ)



- CCS is expected to be deployed at a pace similar to green hydrogen in heavy industry subsectors. By 2060 in TGT, nearly 20% of coal and gas consumption is anticipated to be equipped with CCS. However, the large-scale deployment of these technologies still faces technical, economic, and geological hurdles.
- China has developed dedicated action plans for major energy-intensive subsectors, including iron and steel, cement, aluminium, and plate glass, among others. These initiatives aim to accelerate outdated capacity replacement and equipment renewal to achieve energy efficiency and emission targets.
- Unlike most subsectors, there is a substantial increase in the mining and other metals sectors in TGT. This is primarily attributed to the heightened global demand for critical minerals and materials crucial for low-carbon technologies, such as batteries. China is expected to maintain its role as a significant supplier of these products in the international market.

Non-energy Demand

Figure 5-15. Non-energy demand in REF (PJ)

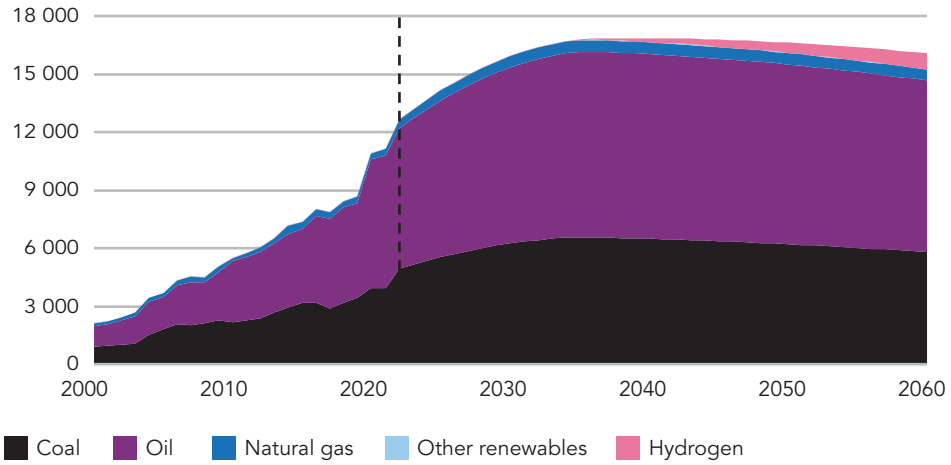
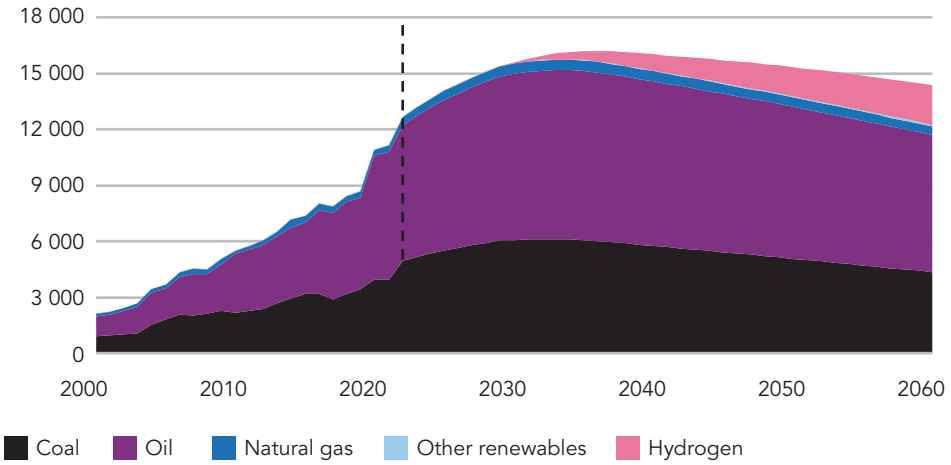


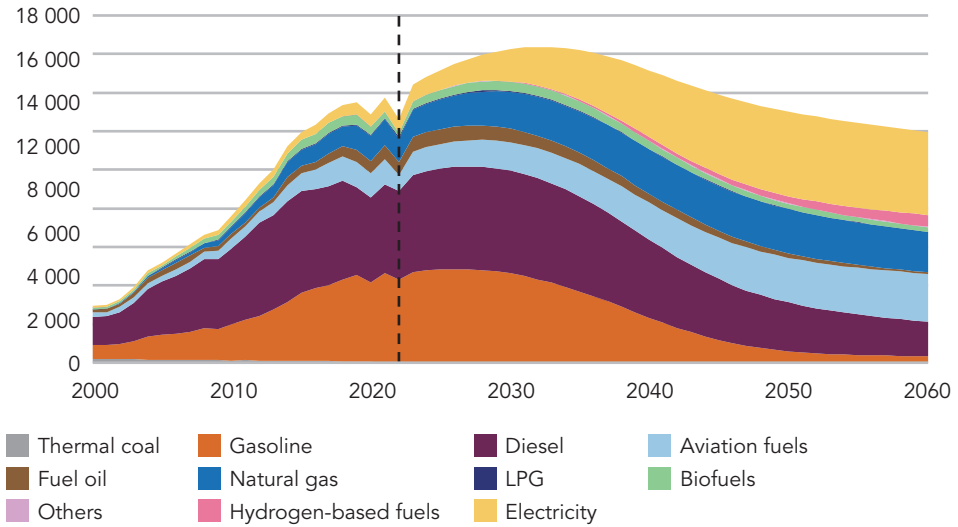
Figure 5-16. Non-energy demand in TGT (PJ)



- Non-energy demand has experienced a rapid expansion since 2000, paralleling China's manufacturing development. In REF, non-energy is projected to increase by one-third from 2022 and reach a plateau above 16,000 PJ from the late 2030s. In TGT, non-energy demand will peak after a 28% growth, followed by a gradual decline to below 15,000 PJ.
- The substantial reliance on coal and oil represents a considerable challenge for replacement, making non-energy one of the most difficult sectors to decarbonise. Therefore, technological innovation and material recycling are crucial for reducing energy intensity and emissions associated with these industrial production processes.
- China is actively exploring using biomass as an abundant, low-emission, and sustainable substitute for manufacturing feedstock. Additionally, captured CO_2 from CCS facilities can be utilised in chemical production. The market potential for these emerging technologies depends on multiple factors, including technology maturity, economic competitiveness, and policy frameworks.
- Gas serves as a raw material for ammonia and other chemicals; however, this application is not encouraged by existing policy. Meanwhile, hydrogen generation has emerged as a new driver for gas demand growth, since gas, despite its higher cost, offers more environmental benefits than coal. Overall, gas consumption within this sector is projected to grow over the next decade before gradually declining as total demand contracts and green hydrogen production expands.
- China is vigorously promoting clean and low-carbon hydrogen in the industrial sector. Industrial by-products and renewable energy are identified as the most promising substitutes for coal and gas for hydrogen production in meeting non-energy demand, particularly in chemicals production and metallurgy. In this projection, by 2060, hydrogen from renewables will contribute 5% of non-energy demand in REF and 15% in TGT. Improved utilisation of industrial by-product hydrogen will play an important role in supporting this transition.

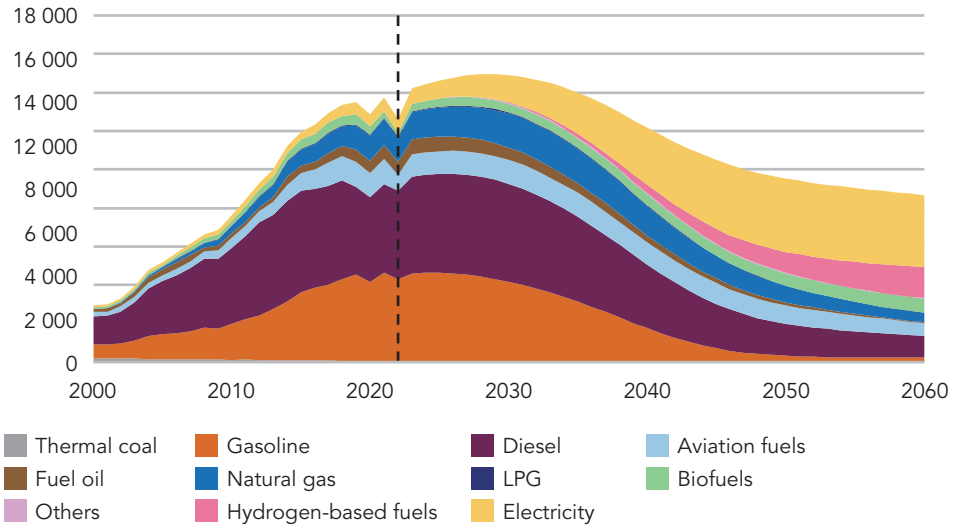
Transport Energy Demand

Figure 5-17. Domestic transport energy demand in REF (PJ)



- China's transport energy consumption is projected to rise in the short term, driven by economic growth, and then decline due to a decreasing population, moderate industrial growth, and efficiency gains. China targets a sustainable, low-carbon transport system through strong policies, including boosting EV sales, promoting public transport, and accelerating innovation.
- Road transport dominates energy demand in the transport sector, and China leads in road engine electrification. Driven by efficient EV fleet growth, total transport energy consumption is projected to peak earlier in TGT (2029) than in REF (2032). This, along with increased rail and electric ship activity, will boost the share of electricity from 6% in 2022 to 36% in REF and to 43% in TGT by 2060.
- LNG trucks offer a competitive, lower-emissions alternative to diesel heavy trucks. Gas consumption in REF grows significantly, reaching over 2,100 PJ by 2060. In TGT, stricter carbon regulations project gas to peak at over 1,800 PJ in 2033, then decline to under 500 PJ by 2060, serving as a transition fuel.

Figure 5-18. Domestic transport energy demand in TGT (PJ)



- Gasoline and diesel, currently 70% of transport energy consumption, have levelled off. Their combined demand is projected to peak before 2027 and ultimately fall to 18% in REF and 16% in TGT by the end of the projection period. By 2060, gasoline will be nearly phased out, though diesel replacement remains challenging. The significant fuel mix shift will require extensive infrastructure and supply chain adaptation.
- Domestic aviation activity is anticipated to increase rapidly, becoming the largest carbon emitter in REF. In TGT, sustainable aviation fuels are expected to achieve similar economic competitiveness, reducing jet fuel demand by half compared to historical peak levels.
- Hydrogen-based fuels and biofuels are promising options for decarbonising long-distance freight, shipping, and aviation. In TGT, greater policy support for technology innovation, upstream feedstock allocation, and market cultivation will be crucial to incentivise their utilisation.

Other Transport Data

Figure 5-19. Transport vehicle stocks in REF & TGT (millions)

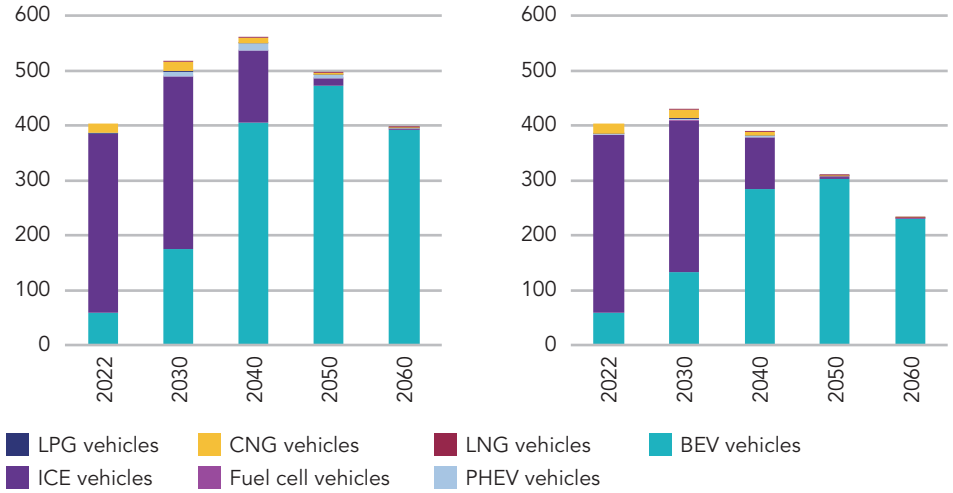
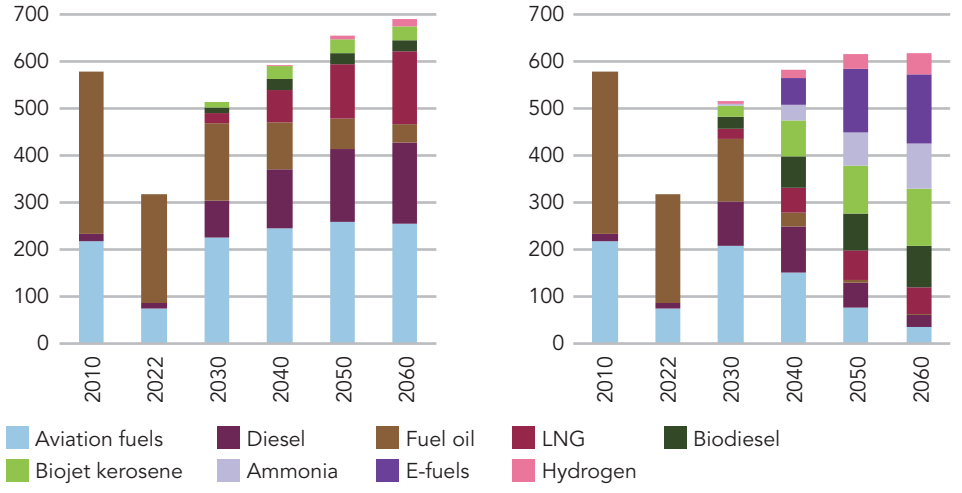
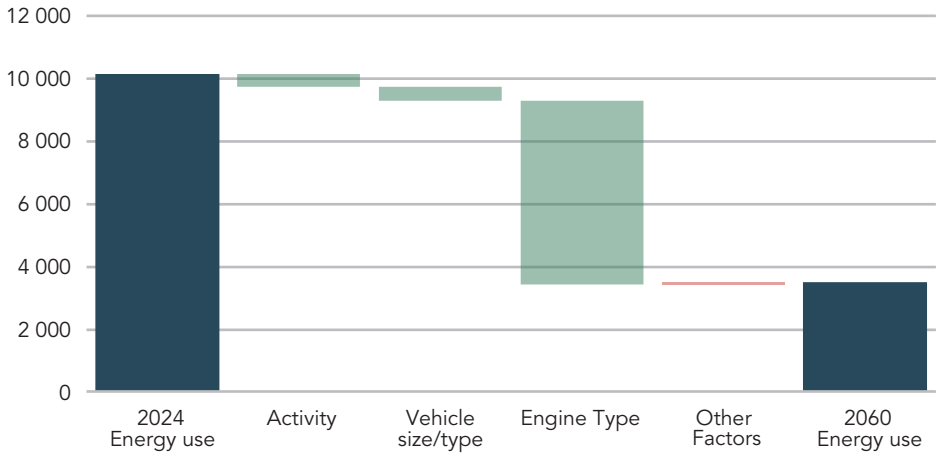


Figure 5-20. International bunker energy demand for shipping and aviation in REF & TGT (PJ)



- China's vehicle market is experiencing a rapid transition from internal combustion engine (ICE) vehicles to electric vehicles (EVs). With proactive policy support and robust industry capacity, battery electric vehicles (BEVs) are projected to constitute 100% of passenger vehicle sales by 2035 in TGT and by 2040 in REF. Notably, the number of plug-in hybrid electric vehicles (PHEVs) has increased significantly in recent years due to improved fuel efficiency and lower prices. This trend is expected to substantially support the full electrification of passenger transport and will be incorporated into future modelling.
- International bunkers are projected to maintain their heavy reliance on fossil fuels in REF, with LNG replacing petroleum fuels. In TGT, the fuel mix is anticipated to become increasingly diversified with biofuel and hydrogen-based fuels accounting for 80% by 2060.
- While improvements in transport system design, public transport, and ICE efficiency contribute to overall efficiency, engine switching is expected to be the primary driver of reduced transport energy use.

Figure 5-21. Components of the change in road energy use in TGT (PJ)



Note: Information on the different drivers in the transport energy decomposition can be found in the *Outlook*'s annex.

Electricity Generation

Figure 5-22. Electricity generation by fuel in REF (TWh)

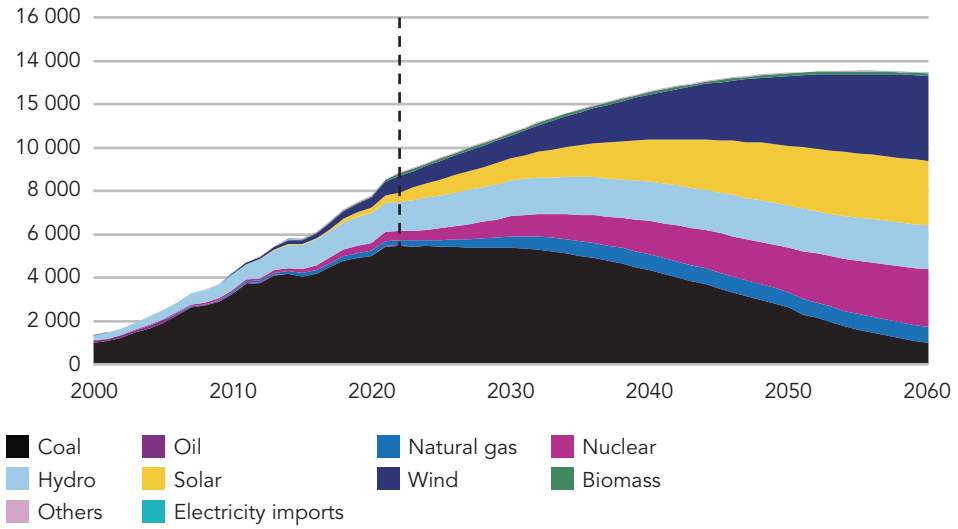
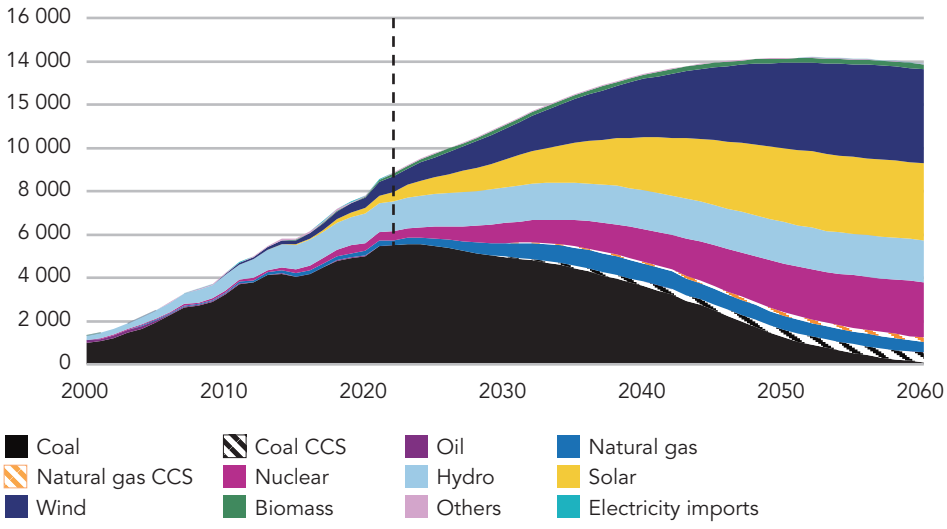


Figure 5-23. Electricity generation by fuel in TGT (TWh)



- Electricity is emerging as the predominant energy carrier for end-users across all sectors. Power production is projected to maintain rapid growth, leveling off at over 13,500 TWh post-2050 in REF and at approximately 14,000 TWh post-2045 in TGT, concurrently transitioning to a diversified fuel mix.
- As China's largest power and emissions source, coal will be gradually phased down. Its share is set to decrease substantially from over 60% to under 10% by 2060 in REF, further declining to 5% in TGT. Despite this reduction, the sheer volume of coal consumption for power remains significant (over 13,000 PJ), providing critical grid stability support.
- Nuclear is projected to replace coal as the largest baseload source, increasing its share from under 5% in the 2022 base year to approximately 20% by 2060.
- China's established renewable energy ecosystem and ample land area will facilitate the steady expansion of solar and wind power. Collectively, solar and wind are projected to account for 51% and 57% of total power generation in REF and TGT, respectively, by 2060. Hydropower is expected to maintain its share at around 15%.
- Gas is expanding as a crucial flexible power source, complementing intermittent renewables. Gas-fired power generation is projected to triple by 2060 in REF. In TGT, its growth will accelerate as coal power diminishes and renewables scale up, peaking around 2040 before gradually declining due to carbon constraints.
- To achieve its ambitious goal in boosting renewable power consumption, China plans to further strengthen regulatory and financial support, alongside deepening market mechanism reform.

Note: Figures 5-22 and 5-23 do not include electricity generation for hydrogen production.

Generation Capacity

Figure 5-24. Generation capacity by fuel in REF (GW)

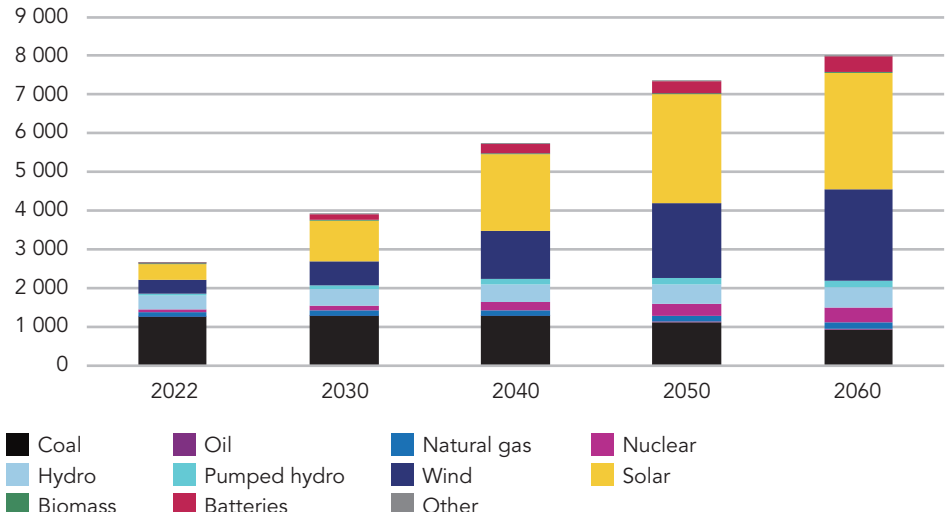
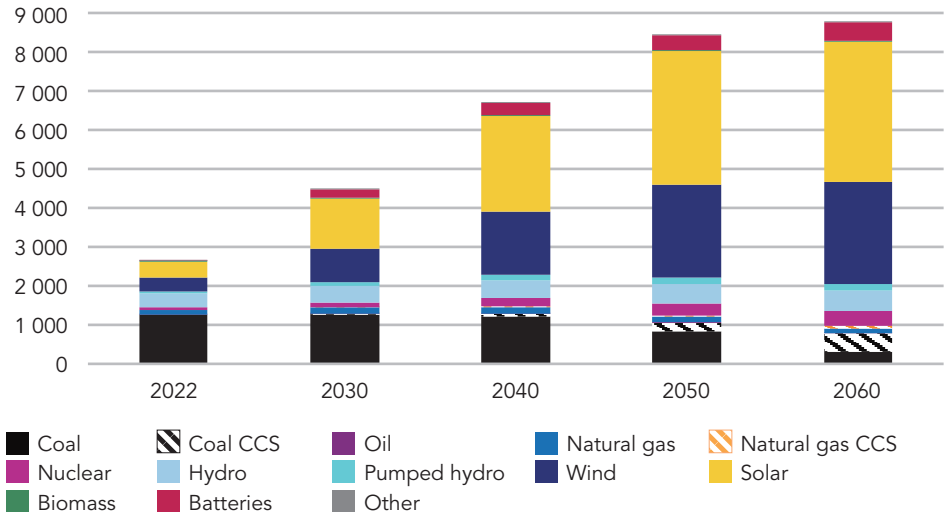


Figure 5-25. Generation capacity by fuel in TGT (GW)



- China's total generation capacity is projected to triple by 2060, reaching approximately 8,000 GW in REF and 8,300 GW in TGT by 2060. Solar and wind power are key drivers of power investment, with 140 GW of new capacity added annually until 2055 in REF. And in TGT, their expansion rate accelerates to around 180 GW/year before leveling off after 2050.
- Coal power generation capacity will plateau at around 1,280 GW for two decades, undergoing upgrades for better flexibility, enhanced efficiency, and reduced emissions. As outdated units retire, coal power capacity is ultimately projected to drop from 47% in 2022 to 12% in REF and 10% in TGT by 2060.
- Gas generation capacity is estimated to increase by 50% to around 180 GW by 2060. China's substantial reliance on natural gas imports introduces higher cost risks for gas power operators. Optimising the electricity market pricing mechanism will provide crucial incentives for new gas power installations.
- To enable the swift replacement of dispatchable fossil-fired power generation, nuclear power construction needs to maintain its current pace, equivalent to eight to ten large-scale units annually. By 2060, 385 GW of nuclear capacity is estimated to be operating at a relatively high capacity factor.
- In TGT, CCS is projected for deployment in 2040 to offset emissions from coal and gas generation. While several pilot projects have been commissioned, significant cost reduction and a clear carbon market framework are essential to attract sufficient investment.
- China's renewable energy resources are primarily concentrated in the western and northern regions, whereas highly populated areas are located in the east. Reinforcing ultra-high voltage transmission and transformation channels is thus prioritised in parallel with generation capacity construction.

Note: Figures 5-24 and 5-25 do not include generation capacity for hydrogen production.

Grid Reliability

Figure 5-26. Total generation capacity and peak load (GW)

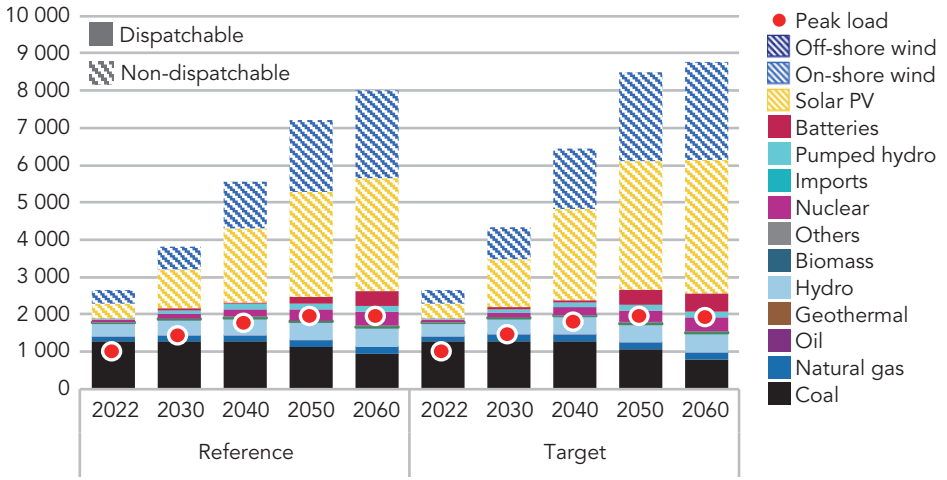
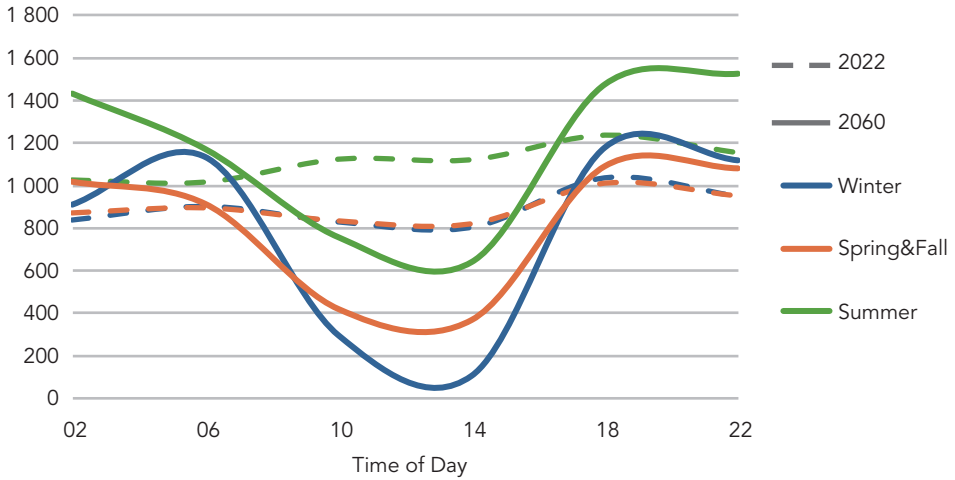


Figure 5-27. Power from dispatchable sources in TGT (GW)



- From the demand side, as China expands its power consumption and shifts towards a service-oriented economy, peak load is expected to grow over 90% from around 980 GW in 2022 to more than 1,900 GW in 2050. In TGT, it is expected to decrease slightly along with total electricity demand thereafter.
- New end-users connected to the grid, such as EV chargers and batteries, make instantaneous peak load challenging to predict. Increasing frequency and intensity of extreme weather events present a growing challenge to energy infrastructure resilience. These all necessitate a higher reserve margin and increased flexibility from dispatchable power sources.
- The mismatch between dispatchable power and load curves across different regions requires enhanced cross-region transmission capacity and coordination. China is developing an interconnected supergrid and distributed smart grids to optimise resource allocation.
- China is striving to build a "new power system" to address these challenges. Notably, coal capacity will be maintained as a vital backup power source. Various energy storage technologies are expected to play a pivotal role in grid balance across different time scales.
- In China, wind resources are typically stronger in spring and autumn, while solar output peaks in the winter. Conversely, peak load occurs in summer due to increased cooling demand. This seasonal variation results in a significant difference in dispatchable power load factors.
- The dynamics of dispatchable power will become substantial by 2060. During morning or evening hours in winter, power units need to ramp up or down by over 800 GW within four hours. The minimum power output drops to under 100 GW in the afternoon.
- During peak hours of renewables output, coal and nuclear power units operating at a low load factor result in decreased efficiency and stability, thus elevating the overall cost. The moment of inertia also needs to be maintained by other sources.
- China is also pushing market reforms from planned dispatch and fixed pricing towards market-based mechanisms. This aims to effectively distribute the cost of ancillary services and additional investment required for grid reliability.

Coal and Biomass

Figure 5-28. Coal and biomass consumption by sector in REF & TGT (PJ)

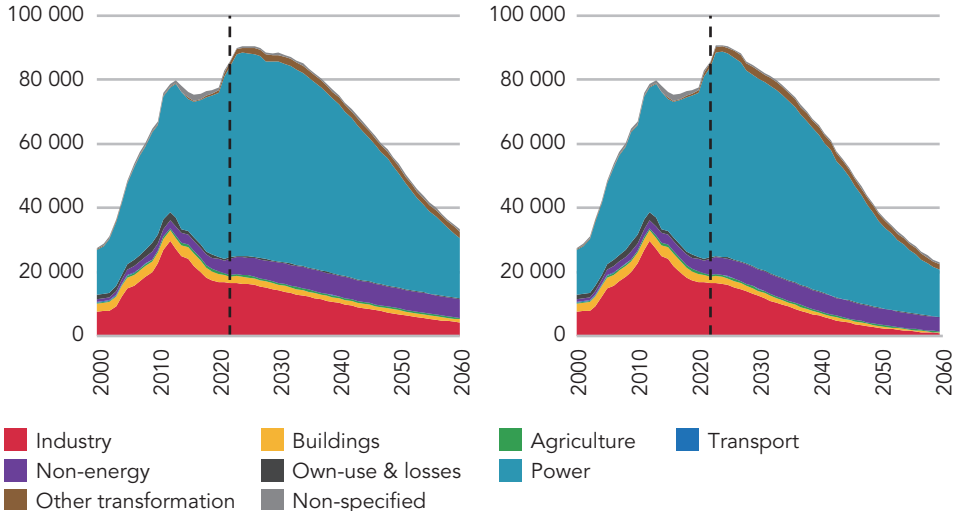
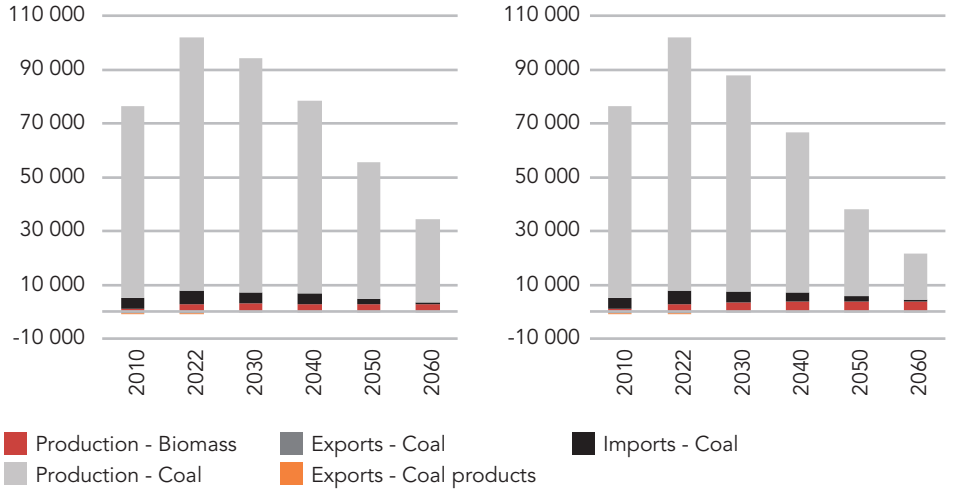


Figure 5-29. Coal and biomass production, imports, and exports in REF & TGT (PJ)

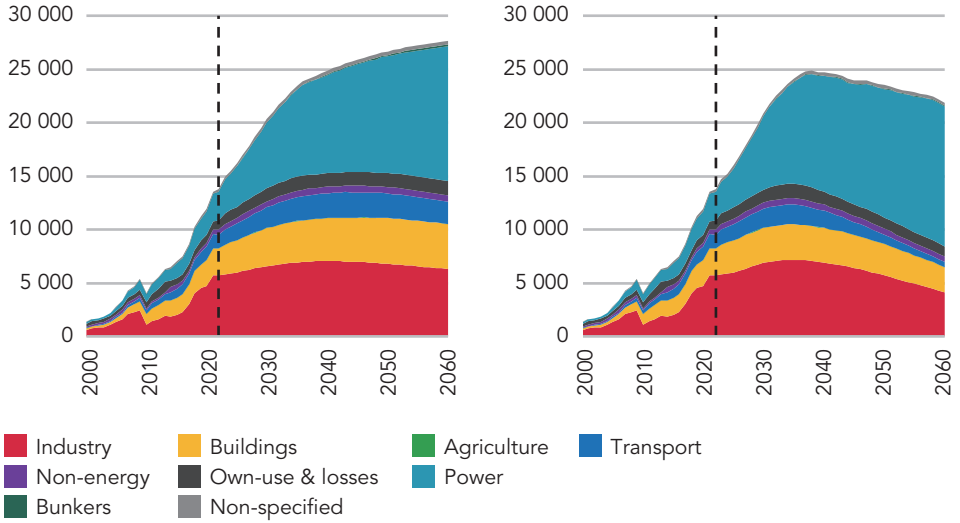


- Coal consumption in China is expected to peak by 2025, then gradually decline as the economy aims for net-zero by 2060. It is projected to drop to just over 30,000 PJ in REF and below 20,000 PJ in TGT by 2060. To achieve cleaner utilisation, China is demonstrating emissions reduction retrofits through biomass and hydrogen co-firing, CCS, and other carbon sink technologies.
- The power sector remains the largest consumer of coal, where coal is transitioning from a dominant fuel to a supporting power source. All newly installed and retrofitted coal power units are mandated to enhance their peak-shaving and load-following capabilities, reflecting this evolving role.
- Solid biomass holds potential in power and heat supply. However, while innovative biomaterials show promise as replacements for fossil feedstock for manufacturing, they are still in early development.
- Coal demand remains robust in the non-energy sector, primarily due to this source's low cost and stable supply. The coal chemistry industry is actively pursuing the expansion of coal chemistry capacity and moving towards high-end, diversified, and low-carbon development.
- Gas works gas (other transformation) is a significant fuel for the buildings and industry sectors. China is exploring advanced coal gasification processes to produce methane with higher transformation efficiency and lower emissions, serving as a supplement to natural gas supply.
- China's coal supply is predominantly met by domestic production. As coal consumption declines, domestic production is projected to contract to 70% in REF and 80% in TGT from its peak level by 2060. The share of imports is also expected to decline accordingly.

Note: Figure 5-28 excludes coal for transformation into coal products.

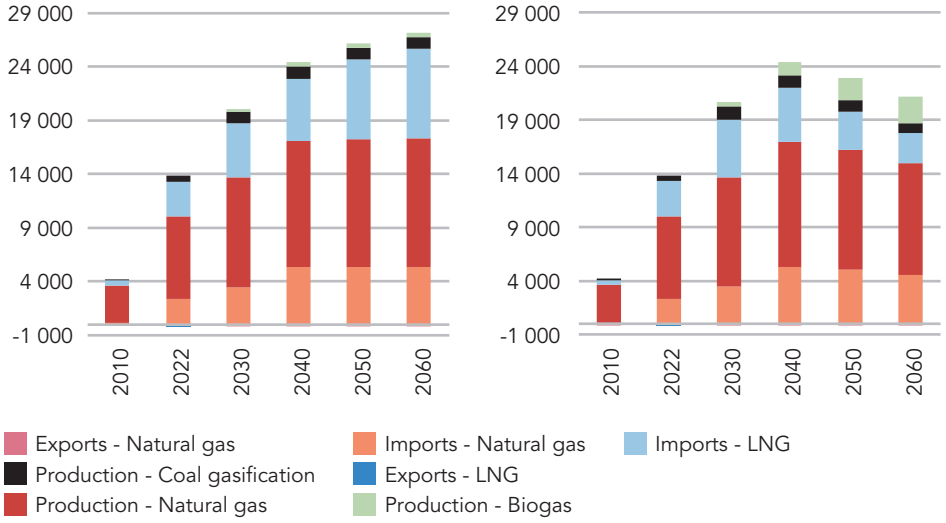
Natural Gas and Biogas

Figure 5-30. Natural gas, gas works gas, and biogas consumption by sector in REF & TGT (PJ)



- In REF, gas consumption expands by three-quarters by 2060, primarily driven by power (84%) and buildings (14%). The growth rate steadies after mid-2030s, aligning with a decrease in total energy demand.
- In TGT, gas consumption is expected to grow faster, peaking in the late 2030s. This surge is due to accelerated coal and oil replacement and support for faster renewables adoption. Subsequently, alternative fuels and storage technologies will offset gas demand.
- Vigorous exploration of conventional and unconventional gas deposits, both onshore and offshore, is estimated to expand domestic natural gas production capacity to above 11,000 PJ (310 bcm) annually. This would meet 44% of total gas supply in REF and 49% in TGT by 2060.

Figure 5-31. Natural gas, gas works gas, and biogas production, imports, and exports in REF & TGT (PJ)



- China has high expectations for biomethane production from organic waste, crucial for the energy transition and gas self-sufficiency. In TGT, it is projected to reach 2,500 PJ in 2060, representing 12% of total gas supply. Greater efforts are required to establish a viable business model for scaling up production.
- As the largest importer of natural gas in the APEC region, China is actively working to secure supply from multiple economies through various channels. In this projection, additional international pipeline capacity will enable natural gas imports to reach around 5,300 PJ (150 bcm) by 2040.
- LNG imports are projected to expand 2.6 times to around 8,400 PJ (170 mt) in 2060 under REF, and peak at 7,100 PJ (140 mt) by 2035 in TGT. Strengthening infrastructure for LNG reception, storage, regasification, and associated gas transport systems will be essential.

Petroleum Liquids

Figure 5-32. Crude oil production, imports, and exports in REF & TGT (PJ)

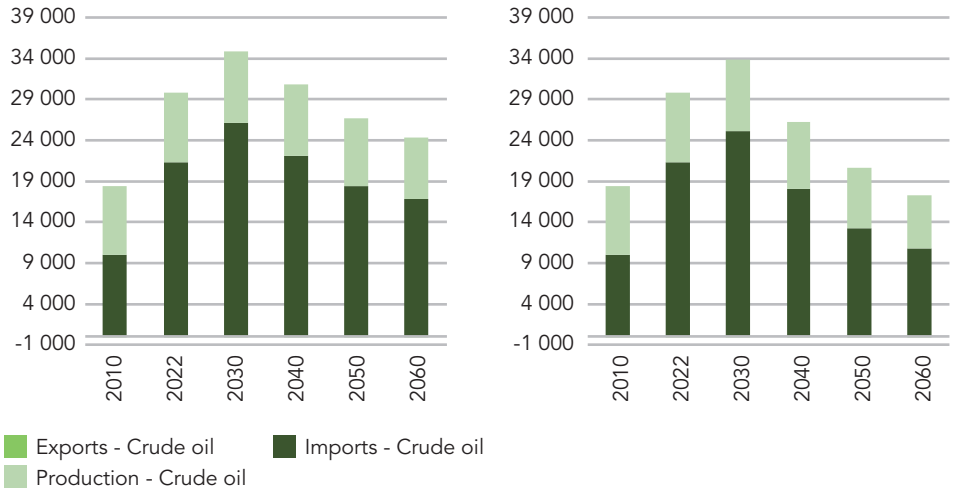
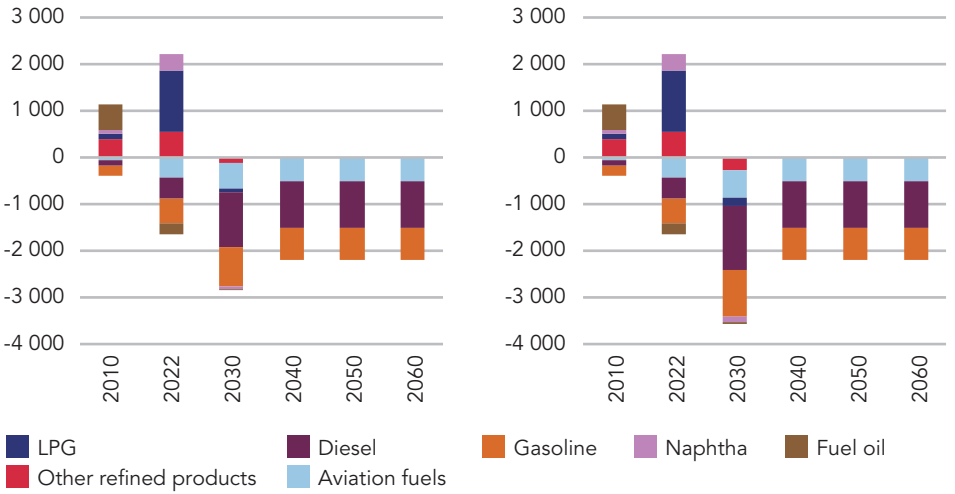


Figure 5-33. Net imports of refined products in REF & TGT (PJ)

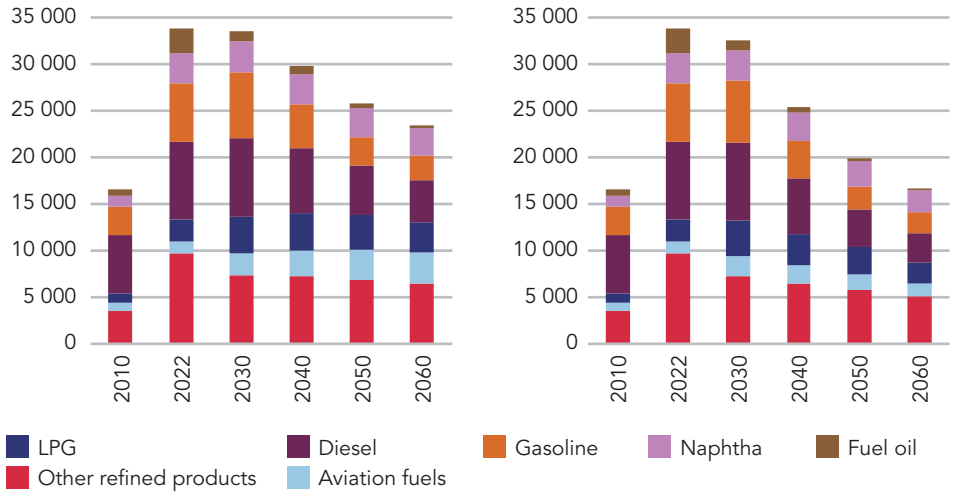


- Domestic production and imported crude oil are supply sources to China refineries. As demand from the transport and industry sectors—which collectively represent over 90% of petroleum product demand—approaches peak consumption, crude oil supply is expected to level off in the late 2020s at approximately 30,000 PJ (5,000 mb) and enter a downward trajectory.
- To secure crude oil supply, China has maintained significant investment in domestic crude oil production. Production is projected to remain stable at around 8,700 PJ (1,430 mb) until 2045 in REF and 2035 in TGT, before slightly declining in response to decreased demand.
- By 2060, crude oil imports are anticipated to contract to around 14,000 PJ (2,300 mb) in REF and 8,700 PJ in TGT, representing 65% and 57% of China's oil supply, respectively. The steeper reduction in TGT directly results from a faster decline in total oil demand and China's heightened focus on energy supply security.
- China built the largest refining sector in the world, achieving self-sufficiency in most refined products. With new large-scale refineries commencing operations, it is expected that the continued high demand of naphtha and LPG as feedstocks to China's chemicals and petrochemicals sectors will be met by refinery outputs by 2030.
- The refining industry is actively promoting a transition towards reducing outputs of fuel products and increasing feedstocks for chemical products, simultaneously shifting towards higher-value outputs. However, given the rapid domestic electrification of vehicles, a constant excess output of gasoline, diesel, and jet fuels is still anticipated.
- China's total refining capacity is assumed to peak at 19.6 mb/d (980 mt/yr) in 2028, aligning with government directives. As demand rapidly declines, refining capacity is projected to decrease to 12.7mb/d in REF and 9.0 mb/d in TGT by 2060.

Note: In Figure 5-33, net imports are presented without deducting bunkers.

Refining

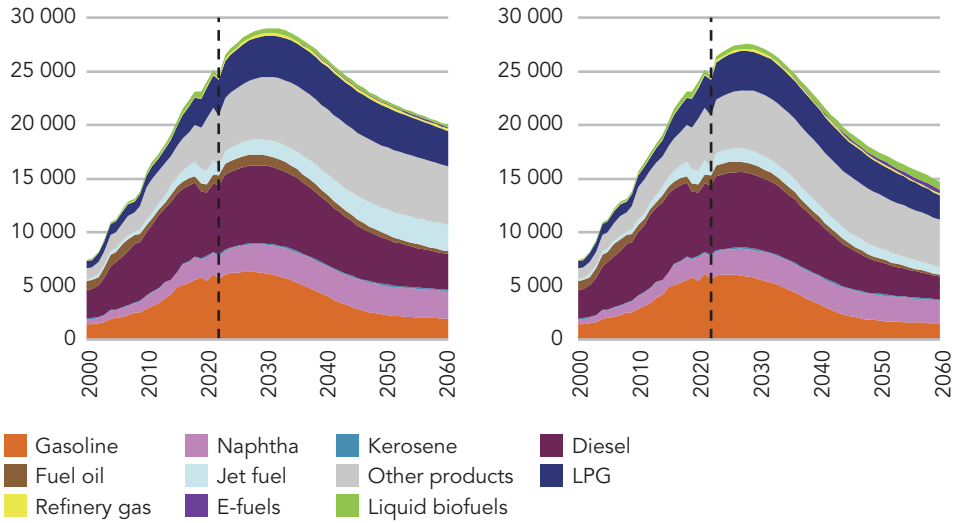
Figure 5-34. Refining outputs in REF & TGT (PJ)



Note: Figure 2-34 only covers power and VRE transmission sector costs. It does not include operating costs associated with hydrogen production and EV charger costs. Costs for electricity imports are included here.

- Total refining output is projected to peak in 2030 in REF and 2028 in TGT, with the average utilisation rate increasing to 75%. Efficiency will be improved through equipment upgrades, investments in process optimisation, crude oil blending, and the decommissioning of less efficient refineries. Furthermore, the shift in demand structure will cause a profound change in the refining product output through refining reconfigurations.
- Major state-owned corporations are establishing large-scale integrated refining and petrochemical complexes designed to enhance efficiency and flexibility in processing diverse feedstocks and tailoring output to market demand. In contrast, existing local and less efficient refineries face challenges due to stricter environmental regulations and intensified competition.

Figure 5-35. Refined products and low carbon fuels demand in REF & TGT (PJ)



Note: Based on our assumptions about future capital and operating costs, Figure 2-35 shows cost compositions over time relative to 2025. It should not be considered an estimate of electricity tariffs and excludes market mechanisms too challenging to estimate.

- The decrease in demand from the transport sector will outpace that of the industry sector. After around 2030, demand for petrochemical production will surpass transport fuel. By 2060, the combined share of gasoline and diesel will decline from the current 50% to under 30%, while demand for naphtha, LPG, and other manufacturing feedstocks remains substantial.
- In TGT, aviation fuel consumption is anticipated to be reduced as biofuel and e-fuels become more economically competitive.
- China is a major exporter of biodiesel, capitalising on its pioneering technology and abundant waste grease feedstock. However, the prospects for this product remain highly uncertain due to evolving trade control policies and the ongoing phase-out of ICE vehicles.

Hydrogen-based Fuels in the Target Scenario

Figure 5-36. Hydrogen-based fuels demand by sector [left]; Hydrogen-based fuels demand by fuel [right] (PJ)

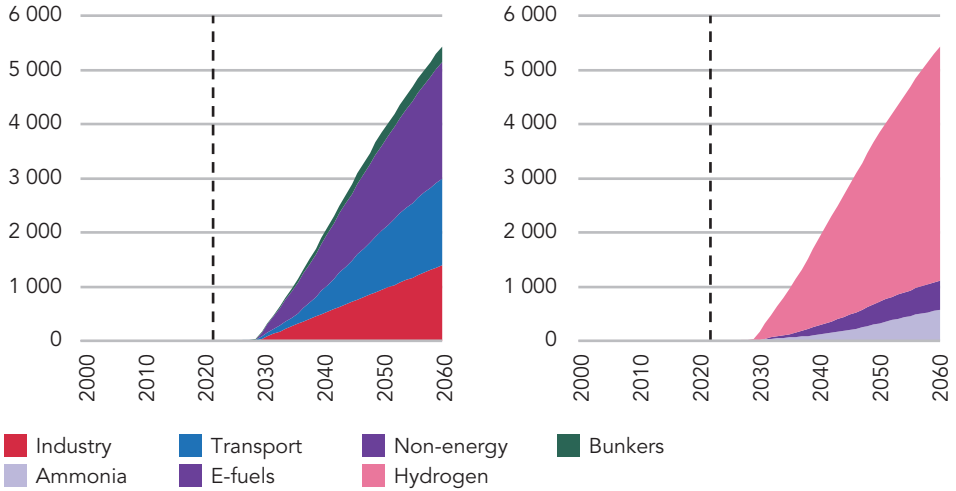
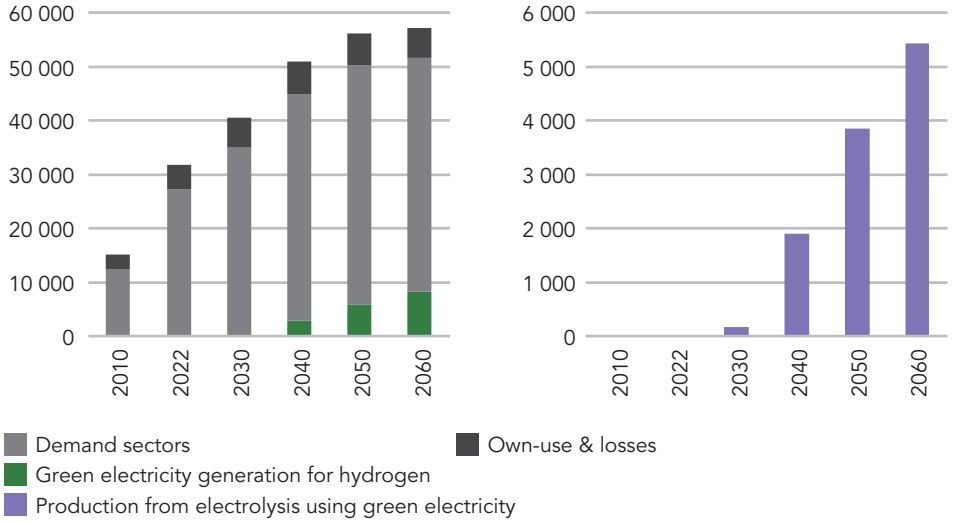


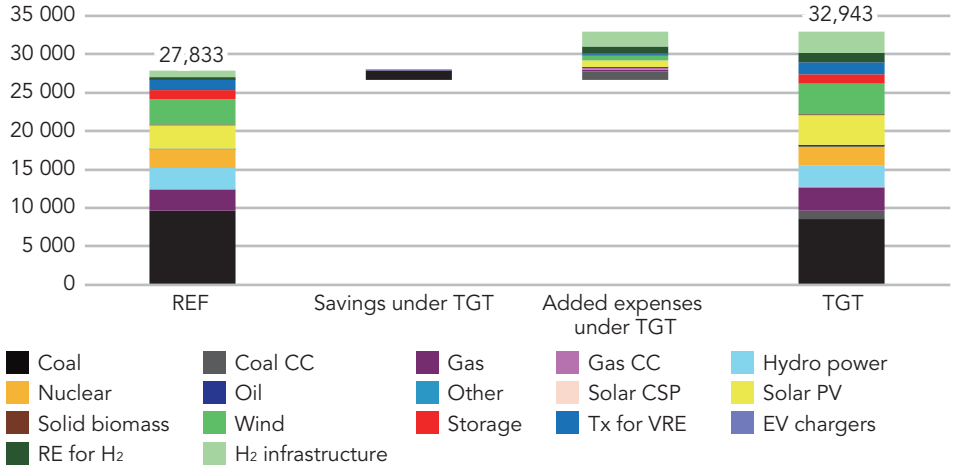
Figure 5-37. Electricity for electrolysis vs other sectors [left]; Hydrogen-based fuels production methods and supply [right] (PJ)



- China is currently the world's largest hydrogen producer, primarily from coal and natural gas for industry applications. The government views hydrogen as a crucial carrier for renewable energy, committing to building green hydrogen capacity while simultaneously promoting its utilisation in transport, industry, energy storage, and other sectors.
- Hydrogen-based fuels are projected to commence commercial-scale deployment from 2030, mainly produced via electrolysis powered by wind and solar, in line with China's strategic plan. Total demand grows at an average rate of 180 PJ/year, reaching around 5,400 PJ by 2060 in TGT.
- Industry, transport, and non-energy will become the primary end-users. Given consumers' sensitivity to electricity prices and the high cost of green hydrogen, demand for hydrogen in power generation is expected to be marginal, limited to remote areas and specific scenarios that require long-term storage.
- The electricity required for hydrogen-based fuel production is projected to be approximately 2,900 PJ (800 TWh) by 2040 and 8,200 PJ (2,300 TWh) by 2060 in TGT. This is equivalent to 6% and 17% of other sectors' total power consumption (including demand, losses, and own-use), or 16% and 29% of other sectors' solar and wind power generation, respectively.
- Green hydrogen production will be concentrated in regions with abundant solar and wind energy resources to minimise costs, concurrently assisting in smoothing the load curve of local grids.
- China is actively promoting the development and demonstration of technologies for long-distance hydrogen transport from major renewable energy bases in the west to highly populated area and industrial bases in the east. Additionally, China is exploring low-carbon hydrogen production using high-temperature nuclear reactors or via coal gasification with CCS.

Costs

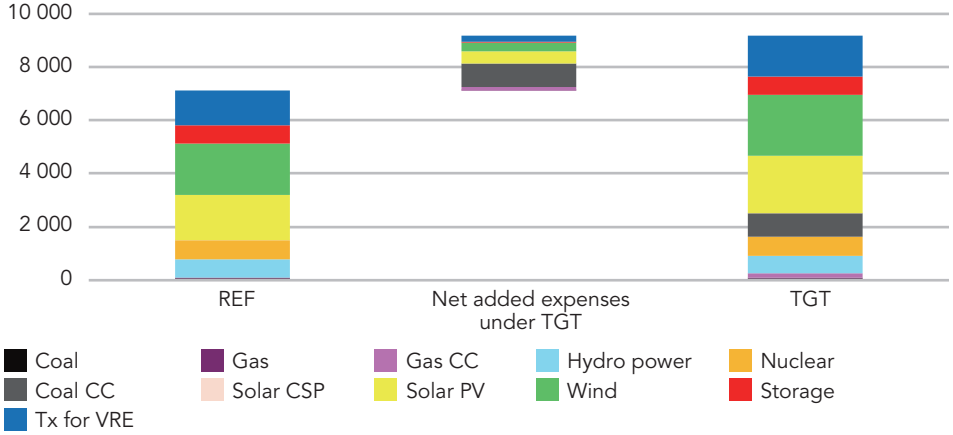
Figure 5-38. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



Note: Tx for VRE is only transmission infrastructure to connect variable renewable capacity to the grid. EV chargers do not cover the cost of associated infrastructure or EV vehicles.

- As economic activities increasingly electrify and decarbonise, securing investment for power supply becomes crucial for economic development and societal well-being. Figure 5-38 considers the total capital, fixed and variable costs for the power sector, heat generation from heat plants, green hydrogen production, EV chargers, and new transmission for added VRE.
- In REF, the total cost for these is estimated at USD 27.8 trillion. Coal and gas account for 35% and 10%, respectively, primarily due to fuel costs and their use in power and heat production. Conversely, renewable costs are primarily driven by CAPEX, with solar PV, wind, hydro, and nuclear comprising significant shares.
- Reduced coal use in TGT produces savings of USD 1.1 trillion. However, increased solar and wind expenses are expected to offset this. 45% of added TGT expenses are allocated to hydrogen production for use in industry, transport, and other sectors. However, increased hydrogen use in transport in TGT will offset conventional fuel use, estimated to save USD 527 billion.

Figure 5-39. Total capital investment (CAPEX) from 2025 to 2060 in the power sector (billion USD, undiscounted)

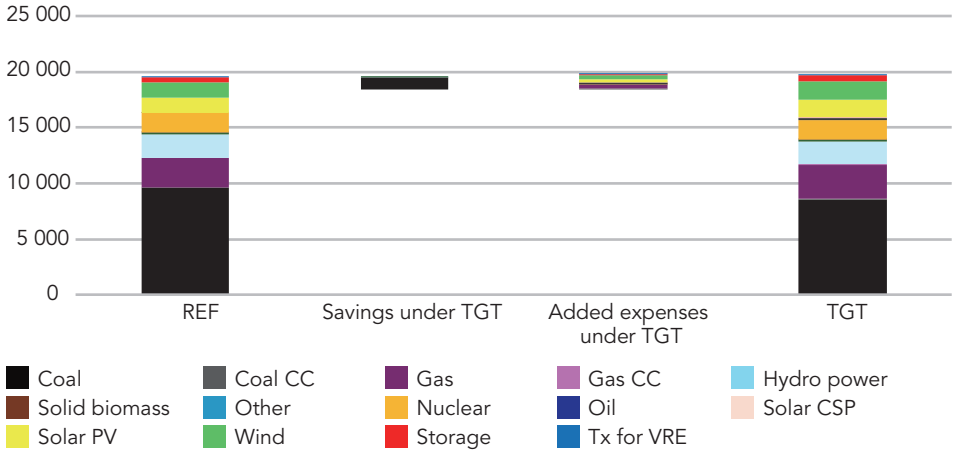


Note: Figure 5-39 only covers power and VRE transmission sector investments. Hydrogen and EV capital investments are not included.

- Total capital investment for REF is estimated to be USD 7.1 trillion with 69% spent on solar PV, wind power, and transmission. TGT requires an additional USD 1.0 trillion in CAPEX for these areas. Notably, the costs for carbon capture installation and retro-fitting in thermal power plants amount to an estimated USD 0.9 trillion, prompting clear policy incentives for such investments.
- As direct government subsidies are reduced, ancillary service costs increase, and time-of-use electricity pricing prevails, renewable investors face increased uncertainty regarding risks and returns. In the long term, land acquisition costs are also expected to become more prominent. Incentives—including regulatory, financial, and tax support, alongside an effective pricing mechanism—are essential for the robust growth of renewables capacity.
- An estimated USD 714 billion will be required for nuclear power deployment in both scenarios. Despite high upfront capital costs and long payback periods, nuclear projects offer a stable long-term income stream. As such, China is beginning to encourage private capital participation in this sector.

Costs

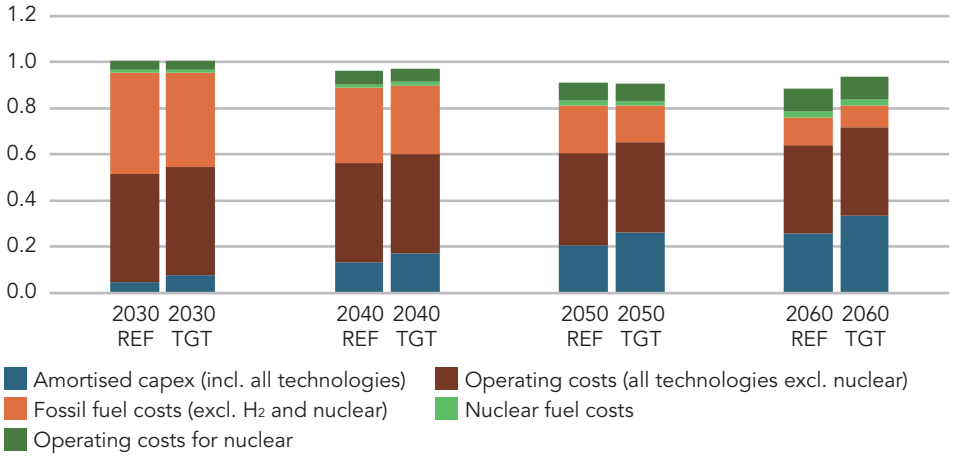
Figure 5-40. Total operating costs from 2025 to 2060 in the power sector (billion USD, undiscounted)



Note: Figure 5-40 covers power, heating and VRE transmission sector costs. It does not include operating costs associated with hydrogen production and EV charger costs.

- Total operating costs of power and heat generation and transmission lines are estimated at approximately USD 19.5 and 19.7 trillion in REF and TGT, respectively. In TGT, savings from reduced coal consumption are offset by increased expenses for gas, renewables, and storage, leading to comparable overall costs with REF.
- In both scenarios, coal represents close to 50% of operating costs, reflecting its major role in power and heat generation during the first half of the projection period. Gas is expected to be 15% of operating costs in both scenarios reflecting its growing use in power and heat generation, bearing in mind uncertainties of gas price projections in the world market.
- Overall, the average cost of electricity from China's wind and solar PV projects has achieved remarkable reductions, driven by rapid technological advancements and industrial capacity ramp-up. However, ensuring grid stability with a high penetration of intermittent renewables necessitates considerable expenses of USD 1.1 trillion in REF and USD 1.3 trillion in TGT for energy storage systems, including batteries and pumped hydro. A clear cost recovery mechanism is key to motivating investments in these projects.

Figure 5-41. Cost of generating electricity relative to 2025 (2025 cost = 1.0) in the power sector



Note: Based on our assumptions about future capital and operating costs, Figure 5-41 shows cost compositions over time relative to 2025. It should not be considered an estimate of electricity tariffs and excludes market mechanisms that are too difficult to estimate.

- Figure 5-41 shows the relative cost of generating electricity in selected years indexed to 2025 as the base year. Overall, the cost of generation is projected to slightly decrease in both scenarios, enhancing electricity access and affordability for its people. The cost of heat generation is not included here.
- The structure of electricity generation costs shows a transition, with a decreased share of fuel expenses and an increase in amortised capital expenditure as more investment in renewables occurs. While the primary driver of fuel cost savings is reducing coal usage, the rising share of import-dependent gas and uranium may increase sensitivity to market fluctuations.
- A decline in generation costs does not automatically translate into lower electricity prices as other market mechanisms exist that are not captured in the above cost estimates. Essential investments in strengthening the power grid and additional expenses for load-following operations will collectively raise the overall cost for power supply.

CO_2 Emissions

Figure 5-42. CO_2 emissions in REF (million tonnes)

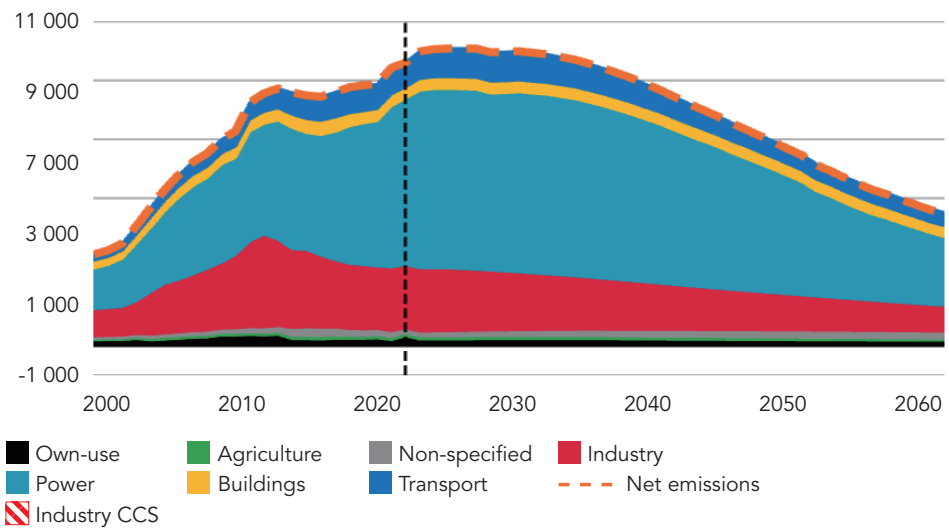
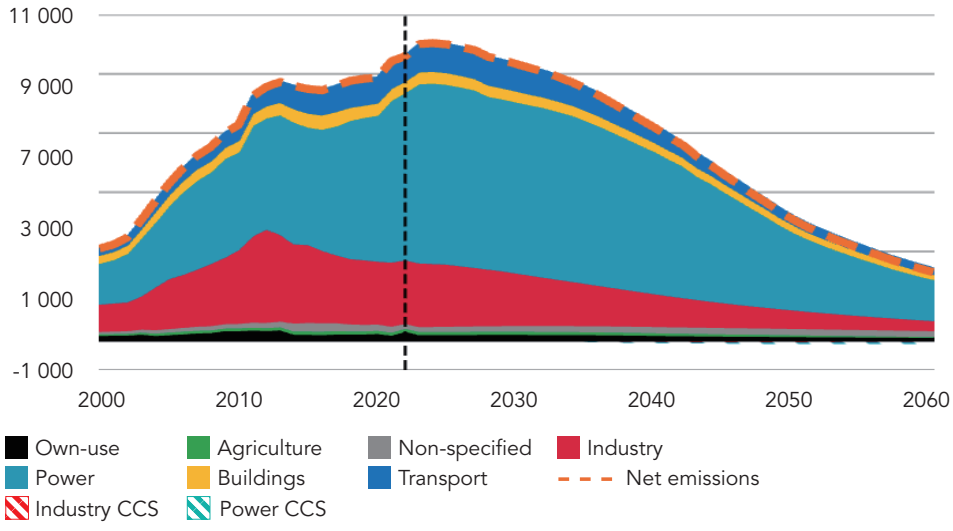
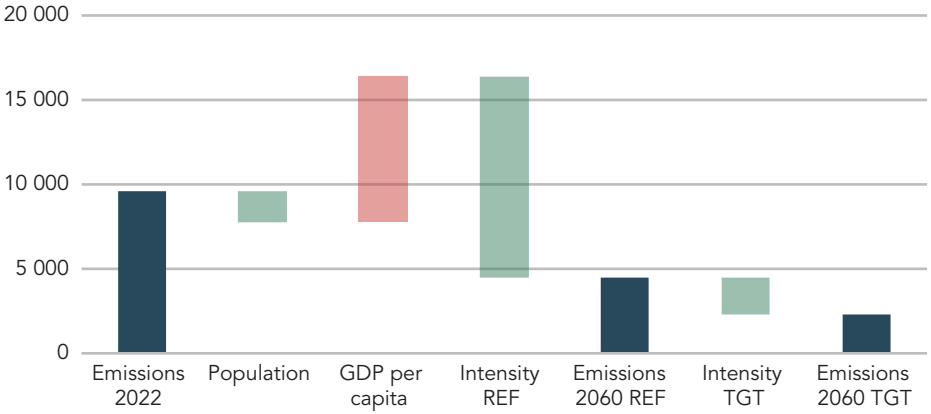


Figure 5-43. CO_2 emissions in TGT (million tonnes)



- Net CO_2 emissions of the energy sector are expected to decline substantially. This is driven by the combined effect of energy intensity improvements, fuel mix shifts, and CCS. With a robust commitment to decarbonisation, China's 2030 carbon-peak target is anticipated to be realised ahead of schedule in both scenarios. The power sector will contribute the majority of these emissions cuts through coal phase-out, supported by steady renewables and nuclear deployment.
- In TGT, CO_2 emissions are projected to decrease by 70% from 2022 to 2060. As 100% post-combustion carbon capture is technically and economically unfeasible with current technologies, achieving China's 2060 net-zero goal will require additional carbon sink measures across both energy and non-energy sectors.

Figure 5-44. CO_2 emissions components (million tonnes)



Note: All values represent energy sector combustion CO_2 emissions. Biogenic CO_2 is treated as zero at the point of combustion.

Useful Links

APERC

APEC Expert Group on Energy Data and Analysis (EGEDA) –
https://www.egeda.ewg.apec.org/

APEC Energy Statistics 2022 –
https://www.egeda.ewg.apec.org/egeda/general/info/pdf/APEC_Energy_Statistics_2022.pdf

APEC Energy Overview –
https://aperc.or.jp/reports/energy_overview.php

The State Council

China's Energy Transition White Paper (2024) –
https://english.www.gov.cn/archive/whitepaper/202408/29/content_WS66d012e8c6d0868f4e8ea52e.html

Working Guidance for Carbon Dioxide Peaking and Carbon Neutrality in Full and Faithful Implementation of the New Development Philosophy (2021) –
https://www.gov.cn/zhengce/2021-10/24/content_5644613.htm

Action Plan for Carbon Dioxide Peaking Before 2030 (2021) –
https://english.www.gov.cn/policies/latestreleases/202110/27/content_WS6178a47ec6d0df57f98e3dfb.html

Comprehensive Work Plan for Energy Conservation and Emission Reduction in the 14th Five-Year Plan (2021) –
http://www.gov.cn/zhengce/zhengceku/2022-01/24/content_5670202.htm

NDRC (National Development and Reform Committee)

Action Plan to Accelerate the Construction of a New Power System (2024-2027) (2024) –
https://www.gov.cn/zhengce/zhengceku/202408/content_6966863.htm

Guiding Opinions on Vigorously Implementing the Renewable Energy Substitution Initiative (2024) –
https://www.ndrc.gov.cn/xxgk/zcfb/tz/202410/t20241030_1394119.html

Action Plan for Low-Carbon Transformation Construction of Coal-Fired Power (2024-2027) (2024) –
https://www.ndrc.gov.cn/xxgk/zcfb/tz/202407/t20240715_1391663.html

14th Five-Year Plan for a Modern Energy System (2022) –
https://www.ndrc.gov.cn/xxgk/zcfb/ghwb/202203/t20220322_1320016.html

Medium- and long-term plan for the development of the hydrogen energy industry (2021-2035) (2022) –
https://www.ndrc.gov.cn/xxgk/zcfb/ghwb/202203/t20220323_1320038.html

14th Five-Year Plan on Renewable Energy Development (2021) –
https://www.ndrc.gov.cn/xxgk/zcfb/ghwb/202206/t20220601_1326719.html

NEA (National Energy Administration)

The Blue Book on the Development of New Power Systems (2023) –
https://www.nea.gov.cn/2023-06/02/c_1310724249.htm



6. Hong Kong, China

Summary

	Reference			Target		
	2022	2060	% Change	2022	2060	% Change
Macroeconomic						
Population (million)	7.35	8.18	11%	7.35	8.18	11%
GDP (billion 2017 USD, PPP)	441	836	90%	441	836	90%
Energy Demand						
Agriculture & fisheries (PJ)	0.137	0.171	25%	0.137	0.13	-5%
Buildings (PJ)	179	226	26%	179	108	-40%
Industry (PJ)	11.7	16.6	42%	11.7	15.2	30%
Non-energy (PJ)						
Transport (PJ)	73	36	-51%	73	29	-60%
Modern renewable share of TFEC (%)	1.5	8.98	454%	1.5	66.89	4,029%
Energy intensity of TFEC (PJ/GDP, billion USD)	0.60	0.33	-45%	0.60	0.18	-70%
Electricity						
Generation (TWh)	36	52	44%	36	14	-61%
Renewables share of generation (%)	1.0	9.23	999%	1.0	65.92	7,748%
Generation capacity (GW)	11.5	13.0	13%	11.5	10.6	-8%
Total Primary Energy Supply (TPES)						
Coal & coal products (PJ)	150	0	-100%	150	0	-100%
Natural gas (PJ)	187	390	108%	187	38	-80%
Petroleum liquids (PJ)	103	23	-78%	103	1	-99%
Low-carbon & waste energy (PJ)	6	35	483%	6	52	767%
CO_2 intensity of energy supply ($MtCO_2/PJ$)	0.064	0.044	-31%	0.064	0.012	-81%
Net CO_2 Emissions (million tonnes)	28.9	23.2	-20%	28.9	2.2	-92%

Note: In this publication, the term "modern renewables" refers to all renewable energy sources excluding solid biomass in the buildings sector. The term "low-carbon & waste energy" includes all bioenergy, waste-derived energy, renewables, nuclear, and hydrogen-based fuels. Total primary energy supply (TPES) numbers include international bunkers. Net emissions are calculated as gross energy sector combustion CO_2 minus CO_2 captured and stored through carbon capture and storage (CCS).

Key Takeaways

Emissions

- The Reference scenario (REF) projects a decrease in Hong Kong, China's energy-related CO_2 emissions to 23 million tonnes by 2035 as coal consumption scales down, achieving a 44% decrease from 2005 levels and nearing the 50% target outlined in Hong Kong, China's Climate Action Plan 2050 (CAP2050). High gas consumption is expected to keep emissions plateaued at this level through the end of the projection period—2060.
- In the Target scenario (TGT), Hong Kong, China's combustible emissions are projected to be 78% below 2005 levels by 2035, driven by improved energy intensity, end-use electrification, and fossil fuel displacement. By 2050, however, an estimated 2.2 million tonnes of CO_2 emissions will remain, primarily from gas-fired power generation. These residual emissions may necessitate offsetting through various carbon-sink technologies.

Energy Import Dependence

- Hong Kong, China's supply of coal, gas, and petroleum products is entirely sourced externally. All of its domestic energy production is derived from biomass, waste, and other renewable sources. Thus, a high share of fossil fuels translates into significant import dependence.
- In REF, the net imports share is expected to remain above 90%, driven by the anticipated scaling-up of gas power generation and increased electricity imports. Production growth will be marginal due to limited indigenous resources. This heavy reliance on gas imports underscores the importance of diversifying gas sources and securing transport channels.
- In TGT, ambitious decarbonisation targets are expected to significantly reduce both the share of gas imports and overall energy fuel import dependency. A faster transition to alternative vehicle engines leads to a rapid decrease in oil demand and drop-in fuels. By 2050, electricity will become the dominant fuel in net imports, underlining critical challenges in transmission reliability and emergency response capability.

Figure 6-1. Net CO_2 emissions (million tonnes)

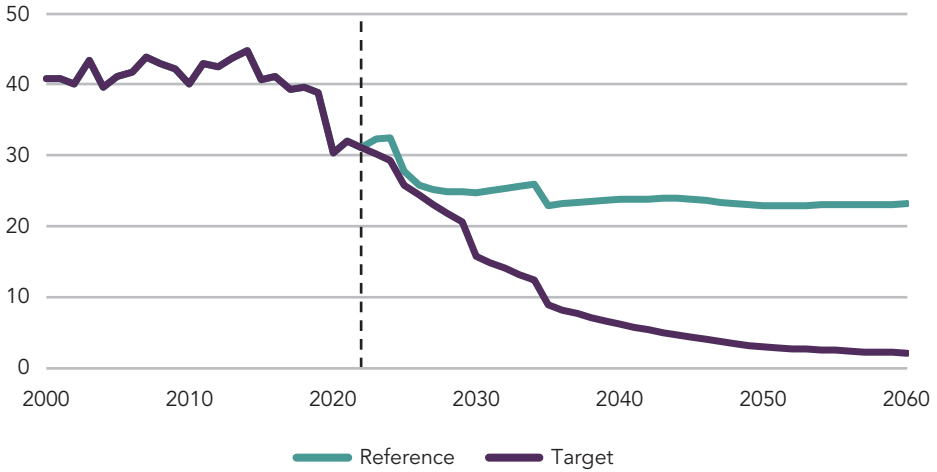
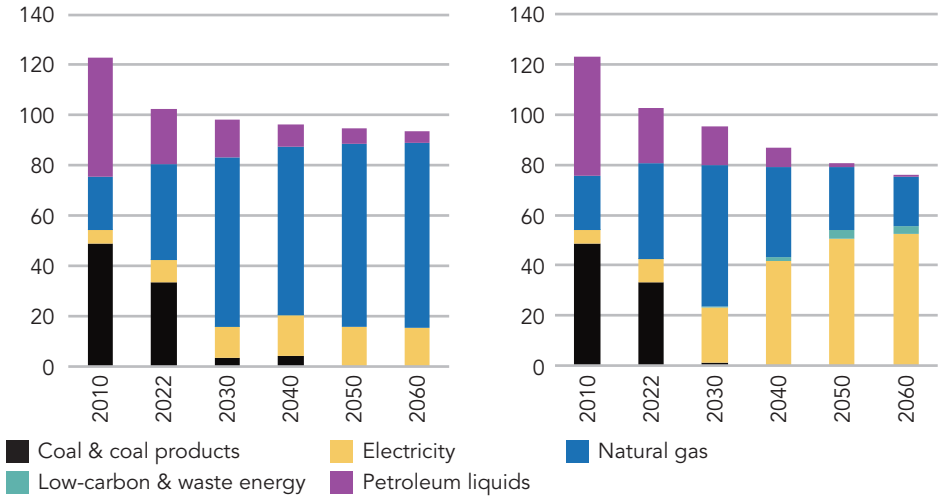


Figure 6-2. Net imports share of TPES in REF & TGT (%)



Note: In Figure 6-2, net imports refer to total imports minus exports and international bunkers. Net imports share higher than 100% is caused by stock increase.

Key Takeaways

Grid Reliability

- In Hong Kong, China, peak electricity consumption typically occurs in summer, driven by high cooling demand. In REF, peak load is expected to grow with total electricity demand through 2060. Conversely, TGT projects peak load to eventually decrease to 5.8 GW. Since winter provides better operating conditions for solar and wind, dispatchable power output will be much lower than the peak load by 2060 in TGT.
- In TGT, a higher share of renewables is expected to flatten the dispatched power curve. However, renewables also introduce additional volatility due to their intermittent nature. As a result, the power grid will require enhanced reliability measures to manage these increased risks.
- Electricity imports are projected to serve as a baseload power source. Thus, gas power units will provide essential flexibility, causing their average load factor to drop to under 7% in TGT. This low utilisation might impact project profitability.

Cost

- The total costs for the power and hydrogen sectors from 2025 to 2060 are estimated to be USD 58 billion lower overall in TGT compared to REF. Costs considered include total capital, fixed, and variable costs to generate electricity plus the costs of additional transmission needed for VRE, electricity imports, the additional costs of electric vehicle chargers, and the costs of importing low-carbon hydrogen for domestic use.
- Overall, the Target scenario projects a significant decrease in power sector costs. One of the key drivers of this reduction is the decrease in cumulative electricity demand achieved through energy saving initiatives. While capital expenditures for low-carbon electricity generation and renewables-related transmission increase in TGT compared to REF, these costs are substantially offset by savings from reduced gas power generation.

Figure 6-3. Peak load and maximum and minimum dependence on dispatched power (GW)

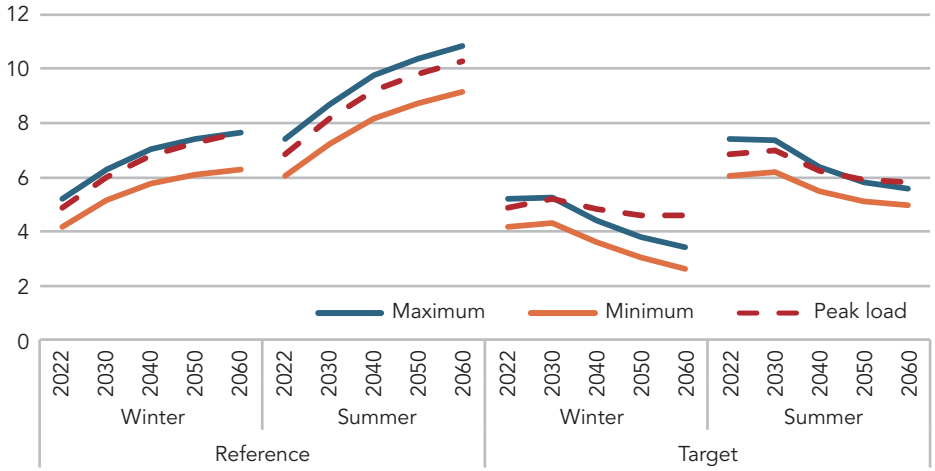
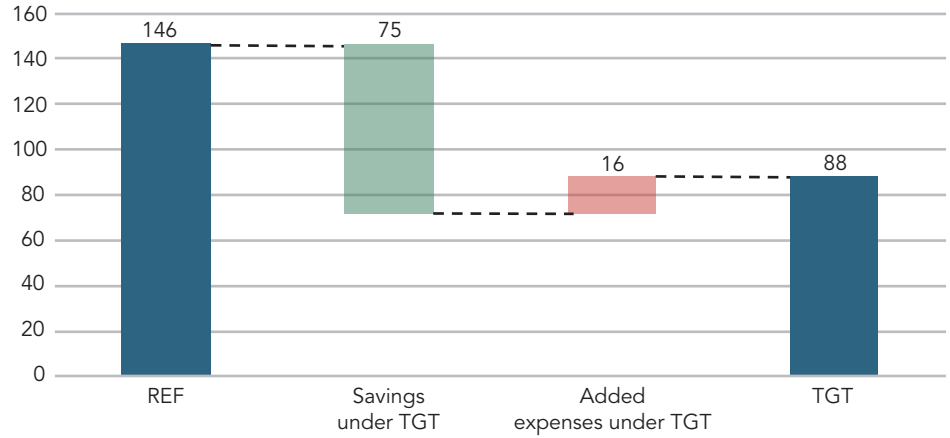


Figure 6-4. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



*Actual costs will differ from estimated costs in the *Outlook* for a variety of reasons including changing commodity prices, manufacturing costs and unforeseen technical advances. All costs are in 2023 real terms.

About Hong Kong, China

Overview

Geographical and Economic Landscape

Hong Kong, China is located at the southeastern tip of China, covering Hong Kong Island, Lantau Island, the Kowloon Peninsula, the New Territories, and 261 outlying islands, reaching approximately 1,114 square kilometres of total land area. As of 2022, Hong Kong, China's population was about 7.3 million.

Hong Kong, China has been a Special Administrative Region of the People's Republic of China (China) since 1997 with a high degree of autonomy. Hong Kong, China's economy is categorised as a highly developed free-market economy, as an international centre of trade, commerce, finance, and communications.

Energy Supply and Consumption

Hong Kong, China's total primary energy supply remained stable at around 600 PJ since 2000 before dropping to below 500 PJ in 2022. Fossil fuels dominate the energy supply, with gas, coal, and oil accounting for 38%, 31%, and 21% in 2022, respectively.

The rising share of buildings and transport in total energy demand over the past two decades reflects the transformation of Hong Kong, China's economy from a manufacturing-based economy to a service-based economy. Electricity represents 61% of the final energy consumption, sourced mainly from gas and coal-fired power plants and direct imports.

Energy Security Challenges and Strategies

Hong Kong, China has limited indigenous energy resources, with very small-scale biomass, solar and wind power generation. Its energy needs are met almost entirely from external supplies, such as oil, gas, and coal products, as well as transformed secondary energy such as electricity.

Hong Kong, China started diversifying its gas sources by importing LNG through its first offshore LNG receiving terminal in 2023. It also keeps exploring ways to enhance regional cooperation to increase the supply of zero-carbon electricity.

Key Energy Initiatives

Decarbonisation Commitment

In 2021, as part of its CAP2050, Hong Kong, China announced its medium-term goal to halve its carbon emissions by 2035 compared with 2005 levels and achieve carbon neutrality before 2050 through four major strategies: "net-zero electricity generation", "energy saving and green buildings", "green transport", and "waste reduction".

Energy Efficiency Initiatives

Dedicated energy efficiency initiatives include the Mandatory Energy Efficiency Labelling Scheme (MEELS), the Voluntary Energy Efficiency Labelling Scheme (VEELS), the Buildings Energy Efficiency Ordinance (BEEO), the District Cooling System (DCS), promotion of retro-commissioning (RCx), incentives for buildings certified with the green building assessment scheme and subsidy schemes for energy-saving retrofit.

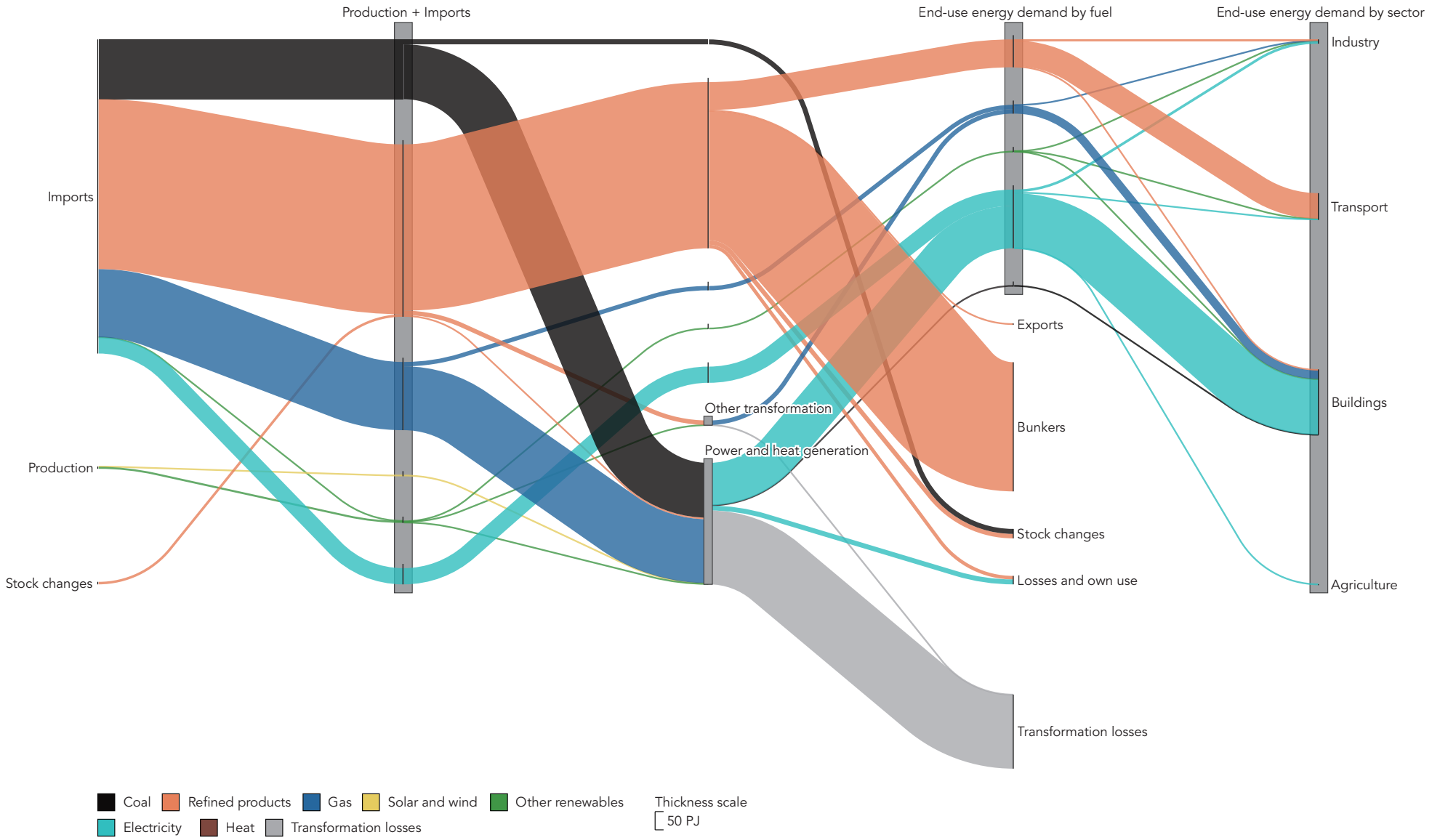
Renewable Energy Initiatives

As set out in the CAP2050, Hong Kong, China will strive to increase the share of renewable energy in the fuel mix for electricity generation from less than 1% at present to 7.5% to 10% by 2035, and further increase it to 15% before 2050. Renewable energy initiatives in Hong Kong, China include the Feed-in Tariff and Renewable Energy Certificate, the installation of a number of large-scale renewable energy systems at government premises, and the planning of many other major projects.

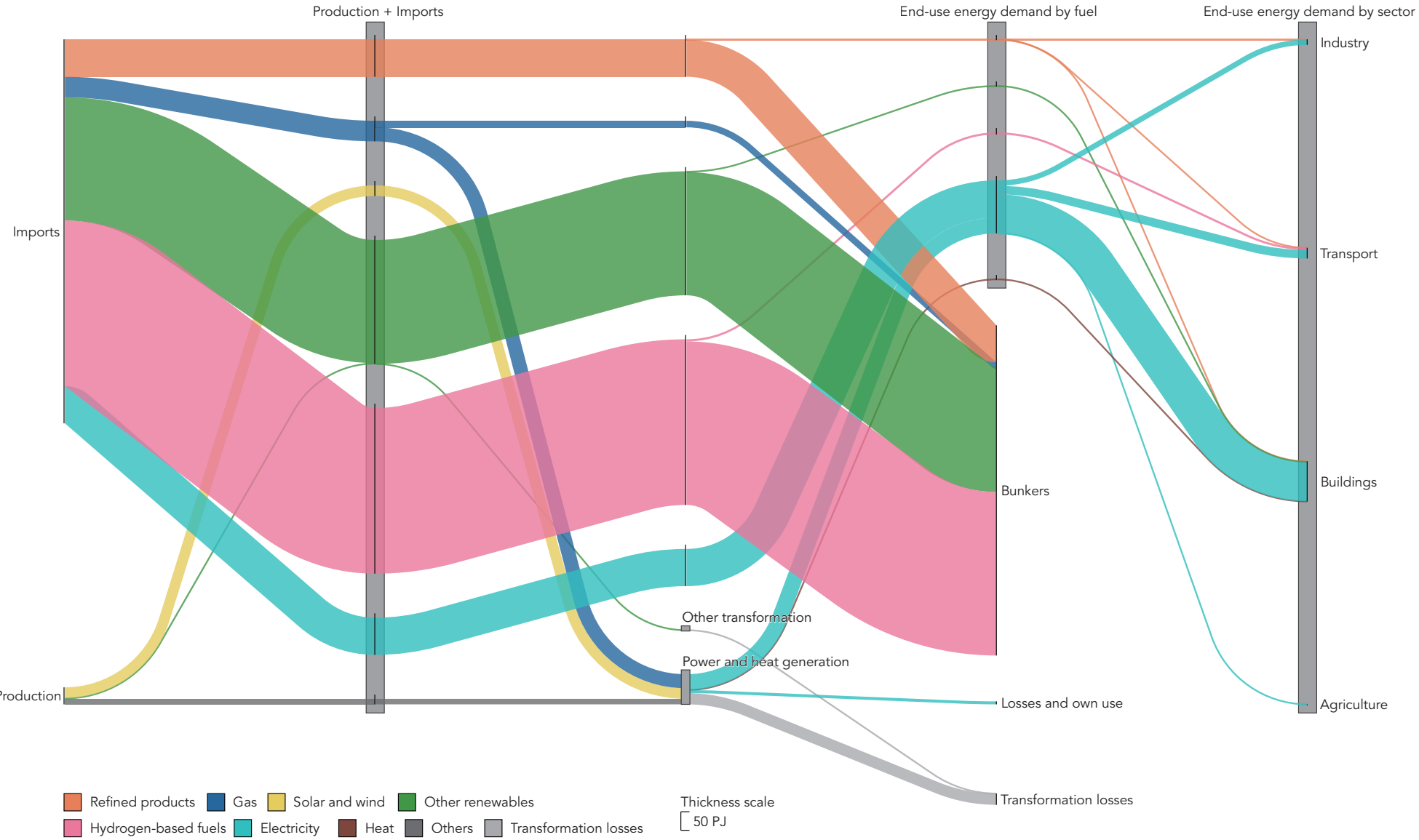
Green Transport Initiatives

Since 2011, Hong Kong, China has been encouraging new energy vehicle adoption through the New Energy Transport Fund. The Hong Kong Roadmap on Popularisation of Electric Vehicles, announced in 2021, set the target to cease the new registration of fuel-propelled and hybrid private cars by 2035 or earlier.

Energy Flow (2022)



Energy Flow (2060, Target Scenario)



Scenarios and Assumptions

In *The Outlook*, APERC analyses energy demand, transformation, and supply, as well as emissions. The **Reference Scenario (REF)** offers a projection based on historical trends, recent developments, and APERC's assumptions about the continuation of those trends in each APEC economy, while acknowledging technical restraints. The REF Scenario offers a baseline to compare with the **Target Scenario (TGT)** projections, which explores a hypothetical pathway where each economy achieves energy-related policy targets, assuming implementation regardless of cost-effectiveness. When implementation details are lacking, assumptions are inferred from the targets themselves or emissions-related goals.

	Reference	Target
General	• Population: Population projections (UN DESA) and Hong Kong, China's government projections from 2025 to 2047, and then levels off. • GDP: APERC model and IMF.	• Same as the Reference scenario.
Buildings	• Assumptions adopted in the APERC model: - Activity increases, driven by population and economic growth. - Modest efficiency gains curb demand slightly. - Electrification follows historical trends. - Marginal LPG consumption is maintained. - Both scenarios assume data centres' electricity demand to grow from 6.35 PJ (2022) to 20 PJ (2035) and plateaus after 2040 (based on potential floor space).	• Hong Kong, China's Climate Action Plan 2050: - New and existing residential buildings' electricity consumption reduces by 10% by 2035 and 20% by 2050 (using the operational conditions of 2015 as a comparison basis). - Commercial buildings electricity consumption reduces by 15% by 2035 and 30% by 2050 (using the operational conditions of 2015 as a comparison basis). • Assumptions adopted in the APERC model: - Fossil fuels are phased out for cooking by 2050.
Industry	• Assumptions adopted in the APERC model: - The majority of industrial energy use is in the manufacturing sector and is assumed to stay flat until 2060. - Electricity takes up 75% of total energy demand by 2050.	• Assumptions adopted in the APERC model: - Moderate efficiency improvement. - Electricity takes up 90% of total energy demand by 2050. - Gas and oil are fully phased out by 2045 and 2060, respectively.
Transport	• Assumptions adopted in the APERC model: - Passenger activity remains relatively constant in both scenarios. - BEV sales share reaches 70% in passenger vehicles and 10% in heavy trucks by 2030. - Faster turnover rate of vehicles as a result of the 'One-for-One Replacement' scheme in both scenarios.	• Hong Kong, China's EV Roadmap: - The target of zero emissions by 2050 is achieved. • Assumptions adopted in the APERC model: - BEV sales share reaches 85% in passenger vehicles, and 35% in heavy trucks by 2030. FCEV sales share reaches 10% in heavy trucks by 2030. - FCEV stock share reaches 15% in heavy trucks by 2040. - E-fuels consumption will ramp up after 2040 and replace all fossil fuel consumption by 2050. - Faster shift to hydrogen and electric boats encouraged by higher sales shares and a higher turnover rate.

	Reference	Target
Power	• Assumptions adopted in the APERC model: - Limited growth in renewable energy capacity due to space constraints. The generation capacity of solar, wind, and others (including waste-to-energy) reaches approximately 1 GW, 0.8 GW, and 1.4 GW, respectively, by 2060. - Coal-fired power generation is phased out by 2050. - Gas-fired generation remains significant for system balancing, with its capacity reaching 9 GW by 2050.	• Hong Kong, China's Climate Action Plan 2050: - Coal-fired generation is phased out by 2035. - The shares of solar, wind, and others (waste-to-energy) generation exceed 1%, 3.5%, and 3%, respectively, by 2035. - The combined generation share of solar, wind, and others (including waste-to-energy) generation is 15% before 2050. - Electricity imports share exceeds 60% by 2035.
Supply	• Assumptions adopted in the APERC model: - Hydrogen demand is 100% met by imports. - Coal, gas, and petroleum products demand (including bunkers) is 100% met by imports. - No re-export of coal, gas, and petroleum products.	• Same as the Reference scenario.
Emissions	• Close to the 2035 target of a 50% reduction compared to 2005 levels.	• Emissions reach the 2035 target of a 50% reduction compared to 2005 levels. • Close to the net-zero emissions target by 2050.

Note: The base year is 2022. Macro-economic assumptions are constant across scenarios. Historical energy balances are from EGEDA submissions for 2022.

Demographic and Macroeconomic Assumptions

Figure 6-5. Population (thousands)

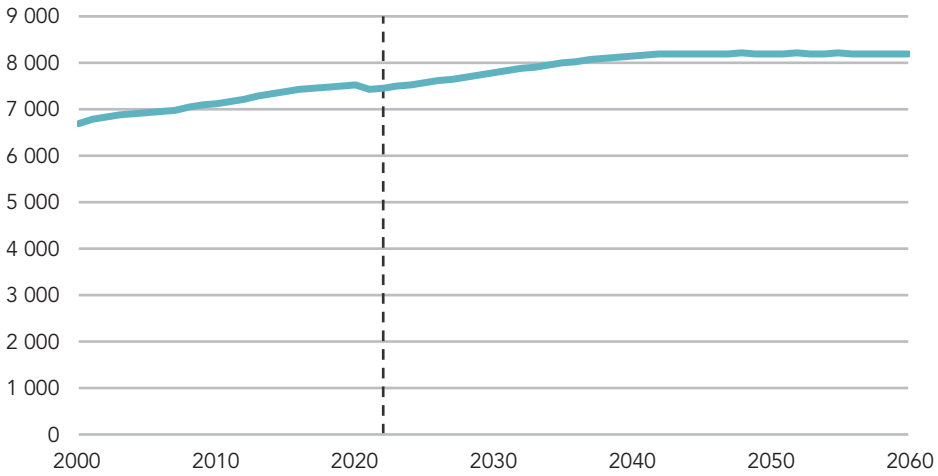
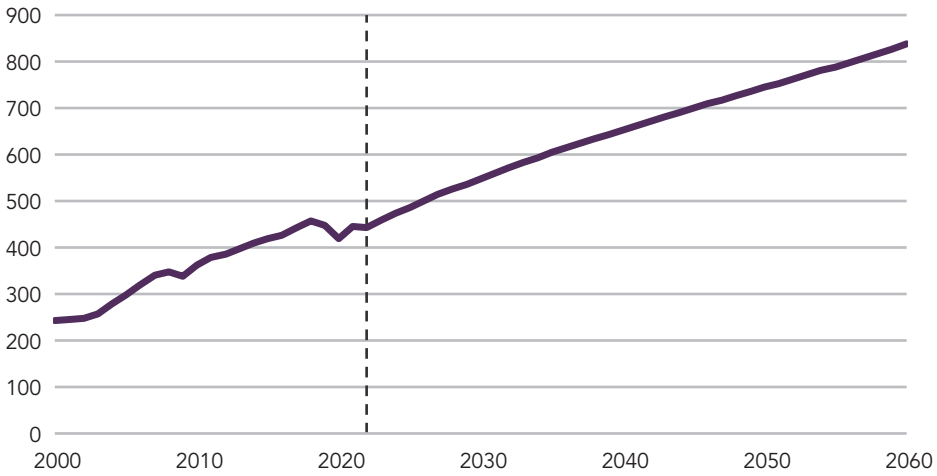


Figure 6-6. Real GDP (billion USD PPP, 2017)



- Hong Kong, China's population is assumed to follow the government's projection, growing gradually from around 7.3 million in 2022 to 8.2 million in 2046. Subsequently, the population is expected to stabilise at the 2046 level until the end of the projection period.
- Hong Kong, China's population is expected to continue its ageing trend. However, inward migration will help offset the decline in the share of the labour force.
- Real GDP is expected to resume its upward trajectory from 2023, growing at a Compound Annual Growth Rate of approximately 1.6%, reaching USD 836 billion (2017 USD purchase power parity [PPP] basis) in 2060. Concurrently, per capita GDP will steadily increase, exceeding USD 98,000 by 2060.
- The services sector has been and will remain the primary driver of Hong Kong, China's economic growth. Financial services, tourism, trading and logistics, as well as professional services and other support services are identified as the four key subsectors constituting the economy.

End-use Energy Demand

Figure 6-7. Energy demand by sector in REF & TGT (PJ)

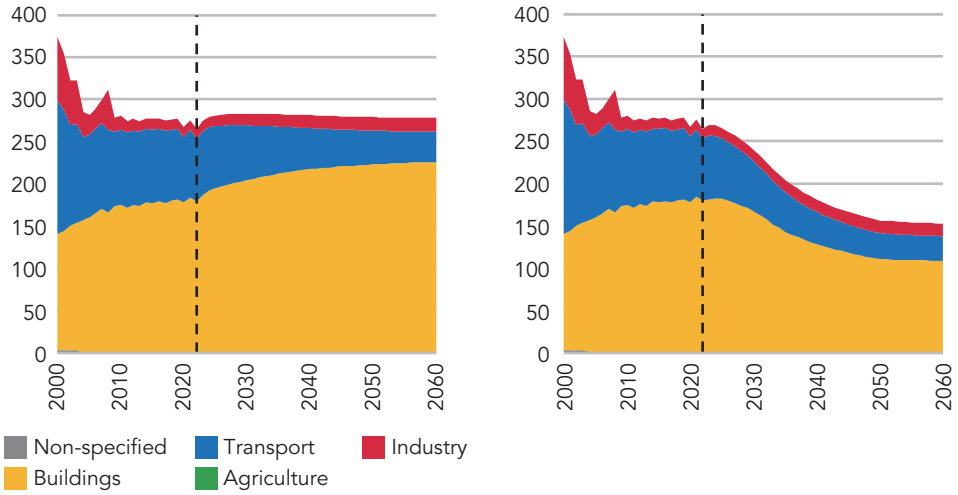
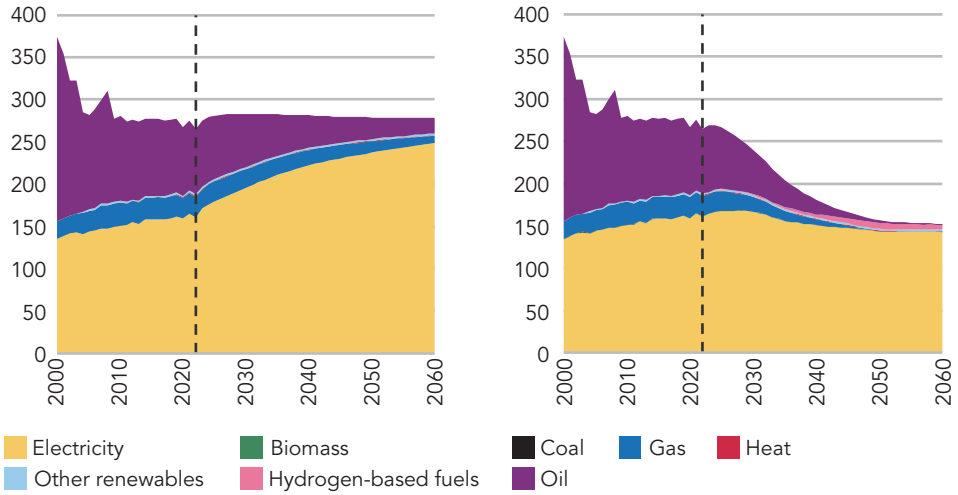


Figure 6-8. Energy demand by fuel in REF & TGT (PJ)



- Given its predominantly services-based economy, Hong Kong, China's end-use energy demand is dominated by the buildings and transport sectors. The growth in population and per capita GDP is expected to drive activity within these sectors.
- In REF, Hong Kong, China's total energy demand is expected to recover from the impact of COVID-19 and remain stable at around 280 PJ. Buildings' energy demand grows by a quarter, with its share increasing from 68% in 2022 to 81% in 2060. Conversely, transport energy demand (excluding international bunkers) halves due to efficiency improvements, resulting in its share decreasing from 28% to 13% over the same period.
- In TGT, the buildings sector is projected to meet the ambitious energy saving targets outlined in the Climate Action Plan 2050 (CAP2050), leading to a 39% decrease in its end-use demand by 2050 compared to 2022. The transport sector also achieves a greater decline in demand of 58% over this period. Overall, total end-use demand decreases by 41%, reaching 156 PJ by 2050.
- Hong Kong, China has already achieved a notable level of electrification. Driven by the promotion of electric vehicles, broader fossil fuel substitution and energy efficiency measures across sectors, by 2060, the share of electricity is projected to substantially increase to 89% in REF and 94% in TGT.
- Oil consumption, primarily from the transport sector, continues its downward trend. In REF, a residual oil demand of 19 PJ is expected to remain by 2060, due to the continued operation of a small number of internal combustion engine (ICE) vehicles. In TGT, there is a nearly complete displacement of oil by 2060.
- Gas consumption for end-use is projected to decline from 9% of the total demand in 2022 to 3% in 2060 in REF, predominantly serving the buildings sector. In TGT, this demand will be entirely substituted by other zero-carbon emission fuels by 2050.
- Hydrogen and synthetic fuels (e-fuels) are considered important low-carbon substitutes for petroleum products in road freight transport and domestic aviation, accounting for 4% of total energy demand in TGT by 2060.

Buildings Energy Demand

Figure 6-9. Buildings energy demand by fuel in REF & TGT (PJ)

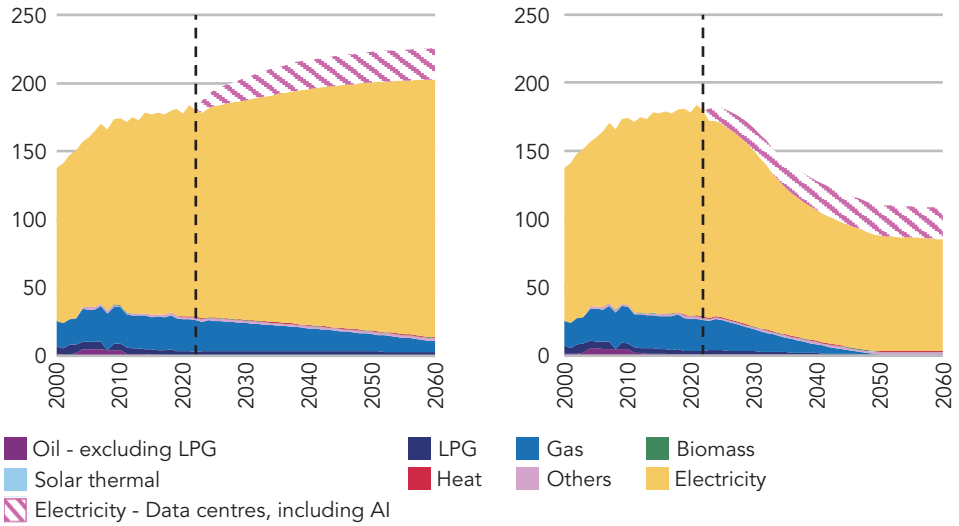
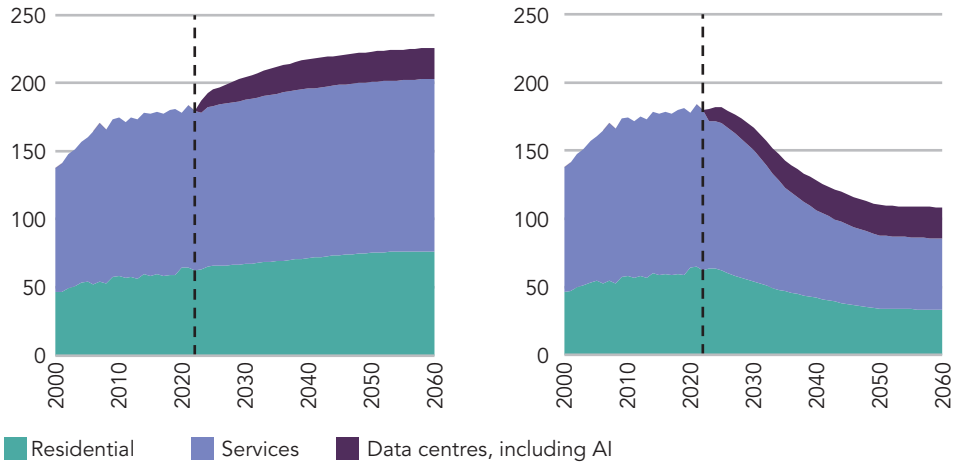


Figure 6-10. Buildings energy demand by sector in REF & TGT (PJ)



- The buildings sector accounts for over 90% of electricity end-use in Hong Kong, China as of 2022. Alongside conventional applications, data centres are emerging as significant power consumers, reflecting their potential in supporting the services sector and technological advancement.
- In REF, non-data centre electricity demand within this sector is projected to grow at an average of 0.7% annually until the late 2040s, driven by sustained economic development and population growth. Notably, this rate is slower than historical trends, attributed to continuous improvements in building energy efficiency. This growth is expected to gradually decelerate as population expansion stabilises.
- Informed by existing data centre scale and government estimates on available floor space, electricity demand from data centres is projected to grow from 6.3 PJ in 2022 to 20 PJ in 2035, eventually stabilising at 23 PJ by 2060. Its share in the total electricity demand of the sector will increase from 4% in 2022 to 11% in REF and 22% in TGT by 2060.
- CAP2050 sets ambitious electricity conservation goals for buildings. In TGT, new and existing residential and commercial (including data centres) electricity consumption is expected to reduce by 10% and 15%, respectively, by 2035 (using the operational conditions of 2015 as a comparison basis), with further reductions to 20% and 30%, respectively, by 2050.
- Achieving these targets may necessitate rigorous enforcement of green building standards, substantial investment in building retrofits and advanced energy-saving technologies, and active promotion of smart energy monitoring and management systems. In this connection, Hong Kong, China continuously reviews the coverage of these measures and explores the potential of district cooling to enhance energy efficiency.
- Buildings' reliance on town gas has been steadily declining. In REF, fossil fuel consumption is projected to decrease to 26 PJ by 2060. Conversely, in TGT, LPG and natural gas are anticipated to be phased out by 2050, leaving only marginal demand for other petroleum products for emergency back-up.

Industry Energy Demand

Figure 6-11. Industry energy demand by fuel in REF & TGT (PJ)

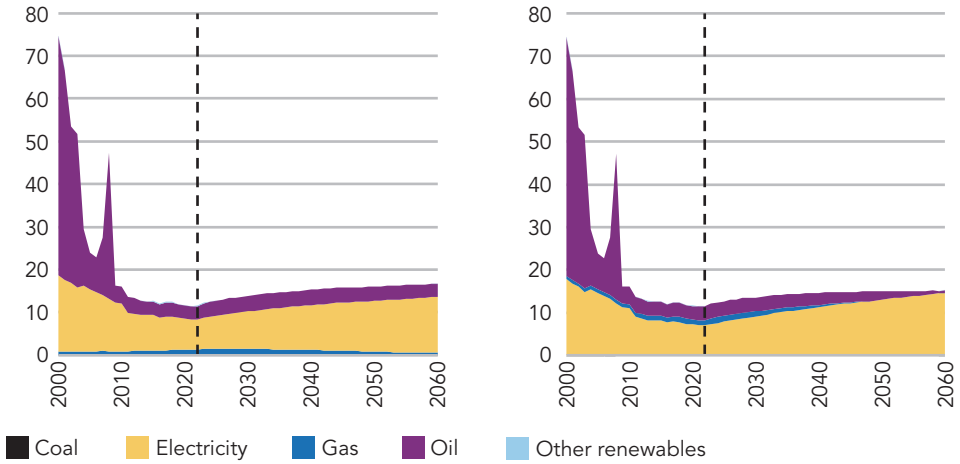
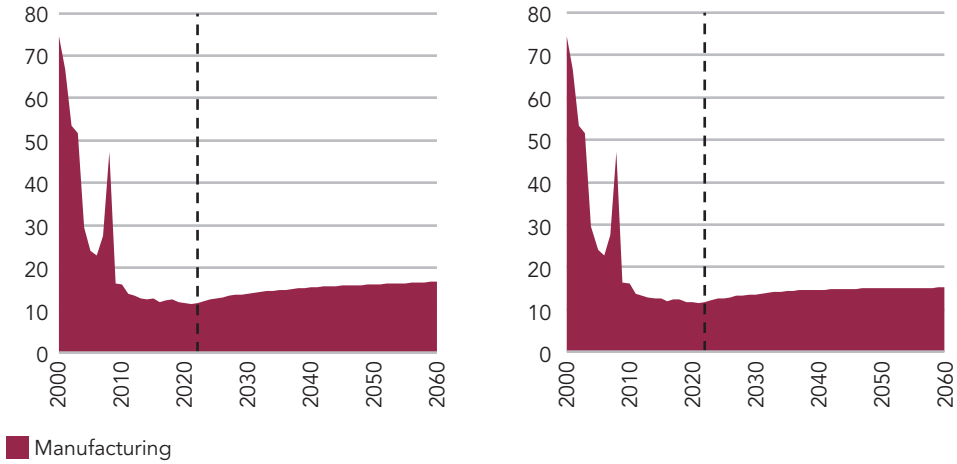


Figure 6-12. Industry energy demand by sector in REF & TGT (PJ)



- Following its transition from a light manufacturing to a service-based economy, Hong Kong, China's industrial energy demand substantially decreased from approximately 20% of the total final energy demand in 2000 to 5% in 2010, subsequently stabilising at around 12 PJ over the past decade. Electricity has been the dominant fuel for this sector since 2004.
- Currently, all industrial energy use in Hong Kong, China is dedicated to manufacturing. Government initiatives, including the Innovation and Technology Development Blueprint and the Northern Metropolis Development Strategy, aim to foster advanced manufacturing and encourage local enterprises to transition towards high-value-added, technology-intensive, and sustainable production.
- Considering the current status and policy direction, moderate growth in industrial activities and increased electrification are assumed in both scenarios.
- In REF, the industry sector's total energy demand is expected to grow from 12 PJ in 2022 to 17 PJ by 2060. Electricity's share will increase from 60% to nearly 80% in this same time period, while oil's share will reduce from 28% to 18%.
- In TGT, enhanced energy efficiency upgrades lead to total energy demand plateauing at around 15 PJ after the mid-2040s. By 2060, only 0.5 PJ of oil demand will remain. Despite the 2050 net-zero electricity generation target, a 100% electrification rate for all manufacturing processes presents significant challenges due to technical limitations in electrifying certain high-temperature processes. The residual emissions may be offset by various carbon-sink technologies to meet carbon neutrality.

Transport Energy Demand

Figure 6-13. Domestic transport energy demand in REF (PJ)

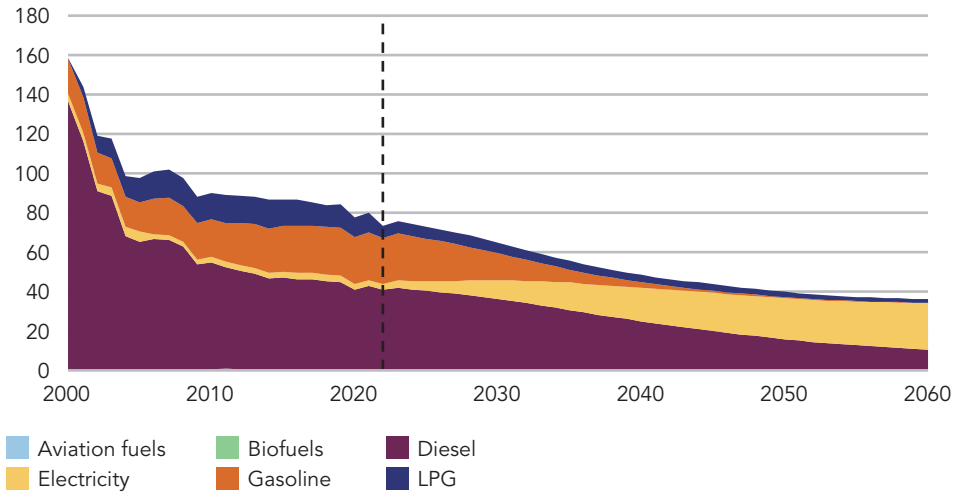
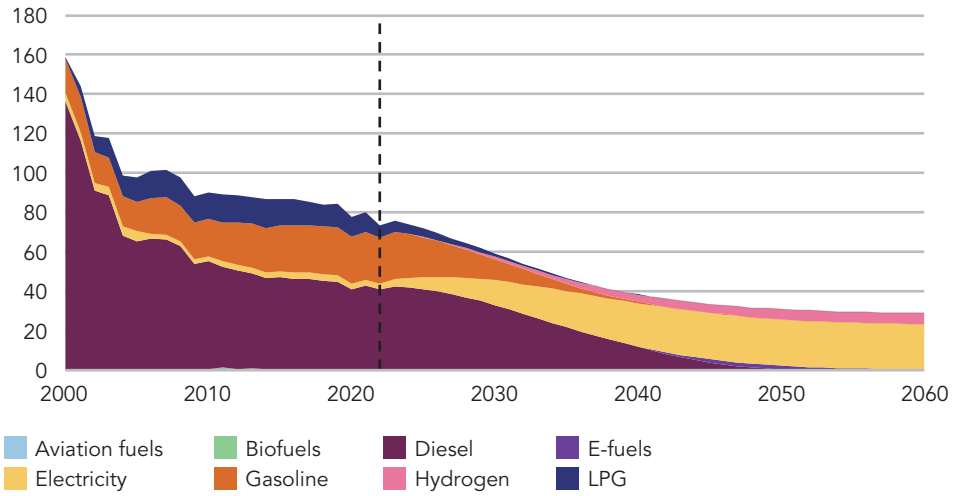


Figure 6-14. Domestic transport energy demand in TGT (PJ)



- The transport sector is a major energy consumer and carbon emissions source in Hong Kong, China, second only to the power sector. Over the past two decades, public transit system extension and efficiency advancement have collectively reduced transport energy demand by more than half.
- The government has outlined several key measures for zero vehicular emissions, including electric vehicles (EVs) promotion, fuel cell electric vehicles (FCEVs) testing, and the adoption of new energy ships (electric and hybrid). Consequently, almost all fossil fuels are projected to be phased out by 2050 in TGT.
- In REF, electricity demand is projected to expand more than sixfold, reaching 24 PJ by 2060, primarily driven by rising sales of battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs). Despite this growth, diesel is still projected to account for 29% of transport energy demand by 2060, underscoring the persistent challenge of decarbonising heavy-duty trucks and ships.
- In TGT, BEVs are projected to constitute 100% of private and light commercial vehicle sales by 2035. With accelerated electrification across road and water transport, electricity consumption is expected to plateau at around 23 PJ after 2040 in TGT.
- After 2050, heavy freight truck sales are expected to be dominated by BEVs (70%) and FCEVs (30%) in TGT. A portion of domestic ships will also transition to fuel cell propulsion. Hydrogen demand is projected to increase to around 5 PJ by 2050 and 5.5 PJ by 2060.
- In TGT, achieving a complete displacement of diesel by 2050 requires the scale-up of hydrogen-based synthetic fuels (e-fuels), which are technically compatible but currently cost-prohibitive drop-in substitutes. E-fuel demand is projected to peak at 2 PJ in 2050, after which it declines sharply to near zero by 2060 as the stock of ICE vehicles retires.
- The large-scale adoption of EVs depends on the expansion of charging infrastructure. In Hong Kong, China, the prevalence of stratified high-density buildings may pose challenges for the deployment of charging facilities.

Other Transport Data

Figure 6-15. Transport vehicle stocks in REF & TGT (millions)

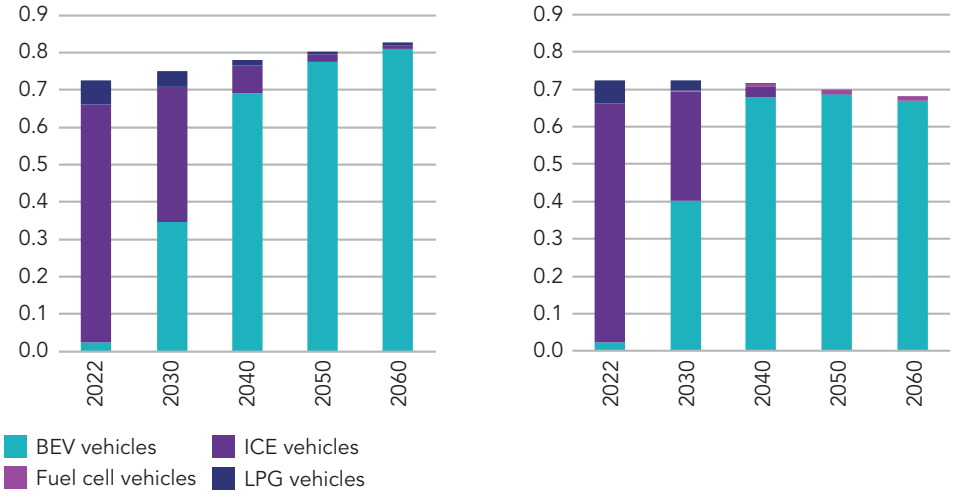
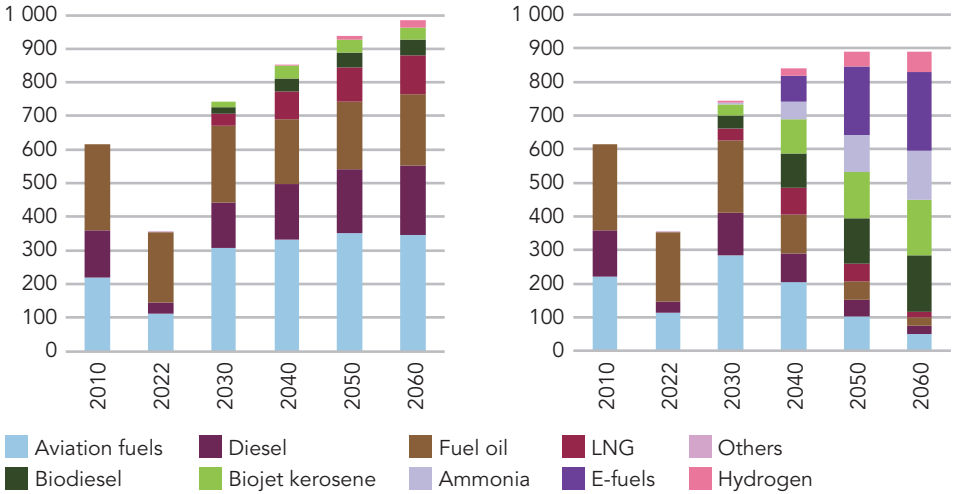
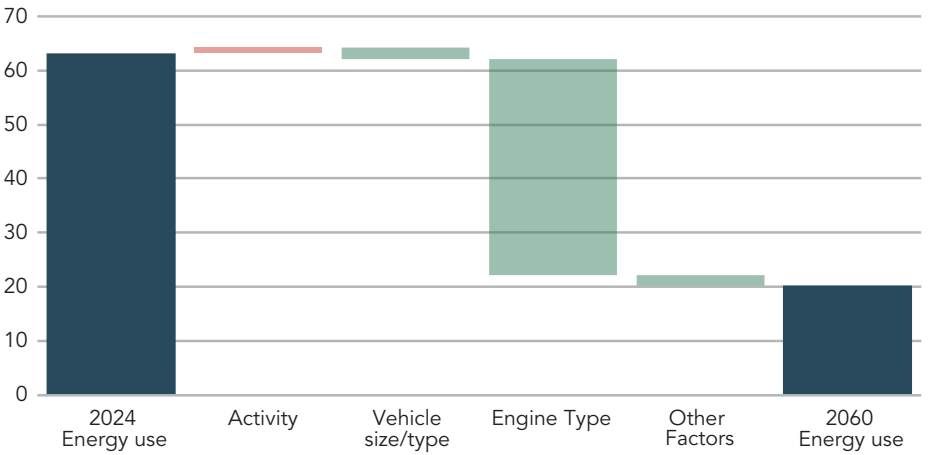


Figure 6-16. International bunkers energy demand for shipping and aviation in REF & TGT (PJ)



- As shown in Figure 6-17, the transition in engine type is expected to be the primary driver of energy conservation in this sector. Hong Kong, China's statistics indicate that, as of April 2025, the total EV stock stands at around 119,000, representing 13% of the total vehicle fleet.
- In REF, there is a projected surge in growth of BEV stock to 775,000 by 2050. In TGT, despite overall vehicle stock reductions due to enhanced efficiency and improved public transportation, BEVs are still expected to increase to 686,000 by 2050. These projections imply reliance on continued policy support and private sector participation.
- As one of the world's busiest and most efficient ports and as a major international aviation hub, Hong Kong, China aims to develop its capabilities as a green maritime fuel bunkering centre and to enhance its usage of sustainable aviation fuel (SAF). In TGT, low-carbon fuels (including LNG) are projected to account for 73% of aviation bunkers and 80% of maritime bunkers by 2050.

Figure 6-17. Components of the change in road energy use in TGT (PJ)



Note: Information on the different drivers in the transport energy decomposition can be found in the *Outlook*'s annex.

Electricity Generation

Figure 6-18. Electricity generation by fuel in REF (TWh)

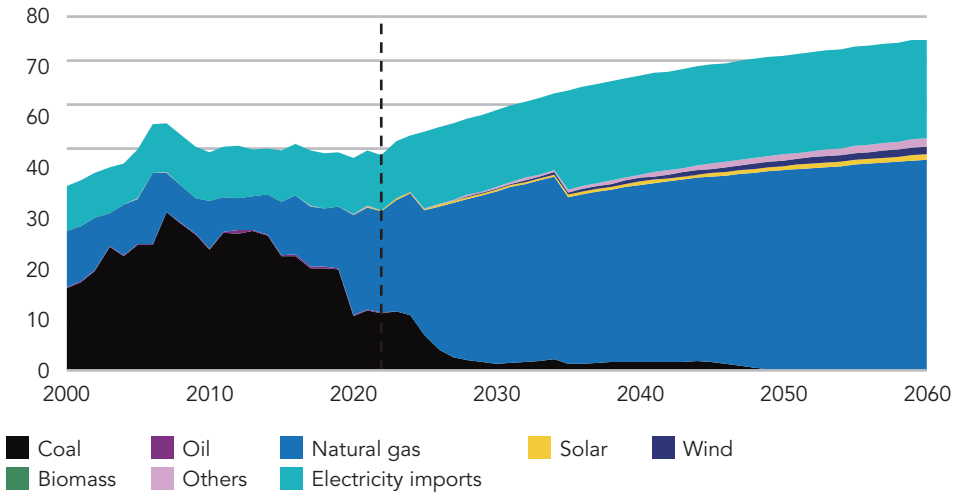
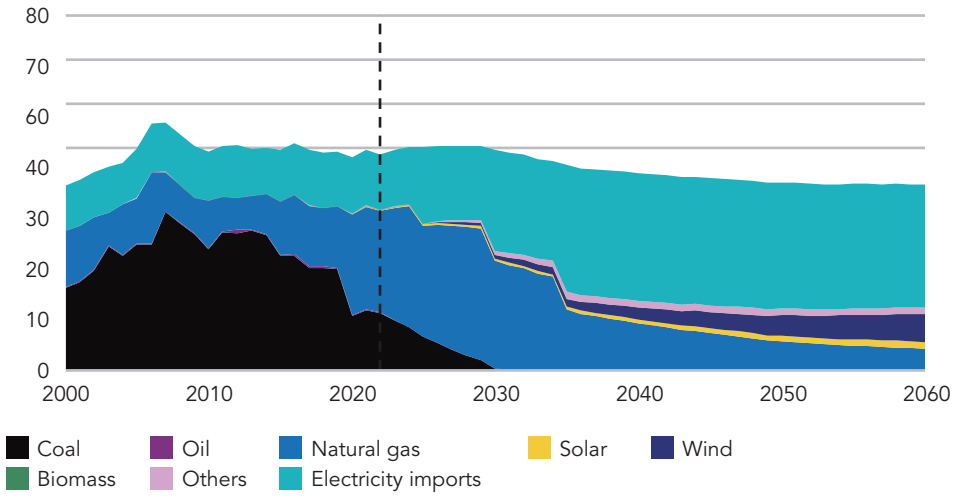


Figure 6-19. Electricity generation by fuel in TGT (TWh)



- In 2022, Hong Kong, China's electricity generation was primarily dominated by fossil fuels, with natural gas and coal accounting for 47% and 26%, respectively. For the past decade, coal-fired generation has progressively been replaced by natural gas. Electricity imports from a nuclear power plant in Guangdong province, China have stabilised at approximately 12 TWh.
- Hong Kong, China has identified "net-zero electricity generation" as the foremost decarbonisation strategy within the CAP2050. It aims to meet this target by progressively replacing existing fossil fuels, developing renewable generating capacity, and increasing zero-carbon electricity imports.
- In REF, driven by the continued electrification across all economic sectors, electricity generation is estimated to increase from 49 TWh in 2022 to 75 TWh by 2060. Electricity imports rise in two steps: reaching around 17 TWh by 2025 and 22 TWh by 2035. Existing coal power units will be gradually retired, ceasing operation entirely by 2050, while gas-fired generation is expected to increase significantly, accounting for 64% by 2060.
- To foster renewable generation capacity, the government is actively promoting investment in distributed renewable power systems via feed-in tariffs, developing waste-to-energy projects, and exploring offshore wind farms. However, the deployment of renewable power generation is constrained by limited space and natural resources. In REF, following the current trend, wind, solar, and other renewables are projected to increase 15 times from 2022 levels, meeting 6.4% of electricity generation by 2060.
- In TGT, propelled by energy savings in the building sector, total power generation peaks before 2030, then gradually decreases to 42 TWh by 2060. By 2035, coal-fired generation will be entirely phased out. Electricity imports, wind, solar, and waste-to-energy (others) are expected to constitute 62%, 3.9%, 1.5%, and 3.2% of total electricity generation, respectively.
- In TGT, gas-fired generation will constitute 15% of the total mix by 2050, serving as essential dispatchable and backup power. CCS is not considered viable due to its poor performance under variable operating conditions.

Note: Figures 6-18 and 6-19 do not include electricity generation for hydrogen production.

Generation Capacity

Figure 6-20. Generation capacity by fuel in REF (GW)

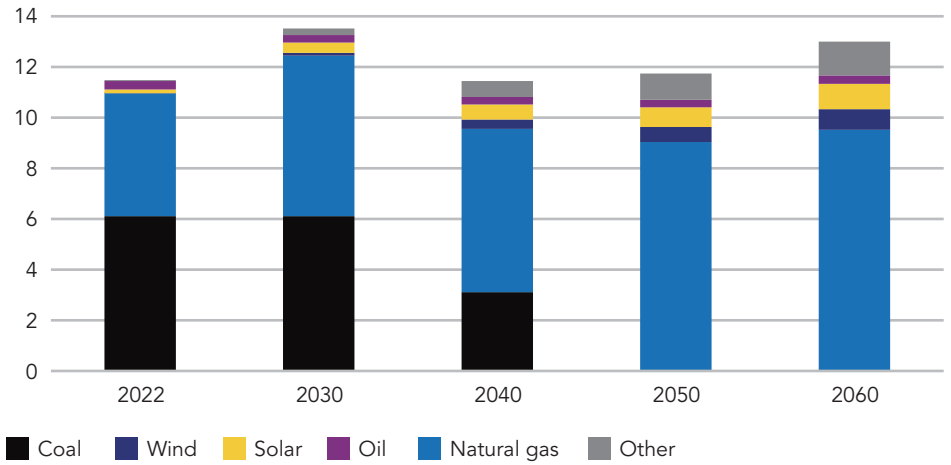
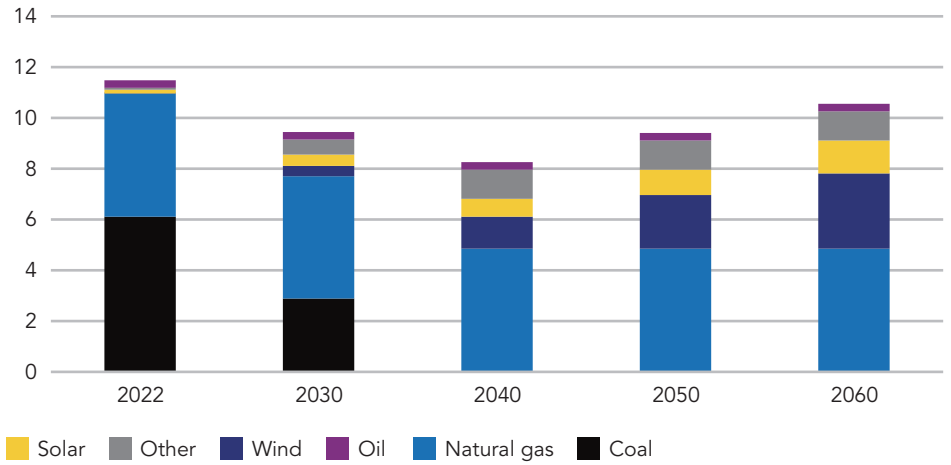


Figure 6-21. Generation capacity by fuel in TGT (GW)



- In REF, total generation capacity is estimated to peak at approximately 13.5 GW in 2030. Subsequently, as coal power plants are rapidly decommissioned, total capacity will decline, falling below 11 GW in the mid-2040s, before recovering with the expansion of gas and renewable power capacity.
- To satisfy rising electricity demand in REF, gas power capacity is expected to expand to 9.5 GW by 2060, with an average annual installation of approximately 123 MW. As renewables generation and import capacity gradually increases, the average capacity factor of gas power units is estimated to decrease from around 50% in the 2030s to 37% in the 2050s.
- Given current projections, the cost of gas power generation is much higher than coal power generation and nuclear power imports, potentially leading to elevated consumer electricity rates.
- A small number of oil-fired generators will remain for emergency backup in both scenarios.

- In TGT, total generation capacity is projected to begin decreasing from 2025, driven by the accelerated retirement of coal power plants, plateaued electricity demand, and increased import capacity. It will reach a low of 7.7 GW in 2035, before recovering to 10.6 GW by 2060, fuelled by renewable expansion and imports.
- To achieve ambitious renewable development targets, wind and solar power capacity are projected to grow at an average rate of 78 MW/year and 29 MW/year, respectively. Additionally, around 1.1 GW of new waste-to-energy power projects will be commissioned by 2050.
- In TGT, the existing 4.8 GW gas power capacity is sufficient to satisfy the projected electricity demand. However, the high ratio of imports and significant renewables penetration will cause the average capacity factor of gas power units to drop to a mere 7% by 2060. This low utilisation may impact project profitability, potentially leading to early closures.

Note: Figures 6-20 and 6-21 do not include generation capacity for hydrogen production.

Grid Reliability

Figure 6-22. Total generation capacity and peak load (GW)

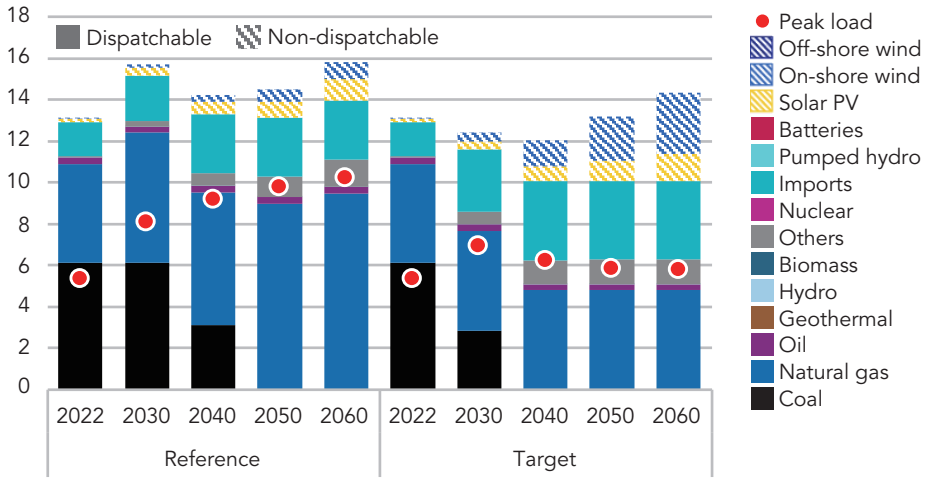
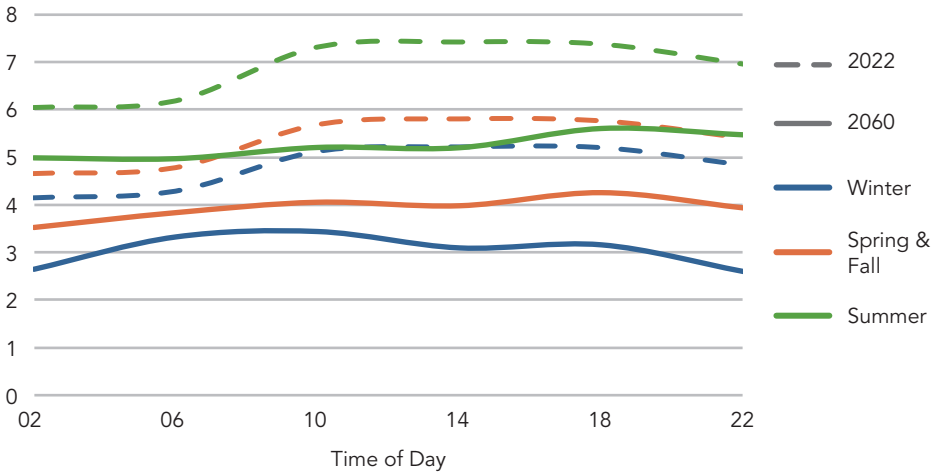


Figure 6-23. Power from dispatchable sources in TGT (GW)



- For Hong Kong, China, a highly electrified economy and a renowned international financial centre, maintaining a reliable power supply system is paramount. Two major power suppliers operate interconnected transmission networks, both achieving a reliability level of 99.999%.
- Hong Kong, China's power grid is also connected with Guangdong province, China, where a pumped storage power station in Guangdong provides 600 MW of dispatchable capacity for Hong Kong, China.
- Electricity imports are projected to serve as a baseload power source, operating constantly at a high capacity factor. Gas power capacity will continue to support the stable operation of the power system by providing an essential reserve margin and flexibility.
- In Hong Kong, China, peak electricity consumption typically occurs in summer, driven by high cooling demand. In REF, the four-hour average peak load is expected to grow with total electricity demand, from 5.4 GW in 2022 to 10.3 GW in 2060. Conversely, in TGT, peak load is projected to reach 7.0 GW around 2030 before eventually decreasing to 5.8 GW.
- In TGT, by 2060, with lower total electricity demand and a higher percentage of intermittent renewables, dispatchable power output is estimated to decrease by approximately 20% during the first three seasons. Since winter provides better operating conditions for solar and wind, dispatchable power decreases even further by more than 30%.
- Currently, dispatched power follows the daily load profile, which peaks around noon. However, renewables are expected to flatten that peak, leading to a smoother dispatched power curve. This will shift the average peak time for dispatchable power, moving it to the morning in winter and postponing it to the evening during the rest of the year.
- However, renewables introduce additional volatility, particularly over short timescales (of seconds and minutes) and due to their sensitivity to extreme weather events. Consequently, the power grid will require enhanced reliability measures to manage these increased risks.

Coal and Biomass

Figure 6-24. Coal and biomass consumption by sector in REF & TGT (PJ)

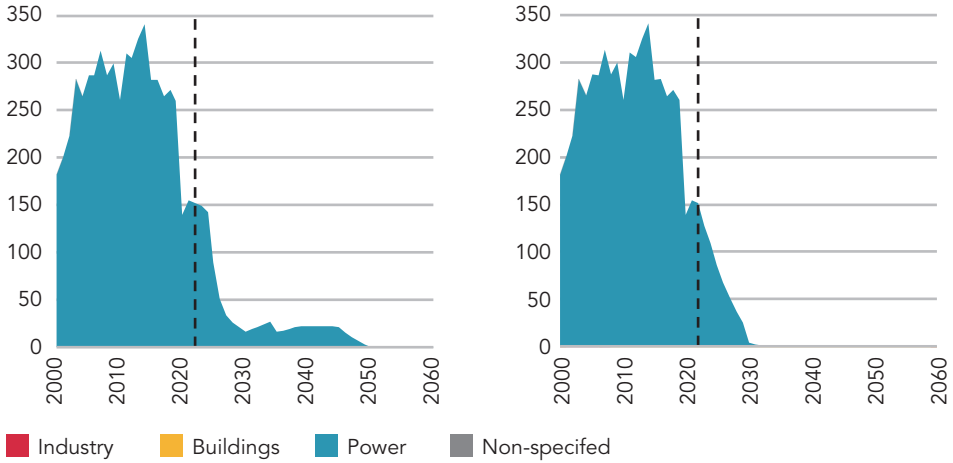
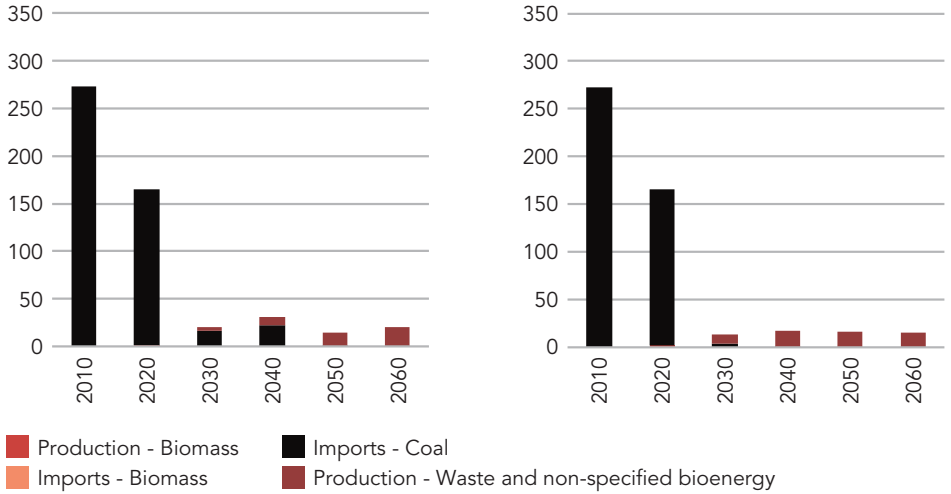


Figure 6-25. Coal and biomass production, imports, and exports in REF & TGT (PJ)



- Since 2004, Hong Kong, China's coal consumption has been exclusively for the power sector. In REF, as coal power generation is rapidly displaced by gas-fired power and increased electricity imports, coal demand is projected to decrease by 90% by 2035 and be completely phased out by 2050.
- In line with the government's target outlined in CAP2050, coal use for electricity generation will cease by 2035 in TGT.
- Hong Kong, China's entire coal supply is met through imports. In this projection, coal imports are assumed to follow the demand trend, with re-export not considered.

- Hong Kong, China is advancing the capacity of waste-to-energy electricity generation from food waste and sewage sludge, alongside constructing new projects to harvest energy from municipal solid waste.
- In REF, the energy input for these facilities is projected to reach 6.8 PJ in 2035 and eventually exceed 20 PJ by 2060. In TGT, this supply is expected to grow to 17 PJ in 2035 and finally stabilise at 15 PJ.

Natural Gas and Biogas

Figure 6-26. Natural gas and biogas consumption by sector in REF & TGT (PJ)

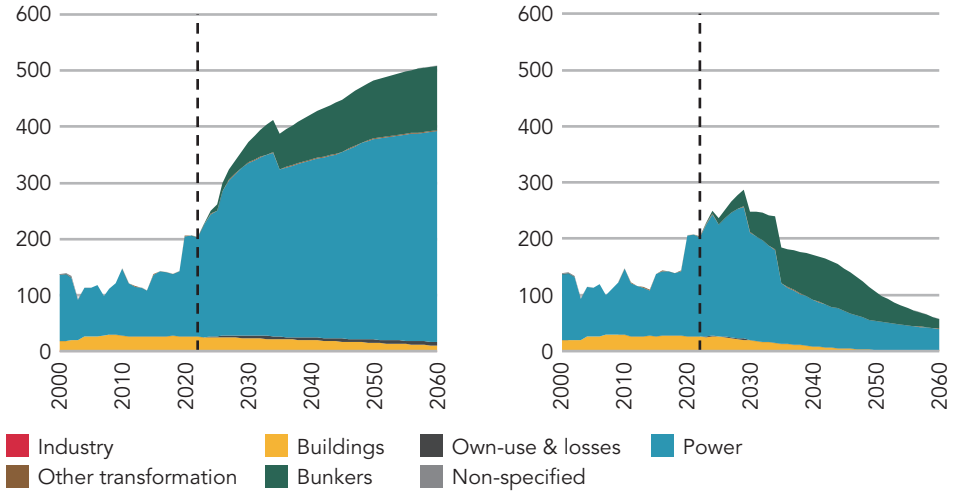
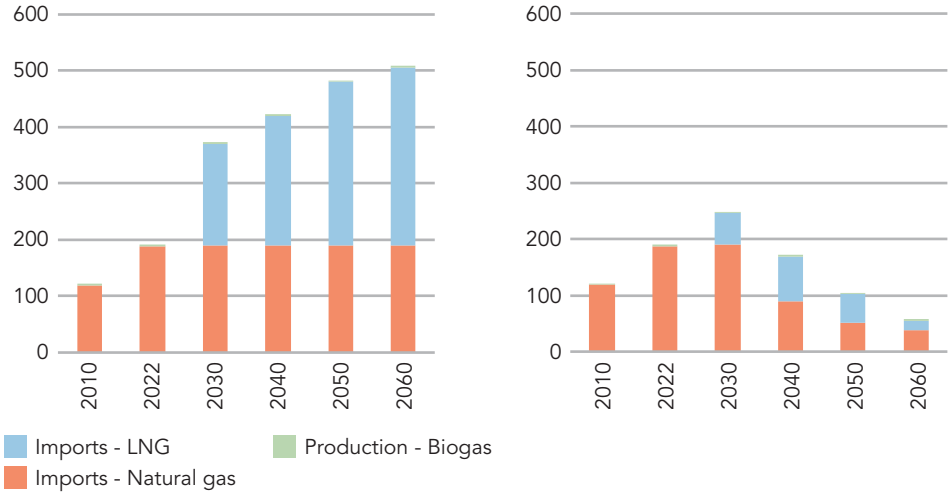


Figure 6-27. Natural gas and biogas production, imports, and exports in REF & TGT (PJ)



- Natural gas in Hong Kong, China is primarily consumed by electricity generation. In 2022, 87% of the natural gas was consumed in the power sector while 12% of natural gas was transformed into gas fuel for consumption by buildings.
- Natural gas demand projections diverge significantly between the two scenarios. In REF, demand for gas power generation continues to grow, with a temporary offset from increased electricity import capacity in 2035. Demand for LNG for international bunkering also expands substantially. By 2060, total natural gas demand is projected to exceed 500 PJ.
- In TGT, natural gas consumption is expected to peak at approximately 285 PJ in 2029, followed by a rapid decline driven by reduced demand from the power sector. While bunkering consumption continues to increase until 2042, it will then be gradually replaced by other low-carbon alternative fuels.
- As of 2022, Hong Kong, China relied on three subsea pipelines for natural gas imports from China. In 2023, an offshore LNG terminal was commissioned, enabling global LNG procurement.
- In REF, pipeline imports are assumed to remain at approximately 190 PJ. LNG imports will meet the remaining demand, expanding to 316 PJ by 2060, which might necessitate expanded LNG receiving capacity.
- In TGT, however, pipeline imports will begin to decline after 2030, in line with total demand. LNG imports are projected to follow the bunkering demand, peaking at 81 PJ in 2042 before declining to approximately 18 PJ by 2060.
- Beyond electricity generation, waste-to-energy projects also produce biogas for building consumption. However, due to Hong Kong, China's limited waste volume, biogas production is assumed to remain minor.

Petroleum Liquids

Figure 6-28. Refined products and low-carbon fuels demand in REF & TGT (PJ)

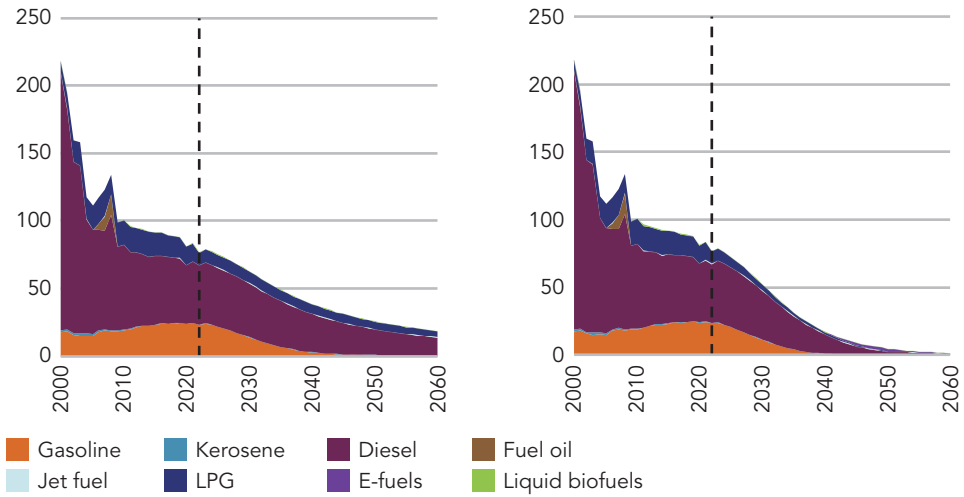
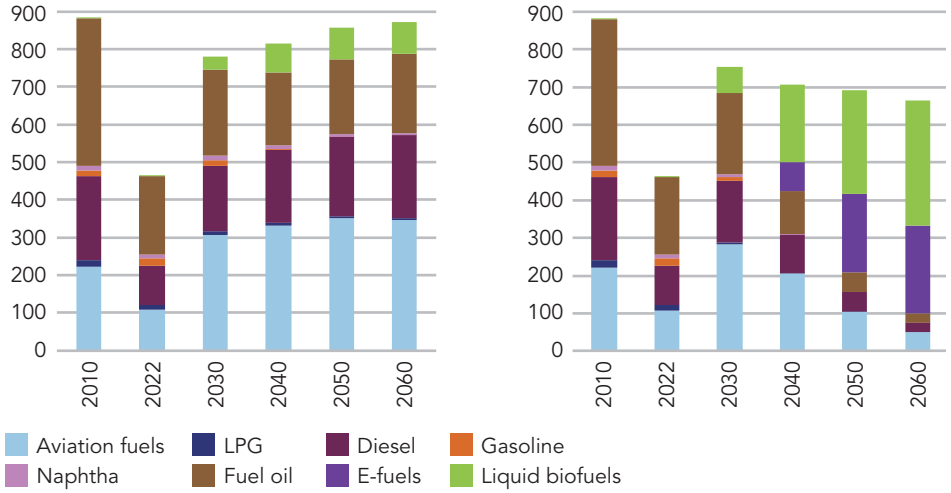


Figure 6-29. Net imports of refined products and low-carbon liquid fuels in REF & TGT (PJ)



- Hong Kong, China's domestic petroleum products demand has continuously declined over the past decade, with the transport sector accounting for over 90% of this consumption. This reduction is largely attributed to increased public transit ridership and vehicle efficiency improvements. In 2022, diesel, gasoline, and LPG represented 57%, 31%, and 12% of total petroleum products consumption, respectively.
- The projected advancement in electrification is expected to facilitate a steady decrease in demand for petroleum products across both scenarios. In REF, gasoline demand is projected to become marginal after 2045, while diesel and LPG consumption will decrease by 69% and 52%, respectively, by 2060, driven by electrification in the transport and buildings sectors.
- In TGT, driven by the net-zero target, oil demand will decrease more rapidly, with only 2.5 PJ remaining by 2050. E-fuels are projected to begin replacing petroleum fuels from 2040, reaching 2.1 PJ in 2050. By 2060, nearly all liquid fuel demand is anticipated to be phased out.

- Lacking domestic refining capacity, Hong Kong, China does not import crude oil and relies entirely on imports of refined products to meet its demand. With the exception of a small volume of domestically produced biodiesel from waste cooking oil, all other low-carbon liquid fuels are also projected to be imported.
- Despite a continuous decline in domestic consumption, liquid fuel imports are projected to remain significant to satisfy international transport demand. International bunkering is expected to return to pre-COVID-19 levels and grow throughout the projection period, as illustrated in Figure 6-16.
- In REF, petroleum products will continue to dominate net imports, growing with overall demand. In contrast, TGT shows a gradual decrease in imports as domestic demand rapidly declines and FCEVs replace a portion of ICE vehicles. By 2060, e-fuels and biofuels are projected to collectively reach 564 PJ in TGT, potentially elevating overall bunkering costs.

Note: Naphtha is traditionally blended with natural gas for town gas supply. In Figure 6-29, net imports are presented without deducting bunkers.

Hydrogen-based Fuels in the Target Scenario

Figure 6-30. Hydrogen-based fuels demand by sector [left]; Hydrogen-based fuels demand by fuel [right] (PJ)

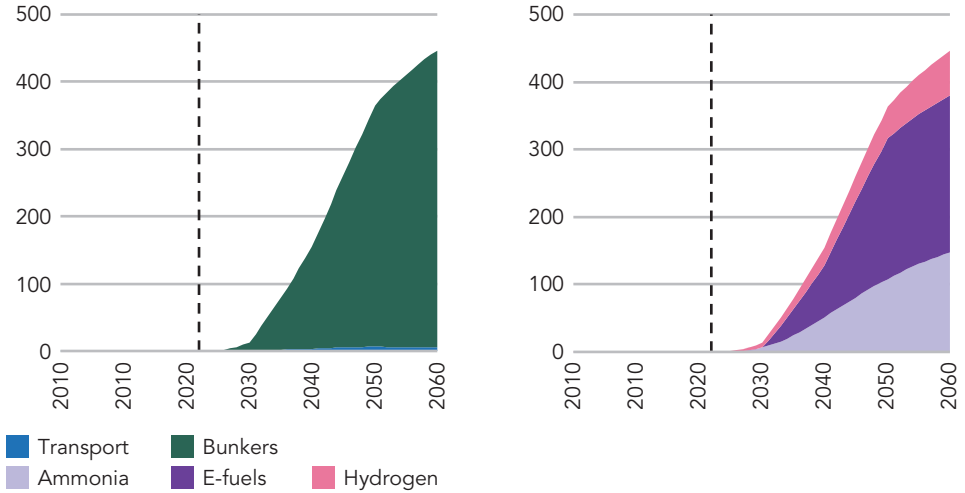
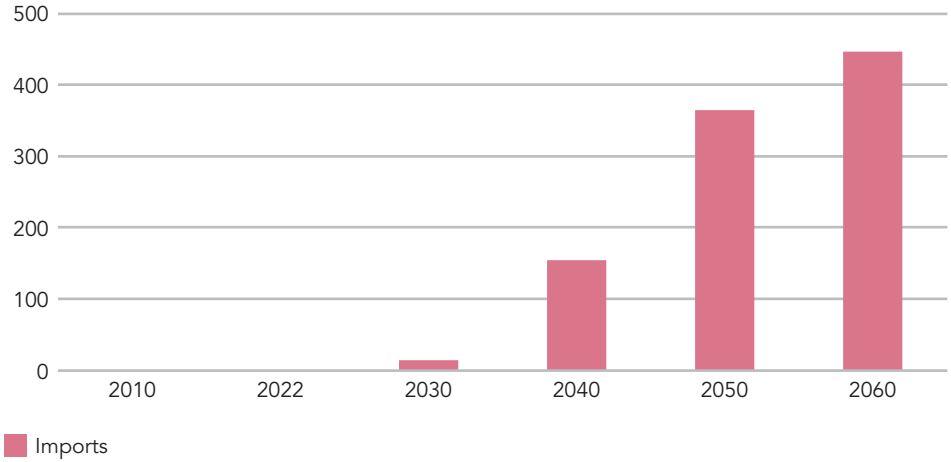


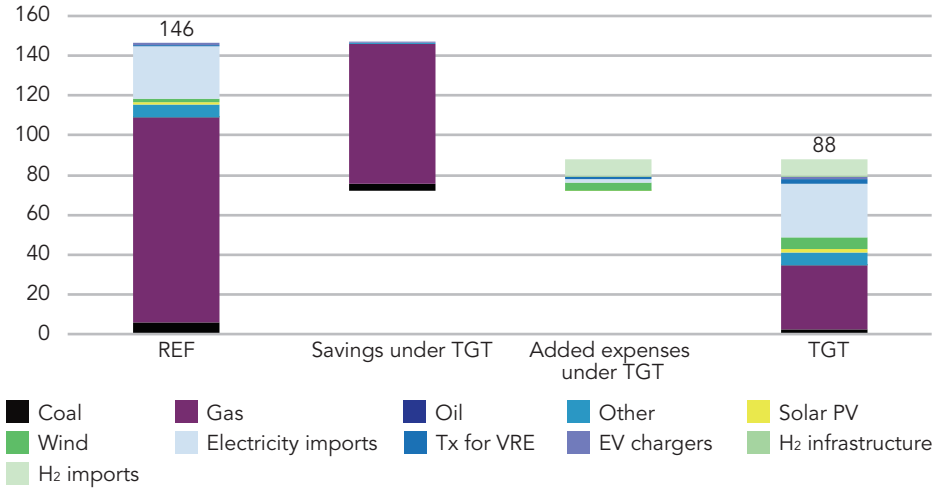
Figure 6-31. Hydrogen-based fuels production methods and supply (PJ)



- For domestic consumption, Hong Kong, China is actively exploring low-carbon hydrogen applications, including testing hydrogen Fuel Cell Electric Vehicles (FCEVs) and studying the feasibility of blending hydrogen with natural gas for electricity generation. Based on current fuel cost assumptions, hydrogen-based fuels are only projected for limited utilisation in the transport sector after 2030 in TGT and after 2040 in REF, since BEVs and electric ships are generally considered more efficient and economically viable alternatives to ICE vehicles and traditional vessels.
- For maritime fuel bunkering, Hong Kong, China aligns with the emission reduction checkpoints set out by the International Maritime Organisation and aims to adopt a multi-fuel strategy to accommodate diverse market demands, including LNG, green methanol, hydrogen, ammonia, and other emerging green fuels. This approach acknowledges the current lack of a clear consensus within the maritime industry regarding a single preferred low-emissions fuel type.
- E-fuels are projected to hold the largest share among hydrogen-based fuels due to their compatibility with existing conventional engines that are still being phased out. Ammonia is also considered a promising alternative fuel, owing to its higher energy density and because it is easier to transport and store compared to hydrogen. However, significant concerns persist regarding the potential environmental impacts and safety issues associated with ammonia combustion.
- In TGT, hydrogen-based fuels are projected to grow at an average rate of 18 PJ/year from 2030 to reach 364 PJ by 2050. Subsequently, this expansion is expected to slow to approximately 8 PJ/year as bunkering demand plateaus.
- Given Hong Kong, China's limited potential for renewable power generation necessary for green hydrogen production, both scenarios assume that all hydrogen-based fuels will be imported.

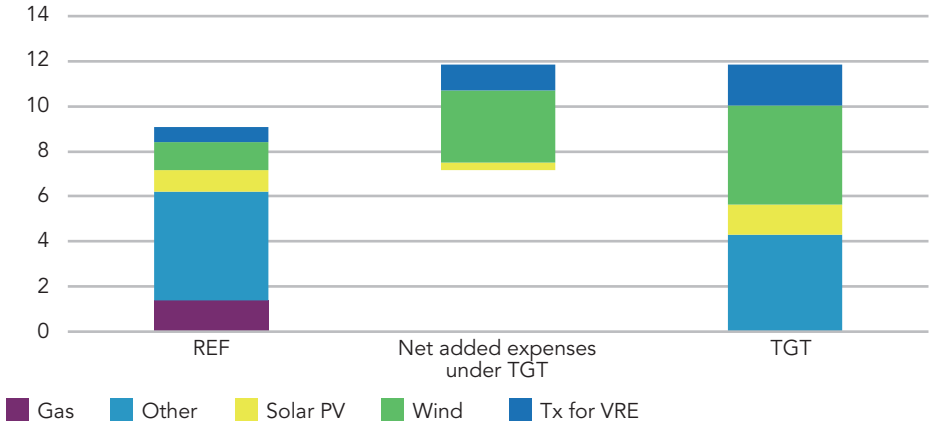
Costs

Figure 6-32. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



Note: Tx for VRE is only transmission infrastructure to connect variable renewable capacity to the grid. EV chargers do not cover the cost of associated infrastructure or EV vehicles. Hydrogen costs do not cover costs for bunkering.

Figure 6-33. Total capital investment (CAPEX) from 2025 to 2060 in the power sector (billion USD, undiscounted)

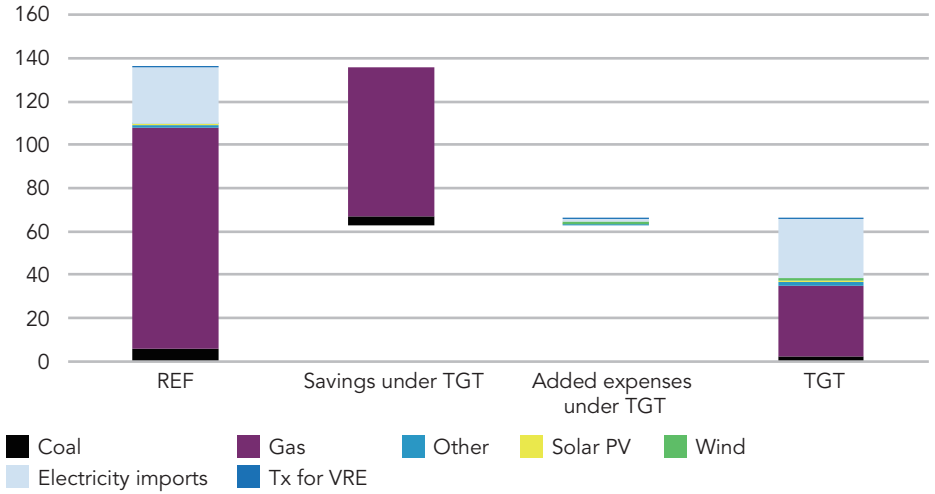


Note: Figure 6-33 only covers power and VRE transmission sector investments. Hydrogen and EV capital investments are not included.

- Meeting future energy demand while advancing Hong Kong, China's decarbonisation objectives will require substantial spending. Figure 6-32 considers total capital, fixed and variable costs in the power sector, electricity imports, spending on low-carbon hydrogen imports, EV chargers, and transmission for added VRE.
- In REF, total gas power costs are projected to reach a notable USD 103 billion, reflecting its dominant role in the power sector. In TGT, 69% of this cost is saved through vigorous energy savings and the accelerated scale-down of gas-fired power generation. Coal-related costs are also projected to experience a 60% reduction across the two scenarios, driven by the government's target of a complete phase-out of coal power by 2035.
- Combined expenditures for low-carbon electricity generation, namely wind, solar PV, waste-to-energy, and renewables-related transmission increase by more than half in TGT compared to REF. Hydrogen imports account for more than half of the additional costs in TGT, primarily for use in the transport sector (when not considering bunkers). Increased hydrogen usage for transport in TGT is expected to offset conventional fuel consumption, yielding an estimated USD 5.9 billion in savings (not shown in Figure 6-32).
- Compared to REF, an additional USD 3.6 billion is allocated for solar PV and wind power installations in TGT, alongside an additional USD 1.2 billion for associated transmission lines. Notably, no investment in new gas power generation facilities is required in TGT, resulting in USD 1.4 billion in savings. As a result, total capital expenditures for the power sector are projected to increase by 31% in TGT.
- Hong Kong, China actively funds renewable energy facilities on government premises and encourages private investment in distributed renewable energy through its Feed-in Tariff scheme. The government is also offering various facilitating measures and financial instruments to facilitate further decentralised renewable projects.
- Beyond the costs analysed in this study, the projected increase in electricity import capacity may necessitate additional investment in new transmission infrastructure connecting Hong Kong, China with neighbouring regions.

Costs

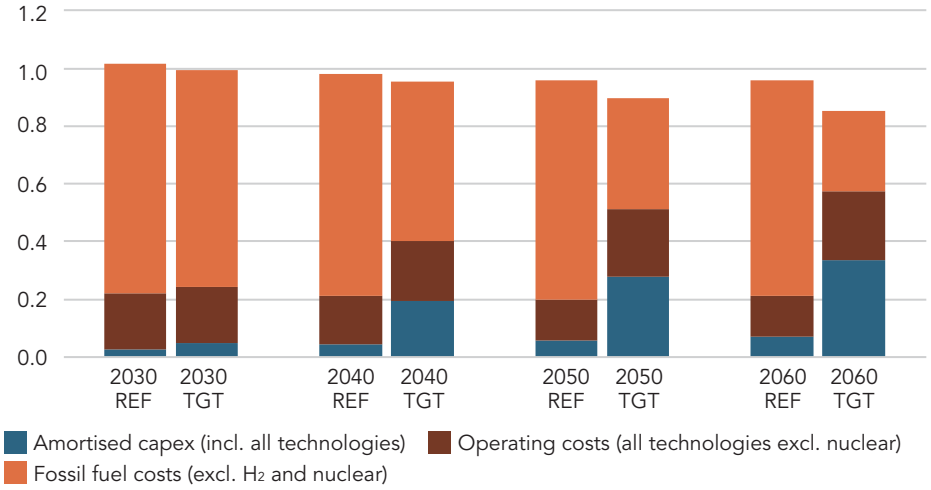
Figure 6-34. Total operating costs from 2025 to 2060 in the power sector (billion USD, undiscounted)



Note: Figure 6-34 only covers power and VRE transmission sector costs. It does not include operating costs associated with hydrogen production and EV charger costs. Costs for electricity imports are included here.

- Figure 6-34 covers variable fuel and non-fuel expenditures, electricity imports, along with fixed costs for both the power sector and transmission. Total operating costs are estimated to be USD 136 billion in REF, but are expected to decline by more than half to approximately USD 66 billion in TGT.
- Operating costs will continue to be driven by fossil-fired power generation and electricity imports in both scenarios. Reduced reliance on gas and coal yields estimated savings of USD 69 billion and USD 4 billion, respectively in TGT. Consequently, the share of expenditure for electricity imports in total operating costs is projected to increase from 19% to 41%.
- Uncertainty exists in fuel prices, as well as variable and fixed costs of gas and coal depending on their operating modes as dispatchable power sources. Electricity import rates may also vary, contingent on the arrangement of power purchase contracts.

Figure 6-35. Cost of generating electricity relative to 2025 (2025 cost = 1.0) in the power sector



Note: Based on our assumptions about future capital and operating costs, Figure 6-35 shows cost compositions over time relative to 2025. It should not be considered an estimate of electricity tariffs and excludes market mechanisms that are too difficult to estimate.

- Figure 6-35 shows the relative cost of generating electricity in selected years indexed to the base year of 2025. Costs related to electricity imports are excluded.
- The indexed electricity generation costs show a decreasing share of fuel expenses and an increasing share of capital and operating expenditures in both scenarios.
- Overall, the cost of electricity generation is projected to decrease in TGT (relative to 2025). Reduced gas-powered generation brought on by an increase in electricity imports (not included in Figure 6-35) leads to greater reductions in TGT fossil fuel costs. Although a higher share of renewables may necessitate additional investments in strengthening the power grid (the cost of which is not included in Figure 6-35), the increased amortisation costs are not enough to offset the declines in fossil fuel costs in TGT.

Gross CO_2 Emissions

Figure 6-36. CO_2 emissions in REF (million tonnes)

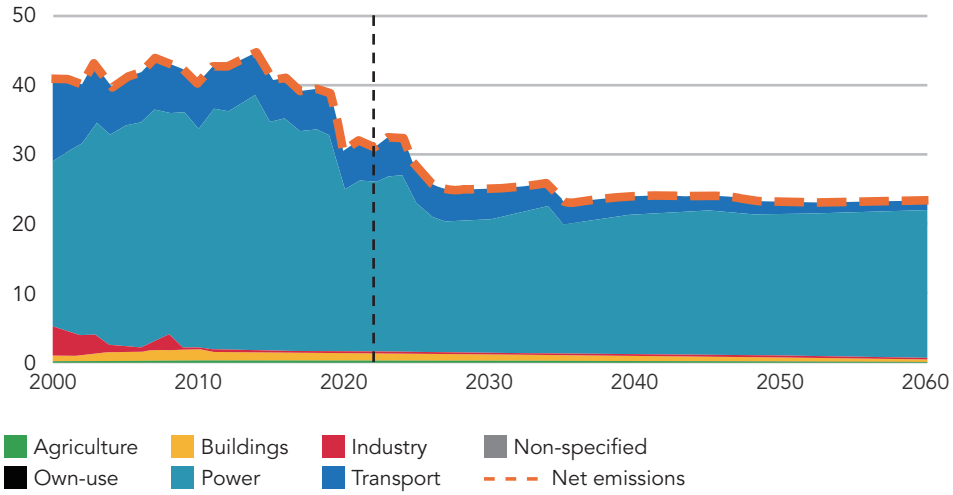
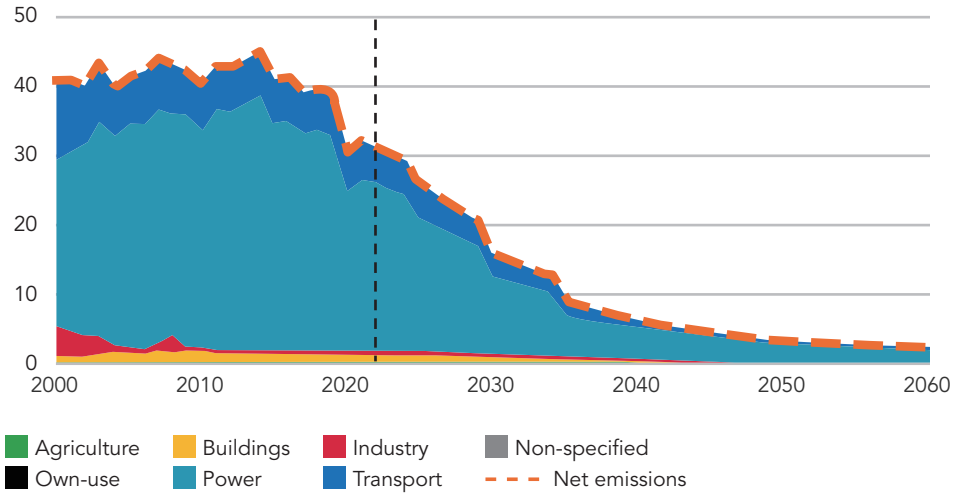
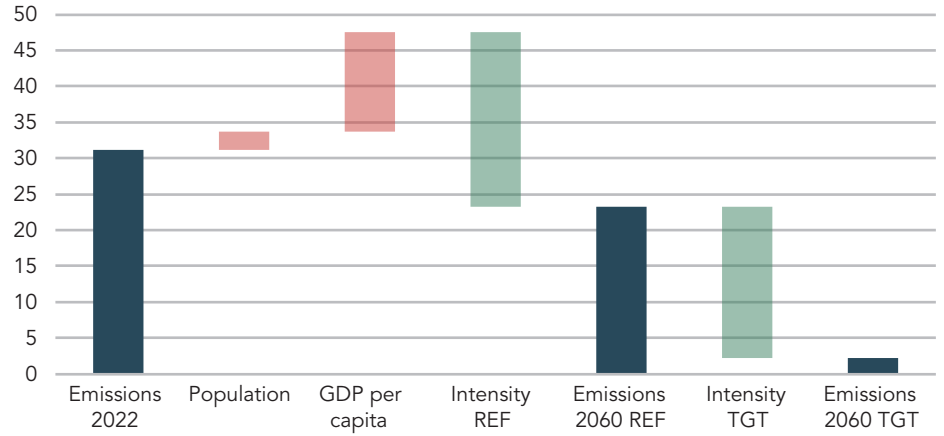


Figure 6-37. CO_2 emissions in TGT (million tonnes)



- Hong Kong, China's energy-related CO_2 emissions stabilised for two decades before an 8 million tonnes drop in 2020, primarily due to replacing coal with natural gas. A further 7 million tonnes decrease by 2035 is anticipated in REF, achieving a 44% decrease from 2005 levels and nearing the 50% target outlined in CAP2050. However, despite significant intensity improvements (as shown in Figure 6-38), high gas consumption is expected to keep emissions plateaued at this level until 2060.
- In TGT, Hong Kong, China's combustible emissions are projected to be 78% below 2005 levels by 2035. By 2050, however, an estimated 2.2 million tonnes of CO_2 emissions will remain, primarily from gas-fired power generation. These residual emissions may necessitate offsetting through various carbon-sink technologies.

Figure 6-38. CO_2 emissions components (million tonnes)



Note: All values represent energy sector combustion CO_2 emissions. Biogenic CO_2 is treated as zero at the point of combustion.

Useful Links

APERC

APEC Expert Group on Energy Data and Analysis (EGEDA) –
https://www.egeda.ewg.apec.org/

APEC Energy Statistics 2022 –
https://www.egeda.ewg.apec.org/egeda/general/info/pdf/APEC_Energy_Statistics_2022.pdf

APEC Energy Overview –
https://aperc.or.jp/reports/energy_overview.php

The Government of the Hong Kong Special Administrative Region

Northern Metropolis Development Strategy (2021) –
https://www.policyaddress.gov.hk/2021/eng/pdf/publications/Northern/Northern-Metropolis-Development-Strategy-Report.pdf

Facilitation Measures for Development of Renewable Energy (Webpage rev. Dec 2024) –
https://www.gov.hk/en/residents/environment/sustainable/renewable/facilitationmeasures.htm

EEB (Environment and Ecology Bureau)

Promotion of Electric Vehicles (Webpage rev. Jul 2025) –
https://www.epd.gov.hk/epd/english/environmentinhk/air/promotion_ev/promotion_ev.html#Measure

Green Transformation Roadmap of Public Buses and Taxis (2024) –
https://www.eeb.gov.hk/sites/default/files/pdf/Bus_Taxi_Roadmap_eng.pdf

The Strategy of Hydrogen Development in Hong Kong (2024) –
https://cnsd.gov.hk/strategy-of-hydrogen-development-in-hong-kong_booklet_en.pdf

Climate Action Plan 2050 (2021) –
https://cnsd.gov.hk/wp-content/uploads/pdf/CAP2050_booklet_en.pdf

Hong Kong Roadmap on Popularisation of Electric Vehicles (2021) –
https://www.eeb.gov.hk/sites/default/files/pdf/EV_roadmap_eng.pdf

Climate Action Plan 2030+ (2017) –
https://cnsd.gov.hk/wp-content/uploads/pdf/HK_Climate_Action_Plan_2030+_booklet_En.pdf

C&SD (Census and Statistics Department)

Monthly statistics on consumption of electricity and gas by type of users (Webpage rev. July 2025) – https://www.censtatd.gov.hk/en/web_table.html?id=127

Population and Household Projections (Webpage rev. Feb 2025) – https://www.censtatd.gov.hk/en/scode190.html

ITIB (Innovation, Technology and Industry Bureau)

Hong Kong Innovation and Technology Development Blueprint (2022) – https://www.itib.gov.hk/en/publications/I&T%20Blueprint%20Book_EN_single_Digital.pdf

TLB (Transport and Logistics Bureau)

Action Plan on Green Maritime Fuel Bunkering (2024) – https://www.tlb.gov.hk/doc/Action_Plan_on_Green_Maritime_Fuel_Bunkering.pdf

Leading Hong Kong's Aviation Development to New Heights (Webpage rev. Dec 2024) – https://www.tlb.gov.hk/eng/blog/20241102.html

DPO (Digital Policy Office)

Accommodating Data Centres (Webpage rev. Jul 2025) – https://www.datacentre.gov.hk/en/accommodating_data_centres/power_supply.html

Summary Report on Review of Concessionary Measures to Facilitate Data Centre Development in Hong Kong (2021) – https://www.datacentre.gov.hk/en/downloads/Data_Centre_Study_Report_2020_Eng.pdf



7. Indonesia

Summary

	Reference			Target		
	2022	2060	% Change	2022	2060	% Change
Macroeconomic						
Population (million)	274.6	350.9	28%	274.6	350.9	28%
GDP (billion 2017 USD, PPP)	3,419	14,255	317%	3,419	14,255	317%
Energy Demand						
Agriculture & fisheries (PJ)	42*	100	143%	42*	92.1	124%
Buildings (PJ)	1,234	3,265	165%	1,234	2,662	116%
Industry (PJ)	3,194	9,800	207%	3,194	9,587	200%
Non-energy (PJ)	400	965	141%	400	869	117%
Transport (PJ)	2,534	3,842	52%	2,534	2,675	6%
Modern renewable share of TFEC (%)	14	22	58%	14	45	224%
Energy intensity of TFEC (PJ/GDP, billion USD)	2.1	1.2	-43%	2.1	1.1	-48%
Electricity						
Generation (TWh)	333	1,705	412%	333	2,452	636%
Renewables share of generation (%)	20	39	95%	20	53	165%
Generation capacity (GW)	83	374	350%	83	625	651%
Total Primary Energy Supply (TPES)						
Coal & coal products (PJ)	4,337	15,148	249%	4,337	11,144	157%
Natural gas (PJ)	1,749	3,877	122%	1,749	4,668	167%
Petroleum liquids (PJ)	3,030	4,372	44%	3,030	1,606	-47%
Low-carbon & waste energy (PJ)	2,029	11,744	479%	2,029	20,300	901%
CO_2 intensity of energy supply ($MtCO_2/PJ$)	0.063	0.054	-14%	0.063	0.013	-79%
Net CO_2 Emissions (million tonnes)	703	1,887	168%	703	388	-45%

Note: In this publication, the term "modern renewables" refers to all renewable energy sources excluding solid biomass in the buildings sector. The term "low-carbon & waste energy" includes all bioenergy, waste-derived energy, renewables, nuclear, and hydrogen-based fuels. Total primary energy supply (TPES) numbers include international bunkers. Net emissions are calculated as gross energy sector combustion CO_2 minus CO_2 captured and stored through carbon capture and storage (CCS).

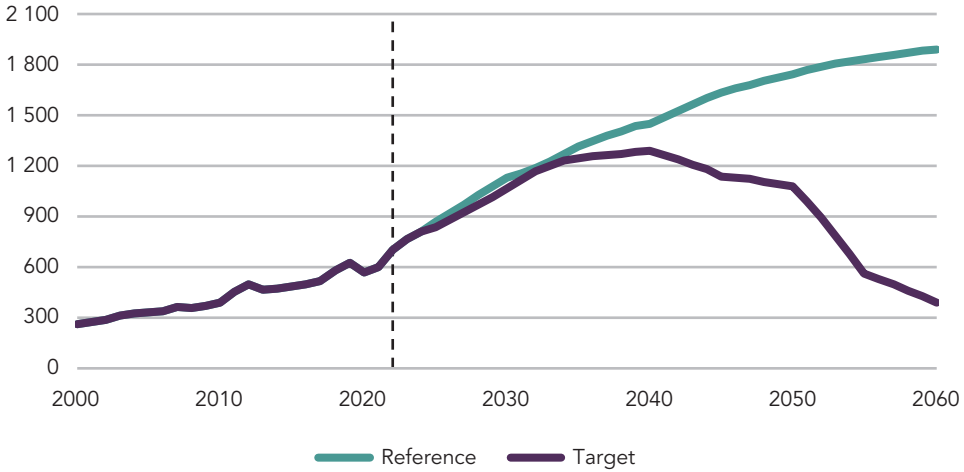
*In this table, Agriculture & fisheries data for 2022 is based on IEA data.

Key Takeaways

Emissions

- Indonesia's CO_2 emissions follow distinct paths in the Reference (REF) and Target (TGT) scenarios after 2030, with ambitious climate policies in TGT driving a significant divergence from REF's business-as-usual trajectory. In TGT, emissions peak in 2040 and decline sharply toward net-zero by 2060.
- In TGT, Indonesia's CO_2 emissions decrease significantly to 387.5 $MtCO_2$ by 2060, a 79.4 % reduction from the REF scenario, with residual emissions likely offset by LULUCF CO_2 sinks to achieve the net-zero goal by 2060.

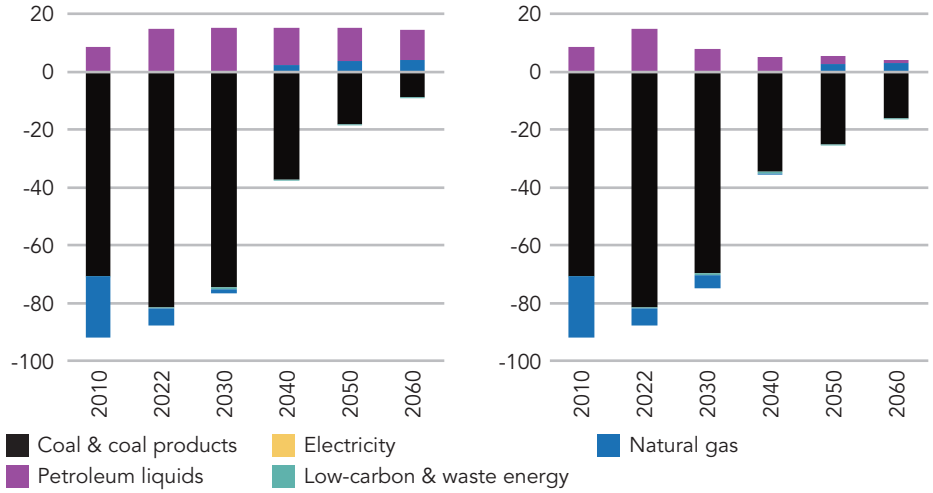
Figure 7-1. Net CO_2 emissions (million tonnes)



Energy Import Dependence

- Indonesia currently maintains its position as a net energy exporter, supported by abundant coal reserves and substantial natural gas exports. However, the economy remains dependent on imports of crude oil and petroleum products.
- With coal reserves sufficient for the next four decades, Indonesia enjoys a secure supply, though it has to prioritise sourcing high-quality metallurgical coal to meet industrial demands.
- While Indonesia targets natural gas production of 12 billion cubic feet per day by 2030, natural gas demand is expected to grow steadily. Projections indicate Indonesia will become a net gas importer by 2040.
- Indonesia aims to achieve crude oil production of 1 million barrels per day by 2030. However, crude oil demand may rise, depending on the pace of transition to electric vehicles. At the same time, investment in deepwater crude oil exploration and production may prove challenging. As a result, the economy is expected to continue relying on crude oil imports.

Figure 7-2. Net imports share of TPES in REF & TGT (%)



Note: In Figure 7-2, net imports refer to total imports minus exports and international bunkers.

Key Takeaways

Grid Reliability

- Figure 7-3 illustrates the daily gap between the minimum and maximum dispatched power required to ensure grid reliability on an average day. The gap is smaller during the rainy season because less VRE operates during the rainy season, which limits their share in the generation mix.
- As more VREs are integrated over the years, the gap between minimum and maximum dispatchable power widens, requiring plants to ramp output more quickly. Investment will be required to make the system more flexibility.
- In TGT, the challenge intensifies after 2040, when dispatchable capacity in the dry season is projected to fall below peak load. As VRE output drops during those periods, the risks of system instability and blackouts increase.

Cost

- Indonesia's efforts toward net-zero emissions will require substantial expenditures. In REF, total costs, which include the total capital, fixed, and variable cost in the power sector, costs for green hydrogen production for domestic use, transmission for VRE, and electric vehicle chargers, are estimated at USD 2.4 trillion, mainly due to coal, gas and hydropower usage. In comparison, TGT, with 42% more capacity, a higher share of renewables and more green hydrogen production, costs are estimated at USD 5.2 trillion, 117% more than REF.
- Although fuel-free sources like solar and wind dominate in TGT, system operating costs remain high, largely due to the use of costly green hydrogen and ammonia for gas and coal blending.
- Electricity generation costs stay relatively stable under REF but rise significantly in the TGT scenario—almost doubling by 2060 compared to 2025, mainly due to the use of hydrogen co-firing in the power sector.

Figure 7-3. Peak load and maximum and minimum dependence on dispatched power (GW)

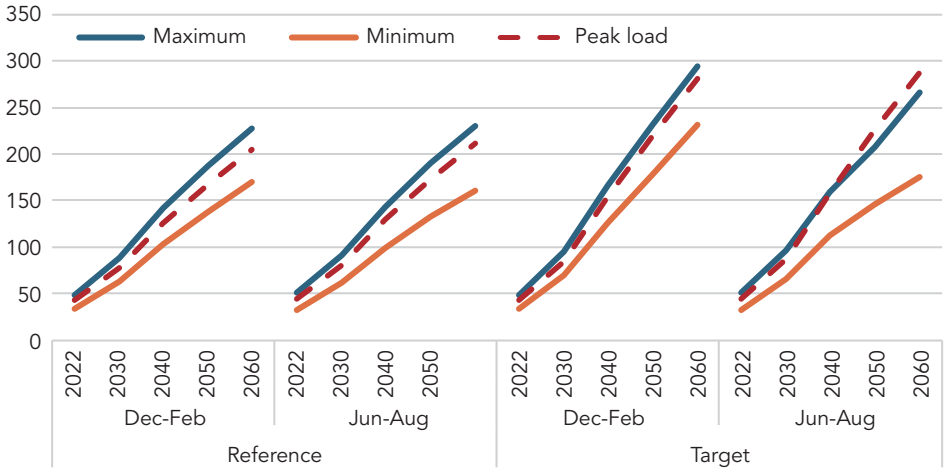
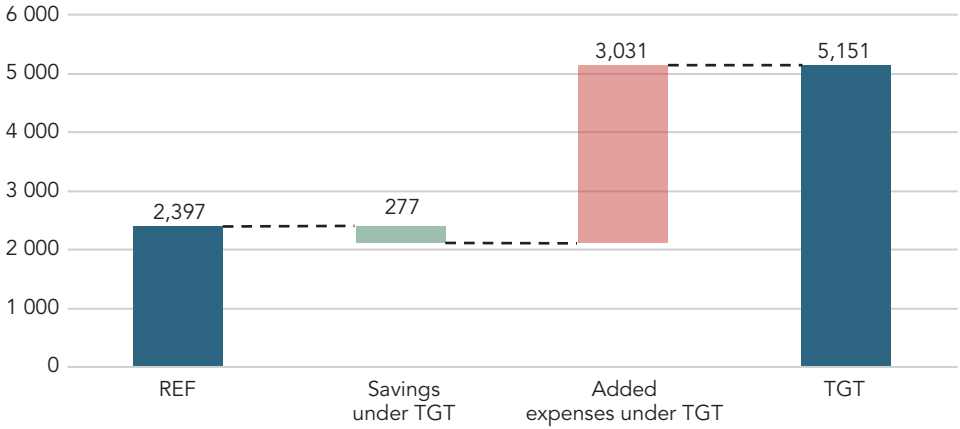


Figure 7-4. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



*Actual costs will differ from estimated costs in the *Outlook* for a variety of reasons including changing commodity prices, manufacturing costs and unforeseen technical advances. All costs are in 2023 real terms.

About Indonesia

Overview

Geographical and Economic Landscape

Indonesia, the world's largest archipelagic economy, spans over 17,000 islands, with around 6,000 inhabited, stretching across 5,120 km from east to west and 1,760 km from north to south. Its total area is approximately 1.9 million km², between the Indian Ocean and the Pacific Ocean, with land borders shared with Malaysia; Papua New Guinea; and Timor-Leste, and maritime boundaries with Australia; the Philippines; Singapore; and Viet Nam. It is currently the largest economy in Southeast Asia and 4th largest economy in APEC.

Energy Supply and Consumption

Indonesia total energy consumption in 2022 reached 7,585 PJ, marking a 26% increase from 2012, driven largely by growing demand in the industrial and transportation sectors as the economy expands. The economy's total primary energy supply stood at 11,148 PJ in the same year, with fossil fuels, such as coal, oil, and natural gas, continuing to dominate the energy mix. Around 85% of power generation capacity is based on fossil fuels, while renewables, such as geothermal and hydropower, contribute just 15%, though their share is gradually increasing. Indonesia faces significant challenges in transitioning to cleaner energy sources, including improving energy access in remote regions and aligning economic growth with environmental sustainability. While government policies and international partnerships are supporting the growth of renewables, fossil fuels are expected to remain the primary energy source in the near future.

Energy Security Challenges and Strategies

Indonesia is expected to undergo major energy changes as it becomes a net importer of natural gas in the future. At the same time, declining global demand for coal could reduce coal export revenues, impacting a key source of domestic income. Additionally, as a long-standing net importer of crude oil, Indonesia will remain exposed to the risks of potential global oil supply disruptions. These shifts highlight the need for strategic planning to ensure energy security and economic resilience.

Key Energy Initiatives

Paris Agreement Commitment

Indonesia has pledged to achieve carbon neutrality by 2060. Under its enhanced NDC, Indonesia set an unconditional emission reduction target of 31.89% by 2030, and a conditional emission reduction target of 43.20% by 2030, subject to international support.

Just Energy Transition Partnership (JETP)

JETP is a USD 20 billion international partnership to accelerate Indonesia's decarbonisation. Launched in November 2022 at the G20 Summit, it aims to reduce coal dependency, retire coal-fired power plants (CFPPs) early, and scale up renewable energy to achieve a 44% renewable energy mix by 2030 and a net-zero power sector by 2050.

Energy Transition Mechanism (ETM) Country Platform

Launched at COP26 in 2021, the ETM Country Platform is a partnership to improve energy infrastructure and accelerate the transition to net-zero by 2060. It focuses on retiring CFPPs and scaling renewable energy investments.

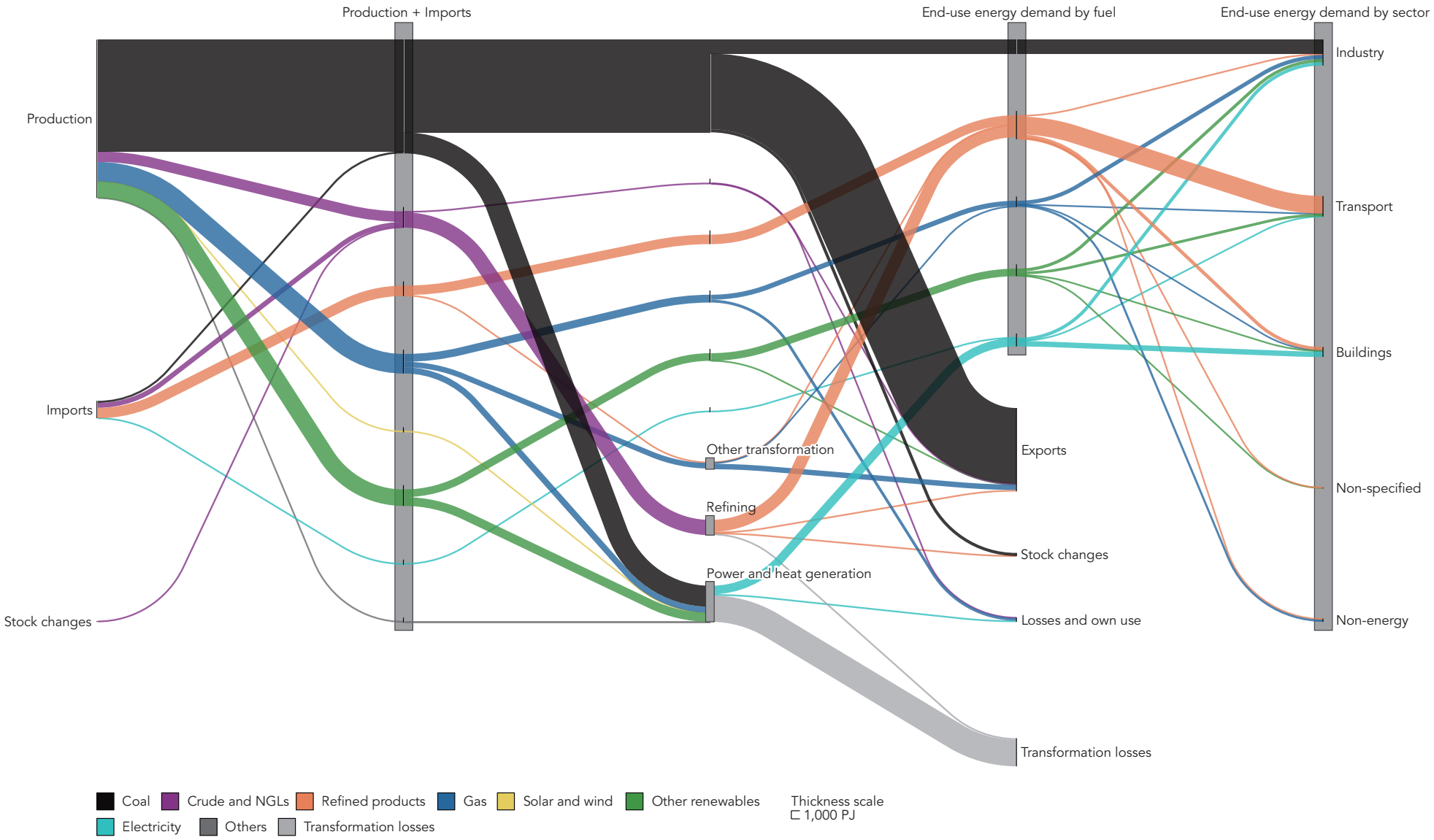
Presidential Regulation Number 112 Year 2022

This regulation aims to accelerate investment in renewable energy, achieve domestic renewable energy (RE) mix targets, and reduce greenhouse gas (GHG) emissions. It governs the pricing of electricity generated from renewable sources, restricts the development of new fossil-fuelled power plants, and includes other provisions to support a greener energy transition.

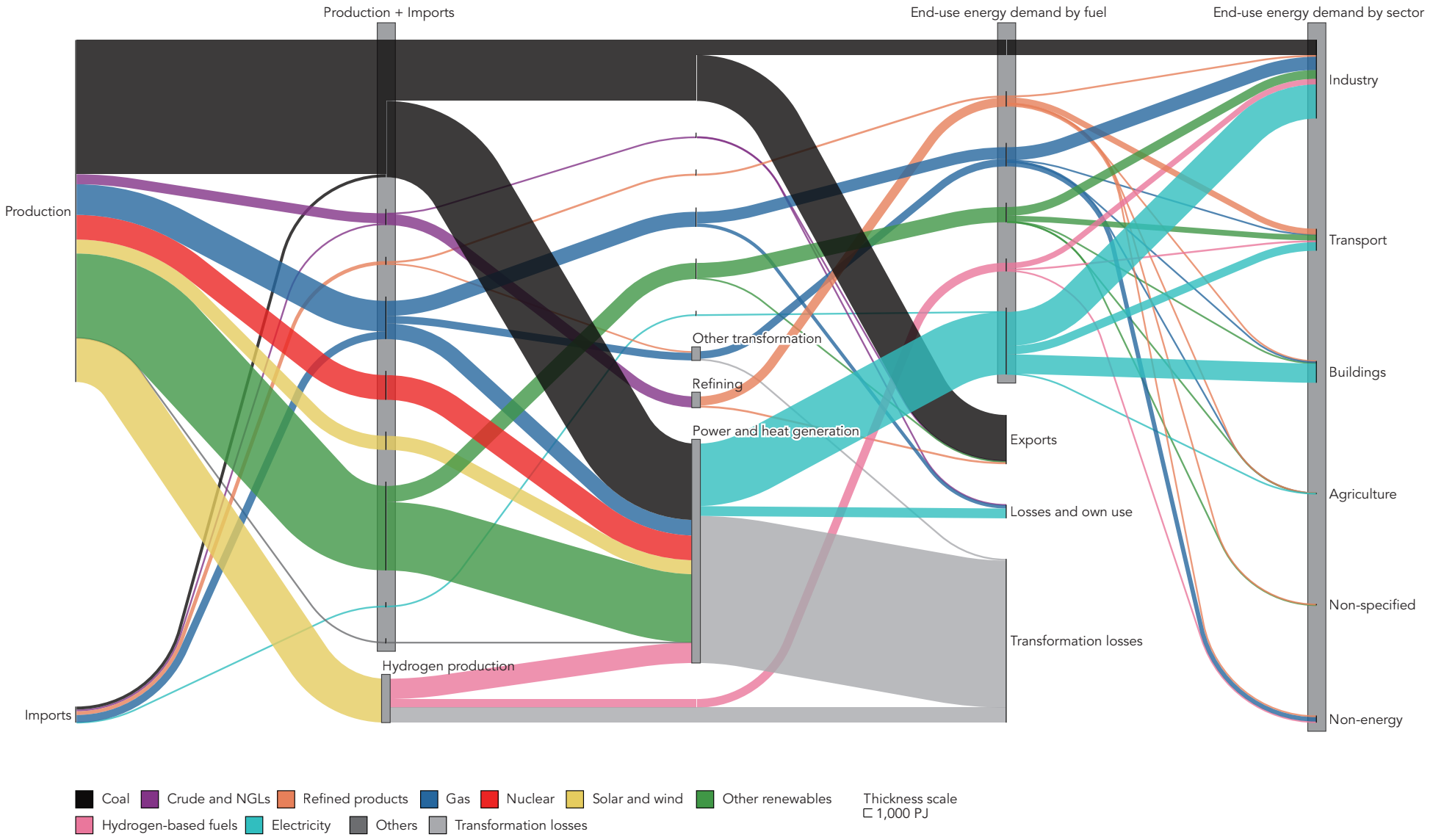
Carbon Tax and Carbon Trade Regulation

Several regulations have been established to support carbon trading and the carbon market in Indonesia, including the Taxation Law Number 7 of 2021, Presidential Regulation Number 98 of 2021 on the Carbon Pricing Mechanism, and a series of ministerial regulations providing technical guidelines. On 26 September 2023, the Carbon Trading Market was officially launched in Indonesia.

Energy Flow (2022)



Energy Flow (2060, Target Scenario)



Scenarios and Assumptions

In *The Outlook*, APERC analyses energy demand, transformation, and supply, as well as emissions. The **Reference Scenario (REF)** offers a projection based on historical trends, recent developments, and APERC's assumptions about the continuation of those trends in each APEC economy, while acknowledging technical restraints. The REF Scenario offers a baseline to compare with the **Target Scenario (TGT)** projections, which explores a hypothetical pathway where each economy achieves energy-related policy targets, assuming implementation regardless of cost-effectiveness. When implementation details are lacking, assumptions are inferred from the targets themselves or emissions-related goals.

	Reference	Target
General	• Population: UN DESA 'Upper 80 PI' scenario; GDP: APERC model and IMF	• Population: UN DESA 'Upper 80 PI' scenario; GDP: APERC model and IMF
Buildings	• Energy efficiency trends continue. • AI & data centre electricity demand grows under both scenarios.	• Mandatory energy efficiency standards MEPS considered. • Increased electrification: 80% of building energy in 2060 is electric. • Greater gas network development.
Industry	• Moderate fuel-switching and efficiency improvements, with slower progress than in TGT.	• Hydrogen deployment begins in 2030, followed by CCS implementation from 2035. • Utilisation of biofuel as mandated by Indonesia Government. • Higher activity in mining and metals processing assumed until 2040 to support energy transition supply chains.
Transport	• EV sales shares grow at a modest rate (e.g. 61% BEV sales share for passenger vehicles by 2060). • Biodiesel blending remains at 32%.	• EV sales share grows quickly (90% BEV sales share for passenger vehicles by 2060). Hydrogen Fuel Cell sales share reaches 22% in 2060 for trucks. • Biodiesel blending for industry and transport starts in 2026 at 40%, rising to 60% by 2060 for transport. Bioavtur is 10% in 2035, 40% in 2060. Assumptions were chosen to reduce emissions to 52 $MtCO_2$ in 2060.
Power	• Moderate renewables integration. • Fossil fuel reliance continues. • No coal phased-out and no CCS implementation.	• Nuclear utilisation for power generation starts in 2039. • Coal and gas with CCS implementation. • Hydrogen and ammonia fuel blending in gas combined power plants.
Supply	• Coal is the main input for electricity, reflecting historic trends. • Oil declines, following historical trends. • Gas production peaks in 2030 and follows historical trends.	• Oil production peaks in 2030, achieving lifting 1 mbopd. • Gas production peaks in 2030, achieving production of 12 billion cubic feet per day.
Emissions	• NDC pathway not modelled.	• NDC and Long-term Strategy used as guidelines

Note: The base year is 2022. Macro-economic assumptions are constant across scenarios. Historical energy balances are from EGEDA submissions for 2022.

Demographic and Macroeconomic Assumptions

Figure 7-5. Population (thousands)

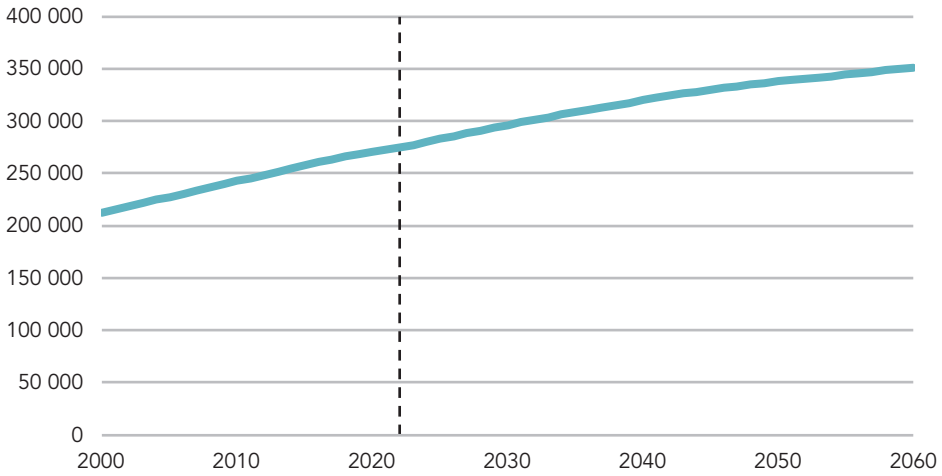
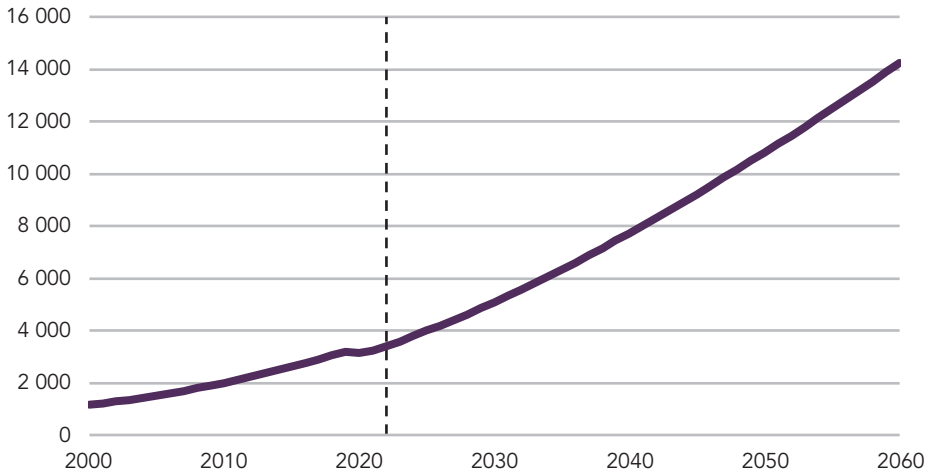


Figure 7-6. Real GDP (billion 2017 USD, PPP)



- Indonesia currently ranks as the 3rd most populous economy in APEC and the 4th most populous economy in the world. Its population is projected to continue growing in the coming decades, with slower growth expected after 2040. However, total population numbers will still rise due to the momentum of its large youth demographic.
- Java Island remains the most populated and densely inhabited region, home to over 150 million people, or more than 50% of Indonesia's total population, despite comprising only around 7% of the total land area. In response to this imbalance, the government has launched major initiatives to decentralise population and economic activity by accelerating infrastructure development across Sumatra, Sulawesi, and Kalimantan, including the planned relocation of the capital to East Kalimantan.
- Indonesia's population growth reflects its historically high fertility rates and current young, productive-age society. While this demographic trend underpins future economic growth, it also leads to significant increases in energy demand, particularly for electricity, transportation fuels, and industrial energy use. These dynamics highlight the critical need for strategic, long-term energy planning to ensure sustainable, secure, and affordable energy development.
- Like several other APEC economies in Southeast Asia, such as the Philippines and Viet Nam, Indonesia is striving to escape the middle-income trap by leveraging its demographic dividend. However, the projected growth remains below domestic targets like those outlined in Visi Indonesia 2045, which aspires to reach a nominal GDP per capita of USD 23,199 by maintaining average annual economic growth above 5%.
- The APERC real GDP projections to 2027 are based on International Monetary Fund (IMF) forecasts. The GDP projection from 2028 to 2060 is based on APERC's Solow-Swan macroeconomic model. Indonesia's real GDP is expected to increase steadily through 2060, averaging 3.9% annual growth. By 2060, real GDP is projected to reach USD 14.26 trillion, with real GDP per capita of USD 40,625.
- The economy is expected to grow around 5% per year between 2022 and 2030, but growth is projected to decelerate in the following decades, reflecting the onset of demographic slowdown and saturation of domestic consumption. These trends highlight the urgency for Indonesia to capitalise its current demographic bonus before entering a period of somewhat slower growth.

End-use Energy Demand

Figure 7-7. Energy demand by sector in REF & TGT (PJ)

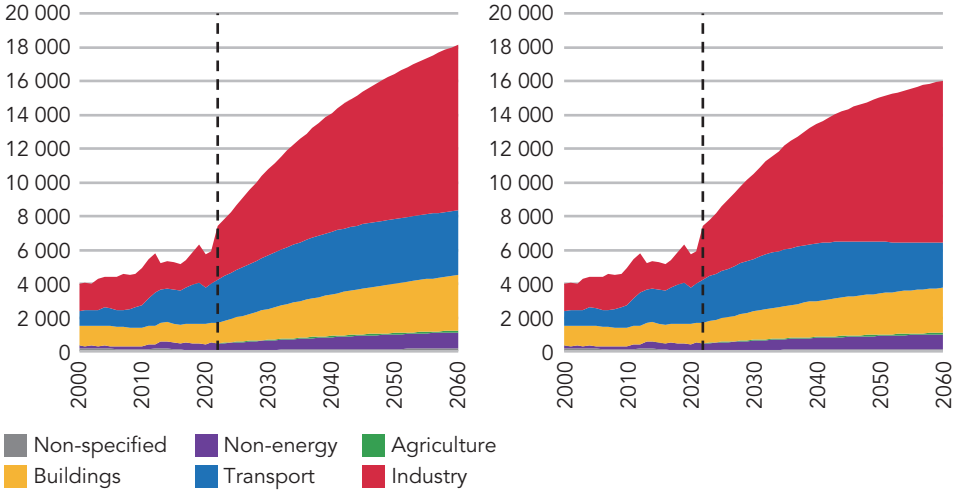
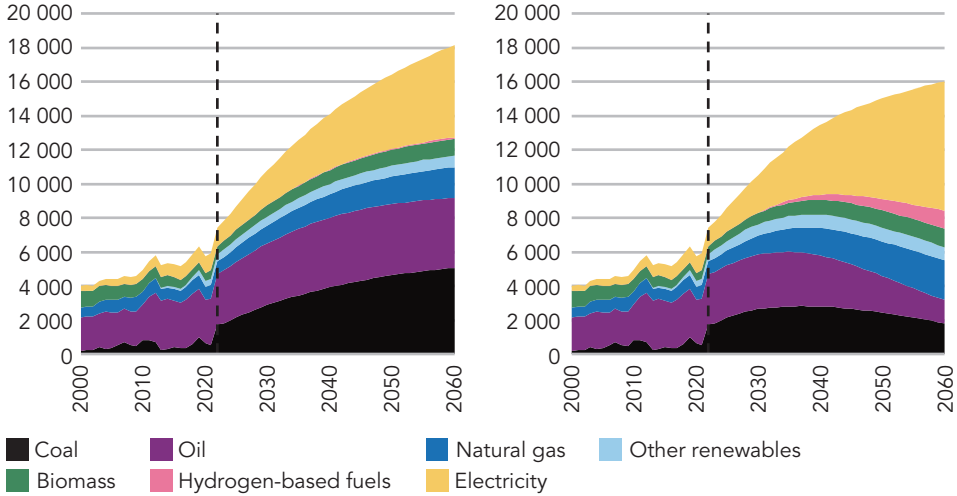


Figure 7-8. Energy demand by fuel in REF & TGT (PJ)



- Energy demand is projected to more than double between 2022 and 2060, with the industrial sector remaining the dominant energy consumer. Total final energy consumption (TFC) per capita is expected to exceed 50 PJ by 2060, reflecting Indonesia's shift toward a more energy-intensive economy, and its progress toward a middle- to high-income economy.
- The transport sector experiences rapid growth after 2022, reaching 3,800 PJ by 2040, after which demand plateaus. This plateau suggests saturation in vehicle ownership levels and the influence of greater energy efficiency, especially from BEVs (battery electric vehicles).
- Energy use in buildings is expected to triple, driven by population growth, urbanisation, and increased appliance use. Currently, Java accounts for nearly 60% of the population and dominates energy consumption. However, future urban development in Kalimantan, Sumatra, and Sulawesi is expected to help redistribute the population and energy use more evenly.
- Agricultural energy demand grows slowly after 2022, reaching just 100 PJ—or about 0.6% of TFC—by 2060, largely due to mechanisation.
- Energy consumption by fuel shows the dominant shift toward electrification, gradually reducing the previous dominance of oil. However, coal remains a major pillar until 2040, where despite global decarbonisation, coal grows nearly 300% in REF and only declines after 2040 in TGT. Coal use is driven by industrial sector demand, especially for steel and cement. The policy of coal utilisation includes integrating CCS applications.
- Gas consumption grows at a moderate but steady rate.
- Hydrogen emerges post-2030 and grows significantly only in TGT due to technology limitations. Hydrogen utilisation is expected in heavy transport, as well as in the steel and ammonia industry subsectors.
- The gradual increase in biomass reflects the use of modern bioenergy such as wood pellets.

Buildings Energy Demand

Figure 7-9. Buildings energy demand by fuel in REF & TGT 2060 (PJ)

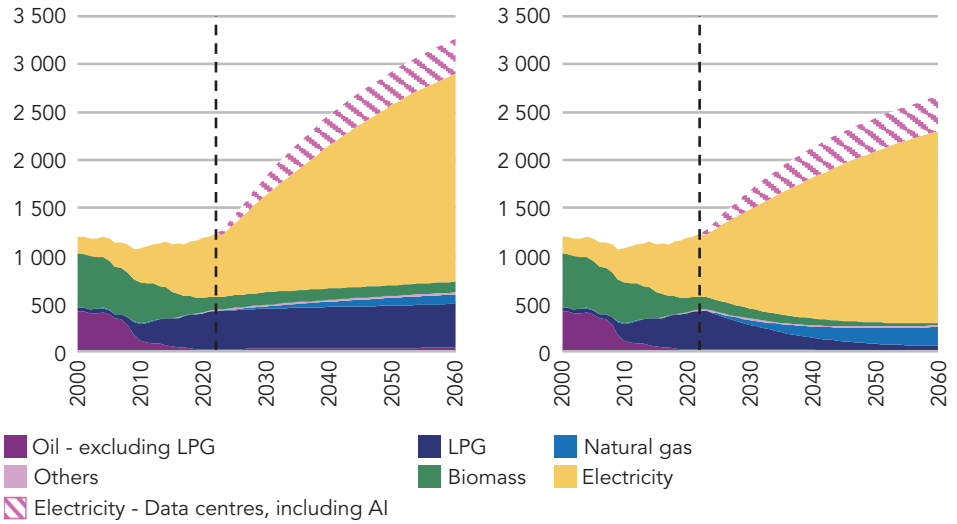
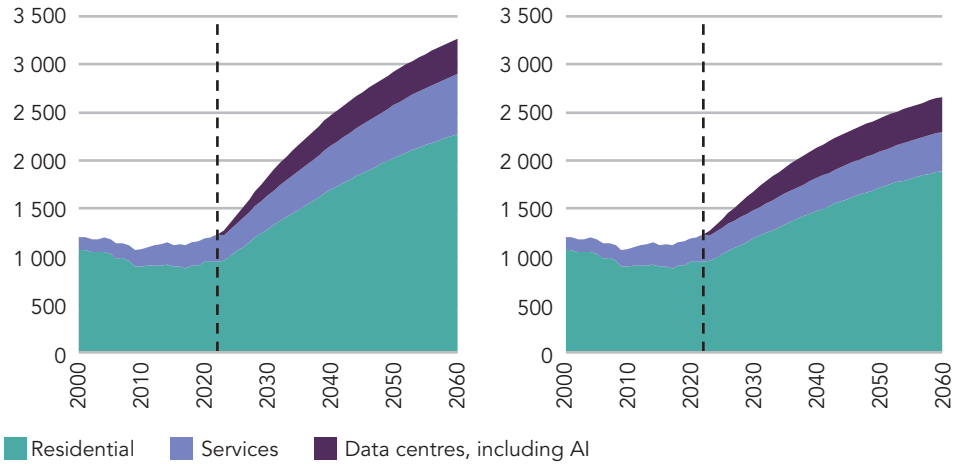


Figure 7-10. Buildings energy demand by sector in REF & TGT (PJ)



- The buildings sector is projected to undergo a significant energy transition by 2060, shifting away from oil and biomass towards natural gas and especially electricity, which is expected to remain the dominant energy source.
- Energy consumption is expected to grow rapidly through 2022-2030, driven by a demographic boom, where the working-age population is projected to peak around the 2040s, which will accelerate urbanisation and the expansion of building infrastructure. After 2040, however, population growth slows, the working-age population plateaus, and the pace of urbanisation and number of households begins to decline, leading to slower growth in building energy use.
- In TGT, assumed energy efficiency gains are substantial. New buildings adopt stricter energy codes, passive cooling strategies, and smart energy management systems. Improved appliance standards also contribute to reducing electricity consumption per unit of service.
- By 2060, under the TGT scenario, nearly 80% of energy use in buildings is expected to be electric. The use of LPG (in cylinders) and biomass becomes marginal as the expansion of city gas networks and the development of urban centres beyond Java Island help redistribute population and modernise energy infrastructure.
- The residential sector remains the dominant consumer of building energy through 2060. However, data centres and AI are anticipated to experience a dramatic increase, leading to their energy demand growing to around 365 PJ by 2060. Between 2023 and 2060, this reflects a growth rate of 9.1%, surpassing the services sector's growth rate of 1.9%, and marking data centres as a significant contributor to electricity demand. The primary causes of this surge are the expansion of the digital economy, increased adoption of cloud services, and the integration of AI across sectors.

Industry Energy Demand

Figure 7-11. Industry energy demand by fuel in REF & TGT (PJ)

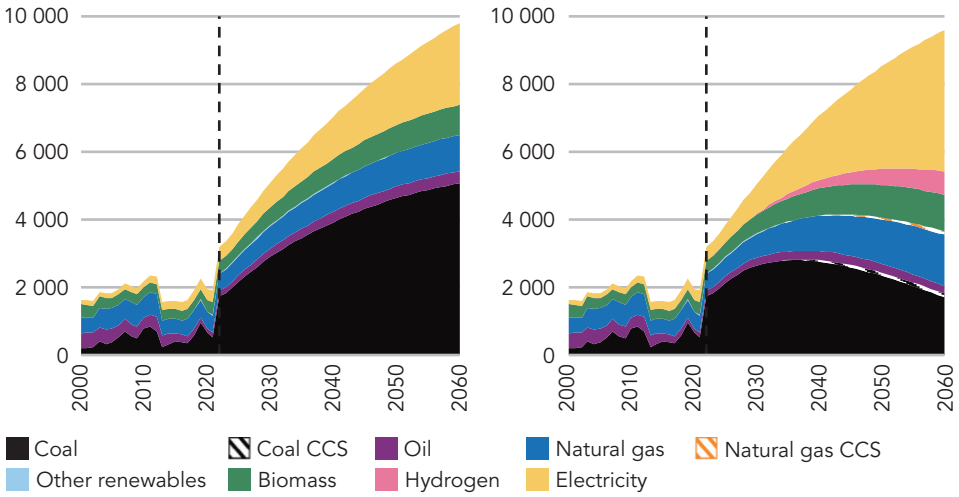
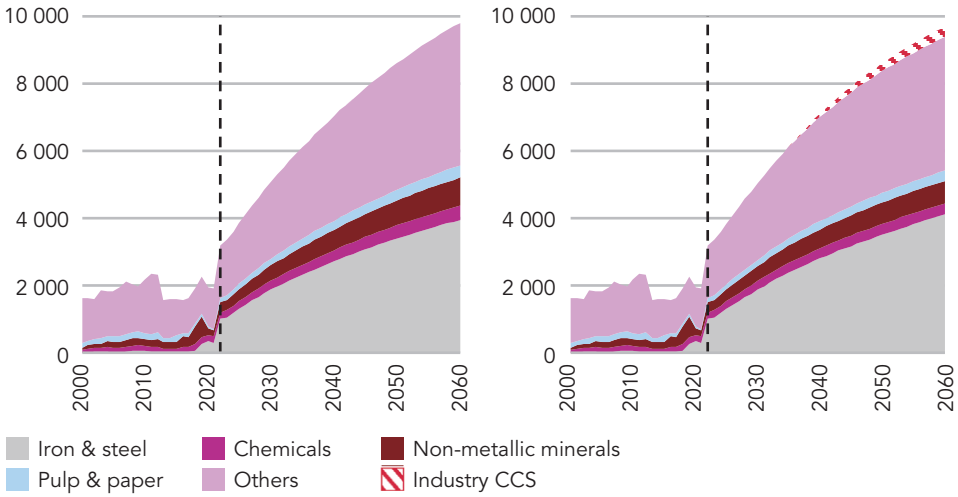


Figure 7-12. Industry energy demand by sector in REF & TGT (PJ)



- In REF, industry remains heavily reliant on fossil fuels. Although electricity use grows rapidly after 2040, it does not significantly displace fossil fuel consumption.
- Coal use more than doubles by 2060, making it the dominant fuel, while natural gas use also doubles and oil remains steady, reinforcing a long-term dependence on fossil energy.
- In contrast, the TGT scenario shows some progress toward decarbonisation, but falls short of full transition. Coal peaks around 2030 and then gradually declines, though unabated use stays high through mid-century. Natural gas use triples, and oil declines but continues in niche applications, keeping both fuels central to industrial energy demand.
- CCS deployment for coal and gas begins around 2035, but remains too limited to significantly reduce CO_2 emissions.

- Iron and steel energy use exhibit the highest relative growth, driven by infrastructure development and rising manufacturing demand. Energy demand in both REF and TGT follows a similar trajectory, suggesting that the adoption of more efficient technologies, such as electric arc furnaces or hydrogen-based steelmaking, may not contribute to significant energy intensity improvements.
- Growth in the non-metallic minerals subsector is largely fueled by increasing demand for cement and ceramics, closely linked to continued urbanisation and construction activity as Indonesia's population grows.
- The 'other industries' category also holds growth potential, which comes from mining, construction, automotive, textile, food and beverages, and other manufacturing. Indonesia is actively promoting mineral down-streaming, developing new industrial streams that convert primary or first-tier mineral products into higher-value secondary products, enhancing domestic value addition and export competitiveness.

Non-energy Demand

Figure 7-13. Non-energy demand in REF (PJ)

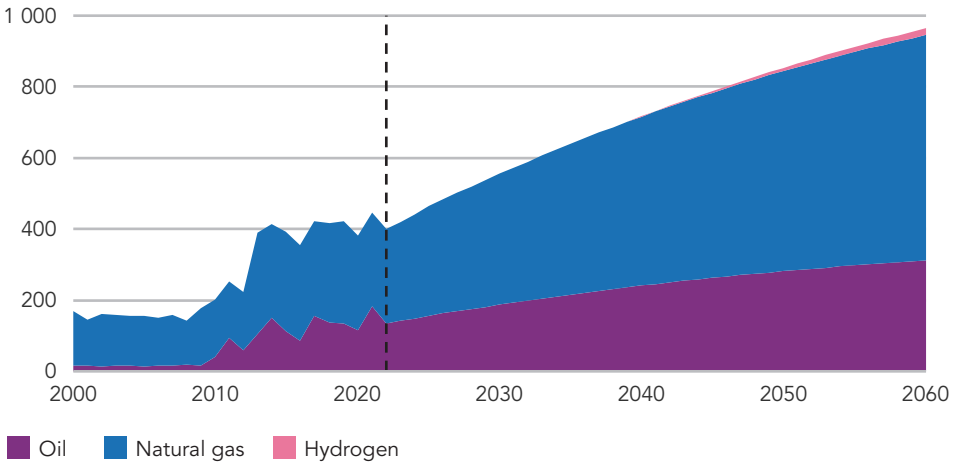
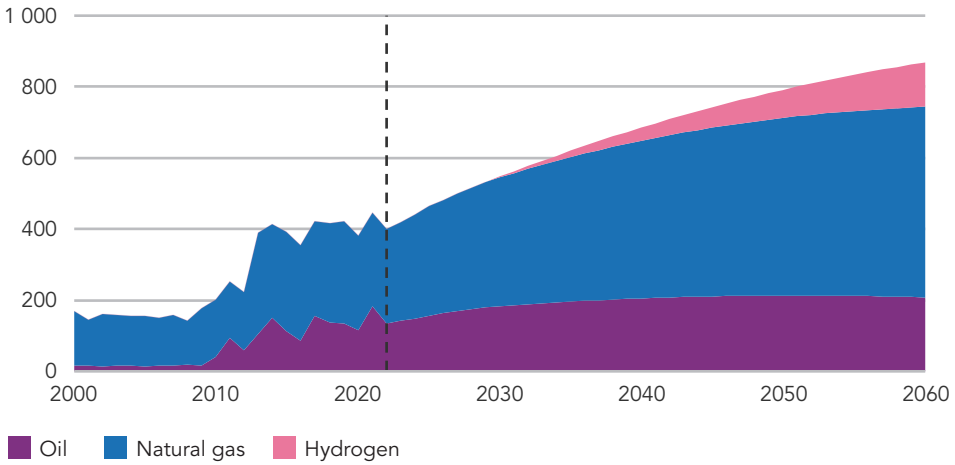


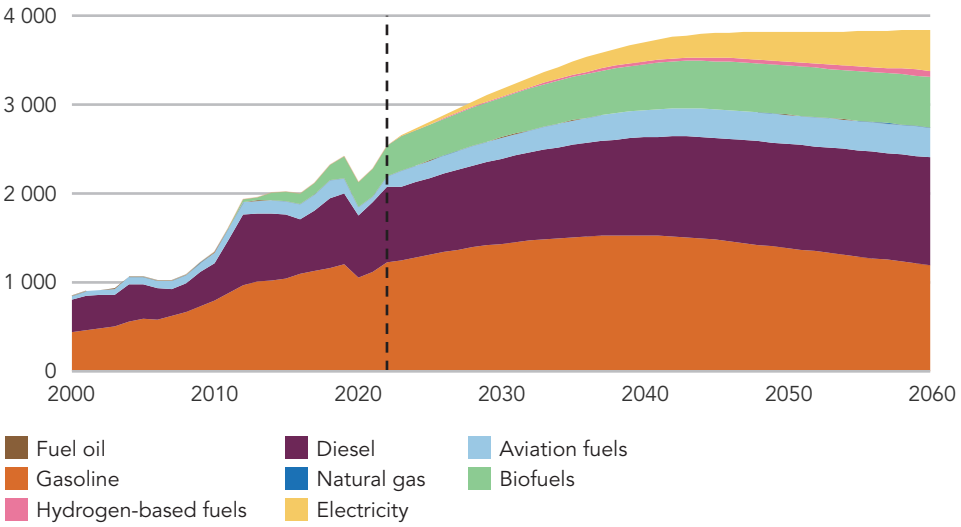
Figure 7-14. Non-energy demand in TGT (PJ)



- Indonesia's non-energy demand is primarily met by natural gas and oil-based feedstocks. Natural gas is used for fertiliser production, while oil-based feedstocks, such as naphtha and LPG, are commonly used in petrochemical processes to produce ethylene, propylene, and polypropylene.
- Natural gas is also utilised in petrochemical production, including methanol, ethylene, propylene, and various plastics, and for hydrogen generation in refinery operations, particularly for producing desulfurised diesel.
- Natural gas feedstock use is expected to grow, gradually substituting oil-based feedstocks. Emerging petrochemical plants are increasingly using natural gas to produce syngas, methanol, and downstream products, such as olefins and plastics, in line with Indonesia's industrial downstreaming strategy. This shift also contributes to reducing dependence on imported crude oil.
- While Indonesia is a major natural gas exporter, via LNG from Tangguh, Bontang, and other terminals, domestic allocation of gas at affordable prices for industry is a growing priority. This creates a strategic trade-off between export revenue and domestic industrial development.
- In the TGT scenario, oil and naphtha feedstock is expected to be gradually substituted with natural gas and hydrogen, particularly in petrochemical processes.
- Natural gas will remain a critical feedstock for Indonesia's fertiliser industry, supporting domestic production to ensure stable food prices and strengthen the agricultural sector.
- Hydrogen is projected to increasingly replace natural gas in ammonia production. Blue hydrogen is expected to dominate industrial feedstock use during the 2030s, leveraging existing natural gas infrastructure and early CCS deployment. From the 2040s onward, green hydrogen is expected to take the lead, driving the decarbonisation of feedstock supply and aligning with Indonesia's net-zero target by 2060. This substitution supports Indonesia's ambition to become a producer and exporter of green commodities such as green ammonia and green methanol, as outlined in the economy's Hydrogen Roadmap.

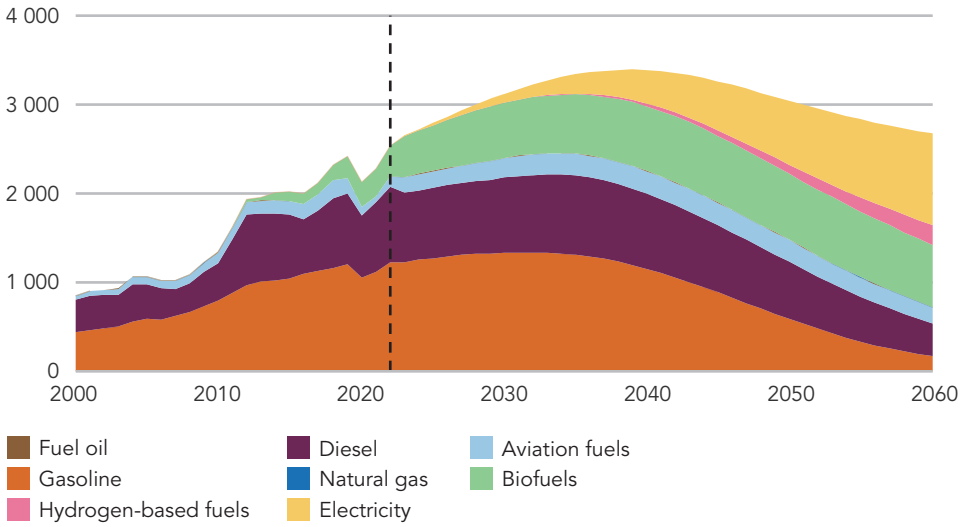
Transport Energy Demand

Figure 7-15. Domestic transport energy demand in REF (PJ)



- Indonesia's transport energy demand is dominated by land transport, particularly two-wheelers, which make up nearly 50% of transport activity, through to 2060. This facilitates the penetration of battery electric vehicles (BEVs) as two-wheelers are among the earliest and most suitable vehicle types for electrification.
- In both scenarios, high levels of growth in population and economic activity lead to a rapid increase in energy use until 2040. Then, levels of vehicle ownership begin to saturate, resulting in a plateau in passenger activity and less growth in energy demand. Even so, freight activity continues to increase, influenced by Indonesia's high levels of industrial growth.
- In REF, where decarbonisation policies are not pursued, energy demand begins to plateau beyond 2050. Aside from the effect of reduced passenger activity growth, the increase in battery electric vehicle (BEV) adoption to around 34% of transport activity in 2060 also helps to flatten energy demand growth.

Figure 7-16. Domestic transport energy demand in TGT (PJ)



- In TGT, more aggressive policies aimed at achieving a 30% emission reduction in the transport sector lead to a significant decrease in energy use. Stricter ICE restrictions strongly support the adoption of more efficient BEVs, increasing their share of transport activity to 68% by 2060.
- The remaining gasoline usage in TGT is primarily for plug-in hybrids used for passenger transport, while diesel consumption is attributed to heavy trucks. However, fuel use and associated emissions would be significantly higher without the ongoing adoption and increasing blending rates of biofuels. By 2060, the share of biofuels blended with other fuels is projected to rise from 28% in 2030 to 60% in diesel, from 0% to 40% in aviation fuels, and from 0% to 10% in gasoline. This expansion in biofuel use is expected to be met through increased domestic production, which will help reduce both emissions and reliance on imported energy.

Other Transport Data

Figure 7-17. Transport vehicle stocks in REF & TGT (millions)

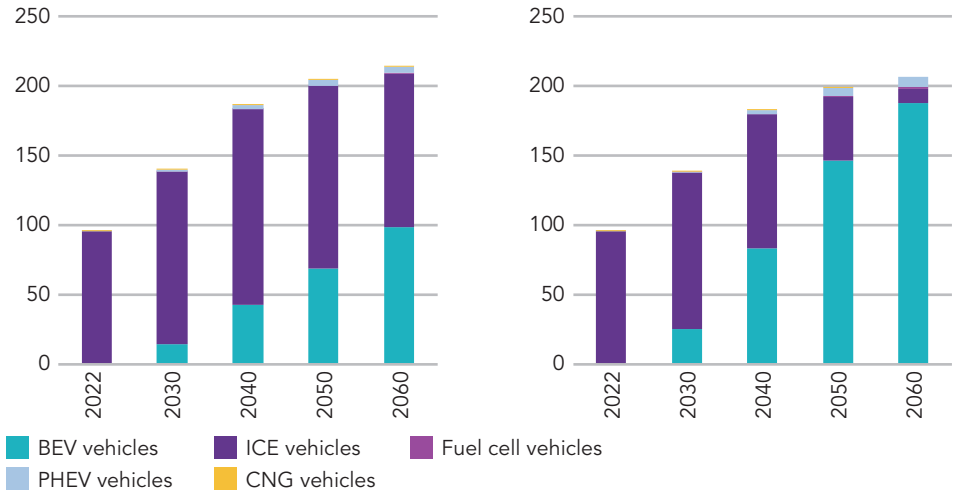
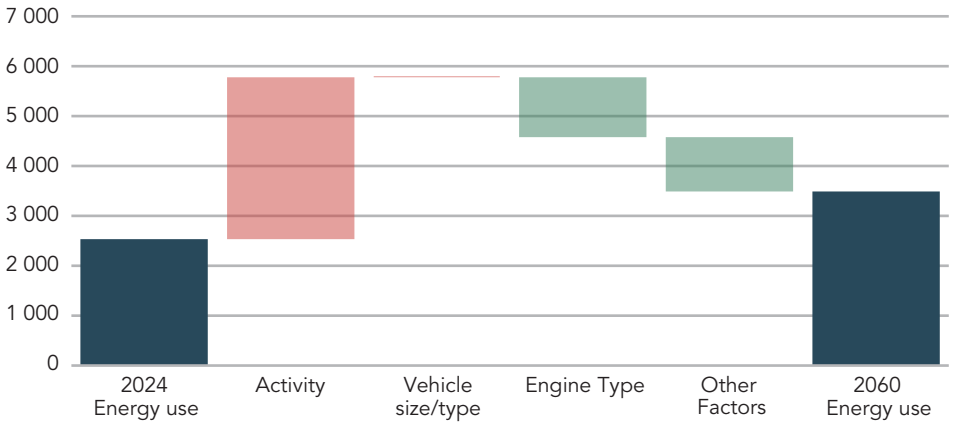
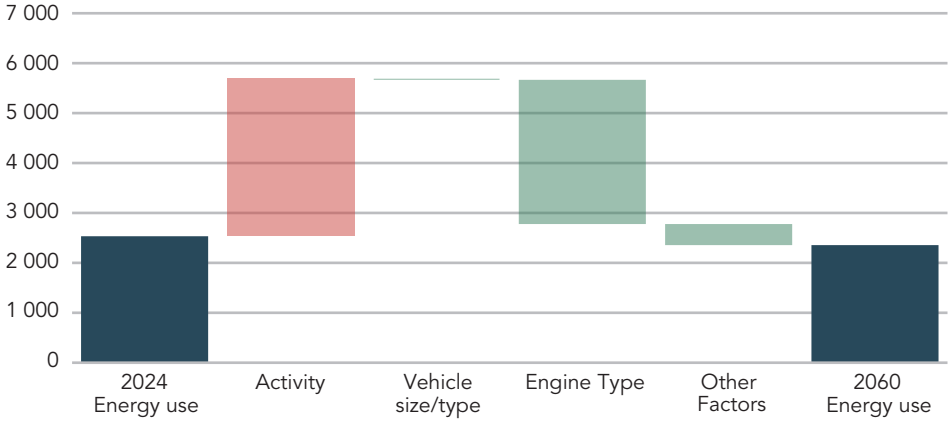


Figure 7-18. Components of the change in road energy use in REF (PJ)



- Figures 7-17 through 7-19 highlight the contrasting trajectories of vehicle stock under two scenarios: a more aggressive decarbonisation policy in TGT versus a more moderate approach in REF.
- In 2060 in REF, approximately 50% of vehicles are BEVs. Whereas in TGT, BEVs become the dominant vehicle type by 2040. While number of PHEVs and fuel cell vehicles also grow in both scenarios, their adoption remains modest compared to BEVs.
- When comparing the components of changes in transport energy use between REF and TGT (7-18 vs 7-19), there is a greater reduction in energy use in TGT because of increased switching to BEVs (as seen in the Engine type component). On the other hand, in REF, improvements from 'Other factors' is also substantial, which is mostly from expected efficiency improvements in new ICE engines. However, increased activity leads to a ~3000 PJ increase in energy use in both scenarios, which limits reductions in total energy use.

Figure 7-19. Components of the change in road energy use in TGT (PJ)



Note: Information on the different drivers in the transport energy decomposition can be found in the *Outlook*'s annex.

Electricity Generation

Figure 7-20. Electricity generation by fuel in REF (TWh)

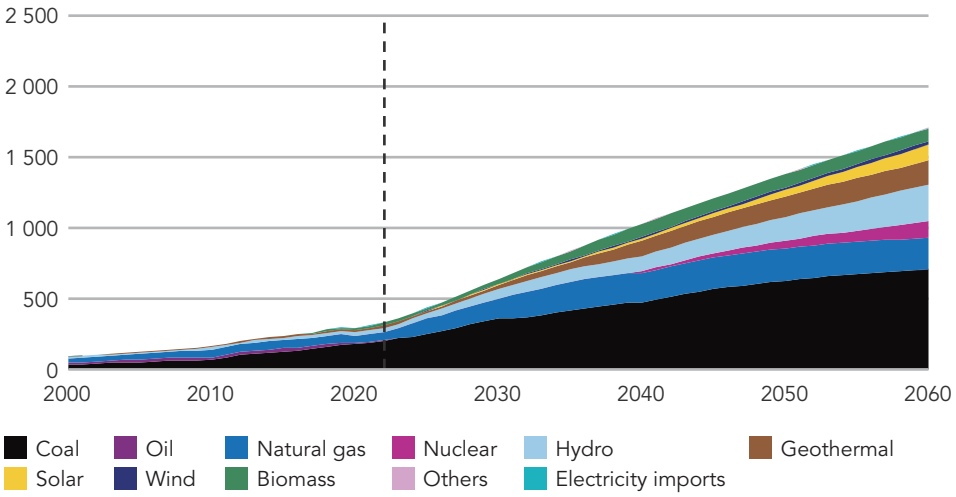
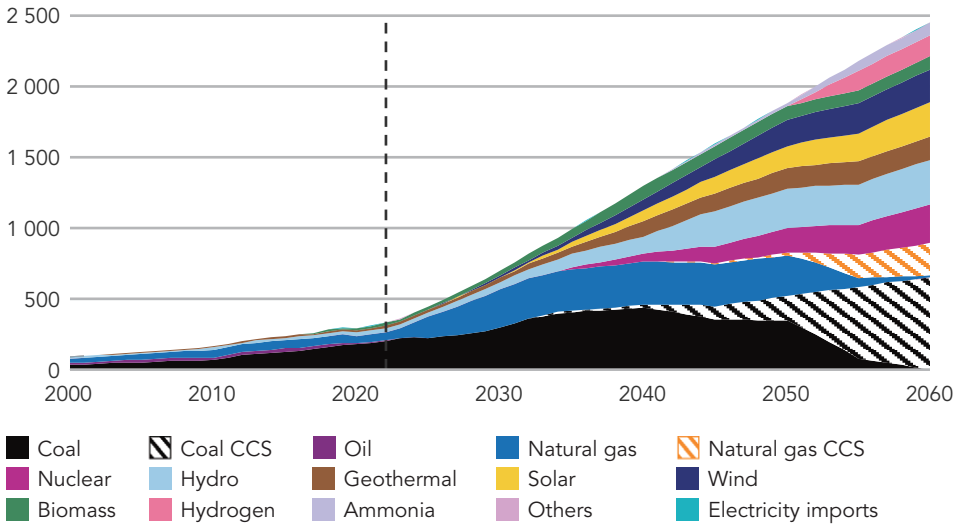


Figure 7-21. Electricity generation by fuel in TGT (TWh)



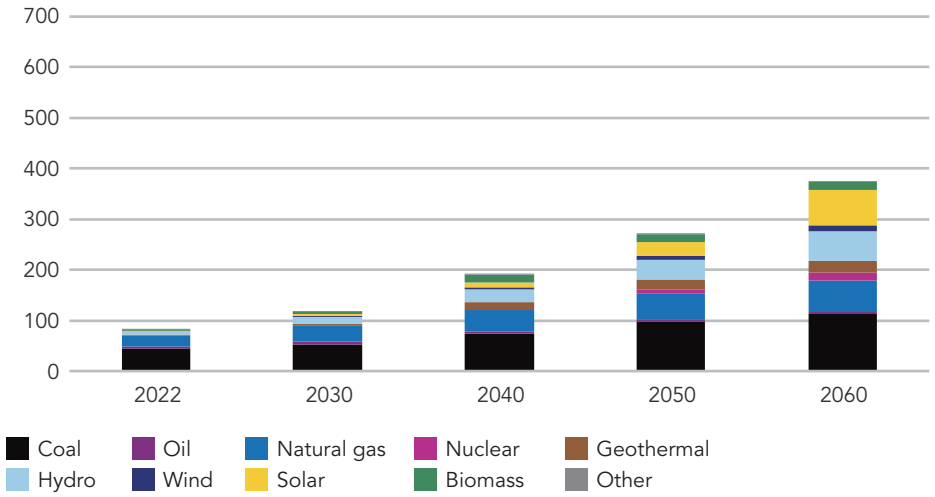
- Indonesia's electricity sector is currently heavily reliant on fossil fuels, particularly coal, which accounted for approximately 61% of the electricity mix in 2022. Indonesia has set ambitious targets to transition toward lower emissions energy sources, including achieving 23% renewable energy in the primary energy mix by 2025 (recently revised to 17–19%) and net-zero emissions by 2060.
- In REF, electricity generation increases steadily driven by rising electrification across all end-use sectors. Electricity generation increases from 334 TWh in 2022 to 2,454 TWh in 2060, reflecting a growth of 5.4% which is intended to support the targeted economic growth of 5.5% annually.
- Coal remains the largest source, growing from 205 TWh (61.5%) in 2022 to 296 TWh (42.2%) in 2030. This reflects continued reliance on existing capacity and limited new additions due to the 2022 coal moratorium (with exceptions). Key challenges remain, including contractual obligations (take-or-pay agreements) and a young coal fleet, requiring significant international funding. After 2030, there is a rapid rise of renewable energy, particularly solar and wind, but early growth is limited by grid capacity and land availability.

- In TGT, Indonesia's electricity generation from 2022 to 2060 shifts from a coal-dominated mix (61.5% in 2022) to a diversified, low-carbon system (53.7% renewables, 11.2% nuclear, 35.9% fossil fuels with CCS, and 9.8% hydrogen/ammonia by 2060). The trajectory aligns with Indonesia's net-zero ambitions, and its effectiveness will depend on the pace of coal phase-out, renewable scaling, and CCS/nuclear adoption.
- Fossil fuels which dominate in 2022 (78%) will decline to 24% by 2060 in TGT. Although a fossil fuel phase-out is planned in line with Indonesia's net-zero target, the continued heavy reliance on coal (peaking at 33.2% in 2040) reflects a delayed energy transition driven by economic dependence and binding contractual obligations.
- As both nuclear and coal with CCS are utilised for baseload power, supported by accelerated policy and investment, solar and wind can scale rapidly post-2030. However, their broader adoption will require grid expansion and improved integration technology. The emergence of alternative fuels, such as hydrogen and ammonia, after 2050 reflects global cost declines and development of new technologies.

Note: Figures 7-20 and 7-21 do not include electricity generation for hydrogen production.

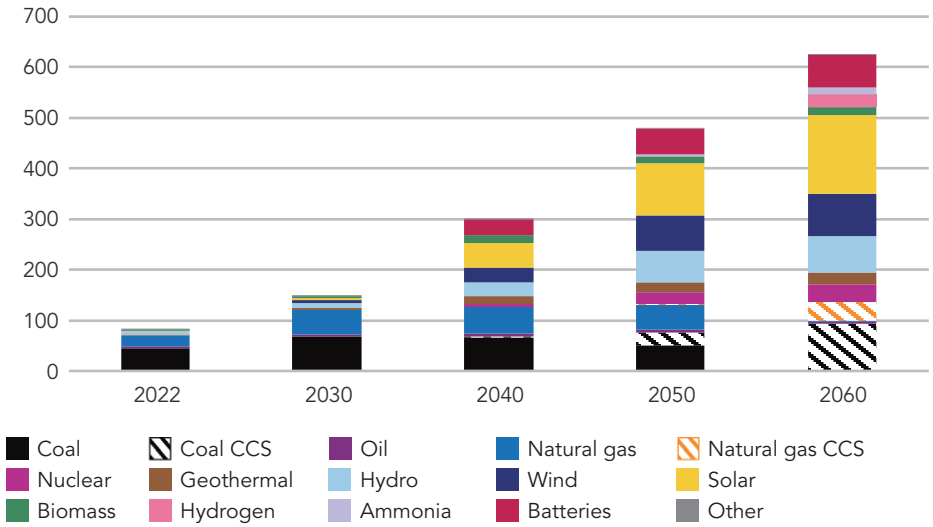
Generation Capacity

Figure 7-22. Generation capacity by fuel in REF (GW)



- In REF, the electricity generation as shown in the previous section, will require generation capacity to increase nearly fivefold, from 83.19 GW in 2022 to 374.21 GW by 2060.
- The most significant growth occurs between 2040 and 2060, during which capacity nearly doubles from 191.29 GW to 374.21 GW. This surge is driven by the integration of large-scale solar, hydro, and geothermal resources. By this period, the power system will be mature enough to accommodate a substantial share of renewable energy.
- Nuclear power is introduced only after 2040, taking into account the required economic conditions, availability of skilled human resources, and the establishment of regulatory and safety frameworks.
- Despite these advancements, the system remains heavily reliant on fossil fuels. Coal continues to dominate due to its cost-effectiveness as a baseload source, while natural gas experiences steady growth, with gas-fired generation serving as a to balance the intermittency of renewable energy.

Figure 7-23. Generation capacity by fuel in TGT (GW)



- In TGT, which reflects Indonesia's efforts towards decarbonisation and achieving net-zero emissions, electricity demand is expected to increase due to higher electrification rates in sectors such as industry and transportation. As a result, total generation capacity in 2060 is projected to be 6.4 times higher than in 2022, approximately 150 GW more than in REF.
- To meet this growing demand with low-emissions energy sources, significant additional capacity from renewables will be required, primarily solar (155 GW) and wind (85 GW). To enable the integration of these variable renewable energy (VRE) sources, battery energy storage systems totaling 62 GW will be needed while natural gas-fired power plants are expected to grow from 20.74 GW in 2022 to a peak of 52 GW in 2040.
- Both new gas-fired plants and existing/planned coal-fired power plants are expected to be equipped with carbon capture and storage (CCS) technologies to mitigate their CO_2 emissions.

Note: Figures 7-22 and 7-23 do not include generation capacity for hydrogen production.

Grid Reliability

Figure 7-24. Total generation capacity and peak load (GW)

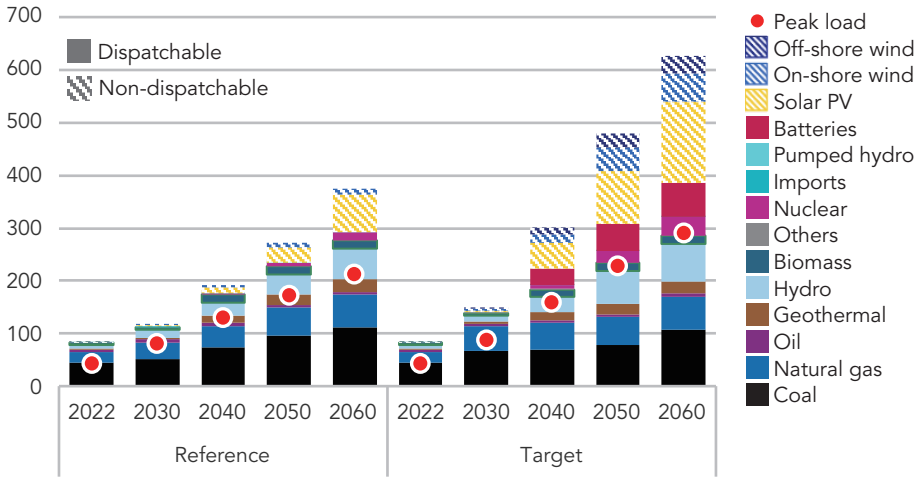
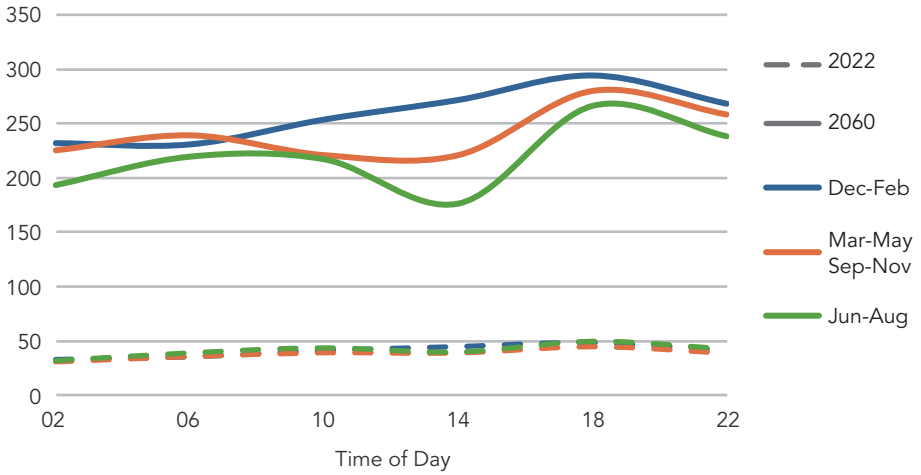


Figure 7-25. Power from dispatchable sources in TGT (GW)



- In REF, the peak electricity load grows by 395% from 43 GW in 2022 to 211 GW in 2060. In TGT, peak load grows by 574% to 288 GW by 2060 due to increased electrification in the Target Scenario.
- Due to the intermittency of solar and wind generation, which results in relatively lower load factors, total system generation capacity must grow faster than peak load to integrate these sources.
- In REF, total generation capacity grows by 349% from 83 GW in 2022 to 375 GW by 2060. In TGT, it needs to grow by 649% to 625 GW.
- Grid reliability requires that power systems have enough dispatchable generation capacity, including batteries, to meet peak load in those periods when wind and solar generation are at its lowest level.
- Increased reliance on wind and solar generation will increase the variability of the generation required from dispatchable power sources. Additionally, as wind and solar capacity increases, the load factor for dispatchable sources declines, which increases total system cost.
- By 2060, fluctuations in dispatchable power generation will increase significantly compared to 2022, due to the higher share of variable renewable energy (VRE) in the system. On a typical dry-season day (June to August), dispatchable generation may drop from 207 GW at 10:00 AM to 168 GW at 2:00 PM, before rising sharply to 253 GW by 6:00 PM.
- In contrast, during the rainy season (December to February), the variation is expected to be less, with dispatchable generation gradually increasing from 207 GW at 10:00 AM to 280 GW at 6:00 PM.
- This variability will likely be a challenge for system operators across the economy and meeting this challenge will likely increase the capital, maintenance, and operating costs of the power system in Indonesia.

Coal

Figure 7-26. Coal consumption by sector in REF & TGT (PJ)

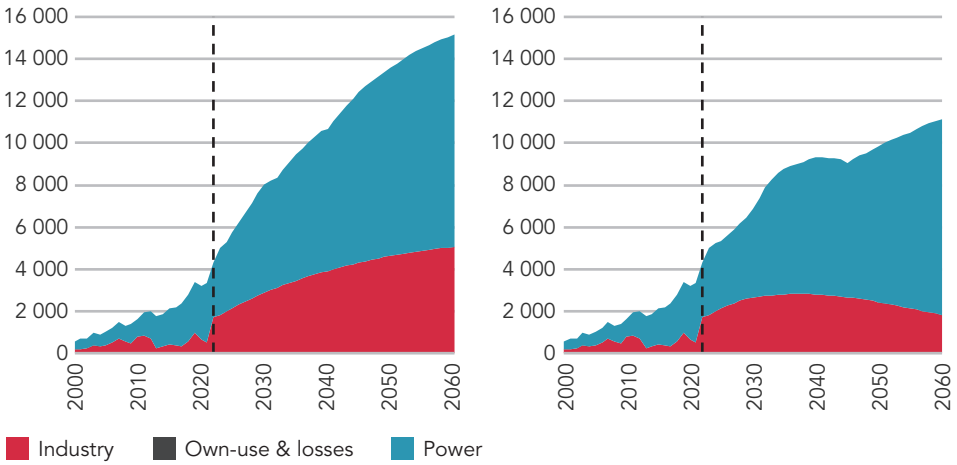
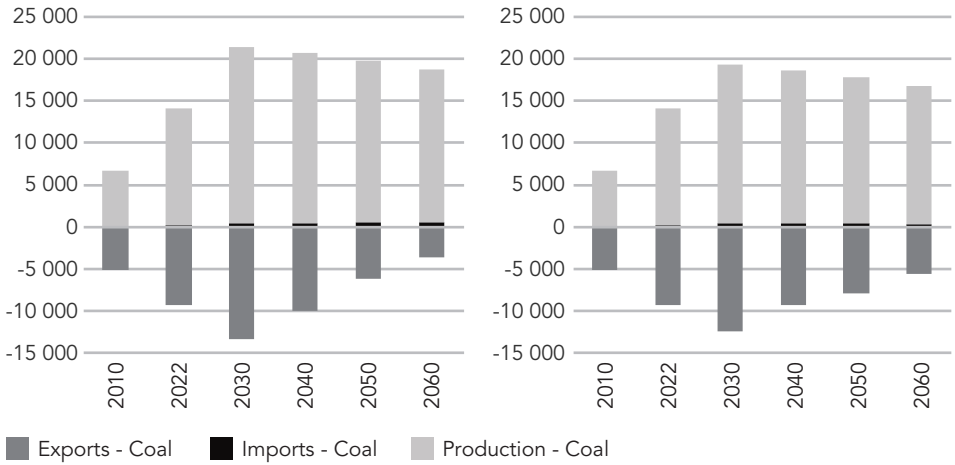


Figure 7-27. Coal production, imports, and exports in REF & TGT (PJ)



- In REF, coal consumption is projected to quadruple by 2060, primarily due to increased coal-fired power plant capacity to meet rising electricity demand.
- Growing industry demand is expected to require more coal due to resource availability, practicality, and affordability. Renewable energy generation deployment has faced challenges related to renewable energy integration and insufficient energy transition funding, leading to coal-fired power generation still playing a significant role in the coming decades.
- In TGT, coal demand triples, with the power sector as the main driver. Continued reliance is sustained by the deployment of CCS and CCUS technology.
- Biomass co-firing remains limited due to constraints on biomass availability.
- Indonesia is largely self-sufficient in coal, gaining revenue from thermal coal exports, primarily to China and India, while also importing small amounts of high-quality coal or metallurgical coal for industrial use (smelting and metal processing).
- Future global demand is expected to decline, leading to reduced export levels in both REF and TGT. Although export levels will shrink, production will be relatively constant as coal continues to be a source of revenue and therefore its production is expected to be maximised.

Natural Gas

Figure 7-28. Natural gas consumption by sector in REF & TGT (PJ)

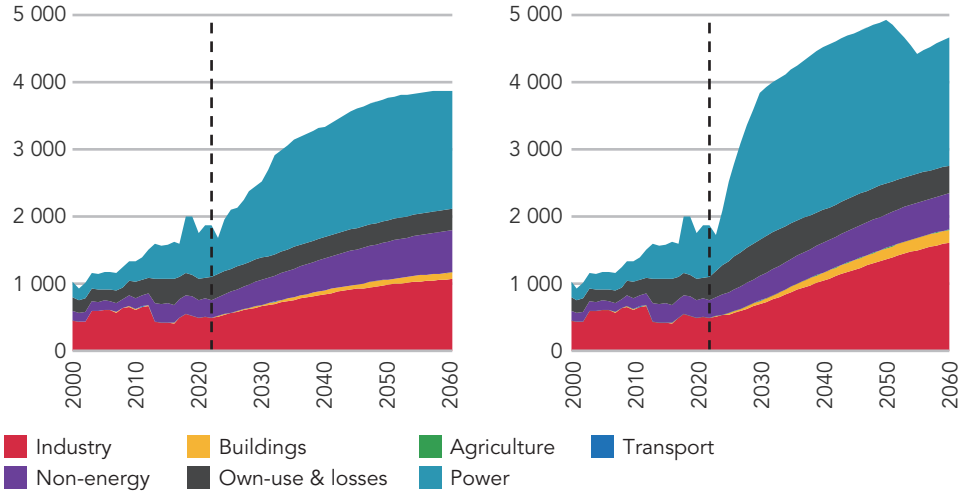
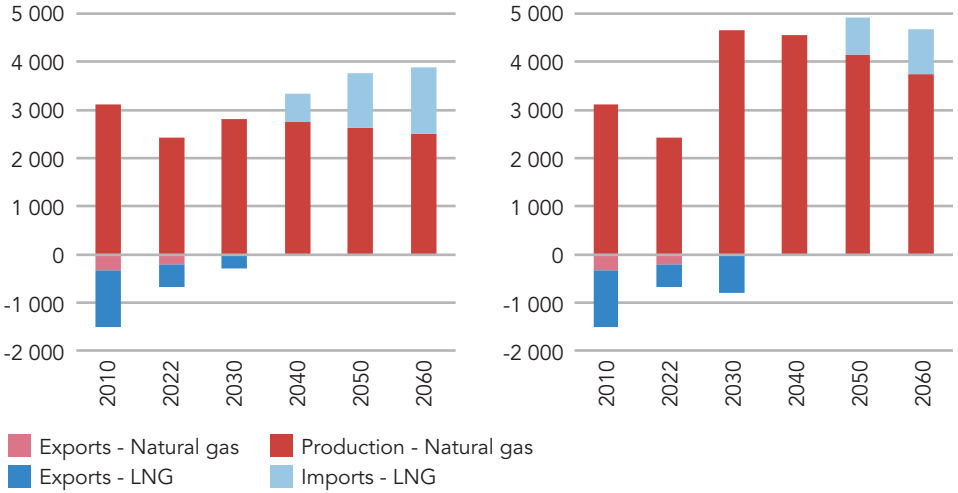


Figure 7-29. Natural gas and biogas production, imports, and exports in REF & TGT (PJ)



- Natural gas consumption in Indonesia is projected to increase, driven by rising demand from the electricity, industry, buildings, and non-energy sectors. In the buildings sector, natural gas is used primarily for cooking and water heating, gradually replacing biomass and subsidised LPG. In the non-energy sector, natural gas is used as feedstock for the fertiliser industry, particularly for ammonia production.
- Although the lack of infrastructure, such as pipelines, storage, and regasification facilities, may hinder distribution, competition among sectors for gas supply is expected to intensify. To manage this, the government will allocate supply quotas for each sector and may also regulate the plant gate price of gas to ensure fair distribution.
- In TGT, gas demand is higher than in REF, as the government allows greater consumption, assuming natural gas production meets the target of 12 billion standard cubic feet per day. When domestic production declines due to reserve depletion, imports will begin to supplement supply.
- In REF, natural gas imports are expected to begin in the early 2030s due to limited successful development of domestic gas reserves. In contrast, in TGT, more gas reserves are anticipated to be developed and start producing, delaying the need for imports until after 2040.

Petroleum Liquids

Figure 7-30. Crude oil production, imports, and exports in REF & TGT (PJ)

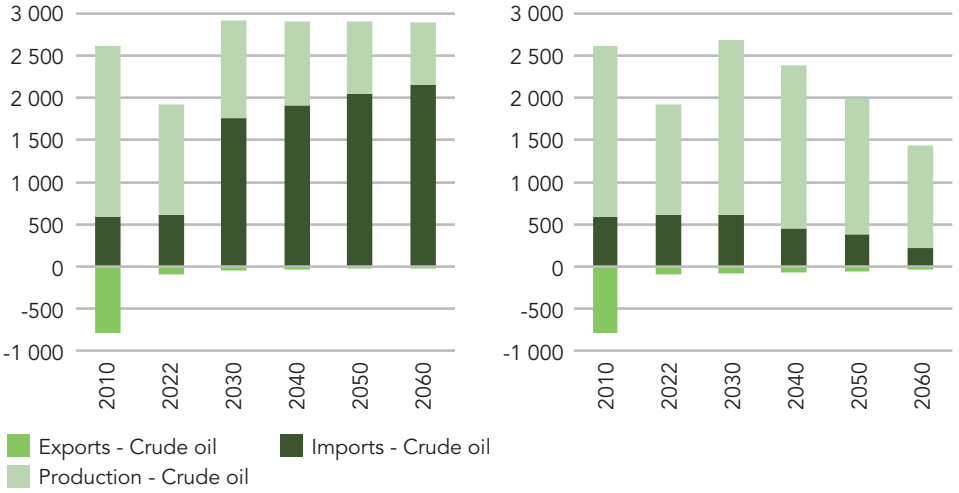
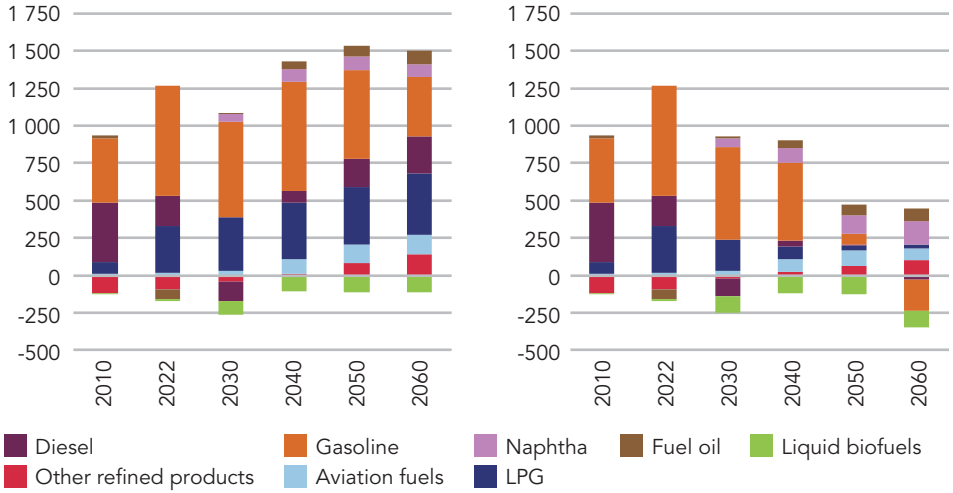


Figure 7-31. Net imports of refined products and low-carbon fuels in REF & TGT (PJ)



- In REF, domestic crude oil production is anticipated to decline due to natural reserve depletion. At the same time, demand is expected to peak around 2030 and remain steady thereafter. The mismatch between declining production and sustained demand will lead to a continued increase in crude oil imports, reaching over 2,000 PJ by 2060.
- In TGT, crude oil production is expected to rise to 1 million barrels per day (approximately 2,000 PJ) by 2030, supported by the development of potential deepwater reserves in Indonesia. At the same time, domestic consumption is projected to decline due to the transition to electric vehicles (EVs), resulting in lower crude import needs, below 500 PJ by 2060.In REF, refinery capacity is projected to increase to 1,589 kb/d by 2030 through the addition of the new Bontang grassroots refinery and the expansion of the Cilacap refinery. This capacity level is expected to be maintained through 2060.
- In TGT, refinery capacity will peak at 1,276 kb/d by 2026, following the Balikpapan refinery expansion, but will gradually decline to 800 kb/d by 2060 due to aging infrastructure and economic considerations.
- The net import of refined petroleum products depends on production, refining capacity, and demand. In REF, imports of most products rise steadily until 2030, with gasoline peaking around 2040 before declining. Diesel imports begin after 2038 as demand grows, while jet fuel and fuel oil imports will also increase, mainly for domestic use. LPG imports appear to rise, though they may be offset by domestic gas processing. In TGT, imports of gasoline and LPG decline due to lower demand, and diesel needs are met by refinery output despite reduced capacity.

Note: In Figure 7-31, net imports are presented without deducting bunkers.

Refining

Figure 7-32. Refined products and low-carbon fuels outputs in REF & TGT (PJ)

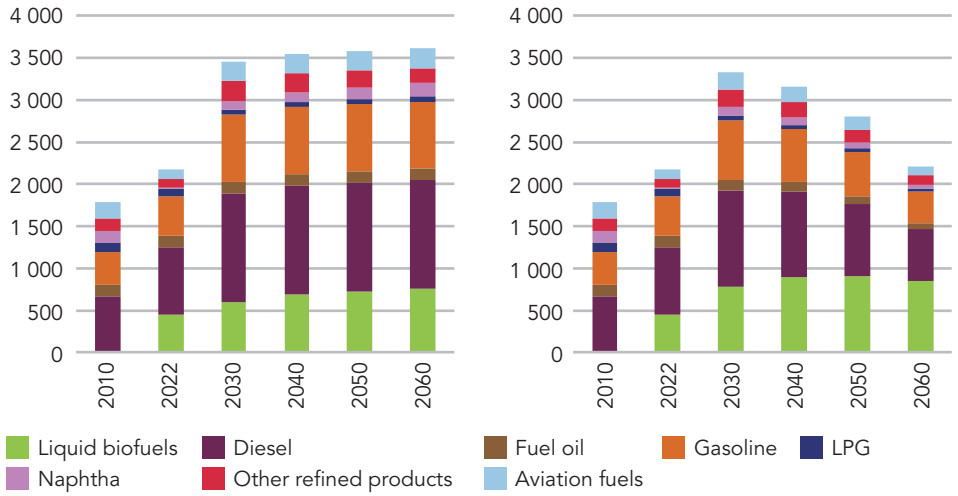
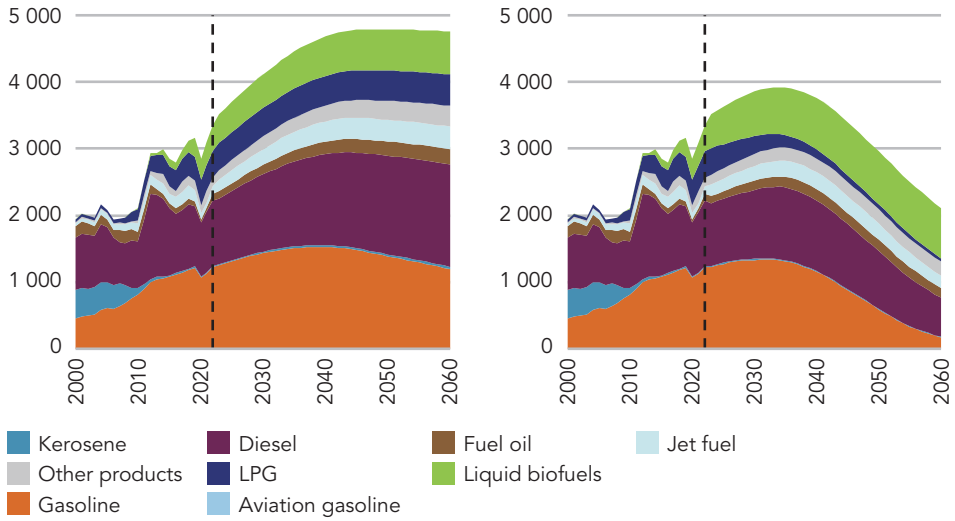


Figure 7-33. Refined products and low-carbon fuels demand in REF & TGT (PJ)



- Figure 7-32 illustrates the changes in product variation over time under the REF and TGT scenarios. In REF, the production of conventional petroleum products, such as gasoline and diesel, remains largely constant. Over the next four decades, the main variation comes from a gradual increase in the production of liquid biofuels, along with a smaller increase in higher-value products like aviation fuels and naphtha.
- This trend is primarily driven by market demand. Indonesia's population continues to rely on internal combustion engine (ICE) vehicles, with gasoline used for two-wheelers and passenger cars, and diesel used for commercial and heavy-duty vehicles.
- In contrast, there is an assumed market shift towards electric vehicles (EVs) in TGT, leading to a gradual decline in the demand for petroleum products, especially gasoline and diesel. This drives refineries to scale down the production of these fuels accordingly.
- LPG production also declines as natural gas pipeline infrastructure and city gas networks expand in larger urban areas, and hence reduce LPG demand.
- Although Figure 7-33 does not explicitly show naphtha demand, its consumption is expected to remain substantial due to the presence of several large petrochemical industries in Indonesia. Refineries may need to consider this potential shift in demand. As conventional fuel consumption declines, shifting refinery output to include more petrochemical feedstocks such as naphtha could help maintain utilisation rates and support the long-term economic viability of refinery operations.

Bioenergy and Waste

Figure 7-34. Bioenergy and waste demand by sector in REF & TGT (PJ)

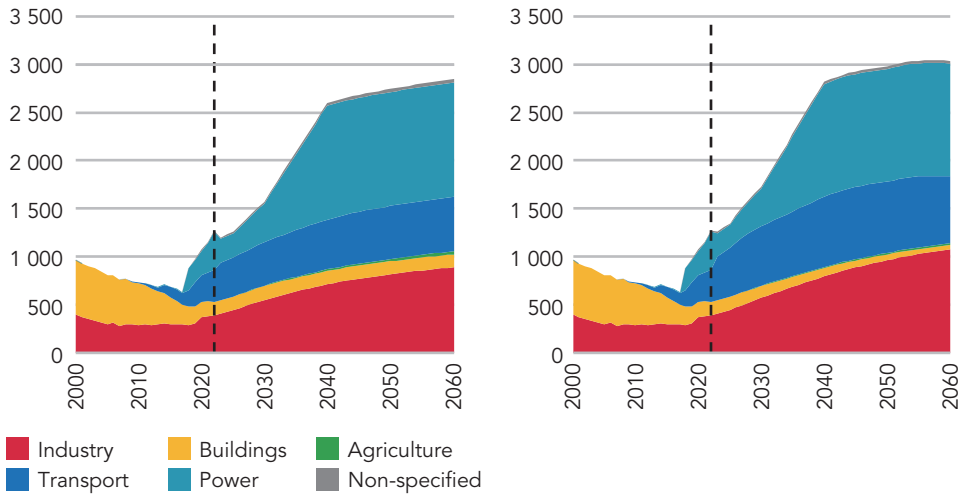
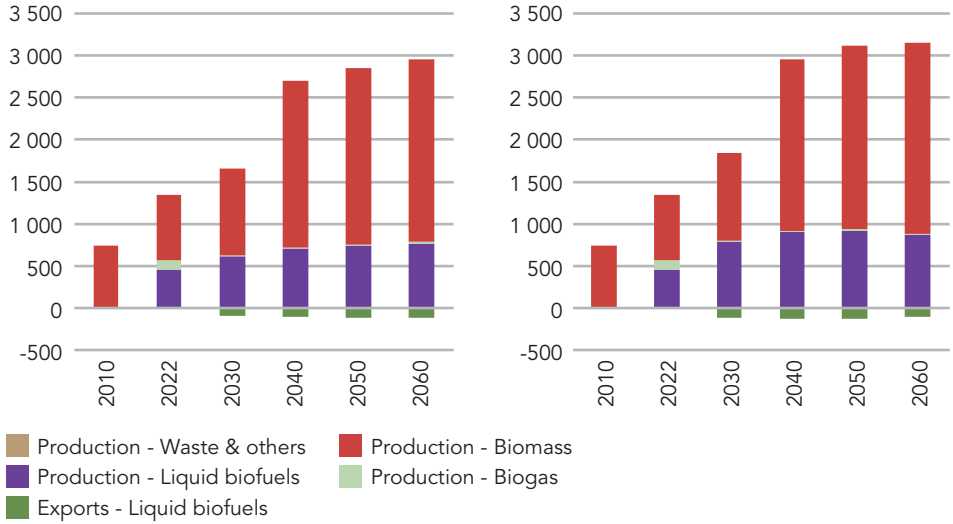


Figure 7-35. Bioenergy and waste production, imports, and exports in REF & TGT (PJ)



- Indonesia has an abundant biomass and waste resources, offering significant potential for energy use. These include the conversion of crude palm oil and sugarcane into liquid biofuels, palm kernel shells and wood sawdust into biomass wood pellets, and various agricultural and municipal wastes into biogas.
- In both scenarios, bioenergy and waste demand is expected to increase across most sectors. A key contributor to this growth is the expansion of biomass co-firing in the power sector, which is expected to triple by 2060 at a 10% blending rate. Future advancements in burner and combustion chamber technologies are expected to allow for higher blending rates.
- The industry and transport sectors are also expected to use more bioenergy with higher biodiesel blending in both scenarios. Indonesia has officially adopted Biodiesel B40, with plans to reach B100 by 2050.
- In TGT, bioenergy use in the buildings sector is expected to decline, primarily due to the reduced use of woodchips for cooking and a higher rate of electrification for household appliances.
- A higher level of liquid biofuel production is expected in TGT than in REF, driven by greater demand for biodiesel in heavy-duty trucks and increased use of sustainable aviation fuel (SAF) in the aviation sector. The deeper penetration of biofuels aligns with rising global demand, potentially boosting Indonesia's export capacity for biofuels.

Hydrogen-based Fuels in the Target Scenario

Figure 7-36. Hydrogen-based fuels production methods and supply [left]; Inputs for hydrogen production [right] (PJ)

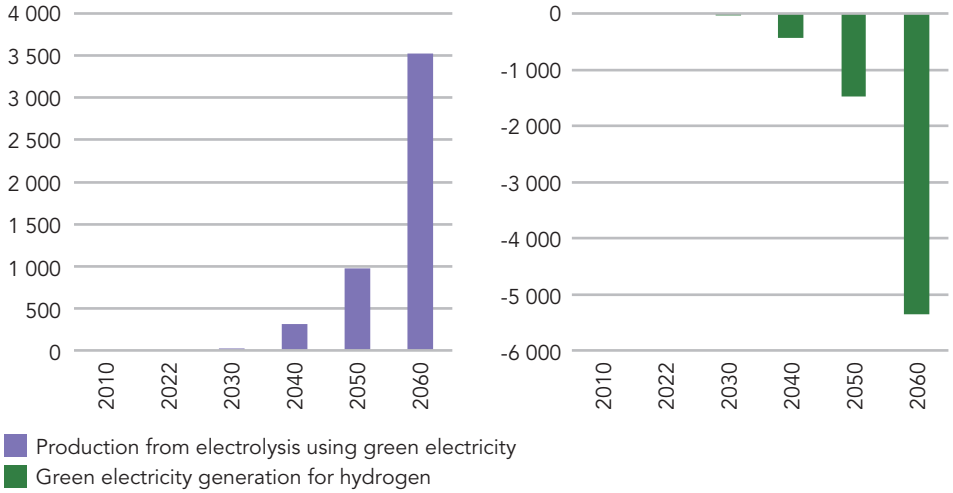
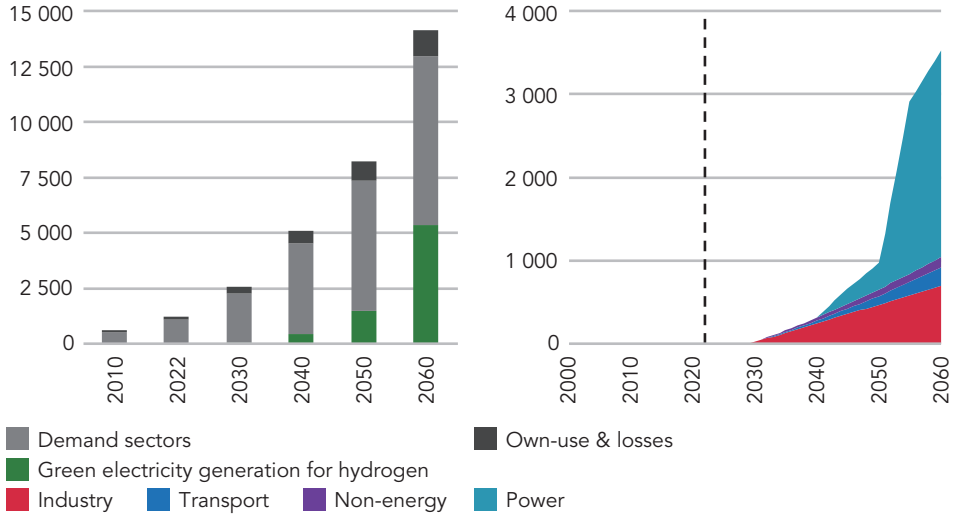


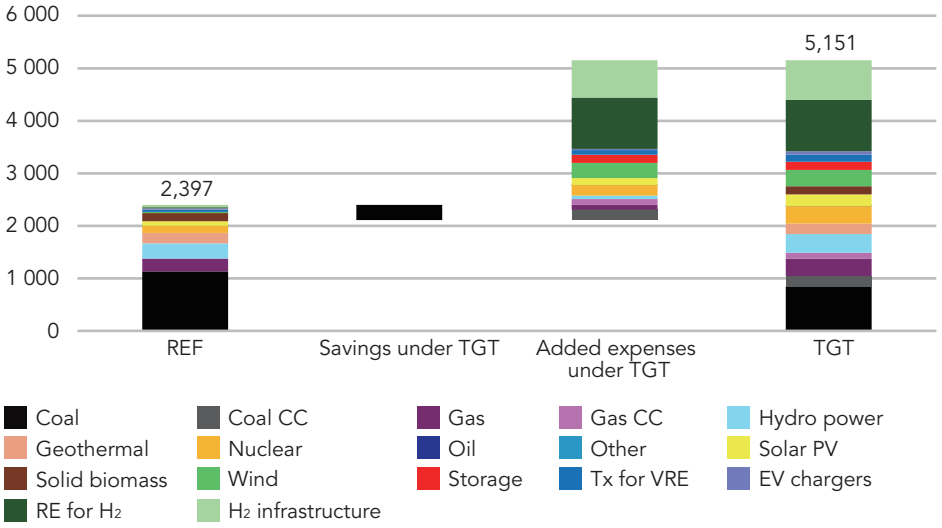
Figure 7-37. Electricity for electrolysis vs other sectors [left]; Hydrogen-based fuels demand by sector [right] (PJ)



- Indonesia's Hydrogen Strategy aims to reduce fossil fuel dependency, enhance energy security, and support its decarbonisation targets by developing a domestic green hydrogen market, primarily using renewable electricity for electrolysis.
- The produced hydrogen is expected to be deployed across multiple sectors, including power generation (e.g. fuel blending for gas-fired power plants), industry, transportation, and non-energy applications.
- As illustrated in Figure 7-37, hydrogen production is projected to commence in 2030, with demand from the power sector alone expected to reach 1,000 PJ by 2050 and then increase significantly to 3,500 PJ by 2060.
- According to Figure 7-36 meeting this level of hydrogen demand via electrolysis will require approximately 5,360 PJ of electricity in 2060, which would account for 38% of Indonesia's total projected electricity demand across all sectors.
- Producing this volume of hydrogen exclusively from green electricity presents major challenges. The TGT scenario addresses this by planning to leverage remaining untapped renewable energy potential, including solar, wind, and nuclear. Other renewables such as geothermal and hydropower, however, have already been extensively utilised to meet the current and projected needs of the power sector.

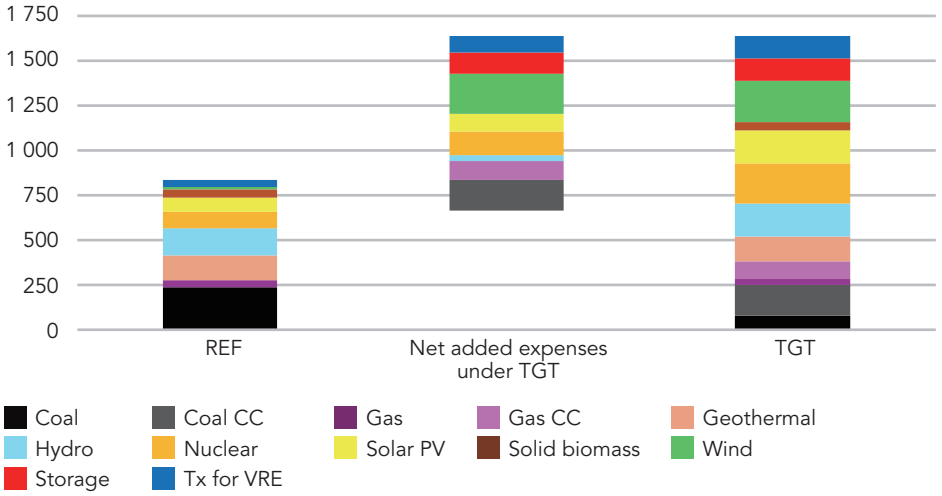
Costs

Figure 7-38. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



Note: Tx for VRE is only transmission infrastructure to connect variable renewable capacity to the grid. EV chargers do not cover the cost of associated infrastructure or EV vehicles.

Figure 7-39. Total capital investment (CAPEX) from 2025 to 2060 in the power sector (billion USD, undiscounted)

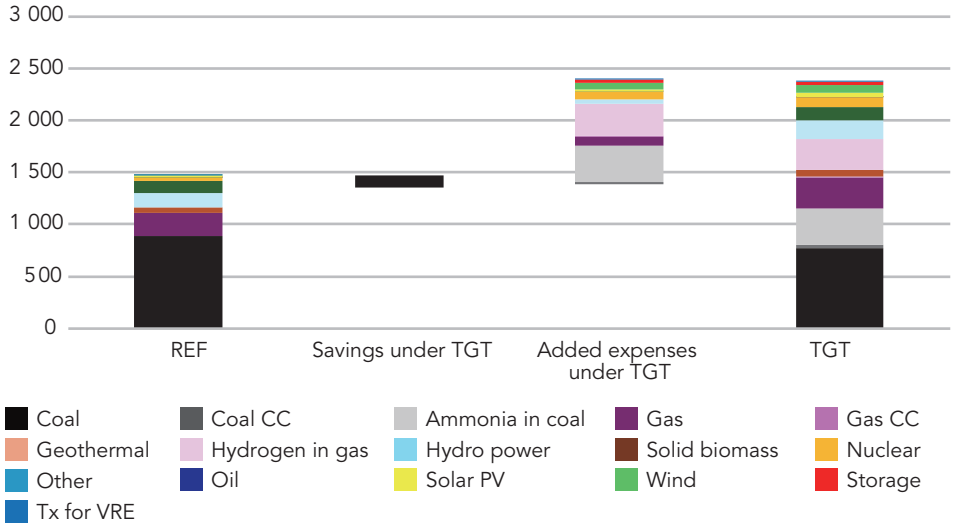


Note: Figure 7-39 only covers power and VRE transmission sector investments. Hydrogen and EV costs are not covered.

- Reaching net-zero emissions in Indonesia will require significant expenditures to drive the economy's energy transformation. The total capital fixed and variable costs in the power sector are considered, along with costs for green hydrogen production, transmission for VRE and added EV chargers.
- In REF, total costs are an estimated USD 2.4 trillion, primarily driven by thermal operating expenses and added hydro power and nuclear capacity.
- In contrast, TGT, which features 42% more total generation capacity with a greater share of renewable energy sees costs rise due to added spending on wind, solar and the storage and transmission needed to support the additional renewables. An additional USD 1.7 trillion dollars is spent on green hydrogen related expenses (renewables and nuclear for electrolysis and green hydrogen fuel producing infrastructure), reflective of the ambitions of its Hydrogen Strategy and the domestic use of green hydrogen. While a significant amount of green hydrogen produced is used in the power sector, usage in the transport and industry sectors also occurs.
- Total capital expenditures in the power sector approach an estimated USD 1.6 trillion in TGT up from an estimated USD 834 billion in REF. Most of the additional expenses in TGT stem from capital expenditures for a variety of new technologies, such as ensuring coal and gas plants include carbon capture technology, new hydro and nuclear capacity, and additional wind and solar.
- One of the key factors of the additional CAPEX expenditure in TGT is the transmission CAPEX for VRE. Due to the site-specific nature and wide spatial distribution of variable renewable energy (VRE) in Indonesia, an expanded transmission network will be necessary to integrate smaller, dispersed generation sources while ensuring system reliability and efficiency. As such, USD 126 billion is estimated to be spent over the projection period to integrate additional VRE into the electricity grid.

Costs

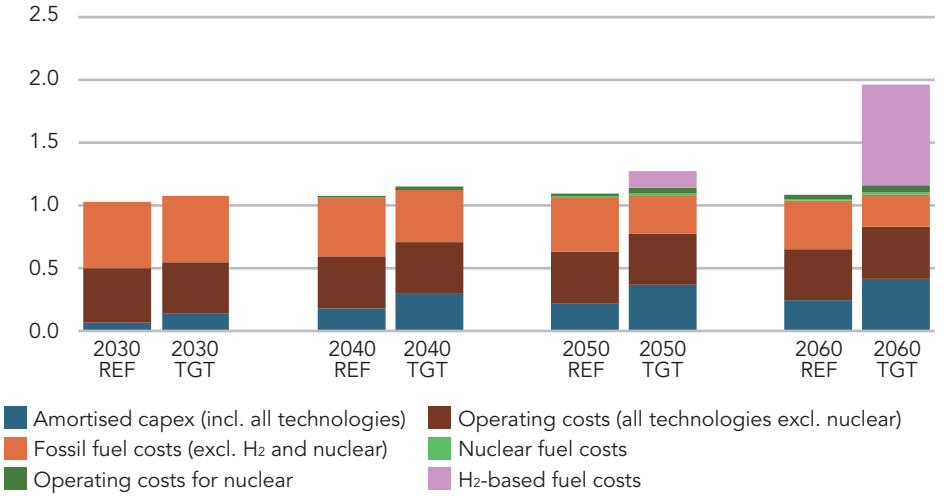
Figure 7-40. Total operating costs from 2025 to 2060 in the power sector (billion USD, undiscounted)



Note: Figure 7-40 only covers power and VRE transmission sector costs. It does not include operating costs associated with hydrogen production and EV charger costs but does include the cost of H_2/ammonia blending in power generation.

- Total operating costs for the power sector of Indonesia are projected to be USD 1,473 billion in REF and USD 2,370 billion in TGT. These costs incorporate variable fuel and non-fuel expenditure and fixed costs for both the power sector and for transmission to 2060.
- Figure 7-40 shows that, despite a significant addition of fuel-free VREs such as solar and wind in the TGT scenario, the overall operating costs are estimated to be higher.
- The higher operational costs in TGT are primarily driven by the greater use of more expensive green hydrogen, which is then co-fired with gas and coal generation (the latter in the form of ammonia). This transition increases fuel costs as both ammonia and hydrogen have higher fuel costs than conventional thermal coal and gas. This will offset the small amount of savings Indonesia will have by reducing their reliance on conventional coal.

Figure 7-41. Cost of generating electricity relative to 2025 (2025 cost = 1.0) in the power sector



Note: Based on our assumptions about future capital and operating costs, Figure 7-41 shows cost compositions over time relative to 2025. It should not be considered an estimate of electricity tariffs and excludes market mechanisms that are too difficult to estimate.

- Figure 7-41 shows the relative cost of generating electricity in selected years, indexed to the base year of 2025 for each scenario.
- Indexed to 2025, generation costs remain relatively stable in REF, with declining fossil fuel costs shares being offset by increased shares of amortised capital costs from new investment.
- The relatively higher cost of producing electricity in TGT is primarily driven by the utilisation of comparatively more expensive hydrogen and ammonia fuel with gas and coal co-firing.
- In TGT, by 2050, growing ammonia blending starts to increase the cost of electricity generation relative to 2025. With the large-scale adoption of hydrogen blending with gas generation in the 2050s, costs increase substantially, resulting in a near doubling of costs by 2060.

CO_2 Emissions

Figure 7-42. CO_2 emissions in REF (million tonnes)

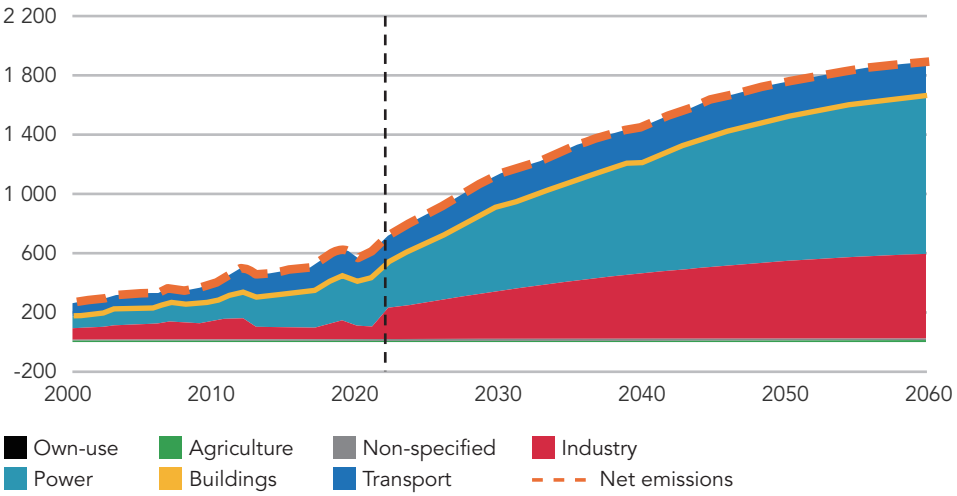
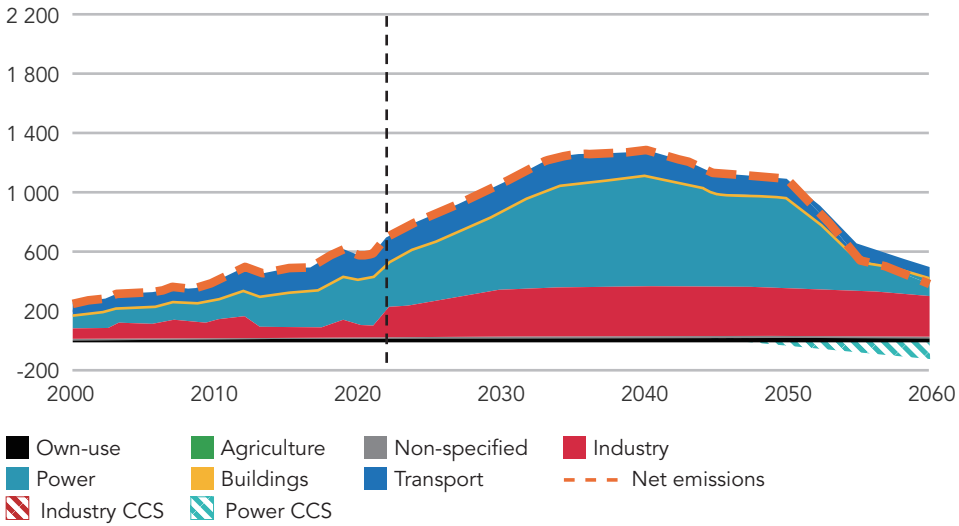
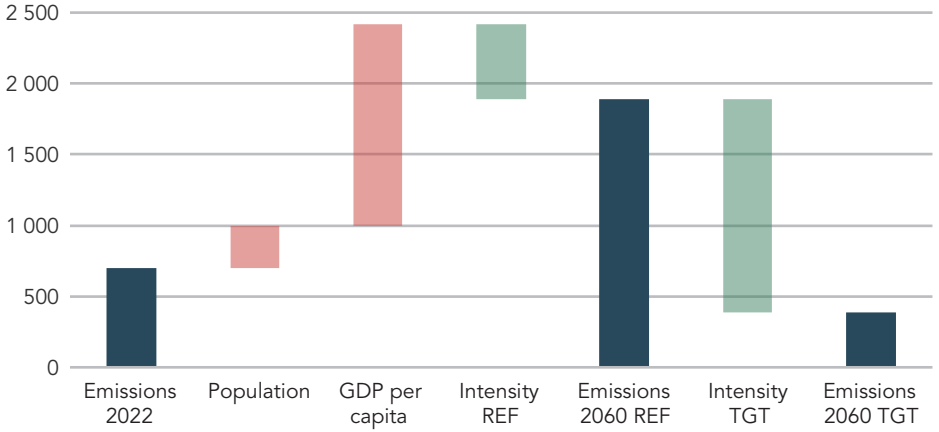


Figure 7-43. CO_2 emissions in TGT (million tonnes)



- The trajectories of CO_2 emissions diverge sharply between REF and TGT after 2040 reflecting different decarbonisation policies and implementation efforts. However, even in TGT emission reductions fall short of achieving carbon neutrality in the energy sector.
- Emission reductions are primarily driven by the deployment of low-emission power generation technology and electrification across the transport, industry, and buildings sectors.
- As shown in Figure 7-44, emissions changes from 2022 to 2060 are largely influenced by expected economic growth and reflected in higher GDP per capital.

Figure 7-44. CO_2 emissions components (million tonnes)



Note: All values represent energy sector combustion CO_2 emissions. Biogenic CO_2 is treated as zero at the point of combustion.

Useful Links

APEC Expert Group on Energy Data and Analysis (EGEDA) – https://www.egeda.ewg.apec.org/

APEC Energy Statistics 2022 – https://www.egeda.ewg.apec.org/egeda/general/info/pdf/APEC_Energy_Statistics_2022.pdf

APEC Energy Overview – https://aperc.or.jp/reports/energy_overview.php

Ministry of Energy and Mineral Resources, Republic of Indonesia – www.esdm.go.id

Directorate General of Electricity – www.gatrik.esdm.go.id

Directorate General of New Renewable Energy and Energy Conservation – www.ebtke.esdm.go.id

Directorate General of Oil and Gas – www.migas.esdm.go.id

Directorate General of Mineral and Coal – www.minerba.esdm.go.id

Special Task Force for Oil and Gas – www.skkmigas.go.id

National Energy Council – www.den.go.id

Indonesia Statistic Office – www.bps.go.id

National Energy Policy – https://jdih.esdm.go.id/dokumen/view?id=186

National Energy Planning – https://www.esdm.go.id/en/publication/ruen

National Electricity Planning – https://gatrik.esdm.go.id/frontend/download_index/?kode_category=rukn

Indonesia Energy Outlook 2024 – https://www.den.go.id/publikasi/Outlook-Energi-Indonesia#

Indonesia Long-term Strategy on Low Carbon and Climate Resilience 2050 – https://unfccc.int/sites/default/files/resource/Indonesia_LTS-LCCR_2021.pdf

Enhanced Nationally Determined Contribution Republic of Indonesia 2022 – https://unfccc.int/sites/default/files/NDC/2022-09/ENDC%20Indonesia.pdf

Updated Nationally Determined Contribution Republic of Indonesia 2021 – https://unfccc.int/sites/default/files/NDC/2022-06/Updated%20NDC%20Indonesia%202021%20-%20corrected%20version.pdf



8. Japan

Summary

	Reference			Target		
	2022	2060	% Change	2022	2060	% Change
Macroeconomic						
Population (million)	124.3	97.0	-21%	124.3	97.0	-21%
GDP (billion 2017 USD, PPP)	5,192	6,576	26%	5,192	6,576	26%
Energy Demand						
Agriculture & fisheries (PJ)	201	166	-17%	201	128	-36%
Buildings (PJ)	3,636	2,966	-18%	3,636	2,301	-37%
Industry (PJ)	3,151	2,957	-6%	3,151	2,599	-18%
Non-energy (PJ)	1,125	1,328	18%	1,125	1,074	-5%
Transport (PJ)	2,692	1,801	-33%	2,692	978	-64%
Modern renewable share of TFEC (%)	9	28	211%	9	72	700%
Energy intensity of TFEC (PJ/GDP, billion USD)	1.9	1.2	-37%	1.9	0.9	-53%
Electricity						
Generation (TWh)	1,010	1,090	8%	1,009	1,243	23%
Renewables share of generation (%)	22	55	150%	22	86	291%
Generation capacity (GW)	355	615	73%	354	815	129%
Total Primary Energy Supply (TPES)						
Coal & coal products (PJ)	4,560	738	-84%	4,560	336	-93%
Natural gas (PJ)	3,467	3,782	9%	3,467	596	-83%
Petroleum liquids (PJ)	6,315	4,214	-33%	6,315	1,725	-73%
Low-carbon & waste energy (PJ)	2,085	4,134	98%	2,085	7,982	282%
CO_2 intensity of energy supply ($MtCO_2/PJ$)	0.055	0.034	-38%	0.055	0.008	-85%
Net CO_2 Emissions (million tonnes)	896	443	-51%	896	62	-93%

Note: In this publication, the term "modern renewables" refers to all renewable energy sources excluding solid biomass in the buildings sector. The term "low-carbon & waste energy" includes all bioenergy, waste-derived energy, renewables, nuclear, and hydrogen-based fuels. Total primary energy supply (TPES) numbers include international bunkers. Net emissions are calculated as gross energy sector combustion CO_2 minus CO_2 captured and stored through carbon capture and storage (CCS).

Key Takeaways

Emissions

- In 2050, energy-related net CO_2 emissions reach around 100 $MtCO_2$ in the Target scenario (TGT), while over 500 $MtCO_2$ is still emitted in the Reference scenario (REF).
- The sharper decline in TGT reflects a fundamental shift in Japan's energy system. Gasoline and diesel consumption in the transport sector is phased out, replaced by BEVs and transitional fuels such as e-fuels. Solar and wind generation expands more significantly in the power sector and hydrogen largely replaces natural gas. CCS is also deployed more extensively in both the power and industry sectors, capturing 50 $MtCO_2$ per year by 2050.
- Despite these ambitious transformations, achieving economy-wide net-zero emissions by 2050 remains a challenge. Residual emissions in the energy sector will need to be offset by increased efforts in forestry, direct air capture (DAC), and bioenergy with CCS (BECCS). Continued policy support and investment in these areas will be critical for closing the remaining gap.

Energy Import Dependence

- In 2022, Japan's energy self-sufficiency rate was just 13%, reflecting its heavy dependence on imported fossil fuels. In REF, this improves greatly to 32% by 2060, supported by expanded renewable generation, nuclear restarts, and reduced coal consumption.
- In TGT, self-sufficiency rate rises even greater to 52% by 2060. This is driven by increased electrification and greater expansion of solar and wind generation.
- To further strengthen energy security, Japan is diversifying import sources for fossil fuels and will need to continue doing so as new supply chains for hydrogen and e-fuels develop. It also maintains key domestic refining capacity to reduce supply risks for petroleum-based feedstocks.

Figure 8-1. Net CO_2 emissions (million tonnes)

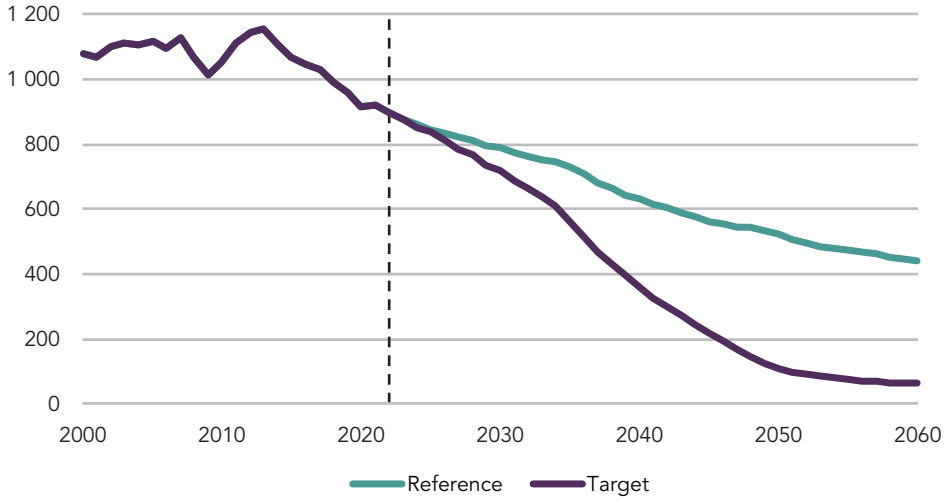
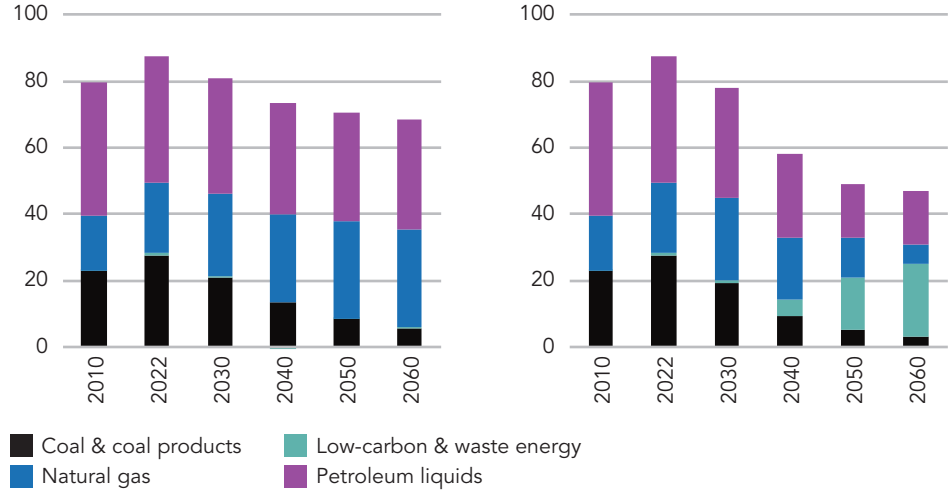


Figure 8-2. Net imports share of TPES in REF & TGT (%)



Note: In Figure 8-2, net imports refer to total imports minus exports and international bunkers.

Key Takeaways

Grid Reliability

- As Japan increases electrification and expands solar and wind, maintaining grid reliability becomes more challenging. Power must be available during peak demand even as the share of dispatchable generation share declines.
- The gap between peak load and dispatchable capacity widens in both scenarios, reflecting greater reliance on renewables. Higher solar use also leads to sharper day-night swings, increasing ramping needs and straining system flexibility.
- Unlike Europe's meshed network, Japan's comb-shaped grid makes long-distance power transfer more difficult. To improve wide-area balancing, Japan is developing interregional transmission lines containing HVDC (High Voltage Direct Current) converters or frequency conversion facilities.
- Improved forecasting and maintaining flexible capacity with gas or hydrogen will be essential for grid reliability, ensuring firm and dispatchable supply to meet variable demand in a high-renewables future.

Cost

- Japan faces major estimated costs in its power and hydrogen sectors through to 2060. Under TGT, total costs are estimated to be USD 5.47 trillion, almost double the cost in the REF scenario. Considered costs include total capital, fixed, and variable costs in the power sector, low-carbon hydrogen importation costs, VRE transmission, costs of heat production and electric vehicle chargers.
- Although spending on imported natural gas declines over time, most of the additional costs come from low-carbon hydrogen and e-fuels, around USD 1.35 trillion for hydrogen in power, and nearly USD 1 trillion for e-fuels in transport. The rest is tied to expanding other low-carbon sources of generation and related infrastructure in the power sector.
- This reflects Japan's commitment to energy security, pursued through a technology-neutral approach. However, it also underscores the trade-offs between ambitious decarbonisation goals and long-term affordability.

Figure 8-3. Peak load and maximum and minimum dependence on dispatched power (GW)

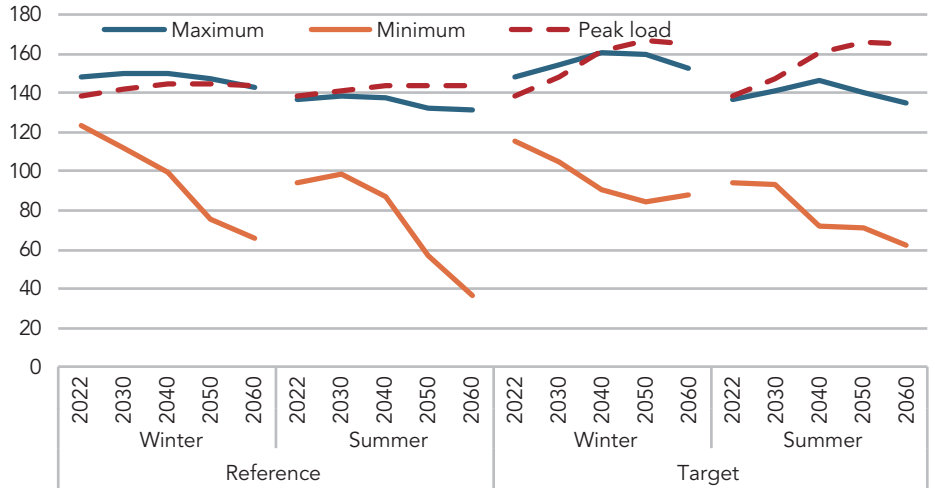
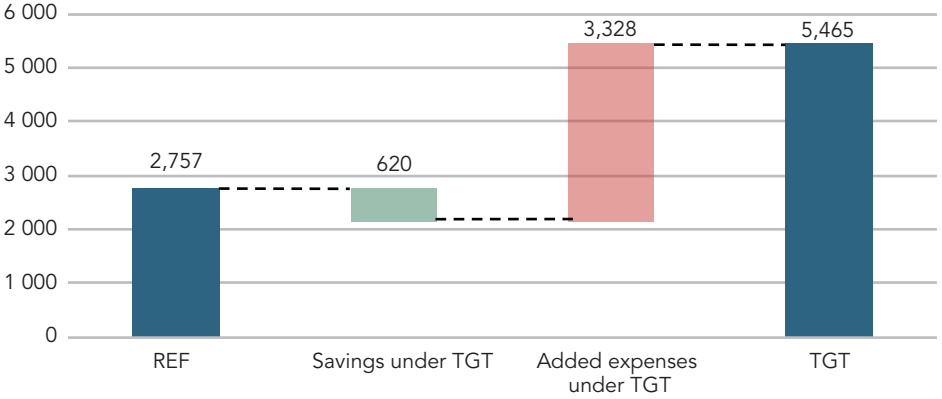


Figure 8-4. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



*Actual costs will differ from estimated costs in the outlook for a variety of reasons including changing commodity prices, manufacturing costs and unforeseen technical advances. All costs are in 2023 real terms.

About Japan

Overview

Geographical and Economic Landscape

Japan is an island economy located in East Asia, comprising four main islands and numerous smaller ones. With limited domestic fossil fuel resources, Japan relies heavily on energy imports to support its advanced and densely populated economy. It is the third-largest economy in APEC by GDP and maintains a highly developed industrial base alongside a strong services sector. Japan's population is aging and gradually declining, creating long-term challenges for economic growth, energy demand, and workforce sustainability.

Energy Supply and Consumption

Japan's energy system is shaped by its resource constraints, vulnerability to global supply shocks, and high urban density. Following the 2011 Fukushima accident, nuclear generation dropped sharply, leading to increased LNG and coal imports. Over time, Japan has pursued a more balanced energy mix, aiming to enhance energy security and meet its decarbonisation goals. Electricity accounts for a growing share of total final energy consumption, driven by policies promoting electrification and efficiency in buildings, transport, and industry. While fossil fuels still dominate primary energy, their share is gradually declining with the expansion of renewables and restart of nuclear capacity.

Energy Security Challenges and Strategies

Energy security remains a top priority in Japan's energy policy. As a major fossil fuel importer, Japan is exposed to price volatility and geopolitical risks. To address this, Japan is diversifying supply sources, increasing fuel stockpiles, and investing in domestic renewables. Long-term strategies focus on achieving net-zero by 2050 while securing stable and affordable energy, such as through innovation, energy efficiency, hydrogen deployment, and advanced thermal and nuclear technologies.

Key Energy Initiatives

7th Strategic Energy Plan (2025)

Japan's core energy policy sets a target of achieving a more balanced and resilient power mix by 2040, with maximised use of both renewables and nuclear power. The plan emphasises the principle of S+3E (Safety as a fundamental premise, Energy security, Economic efficiency, and Environment) while aligning with Japan's 2050 carbon neutrality pledge.

Updated Nationally Determined Contribution (NDC)

In 2025, Japan committed to reducing greenhouse gas emissions by 60% by 2035 and 73% by 2040 from 2013 levels under the Paris Agreement.

GX (Green Transformation) Strategy and Vision

The GX strategy outlines a long-term pathway for decarbonisation beyond 2050, focusing on hydrogen, ammonia, CCUS, renewables, and next-generation nuclear technologies.

Hydrogen Strategy

Japan revised its Basic Hydrogen Strategy in 2023, setting supply targets of 3 million tons by 2030, 12 million tons by 2040, and 20 million tons by 2050.

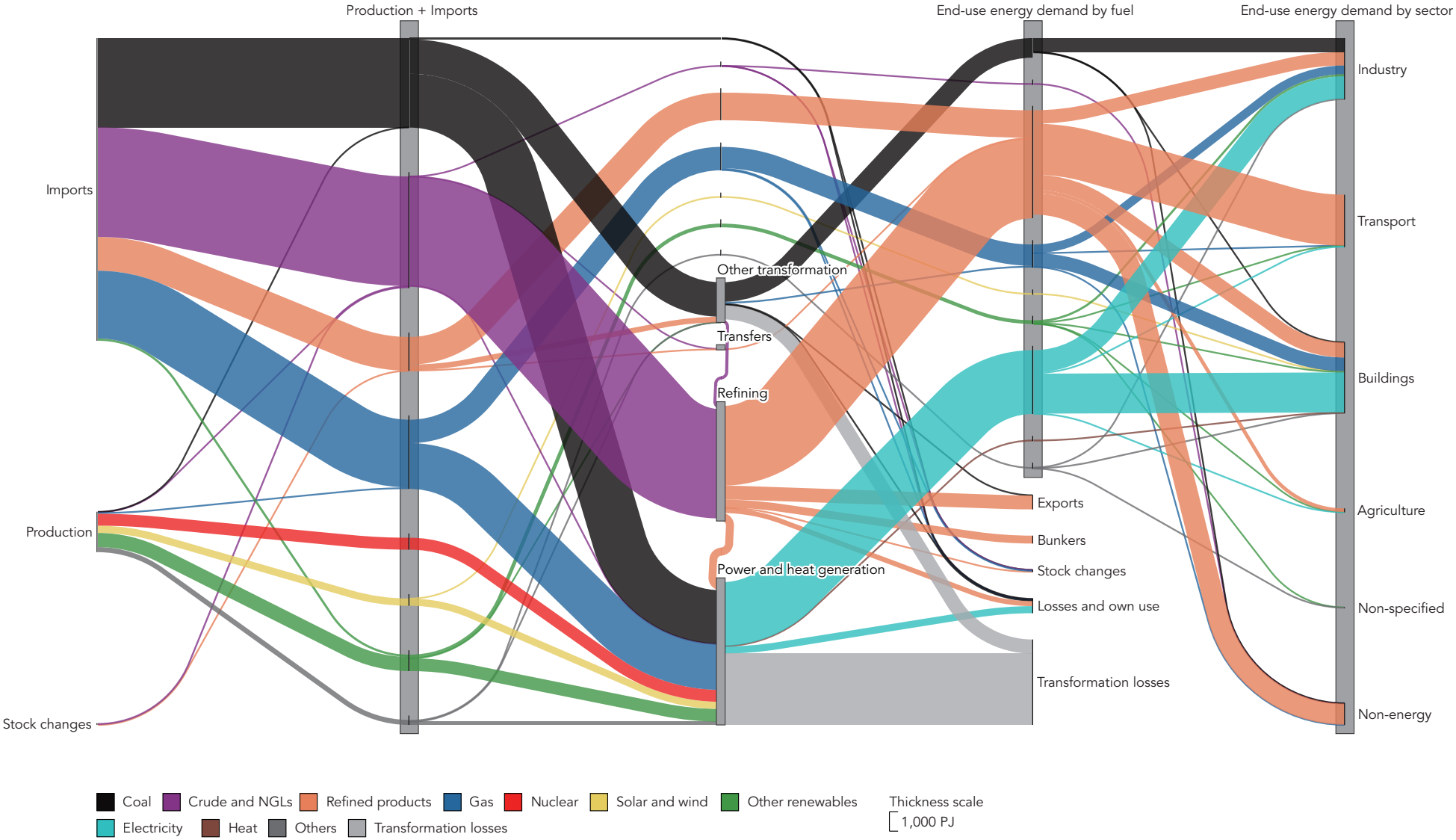
Nuclear Restart

Japan has maintained the framework of a maximum operational period of 60 years for nuclear reactors, while introducing a new system that allows periods during which reactors were shut down due to factors beyond the control of nuclear operators to be excluded from the 60-year operational count. Also, the government will proceed with restarts only for those reactors that have been approved by the Nuclear Regulation Authority, while gaining the understanding of local municipalities.

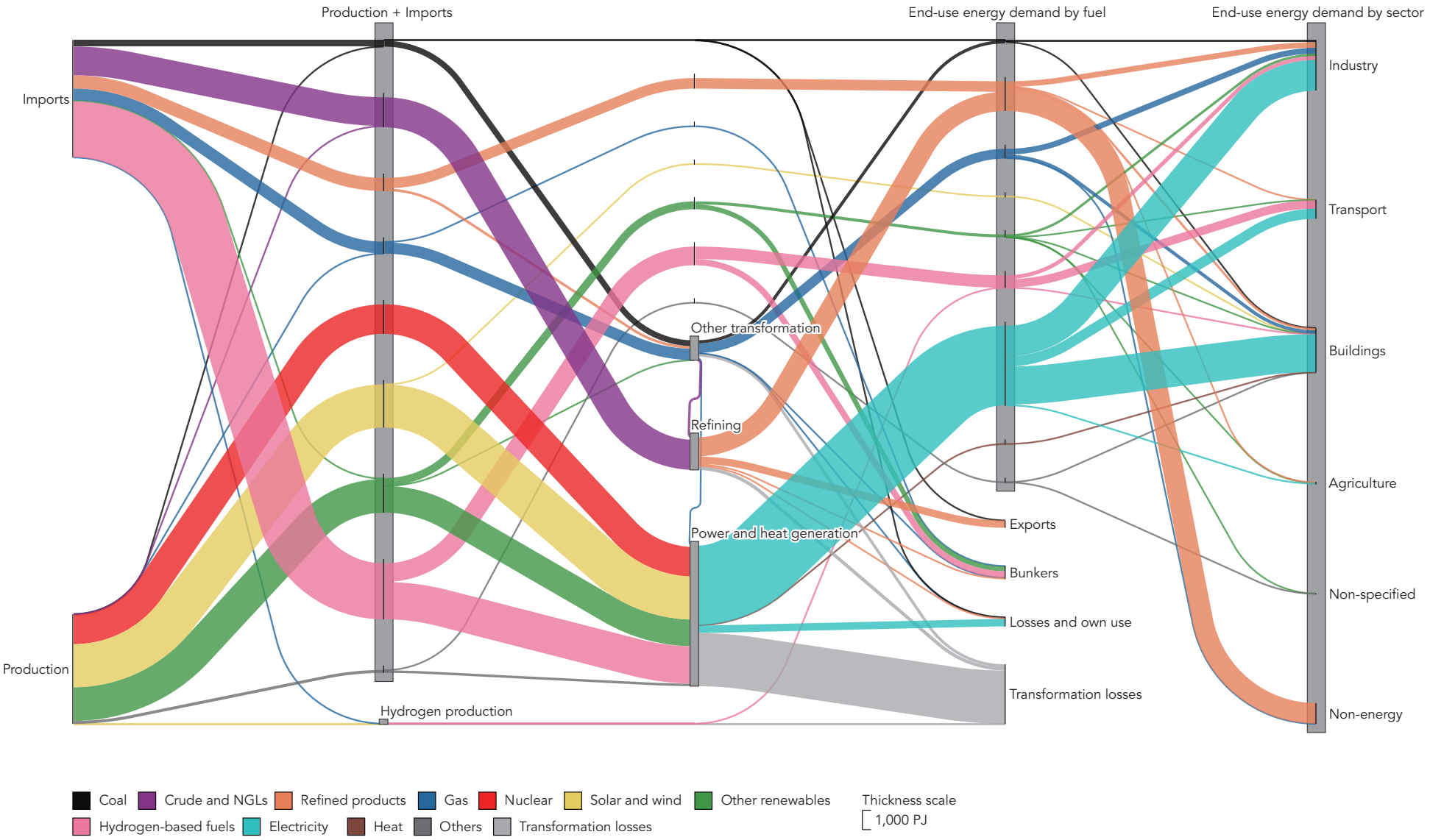
Solar and Wind Expansion

Japan is promoting rapid deployment of rooftop solar and offshore wind. New investments in perovskite solar cells aim to improve efficiency and land-use flexibility.

Energy Flow (2022)



Energy Flow (2060, Target Scenario)



Scenarios and Assumptions

In *The Outlook*, APERC analyses energy demand, transformation, and supply, as well as emissions. The **Reference Scenario (REF)** offers a projection based on historical trends, recent developments, and APERC's assumptions about the continuation of those trends in each APEC economy, while acknowledging technical restraints. The REF Scenario offers a baseline to compare with the **Target Scenario (TGT)** projections, which explores a hypothetical pathway where each economy achieves energy-related policy targets, assuming implementation regardless of cost-effectiveness. When implementation details are lacking, assumptions are inferred from the targets themselves or emissions-related goals.

	Reference	Target
General	• Population: UN DESA medium scenario; GDP: APERC macro model (IMF projections to 2027)	
Buildings	• Population decline is assumed to reduce end-use energy demand over time. • Fuel switching remains minimal. • Data centres and AI electricity demand appear in REF and TGT. The same demand is assumed in both scenarios.	• Increased fuel switching from oil and gas to electricity. • Greater improvement in end-use energy efficiency and building envelope performance.
Industry	• Activity is assumed to slowly decline. • Hydrogen for steel making begins in the 2040s. • Electrification makes inroads in most subsectors.	• Material and energy efficiency improvements are assumed to be greater in TGT. • Greater demand for critical minerals in TGT. • Hydrogen and CCS are introduced from 2030.
Transport	• Passenger activity decreases slowly in line with population in both REF and TGT. • BEV sales share for light vehicles and buses slowly increases to around 80% by 2060. • BEV and FCEV sales share for heavy trucks slowly increases to 55% and 10% respectively by 2060.	• 100% electrified vehicles (BEV, PHEV, FCV, HEV) in new car sales by 2035. • Advanced introduction of 5,000 electrified HDVs in the 2020s. • Commercialisation of e-fuels by the early 2030s and increase the utilisation of biofuels to start 20% direct bioethanol blending (E20) by 2040.
Power	• Phase out of coal power generation around 2050 for both scenarios while capacity kept at minimal. • No CCS, batteries, or hydrogen in REF. • No oil power generation in both scenarios. • Gas power generation remains constant throughout.	• Gas power generation declines significantly and is minimal in 2060. • CCS starts from 2040 and peaks in 2050. • Hydrogen emerges rapidly, replacing gas. • Renewables grow more significantly in TGT, led by solar and wind. • Nuclear reclaims a stable share after restarts and remains a key baseload source.
Supply	• In both scenarios, coal, crude oil, and LNG supply follows demand projections and is covered by imports, except for a small portion of production.	• Net trade of petroleum products moderately follows historical trends. • Hydrogen supply is mostly met by imports.
Emissions	• CO_2 emissions are calculated at post consumption based on IPCC emission factors.	

Note: The base year is 2022. Macro-economic assumptions are constant across scenarios. Historical energy balances are from EGEDA submissions for 2022.

Demographic and Macroeconomic Assumptions

Figure 8-5. Population (thousands)

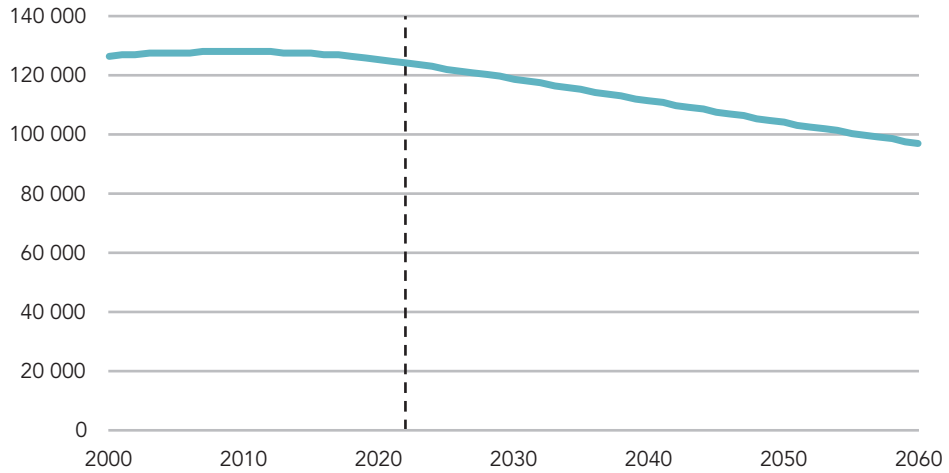
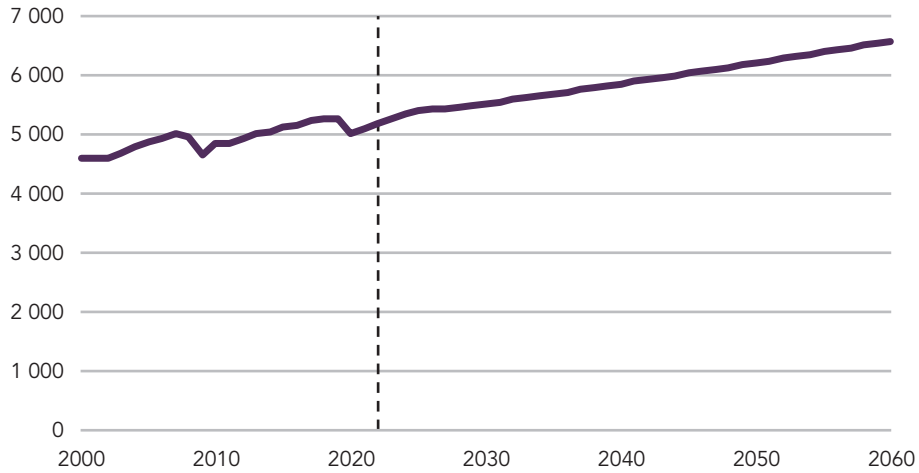


Figure 8-6. Real GDP (billion 2017 USD, PPP)



- Japan's population and economic trends play a central role in shaping the economy's energy demand and supply outlook. The population peaked at 128.1 million in 2010 and has been in continuous decline for nearly 15 years, driven by a combination of low fertility rates, population aging, and limited inward migration. In 2024, Japan's fertility rate dropped to 1.15, the lowest level on record, marking nine consecutive years of decline. This is far below the replacement level of 2.07. Despite a series of policy initiatives, a sustained recovery in birth rates has yet to be achieved. As a result, Japan's population is projected to fall below 100 million by 2060.
- Despite these demographic challenges, Japan's real GDP is projected to grow steadily over the projection period. The COVID-19 pandemic caused a sharp but temporary economic contraction around 2020, followed by a gradual recovery supported by exports, digitalisation, and fiscal stimulus. Real GDP is expected to increase from just under USD 5 trillion (2017 PPP) in 2020 to more than USD 6.5 trillion by 2060.
- With the population shrinking and the economy expanding, GDP per capita is projected to increase significantly, from around USD 40,000 in 2020 to nearly USD 70,000 by 2060. This trend reflects rising productivity and living standards, which may lead to greater expectations for energy services on a per-person basis.
- These demographic and macroeconomic assumptions form the foundation of Japan's energy demand and supply projections. They underscore the importance of improving energy productivity, accelerating technological innovation, and enabling structural shifts that support economic resilience and long-term decarbonisation in the context of a declining population.

End-use Energy Demand

Figure 8-7. Energy demand by sector in REF & TGT (PJ)

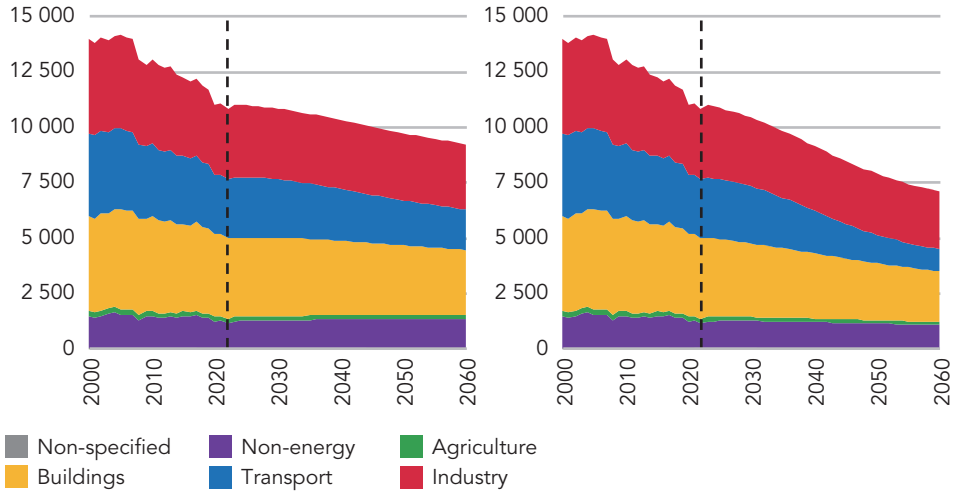
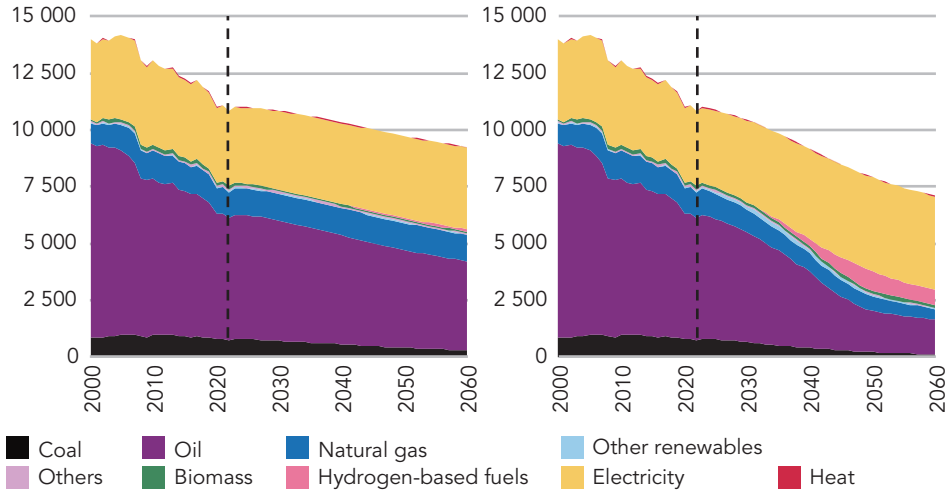


Figure 8-8. Energy demand by fuel in REF & TGT (PJ)



- Total final consumption declines steadily over the projection period due to structural economic changes, improved efficiency, and a shrinking population. The decline is more pronounced in TGT, where stronger decarbonisation efforts accelerate the reduction in energy demand.
- Buildings remain the largest energy-consuming sector throughout the projection period, though demand falls by around 22% in REF and nearly 40% in TGT. This drop reflects continued electrification, energy-saving appliances, and improved insulation, especially in residential spaces. However, rising demand from digital infrastructure, particularly data centres, partially offsets these efficiency gains in the long term.
- Industry experiences a more moderate reduction, with energy use falling by around 7% in REF and 18% in TGT. Efficiency gains help counteract rising output in some subsectors. In TGT, fuel switching toward electricity and hydrogen occurs in specific processes, while widespread deployment of CCS for coal and gas allows continued use of fossil fuels in hard-to-abate industrial processes.
- Transport undergoes the most significant shift, with final energy use falling by 31% in REF and a steep 63% in TGT. This reflects widespread electrification, improved vehicle efficiency, and reduced travel demand due to population aging. In TGT, the rapid deployment of e-fuels and biofuel blending supplements electrification and plays a critical role in reaching net-zero targets.
- Electricity becomes the dominant final energy carrier by mid-century in both scenarios, while hydrogen-based fuels grow more visibly in TGT. Fossil fuel use, especially oil and gas, declines steadily across sectors. The transition is faster in TGT, where low-carbon fuels such as biomass, district heat, and hydrogen displace conventional fuels more aggressively.
- Non-energy use reflects petrochemical demand, and in TGT, it accounts for most of the remaining oil demand beyond 2050.

Buildings Energy Demand

Figure 8-9. Buildings energy demand by fuel in REF & TGT (PJ)

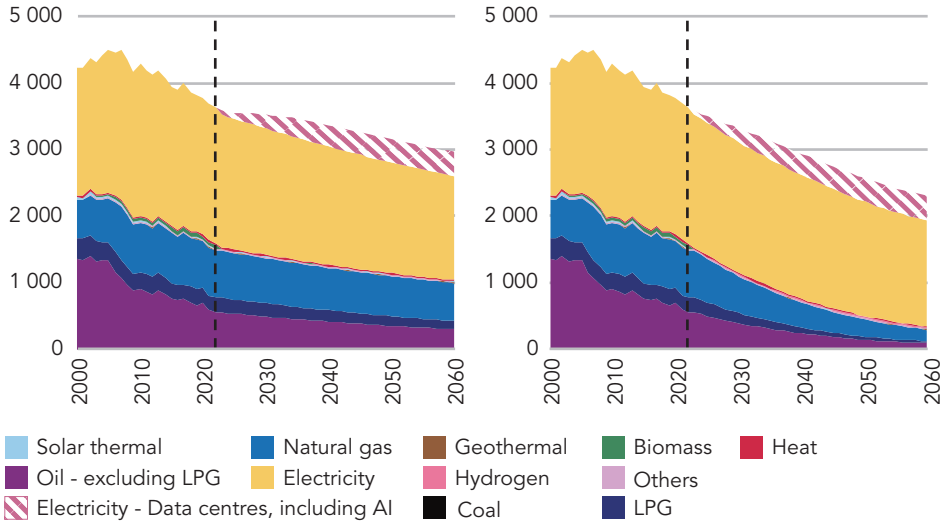
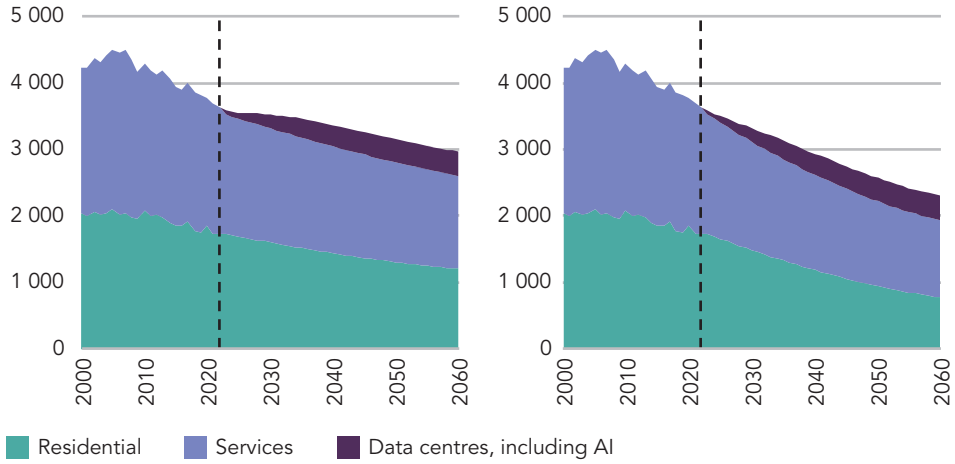


Figure 8-10. Buildings energy demand by sector in REF & TGT (PJ)



- Energy consumption in the buildings sector declines in both scenarios, though the pace differs. In TGT, stronger efficiency and conservation standards, electrification policies, and support measures lead to demand that is more than 20% lower by 2060 compared to REF.
- Both residential and services subsectors see gradual declines in energy use, reflecting population shrinkage and continued improvements in insulation, equipment efficiency, and behavioural shifts. A key exception is data centres and AI, with electricity demand rising rapidly in the first half of the period.
- From 2023 to 2040, data centre electricity demand grows from 20 TWh to nearly 90 TWh, making Japan the third-largest user in APEC after the United States and China. This growth accounts for about 40% of total electricity demand increase by 2040 in TGT and may reach nearly 10% of total electricity demand.
- Electricity demand from data centres and AI may not place significant additional strain on the grid. This is because electricity use in the services sector is declining year by year, at a rate similar to or slightly faster than the growth in data centre demand. If new centres are developed in areas where services demand is falling, existing infrastructure may be able to support this emerging demand source more readily.
- Electricity becomes the dominant energy source across the sector, replacing oil and gas, especially in TGT, as Japan moves toward all-electric, high-efficiency buildings. Hydrogen remains a minor contributor, and other low-carbon fuels such as biomass and district heat remain modest but locally relevant.
- Despite ongoing progress, fully decarbonizing the buildings sector remains a long-term challenge, due to the diversity of building types, slow stock turnover, and the persistence of fossil-based heating systems. Continued progress may require a combination of technology deployment, market readiness, and supportive conditions that encourage deeper transformation, while maintaining affordability and resilience.

Industry Energy Demand

Figure 8-11. Industry energy demand by fuel in REF & TGT (PJ)

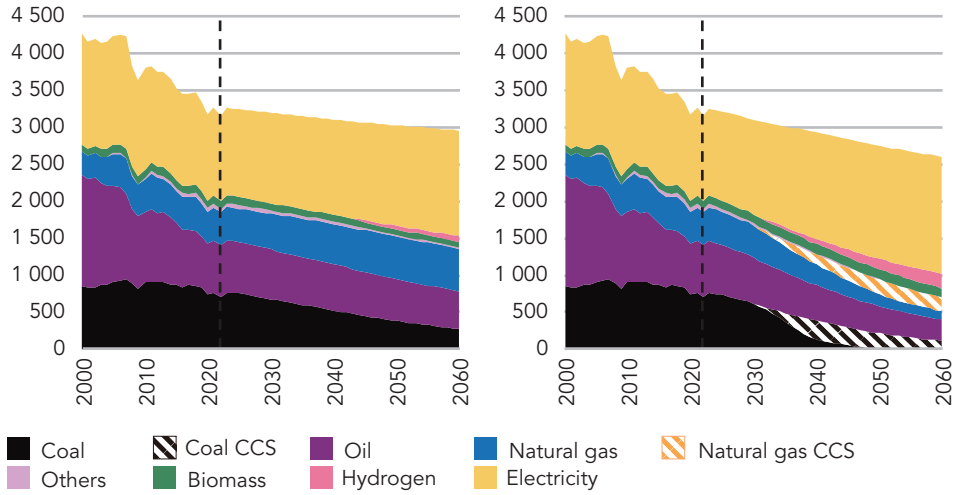
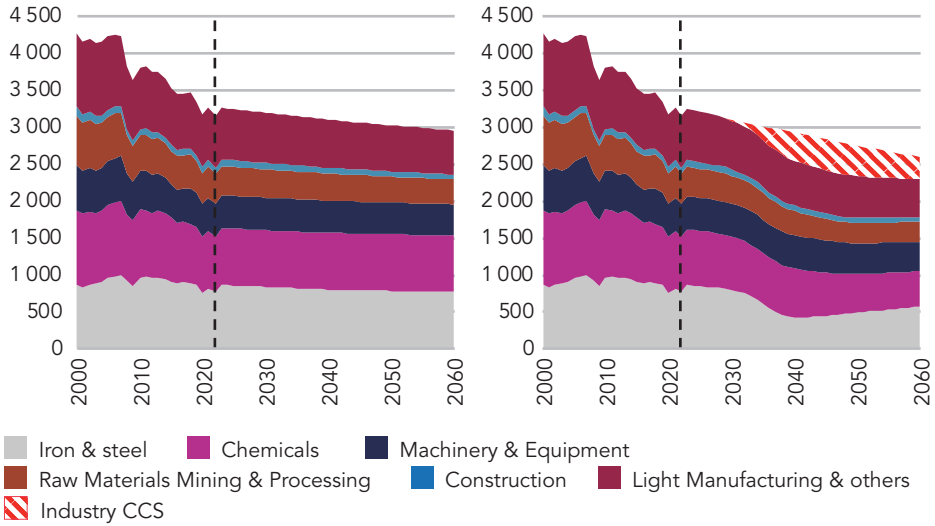


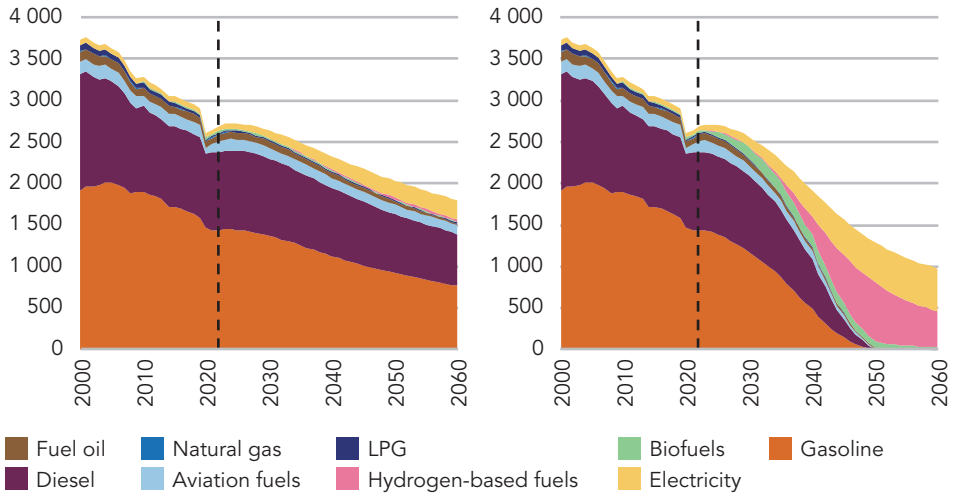
Figure 8-12. Industry energy demand by sector in REF & TGT (PJ)



- Energy demand in Japan's industry sector declines in both scenarios, with a sharper reduction in TGT driven by the greater adoption of energy and material efficiency measures. This occurs alongside the integration of low-carbon technologies that reshape the fuel mix and reduce emissions.
- A key difference in TGT is that CCS is deployed in the most carbon-intensive subsectors, notably iron and steel, cement, and partially in petrochemicals. These sectors account for a large share of industrial CO_2 emissions due to their reliance on fossil fuels for high-temperature heat and, in the case of steel, process-related emissions from coke use. CCS deployment begins modestly in the 2030s, then scales up significantly by 2050, as carbon capture infrastructure, storage capacity, and transport systems mature. Japan's coastal industrial clusters provide favourable conditions for CO_2 capture and transport, enabling these industries to decarbonise while continuing to produce essential materials.
- Hydrogen plays a growing role in hard-to-electrify industrial processes. In the iron subsector, hydrogen is primarily used as a reducing agent in hydrogen-based direct reduced iron (H_2-DRI) processes, replacing coke. While some H_2-DRI may be produced domestically, Japan may also turn to imports of hot briquetted iron (HBI) from regions with abundant low-cost renewable hydrogen. The resulting DRI or HBI is then processed into steel using electric arc furnaces (EAFs), which are also increasingly adopted in TGT. In the cement subsector, hydrogen is used to replace coal and oil as a combustion fuel for high-temperature kilns, contributing to emissions reductions in one of the most challenging processes to decarbonise.
- Fuel switching is visible across the industrial landscape. Electricity becomes the dominant energy source by 2060, displacing fossil fuels used for low- and medium-temperature heat. Biomass experiences limited growth but increases in specific subsectors like cement and pulp & paper to lower coal or oil usage. In TGT, natural gas and oil decline steadily, while coal is reduced more aggressively through a combination of hydrogen and electrification.

Transport Energy Demand

Figure 8-13. Domestic transport energy demand in REF & TGT (PJ)



- Energy use in Japan's transport sector declines gradually in REF, reflecting a reduction in activity due to population decline, as well as incremental changes in the vehicle stock composition towards electrification. Electrification progresses at a moderate pace, and fossil fuels remain dominant across all modes through most of the period.
- In TGT, gasoline and diesel are fully phased out by 2050, replaced largely by electricity, bioethanol, and hydrogen-based fuels in pursuit of Japan's net-zero target. Around 80% of hydrogen use by that year is in the form of e-fuels, particularly in heavy trucks where full electrification remains challenging. Some e-fuel use also occurs in light passenger vehicles, reflecting Japan's technology-neutral approach. Under the 7th Strategic Energy Plan, Japan targets 100% of new light passenger vehicle sales to be electrified by 2035—including BEVs, PHEVs, HEVs, and FCEVs—without specifying the mix. As a result, although most ICE vehicles are replaced by 2050, the continued presence of HEVs and PHEVs sustains residual liquid fuel demand. HEVs always rely on a combustion engine, but improve efficiency through battery integration and regenerative braking. This *Outlook* assumed a 50/50 mix of mild and strong hybrids, which achieve different levels of efficiency improvement. PHEVs, assumed to operate about 60% on electricity and 40% on an efficient combustion engine, deliver deeper reductions but still require liquid fuels. Both HEVs and PHEVs are significantly more efficient than ICEs, yet their presence necessitates e-fuels or biofuels to fully eliminate fossil fuel use. Over time, as BEV stock shares expand beyond 2050, the role of e-fuels and biofuels in road transport declines, underscoring their transitional function in Japan's pathway to net-zero emissions, as outlined in the 7th Strategic Energy Plan.
- By 2060, electricity becomes the main fuel source for both passenger and freight road transport, while hydrogen-based options support applications requiring longer range and heavier loads. In parallel, decarbonisation of domestic aviation and marine transport advances through the continued use of electricity, SAF, e-fuels, and blended biofuels, which see increased uptake starting from the 2030s.
- While a wide range of low-carbon fuels are introduced in TGT, the transition depends heavily on infrastructure and cost developments. BEV uptake requires widespread charging networks, while FCEV deployment hinges on refuelling stations and vehicle costs. E-fuel supply chains would also need to expand rapidly despite high production costs. Japan's technology-neutral approach reflects not only efficiency but also energy security, industry competitiveness, and supply chain resilience. Each technology offers unique strengths—the versatility of liquid fuels in PHEVs and HEVs, or the efficiency of BEVs—but also weaknesses, such as the current concentration of battery supply chains. However, this neutrality may slow the transition compared with a more centralised "decide and provide" strategy centred on BEVs, thereby increasing reliance on e-fuels to eliminate residual fossil fuel use by 2050. As detailed in the costs section, this pathway could result in higher overall expenditures, underscoring the trade-offs between flexibility, security, competitiveness, and cost-effectiveness in Japan's transport transition.

Other Transport Data

Figure 8-14. Transport vehicle stocks in REF & TGT (millions)

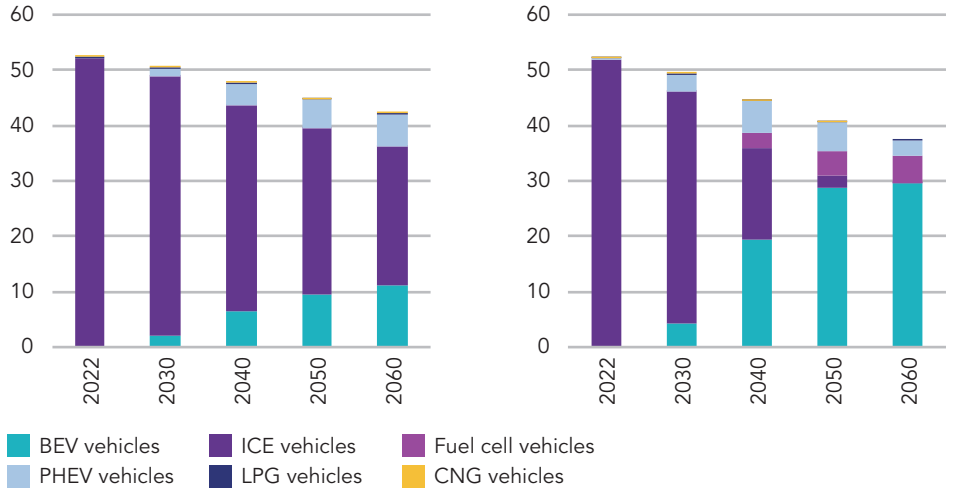
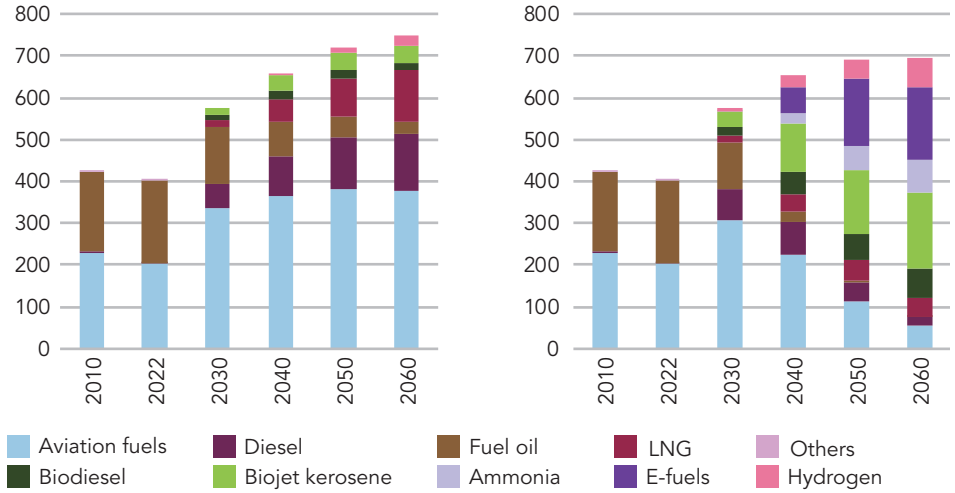
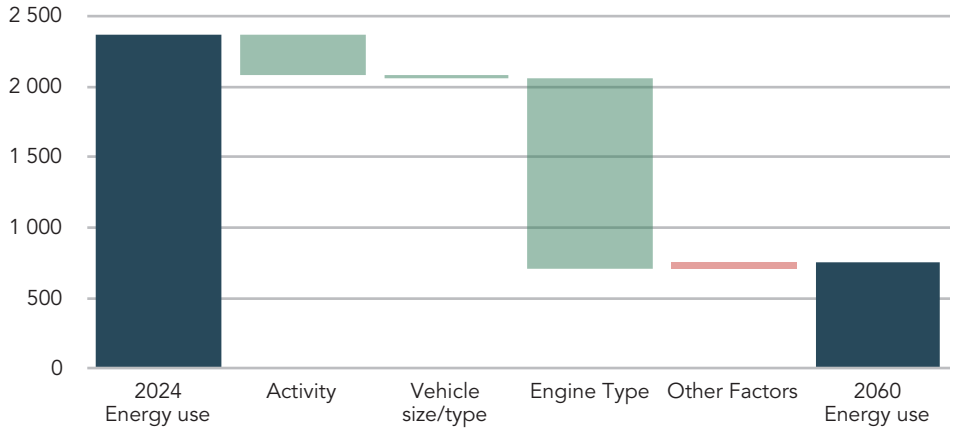


Figure 8-15. International bunker energy demand for shipping and aviation in REF & TGT (PJ)



- The shift in vehicle stock is more pronounced in TGT, where BEVs make up the majority by 2060 and ICE vehicles steadily decline. PHEVs are adopted early but are gradually replaced by BEVs. FCEVs expand in harder-to-electrify segments. The sharper decline in total vehicle numbers in TGT compared to REF is driven by a shift toward public transport through increased bus and rail use. HEVs are grouped under the ICE category due to a modelling limitation and are therefore not shown separately, although they deliver significant efficiency improvements—especially if, as assumed here, they make up 100% of ICE vehicle sales by 2035, TGT.
- In TGT, bunker fuels (used for international transport) begin shifting to lower-emissions alternatives. This is based on decarbonisation targets set by international transport organisations.
- Figure 8-16 shows that shifting engine types drives the largest reduction in transport energy use, cutting around 1,300 PJ by 2060. This is mainly due to the uptake of BEVs, which are about three times more efficient than ICEs. PHEVs provide about half that benefit. Moreover, a unique reduction of 400 PJ comes from declining activity driven by population decline.

Figure 8-16. Components of the change in road energy use in TGT (PJ)



Note: Information on the different drivers in the transport energy decomposition can be found in the *Outlook*'s annex.

Electricity Generation

Figure 8-17. Electricity generation by fuel in REF (TWh)

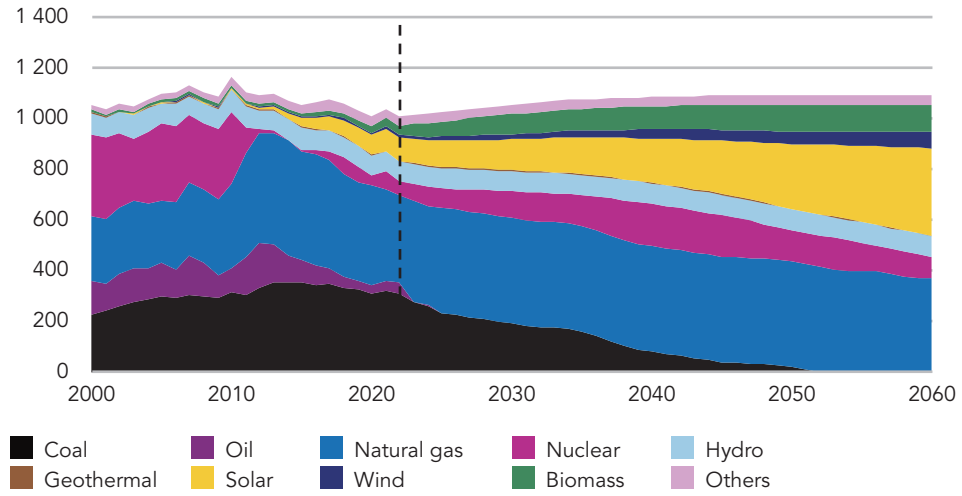
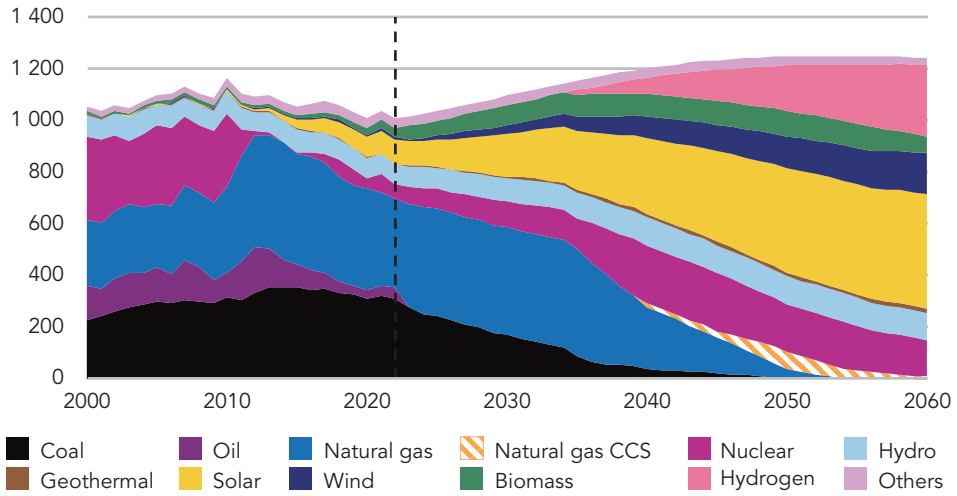


Figure 8-18. Electricity generation by fuel in TGT (TWh)

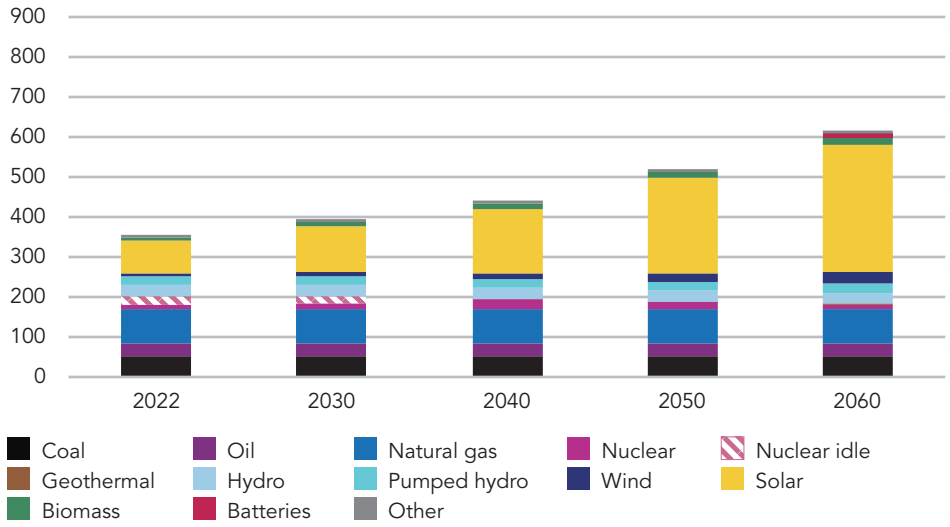


- Electricity generation sees only a modest increase in REF, remaining below 1,100 TWh throughout the outlook period. In TGT, generation grows to around 1,200 TWh by 2040, driven by higher electrification across the demand sectors.
- In REF, coal is gradually phased out by 2050, but natural gas continues to play a major role. Gas-fired generation remains around 400 TWh over the long term, while renewables and nuclear power see moderate growth.
- In TGT, the 2040 power mix includes 49% renewables (24% solar, 7% wind, 9% hydro, 1% geothermal, and 7% biomass), 19% nuclear (224 TWh), and 32% thermal (24% fossil fuels, including 2% gas with CCS; 5% hydrogen; and 3% others). Most segments align to the extent feasible with Japan's "Outlook for Energy Supply and Demand in FY2040", which was released alongside the 7th Strategic Energy Plan, reflecting a comprehensive shift toward low emissions energy sources while ensuring reliability.
- From the mid-2030s onward, natural gas declines sharply in TGT as hydrogen replaces gas to support deeper decarbonisation. Hydrogen generation ramps up rapidly, reaching over 60 TWh by 2040. CCS is introduced to enable a smoother transition, allowing existing gas infrastructure to support grid reliability during the shift.
- Overall, Japan achieves a more balanced and lower-emission generation mix in TGT by combining renewables, nuclear, hydrogen, and CCS, in line with Japan's emissions reduction targets and energy security priorities.

Note: Figures 8-17 and 8-18 do not include electricity generation for hydrogen production.

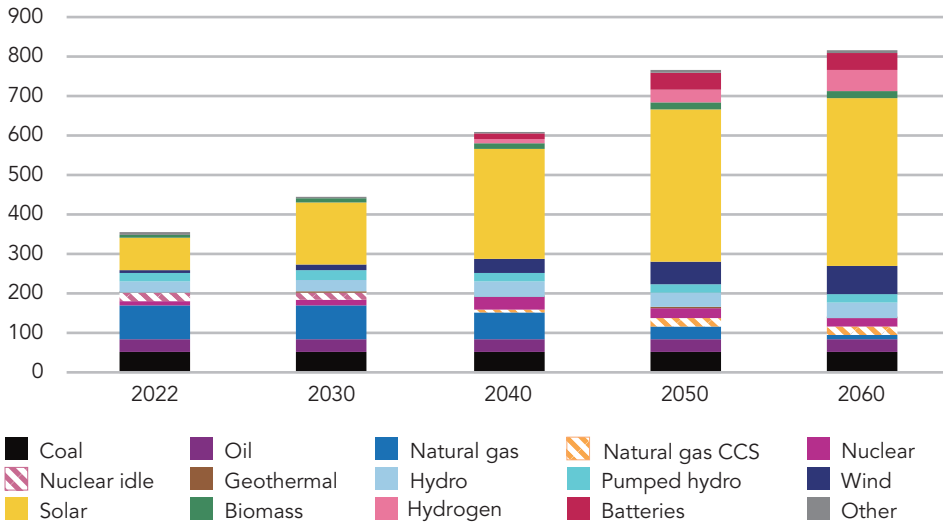
Generation Capacity

Figure 8-19. Generation capacity by fuel in REF (GW)



- In REF, total installed capacity increases significantly, rising from around 350 GW in 2022 to over 600 GW by 2060. However, the pace and nature of expansion differ from TGT as much of the capacity is retained for natural gas. Moreover, capacity additions are not as heavily driven by variability management as in TGT, since electrification progresses more slowly and renewable expansion is less aggressive than in TGT, despite it still being substantial particularly for solar.
- In TGT, installed capacity grows more rapidly, reaching over 800 GW by 2060. This expansion is primarily driven by the growing share of variable renewables, which require additional capacity to ensure grid stability and supply adequacy.
- Solar capacity expands from around 80 GW in 2022 to over 275 GW by 2040, more than tripling over the period. Wind capacity grows even faster in relative terms, from around 5 GW to over 35 GW, representing a more than sevenfold increase. These gains are ambitious given Japan's limited land availability, reflecting expectations of major technological breakthroughs, cost reductions, and increased deployment of offshore and rooftop systems.

Figure 8-20. Generation capacity by fuel in TGT (GW)



- Natural gas capacity declines in TGT, replaced by hydrogen, which ramps up from the mid-2030s to support growing generation needs while decarbonising. It is also supported by CCS retrofits to maintain dispatchable generation while decarbonising at the transitional phase.
- Coal and oil capacity are retained at minimal levels as emergency backups, without playing a central role in the power system.
- Battery storage scales up significantly in TGT to enhance flexibility and support solar and wind integration, while pumped hydro storage remains constant due to geographic constraints.

Note: Figures 8-19 and 8-20 do not include electricity generation for hydrogen production.

Grid Reliability

Figure 8-21. Total generation capacity and peak load (GW)

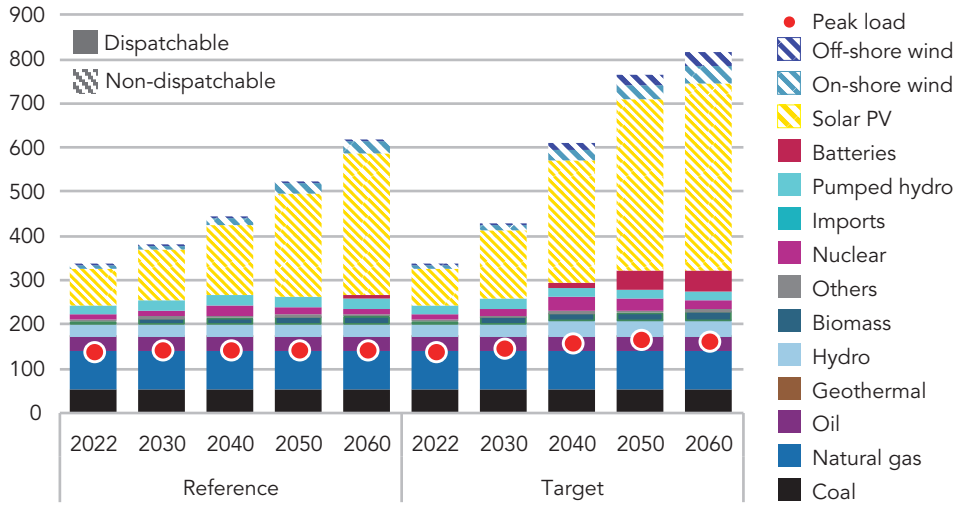
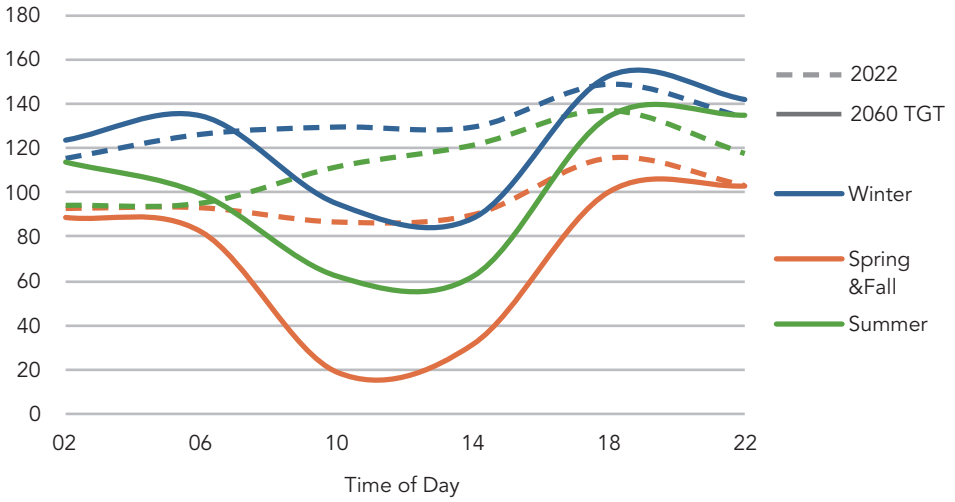


Figure 8-22. Power from dispatchable sources in TGT (GW)



- Japan's electricity system will require significant expansion to ensure reliability amid rising electrification and growing shares of variable renewable energy. While peak load increases only modestly, from approximately 140 GW in 2022 to 165 GW in 2060 in TGT, total installed capacity must more than double, reaching 815 GW, to accommodate intermittent sources like solar and wind.
- The resulting capacity-to-peak-load ratio rises from 2.37 in 2022 to 4.94 in 2060, underscoring the need for a much larger power system capacity relative to peak demand. This ensures that enough generation capacity is available during periods of low solar and wind output.
- In a high-renewables system, dispatchable generation is used less during midday when solar output is high but must ramp up quickly to meet evening demand as solar generation drops. This pattern occurs across all seasons in 2060, with dispatchable output rising sharply during critical hours, underscoring the growing need for system flexibility.
- While winter has the highest overall demand, the largest intraday ramp-up of dispatchable power occurs during spring and fall, where low morning demand and high solar generation during midday are followed by sharp evening increases. For instance, dispatchable generation in spring and fall increases from a minimum of around 20 GW to a peak of around 100 GW within hours.
- This steep ramping requirement, common across all seasons, poses a major challenge for system flexibility. It highlights the importance of investment in flexible capacity, including battery storage and demand-side response, along with efficient market designs and advanced grid operation technologies.
- Ensuring grid reliability in such a high-renewables scenario will require not only physical infrastructure, but also strategic planning and real-time coordination to balance supply and demand across time and geography, especially during critical hours with steep load changes.

Coal

Figure 8-23. Coal and coal products consumption by sector in REF & TGT (PJ)

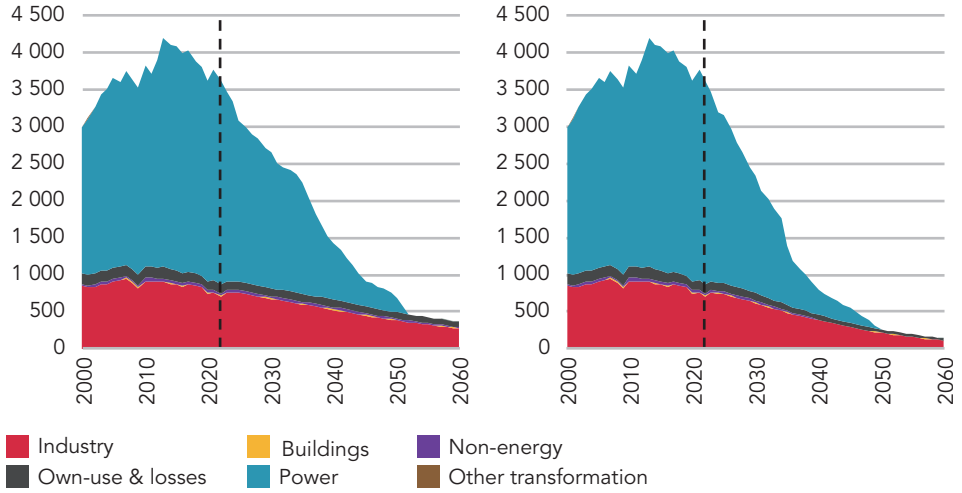
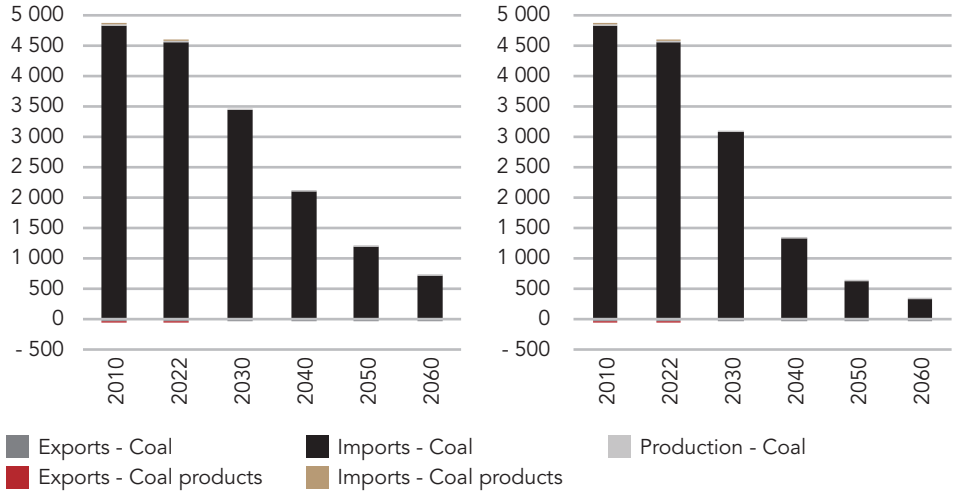


Figure 8-24. Coal and coal products production, imports, and exports in REF & TGT, 2010-2060 (PJ)



- Coal demand in Japan declines sharply in both scenarios, led by a major reduction in the power sector. In REF, coal-fired generation continues into the 2050s but is phased out before 2060. In TGT, coal use in the power sector declines more rapidly and is phased out by 2050 to support Japan's net-zero commitment. This transition reflects Japan's policy direction to reduce coal dependence and retire inefficient thermal plants.
- Industry remains the largest residual coal consumer in both scenarios, particularly for subsectors such as steel and cement where high-temperature heat is required and alternative fuels remain limited. However, coal demand still falls more substantially in TGT due to greater fuel switching, efficiency improvements, and adoption of technologies like hydrogen-based direct reduced iron. This reflects the challenges of fully decarbonising hard-to-abate processes, even with aggressive policy support.
- Japan has no significant domestic coal production and therefore its coal supply is almost entirely met through imports. As demand decreases, import volumes drop from over 4,500 PJ in 2022 to nearly 300 PJ by 2060 in TGT.
- The accelerated coal decline, when viewed solely from the demand-side perspective, not only supports emissions reduction goals but also enhances Japan's energy security by reducing reliance on overseas fossil fuel suppliers. However, this shift is somewhat idealistic and poses significant risks to the stable supply of energy, as it overlooks Japan's S+3E energy mix concept. Ensuring the safety and stable supply of coal highlights the need for timely investment in alternative infrastructure such as hydrogen supply chains, electrification capacity, and industrial process transformation, in alignment with the harmonisation of energy security, environmental objectives, and economic efficiency.

Note: Figure 8-23 excludes coal for transformation into coal products.

Natural Gas

Figure 8-25. Natural gas consumption by sector in REF & TGT (PJ)

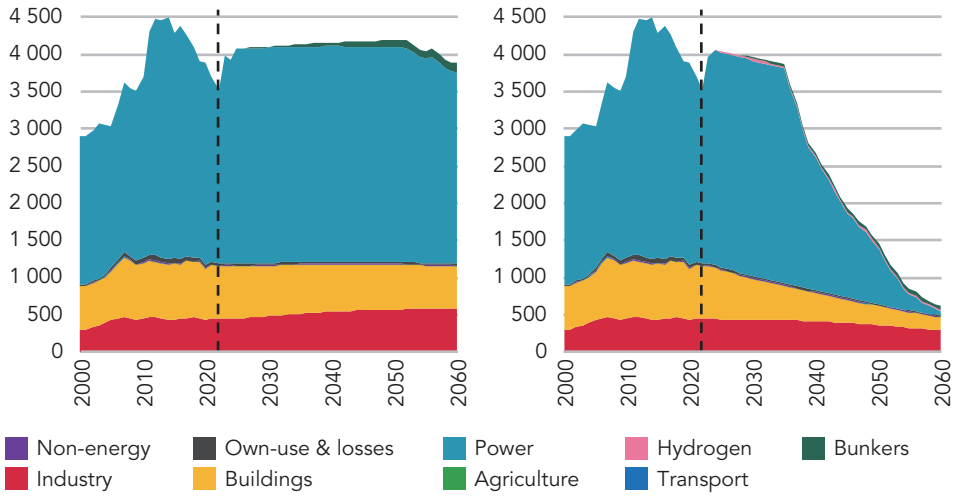
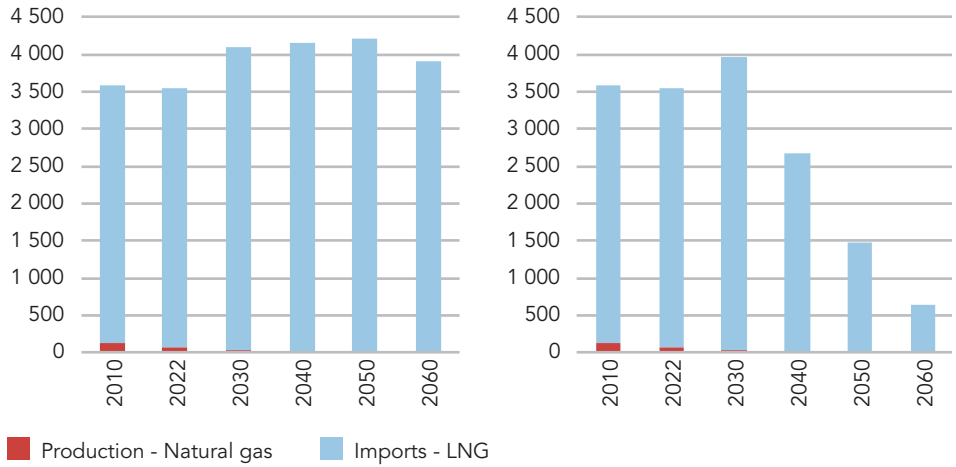


Figure 8-26. Natural gas production and imports in REF & TGT (PJ)

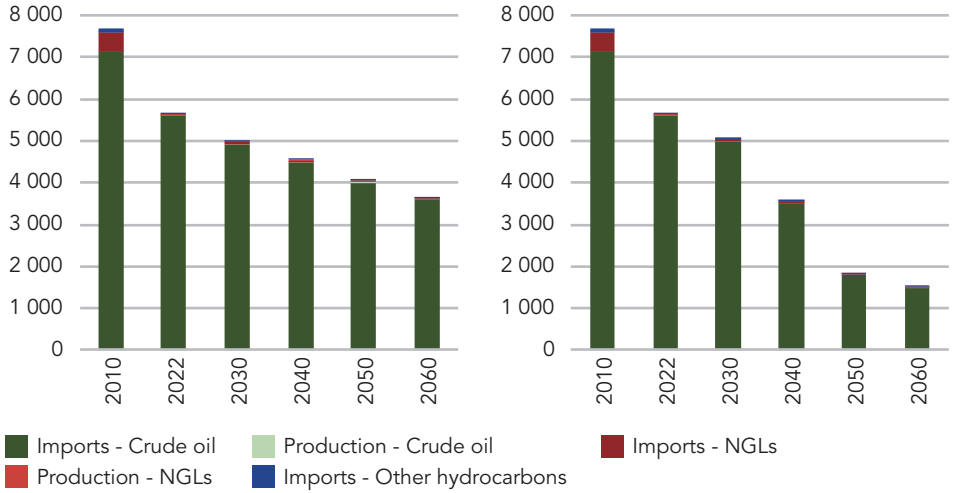


- In REF, natural gas demand remains stable through the outlook period, driven largely by its continued role in the power sector. While coal is phased out in the 2050s and renewables expand less aggressively compared to TGT, gas-fired power remains essential for ensuring dispatchable generation capacity. This allows the system to meet demand during peak periods and support grid reliability in the face of daily and seasonal fluctuations.
- In TGT, natural gas demand declines rapidly from the mid-2030s onward, particularly in the power sector where it is progressively replaced by hydrogen and supported by CCS deployment to meet Japan's net-zero target. Buildings and industry also reduce their reliance on gas as electrification and alternative fuels are introduced.
- While CCS retrofits help to extend the use of existing gas infrastructure during the transition, the sharp decline in gas demand in later years may lead to reduced utilisation of CCS assets. However, these investments play a critical bridging role in decarbonisation, ensuring reliable supply in the medium term while hydrogen and renewables continue to scale up.
- Across both scenarios, Japan remains heavily dependent on LNG imports, with domestic production contributing only a small fraction of total supply. To strengthen energy security, Japan is actively expanding and diversifying its LNG procurement, including signing new long-term contracts with suppliers such as Canada and the United States. These efforts aim to reduce reliance on any single supplier and to enhance resilience against geopolitical and market shocks.

Note: Historical data for LNG is based on JODI gas data.

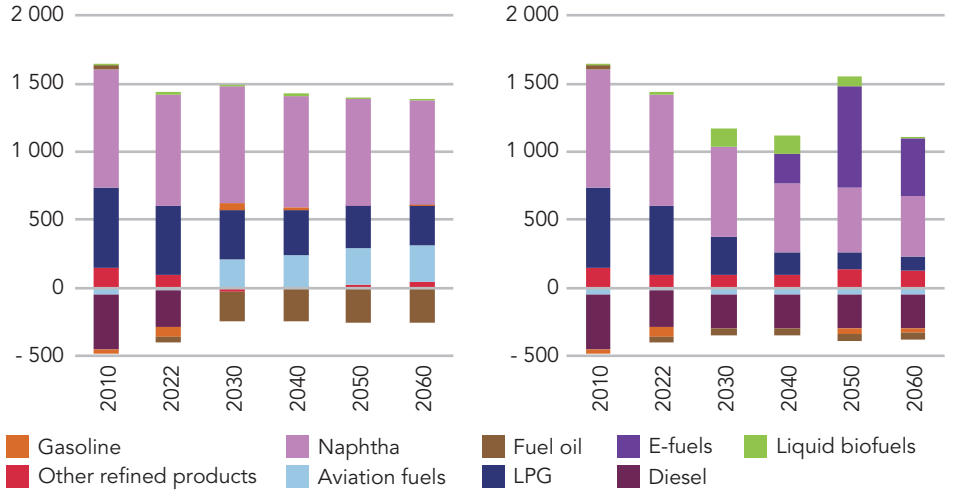
Petroleum Liquids

Figure 8-27. Crude oil, NGLs, and other hydrocarbon production and imports in REF & TGT (PJ)



- Japan's crude oil supply remains almost entirely dependent on imports across both scenarios. Domestic production is negligible, and limited scope for increased exploration means this import reliance is expected to continue.
- In REF, crude oil imports gradually decline in line with the long-term reduction in overall refined product demand. However, Japan continues to maintain a sizeable refining capacity to meet domestic fuel needs, particularly diesel and gasoline, and to support petrochemical feedstock production.
- In TGT, crude oil imports decline more sharply, dropping by more than two-thirds by 2050 from 2022, due to the accelerated phase-out of gasoline and diesel in the transport sector. This is accompanied by a shift in refinery output, with increased naphtha and LPG shares for petrochemical production, resulting in reducing and less reliance on imports for the two products.

Figure 8-28. Net imports of refined products and low carbon fuels in REF & TGT (PJ)



- Meanwhile, e-fuels imports rise substantially after 2040 in TGT, helping to decarbonise transport segments that are difficult to electrify. A smaller but notable increase in liquid biofuels imports also contributes to meeting energy transition targets, particularly in aviation and marine transport.
- Petroleum products remain critical for the industry and non-energy sectors, particularly for petrochemical feedstocks, and for exports. Japan's refineries continue to export diesel, fuel oil, jet fuel, and gasoline to meet growing regional demand in Southeast Asian and Oceanian economies. These exports help sustain the viability of domestic refining despite declining local consumption.

Note: In Figure 8-28, net imports are presented without deducting bunkers.

Refining

Figure 8-29. Refining outputs in REF & TGT (PJ)

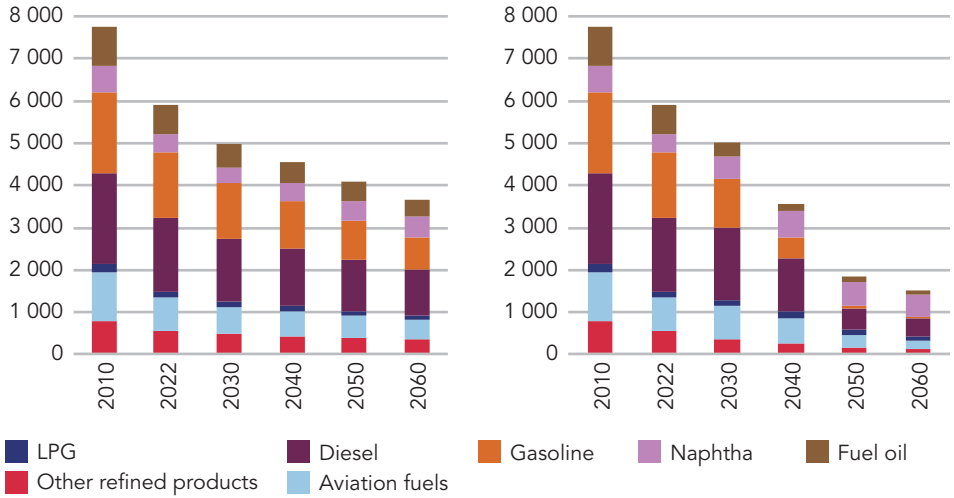
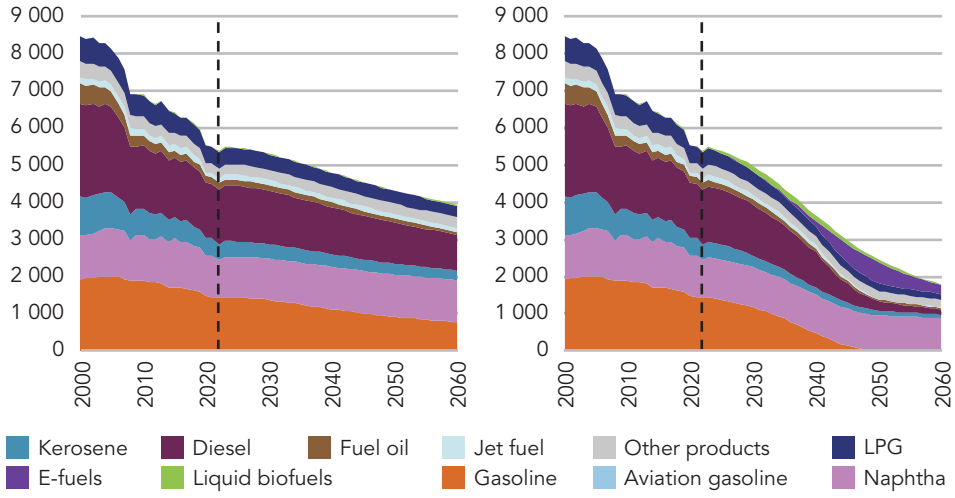


Figure 8-30. Refined products and low carbon fuels demand in REF & TGT (PJ)



- In REF, refining capacity declines from 3,285 thousand barrels per day (kbd) in 2020 to 1,880 kbd by 2060. Despite this reduction, Japan continues to operate a robust refining sector focused on diesel production held at a ~30% output ratio to meet domestic transport needs. Gasoline output decreases, falling from a 27% output ratio in 2020 to 20% in 2060; this capacity is reoriented toward higher naphtha production to support growing petrochemical demand, increasing naphtha's output ratio from 7% in 2020 to 14% in 2060.
- In TGT, refining capacity contracts more sharply, reaching 770 kbd by 2060, in line with the decline in domestic demand. Rather than fully exiting refining, Japan is expected to maintain a core refining base to supply critical products, particularly naphtha and LPG for the petrochemical sector.
- To strengthen domestic feedstock resilience despite declining transport fuel demand, Japan is assumed to invest in the new refining process technology such as crude oil to chemicals (C2C) technology to improve the output ratio of naphtha from 7% in 2020 to reach 35% by 2060, allowing the refining sector to pivot toward supporting industrial and non-energy use.
- At the same time, refining viability is supported by continued exports of diesel, maintained at historic levels, as demand remains strong in neighbouring APEC economies in Southeast Asia and Oceania. Jet fuel exports also play a key role in maintaining balanced refining operations and ensuring stable output of middle distillates, even as domestic consumption declines.

Bioenergy and Waste

Figure 8-31. Bioenergy and waste demand by sector in REF & TGT (PJ)

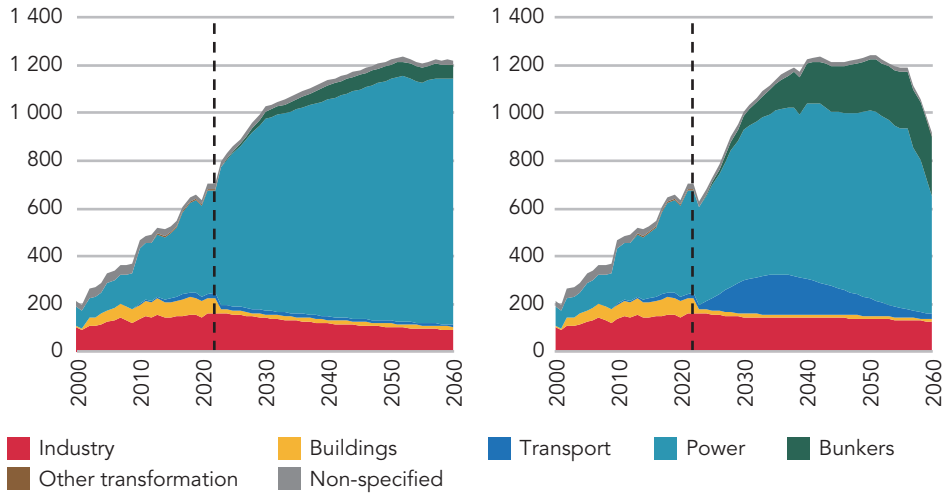
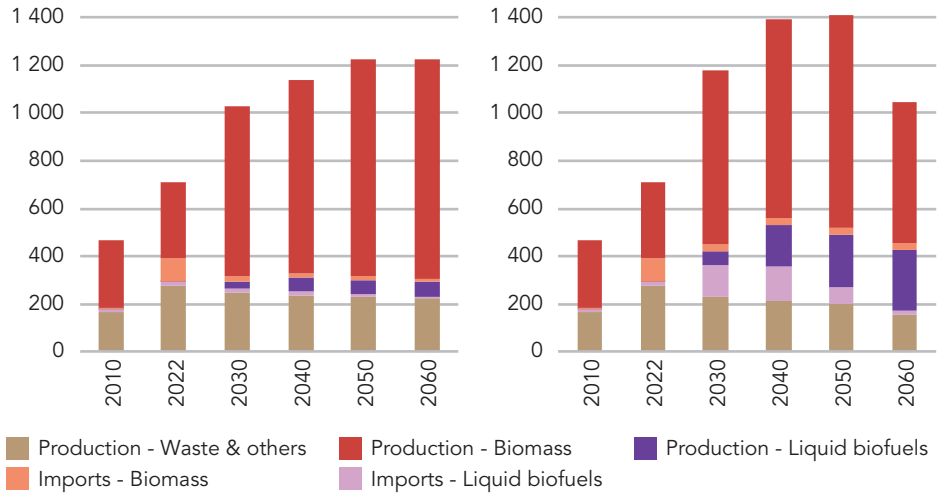


Figure 8-32. Bioenergy and waste production and imports in REF & TGT (PJ)



- Bioenergy and waste play a modest but strategic role in Japan's energy mix. While overall demand is lower than for other fuels, it contributes to decarbonisation in specific sectors, particularly power, transport, bunkers, and industry. Supply of this fuel is shaped by Japan's limited domestic biomass resources and import reliance.
- In the power sector, demand is dominated by solid biomass, which expands steadily and becomes the primary form of bioenergy used for electricity generation. Waste is also used, but to a lesser extent.
- Industry sector use is smaller but persistent, with most solid biomass consumed in the pulp, paper, and printing subsector. Smaller quantities are used in wood products and non-metallic mineral products (the latter also consumes industrial waste).
- In the transport sector, biogasoline is blended into conventional fuel for road vehicles, while biojet kerosene is increasingly used in aviation. Biodiesel use also expands in international marine bunkers, reflecting efforts to decarbonise shipping.
- On the supply side, solid biomass is largely domestically produced. For liquid biofuels, Japan continues its entire dependence on biogasoline imports, while biodiesel is primarily produced domestically with small volumes of imports. In TGT, total bioenergy supply grows more rapidly, with liquid biofuels expanding to support low-carbon transport.
- Biojet kerosene (SAF) is expected to account for bulk of Japan's biofuels production in both REF and TGT. Several companies, including ENEOS, LanzaJet, and Cosmo are actively exploring ways to produce SAF, utilizing domestic resources such as used cooking oil and animal fats. However, Japan faces challenges that include high production costs, procurement of stable feedstock, and overcoming infrastructure limitations.

Hydrogen-based Fuels

Figure 8-33. Hydrogen-based fuels demand by sector in REF & TGT (PJ)

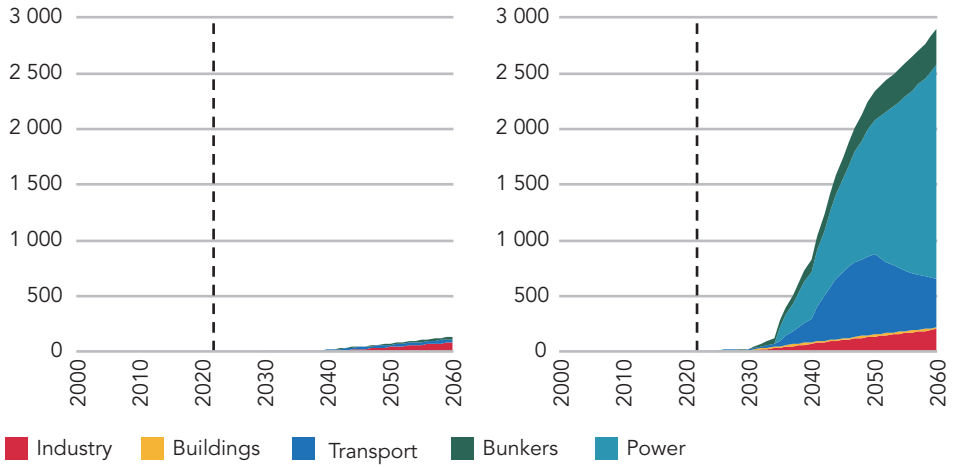
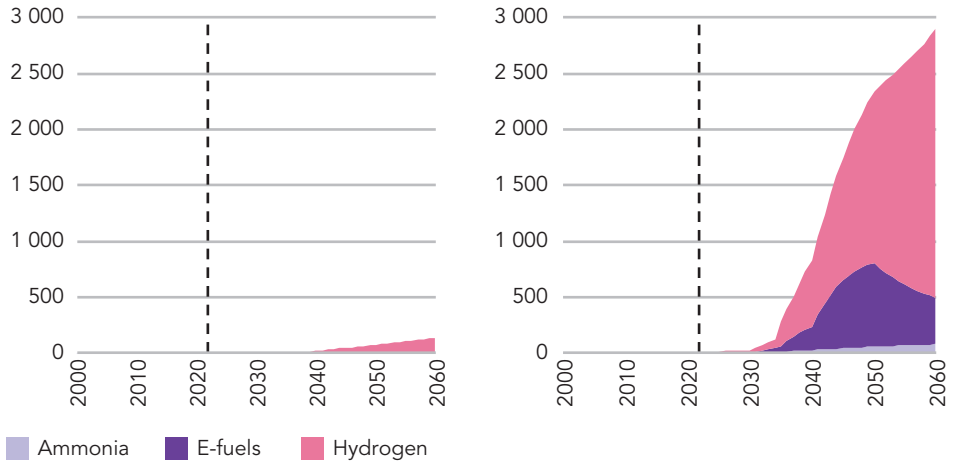
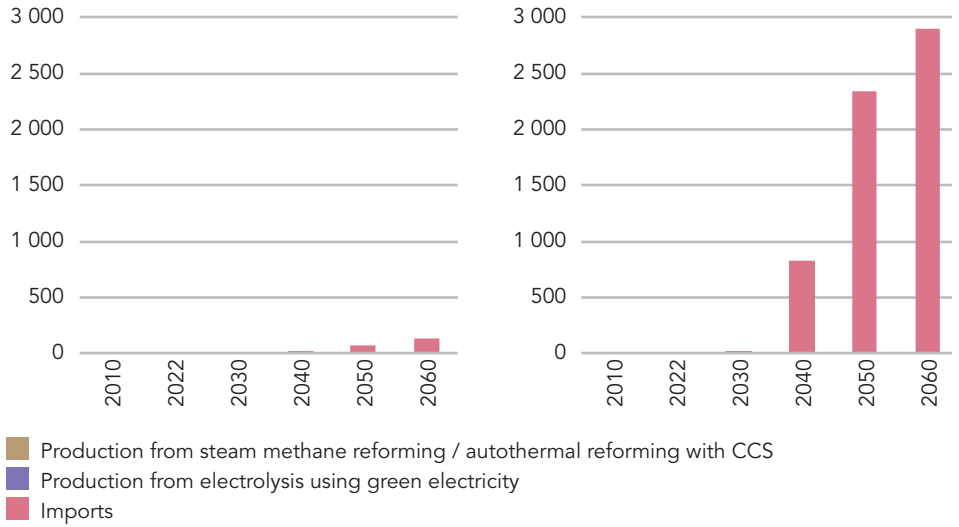


Figure 8-34. Hydrogen-based fuels demand by fuel in REF & TGT (PJ)



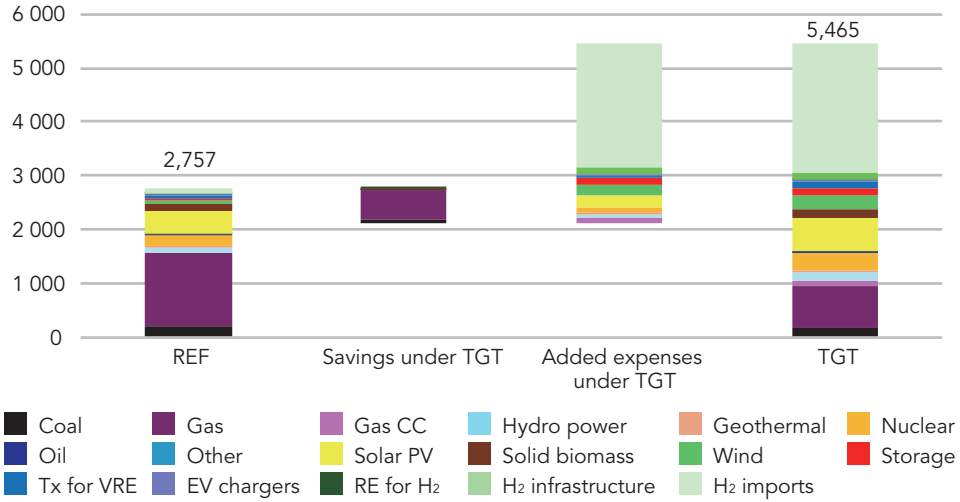
- Hydrogen demand in REF remains modest, approaching 140 PJ by 2060. Growth is limited due to uncertainty around commercial-scale projects and the lack of large-scale deployment to date.
- In contrast, hydrogen-based fuels demand in TGT approaches nearly 2,900 PJ by 2060. This reflects Japan's ambitions to achieve 12 million tons of hydrogen supply by 2040 and 20 million tons by 2050, alongside deeper decarbonisation targets. Hydrogen replaces gas in the power sector, while e-fuels are key to phasing out remaining gasoline and diesel in transport and bunkers.
- Most of the hydrogen-based fuels supply is imported. Domestic electrolysis remains minimal due to land and renewable constraints. Producing just 0.1 PJ of hydrogen via electrolysis would require around 32 MW of new solar, which is difficult given the significant renewable expansion in the power sector. Additionally, 12 PJ of natural gas-fuelled hydrogen is produced by consuming 22 PJ of natural gas.

Figure 8-35. Hydrogen-based fuels production methods and supply in REF & TGT (PJ)



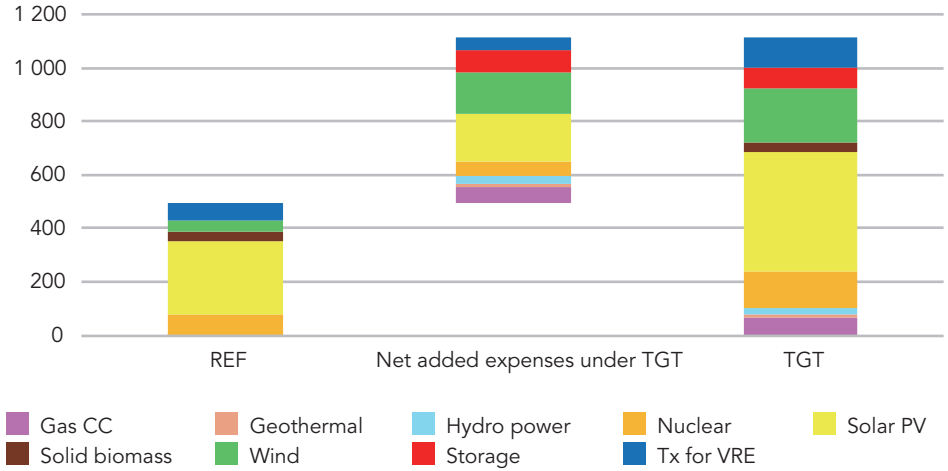
Costs

Figure 8-36. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



Note: Tx for VRE is only transmission infrastructure to connect variable renewable capacity to the grid. EV chargers do not cover the cost of associated infrastructure or EV vehicles. H_2 imports to meet bunkering obligations are not included in Figure 8-36.

Figure 8-37. Total capital investment (CAPEX) from 2025 to 2060 in the power sector (billion USD, undiscounted)

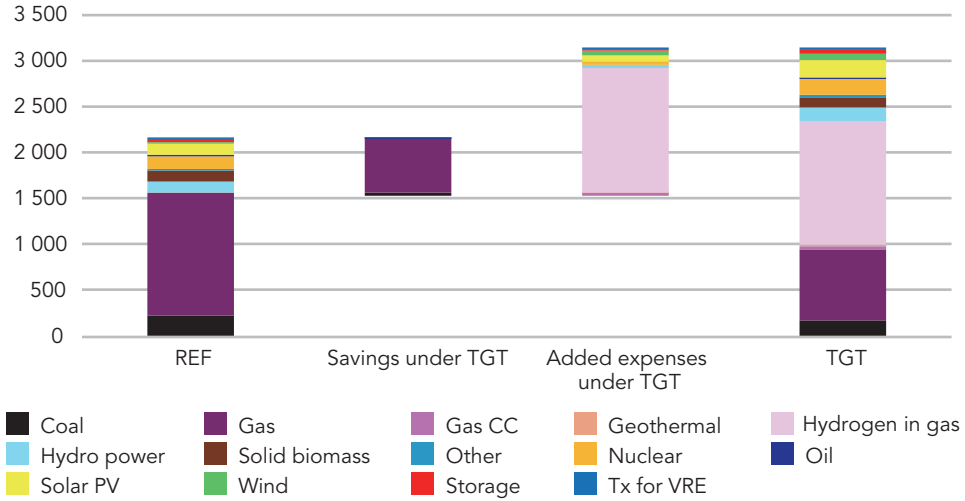


Note: Figure 8-37 only covers power and VRE transmission sector investments. Hydrogen and EV capital investments are not included.

- Meeting Japan's future energy demand will incur large costs, especially under a deep decarbonisation pathway. Total costs are estimated to be USD 2.75 trillion in REF and USD 5.5 trillion in TGT. Total costs include incremental costs from the power sector (capital, fixed and variable), low-carbon hydrogen imports for demand sectors (including power), transmission for VRE, heat generation costs and deployment of EV chargers.
- In REF, total costs are largely driven by LNG imports, as well as capital investment in solar PV and nuclear restarts.
- Costs in TGT rise more sharply, reaching an estimated USD 5.5 trillion by 2060, due primarily to the importation of large amounts of low-carbon hydrogen and hydrogen-based fuels; significant expansion of solar, wind, and battery storage; and the introduction of carbon capture (CC) in gas-fired power plants. Although LNG import costs decline by approximately USD 570 billion, these savings are outweighed by more than USD 2.3 trillion in hydrogen-based fuel import costs, of which an estimated USD 1.3 trillion is for hydrogen blending in the power sector, nearly USD 1 trillion is for e-fuel use in the transport sector, and approximately USD 80 billion is for hydrogen use in industrial processes, the transport sector, and the buildings sector. Increased hydrogen use for transport in TGT will offset conventional fuel consumption, estimating to save USD 340 billion (not shown in Figure 8-36).
- Total capital expenditures in TGT are nearly double those in REF. Investment in solar PV and wind is doubled in TGT compared to REF, increasing the need for corresponding new transmission. As a result, transmission expenditures increase by an estimated 84% relative to REF. There are also additional capital requirements for storage to meet demand peaks with an added USD 81 billion invested in TGT.
- The introduction of carbon capture for gas-fired power adds an estimated USD 65 billion in capital costs, supporting a capture potential of up to 24 $MtCO_2$ in 2050.

Costs

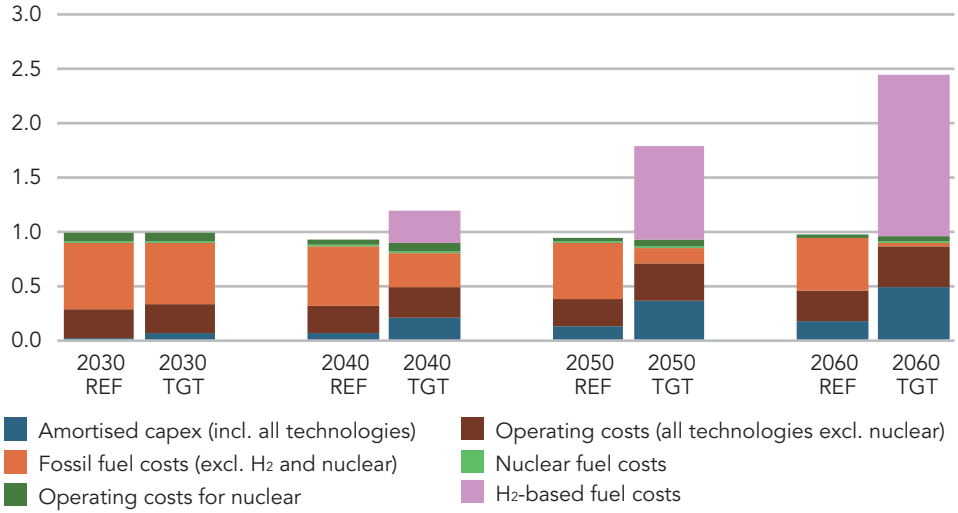
Figure 8-38. Total operating costs from 2025 to 2060 in the power sector (billion USD, undiscounted)



Note: Figure 8-38 only covers power and VRE transmission sector costs. It does not include operating costs associated with hydrogen production and EV charger costs but does include the cost of H_2 blending in power generation.

- Figure 8-38 outlines total operating costs in the power sector for each scenario and decomposes the difference between REF and TGT into cost savings and additional expenditures. These costs include variable fuel and non-fuel expenditures, as well as fixed costs for both power generation and transmission for VRE. Fuel costs for generating heat from stand-alone heat plants are also included.
- In addition to higher capital investments in TGT, operating costs also rise significantly. While capital-intensive systems often lead to lower operating costs over time, the opposite occurs here due to the large-scale introduction of low carbon hydrogen blending with gas. Although around USD 570 billion in gas expenditures is avoided in TGT relative to REF, these savings are offset by over USD 1.35 trillion in fuel costs for hydrogen use in gas-fired generation. With limited domestic production of hydrogen, Japan will be exposed to the comparatively higher prices of the international market.

Figure 8-39. Cost of generating electricity relative to 2025 (2025 cost = 1.0) in the power sector



Note: Based on our assumptions about future capital and operating costs, this chart shows cost compositions over time relative to 2025. It should not be considered an estimate of electricity tariffs and excludes market mechanisms that are too difficult to estimate.

- Figure 8-39 shows relative electricity generation costs, indexed to 2025. In REF, these costs remain relatively stable. In contrast, generation costs in TGT rise significantly from the 2040s onward, driven primarily by growing low carbon hydrogen use in gas blending.
- Despite reductions in fossil fuel imports, low carbon hydrogen remains a costly alternative and is assumed to be more expensive than gas despite assumptions about declining costs due to technological improvements. By 2050, hydrogen-based generation contributes to a near doubling of electricity generation costs compared to 2025 levels.
- These results highlight a critical trade-off: while hydrogen can contribute to power sector decarbonisation, its adoption entails significant long-term cost implications.

CO_2 Emissions

Figure 8-40. CO_2 emissions in REF (million tonnes)

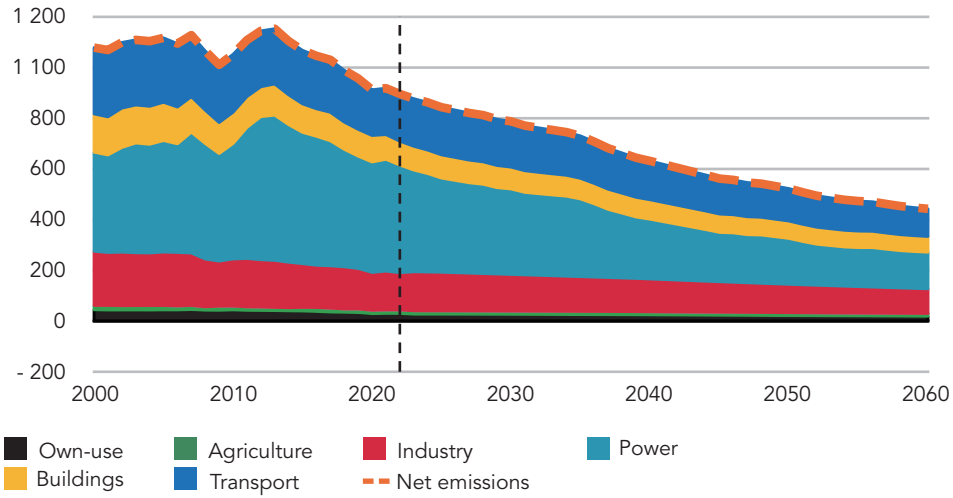
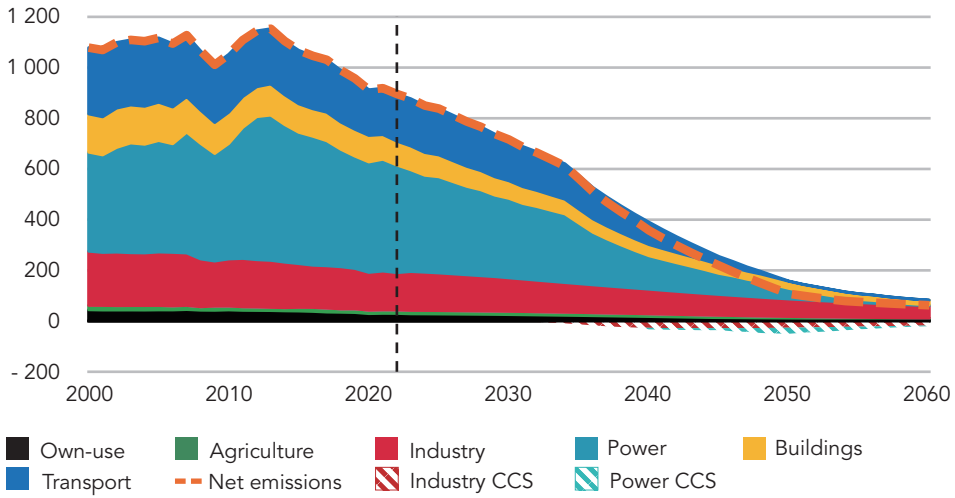
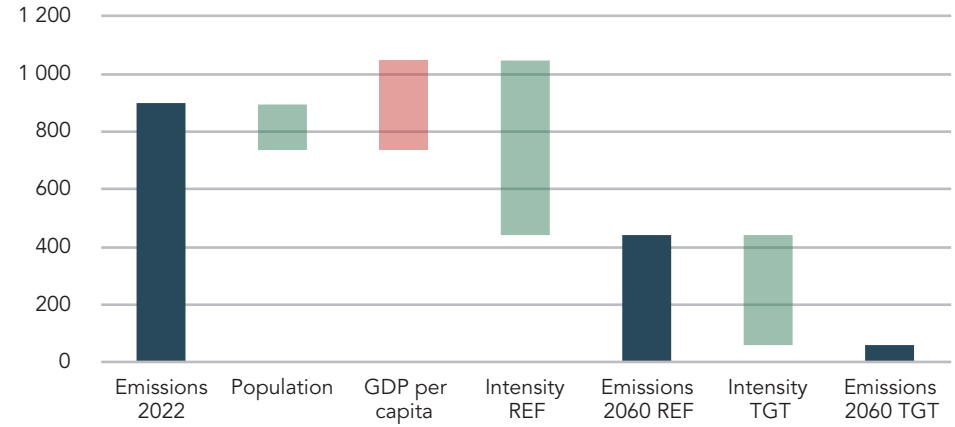


Figure 8-41. CO_2 emissions in TGT (million tonnes)



- In REF, emissions fall by 45% in 2040 compared to 2013, falling short of Japan's 73% economy-wide reduction target under its 2040 NDC. By 2050, over 500 $MtCO_2$ remain in the energy sector alone, highlighting the limits of modest electrification and continued reliance on fossil fuels.
- In contrast, TGT reduces energy-related CO_2 emissions by 70% by 2040 and reaches approximately 100 $MtCO_2$ by mid-century. This progress is driven by widespread fossil fuel reductions and CCS, which captures around 50 $MtCO_2$ in 2050 across the power and industry sectors. This significant reduction suggests that net-zero could be within reach, provided complementary contributions from LULUCF, DAC, and BECCS are mobilised to offset the remaining emissions.
- As shown in Figure 8-42, while Japan's declining population may slightly reduce emissions, most reductions come from improvements in energy intensity and emissions intensity, reflecting a more efficient and decarbonised energy system.

Figure 8-42. CO_2 emissions components (million tonnes)



Note: All values represent energy sector combustion CO_2 emissions. Biogenic CO_2 is treated as zero at the point of combustion.

Useful Links

APEC Expert Group on Energy Data and Analysis (EGEDA) – https://www.egeda.ewg.apec.org/

APEC Energy Statistics 2022 – https://www.egeda.ewg.apec.org/egeda/general/info/pdf/APEC_Energy_Statistics_2022.pdf

APEC Energy Overview – https://aperc.or.jp/reports/energy_overview.php

Agency for Natural Resources and Energy – https://www.enecho.meti.go.jp/en/

Ministry of Economy, Trade and Industry – https://www.meti.go.jp/english/index.html

Ministry of the Environment – https://www.env.go.jp/en/index.html



9. Korea

Summary

	Reference			Target		
	2022	2060	% Change	2022	2060	% Change
Macroeconomic						
Population (million)	51.8	41.1	-21%	51.8	41.1	-21%
GDP (billion 2017 USD, PPP)	2,350	4,003	70%	2,350	4,003	70%
Energy Demand						
Agriculture & fisheries (PJ)	108	99	-9%	108	85	-21%
Buildings (PJ)	1,739	2,082	20%	1,739	1,767	2%
Industry (PJ)	1,991	2,296	15%	1,991	1,993	0%
Non-energy (PJ)	2,174	3,021	39%	2,174	2,768	27%
Transport (PJ)	1,531	1,160	-24%	1,531	649	-58%
Modern renewables share of TFEC (%)	4	16	302%	4	49	1,125%
Energy intensity of TFEC (PJ/GDP, billion USD)	2.3	1.4	-38%	2.3	1.1	-51%
Electricity						
Generation (TWh)	610	875	43%	610	976	60%
Renewables share of generation (%)	7	28	282%	7	60	711%
Generation capacity (GW)	154	342	122%	154	513	233%
Total Primary Energy Supply (TPES)						
Coal & coal products (PJ)	2,856	1,056	-63%	2,856	153	-95%
Natural gas (PJ)	2,230	4,113	84%	2,230	1,828	-18%
Petroleum liquids (PJ)	4,270	4,508	6%	4,270	2,620	-39%
Low-carbon & waste energy (PJ)	2,354	2,827	20%	2,354	6,104	159%
CO_2 intensity of energy supply ($MtCO_2/PJ$)	0.043	0.032	-24%	0.043	0.013	-71%
Net CO_2 Emissions (million tonnes)	503	408	-19%	503	101	-80%

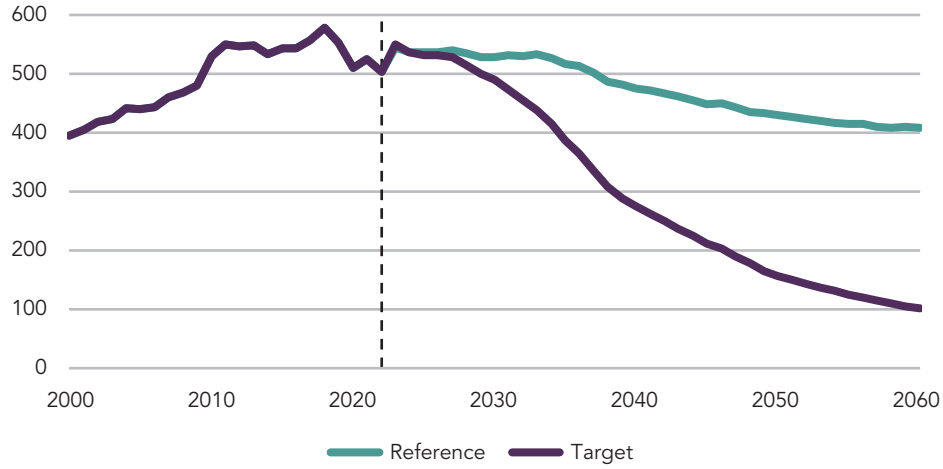
Note: In this publication, the term "modern renewables" refers to all renewable energy sources excluding solid biomass in the buildings sector. The term "low-carbon & waste energy" includes all bioenergy, waste-derived energy, renewables, nuclear, and hydrogen-based fuels. Total primary energy supply (TPES) numbers include international bunkers. Net emissions are calculated as gross energy sector combustion CO_2 minus CO_2 captured and stored through carbon capture and storage (CCS).

Key Takeaways

Emissions

- Korea's CO_2 emissions peaked in 2018 and are projected to decline through 2060 in both the Reference (REF) and Target (TGT) scenarios. In REF, emissions remain relatively constant until the early 2030s, then fall to 408 Mt by 2060. In TGT, emissions decline more deeply to around 100 Mt, an 80% reduction from 2022, driven by fuel transitions, electrification, and efficiency improvements.
- Electrification in industry and transport significantly reduces demand-side emissions but drives up electricity demand. Emissions from the building sector also decline, though growing data centre loads partially offset these reductions.
- The power sector is central to overall reductions. In TGT, power sector emissions drop 74% by 2060, with partial carbon removal achieved through CCS. However, additional negative emissions are required across sectors to meet Korea's 2030 NDC and 2050 net-zero targets.

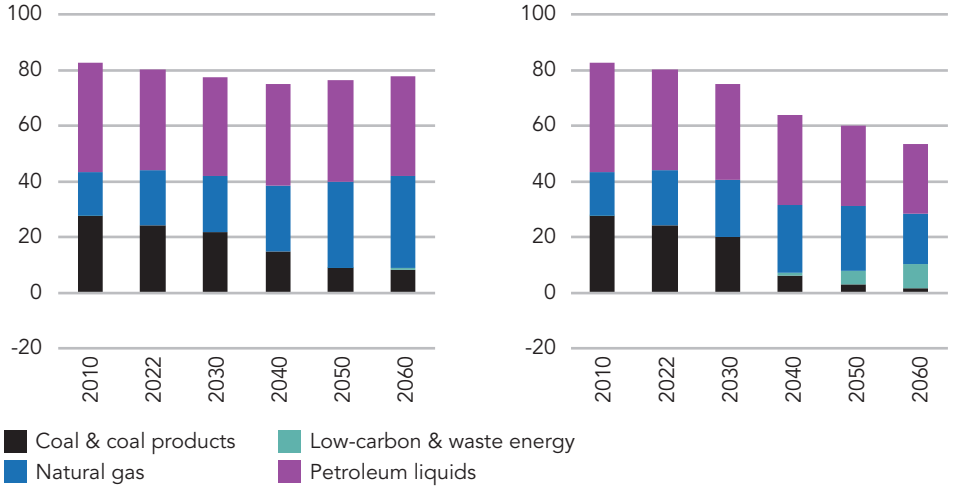
Figure 9-1. Net CO_2 emissions (million tonnes)



Energy Import Dependence

- Energy security remains vital for Korea due to its heavy reliance on imported energy. In 2022, imports accounted for 80% of total primary energy supply (TPES), highlighting the need for diversified sources and stable international supply chains.
- Korea's import dependency remains high at around 77% through 2060 in REF. Continued reliance on fossil fuels will expose Korea to geopolitical risks, price volatility, and potential supply disruptions.
- In TGT, dependency declines to 53% by 2060, as Korea shifts its fuel mix toward renewable energy, improving self-sufficiency, and supply resilience. However, fossil fuels including natural gas and petroleum liquids still comprise 43% of supply due to their continued roles in industry and power. Low-carbon fuels, such as hydrogen, are projected to account for 9% of TPES. Korea is expected to remain import-dependent for these fuels, necessitating investment in infrastructure and diversification of supply chains.

Figure 9-2. Net imports share of TPES in REF & TGT (%)



Note: In Figure 9-2, net imports refer to total imports minus exports and international bunkers.

Key Takeaways

Grid Reliability

- Electric grid reliability requires a near-instantaneous balance between power supply and demand at all times, supported by adequate dispatchable power sources including batteries.
- Figure 9-3 shows the grid's dependence on dispatchable power in the 4-hour period of maximum dependence and 4-hour period of minimum dependence. In 2022, there was a relatively small difference between the minimum and maximum, so dispatchable generators could produce at a fairly constant rate.
- As total electricity demand increases in both REF and TGT, Korea will require increased dispatchable capacity for those periods when variable renewable energy (VRE) sources, such as wind and solar, are not producing at their maximum level. As the VRE rises, the gap between the minimum and maximum demands on dispatched power increases, which will increase capital, maintenance, and operating costs.

Cost

- Korea's power and hydrogen sectors are projected to incur substantial costs through to 2060. Under TGT, total costs reach an estimated USD 3.7 trillion, which is USD 1.5 trillion higher than in REF. This includes total capital and operational costs for power and heat generation, low-carbon hydrogen importation and production, investments in transmission for VRE and electric vehicle chargers.
- The higher cost in TGT is mainly driven by the large-scale deployment of low-emission sources such as nuclear, solar PV, and low-carbon hydrogen. Additional investment is required for energy storage, grid expansion to support a more electrified and decentralised system, and EV chargers.
- Addressing these cost challenges will require strong policy support, including targeted incentives for storage, R&D, and financing mechanisms for infrastructure development.

Figure 9-3. Peak load and maximum and minimum dependence on dispatched power (GW)

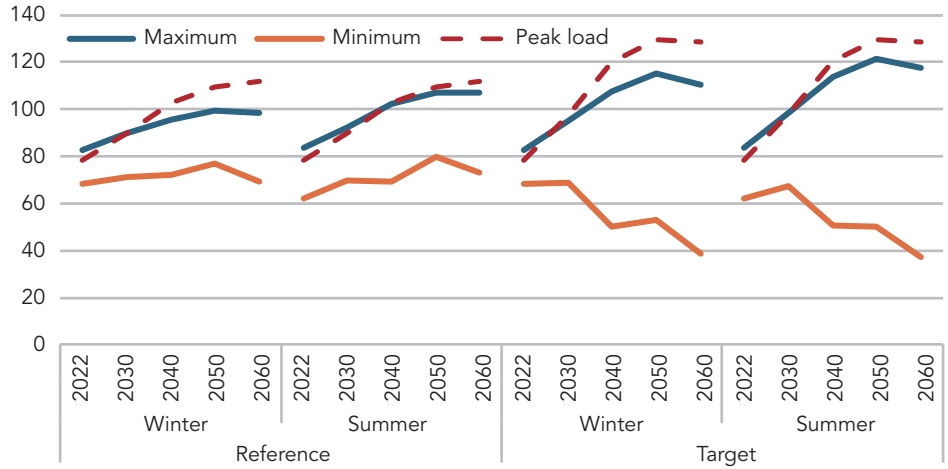
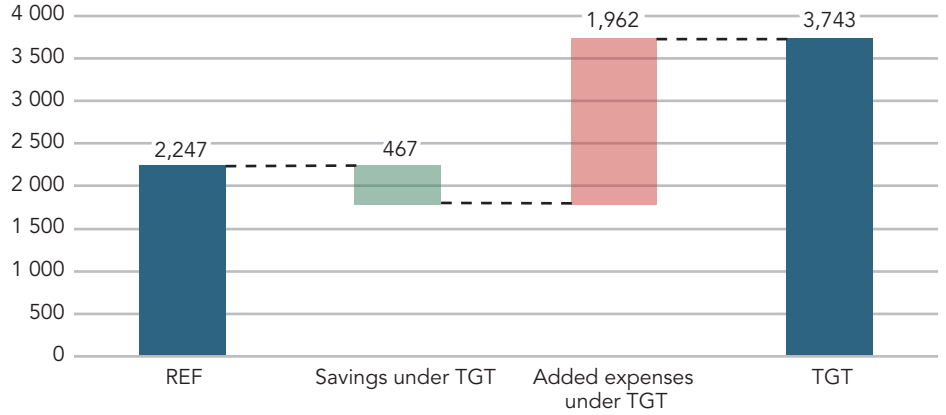


Figure 9-4. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



*Actual costs will differ from estimated costs in the *Outlook* for a variety of reasons including changing commodity prices, manufacturing costs, and unforeseen technical advances. All costs are in 2023 real terms.

About Korea

Overview

Geographical and Economic Landscape

Korea features a high population density and a geography characterised by mountains, hills, and coastal plains. It experiences four distinct seasons, with weather patterns significantly influencing energy use. Over recent decades, Korea has emerged as one of Asia's most dynamic economies, driven by key industries such as semiconductors, automobiles, steel, and petrochemicals.

Energy Supply and Consumption

Korea's total energy consumption in 2022 was 7,585 PJ, with the industrial and non-energy sectors accounting for the largest shares at 26% and 28%, respectively. Over the period from 1990 to 2022, Korea's total energy supply nearly tripled due to its growing economy. Given its limited domestic resources, Korea depends heavily on energy imports. While coal, oil, and gas continue to dominate the energy supply, renewable energy has increased continuously since 2000.

In recent years, economic growth caused a sharp increase in electricity demand. Between 2000 and 2022, electricity generation more than doubled, from 288 TWh to 610 TWh. With a growing focus on carbon neutrality, coal-fired power generation is expected to decline significantly over the long run, while nuclear and renewable energy are projected to increase.

To support this transition, the Korean government has emphasised the widespread adoption of low-emission energy sources, including renewables, nuclear, and hydrogen, to achieve carbon neutrality and support sustainable growth. In line with this policy initiative, the 11th Basic Plan for Electricity Demand and Supply was published in February 2025.

Energy Security Challenges and Strategies

As an energy-importing economy, Korea has updated its energy policy to strengthen its energy security amid geopolitical uncertainty. Key strategies include pursuing a balanced energy mix, expanding nuclear power, enhancing grid infrastructure, and diversifying energy imports.

Key Energy Initiatives

Paris Agreement Commitment

Korea has pledged to achieve carbon neutrality by 2050, with a NDC target of reducing greenhouse gas emissions by 40% from 2018 levels by 2030.

Promoting Low-carbon Energy in the Industrial Sector

Korea is promoting low-carbon energy technologies including renewables, hydrogen, nuclear, and CCUS (Carbon Capture, Utilisation, and Storage) in high-emission industry sectors.

Strengthening Transmission Infrastructure

Korea plans to build an HVDC-based West Coast transmission line by the 2030s, followed by a U-shaped offshore power grid by the 2040s, to ensure the stable delivery of renewable electricity to high demand areas.

Expansion of Renewable Energy

In May 2024, Korea unveiled a strategy to accelerate deployment of offshore wind and solar power. The plan includes supply chain stabilisation, market reform, and aims to install more than 6 GW of renewable energy annually.

Hydrogen Economy Strategy

Korea aims to expand the role of hydrogen as a clean energy option. Key areas include its use in power generation, transport, and industry.

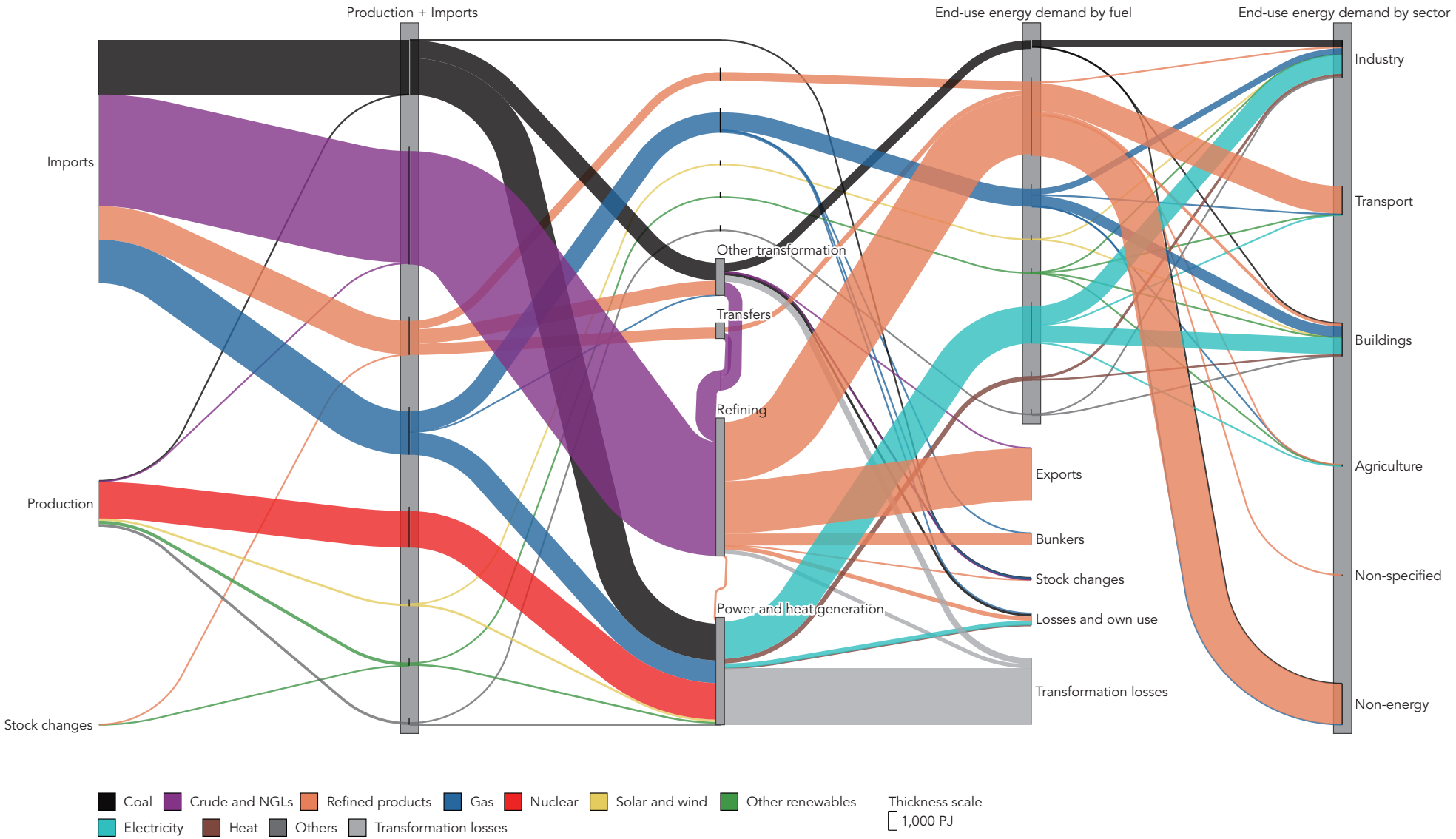
Ensuring Energy Security

In January 2024, Korea enacted *the Special Act on National Resource Security*, establishing a comprehensive policy framework to strengthen Korea's energy resource security.

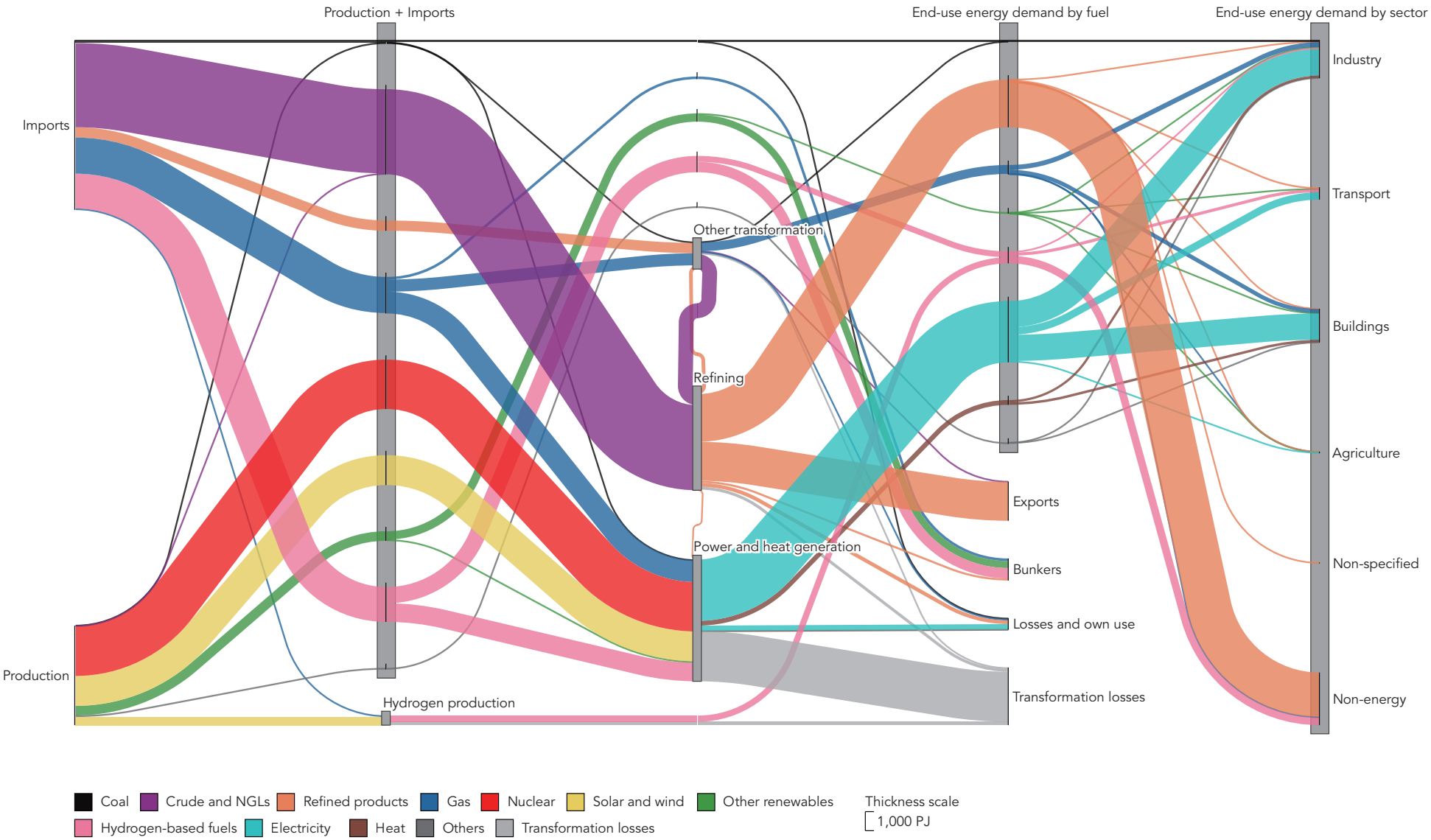
National Basic Plan for Carbon Neutrality and Green Growth

Released in April 2023, Korea's 1st Basic Plan outlines implementation measures to achieve carbon neutrality, including expanding low-emission energy, supporting technological advancement, and strengthening international cooperation.

Energy Flow (2022)



Energy Flow (2060, Target Scenario)



Scenarios and Assumptions

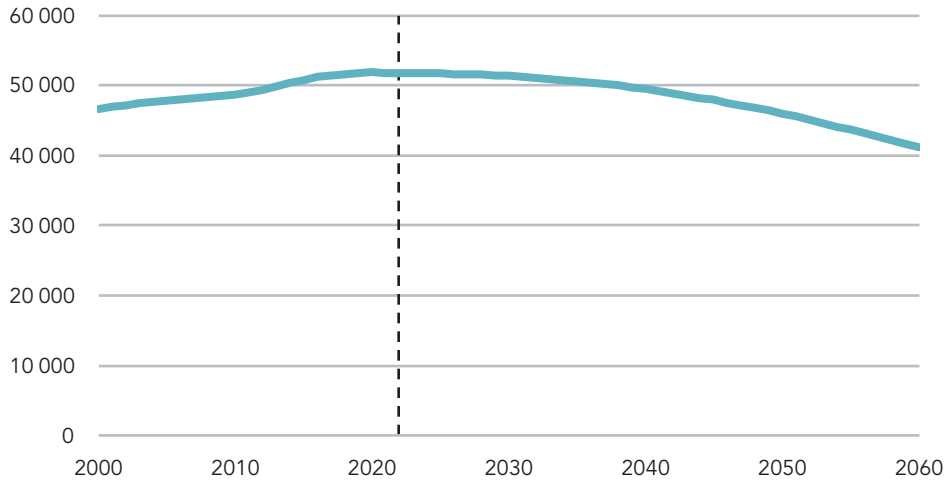
In *The Outlook*, APERC analyses energy demand, transformation, and supply, as well as emissions. The **Reference Scenario (REF)** offers a projection based on historical trends, recent developments, and APERC's assumptions about the continuation of those trends in each APEC economy, while acknowledging technical restraints. The REF Scenario offers a baseline to compare with the **Target Scenario (TGT)** projections, which explores a hypothetical pathway where each economy achieves energy-related policy targets, assuming implementation regardless of cost-effectiveness. When implementation details are lacking, assumptions are inferred from the targets themselves or emissions-related goals.

	Reference	Target
General	• Population: UN medium, GDP: APERC model and IMF	• Population: UN medium, GDP: APERC model and IMF
Buildings	• Existing efficiency standards and insulation maintained. • Zero Energy Building (ZEBs) certification selectively considered. • Modest electrification in residential and services sectors.	• Mandatory ZEBs for all new buildings and stricter efficiency standards. • Large-scale green remodelling for existing buildings considered. • Accelerated electrification for heating, cooking, and building systems. • AI & data centre electricity demand grows under both scenarios.
Industry	• Key manufacturing sectors sustain strong output. • Hydrogen-based steelmaking begins from 2040s, remains minor. • Electricity grows modestly; fossil fuels share still 27% by 2060.	• Greater electrification and efficiency, fossil fuels share falls to 16% by 2060. • Hydrogen use expands from the 2030s, scaling faster than in REF. • CCS deployment mitigates residual emissions in heavy industries from 2030.
Transport	• ICE vehicles steadily decline, shifting toward electrification. • BEVs and PHEVs gradually increase to account for 40% of the total vehicle stock by 2060.	• BEVs rapidly grow to 50% of the passenger vehicle stock by 2040 and fully replace ICE vehicles by 2060. • PHEV, LPG, and CNG vehicles are nearly phased out by 2060.
Power	• 30 nuclear reactors operational by 2035, including 26 existing, 2 under construction, and 2 planned, with 60 years of lifespan restriction. • Natural gas plays a flexible backup role to support grid stability. • CCS is not incorporated.	• Existing coal-fired power plants phased out by 2060. • No lifespan restrictions in nuclear reactors. Two new nuclear reactors and an SMR added, based on the 11th Basic Plan for Electricity Demand and Supply. • Higher renewable capacity with batteries and greater use of hydrogen-based fuels are incorporated. • CCS is incorporated in the late 2030s.
Supply	• Coal, oil, and gas are entirely imported. • All hydrogen-based fuels (hydrogen, ammonia, e-fuels) are imported.	• Fossil fuel supply follows demand and is entirely imported. • Hydrogen-based fuels are supplied from both imports and production. • Bioenergy (biomass, biogas, liquid biofuel) is produced in both scenarios.
Emissions	• CO_2 emissions are calculated at post consumption based on IPCC emission factors.	

Note: The base year is 2022. Macro-economic assumptions are constant across scenarios. Historical energy balances are from EGEDA submissions for 2022.

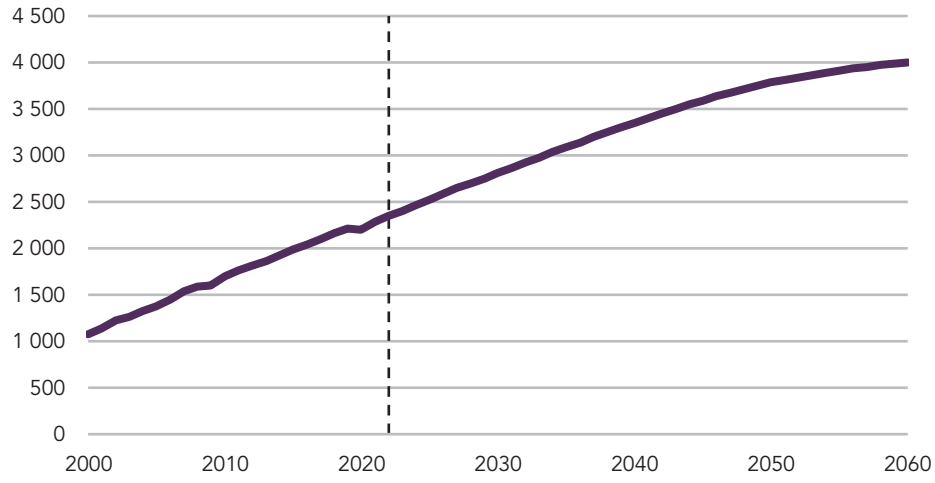
Demographic and Macroeconomic Assumptions

Figure 9-5. Population (thousands)



- Korea's population is projected to decline over the coming decades, from a peak of approximately 52 million in 2022 to around 41 million by 2060. Despite this overall decline, the number of households is expected to remain relatively stable due to the continued rise in single-person households.
- Korea has an extremely high population density, averaging around 516 people per km², with densities in metropolitan areas continuing to increase.
- This population decline reflects Korea's persistently low fertility rates and rapidly ageing society. The demographic shifts pose long-term structural challenges and are expected to impact energy demand projections, particularly in the buildings and transport sectors.

Figure 9-6. Real GDP (billion 2017 USD, PPP)



- Korea's GDP maintains a consistent upward trajectory through 2060, despite long-term demographic challenges. After a brief contraction of 0.7% in 2020 due to the COVID-19 pandemic, the economy recovered with annual real GDP growth ranging between 2% and 3%.
- Between 2022 and 2030, the economy grows at a compound annual growth rate (CAGR) of 2.2%, supported by strong export performance and resilient manufacturing activity, particularly in the semiconductor and automotive industries. Over the longer term, growth is projected to slow toward 2060, reflecting the impact of an ageing population and the structural maturity of the economy.
- Despite the slowing growth rate, industrial activity remains strong through 2060, especially in high-value-added sectors such as machinery and chemicals. The services sector is also expected to expand, driven by sustained growth in healthcare and information technology industries.

End-use Energy Demand

Figure 9-7. Energy demand by sector in REF & TGT (PJ)

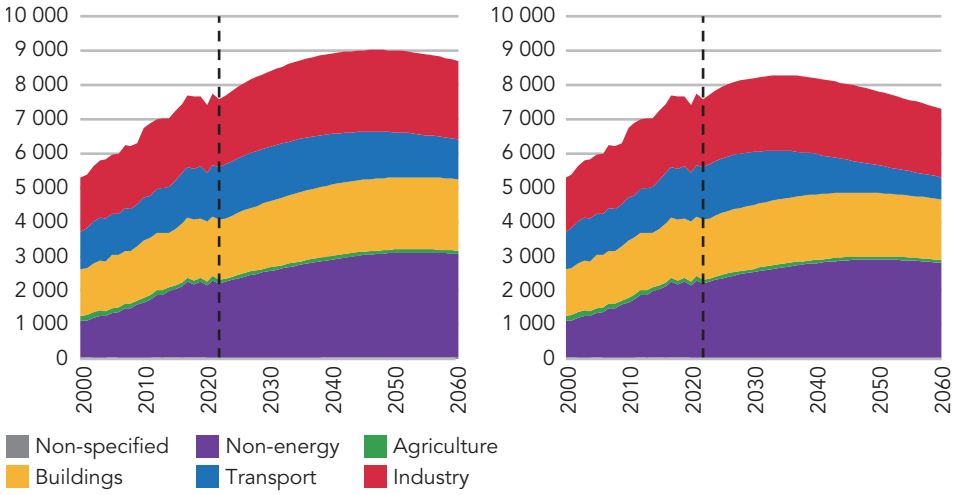
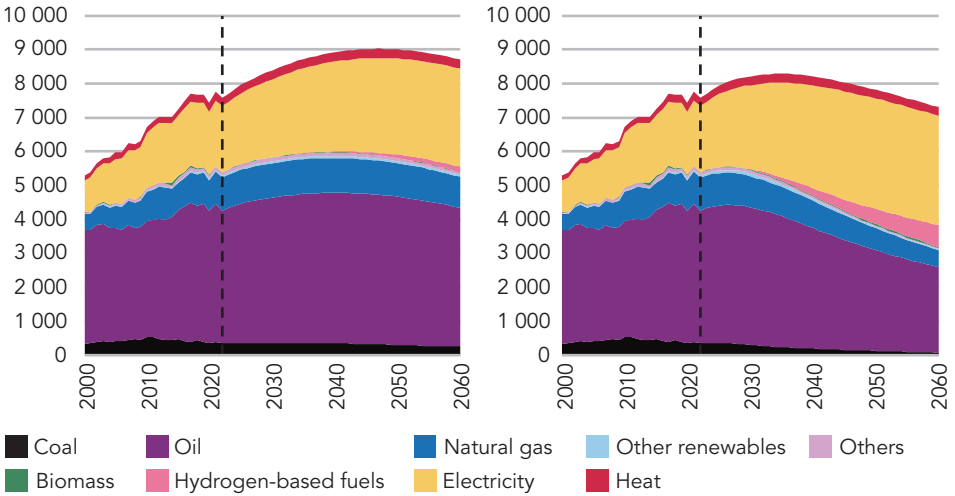


Figure 9-8. Energy demand by fuel in REF & TGT (PJ)



- Korea's total end-use energy demand peaks at nearly 9,000 PJ around 2050 in REF, before declining slightly to 8,700 PJ by 2060. Overall, demand increases by 15% between 2022 and 2060. In contrast, demand in TGT peaks in the mid-2030s and declines by 12% to 7,300 PJ by 2060, driven by accelerated energy efficiency improvements and structural changes under a decarbonisation pathway.
- Industrial and non-energy use remains the dominant contributor, with their combined share growing from 55% in 2022 to 61% in REF and to 65% in TGT, supported by petrochemical and manufacturing industries.
- Transport demand in REF rises slightly to 2040, then falls to 1,160 PJ by 2060. In TGT, it drops more deeply to 649 PJ.
- Energy use in buildings rises sharply during the first decade in both scenarios, driven by growing data centre demand. In TGT, demand then declines modestly as efficiency improvements begin to offset this growth.

- Fossil fuels have historically dominated Korea's end-use energy demand. In 2022, they accounted for 69% of total demand, led by oil (45%), gas (19%), and coal (5%), while electricity comprises 26%.
- In the REF scenario, the fossil fuel share declines to 60% by 2060 but remains the largest energy source. Electricity's share rises gradually to 33%, reflecting moderate electrification across all sectors.
- In contrast, fossil fuel use declines more sharply in the TGT scenario. Oil remains the dominant fuel at 31%, mainly as a petrochemical feedstock. Gas demand falls to half of 2022 levels but continues to serve the buildings, industry, and power sectors.
- Electricity's share grows markedly to 44% by 2060. Hydrogen expands to 9%, supported by uptake in steelmaking, fuel cell vehicles, and power generation, highlighting a stronger shift toward decarbonisation technologies under the TGT pathway.

Buildings Energy Demand

Figure 9-9. Buildings energy demand by fuel in REF & TGT (PJ)

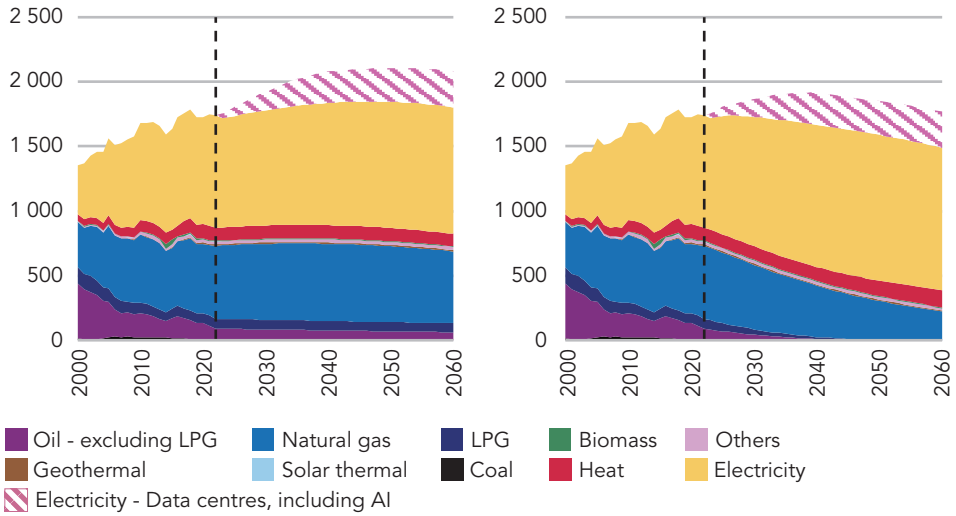
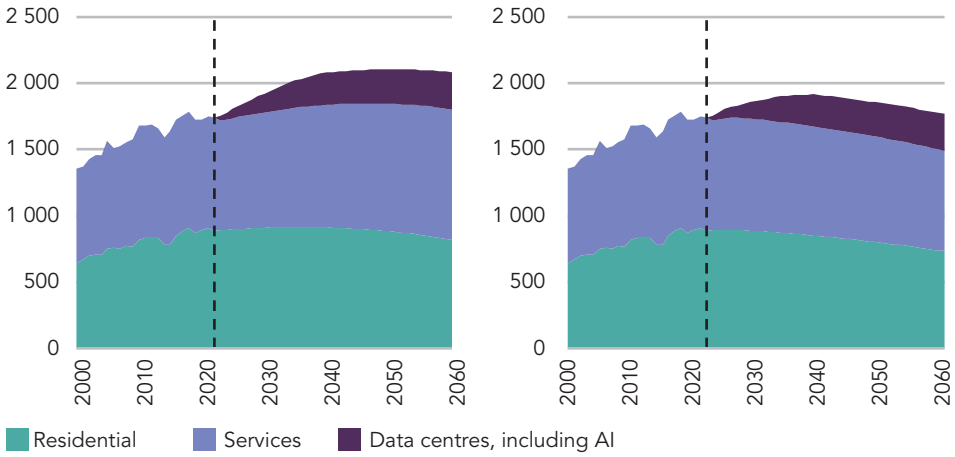


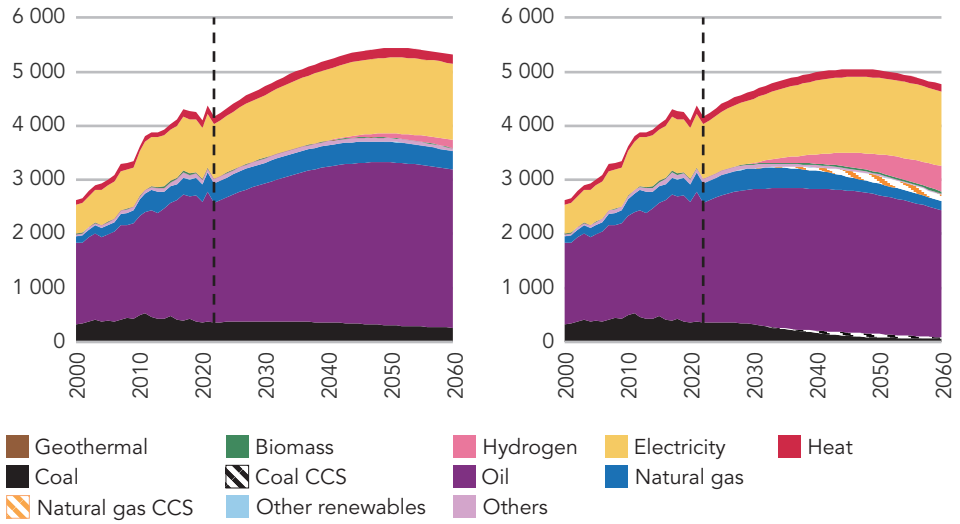
Figure 9-10. Buildings energy demand by sector in REF & TGT (PJ)



- Korea's buildings energy demand is projected to peak at around 2,100 PJ by 2050 under the REF scenario, and then remain flattened. In contrast, demand peaks earlier at 1,900 PJ before 2040 in TGT, followed by a steady decline to around 1,800 PJ by 2060, similar to 2022 levels. The fuel mix shifts significantly from fossil fuels to electricity, with associated efficiency gains contributing to lower overall demand in TGT compared to REF.
- In 2022, electricity accounted for 50% of buildings energy use, followed by gas (37%) and oil (5%). By 2060, electricity's share rises to 61% in REF and 78% in TGT, driven by increased demand for cooling, appliances, and fast-growing data centre loads. Gas remains important for heating and cooking, accounting for a 30% share in REF but dropping to 12% in TGT. Oil and coal are nearly phased out by 2060 in TGT, reflecting stronger electrification and decarbonisation measures.
- A key feature of the buildings sector in the *Outlook* is rising electricity demand from data centres, including AI energy consumption, growing from 40 PJ in 2023 to 278 PJ by 2060. By 2040, data centres energy demand is six times higher than in 2023, which raises potential grid reliability challenges and may necessitate infrastructure adjustments.
- Population decline reduces residential energy demand over time in both scenarios, while in REF, growth in commercial activity drives higher service sector energy demand.
- In TGT, stronger efficiency standards and widespread adoption of Zero Energy Buildings (ZEBs) lower energy use across both subsectors. By 2060, residential demand falls by 17% and service sector demand declines by 13%, offsetting the upward pressure from growing service activity. These shifts illustrate how efficiency improvements and building design can decouple energy demand from economic growth.

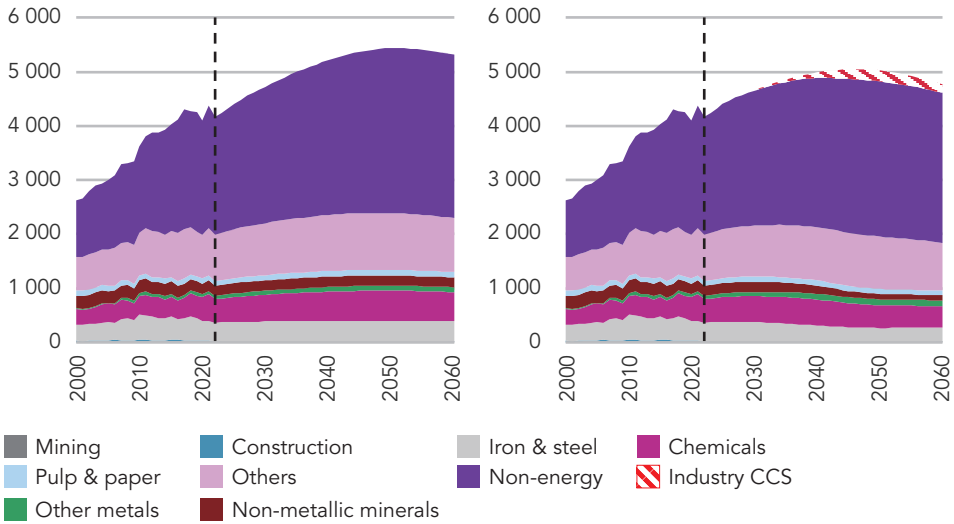
Industry Energy and Non-energy Demand

Figure 9-11. Industry & non-energy demand by fuel in REF & TGT (PJ)



- Korea's industrial and non-energy demand remains significant through 2060 in both scenarios, supported by robust economic activity despite a declining population. In REF, the industry and non-energy demand increases steadily to over 5,300 PJ by 2050 before a slight decline, while in TGT it peaks earlier and falls to 4,800 PJ by 2060 due to stronger efficiency gains and decarbonisation efforts.
- Oil and electricity are the primary fuels. Oil remains dominant due to continued demand for petrochemical feedstocks, indicating limited structural shifts in non-energy consumption. Electricity use grows in both scenarios, highlighting gradual electrification in sectors such as iron and steel, chemicals, and semiconductors.
- A key distinction in TGT is the earlier and broader uptake of low-emission fuels. Hydrogen use begins in the 2030s and reaches 470 PJ (a 10% share) by 2060, and CCS is deployed from 2030, scaling to 150 PJ by 2060, playing a crucial role in decarbonising coal and gas use in industry.

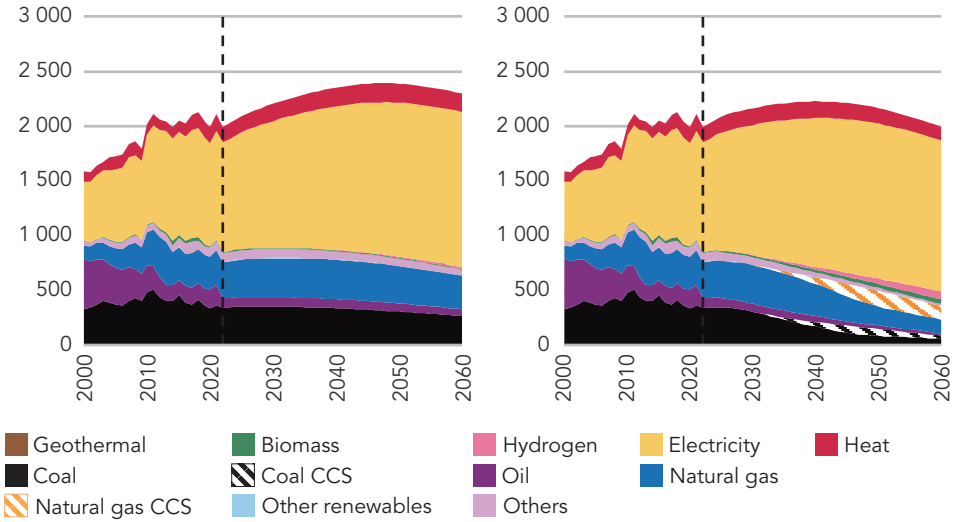
Figure 9-12. Industry & non-energy demand by sector in REF & TGT (PJ)



- Korea's industrial and non-energy demand outlook underscores persistent reliance on hard-to-abate sectors, which could pose challenges for decarbonisation.
- In both scenarios, energy use remains concentrated in energy-intensive industries. While total demand is lower in TGT due to improvements in material efficiency and technological shifts for decarbonisation, the sectoral composition shows limited structural change.
- Non-energy use, mainly for petrochemical feedstocks like naphtha and LPG, remains higher than industrial energy use, accounting for 2,100 PJ in 2022 (52% share) and maintaining over 57% of total demand throughout the outlook period.
- This persistent demand underscores the difficulty of replacing fossil feedstocks without major innovation or structural changes in Korea's petrochemical and downstream industries.

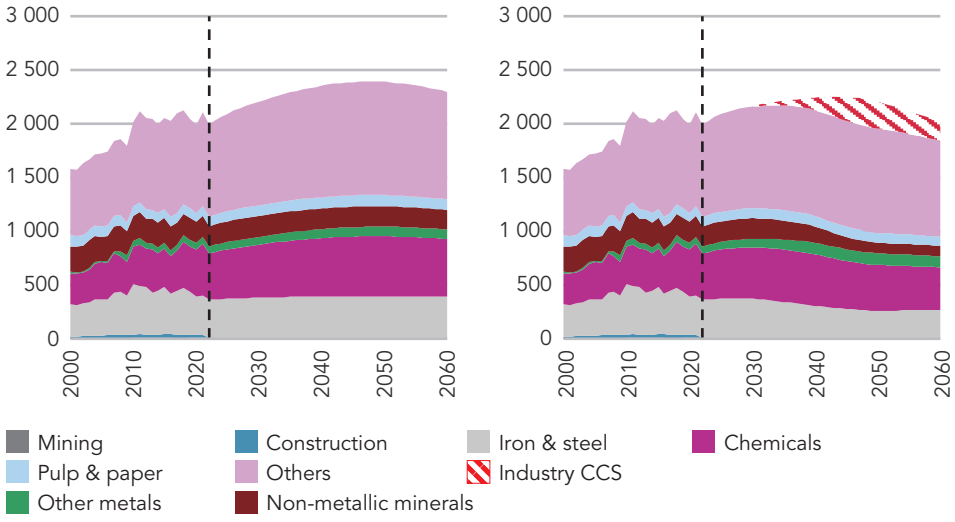
Industry Energy Demand

Figure 9-13. Industry energy demand by fuel in REF & TGT (PJ)



- Industrial energy demand in Korea increases until 2050 in REF and 2040 in TGT, before declining to 2,300 PJ and 2,000 PJ by 2060, respectively. This reflects ongoing efficiency improvements across energy-intensive sectors.
- By 2060, the industrial sector undergoes notable fuel diversification, with electrification and low-emission technologies advancing at different speeds across scenarios. Electricity, which already accounts for 50% of demand in 2022, rises to 70% in TGT and 62% in REF. Expanding electrification emerges as a key pathway for industrial decarbonisation, particularly when backed by low-emission power supply.
- In TGT, alternative fuels expand after 2040, with hydrogen reaching 4% and bioenergy 2% by 2060. Natural gas becomes a key substitute for coal and oil, while CCS adoption accounts for 6% of industrial energy use, primarily in chemicals, cement, and steel. Excluding non-energy use, oil dependency drops significantly, highlighting the sector's transition potential.

Figure 9-14. Industry energy demand by sector in REF & TGT (PJ)



- Korea's industrial energy demand by sector reflects the combined effects of output growth, technology advancement, and structural change. While overall demand trajectories are similar across scenarios, the sectoral composition diverges modestly by 2060.
- In TGT, energy-intensive sectors such as iron and steel and chemicals decline in both absolute volume and share, from 40% in 2022 to 32% in 2060, driven by reduced output, efficiency gains, and process innovation. Widespread deployment of CCS technology, which accounts for 9% of industrial energy use, also contributes to emissions mitigation.
- In contrast, low energy-intensity sectors such as machinery and light manufacturing maintain a strong presence, with a combined share of 48% in TGT, supported by growing demand for semiconductors, batteries, and high-value precision equipment.

Note: Non-energy is not shown in Figures 9-13 and 9-14.

Non-energy Demand

Figure 9-15. Non-energy demand in REF (PJ)

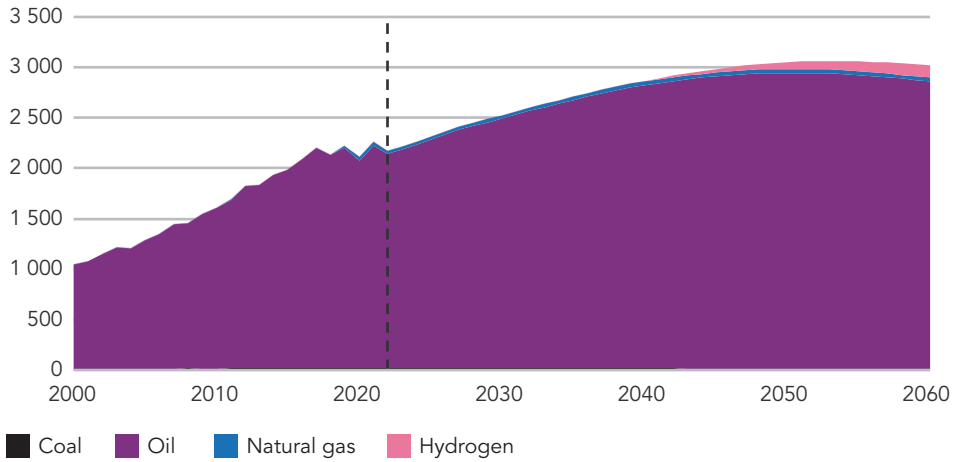
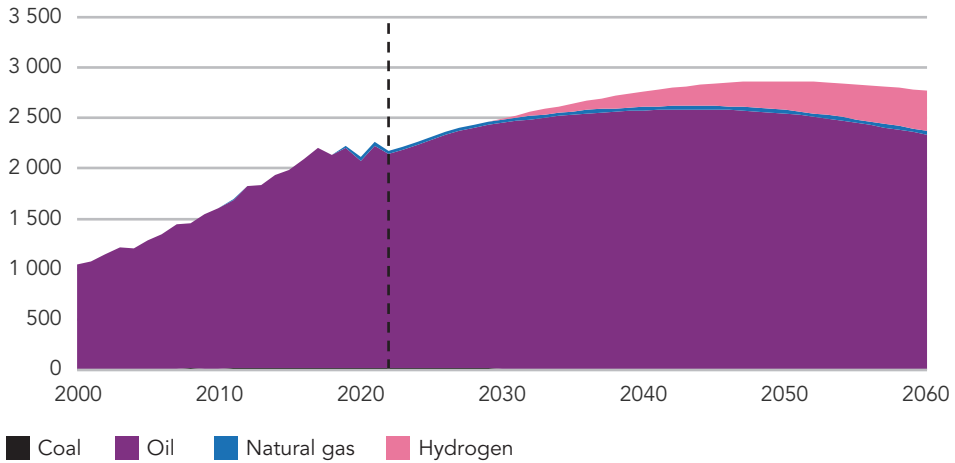


Figure 9-16. Non-energy demand in TGT (PJ)



- Korea's non-energy demand, primarily for oil-based petrochemical feedstocks such as naphtha and LPG, has long been a major component of final energy use, accounting for 29% in 2022. This reflects Korea's strong export-oriented petrochemical industry producing synthetic resins, rubbers, and fibres.
- In REF, non-energy demand grows by 40% and peaks at over 3,000 PJ in the early 2050s, with continued reliance on fossil fuels. Oil remains the dominant input, especially for naphtha, due to limited substitution options and the inflexibility of existing petrochemical processes. This highlights a structural challenge for long-term decarbonisation in this sector.
- While the oil-based petrochemical sector continues to dominate, hydrogen begins to play a role in non-energy applications, reaching a 4% share by 2060. This marks a step toward fuel diversification, though further uptake will require cost reductions and infrastructure improvements, particularly for import, storage, and handling of hydrogen and ammonia.
- In TGT, Korea's non-energy demand peaks earlier and at a lower level than in REF, reaching just over 2,800 PJ by 2050. This reflects improvements in material efficiency, reduced reliance on petroleum-based feedstocks, and early adoption of low-emission technologies.
- Hydrogen use begins in the 2030s and expands significantly in TGT, reaching 8% of non-energy demand by 2060. This growth is driven by advances in green hydrogen and ammonia production, as well as its application in chemical and steelmaking processes. However, oil-based feedstocks such as naphtha and LPG still account for the majority share, posing ongoing challenges for full decarbonisation.
- To enable wider fuel substitution, it is critical for Korea to accelerate R&D and policy support for clean feedstock commercialisation, especially during the 2030s transition period.

Transport Energy Demand

Figure 9-17. Domestic transport energy demand in REF (PJ)

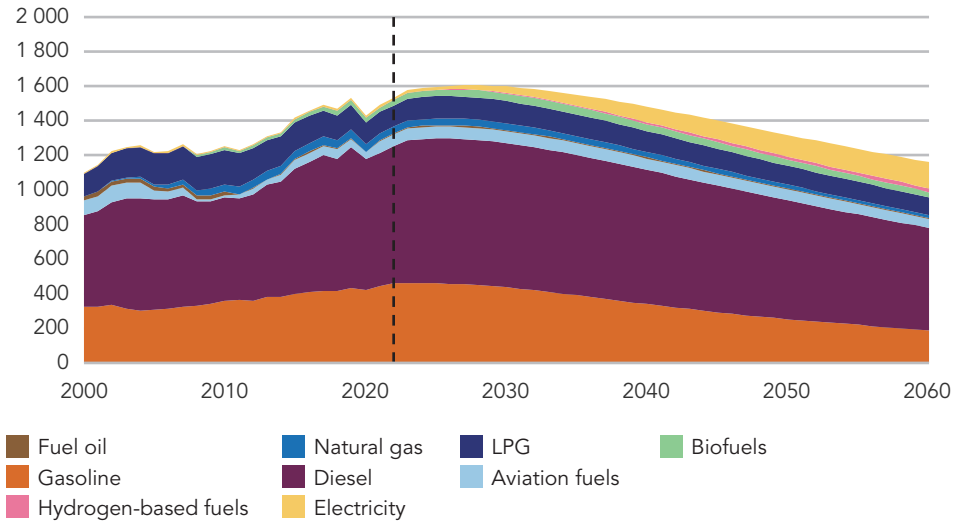
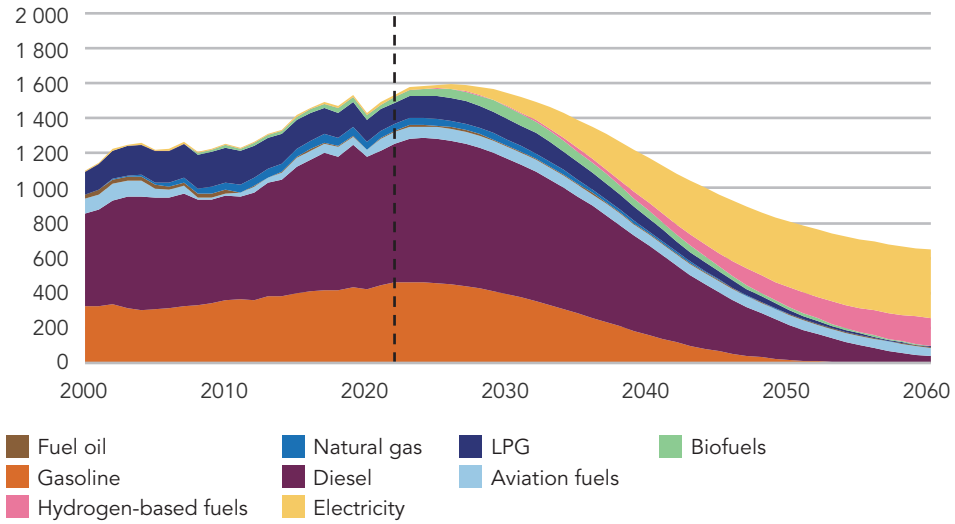


Figure 9-18. Domestic transport energy demand in TGT (PJ)



- Korea's road transport accounted for 94% of total transport energy demand in 2022, making the sector a major focus for decarbonisation efforts.
- In REF, total transport energy demand declines from 1,531 PJ in 2022 to 1,160 PJ by 2060, while in TGT, stronger policy drives a steeper decline to 650 PJ.
- Population contraction leads to a modest reduction in energy use. However, rising income levels and growing freight activity partially offset these savings, resulting in a slight increase in energy use from activity (shown in Figure 9-21 on the next page).
- Battery Electric Vehicle (BEV) sales shares for light vehicles and buses grow to 52% by 2060 in REF. In TGT, BEV uptake accelerates more rapidly, reaching 90% by 2035 and stabilising at that level thereafter. This early surge in BEV sales expands the BEV stock and enables faster emissions reductions, though it also implies substantial infrastructure requirements to support the transition.
- Fuel cell electric vehicles (FCEVs) complement BEVs in decarbonising the heaviest and longest-range transport. By 2060, FCEVs are projected to consist of 30% of freight truck sales and 10% of other vehicle sales.
- As a result of the high uptake of BEVs and FCEVs in TGT, electricity and hydrogen-based fuels dominate the transport energy mix by 2060, accounting for 60% and 25%, respectively. Electricity demand alone increases from 13 PJ in 2022 to 390 PJ by 2060, a nearly 30-fold rise. In contrast, fossil fuel consumption falls sharply to just 40 PJ.
- These shifts position the transport sector as a key pillar of Korea's decarbonisation pathway, enabled by technological adoption, ambitious policy, and structural transformation.

Other Transport Data

Figure 9-19. Transport vehicle stocks in REF & TGT (millions)

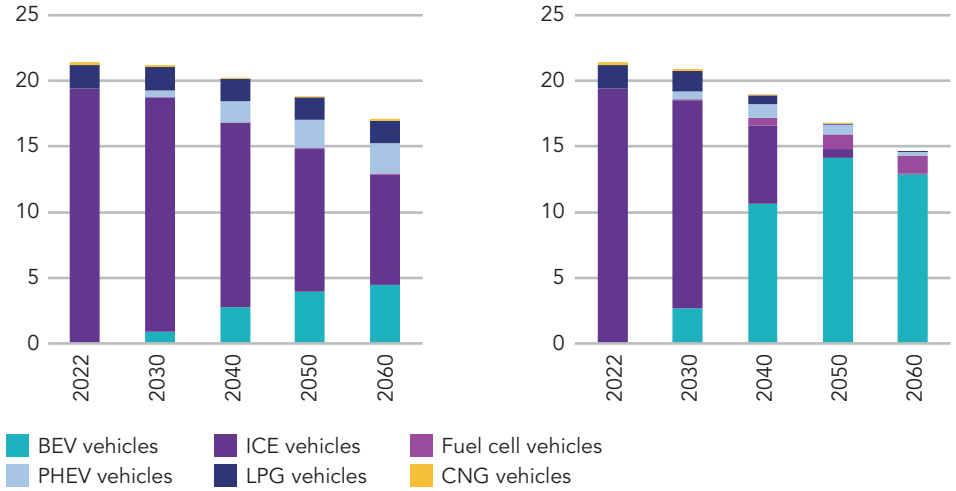
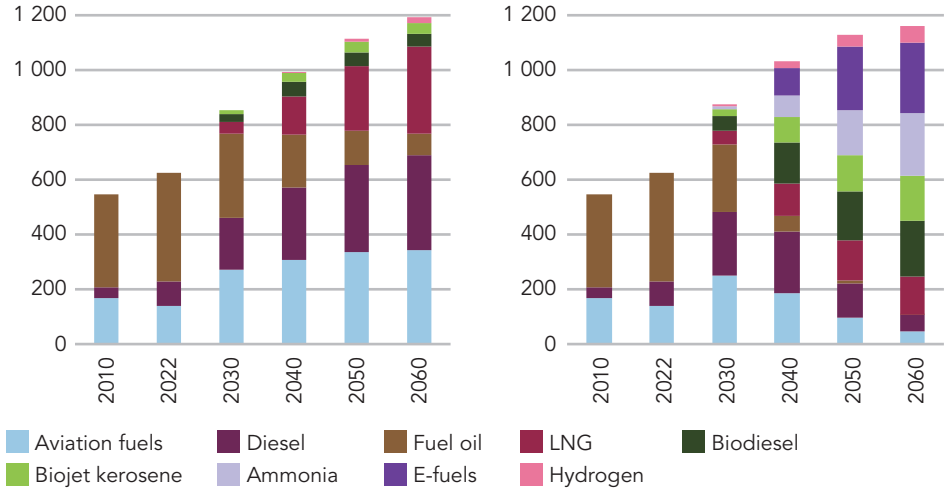
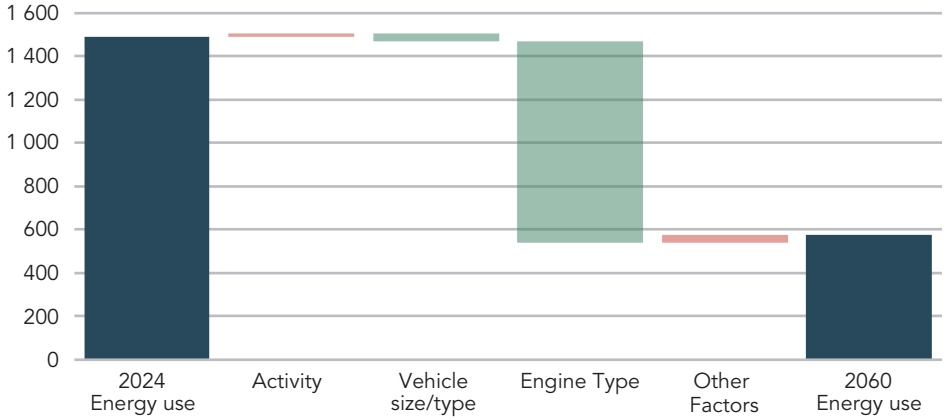


Figure 9-20. International bunker energy demand for shipping and aviation in REF & TGT (PJ)



- Market and technology shifts significantly influence Korea's transport decarbonisation pathway (Figure 9-19). In TGT, strong policy support enables BEVs to surpass internal combustion engine (ICE) vehicles by 2040. In contrast, ICE vehicles remain dominant in REF, where the uptake of low-emission vehicles including BEVs and PHEVs is more gradual.
- International bunker fuel demand increases in both scenarios (Figure 9-20). In REF, jet fuel remains prominent, and hydrocarbon fuels continue to be used for marine transport. Over the projection period, there is a shift to liquefied natural gas (LNG) and diesel, replacing fuel oil. In TGT, the fuel mix becomes more diverse, with significant growth in low-emissions alternative fuels, such as ammonia, biodiesel, and e-fuels by 2060, reflecting assumptions aligned with international transport decarbonisation targets.
- Figure 9-21 further illustrates the significant transition in engine types in Korea, particularly the adoption of BEVs, which leads to reduced energy use in TGT. Increases in bus use (captured in the Vehicle size/type component), also contributes to a slight decrease in energy use.

Figure 9-21. Components of the change in road energy use in TGT (PJ)



Note: Information on the different drivers in the transport energy decomposition can be found in the *Outlook*'s annex.

Electricity Generation

Figure 9-22. Electricity generation by fuel in REF (TWh)

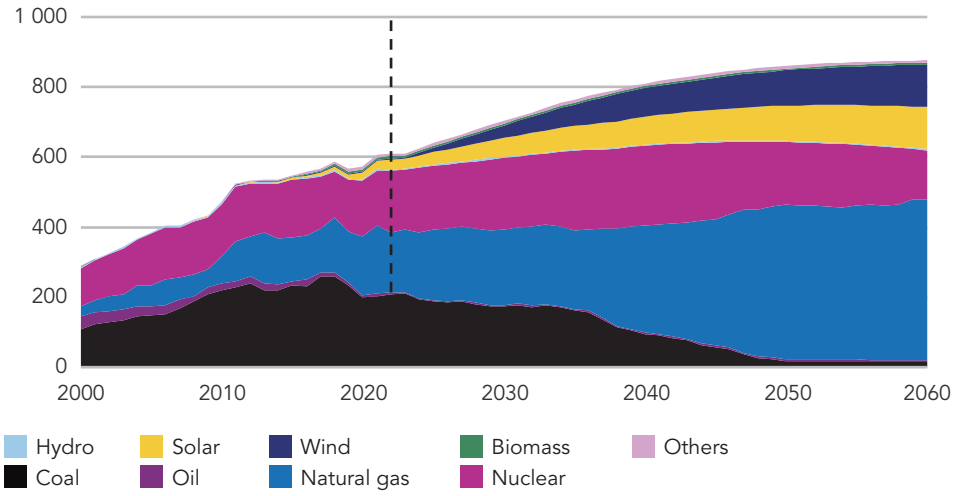
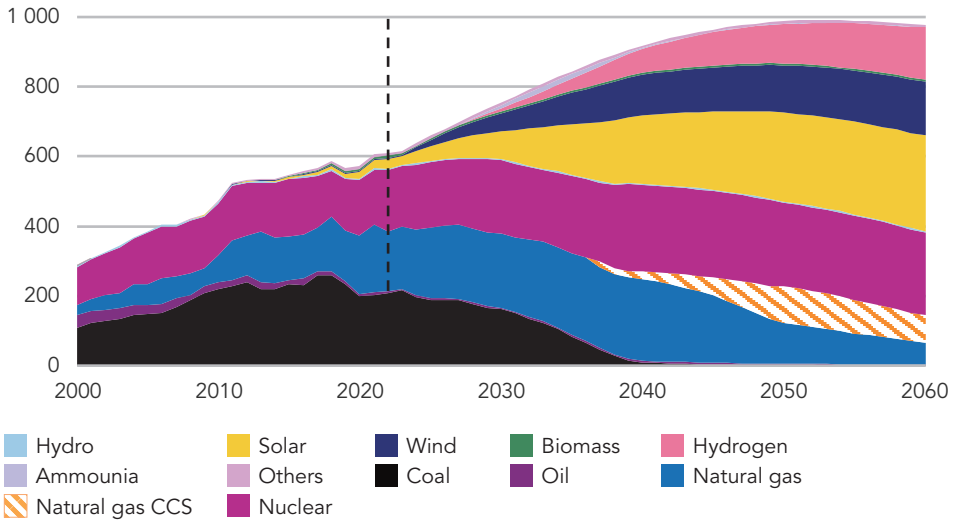


Figure 9-23. Electricity generation by fuel in TGT (TWh)



- Electricity demand in Korea rises substantially through 2060 in both scenarios, driven by widespread electrification across end-use sectors, including increased data centres demand. By 2060, electricity demand in TGT is projected to be approximately 11% higher than in REF.
- In REF, total generation grows from 610 TWh in 2022 to 880 TWh by 2060, marking a 1.5-fold increase. Variable renewable generation, primarily solar and wind, expands 2.7 times by 2030 and reaches a 28% share by 2060, reflecting greater integration into the grid.
- The share of nuclear power declines from 29% in 2022 to 16% in 2060 due to the retirement of ageing reactors and the absence of new additions. Coal-fired generation drops sharply from 31% to just 2%, driven by regulatory phaseouts and plant closures. To maintain system stability, LNG-fired generation is expected to play a growing role as a dispatchable source, rising from 28% in 2022 to 52% of the electricity mix by 2060.

- In TGT, electricity generation increases rapidly in response to strong demand growth, reaching 980 TWh by 2060, around 60% above 2022 levels. Since the projected electricity demand in the *Outlook* exceeds Korea's demand projections in Korea's *11th Basic Plan for Electricity Demand and Supply*, more ambitious assumptions for generation mix are incorporated into TGT.
- A greater share of low-emission sources is adopted to support the shift toward a decarbonised power sector. Wind and solar generation triples by 2030 from 2022 levels and expands further to reach 45% of the mix by 2060. Hydrogen-fired power begins in 2028 and expands to 15% by 2060, supported by strong policy measures and technological progress.
- Higher VRE penetration requires sufficient dispatchable generation for grid reliability. Nuclear output remains stable with lifespan extensions for existing reactors. LNG also serves as a key dispatchable source, and from the late 2030s, CCS-equipped LNG plants help reduce emissions.

Note: Figures 9-22 and 9-23 do not include electricity generation for hydrogen production.

Generation Capacity

Figure 9-24. Generation capacity by fuel in REF (GW)

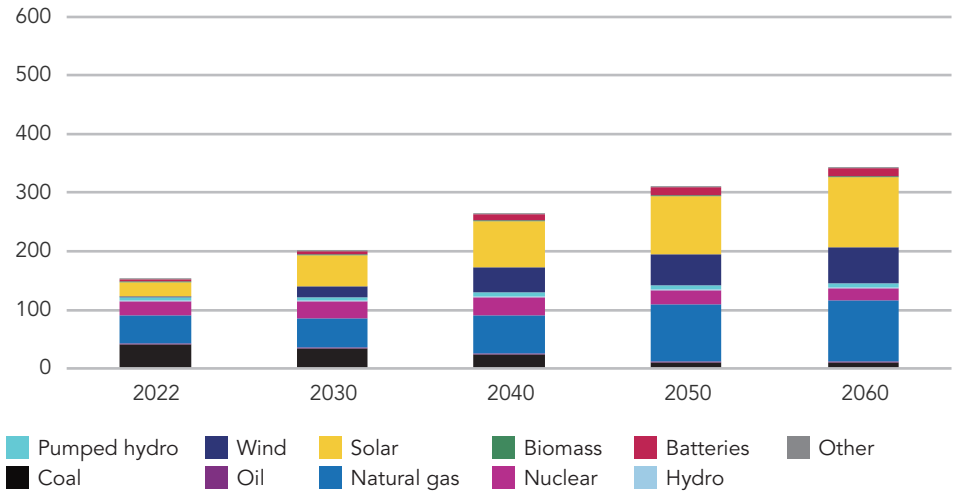
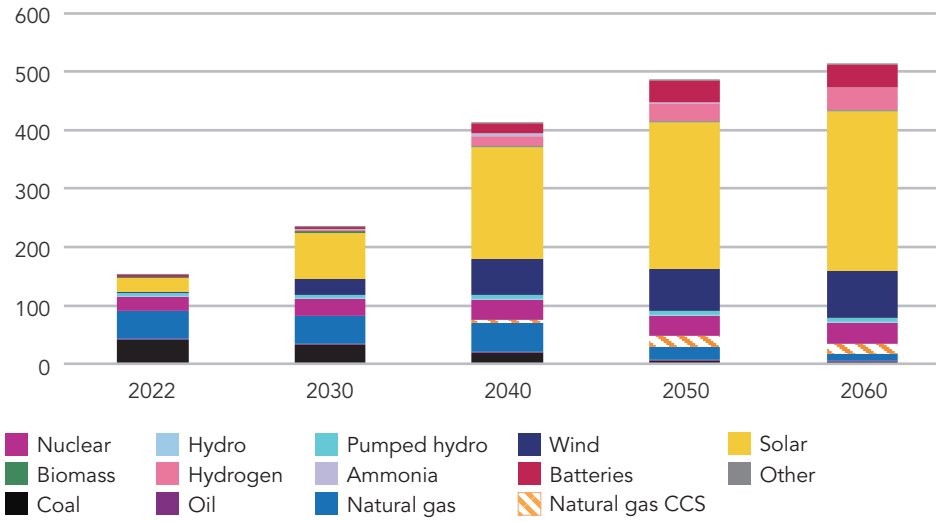


Figure 9-25. Generation capacity by fuel in TGT (GW)



- Korea's installed generation capacity rises substantially in both scenarios, alongside a major shift in the capacity mix. In REF, solar and wind capacity nearly triples from 25 GW in 2022 to 72 GW by 2030, with continued growth through 2060. This expansion increases the need for battery storage to ensure grid reliability amid higher shares of variable renewables.
- Nuclear capacity includes 30 reactors (26 existing, two under construction, and two planned), with no assumed extension beyond a 60-year lifespan. As older units retire, nuclear capacity declines from 25 GW (16% of total) in 2022 to 19 GW (6%) by 2060.
- Coal-fired capacity is almost entirely phased out by 2060, dropping to just 3% of capacity by 2060. To maintain system flexibility and offset the decline in coal and nuclear, gas-fired capacity more than doubles, reinforcing its role as a key dispatchable source.

- Compared to REF, Korea's generation capacity shifts more ambitiously in TGT to meet growing electricity demand. Renewable capacity quadruples by 2030, while the share of fossil fuel capacity falls sharply from 58% in 2022 to just 3% by 2060. To support grid reliability amid higher shares of variable renewables, battery storage expands from 4 GW in 2022 to 38 GW by 2060.
- LNG remains essential for peak load management, with CCS-equipped gas plants supporting emissions reductions. Hydrogen-fired capacity grows to 39 GW by 2060 under Korea's *Clean Hydrogen Portfolio Standard (CHPS)* launched in 2024, starting with natural gas co-firing.
- From the late 2030s, two new conventional reactors and one small modular reactor (SMR) are added, as outlined in *the 11th Basic Plan for Electricity*, enabling nuclear capacity to reach and sustain 35 GW from 2040, which supports rising electricity demand from electrification and data centres.

Note: Figures 9-24 and 9-25 do not include generation capacity for hydrogen production.

Grid Reliability

Figure 9-26. Total generation capacity and peak load (GW)

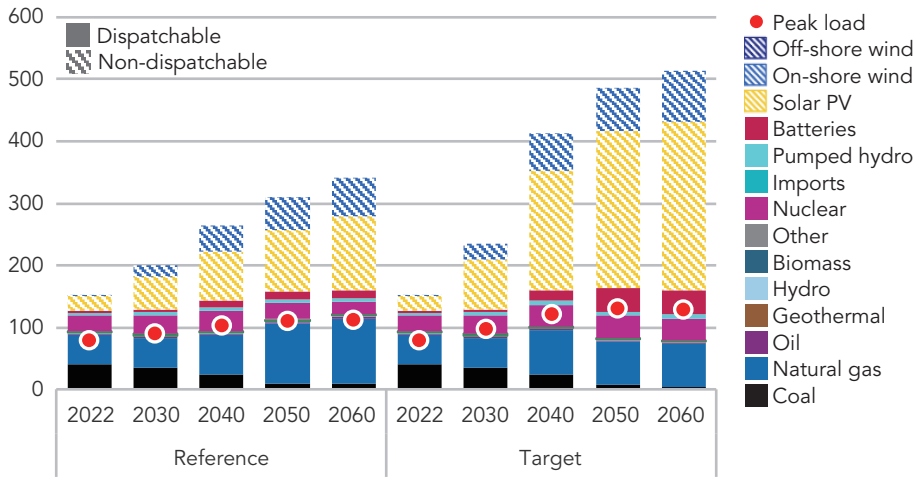
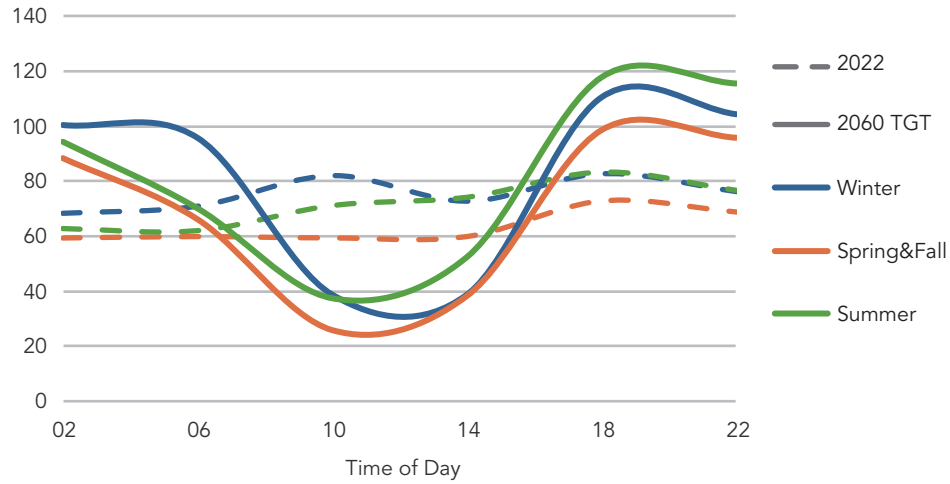


Figure 9-27. Power from dispatchable sources in TGT (GW)



- In REF, the peak electricity load grows by 44% from 78 GW in 2022 to 112 GW in 2060. In TGT, peak load grows by 65% to 129 GW by 2060 due to increased electrification in the Target Scenario.
- Due to the intermittency of solar and wind generation, which results in relatively lower load factors, total system generation capacity must grow faster than peak load to integrate these sources.
- In REF, total generation capacity grows by 122% from 154 GW in 2022 to 342 GW by 2060. In TGT, it needs to grow by 233% to 513 GW.
- Grid reliability requires that power systems have enough dispatchable generation capacity, including batteries, to meet peak load in those periods when wind and solar generation are at its lowest level.
- Increased reliance on wind and solar generation will increase the variability of the generation required from dispatchable power sources. Additionally, as wind and solar capacity increases, the load factor for dispatchable sources declines, which increases total system cost.
- In 2022, the contribution of dispatched sources to the system remained relatively constant throughout the day, with minor fluctuations during the daytime in Korea. By 2060, however, the variability of dispatched power increases substantially in TGT due to the higher share of renewables. As shown in Figure 9-27, generation from dispatched sources must ramp up and down as much as 80 GW between 10:00 am and 6:00 pm, on an average summer day. Similar fluctuations are observed in other seasons, reaching 72 GW in spring and fall, and 71 GW in winter.
- The actual variability will be different from this total since the variability will be spread across the entire economy, but it could also be larger since some individual days will experience greater variability than the seasonal averages.
- This variability will likely be a challenge for system operators across the economy and meeting this challenge will likely increase the capital, maintenance, and operating costs of the electric grids in Korea.

Coal and Biomass

Figure 9-28. Coal and biomass consumption by sector in REF & TGT (PJ)

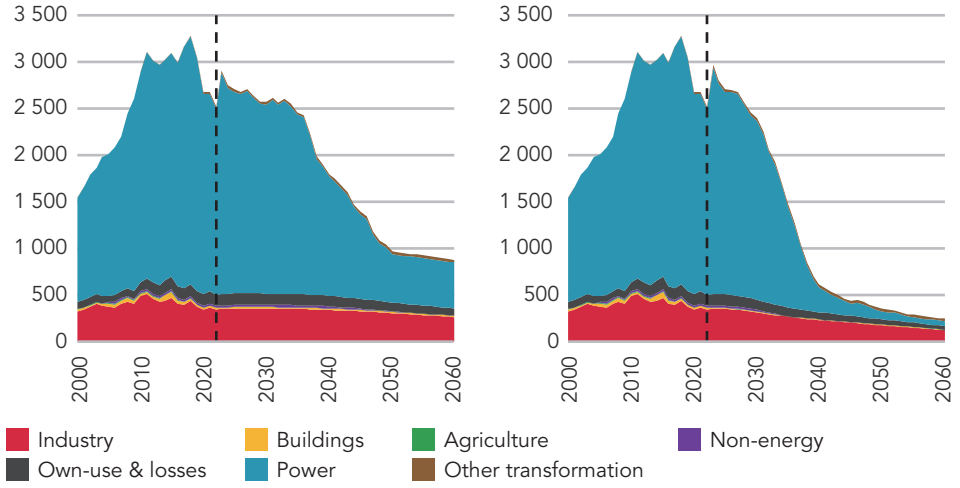
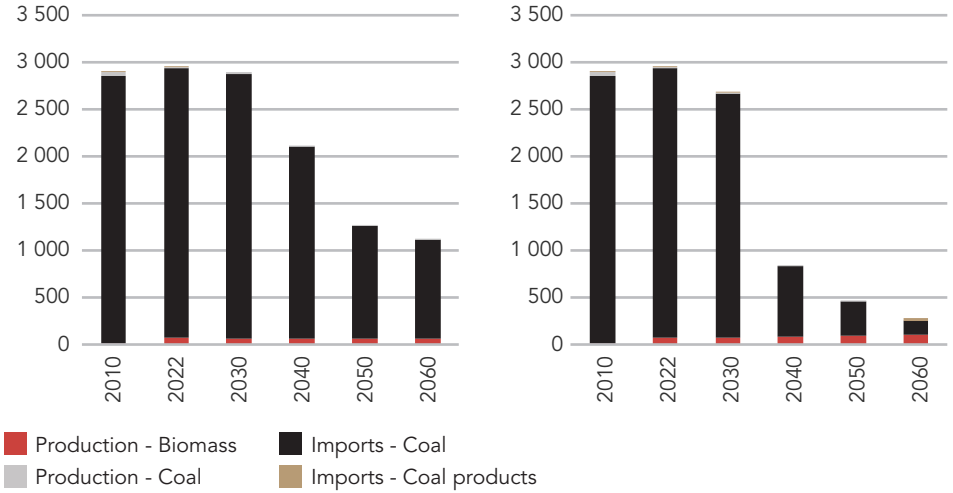


Figure 9-29. Coal and biomass production, imports, and exports in REF & TGT (PJ)



- Korea's coal consumption peaked in 2018 after two decades of rapid growth driven by thermal power. The power sector, accounting for 79% of coal use in 2022, is the main driver of reductions, as ageing plants are retired under government policy. In the REF scenario, coal use in power drops 77% by 2060, while it is nearly eliminated in TGT.
- Industrial coal use, the second-largest component, accounted for 14% of total consumption in 2022. Although coal remains essential in iron, steel, and cement industries, fuel switching leads to steady declines in both scenarios, with a sharper drop in TGT from 350 PJ in 2022 to 127 PJ by 2060.
- Solid biomass remains limited but is utilised in industry, buildings, agriculture and power sectors, partly contributing to decarbonisation efforts through co-firing and waste-to-energy.

- Korea's coal supply remains heavily reliant on imports, which comprises nearly all coal consumption in 2022. In the REF scenario, coal imports decline by 63%, from 2,855 PJ in 2022 to 1,052 PJ by 2060. In the TGT scenario, the drop is more significant, with imports falling to 153 PJ, reflecting the sharp reduction in coal use across sectors. This transition reduces Korea's dependence on imported coal, thereby enhancing its energy security.
- As solid biomass accounts for a small share of total supply, domestic production slightly increases in TGT, supporting efforts to diversify energy sources.

Note: Figure 9-28 excludes coal for transformation into coal products.

Natural Gas and Biogas

Figure 9-30. Natural gas and biogas consumption by sector in REF & TGT (PJ)

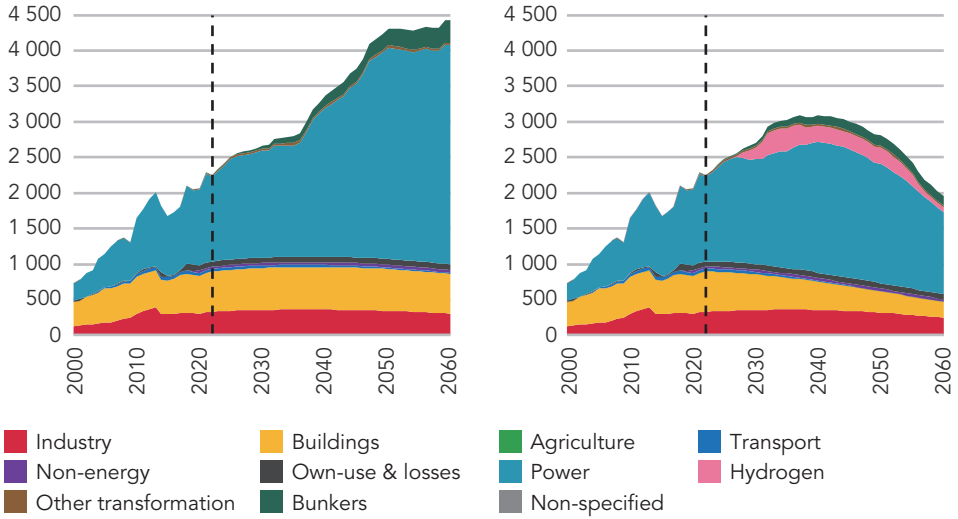
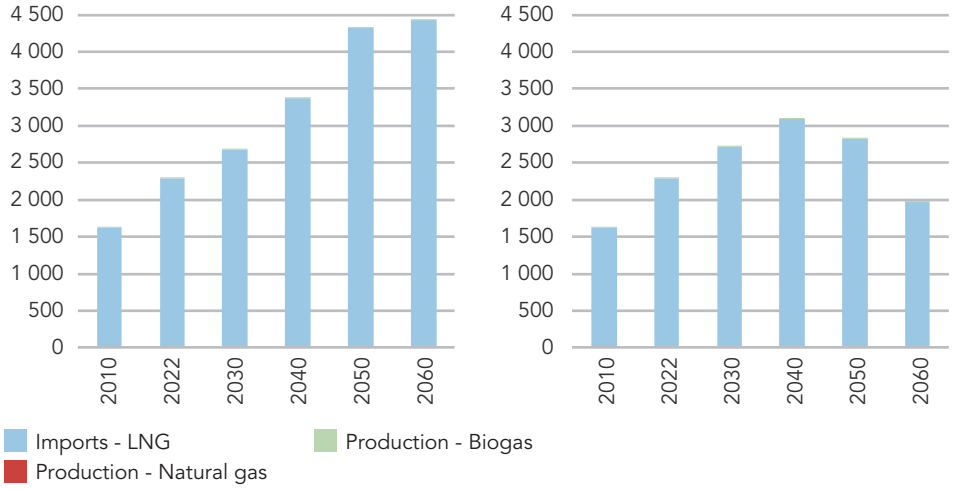


Figure 9-31. Natural gas and biogas production, imports, and exports in REF & TGT (PJ)



- Gas is expected to remain a major transitional fuel across Korea's economy, particularly in the power sector, which drives most of the growth in demand. In REF, total gas consumption nearly doubles from 2,254 PJ in 2022 to around 4,424 PJ by 2060.
- In REF, the power sector's share of gas use rises from 53% in 2022 to 70% by 2060, as gas plays a critical role in coal replacement and provides system flexibility. Gas demand in the industrial and building sectors remains relatively stable, while LNG-fueled ships contribute to bunker fuel demand, reaching 318 PJ by 2060.
- In TGT, gas demand peaks around 2040 and declines to 1,960 PJ by 2060, due to reduced LNG use in power generation, demographic decline, and efficiency gains. Hydrogen production emerges as a significant new demand source, accounting for 8% of total gas use by 2050. The share of biogas consumption remains minimal.
- Although natural gas consumption is projected to decline in TGT, LNG serves as a flexible and dispatchable source in the power sector, underscoring the importance of a stable LNG supply for energy security.
- Korea relies almost entirely on LNG imports to meet its gas demand, as outlined in its biennial *Long-term Plan for Natural Gas Supply and Demand*. To mitigate risks from market volatility, Korea enhances supply resilience through diversification of LNG import sources and the expansion of competitive long-term contracts. These efforts support system reliability, especially amid rising electrification.
- Biogas production contributes minimally to total supply due to limited domestic potential and economic viability, with no significant changes projected over the outlook period.

Note: Historical data for LNG is based on JODI gas data.

Petroleum Liquids

Figure 9-32. Crude oil, NGLs, and other hydrocarbon production, imports, and exports in REF & TGT (PJ)

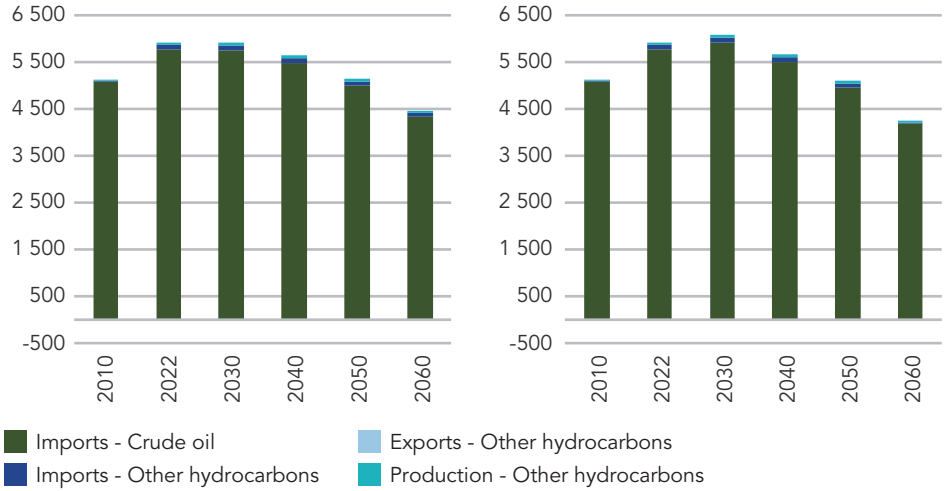
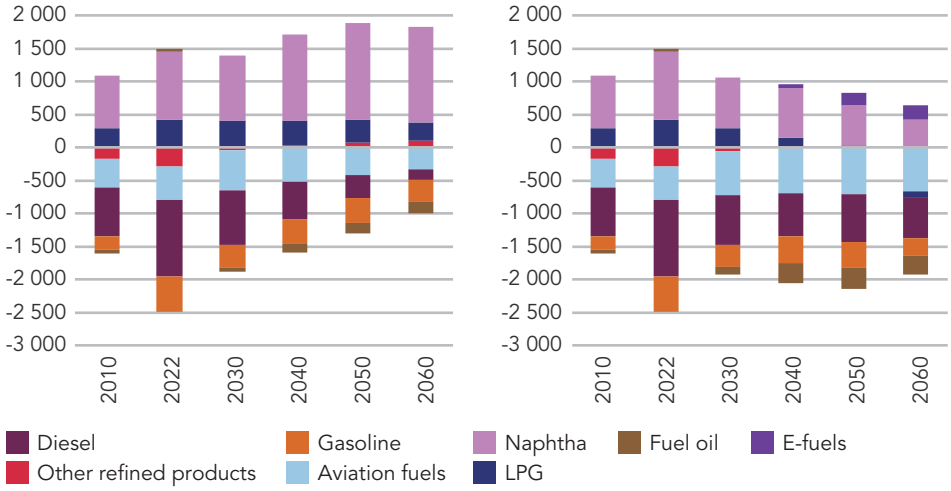


Figure 9-33. Net imports of refined products and low-carbon fuels in REF & TGT (PJ)



- Korea's supply of crude oil, NGLs, and other hydrocarbons remains almost entirely import-dependent. Total supply peaks at over 5,900 PJ around 2030 before declining by 2060 in both scenarios, reflecting reduced reliance on fossil fuel imports and strategies to diversify energy sources. Nevertheless, crude oil imports remain substantial to support Korea's large refining sector, which is increasingly integrated with the petrochemical industry and is shifting toward feedstock production, particularly naphtha and LPG.
- It is notable that historically around 20% of total refinery feedstock inputs (1,000 PJ) have been sourced from transfers (byproducts of petrochemical processing) since 2019. This internal recycling could reduce import dependence on crude and feedstocks, enhance process efficiency, and lower costs. The continued use of these byproducts as inputs is assumed, implying a structural shift in refining that improves energy security, and supports emissions reductions amid evolving global markets.
- Korea's refined product trade evolves as refining becomes increasingly geared toward petrochemical production. In REF, net imports of naphtha rise by 40% between 2022 and 2060 due to strong petrochemical feedstock demand. In TGT, however, naphtha imports decline with lower domestic consumption and improved efficiency. LPG imports fall by 34% in REF, but reach trade balance from 2050 in TGT, indicating greater self-sufficiency.
- Liquid biofuels, including biodiesels and biojet kerosene, are fully supplied domestically under Korea's *Renewable Fuel Standard (RFS)* in both scenarios. In TGT, e-fuel imports begin in the 2040s and grow to 217 PJ by 2060, supporting hard-to-abate sectors, such as bunkering.
- In REF, refined product exports gradually decline toward 2060 as refinery output falls in response to a sharper drop in ICE fuel demand. In TGT, by contrast, exports hold near 2,000 PJ due to a larger decline in domestic consumption, led by diesel, followed by aviation fuels and gasoline.

Note: In Figure 9-33, net imports are presented without deducting bunkers.

Refining

Figure 9-34. Refined products and low-carbon fuels outputs in REF & TGT (PJ)

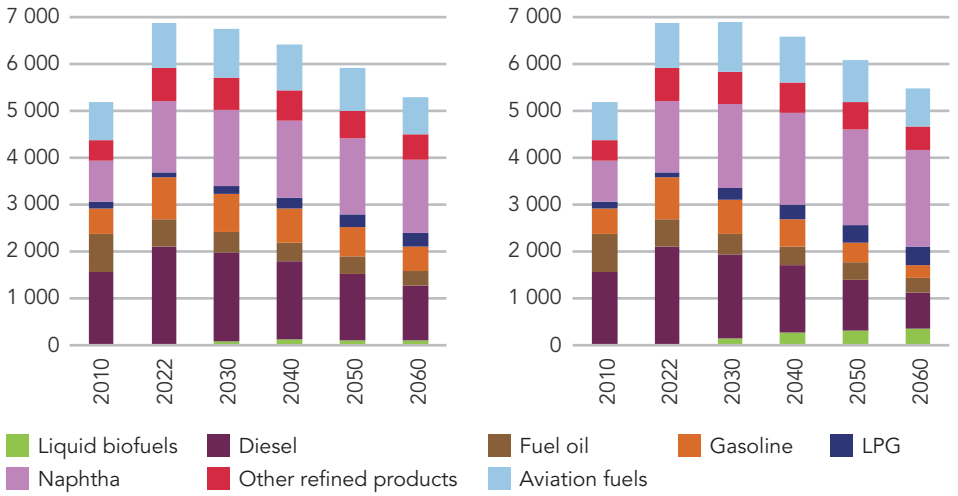
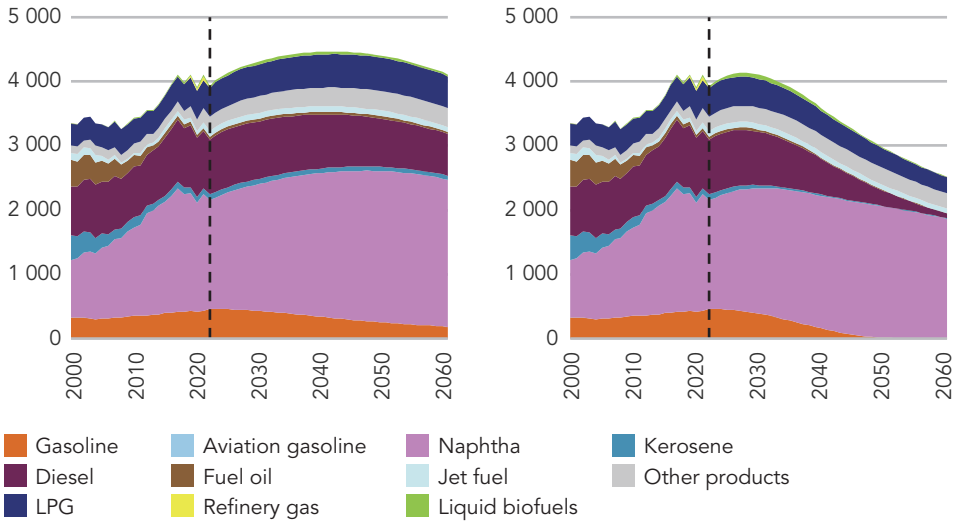


Figure 9-35. Refined products and low-carbon fuels demand in REF & TGT (PJ)



- Korea's refining output undergoes a structural shift toward petrochemical production. Diesel and gasoline outputs decline significantly, by 43% in REF and 66% in TGT by 2060, while aviation fuel sees a more moderate reduction of around 15% in both scenarios. LPG output increases in both scenarios, driven by its sustained use in industrial and non-energy applications, even as demand declines in other end-use sectors.
- Liquid biofuels gradually rise to 116 PJ in REF and 369 PJ in TGT by 2060, consistent with Korea's biodiesel blending mandates under the RFS.
- The most notable trend is the rising share of naphtha. In both REF and TGT, the naphtha output share is assumed to grow substantially by 2060, supported by crude-to-chemical upgrades and improved yields, reinforcing Korea's strategy for high-value petrochemical production and integration.

- Korea's refined product demand shows diverging trends, with declining transport fuel use contrasted by rising demand for petrochemical feedstocks. In REF, total demand peaks at around 4,500 PJ in the 2040s, while in TGT, it peaks earlier at approximately 4,000 PJ, followed by a more rapid decline.
- Gasoline and diesel demand drops sharply in both scenarios, driven by the accelerating electrification of the transport sector. In TGT, demand for both fuels are nearly phased out by 2060. In contrast, naphtha demand for petrochemical production rises until 2050, partially offsetting the decline in transport fuels.
- These shifts reflect Korea's structural transformation, requiring significant investment in higher integrations between refining and petrochemical processes. This approach aims to sustain competitiveness in high-value chemical products while maintaining efficiency in the refining sector amid declining transport fuel consumption.

Hydrogen-based Fuels in the Target Scenario

Figure 9-36. Hydrogen-based fuels production methods and supply [left]; Inputs for hydrogen production [right] (PJ)

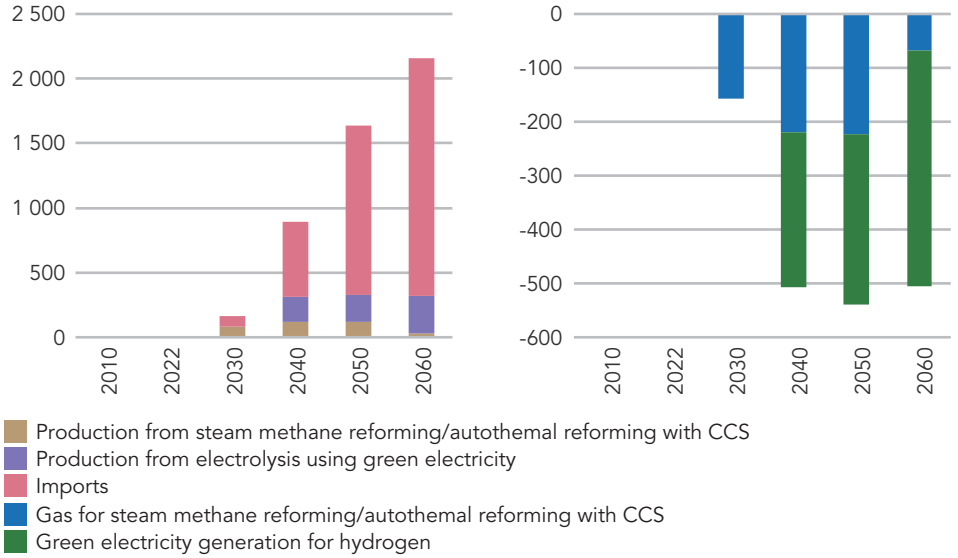
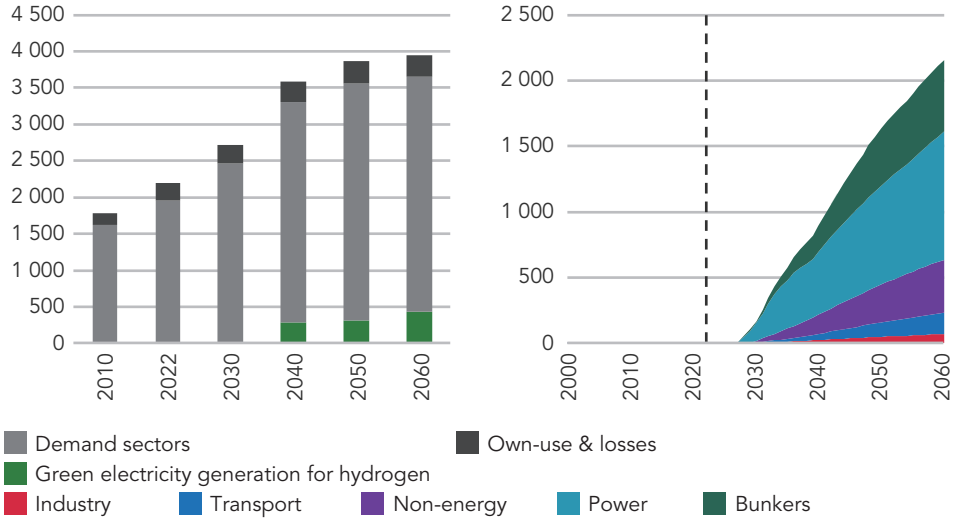


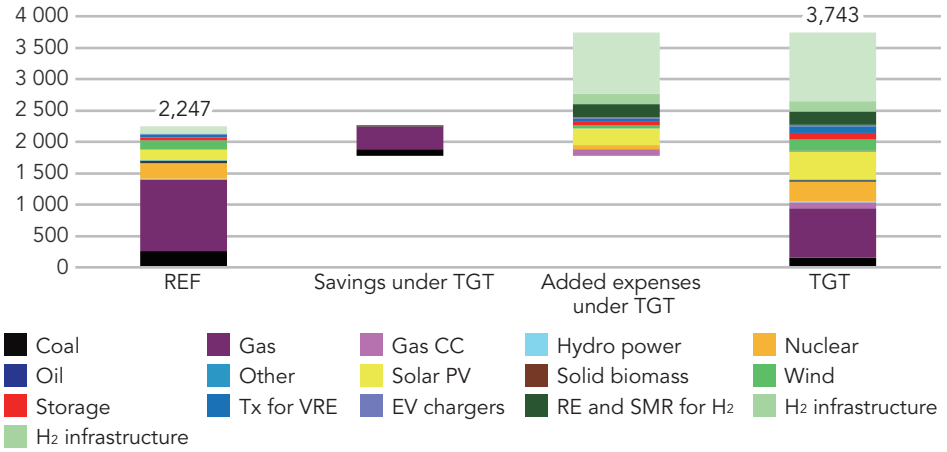
Figure 9-37. Electricity for electrolysis vs other sectors [left]; Hydrogen-based fuels demand by sector [right] (PJ)



- Hydrogen-based fuels in Korea (hydrogen, ammonia, and e-fuels) follow distinct supply pathways under both scenarios. In REF, low demand in early decades delays domestic production, with imports beginning after 2040 as they become cost-effective. In TGT, a more diversified supply mix emerges from the 2030s, combining imports with electrolysis and Steam Methane Reforming (SMR)-CCS (Figure 9-36 [left]). By 2060, imports remain dominant, accounting for over 80% of total hydrogen-based fuels supply, which aligns with Korea's hydrogen policy direction.
- Green hydrogen expands notably, reaching around 13% of supply by 2060, supported by low-emissions hydrogen policies and energy security goals. Input energy for hydrogen production increases accordingly, with green electricity generation for hydrogen gradually growing from the 2040s and becoming dominant by 2060 (Figure 9-36 [right]). This shift will rely on Korea's renewable deployment and decarbonisation efforts with low-carbon hydrogen.
- Green electricity generation for hydrogen (Figure 9-37 [left]) grows sharply after 2040, surpassing 430 PJ by 2060. This highlights the need for substantial renewable capacity expansion and grid upgrades to support large-scale hydrogen production while maintaining system stability.
- In TGT, excluding international bunker use, hydrogen-based fuel demand exceeds 1,600 PJ by 2060, over nine times higher than in REF, driven by increased adoption in power, transport, industry, and non-energy.
- This surge reflects Korea's strategies for hydrogen economy, guided by initiatives such as the *2019 Hydrogen Economy Roadmap* and the *2021 Basic Plan for Implementing the Hydrogen Economy*. Notably, Korea launched its first clean hydrogen power generation auction in 2024, advancing the integration of hydrogen and ammonia into the low-carbon power mix.

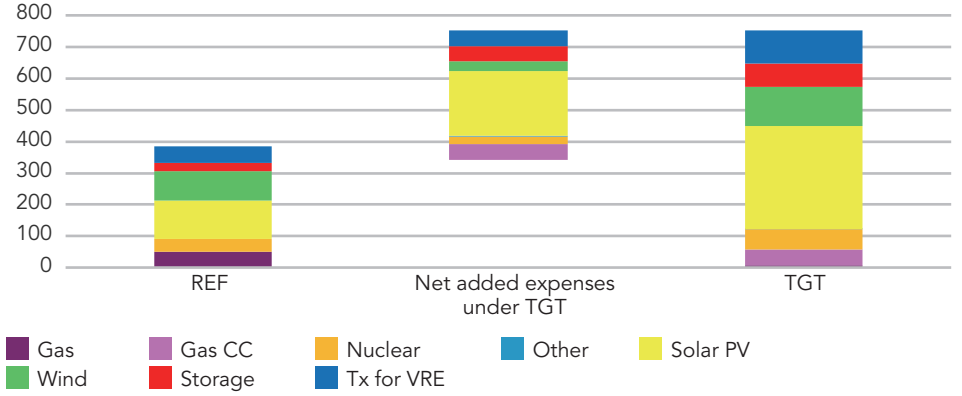
Costs

Figure 9-38. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



Note: Tx for VRE is only transmission infrastructure to connect variable renewable capacity to the grid. EV chargers do not cover the cost of associated infrastructure or EV vehicles. SMR is Steam Methane Reforming used to produce blue hydrogen.

Figure 9-39. Total capital investment (CAPEX) from 2025 to 2060 in the power sector (billion USD, undiscounted)

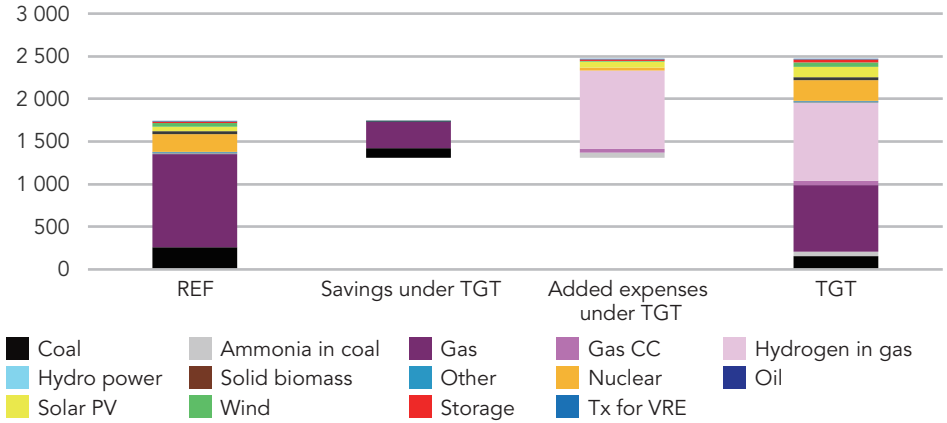


Note: Figure 9-39 only covers power and VRE transmission sector investments. Hydrogen and EV capital investments are not included.

- Meeting Korea's future energy needs and decarbonisation goals will require substantial expenditures. From 2025 to 2060, total costs increased markedly in both scenarios, including total capital, fixed, and variable costs in the power sector, low-carbon hydrogen imports and supply, heat produced from combined heating plants, VRE transmission, and EV chargers.
- In REF, total costs reach an estimated USD 2.25 trillion, primarily driven by operational expenditure for LNG-fired generation, and capital investment in renewables, nuclear, and VRE transmission infrastructure.
- In TGT, costs rise by 67% compared to REF, reaching an estimated USD 3.7 trillion. The cost of hydrogen importation and production for Korea's various sectors, such as power, industry, and transport, comprises 40% of total costs by 2060, alongside increased capital spending on nuclear, solar PV, and wind. Although fossil fuel expenditures decline slightly, these savings are offset by greater investment in low emissions technologies. Spending on hydrogen imports to meet international bunkering obligations is not included.
- Additional spending is required to maintain grid reliability, including battery storage and expanded transmission to support greater electrification and system flexibility. Total capital investment in the power sector exceeds USD 750 billion in TGT, 94% higher than in REF, driven by capacity additions in solar PV (56% of net added expenses), transmission (14%), gas carbon capture (CC) (14%), and storage (13%) to support variable renewable integration.
- Solar PV and transmission investment nearly double in TGT, reflecting greater infrastructure needs. *Korea's 11th Long-term Transmission Plan (2022-2036)* also emphasises major grid upgrades, including HVDC lines to connect renewable-rich areas with major load regions.
- Gas CC and nuclear investment rise moderately to ensure sufficient dispatchable capacity and support low-emission transitions. These trends highlight the importance of timely and targeted investment to maintain system reliability while advancing a cost-effective energy transition.

Costs

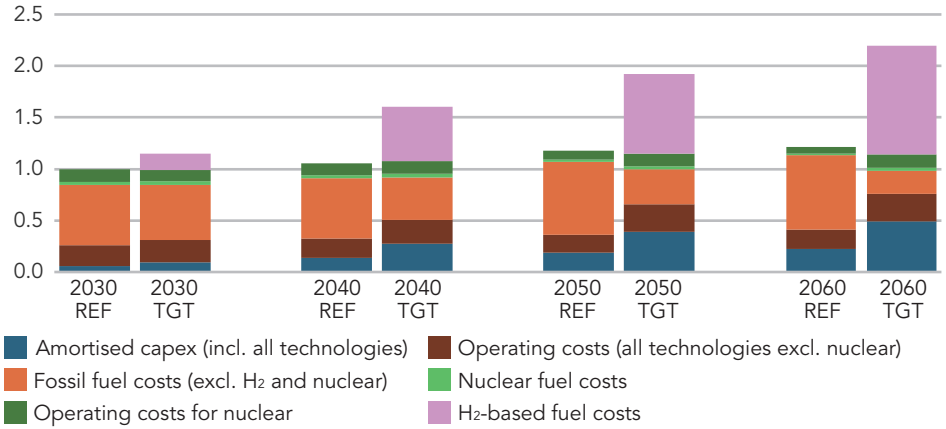
Figure 9-40. Total operating costs from 2025 to 2060 in the power sector (billion USD, undiscounted)



Note: Figure 9-40 only covers power and VRE transmission sector costs. It does not include operating costs associated with hydrogen use and EV charger costs but does include the cost of H_2/ammonia blending in power generation.

- Korea's total operating costs for the power sector are projected to be an estimated USD 2.5 trillion in TGT, compared to USD 1.7 trillion in REF. The majority of these costs stem from variable fuel expenditures, with low-carbon hydrogen fuel blending costs being the largest cost driver in TGT due to its growing role in the energy transition.
- Operating costs significantly increase in TGT with the adoption of low-emission technologies, particularly from hydrogen co-firing in gas turbines, as promoted under Korea's *Clean Hydrogen Energy Portfolio Standard (CHPS)*.
- These projections highlight the economic challenges of decarbonising the power sector. Securing cost-efficient low-carbon hydrogen supply will be essential to managing long-term costs in Korea's pathway for the clean energy transition. Future market price volatility for low-carbon hydrogen will remain a major uncertainty influencing overall fuel expenditures.

Figure 9-41. Cost of generating electricity relative to 2025 (2025 cost = 1.0) in the power sector



Note: Based on our assumptions about future capital and operating costs, Figure 9-41 shows cost compositions over time relative to 2025. It should not be considered an estimate of electricity tariffs and excludes market mechanisms that are too difficult to estimate.

- Figure 9-41 shows electricity generation costs for selected years, indexed to 2025 levels. These figures represent generation costs only and do not reflect retail electricity prices. Amortised capital expenditures (CAPEX) increase their cost shares in both scenarios due to ongoing investments in generation and grid infrastructure, especially in TGT, whilst fossil fuel costs decrease in their share as overall usage declines in line with reduced fossil fuel usage.
- In REF, generation costs remain relatively stable through 2060, reflecting a steady fossil fuel mix and limited changes in capital or variable costs.
- In TGT, generation costs reach 220% of 2025 levels by 2060. This reflects deeper decarbonisation, driven primarily by large-scale low-carbon hydrogen deployment in gas co-firing, adoption of higher-cost technologies like CC-equipped gas, and greater renewables investment, all of which involve higher capital and operational costs. Nuclear fuel and operational costs grow moderately but remain relatively stable, offering potential long-term cost advantages.

CO_2 Emissions

Figure 9-42. CO_2 emissions in REF (million tonnes)

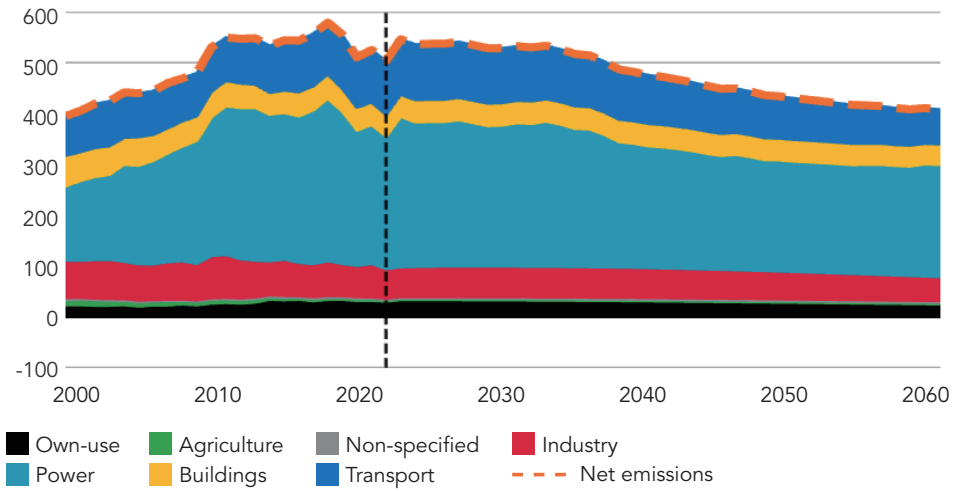
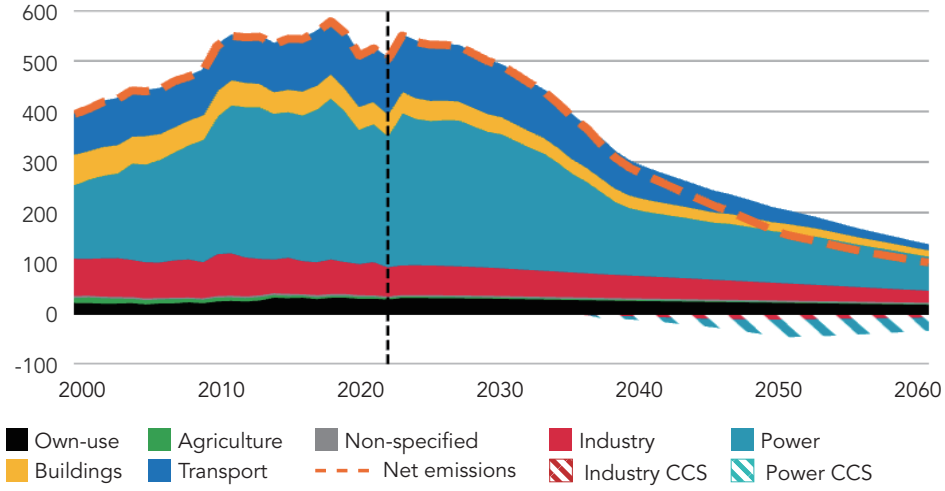
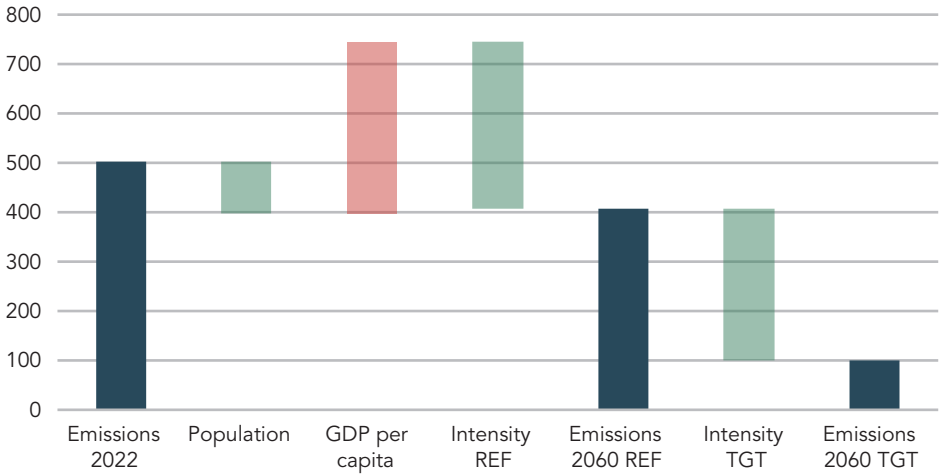


Figure 9-43. CO_2 emissions in TGT (million tonnes)



- Gross CO_2 emissions are projected to decline through 2060 in both scenarios. In REF, reductions are insufficient to meet Korea's 2030 NDC, mainly due to growing electricity demand and limited gains in efficiency (Figure 9-42).
- In contrast, emissions fall to around 100 Mt by 2060 in TGT (Figure 9-43). Further emissions abatement may be possible through technology advancements, closing the gap toward full carbon neutrality. Key drivers for emissions reductions include fuel switching, electrification, and efficiency improvements across all demand sectors. The power sector plays a critical role, with faster deployment of renewables, nuclear, and hydrogen contributing significantly. Some of the remaining emissions from LNG-fired generation could be mitigated by CCS deployment.
- As shown in Figure 9-44, changes in emissions between 2022 and 2060 are primarily influenced by improvements in energy and carbon intensity, which help offset growth from economic expansion. Continued progress in clean technology adoption and stronger policy enforcement will be essential to realising Korea's long-term decarbonisation goals.

Figure 9-44. CO_2 emissions components (million tonnes)



Note: All values represent energy sector combustion CO_2 emissions. Biogenic CO_2 is treated as zero at the point of combustion.

Useful Links

APEC Expert Group on Energy Data and Analysis (EGEDA) – https://www.egeda.ewg.apec.org/

APEC Energy Statistics 2022 – https://www.egeda.ewg.apec.org/egeda/general/info/pdf/APEC_Energy_Statistics_2022.pdf

APEC Energy Overview – https://aperc.or.jp/reports/energy_overview.php

Ministry of Climate, Energy and Environment – https://www.mcee.go.kr/home/web/main.do

Ministry of Trade, Industry and Resources – https://www.motir.go.kr/

Presidential Commission on Carbon Neutrality and Green Growth – https://www.2050cnc.go.kr/base/main/view

Statistics Korea – http://kostat.go.kr/portal/eng/index.action

Korea Electric Power Corporation – https://home.kepco.co.kr/kepco/main.do

Korea Energy Agency – www.energy.or.kr/web/kem_home_new/new_main.asp

Korea Energy Economics Institute – www.keei.re.kr/main.nsf/index.html

Korea Energy Information Culture Agency – https://www.e-policy.or.kr/web/index.do

Korea Energy Statistical Information System – https://www.kesis.net/main/main.jsp

Korea Gas Corporation – https://www.kogas.or.kr:9450/portal/index.do

Korea Hydro and Nuclear Power – https://www.khnp.co.kr/eng/index.do

Korea National Oil Corporation – https://www.knoc.co.kr/



10. Malaysia

Summary

	Reference			Target		
	2022	2060	% Change	2022	2060	% Change
Macroeconomic						
Population (million)	33.8	42	24%	33.8	42	24%
GDP (billion 2017 USD, PPP)	932	2,863	207%	932	2,863	207%
Energy Demand						
Agriculture & fisheries (PJ)	50	71	43%	50	31	-37%
Buildings (PJ)	357	1,028	188%	357	787	120%
Industry (PJ)	803	1,862	132%	803	1,586	98%
Non-energy (PJ)	300	1,106	269%	300	1,013	238%
Transport (PJ)	958	1,225	28%	958	798	-17%
Modern renewables share of TFEC (%)	8	8	0%	8	30	275%
Energy intensity of TFEC (PJ/GDP, billion USD)	2.3	1.5	-35%	2.3	1.1	-52%
Electricity						
Generation (TWh)	192	645	236%	192	622	224%
Renewables share of generation (%)	20	10	-50%	20	31	55%
Generation capacity (GW)	42	119	180%	42	196	363%
Total Primary Energy Supply (TPES)						
Coal & coal products (PJ)	921	330	-64%	921	0	-100%
Natural gas (PJ)	1,919	6,679	248%	1,919	5,291	176%
Petroleum liquids (PJ)	1,286	1,623	26%	1,286	586	-54%
Low-carbon & waste energy (PJ)	202	482	139%	202	2,018	901%
CO_2 intensity of energy supply ($MtCO_2/PJ$)	0.052	0.048	-8%	0.052	0.035	-33%
Net CO_2 Emissions (million tonnes)	226	442	95%	226	274	21%

Note: In this publication, the term "modern renewables" refers to all renewable energy sources excluding solid biomass in the buildings sector. The term "low-carbon & waste energy" includes all bioenergy, waste-derived energy, renewables, nuclear, and hydrogen-based fuels. Total primary energy supply (TPES) numbers include international bunkers. Net emissions are calculated as gross energy sector combustion CO_2 minus CO_2 captured and stored through carbon capture and storage (CCS).

Key Takeaways

Emissions

- In the Reference scenario (REF), emissions increase steadily, reflecting Malaysia's expanding population and economic activities, continued reliance on fossil fuels (particularly unabated coal and gas in power generation), and slow decarbonisation progress in the transport and industry sectors.
- In contrast, the Target scenario (TGT) demonstrates a clear commitment to emissions mitigation. An initial increase in emissions is observed up to approximately 2030, and then projected to stabilise and decline significantly lower than the REF scenario, to around 270-280 Mt through to 2060.
- Electrification (in the transportation and building sectors) is key to emissions cuts in TGT. Malaysia's power sector remains heavily reliant on unabated natural gas, a key energy source under Malaysia's current and future energy mix, limiting decarbonisation progress.
- Achieving Malaysia's 2030 NDC and 2050 net-zero goals is possible by prioritising more renewable energy deployment and grid modernisation.

Energy Import Dependence

- Malaysia will be a net energy importer by 2030, resulting in energy security remaining a key concern. Based on the *Outlook's* projection of increased import dependency, Malaysia likely faces higher exposure to international energy price volatility and supply disruptions, especially in REF, where petroleum and natural gas imports rise substantially by 2060.
- In TGT, Malaysia faces the dual challenges of managing its fossil fuel import reliance while transitioning to lower emissions energy sources. While the REF scenario projects continued growth in fossil fuel imports, TGT envisions a more balanced energy mix, incorporating renewables, biofuels, hydrogen, and increased electrification.
- Coal and coal products imports decrease over the projection period, which results from prioritising reducing emissions in the power sector, the largest consumer of coal. The government plans to gradually decommission coal-fired power plants, replacing them with renewables alongside grid modernisation.

Figure 10-1. Net CO_2 emissions (million tonnes)

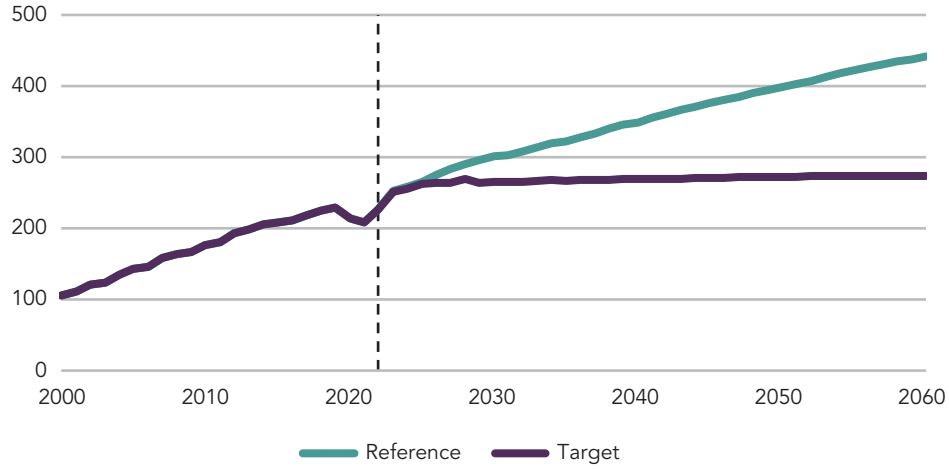
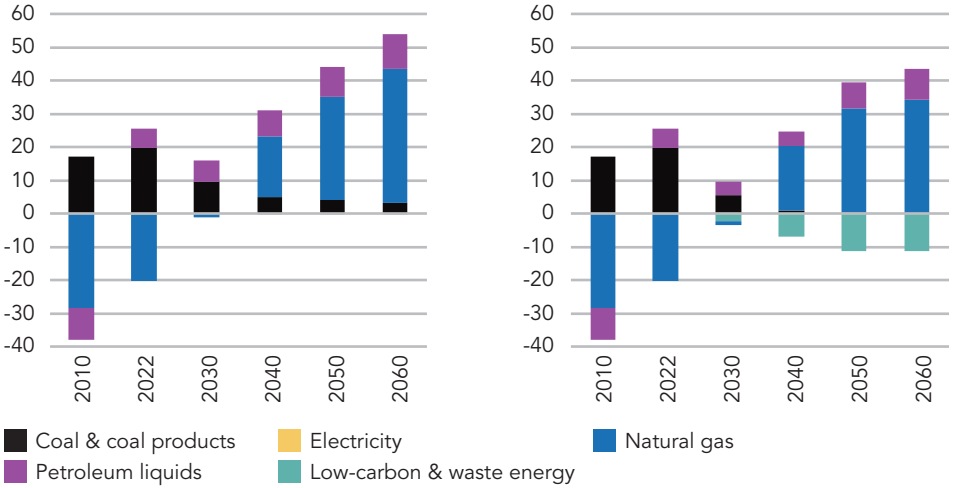


Figure 10-2. Net imports share of TPES in REF & TGT (%)



Note: In Figure 10-2, net imports refer to total imports minus exports and international bunkers.

Key Takeaways

Grid Reliability

- Malaysia's electricity mix is gradually diversifying, with increasing contributions from renewables, particularly solar and hydropower. However, the intermittent nature of variable renewable energy (VRE) sources poses challenges in maintaining a stable power supply, especially during peak demand periods.
- Malaysia's grid currently relies on a combination of gas-fired generation, coal, and hydropower to meet baseload and peak demand. Gas remains a key flexible source, maintaining a high-capacity factor, while coal is expected to decline in alignment with Malaysia's decarbonisation targets.
- In TGT, by 2050, the gap between minimum and maximum dispatchable power widens, indicating a need for more flexible generation and demand-response. Malaysia may need to consider grid modernisation, pumped hydro, and large scale batteries, and also ASEAN grid integration.

Cost

- Major estimated costs for Malaysia's power and hydrogen sectors for each scenario through to 2060 are shown in Figure 10-4. In TGT scenario, total costs are estimated to be USD 851 billion, USD 144 billion higher than in REF. Costs considered include total capital, fixed, and variable costs in the power sector, costs for blue/green hydrogen production, transmission for VRE, and electric vehicle chargers.
- In both scenarios, fuel costs (mainly gas) are the cost drivers. TGT's higher cost stems from additional solar PV and renewables needed for hydrogen production. This aligns with the energy transition financing needs identified in the National Energy Transition Roadmap (NETR), with the government introducing a National Energy Transition Facility (NETF) to unlock additional capital.
- Malaysia's energy costs mirror regional trends, but its unique assets (hydro resources and LNG infrastructure) offer pathways to moderate expenses. Strategic retrofitting, regional integration, and hydrogen adoption are key in balancing ambition with affordability.

Figure 10-3. Peak load and maximum and minimum dependence on dispatched power (GW)

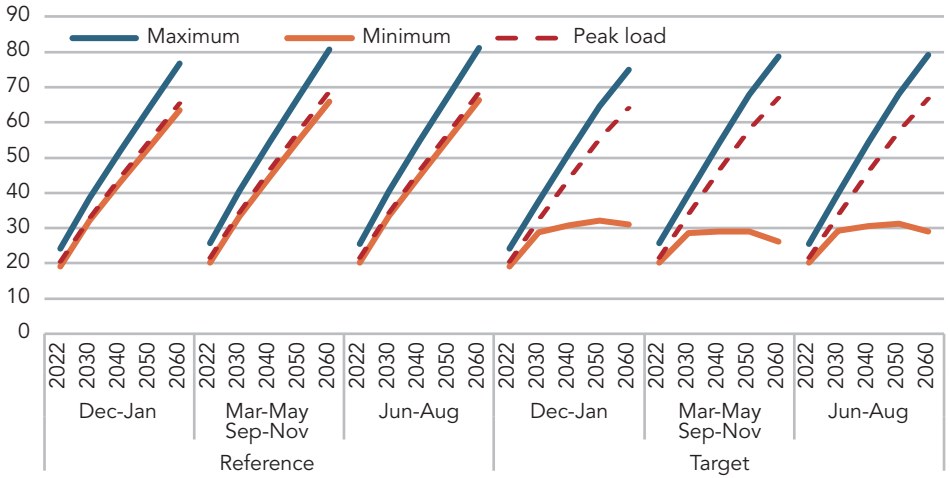
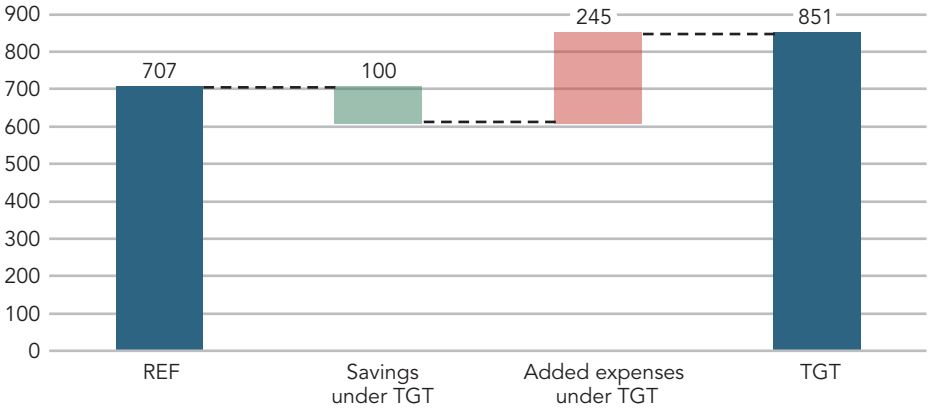


Figure 10-4. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



*Actual costs will differ from estimated costs in the *Outlook* for a variety of reasons including changing commodity prices, manufacturing costs, and unforeseen technical advances. All costs are in 2023 real terms.

About Malaysia

Overview

Geographical and Economic Landscape

Malaysia is a Southeast Asian economy comprising of Peninsular Malaysia and East Malaysia on Borneo Island, with a total territory of approximately 330,441 square kilometers. Malaysia is a multi-ethnic economy, with Malay and Bumiputera contributing 70% of the population, Chinese at 22%, Indians at 7%, and other ethnicities at 1%. Malaysia aims to achieve high-income nation status between 2027 and 2029 based on the 13th Malaysia Plan (13MP).

Energy Supply and Consumption

Increasing economic activity and population growth led Malaysia's total energy consumption to steadily increase 125% from 2000 to 2022, with the transport and industry sectors accounting for the largest shares at 40% and 32%, respectively. Fossil fuels, such as coal, oil, and natural gas, have historically dominated Malaysia's energy sector and Malaysia is projected to continue to rely heavily on natural gas throughout the *Outlook* period. While coal, oil, and gas continue to dominate the energy supply, renewable energy's share has increased since 2022.

Malaysia's energy demand increases more than double in both the REF and TGT scenarios, subsequently causing a significant increase in electricity demand. Between 2022 and 2060, electricity generation more than doubled, from 192 TWh to 645 TWh in REF and 622 TWh in TGT. As Malaysia has set forth a comprehensive plan to phase out coal-fired power plants by 2040, coal-fired power generation is expected to decline significantly and will be replace by natural gas as transition fuel. Renewable energy (RE) expansion also plays a central role in Malaysia's long term energy transition strategy.

Energy Security Challenges and Strategies

Fossil fuels have historically dominated Malaysia's energy sector. Malaysia has released the National Energy Transition Roadmap (NETR), which outlines a comprehensive approach to achieve net-zero greenhouse gas emissions by 2050, while ensuring energy security mainly through the diversification of energy sources, infrastructure development and grid modernisation, and regional energy cooperation.

Key Energy Initiatives

Paris Agreement Commitment

Malaysia intends to unconditionally reduce its greenhouse gas (GHG) emissions intensity against GDP by 45% by 2030, relative to its 2005 levels.

Energy Efficiency and Conservation Act (EECA)

Effective from 1 January 2025, EECA is targeted to enhance energy efficiency and conservation across various sectors in peninsular Malaysia by providing a robust legislative framework.

Cross Border Renewable Energy (RE) Trading

Malaysia launched the Energy Exchange Malaysia (ENEGEM) in April 2024 to enable cross-border RE trading, particularly within Association of Southeast Asian Nations (ASEAN) economies.

Renewable Energy Development

Guided by two key policy frameworks, the Malaysia Renewable Energy Roadmap (MyRER) and the NETR, Malaysia targets to have 31% RE share in the domestic installed capacity mix by 2025, 40% by 2035, and 70% by 2050.

Hydrogen Economy and Technology Roadmap (HETR)

A comprehensive plan to develop Malaysia's hydrogen sector with the key objective of integrating hydrogen into Malaysia's energy mix through development of robust hydrogen supply chain and technological innovation.

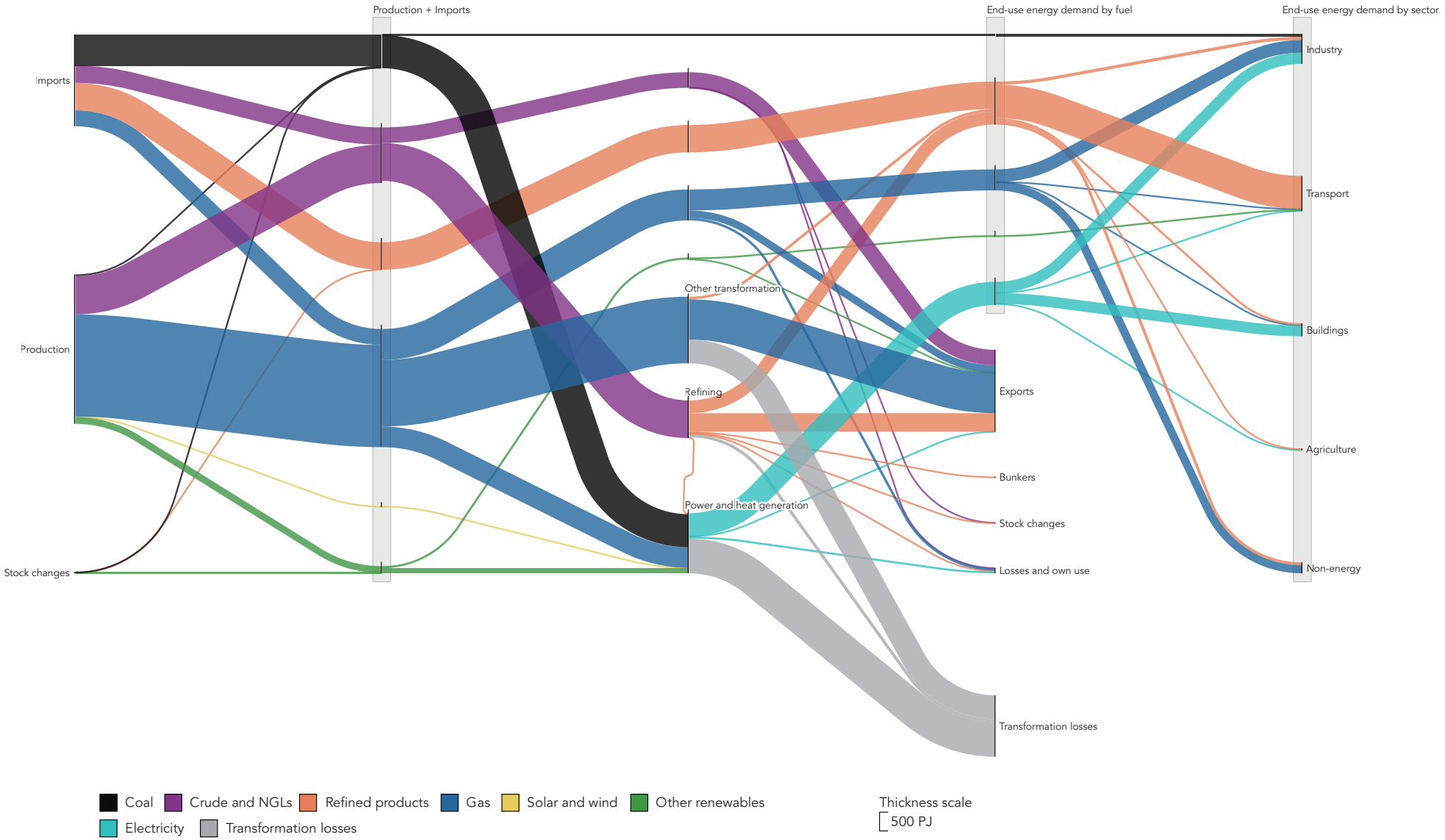
Electric Vehicle (EV) Development

Proton, Malaysia's leading automaker, launched its first electric vehicle, the e.MAS 7, in December 2024, while Malaysia's second car manufacturer, Perodua, is targeted to launch the eMO-11 electric vehicle by the end of 2025.

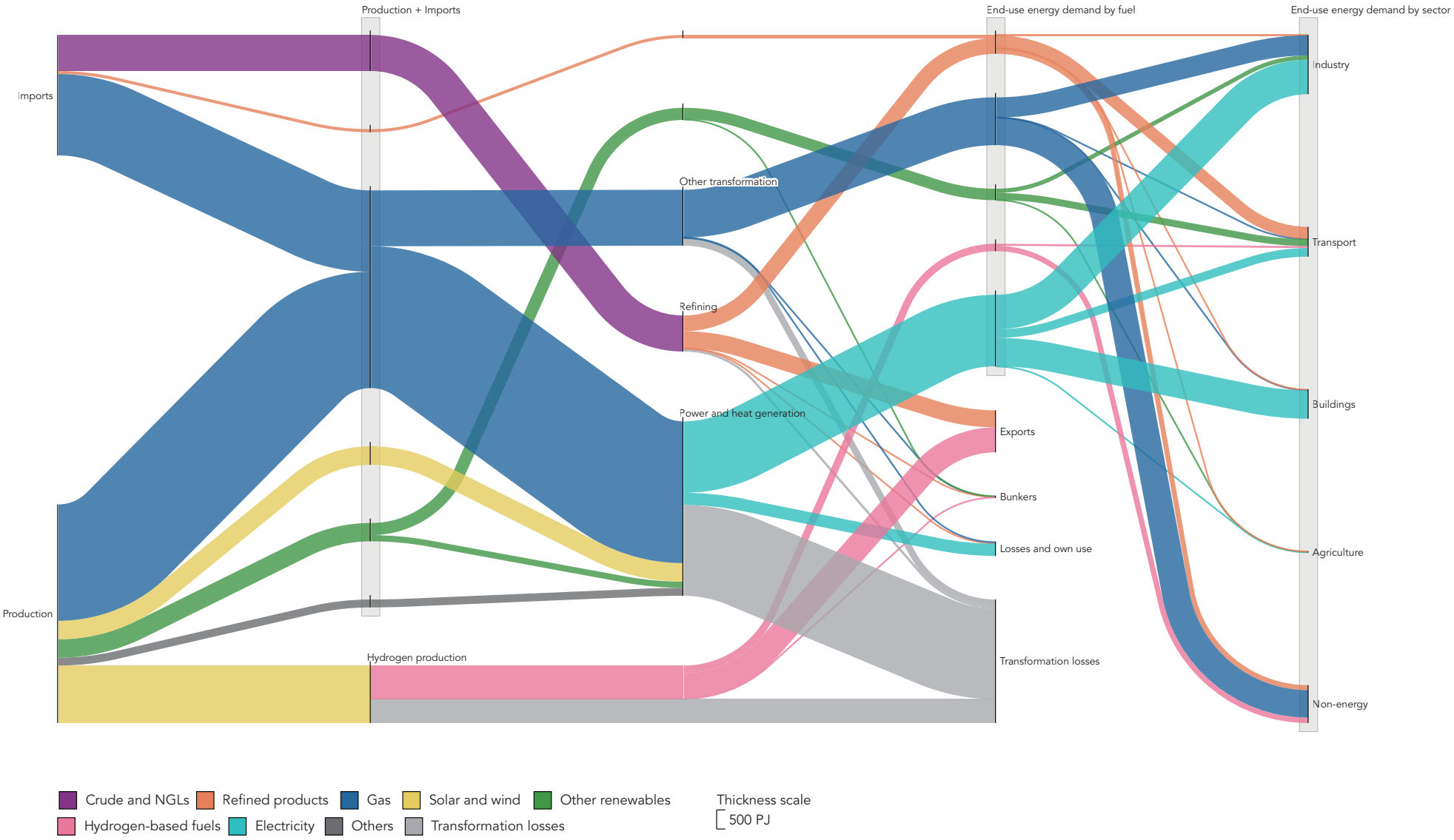
Climate Change Act

A public consultation was conducted in late 2024 to gather feedback on the draft bill, which is expected to be finalised and tabled in Parliament between 2025 and 2026.

Energy Flow (2022)



Energy Flow (2060, Target Scenario)



Scenarios and Assumptions

In *The Outlook*, APERC analyses energy demand, transformation, and supply, as well as emissions. The **Reference Scenario (REF)** offers a projection based on historical trends, recent developments, and APERC's assumptions about the continuation of those trends in each APEC economy, while acknowledging technical restraints. The REF Scenario offers a baseline to compare with the **Target Scenario (TGT)** projections, which explores a hypothetical pathway where each economy achieves energy-related policy targets, assuming implementation regardless of cost-effectiveness. When implementation details are lacking, assumptions are inferred from the targets themselves or emissions-related goals.

	Reference	Target
General	• Population: UN medium; GDP: APERC model and IMF	• Population: UN medium; GDP: APERC model and IMF
Buildings	• Energy Efficiency Conservation Act (EECA). • AI data centres substantially expand under both the REF and TGT scenarios.	• Stringent energy efficiency standards, greater EE measures in residential and services premises, approximately 10% by 2040, 20% by 2050. • More fuel-switching from LPG to electricity for cooking and water heating.
Industry	• The challenge for Malaysia is that all industry energy consumption is recorded as non-specified. • Biodiesel and biomass are incorporated into the fuel mix to supplant regular diesel and replace some fossil fuels. • Electrification is modest in REF.	• Greater efficiency (material and energy efficiency). • More biomass and biodiesel are incorporated in TGT, but the shares are prevented from rising higher than in REF due to greater electrification.
Transport	• 20% public transport modal share from 2022 onwards. • EV sales shares grow at a modest rate (e.g., 45% BEV sales share for passenger vehicles by 2060). • In both scenarios, passenger activity growth is regulated by slowing growth in vehicle ownership.	• 60% modal share of public transport by 2050. • EV sales shares grow at a rapid rate (e.g., 66% BEV sales share for passenger vehicles by 2035). • Biojet blending rises to 50% by 2050. Biodiesel rises to 30% by 2040.
Power	• Rapid decline of generation from coal-fired units. • Gradual increase in the capacity of gas-fired units and RE in REF and TGT. • No CCS, hydrogen, and nuclear development in both scenarios. • Only two renewable energies are viable for Malaysia: hydro and solar. Their capacity factors are 50% for hydro and 17.1% for solar. • No battery installation.	• Rapid decline of generation from coal-fired units and complete phase-out by 2045. • Gradual increase in the capacity of gas-fired units. • Only two renewable energies are viable for Malaysia: hydro and solar. Their capacity factors are 50% for hydro and 17.1% for solar. • With the given assumptions for solar capacity, batteries are not needed. • Carbon Capture and Storage (CCS) will be applied if necessary. • No long-term storage. • No hydrogen. • No nuclear development.

	Reference	Target
Supply and Refining	• Coal imports continue to satisfy domestic demand. • Gas demand will rapidly increase, mainly due to the power sector, making Malaysia a net importer. • Total refining capacity in REF is assumed to be 955 kb/d (2,130 PJ) throughout the projection, as there is no announced new refinery or capacity addition project. • Refinery utilisation ratios are assumed to increase from 60% in 2022 (based on EI) and reach 80% by the early 2030s to achieve economic viability. • Average refinery production yield ratios refer to the five-year average: 24.2% gasoline, 39.1% diesel, 12.6% jet fuel, 6.8% fuel oil, and 3.5% LPG. • Naphtha output was not reported.	• Coal demand falls faster due to higher fuel switching. • New gas reserves to be developed; however, these are still insufficient to meet demand. • Reduced refinery capacity as consumption declines more rapidly than in REF. • Refinery closure in TGT is projected to start in late 2020s, slowly declining to 585 kb/d (1,300 PJ) by 2060. • Utilisation rates reach 80% before 2040 and begin to decline to 70% by 2060. • Average refinery production yield ratios are the same as in REF.
Emissions	• Reduces CO_2 emissions but falls short of Malaysia's 2030 NDC and 2050 carbon neutrality targets.	• Reduces CO_2 emissions but falls short of Malaysia's 2030 NDC and 2050 carbon neutrality targets.

Note: The base year is 2022. Macro-economic assumptions are constant across scenarios. Historical energy balances are from EGEDA submissions for 2022.

Demographic and Macroeconomic Assumptions

Figure 10-5. Population (thousands)

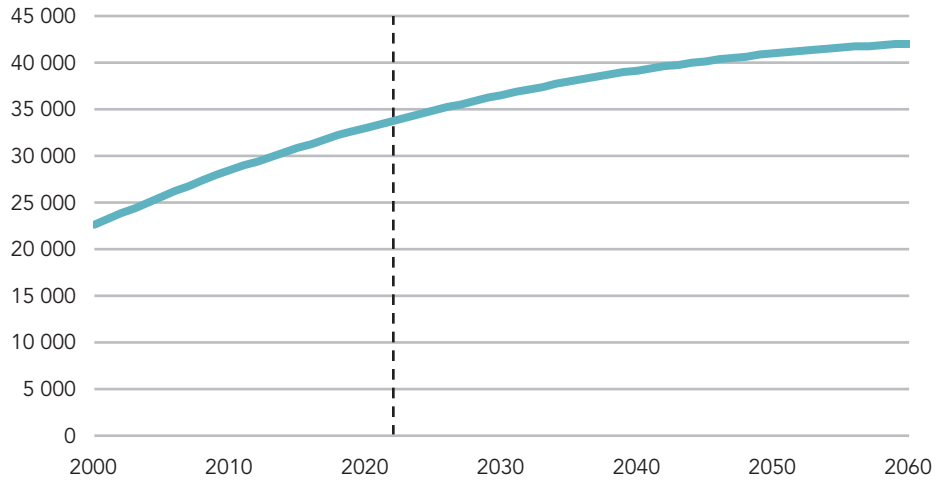
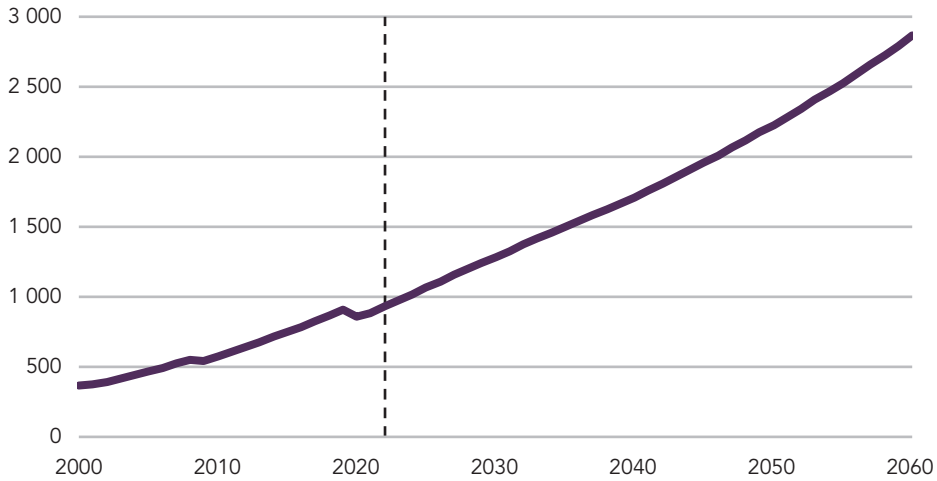


Figure 10-6. Real GDP (billion 2017 USD, PPP)



- Population assumptions are taken externally from the United Nations Department of Economic and Social Affairs (UNDESA) World Population Prospects 2022 projection. For the *Outlook*, the UNDESA medium projection is used for Malaysia.
- Malaysia's population is projected to increase significantly over the coming decades, from a peak of approximately 33.6 million in 2022 to around 42.5 million by 2060. This steady growth aligns with projections from the Department of Statistics Malaysia (DOSM) and is driven by urbanisation, improved healthcare, and increased life expectancy.
- However, the growth rate slows post-2040, reflecting declining fertility rates and an ageing population. By 2060, Malaysia is anticipated to become a super-aged society, with over 20% of its population aged 65 and above. This demographic shift underscores the need for policies focusing on healthcare, elder care, and sustainable urban development to manage the impending challenges effectively.
- As a simplifying assumption, the macroeconomic projections are the same in both scenarios.
- The *Outlook* assumes that Malaysia's GDP follows a consistent upward trajectory through 2060. This positive trend is driven by several key structural and policy initiatives implemented by the Malaysian government. These includes the diversification of the economy, growth in services and manufacturing sectors, rapid digitalisation, and a green economy transition as outlined in the NETR and New Industrial Master Plan (NIMP) 2030.
- The economy is projected to expand substantially by 207% between 2022 and 2060.

End-use Energy Demand

Figure 10-7. Energy demand by sector in REF & TGT (PJ)

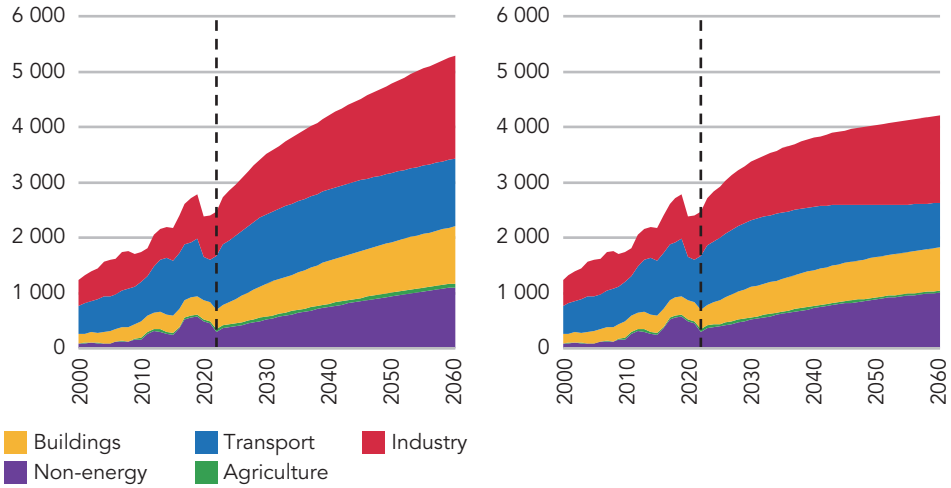
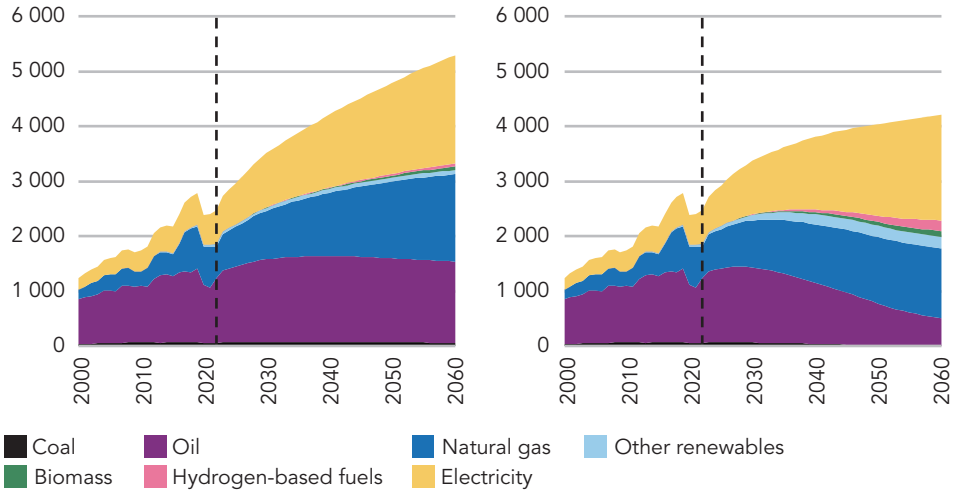


Figure 10-8. Energy demand by fuel in REF & TGT (PJ)



- Malaysia's total end-use energy demand peaks at nearly 5,300 PJ around 2060 in the REF scenario, with a CAGR of 2.03% from 2022 to 2060. Following a sharp decline pattern from 2019 to 2021, Malaysia slowly recovered from the pandemic as businesses were allowed to operate again, and COVID-19 vaccines were rolled out in stages. In contrast, the TGT scenario experiences a reduction in demand, falling by 20% to 4,200 PJ by 2060, due to accelerated efficiency gains and electrification.
- The industrial, transport, and non-energy sectors remain the most significant consumers throughout the projection period. Transport demand in TGT decreases significantly due to the adoption of EVs and biofuels and the improvement of public transport. There has been no significant change in the industry sector in TGT, partly because of the limitations in employing energy efficiency (EE) technologies commercially.
- Building energy demand doubles in both REF and TGT due to the demand for services and space cooling. The difference is attributed to the consideration of stringent regulations and efficiency measures.
- Historically, Malaysia's energy demand has been dominated by fossil fuels, primarily oil, gas, and coal, which powered the transport, industrial, and electricity sectors. In 2022, they accounted for 73% of total demand, led by oil (48%), gas (23%), and coal (3%), while electricity comprises 25%.
- The TGT scenario reflects Malaysia's ambition to reduce fossil fuel dependency, increase EE and RE, and decarbonise its energy system, especially by 2060.
- Electricity becomes central with minimal changes, while oil declines significantly, and the phasing out of coal is expected as early as 2040. These changes are driven by policy, investment, technology, and climate goals, mainly in the transportation sector.
- Other renewables, biomass, and hydrogen will account for almost a tenth of 2060's TGT demand, doubling their share from REF.

Buildings Energy Demand

Figure 10-9. Buildings energy demand by fuel in REF & TGT (PJ)

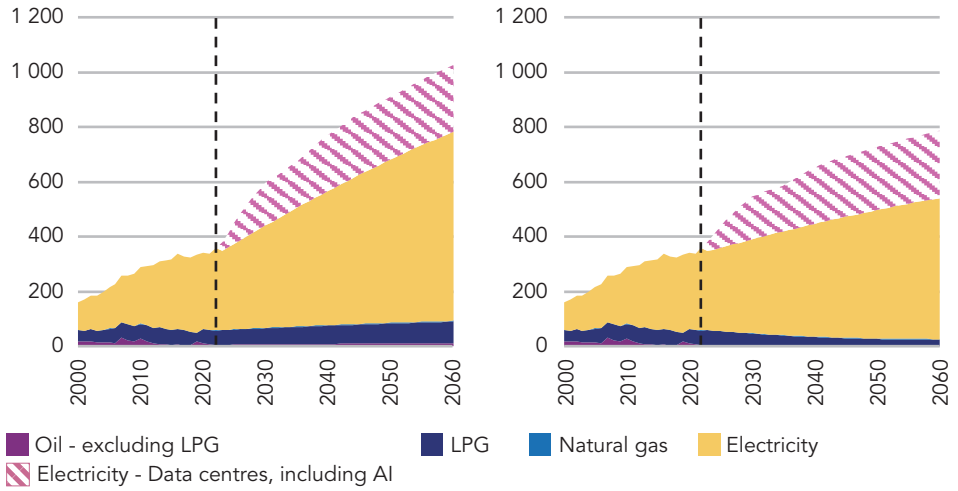
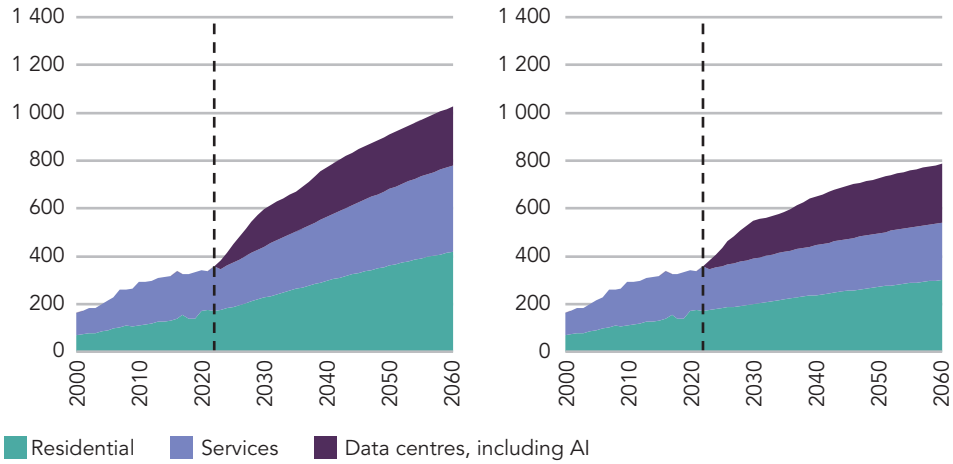


Figure 10-10. Buildings energy demand by sector in REF & TGT (PJ)



- Buildings accounted for 14% of Malaysia's total energy demand in 2022 and about 19% in both REF and TGT by 2060. Malaysia's rapid urbanisation and economic development have led to commercial, residential, and data centre expansion. This growth correlates with increased energy consumption.
- A main driver of building demand in Malaysia is electricity, which is mainly used for space cooling, plug loads, and lighting. In 2022, electricity accounted for 83% of building energy use, followed by gas (15%) and oil (2%).
- Oil and gas remain essential for heating and cooking, with a 9% share in REF but dropping to 3% in TGT in 2060. Oil and coal are nearly phased out by 2060, and electricity continues to dominate energy demand for buildings throughout the projection period. However, electricity decreases from 688 PJ in REF to 513 PJ in TGT, because of EE measures, technology improvement, and stove electrification, which results in more switching away from oil.
- One notable aspect of APERC's *Outlook* for the Malaysia's buildings sector is the projected surge in electricity demand driven by data centres and AI, increasing sharply to 246 PJ by 2060 and playing a significant role in overall electricity consumption growth.
- The number of residential and commercial buildings is expected to increase by 2060; however, the correlated rise in energy demand is expected to be offset by EE and RE initiatives. In REF, residential energy demand gradually increases, reaching 419 PJ (41% of total buildings demand) by 2060. Similarly, the service sector continues to grow increasing to 362 PJ (35%) by 2060.
- Additionally, in TGT, stringent efficiency standards, including adoption of more efficient electrical appliances and widespread adoption of Zero Energy Buildings (ZEBs), are anticipated to reduce energy use across both the residential and commercial sectors.

Industry Energy and Non-energy Demand

Figure 10-11. Industry & non-energy demand by fuel in REF & TGT (PJ)

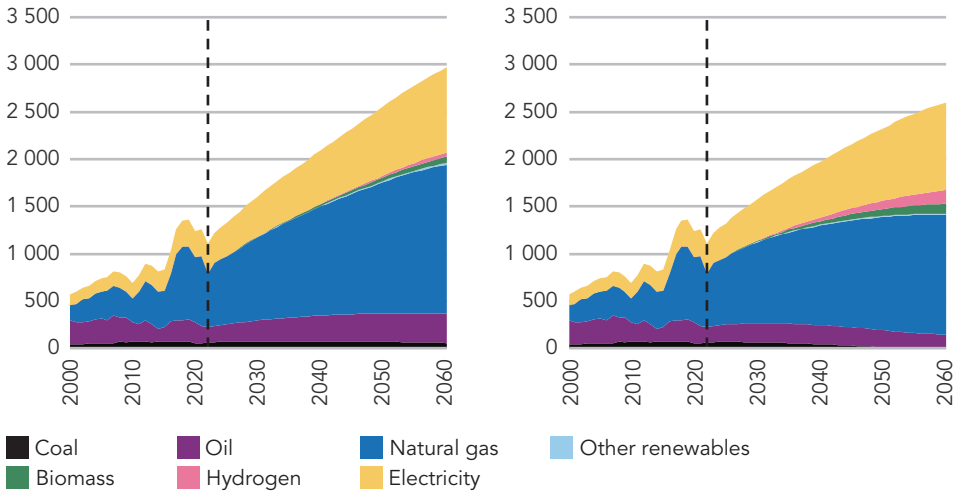
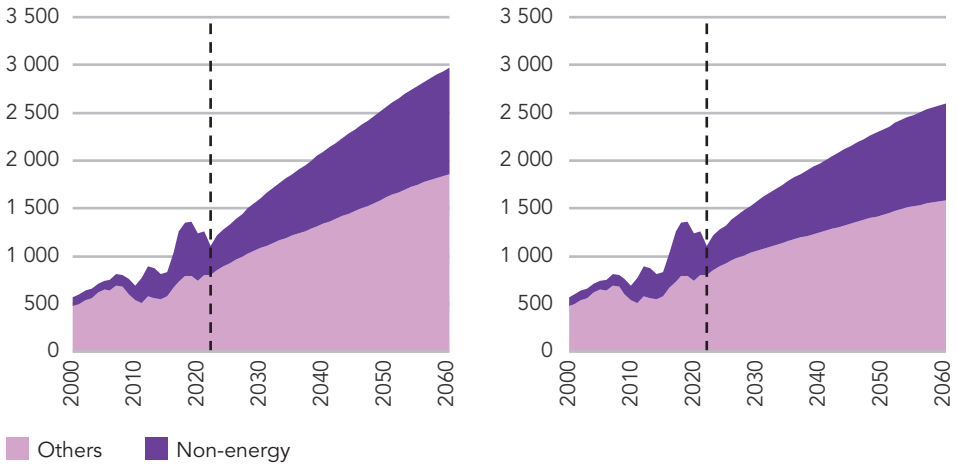


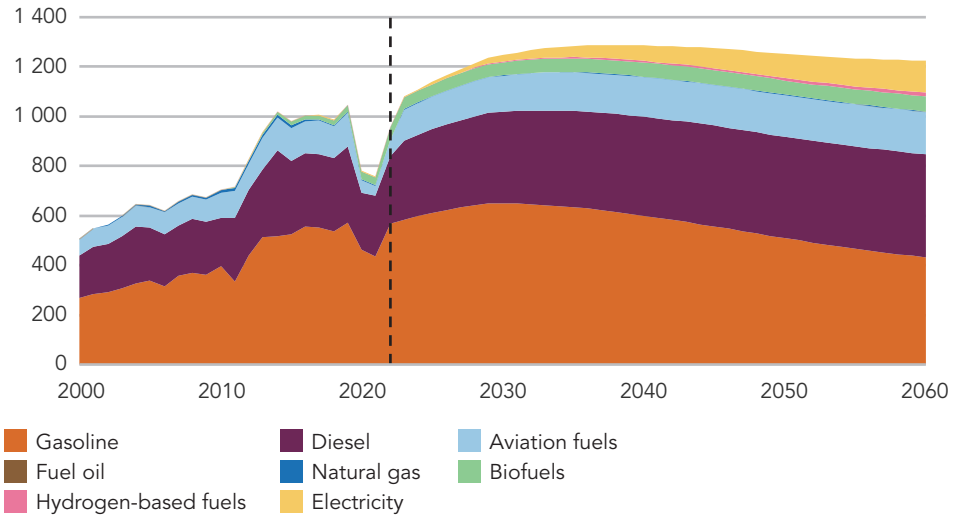
Figure 10-12. Industry & non-energy demand by sector in REF & TGT (PJ)



- Industry is Malaysia's largest sectoral energy consumer. Malaysia's industrial and non-energy demand remains strong through 2060 in both the REF and TGT scenarios, supported by ongoing efforts to strengthen long-term economic and industrial growth in Malaysia.
- In both scenarios, total demand increases steadily to over 2,968 PJ (REF) and 1,862 PJ (TGT) by 2060. Fossil fuels continue to play a role in the fueling industry, contributing a quarter of the total in REF. Meanwhile, electricity significantly grows from 304 PJ (28%) in 2022 to 898 PJ (30%) in 2060 in REF and to 924 PJ (58%) in TGT, reflecting greater electrification.
- TGT's demand will be 924 PJ lower by 2060 due to stronger energy efficiency regulation and fuel switching, including biomass and biodiesel.
- Historical industry data for Malaysia is recorded as non-specified, which makes it challenging to model effectively. In the absence of subsector-level information, the model assumes that overall industrial energy consumption grows in line with Malaysia's economic expansion.
- In the REF and TGT scenarios, energy use remains concentrated in non-specified and other subsectors. TGT projects lower overall demand due to the consideration of multiple initiatives including the 23% EE savings in industry sector by 2050 and the mandatory audit program started in 2024.

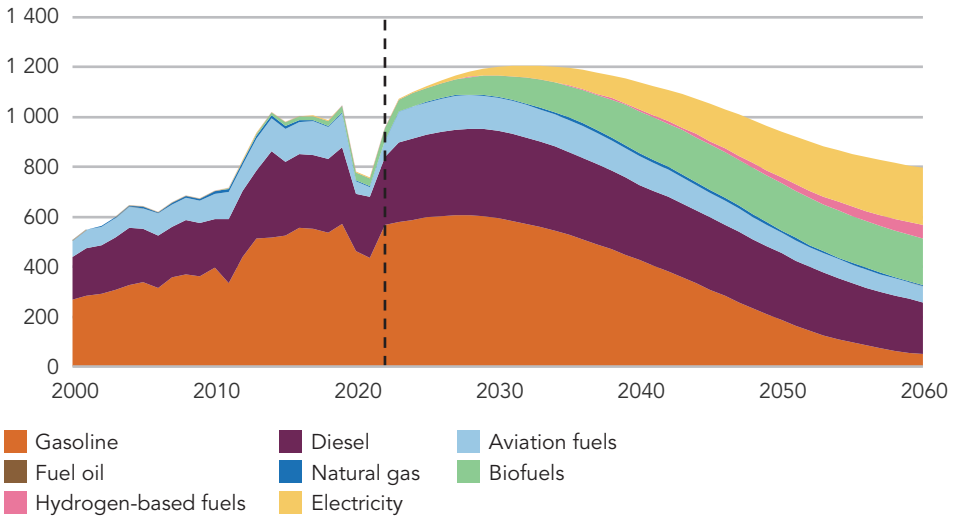
Transport Energy Demand

Figure 10-13. Domestic transport energy demand in REF (PJ)



- The transport sector remains one of Malaysia's largest energy consumers in both REF and TGT, dominated by road transport.
- TGT assumptions are based primarily on the Low Carbon Mobility Blueprint (LCMB) and the National Energy Transition Roadmap (NETR), which target greater public transport use, adoption of EVs and energy-efficient engines in passenger and freight vehicles, and expanded biofuel use.
- In TGT, public transport's share of total passenger activity increases from approximately 20% to nearly 60% by 2050, in line with LCMB targets. Passenger travel by car declines from 50% to 20%, and by two-wheelers from 20% to 8%. This shift enhances energy efficiency and social mobility, although it entails substantial investment and planning.

Figure 10-14. Domestic transport energy demand in TGT (PJ)



- In REF, diesel and gasoline remain dominant, supplying 69% of transport energy. In TGT, their combined share falls to 32%, driven largely by EV adoption and the resulting increase in electricity demand.
- TGT meets Malaysia's biofuel targets, including B30 blending for heavy transport by 2040 and 47% sustainable aviation fuel (SAF) blending by 2050. This results in biofuels displacing 190 PJ of petroleum products by 2060.
- Following the introduction of hydrogen vehicles in 2024, Malaysia is projected to exceed its 2050 target of 5% heavy vehicle penetration, reaching 10%. This corresponds to 54 PJ of hydrogen demand for FCEV heavy trucks by 2060.

Other Transport Data

Figure 10-15. Transport vehicle stocks in REF & TGT (millions)

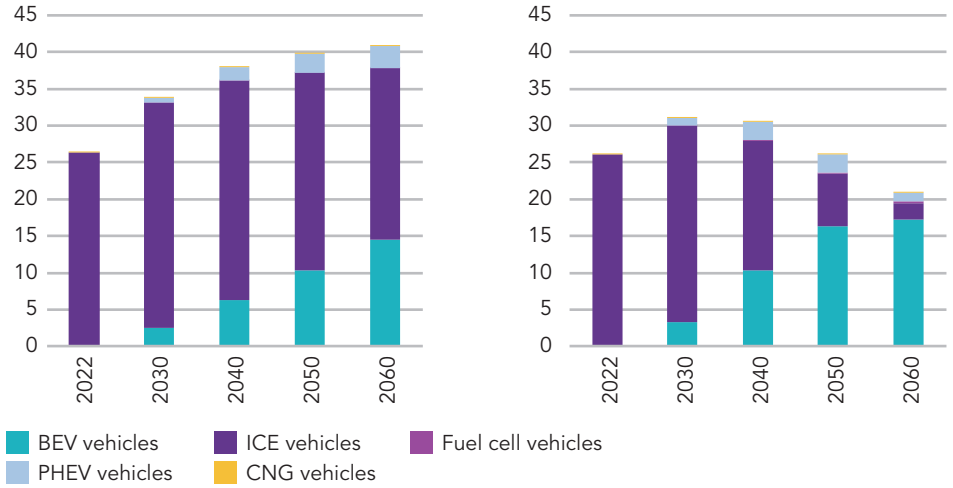
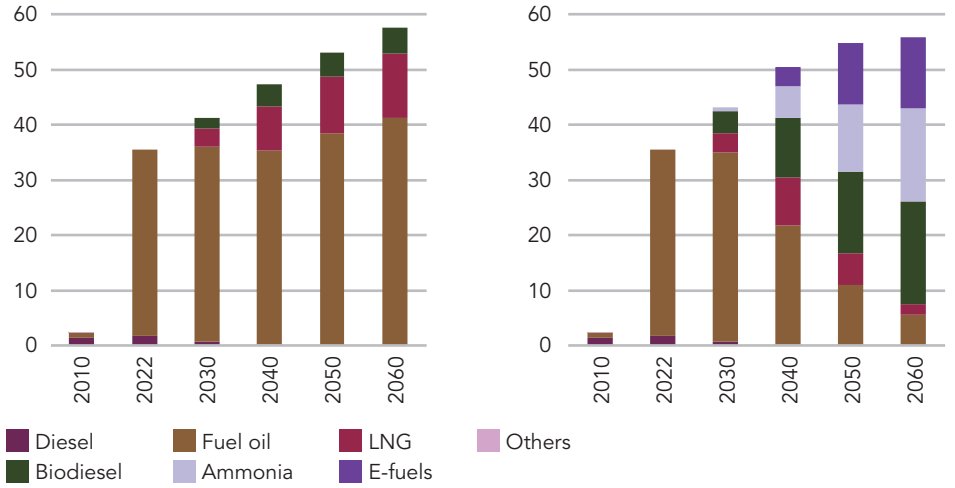
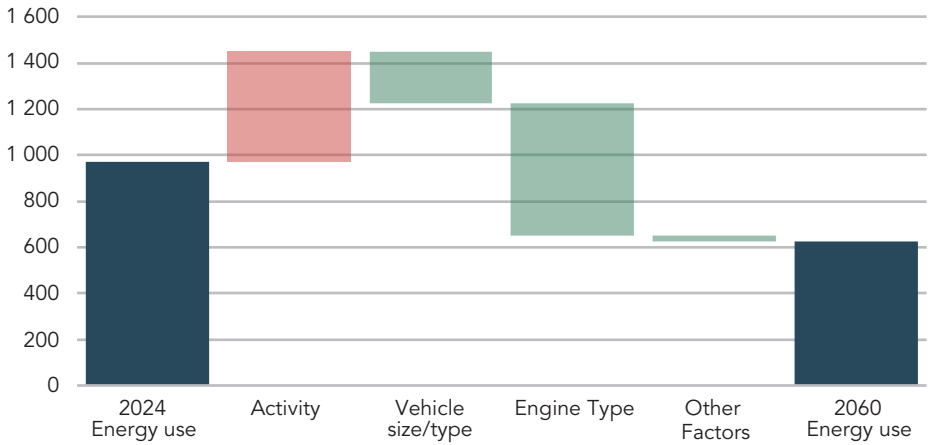


Figure 10-16. International bunker energy demand for shipping in REF & TGT (PJ)



- In line with the LCMB, BEVs reach an 80% share of the vehicle stock by 2060 in TGT. This yields nearly 600 PJ of energy savings (Figure 10-17, Engine Type component) compared with maintaining the 2022 vehicle stock composition.
- Hybrid vehicles (PHEVs and HEVs) serve a transitional role in TGT. For example, the LCMB target of 100% Energy Efficient Vehicle (EEV) penetration by 2030 is achieved primarily through hybrid adoption.
- TGT experiences a reduction in total vehicle stock relative to REF, driven by the substantial shift to public transport. Although the magnitude of this effect may vary, APERC modeling indicates that it lowers energy use by nearly 190 PJ (Figure 10-17, Vehicle size/type component) by 2060.
- In TGT, bunkers (fuel for international transport) shift to lower-emission alternatives in line with the goals set by international transport bodies.

Figure 10-17. Components of the change in road energy use in TGT (PJ)



Note: Information on the different drivers in the transport energy decomposition can be found in the *Outlook*'s annex.

Electricity Generation

Figure 10-18. Electricity generation by fuel in REF (TWh)

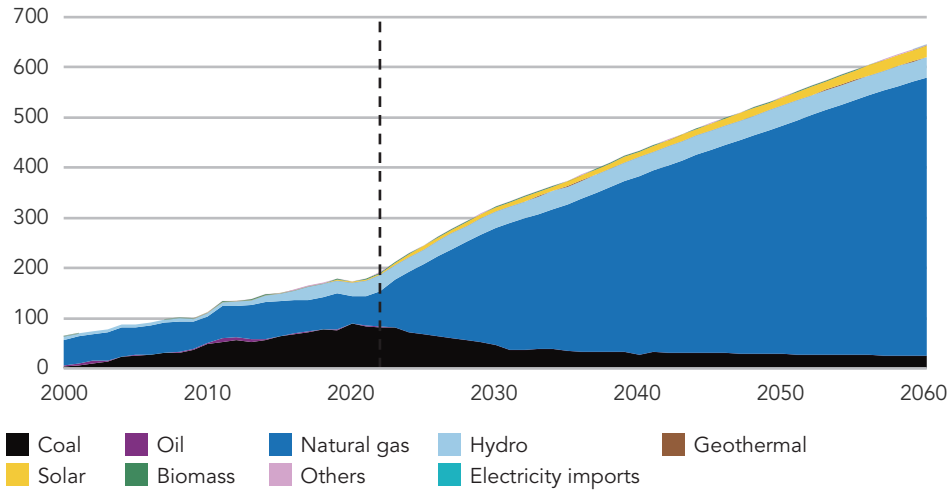
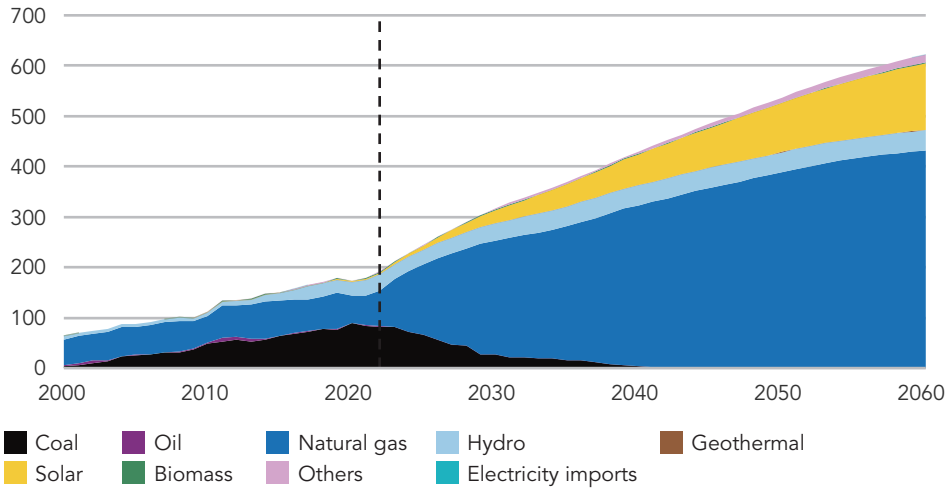


Figure 10-19. Electricity generation by fuel in TGT (TWh)



- Malaysia's electricity generation rises substantially from approximately 70 TWh in 2000 to over 640 TWh in 2060, a nearly nine-fold increase. This growth reflects a sustained rise in electricity demand, driven by economic growth, urbanisation, electrification, and industrialisation. Malaysia's electricity mix is shifting toward lower-carbon fossil fuels, with natural gas serving as a bridge fuel in TGT to support the policy-directed phase-out of coal.
- Coal peaks in REF around 2022 and declines gradually, from 25 TWh in 2000 to below 20 TWh in 2060. In TGT, coal is phased out by 2045, reflecting Malaysia's commitment to reducing its reliance on coal. Malaysia has pledged to not build new coal power plants (as per the 12th Malaysia Plan).
- Thermal generation remains the primary means of generating electricity in both scenarios, with fossil fuels increasing from a share of 80% in 2022 to 90% in REF and 69% in TGT by 2060. Both scenarios see a reversal of historical trends, with generation switching from coal to gas, as part of Malaysia's commitments to reduce economy-wide CO_2 emissions.
- Renewables generation nearly doubles in REF and triples in TGT due to robust solar, biomass, and stable hydropower contributions. Malaysia is transitioning from a fossil-fuel-dominated electricity mix toward a more sustainable, gas-and-renewables-driven system.
- The decline of coal, the steady use of gas as a transitional fuel, and the rapid growth of solar and biomass reflect policy decisions and technological trends. The economy's shift aligns with its international climate commitments and domestic development priorities, especially under frameworks like NETR and MyRER.

Note: Figures 10-18 and 10-19 do not include generation capacity for hydrogen production.

Generation Capacity

Figure 10-20. Generation capacity by fuel in REF (GW)

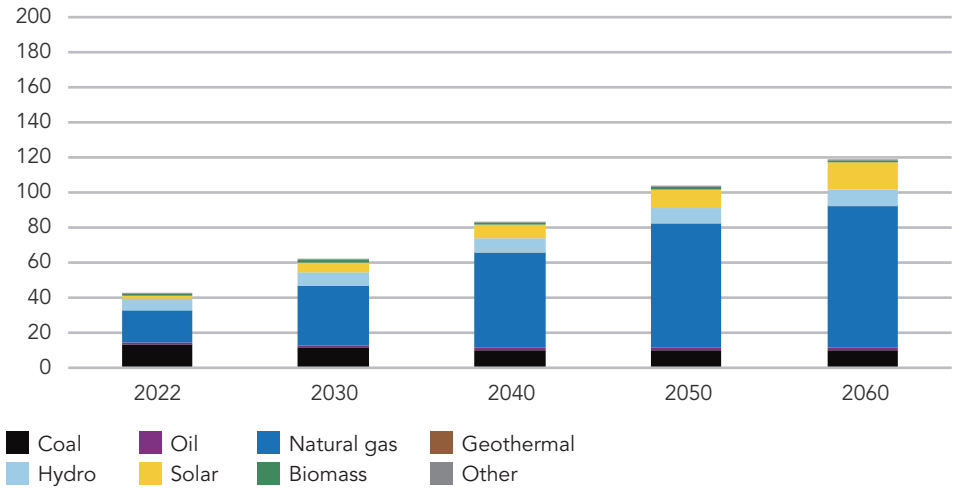
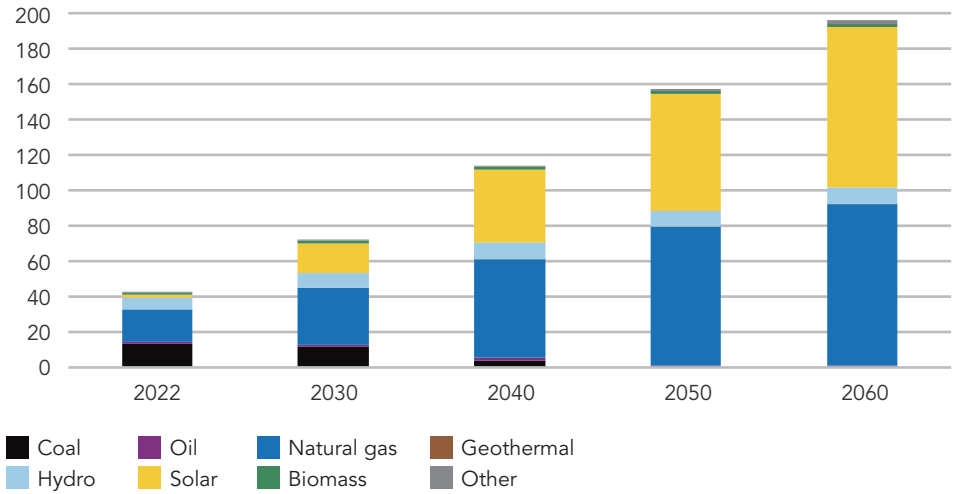


Figure 10-21. Generation capacity by fuel in TGT (GW)



- The generation capacity projections in Malaysia show a clear transition from fossil fuels to renewable energy, with solar and gas leading the mix and coal nearly phased out by 2060 (REF) and 2045 (TGT). Robust domestic strategies generally back these changes focused on sustainability, energy security, and net-zero carbon goals.
- In REF, gas remains dominant throughout the projection period, growing from 24 GW in 2022 to 60 GW in 2060, though its share slightly decreases from 53% to 50%. Coal capacity declines steadily from 9 GW to 3 GW, a 17% reduction. Solar experiences the fastest relative growth, increasing its share from 7% to 17% during the projection period.
- The TGT scenario for Malaysia's electricity generation capacity from 2022 to 2060 is significantly more ambitious than the REF scenario. Total generation capacity grows to approximately 200 GW by 2060, about 80 GW higher than in the REF scenario.
- Solar capacity experiences the most dramatic rise, increasing from around 3 GW in 2022 to 85 GW (45%) by 2060, compared to just 20 GW (17%) in REF.
- Gas remains important in TGT, serving as a transition fuel and providing a stable load capacity. Notably, coal is fully phased out in the TGT scenario by 2045.
- This trajectory aligns closely with Malaysia's National Energy Transition Roadmap (NETR) and the Malaysia Renewable Energy Roadmap (MyRER), which outlines targets for 70% renewable energy capacity by 2050 and net-zero emissions by mid-century.

Note: Figures 10-20 and 10-21 do not include generation capacity for hydrogen production.

Grid Reliability

Figure 10-22. Total generation capacity and peak load (GW)

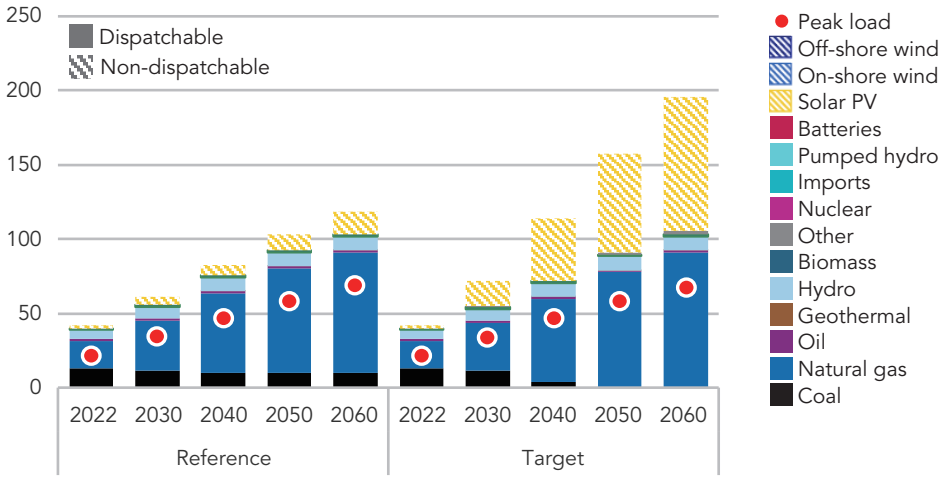
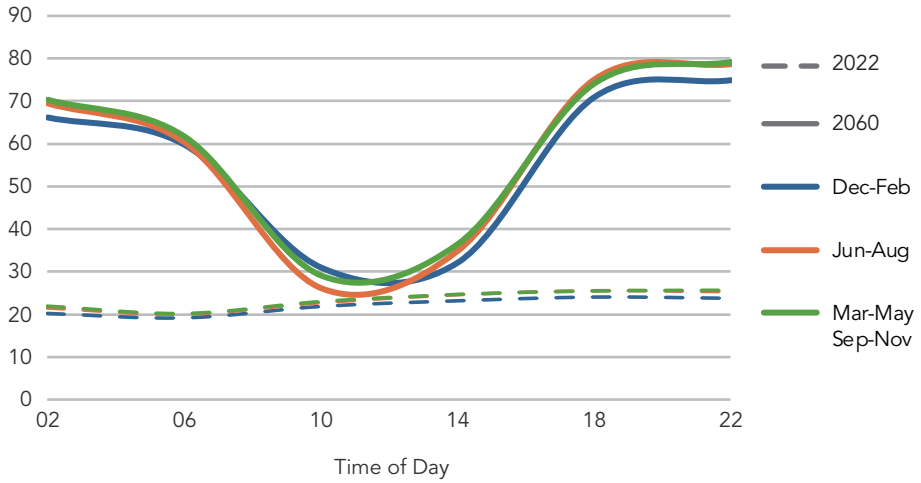


Figure 10-23. Power from dispatchable sources in TGT (GW)



- Malaysia's peak electricity demand is projected to rise substantially due to economic growth, population expansion, and electrification. In REF and TGT, peak demand could more than triple.
- Despite this growth, Malaysia's current and planned dispatchable capacity (gas, coal, hydro) remains sufficient to meet peak demand in the near term. However, the declining utilisation of fossil fuel plants, especially coal, may pose financial challenges for operators, necessitating policy interventions such as capacity payments or early retirements.
- Solar PV is expected to dominate Malaysia's RE mix, supported by the current large-scale solar (LSS) auctions and rooftop solar initiatives. Other RE sources are technically less viable for Malaysia. Nuclear is not being considered as future energy source under the current established policies in Malaysia.
- Gas remains a critical transition fuel, with capacity expanding to back up renewables. Malaysia plans to retire coal plants by 2045 (NETR), but their retained operation at lower capacities may be necessary for grid reliability.

- The power model uses 36 time slices calculated as 3 seasons × 2-day types × 6 four-hour daily segments to represent temporal variations throughout the year. The three seasons are Winter (Dec–Feb), Summer (Jun–Aug), and Intermediate (other months), with two-day types: weekdays and holidays. Renewable generation varies seasonally.
- Malaysia has relatively minimal seasonal fluctuations in dispatched power compared to temperate climates, primarily due to its tropical climate, consistent electricity demand patterns, and energy mix. There are slight variations between months, but the overall dispatched power remains stable due to climate-driven demand consistency (uniformly high temperature year-round), gas-dominated generation, small renewable variability, and industrial and commercial baseload.
- However, as renewables expand, government and grid operators must prepare for shorter-term variability rather than seasonal shifts, ensuring reliability through flexible gas plants, battery storage, and regional grid integration.

Coal and Biomass

Figure 10-24. Coal and biomass consumption by sector in REF & TGT (PJ)

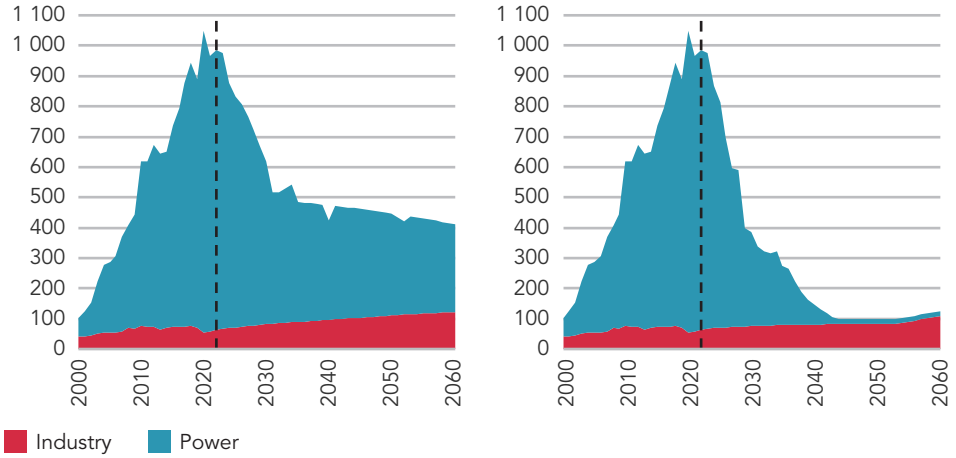
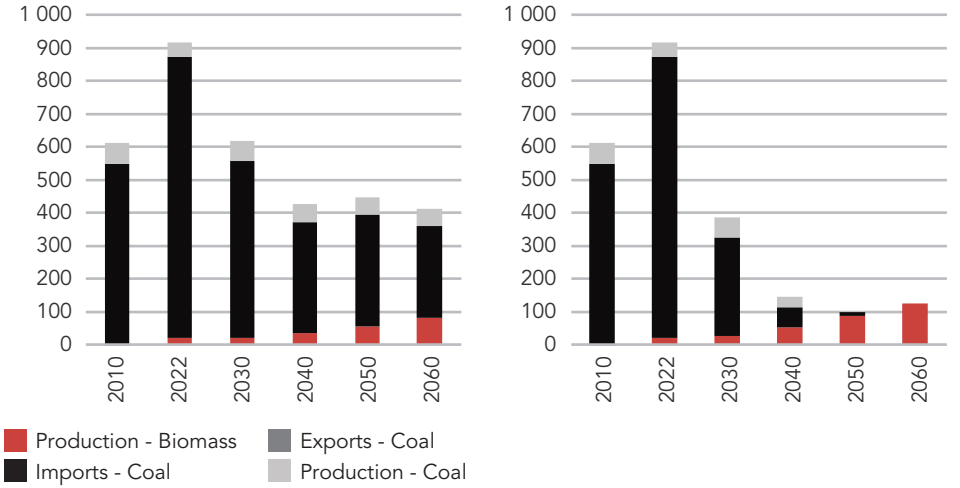


Figure 10-25. Coal and biomass production, imports, and exports in REF & TGT (PJ)



- Coal in Malaysia is primarily used in the power sector, and also provides heat sources for industrial processes, particularly the cement, iron, and steel subsectors. Coal consumption dominates over biomass, peaking at 1,000 PJ in the power sector, while the industrial sector consumed less than 150 PJ. By 2060 in REF, total coal use declines modestly to approximately 550 PJ, with the power sector remaining the main consumer.
- In contrast, the TGT scenario reflects a sharp decline to below 200 PJ by 2038 from its peak in 2020, with the power sector nearly eliminating coal and biomass use.
- Malaysia has some indigenous resources that produce a small amount of coal in the Sarawak region. Still, Malaysia's coal supply remains heavily reliant on imports, which made up nearly all coal consumption in 2022. In REF, coal imports decline by around 67%, from 852 PJ in 2022 to 280 PJ by 2060. In TGT, the drop is more significant, with coal imports projected to decline to zero by the early 2050s, reflecting the sharp reduction in coal use across sectors, while biomass production substantially rises. This is due to early coal retirements, improved efficiency in coal power plants, and higher coal-to-gas switching.
- This transition reduces Malaysia's dependence on imported coal and increases the use of natural gas, especially in the power sector, thereby enhancing its energy security.
- Although biomass accounts for a small share of the total supply, domestic production expands slightly in TGT. Biomass gains prominence due to its potential for renewable energy generation using agricultural and palm oil residues and the introduction of biomass clustering initiatives in NETR.

Natural Gas and Biogas

Figure 10-26. Natural gas and biogas consumption by sector in REF & TGT (PJ)

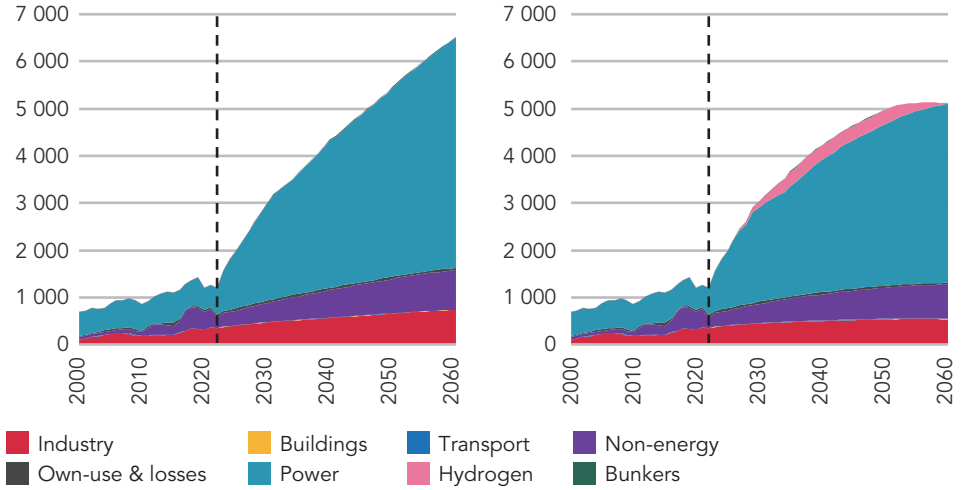
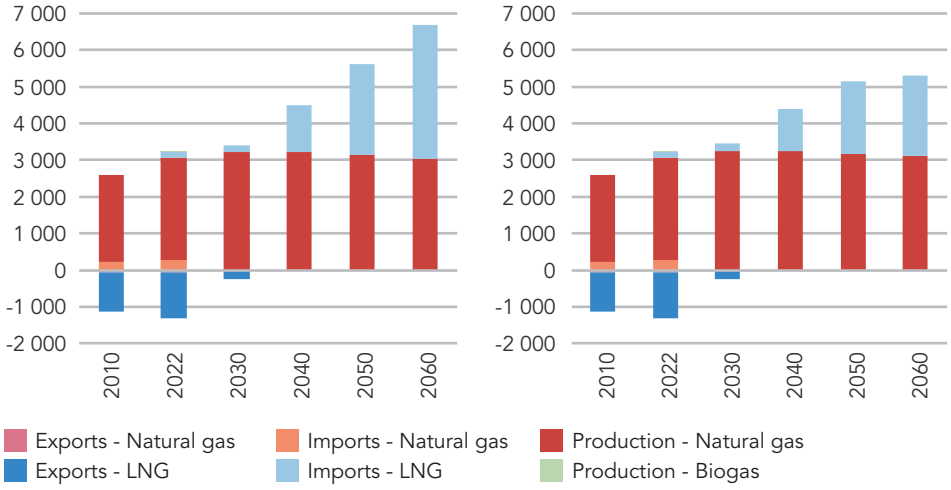


Figure 10-27. Natural gas and biogas production, imports, and exports in REF & TGT (PJ)



- In 2022, total natural gas consumption was around 2,000 PJ in both scenarios. By 2060, REF consumption rises sharply to about 6,800 PJ, while TGT experiences a more moderate increase to approximately 5,500 PJ, indicating a more sustainable trajectory under the TGT scenario.
- Gas is predominantly used in the power, non-energy, and industry sectors, accounting for almost 100% of Malaysia's total gas use in 2022. Under both scenarios, the power sector becomes the dominant gas consumer by 2060, accounting for more than 60% of total usage, driven by continued reliance on natural gas for electricity generation. In contrast, the TGT scenario reflects a diversified energy mix with reduced gas dependency in power generation, consistent with the shift toward renewable energy sources. In TGT, hydrogen consumption is expected to grow substantially by 2060, leading to the use of gas for hydrogen production, highlighting Malaysia's commitment to green hydrogen development under the Hydrogen Economy and Technology Roadmap (HETR).

- In REF, Malaysia maintains its current energy trajectory with stable natural gas production (~2,800 PJ) between 2022 and 2060. However, LNG imports rise by 78% and exports of both piped gas and LNG increase moderately.
- Similarly, TGT reflects Malaysia's energy transition goals. Natural gas production stays the same as in REF reaching 3.240 in PJ in 2027, in line with Petronas' target in the Petronas Activity Outlook and remains stable for ten years and declines very slowly (0.4% per year). LNG imports decrease, highlighting a deliberate shift away from fossil fuel dependence.

Petroleum Liquids

Figure 10-28. Crude oil and NGLs, and other hydrocarbon production, imports and exports in REF & TGT (PJ)

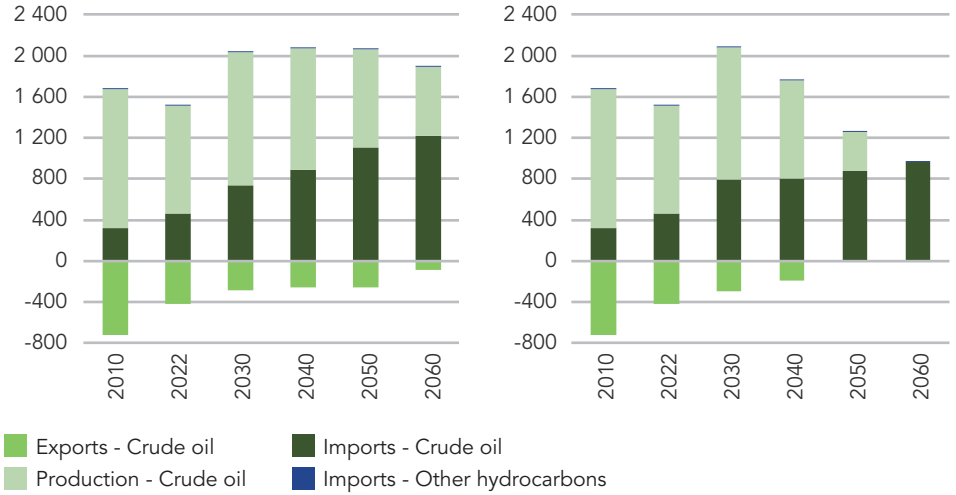
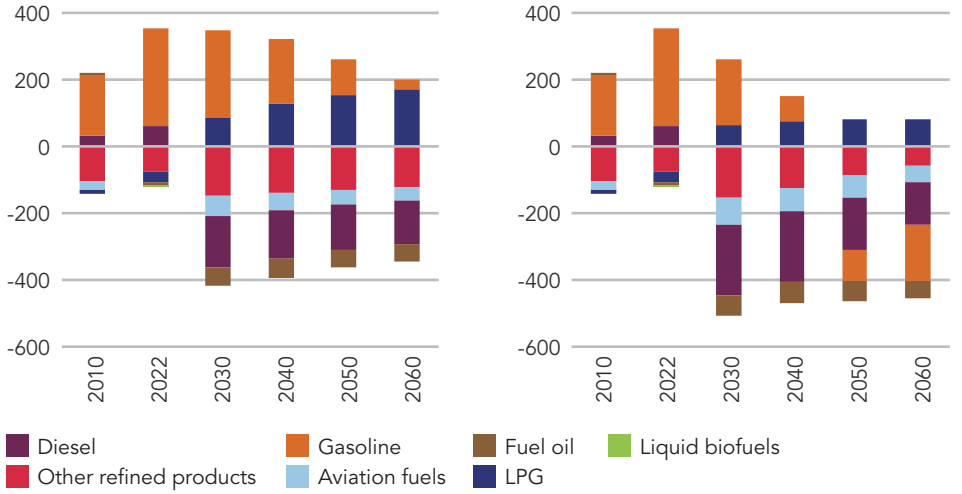


Figure 10-29. Net imports of refined products and low-carbon fuels in REF & TGT (PJ)



- In REF, crude oil production is expected to reach 1,270 PJ in 2025–2027, aligning with Petronas' target of two million barrels per day by 2027. This production level is projected to be sustained for a few years before declining due to depleting oil reserves. No significant new oil discoveries have been identified, and historically, production has shown a downward trend, with 2022's output declining compared to 2021.
- The TGT scenario aligns with Malaysia's domestic decarbonisation goals. Malaysia's crude oil and NGL production decreases by 50% from 2022 to 2060, driven by continued domestic demand and the expansion of oil imports. Exports drop by 27%, reflecting improved self-sufficiency. Crude production falls by 31%, exports shrink, and crude imports decline by 40%, indicating a strategic move away from fossil fuels especially in the transport sector.
- To maintain refinery supply, imports will increase, while exports are expected to remain steady and decline when production declines.

- Transport is the largest consumer of refined products, accounting for over two-thirds of total consumption during the projection period. Malaysia's refined product trade evolves as transport fuel demand declines. In REF, net imports of other refined products, mainly LPG, rise sharply by almost 100% through 2060 to respond to continued growth in non-energy and household sectors. In TGT, however, LPG import dependence declines with lower consumption and improved efficiency.
- Malaysia has been a net importer of refined products since 2010; however, it is projected to become a net exporter in the 2020s and is forecasted to remain so until 2060 in both scenarios, with the new facilities commissioned in Tanjung Bin and Pengerang and significant reductions in refined product demand in the transport sector.
- In TGT, diesel remains the primary export, followed by other refined products, aviation fuels, and gasoline.

Note: In Figure 10-29, net imports are presented without deducting bunkers.

Refining

Figure 10-30. Refining outputs in REF & TGT (PJ)

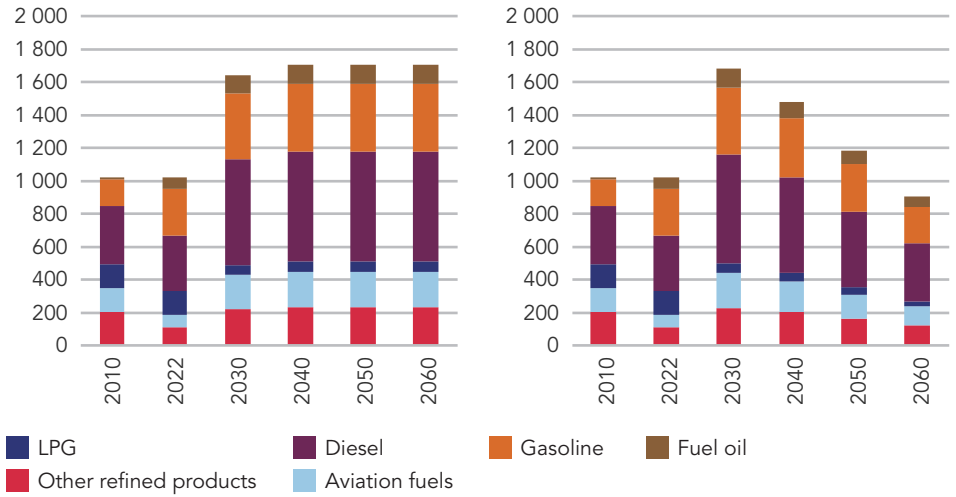
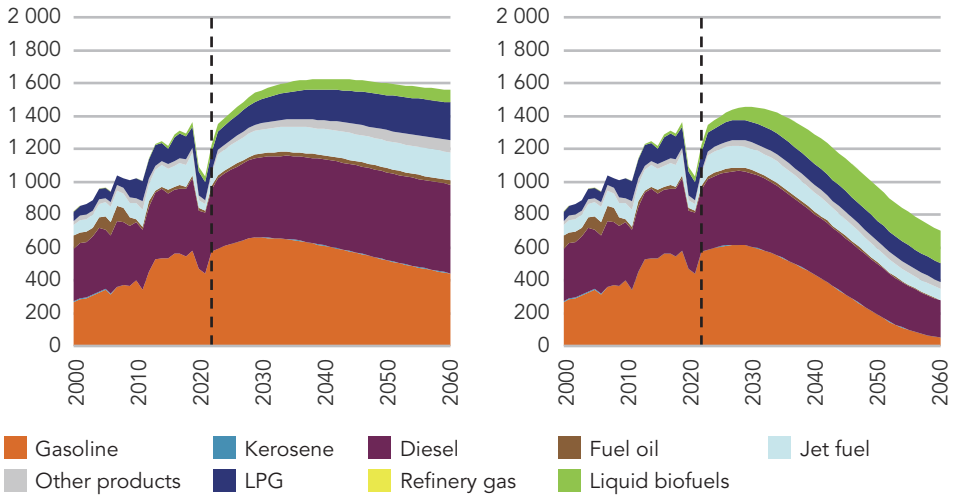


Figure 10-31. Refined products and low-carbon fuels demand in REF & TGT (PJ)



- Malaysia's total refining capacity is maintained at 955 thousand barrels per day (kb/d) long-term in REF and reduced to 585 kb/d in TGT. The Pengerang RAPID refinery (300 kb/d) was added to production and was used as a part of the assumption for future projections.
- The REF scenario projects minimal change, implying business-as-usual with sustained fossil fuel dependence. The slight rise in biofuels aligns with Malaysia's B20 biodiesel mandate but lacks aggressive renewable scaling.
- The TGT scenario aligns with Malaysia's NETR goals. By 2060, diesel and gasoline outputs drop by 50% and 39%, respectively, driven by electric vehicle adoption and less polluting transportation. Fuel oil use is nearly eliminated, indicating industrial decarbonisation, while liquid biofuels surge by over 1,200%, highlighting a substantial shift toward renewable energy.

- The demand for refined products and biofuels in REF continues to grow, reaching about 4,000 PJ by 2060. Consumption of all refined products continues to rise over the projection period and peaks in 2040, while gasoline consumption peaks around 2028 and then declines gradually. Alternative fuels (particularly liquid biofuels) will increase in the future mix.
- In TGT, total refined products and biofuels demand are projected to peak around 2030 and then gradually decline until the end of the projection period. Gasoline demand will peak around 2025 and is projected to decline and almost reach zero by 2050, while diesel demand will peak in 2028 and decline from thereafter. The share of liquid biofuels is expected to rise dramatically due to an aspirational target to utilise low-carbon energy.

Bioenergy and Waste

Figure 10-32. Bioenergy and waste demand by sector in REF and TGT (PJ)

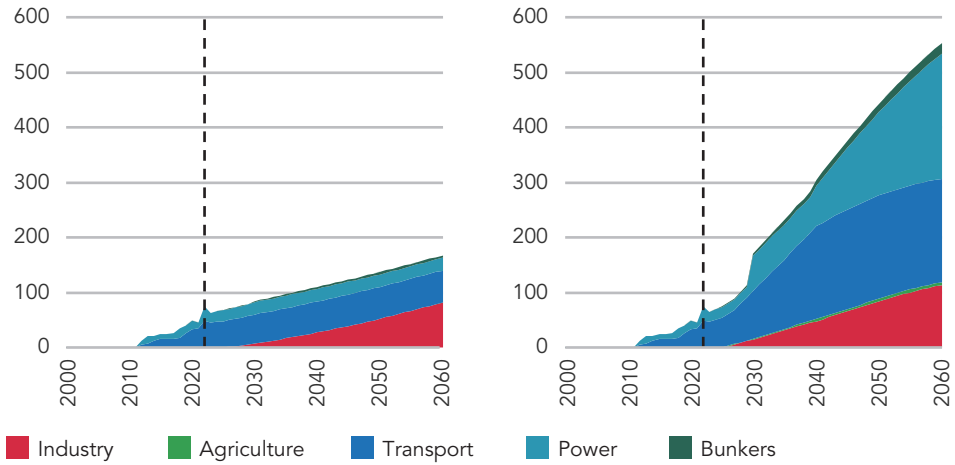
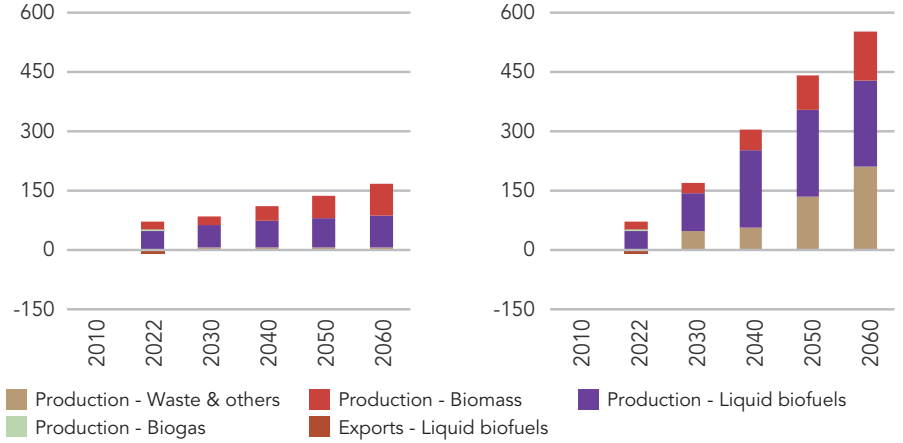


Figure 10-33. Bioenergy and waste production, imports, and exports in REF and TGT (PJ)



Note: Figure 10-33 does not include bunkers.

- Bioenergy is a strategic component of Malaysia's renewable energy mix, particularly due to the economy's rich agricultural base.
- In REF, bioenergy and waste demand increases steadily from approximately 74 PJ in 2022 to around 170 PJ by 2060, representing roughly a 2.3-fold increase over the projection period. TGT demand continues to grow significantly to 560 PJ by 2060. Industry dominates the total bioenergy demand, followed by transport, and then power.
- The driving force behind demand trends is the various government policies and mandates. In the power sector, biomass power plants are supported by a feed-in tariff mechanism. Malaysia mandates biodiesel blending in diesel fuel at B10 for transportation and at B7 and B20 for industrial sectors. In addition, Malaysia aims to produce SAF at 1% blending rate, which will rise to 47% by 2050.
- Bioenergy demand in Malaysia is assumed to be met by domestic production throughout the projection period. Production increases 2.3-fold in REF and 7.5-fold in TGT, mirroring demand trends. To prioritise domestic demand, exports of liquid biofuels are assumed to scale down to zero by 2022.
- Like in demand, trends in TGT bioenergy production are driven by policy in the power and transport sectors. Higher adoption rates of EVs and fuel cell vehicles reduce refined product demand, which in turn shifts to biofuels. A rise in biomass and waste was assumed based on the increase in use in the industrial sector, typically in palm oil mills and wood processing plants. The cement and other heavy industries also use palm kernel shells and wood chips as alternative fuels.

Hydrogen-based Fuels in the Target Scenario

Figure 10-34. Hydrogen-based fuels demand by sector [left]; Hydrogen-based fuels demand by fuel [right] (PJ)

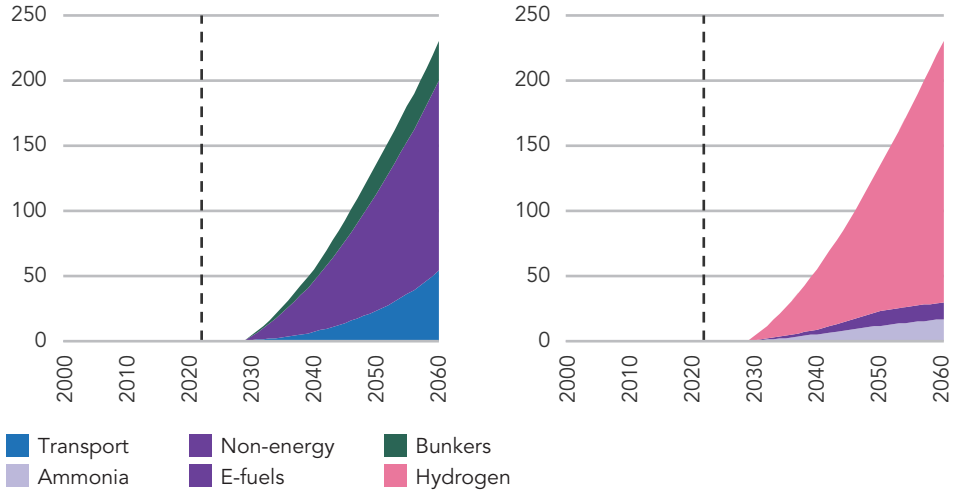
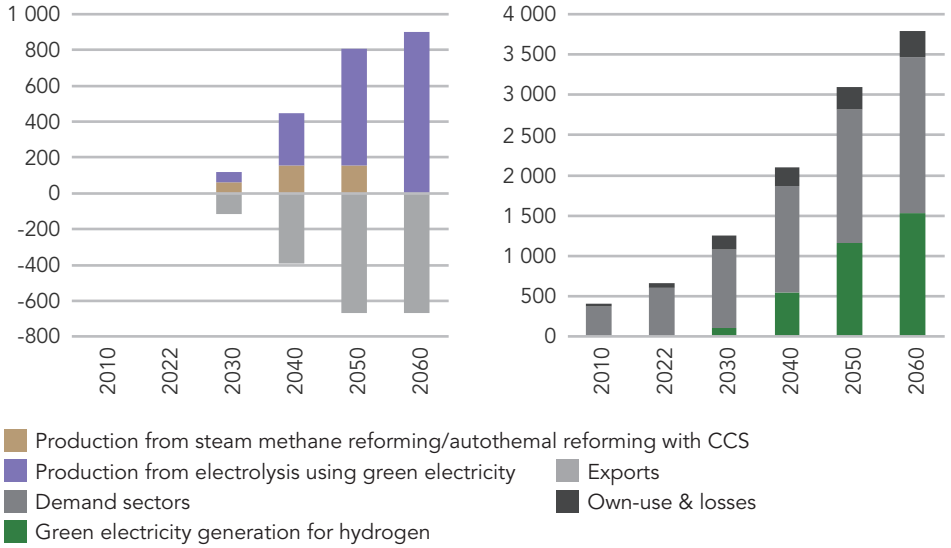


Figure 10-35. Hydrogen-based fuels production methods and supply [left]; Electricity for electrolysis vs other sectors [right] (PJ)

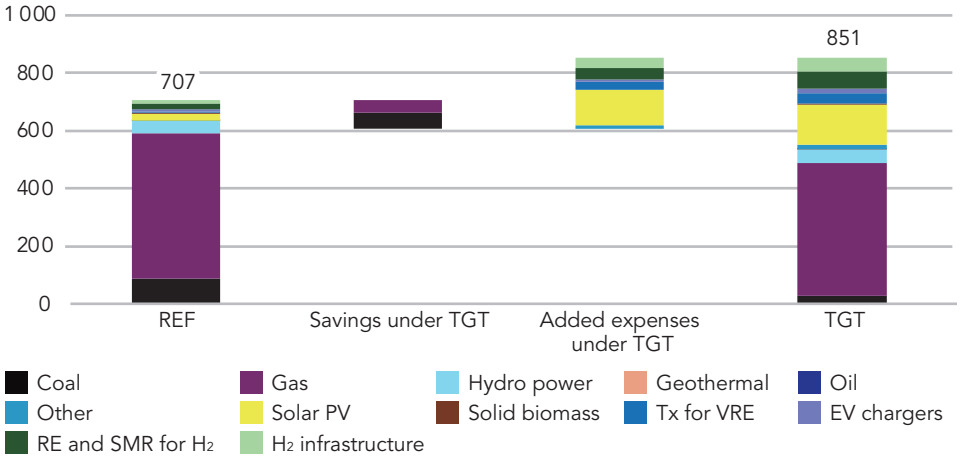


- Hydrogen demand in Malaysia is not used widely across sectors. In 2060, about 63% is expected to be used in non-energy, 24% in transport, with the remaining 13% to be used for bunkers.
- Hydrogen-based fuel demand is assumed to be greater in TGT than in REF. Malaysia is projected to increase its hydrogen production to 50,000 tonnes/year by 2030 in line with the NETR and the Malaysia Hydrogen Economy and Technology Roadmap (HETR).

- Malaysia is targeting green hydrogen exports to high-demand economies like Japan; Korea; and Singapore. With significant potential in renewable energy, in 2060, Malaysia aims to fully utilise electrolysis to produce green hydrogen from domestic sources. Grey hydrogen feedstock is targeted to be completely phased out by 2050. This will satisfy all demand requirements and export potential. Green electricity for hydrogen production could account for around 30% of total electricity demand, imposing a large demand on power generation. This renewable electricity generation is assumed to be dedicated to hydrogen production and is not included in the renewable generation shown in the power sector model.
- In TGT, hydrogen-based fuel production begins in 2030, continuously grows, and peaks in 2060 at 900 PJ. Hydrogen exports are projected according to NETR and HETR targets to reach over 670 PJ by 2050. These export ambitions also complement efforts to decarbonise domestic sectors while boosting regional green hydrogen trade with the support of the government.

Costs

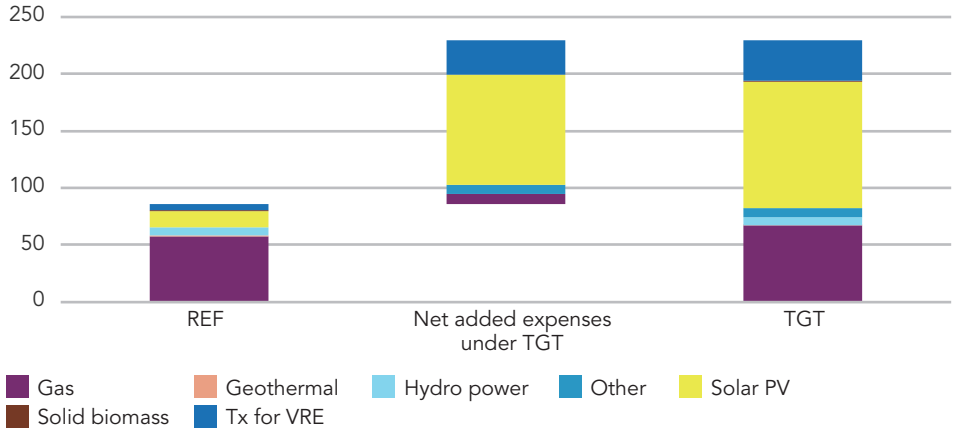
Figure 10-36. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



Note: Tx for VRE is only transmission infrastructure to connect variable renewable capacity to the grid. EV chargers do not cover the cost of associated infrastructure or EV vehicles. Hydrogen costs do not cover costs for bunkering obligations.

- Meeting future energy demand in Malaysia is expected to require substantial expenditures and pose a major challenge for decarbonising the grid, with total costs rising significantly from 2025 to 2060 in both scenarios. Total costs cover capital, fixed, and variable costs in the power sector, expenditures for low-carbon hydrogen production (both green and blue using Steam Methane Reforming (SMR)), transmission for variable renewable electricity, and electric vehicle charging infrastructure.
- In REF, total costs reach an estimated USD 707 billion, primarily driven by fossil fuel expenditures, especially in natural gas as it is Malaysia's choice transition fuel. In TGT, total costs rise to an estimated USD 851 billion. Although fossil fuel spending, particularly for coal, declines slightly in TGT, gas remains a significant cost together with added expenses for renewables and hydrogen production for domestic use.
- Total capital investment for Malaysia's power sector reaches an estimated USD 235 billion in TGT, up from USD 80 billion in REF. This represents a significant increase of around 194% in capital investment, highlighting the financial scale of Malaysia's energy transition.

Figure 10-37. Total capital investment (CAPEX) from 2025 to 2060 in the power sector (billion USD, undiscounted)

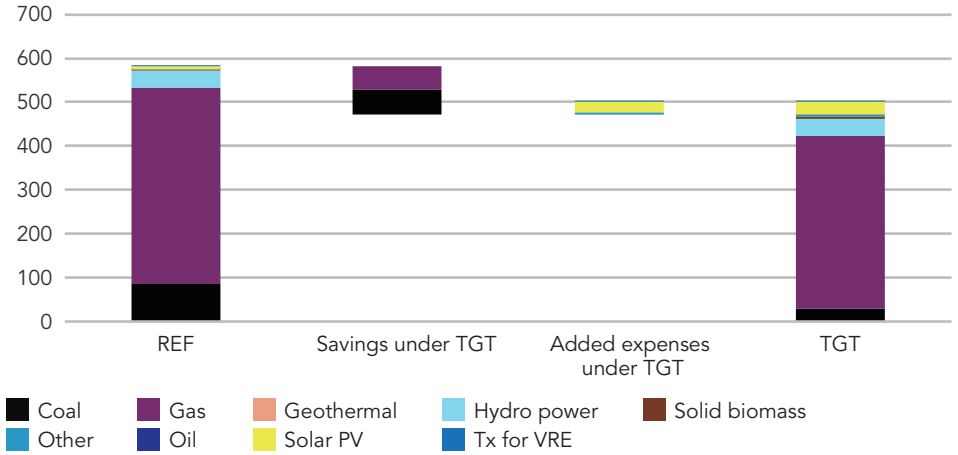


Note: Figure 10-37 only covers power and VRE transmission sector investments. Hydrogen and EV capital investments are not included.

- In REF, gas dominates the investment mix. Solar PV and hydro receive relatively modest investment, reflecting a continuation of existing policies without aggressive decarbonisation measures. This is consistent with past trends in Malaysia's energy policy, which emphasised economic growth and energy security through fossil fuels and limited renewable expansion.
- Investment in solar PV and transmission for VRE surge dramatically in TGT as Malaysia seeks to decarbonise its grid. Similarly for gas, investment relatively remains the same, which is crucial for grid stability.
- The increase in VRE transmission investment also indicates the need for enhanced grid infrastructure to accommodate intermittent renewable sources.

Costs

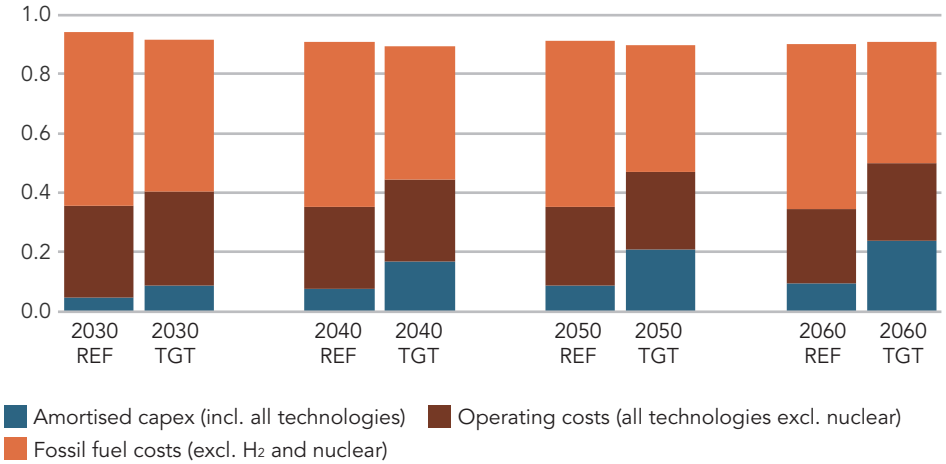
Figure 10-38. Total operating costs from 2025 to 2060 in the power sector (billion USD, undiscounted)



Note: Figure 10-38 only covers power and VRE transmission sector costs. It does not include operating costs associated with hydrogen production and EV charger costs.

- Malaysia's operating costs for the power sector are projected to reduce to an estimated USD 500 billion in TGT, compared to approximately USD 580 billion in REF. These costs primarily reflect variable fuel expenditures, with gas and coal-fired generation remaining the dominant cost driver in both scenarios due to their role in ensuring system reliability.
- Savings in TGT come primarily from reductions in coal and gas usage. These savings are offset partially by increased renewable expenses, such as hydro power and solar PV. However, the overall net savings indicates that the TGT scenario is more cost-efficient long term from an operational perspective, necessitating policy to unlock capital for renewable deployment instead.
- Malaysia has implemented policies that aim to boost rooftop and large-scale solar adoption under programs like the Net Energy Metering (NEM) and Large-Scale Solar (LSS) schemes. Solar PV may involve higher upfront capital expenditure, but its low operating costs make it an economically attractive option.

Figure 10-39. Cost of generating electricity relative to 2025 (2025 cost = 1.0) in the power sector



Note: Based on our assumptions about future capital and operating costs, Figure 10-39 shows cost compositions over time relative to 2025. It should not be considered an estimate of electricity tariffs and excludes market mechanisms that are too difficult to estimate.

- Figure 10-39 shows the relative cost of generating electricity for selected years indexed to the base year of 2025 for each scenario. To note, this is not reflective of the retail cost of electricity. In both REF and TGT, overall costs decline slightly over time.
- The declining share of fossil fuel costs, particularly in TGT reflects Malaysia's strategic shift towards lower emission energy sources. Reducing fossil fuels, especially minimising coal reliance, lessens fuel costs and enhances energy security. As the gas price in Malaysia is relatively low compared to other economies, its continual use means that fossil fuel costs do not contribute to generation costs rising. Amortised capital expenditures increase under TGT scenarios, signaling greater investments in renewables and grid infrastructure.
- Operating costs (non-nuclear) remain steady, reflecting current policy preferences that prioritise solar, hydro, and biomass over nuclear development.

CO_2 Emissions

Figure 10-40. CO_2 emissions in REF (million tonnes)

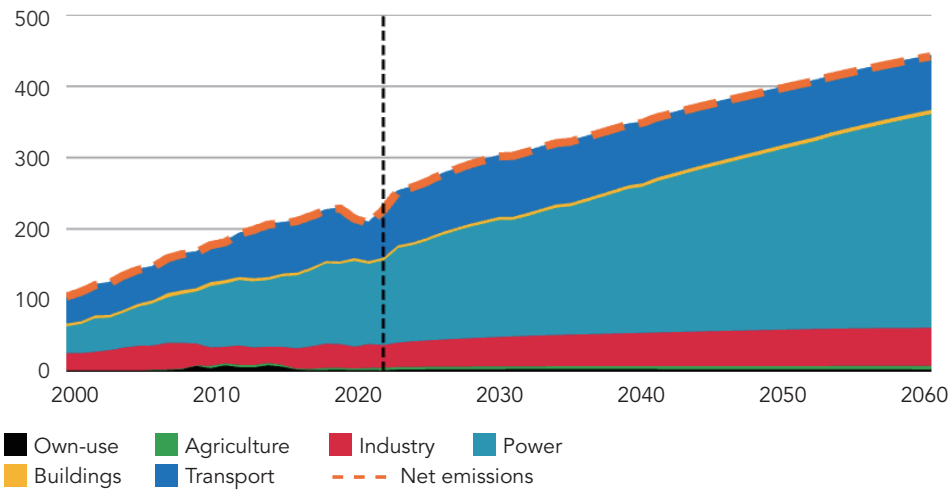
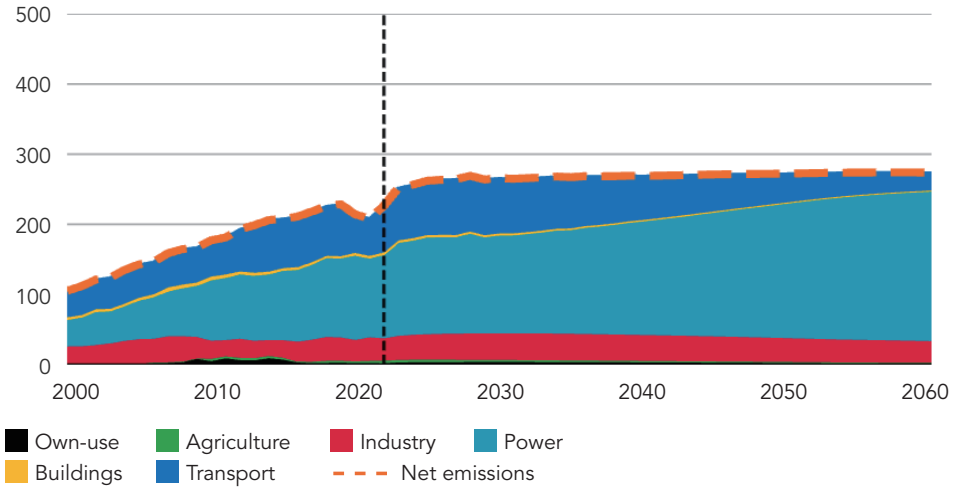
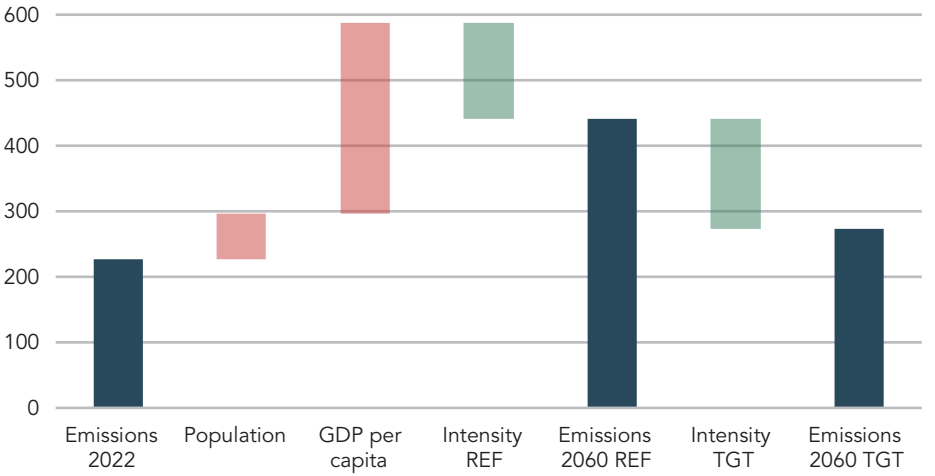


Figure 10-41. CO_2 emissions in TGT (million tonnes)



- By 2060, CO_2 emissions in the REF scenario reach nearly 450 million tonnes, compared to about 280 million tonnes in the TGT scenario, a reduction of around 170 million tonnes or approximately 38%. The power sector dominates, followed by the transport and industry sectors.
- The REF scenario assumes no major policy shifts, while TGT reflects Malaysia's carbon reduction commitments, such as the National Energy Policy 2022–2040 and the Low Carbon Mobility Blueprint. These policies aim to decarbonise power generation, promote electric mobility, and improve energy efficiency.
- Emissions trends are primarily shaped by improvements in energy and carbon intensity, which help counterbalance the growth in population and GDP per capita. In the TGT scenario, intensity improvements are crucial for achieving emissions reductions and meeting climate targets. Figure 10-42 reinforces that without such efficiency gains, emissions would rise significantly due to economic and demographic pressures.

Figure 10-42. CO_2 emissions components (million tonnes)



Note: All values represent energy sector combustion CO_2 emissions. Biogenic CO_2 is treated as zero at the point of combustion.

Useful Links

APEC Expert Group on Energy Data and Analysis (EGEDA) – https://www.egeda.ewg.apec.org/

APEC Energy Statistics 2022 – https://www.egeda.ewg.apec.org/egeda/general/info/pdf/APEC_Energy_Statistics_2022.pdf

APEC Energy Overview – https://aperc.or.jp/reports/energy_overview.php

Department of Statistics Malaysia (DOSM) (2024), *OpenDOSM, Current population and GDP* – https://open.dosm.gov.my/

Energy Commission (EC) (2023), National Energy Balance 2021 – https://meih.st.gov.my/documents/

Ministry of Economy, National Energy Transition Roadmap (NETR) 2023 – https://www.ekonomi.gov.my/sites/default/files/202309/National%20Energy%20Transition%20Roadmap_0.pdf

Ministry of Economy, Twelfth Malaysia Plan (12MP) 2021-2025 – https://rmke12.ekonomi.gov.my/en

Ministry of Economy, National Energy Policy (DTN) (2022) – https://www.ekonomi.gov.my/sites/default/files/2022-09/Dasar_Tenaga_Negara_2022-2040.pdf

Ministry of Natural Resources and Environmental Sustainability (2023), Fourth Biennial Update Report Under the United Nations Framework Convention on Climate Change – https://unfccc.int/documents/624776

Ministry of Transport, National Transport Policy (2019) – https://dpn.mot.gov.my/

Sustainable Energy Development Authority (SEDA) Malaysia (2023), Malaysia Renewable Energy Roadmap (MYRER) – https://www.seda.gov.my/reportal/myrer/

Single Buyer (2024), Energy Exchange Malaysia (ENEGEM) – https://www.singlebuyer.com.my/enegem.php

Malaysian Green Technology and Climate Change Corporation, Low Carbon Mobility Blueprint (LCMB) – https://www.mgtc.gov.my/what-we-do/low-carbon-mobility-2/low-carbon-mobility-blueprint/

Ministry of Science, Technology and Innovation (MOSTI), Hydrogen Economy and Technology Roadmap (HETR) – https://mastic.mosti.gov.my/publication/hydrogen-economy-technology-roadmap/



11. Mexico

Summary

	Reference			Target		
	2022	2060	% Change	2022	2060	% Change
Macroeconomic						
Population (million)	127	143	13%	127	143	13%
GDP (billion 2017 USD, PPP)	2,481	4,539	83%	2,481	4,539	83%
Energy Demand						
Agriculture & fisheries (PJ)	177	251	42%	177	202	14%
Buildings (PJ)	959	1,117	16%	959	804	-16%
Industry (PJ)	1,339	2,073	55%	1,339	1,676	25%
Non-energy (PJ)	153	229	50%	153	212	39%
Transport (PJ)	1,862	2,042	10%	1,862	1,149	-38%
Modern renewable share of TFEC (%)	8	21	163%	8	41	413%
Energy intensity of TFEC (PJ/GDP, billion USD)	1.8	1.2	-33%	1.8	0.9	-50%
Electricity						
Generation (TWh)	344	684	98%	344	720	109%
Renewables share of generation (%)	24	50	108%	24	67	179%
Generation capacity (GW)	98	245	149%	98	303	208%
Total Primary Energy Supply (TPES)						
Coal & coal products (PJ)	384	180	-53%	384	66	-83%
Natural gas (PJ)	2,923	3,640	25%	2,923	2,780	-5%
Petroleum liquids (PJ)	3,417	3,538	4%	3,417	1,816	-47%
Low-carbon & waste energy (PJ)	923	1,821	97%	923	2,754	198%
CO_2 intensity of energy supply ($MtCO_2/PJ$)	0.049	0.044	-10%	0.049	0.032	-35%
Net CO_2 Emissions (million tonnes)	374	411	10%	374	241	-35%

Note: In this publication, the term "modern renewables" refers to all renewable energy sources excluding solid biomass in the buildings sector. The term "low-carbon & waste energy" includes all bioenergy, waste-derived energy, renewables, nuclear, and hydrogen-based fuels. Total primary energy supply (TPES) numbers include international bunkers. Net emissions are calculated as gross energy sector combustion CO_2 minus CO_2 captured and stored through carbon capture and storage (CCS).

Key Takeaways

Emissions

- Mexico's net CO_2 emissions are projected to peak in the mid-2030s and then decline slightly in the Reference scenario (REF). In the Target scenario (TGT), emissions are projected to be 41% lower than in REF by 2060.
- The transport sector contributes the most to the reduction in CO_2 emissions, accounting for around 50% of the total decrease due to rapid electrification. The power sector provides the second largest share, contributing about 30% of the reduction through the faster integration of wind and solar energy.
- These trends highlight the key role of transport electrification in reducing emissions and curbing energy demand growth. They also emphasize the importance of expanding renewable generation in the electricity mix while maintaining grid reliability to meet increasing electricity demand.

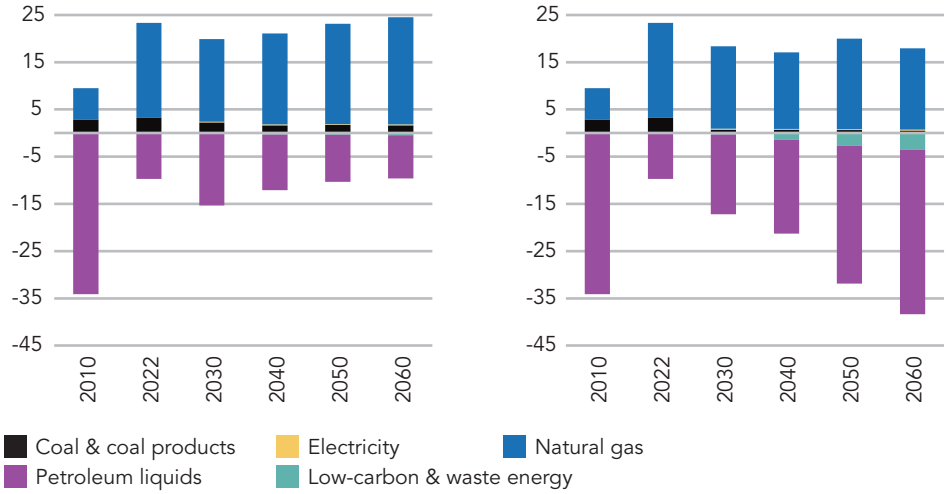
Energy Import Dependence

- Mexico is currently a net energy importer, with natural gas making up the largest share of imports. The economy is connected to the United States through extensive pipeline infrastructure that supplies competitively priced natural gas, primarily for power generation and industrial use. As domestic oil and gas production has declined in recent years, concerns have grown over Mexico's high dependence on U.S. natural gas, which accounted for approximately 70% of total gas consumption in 2022.
- In TGT, greater integration of renewable power generation reduces reliance on natural gas imports compared to REF. However, Mexico is projected to continue importing natural gas in both scenarios.
- Mexico is traditionally a crude oil exporter but relies heavily on imported refined petroleum products, especially transportation fuels. Aging refineries and limited capacity to process heavy crude oil reduced the domestic output of refined products in the 2010s. Ongoing upgrades to the refining system aim to cut imports by increasing domestic refining.

Figure 11-1. Net CO_2 emissions (million tonnes)



Figure 11-2. Net imports share of TPES in REF & TGT (%)



Note: In Figure 11-2, net imports refer to total imports minus exports and international bunkers.

Key Takeaways

Grid Reliability

- Electric grid reliability depends on maintaining a near-instantaneous balance between supply and demand. This requires adequate dispatchable power sources, which in Mexico are dominated by gas-fired generation but may also include hydropower, batteries, and other flexible technologies.
- Figure 11-3 shows grid dependence on dispatchable power in the 4-hour period of maximum dependence and 4-hour period of minimum dependence.
- In both the REF and TGT scenarios, electricity demand in Mexico increases, requiring significant capacity expansion. This expansion must ensure that enough dispatchable power is available during periods when variable renewable electricity (VRE) sources, such as wind and solar, are not generating at high levels.
- As the share of VRE grows in both scenarios, especially in TGT, the variability in dispatchable power requirements widens, leading to increased capital, maintenance, and operating costs for the system.

Cost

- There are major estimated costs for Mexico for each scenario through to 2060, predominantly in its power sector. Under TGT, total costs are estimated to be USD 1 trillion, USD 167 billion higher than in REF. Costs considered include total capital, fixed, and variable costs in the power sector, costs for green hydrogen production for domestic use, transmission for VRE, and electric vehicle chargers.
- Power system costs are primarily driven by gas and renewable energy expenditure in both scenarios.
- Additional costs in TGT primarily reflect increased spending on wind and solar capacity, and the transmission and storage infrastructure needed to accommodate the additional VRE, in line with Mexico's greater decarbonisation efforts in this scenario. Added expenditure on EV chargers is also a key contributor to the additional spending.

Figure 11-3. Peak load and maximum and minimum dependence on dispatched power (GW)

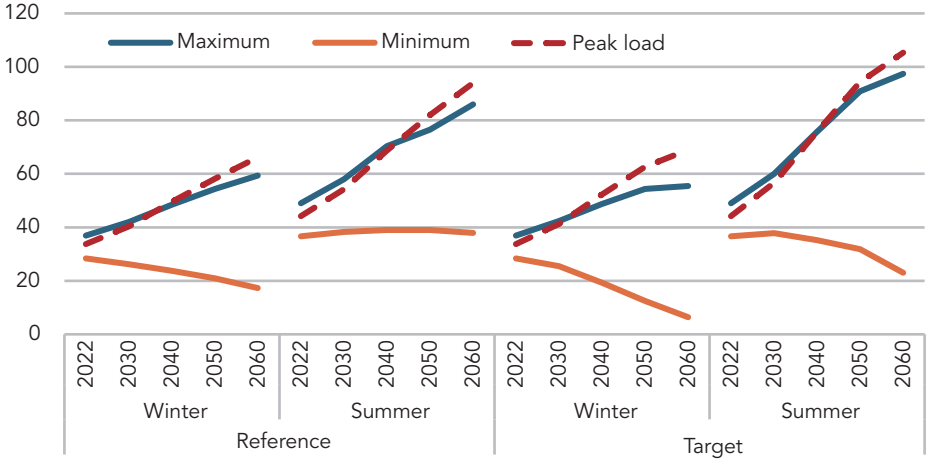
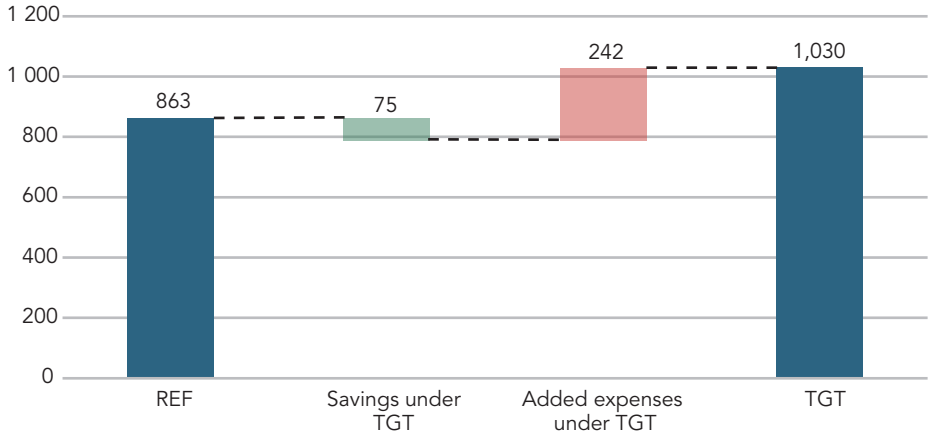


Figure 11-4. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



*Actual costs will differ from estimated costs in the *Outlook* for a variety of reasons including changing commodity prices, manufacturing costs, and unforeseen technical advances. All costs are in 2023 real terms.

About Mexico

Overview

Geographical and Economic Landscape

Mexico is a geographically diverse and resource-rich economy located in North America with coastlines along the Pacific and Atlantic oceans. Its varied landscape includes deserts, mountains, and tropical zones, supporting abundant energy resources such as hydrocarbons, solar, wind, geothermal, and hydropower. Mexico plays a key role in North American manufacturing and trade, with major industries such as automotive, aerospace and electronics manufacturing, agriculture, and energy. Its economy features a strong industrial base, growing services sector, and deep integration into global value chains.

Energy Supply and Consumption

Mexico is a major energy producer within APEC and the fifth-largest oil producer in the region, primarily through Pemex. While oil remains central in the Mexican energy mix, natural gas has expanded across the industry and building sectors, supported by domestic production and affordable imports. Natural gas use has largely surpassed oil and coal use for power generation, while wind and solar have gained ground due to Mexico's strong renewable potential. Biomass energy remains significant in residential use, particularly in rural areas, though the government has encouraged a shift to more efficient stoves to mitigate health and environmental risks. Final energy consumption is led by the transport sector, which relies heavily on refined products; over time, electricity is expected to play a greater role, offering strong potential for reducing energy demand and emissions in this sector.

Energy Security Challenges and Strategies

Mexico faces energy security challenges due to declining oil production, heavy reliance on imported natural gas and refined products, and aging infrastructure. In response, the government is rehabilitating refineries, expanding gas pipeline capacity, and investing in electricity transmission. Projects such as the new Dos Bocas refinery and the Zama and Trion oil and gas fields aim to strengthen energy self-reliance. Efforts also focus on reinforcing the role of publicly owned energy enterprises, though regulatory uncertainty and limited investment in renewables and grid modernization remain concerns.

Key Energy Initiatives

2025 Energy Reform

The reforms seek to modify the energy framework established by previous administrations, particularly the 2013 energy reform. The decree introduces new laws governing PEMEX and CFE, aiming to restore a leading role to the publicly owned enterprises over private sector initiatives. It also addresses the electricity and hydrocarbons sectors, energy planning and transition, renewables, and the creation of the National Energy Commission. Additionally, it amends various provisions of the Mexican Petroleum Fund Law and the Federal Public Administration Law.

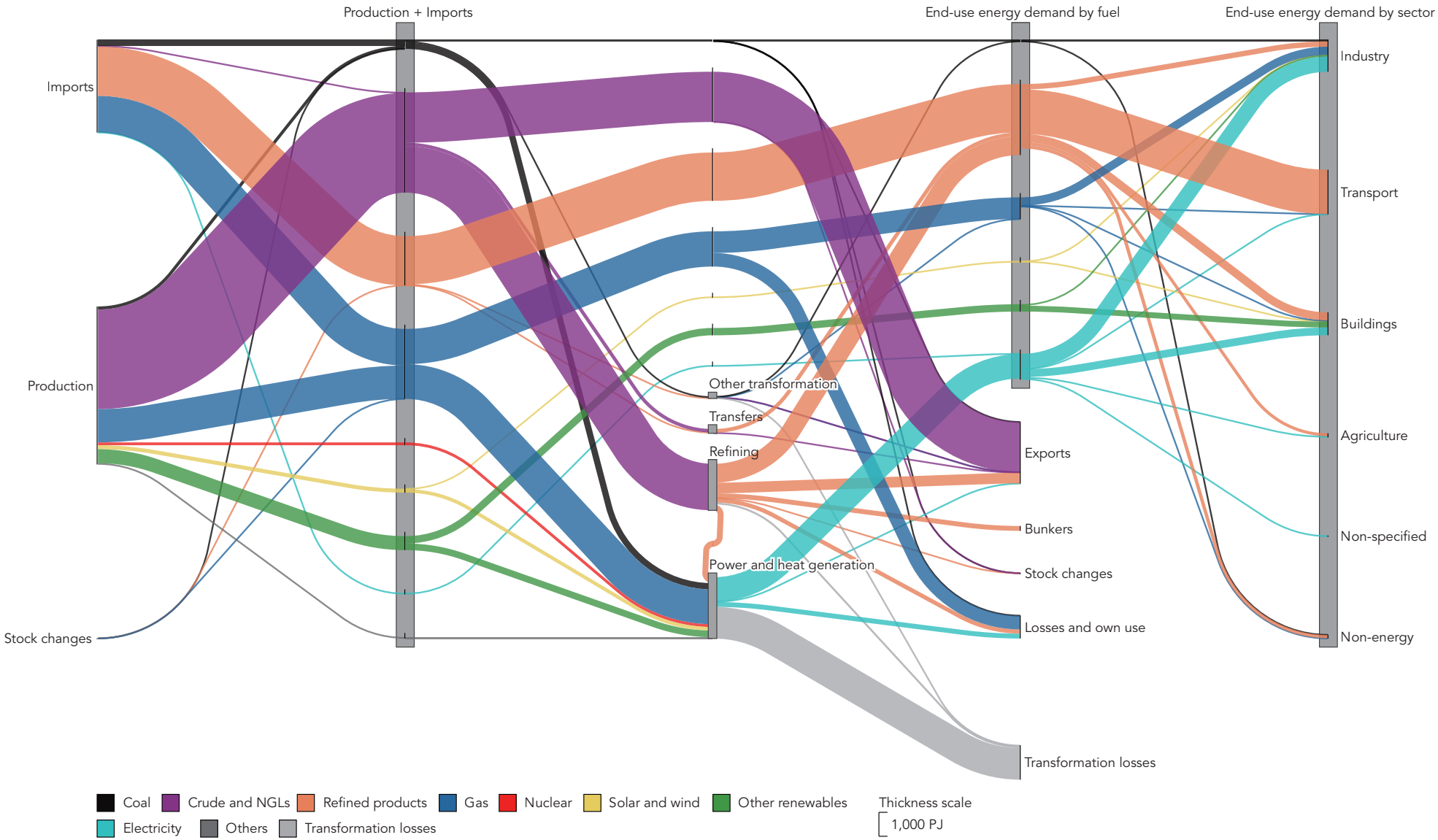
2024 Updated Energy Transition Strategy

In January 2024, Mexico updated its energy transition strategy officially known as "Strategy for the Transition to Promote the Use of Cleaner Technologies and Fuels". Led by SENER with support from CONUEE and other agencies, the revised strategy introduces new initiatives focused on energy efficiency, electromobility, energy storage, and renewables. It reaffirms goals to reduce final energy consumption and increase the use of clean energy.

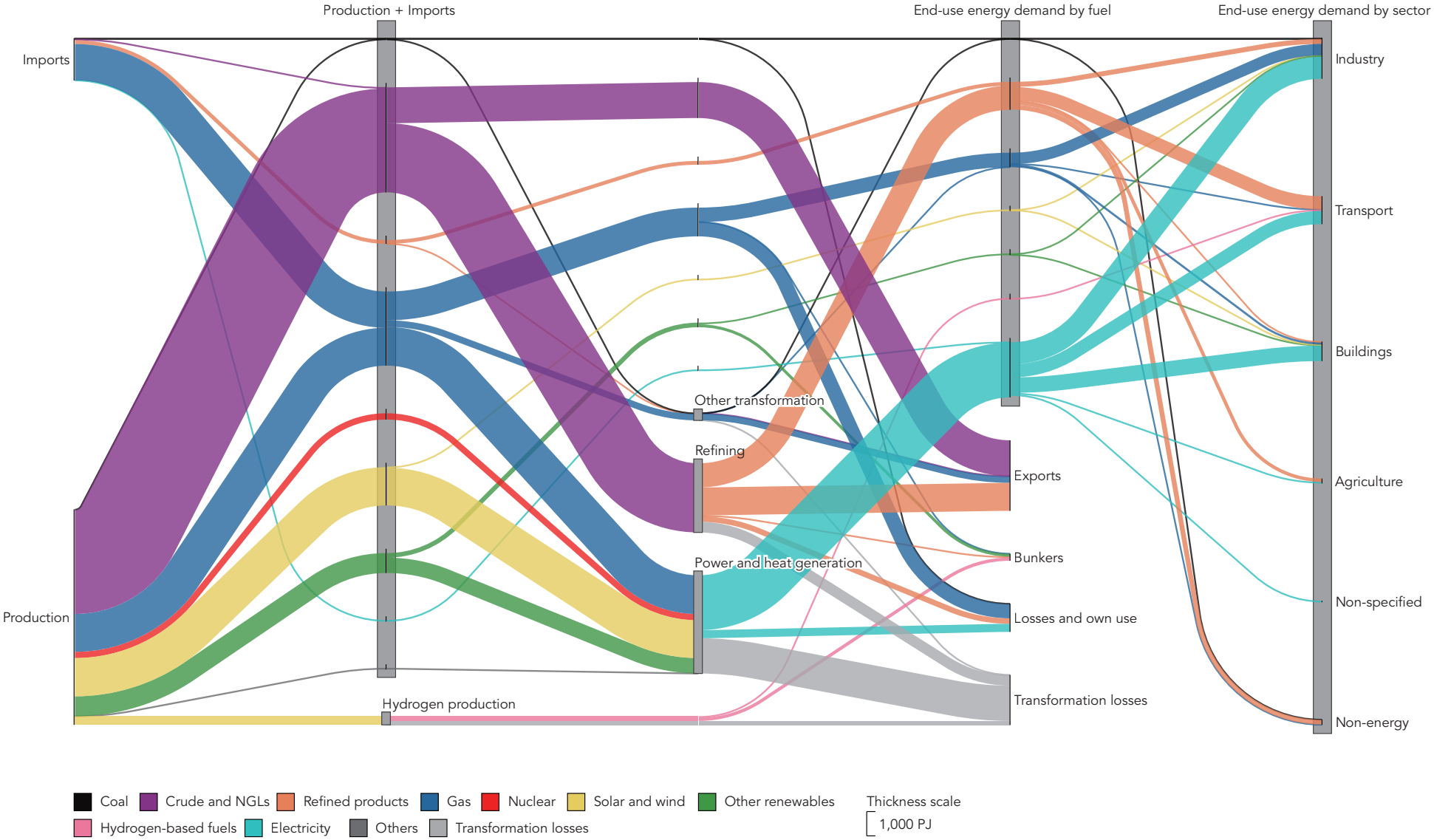
PRODESEN 2024-2038

In 2024, Mexico published the latest edition of its PRODESEN (National Electric System Development Program), outlining electricity infrastructure plans through 2038. The program prioritizes expanding renewable energy capacity, with a strong focus on wind power, modernizing the grid, and enhancing reliability and coverage. It emphasizes the integration of solar, wind, and hydro power, alongside strengthening transmission and distribution networks to support a cleaner and more resilient electricity system.

Energy Flow (2022)



Energy Flow (2060, Target Scenario)



Scenarios and Assumptions

In *The Outlook*, APERC analyses energy demand, transformation, and supply, as well as emissions. The **Reference Scenario (REF)** offers a projection based on historical trends, recent developments, and APERC's assumptions about the continuation of those trends in each APEC economy, while acknowledging technical restraints. The REF Scenario offers a baseline to compare with the **Target Scenario (TGT)** projections, which explores a hypothetical pathway where Mexico achieves energy-related policy targets, assuming implementation regardless of cost-effectiveness. When implementation details are lacking, assumptions are inferred from the targets themselves or emissions-related goals.

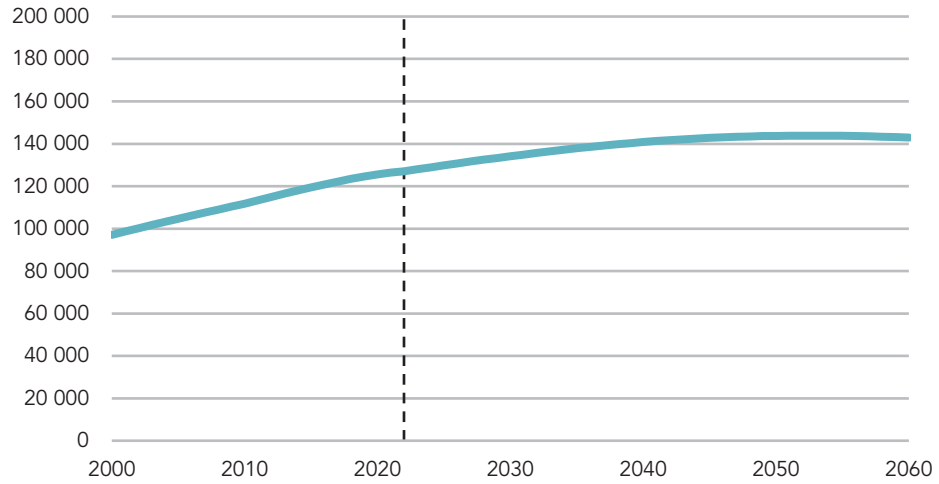
	Reference	Target
General	• Population: UN medium; GDP: APERC model and IMF.	• Population: UN medium; GDP: APERC model and IMF.
Buildings	• Energy demand is influenced by population and GDP per capita in both scenarios. • Demand growth is met by natural gas and electricity. • AI and data centre growth is the same under both scenarios.	• More aggressive efficiency measures are considered. • Demand growth is met by natural gas and electricity. • Fuel switching is implemented.
Industry	• Industry growth supports increased GDP growth in Mexico in both scenarios. • Increasing role for natural gas use in most sectors. • Electrification of many end-use applications. • No implementation of CCS or low-emissions fuels such as hydrogen in either scenario. • Non-energy growth tied to the petrochemical sector in both scenarios.	• Increased activity for minerals mining and metals processing. • Increased material and energy efficiency improvements as it is a focus of the energy transition strategy. • Greater electrification of end-use applications. • A large role for natural gas is maintained.
Transport	• In both scenarios, passenger activity growth is regulated by slowing growth in vehicle ownership. • EV sales shares grow at a modest rate (e.g., a 35% BEV sales share for passenger vehicles by 2060).	• EV sales shares grow quickly (e.g., an 80% BEV sales share for passenger vehicles by 2040). • Proportion of public transport use grows.
Power	• Coal generation is maintained. • Gas generation is the main type of generation until the end of the 2030s in both scenarios. • No CCS or H_2 co-firing in either scenario.	• Coal generation is phased out in 2030. • Renewable electricity share (Hydro, Geothermal, Bio, Solar, Wind) in 2033 is 40%, in 2050 is 58%. • Moderate batteries installation.

	Reference	Target
Supply	• Coal production continues its declining trend in both scenarios. • Oil and gas production increases and stabilizes (in line with Mexico's goals) in both scenarios. • LNG exports remain moderate in both scenarios. • Utilization rate of the refining system reaches 80% by 2028 in both scenarios. • Hydrogen for use outside of the fossil energy industry is produced by electrolysis with renewable power in both scenarios.	• Utilization rate of the refining system starts to decline during the late 2030s due to declining demand for refined products. • 190 kb/d of refining capacity are assumed to stop operations by 2050 due to declining demand for refined products.
Emissions	• CO_2 emissions are calculated at post consumption based off IPCC emission factors.	• CO_2 emissions are calculated at post consumption based off IPCC emission factors.

Note: The base year is 2022. Macro-economic assumptions are constant across scenarios. Historical energy balances are from EGEDA submissions for 2022.

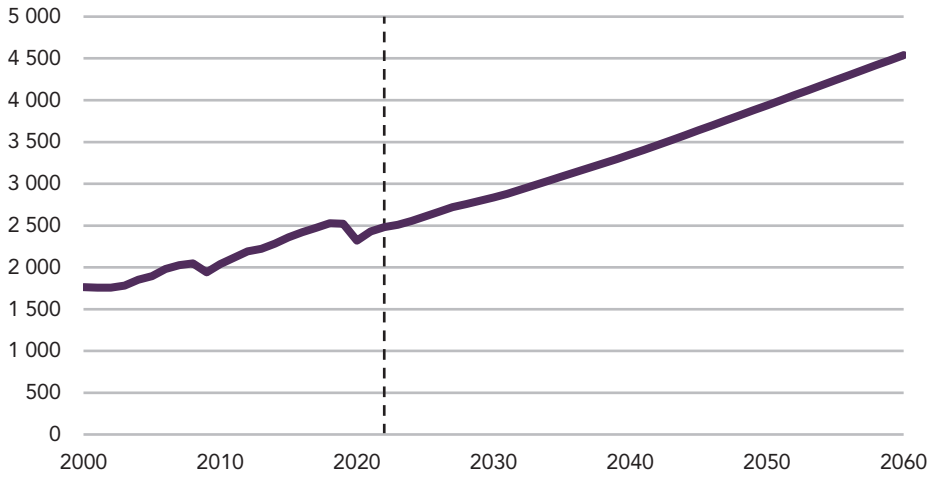
Demographic and Macroeconomic Assumptions

Figure 11-5. Population (thousands)



- Mexico's population is projected to continue growing in the coming decades, although at a slower pace than in previous periods. Demographic projections indicate that the population will peak at approximately 143 million people in the early 2050s, reflecting a shift toward more moderate population growth in the long term.
- Despite the gradual slowdown in population growth, Mexico has a relatively young population, with a median age of 29.6 years. This demographic profile supports a large and active labour force, which plays a critical role in sustaining the Mexico's manufacturing output and the development of its extensive natural resources.
- At the same time, Mexico has become increasingly urbanised, with an estimated 87% of its population now residing in urban areas. As urban centres expand and living standards increase, the energy needs of households, businesses, and infrastructure are expected to rise steadily, posing challenges and opportunities for Mexico's energy planning and economic development.

Figure 11-6. Real GDP (billion 2017 USD, PPP)



- Mexico's real GDP is projected to grow steadily at an average annual rate of 1.5 to 1.6% through 2060. This projected growth rate is slightly lower than the 1.8% average observed between 2000 and 2019.
- The slower expected growth is driven by several factors. Two of the main ones include a slowing demographic momentum, characterized by slower population growth and an increasing median age, which reduces the pace of labour force expansion. Additionally, the rapid manufacturing expansion experienced in the early 2000s, fuelled by Mexico's integration into the North American supply chain, has now slowed down, even though the economy remains deeply integrated as a manufacturing hub in the regional trade network.

End-use Energy Demand

Figure 11-7. Energy demand by sector in REF & TGT (PJ)

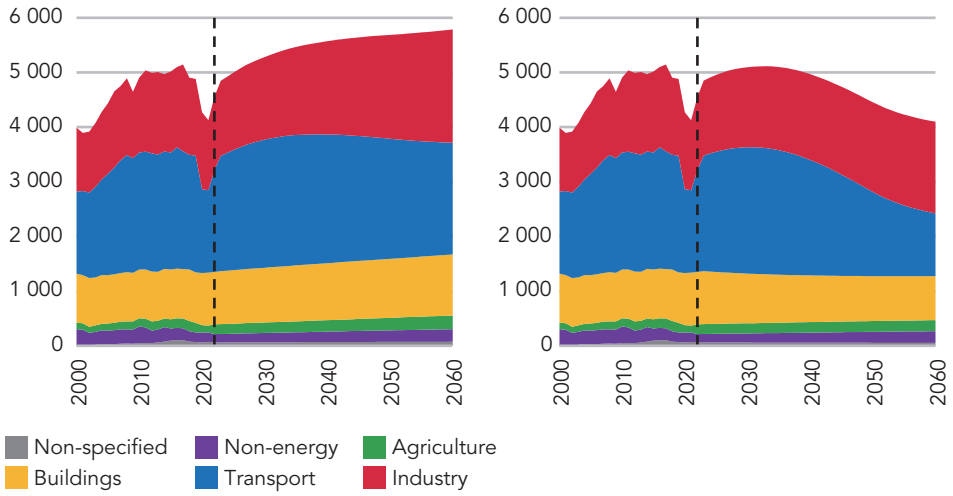
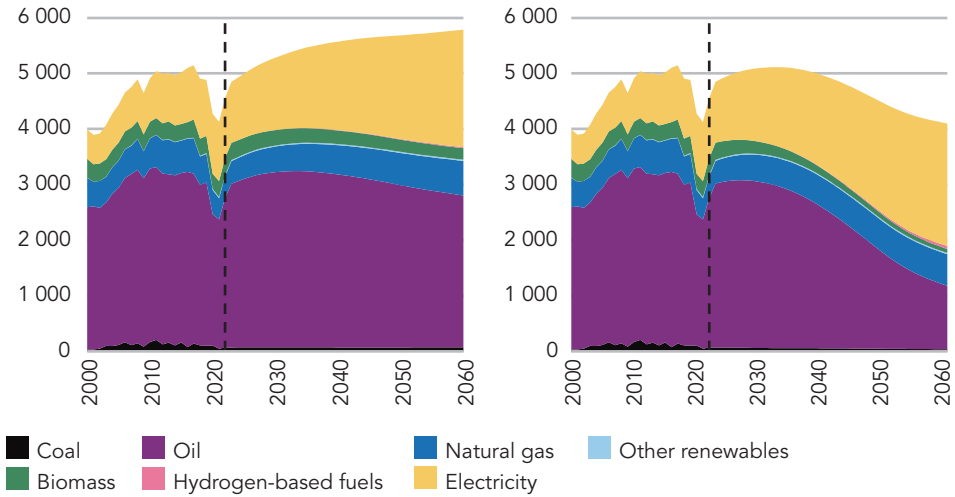


Figure 11-8. Energy demand by fuel in REF & TGT (PJ)



- Mexico's total end-use energy demand continues to grow in REF, reaching 5,787 PJ by 2060, which represents a 27% increase from the 2022 baseline. In contrast, demand in TGT peaks in the early 2030s at 5,114 PJ and then rapidly declines, driven by reduced energy demand in the transport sector.
- The industry and transport sectors are the main contributors to total energy demand and remain so in both scenarios. Energy efficiency improvements and electrification in these sectors are the key factors shaping Mexico's energy demand trajectory.
- Energy demand in the transport sector is projected to peak in 2035 in the REF scenario, after which growing electric vehicle adoption and the related energy efficiency improvements lead to a decline. In TGT, a faster pace of electric vehicle adoption causes a more significant reduction in energy use.
- The industry sector is expected to surpass transport as the largest end-use energy consumer by 2060 in both scenarios, driven by economic growth and Mexico's strategic role as a manufacturing hub in North America.
- Fossil fuels have historically dominated Mexico's end-use energy demand. Oil is currently the main end-use energy source, due to its essential role in transport and its presence across other sectors. In REF, oil is expected to maintain this dominant position.
- In both scenarios, electricity is expected to play an increasingly important role in meeting end-use energy demand as electrification progresses across sectors.
- In TGT, faster electrification in transport and industry, and to a lesser extent in other sectors, leads to an end-use energy system dominated by electricity.

Buildings Energy Demand

Figure 11-9. Buildings energy demand by fuel in REF & TGT (PJ)

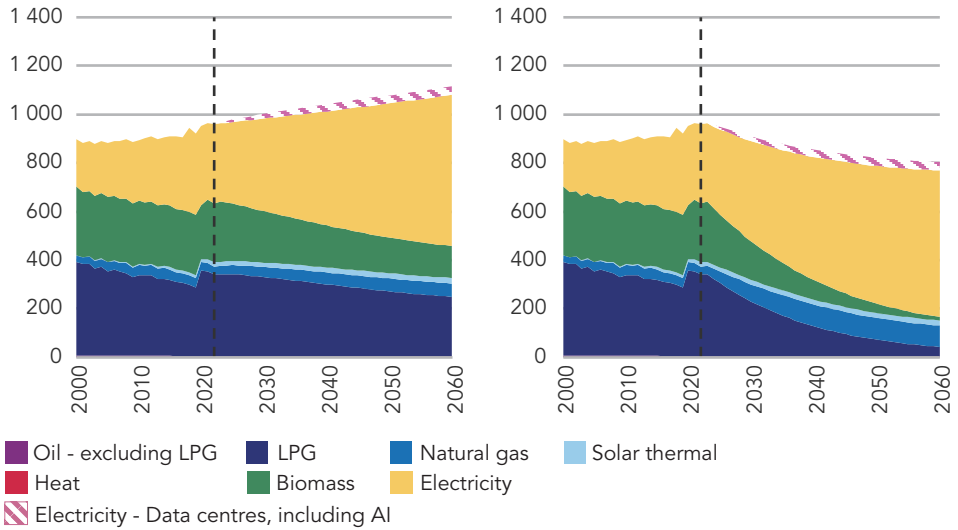
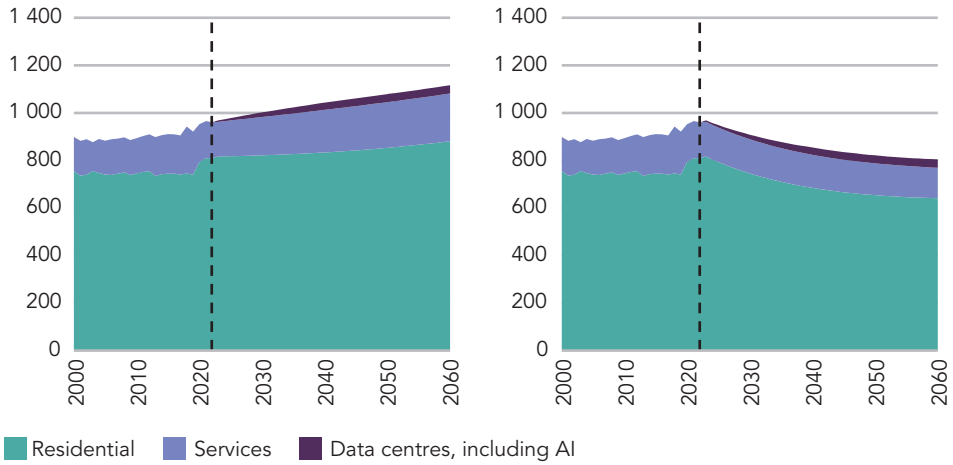


Figure 11-10. Buildings energy demand by sector in REF & TGT (PJ)



- Buildings energy demand in Mexico is expected to continue growing in REF, driven by population and economic growth, reaching a level 16% higher in 2060 compared to the 2022 baseline.
- In TGT, energy demand in buildings decreases due to more aggressive energy efficiency measures, including increased electrification and improvements to building envelopes that enhance energy conservation. As a result, demand drops 16% from the 2022 baseline, in line with the ambitious energy efficiency goals for the buildings sector outlined in Mexico's updated Energy Transition Strategy.
- The current energy mix in buildings consists mainly of LPG, electricity, and biomass. LPG and biomass are widely used in Mexico's building sector due to their flexibility and low access costs, especially for water heating, space heating, and cooking in residential and service buildings.
- In both scenarios, increased electrification and the expansion of natural gas infrastructure are expected to reduce the use of LPG and biomass, resulting in energy efficiency gains. In TGT, faster displacement of LPG and biomass and additional energy efficiency efforts are assumed, leading to a 28% reduction in overall buildings energy demand in 2060 compared to REF.
- Residential buildings account for more than 80% of energy consumption in the buildings sector and are expected to remain the main energy users in both scenarios. Efforts to improve thermal insulation and increase efficiency of electric and gas-based appliances in residential units are essential to materialise the TGT scenario. Current initiatives to support these efforts include, but are not limited to, Minimum Energy Performance Standards (MEPS) and the ENER labelling program.
- Energy demand for data centres and AI applications is expected to increase in the coming decades. Early estimates for Mexico indicate a moderate rise in electricity demand from AI; however, if adoption accelerates, electricity use could exceed current projections.

Industry Energy and Non-energy Demand

Figure 11-11. Industry & non-energy demand by fuel in REF & TGT (PJ)

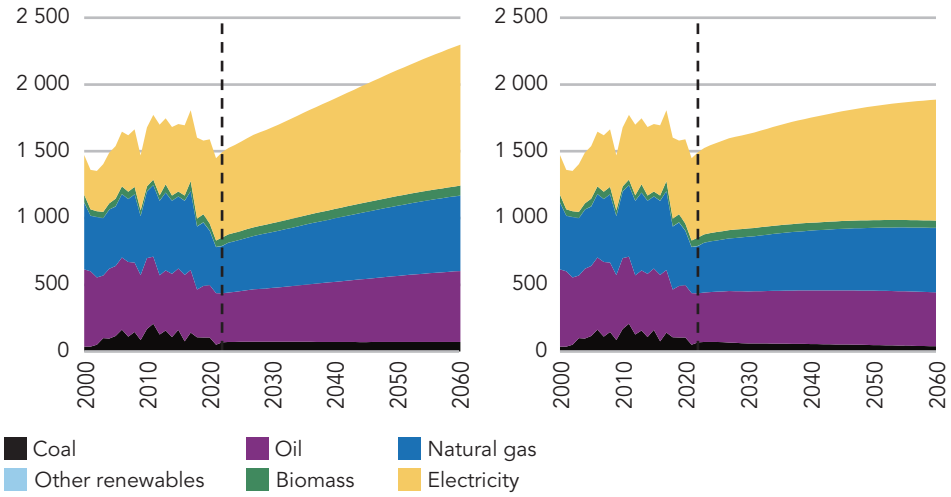
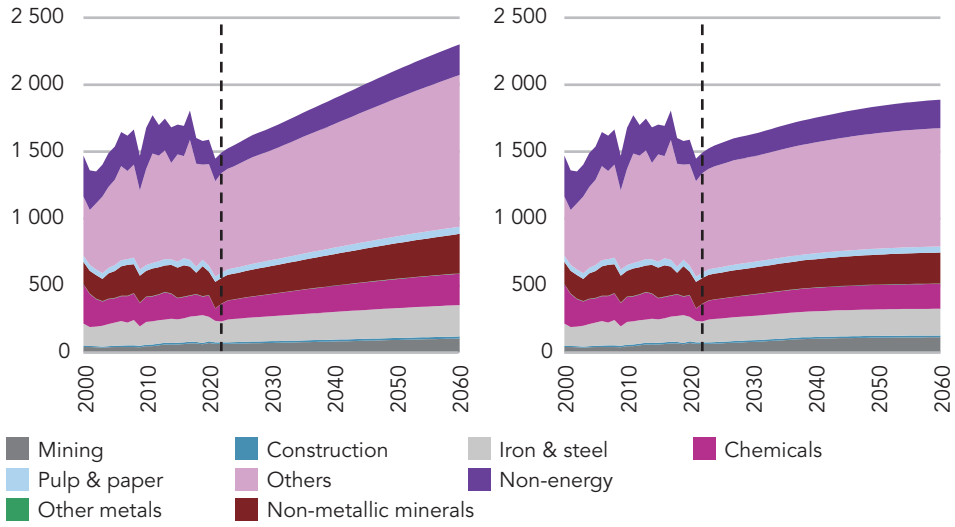


Figure 11-12. Industry & non-energy demand by sector in REF & TGT (PJ)



- Mexico's industry and non-energy demand continues to increase in both scenarios, driven by economic growth. In REF, energy demand in this sector grows by 54% by 2060 compared to the 2022 baseline. In the TGT scenario, growth is more moderate at 26%, as energy efficiency gains reduce the energy intensity of activities in this sector.
- Electricity, oil products, and natural gas are the main energy sources for the industry sector, while the non-energy sector primarily uses oil. In both scenarios, electricity remains the leading energy source in the industry sector. Between 2022 and 2060, electricity demand increases by 65% in REF and 42% in TGT, with the lower growth in TGT reflecting greater material and energy efficiency gains that offset a slightly higher electrification rate.
- In REF, oil use for energy increases slightly, while in TGT, it declines as electricity and natural gas become more competitive due to cost and energy efficiency gains. In TGT, the faster shift toward electricity and gas in industry displaces more oil, especially in low- to medium-heat applications. Oil use as a feedstock for petrochemicals (non-energy) supports the modest rise in REF and keeps demand flat in TGT.
- Coal use grows slowly in the REF scenario, as its expansion is limited by increased reliance on electricity and natural gas. However, coal remains difficult to replace in certain applications such as steel production (coking coal) and cement manufacturing. In the TGT scenario, some technological advances are expected to allow partial displacement of coal in these uses.
- In addition to large energy consumers, such as the mining and the manufacturing of metals, minerals, and chemicals industries, energy demand in Mexico is also driven by a large number of unclassified consumers, which hinders the development of a clear energy strategy in both scenarios.

Transport Energy Demand

Figure 11-13. Domestic transport energy demand in REF (PJ)

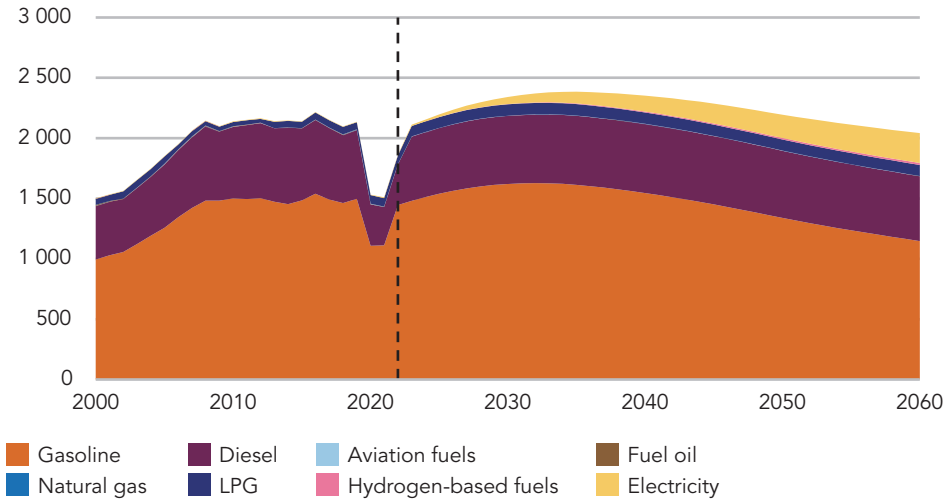
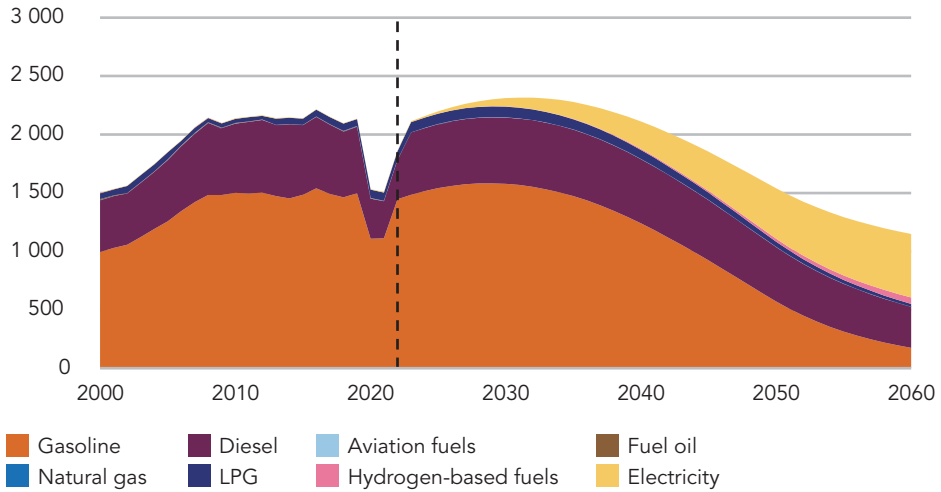


Figure 11-14. Domestic transport energy demand in TGT (PJ)



- In Mexico, the transport sector's energy demand is overwhelmingly dominated by road transport, which accounted for 97% of the sector's consumption in 2022. Road transport is projected to remain the dominant mode in both scenarios.
- Energy demand in the transport sector peaks in the 2030s in both scenarios. This trend results from a moderate increase in transport activity due to population and economic growth, which pushes demand up, and the growing adoption of electric vehicles (EVs), which reduces energy intensity.
- Petroleum products have historically accounted for the majority of energy use in Mexico's transport sector. However, with the increasing adoption of EVs, especially for passenger transport, electricity demand is projected to rise. In TGT, faster adoption of battery electric vehicles (BEVs) leads to a significant decline in energy use by 2060. By that year, the transport sector is expected to consume 43% less energy in TGT than in REF, as electric engines are more energy-efficient than internal combustion engines.
- The electrification of transport in TGT results in a substantial reduction in fossil fuel demand. Gasoline demand drops more rapidly than diesel and LPG as EV adoption advances faster in passenger vehicles than in freight.
- The decline in demand for refined products, combined with the additional supply from the new Dos Bocas refinery, provides Mexico with an opportunity to improve its energy self-sufficiency.
- In REF, the gradual rollout of EVs reduces gasoline imports and could eliminate the need for diesel imports by 2030. In TGT, faster EV uptake is projected to end gasoline imports in the second half of the 2040s, while diesel imports end around 2030.

Other Transport Data

Figure 11-15. Transport vehicle stocks in REF & TGT (millions)

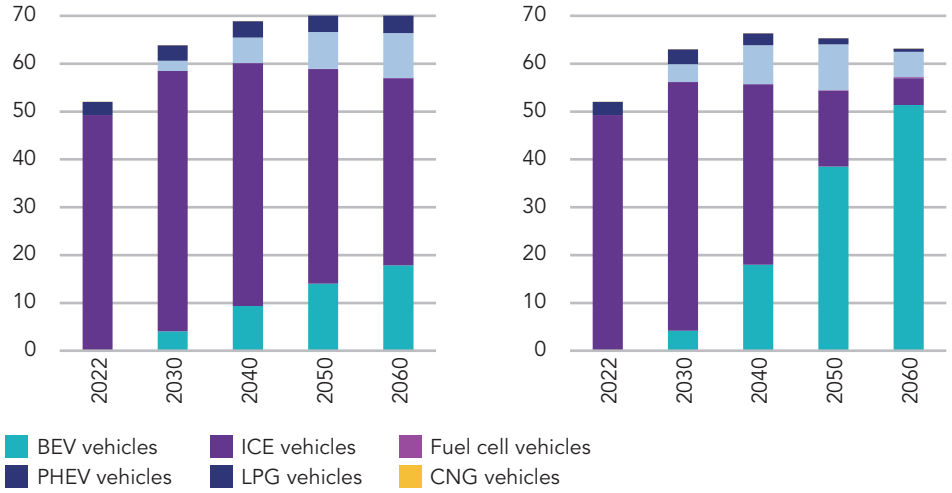
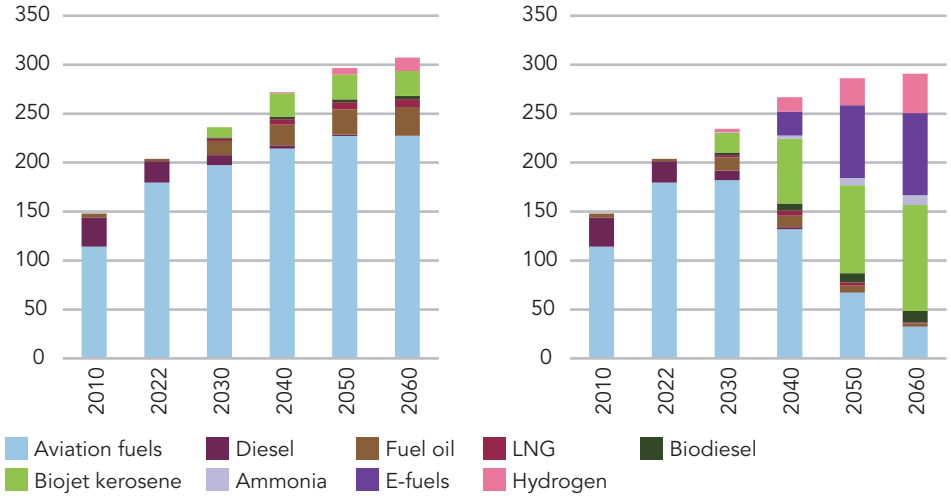
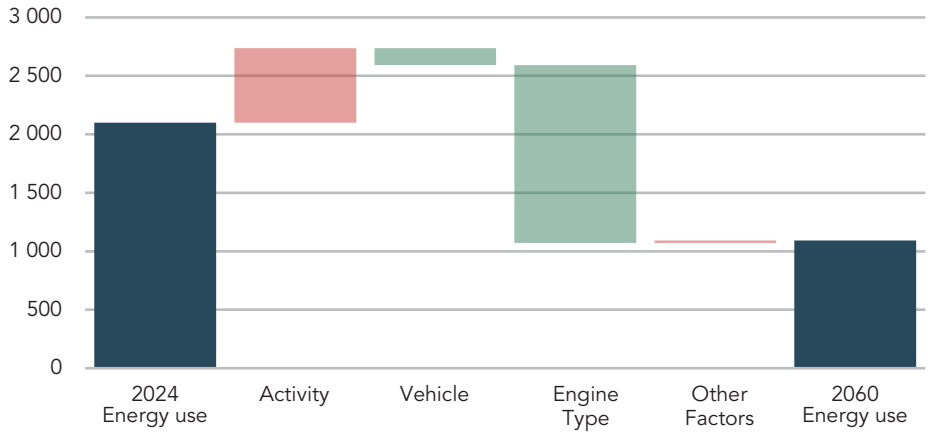


Figure 11-16. International bunker energy demand for shipping and aviation in REF & TGT (PJ)



- The share of internal combustion engine (ICE) vehicles declines in both scenarios as battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs) gain market share, with a sharper decline in TGT. By 2060, electric vehicles (EVs), mostly BEVs, are expected to make up 90% of the vehicle stock, aligning with Mexico's goal of 100% EV sales for new light vehicles by 2040.
- Figure 11-17 illustrates how the shift in engine type leads to a significant reduction in energy use in TGT. The rapid adoption of EVs, particularly BEVs, more than offsets the increase in transport activity driven by population and economic growth. The decrease in energy demand due to changes in vehicle size/type reflects the effect of growth in the proportion of public transport use.
- Demand for international bunker fuels increases in both scenarios due to economic growth and expanding trade involving Mexico. In TGT, anticipated global emissions standards from international transportation bodies are expected to drive greater use of lower-emission fuels.

Figure 11-17. Components of the change in road energy use in TGT (PJ)



Note: Information on the different drivers in the transport energy decomposition can be found in the *Outlook*'s annex.

Electricity Generation

Figure 11-18. Electricity generation by fuel in REF (TWh)

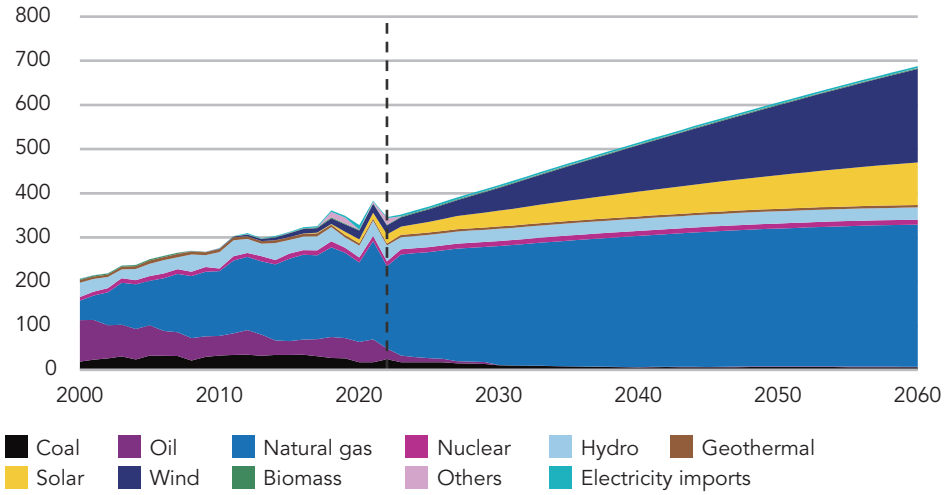
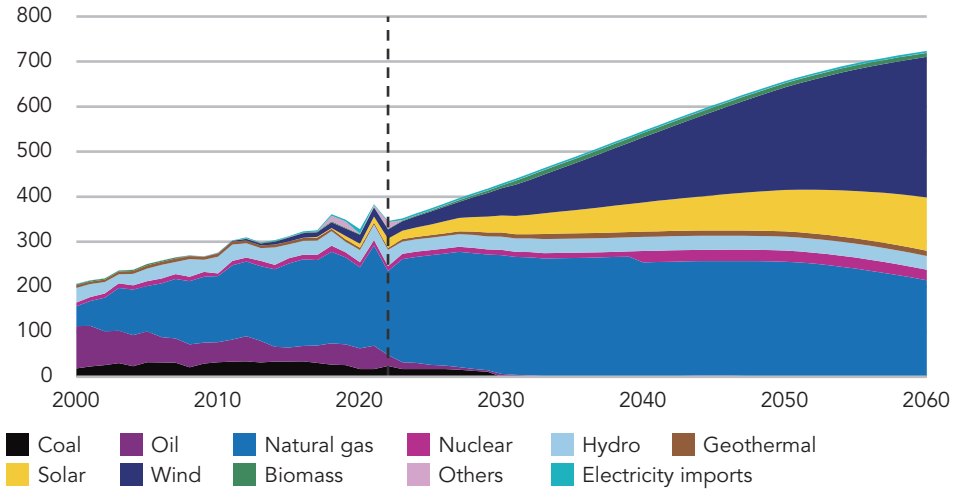


Figure 11-19. Electricity generation by fuel in TGT (TWh)

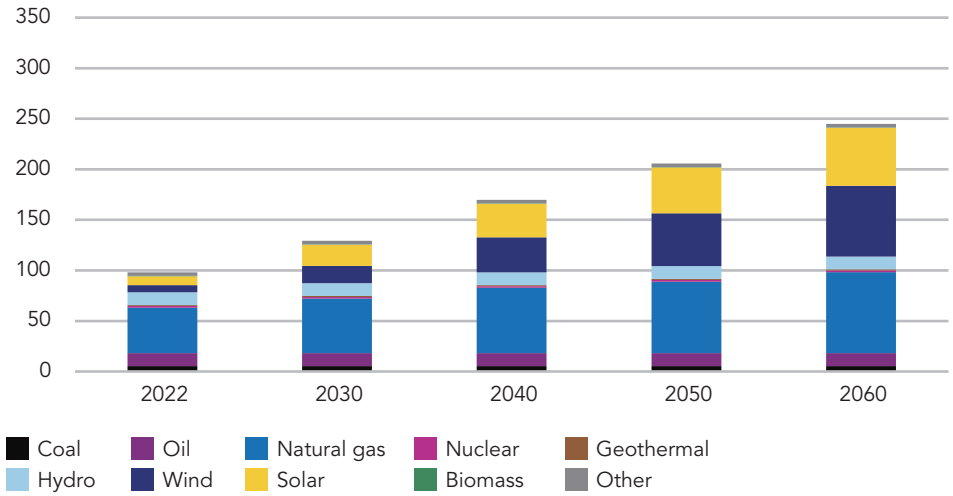


- Coal and fuel oil, which previously dominated Mexico's electricity mix, have experienced a substantial decline over the past two decades. This shift is largely due to the economic and environmental benefits of natural gas, supported by domestic production, competitively priced imports from the United States, and an expanded natural gas pipeline network.
- In REF, dispatchable power continues to play a dominant role in electricity generation, with gas-fired generation remaining the primary source of flexible and reliable electricity supply.
- In both scenarios, Mexico's electricity generation increases significantly from 346 TWh in 2022, reaching 688 TWh in REF and 723 TWh in TGT by 2060. The larger increase in TGT reflects the higher levels of electrification projected in the transport and industrial sectors.
- Renewable energy deployment expands in both scenarios, driven by advancements in technology and declining costs. In TGT, this expansion is more pronounced as decarbonisation goals and rapid electrification further accelerate the growth of wind and solar generation.
- The 2024 Electric System Development Plan marks a strategic shift in Mexico's approach to power sector decarbonisation. The plan redirects emphasis from solar to wind, positioning wind as the leading source of zero-emissions electricity in the coming decades, as its higher generation potential during summer aligns more closely with the seasonal peak in electricity demand.
- In TGT, wind and solar generation are projected to overtake gas-fired generation by 2045, and wind becomes the main source of electricity in the 2050s. Gas-fired generation remains stable until mid-century, after which it begins to decline as growing battery capacity enables greater integration of variable renewable sources.

Note: Figures 11-18 and 11-19 do not include electricity generation for hydrogen production.

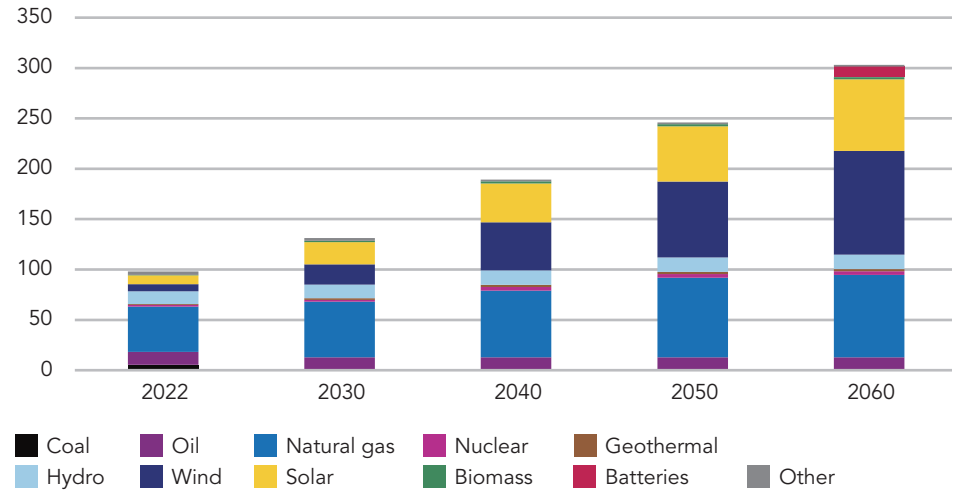
Generation Capacity

Figure 11-20. Generation capacity by fuel in REF (GW)



- Installed generation capacity is projected to grow significantly in both scenarios, with wind and solar expected to surpass gas-fired capacity by 2040 as Mexico continues to adopt more renewables.
- In REF, installed generation capacity more than doubles between 2022 and 2060, reaching 245 GW. Wind and solar capacity grow steadily, while gas-fired capacity increases by 78% due to favourable economics and its role in maintaining system stability and supporting renewable integration. All existing coal and oil power plants are expected to remain operational
- The moderate penetration of solar power in REF reduces the need for significant battery capacity. Wind power aligns more closely with Mexico's daily and seasonal peak loads, allowing gas-fired generation to balance the system and meet peak demand.

Figure 11-21. Generation capacity by fuel in TGT (GW)

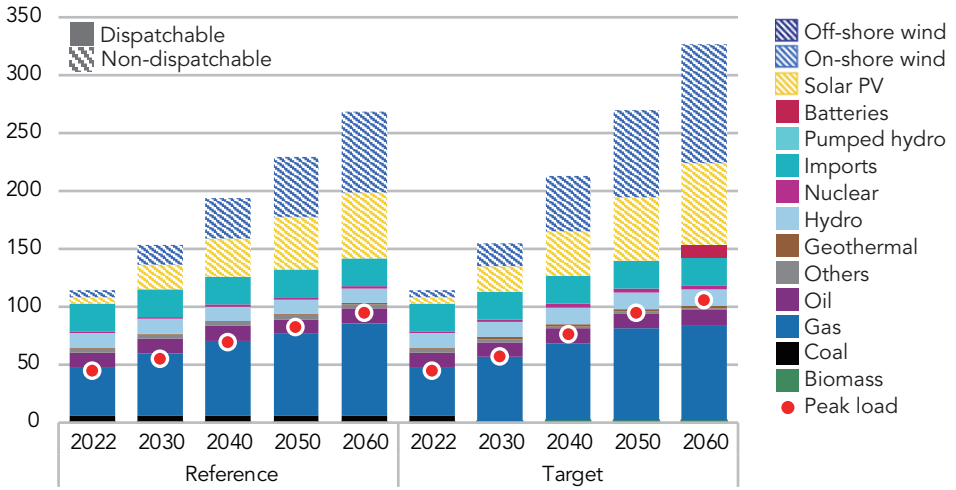


- In TGT, installed capacity is expected to almost triple, reaching around 300 GW by 2060. Wind and solar drive most of the growth as adoption of renewables accelerates. The higher share of solar generation increases the usefulness of battery capacity, particularly outside the summer season.
- Gas-fired capacity in TGT rises by 81% from 2022 to 2060. It plays a key role in enabling the faster integration of renewable power, serving as peak capacity in winter, spring, and autumn, and helping stabilize the grid during the summer months.

Note: Figures 11-20 and 11-21 do not include generation capacity for hydrogen production.

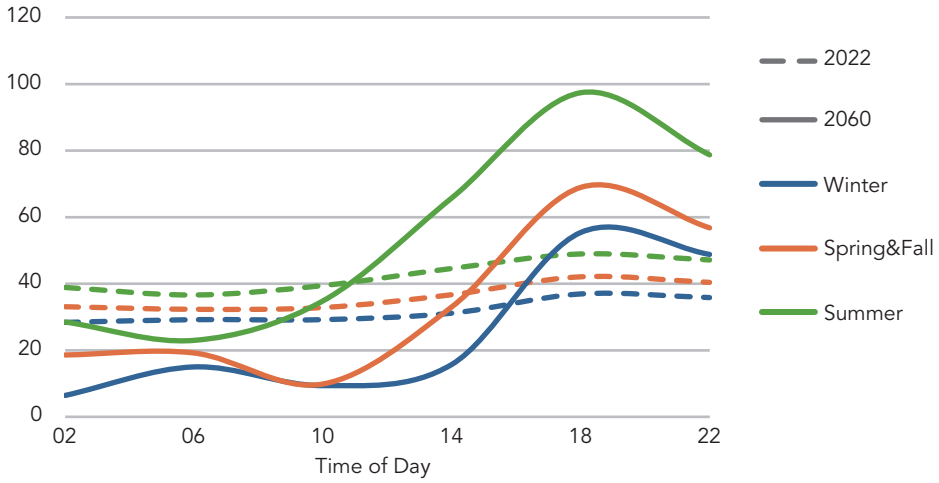
Grid Reliability

Figure 11-22. Total generation capacity and peak load (GW)



- In REF, peak electricity load is expected to grow by roughly 110% by 2060 from the 2022 baseline. In TGT, peak load grows by roughly 140% by 2060 from the same baseline as electrification increases significantly.
- The capacity to load ratio (total capacity divided by peak load) was estimated at 2.6 in 2022, including capacity related to electricity imports. The effective load ratio is lower when considering only power plants within the economy.
- This ratio is expected to increase by 2060 due to the integration of renewables with lower capacity factors. In REF, it rises to 2.9 because of solar and wind capacity. In TGT, with higher renewables adoption, it increases further to 3.1.
- The need to retain and install dispatchable generation capacity, including batteries, to cover peak load demand and balance the system also increases the overall size and cost of the electricity system.

Figure 11-23. Power from dispatchable sources in TGT (GW)



- In TGT, by 2060, the higher penetration of wind and solar power significantly increases the variability of generation required from dispatchable power sources. As shown in Figure 11-23, on an average summer day in Mexico, dispatchable power demand rises sharply from around 20 GW at 6:00 am to 97 GW by 6:00 pm.
- This variability is spread across the entire economy, but individual days may experience even greater fluctuations.
- These increasing fluctuations in dispatched power represent a substantial challenge for system operators. Meeting this challenge will likely raise the capital, maintenance, and operating costs of the electric grid, posing important considerations for electric system management and financing decisions.

Coal and Biomass

Figure 11-24. Coal and biomass consumption by sector in REF & TGT (PJ)

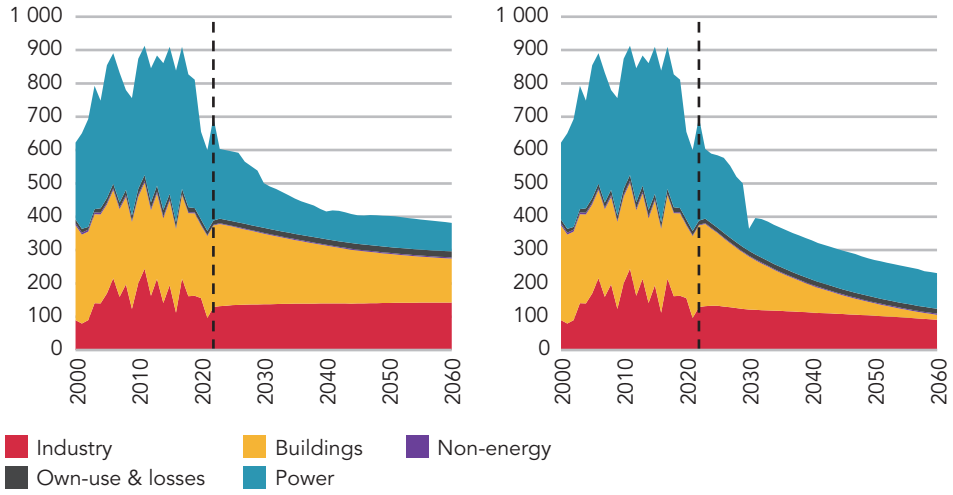
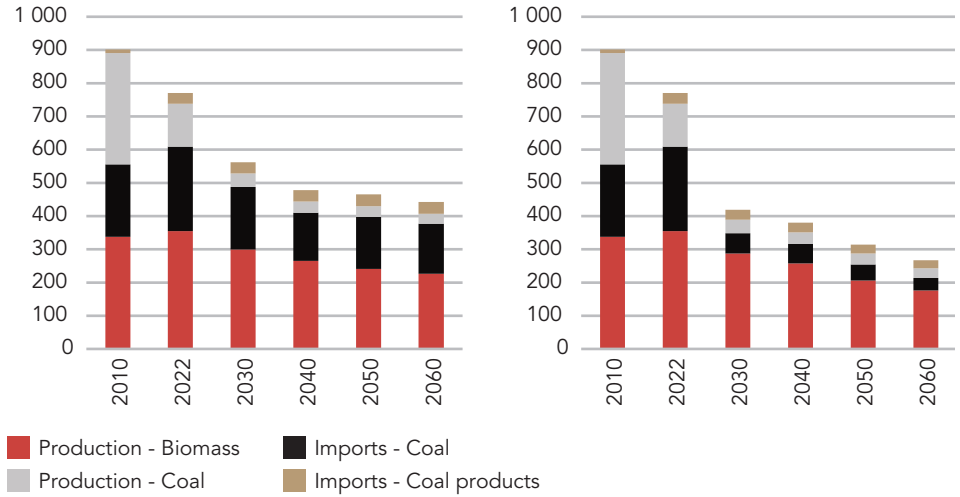


Figure 11-25. Coal and biomass production, imports, and exports in REF & TGT (PJ)



- Mexico's coal demand is mainly driven by the power and industry sectors. In REF, a moderate shift from coal to gas in power generation reduces coal demand slightly, while coal use in industry remains flat since metallurgical coal and coal for cement manufacturing are difficult to replace. In TGT, coal use in power generation is phased out by 2030, while industrial use declines gradually as technological advances enable partial displacement.
- Production of thermal coal in Mexico continues to decline and becomes negligible by the mid-2030s in both scenarios. In REF, imports of thermal coal continue throughout the period as coal still plays a role in power generation.
- Metallurgical coal production in Mexico slowly declines from 2022 levels in both scenarios. Mexico is expected to remain reliant on metallurgical coal imports to meet the needs of its steel manufacturing industry.

- Biomass is the main bioenergy source used in Mexico, primarily in the buildings sector for heat applications like water heating and cooking. The industry sector is a distant second, using residual biomass from food and wood processing for heat. Biomass has a limited role in power generation, but is projected to partially offset the coal generation phased out by 2030 in TGT.
- In REF, the moderate electrification of heat applications in buildings and increased access to gas, particularly in the residential segment, gradually reduces biomass consumption. In TGT, the faster pace of electrification and gas adoption in buildings accelerates this decline.
- As biomass use decreases in both scenarios, biomass production is projected to fall as well, especially in cases where biomass is not a by-product of industrial processes.

Natural Gas and Biogas

Figure 11-26. Natural gas and biogas consumption by sector in REF & TGT (PJ)

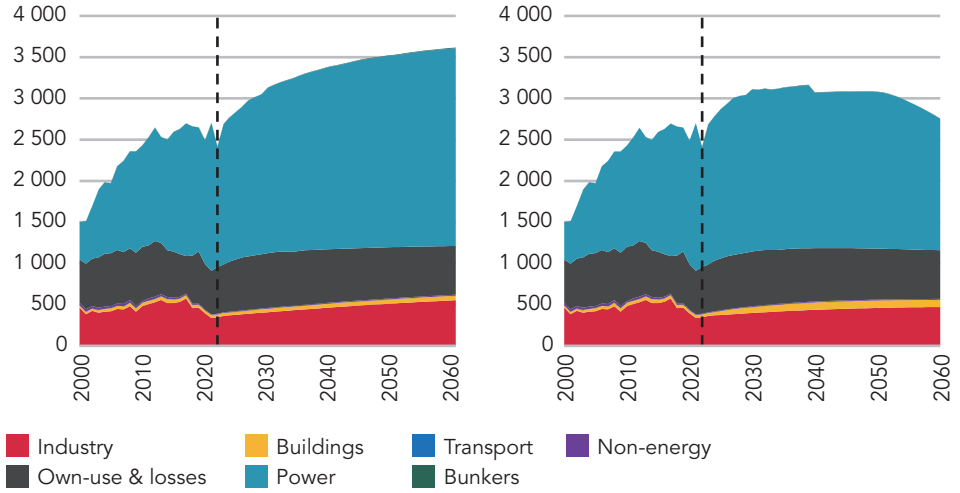
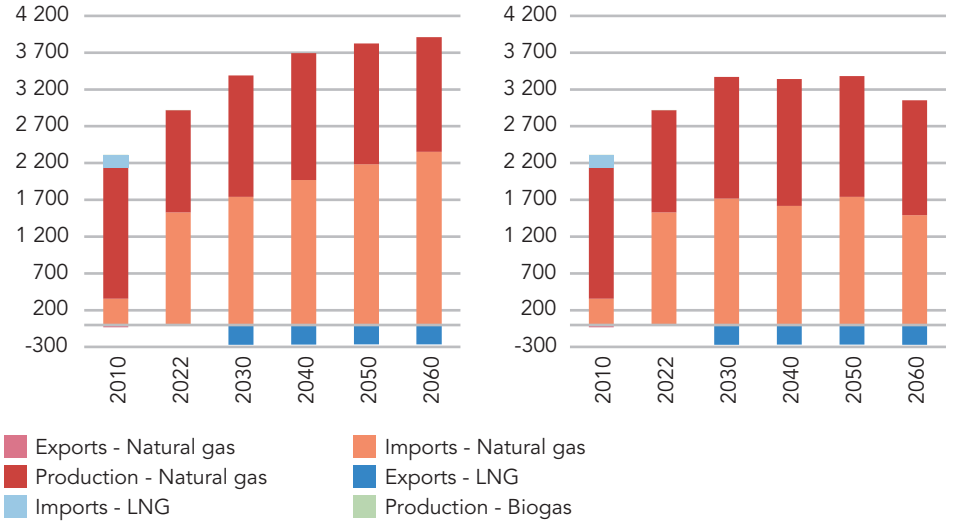


Figure 11-27. Natural gas and biogas production, imports, and exports in REF & TGT (PJ)



- Natural gas consumption in Mexico has been steadily increasing, primarily driven by gas-fired power generation. The fossil fuel industry is the second largest consumer, using gas mostly for oil and gas extraction and crude oil refining. The industrial sector ranks third, where gas is used for heat applications.
- In REF, natural gas demand continues to grow throughout the projection period. In contrast, in TGT, demand peaks in the late 2030s due to increased adoption of wind and solar generation, battery storage, and the electrification of low- and medium-heat industrial applications.
- After a steep decline between 2013 to 2018, natural gas production in Mexico began to recover, reaching about 1,400 PJ in 2022, supported by production stabilization efforts and new onshore developments. According to the 2023-37 Natural Gas Prospectives, Mexico aims to increase production to surpass 1,700 PJ in the second half of the 2030s, a target included in both REF and TGT.
- Even if the production goal is met, Mexico is expected to remain heavily dependent on U.S. gas imports. In TGT, higher renewables integration in the power sector reduces import needs, but throughout the modelled period, around 50% of demand is still met through imports.
- Biogas production is projected to remain minimal in both scenarios.
- Mexico is becoming an alternative route for U.S. LNG exports with liquefaction projects on the Pacific and Atlantic coasts serving Asian and European markets, respectively. The future expansion of LNG capacity in Mexico will depend on U.S. energy policies and preferences for domestic versus Mexican liquefaction projects.

Note: Historical data for LNG is based on JODI gas data.

Petroleum Liquids

Figure 11-28. Crude oil, NGLs, and other hydrocarbon production, imports, and exports in REF & TGT (PJ)

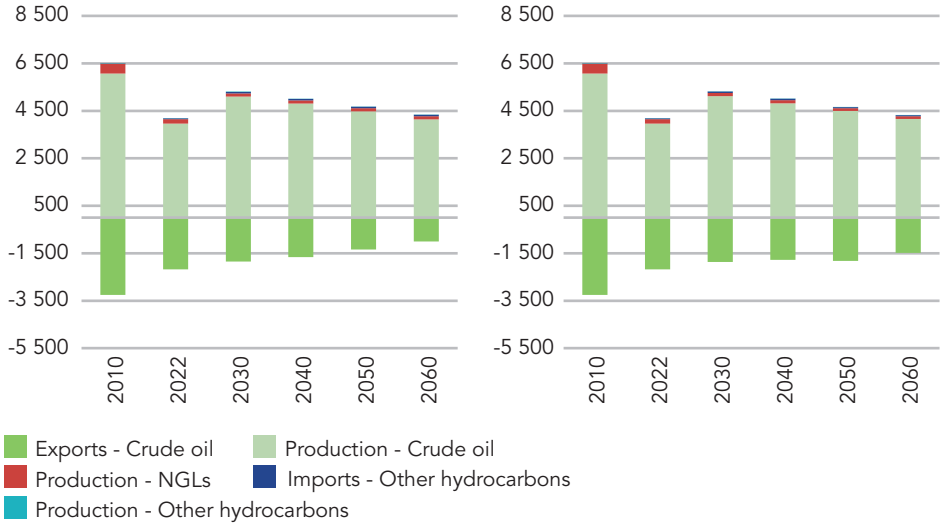
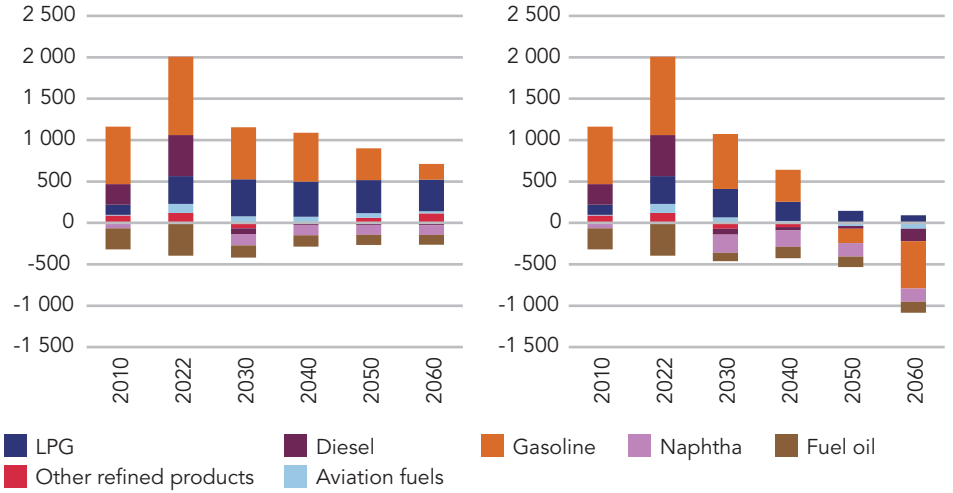


Figure 11-29. Net imports of refined products in REF & TGT (PJ)



- Crude oil production and exports have long been central to Mexico's economy. Production has been on a declining trend since the early 2000s, but between 2019 and 2022, production stabilized.
- According to the 2023–37 Crude Oil and Refined Products Prospectives, Mexico expects to increase crude oil production to roughly 5,100 PJ in the early 2030s, a 28% rise over 2022 volumes. This optimistic target is reflected in both scenarios. Meanwhile, production of NGLs remains relatively low throughout the period.
- Mexico's heavy crude oil exports have traditionally been directed to the United States, where Gulf Coast refineries are optimized for heavy crude. However, exports are expected to gradually decline as the domestic refinery utilization rate rises and domestic crude production begins to fall again after the 2030s.
- Crude oil exports remain higher in TGT than in REF, due to the reduced demand for crude oil in the domestic refineries.

- Mexico remains heavily reliant on gasoline, diesel, and LPG imports, primarily from the United States. This dependence deepened in the late 2010s when crude oil production and refinery utilization rates declined sharply.
- Refined products output in Mexico is expected to increase during the second half of the 2020s. In both scenarios, this leads to a decline in refined product imports, most notably gasoline and diesel.
- Mexico is projected to become self-reliant for diesel before 2030 in both scenarios. Gasoline imports continue in REF but phase-out in the 2040s in TGT due to transport electrification. LPG imports persist in both scenarios.
- In both scenarios, crude oil and refined product export levels in the later years will depend on international demand for these commodities. This is especially important in TGT, as other economies also pursue decarbonisation.

Note: In Figure 11-29, net imports are presented without deducting bunkers.

Refining

Figure 11-30. Refining outputs in REF & TGT (PJ)

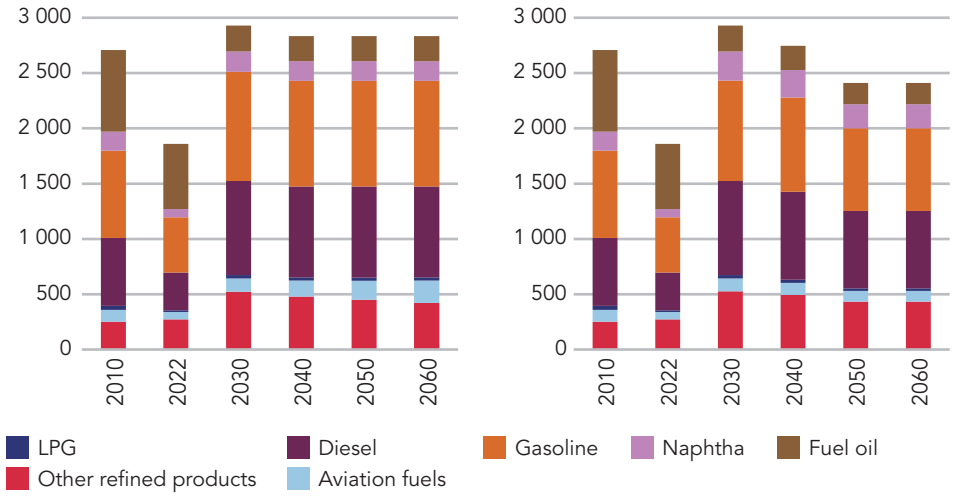
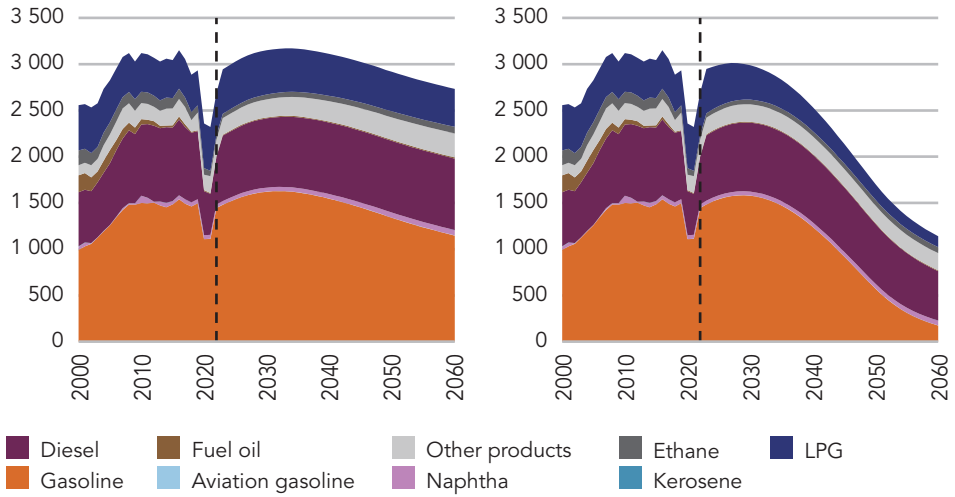


Figure 11-31. Refined products and low-carbon fuels demand in REF & TGT (PJ)



- Mexico's refining output is expected to increase significantly by 2030 from 2022 levels in both scenarios. This is driven by improved utilization of the six original refineries and the ramp-up of operations of the Dos Bocas refinery's newly added refining capacity, which began operations in 2024.
- Since 2019, Mexico has prioritized revitalizing its domestic refining industry by investing heavily in the maintenance and upgrading of its six existing refineries. These efforts, which include adapting the facilities to process heavy crude oil, are expected to raise the production of high-value refined products and reduce the output of fuel oil.
- In line with Mexico's 2023–37 Crude Oil and Refined Products Prospectives, the output of high-value refined products by 2030 in both scenarios is projected to roughly equal or surpass the levels observed in the early 2000s. This reduces reliance on imports, especially for gasoline and jet fuel. More importantly, the ramp up of high value output will enable self-reliance for diesel in the near term in both scenarios. LPG output also partially recovers.
- In TGT, refining output is projected to decline after the 2030s. Lower domestic demand for refined products, primarily in the transport sector, reduces the economic feasibility of maintaining high utilization rates and operating all refineries.
- The transport sector is the main driver of refined product demand and refining activity. Demand is expected to peak in the 2030s in both scenarios.
- In REF, moderate electrification of the transport sector drives the decrease in demand for gasoline and diesel. In TGT, faster electrification across the transport, industry, and buildings sectors results in a sharp decline in gasoline use, a considerable reduction in diesel demand, and a decrease in LPG consumption.
- Liquid biofuels production is projected to increase in both scenarios, mainly driven by demand from international bunkers. Growth is faster in TGT due to expected emissions reduction standards from international transport bodies.

Hydrogen-based Fuels

Figure 11-32. Hydrogen-based fuels demand by sector in REF & TGT (PJ)

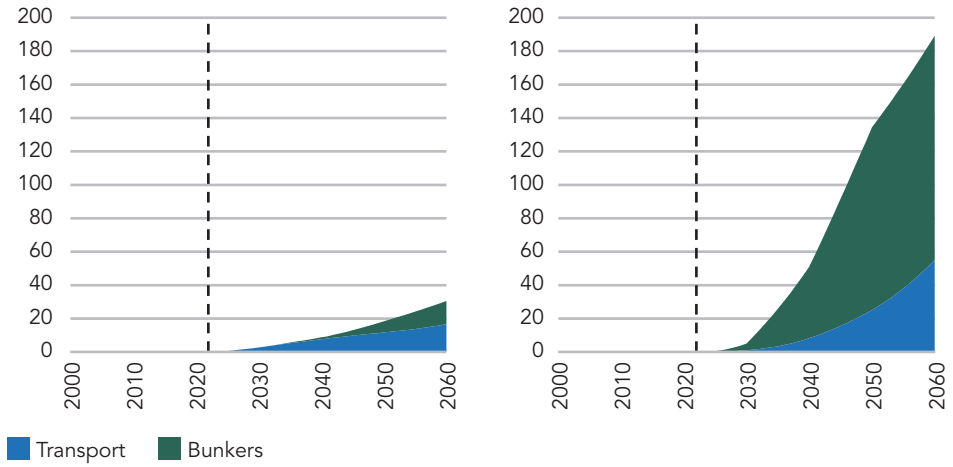
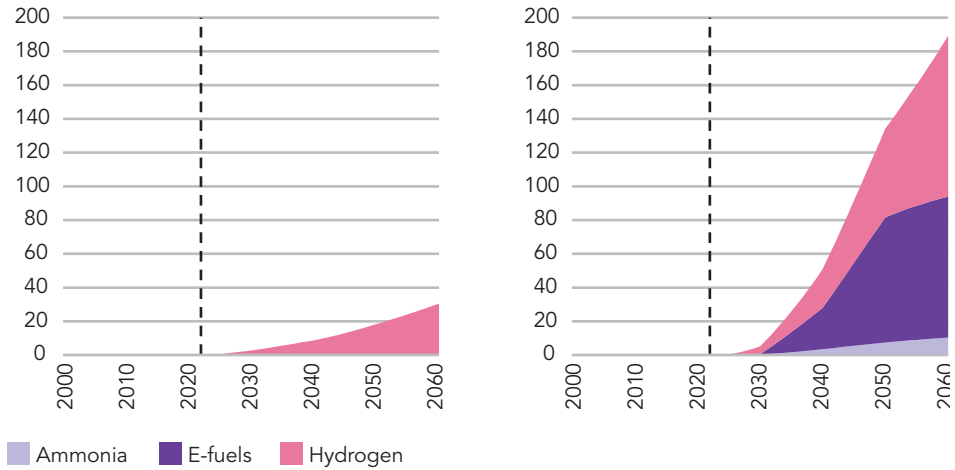
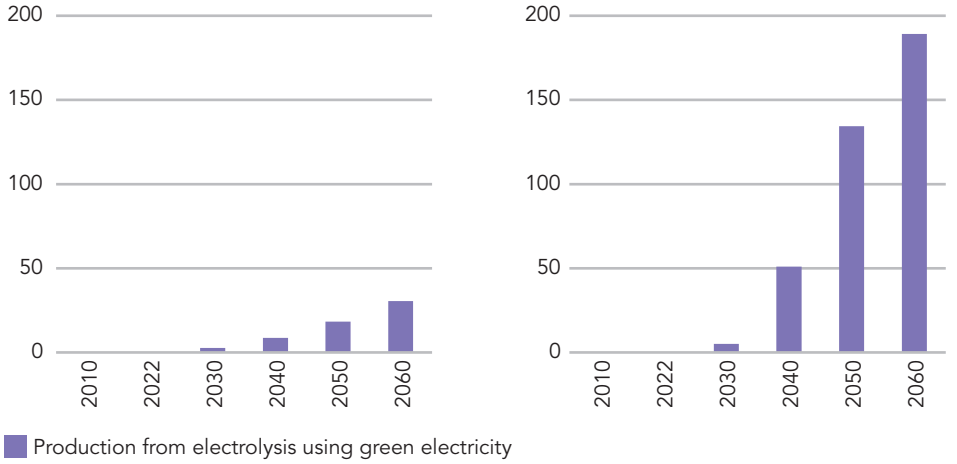


Figure 11-33. Hydrogen-based fuels demand by fuel in REF & TGT (PJ)



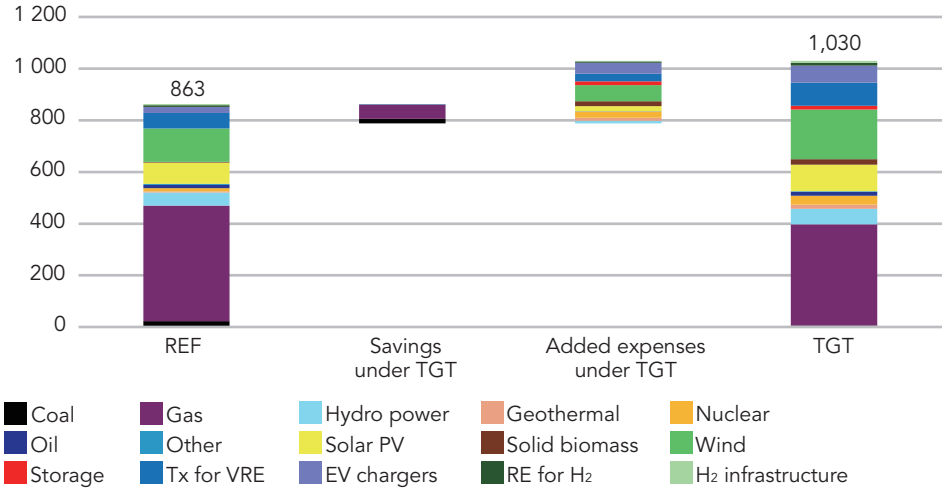
- Mexico, in its 2024 Updated Energy Transition Strategy, states that green hydrogen production could be implemented in the medium term but does not provide a detailed implementation roadmap. In REF, hydrogen-based fuels are assumed to have a limited role, mainly in the transport sector and international bunkers. In TGT, their role expands, driven by increased consumption in international bunkers as low-emission policies for global trade are expected to encourage adoption.
- In REF, hydrogen is used directly in fuel cell electric vehicles and bunkers. In TGT, hydrogen is also converted to ammonia and e-fuels to facilitate storage and transport, expanding its applications (Figure 11-33). The faster implementation of hydrogen-based fuels in TGT assumes a supportive regulatory environment and technological advancements that improve their economic competitiveness.
- Hydrogen production in both scenarios is expected to rely on electrolysis powered by green electricity.

Figure 11-34. Hydrogen-based fuels production methods and supply in REF & TGT (PJ)



Costs

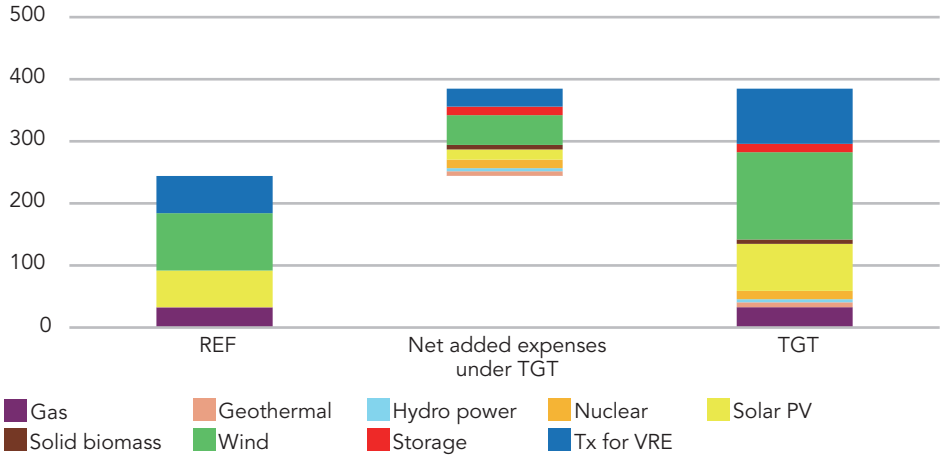
Figure 11-35. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



Note: Tx for VRE is only transmission infrastructure to connect variable renewable capacity to the grid. EV chargers do not cover the cost of associated infrastructure or EV vehicles. H_2 costs to meet bunkering obligations are not included here.

- Meeting future electricity demand in Mexico is expected to require substantial investment and expenditure from 2025 to 2060 in both scenarios. Figure 11-35 presents the total capital, fixed, and variable costs in the power sector, green hydrogen production for domestic use (albeit small), transmission for variable renewable electricity (VRE), and electric vehicle chargers.
- Gas, wind and solar generation, and variable renewables-related transmission account for most of the increase in electricity system spending in both scenarios. Gas-fired generation remains the primary dispatchable source, essential for reliable, on-demand electricity to support system stability, especially in TGT as wind and solar reach 57% of installed capacity by 2060.
- The total cost in TGT is projected to be 19% higher than in REF by 2060. This difference is mainly driven by additional investments in wind capacity, electric vehicle chargers, and transmission infrastructure for VRE.

Figure 11-36. Total capital investment (CAPEX) from 2025 to 2060 in the power sector (billion USD, undiscounted)

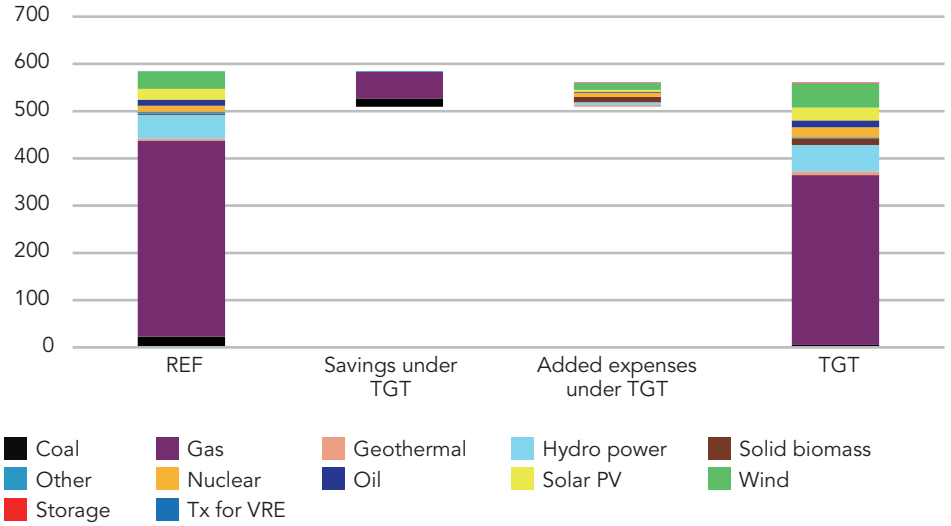


Note: Figure 11-36 only covers power and VRE transmission sector investments. Hydrogen and EV capital investments are not included.

- Total CAPEX in the power sector reaches USD 385 billion in TGT, up from an estimated USD 245 billion in REF. Most of the additional spending in TGT comes from investments in new wind and solar power and VRE transmission.
- Although TGT requires additional investment in transmission infrastructure to integrate more solar and wind, battery investments remain moderate. This is due to the presence of sufficient dispatchable capacity and the favourable alignment of wind generation with Mexico's daily and seasonal load patterns.
- In TGT, investments in additional wind and solar capacity, together with the transmission and battery infrastructure needed for their integration, account for 76% of the added capital expenditures. These investments contribute significantly to the roughly 37% reduction in power sector emissions in TGT compared to REF in 2060.

Costs

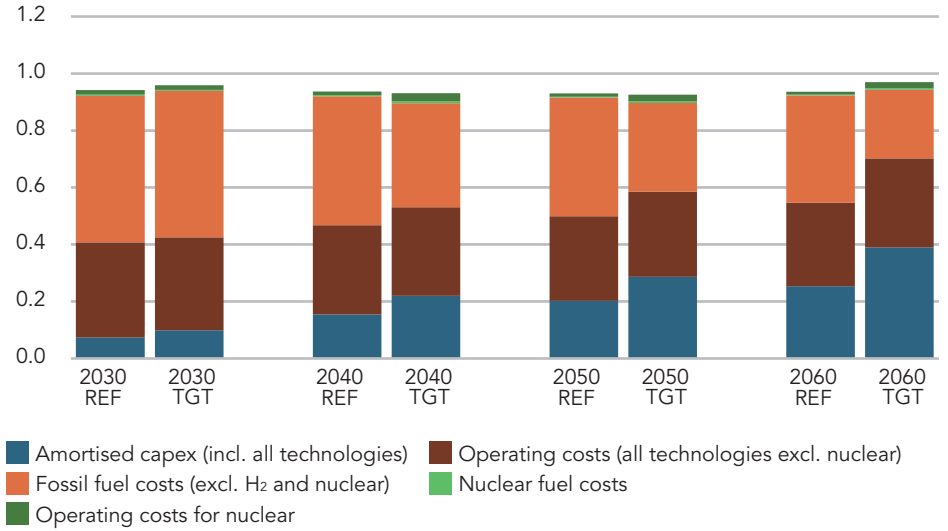
Figure 11-37. Total operating costs from 2025 to 2060 in the power sector (billion USD, undiscounted)



Note: Figure 11-37 only covers power and VRE transmission sector costs. It does not include operating costs associated with hydrogen production and EV charger costs.

- Total operating costs are estimated at approximately USD 584 and 561 billion in REF and TGT respectively between 2025 and 2060. These costs include variable fuel and non-fuel expenditures, as well as fixed costs for both power generation and transmission for VRE.
- While the overall difference in operating costs between REF and TGT is relatively small, the composition of these costs changes. In TGT, reduced reliance on natural gas and coal results in fuel costs savings that more than offset the increased operational costs associated with more renewables.
- The added costs in TGT reflect a mix of operational costs from the addition or expansion of low-carbon technologies such as wind, nuclear generation, and biomass co-firing.

Figure 11-38. Cost of generating electricity relative to 2025 (2025 cost = 1.0) in the power sector



Note: Based on our assumptions about future capital and operating costs, Figure 11-38 shows cost compositions over time relative to 2025. It should not be considered an estimate of electricity tariffs and excludes market mechanisms that are too difficult to estimate.

- Figure 11-38 shows the relative cost of generating electricity in selected years, indexed to the base year of 2025 for each scenario.
- Indexed to 2025, generation costs in both scenarios stay relatively constant throughout the modelled period. In REF, while fossil fuels decrease in their contribution to total costs, these are almost outweighed by rising amortised capital costs from new renewable deployment resulting in costs remaining relatively constant throughout the period.
- In TGT, the even faster deployment of renewables compared to REF leads to greater fossil fuel savings, especially with the further decline in gas usage. However, these savings are outweighed by the greater increase in amortised capital compared to REF. By 2060, the generation costs in TGT appear broadly in line with those in REF.

CO_2 Emissions

Figure 11-39. CO_2 emissions in REF (million tonnes)

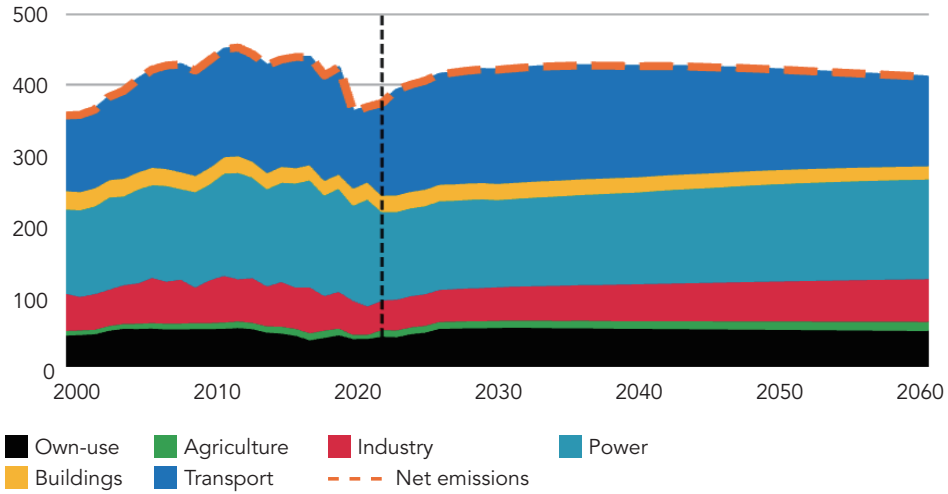
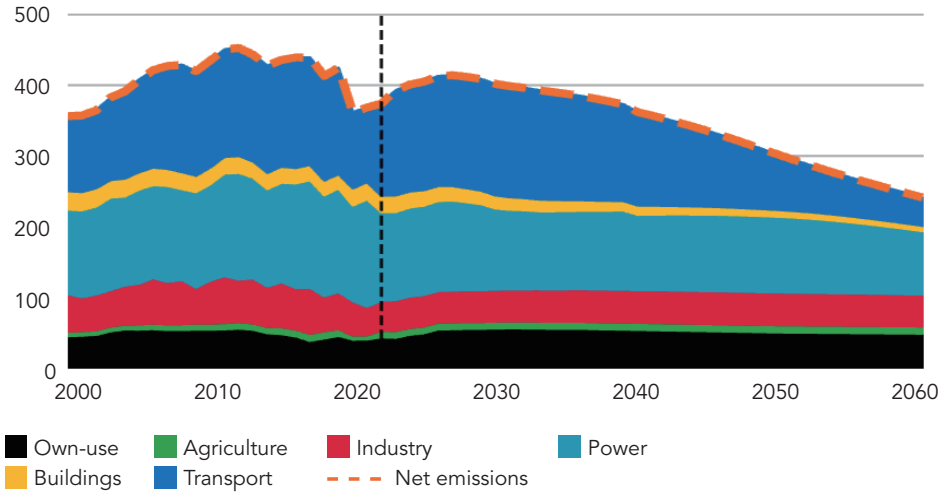
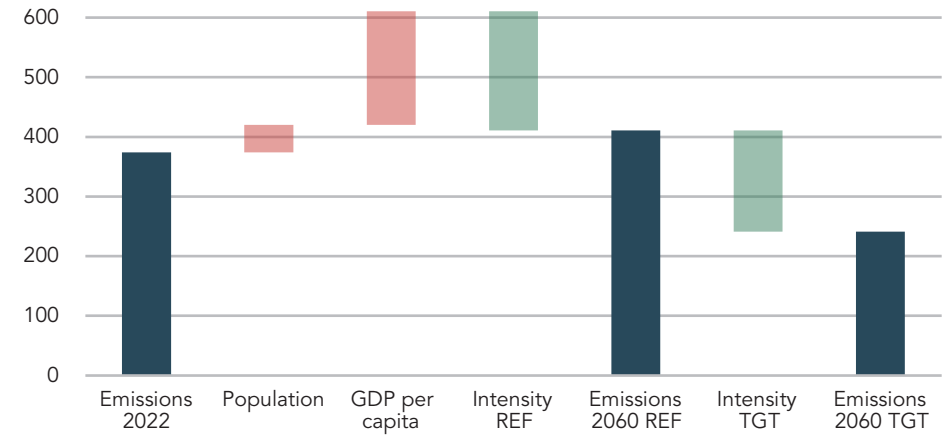


Figure 11-40. CO_2 emissions in TGT (million tonnes)



- In REF, CO_2 emissions rise by 10% by 2060 compared to 2022, peaking in the mid-2030s before declining slightly toward the end of the projection period. In TGT, emissions fall by 35% by 2060. These trends are driven by the transport and power sectors. In REF, transport emissions peak and decline with gradual electrification, while power sector emissions rise modestly as renewables limit gas-fired generation. In TGT, faster electrification and greater renewable deployment lead to deeper emission cuts.
- As shown in Figure 11-41, population and GDP per capita growth would raise emissions if not for declining emissions intensity. In REF, intensity improvements partly offset this effect. In TGT, stronger emissions intensity reductions lead to a 35% decline.
- Mexico's Nationally Determined Contribution (NDC) sets 2030 emissions reduction targets of 18% for transport and 31% for power, based on baselines of 250 $MtCO_2e$ and 186 $MtCO_2e$, respectively. These levels are significantly higher than the CO_2-only values in the REF scenario, suggesting that the targets are met even under REF. However, differences in emissions coverage make direct comparisons challenging.

Figure 11-41. CO_2 emissions components (million tonnes)



Note: All values represent energy sector combustion CO_2 emissions. Biogenic CO_2 is treated as zero at the point of combustion.

Useful Links

APEC Expert Group on Energy Data and Analysis (EGEDA) – https://www.egeda.ewg.apec.org/

APEC Energy Statistics 2022 – https://www.egeda.ewg.apec.org/egeda/general/info/pdf/APEC_Energy_Statistics_2022.pdf

APEC Energy Overview – https://aperc.or.jp/reports/energy_overview.php

Energy Institute Statistical Review of World Energy – https://www.energyinst.org/statistical-review

2025 Energy Reform (Secondary Energy Laws) – https://www.gob.mx/sener/en/articulos/aprobacion-de-las-leyes-secundarias

2024 Updated Energy Transition Strategy (Strategy for the Transition to Promote the Use of Cleaner Technologies and Fuels) – https://www.gob.mx/conuee/acciones-y-programas/estrategia-de-transicion-para-promover-el-uso-de-tecnologias-y-combustibles-mas-limpios

National Electric System Development Program (PRODESEN) – https://www.gob.mx/sener/articulos/programa-de-desarrollo-del-sistema-electrico

Energy Sector Prospectives – https://www.gob.mx/sener/articulos/prospectivas-del-sector-energetico



12. New Zealand

Summary

	Reference			Target		
	2022	2060	% Change	2022	2060	% Change
Macroeconomic						
Population (million)	5.2	6.1	17%	5.2	6.1	17%
GDP (billion 2017 USD, PPP)	221	431	94%	221	431	94%
Energy Demand						
Agriculture & fisheries (PJ)	29	27	-6%	29	21	-27%
Buildings (PJ)	120	139	16%	119	99	-17%
Industry (PJ)	155	157	2%	155	144	-7%
Non-energy (PJ)	44	8	-81%	44	8	-81%
Transport (PJ)	205	211	3%	204	115	-44%
Modern renewables share of TFEC (%)	29	48	66%	29	87	200%
Energy intensity of TFEC (PJ/GDP, billion USD)	2.3	1.2	-48%	2.3	0.9	-61%
Electricity						
Generation (TWh)	45	68	53%	45	79	77%
Renewables share of generation (%)	87	95	9%	87	99.95	15%
Generation capacity (GW)	11	24	117%	11	32	196%
Total Primary Energy Supply (TPES)						
Coal & coal products (PJ)	42	29	-31%	42	0	-100%
Natural gas (PJ)	130	37	-71%	130	4	-97%
Petroleum liquids (PJ)	268	238	-11%	268	50	-81%
Low-carbon & waste energy (PJ)	360	553	54%	360	698	94%
CO_2 intensity of energy supply ($MtCO_2/PJ$)	0.035	0.024	-31%	0.035	0.004	-89%
Net CO_2 Emissions (million tonnes)	28	21	-25%	28	3	-88%

Note: In this publication, the term "modern renewables" refers to all renewable energy sources excluding solid biomass in the buildings sector. The term "low-carbon & waste energy" includes all bioenergy, waste-derived energy, renewables, nuclear, and hydrogen-based fuels. Total primary energy supply (TPES) numbers include international bunkers. Net emissions are calculated as gross energy sector combustion CO_2 minus CO_2 captured and stored through carbon capture and storage (CCS).

Key Takeaways

Emissions

- By 2060, New Zealand's CO_2 emissions from fuel combustion decline in both scenarios. Emissions are 25% lower in the Reference scenario (REF) and 88% lower in the Target scenario (TGT), compared to 2022.
- The main enablers of emissions reductions in TGT are battery electric vehicles (BEVs), which make up 94% of vehicle stocks in 2060, and switching from coal to biomass in the industry and power sectors. Much of the remaining emissions are from diesel and other refined products used in agriculture, industry and heavy transport—the hard to abate sectors.
- In TGT, achieving net-zero emissions by 2050 depends on the use of negative emissions technologies, such as carbon sequestration. This reflects a modelling pathway designed primarily to align with the New Zealand government's stated energy aspirations. In TGT, the selected decarbonisation pathway utilises proven technologies which have strong government support.

Energy Import Dependence

- In TGT, the net-import share of TPES declines as oil demand is reduced by 78%. Also in TGT, New Zealand begins exporting indigenously produced hydrogen, e-fuels, and biofuels for international bunkering in shipping and aviation.
- New Zealand has long relied on imported petroleum products and crude oil; even the Marsden Point Oil Refinery, which closed in 2023, processed imported crude. However, the shift to electric vehicles (EVs) projected in REF and TGT is expected to lead to a major reduction in oil imports.
- A looming domestic gas shortfall poses the principal energy security risk for New Zealand. In REF, LNG imports from 2030 add 20 PJ per year—slightly increasing dependence but reducing the risk of unmet demand. The development of a 900 PJ domestic gas field is also assumed in REF, commissioned in 2035 with a 15% government stake, partially offsetting import reliance.

Figure 12-1. Net CO_2 emissions (million tonnes)

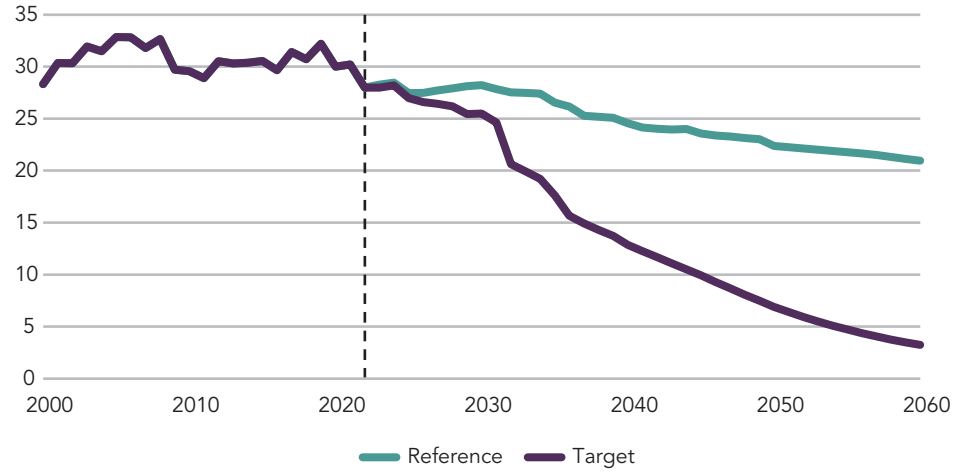
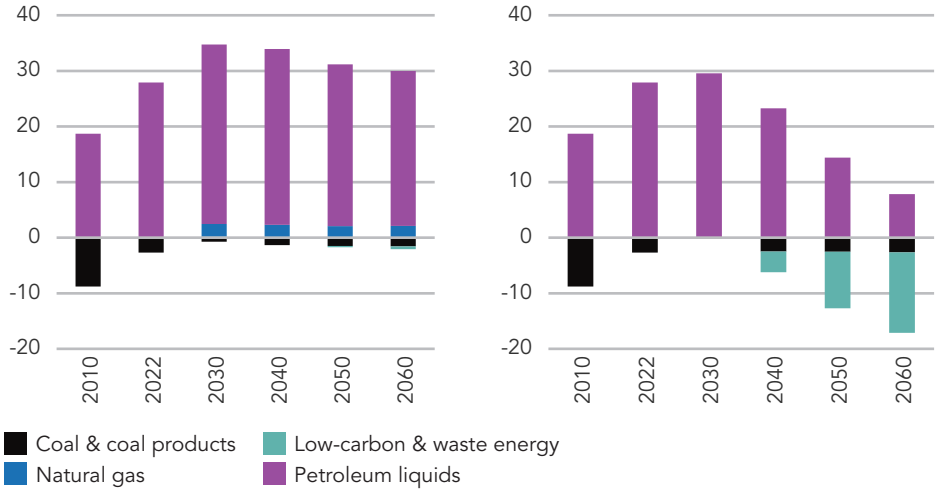


Figure 12-2. Net imports share of TPES in REF & TGT (%)



Note: In Figure 12-2, net imports refer to total imports minus exports and international bunkers.

Key Takeaways

Grid Reliability

- Going forward, essentially all new generation capacity in New Zealand will be renewable. By 2060, variable renewable energy (VRE) sources—primarily solar and wind—are projected to account for 87% and 88% of increased generation capacity in REF and TGT, respectively.
- Rising VRE shares increase the need for dispatchable generation to cover periods when VRE output is insufficient, as indicated by the widening spread between minimum and maximum dependence on dispatched power. The remaining gap between peak load and available dispatchable power sources (including batteries) is typically during low-solar periods so it must be supplied by wind.
- While New Zealand's substantial hydro resources provide a useful source of dispatchable generation, this further increases New Zealand's reliance on hydro-power. Historically, dry years have necessitated greater fossil fuel generation, leading to increased electricity costs.
- In REF, LNG and new domestic gas reserves provide dry-year cover. In TGT, with no LNG imports assumed and declining indigenous gas, the system is more exposed in dry years under current assumptions.

Cost

- Figure 12-4 illustrates that estimated total costs in the power and hydrogen sectors from 2025 to 2060 in TGT will be 30%, or an estimated USD 26 billion, higher than in REF. The costs consider total capital, fixed, and variable costs in the power sector, as well as costs for green hydrogen production, transmission for variable renewables electricity, and electric vehicle chargers.
- TGT's higher shares of solar and wind raise costs further due to their added capital, storage, and transmission needs.
- Fuel costs also increase in both scenarios: in TGT, due to fuel switching from gas to biomass and renewable generation, and in REF, supplementing declining domestic gas production with imported LNG. The total does not include costs for any fuel use outside the power sector.

Figure 12-3. Peak load and maximum and minimum dependence on dispatched power (GW)

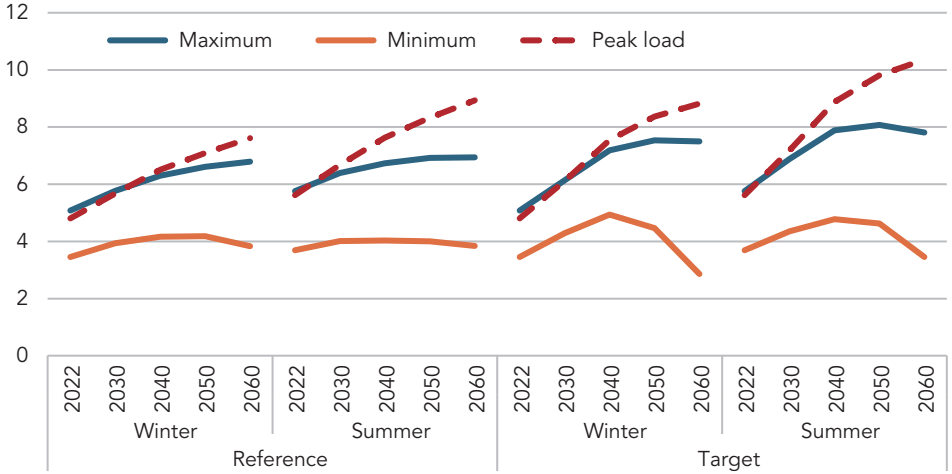
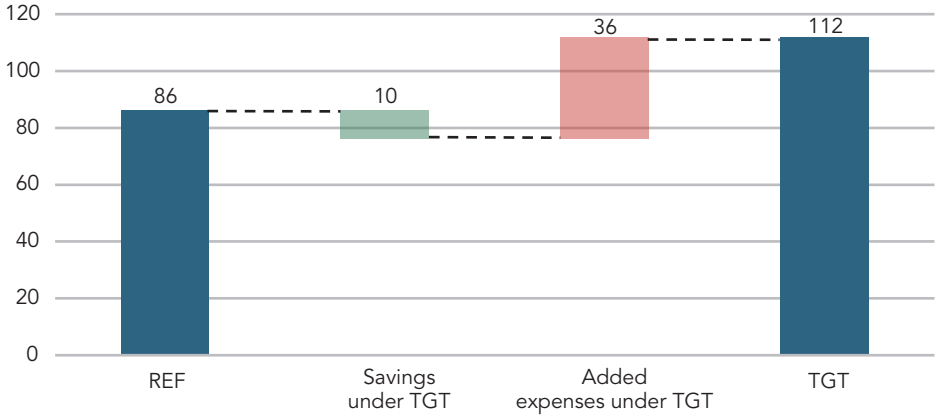


Figure 12-4. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



*Actual costs will differ from estimated costs in the *Outlook* for a variety of reasons including changing commodity prices, manufacturing costs and unforeseen technical advances. All costs are in 2023 real terms.

About New Zealand

Overview

Geographical and Economic Landscape

Despite being one of the most geographically isolated economies in the world, New Zealand thrives due to its strong integration into international trade and financial markets. The economy benefits from abundant natural resources, high global demand for its premium agricultural products, and a robust services sector.

Energy Supply and Consumption

New Zealand has a diverse and low-emission energy mix, primarily supported by hydro-electric and geothermal power and supplemented by thermal peaker plants when demand is high or during dry periods when hydro stores are low. Renewables accounted for 86% of electricity generation in 2024, positioning New Zealand advantageously as it pursues deeper emissions reductions. The central challenge for decarbonisation lies in sectors beyond the power sector, notably transport and industry, which remain heavily reliant on fossil fuels. Transport, dominated by oil consumption, accounts for the largest share of emissions, followed by the industrial sector where significant fossil fuel use persists.

Energy Security Challenges and Strategies

The main energy security challenges for New Zealand are its shortage of gas and its reliance on hydro, which provides around 60% of generation. During dry periods, lake levels fall, and if severe enough, can result in curtailments. The government is exploring strategies such as improving market flexibility, strengthening demand-side responses, and diversifying the generation mix.

Addressing New Zealand's gas shortage may assist with the hydro dry-year challenge. The shortage reflects several long-term factors, including historically low-margin chemical production tied to capital-intensive gas extraction, as well as reduced investment following the 2017 ban on offshore oil and gas exploration. Possible future pathways include demand reduction initiatives, as explored in the TGT scenario, or supply-side options such as renewed domestic gas exploration (now legally permitted) or potential LNG imports, as considered in the REF scenario.

Key Energy Initiatives

Climate Change Response (Zero Carbon) Amendment Act

In 2019, New Zealand set a 2050 net-zero emissions target (excluding biogenic methane) and a 24–47% cut in biogenic methane below 2017.

NDC 2030 Target (2021-2030)

Submitted NDC2 in January 2025, committing to a 51–55% net-emissions cut below 2005 by 2035; retains a 50% reduction target for 2030.

Emissions trading scheme (ETS)

Includes price ceiling/floor and five-year budgets; agriculture excluded. First period: 2021–2025 (354 $MtCO_2$-e).

Oil and Gas Exploration Ban Repeal

Crown Minerals Amendment Bill to repeal the offshore oil and gas exploration ban is with Select Committee.

New Climate Strategy

Issued July 2024, focusing on resilient infrastructure, clean energy, innovation and forestation.

Emissions Reduction Plan 2 (ERP2)

Released December 2024, it is the legally binding 2026–2030 emissions roadmap, detailing 150+ sector actions tied to the second five-year budget.

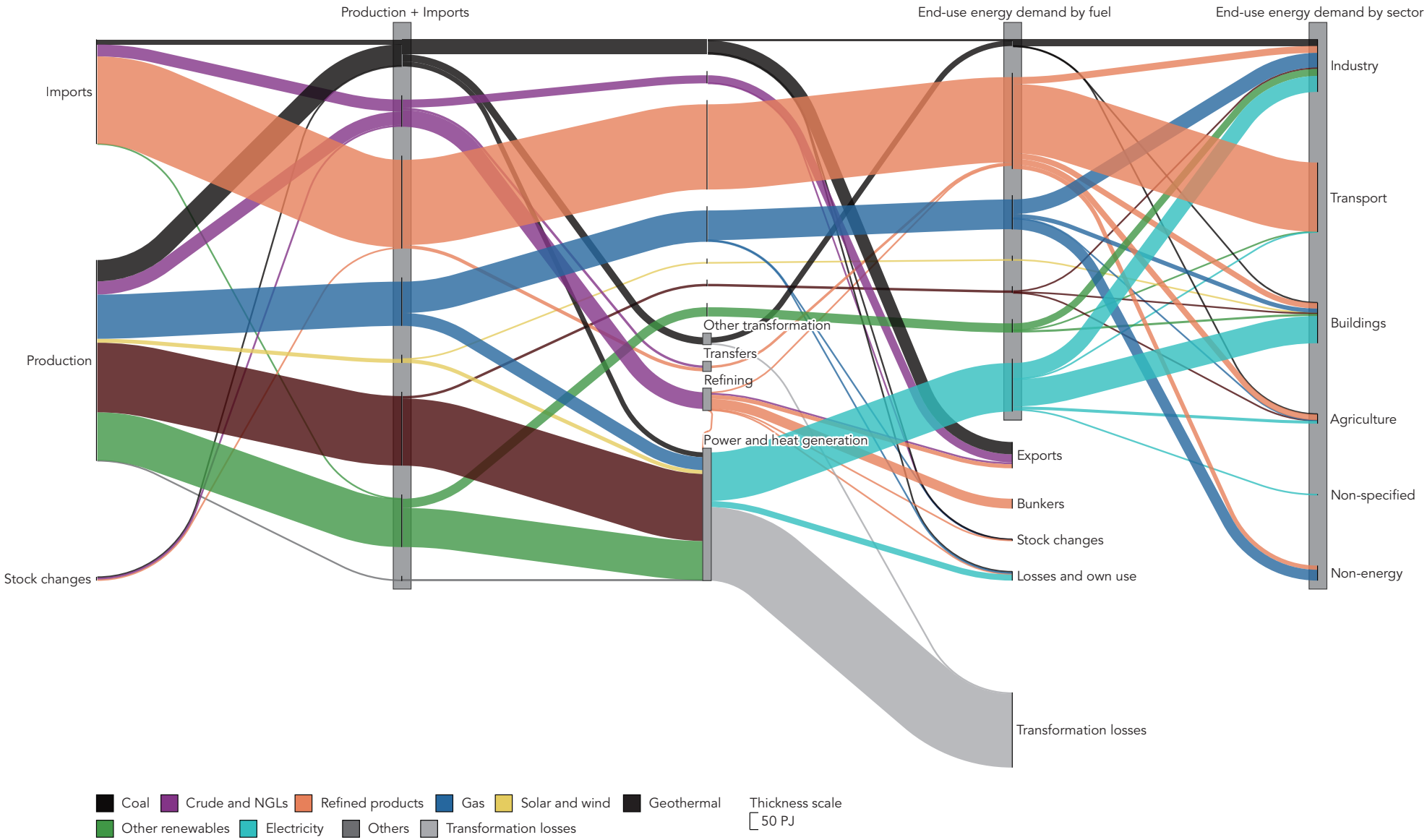
Climate Change Commission

Provides independent advice, assesses progress, and recommends policies to meet targets.

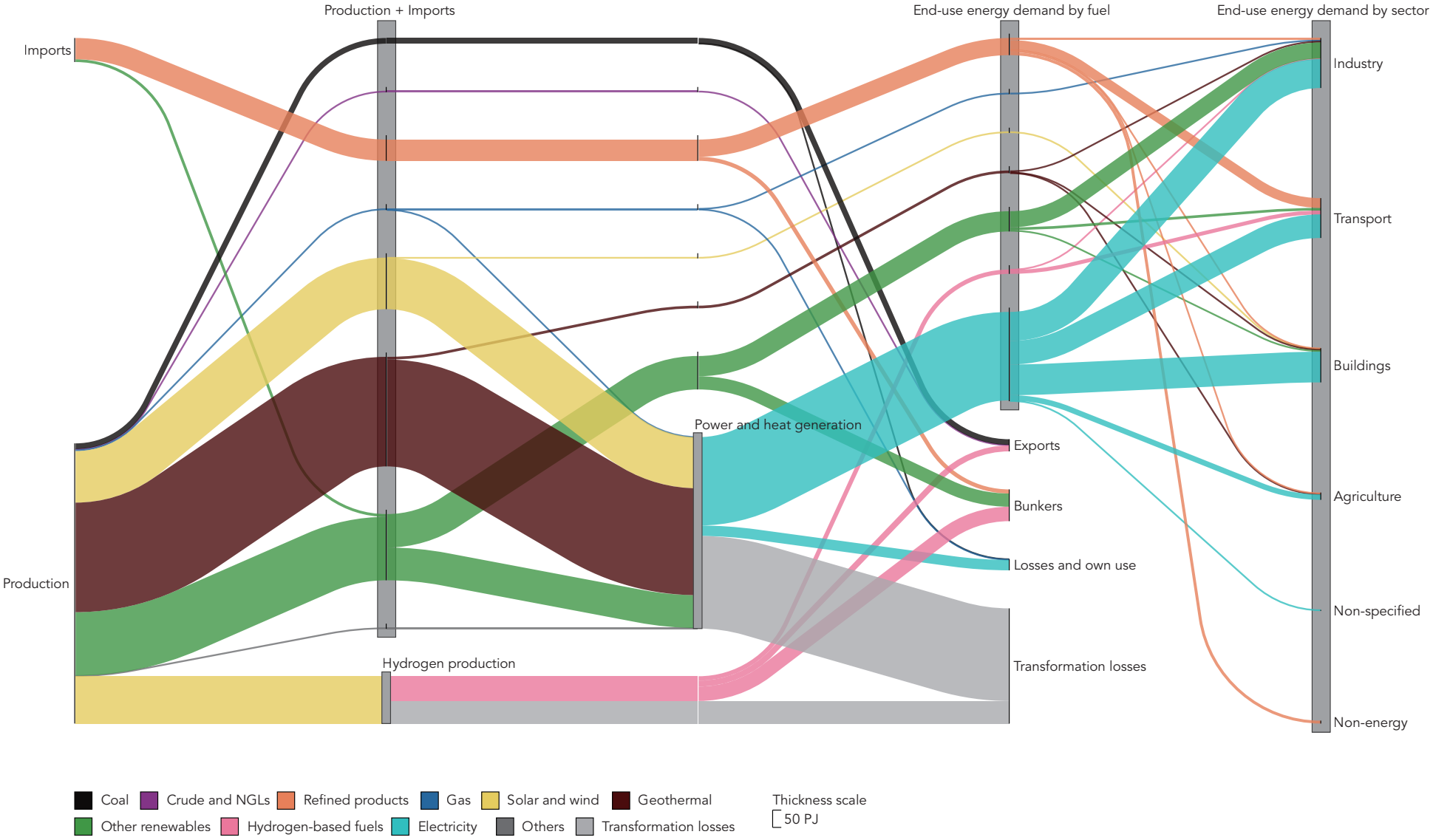
Clean Car Standard

From 2023, mandates declining fleet CO_2 targets for light-duty imports via tradable credits and penalties; administered by Waka Kotahi and the Ministry of Transport.

Energy Flow (2022)



Energy Flow (2060, Target Scenario)



Scenarios and Assumptions

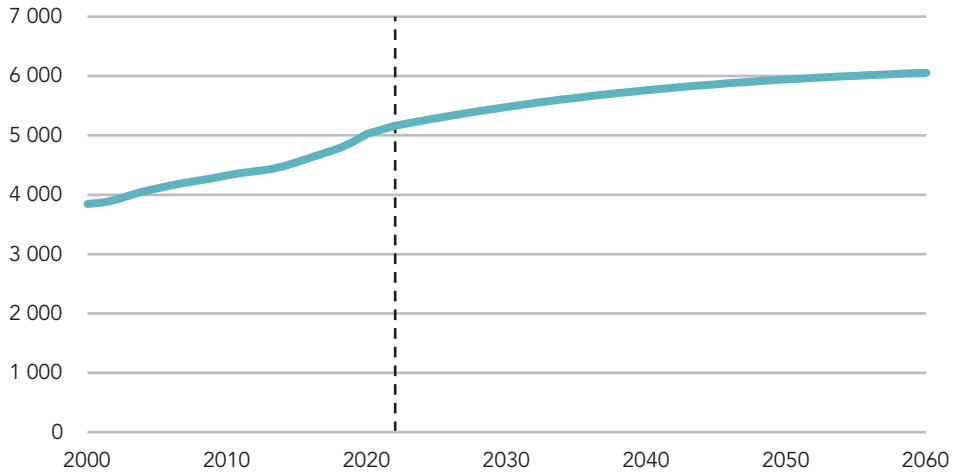
In *The Outlook*, APERC analyses energy demand, transformation, and supply, as well as emissions. The **Reference Scenario (REF)** offers a projection based on historical trends, recent developments, and APERC's assumptions about the continuation of those trends in each APEC economy, while acknowledging technical restraints. The REF Scenario offers a baseline to compare with the **Target Scenario (TGT)** projections, which explores a hypothetical pathway where each economy achieves energy-related policy targets, assuming implementation regardless of cost-effectiveness. When implementation details are lacking, assumptions are inferred from the targets themselves or emissions-related goals.

	Reference	Target
General	• Population: UN DESA 'Median PI' scenario; GDP: APERC macro model (IMF projections to 2027).	
Buildings	• 200MW of data centres in 2025, 300 MW by 2030, in REF and TGT.	
	• Residential and commercial gas use is gradually phased out until 2040.	• More aggressive electrification and efficiency assumptions. • Residential and commercial gas use is gradually phased out until 2035.
Industry	• Tiwai point assumed to operate indefinitely in REF and TGT. Closure of all chemicals sector gas use in 2035 in REF and TGT. EAF furnace at the NZ steel plant operational in 2026.	
	• Electrification of low to high process heat occurs at a modest rate. • Modest energy efficiency improvements.	• Electrification and efficiency improvements more widespread. • Biomass helps meet low and medium process heat demand needs. • Small role for hydrogen in the steel sector and other special cases.
Transport	• Passenger activity is correlated with population, while freight is correlated with GDP.	
	• EV sales shares grow at a modest rate (e.g., 30% BEV sales share for passenger vehicles by 2060). This does not assume any effect from the Clean Car Standard.	• EV sales shares grow quickly (100% BEV sales share for passenger vehicles by 2050). • Emissions intensity of transport fuels is reduced by 10% by 2035 through 10% biofuel blending in jet fuel, gasoline, and diesel. By 2060, blending reaches 25% for biojet, and synthetic e-fuels also substitute 5% of total fuel use. • Boats and aviation begin switching to electricity, biofuels and hydrogen.
Power	• There is still some coal generation for emergencies. • Gas power plants switch to using imported LNG in 2030. • Batteries comprise 3% of capacity.	• There is still some gas used for emergencies, but it is limited due to the gas shortage. • Batteries comprise 7% of capacity. • Biomass replaces all coal use in Huntly Power Station in 2032.
Supply	• 5.6 PJ of green hydrogen production using electrolysis in 2060. 4.1 PJ is used in international bunkers. • 20 PJ/yr of LNG imports begin in 2030. • 900 PJ of gas reserves becomes available in 2035.	• 71.5 PJ of green hydrogen production using electrolysis in 2060. 17.1 PJ is exported, and 41.7 PJ is used in international bunkers. • Production for export of metallurgical coal and crude falls in both scenarios.

Note: The base year is 2022. Macro-economic assumptions are constant across scenarios. Historical energy balances are from EGEDA submissions for 2022.

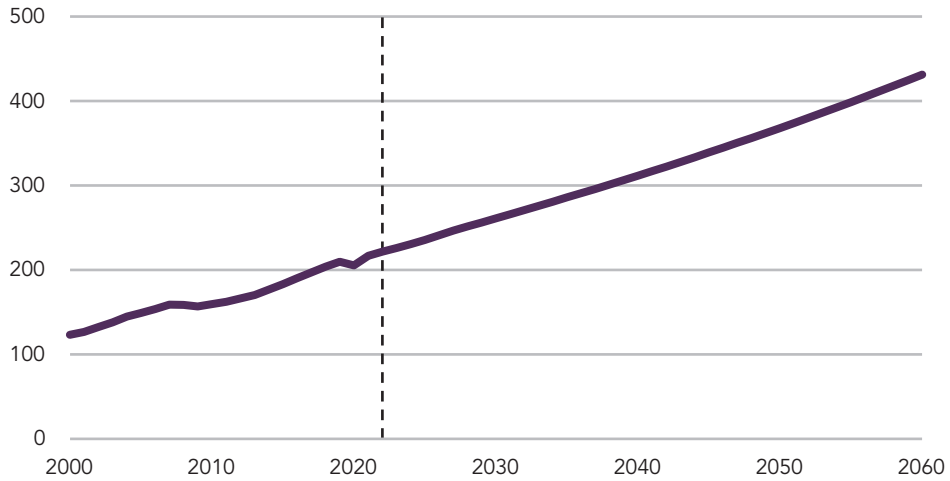
Demographic and Macroeconomic Assumptions

Figure 12-5. Population (thousands)



- New Zealand's population is projected to grow from 5.1 million in 2024 to around 6 million by 2060. By 2050, migration may play a critical role in offsetting the impacts of demographic aging and sustaining workforce growth.
- The population projection is based on the 'Median PI' United Nations Department of Economic and Social Affairs (DESA) projection, which was the closest projection to the median projection from StatsNZ in 2020.
- Despite high urbanisation levels, New Zealand's cities will likely remain characterised by low-density development, which is typically associated with high energy use per household and high vehicle ownership rates. However, low-density urbanisation simplifies private electric vehicle charging, potentially reducing the future burden on public charging infrastructure.

Figure 12-6. Real GDP (billion 2017 USD, PPP)



- GDP and population are fixed, exogenous inputs in both scenarios. Although the scenarios imply different energy investment profiles and energy trade balances, these do not feed back into GDP or its components.
- Within the modelling, population and GDP growth are major drivers of energy consumption across all demand sectors. Rising population and wealth levels elevate residential and passenger transport energy use, while freight transport and industrial activities are driven by broader economic growth. However, these effects are offset by opposing emissions and energy intensity improvements (such as renewable energy or energy efficiency improvements), resulting in the projections presented in the next chapter.

End-use Energy Demand

Figure 12-7. Energy demand by sector in REF & TGT (PJ)

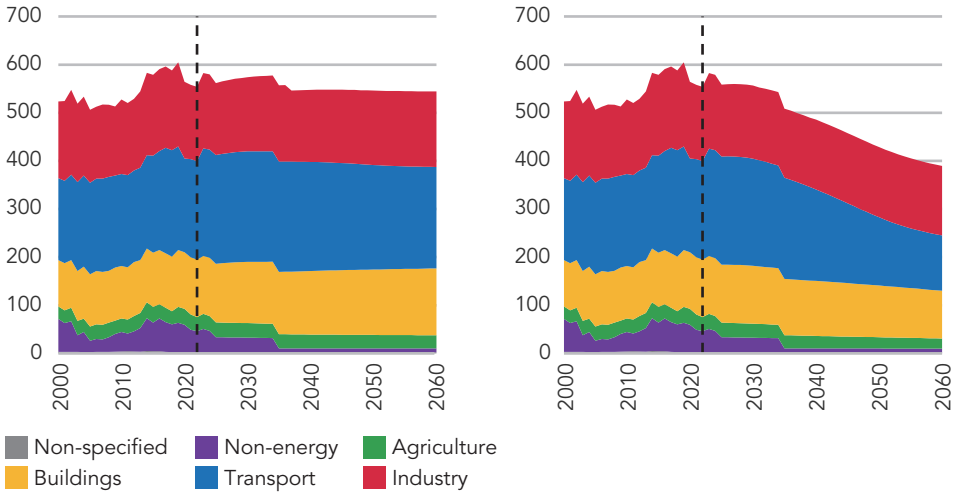
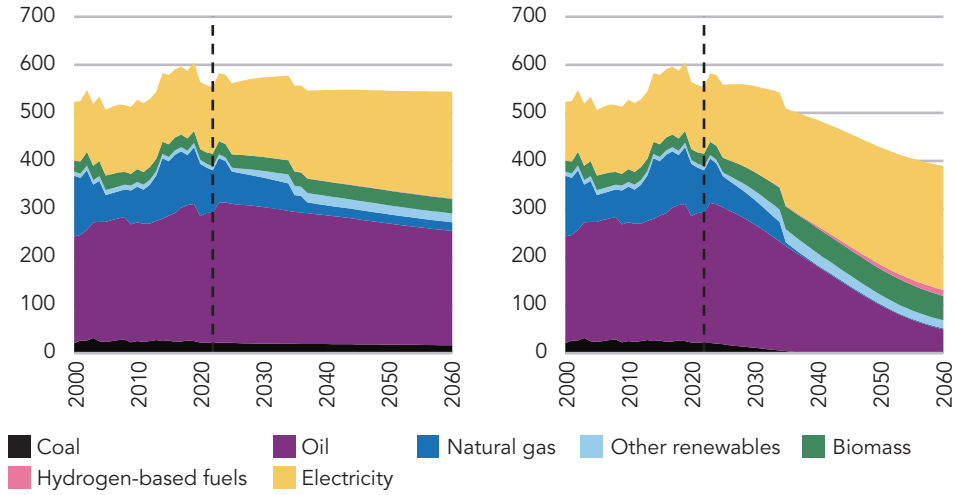


Figure 12-8. Energy demand by fuel in REF & TGT (PJ)



- The major differences in energy demand between the REF and TGT scenarios arise from accelerated electrification (significantly enhancing efficiency), increased biomass use replacing industrial boilers, and differing strategies to address the domestic gas shortage.
- When compared to 2019, transport energy use declines by 46% by 2060 in TGT due to accelerated adoption of BEVs, which are roughly three times as efficient as internal combustion engine (ICE) vehicles. In REF, slower BEV uptake struggles to overcome the upwards pressure of increasing activity, resulting in a more modest 2% reduction in 2060 compared to 2019.
- In buildings, there is an ongoing transition from gas and oil to electricity, which is more pronounced in TGT. However, steady housing growth aligned with population increases partially offsets electrification-driven efficiency gains.
- Hyperscale data-centre development leads to significant growth (18%, 14 PJ) in electricity use in both REF and TGT.
- The industrial sector undergoes electrification in both scenarios, though efficiency gains are relatively modest due to electricity's limited advantage in process heat applications, which dominate industrial energy use.
- Gas consumption in industry and non-energy uses approaches zero in TGT by 2040, while declining by about 50% in REF, driven mainly by the anticipated closure of Methanex's methanol facilities amid tightening domestic gas supply. Higher gas availability in REF reflects the assumed addition of 20 PJ per year of LNG imports from 2030 and a new 900 PJ gas field from 2035.
- Agricultural energy demand for natural gas phases out completely by 2040 in REF and by 2035 in TGT. In TGT, electricity replaces 50% of diesel use, and coal use is completely phased out by 2037.

Buildings Energy Demand

Figure 12-9. Buildings energy demand by fuel in REF & TGT (PJ)

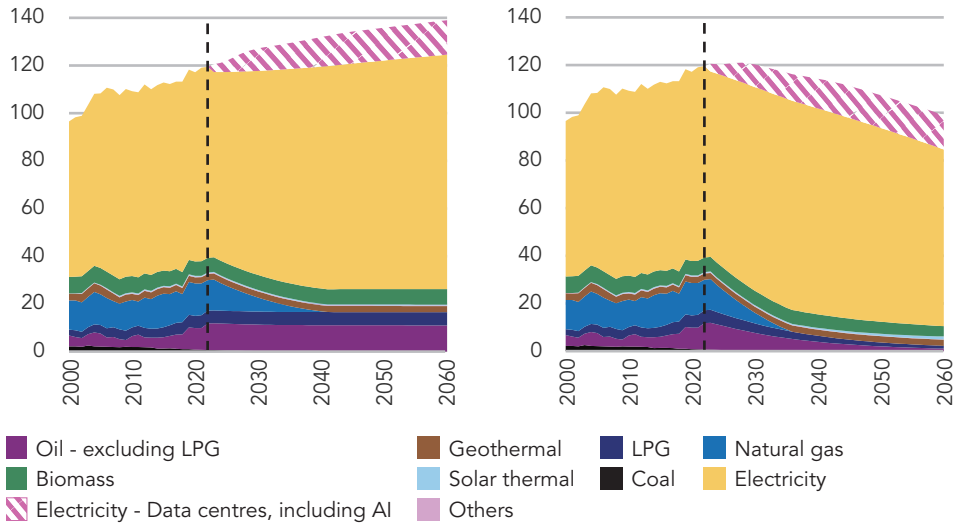
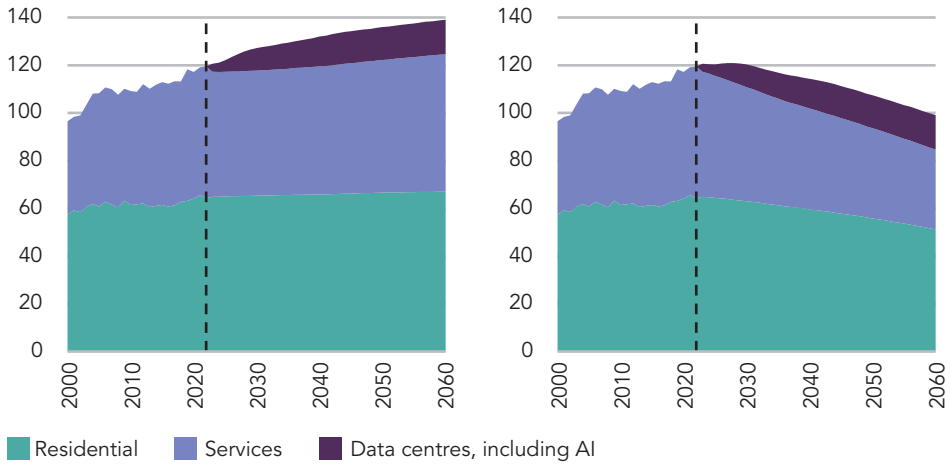


Figure 12-10. Buildings energy demand by sector in REF & TGT (PJ)



- Efficiency improvements in TGT are driven by government programmes, such as Warmer Kiwi Homes, and track targets in the Climate Change Commission's EB4 advice, which call for 19% and 43% reductions in residential and commercial heating demand by 2050, respectively, relative to 2019. In New Zealand's cool, temperate climate, heating is the dominant driver of demand, and heat pumps play a central role in achieving these efficiency gains by providing around three units of heat for every unit of electricity consumed. The slow turnover of the building stock constrains how quickly these savings materialise, but appliance upgrades and retrofits deliver earlier benefits.
- In REF, weaker policy support limits efficiency gains, keeping residential and services energy use broadly flat at around 60 PJ each through 2060. Some improvements still occur through gradual appliance replacement and retrofits, but without stronger incentives, uptake of efficient technologies such as heat pumps remains patchy, and building envelope upgrades spread more slowly across the housing stock.
- Declining domestic gas reserves push prices higher, encouraging electrification. Government policies to phase down fossil fuels reinforce this trend, with natural gas use falling to zero by 2035 in TGT and by 2040 in REF.
- Hyperscale data centres are expected to drive a substantial share of future electricity growth in both scenarios. Current projections, based on operational and publicly announced facilities, show capacity rising from about 200 MW in 2025 (up from 100 MW in 2020) to roughly 300 MW by 2030, with another 150 MW possible in Southland. While this rapid expansion could strain New Zealand's power grid, it also presents an opportunity for economic growth.

Industry Energy Demand

Figure 12-11. Industry demand by fuel in REF & TGT (PJ)

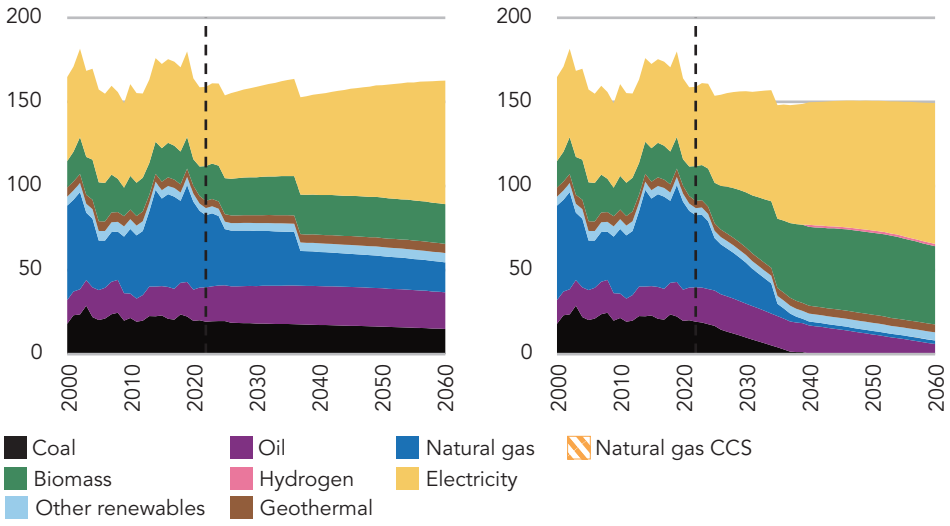
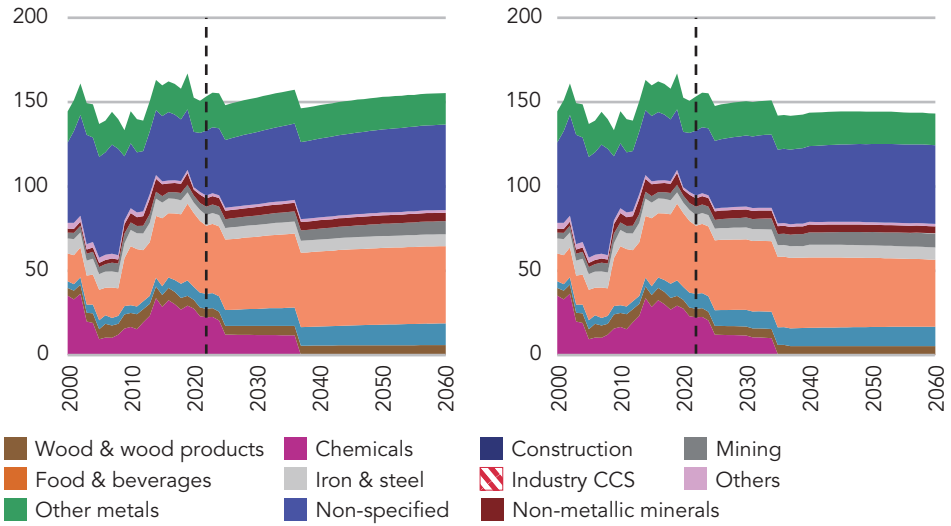


Figure 12-12. Industry demand by sector in REF & TGT (PJ)



- The Tiwai Point aluminium smelter currently consumes around 5 TWh (18 PJ), representing 13% of New Zealand's electricity demand. This demand is expected to remain steady throughout the projection period due to the plant's economic significance and its critical role as a stable load for the South Island grid.
- An electric-arc furnace scheduled for 2026 at New Zealand Steel is expected to cut the plant's coal use by half while adding an equivalent electricity load. In TGT, hydrogen replaces coke and natural-gas firing from 2040, displacing only about 1.2 PJ of fuel in total.
- Fonterra and other dairy processors, which rely mainly on low- and medium-temperature heat, are already shifting from coal to wood-pellet biomass and electricity. This transition continues under TGT in line with corporate decarbonisation plans. Similar low- and medium-temperature processes across the wider industrial sector also adopt biomass and electricity, enabling a complete coal phase-out by 2037 in TGT, consistent with earlier government targets.
- In TGT, gas use declines quickly due to fuel switching, consistent with government decarbonisation targets and ongoing supply constraints.
- In REF, continued gas use is supported by a new 900 PJ field from 2035 and 20 PJ of LNG imports per year from 2030 (a total of ~600 PJ by 2060). LNG is assumed to flow mainly to generators in the years before the field comes online, but it could also supply industry if buyers can bear the higher costs during the period of lower reserves (2030-2035). In either case, higher fuel costs could curb industrial activity and push actual gas use below model projections.
- Market access and trade deals may become a strong driver of New Zealand's continued decarbonisation. For example, the recent EU-NZ Free Trade Agreement allows the European Union (EU) to temporarily suspend tariff preferences if New Zealand fails to uphold its climate obligations. This will provide an extra incentive for producers and policymakers to maintain or strengthen domestic decarbonisation policies to avoid trade sanctions.

Non-energy Demand

Figure 12-13. Non-energy demand in REF & TGT (PJ)

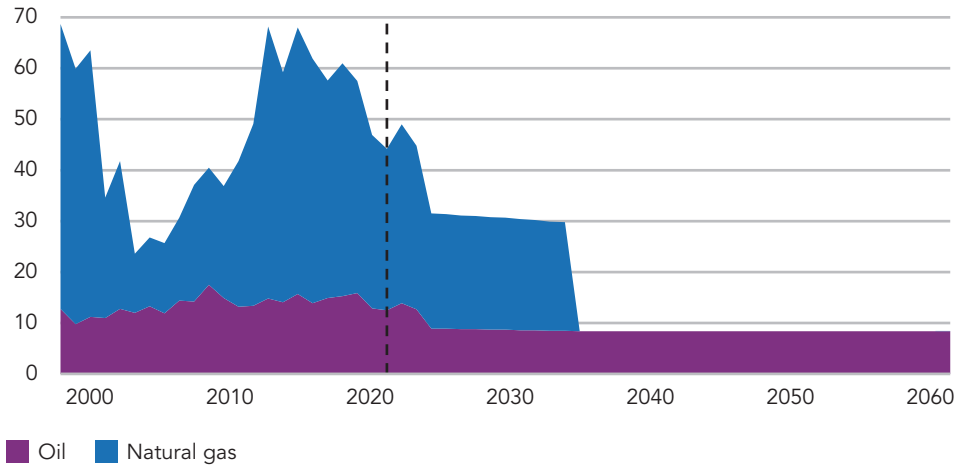
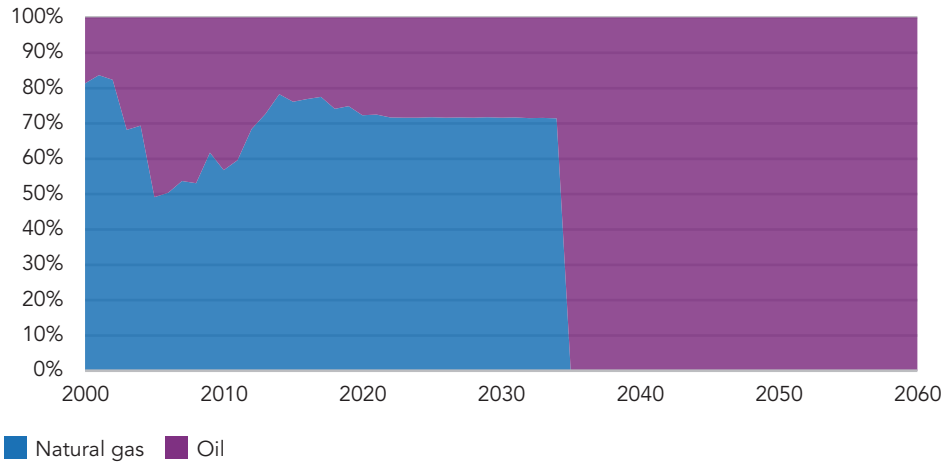


Figure 12-14. Share of non-energy demand in REF & TGT (%)



- The remaining oil use in 2060 in both REF and TGT is spread across various applications, including bitumen, petrochemical feedstocks and lubricants. This demand is assumed to remain broadly constant, and because it relates to non-energy uses, it does not result in combustion emissions.
- The chemicals sector accounts for all non-energy gas use in New Zealand but is projected to decline steeply as domestic gas supply tightens.
- Two companies dominate the non-energy sector's gas use: Methanex, with the capacity to consume 30 PJ of gas for process heat and 60 PJ as feedstock, and Ballance, which uses around 2 PJ for heat and 5 PJ as feedstock in fertiliser production.
- At the time of writing, Methanex had already mothballed its 17 PJ Waitara plant, and one of its two 35 PJ Motunui units is also assumed to have closed in 2025. Existing gas contracts for these closed plants are likely to have been transferred to electricity generators due to tightening supply, reflected as a significant drop in gas use by 2025.
- By 2035, all remaining feedstock users are assumed to cease operations in both REF and TGT. Even with LNG imports from 2030 and a 900 PJ field from 2035, most supply is directed to electricity generation and broader system needs, leaving little available for large, gas-intensive users in the non-energy sector, whose operations are highly sensitive to gas price and availability. The loss of these industries reduces value-added exports, increases reliance on imported fertiliser and could affect regional employment.

Transport Energy Demand

Figure 12-15. Domestic transport energy demand in REF (PJ)

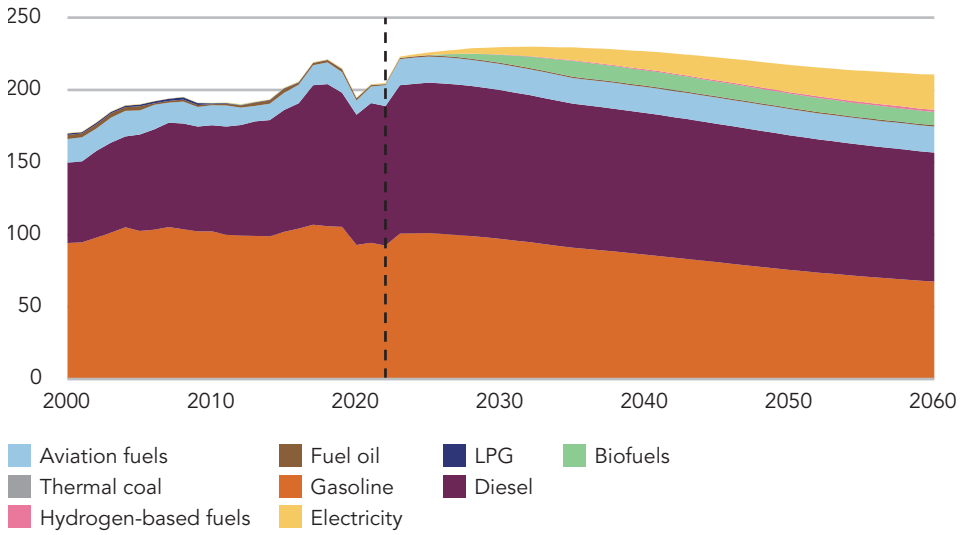
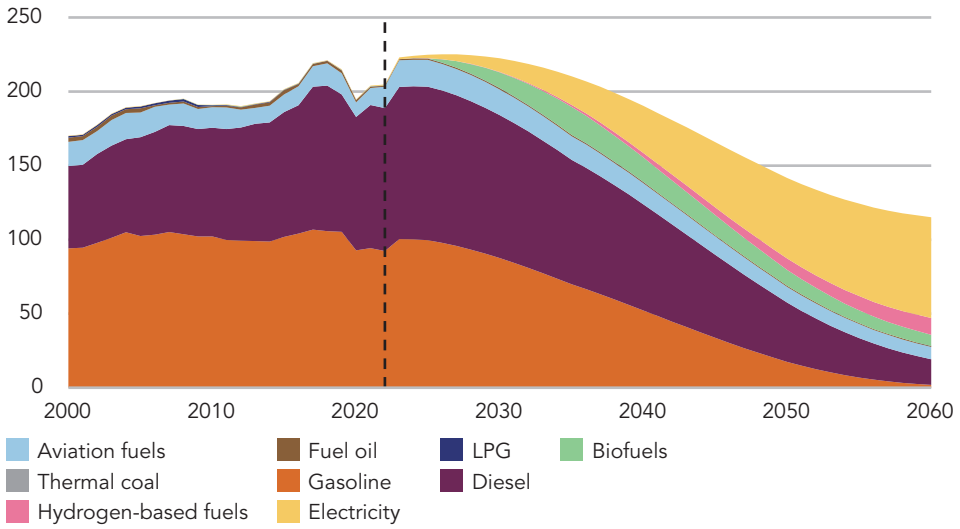


Figure 12-16. Domestic transport energy demand in TGT (PJ)



- As projected in TGT, New Zealand aims for 30% of its light vehicle stock to be zero-emission vehicles (ZEVs) by 2035. Given the slow rate of fleet turnover, this requires an 81% sales share for battery electric vehicles (BEVs) by that year. Plug-in hybrid electric vehicle (PHEV) sales peak at 10% in 2035 before tapering to zero by 2050, though they may still play a role in remote regions.
- Compared with the Clean Car Standard, TGT reflects the measures needed for importers to reach 63 gCO_2/km in new vehicles by 2027, down from 145 gCO_2/km in 2023. This assumes a sales share of 40% BEVs and 10% PHEVs in 2027, with the remainder met by more efficient internal combustion engine (ICE) vehicles. CO_2 intensity of new cars continues to improve beyond the Standard as BEV sales rise to 100% by 2050. In contrast, REF, consistent with current trends, does not meet the Standard, leading to extra fees for importers.
- Uptake of low-carbon fuels is included in the assumptions. Initially encouraged under a previous government target, they are now considered less cost-effective than electrification but remain relevant for some applications, particularly aviation, shipping, and heavy freight trucks (HFTs).
- In the HFT sector, BEV uptake is gradual in TGT, reaching 50% of sales and making up a 30% stock share by 2050, while fuel cell electric vehicles (FCEVs) reach 30% of sales and 15% of stocks.
- The New Zealand government recently refreshed the Low Emissions Heavy Vehicle Fund. However, its impact is expected to be limited, as decarbonising heavy freight will depend on future technological advances. Key challenges include the high costs of hydrogen and liquid biofuel supply chains and the low energy density of batteries, which must be resolved for these technologies to become viable.
- BEV adoption reduces import dependency by replacing imported fuels with domestically generated electricity, most of which comes from renewable sources. It also lowers fuel costs but places additional pressure on the electricity grid and requires coordinated infrastructure planning to ensure a sufficient ratio of chargers to vehicles, avoiding barriers to adoption.

Other Transport Data

Figure 12-17. Transport vehicle stocks in REF & TGT (millions)

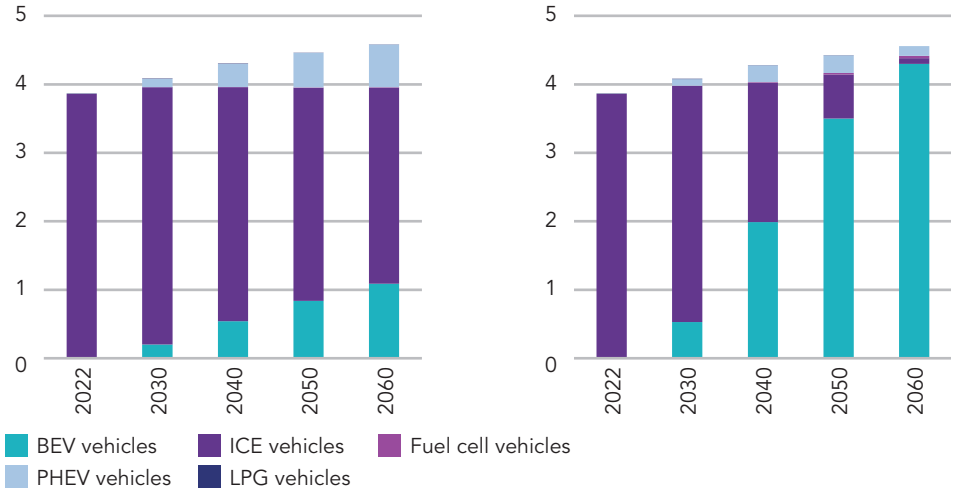
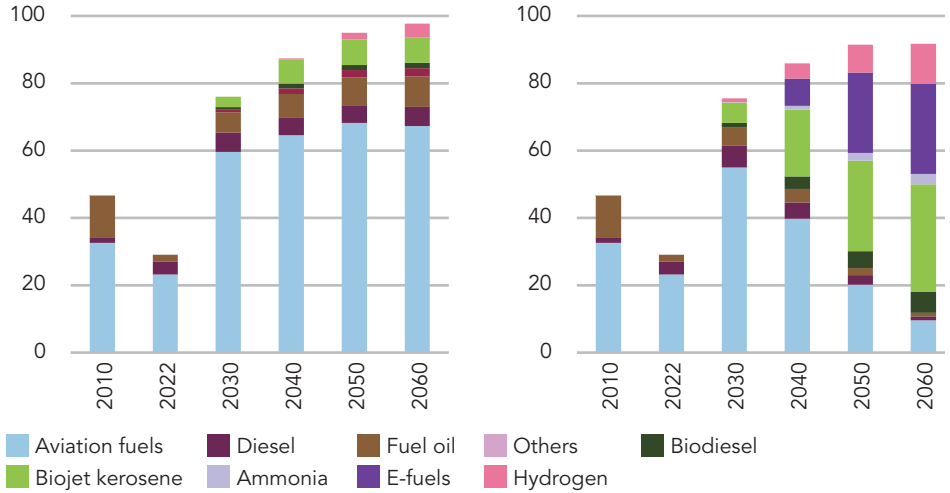
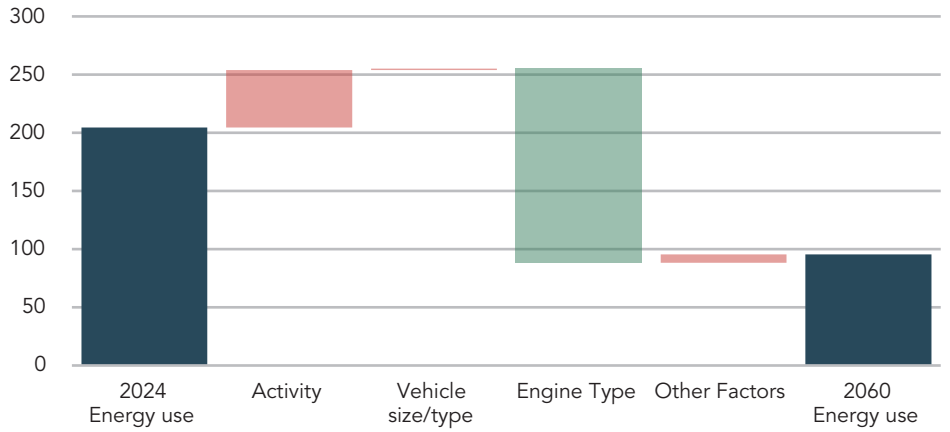


Figure 12-18. International bunkers energy demand for shipping and aviation in REF & TGT (PJ)



- The transition to BEVs is the largest driver of reduced transport emissions and energy use, cutting approximately 146 PJ by 2060 in TGT, according to decomposition analysis (Figure 12-19). PHEVs and FCEVs offer smaller efficiency gains but remain key options for fully decarbonising longer-range transport.
- With New Zealand already exhibiting high passenger vehicle ownership, total vehicle kilometres travelled (VKT) is projected to grow only in line with population growth. Freight activity is expected to grow moderately, contributing to a modest increase of approximately 50 PJ in energy demand from activity growth in TGT (Figure 12-19).
- In TGT, bunker fuels (used for international transport) begin shifting to lower-emissions alternatives. This is based on decarbonisation targets set by international transport bodies.

Figure 12-19. Components of the change in road energy use in TGT (PJ)



Note: Information on the different drivers in the transport energy decomposition can be found in the *Outlook*'s annex.

Electricity Generation

Figure 12-20. Electricity generation by fuel in REF (TWh)

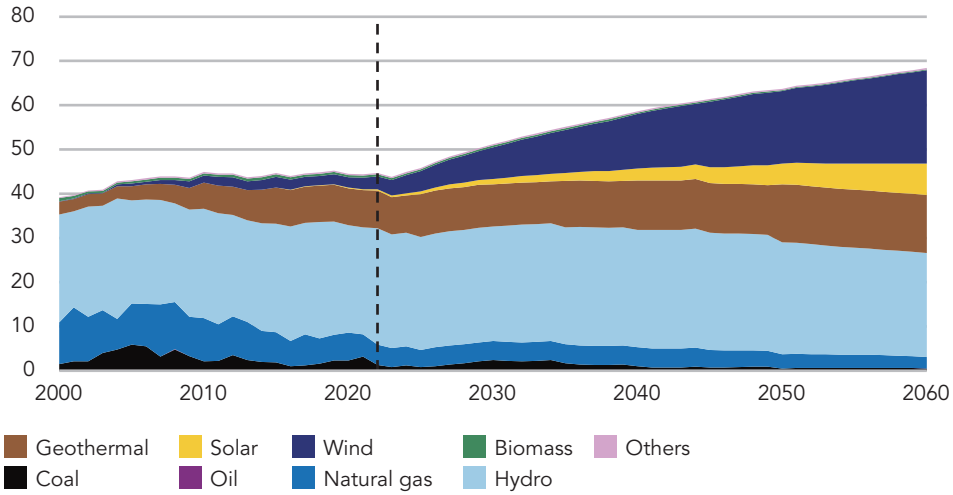
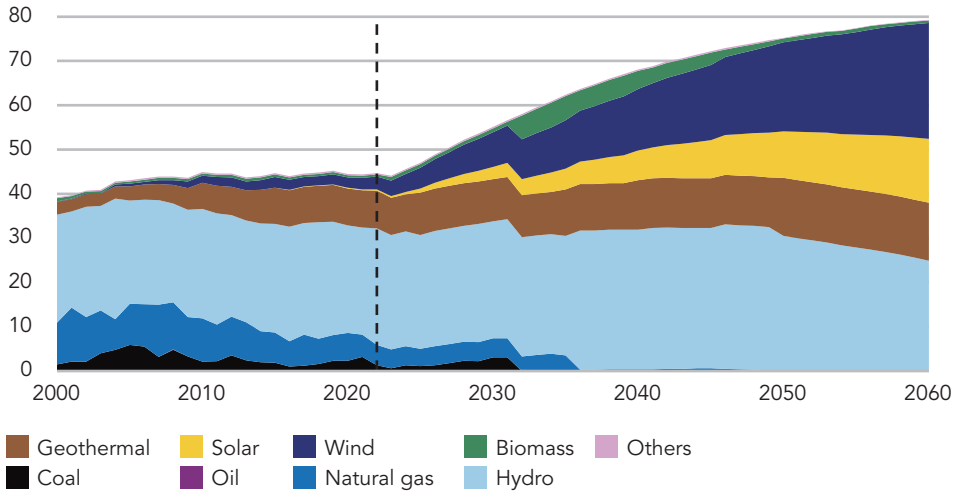


Figure 12-21. Electricity generation by fuel in TGT (TWh)



- In TGT, electricity demand is projected to be 16% higher in 2060 than in REF due to more extensive electrification across end-use sectors. This implies greater capacity additions, grid build-out and higher system capex; overall costs are explored in the Costs section at the end of this chapter.
- Solar and wind generation comprise most of the growth in generation. Their combined total increases by 25 TWh in REF and 37 TWh in TGT. Wind growth is supported by expected offshore deployment, with the Offshore Renewable Energy Bill scheduled for passage in mid-2025 and feasibility permits expected to be granted from 2026.
- In REF, gas generation from 2030 to 2035 is assumed to rely on 20 PJ of LNG imports per year, shifting to a mix of LNG and field gas thereafter. LNG is directed to the power sector because it can be brought online more quickly, while the field (assumed from 2035) provides scale; however, both options raise costs and carry risks. Generators may justify paying a premium for reliable supply in the years before the field comes online, but it will increase marginal generation costs in REF.

- Huntly's three 250 MW Rankine units are under evaluation for conversion to biomass, as projected in TGT. This would potentially leverage North Island forestry residues and new wood pellet production, which also supports decarbonisation in the dairy sector. Despite technical and cost uncertainties, biomass offers a dispatchable, net-zero generation option that is particularly valuable during hydro shortages.
- To meet emissions targets and avoid cost increases from dwindling gas supplies, gas generation in TGT is assumed to fall to near zero by 2035, with retained capacity reserved for emergencies. Biomass (at Huntly) and expanded geothermal and hydro are expected to backfill the baseload gap, with batteries supporting short-duration variability management.

Note: Figures 12-20 and 12-21 do not include electricity generation for hydrogen production.

Generation Capacity

Figure 12-22. Generation capacity by fuel in REF (GW)

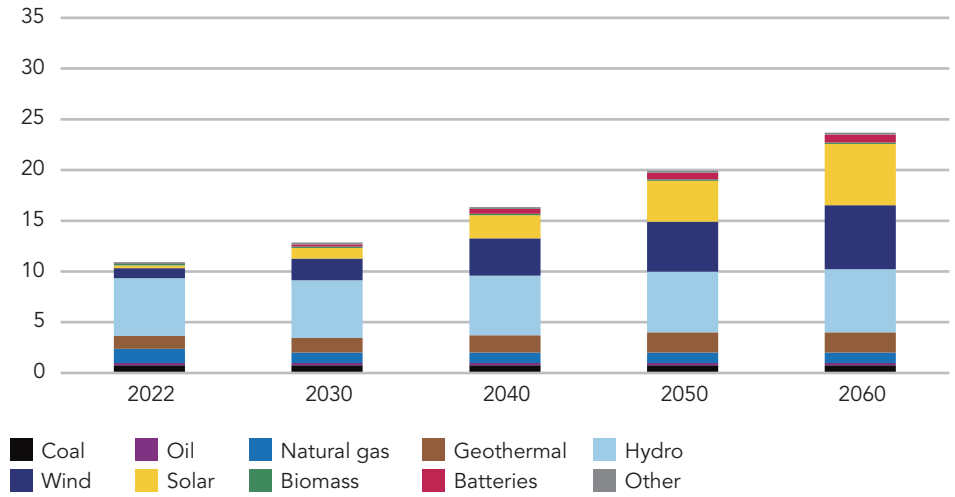
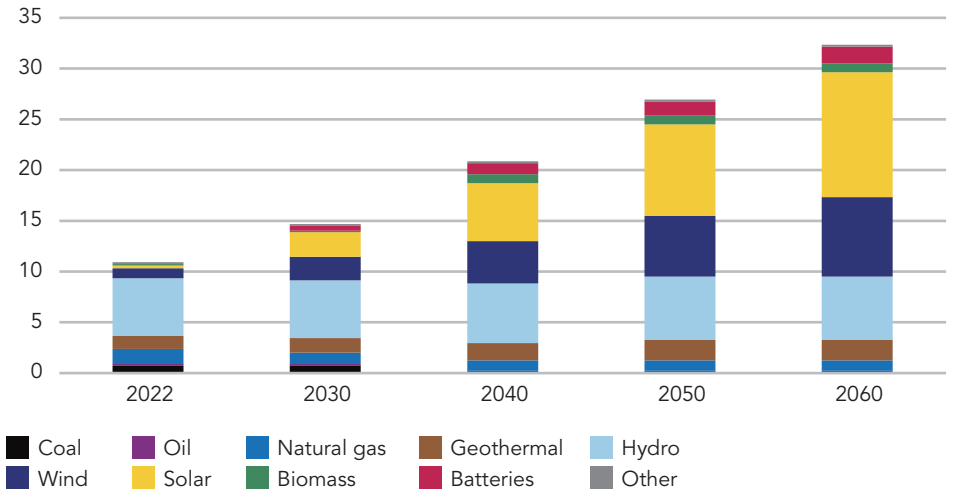


Figure 12-23. Generation capacity by fuel in TGT (GW)



- No new fossil fuel generation capacity is assumed in either REF or TGT, as these investments are considered unlikely to be cost-effective given gas supply constraints, reliance on imported coal, and New Zealand's strong renewable resource base. While renewables reduce fuel import dependence and lower emissions, they also raise reliability concerns due to the variable output of solar, wind, and even hydro.
- The modelling assumes the Huntly Power Station will be redeveloped to extend its operational life (and converted to biomass in TGT). Despite being over 40 years old, Huntly remains critical for grid stability, given the lack of alternative baseload options.
- Utility-scale battery storage is already being installed in New Zealand and grows to around 3% and 7% of total generation capacity by 2060 in REF and TGT, respectively. The primary function is to provide short-duration dispatchable power, helping to smooth fluctuations in solar and wind output.
- Most viable hydro and geothermal sites have already been developed. While it was assumed there would be some additions (~1.3 GW over the projection period), these are small compared to projected wind and solar capacity growth (~11 GW and ~19 GW in REF and TGT, respectively).
- The New Zealand government has shown particular interest in supercritical geothermal technology, which could offer reliable baseload capacity without increasing reliance on fossil fuel imports. However, this analysis assumes no major breakthroughs in advanced geothermal technologies.
- Demand-response potential for new and existing data centres remains uncertain. U.S. studies of hyperscale campuses indicate operators might curtail for only 0.25-1 % of annual hours, and there is even less information regarding traditional facilities. Depending on the level of curtailment available in New Zealand, more baseload capacity or long-duration storage may be required for emergency situations.

Note: Figures 12-22 and 12-23 do not include electricity generation for hydrogen production.

Grid Reliability

Figure 12-24. Total generation capacity and peak load (GW)

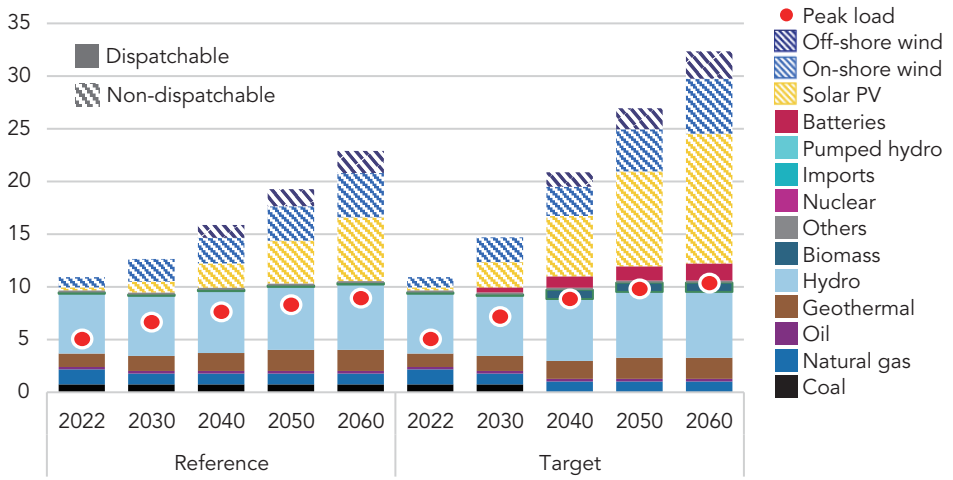
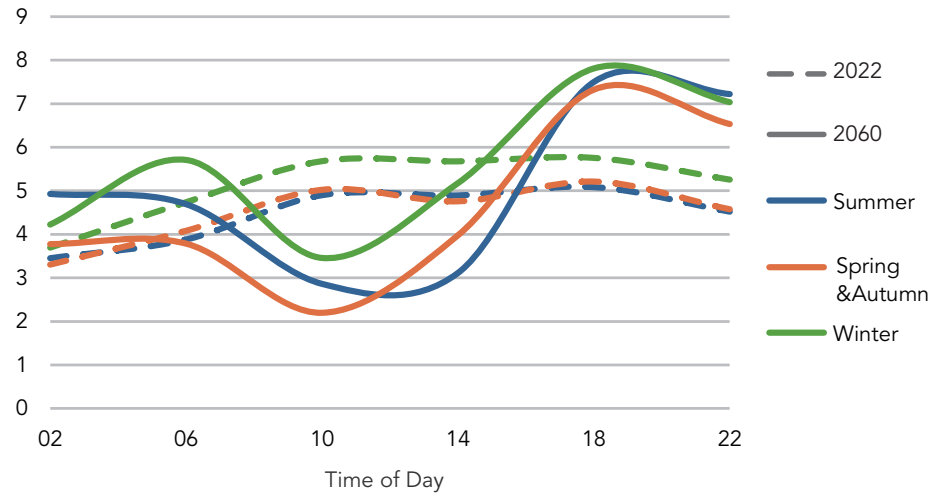


Figure 12-25. Power from dispatchable sources in TGT (GW)



- Grid reliability requires having enough dispatchable capacity to cover peak demand when solar and wind are low. As peak load climbs, this firm capacity must also rise despite rapid VRE growth.
- By 2060, dispatchable output exhibits a new pattern, surging during peak hours and then dropping. This is driven by VRE under-producing at peak times, forcing conventional plants to fill the gap.
- As a result, increasing the share of VREs leads to a larger electricity system since dispatchable capacity must be available for the peak hours, while the cheaper non-dispatchable sources are used more during the off-peak hours.
- Even so, dry year conditions remain the key reliability risk for New Zealand. In 2023, hydro supplied 60% of all generation but the lakes only hold ~5 TWh of usable storage—barely five to seven weeks of mid-winter demand.
- In REF, dry-year risks are partly mitigated by 20 PJ per year of LNG imports from 2030 and additional field gas from 2035, supporting extra generation when lakes used for hydro generation are low. In contrast, TGT faces greater risks due to heavier reliance on VRE and limited backup gas.
- A demand-side response agreement with the Tiwai Point aluminium smelter (572 MW) enables temporary load reductions of 25–185 MW. This mechanism has already been used during periods of low lake levels and weak wind output, most recently in August 2024. However, curtailing aluminium production likely entails significant economic costs.
- Furthermore, while batteries and demand-side response agreements provide short-term dispatchable power, they offer less benefit during extended low-VRE, low lake level periods. This underscores the need for long-duration storage or dispatchable low-emissions generation to maintain reliability.
- Average annual hydro capacity factors are projected to decline from ~50% to ~30% in both scenarios. This is because of displacement by increased wind and solar generation during favourable weather, leading to higher average lake levels and more frequent spilling. While this slightly mitigates dry year risks, the shallow nature of New Zealand's lakes used for hydro generation limits the extent of any buffering effect.

Coal

Figure 12-26. Coal consumption by sector in REF & TGT (PJ)

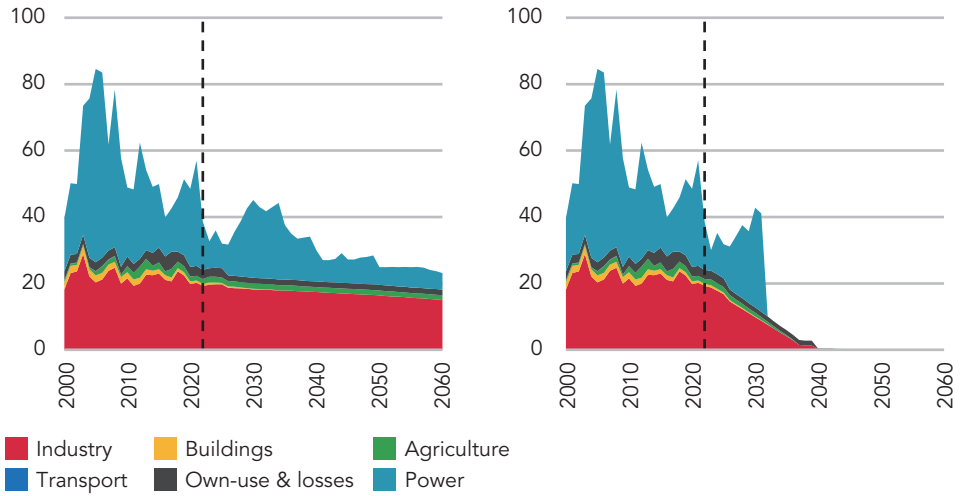
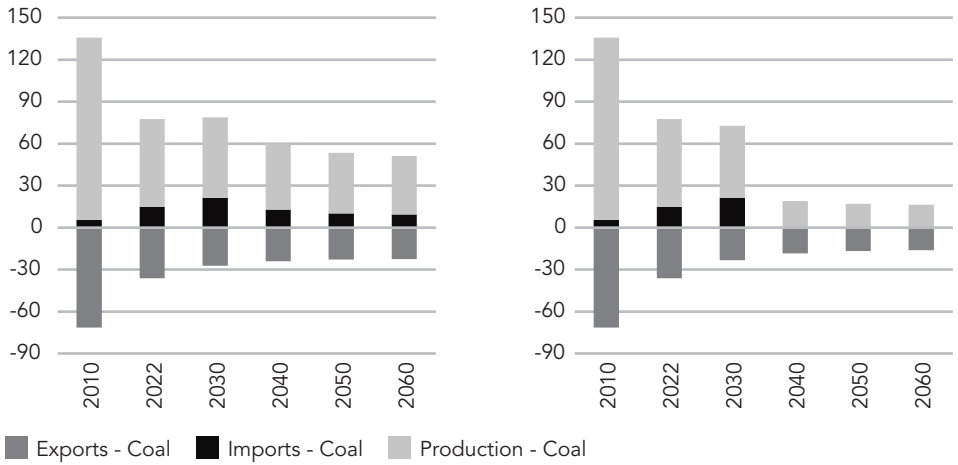


Figure 12-27. Coal production, imports, and exports in REF & TGT (PJ)



- Coal consumption in New Zealand is relatively low, at about 5% of TPES compared with the APEC average of 35%. Most demand comes from the industry sector for milk drying, steel production (which accounts for most own-use consumption), and other manufacturing applications.
- As shown in Figure 12-26, historical coal use for electricity generation has spiked during dry years, when hydro generation is low. At such times, the Huntly power station burns imported coal (mostly from Indonesia) as marginal generation, raising emissions and import exposure. This continues in REF but is fully replaced by biomass in 2032 in TGT.
- Outside of electricity generation, coal is primarily used in industry, buildings, and agriculture. In TGT, these uses are phased out entirely by 2037, replaced by electricity, biomass, and, in the steel sector, some hydrogen, consistent with the previous government's coal phase-out target.
- New Zealand produces about 30 PJ of metallurgical-grade coal each year, almost all of which is exported, as the domestic market has little need for such high-quality coal. The remaining ~30 PJ of lower-grade coal is consumed locally.
- Over the course of the projection period, coal production in REF declines slightly to around 20 PJ each of high- and low-grade coal, while imports from Indonesia continue. In TGT, high-grade coal production falls to about 13 PJ by 2060, while low-grade coal use drops to nearly zero by 2040 due to major shifts to biomass and electrification. Coal imports decline to zero by 2032 as Huntly transitions to biomass, reducing import dependence and lowering system emissions, though at the cost of facing hurdles such as transport logistics, pellet supply, and boiler retrofits.

Natural Gas

Figure 12-28. Natural gas consumption by sector in REF & TGT (PJ)

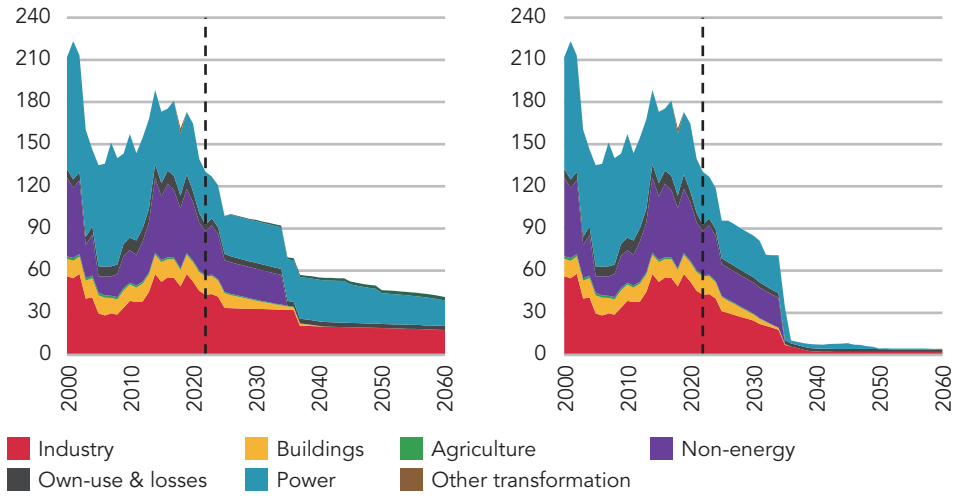
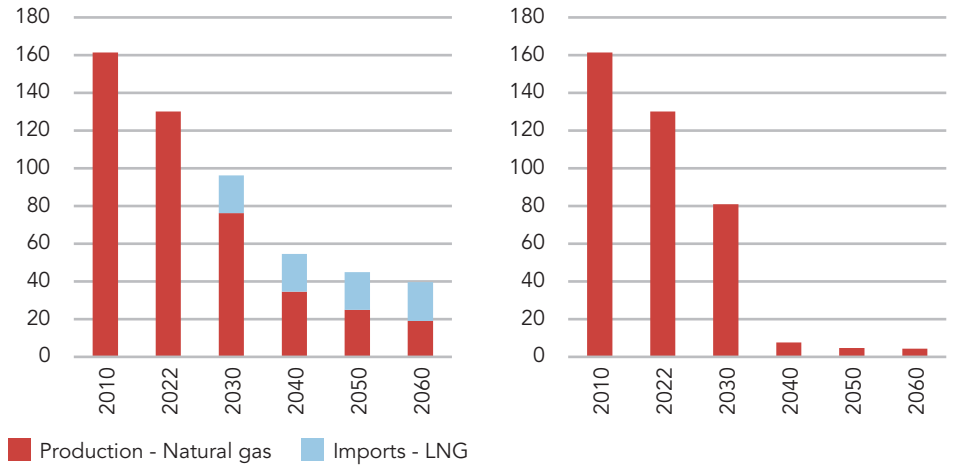


Figure 12-29. Natural gas production, imports, and exports in REF & TGT (PJ)



- New Zealand may run out of gas reserves by 2030 under current consumption trends. Both scenarios therefore assume rapid demand decline, driven by chemicals sector shutdowns that sharply cut industrial and non-energy gas use around 2025 and again in 2037.
- In REF, a major supply solution is assumed: LNG imports of around 20 PJ per year beginning in 2030 (equivalent to about five cargoes annually), and one new 900 PJ gas field coming online in 2035. These are scenario inputs rather than committed projects, and their realisation would depend on substantial commercial and regulatory progress.
- To boost investor confidence, the NZ Budget 2025 allocated NZD 200 million for the Crown to assume a 15% stake in new gas fields. Whether this offsets lingering policy risks from the 2018 exploration ban is uncertain.
- At 20 PJ/year (~0.4 Mt), New Zealand's proposed LNG intake represents less than 1% of Japan's, one of APEC's largest LNG buyers. According to Enerlytica's Port-Taranaki cost stack, once freight, regas, and terminal fees are added, gas would enter NZ pipelines at USD 15–18/MMBtu—around 30% more than JKM cargoes into Japan and Korea, and up to 90% above New Zealand's current emsTradepoint price.
- Timing is also critical if New Zealand is to avoid reserve depletion: the FSRU must progress from investment decision to first gas within four years, while the 900 PJ field requires appraisal, permitting, and construction to achieve production by 2035. Both face tight delivery windows.
- A new 900 PJ field could supply decades of demand but is not expected until 2035. LNG therefore bridges the early-2030s gap and insures against delays or dry-year shortages. Though after 2035 both the field and the LNG terminal face risks of under-utilisation if demand declines faster than expected.
- If an unexpected shortage occurs, the assumed standard FSRU could supply up to 165 PJ/year, provided shipping and cargo windows align. Alternatively, that same FSRU can be redeployed to another economy if it is under-utilised.

Natural Gas Reserves

Figure 12-30. Natural gas reserves, LNG imports and cumulative consumption in REF (PJ)

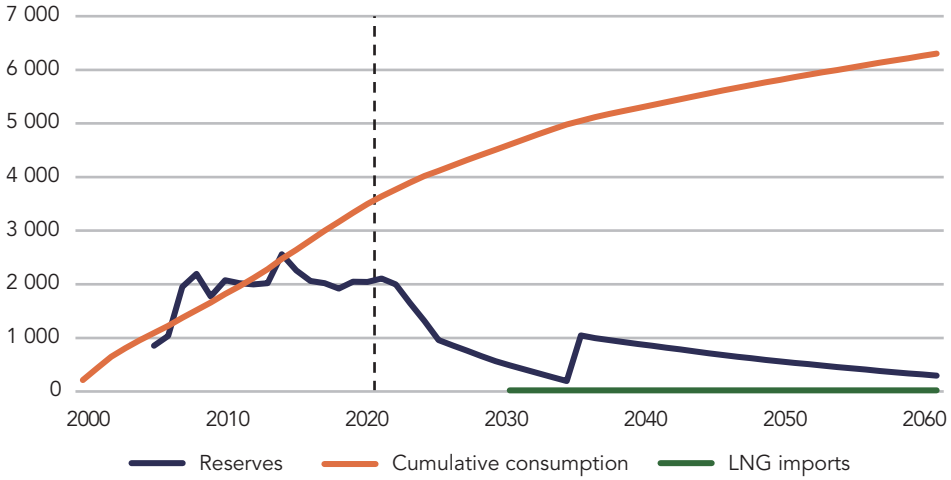
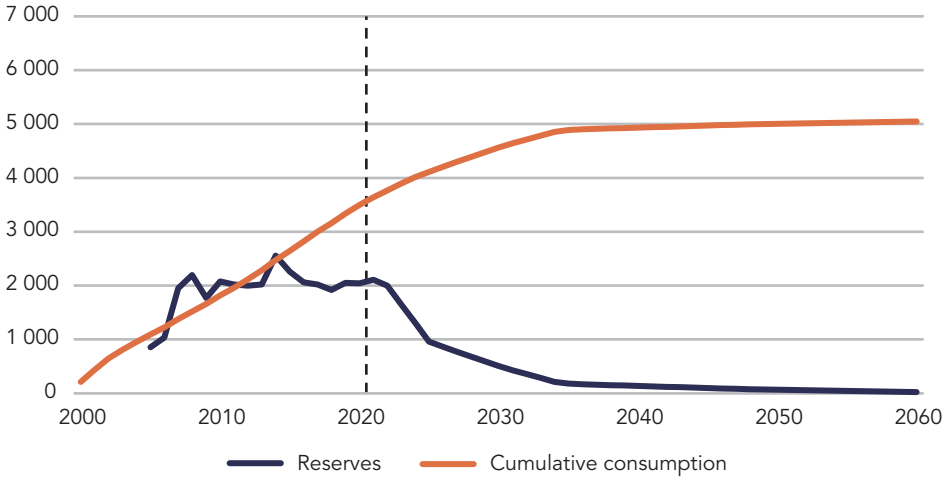


Figure 12-31. Natural gas reserves and cumulative consumption in TGT (PJ)



- In 2025, MBIE cut proved and probable reserves (2P) by 18%, reclassifying large volumes as contingent resources (2C). This revision illustrates the volatility of reserve estimates and highlights the importance of timely supply or demand management measures.
- Figures 12-30 and 12-31 show the effects of assumed supply strategies: REF adds capacity through LNG imports and a new field, while TGT balances primarily through demand reduction. The gap between reserves and cumulative use evolves differently in each scenario.
- Consumption trajectories are similar through 2035 but diverge thereafter. In TGT, demand from buildings and agriculture phases out, and industry and power use continue to fall quickly, creating an annual reduction of approximately 59 PJ that accumulates into a growing difference in cumulative consumption by 2060.
- In REF, LNG imports of 600 PJ and a new 900 PJ field provide sufficient supply equivalent to about 30 years at projected demand levels. LNG provides flexibility, while the field provides scale; both options involve uncertainties, and the balance between them would influence overall costs and risks.
- By 2060, reserves are projected at 21 PJ in TGT and 295 PJ in REF, with annual production of about 4 PJ and 21 PJ, respectively. Reserves also dip as low as 95 PJ in REF by 2034 and remain limited in TGT for much of the projection, suggesting further supply may be required beyond 2060 if demand trends persist.
- Imported gas prices are assumed independent of domestic supply, thereby setting a price ceiling for domestic gas.

Petroleum Liquids

Figure 12-32. Crude oil, NGLs and other hydrocarbon production, imports, and exports in REF & TGT (PJ)

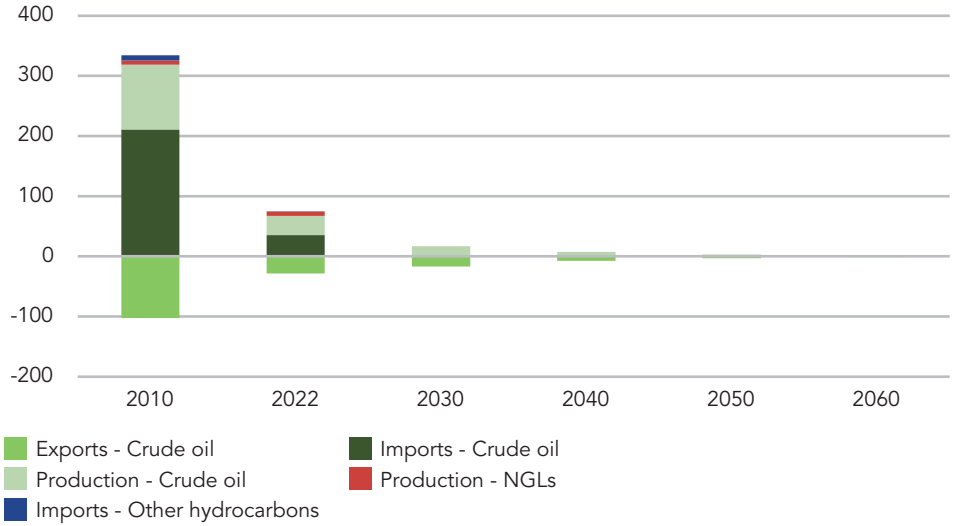
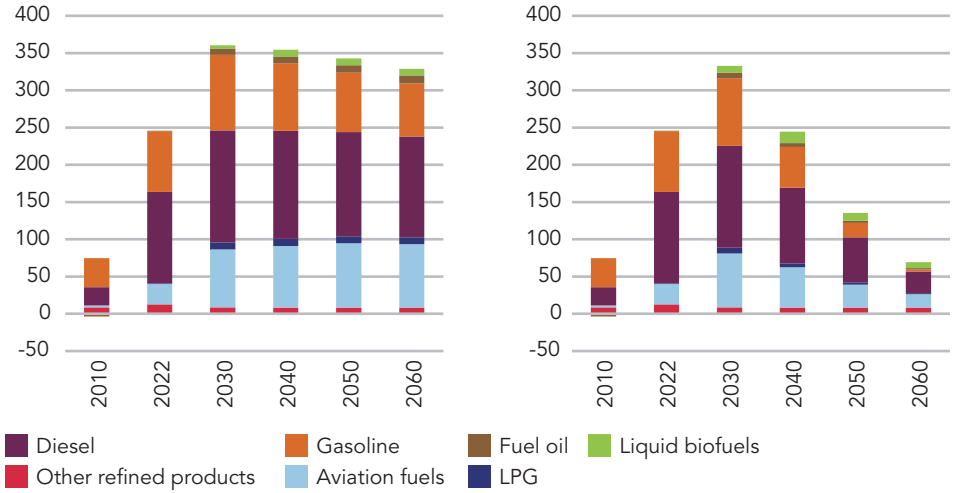


Figure 12-33. Net imports of refined products and low-carbon fuels in REF & TGT (PJ)



- Assumptions for crude oil and natural gas liquids (NGLs) production are identical in both scenarios. All domestic production is exported, and output is expected to gradually decline over the projection period.
- The closure of New Zealand's only oil refinery, Marsden Point, in 2022 was due to declining profitability and rising competition from overseas refineries. In the decade prior, the refinery supplied about two-thirds of New Zealand's gasoline and diesel consumption and nearly all of its jet fuel. Because refined fuels were sold at international market prices, the closure is not expected to significantly affect domestic fuel prices.
- A minimum fuel stockholding obligation for importers took effect in 2025 to improve fuel security. Additional measures introduced thereafter include tighter reporting requirements, phased diesel stock increases for major importers, an Auckland jet fuel buffer, and a planned government diesel reserve. These steps aim to bring New Zealand closer to meeting the IEA's 90-day fuel stockholding standard, enhancing resilience against import disruptions.
- In TGT, refined fuel imports decline rapidly as decarbonisation progresses, driven largely by BEV adoption, which is most effective at displacing gasoline and diesel in the light vehicle fleet. Diesel and jet fuel maintain higher levels of demand due to the challenges of electrifying heavy freight, maritime, and aviation transport, as well as the high cost of alternatives such as hydrogen and biofuels.
- Other uses of imported refined fuels include fuel oil for maritime transport (domestic and international), diesel for industrial and agricultural operations, and non-energy applications such as roughly 6 PJ of bitumen used in road, airport, and port surfacing. LPG is also used in residential households.

Note: In Figure 12-33, net imports are presented without deducting bunkers.

Bioenergy and Waste

Figure 12-34. Bioenergy demand and waste by sector in REF & TGT (PJ)

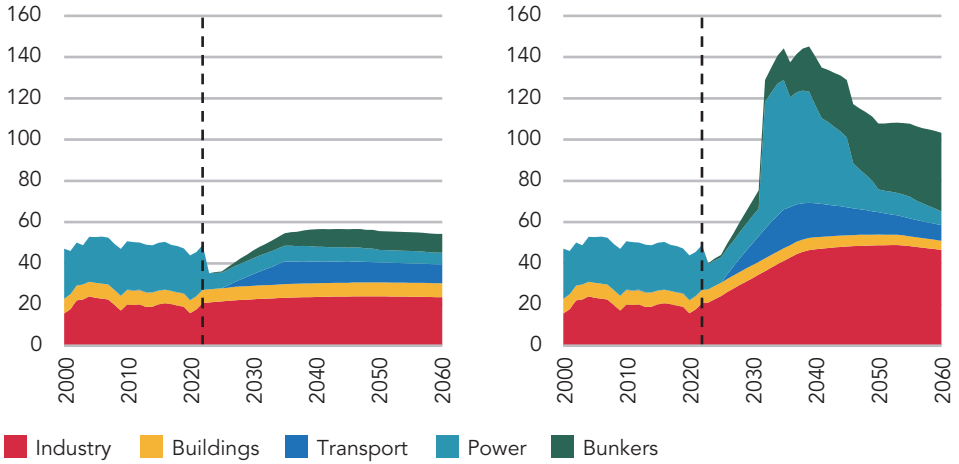
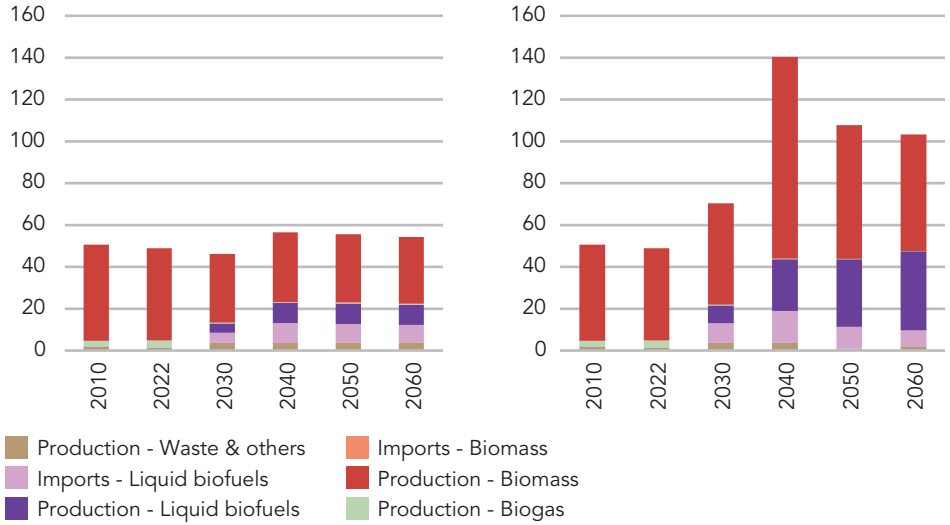


Figure 12-35. Bioenergy and waste production, imports, and exports in REF & TGT (PJ)



- The dairy processing sector is already transitioning from coal toward biomass, particularly wood pellets. Fonterra, New Zealand's largest dairy processor, has committed to phasing out coal by 2037. It currently uses biomass at three sites, with conversions underway at two more.
- In TGT, the Huntly coal power station is expected to transition to using wood pellets by 2032. Its utilisation gradually declines over time as lower-cost generation technologies are deployed, yet it still provides an essential form of dispatchable, near-zero-emissions capacity during the transition.
- Biomass transitions face hurdles such as transport logistics, pellet supply, and boiler retrofits. Yet these issues are being addressed: in 2024 Nature's Flame, New Zealand's largest wood pellet producer, more than doubled production capacity in 2024 to approximately 180 kt/year (~3 PJ) to support Fonterra's Te Awamutu site and other future users.
- Liquid biofuels are projected to be both produced domestically and imported. By 2035, they are mainly used to displace gasoline and diesel. In TGT, consumption shifts toward biojet fuel, as aviation faces fewer viable decarbonisation options, especially since alternatives such as e-fuels are unproven and relatively costly.
- Feedstock requirements for liquid biofuels are not explicitly considered in the modelling. Assessing feasibility would require consideration of potential interactions with food production, chemical feedstock use, and other bioenergy applications, given domestic availability.

Hydrogen-based Fuels in the Target Scenario

Figure 12-36. Hydrogen-based fuels demand by sector [left]; Hydrogen-based fuels demand by fuel [right] (PJ)

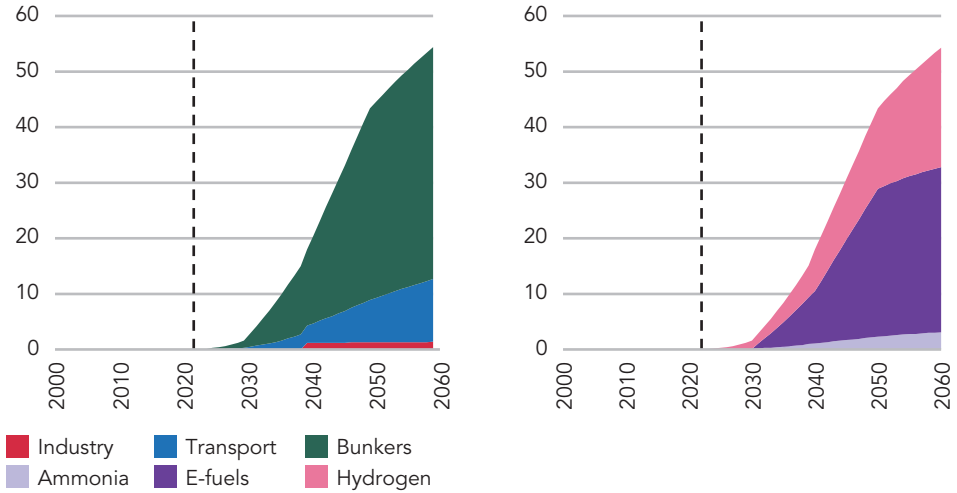
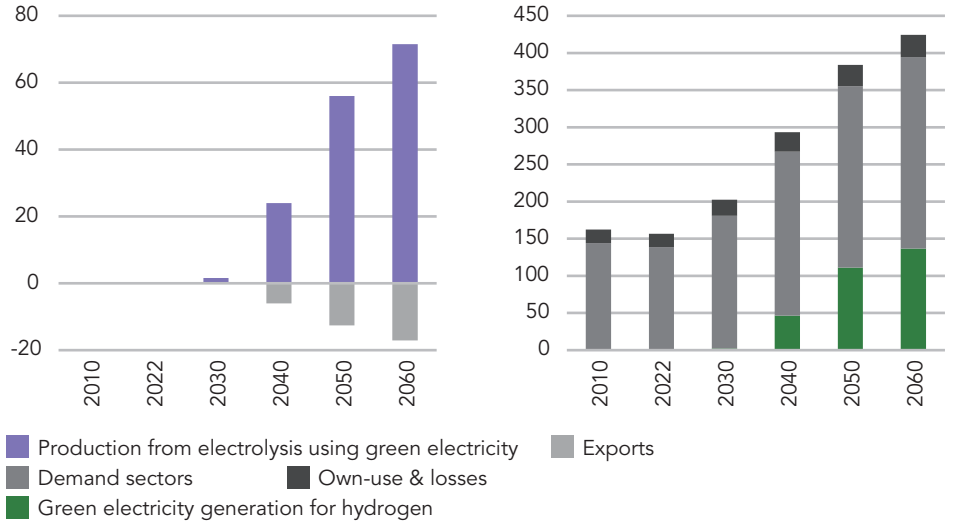


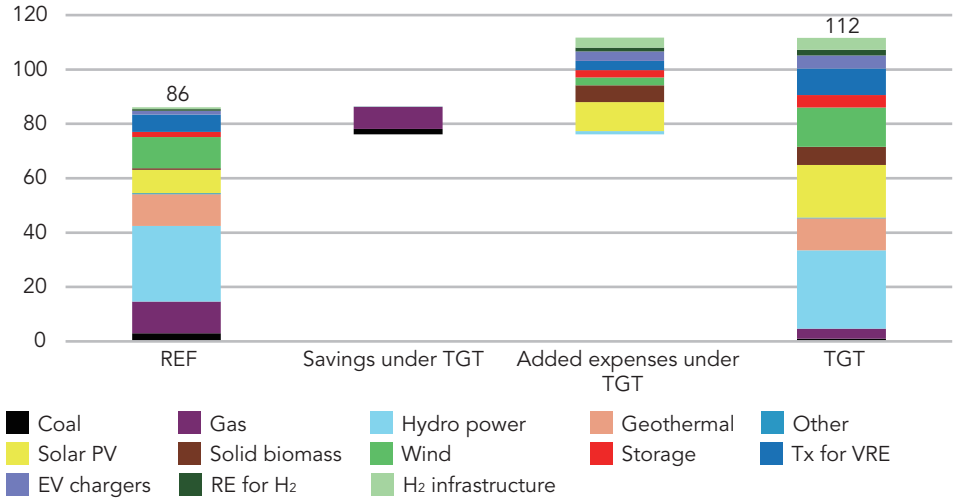
Figure 12-37. Hydrogen-based fuels production methods and supply [left]; Electricity for electrolysis vs other sectors [right] (PJ)



- Hydrogen production in TGT is based on the intentions outlined in the New Zealand Hydrogen Action Plan. By 2060, hydrogen-based fuel production reaches 72 PJ: 17 PJ for export, 42 PJ for international bunkers, and the remainder (13 PJ) for domestic use.
- In TGT, bunker demand follows international transport bodies' targets, so actual demand largely depends on overseas offtake and certification. Consequently, with bunkers and exports comprising the majority, the hydrogen sector is largely export-oriented and has limited direct impact on domestic emissions targets.
- It is assumed that all hydrogen, including that used for e-fuel and ammonia production, is generated using electricity from solar and wind (not shown in previous electricity generation/capacity figures). Producing 72 PJ of hydrogen-based fuels requires approximately 140 PJ of electricity in 2060, implying an overall 50% conversion efficiency (efficiency of electrolysis alone is around 65%-73%). As shown in Figure 12-37 [right], this electricity use accounts for more than one-quarter of New Zealand's projected total generation in 2060 in TGT, with implications for capacity build-out, transmission, and electrolyser utilisation.
- New Zealand's first large-scale green hydrogen project is underway at the Tuaropaki geothermal power station, producing hydrogen for domestic use and potential export to Japan, though current output is only 0.03 PJ. Further expansion of geothermal-powered electrolysis is not assumed, given limited additional capacity beyond baseload needs in the power sector and the lower costs of VRE, unless major geothermal cost reductions occur.
- E-fuels are treated as a strong alternative to hydrogen in the *Outlook* due to their compatibility with existing internal combustion engines, ease of blending, and simpler storage and transport requirements. However, they are even more energy-intensive to produce than hydrogen and require a source of carbon, so scalability also depends on access to sustainable CO_2 streams which were not considered in this *Outlook*.

Costs

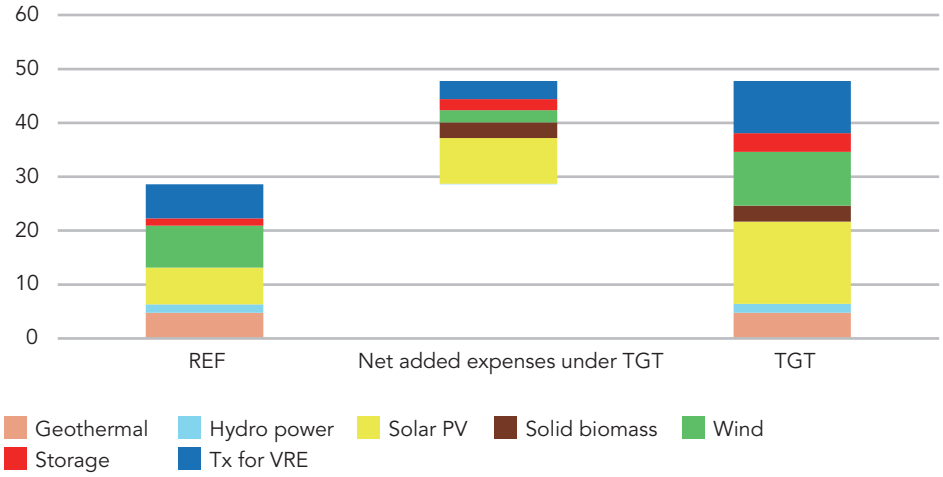
Figure 12-38. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



Note: Tx for VRE is only transmission infrastructure to connect variable renewable capacity to the grid. EV chargers do not cover the cost of associated infrastructure or EV vehicles. Hydrogen costs do not cover costs for bunkering.

- Meeting future energy demand in New Zealand will require additional investment, with total costs rising from 2025 to 2060 in REF and more so in TGT. The model considers total capital, fixed, and variable costs in the power sector, as well as costs for green hydrogen production for domestic use (mostly transport), transmission for variable renewable electricity, and electric vehicle chargers.
- These costs can be compared with Motu's estimates in the National Infrastructure Plan (NIP). Motu reports extra capital costs of NZD 1.02 billion (2023 prices) per new TWh between the Climate Change Commission (CCC)'s Reference and EB4 scenarios from 2023 to 2050, based on 21.9 TWh of new generation. In APERC's modelling, the equivalent cost is NZD 1.11 billion per new TWh between 2022 and 2060 when comparing REF and TGT, excluding transmission costs, for 8.7 TWh of new generation. Differences in assumptions partly explain the gap: the REF scenario projects nearly 40% more generation than the CCC Reference scenario, and Motu includes some operating costs (such as hydro refurbishments) as capital costs that APERC's modelling does not.

Figure 12-39. Total capital investment (CAPEX) from 2025 to 2060 in the power sector (billion USD, undiscounted)

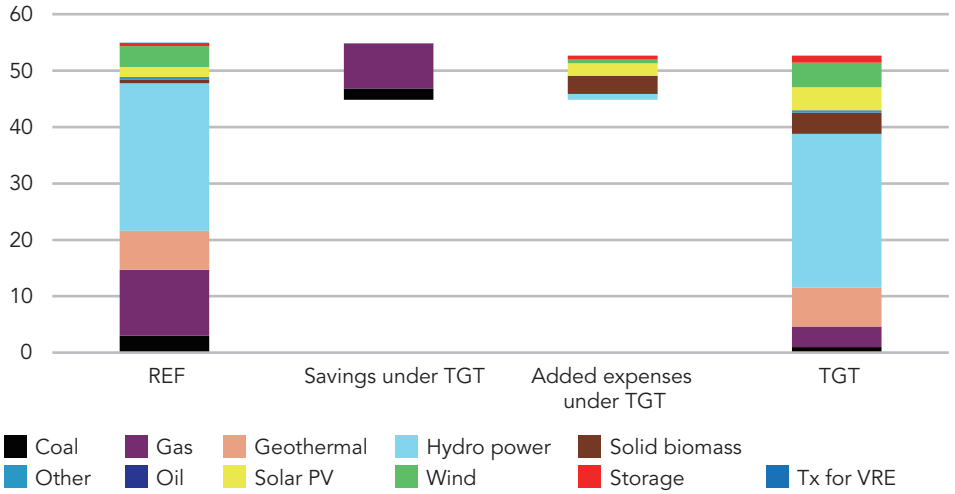


Note: Figure 12-39 only covers power and VRE transmission sector investments. Hydrogen and EV capital investments are not covered.

- The difference in capital costs between TGT and REF is far greater than the difference in their operating costs. This reflects the capital-intensive investments that come with switching Huntly coal station to biomass, the additional solar and wind capacity required to meet higher generation in TGT and the associated storage and transmission needed to support the added VRE capacity. As a result, achieving TGT's electricity mix depends more on reducing barriers to capital deployment than on operating subsidies.
- The cost of producing green hydrogen for international bunkering obligations is excluded, as cost recovery is assumed. Increased hydrogen production for transport in TGT offsets conventional fuel use, with estimated savings of USD 5 billion (not shown in Figure 12-38).

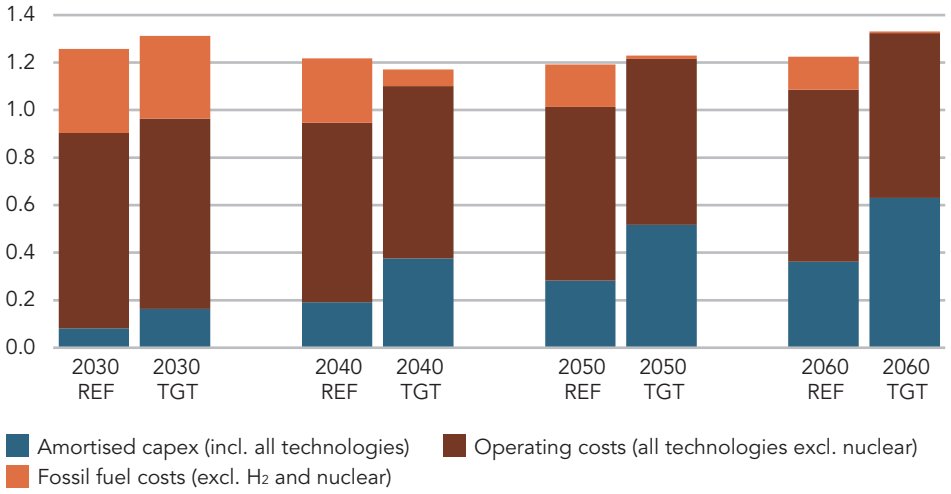
Costs

Figure 12-40. Total operating costs from 2025 to 2060 in the power sector (billion USD, undiscounted)



Note: Figure 12-40 only covers power and VRE transmission sector costs. It does not include operating costs associated with hydrogen production and EV charger costs.

Figure 12-41. Cost of generating electricity relative to 2025 (2025 cost = 1.0) in the power sector



Note: Based on our assumptions about future capital and operating costs, Figure 12-41 shows cost compositions over time relative to 2025. It should not be considered an estimate of electricity tariffs and excludes market mechanisms that are too difficult to estimate.

- New Zealand's electricity system relies predominantly on hydropower (59% of generation in 2022; 34% in 2060 in TGT). Due to its relatively high fixed annual costs, hydropower accounts for a large share of total operating costs. This is similar to geothermal generation, which also incurs high fixed costs.
- In REF, reliance on imported LNG for a large portion of gas-fired generation from 2030 raises operating costs, resulting in higher total gas generation costs than in TGT. Capital costs for LNG, pipelines, and gas fields are excluded.
- In TGT, gas use declines substantially due to its shift to peak-only generation, reducing overall generation costs. However, switching from coal to biomass consumption at the Huntly Power Station, in TGT, will partially offset these savings.

- In Figure 12-41, the TGT scenario's 2060 value of 1.33 indicates that electricity generation costs, indexed to the base year of 2025, are projected to be 33% higher (allowing for a margin of error given the uncertainty of forecasts). Despite fossil fuels being largely eliminated, amortised capital costs for renewables and storage push up this cost above REF, but with the benefit of reduced emissions.
- TGT's higher electricity generation costs reflect the combined effect of eliminating fossil fuels and meeting additional demand from electrification with greater investments in renewable capacity. However, the dry-year challenge may be worsened by the lack of a secure gas supply for backup generation, affecting grid reliability. In contrast, REF includes LNG and a new gas field, which provides more supply for reliable dry-year coverage but at the cost of higher emissions and unaccounted gas infrastructure expenses (the LNG import terminal is estimated at less than USD 0.5 billion according to the Enerlytica Port Taranaki cost stack).

CO_2 Emissions

Figure 12-42. CO_2 emissions in REF (million tonnes)

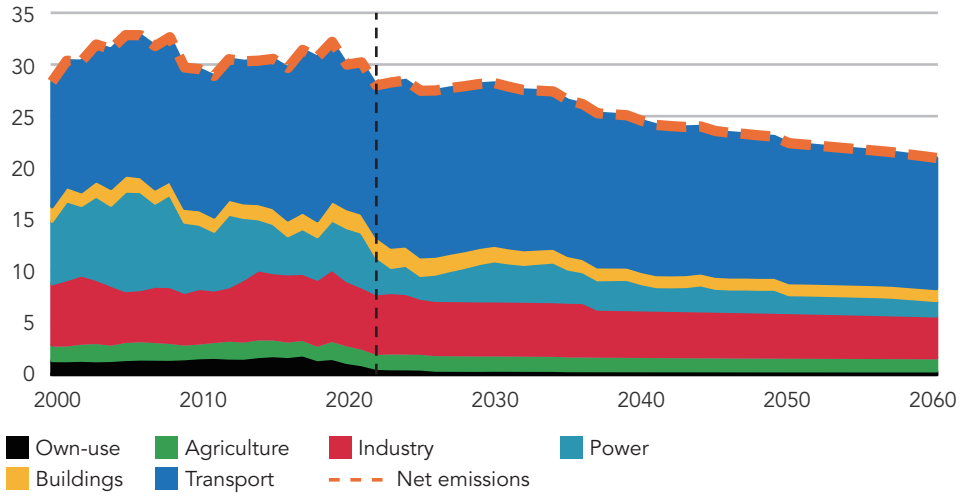
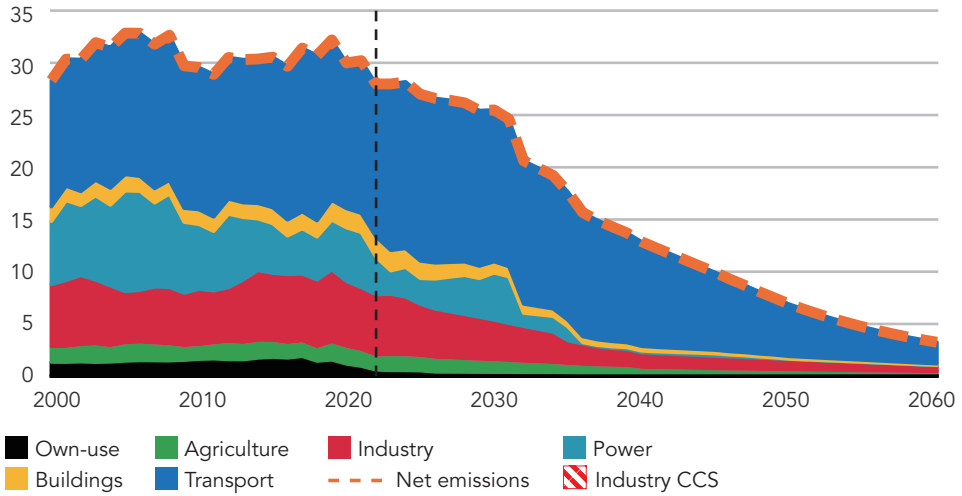
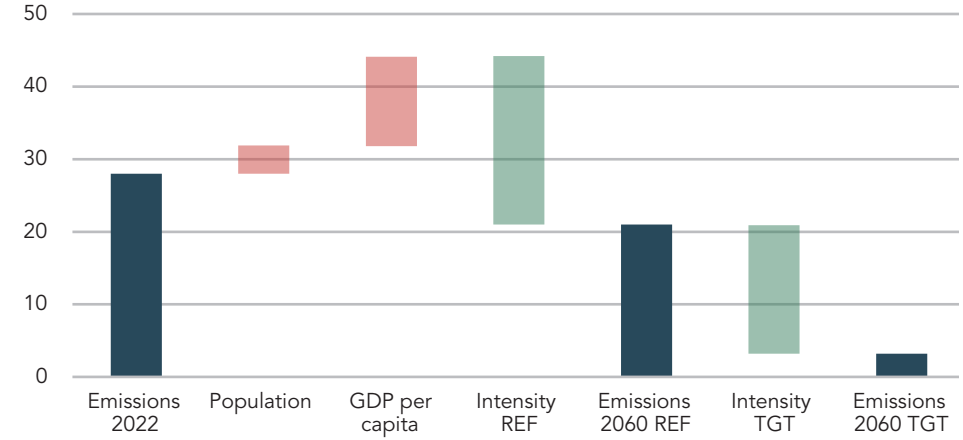


Figure 12-43. CO_2 emissions in TGT (million tonnes)



- In TGT, some residual emissions remain by mid-century due to energy use in hard-to-abate sectors such as heavy freight, aviation, and certain industrial oil applications (e.g., motive power or unclassified uses).
- If energy is assumed to account for 40% of domestic carbon budgets, the sector would not meet any of the interim budgets: ~116 Mt for 2022-25, ~116 Mt for 2026-30, and ~96 Mt for 2031-35. Achieving net-zero therefore requires offsetting these residual emissions through forest sequestration or other carbon removal approaches. While TGT includes limited industrial carbon capture, the expected contribution (0.003 Mt) is relatively small.
- The Kaya Identity analysis in Figure 12-44 shows that from 2022 to 2060, improvements in energy and emissions intensity are offset by upward pressures from population growth and economic activity (represented by increasing GDP per capita). This highlights the importance of continued adoption of lower carbon energy sources and further efficiency improvements to expand the contribution of intensity improvements and outpace the effects of macroeconomic growth.

Figure 12-44. CO_2 emissions components (million tonnes)



Note: All values represent energy sector combustion CO_2 emissions. Biogenic CO_2 is treated as zero at the point of combustion. Emissions reductions from CCS are comparatively small and do not register in Figure 12-43.

Useful Links

APEC Expert Group on Energy Data and Analysis (EGEDA) – https://www.egeda.ewg.apec.org/

APEC Energy Statistics 2022 – https://www.egeda.ewg.apec.org/egeda/general/info/pdf/APEC_Energy_Statistics_2022.pdf

APEC Energy Overview – https://aperc.or.jp/reports/energy_overview.php

Ministry of Business, Innovation & Employment (MBIE) — Hīkina Whakatutuki – https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources

New Zealand Government — Beehive (official ministerial releases) – https://www.beehive.govt.nz

Ministry for the Environment (MfE) — Manatū Mō Te Taiao – https://environment.govt.nz/

Climate Change Commission (CCC) — He Pou a Rangi – https://www.climatecommission.govt.nz/

Te Waihanga — New Zealand Infrastructure Commission: National Infrastructure Plan – https://tewaihanga.govt.nz/national-infrastructure-plan

Hydrogen Action Plan (MBIE) – https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-generation-and-markets/hydrogen/hydrogen-action-plan

New Zealand clean car standard (Waka Kotahi NZ Transport Agency) – https://nzta.govt.nz/vehicles/clean-car-programme/clean-car-standard

Enerlytica (2023). LNG import and options to increase indigenous gas market capacity and flexibility in New Zealand – https://www.gasindustry.co.nz/assets/CoverDocument/LNG-import-and-options-to-increase-indigenous-gas-market-capacity-and-flexibility-in-New-Zealand-March-2023-v2.pdf

Motu (for Te Waihanga). Infrastructure needs analysis for Decarbonisation – https://media.umbraco.io/te-waihanga-30-year-strategy/ly1aaixk/infrastructure-needs-analysis-decarbonisation.pdf



13. Papua New Guinea

Summary

	Reference			Target		
	2022	2060	% Change	2022	2060	% Change
Macroeconomic						
Population (million)	10	16.1	61%	10	16.1	61%
GDP (billion 2017 USD, PPP)	33	191	476%	33	191	476%
Energy Demand						
Agriculture & fisheries (PJ)	5	6	32%	5	5	14%
Buildings (PJ)	77	115	49%	77	99	29%
Industry (PJ)	39	179	366%	39	154	300%
Transport (PJ)	25	57	128%	25	46	83%
Modern renewables share of TFEC (%)	5	19	280%	5	66	1,220%
Energy intensity of TFEC (PJ/GDP, billion USD)	65	28	-57%	65	24	-63%
Electricity						
Generation (TWh)	4	28	552%	4	56	1,176%
Renewables share of generation (%)	25	56	124%	25	100	300%
Generation capacity (GW)	1	13	859%	1	25	1,611%
Total Primary Energy Supply (TPES)						
Natural gas (PJ)	36	82	127%	36	84	131%
Petroleum liquids (PJ)	84	255	202%	84	42	-50%
Low-carbon & waste energy (PJ)	83	179	116%	83	305	268%
CO_2 intensity of energy supply ($MtCO_2/PJ$)	0.037	0.047	27%	0.037	0.015	-59%
Net CO_2 Emissions (million tonnes)	8	24	221%	8	7	-12%

Note: In this publication, the term "modern renewables" refers to all renewable energy sources excluding solid biomass in the buildings sector. The term "low-carbon & waste energy" includes all bioenergy, waste-derived energy, renewables, nuclear, and hydrogen-based fuels. Total primary energy supply (TPES) numbers include international bunkers. Net emissions are calculated as gross energy sector combustion CO_2 minus CO_2 captured and stored through carbon capture and storage (CCS).

Key Takeaways

Emissions

- Papua New Guinea (PNG)'s emissions trajectory presents two contrasting futures over the next 35 years. Both assume the same rapid economic and population growth, but the evolution of the energy system differs.
- The Target scenario (TGT) reflects the government's Vision 2050 goal for 100% renewable electricity by 2050, alongside major grid expansion under the National Electrification Rollout Plan (NEROP). Further assumptions include electrification across all sectors, mining decarbonisation, EV adoption, and low-emissions fuel switching in buildings, resulting in lower emissions in 2060 compared to 2022.
- The Reference scenario (REF) illustrates outcomes for PNG under strong economic and population growth, but with limited progress in shifting the energy mix, expanding the grid, improving efficiency, or widening energy access. As a result, emissions move upward as economic activity expands.

Energy Import Dependence

- PNG's total primary energy supply was 204 PJ in 2022, while LNG exports exceeded 446 PJ. With the Papua LNG project, exports are projected to rise to 666 PJ by 2030, underscoring the growing role of LNG as a main driver of economic growth and export revenue.
- Oil is a major energy source across mining, power, transport, and buildings. Despite the Napa Napa refinery (33 000 b/d; ~74 PJ capacity), PNG imports most refined products and relies largely on imported crude, heightening exposure to international price and supply risks.
- REF's growth increases oil demand—including in power—deepening import dependence; TGT replaces oil in power and electrifies end uses, making PNG a net exporter of oil products by 2060.
- In TGT, to capture more value from gas production, a 45 PJ gas-to-ammonia plant (~22 PJ output) serves domestic fertiliser and bunkering, while remaining largely export-oriented; its advantage over LNG depends on margins after conversion and transport.

Figure 13-1. Net CO_2 emissions (million tonnes)

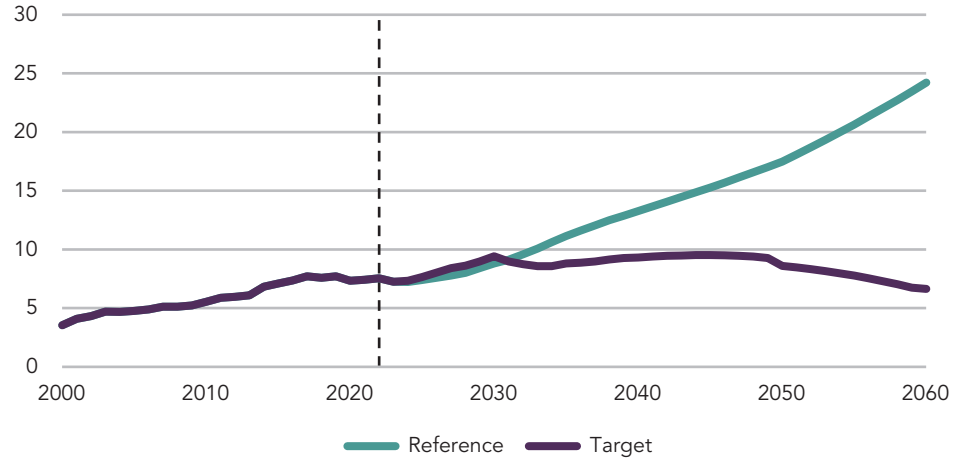
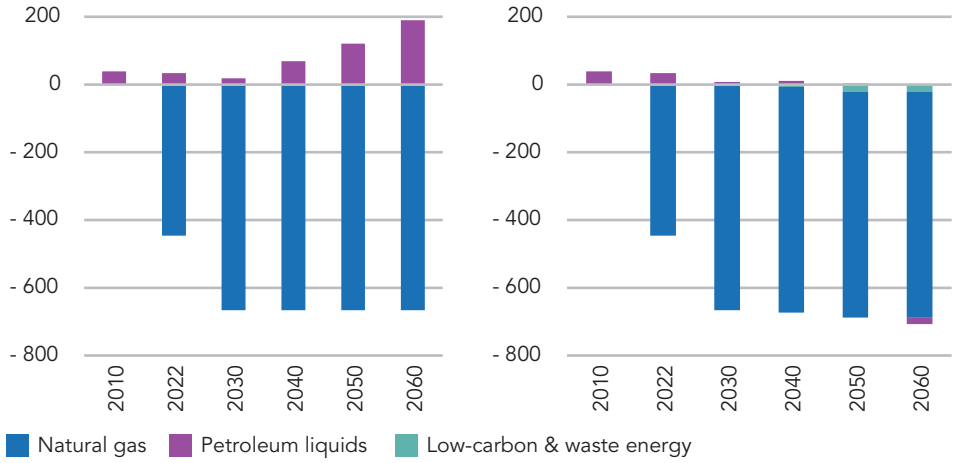


Figure 13-2. Net imports in REF & TGT (PJ)



Note: In Figure 13-2, net imports refer to total imports minus exports and international bunkers.

Key Takeaways

Grid Reliability

- Figure 13-3 illustrates PNG's reliance on dispatchable power during periods of maximum and minimum demand. The widening gap signals a growing need for dispatchable power as solar is installed.
- In REF, solar provides most new capacity, backed by oil generators and some gas. This mix provides enough dispatchable power to maintain reliability but exposes PNG to high fuel costs and competition with LNG exports.
- In TGT, batteries expand to integrate solar but only provide short-duration storage. Firm resources, especially hydro, continue to expand, while gas and oil are phased out by 2050. With substantial hydro additions, reliability risks from higher VRE shares (e.g. solar) remain relatively low and are secondary to grid development and expanding electricity access.
- Grid reliability in PNG depends most heavily on the success of NEROP and other initiatives in linking the economy's two main grids, isolated mini-grids and autoproducers.

Cost

- Figure 13-4 illustrates that estimated total costs for the power sector from 2025 to 2060 in the TGT scenario will be 51%, or an estimated USD 24 billion, higher than in REF.
- These costs consider total capital, fixed, and variable costs in the power sector, and electric vehicle chargers. Compared to other economies, costs for transmission in variable renewables are excluded because they depend greatly on the buildout of the main grid, the expense of which is difficult to quantify.
- Costs diverge between scenarios due to PNG's reliance on imported oil in REF versus heavy investment in hydro, solar, and batteries in TGT. Although upfront capital costs are higher in TGT, amortising the capital costs of these renewable assets over their expected lifetime yields a lower average annual cost of electricity generation in TGT—largely because TGT generates about twice as much electricity as REF for only a 51% increase in total cost.

Figure 13-3. Peak load and maximum and minimum dependence on dispatched power (GW)

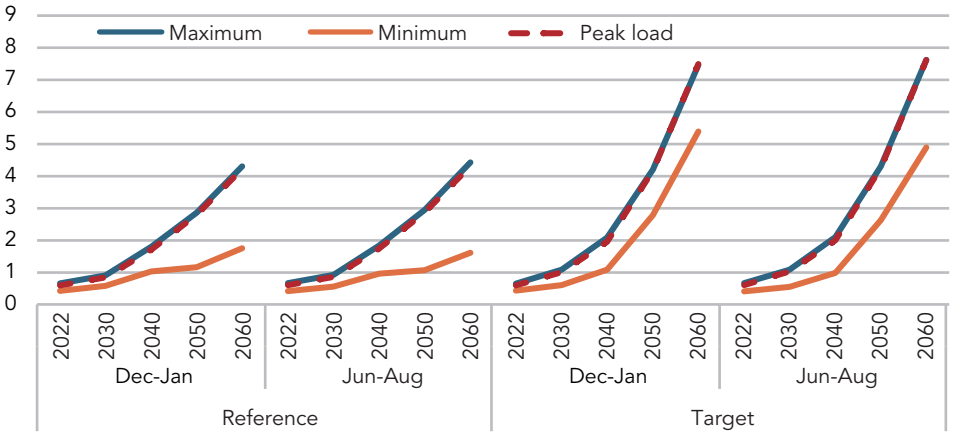
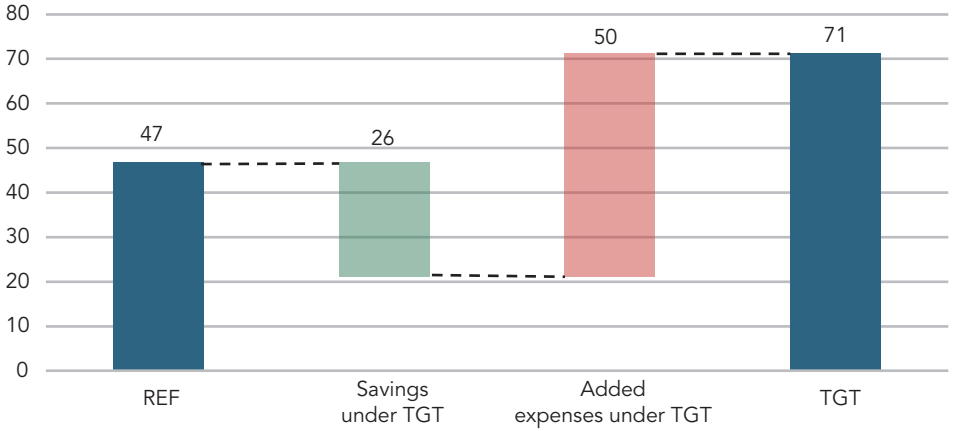


Figure 13-4. Costs in the power sector, 2025 to 2060 (billion USD, undiscounted)



*Actual costs will differ from estimated costs in the *Outlook* for a variety of reasons including changing commodity prices, manufacturing costs and unforeseen technical advances. All costs are in 2023 real terms.

About Papua New Guinea

Overview

Geographical and Economic Landscape

Papua New Guinea (PNG) lies in the South Pacific, north of Australia. It has a highly varied geography of mountains, coastal plains, and islands, and is among the most culturally diverse economies in the world. The climate is tropical, with distinct wet and dry seasons. Only 13% of the population lives in urban areas, making PNG one of the most rural economies globally. The economy is resource-driven, centred on mining (e.g., gold and copper), LNG and oil production, forestry, and agriculture. Resource exports have driven periods of strong GDP growth in PNG, but the benefits have been unevenly distributed, with ongoing challenges in infrastructure, financing, service access, and economic diversification.

Energy Supply and Consumption

PNG's energy supply has grown markedly over recent decades, primarily due to the expansion of the LNG export sector. LNG is now the economy's largest export, with most cargoes bound for China and Japan. In 2022, LNG exports reached 446 PJ, while domestic energy demand was about 150 PJ. Most domestic consumption comes from biomass (traditional fuelwood) and oil products (for transport and generators). Electricity access remains limited, with around 80% of the population—mainly in rural areas—not connected to an electric grid.

Energy Security Challenges and Strategies

PNG's energy security is influenced by its reliance on imported oil products and the configuration of its grid infrastructure. Access to foreign exchange influences supply, as seen during the 2022 jet fuel shortage, when international fuel was available, but importers encountered logistical and financial challenges. Additionally, export earnings from LNG and mining are concentrated among a few companies, affecting how foreign currency is distributed across the broader economy.

To address these challenges, PNG is investing in renewable energy (hydro and solar), developing off-grid and mini-grid systems, and expanding electrification under the National Electrification Rollout Plan (NEROP). Additional measures, including strategic fuel stockpiles and closer monitoring of supply risks, are also under consideration.

Key Energy Initiatives

National Electrification Rollout Plan (NEROP)

Targeting 70% household access to electricity by 2030 and 100% by 2050 through on-grid, off-grid, and mini-grid solutions.

Vision 2050, 100% Renewable Electricity Target

Expanding hydro, solar, and biomass to reduce reliance on diesel generation.

LNG Exports

The Papua LNG project, led by TotalEnergies, ExxonMobil, and Oil Search, with a nameplate capacity of about 5.6 Mt per year, will expand PNG's LNG export volumes. Final investment decisions and associated field developments (e.g., P'nyang) are targeted around 2029 for completion, with parallel efforts to channel more gas into domestic industry and power.

Energy Security

PNG's National Energy Policy (2017–2027) emphasises strengthening fuel security by improving storage and logistics and exploring small-scale refining and gas-to-liquids (GTL) applications to reduce reliance on imported fuel.

Enhanced Nationally Determined Contribution (NDC) (2020)

The NDC was revised to target a 78% share of installed renewable energy capacity by 2030.

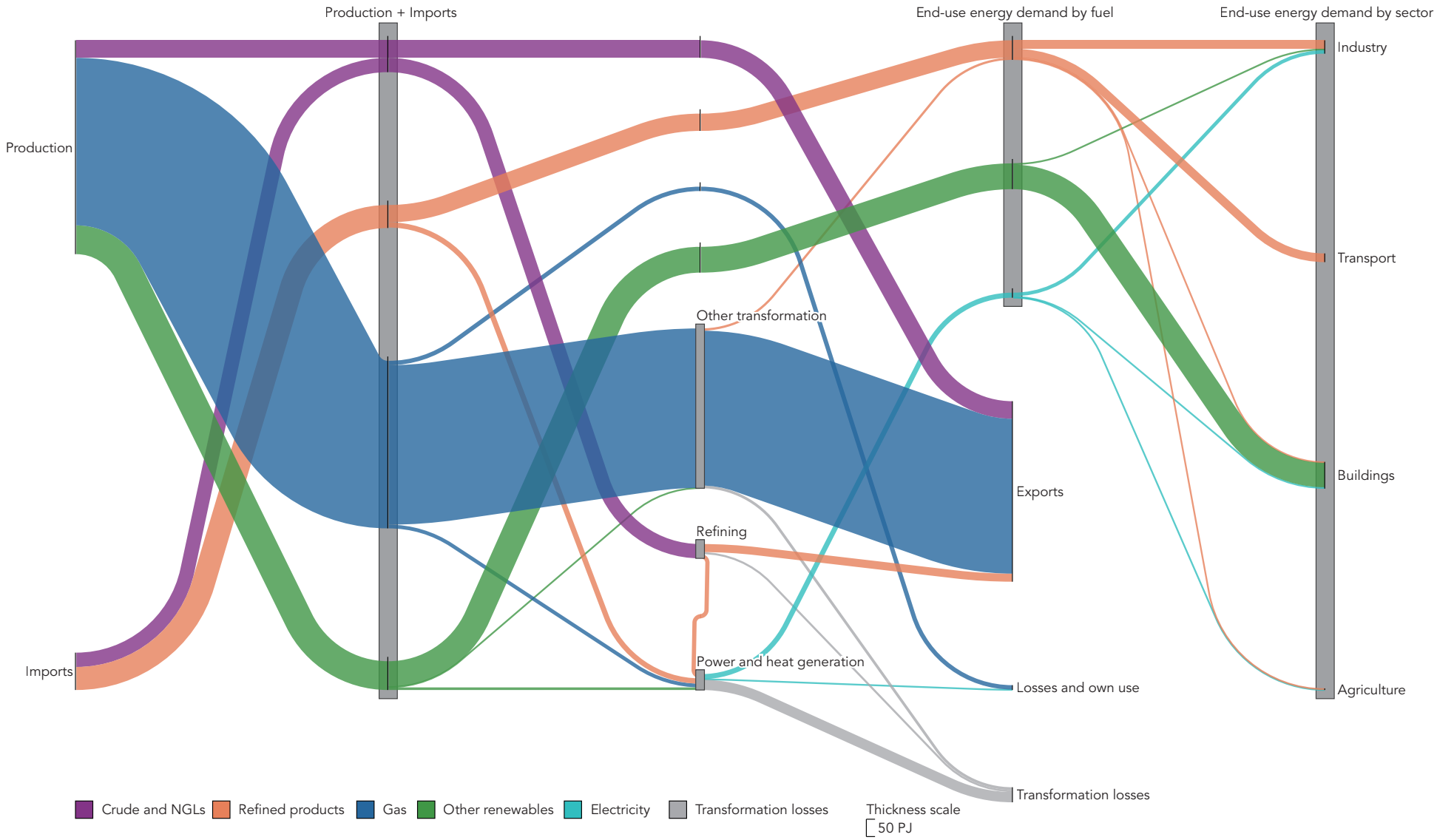
Domestic Resource Utilisation

Under PNG's Domestic Market Obligation policy, private gas investors must reserve 15% of gas production for domestic use, ensuring local supply for domestic utilisation rather than full export to LNG terminals.

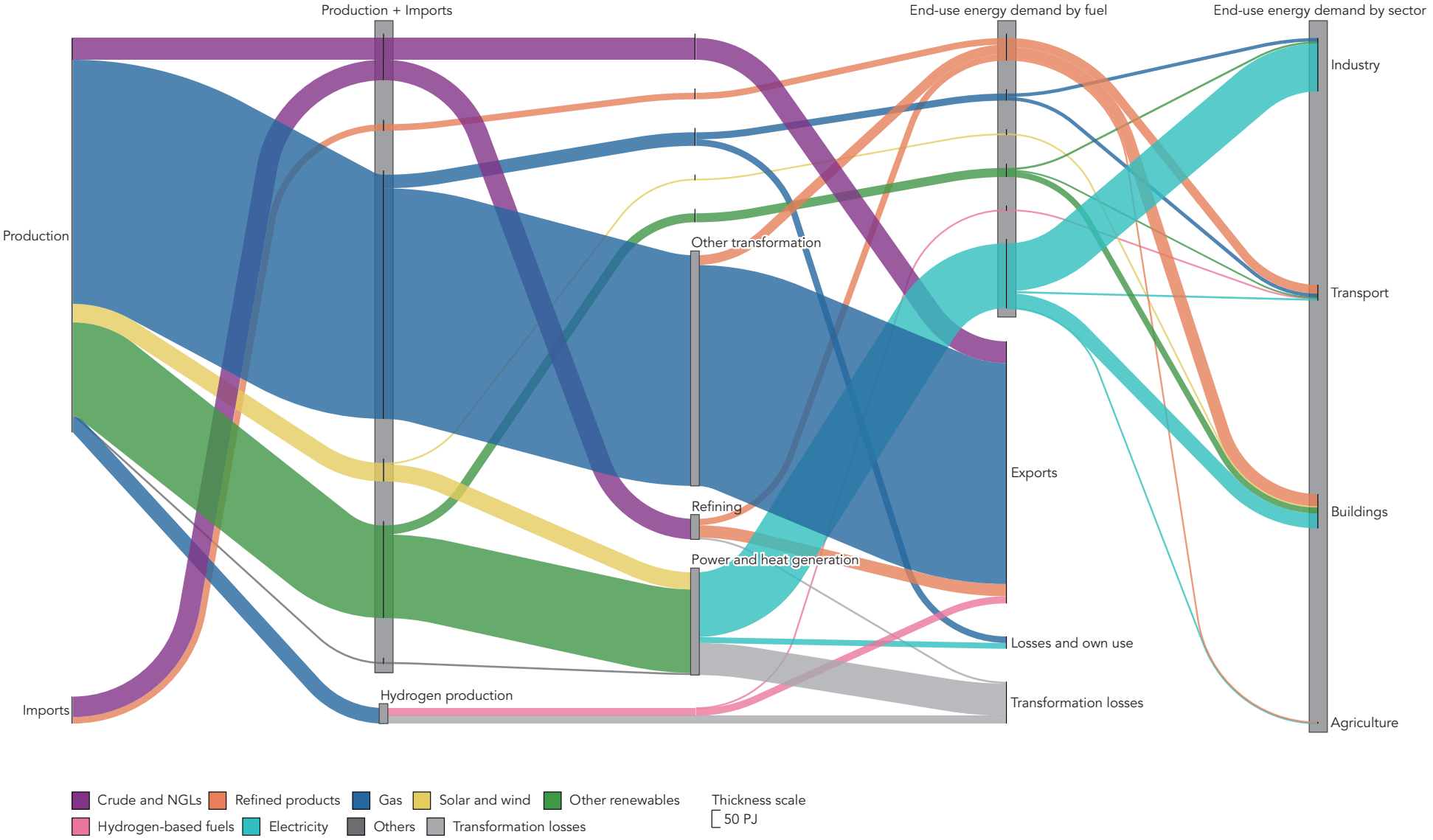
National Energy Authority Act 2021

Passed in April 2021, it decommissioned all the regulatory powers and functions of PNG Power Limited and vested them with the National Energy Authority. The National Energy Authority Act also empowers the government's ability to collect energy data from private groups to obtain statistics.

Energy Flow (2022)



Energy Flow (2060, Target Scenario)



Scenarios and Assumptions

In *The Outlook*, APERC analyses energy demand, transformation, and supply, as well as emissions. The **Reference Scenario (REF)** offers a projection based on historical trends, recent developments, and APERC's assumptions about the continuation of those trends in each APEC economy, while acknowledging technical restraints. The REF Scenario offers a baseline to compare with the **Target Scenario (TGT)** projections, which explores a hypothetical pathway where each economy achieves energy-related policy targets, assuming implementation regardless of cost-effectiveness. When implementation details are lacking, assumptions are inferred from the targets themselves or emissions-related goals.

	Reference	Target
General	• Population: UN medium; GDP: APERC model and IMF.	• Population: UN medium; GDP: APERC model and IMF.
Buildings	• New demand met by electricity, LPG, and kerosene. • Minimal replacement of existing biomass systems. • Electricity access expanded but NEROP targets not reached. • AI and data centre growth is the same under both scenarios.	• New demand met by electricity, LPG, and kerosene. • Replacement of biomass systems with electricity and LPG alternatives. • Electricity access targets of 70% in 2030 and 100% by 2050 reached. • Considers efficiency gains from residential appliance labelling.
Industry	• Both scenarios assume further growth in agro-processing. • Light manufacturing also expands later in the projection period.	• Complete decarbonisation of mining sector by 2050. • 5 PJ cement plant, and several smaller manufacturing facilities that use gas are built between 2035 and 2040.
Transport	• EV sales shares grow at a modest rate (e.g., 30% BEV sales share for passenger vehicles by 2060). • Liquid biofuel blending reaches 5% of all transport fuels by 2040 in REF and 10% in TGT.	• EV sales shares grow at a faster rate (e.g., 50% BEV sales share, 25% PHEV sales share for passenger vehicles by 2060). • CNG fuelled freight vehicles sales shares reach 30% by 2030 and then fall slowly to 15% by 2060 as they are replaced by FCEVs, PHEVs and BEVs (which have a 20%, 6%, and 40% sales share by 2060). • Small number of electric planes for PNG's short flights.
Power	• Electricity access targets in buildings also affect power.	• 100% renewable electricity generation by 2050. • Autoproducers are assumed to connect to the main grid where feasible.
Supply	• Papua LNG begins operation in 2029, bringing total liquefaction capacity to 666 PJ. • Crude production rises to 66 PJ in 2030 and remains at that level.	• Gas use for ammonia production ramps up to 45 PJ natural gas input (22 PJ output) capacity between 2035 and 2050. Ammonia is all assumed to be exported. This is not related to any government initiatives. • Crude production rises to 75 PJ by 2030 in TGT and then falls slightly.

Note: The base year is 2022. Macro-economic assumptions are constant across scenarios. Historical energy balances are from EGEDA submissions for 2022.

Demographic and Macroeconomic Assumptions

Figure 13-5. Population (thousands)

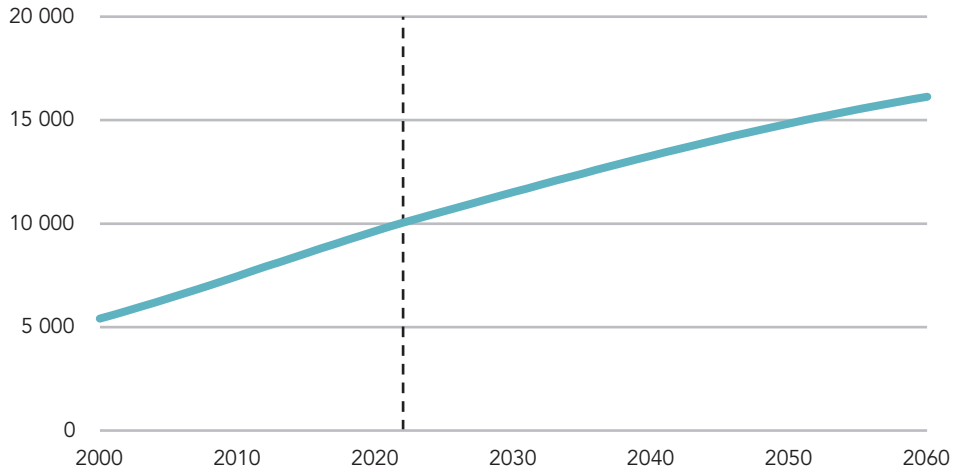
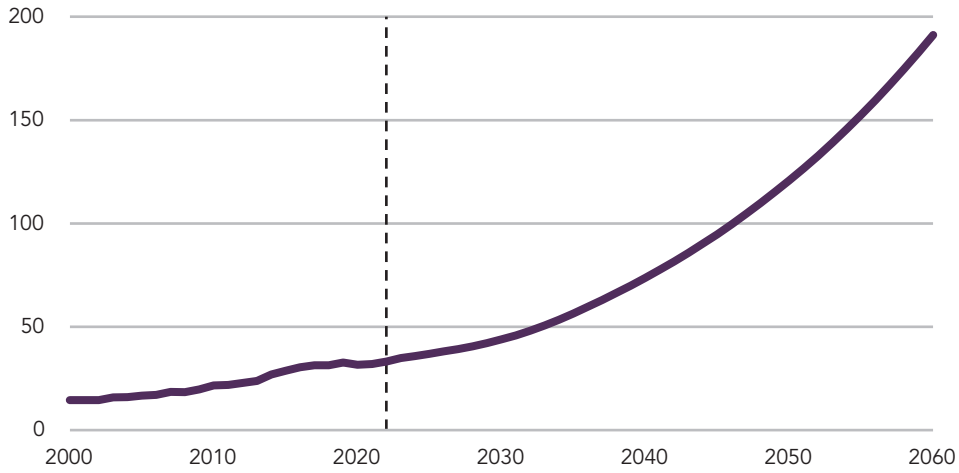


Figure 13-6. Real GDP (billion 2017 USD PPP)



- Papua New Guinea's population is expected to grow at the fastest rate in APEC, directly driving higher energy demand in the residential and passenger transport sectors. Growth stems from a high birth rate, keeping the median age low and the working-age population share elevated throughout the projection period.
- Estimates of PNG's current population vary widely. UN data places the 2023 population at about 10.39 million (up from 9.95 million in 2021), compared with 7.26 million recorded in the last formal census in 2011. Some satellite-based estimates have suggested figures as high as 17 million in 2022, which is almost double the official count. This uncertainty directly affects residential and passenger transport energy projections, since higher population figures translate into proportionally higher demand.
- At present, only 13% of the population resides in urban areas, though UN DESA projects this share will rise to 24% by 2060. Greater urbanisation is expected to expand the services sector and shift energy use toward electricity.
- GDP is projected using the APERC macro model (IMF baseline to 2027, then endogenous), with rapid growth reflecting a transition to a new development phase supported by industrial expansion and broader electricity access.
- PNG's GDP is also projected to grow at the fastest rate in APEC. However, results will vary with improvements in governance, the investment climate, and infrastructure; the projections illustrate one plausible path under continued improvement.

End-use Energy Demand

Figure 13-7. Energy demand by sector in REF & TGT (PJ)

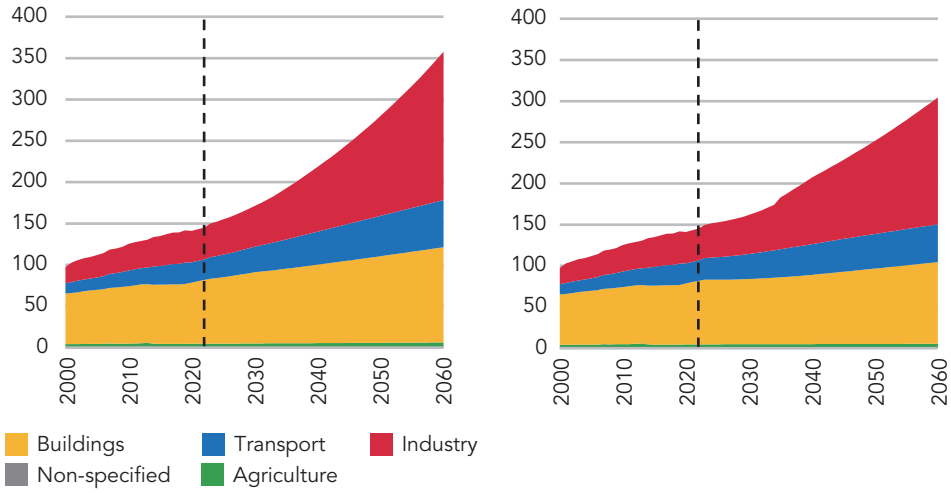
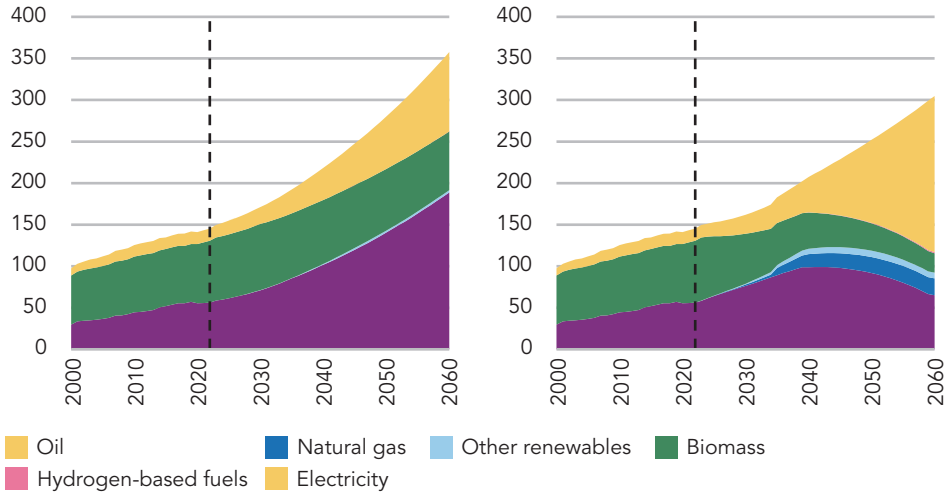


Figure 13-8. Energy demand by fuel in REF & TGT (PJ)



- Papua New Guinea's energy economy is shaped by three key factors. First is the widespread reliance on traditional biomass in buildings, which has implications for efficiency and health.
- Second is the dominance of mining and industrial sites in both energy consumption and electricity generation. Most power is produced by industrial autoproducers for their own use, resulting in domestic statistics that may not fully capture that around 20% of PNG's population had electricity access in 2023. This underlines the challenge of securing enough electricity supply to expand access beyond industry.
- Third is PNG's expanding LNG export industry, projected to reach nearly 666 PJ per year within two decades. Under PNG's Domestic Market Obligation policy, private gas investors must reserve 15% of gas production for domestic use. This would amount to 112 PJ once the Papua LNG project is complete, if fully utilised — highlighting the need to balance export growth with domestic demand.

- Total energy demand is projected to grow by around 146% and 110% by 2060 in REF and TGT, respectively, driven in both scenarios by population growth, increased energy access, and industrial expansion.
- The energy demand projection in REF reflects a future where government energy and decarbonisation targets are not fully met. Slower grid development constrains the National Electrification Rollout Plan (NEROP), domestic gas use outside power remains limited, and higher demand reflects insufficient efficiency improvements.
- In contrast, TGT's projection reflects the achievement of the NEROP and stronger domestic gas utilisation. For the sake of scenario contrast, additional assumptions not associated with government targets were made, such as EV adoption, mining decarbonisation, and low-emissions fuel uptake in buildings.

Buildings Energy Demand

Figure 13-9. Buildings energy demand by fuel in REF & TGT (PJ)

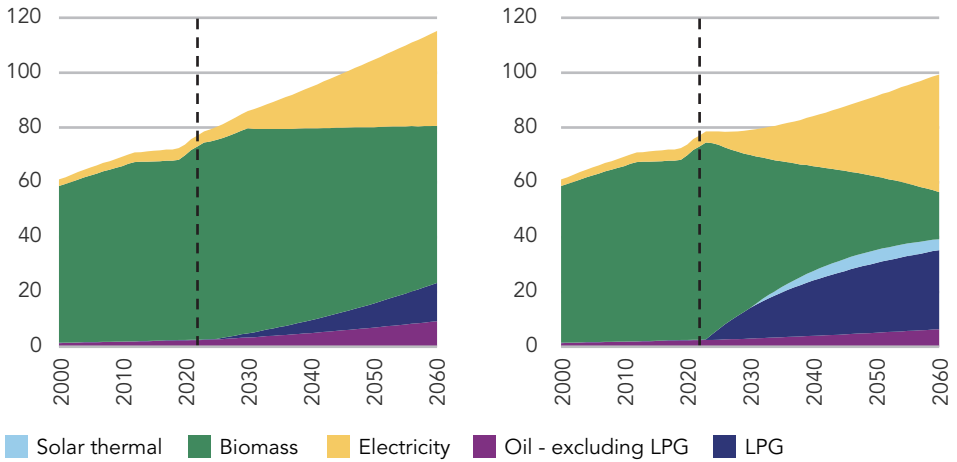
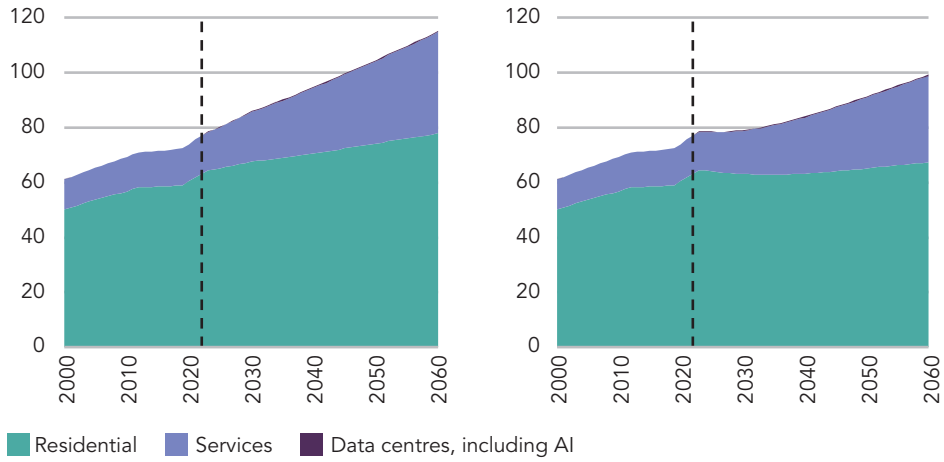


Figure 13-10. Buildings energy demand by sector in REF & TGT (PJ)



- Papua New Guinea's building sector is projected to change substantially, guided by the government's goal of 70% electricity access by 2030 and 100% by 2050 in TGT. Achieving tier-1 access (electricity for lighting and small appliances) will require grid expansion as well as multiple remote mini-grids.
- LPG, a by-product of gas processing plants, is expected to grow rapidly in both scenarios as a more efficient and convenient alternative to firewood. Supply is currently limited to specific areas, but broader access could raise living standards and increase the value captured from domestic gas production. TGT models the National Electricity Rollout Plan (NEROP) by assuming a sharp increase in per-capita electricity consumption. In REF, a slower rollout and lower growth in access is assumed.
- Fuelwood remains the dominant residential energy source as of 2022. In REF, most new demand after 2030 is met by electricity, LPG, and some kerosene.
- In TGT, more rapid fuel switching replaces existing biomass use with LPG and electricity for cooking and lighting. This transition reduces reliance on traditional fuels, improves efficiency, and helps moderate demand growth.
- In addition, TGT assumes higher appliance efficiency through standards on imported products. Combined with widespread fuel switching, this keeps total electricity consumption in 2060 broadly similar in REF and TGT, despite much higher electricity access in TGT.

Industry Energy Demand

Figure 13-11. Industry demand by fuel in REF & TGT (PJ)

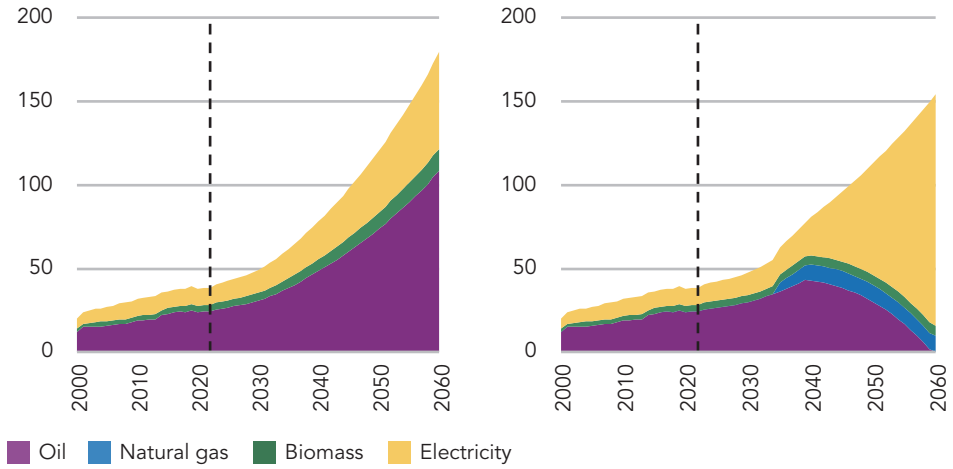
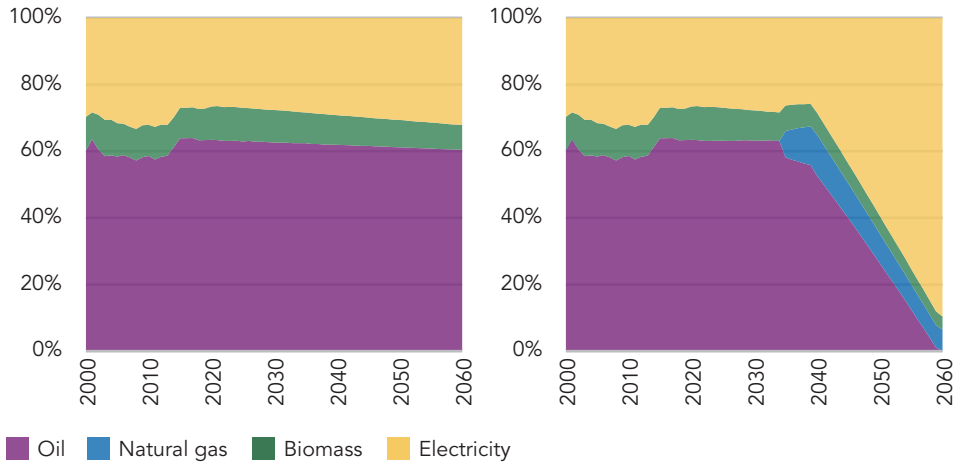


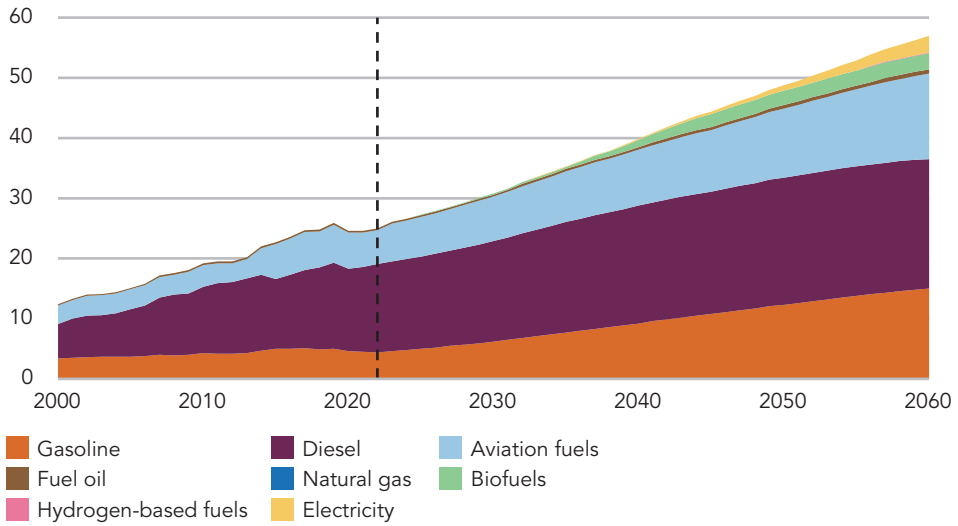
Figure 13-12. Share of industry demand by fuel in REF & TGT (%)



- Papua New Guinea's industrial sector is dominated by large-scale mining and oil and gas extraction, which contribute about 80% of export earnings and 25% of GDP. As a result, shifts in resource production strongly influence energy consumption.
- Major mines (gold, copper, nickel) are typically remote and rely on self-supplied power, mostly diesel or heavy fuel oil. Upcoming projects include the Wafi-Golpu copper-gold mine, with a planned 100+ MW gas-fired plant, and the Frieda River project, powered by a proposed 490 MW hydro facility.
- While new mining projects are expected in future decades, several existing sites will face resource depletion, raising potential issues with stranded generation capacity, particularly for isolated facilities impractical to connect to the main grid.
- Although the PNG government has not set mining sector decarbonisation targets, it was assumed that mining operators would adopt prevailing international net-zero targets by 2050. This assumption, made solely for scenario contrast, drives major electricity growth in TGT, while diesel use continues rising in REF.
- Both scenarios assume further growth in agro-processing, using residual biomass for co-generation and diesel for other energy needs. Light manufacturing, increasingly powered by electricity, also expands later in the projection period, contributing to rising demand for both electricity and biomass.
- To meet the obligation for producers to supply 15% of gas domestically, TGT assumes a 5 PJ cement plant and smaller gas-fired manufacturing facilities come online by 2040. This creates demand growth in the local market while acknowledging that expanding manufacturing takes time.

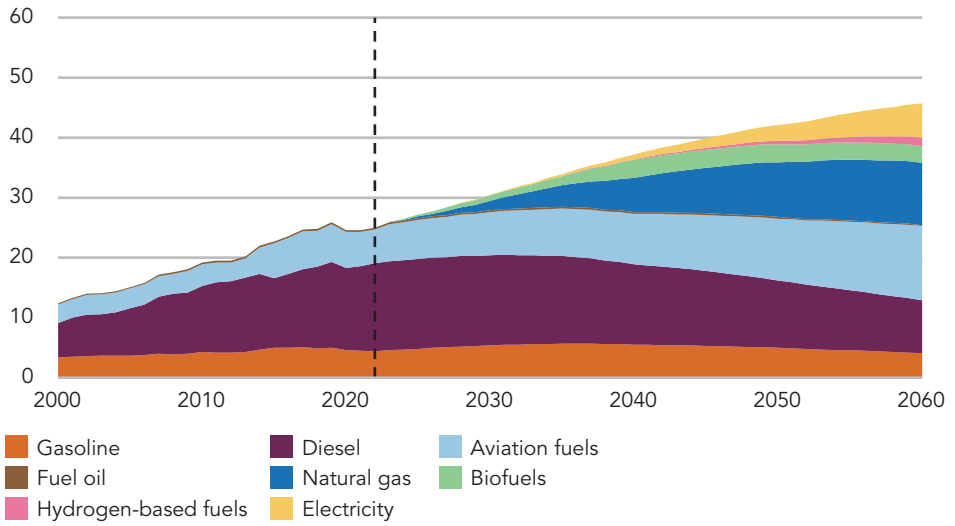
Transport Energy Demand

Figure 13-13. Domestic transport demand in REF (PJ)



- PNG's transport sector is still developing; for example, there is currently no road link between its two largest cities, Port Moresby and Lae. In both scenarios, the same level and rate of transport infrastructure development is assumed. This approach isolates energy-related changes by keeping freight and passenger activity levels identical across both scenarios.
- In REF, present trends continue, with used vehicle imports remaining dominant amid weak regulations on vehicle quality. Consequently, demand for gasoline, diesel, and aviation fuel grows in line with PNG's rapid GDP and population growth, among the highest in APEC. In TGT, assumptions emphasise efficiency improvements and emissions reductions from new energy vehicles (NEVs), while recognising the challenges associated with developing supporting infrastructure, such as EV chargers.

Figure 13-14. Domestic transport demand in TGT (PJ)



- By 2060, passenger vehicle sales in TGT result in a stock mix of approximately 40% BEVs and 30% PHEVs. PHEVs provide roughly half the efficiency gains of BEVs but continue to play an important role in rural areas with limited charging infrastructure. Compressed natural gas (CNG) is introduced mainly for heavy trucks and buses, reaching about 20% of the truck fleet by 2060, with limited use in other vehicles. While CNG does not improve efficiency, it substitutes imported diesel with domestic gas, provided it remains cost-competitive and supporting infrastructure is available.
- A domestic liquid biofuels industry is also assumed to develop in TGT. Gradual growth offsets a share of gasoline and diesel imports, reduces energy dependence, and leverages PNG's bio-feedstock potential.
- Overall, the TGT scenario combines electrification, gas, and biofuels to reduce import dependence and deliver efficiency and emissions benefits, while reflecting the practical challenges of rolling-out NEV infrastructure in a dispersed and predominately rural economy.

Other Transport Data

Figure 13-15. Transport vehicle stocks in REF & TGT (millions)

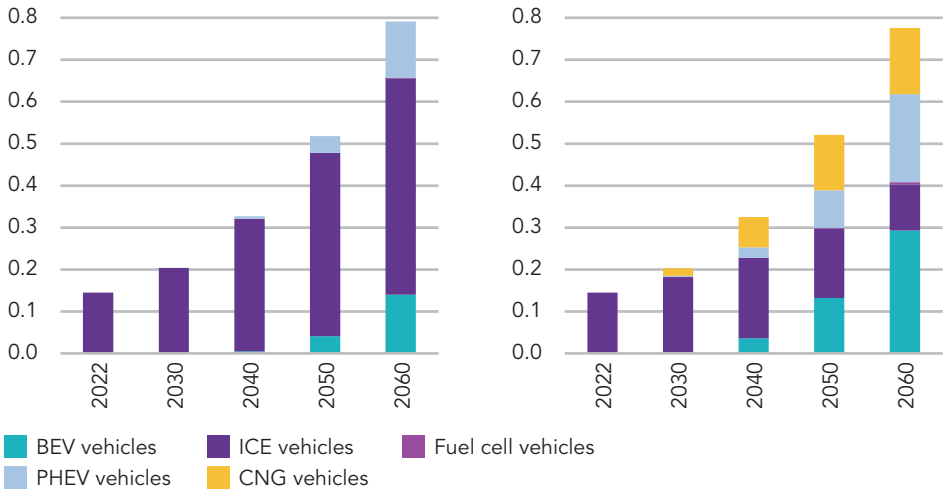
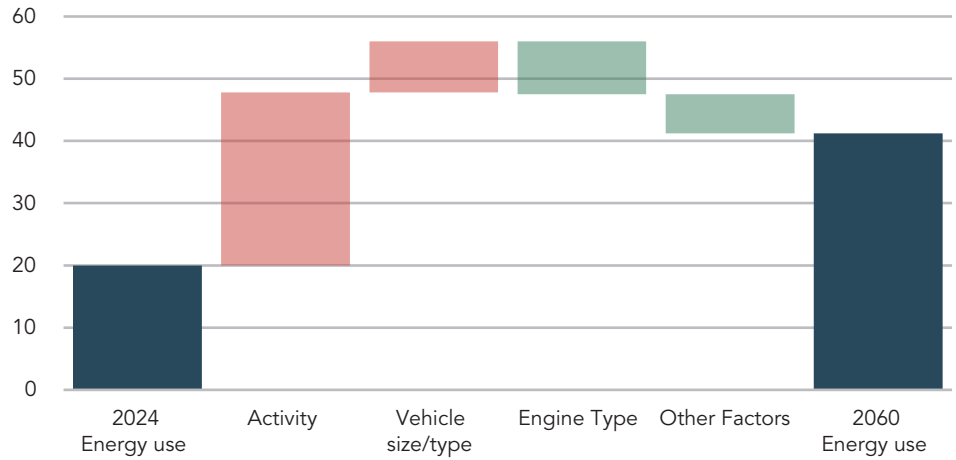
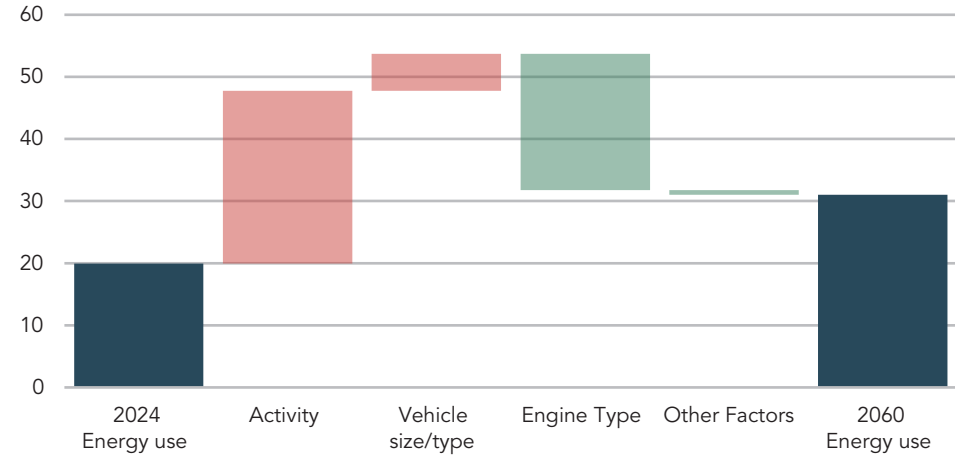


Figure 13-16. Components of the change in road energy use in REF (PJ)



- As income levels rise, a gradual shift toward private vehicle ownership is expected. In the modelling, this relationship is proxied with GDP per capita, assuming higher GDP per capita translates into higher household incomes.
- Greater ownership increases personal mobility and flexibility but slightly reduces overall transport efficiency as private cars displace vans and buses. This effect is shown in the Vehicle size/type component of Figures 13-16 and 13-17.
- Efficiency gains from EV uptake are substantial, as indicated by the 'Engine Type' component in Figures 13-16 and 13-17. However, these benefits must be weighed against potential charging constraints in areas with limited electricity infrastructure.
- The REF scenario also assumes efficiency improvements, particularly the gradual enhancement of imported ICE vehicles. The combined impact of these improvements is reflected in the 'Other factors' bar in Figure 13-16.

Figure 13-17. Components of the change in road energy use in TGT (PJ)



Note: Information on the different drivers in the transport energy decomposition can be found in the *Outlook*'s annex.

Electricity Generation

Figure 13-18. Electricity generation by fuel in REF & TGT (TWh)

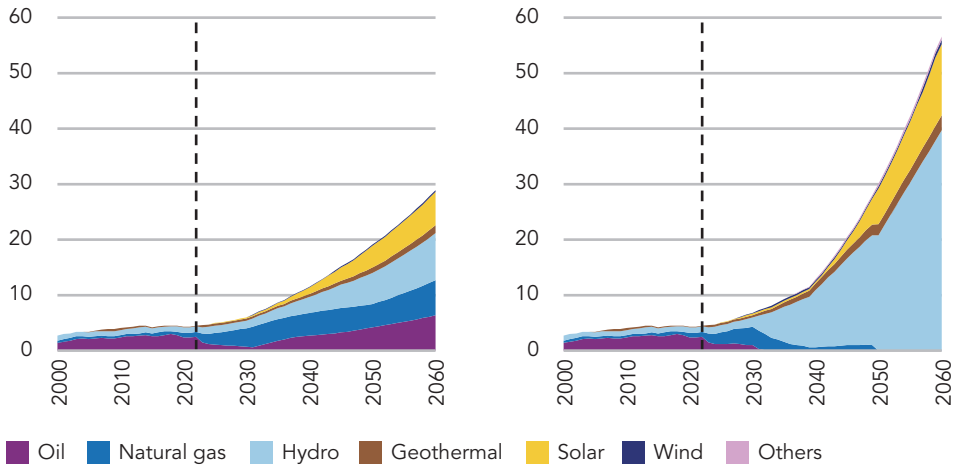
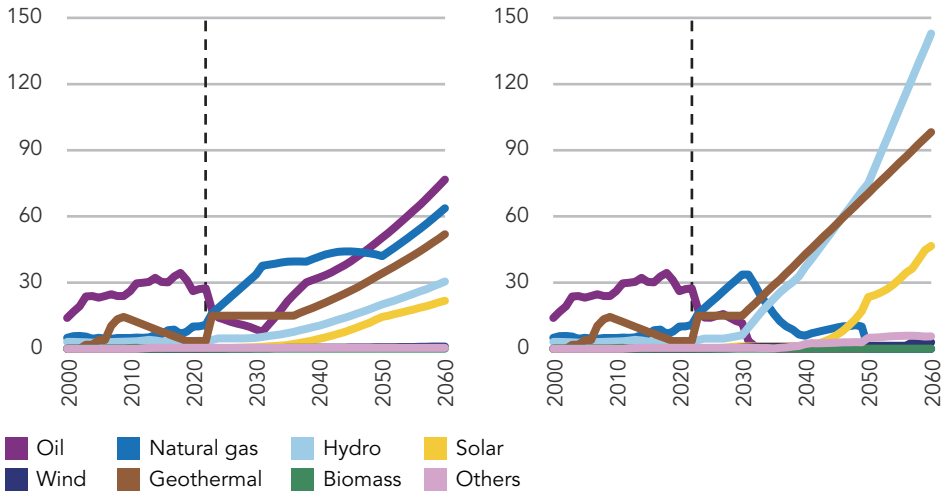


Figure 13-19. Fuel consumption in REF & TGT (PJ)



- As of now, PNG's grid is largely unconnected, with estimates suggesting that around two-thirds of generation and consumption is supplied by industrial autoproducers. Future growth in grid connections and electricity market development could influence the evolution of PNG's power system, though these elements are not explicitly captured in the projections.
- In REF, generation continues to rely heavily on oil due to its portability and low upfront cost, despite higher long-term operating expenses. Solar expands as a cost-effective supplement but remains constrained by the need for dispatchable backup. Gas generation also plays a role, supporting grid development by providing lower operating costs than oil and serving both baseload and peak needs prior to widespread renewable adoption.
- In TGT, PNG's Vision 2050 drives a full transition to renewables by mid-century, eliminating fossil generation. The mix relies mainly on hydro and solar, with contributions from wind and geothermal. Autoproducers are assumed to switch to renewables and connect to the grid where feasible, thereby adding capacity to the wider system.
- Fuel use diverges sharply across the scenarios: REF maintains oil and gas generation, while TGT phases them out entirely by 2050, replacing them with hydro, solar, and batteries. The relatively low conversion efficiency of geothermal results in it accounting for a larger share of fuel consumption than its modest share of generation would suggest. The phase-out of fossil fuels in TGT, combined with roughly double the generation output, leads to a substantial reduction in generation costs, as discussed in the Costs section of this chapter.

Note: Figures 13-18 and 13-19 do not include electricity generation for hydrogen production.

Generation Capacity

Figure 13-20. Generation capacity by fuel in REF (GW)

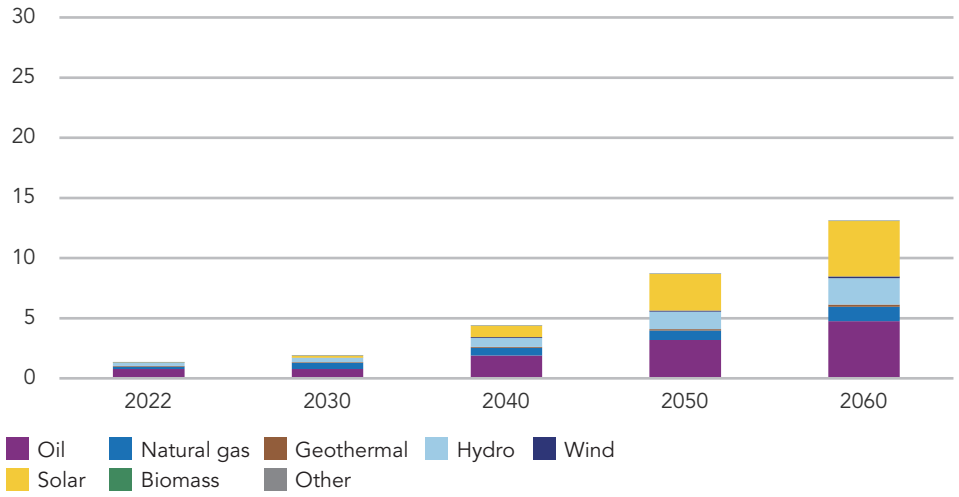
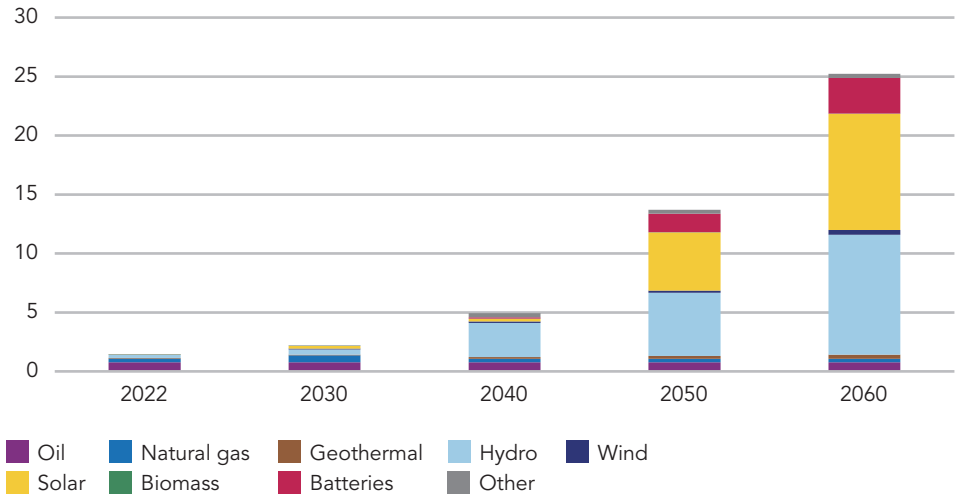


Figure 13-21. Generation capacity by fuel in TGT (GW)



- In REF, capacity growth follows a mixed trajectory, dominated by oil and supplemented by solar, though expansion in solar is constrained by the need to maintain dispatchable reserves. Oil generators remain widely used because they can be deployed quickly, operate independently of the grid, and provide reliable backup in remote areas. Their low upfront costs make them attractive, even though operating expenses are high over time.
- Achieving 100% renewables in TGT requires a major capacity shift: by 2060, hydro expands to 10.2 GW (up from 2.2 GW in REF) and solar to 9.9 GW (up from 4.6 GW). Batteries provide about 11% of total capacity to help manage solar variability. This new system maintains enough dispatchable generation, mostly through hydro, to handle the seasonal variability of solar. However, reliance on hydro creates exposure to a possible 'dry year problem'.

- Hydro delivers most of the dispatchable capacity in TGT, though its expansion entails environmental, social, and capital costs. Solar growth includes both utility-scale projects and mini-grids. Together, these capacity additions require substantial grid expansion, on top of the investments already needed to extend access to 100% of households under NEROP.
- A small amount of fossil capacity remains in TGT for emergency backup but contributes no generation after 2050.

Note: Figures 13-20 and 13-21 do not include generation capacity for hydrogen production.

Grid Reliability

Figure 13-22. Total generation capacity and peak load (GW)

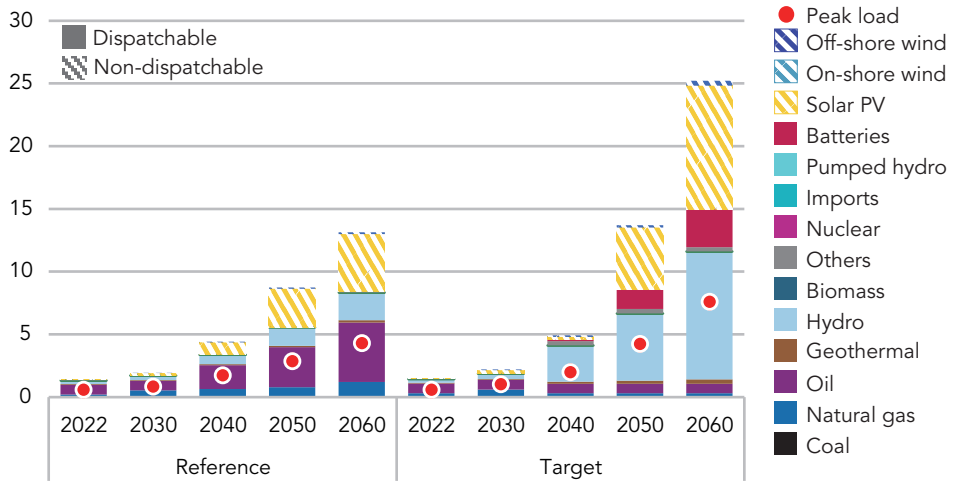
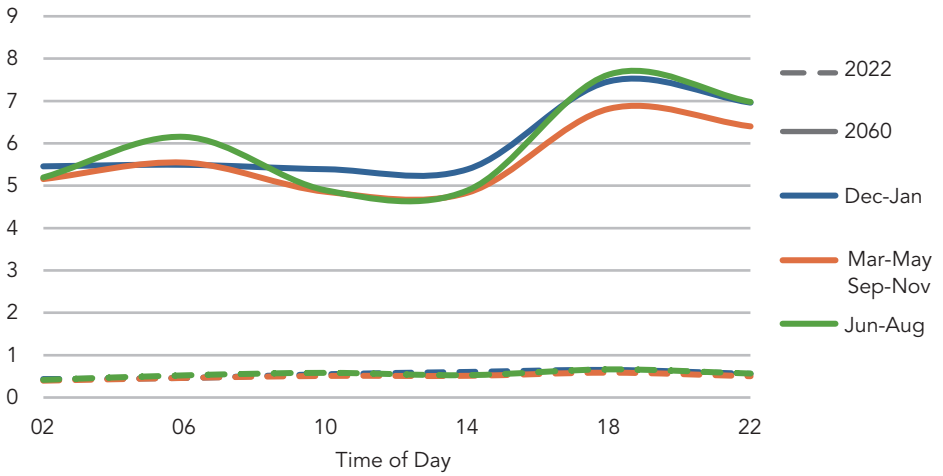


Figure 13-23. Power from dispatchable sources in TGT (GW)



- Grid reliability in PNG depends heavily on the success of NEROP in linking isolated mini-grids and autoproducers. The current reliance on decentralised oil generators raises costs and lowers efficiency.
- As the share of solar expands, the need for dispatchable capacity grows to meet peak demand and smooth variability. Hydro becomes PNG's primary renewable dispatchable resource, offsetting some of the reliability risks typically associated with high-VRE systems, though it remains vulnerable to dry years.
- Batteries support solar integration in TGT but are costly and provide only short-term balancing rather than seasonal storage. Without hydro's role, system stability would be weaker.
- In REF, gas provides dispatchable capacity but competes with LNG exports. If PNG does not pursue a 100% renewables pathway, gas becomes a practical back-up option that also absorbs about 15% of domestic production, thereby helping to achieve the goal of 15% domestic gas utilisation.
- PNG's substantial hydro potential is a key strength, providing dispatchable renewable capacity that reduces dependence on storage or gas and helps offset the current heavy reliance on imported oil. The extent to which this advantage translates into reliable supply will depend on effective governance and grid management.
- Figure 13-23 shows how much PNG's energy system could change with the success of its grid development. Currently, all major generation sources are dispatchable and mostly tied to autoproduction, so power is supplied at a constant rate. In the future, the system could shift to reflect the daily variability of solar, requiring greater flexibility of grid operations and dispatchable sources.

Natural Gas

Figure 13-24. Natural gas consumption by sector in REF & TGT (PJ)

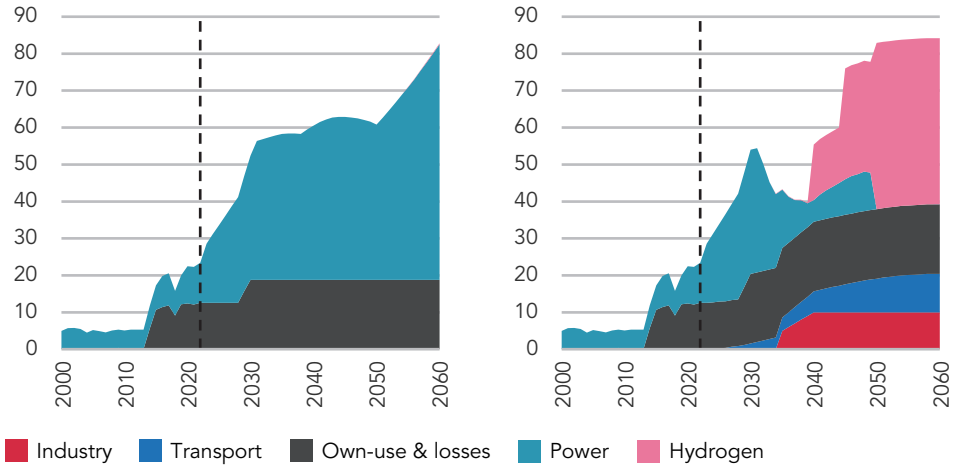
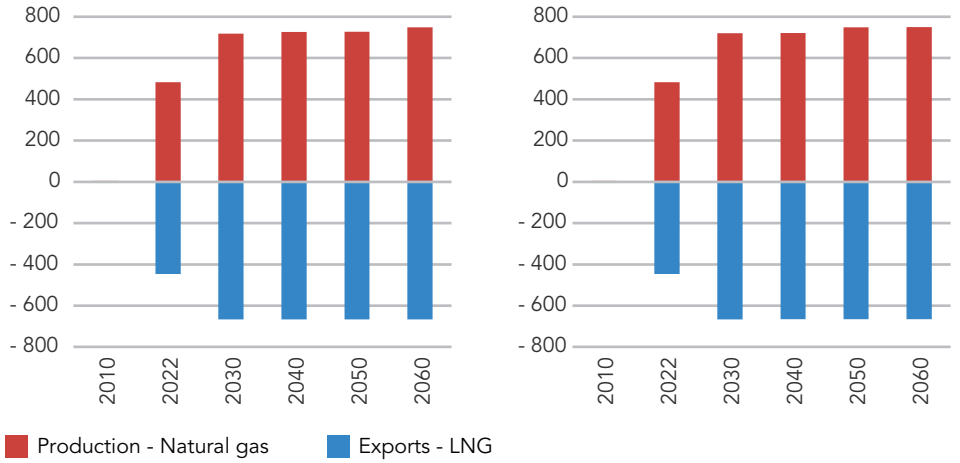


Figure 13-25. Natural gas production, imports, and exports in REF & TGT (PJ)



- Under PNG's Domestic Market Obligation (DMO) policy, private gas investors must reserve 15% of production for domestic use, ensuring that part of supply supports domestic consumption and economic activity rather than being fully exported.
- In TGT, gas uptake is projected across selected sectors to utilise this allocation, including about 10 PJ for industrial process heat, 10 PJ for heavy freight transport, and 60 PJ as feedstock for a new ammonia plant. However, total gas use in TGT still falls short of the 112 PJ target within the projection period, with the balance assumed to be met after 2060. Meeting this demand would also require investment in pipelines, with major users ideally located near existing infrastructure to avoid high costs.
- In REF, a larger share of gas is directed to electricity generation, in contrast with the renewable-based system in TGT. Without the 100% renewables constraint in TGT, the 15% DMO target can be achieved earlier than projected.
- Current LNG export capacity is assumed at 445 PJ, reflecting the peak export level recorded in 2019 when PNG LNG operated at 115% of nominal capacity.
- Papua LNG is assumed to begin operations in 2029 and reach full capacity by 2030, bringing total liquefaction capacity to 13.9 Mtpa and annual exports to 666 PJ in both scenarios.
- At the combined rate needed to supply LNG exports and domestic demand, PNG's 2P gas reserves (21,900 PJ as of the end of 2022) are projected to be exhausted by 2055 in both REF and TGT unless new reserves are developed.

Petroleum Liquids

Figure 13-26. Crude oil, NGLs & other hydrocarbon production, imports, and exports in REF & TGT (PJ)

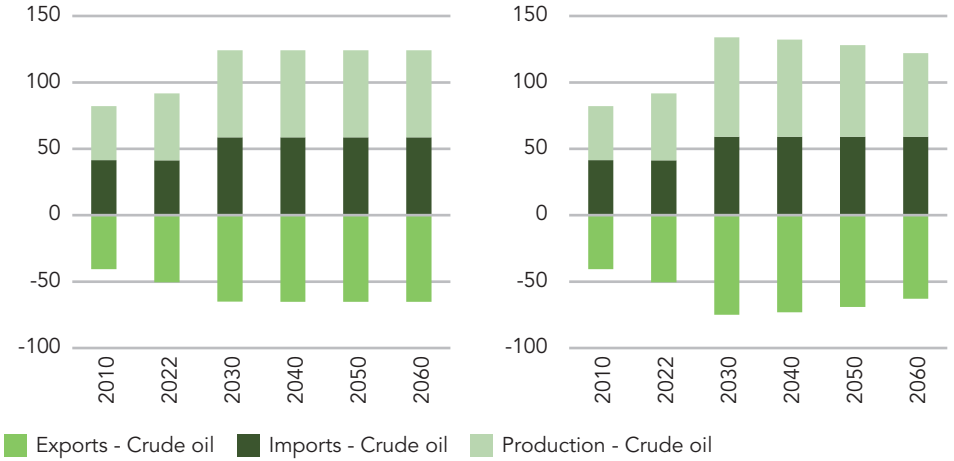
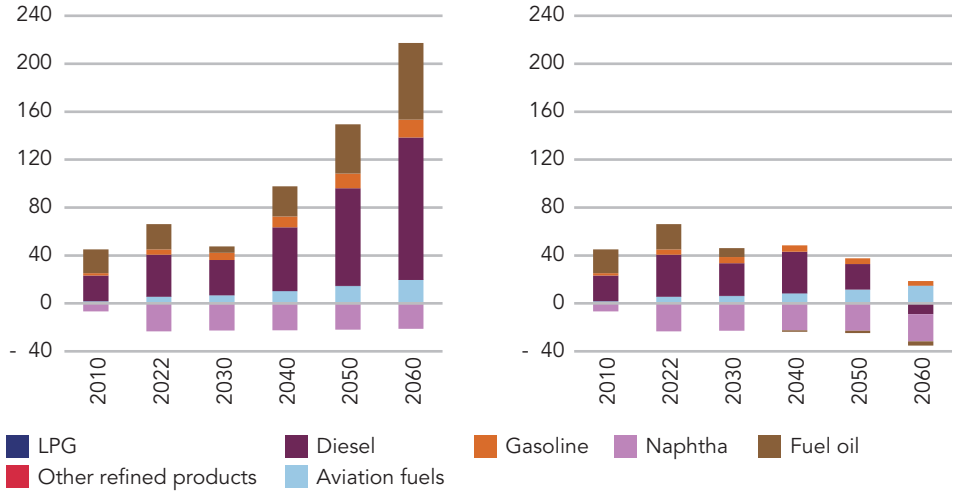


Figure 13-27. Net imports of refined products in REF & TGT (PJ)



- In both scenarios, crude imports for the Napa Napa refinery remain constant at 59 PJ (the 2021 level). In TGT, PNG's crude production rises to 75 PJ (12.5 million barrels) by 2030 but is almost entirely exported. While in REF, production increases to 66 PJ by 2030 and remains at that level thereafter, also exported. Together, these trends show that domestic refining will remain dependent on imported crude.
- The Napa Napa refinery maintains a simple hydroskimming configuration optimised to process PNG's light-sweet Kutubu Blend crude but does not include secondary conversion units. In practice, it operates primarily on imported light-sweet crudes, particularly from Malaysia, likely because PNG's domestic crude is locked into export contracts.
- PNG's reliance on imports highlights certain supply vulnerabilities. In 2022, a domestic jet fuel shortage led to airline cancellations, not due to global supply constraints but because foreign exchange shortages limited importers' ability to secure shipments, despite fuel being available on international markets. This shows that the biggest risks often come from financial and logistical factors, as well as physical supply, underlining the value of maintaining fuel stocks and reliable access to foreign exchange.
- In TGT, diesel shifts from PNG's largest import to an export, reflecting steep demand declines in the power, industry, and transport sectors as electrification and renewables expand. This improves the trade balance and reduces exposure to oil-price volatility. By contrast, in REF, diesel imports continue to rise in line with growing oil dependence, increasing import bills and exposure to external shocks.

Note: In Figure 13-27, net imports are presented without deducting bunkers.

Refining

Figure 13-28. Refined product outputs in REF & TGT (PJ)

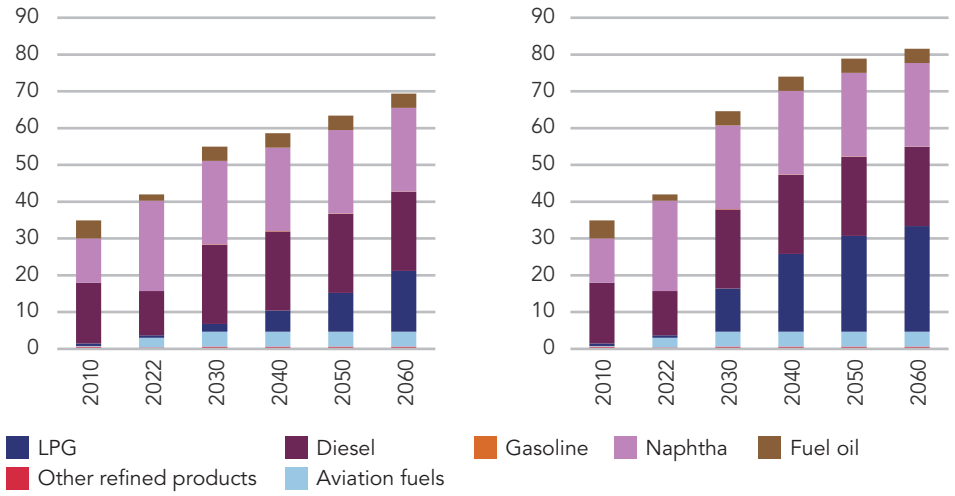
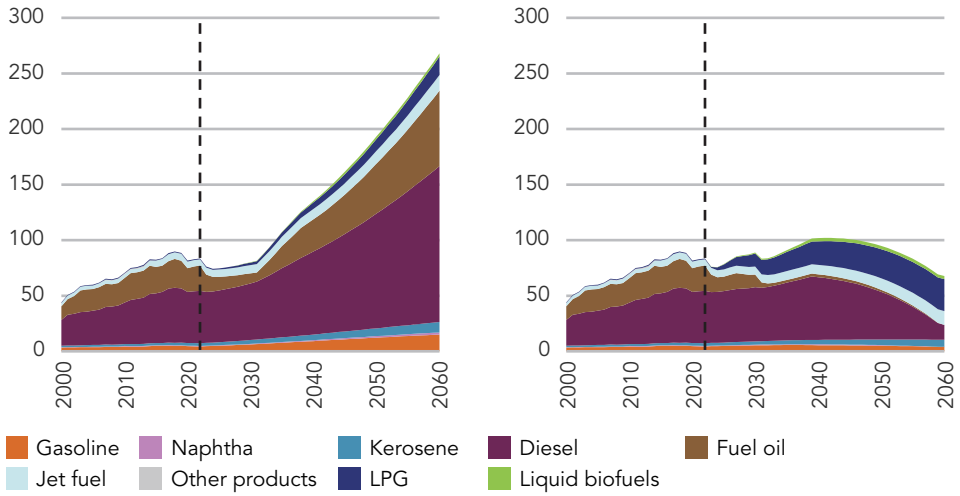


Figure 13-29. Refined products and low-carbon fuels demand, REF & TGT (PJ)



- Refined output from the Napa Napa refinery is held constant at 56 PJ in both scenarios, reflecting its capacity of 33,000 barrels per day (74 PJ per year). This assumption leaves any demand growth to be met by imports.
- Because it does not have secondary conversion units, the refinery produces a large share of naphtha, most of which is exported as petrochemical feedstock. A significant portion of output is diesel, which is consumed domestically.
- PNG records no natural gas liquids (NGLs) or LPG production, despite typical gas processing yields suggesting at least 5% recovery. Rising domestic LPG demand is therefore assumed to be partly met by capturing this byproduct, rather than relying solely on imports. This aligns with the National Energy Policy (2017–2027) objective of reducing dependence on imported fuels and making greater use of domestic gas. Delivering this outcome requires investment in processing and distribution infrastructure and appropriate commercial arrangements for NGL recovery.

- In REF, refined product demand nearly quadruples by 2060, with all incremental demand met by imports, substantially heightening exposure to international markets. This includes diesel and fuel oil for electricity generation, which grows from 27 PJ in 2022 to 77 PJ in 2060, as well as bunkers.
- In TGT, refined product demand falls sharply as diesel and fuel oil use decline across all sectors. Diesel shifts from a major import to a minor export, driven by transport electrification and the replacement of oil-fired generation with renewables and other sources. Fuel oil demand also drops, reflecting both reduced reliance on oil in power generation and declining use in international transport.

Note: Figure 13-29 includes all demand sectors, transformation inputs (e.g. power), losses & own use, and bunkers.

Bioenergy and Waste

Figure 13-30. Bioenergy and waste demand by sector in REF & TGT (PJ)

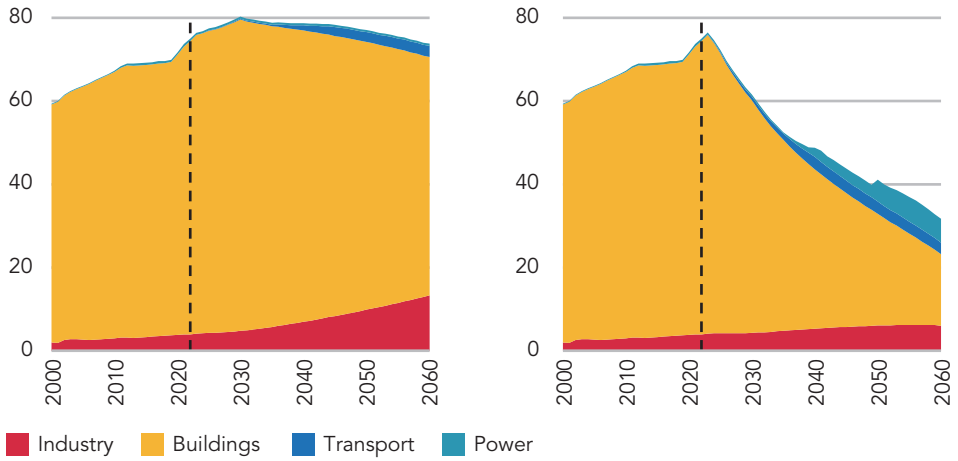
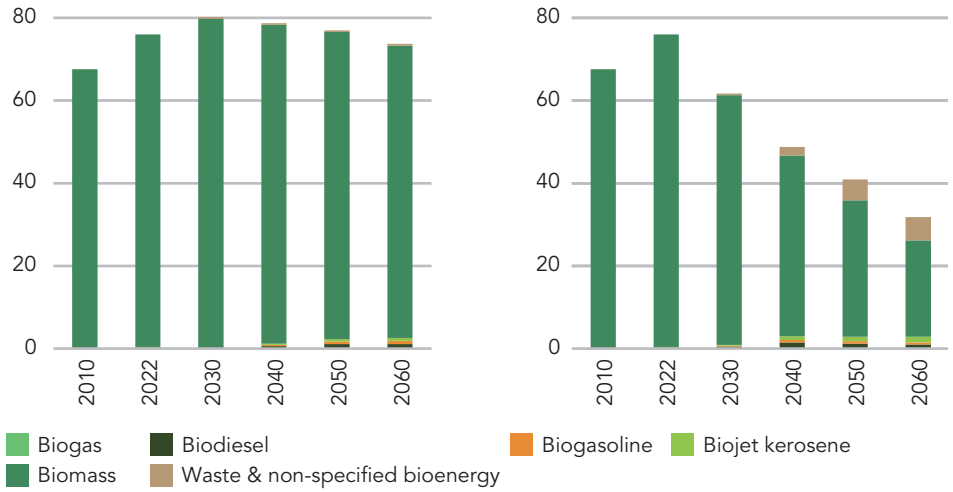


Figure 13-31. Bioenergy and waste production in REF & TGT (PJ)



- Almost all domestic bioenergy demand currently comes from traditional biomass, mainly firewood for cooking, heating, and lighting. This reflects PNG's limited electrification rate (about 20%) and restricted access to alternatives such as LPG. Biomass is also used in agro-processing within industry, and its role in power generation grows modestly in REF and expands further under TGT.
- As electrification grows and LPG access increases, biomass use in buildings declines. This transition occurs more rapidly in TGT, reflecting assumptions of stronger efforts to expand modern energy access, while in REF the shift is slower, tied to gradual infrastructure development and income growth.
- Estimating biomass use in buildings presents challenges, adding uncertainty to assessments of PNG's current energy intensity, modern renewables share and total energy demand, as well as to projections of the rate at which electricity and LPG could displace fuelwood.
- PNG has abundant biomass resources, and both scenarios assume the development of a domestic liquid biofuels industry for transport. The economy's strong agricultural and agro-processing sectors also present potential for biogas development, which could support gas decarbonisation in TGT. However, because this would conflict with the objective of utilising domestic gas production, biogas is not deployed in the projections.
- The share of modern renewables in PNG's total final energy consumption rises from 5% in 2022 to 20% in REF and 66% in TGT by 2060. Since traditional biomass is not classified as a modern renewable, even switching from fuelwood to LPG improves this share by reducing inefficiencies in household energy use. The pace of the fuelwood transition will determine how quickly PNG shifts from traditional to modern energy sources, and how much it contributes to meeting APEC's modern renewables goals.

Hydrogen-based Fuels in the Target Scenario

Figure 13-32. Hydrogen-based fuels demand by sector [left]; Hydrogen-based fuels demand by fuel [right] (PJ)

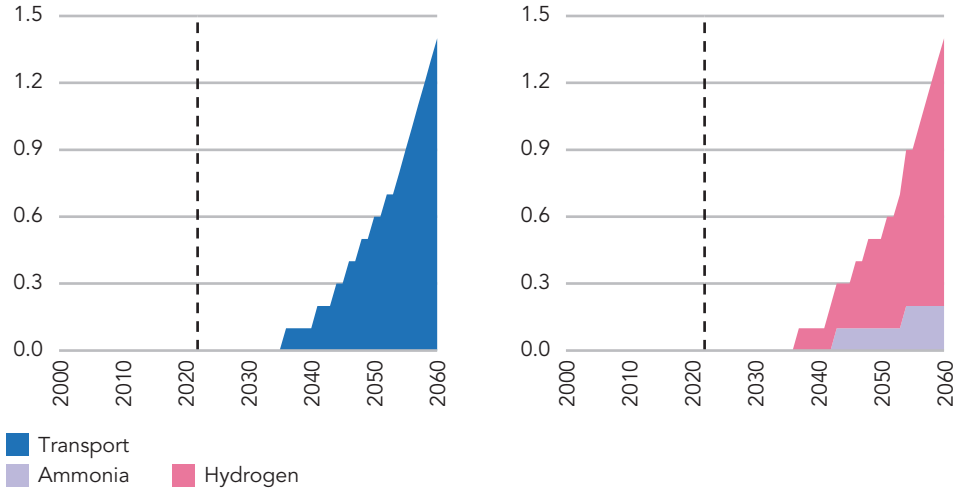
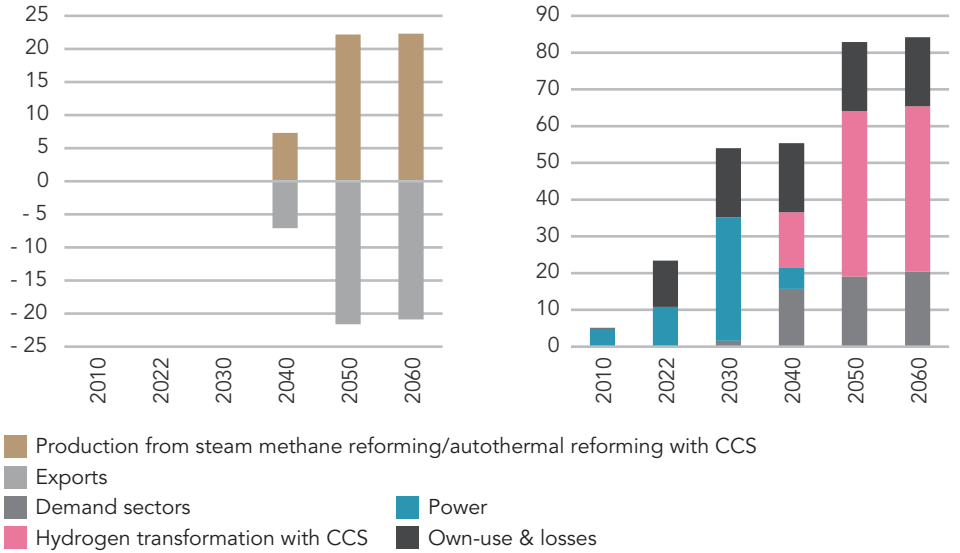


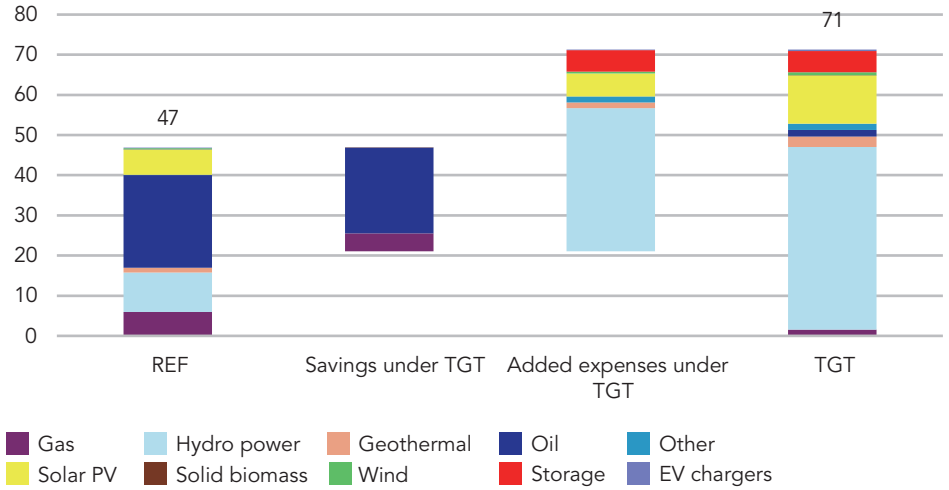
Figure 13-33. Hydrogen-based fuels production methods and supply [left]; Gas for hydrogen production vs other consumption [right] (PJ)



- The TGT scenario assumes the development of an ammonia plant with a natural gas input capacity of 45 PJ, built in three 15 PJ phases between 2035 and 2050. While some output would meet domestic fertiliser demand, most is projected for export in response to rising global demand for ammonia as a fuel. This can provide PNG with a higher-value export than LNG from the same gas feedstock, depending on market margins. However, conversion inefficiencies mean that 45 PJ of gas yields only 22.3 PJ of ammonia—roughly equal to the current gas demand of all other domestic sectors combined. This underscores the trade-off between allocating gas to exports and meeting domestic uses.
- Based on aggregate APERC projections, APEC economies are expected to export 3,970 PJ of ammonia in TGT. PNG's projected 21 PJ—about 0.53% of the total—indicates a small share and a price-taking position in international markets.
- To achieve lower lifecycle emissions than the fossil fuels it would replace (such as diesel), ammonia production is assumed to include carbon capture and storage (CCS). This introduces additional costs and project risk. If these risks are considered too high, an alternative approach could involve continuing LNG exports and allocating revenues to other sectors.
- PNG's domestic hydrogen demand is expected to remain small, with any use in TGT confined to heavy mining vehicles operated by large industrial players, so the investment case is primarily export-led and does not require extensive domestic distribution infrastructure.

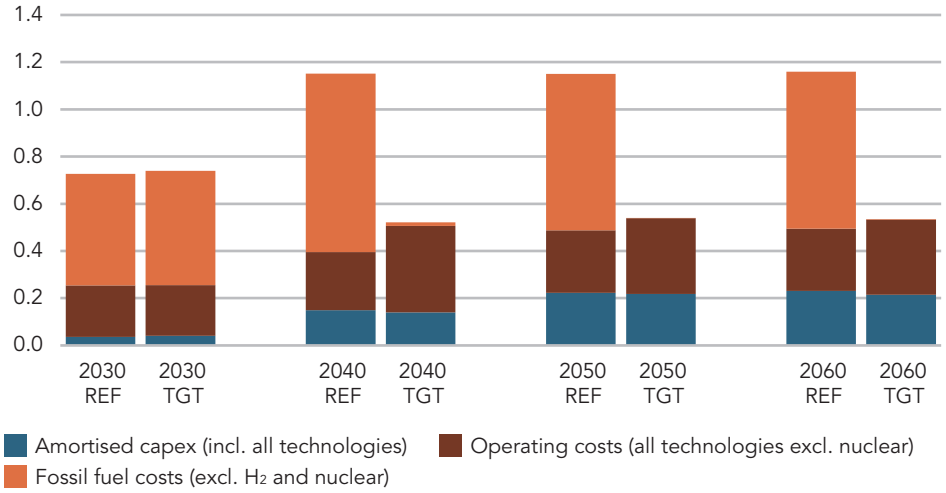
Costs

Figure 13-34. Costs in the power sector, 2025 to 2060 (billion USD, undiscounted)



Note: EV chargers do not cover the cost of associated infrastructure or EV vehicles. Hydrogen-based fuel production costs are not considered since the majority of the small amount of production is exported (assumed to be cost neutral).

Figure 13-35. Cost of generating electricity relative to 2025 (2025 cost = 1.0) in the power sector

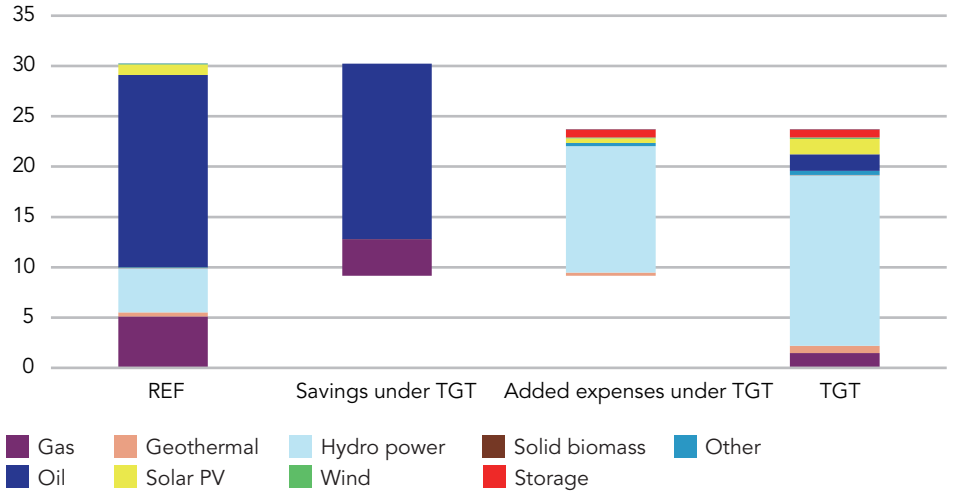


Note: Based on assumptions about future capital and operating costs, Figure 13-35 shows cost compositions over time relative to 2025. It should not be considered an estimate of electricity tariffs and excludes market mechanisms that are too difficult to estimate.

- Unlike other *Outlook* cost projections, the following two pages exclude estimates for transmission infrastructure in PNG. This reflects the current underdevelopment of the grid, which makes such estimates highly uncertain.
- The main cost differences between the two scenarios stem from fuel use in REF versus renewable deployment in TGT. REF relies on oil and gas generation, with high and persistent fuel costs, while TGT faces higher capital and operating costs for hydro, solar, and batteries usage. Much of this extra investment in TGT is aligned with the government's Vision 2050 plan, which targets 100% renewable generation by mid-century.
- Figure 13-35 shows the relative cost of generating electricity in selected years indexed to the base year of 2025. Costs decline in 2030 relative to 2025 as indigenous gas replaces imported diesel in power generation in both REF and TGT.
- By 2060, TGT generates nearly twice as much electricity as REF for a 51% increase in total costs. However, most of this additional expenditure comes from one-time hydro and solar investments that can be spread over plant lifetimes, leading to average annual generation costs in TGT falling below REF after 2030.
- In REF, costs continue to rise relative to 2025, as fuel expenses remain high and amortised capital costs accumulate. In contrast, TGT experiences a rapid decline in fossil fuel use between 2030 and 2040, which lowers electricity generation costs and provides PNG with both an economic and environmental rationale for reducing oil-fired generation.
- These benefits in TGT are partially offset by the higher operating costs of large hydro developments and would be further moderated if the additional transmission investments required for renewable integration were included.

Costs

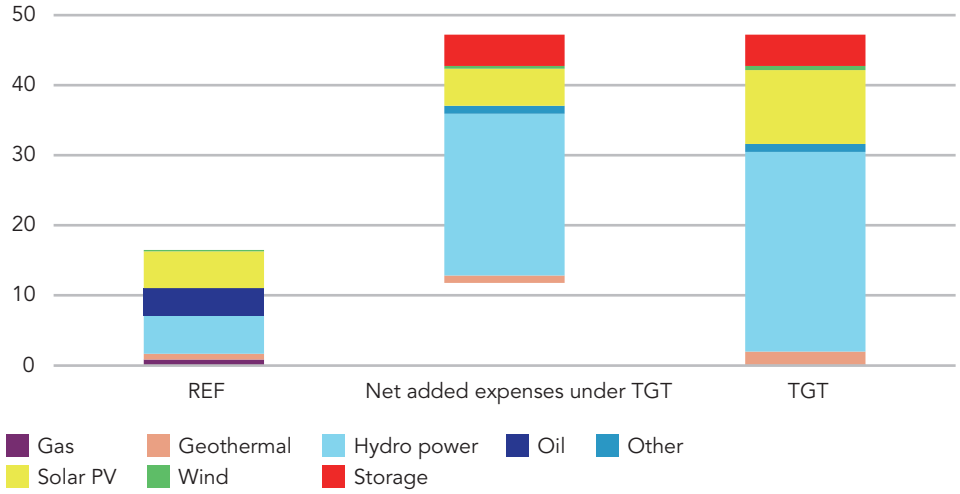
Figure 13-36. Total operating costs from 2025 to 2060 in the power sector (billion USD, undiscounted)



Note: Figure 13-36 only covers power sector costs. It does not include operating costs associated with EV chargers.

- Figure 13-36 covers variable fuel and non-fuel expenditures, along with fixed costs for the power sector. Total operating costs are estimated to be USD 30.2 billion in REF, but will decline to 23.7 billion in TGT.
- Gas is assumed to be approximately six times cheaper than oil for electricity generation. In REF, fuel costs reach USD 19.1 billion for 110 PJ of diesel and fuel oil, compared with USD 5.1 billion for 151 PJ of gas. This reflects PNG's reliance on domestically sourced gas, which may benefit from favourable local pricing, in contrast with oil priced on international markets. In TGT, these oil costs are largely avoided, though the savings are partly offset by higher operating costs for hydro and, to a lesser extent, batteries.

Figure 13-37. Total capital investment (CAPEX) from 2025 to 2060 in the power sector (billion USD, undiscounted)



Note: Figure 13-37 only covers power sector costs. EV capital investments are not included.

- Total capital expenditure in the power sector is estimated at USD 47.2 billion in TGT, compared with USD 16.5 billion in REF. This sharp increase reflects large-scale investment in hydro, solar, and battery capacity, with spending divided between meeting higher electricity demand—nearly double REF levels by 2060—and replacing fossil-fuel generation.
- A key uncertainty is the assumed hydro capital cost of USD 3,200/kW, which excludes related expenses such as access to roads and supporting infrastructure. As a result, total hydro development costs are challenging to fully quantify.
- Additional solar and wind capacity requires further investment in transmission infrastructure in both scenarios. However, incremental battery investment is only needed in TGT, as REF already has sufficient dispatchable capacity to provide system flexibility without storage.

CO_2 Emissions

Figure 13-38. CO_2 emissions in REF (million tonnes)

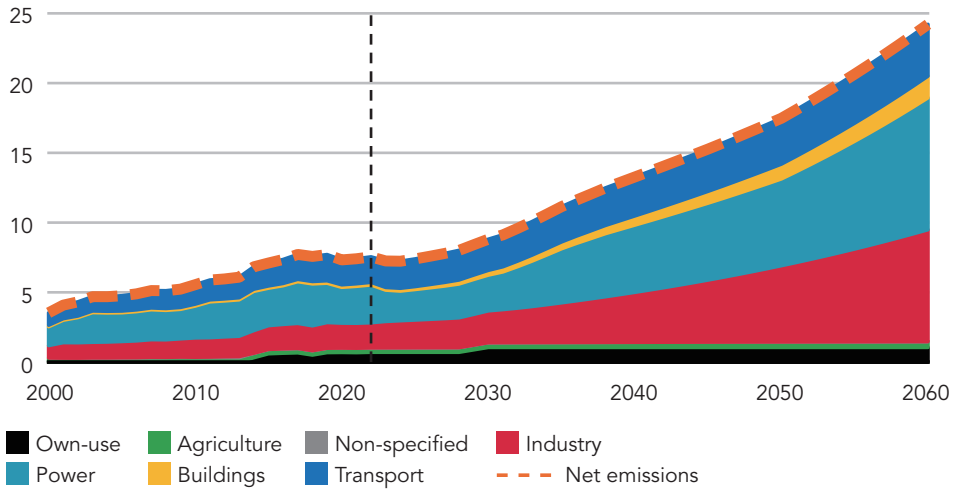
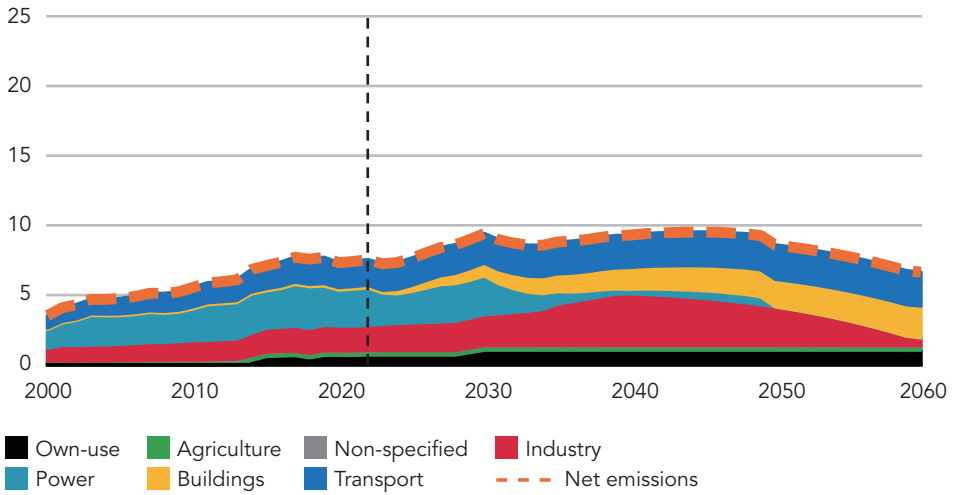
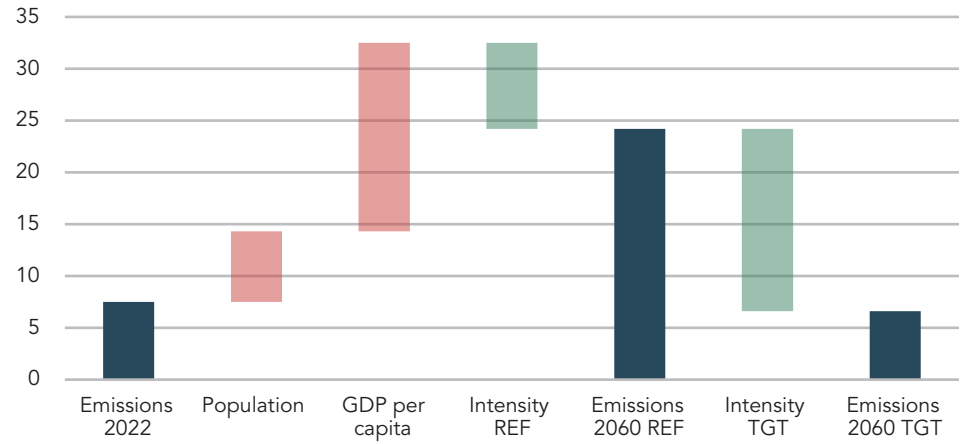


Figure 13-39. CO_2 emissions in TGT (million tonnes)



- In 2022, 83% of PNG's combustion emissions came from oil. This share declines only slightly in REF, to 80% by 2060, but more substantially in TGT, to 67%, as gas use grows modestly and oil is displaced in some sectors.
- In TGT, rapid renewable expansion in the power sector achieves zero generation emissions by 2050. Combined with mining sector decarbonisation, this results in a modest reduction in total emissions compared with 2022.
- Buildings emissions rise more in TGT than REF due to widespread LPG uptake replacing fuelwood. However, this trade-off delivers co-benefits, including improved air quality and reduced deforestation pressure, which in turn helps preserve carbon sinks.
- A Kaya Identity analysis suggests that rising GDP per capita is the primary driver of emissions growth to 2060. Expanding energy access, transport, and industrial activity, along with improved living standards, lead to higher energy use.

Figure 13-40. CO_2 emissions components (million tonnes)



Note: All values represent energy sector combustion CO_2 emissions. Biogenic CO_2 is treated as zero at the point of combustion.

Useful Links

APEC Expert Group on Energy Data and Analysis (EGEDA) – https://www.egeda.ewg.apec.org/

APEC Energy Statistics 2022 – https://www.egeda.ewg.apec.org/egeda/general/info/pdf/APEC_Energy_Statistics_2022.pdf

APEC Energy Overview – https://aperc.or.jp/reports/energy_overview.php

Urbanisation projections from UN DESA's World Urbanization Prospects (2018 revision) – https://population.un.org/wup/assets/WUP2018-Report.pdf

Vision 2050 – https://png-data.sprep.org/dataset/papua-new-guinea-vision-2050

Enhanced Nationally Determined Contribution – https://png-data.sprep.org/resource/papua-new-guineas-enhanced-nationally-determined-contribution-2020

National Energy Policy 2017-2027 – https://policy.asiapacificenergy.org/sites/default/files/National%20Energy%20Policy%202017-2027.pdf

National Energy Agency – https://nea.gov.pg/regulatory/

Asian Transport Outlook (2024) – https://asiantransportoutlook.com/analytical-outputs/countryprofiles/profile-papua-new-guinea/



14. Peru

Summary

	Reference			Target		
	2022	2060	% Change	2022	2060	% Change
Macroeconomic						
Population (million)	33.9	43.4	28%	33.9	43.4	28%
GDP (billion 2017 USD, PPP)	443	1,239	179%	443	1,239	179%
Energy Demand						
Agriculture & fisheries (PJ)	11	19	80%	11	16	49%
Buildings (PJ)	242	377	56%	242	338	40%
Industry (PJ)	271	569	110%	271	540	99%
Non-energy (PJ)	8	10	17%	8	9	13%
Transport (PJ)	399	736	84%	399	490	23%
Modern renewables share of TFEC (%)	15	15	0%	15	30	100%
Energy intensity of TFEC (PJ/GDP, billion USD)	2.1	1.4	-34%	2.1	1.1	-46%
Electricity						
Generation (TWh)	60	146	144%	60	229	283%
Renewables share of generation (%)	55	44	-20%	55	47	-15%
Generation capacity (GW)	15	36	132%	15	57	272%
Total Primary Energy Supply (TPES)						
Coal & coal products (PJ)	30	21	-31%	30	13	-56%
Natural gas (PJ)	362	1,049	190%	362	1,138	214%
Petroleum liquids (PJ)	503	768	53%	503	374	-26%
Low-carbon & waste energy (PJ)	300	360	20%	300	530	77%
CO_2 intensity of energy supply ($MtCO_2/PJ$)	0.048	0.051	6%	0.048	0.044	-8%
Net CO_2 Emissions (million tonnes)	57	111	95%	57	89	57%

Note: In this publication, the term "modern renewables" refers to all renewable energy sources excluding solid biomass in the buildings sector. The term "low-carbon & waste energy" includes all bioenergy, waste-derived energy, renewables, nuclear, and hydrogen-based fuels. Total primary energy supply (TPES) numbers include international bunkers. Net emissions are calculated as gross energy sector combustion CO_2 minus CO_2 captured and stored through carbon capture and storage (CCS).

Key Takeaways

Emissions

- Population and economic growth drives energy consumption and emission growth mainly in the Reference scenario (REF). This growth is curbed by measures simulated in the Target scenario (TGT), though these measures were not sufficient to achieve Peru's NDC emissions goal. While the transport electrification reduces fossil fuel consumption, electricity generation continues to rely on natural gas for grid stability. Decarbonising the power sector remains challenging; however, unlike coal-dependent systems in other APEC economies, Peru's power mix is already dominated by natural gas and renewables.
- Further decarbonisation of power sector—beyond what is modelled in these scenarios—will require substantial investments in transmission infrastructure, as well as a more robust regulatory framework to enable the deployment of energy storage systems and other ancillary services.

Energy Import Dependence

- Peru maintains a net energy import position in both scenarios. However, dependence on imported oil and petroleum products is lower under TGT. In both scenarios, oil imports account for approximately 38% of TPES around 2040. By 2060, this share declines to 32% in REF, while in TGT, it declines to 14% by 2060.
- Conversely, reliance on imported natural gas increases in both scenarios. The adoption of this transition fuel is in accordance with the National Energy Policy. By 2060, imports could account for 45% of natural gas supply in REF and 55% in TGT, potentially heightening exposure to global market volatility and supply risks if domestic production is not expanded and/or fuel switching to renewables is not implemented.

Figure 14-1 Net CO_2 emissions (million tonnes)

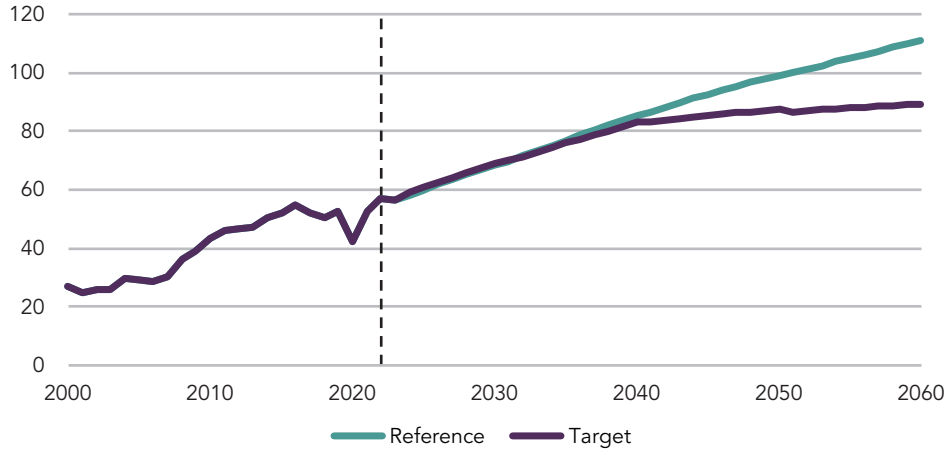
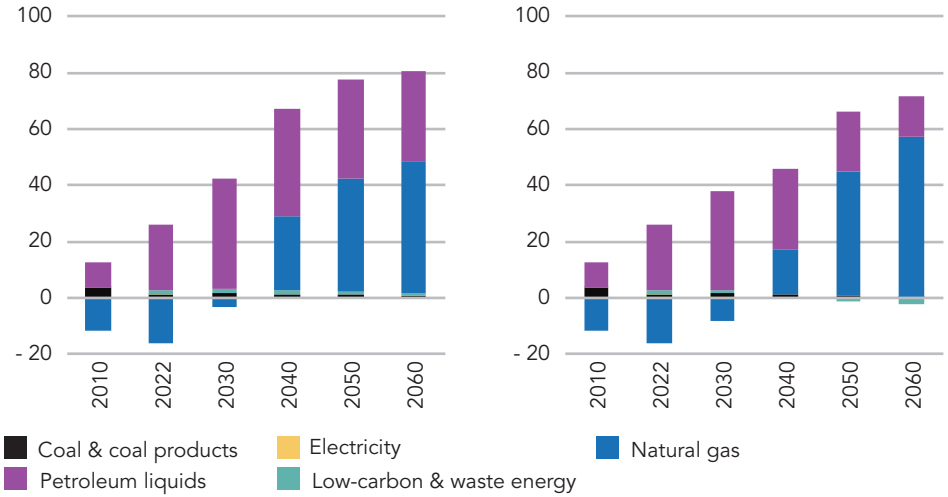


Figure 14-2. Net imports share of TPES in REF & TGT (%)



Note: In Figure 14-2, net imports refer to total imports minus exports and international bunkers.

Key Takeaways

Grid Reliability

- The expansion of variable renewable energy (e.g., solar and wind) is supported by increased dispatchable generation, mainly natural gas and large hydropower. However, limited hydropower during the dry season (Southern Hemisphere's winter) increases system risk.
- Hydropower and natural gas capacity must increase to provide flexibility and reliability to the grid to handle demand and supply fluctuations, particularly in TGT. The increasing gap between minimum and maximum dependence on dispatchable power on an average day highlights the importance of dispatchable power for grid reliability as the share of variable renewable energy (VRE) sources increases. Given the seasonality of renewable energy resources, the gap is larger between June and August.

Cost

- The total cost in the power and hydrogen sectors in REF is estimated at USD 117 billion. To meet the energy demand in TGT, an additional USD 79 billion will be needed. These costs include the total capital, fixed, and variable costs in the power sector, costs for green hydrogen production for domestic use, transmission for variable renewable electricity, and electric vehicle chargers.
- The largest component of the additional costs are additional gas costs followed by wind and solar, and the added transmission lines needed to connect new VRE to demand centres.
- Increased gas costs reflect the growing reliance on gas plants to provide flexible capacity that can quickly ramp up and down to balance a grid with higher volumes of VRE, given the limited adoption of energy storage and constraints on expanding hydropower generation.

Figure 14-3. Peak load and maximum and minimum dependence on dispatched power (GW)

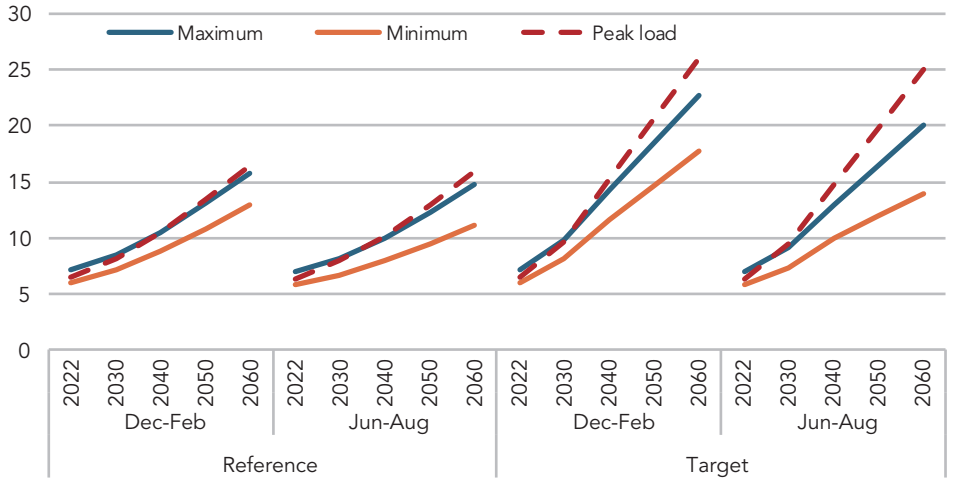
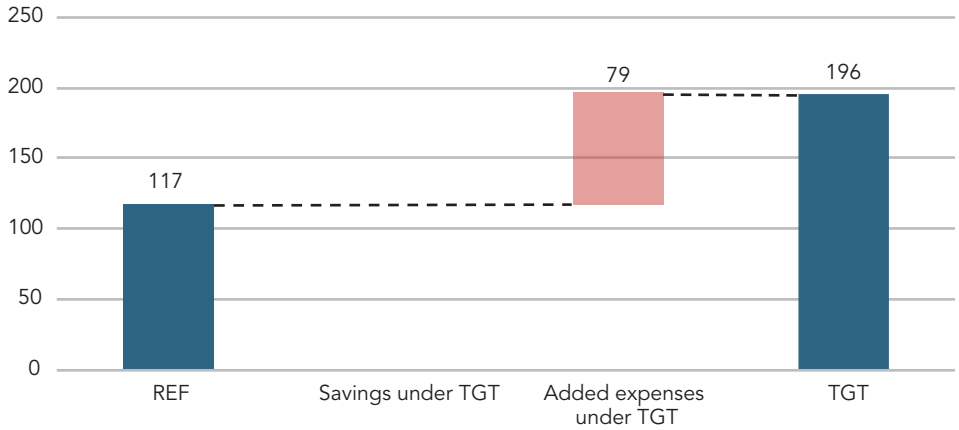


Figure 14-4. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



*Actual costs will differ from estimated costs in the *Outlook* for a variety of reasons including changing commodity prices, manufacturing costs, and unforeseen technical advances. All costs are in 2023 real terms.

About Peru

Overview

Geographical and Economic Landscape

Peru is located in central South America and has a long coastline along the Pacific Ocean, offering strategic connectivity between South America's Atlantic shore and the rest of the Asia-Pacific region. Covering approximately 1.285 million km², Peru ranks among the 20 largest economies in the world by land area.

Peru is rich in energy resources—both developed and untapped—including natural gas, oil, solar, wind, and hydropower. Peru also holds substantial copper reserves, positioning it as a key player in the global energy transition.

Peru's economy grew at an average annual rate of approximately 5% between 2000 and 2019, with peak growth rates reaching between 6% and 9%. In 2020, the COVID-19 pandemic caused a sharp economic contraction, with GDP declining by around 12%. Since then, economic growth has moderated, with projections indicating a rate of around 3% in the coming years.

Despite these strengths, Peru faces an infrastructure gap that must be addressed to sustain long-term economic growth.

Energy Supply and Consumption

Economic growth significantly increased energy demand. Between 2000 and 2022, total energy consumption doubled from 457 PJ to 930 PJ, while electricity demand nearly tripled from 62.4 PJ to 187.7 PJ. Since the mid-2000s, the Camisea Project has expanded the role of domestically produced natural gas in Peru's energy mix, primarily for electricity generation and LNG exports.

Energy Security Challenges and Strategies

Despite its energy resources, Peru's energy demand, especially in transport, relies heavily on imported hydrocarbons. Peru emphasises the importance of diversifying energy sources and promoting the development of domestic renewable energy and natural gas to enhance energy security.

Key Energy Initiatives

Paris Agreement Commitment

Peru is a signatory to the Paris Agreement, which aims to limit global warming to well below 2°C, preferably to 1.5°C above pre-industrial levels. In this regard, Peru submitted its updated Nationally Determined Contribution (NDC) in 2021, committing to reduce greenhouse gas emissions by 30% unconditionally, and up to 40% conditionally, by 2030.

Net Zero-emissions by 2050

Peru has not made a formal commitment to achieving carbon neutrality by 2050, but its vision has been expressed in several high-level statements. In 2024, Peru published its National Climate Change Strategy to 2050, outlining the pathway toward achieving net zero emissions by 2050.

Expansion of Renewable Energy in Electricity Generation

Renewable energy, mainly hydropower, supplies about half of Peru's electricity; natural gas provides the rest. There is growing interest in increasing the share of renewables—solar, wind, biomass, and small hydropower—in the energy mix. The Supreme Decree Declaring the Climate Emergency a Matter of National Interest calls for increasing the share of renewables to 20% by 2030.

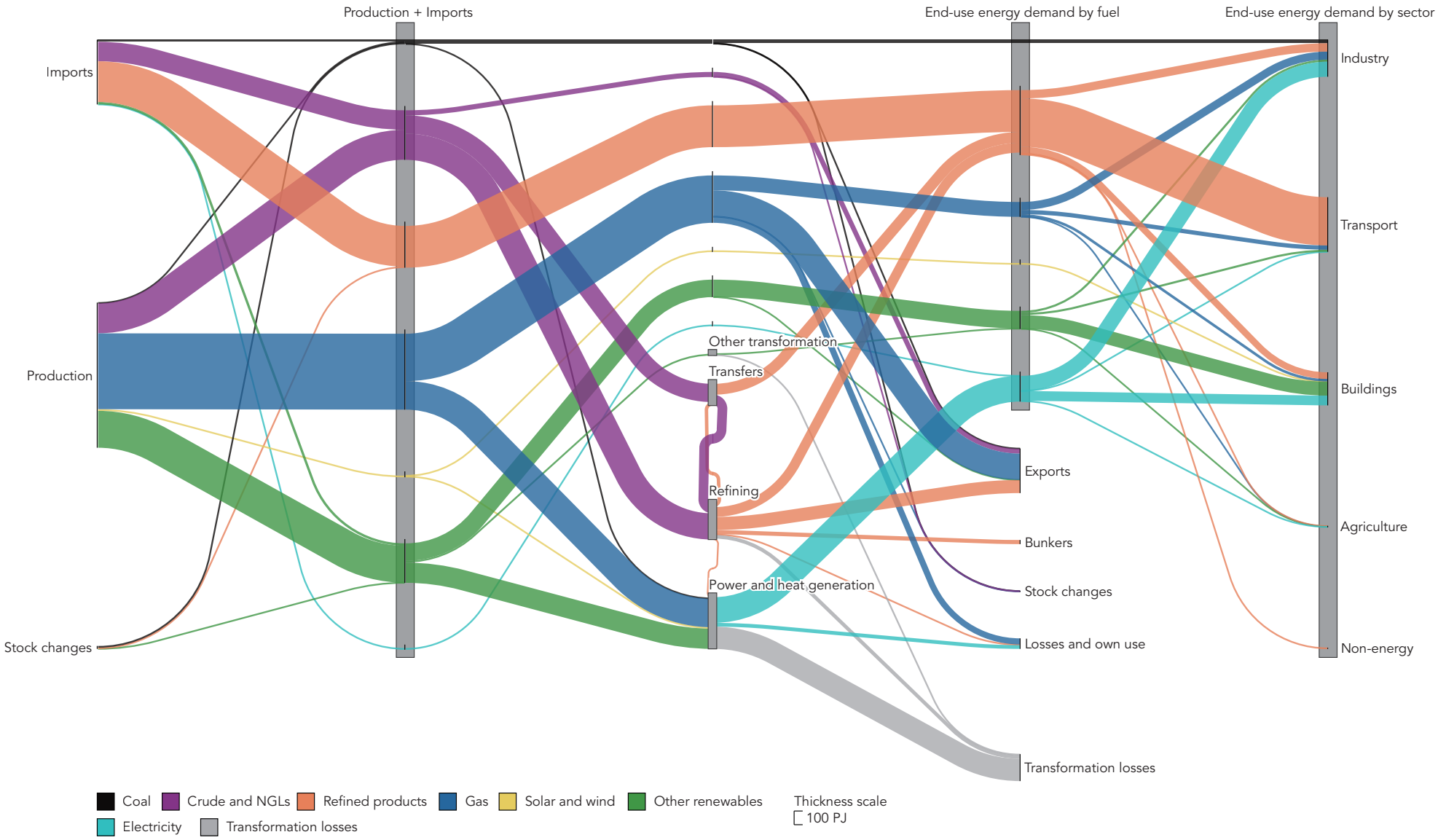
Hydrogen Economy

In 2024, Peru enacted the Law to Promote Green Hydrogen, supporting research, production, distribution, use, and export as a fuel and energy carrier.

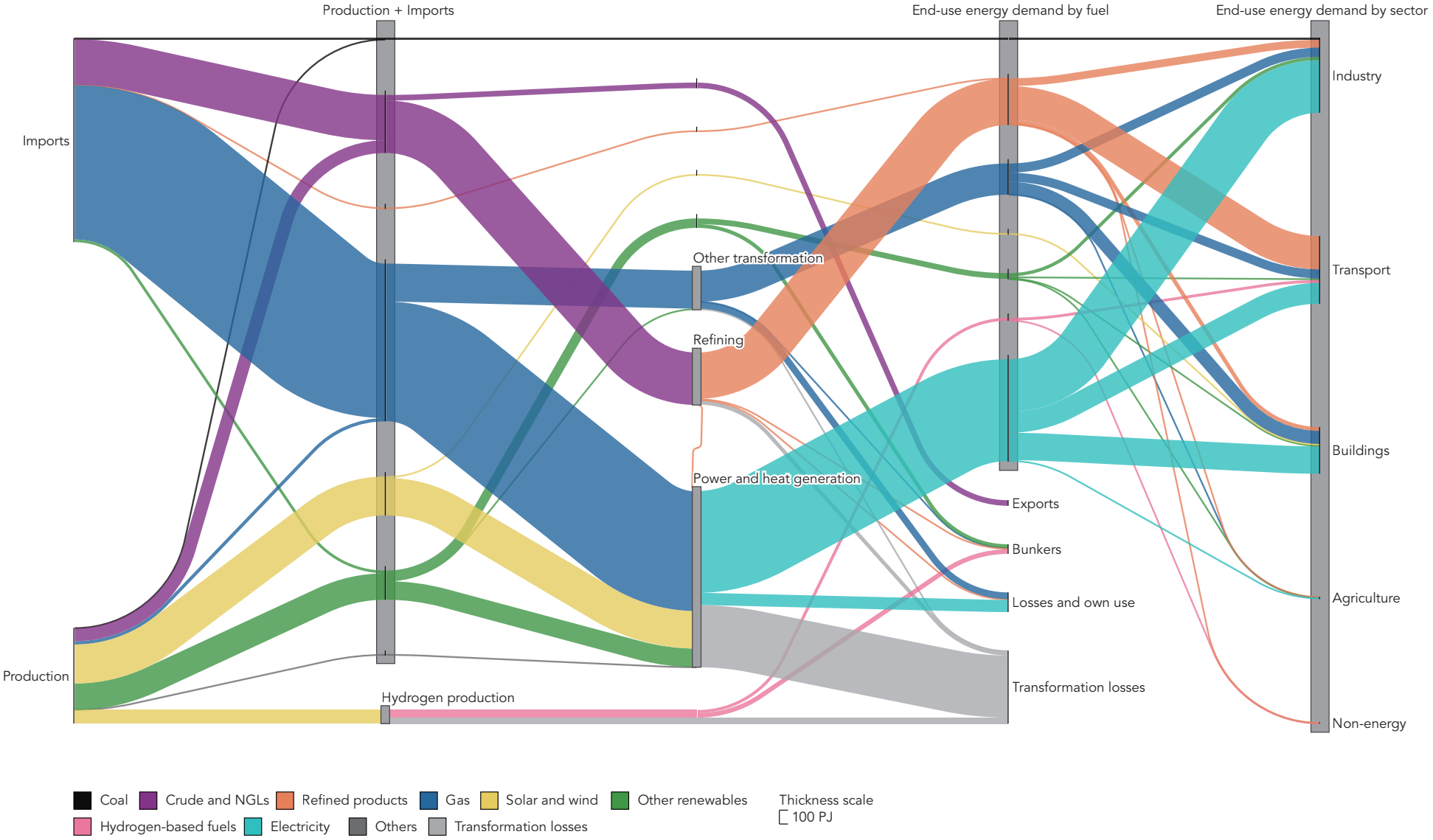
Adoption and Use of Natural gas

Under the framework of the Energy Policy 2010-2040, Peru is promoting the widespread adoption of natural gas in buildings, industry, and transport to reduce reliance on imported oil products.

Energy Flow (2022)



Energy Flow (2060, Target Scenario)



Scenarios and Assumptions

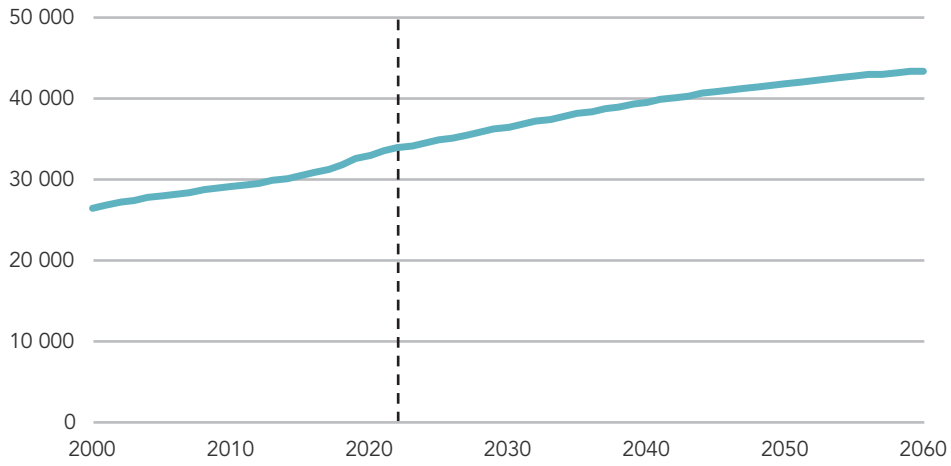
In *The Outlook*, APERC analyses energy demand, transformation, and supply, as well as emissions. The **Reference Scenario (REF)** offers a projection based on historical trends, recent developments, and APERC's assumptions about the continuation of those trends in each APEC economy, while acknowledging technical restraints. The REF Scenario offers a baseline to compare with the **Target Scenario (TGT)** projections, which explores a hypothetical pathway where each economy achieves energy-related policy targets, assuming implementation regardless of cost-effectiveness. When implementation details are lacking, assumptions are inferred from the targets themselves or emissions-related goals.

	Reference	Target
General	• Population: UN medium; GDP: APERC model and IMF	• Population: UN medium; GDP: APERC model and IMF
Buildings	• Traditional biomass is reduced following historical trends, assuming fuel switching to LPG. • Modest electrification in residential and services sectors.	• Stricter efficiency standards for buildings. • Accelerated electrification for heating, cooking, and building systems. • AI and data centre growth is the same in both scenarios.
Industry	• Key manufacturing sectors sustain strong output. • Electricity grows modestly.	• Greater electrification and efficiency. • Hydrogen use for steel and chemical industries expands from the 2030s, scaling faster than in REF.
Transport	• ICE vehicles steadily decline, shifting toward electrification. • BEVs and PHEVs gradually increase to account for 40% of the total vehicle stock by 2060.	• BEVs rapidly grow to 50% of the passenger vehicle stock by 2040 and fully replace ICE vehicles by 2060. • PHEV, LPG, and CNG vehicles are nearly phased out by 2060.
Power	• Electricity capacity expansion is driven by cost optimisation. • Natural gas plays a flexible backup role to support grid stability.	• Electricity capacity expansion is driven by cost optimisation; however, non-conventional renewable energy share in power generation reaches 20% by 2030 • Natural gas plays a flexible backup role to support grid stability.
Supply	• Declining trend of production of natural gas and oil continues. Reserves are not expanded. Natural gas remains at 10,800 PJ. • Declining trend of production continues. Reserves are not increased.	• Fossil fuel supply follows demand, and import dependency remains high. • Investment in reserves and increase of domestic production of natural gas and oil is considered. Natural gas reserves expand an additional 5400 PJ. Reduction of dependence on imported fuels. Fuel reserves increase after 2040.
Emissions	• While the NDC targets were taken into account, the simulation was not explicitly constrained to achieve them.	• While the NDC targets were taken into account, the simulation was not explicitly constrained to achieve them.

Note: The base year is 2022. Macro-economic assumptions are constant across scenarios. Historical energy balances are from EGEDA submissions for 2022.

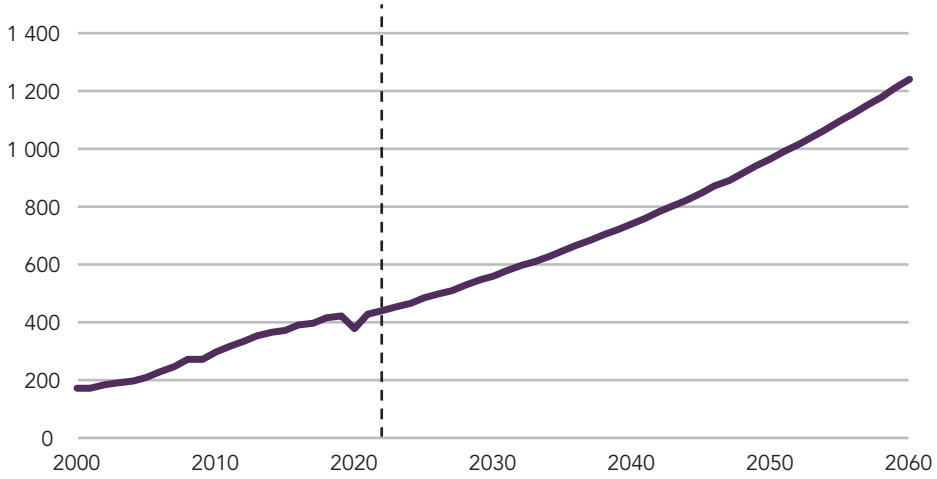
Demographic and Macroeconomic Assumptions

Figure 14-5. Population (thousands)



- Population is expected to reach 40 million by the early 2040s. Unlike some more advanced APEC economies, Peru's population is relatively young and is expected to continue growing, though at a gradually slowing pace: 0.96% annually during 2021–2030, 0.79% in 2031–2040, 0.57% in 2041–2050, and 0.34% in 2051–2060.
- Urbanisation, at 79% in 2023, is expected to continuously rise, increasing energy and service demand in cities.

Figure 14-6. Real GDP (billion 2017 USD, PPP)



- Real GDP projections are divided into distinct periods. For 2021–2027, growth at constant prices follows the IMF's World Economic Outlook (October 2022). Post-2027, projections are based on APERC's macroeconomic model, based on the Solow-Swan framework.
- Projected average annual real GDP growth is 2.67% (2021–2030), 2.77% (2031–2040), 2.66% (2041–2050), and 2.50% (2051–2060). Consequently, GDP is expected to nearly triple by 2060.

End-use Energy Demand

Figure 14-7. Energy demand by sector in REF & TGT (PJ)

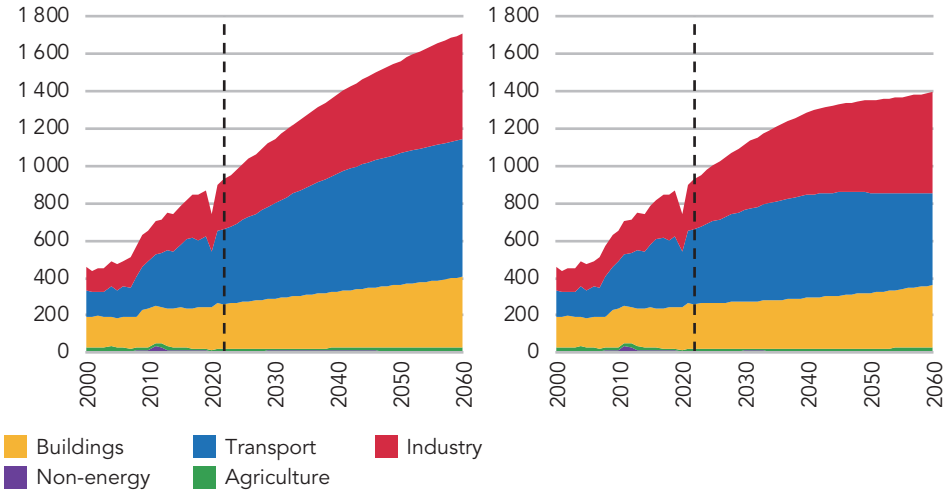
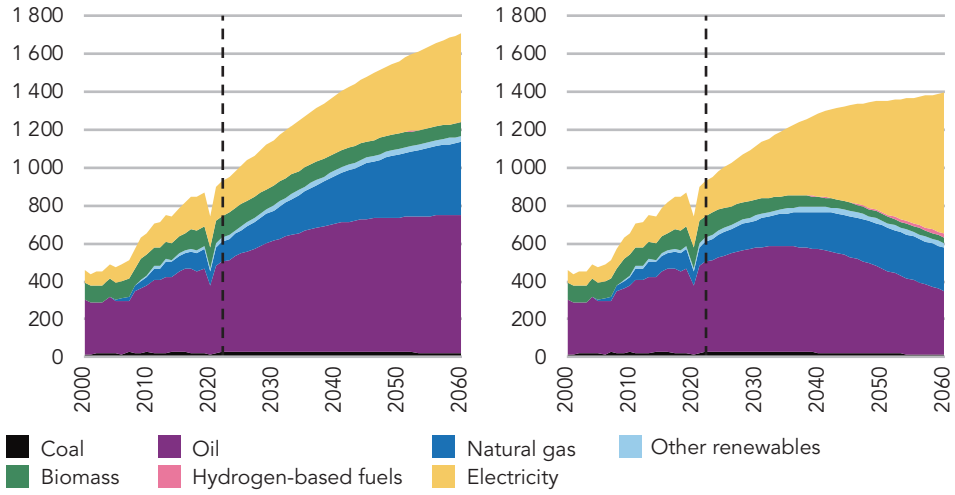


Figure 14-8. Energy demand by fuel in REF & TGT (PJ)



- As an emerging economy with a growing population, Peru is expected to experience sustained energy demand growth under both scenarios, though at a gradually slowing rate. Demand increases from 922 PJ in 2022 to 1,710 PJ by 2060 in the REF scenario (an 84% rise), and to 1,393 PJ in the TGT scenario (a 50% rise). The slower growth in TGT is driven by improved energy efficiency, reduced fossil fuel use, and a shift towards electricity.
- Traditional biomass use—primarily for water heating and cooking in rural residential buildings—declines as Peru promotes fuel switching, initially to LPG and later to other sources such as electricity. A more ambitious transition is constrained by limited infrastructure, including the natural gas network and grid electricity access in under-served areas.
- Nearly half of Peru's oil supply is imported. In the REF scenario, oil and oil product demand grows steadily from 478 PJ in 2020 to 727 PJ by 2060. In contrast in TGT, increased electrification causes oil demand to peak at 560 PJ in the mid-2030s before declining to 329 PJ by 2060.
- Natural gas consumption increases from 108 PJ in 2022 to 386 PJ by 2060 in REF. In TGT, it peaks at 229 PJ in the mid-2050s and then stabilises. The declining trends in oil and gas demand highlight the role of electricity substituting for oil and gas. Electricity demand rises from 188 PJ in 2022 to 472 PJ by 2060 in REF, and to a significantly higher 740 PJ in TGT, an increase of nearly 56%.
- The transport sector is currently the main energy consumer in Peru, comprising nearly 399 PJ or 42% of energy demand in 2022. The key distinction between scenarios is that, in TGT, transport demand peaks in the early 2040s and subsequently declines to 490 PJ, reflecting more optimistic assumptions regarding electrification, modal shifts, and improvements in fuel efficiency.

Buildings Energy Demand

Figure 14-9. Buildings energy demand by fuel in REF & TGT (PJ)

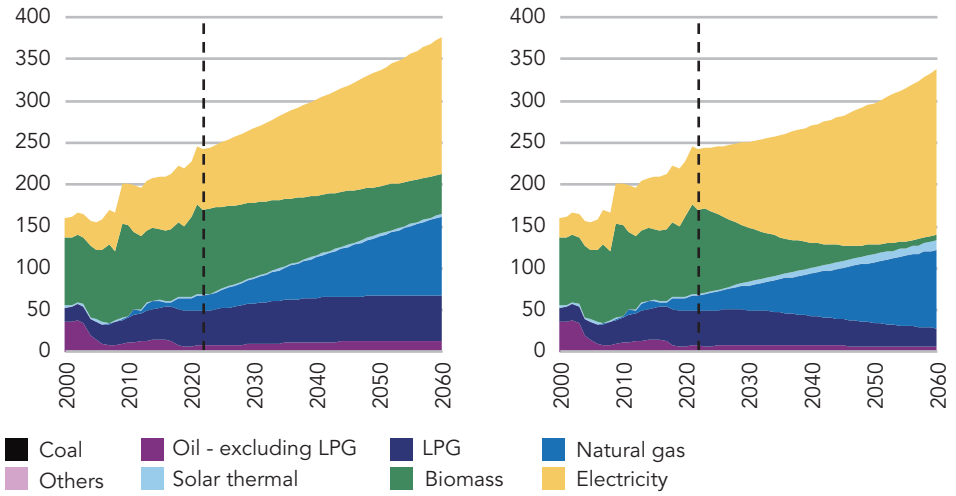
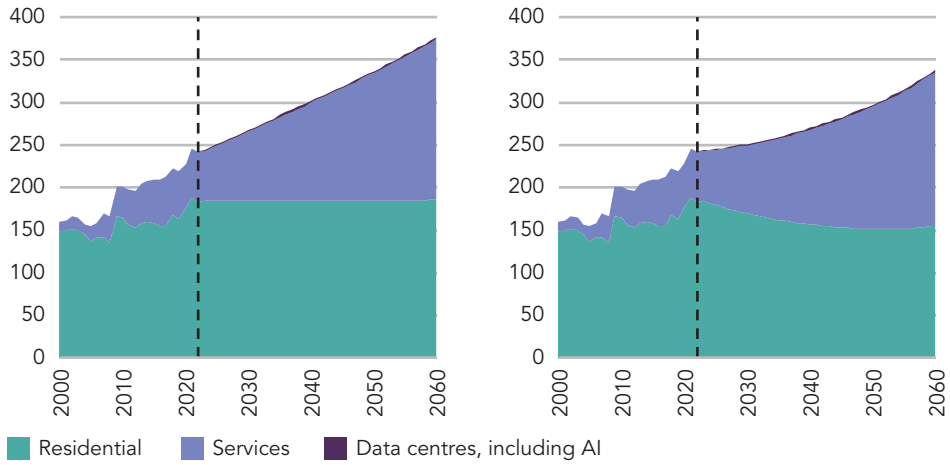


Figure 14-10. Buildings energy demand by sector in REF & TGT (PJ)



- Since 2000, Peru's building sector has undergone a significant shift in energy demand. The inefficient use of traditional biomass, once accounting for nearly 50% of building energy consumption, is declining due to efforts promoting cleaner alternatives, including natural gas and LPG. Biomass demand falls from 101 PJ in 2022 to 47.5 PJ by 2060 in REF, and to just 7.5 PJ in TGT.
- Natural gas is mainly consumed in Lima and Callao, with 56% coverage. Domestic coverage was about 25% in 2022, with lower access in other regions and commercial buildings. By the late 2040s, gas will supply nearly half of building fossil fuel demand, mainly for cooking and water heating. Gas demand rises from 19 PJ in 2022 to 94 PJ by 2060 in both scenarios, remaining significant even in TGT.
- LPG is the primary oil product used in buildings. In REF, demand grows moderately and stabilises at 54 PJ by the mid-2040s. In TGT, it peaks at 43 PJ by 2030 before declining to 22 PJ by 2060.
- Electricity drives most of the energy demand growth in both scenarios. In REF, demand rises from 71 PJ in 2022 to 164 PJ by 2060. In TGT, it reaches 198 PJ as electricity increasingly replaces fossil fuels, especially for cooking and water heating.
- Unlike the residential sector, where demand stabilises or declines, the services sector continues to grow, reaching around 180 PJ by 2060. The impact of AI on energy use remains minimal, as large-scale data centre investments are not expected.

Industry Energy and Non-energy Demand

Figure 14-11. Industry & non-energy demand by fuel in REF & TGT (PJ)

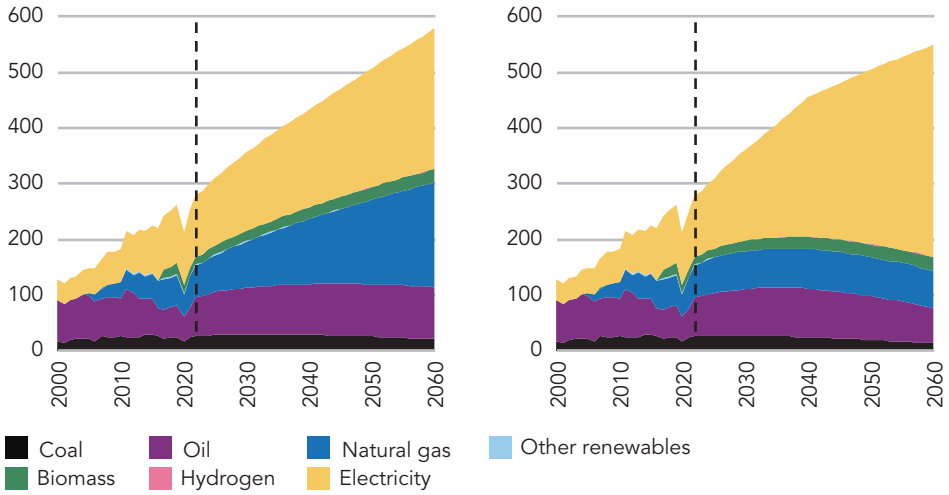
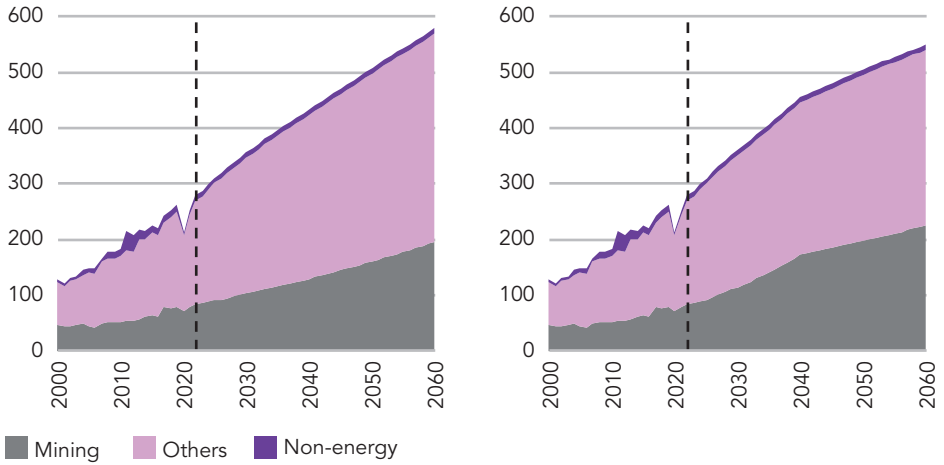


Figure 14-12. Industry & non-energy demand by sector in REF & TGT (PJ)



- Key strategies to manage industrial energy demand include improving energy efficiency and substituting fossil fuels with electricity in selected processes.
- Electricity is the fastest-growing industrial energy source, driven by electrification and a shift away from fossil fuels. Demand rises from 110 PJ in 2022 to 252 PJ by 2060 in REF, and to 380 PJ in TGT, reflecting deeper electrification.
- Natural gas demand increases steadily in REF, from 58 PJ in 2022 to 188 PJ in 2060. In TGT, demand peaks at 71 PJ in 2040, then declines to 67 PJ by 2060. Both scenarios indicate a need for expanded gas transmission and distribution infrastructure.
- Coal and oil demand peaks between 2030 and 2040, then declines gradually. A complete phase-out remains difficult due to economic constraints and technological barriers, especially in high-temperature heat applications.
- In TGT, industrial energy intensity remains stable through 2040, primarily due to increased mining activity driven by rising mineral demand associated with the global energy transition. After 2040, energy intensity begins to decline, reaching a 17% reduction by 2050 compared to 2021 levels.
- Conventional hydrogen used as industrial feedstock is excluded from final energy demand statistics. In TGT, clean and low-carbon hydrogen partly replaces this conventional hydrogen, reaching 8,300 tonnes by 2050.

Transport Energy Demand

Figure 14-13. Domestic transport energy demand in REF (PJ)

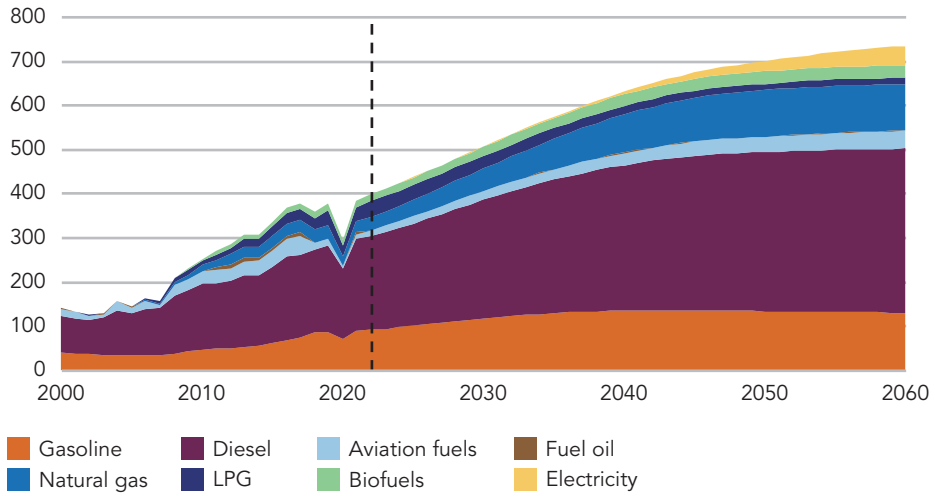
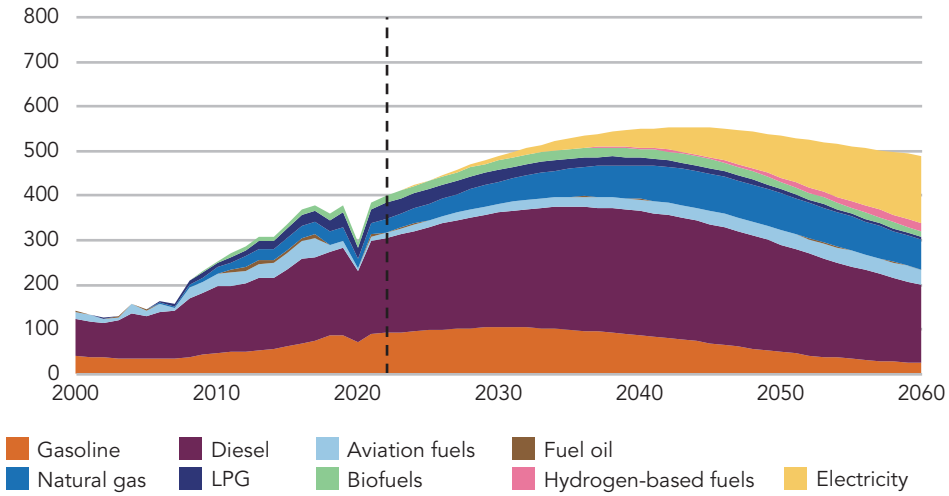


Figure 14-14. Domestic transport energy demand in TGT (PJ)



- Electric vehicle (EV) sales in Peru are expected to rise in line with global trends. In REF, EV adoption grows moderately, reflecting assumptions similar to those for other APEC economies. In TGT, adoption is higher, driven by more favourable economic conditions.
- Policy measures in both scenarios support a shift to low-carbon vehicles. In REF, transport demand grows from 399 PJ in 2022 to 736 PJ in 2060. In TGT, demand peaks at 550 PJ in the mid-2040s, then declines to 490 PJ by 2060, driven by EVs, hydrogen vehicles, fuel efficiency standards, and technology advances.
- By 2060 in TGT, electricity and hydrogen supply 30% and 4% of transport energy, respectively. Electricity demand grows from 0.3 PJ in 2022 to 151 PJ, making transport central to Peru's decarbonisation.
- The number of natural gas-fuelled vehicles continues to increase in both scenarios. While approximately 85% of these vehicles are currently in Lima, natural gas-fuelled vehicles are also being adopted in other regions of Peru, driving the construction of natural gas fuelling stations. Natural gas consumption grows to 31 PJ in 2022 to 104 PJ in REF and 65 PJ in TGT in 2060.
- Replacing diesel-fueled heavy-duty vehicles used for long-distance transportation with new technologies such as EVs is more challenging than replacing gasoline vehicles, due to the need for extensive supporting infrastructure along long-distance roads. Potential emerging solutions such as battery swapping or improvements of technologies such as advanced hydrogen technologies could help to address these challenges.

Other Transport Data

Figure 14-15. Transport vehicle stocks in REF & TGT (millions)

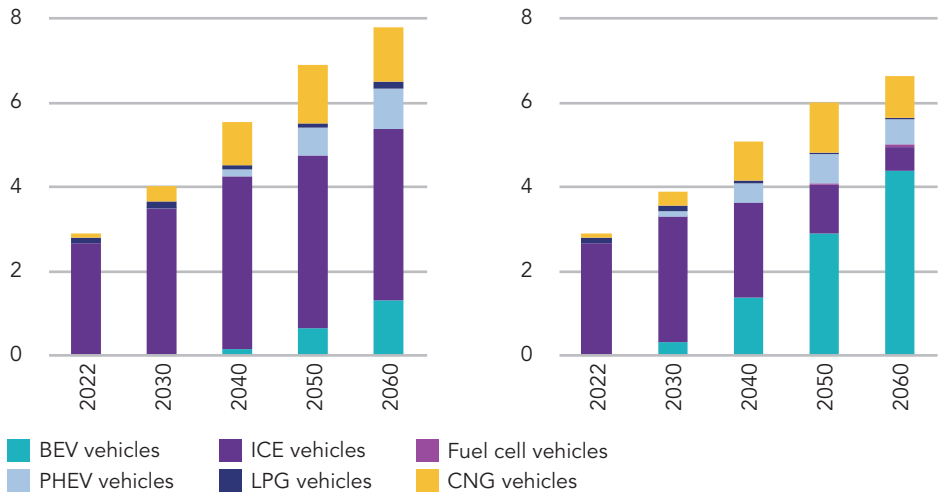
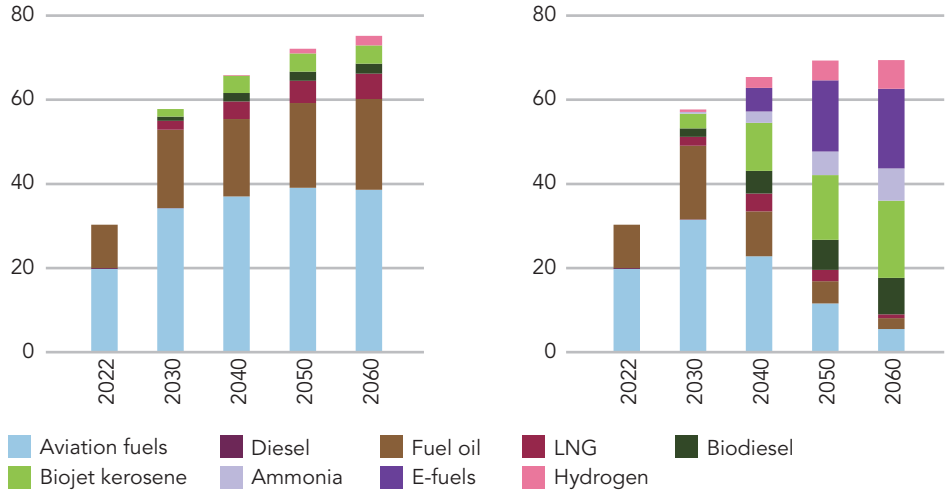
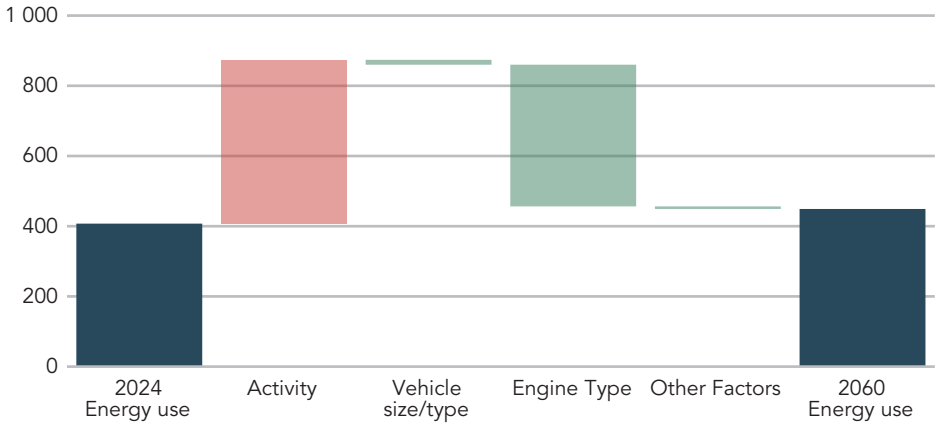


Figure 14-16. International bunker energy demand for shipping and aviation in REF & TGT (PJ)



- In REF, the EV fleet is projected to reach approximately 2.2 million units by 2060. By 2050, the combined market share of new fuel cell electric vehicles (FCEVs), plug-in hybrid electric vehicles (PHEVs), and battery electric vehicles (BEVs) is expected to reach 35% for passenger vehicles and 16% for freight vehicles. In TGT, the EV fleet expands more rapidly, reaching 5.1 million units by 2060.
- Bunker fuel consumption is projected to more than double by 2040 in both scenarios, exceeding 60 PJ. In TGT, stronger global decarbonisation efforts are assumed to facilitate the adoption of alternative fuels, such as ammonia for maritime shipping and e-fuels for aviation.
- Decomposition analysis shows that demand growth is primarily driven by increased economic activity. Conversely, the main driver of reduced energy consumption is the adoption of more energy-efficient technologies.

Figure 14-17. Components of the change in road energy use in TGT (PJ)



Note: Information on the different drivers in the transport energy decomposition can be found in the *Outlook*'s annex.

Electricity Generation

Figure 14-18. Electricity generation by fuel in REF (TWh)

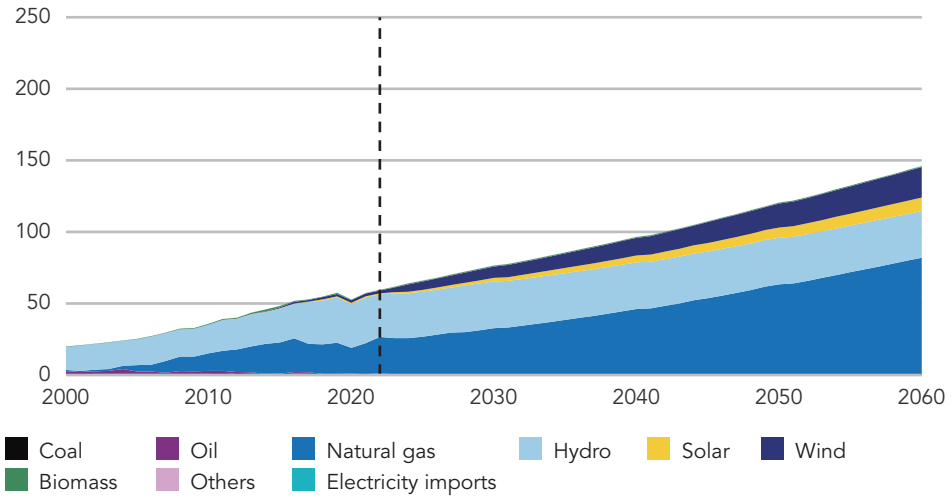
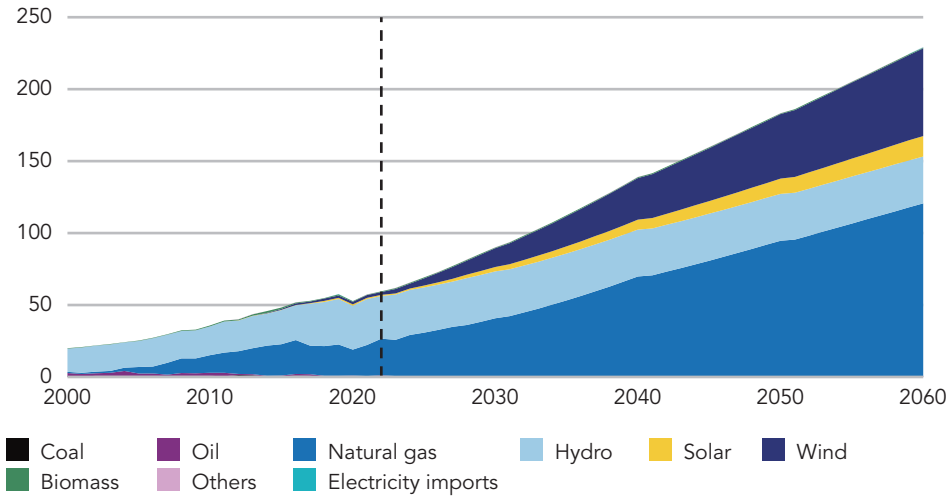


Figure 14-19. Electricity generation by fuel in TGT (TWh)



- Electricity demand is projected to increase in both scenarios—doubling in REF and tripling in TGT by 2050 from 2022 levels—requiring a significant expansion of generation capacity. Natural gas is expected to remain a key part of the power mix.
- In REF, natural gas generation grows 2.5 times from 2022 to 2050. Non-conventional renewable energy (NCRE), mainly solar and wind, gradually increases in share, reaching nearly 9% by 2024 and projected to grow to 15% by 2030 and 20% by 2050. Meeting these targets requires solar PV to grow eightfold and wind ninefold compared to 2022 levels.
- In TGT, stronger electrification policies lead to even higher electricity demand. Natural gas generation rises 3.7 times by 2050, alongside substantial growth in renewables. To meet domestic policy targets, NCRE is expected to supply 20% of electricity by 2030, requiring a twelvefold increase in solar PV and a twenty-fourfold increase in wind generation over 2022 levels.
- Natural gas grows due to its cost competitiveness, keeping a stable share in both scenarios. However, this results in a similar carbon intensity in power generation. Deeper decarbonisation would require new hydropower or a large-scale expansion of variable renewable energy (VRE) with storage. This shift entails major investment in grid infrastructure and market reforms to support ancillary services and flexibility.

Note: Figures 14-18 and 14-19 do not include electricity generation for hydrogen production.

Generation Capacity

Figure 14-20. Generation capacity by fuel in REF (GW)

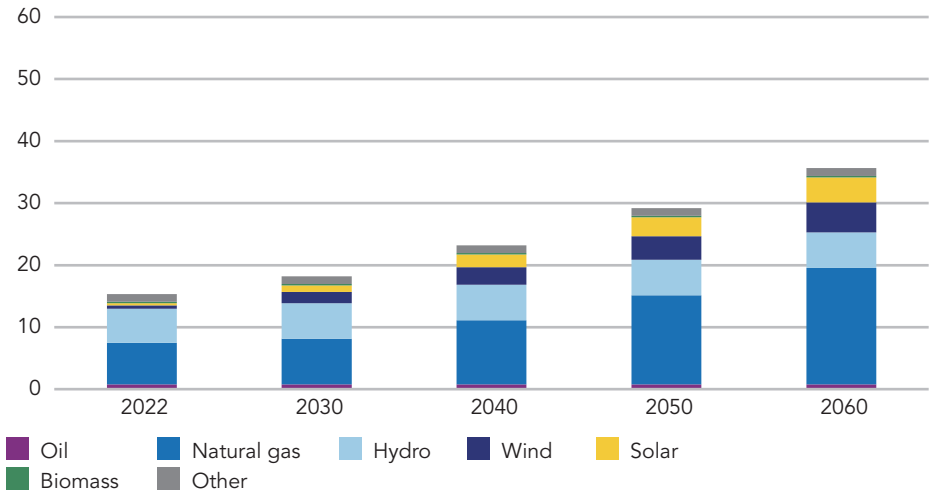
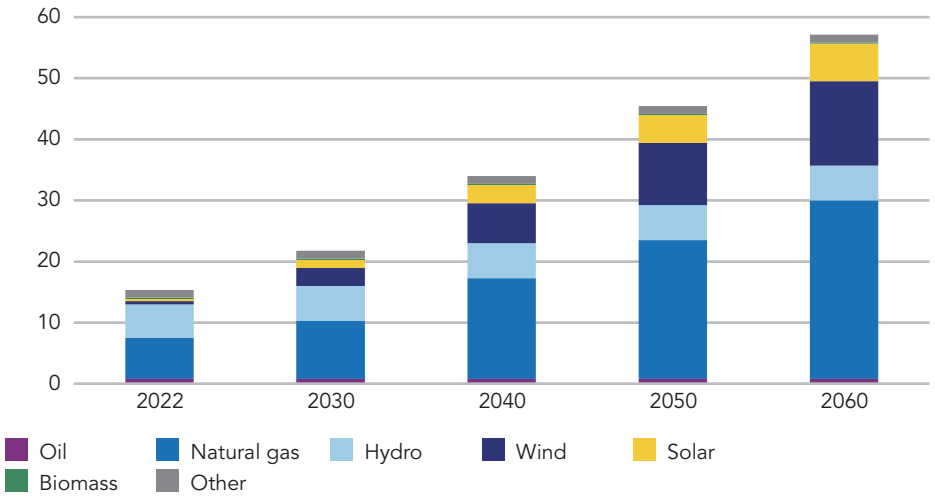


Figure 14-21. Generation capacity by fuel in TGT (GW)



- Significant investment in natural gas and renewable energy generation is required in both scenarios to meet rising electricity demand. Although Peru has considerable untapped hydropower potential, the development of new hydro projects is limited by technical, environmental, and social constraints. As a result, natural gas and variable renewables are expected to supply most of the additional demand.
- In REF, natural gas capacity doubles from 2022 levels to 14 GW by 2050. Wind capacity reaches 1.8 GW by 2030 and 3.8 GW by 2050. Solar capacity increases to 1.0 GW by 2030 and reaches 3.0 GW by 2050.
- In TGT, natural gas capacity triples to 22 GW by 2050. Wind capacity grows to 3.0 GW by 2030 and 10 GW by 2050. Solar capacity rises to 1.4 GW by 2030 and reaches 4.5 GW by 2050.
- The growth in solar and wind generation will require upgrades to the power transmission system to ensure reliable delivery from southern generation sites to demand centres in central Peru and to reduce grid congestion. With current transmission capacity between southern and central regions estimated between 1500 MVA to 2500 MVA, projected VRE expansion may quickly exceed available limits if installed in the same areas without transmission strengthening. Renewable deployment should also avoid over-concentration in regions with limited grid capacity.
- Expanding natural gas-fired generation also requires securing additional gas transmission capacity. The current pipeline system has a maximum capacity of 920 million cubic feet per day (MMcf/d), and around 500–550 MMcf/d is used for electricity generation. In REF, gas transport capacity that is dedicated to power generation is required to begin expanding around 2030 and double by 2050. In TGT, demand rises by 20% by 2030 and by 180% by 2050, relative to 2022.

Note: Figures 14-20 and 14-21 do not include generation capacity for hydrogen production.

Grid Reliability

Figure 14-22. Total generation capacity and peak load (GW)

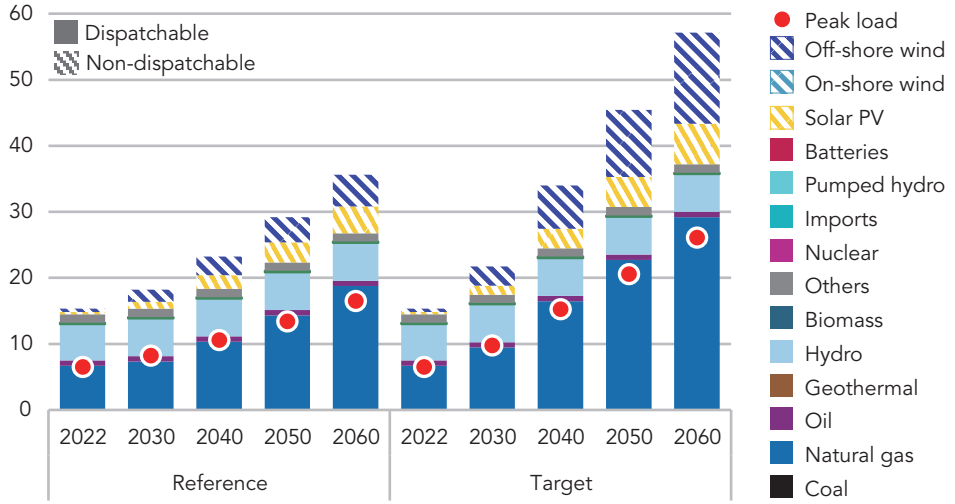
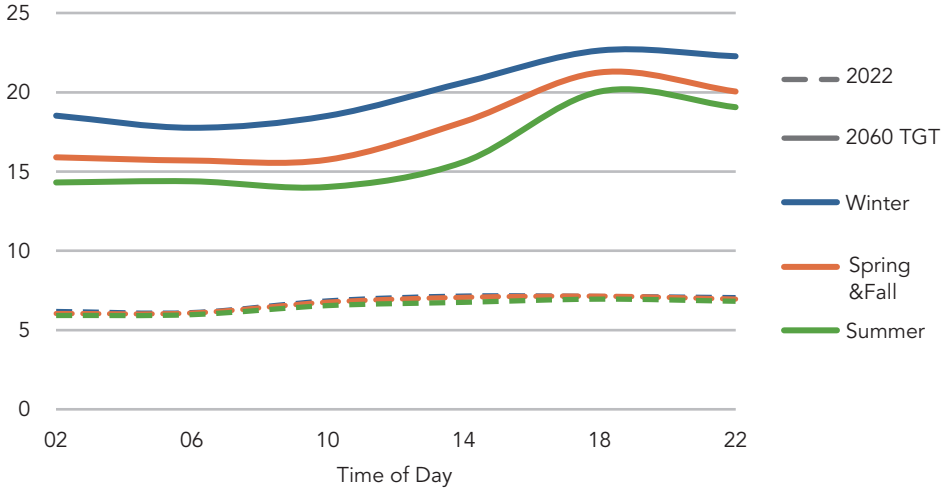


Figure 14-23. Power from dispatchable sources in TGT (GW)



- Peru's electricity grid requires an expansion of thermal power plants to ensure system reliability, as the growth of hydropower is assumed to be constrained by social and environmental factors. Consequently, the installed capacity-to-peak load ratio declines from 2.59 in 2020 to 2.16 in 2060 under the REF scenario, and to 2.19 in TGT. In TGT, natural gas-fuelled power plants continue to provide baseload generation while maintaining sufficient reserve margins to manage the variability introduced by increasing wind and solar capacity. An alternative pathway to maintain reliability involves expanding energy storage systems, although this would raise both generation and ancillary service costs.
- A major challenge in Peru is the geographic concentration of solar and wind projects, which are located in specific regions and not necessarily close to demand centres. This creates difficulties in transmitting electricity over long distances and maintaining reliability over time.
- As shown in Figure 14-23, during summer—when solar generation is higher—the ramp-up requirement for dispatchable power can reach 5 GW within six hours. This creates significant flexibility challenges for the electricity system. Higher share of VRE will intensify this issue, highlighting the need for investments in grid flexibility and storage solutions.

Coal and Biomass

Figure 14-24. Coal and biomass consumption by sector in REF & TGT (PJ)

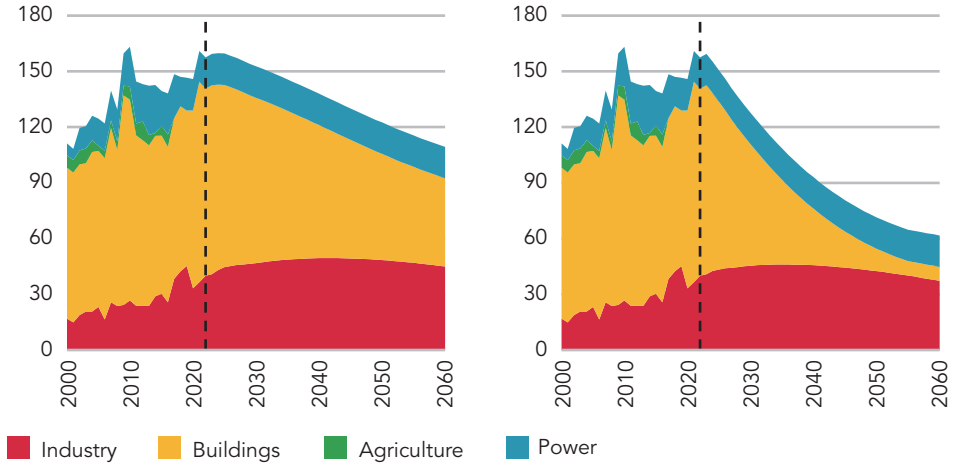
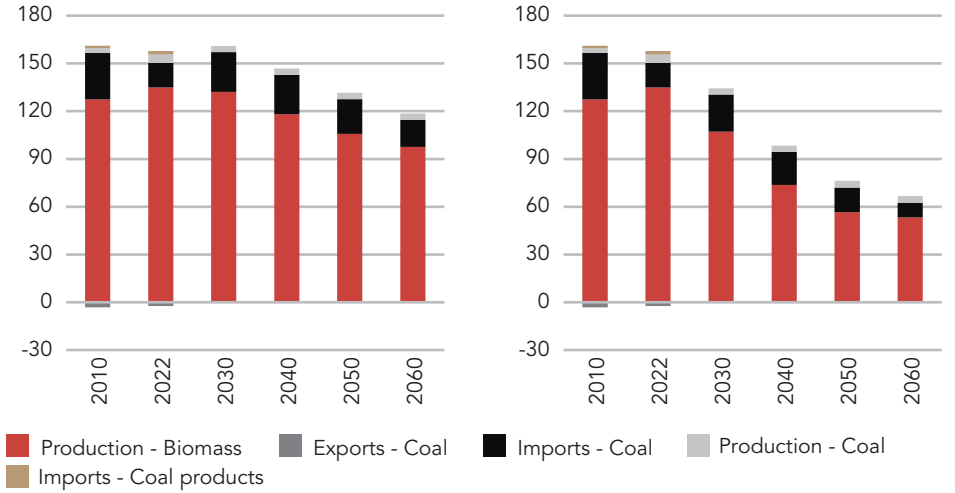


Figure 14-25. Coal and biomass production, imports, and exports in REF & TGT (PJ)



- Anthracite is the main type of coal produced in Peru. The primary consumers are in the industrial sector, particularly the cement industry. Peru exports anthracite and imports bituminous coal for industrial use and electricity generation for autoproducers. Compared to other APEC economies, coal does not represent a significant share of electricity production in Peru. The Ilo coal power plant ceased commercial operation in 2022, marking the end of coal-based generation in Peru's main electricity market.
- Although improved biomass could serve as a lower emission energy source, most initiatives in Peru have focused on reducing biomass use in rural and peri-urban areas analysed in buildings, such as through the Improved Cookstoves Plan and the Energy Social Inclusion Fund. This reduction not only limits traditional biomass combustion but also alleviates pressure on forests, supporting emissions mitigation. In Peru, deforestation is the largest source of greenhouse gas emissions.
- Peru is generally self-sufficient in coal and biomass supply, so coal and biomass trade is minimal. In 2022, these fuels accounted for 15% of total final consumption (TFC), but their share declines to 5% in 2060 under the REF scenario and 3% under TGT.
- Since coal consumption is concentrated mainly in industry, further reductions of its consumption will require innovation, as coal is integrated into critical industrial processes such as reduction reactions and kiln operations.

Natural Gas

Figure 14-26. Natural gas consumption by sector in REF & TGT (PJ)

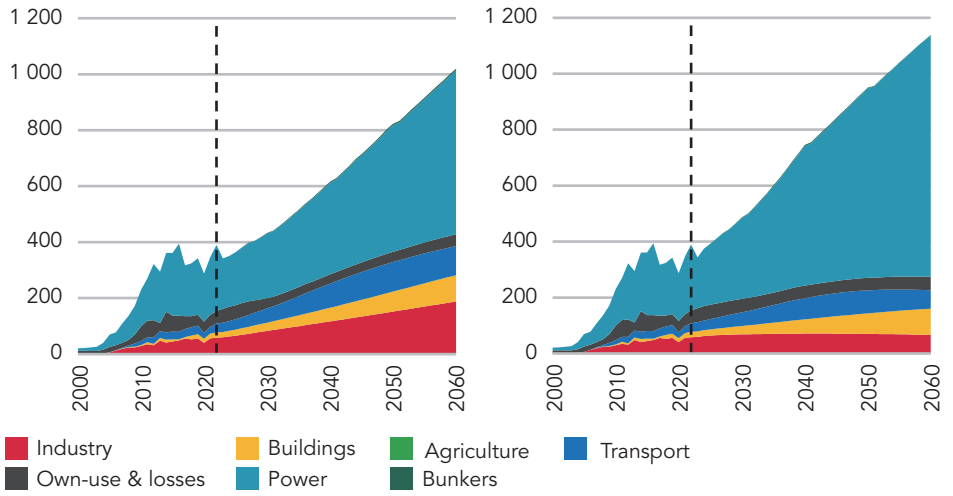
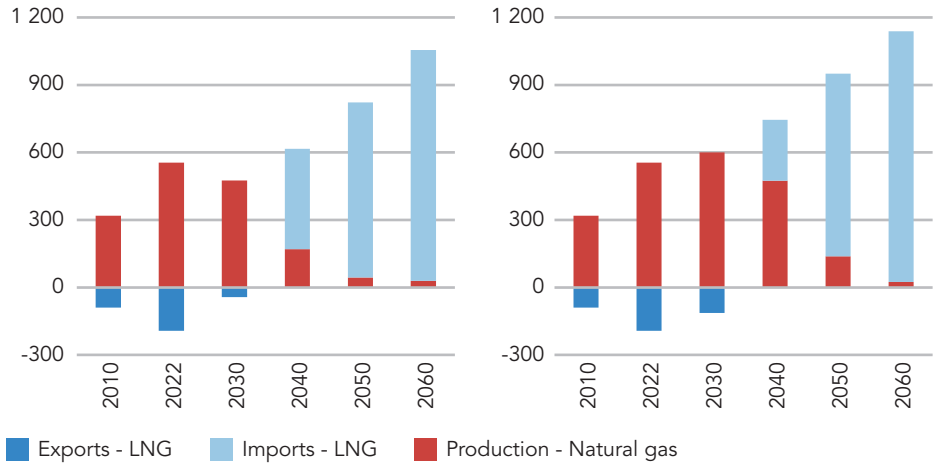


Figure 14-27. Natural gas production, imports, and exports in REF & TGT (PJ)



- Natural gas plays a critical role as a transition fuel in both scenarios. In the TGT scenario, total demand for natural gas is higher due to increased electrification requiring more natural gas-fired power generation to meet higher electricity demand and support increasing variable renewable generation.
- Battery energy storage systems are also dispatchable electricity sources and can provide grid reliability, but batteries must be charges to be effective. During long periods of low wind and solar resources, it may be difficult to keep batteries fully charged.
- If natural gas reserves are not expanded, domestic production will begin to decline after 2028. Current proven reserves are estimated at 10,800 PJ. Under a 7% annual decline rate, production could continue through 2060. However, due to rising demand, Peru is projected to become an LNG importer by the 2030s.
- Expansion of gas pipeline infrastructure is necessary to meet growing demand. The current nominal capacity of the main Camisea–Lima pipeline is 920 MMcf/day (approximately 385 PJ/year). This capacity will need to double by the mid-2040s if natural gas is supplied from the same area in Peru.
- In the TGT scenario, Peru is expected to expand its natural gas reserves after 2030, adding approximately 5,400 PJ. However, due to increasing demand, natural gas imports will still be required by 2036.

Note: Historical data for LNG is based on JODI gas data.

Petroleum Liquids

Figure 14-28. Crude oil, NGLs, and other hydrocarbons production, imports, and exports in REF & TGT (PJ)

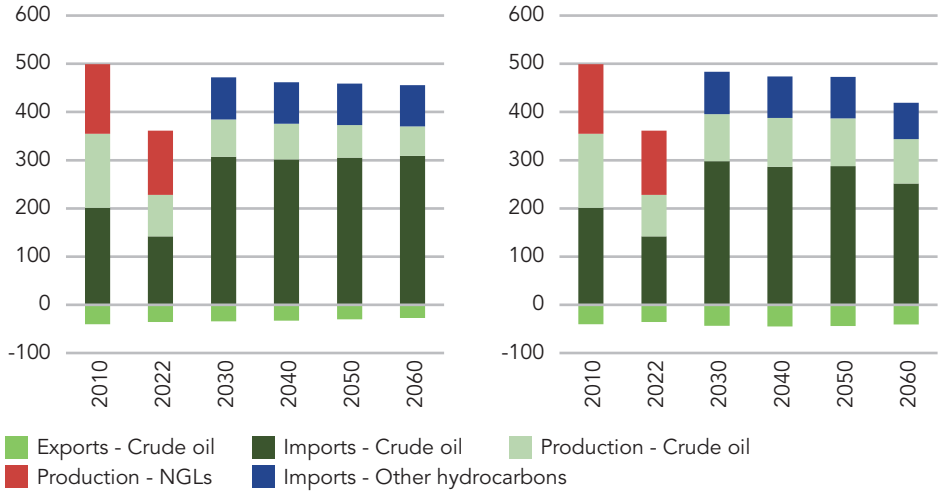
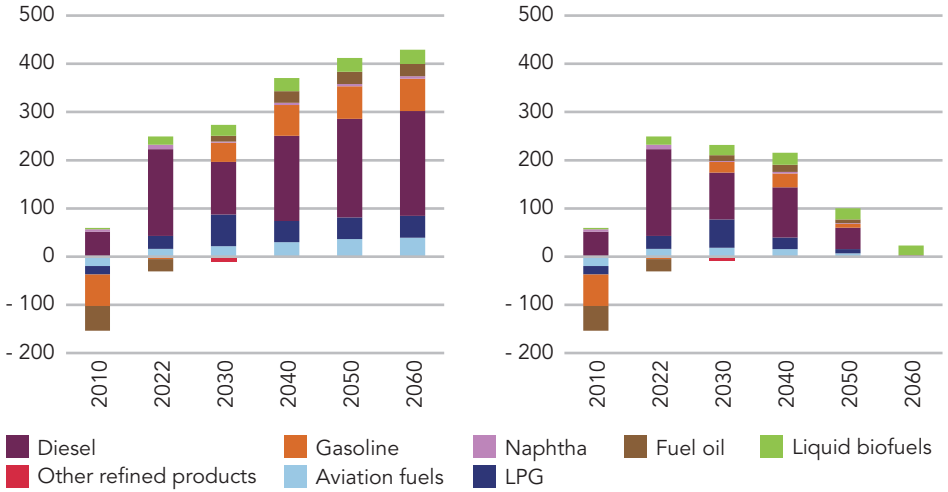


Figure 14-29. Net imports of refined products and low-carbon fuels in REF & TGT (PJ)



- Crude oil production is projected to decline in both scenarios, with a sharper drop in REF. In REF, limited development of new onshore blocks moderates the decline, but these additions are expected to be small and only partially offset losses. The decline increases reliance on refined oil imports.
- Crude oil imports are expected to rise in REF to sustain refinery utilisation and meet domestic demand. This reflects assumptions of no growth in domestic crude output and no expansion of refining capacity.
- Natural gas liquids (NGLs) have consistently accounted for over half of crude oil output. Their share rose to 63% in 2022 and is assumed to remain stable over the projection period.
- In the TGT scenario, crude oil production rises to 280 PJ/year, consistent with Petroperu's 107 kb/d target and additional output from CNPC and Maple Energy. This growth assumes reserve expansion, but production begins to decline after 2040 due to resource depletion, underscoring the need for long-term supply diversification.
- TGT also assumes an increase in natural gas liquids (NGL) reserves, from 240 TJ in 2020 to 360 TJ. This extension sustains output until 2050, after which production gradually declines. The scenario highlights the importance of reserve development and resource management strategies.
- While crude oil production stabilises in TGT, overall domestic demand decreases. Higher production reduces import dependency but does not eliminate it, as demand for oil and oil-derived products continues to outpace domestic supply despite decarbonisation efforts. This points to a persistent vulnerability to external markets.

Note: In Figure 14-29, net imports are presented without deducting bunkers.

Refining

Figure 14-30. Refining outputs in REF & TGT (PJ)

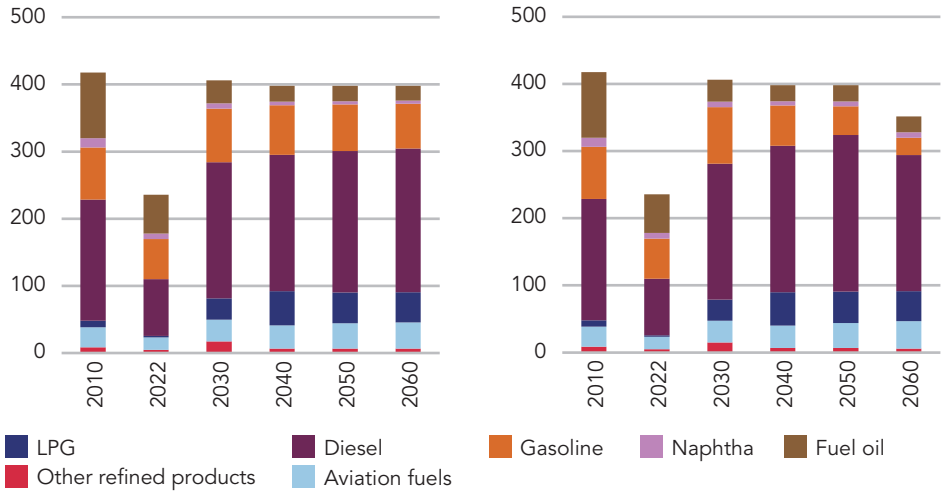
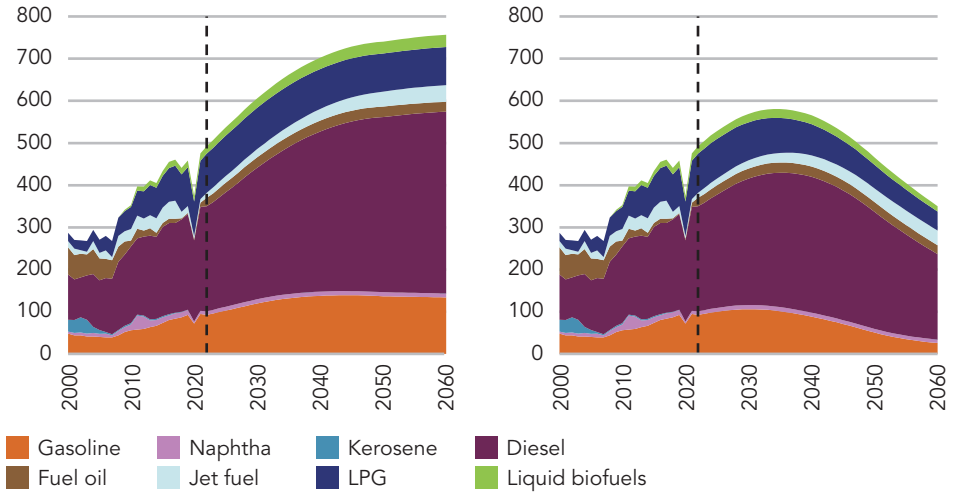


Figure 14-31. Refined products and low-carbon fuels demand in REF & TGT (PJ)



- Transport remains the largest consumer of petroleum products—primarily diesel and gasoline—in both scenarios, highlighting its critical role in Peru's energy security. While gasoline consumption declines in both cases, diesel use, primarily in heavy freight transport and certain industrial applications, is more stable. This stability helps sustain refinery operations, as demand continues to exceed domestic production even under the TGT scenario.
- In the REF scenario, approximately 57% of domestic petroleum product demand in 2060 is met through imports, reflecting limited progress in reducing oil dependency.
- In the TGT scenario, petroleum product imports account for only about 7% of oil product demand by 2060, as overall consumption declines due to decarbonisation efforts. To maintain high refinery utilisation rates, exports of refined products increase; otherwise, lower domestic demand would result in underused refining capacity.

Hydrogen-based Fuels in the Target Scenario

Figure 14-32. Hydrogen-based fuels production methods and supply [left]; Inputs for hydrogen production [right] (PJ)

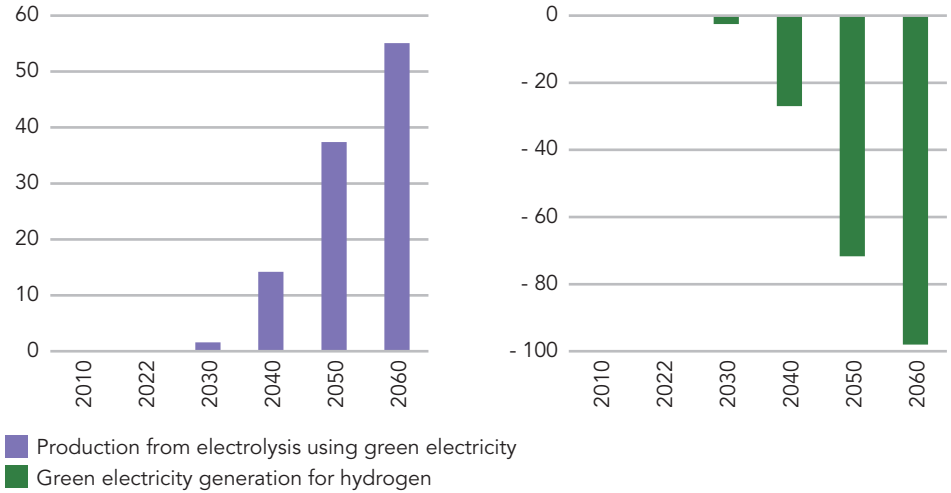
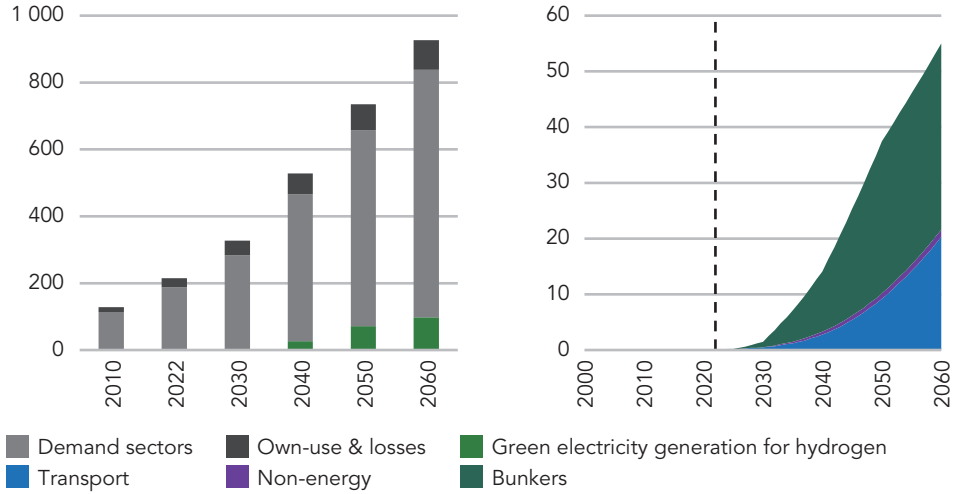


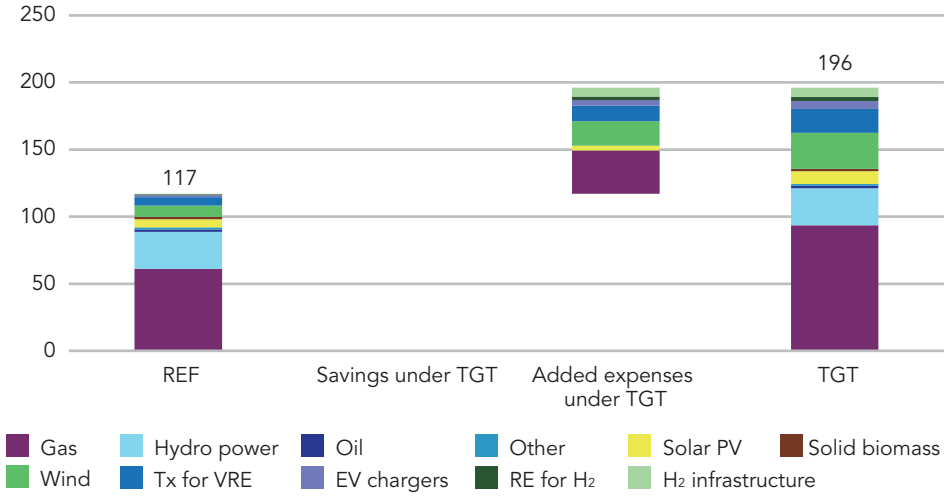
Figure 14-33. Electricity for electrolysis vs other sectors [left]; Hydrogen-based fuels demand by sector [right] (PJ)



- Peru is advancing the development of a hydrogen economy to leverage its abundant variable renewable energy (VRE) resources. While the economy also has natural gas reserves that could be used for hydrogen production, these reserves are allocated to meet growing demand in other sectors.
- In TGT, clean hydrogen supplies around 2% of total final energy consumption (TFEC) by 2060. Most hydrogen use is concentrated in the transport sector, particularly for long-distance freight and international bunkering. Adoption in bunkering is driven by anticipated stricter international emissions regulations. Ammonia is used in marine shipping, while e-fuels are adopted in aviation.
- Electricity demand for hydrogen production via electrolysis (Figure 14-33) increases significantly after 2040, reaching nearly 100 PJ by 2060. This accounts for approximately 12% of the additional electricity generation, assumed to be fully supplied by renewable sources.
- To meet hydrogen demand under the TGT scenario, 3,600 MW of electrolyser capacity, 300 MW of ammonia production capacity, and 750 MW of e-fuel production capacity are required. Supporting this will require an additional 2.5 GW of solar and 6.6 GW of wind power capacity.

Costs

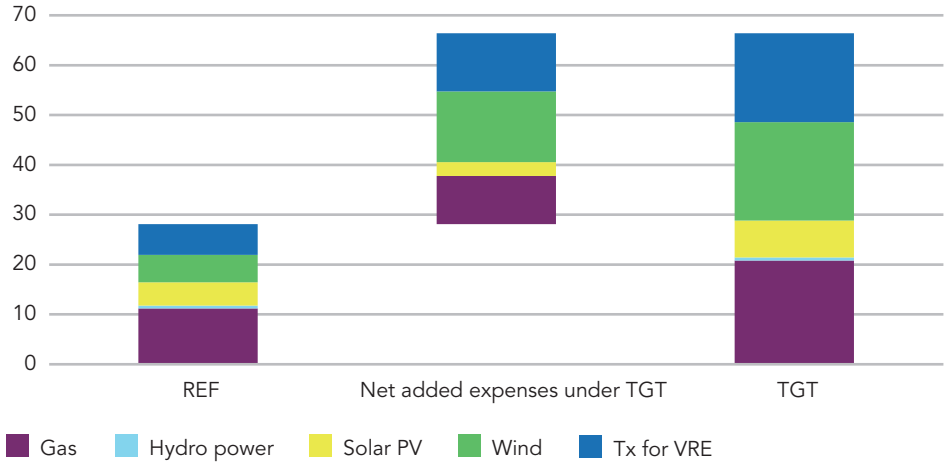
Figure 14-34. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



Note: Tx for VRE is only transmission infrastructure to connect variable renewable capacity to the grid. EV chargers do not cover the cost of associated infrastructure or EV vehicles. Hydrogen costs do not cover costs for bunkering.

- From 2025 to 2060, total costs rise significantly in both scenarios, with an 68% increase from REF to TGT. Total costs cover the capital, fixed and variable costs in power generation, costs for green hydrogen production for domestic use, transmission for VRE and EV chargers.
- In REF, total costs reach USD 117 billion, primarily driven by fossil fuel investments, especially in natural gas, alongside moderate growth in low-emission technologies. In TGT, total costs rise to USD 196 billion. In our cost estimations, cost savings do not occur in TGT as increased spending on all generation types is required to meet the added electricity demand in TGT. Natural gas grows in both scenarios, reflecting its cost competitive role as a transition fuel necessary for Peru to meet its rising electricity demand and maintain grid stability.

Figure 14-35. Total capital investment (CAPEX) from 2025 to 2060 in the power sector (billion USD, undiscounted)

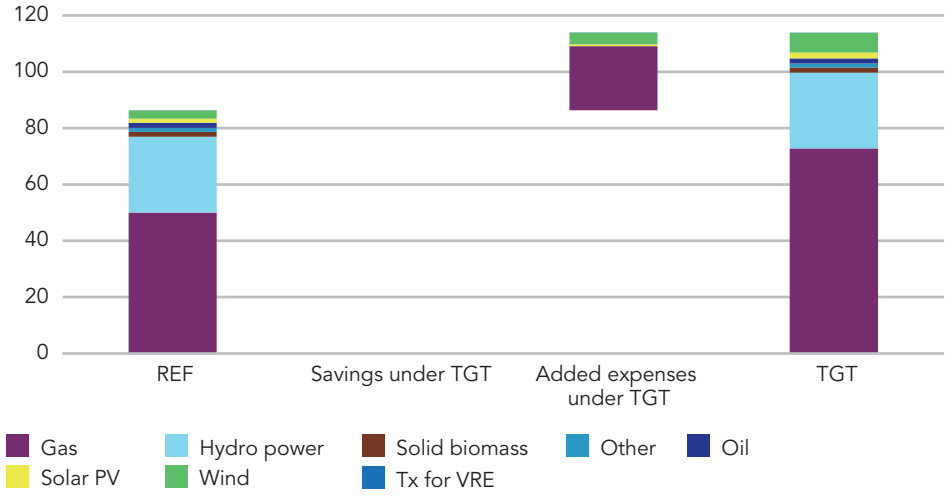


Note: Figure 14-35 only covers power and VRE transmission sector investments. Hydrogen and EV capital investments are not included.

- Total capital investment for Peru's power sector is an estimated USD 66 billion in TGT, up from USD 28.1 billion in REF. This rise is driven by capacity additions namely wind, solar and gas and the cost of integrating added variable renewable energy via expanded transmission networks.
- Although the TGT scenario requires additional investment in transmission infrastructure to integrate more solar and wind, battery investments are not present. This is due to the presence of sufficient dispatchable capacity (in particular gas) necessary to meet peak demand.
- Investment in gas increases in both scenarios to support dispatchable supply reflecting its cost competitiveness in the sector. These results emphasise the importance of timely and strategic investment to ensure grid stability and support a reliable, affordable decarbonisation approach as gas expansion occurs in line with added renewables.

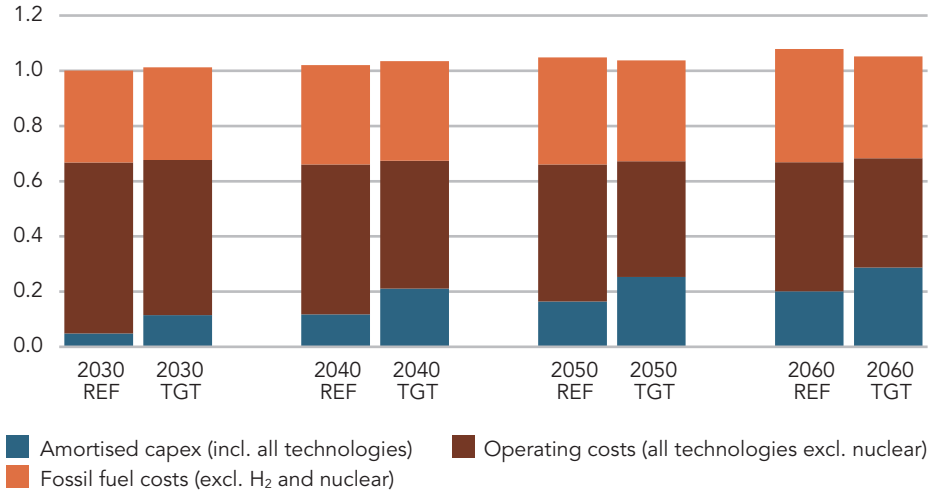
Costs

Figure 14-36. Total operating costs from 2025 to 2060 in the power sector (billion USD, undiscounted)



Note: Figure 14-36 only covers power and VRE transmission sector costs. It does not include operating costs associated with hydrogen production and EV charger costs.

Figure 14-37. Cost of generating electricity relative to 2025 (2025 cost = 1.0) in the power sector



Note: Based on our assumptions about future capital and operating costs, Figure 14-37 shows cost compositions over time relative to 2025. It should not be considered an estimate of electricity tariffs and excludes market mechanisms that are too difficult to estimate.

- Peru's total operating costs for the power sector are an estimated USD 114 billion in TGT, compared to USD 86 billion in REF. These operating costs primarily reflect variable fuel expenditures, with gas-fired generation remaining the dominant cost driver in both scenarios due to its role in ensuring system reliability, with these costs increasing in TGT.
- Operational costs for hydro power generation are also significant in both scenarios given how Peru is expected to maintain its hydro power assets in both scenarios.
- These projections highlight the sustained operational burden of a decarbonised pathway. Effective fuel management, especially for gas fuel inputs, will be essential to maintaining economic efficiency while supporting Peru's energy transition.

- Figure 14-37 shows the relative cost of generating electricity in selected years indexed to the base year of 2025 in REF and TGT, with the cost staying roughly the same throughout the projection period.
- The decreasing share of operating costs is balanced out by the increased share of amortised capital costs (CAPEX). Amortised CAPEX rises steadily in both scenarios as additional capital expenditure is required for wind and solar capacity additions. The continual dominance of gas means fossil fuel costs do not decline across both scenarios however given the comparatively lower operational costs of running a gas plant (compared to other thermal sources), operating costs comprise a small share of total costs over time as total generation increases. However, the increased amortised capital costs offsets this decrease.

CO_2 Emissions

Figure 14-38. CO_2 emissions in REF (million tonnes)

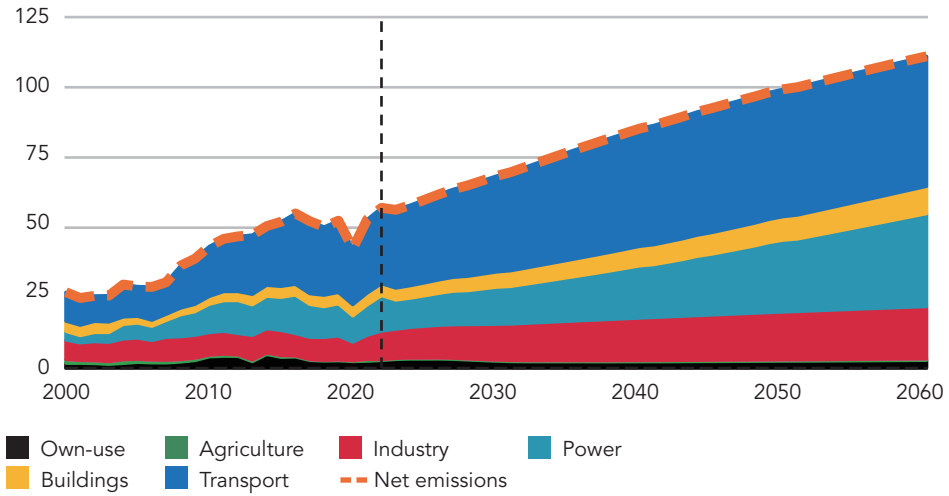
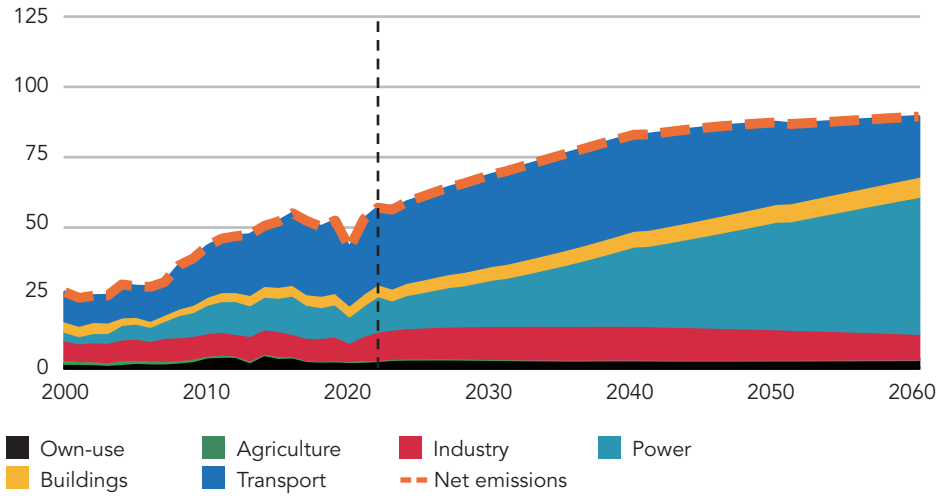
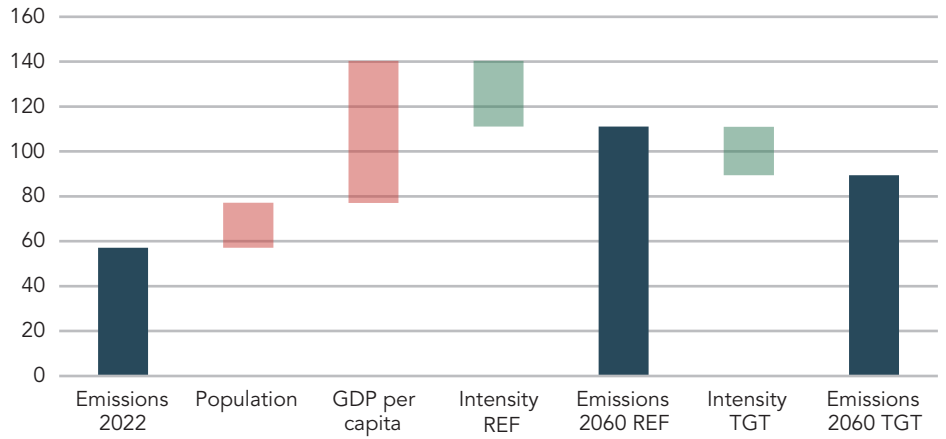


Figure 14-39. CO_2 emissions in TGT (million tonnes)



- Gross CO_2 emissions are projected to rise in both scenarios, primarily driven by the transport and power sectors. In REF, transport emissions surge from 10 Mt in 2000 to over 46 Mt by 2060. In TGT, they peak at 34 Mt around 2030, then decline to 21 Mt by 2060, supported by transport electrification, mainly through EV adoption.
- Power sector emissions increase due to expanded natural gas generation, which supports EV integration and grid stability amid rising renewables. Emissions from the power sector reach 33 Mt in REF and 48.7 Mt in TGT by 2060. Further renewable expansion is essential to mitigate this rise.
- Efficiency improvements and fuel switching in other sectors help to moderate overall emissions growth.

Figure 14-40. CO_2 emissions components (million tonnes)



Note: All values represent energy sector combustion CO_2 emissions. Biogenic CO_2 is treated as zero at the point of combustion.

Useful Links

APEC Expert Group on Energy Data and Analysis (EGEDA) – https://www.egeda.ewg.apec.org/

APEC Energy Statistics 2022 – https://www.egeda.ewg.apec.org/egeda/general/info/pdf/APEC_Energy_Statistics_2022.pdf

APEC Energy Overview – https://aperc.or.jp/reports/energy_overview.php

BP Statistical Review of World Energy – https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/statistical-review/bp-stats-review-2021-natural-gas.pdf

Department of Economic and Social Affairs of the United Nations (UNDESA)/ Population Division – https://www.un.org/development/desa/pd/data-landing-page

Energy Institute Statistical Review of World Energy – https://www.energyinst.org/statistical-review

International Monetary Fund/World Economic Outlook Database – https://www.imf.org/en/Publications/WEO/weo-database/2022/October

Ministry of Energy and Mines - https://www.gob.pe/minem

World Bank Open Data – https://data.worldbank.org/



15. The Philippines

Summary

	Reference			Target		
	2022	2060	% Change	2022	2060	% Change
Macroeconomic						
Population (million)	114.7	167.6	46%	115	168	46%
GDP (billion 2017 USD, PPP)	981	5,103	420%	981	5,103	420%
Energy Demand						
Agriculture & fisheries (PJ)	16	74	357%	16	67	315%
Buildings (PJ)	618	1,675	171%	618	1,471	138%
Industry (PJ)	298	1,031	246%	298	926	211%
Non-energy (PJ)	54	190	252%	54	170	215%
Transport (PJ)	516	1,446	180%	516	904	75%
Modern renewables share of TFEC (%)	9.36	21.24	127%	9.36	28.80	208%
Energy intensity of TFEC (PJ/GDP, billion USD)	1.47	0.83	-44%	1.47	0.66	-55%
Electricity						
Generation (TWh)	112	558	401%	112	626	462%
Renewables share of generation (%)	22.12	41.46	87%	22.12	41.36	87%
Generation capacity (GW)	29	200	596%	29	212	638%
Total Primary Energy Supply (TPES)						
Coal & coal products (PJ)	799	969	21%	799	634	-21%
Natural gas (PJ)	109	1,780	1,528%	109	1,988	1,718%
Petroleum liquids (PJ)	830	2,147	159%	830	1,181	42%
Low-carbon & waste energy (PJ)	880	1,912	117%	880	2,361	168%
CO_2 intensity of energy supply ($MtCO_2/PJ$)	0.052	0.048	-8%	0.052	0.039	-25%
Net CO_2 Emissions (million tonnes)	136	328	141%	136	242	78%

Note: In this publication, the term "modern renewables" refers to all renewable energy sources excluding solid biomass in the buildings sector. The term "low-carbon & waste energy" includes all bioenergy, waste-derived energy, renewables, nuclear, and hydrogen-based fuels. Total primary energy supply (TPES) numbers include international bunkers. Net emissions are calculated as gross energy sector combustion CO_2 minus CO_2 captured and stored through carbon capture and storage (CCS).

Key Takeaways

Emissions

- CO_2 emissions are projected to rise in both scenarios. By 2060, emissions projected to increase by 142% in in the Reference scenario (REF), as opposed to the 78% increase in the Target scenario (TGT). Relative to REF, TGT could reduce CO_2 emissions by around 22% and 26% in 2050 and 2060, respectively.
- Most CO_2 emissions will continue to come from the power sector. With increased electrification and fossil fuel-based power generation, the power sector's CO_2 emissions share will increase. The increase in share is much higher in TGT because of transport sector's electrification. Therefore, efforts to decarbonise the power sector will help to reduce CO_2 emissions.
- The decrease in CO_2 emissions in TGT is greatly influenced by the reduction of energy demand in the transport sector. Further reductions could be achieved by increasing the fleet of electric vehicles (EVs) while ensuring that additional electricity demand is supplied using low-emission energy sources.

Energy Import Dependence

- Import dependence will continue in both scenarios, with a significant increase in natural gas' share. In REF, while oil and petroleum products remain around 32%, natural gas' share has increased from non-existent in 2022 to 25% by 2060. Coal's share will gradually decrease to 14% by 2060. The shift from coal to natural gas is due to the transition in the power sector. This raises the issue of trading coal dependence for gas dependence for the energy transition.
- In TGT, with the reduction of total primary energy supply, along with the increase in production attributed to nuclear, gas, and wind, import dependence is reduced to below 60%. In TGT, the share of imported natural gas also increases, becoming more prominent than petroleum imports. The electrification of the transport sector directly reduces petroleum demand.
- Despite efforts to reduce import dependence in TGT, the increase in energy demand in the Philippines, to continue driving its economic growth, will require more imports. Further efforts are necessary to retain the current import dependence of around half the total primary energy supply.

Figure 15-1. Net CO_2 emissions (million tonnes)

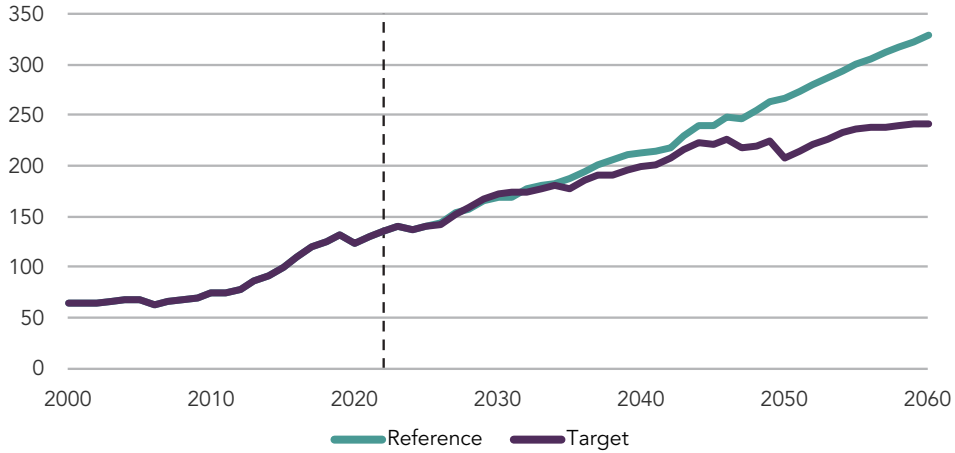
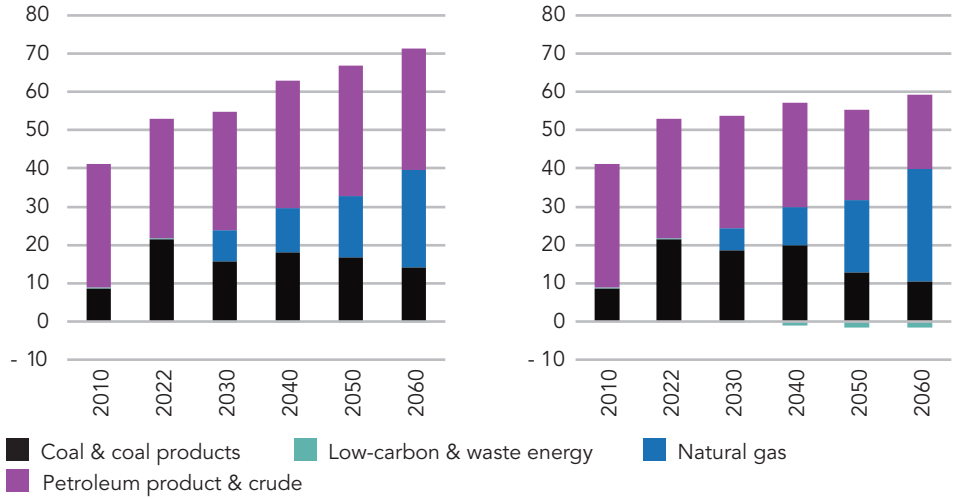


Figure 15-2. Net imports share of TPES in REF & TGT (%)



Note: In Figure 15-2, net imports refer to total imports minus exports and international bunkers.

Key Takeaways

Grid Reliability

- Grid reliability fundamentally depends on the principle that electricity must be produced to always match demand. As renewable energy capacity increases, renewable energy share and dispatchable power flexibility must be considered.
- The renewable energy share, the gap between maximum dispatched power and peak load, is seen in Dec-Feb due to wind and solar energy. In Jun-Aug, reduced wind and solar energy increases dependence on dispatchable generation.
- Dispatchable power flexibility, the gap between the minimum and maximum output of dispatchable plants, is larger in Dec–Feb than in Jun–Aug, reflecting the need to manage fluctuations due to abundant renewable energy.
- Collectively, these factors challenge grid reliability, necessitating sufficient dispatchable capacity for Jun-Aug demand while maintaining operational flexibility during Dec-Feb months. Effectively, there is a need to build flexible power plants that can meet demand and reduce generation as needed.

Cost

- The total cost in the power and hydrogen sectors from 2025 to 2060 is an estimated USD 903 billion and USD 1,027 billion in the REF and TGT scenarios, respectively. These costs include the total capital, fixed, and variable costs in the power sector, costs for green hydrogen production, transmission for variable renewable electricity, and electric vehicle chargers.
- In REF, 44% of the cost is attributed to additional gas-related expenditure. A significant portion of the additional cost for gas is due to the fuel needed to operate gas power plants. The Philippines will have minimal additional capacity for coal due to the coal moratorium, but operating costs for existing plants will remain high. In contrast, the cost attributed to solar power plants will mostly be capital costs for new capacity.
- In TGT, the savings are minimal and are mostly due to slightly lower coal usage. The additional cost is mainly due to the extra investment needed for the nuclear power plant, increased wind capacity, and additional fuel for gas power plants.

Figure 15-3. Peak load and maximum and minimum dependence on dispatched power (GW)

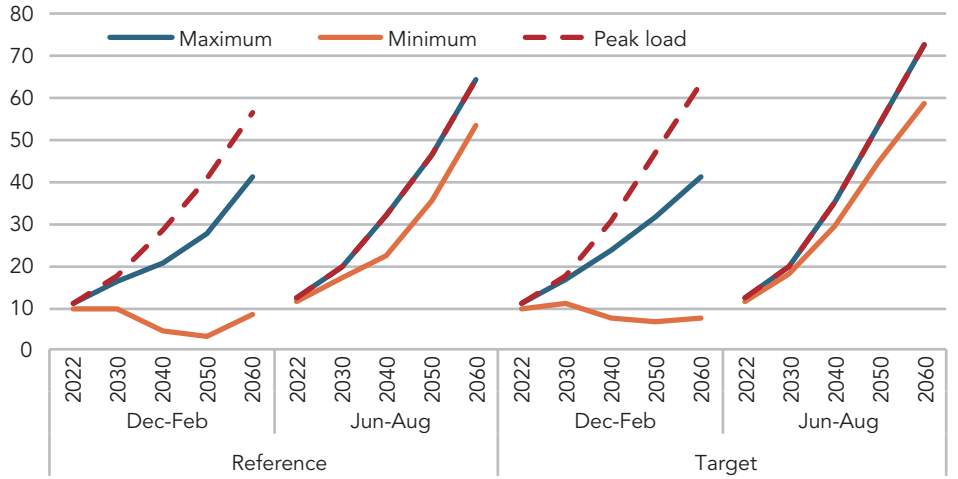
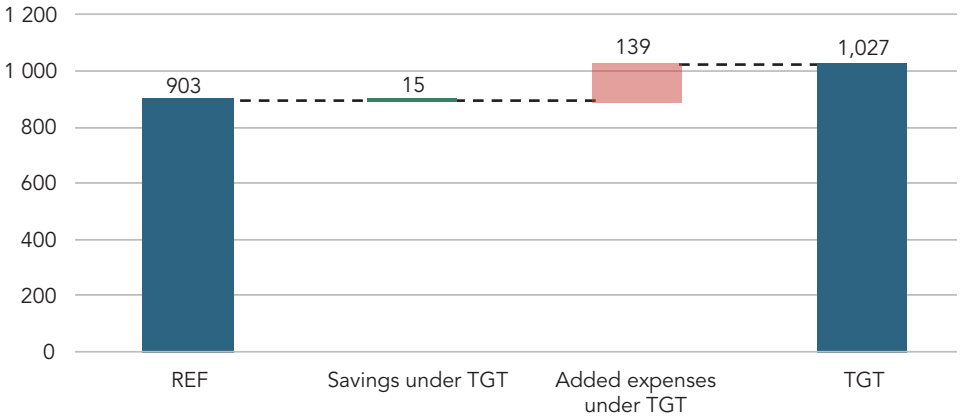


Figure 15-4. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



* Actual costs will differ from estimated costs in the *Outlook* for a variety of reasons including changing commodity prices, manufacturing costs and unforeseen technical advances. All costs are in 2023 real terms.

About The Philippines

Overview

Geographical and Economic Landscape

The Philippines, an archipelago of 7,641 islands, comprises of Luzon (home to the capital, Manila), Visayas, and Mindanao. A rapidly expanding service sector, including business process outsourcing, wholesale and retail trade, and tourism, has driven economic growth, elevating the gross domestic product to USD 1,078 billion (2021 USD PPP). The World Bank predicts the Philippines to move from lower-middle to upper-middle-income status by 2026 (World Bank, 2025).

Energy Supply and Consumption

Given its modest domestic resources, the Philippines is historically a predominant net importer, mainly of oil and coal. Total primary energy supply (TPES) reached a record-high volume of 2,618 PJ in 2022, showing a 4.6% growth from 2021 and exceeding pre-pandemic levels. Net imports rebounded significantly, posting about a 7.6% increase, driven primarily by a rise in overall imports in response to domestic energy demand (APEC Overview 2025, n.p.).

The total final consumption (TFC) rose by over 2.0% to 502 PJ in 2022 from 2021 levels, with transport consuming 34%, residential 29%, and industry 20%. Electricity generation reached 112 TWh, a 5.1% increase driven by coal (+7.1%) and renewables (+6.0%), particularly hydropower (+10%), and geothermal (+4.1%); however, gas output declined by over 6.0% due to depleted natural gas reserves (APEC Overview 2025, n.p.).

Energy Security Challenges and Strategies

The Philippines faces significant energy security challenges due to its high vulnerability to disasters, its predominant status as a net energy importer, and decreasing gas supply from the depletion of its sole natural gas source.

To address these issues, the Philippines' energy strategy, known as ARC, prioritises achieving access to affordable energy, enhancing reliability and resiliency, and promoting clean and sustainable energy. This strategy focuses on aggressive renewable energy deployment, heightened efficiency goals, and diverse technological solutions, all underpinned by the development of climate-resilient infrastructure.

Key Energy Initiatives

Paris Agreement Commitment

The Philippines' Nationally Determined Contribution (NDC) targets a 75% reduction in greenhouse gas emissions by 2030, comprising an unconditional 2.7% cut and a 72.3% reduction conditional on international support.

Carbon-free Energy Initiative

Various carbon-free energy technologies are being explored by the economy, including solar, wind (both onshore and offshore), nuclear power, and electric vehicles. The feasibility of low-carbon fuels and technologies such as hydrogen, ammonia, and energy storage systems are also being assessed.

Power Development Plan 2023-2050

The short-term power generation roadmap focuses on rapidly increasing the use of renewable energy sources, streamlining new technology integration, and enhancing grid flexibility and reliability. The long-term goals prioritise achieving a fully decarbonised power system by 2050, upgrading infrastructure, and ensuring the grid can handle the demands of high renewable energy use.

Comprehensive Roadmap for the Electric Vehicle Industry 2023-2040

The Philippines aims to accelerate EV adoption by providing tax breaks discounted fees, as well as expanding charging infrastructure. Under the Clean Energy Scenario, the Philippines aspires to achieve a 50% EV fleet share by 2040.

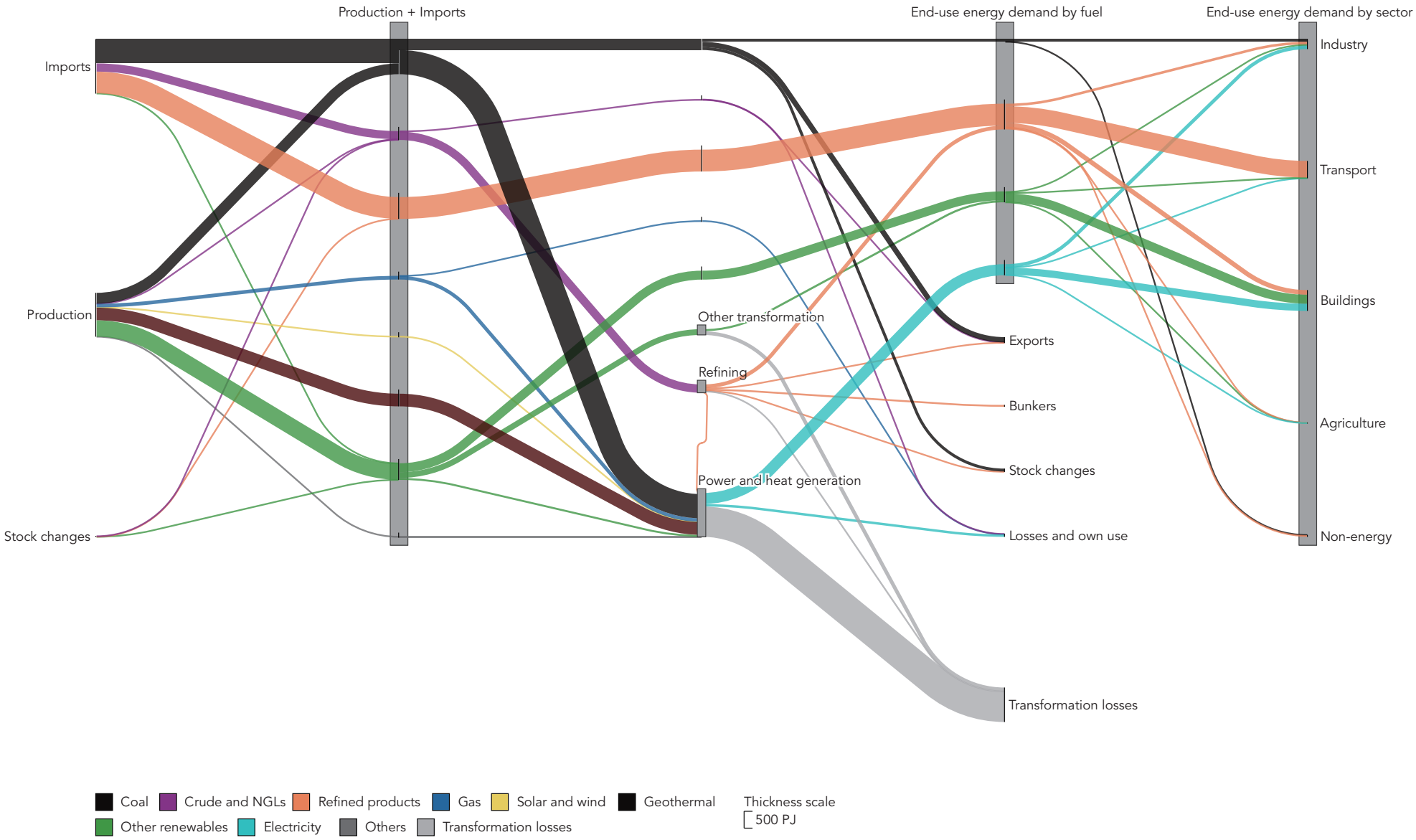
Energy Efficiency and Conservation Initiatives

The Energy Efficiency and Conservation Act of 2019 establishes frameworks for energy efficiency and conservation. This includes promoting the effective use of energy and providing incentives for energy efficiency and conservation projects.

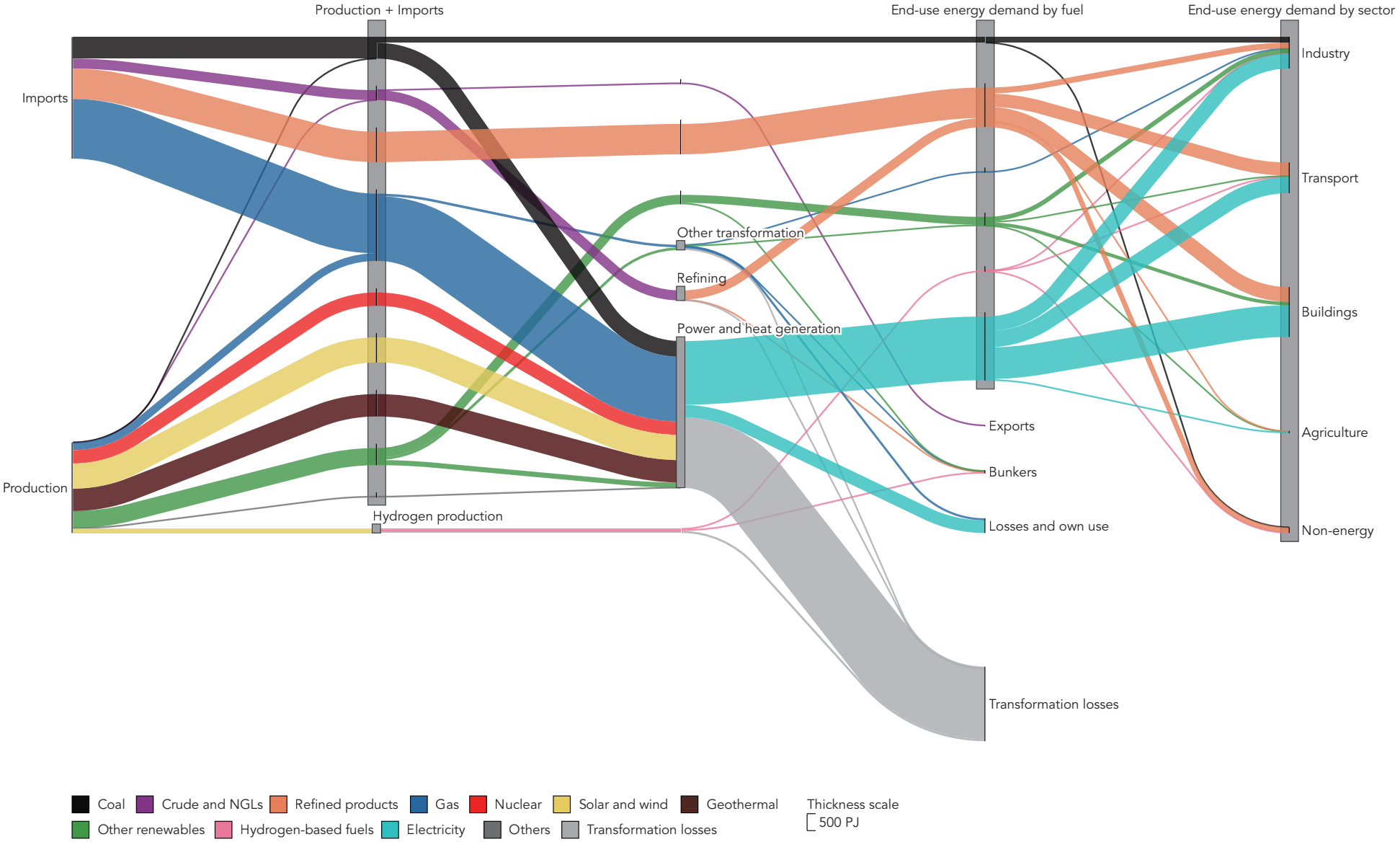
Implementation of Nuclear Energy for Power Generation

The Philippines established the Nuclear Energy Program Inter-Agency Committee (NEP-IAC) to conduct a comprehensive study on the adoption of Nuclear Power Plants in accordance with International Atomic Energy Agency (IAEA) guidelines and relevant regulations.

Energy Flow (2022)



Energy Flow (2060, Target Scenario)



Scenarios and Assumptions

In *The Outlook*, APERC analyses energy demand, transformation, and supply, as well as emissions. The **Reference Scenario (REF)** offers a projection based on historical trends, recent developments, and APERC's assumptions about the continuation of those trends in each APEC economy, while acknowledging technical restraints. The REF Scenario offers a baseline to compare with the **Target Scenario (TGT)** projections, which explores a hypothetical pathway where each economy achieves energy-related policy targets, assuming implementation regardless of cost-effectiveness. When implementation details are lacking, assumptions are inferred from the targets themselves or emissions-related goals.

	Reference	Target
General	• Population: UN medium; GDP: IMF (~2027) and APERC model (2028-2060)	
Buildings	• Energy demand grows significantly out to 2060 to a 450% increase in demand from the services subsector. • Energy demand is largely met by electricity. • Economic growth allows for the switch to low-carbon fuels, including LPG.	• Buildings energy demand is about 30% lower in TGT than in REF due to higher electrification rates and stringent efficiency measures for appliances. • Biomass use slowly phases down from the early 2020s out to 2060. • Oil use remains but consumption does not increase.
Industry	• Industrial energy consumption roughly triples out to 2060 to support economic growth. • Mining grows strongly which is associated with the increased global demand for minerals needed for increase in electrification of many applications. • Biogas begins to substitute for many other fossil fuels in certain applications in multiple subsectors. • Low emissions hydrogen as a feedstock for methanol and ammonia begins to scale in the 2040s in REF.	• Energy efficiency improvements are assumed to be greater for all sectors in TGT. These improvements are dependent on subsector and energy efficiency potential of industrial processes. • Material efficiency reduces demand by lowering end-use consumption of heavy industry goods and increasing recycling, resulting in lower steel, cement, and chemicals use. • Greater demand for end-use critical minerals leads to increasing activity in minerals mining, though the rate of activity growth is expected to slow from 2040 onwards. • Electrification makes greater inroads in more subsectors, including heavy industry, to supplant direct fuel combustion energy sources. • Biomass plays a role in decarbonising the cement and pulp and paper sectors. Biogas supplants some fossil fuel uses in many subsectors as well. • Hydrogen use in steelmaking begins in the mid-2030s and scales rapidly. It is also blended with natural gas for high-heat processes in the chemicals and cement subsectors. Low-emissions hydrogen for methanol and ammonia feedstock starts scaling in the 2030s.

Transport	• Vehicle ownership is projected to grow steadily, amplifying the effects of increasing population and income levels, leading to a steep increase in passenger energy use. • Battery EVs (BEVs) account for about 30% of light-vehicle sales by 2030, rising to around 70% by 2060, with their share of the vehicle stock reaching about 30% by 2060. • Engine type switching for heavy trucks is not considered but is expected to increase post-2060.	• BEVs make up about 50% of light-vehicle sales by 2035, increasing to roughly 80% by 2050, with their stock share reaching about 80% by 2060. • In heavy freight, adoption is slower, with BEV and FCEV trucks reaching around 30% of sales by 2060. • Electrification of ships and some ammonia use, leading to about one-third of boat activity using electricity and <5% using ammonia by 2060, resulting in approximately 4 PJ use for each new fuel type.
Power	• Gradual increase in the capacity of gas-fired units. • Capacity factors for renewables: Hydro (29.8%), Geothermal (65%), Solar (15.5%), On-shore wind (29%), Off-shore wind (44%). • No long-term storage or Carbon Capture Storage (CCS). • Coal-fired capacity grows over the projected period, following the committed capacity; no new coal-fired units are added after 2050. • No deployment of nuclear reactors. • Moderate batteries installation.	• No new coal-fired power plants are added during the projected period. • Commissioning of new nuclear reactors begins after 2030, with no distinction made between conventional and small modular technologies. • Battery capacity rises above REF levels, consistent with the expansion of solar capacity.
Supply	• Reflects current trends and the gradual decline in hydrocarbon imports.	• Fossil fuel use follows domestic demand trends, but import dependency remains high.
Emissions	• CO_2 emissions are calculated at post consumption based on IPCC emission factors. CO_2 emissions are specific to the energy sector.	

Note: The base year is 2022. Macro-economic assumptions are constant across scenarios. Historical energy balances are from EGEDA submissions for 2022.

Demographic and Macroeconomic Assumptions

Figure 15-5. Population (thousands)

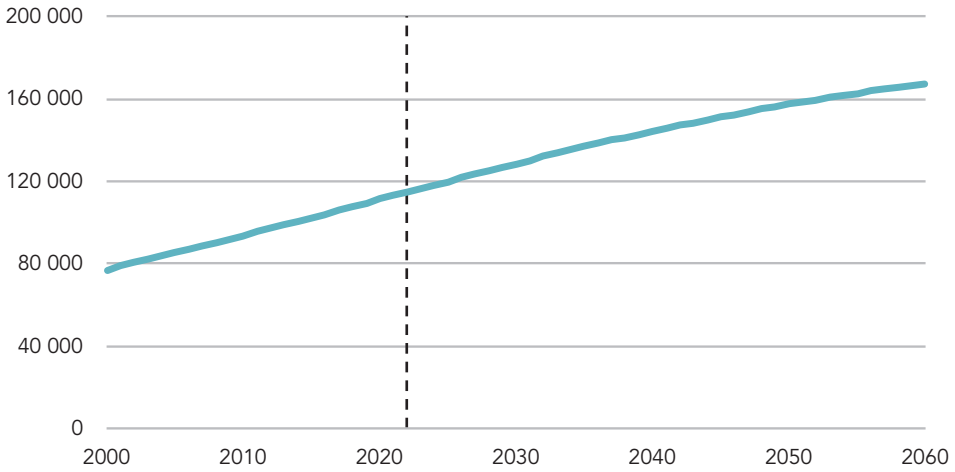
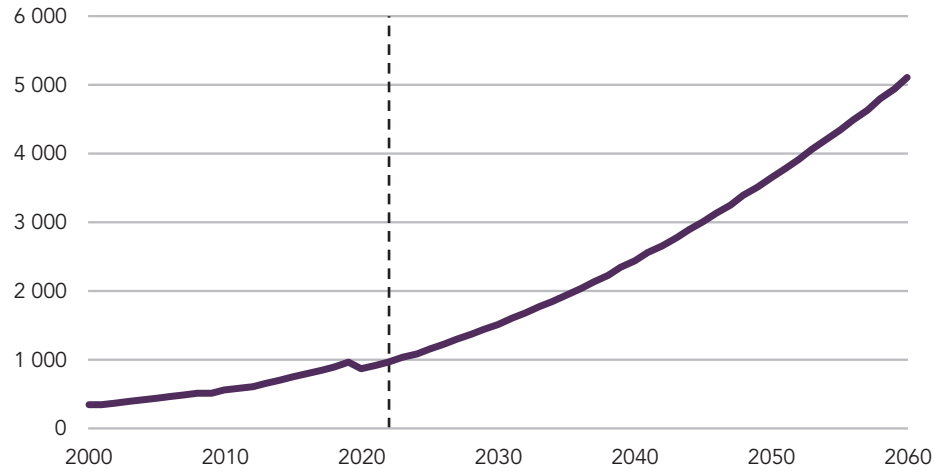


Figure 15-6. Real GDP (billion 2017 USD, PPP)



- The population of the Philippines is expected to reach around 168 million people by 2060, up from roughly 115 million in 2022, with a Compound Annual Growth Rate (CAGR) of approximately 1.0024%. Although the population is still expected to grow, the growth rate has been decreasing recently. According to past censuses, the Philippines had an average five-year growth rate of 2.7% in 1980, 2.3% in 2000, and only 1.6% in 2020.
- The Philippines has experienced consistent economic growth, posting an average annual GDP growth of 6.6% from 2015 to 2019. COVID caused a 9.5% reduction in 2020, but the economy has since recovered, posting annual growth rates of 5.7% and 6.4% in 2021 and 2022, respectively. The IMF, in their WEO 2022, projects around 6% annual growth from 2025 to 2027.
- According to the IMF (IMF 2024), despite a strong post-pandemic recovery, the Philippines' GDP growth is limited by low labour productivity and structural gaps. The Philippines can boost growth by leveraging its large, young workforce through targeted reforms in governance, human capital (especially education and female labour participation), trade openness, and infrastructure. These changes could attract more private and foreign investment and improve productivity for a better economic future.
- Beyond 2027, the APERC macro model projects GDP using a Solow-Swan framework, incorporating UN population data, estimated capital stock dynamics (depreciation and investment), and productivity growth assumptions based on historical trends. APERC's projection anticipates that growth will slow down a bit to 5% annually until 2035, and it will drop below 4% in the late 2040s.
- As these two major macroeconomic indicators continue to increase, the demand for energy in the buildings, industry, and transport sectors is anticipated to grow. In the buildings sector, population growth and higher household income will increase the demand for electricity and modern energy sources. In the industry sector, higher productivity will drive the need for more energy. In the transport sector, higher population and improved purchasing power will lead to greater passenger activity for mobility and freight activity for the movement of goods. Thus, throughout the projection period, the overall demand for electricity is projected to increase.

End-use Energy Demand

Figure 15-7. Energy demand by sector in REF & TGT (PJ)

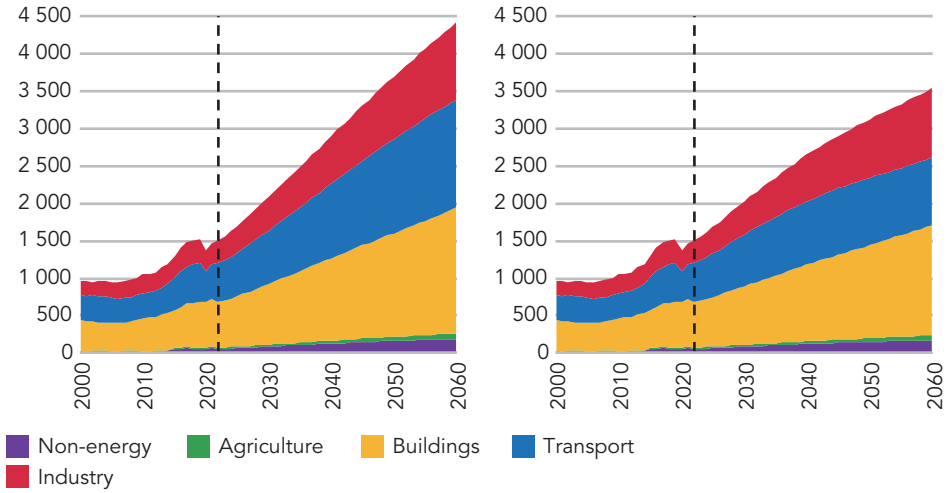
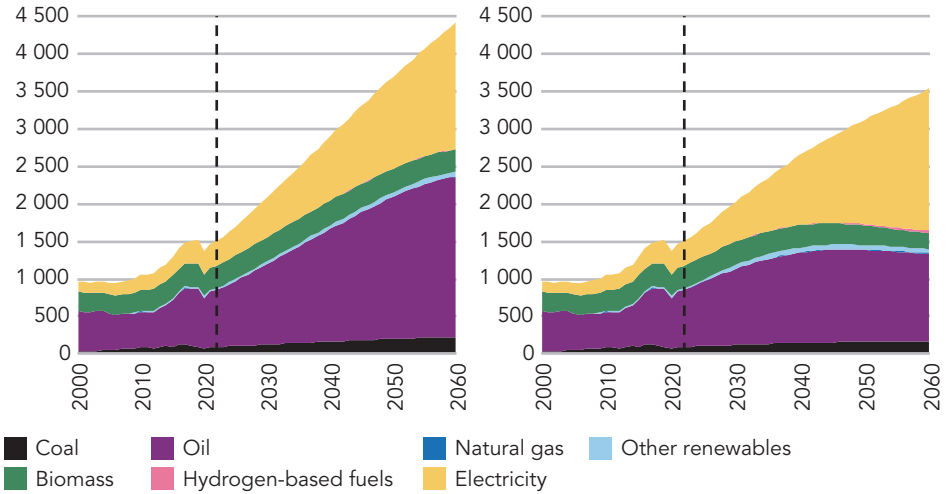


Figure 15-8. Energy demand by fuel in REF & TGT (PJ)



- The Philippines' total energy demand is expected to grow steadily driven by ongoing economic expansion. This growth increases energy needs across buildings, services, industrial, and transport sectors, fuelled by population growth, expansion in the services sector, sustained downstream manufacturing, and a rise in passenger and freight transport activity.
- Energy demand increases by almost three times in REF (2022-2060). In terms of per-unit energy increase, the buildings sector grew the most, while in terms of overall growth rate, the industrial sector saw the highest increase. In TGT (2022-2060), the growth is more modest at around 2.6 times. The buildings and industry subsector growth is nearly identical, but the transport sector's growth fell from 2.8 times in REF to 1.8 in TGT.
- Similar to 2022, by 2060, agriculture and non-energy sectors still account for a minor share of energy demand, but their growth rates are much higher, with agriculture rising about four times and non-energy demand about three times in both the REF and TGT scenarios.
- Historically, diesel was the primary fuel in agriculture, reaching parity with electricity around 2015. By 2022, electricity met around 60% of agriculture's energy needs, rising slightly to 65% during the projection period.
- On the other hand, growth in non-energy use is tied to the chemicals subsector, where oil and coal serve as raw materials in various production processes. Low-emission hydrogen starts to be utilised as feedstock in REF by 2040 and in TGT by 2030 to produce methanol and ammonia.
- Oil and electricity account for 51% and 22%, respectively, of the end-use energy demand in 2022. In REF, by 2060, these energy carriers remain the primary sources of energy needs, accounting for 48% and 38%, respectively. There is a noticeable increase in the share of electricity, while biomass utilisation significantly decreased from 20% in 2022 to only 6.7% in 2060.
- In TGT, electricity becomes the most dominant end-use energy source, with a share of 54%, while oil drops to 33% and biomass to 6%. Oil reduction is most evident in the transport sector due to electrification. The industrial sector also cuts coal, oil, and biomass use, while increasing biodiesel use.

Buildings Energy Demand

Figure 15-9. Buildings energy demand by fuel in REF & TGT (PJ)

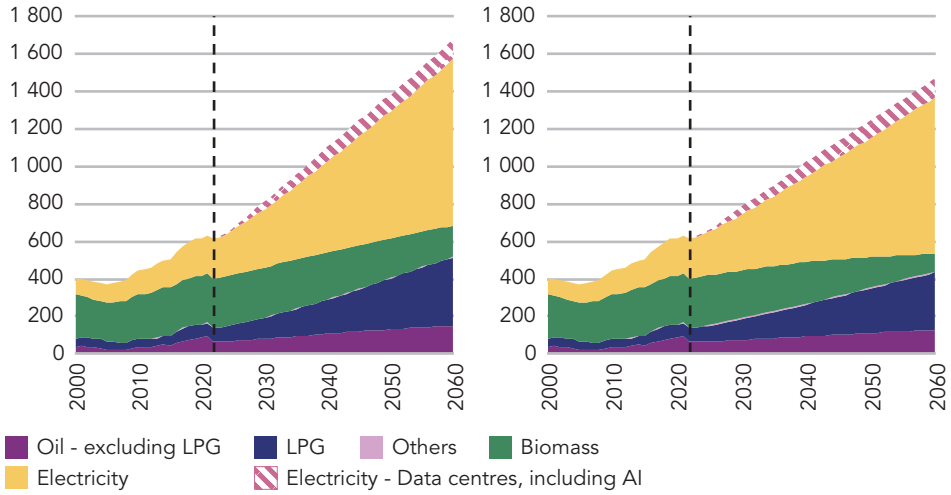
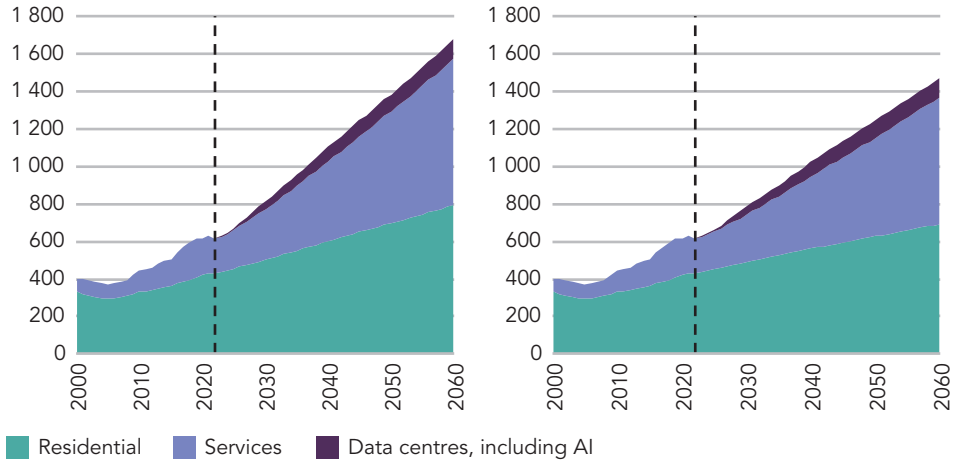


Figure 15-10. Buildings energy demand by sector in REF & TGT (PJ)



- The Philippines' services sector has been known for its growth potential, as well as a major driver of economic growth. Excluding the additional demand from data centres, energy demand in the services subsector eventually reaches parity with demand in the residential sector in both scenarios.
- Data centres demand grows alongside the service sector, and its value hovers around 15% of the service sector demand. The combined energy demand of the services sector and data centres rises by 4.7 times in REF and 4.2 times in TGT from 2022 to 2060. During the same period, the residential sector only roughly doubles its demand in both scenarios.
- Relative to REF, there is around a 10% demand reduction in TGT in the services sector starting in 2040. This level of energy reduction is also seen in the residential sector by 2050, decreasing further to 13% by 2060.
- Most of the anticipated demand growth will be supplied by electricity, followed by LPG and diesel. The buildings sector's electrification increased from 35% in 2022 to 59% in REF and 64% in TGT by 2060. The share of LPG roughly doubles from 12% in 2022 to 22% in REF and 21% in TGT by 2060.
- In REF, current efforts for energy efficiency and conservation are sustained. Oil (kerosene, diesel, and fuel oil) use increases mildly throughout the projection period, as some fuel switching from biomass to oil or oil products is assumed.
- In TGT, heightened energy efficiency gains are assumed, thereby decreasing total energy demand. Oil use remains relatively steady throughout the projection period. Under the assumption of fuel switching, the share of biomass in TGT declines relative to REF, reflecting a transition toward other energy sources such as LPG and electricity.
- In the residential sector, the use of biomass decreased in both REF and TGT, with a larger reduction in TGT. This change reflects an assumed shift to cleaner cooking fuels as incomes rise.

Industry Energy Demand

Figure 15-11. Industry energy demand by fuel in REF & TGT (PJ)

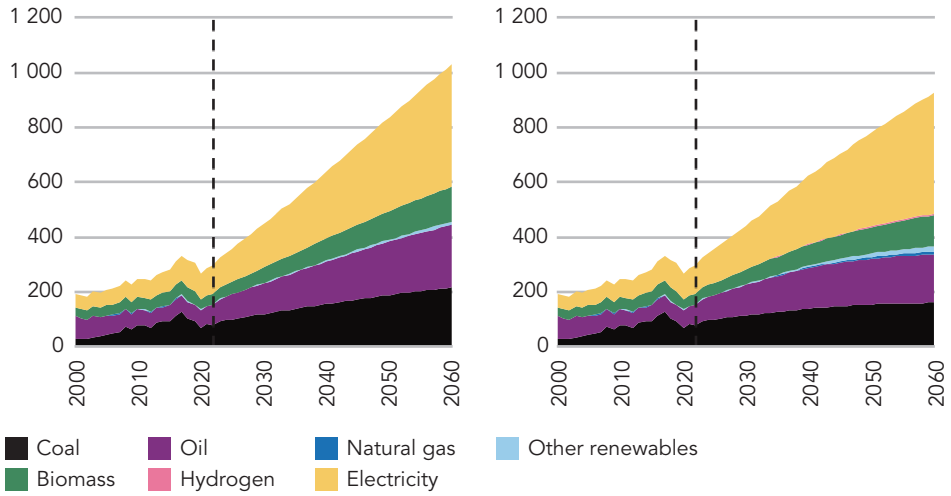
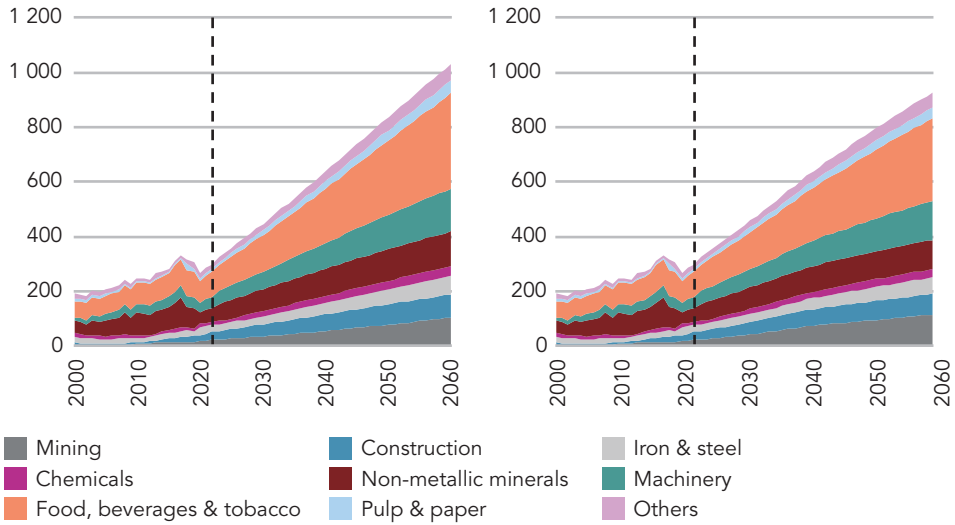


Figure 15-12. Industry energy demand by sector in REF & TGT (PJ)



- Industrial growth is essential for the sustained economic development of the Philippines. The total demand of the industry sector increases by 3.5 times in REF and 3.1 times in TGT by 2060 relative to 2022.
- Downstream manufacturing is already prominent in the Philippines and is expected to grow at rates comparable to the overall GDP. The food and beverages subsector retains about 30% of energy consumption throughout the projection period, while machinery and non-metallic mineral products hold around 10%. The share of energy use in mining and quarrying is anticipated to increase in both the REF and TGT scenarios.
- When comparing the REF and TGT scenarios by 2060, total energy consumption tends to decrease by 10% in almost all subsectors. The use of coal and oil products drops by 20-25%, while biodiesel demand rises by 60%, mainly driven by the food and beverages and mining and quarrying subsectors. In TGT, an optimistic pathway is assumed, with fuel switching from fossil-based to bio-based fuels as a form of decarbonisation.
- Electrification increases in REF and TGT, rising from a 34.9% electrification rate in 2022 to comprise 43.46% of the industry energy mix in REF and 47.66% in TGT by 2060. Electrification rate in mining and quarrying, construction, food and beverages, and pulp and paper experience larger increases.
- In TGT, greater recycling and reduced end-use demand for materials due to innovation in end-use products mean that there is less production/activity in steel, cement, and chemicals (heavy industry). This material efficiency means that heavy industry production is roughly 10% lower in TGT than REF by 2060.
- In contrast to this lower activity in heavy industry, the Philippines is assumed to have increased minerals mining activity in TGT from now until 2040 to support much higher global demand for critical minerals.
- Cement production grows but stays below the historical energy consumption peak in 2016. The chemicals and steel sectors also grow strongly, but these heavy industries tend to have a lower share of energy consumption.

Transport Energy Demand

Figure 15-13. Domestic transport energy demand by fuel in REF & TGT (PJ)

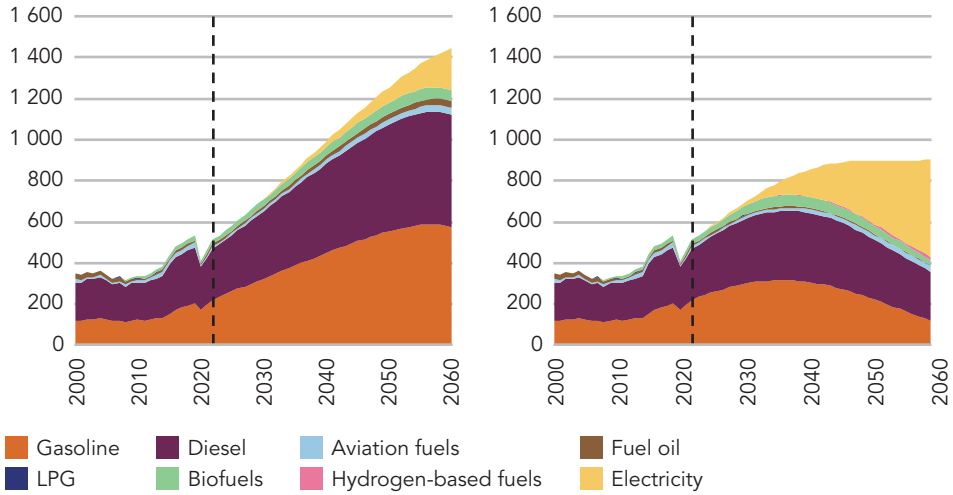
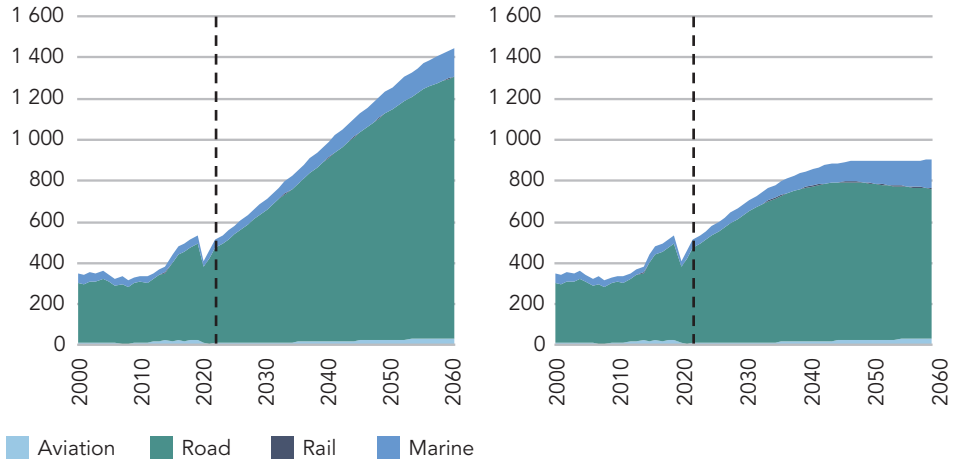


Figure 15-14. Domestic transport energy demand by sector in REF & TGT (PJ)



- Vehicle ownership in the Philippines is projected to grow steadily leading to a steep increase in passenger activity and energy use. Freight activity is expected to grow but at a slower rate than passenger activity.
- The Philippines' reliance on motorcycles over cars makes its passenger road sector nearly 15% more efficient than a car-based system. It is assumed that the proportion of 2Ws will remain constant (at around 50% of passenger activity), retaining these efficiency advantages. The battery electric vehicle (BEV) and plug-in hybrid electric vehicle (PHEV) sales share targets are based on data from the Philippine Energy Plan 2023-2050, excluding hybrid electric vehicles (HEVs) from the forecasts as they are too similar to internal combustion engine (ICE) vehicles.
- Majority of the demand in 2022 was mostly due to motor gasoline and diesel. In REF, the demand for gasoline and diesel increases until 2060, but electricity demand also increases. In TGT, the increase in demand for gasoline and diesel peaks around 2035 and decreases below the 2022 level by 2060, accompanied by a significant increase in electricity demand.
- In 2060, gasoline and diesel consumption in TGT is around 80% and 60% lower, respectively, than in REF, mainly due to the reduced use of these fuels in the road sector, especially in the bus, car, and motorcycles subsectors.
- Along with the reduction in total energy demand, changes in fuel use resulted in electricity covering around 50% of the energy demand in the transport sector in TGT by 2060. This significant increase in the share of electricity can be attributed to the higher growth rate of buses in TGT, which are more likely to be electrified. This results in the bus subsector using seven times more electricity in TGT than in REF. Electricity use by other road vehicles in TGT is projected to be roughly double that in REF.
- Most of the energy demand reduction in the transport sector is attributed to the reduction in energy demand in the road subsector. Relative to 2022, the road subsector will increase energy demand by 2.6 times in REF but only by 1.5 times in TGT.

Other Transport Data

Figure 15-15. Transport vehicle stocks in REF & TGT (million vehicles)

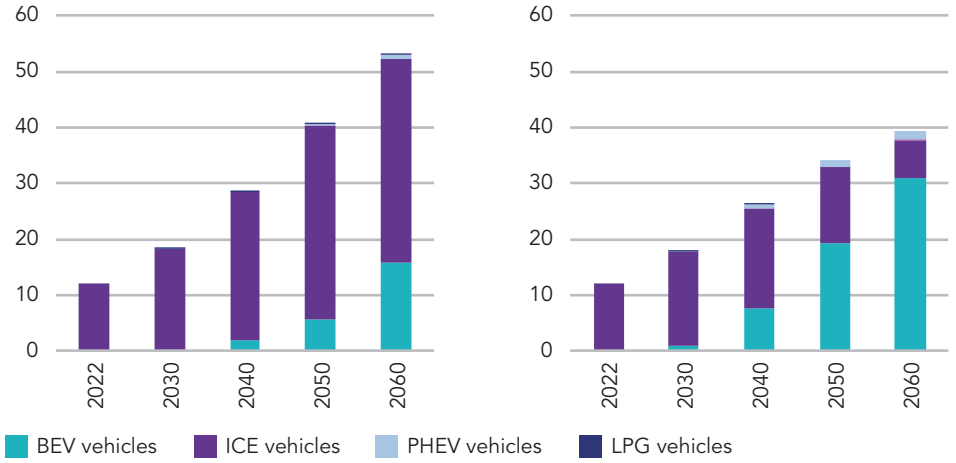
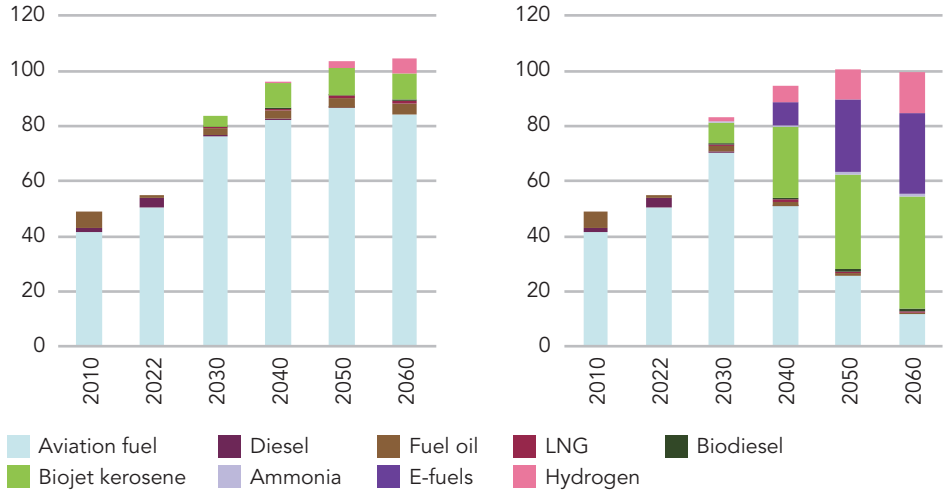
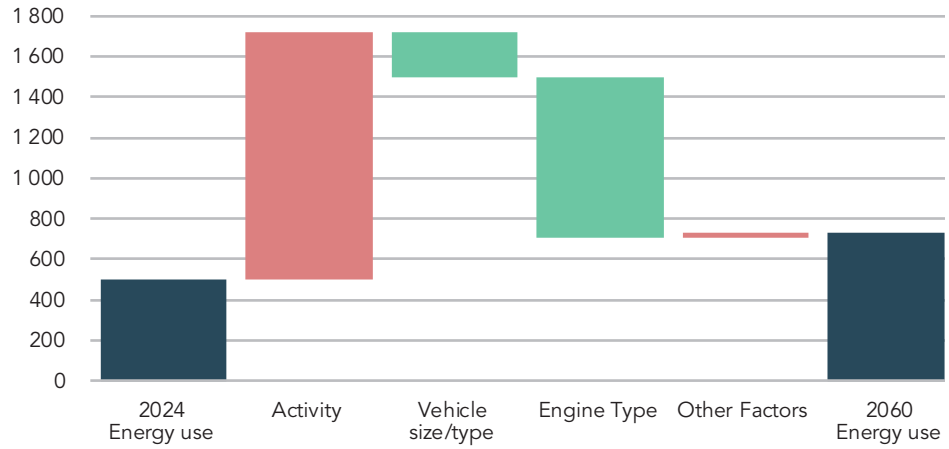


Figure 15-16. International bunker energy demand for shipping and aviation in REF & TGT (PJ)



- The transport stocks in both REF and TGT will continue to grow, but more slowly in TGT, with most of the growth being in BEVs compared to the additional ICE vehicles in REF. By 2060, there are roughly twice as many BEVs in TGT as in REF, which explains the increase in electricity demand. The number of ICE vehicles in TGT is only 20% that of those in REF.
- In REF, the growth in aviation fuel demand is barely met by lower-emission alternative fuels. In contrast, biojet kerosene, e-fuels, and hydrogen could exceed 40% of the total share by 2040 and nearly 85% of the total share by 2060 in TGT. Due to infrastructure compatibility, biojet leads, followed by e-fuels, limited by high costs. Hydrogen has the smallest share due to infrastructure and technology challenges.
- Increasing population and income levels are expected to significantly increase transport activity in the Philippines, particularly in the passenger and freight sectors. However, the shift from ICE vehicles to BEVs contributes to the significant reduction in final energy consumption in TGT by 2060.

Figure 15-17. Components of the change in road energy use in TGT (PJ)



Note: Information on the different drivers in the transport energy decomposition can be found in the *Outlook*'s annex.

Electricity Generation

Figure 15-18. Electricity generation by fuel in REF (TWh)

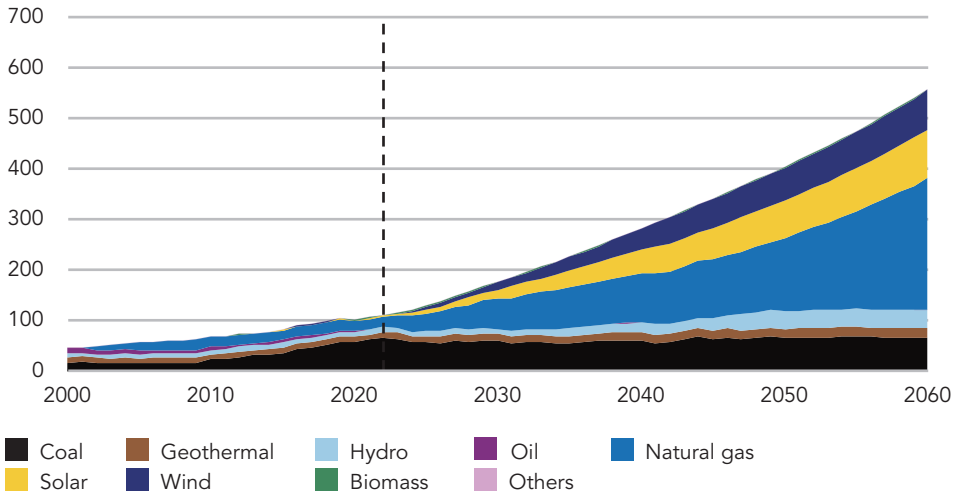
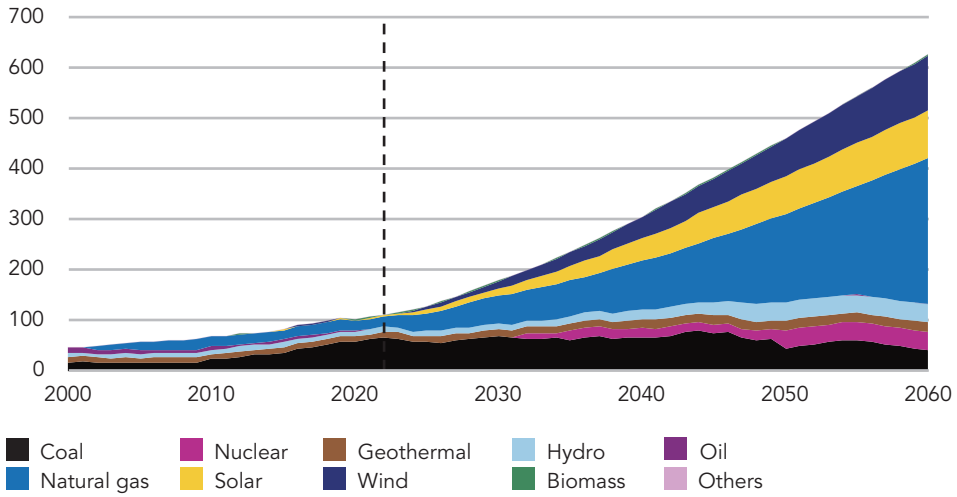


Figure 15-19. Electricity generation by fuel in TGT (TWh)



- Electricity demand is projected to increase by approximately five times from 2022 to 2060 in both scenarios. By 2060, electricity demand is expected to be approximately 12% higher in TGT compared to REF, mainly due to faster EV adoption in TGT, which results in more than double the demand in this area relative to REF. In contrast, electricity demand from industry and buildings remains roughly the same for both scenarios in 2060.
- In both scenarios, most of the increased demand is supplied by solar, wind, and natural gas. Gas is expected to increase as it provides flexible and reliable power to complement solar and wind.
- In 2022, coal remains to be the main fuel source for electricity production in the Philippines. In REF, by 2030, coal and gas each produce one-third of the electricity. By 2060, almost half of the electricity is generated using gas, while coal's share is reduced to 12%.
- In TGT, the same trend occurs for gas, but coal's share is reduced further post-2030 due to the introduction of nuclear energy. Starting around 2050, coal's share drops below 10%, while nuclear supplies roughly the same amount of electricity.
- In REF, solar and wind are expected to reach around a 20% share by 2030, and will reach around 30% by 2040, remaining at this level throughout the projection period. In contrast, in TGT, the share of solar and wind by 2030 is only around 15%, but could also reach around 30% by 2060. This discrepancy could be attributed to the higher demand in TGT but is counterbalanced by the higher electricity generation from wind.
- Hydropower's share hovers around 6-8% throughout the projection period. Since geothermal energy capacity increases only marginally, its share decreases to below 5% by 2050, despite actual amounts increasing.
- In both scenarios, coal use for electricity production is minimised, but this remains as the primary producer when other technologies cannot meet demand growth. Oil-based electricity generation is expected to be minimal post-2030. Hydropower and geothermal show small marginal growth.

Note: Figures 15-18 and 15-19 do not include electricity generation for hydrogen production.

Generation Capacity

Figure 15-20. Generation capacity by fuel in REF (GW)

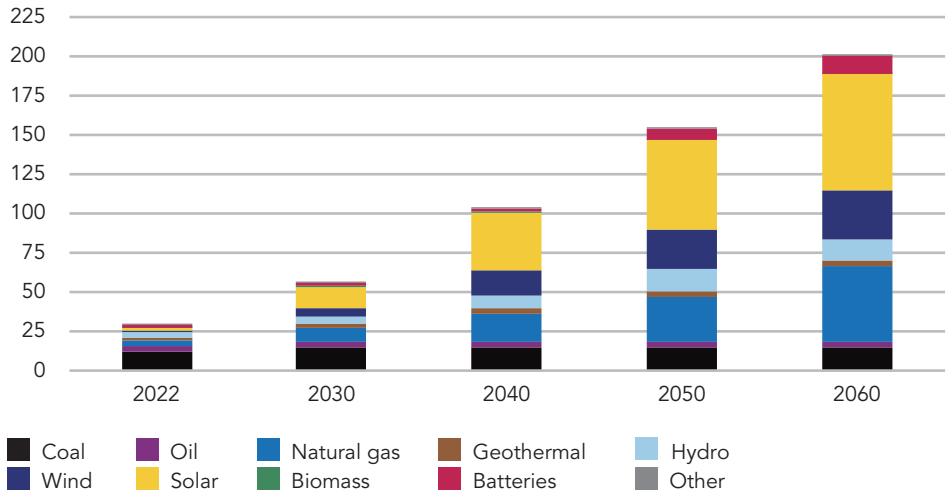
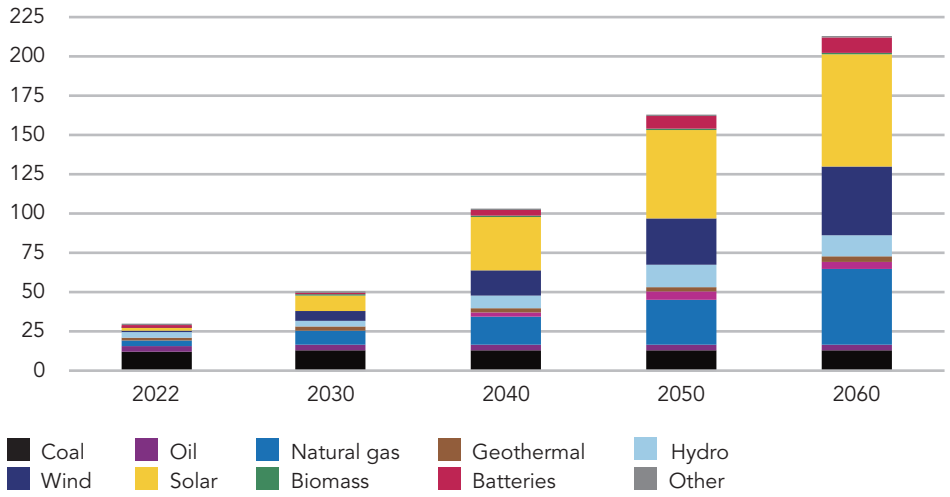


Figure 15-21. Generation capacity by fuel in TGT (GW)

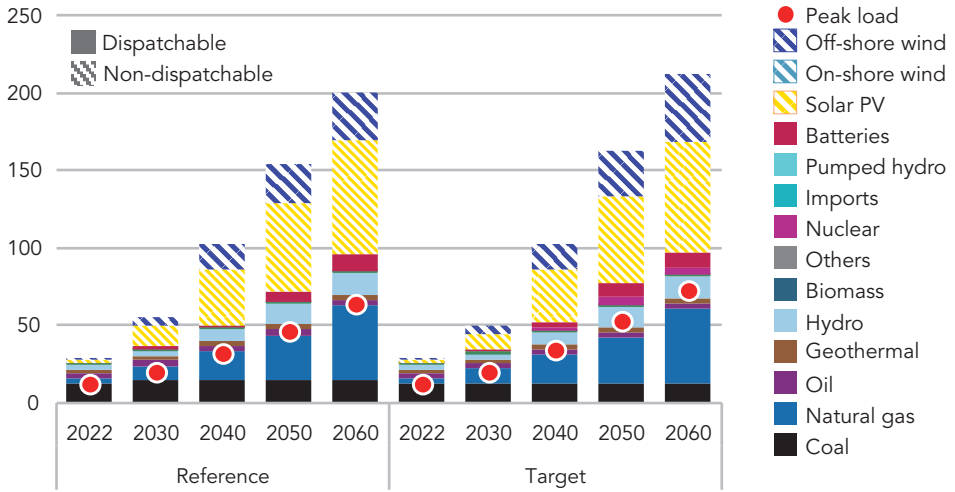


- The capacity of dispatchable generators is anticipated to increase to 85 GW and 87 GW in REF and TGT, respectively, by 2060. Gas capacity is expected to gain the most as it provides the flexible generation necessary to complement the electricity produced from renewable sources.
- Coal capacity will increase slightly in REF by 2030, but not in TGT due to the introduction of nuclear energy. Following the Philippine Energy Plan 2023-2050, in TGT, 1.2 GW of nuclear capacity is introduced in 2032, which doubles in 2035 and reaches 4.8 GW by 2050. Despite the introduction of nuclear, the coal power plants are expected to continue operating throughout the projected period as coal remains a reliable source of baseload electricity and fits into the Philippines' fuel diversification goals.
- Solar capacity in both scenarios is anticipated to increase rapidly between 2030 and 2045 by around 2.3 GW annually in each scenario. This slows down to 1.7 GW per annum after 2045 until 2060. Solar capacity is projected to reach 73 GW and 71 GW in REF and TGT, respectively, by 2060.
- Wind capacity increases more slowly at a rate of around 1.13 GW per annum from 2030 to 2045 in both scenarios. From 2045 until 2060, this slows down to 0.6 GW per annum in REF but increases to 1.4 GW per annum in TGT. By 2060, wind capacity is projected to reach 31 GW and 43 GW in REF and TGT.
- In both scenarios, hydropower capacity is anticipated to increase from 3.8 GW in 2022 to 14 GW by 2050. Geothermal capacity is anticipated to increase from 1.9 GW in 2022 to 3.3 GW by 2050. The capacity of these two technologies will remain at this level throughout the projection period.
- Battery capacity is essential to support the intermittency of solar and wind, and its capacity is anticipated to reach 10 GW by 2060. Growth is slower in REF, where it will only reach 2 GW and 6.7 GW by 2040 and 2050, respectively. In TGT, it will reach 3.7 GW and 8.8 GW by 2040 and 2050, respectively.
- Although alternative and emerging technologies could improve the electricity mix of the Philippines, given the experimental state of these technologies, they are not expected to have a significant impact.

Note: Figures 15-20 and 15-21 do not include generation capacity for hydrogen production.

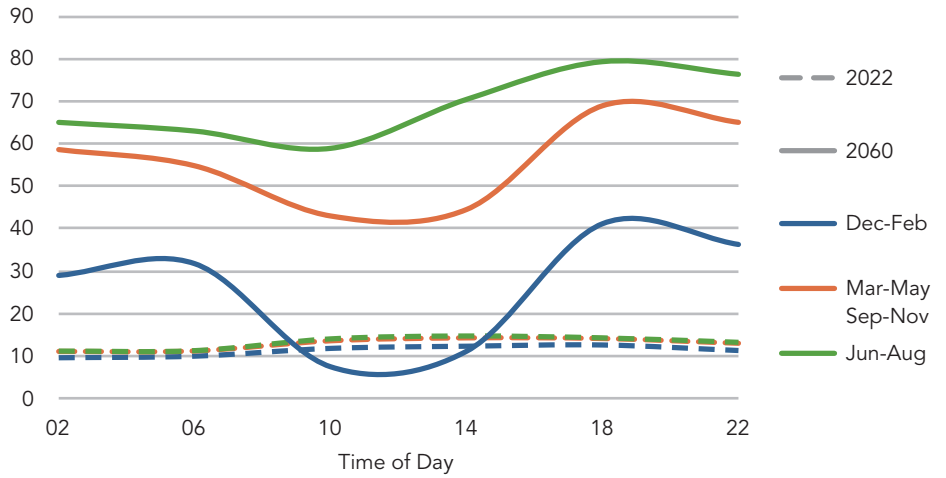
Grid Reliability

Figure 15-22. Total generation capacity and peak load (GW)



- Peak electricity demand in the Philippines is expected to grow to 64 GW and 73 GW by 2060 in REF and TGT respectively from 11.5 GW in 2022. Despite this, the peak demand is still lower than the capacity of the dispatchable generators. This could be attributed to the continued operation of the coal power plants, albeit at a lower capacity factor post-2040, especially in TGT. This may make it financially challenging for coal power plant operators to remain profitable, but continued operation is necessary for grid reliability.
- Gas capacity increases greatly throughout the projection period, which is a necessity due to the increase in solar and wind capacity. The capacity of these variable renewable energy sources will reach parity with the peak load by 2030 in REF and 2040 in TGT. This will greatly challenge grid operators in balancing the dispatchable generators and managing the grid.
- The introduction of batteries will greatly support the use of excess renewable energy, but this will also cut into the operation time of other dispatchable generators. In the long run, it may be necessary for the Philippines to start considering decommissioning some of its older dispatchable generation, but careful consideration is necessary to ensure the fuel diversification goal.

Figure 15-23. Power from dispatchable sources in TGT (GW)



- APERC's Power Model uses 36 time slices calculated as 3 seasons × 2 day types × 6 four-hour daily segments to represent temporal variations throughout the year. The three seasons are Winter (Dec–Feb), Summer (Jun–Aug), and Intermediate (other months), with two-day types: weekdays and holidays.
- Peak electricity demand occurs in April or May, which is more closely represented by the Jun-Aug curve in Figure 15-23. There are minimal variations in dispatched power since increased demand aligns with solar production. However, solar efficiency is reduced due to higher temperatures, and wind generation is minimal during these periods.
- The lowest demand occurs during cold months, represented by the Dec-Jan curve. Two factors contribute to this: lower demand and higher wind power generation. This period requires greater flexibility from dispatchable power generation throughout the day.
- These extremes represent two operational modes of the electricity system. Investment in dispatchable generation is necessary to meet peak demand while satisfying flexibility requirements. Dec-Jan presents two flexibility challenges: seasonal and daily flexibility.

Coal

Figure 15-24. Coal consumption by sector in REF & TGT (PJ)

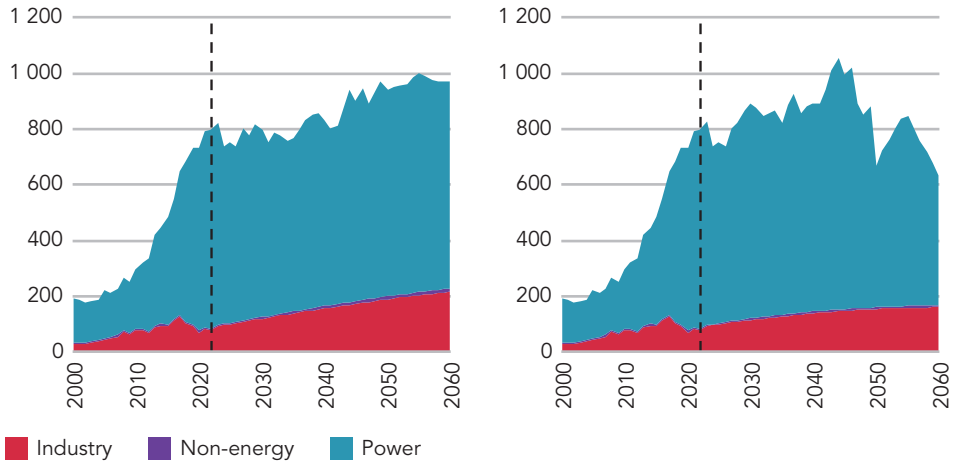
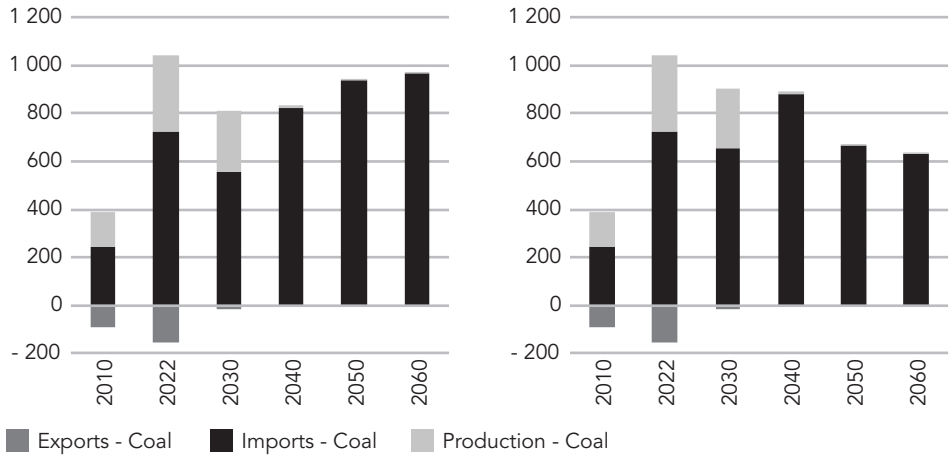


Figure 15-25. Coal production, imports, and exports in REF & TGT (PJ)



- Coal consumption is anticipated to grow in both scenarios until the 2040s. In REF, demand will gradually increase by 10% by the mid-2040s, then increase by another 10% in the late 2040s, and remain at that level until 2060. In contrast, in TGT, coal demand will peak in the mid-2040s with a 30% increase but will return to 2022 levels around 2050 and begin decreasing.
- The rise in coal demand is driven by increased electricity requirements, as coal continues to supply unmet demand due to its affordability and ability to provide baseload generation. In 2022, approximately 90% of coal demand was consumed by the power sector, declining gradually to around 75% by 2060 in both scenarios. In TGT, coal demand is higher overall due to greater electricity demand, while the decline around 2050 reflects the integration of additional nuclear capacity into the grid.
- Industrial coal demand is also anticipated to grow, but the distribution within the sector remains mostly the same in REF and TGT. More than 40% of industrial consumption comes from non-metallic mineral products, which is mostly cement production. Pulp, paper, and printing; iron and steel; and food, beverages, and tobacco individually consume around 10-15% each.
- Reductions in industrial coal demand in TGT relative to REF are driven primarily by declines of about 40% in the iron and steel subsector; 30% in pulp, paper, and printing; and 20% in non-metallic mineral products. These reductions could be attributed to lower activity in energy-intensive production, higher electrification across processes, and a shift from coal to lower-carbon energy sources.
- In both scenarios, coal production is projected to reach 20 million tonnes per year (400 PJ) by 2025 until 2028. The estimated total production from 2029 to 2050 is around 65 million tonnes (1,300 PJ). Coal exports decrease sharply by 2030 and become almost non-existent by 2040. Domestic coal production diminishes by mid-2035 and becomes negligible by 2040.
- The Philippines will continue to rely on coal imports throughout the projection period, specially beyond 2040. In REF, imports rise in line with continued demand growth to meet overall supply requirements. However, in TGT, imports peak in 2044 and decline thereafter. Between 2050 and 2060, there is a noticeable increase in coal imports, but the general decreasing trend will continue as the demand for coal decreases.

Natural Gas

Figure 15-26. Natural gas by sector in REF & TGT (PJ)

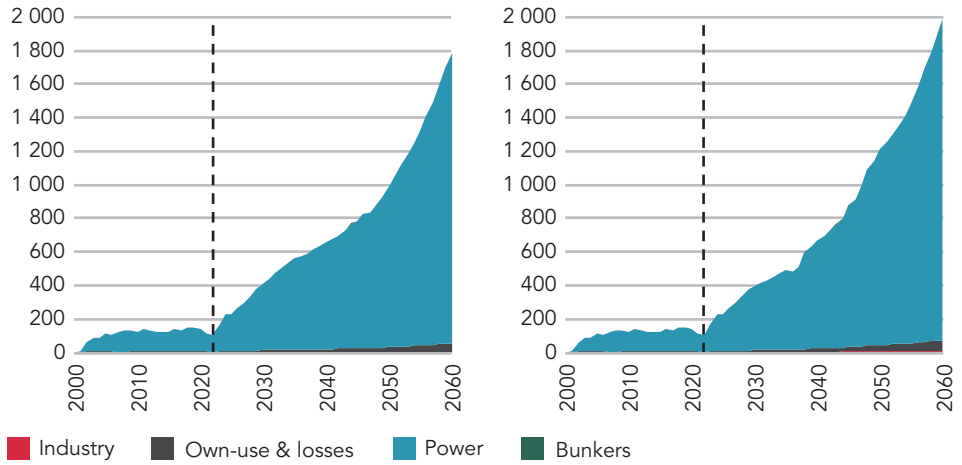
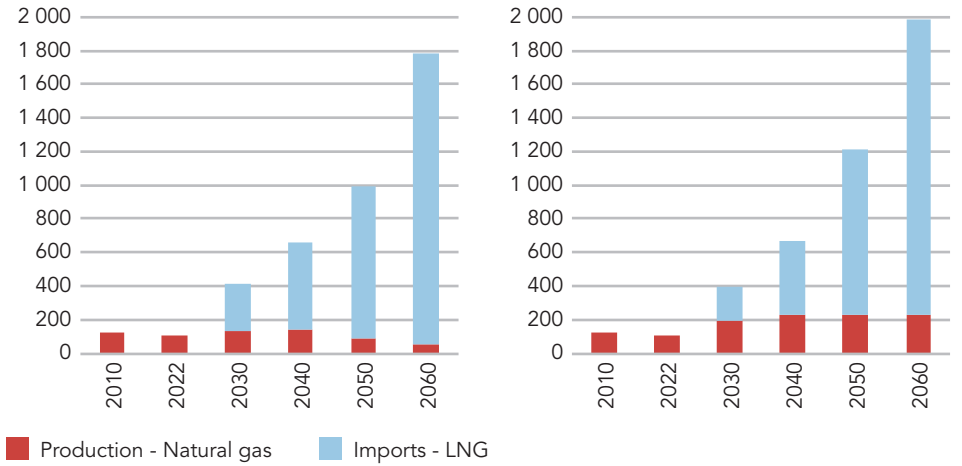


Figure 15-27. Natural gas production, imports, and exports in REF & TGT (PJ)



- Natural gas consumption is anticipated to grow due to the need for flexible power generation. Relative to 2022, demand will increase six times in both scenarios by 2040. Although both scenarios reach the same demand by 2040, the trajectory differs due to nuclear energy's introduction in the mid-2030s.
- Beyond 2040, in REF, gas demand will be nine times higher by 2050 and 16 times higher by 2060 compared to 2022 levels. In TGT, increases are even steeper: 11 times higher by 2050 and 18 times higher by 2060. In contrast to the pre-2040 period, nuclear energy is unable to mitigate further increases in gas demand because electricity demand in TGT is substantially higher.
- In REF, gas production follows the medium-term goals for 2025-2028 included in the Philippine Energy Plan 2023-2050. Production is anticipated to gradually increase until production peaks in 2034, remains there until 2039, and declines by 5% per annum due to lack of investment in new fields.
- In contrast, in TGT, gas production peaks in 2038 and remains there throughout the remainder of the projection period. This aligns with the long-term goals stated in the Philippine Energy Plan 2023-2050.
- In both scenarios, gas demand forecasts are much larger than production forecasts, thus necessitating LNG imports. The Philippines started importing LNG in 2023, and import volumes are expected to rise further to meet growing demand.
- In REF, approximately 274 PJ of natural gas imports are required by 2030, with imports nearly doubling each decade to reach 1,730 PJ by 2060. In TGT, although gas demand is higher, increased domestic production keeps import requirements at a similar level to REF.
- With increasing LNG imports, maintaining a secure supply, sufficient regasification capacity, and adequate storage facilities depends on ongoing investment in these sectors.

Petroleum Products

Figure 15-28. Refined products and low carbon fuels demand in REF & TGT (PJ)

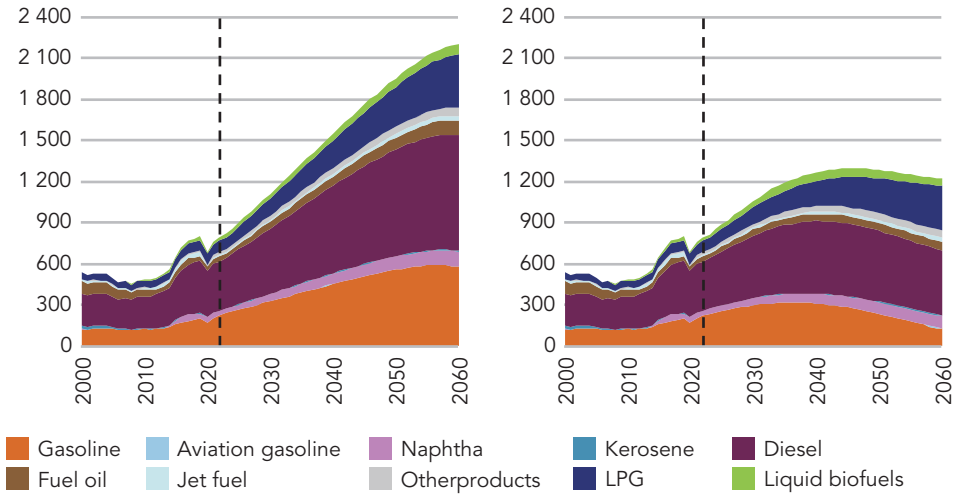
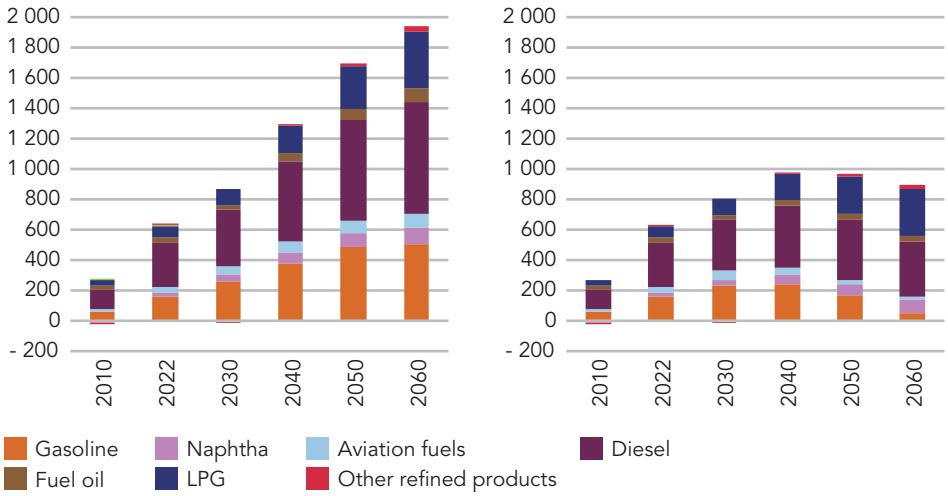


Figure 15-29. Net imports of refined products in REF & TGT (PJ)



- The demand for petroleum products is anticipated to increase due to projected higher demand from the transport sector. In 2022, the transport sector consumed roughly 65.5% of petroleum products, mostly in the forms of motor gasoline and diesel oil. This trend will continue in REF until 2060 but at a reduced share of 55.7%.
- In TGT, by 2060, the share of the transport sector demand is reduced to 33.2%, which is now lower than the share of the buildings sector at 37.2%. In this scenario, the demand for gasoline and diesel is roughly the same as in 2022 despite the increase in the number of vehicles due to electrification.
- In 2022, diesel dominated demand at 45.5%, followed by gasoline at 27.7%, and LPG at 10.5%. This distribution roughly continues in REF by 2060, but the share of gasoline significantly decreases to 10.0% in TGT by 2060 because of lower utilisation from the transport sector, while demand for diesel is still relatively significant.
- The share of LPG demand increases to 17.6% in REF and 26.8% TGT by 2060 due to higher demand in the industry and buildings sectors. This increase in LPG demand is attributed to the transition to cleaner cooking fuels.
- After the closure and conversion of the Tabangao refinery into an import terminal, the Philippines now operates only one refining facility; thus, the increase in demand for refined products must be supplied solely from imports. From around 589 PJ of imported petroleum products in 2022, this increases to 1,922 PJ and 938 PJ in REF and TGT, respectively, by 2060.
- Most of the increase in import demand is driven by diesel and gasoline. In REF, imports of both fuels rise steadily but plateau by the late 2050s, with diesel projected to decline thereafter. In TGT, gasoline imports peak in the mid-2030s, while diesel imports reach their maximum in the mid-2040s.
- Imports for jet fuel are anticipated to increase in REF due to higher demand, but in TGT, this increase in imports is expected to peak in the 2030s and then start to decline due to the use of alternative jet fuel.

Note: In Figure 15-29, net imports are presented without deducting bunkers.

Refining

Figure 15-30. Refining outputs in REF & TGT (PJ)

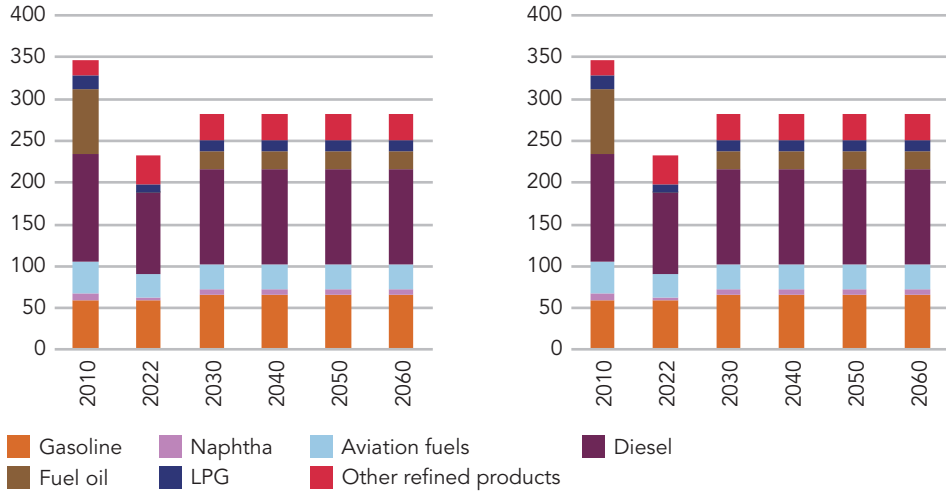
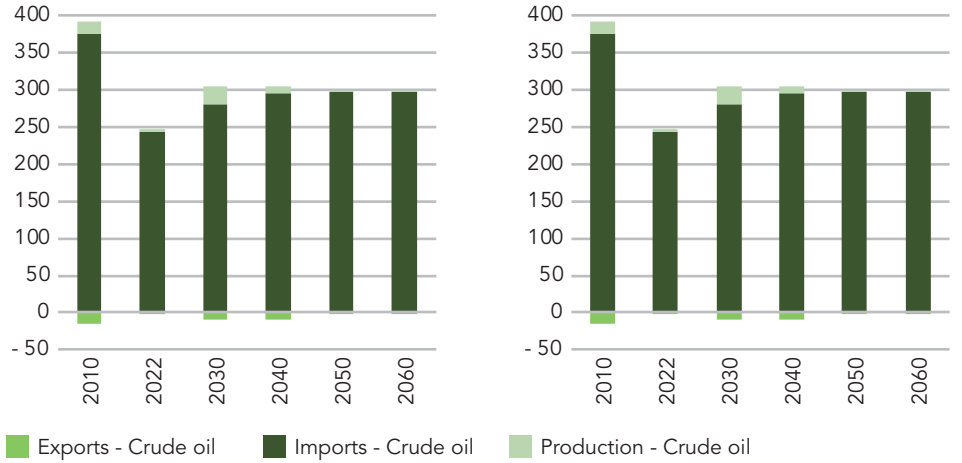


Figure 15-31. Crude oil and NGLs production, imports and exports in REF & TGT (PJ)



- Historically, the refining sector in the Philippines comprised two refineries, namely the Tabangao and Bataan refineries. Due to the impact of the COVID-19 pandemic, operations of the Tabangao refinery were suspended in May 2020 and, in August 2020, Pilipinas Shell decided to convert it into an import terminal. These closures left the Bataan Refinery of Petron as the sole operating oil refinery in the Philippines, with a 180 kb/d capacity.
- The downstream oil industry in the Philippines operates in a deregulated environment, with infrastructure largely driven by the private sector. It is assumed that the refinement capacity of the Philippines remains the same in both REF and TGT.
- Given the current capacity, the refinement facility in the Philippines can only supply 12.8% and 23.1% of the petroleum products demand in REF and TGT, respectively. While importing refined petroleum products allows for less capital investment and operational flexibility, this approach exposes the Philippines to significant price volatility risks, as refined product prices exhibit greater fluctuation than crude oil prices.
- The refinery is assumed to operate at a 70% utilisation rate. The output yields for gasoline and diesel are set at roughly 24% and 40%, respectively. Fuel oil yield substantially dropped to less than 10% in 2015, and it is assumed to be 8% in both REF and TGT. Naphtha output yield is set to 2.4%.
- The increase in utilisation rate to 70% reflects the increase in demand for crude oil from 2023 onwards, which increased from 244 PJ in 2022 to 296 PJ by 2060. With both capacity and utilisation assumed constant throughout the projection period, the demand for crude oil remains roughly the same.
- Both scenarios followed the production targets stipulated in the PEP 2023-2050 Roadmap. Crude oil production is projected to reach around 4 million barrels per year by 2025 and peak in 2028. From 2029-2050, annual production is expected to average 2 million barrels, with most occurring by 2040. Some production is exported due to refinery incompatibilities.
- This production, which is equivalent to 23.6 PJ at peak in 2028, is insufficient to meet the refineries' demand. Consequently, the Philippines is projected to require long-term crude oil imports of up to 300 PJ to ensure supply.

Bioenergy

Figure 15-32. Bioenergy demand by sector in REF & TGT (PJ)

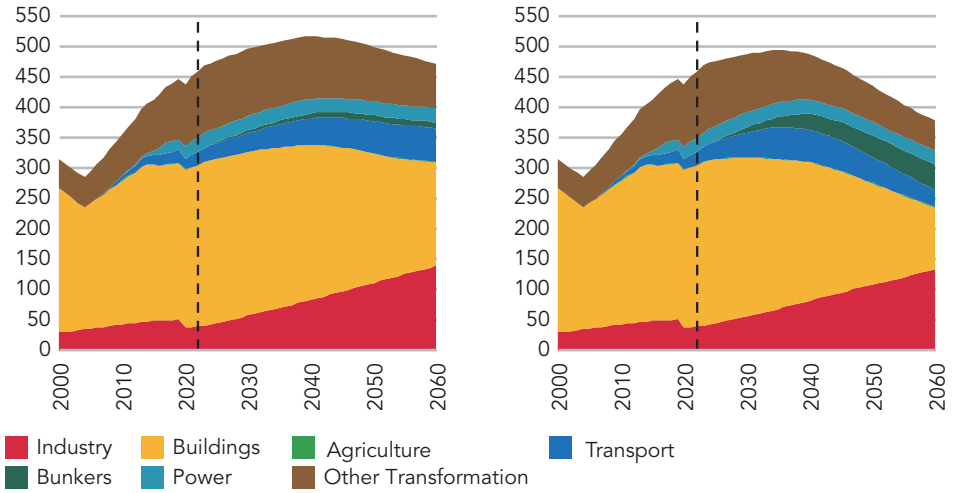
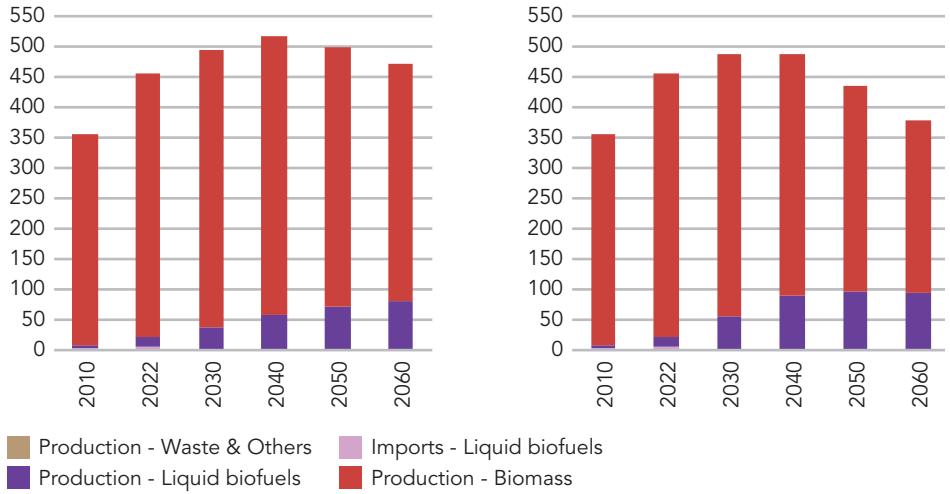


Figure 15-33. Bioenergy production, imports in REF & TGT (PJ)



- The demand for bioenergy will peak between 2030 and 2040 and then will start to decline. In REF, the demand will return to 2022 levels by 2060, while TGT will reach the 2022 levels by 2050 and continue to decline further.
- The buildings sector accounts for most bioenergy demand in 2022. In REF, this trend will continue but at a lower rate. In TGT, the buildings sector's share decreases further, and industry becomes the main bioenergy consumer. The reduction in buildings sector bioenergy consumption is attributed to fuel switching with approximately 40% reduction in fuelwood and charcoal use in REF and an approximately 60% reduction in TGT.
- Industry's increased bioenergy consumption stems from greater use of fuelwood, bagasse, and other biomass where demand for these energy sources approximately tripled in both REF and TGT.
- Industry sector demand for biodiesel also increased in both scenarios. The increase is higher in TGT due to the assumption of massive fuel switching from fossil fuels to biofuels as a decarbonisation strategy.
- The transport sector is anticipated to consume twice as much bio-gasoline and biodiesel in REF by 2060. In TGT, road subsector electrification decreases bio-gasoline demand, but biodiesel demand will remain similar to REF levels.
- Power sector demand will remain stable throughout the projection period. Although agricultural demand is anticipated to increase, its low utilisation volume means its share of total demand will remain low.
- The government of the Philippines recognises that biofuel and biomass are critically important as they are locally produced, sustainable sources of energy and reduces the dependence on imported oil. This is reflected in the bioenergy supply in the Philippines, where all bioenergy is anticipated to be produced locally. However, constraints such as feedstock availability, infrastructure, and economic viability may affect the expansion of domestic production.
- Despite the introduction of the Biofuel Act of 2006, based on the current trajectory, most of the bioenergy is still fuelwood in both scenarios. Nonetheless, the increase in biofuel production should not be discounted since it could still support the decarbonisation of the transport sector.

Hydrogen-based Fuels

Figure 15-34. Hydrogen-based fuels demand by sector (PJ)

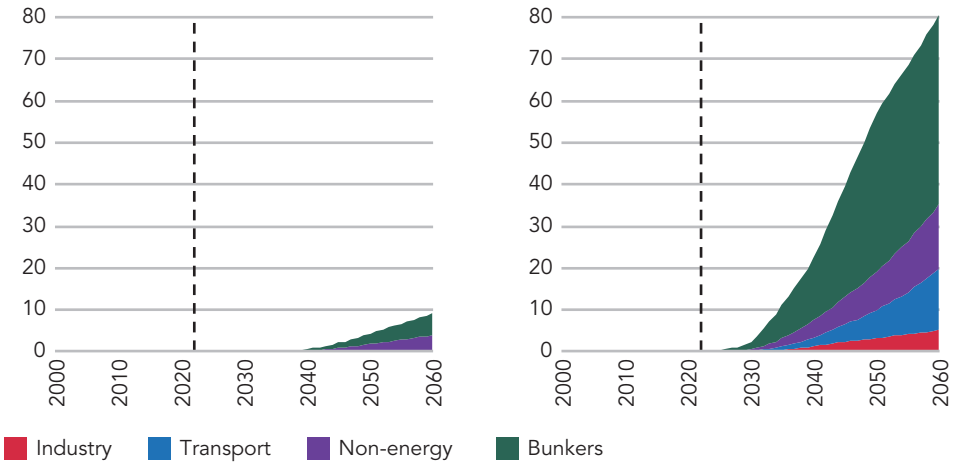
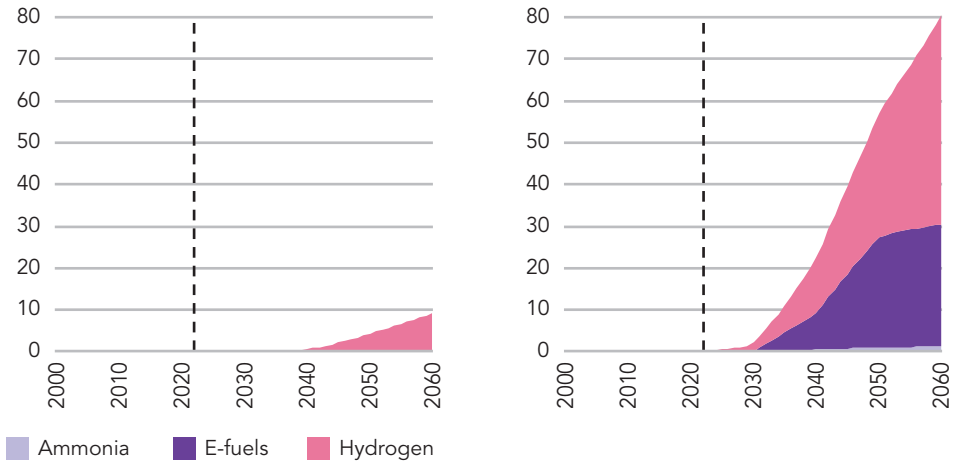


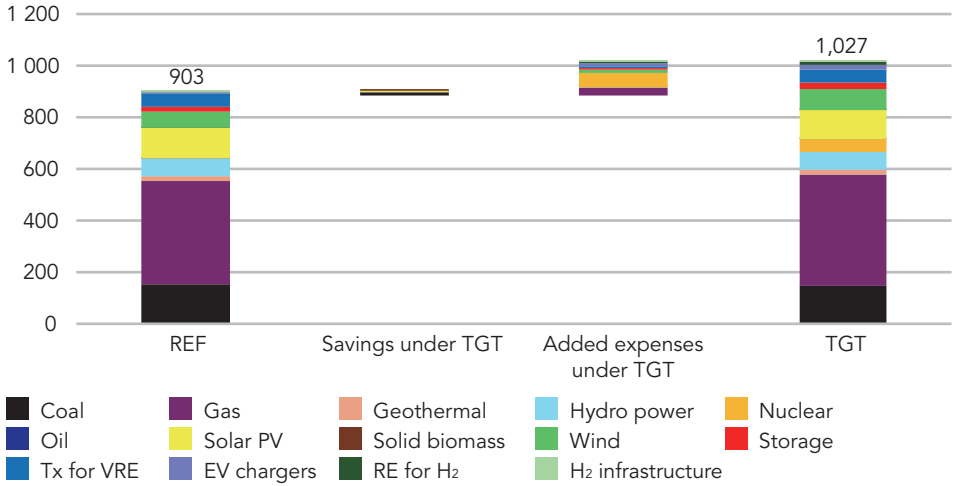
Figure 15-35. Hydrogen-based fuels demand by fuel in REF & TGT (PJ)



- The government of the Philippines has considered the potential of hydrogen as a low-carbon energy alternative since the Philippine Energy Plan 2022-2040. This was further emphasised in the Philippine Energy Plan 2023-2050, wherein the utilisation of locally produced alternative fuels is envisioned in the long-term roadmap for the adoption of these fuels from 2029 to 2050.
- Hydrogen-based fuels include hydrogen, hydrogen-derived e-fuels, and ammonia. The demand for these fuels is projected to be relatively smaller than that of other energy carriers, but will primarily be used to decarbonise the aviation sector and for non-energy purposes.
- The hydrogen demand in the two scenarios shows a substantial difference, with the demand in TGT being eight times greater than in REF, as REF is less optimistic regarding the introduction of hydrogen into the energy mix. In contrast, in TGT, hydrogen will also be used in the industry and transport sectors to support green steel production and freight transport.
- In REF, only hydrogen is used directly, primarily to decarbonise the aviation sector. In TGT, a small amount of ammonia is introduced. By 2060, e-fuels contribute twice as much as hydrogen in the aviation industry, as it is simpler to adapt e-fuels to replace jet fuel. Furthermore, in TGT, hydrogen is also used in the transport and industry sectors.
- Hydrogen use in steelmaking begins in the mid-2030s in both scenarios, but it scales more rapidly in TGT. It is also blended with natural gas for high-heat processes in the chemicals and cement subsectors. Low-emissions hydrogen for methanol and ammonia feedstock begins scaling in the 2030s in TGT, but not until the 2040s in REF.
- Although the Philippines also aspires to utilise hydrogen from other sources, the *Outlook* uses water electrolysis with renewable energy from wind power to produce hydrogen. It is assumed that all hydrogen produced will be domestic and sufficient to satisfy demand.

Costs

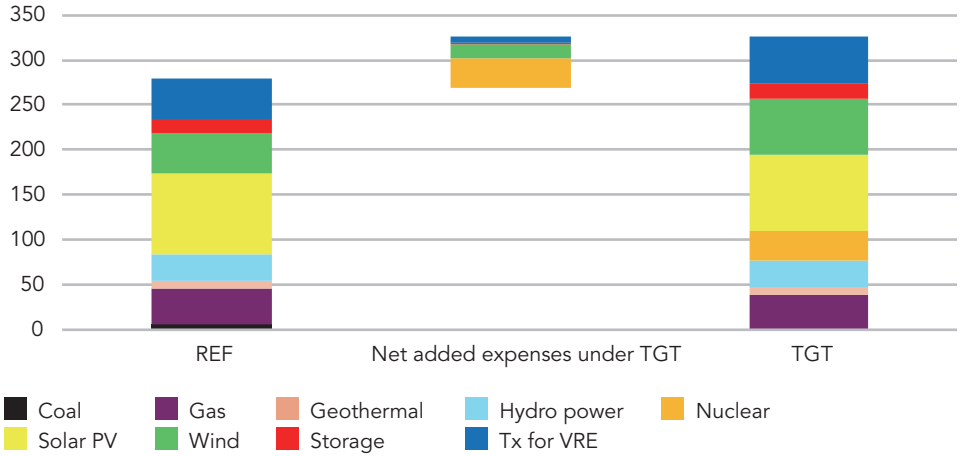
Figure 15-36. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



Note: Tx for VRE is only transmission infrastructure to connect variable renewable capacity to the grid. EV chargers do not cover the cost of associated infrastructure or EV vehicles. Hydrogen costs do not cover costs for bunkering.

- Meeting the growing energy demand of the Philippines involves substantial costs in both REF and TGT because of the relatively similar increase in energy demand in both scenarios. The total capital, fixed, and variable costs in the power sector from 2025 to 2060 are considered, as well as costs for green hydrogen production, transmission for VRE, and electric vehicle chargers.
- In REF, the total costs will reach an estimated USD 903 billion. Gas plays a significant role in meeting additional demand and serving as a flexible balancing fuel for renewable energy, making up 44% of the total cost.
- In TGT, the total cost increases by an estimated USD 124 billion. Most of the additional investment is needed to build nuclear power capacity and expand gas and wind capacity. About USD 17.8 billion is required for the additional wind and solar power plants and electrolysers necessary for green hydrogen production for domestic green hydrogen use.
- The small difference in costs between scenarios reflects their relatively similar electricity generation profiles, in terms of size and composition.

Figure 15-37. Total capital investment (CAPEX) from 2025 to 2060 in the power sector (billion USD, undiscounted)

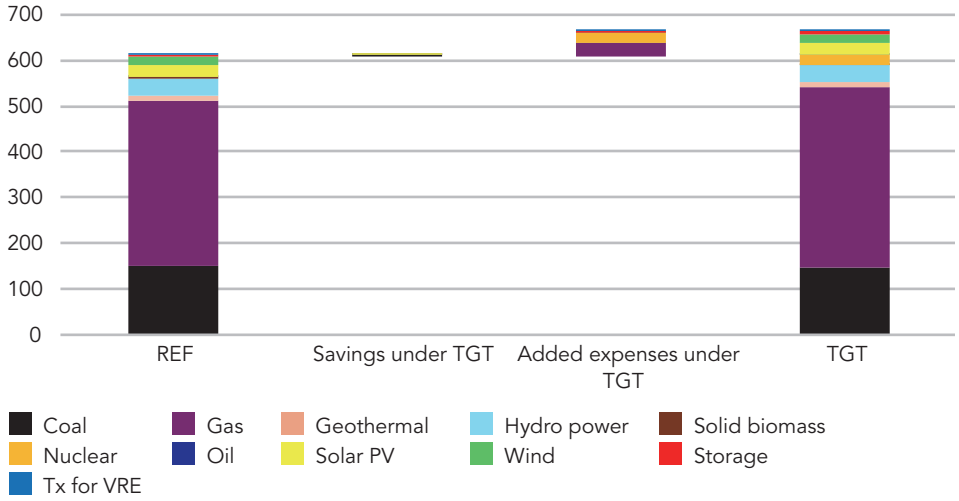


Note: Figure 15-37 only covers power and VRE transmission sector investments. Hydrogen and EV capital investments are not included.

- Although REF also considers low emissions options, the investment for the lower emissions option in TGT is only 14% higher.
- In both scenarios, most capital investment goes toward upfront costs for renewable energy (solar, wind, hydro) and transmission infrastructure to deliver power to demand centres. Higher renewable capacity also requires additional storage. Since demand is met significantly by gas power generation, investment in new gas plants is also required.
- The cost structure is roughly the same in TGT but the anticipated gradual rollout of nuclear power plants in TGT will incur additional costs. The additional wind energy and the corresponding transmission infrastructure will also lead to higher investment requirements in this scenario.
- In both scenarios, the upfront cost of building additional renewable energy could be challenging for the Philippines. It is important to emphasise that this will require support through loans from financial institutions and government policy to unlock capital for new investment.

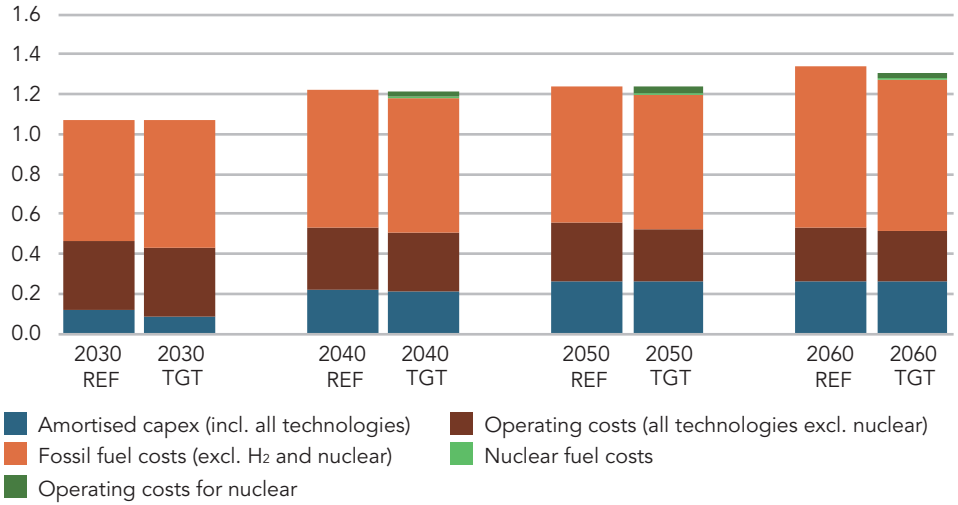
Costs

Figure 15-38. Total operating costs from 2025 to 2060 in the power sector (billion USD, undiscounted)



Note: Figure 15-38 only covers power and VRE transmission sector costs. It does not include operating costs associated with hydrogen production and EV charger costs.

Figure 15-39. Cost of generating electricity relative to 2025 (2025 cost = 1.0) in the power sector



Note: Based on our assumptions about future capital and operating costs, this chart shows cost compositions over time relative to 2025. It should not be considered an estimate of electricity tariffs and excludes market mechanisms that are too difficult to estimate.

- A significant portion of the operating costs required to meet the growing energy demand in the Philippines is attributed to the fuel needed to operate the coal and gas power plants. In both scenarios, about 80% of the operating costs are due to the associated fuel costs of coal and gas power generation.
- TGT incurs a slightly higher operational cost from increased gas consumption and nuclear power, though the difference remains relatively small. Although minimal, the savings under TGT arise mostly from reduced coal usage.
- Although gas entails significant costs, the fact that these are incurred annually makes it easier to finance this portion of the energy transition without requiring additional loans from financial institutions to amortise the substantial upfront capital investment needed for expanding capacity.
- Overall, coal and gas fuel costs will continue to dominate operating expenses in both scenarios. Sustaining the energy transition will thus require careful management of these costs, including potential long-term contracts.

- The difference in costs between REF and TGT is further reflected in the cost of generating electricity. By 2030, when indexed to 2025 as the base year, it is anticipated that electricity generation costs will still be similar for both scenarios. However, the ramp-up of investment and gas usage by 2040 is expected to increase electricity generation costs for both scenarios substantially, reaching a level approximately 20% higher than in 2025.
- The increase in the cost of electricity over the projection period is similar in both scenarios given their similar capacity additions. Operating and fuel costs for nuclear contribute to the overall increase of the cost in TGT; however, their impact remains limited due to the relatively small nuclear capacity addition.
- It should be noted that Figure 15-39 presents estimates for electricity generation costs only and does not account for consumer electricity prices, which incorporate complex and uncertain market mechanisms that will add to the overall cost of supply.

CO_2 Emissions

Figure 15-40. CO_2 emissions in REF (million tonnes)

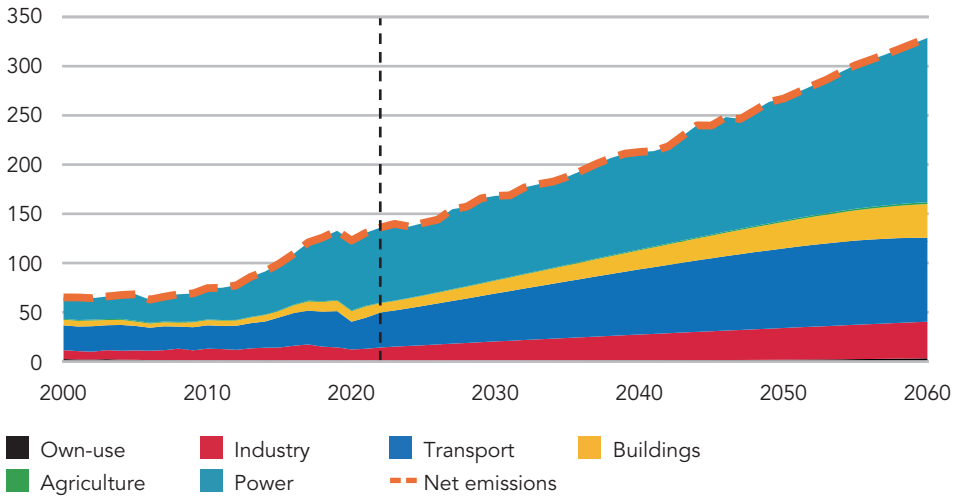
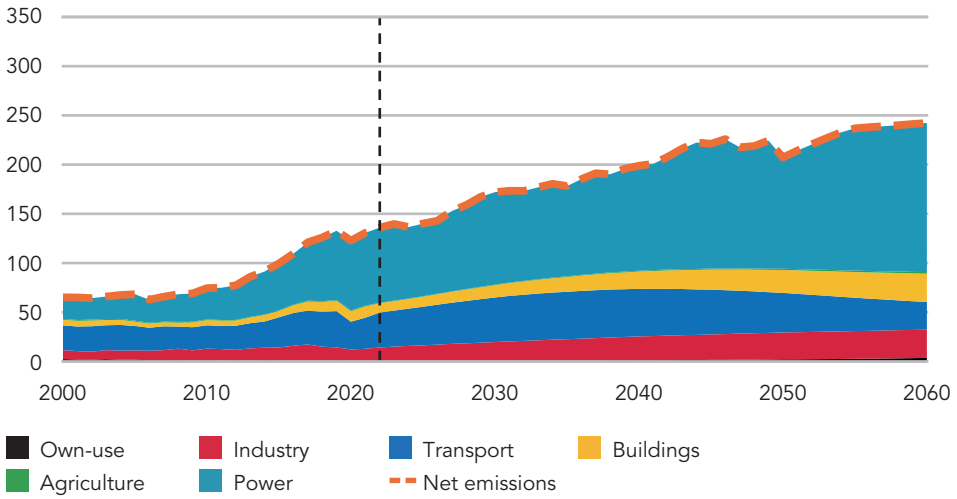
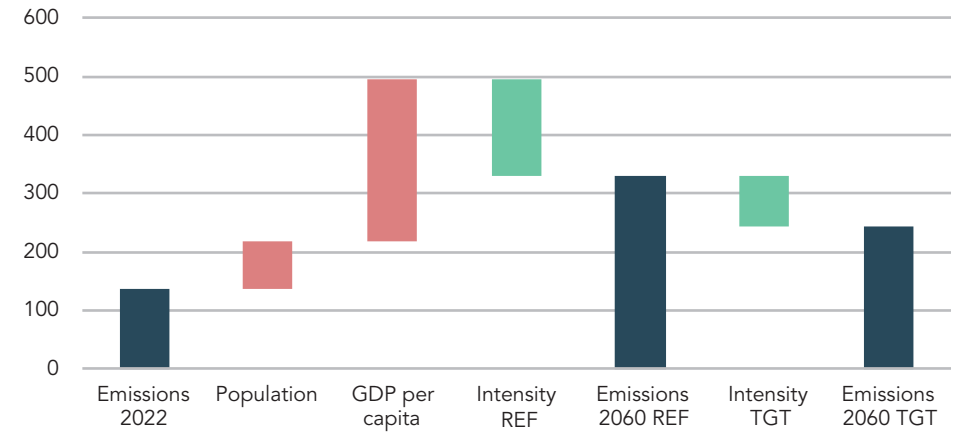


Figure 15-41. CO_2 emissions in TGT (million tonnes)



- In REF, CO_2 emissions are anticipated to increase by 142% by 2060 relative to 2022. The sectoral shares remain largely unchanged. The power sector consistently accounts for around 50%, while the transport sector ranges from 25% to 30%. The buildings sector's share increases from about 7% to 10% from 2022 to 2060, while the industry sector continues to hover around 11%.
- In TGT, the increase in CO_2 emissions is expected to be more moderate, rising by 78% by 2060. The power sector's share increases to over 60%, up from around 40%, due to the electrification of multiple sectors, particularly the transport sector. This reduces the share of the transport sector to approximately 11%, down from more than 30%. By 2060, the shares of the buildings, industry, and transport sectors all hover around 11% each.
- The increase in CO_2 emissions is partly attributed to population growth but is driven more significantly by the rise in GDP per capita. In REF, this is partially offset by improvements in energy intensity. In TGT, emissions could be further reduced through energy intensity improvements. However, these reductions are insufficient to counterbalance the increase resulting from GDP growth.

Figure 15-42. CO_2 emissions components (million tonnes)



Note: All values represent energy sector combustion CO_2 emissions. Biogenic CO_2 is treated as zero at the point of combustion.

Useful Links

APEC Expert Group on Energy Data and Analysis (EGEDA) – https://www.egeda.ewg.apec.org/

APEC Energy Statistics 2022 – https://www.egeda.ewg.apec.org/egeda/general/info/pdf/APEC_Energy_Statistics_2022.pdf

APEC Energy Overview – https://aperc.or.jp/reports/energy_overview.php

World Bank – The Philippines Data, Research & Development News – https://www.worldbank.org/en/country/philippines

Department of Energy, Republic of the Philippines (DOE) – http://www.doe.gov.ph

Philippine Energy Plan 2023–2050 – https://legacy.doe.gov.ph/pep

Power Development Plan 2023–2050 – https://legacy.doe.gov.ph/electric-power?q=power-development-plan

Philippine Nuclear Energy Roadmap – https://legacy.doe.gov.ph/press-releases/philippines-unveils-nuclear-energy-roadmap-largest-annual-gathering-stakeholders

Philippine Republic Act (RA) 9367 – Biofuels Act 2006 – https://legacy.doe.gov.ph/renewable-energy?q=renewable-energy/republic-act-no-9367

Philippine National Renewable Energy Program (DOE) – https://legacy.doe.gov.ph/national-renewable-energy-program



16. The Russian Federation

Summary

	Reference			Target		
	2021	2060	% Change	2021	2060	% Change
Macroeconomic						
Population (million)	147.2	137.1	-7%	147.2	137.1	-7%
GDP (billion 2017 USD, PPP)	4,091	5,249	28%	4,091	5,249	28%
Energy Demand						
Agriculture & fisheries (PJ)	389	414	6%	389	320	-18%
Buildings (PJ)	6,580	6,542	-1%	6,580	6,126	-7%
Industry (PJ)	5,758	5,847	2%	5,758	5,167	-10%
Non-energy (PJ)	4,428	5,345	21%	4,428	4,822	9%
Transport (PJ)	3,667	4,137	13%	3,667	3,620	-1%
Energy intensity of TFEC (PJ/GDP, billion USD)	4.3	3.4	-20%	4.3	3.1	-28%
Electricity						
Generation (TWh)	1,163	1,444	24%	1,163	1,555	34%
Renewables share of generation (%)	19	19	0%	19	22	16%
Generation capacity (GW)	244	303	24%	244	373	53%
Total Primary Energy Supply (TPES)						
Coal & coal products (PJ)	3,857	3,305	-14%	3,857	2,569	-33%
Natural gas (PJ)	17,138	19,750	15%	17,138	19,154	12%
Petroleum liquids (PJ)	6,857	6,454	-6%	6,857	4,804	-30%
Low-carbon & waste energy (PJ)	3,387	5,978	76%	3,387	7,146	111%
CO_2 intensity of energy supply ($MtCO_2/PJ$)	0.042	0.040	-5%	0.042	0.036	-15%
Net CO_2 Emissions (million tonnes)	1,297	1,406	8%	1,297	1,199	-8%

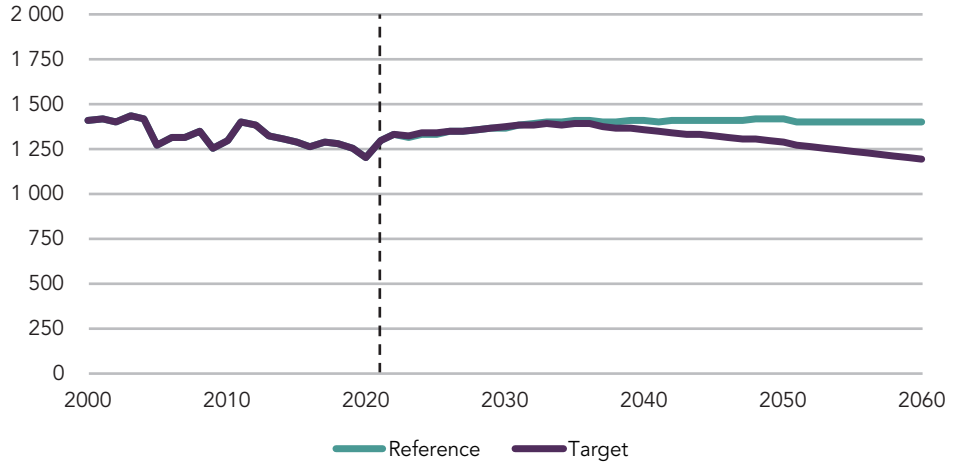
Note: The term "low-carbon & waste energy" includes all bioenergy, waste-derived energy, renewables, nuclear, and hydrogen-based fuels. Total primary energy supply (TPES) numbers include international bunkers. Net emissions are calculated as gross energy sector combustion CO_2 minus CO_2 captured and stored through carbon capture and storage (CCS).
Historical data is based on publicly available official Russian statistics, supplemented by APERC estimates.

Key Takeaways

Emissions

- Net CO_2 emissions peak in mid-2030s and remain relatively flat in the Reference scenario (REF), while they are projected to be 15% lower by 2060 in the Target scenario (TGT).
- The largest contributors to the emissions reductions are in the power sector, which accounts for around 43% of the total reduction, due to increases in nuclear and renewable capacity, as well as a switch from coal to gas in thermal generation. Additional emission reductions come from the transport and industry sectors.
- Further reductions in CO_2 emissions would require reduced reliance on natural gas in the power sector and more electrification of vehicles in the transport sector.

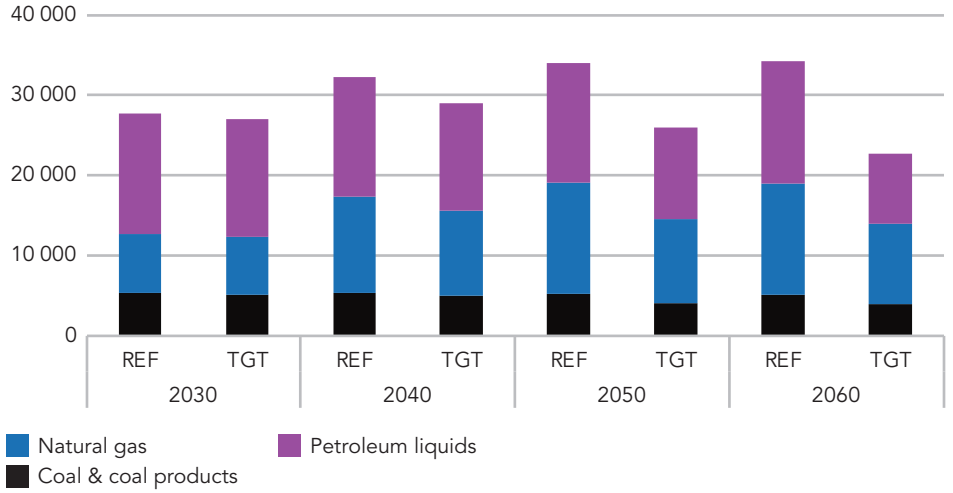
Figure 16-1. Net CO_2 emissions (million tonnes)



Energy Import Dependence

- As one of the world's largest producers and exporters of fossil fuels, Russia positions itself not only as a key global energy supplier, but also as a stabilising force in international energy markets.
- While REF anticipates Russia's continued leadership in energy exports, sustaining this role will require market diversification and infrastructure expansion. Exporting oil, gas, and coal in a decarbonising global economy presents structural risks. In TGT, coal, crude oil and petroleum product exports may decline due to ongoing efforts outside of Russia to decarbonise the power sector and electrify end-use sectors, especially transport.
- Russia's LNG export capacity is expected to grow significantly, supported by major new projects in the Arctic and Far East. This positions Russia to become a flexible and competitive LNG supplier.

Figure 16-2. Net exports (PJ)



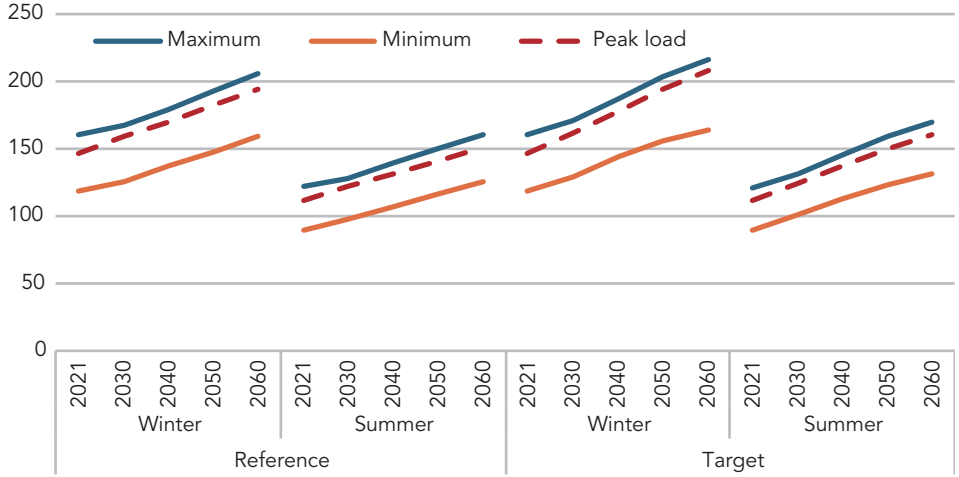
Note: Net exports are calculated as total exports minus imports, with the addition of international bunkers.

Key Takeaways

Grid Reliability

- Electric grid reliability requires a near-instantaneous balance between power supply and demand at all times. Maintaining this balance requires adequate dispatchable power sources, which can include batteries.
- Figure 16-3 shows grid dependence on dispatchable power in the 4-hour period of maximum dependence and 4-hour period of minimum dependence by season and year in REF and TGT.
- In both REF and TGT scenarios, total electricity consumption is projected to increase, requiring a substantial power capacity expansion, both to meet the increased demand but also to replace Russia's aging thermal generation infrastructure. Regional constraints contribute to the challenges for timely and balanced capacity development.

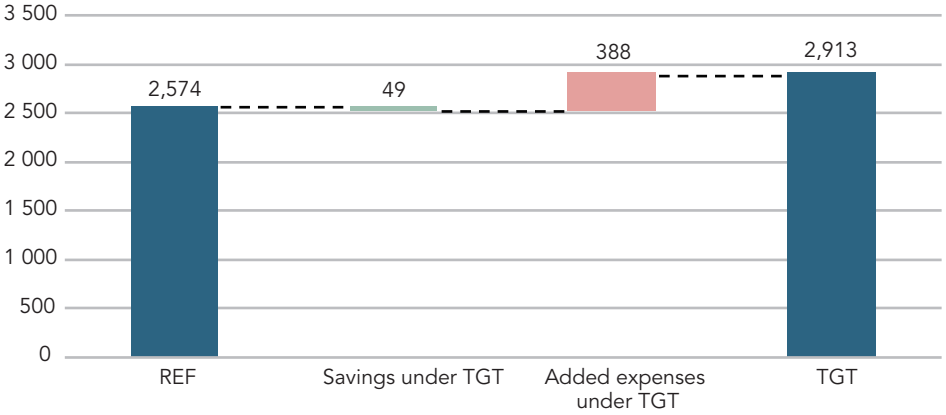
Figure 16-3. Peak load and maximum and minimum dependence on dispatchable power (GW)



Cost

- Figure 16-4 illustrates total costs in the power and hydrogen sectors from 2025 to 2060, which will be 13% higher in TGT relative to REF. In REF, the estimated costs are USD 2574 billion with this cost rising to USD 2913 billion in TGT.
- In REF, costs are largely accumulated from operating costs for electricity and heat generation, as well as capital investments in new nuclear, solar, wind, and related transmission infrastructure.
- In TGT, reduced reliance on coal leads to relatively small reduction in operating cost savings, and these savings are more than offset by increased costs in the larger implementation of conventional nuclear and SMRs, variable renewables, and gas-fired power plants to replace coal-fired generation. Costs for producing blue hydrogen for domestic use are also greater in TGT and contribute to the increased costs.

Figure 16-4. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



*Actual costs will differ from estimated costs in the *Outlook* for a variety of reasons including changing commodity prices, manufacturing costs, and unforeseen technical advances. All costs are in 2023 real terms.

About Russia

Overview

Geographical and Economic Landscape

Russia, the world's largest economy by land area, spans over 17 million square kilometers across Eastern Europe and Northern Asia. Due to its geography and settlement patterns, Russia requires substantial energy to maintain comfortable living conditions, contributing to the highest energy intensity among APEC economies. These demands have driven the development of centralised electricity and heat supply systems, including widespread use of combined heat and power plants. As a result, Russia operates the world's largest district heating networks across major cities.

Energy Supply and Consumption

Russia is a major player in the global energy landscape, ranking as the third-largest energy producer and consumer in the APEC region. The economy is among the world's leading producers and exporters of oil, natural gas, and coal, supported by some of the largest proven reserves globally. Natural gas dominates Russia's primary energy mix, accounting for nearly 60% of supply, followed by oil, with nuclear and hydropower making up a significant share. While gas remains the foundation of the energy system, nuclear and hydro resources provide important diversification. There also is growing attention to renewables, constrained by geographic and technological factors. Russia's final consumption is concentrated in the industrial and residential sectors, reflecting the economy's production base and high heating demand.

Energy Security Challenges and Strategies

Russia's energy strategy emphasises maintaining its role as a global energy supplier while ensuring domestic energy reliability and affordability. In recent years, changes in the geopolitical and economic landscape have posed challenges to energy trade, technology access, and investment. In response, Russia has placed greater emphasis on enhancing energy self-sufficiency, modernising infrastructure, and expanding partnerships beyond traditional markets, particularly in Asia.

Key Energy Initiatives

Strategy for Socio-Economic Development with Low Greenhouse Gas Emissions until 2050 (2021)

This strategy outlines Russia's approach to a low-carbon future by promoting less carbon intensive energy sources, such as combined-cycle gas, nuclear, hydro, and renewables. It aims to reduce greenhouse gas emissions from coal through advanced technologies, encourage the deployment of carbon capture, utilisation, and storage (CCUS), and enhance the absorption capacity of ecosystems through better land use practices. This strategy also emphasises technological neutrality and alignment with international climate standards.

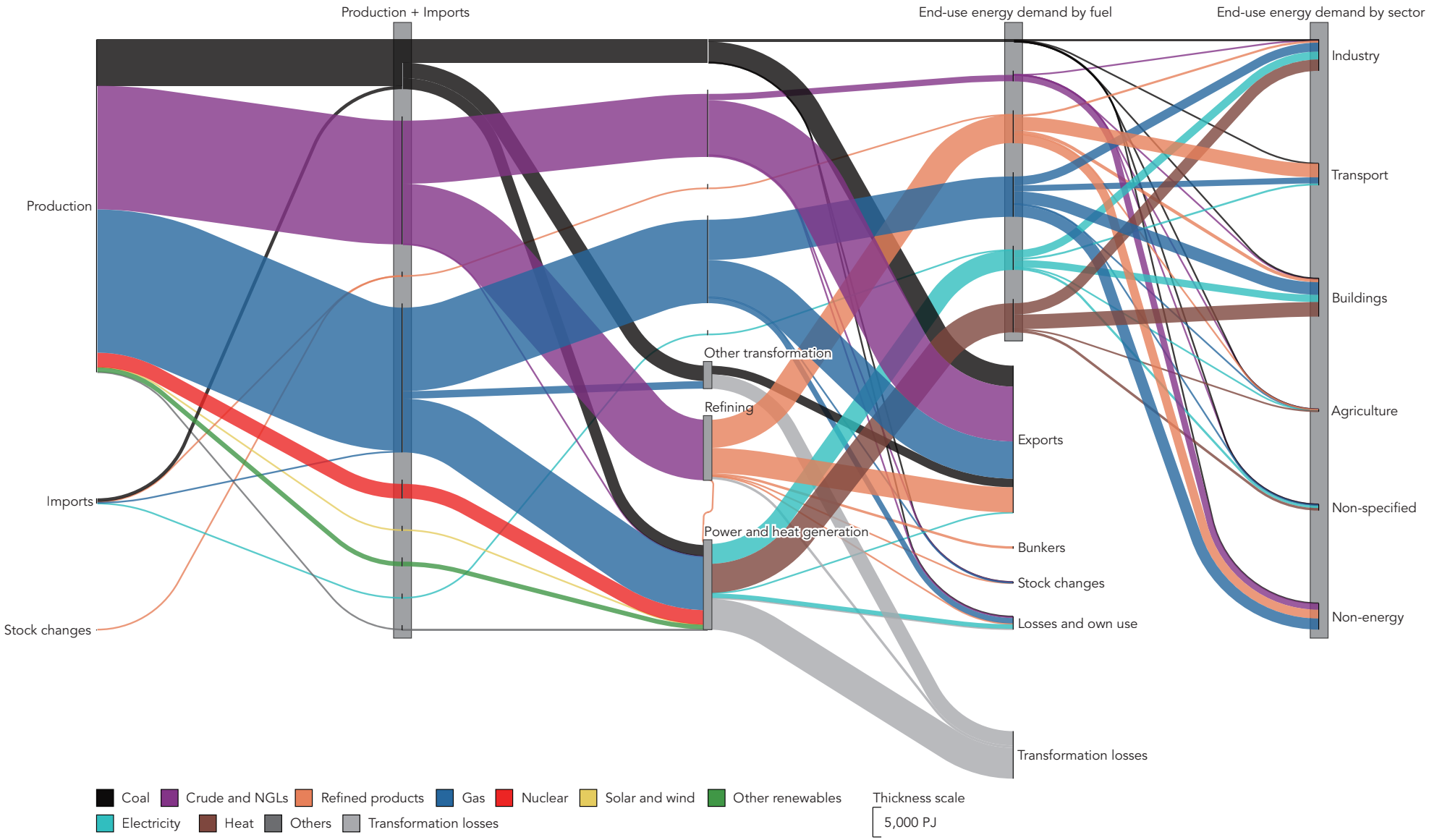
General Scheme for the Placement of Electric Power Facilities until 2042 (2024)

This long-term infrastructure plan seeks to modernise Russia's power system while shifting toward less carbon intensive energy sources. It aims to commission approximately 90 GW of new capacity, expand the share of nuclear and renewable energy, and gradually reduce reliance on coal-fired generation. The plan emphasises reliability, environmental performance, and economic growth.

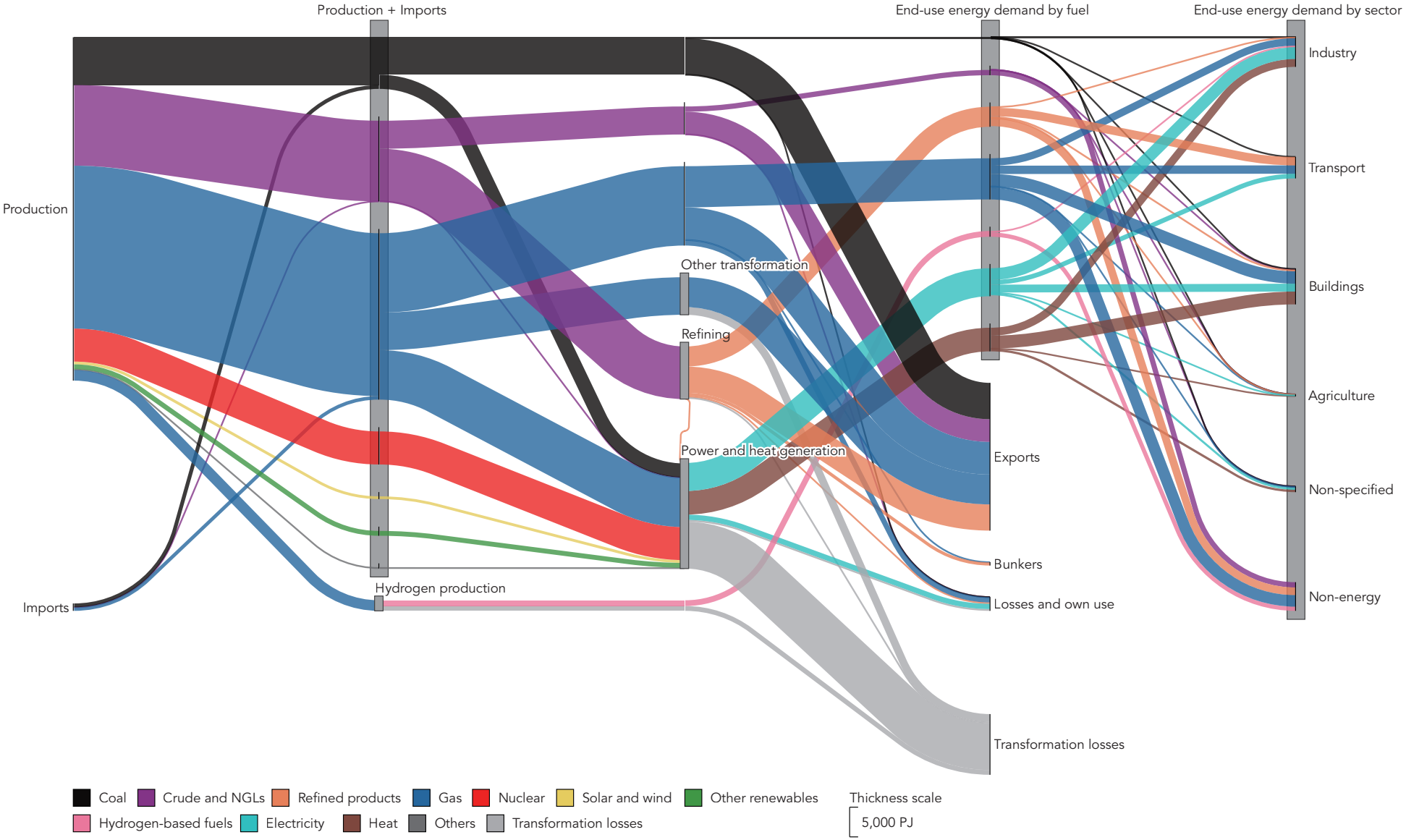
Energy Strategy 2050 (2025)

Russia's Energy Strategy 2050 sets a comprehensive vision for a safe, efficient, and technologically independent energy system. It maintains stable oil and gas production, with increased LNG exports, while expanding the role of nuclear and renewable energy. The strategy focuses on enhancing energy efficiency, adopting cleaner technologies, and strengthening international energy cooperation, especially with Asian and emerging markets.

Energy Flow (2021)



Energy Flow (2060, Target Scenario)



Scenarios and Assumptions

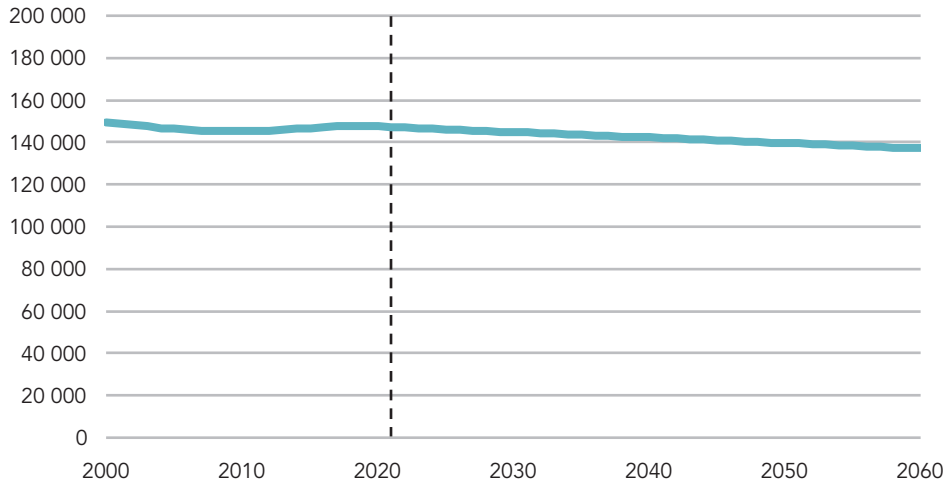
In *The Outlook*, APERC analyses energy demand, transformation, and supply, as well as emissions. The **Reference Scenario (REF)** offers a projection based on historical trends, recent developments, and APERC's assumptions about the continuation of those trends in each APEC economy, while acknowledging technical restraints. The REF Scenario offers a baseline to compare with the **Target Scenario (TGT)** projections, which explores a hypothetical pathway where each economy achieves energy-related policy targets, assuming implementation regardless of cost-effectiveness. When implementation details are lacking, assumptions are inferred from the targets themselves or emissions-related goals.

	Reference	Target
General	• The main efforts are focused on improving energy efficiency.	• Significant energy efficiency improvements. • The use of environmentally-friendly technologies in carbon-intensive industries.
Buildings	• Expanded natural gas pipelines induce fuel switching to natural gas. • AI and data centre growth is the same under both scenarios.	• Greater energy efficiency improvements and retrofits than REF. • Expanded natural gas pipelines induce fuel switching to natural gas.
Industry	• Current trends are expected to continue. • Moderate energy conservation. • Hydrogen and gas with CCS are incorporated from 2040.	• Some processes in iron & steel and chemicals incorporate hydrogen, while CCS is deployed in the steel, cement, and chemical subsectors beginning in 2030. Hydrogen incorporated in non-energy from 2030. • Higher electrification rates in most subsectors. • Energy and material intensity improvements are greater than in REF.
Transport	• Some PHEV and BEV adoption in passenger vehicles starting in 2030. • No electrification of pipeline operations.	• Increased ZEV adoption in passenger vehicles starting in early 2020s. • Higher use of CNG, PHEV, and BEV in freight starting in early 2020s. • Some electrification of pipeline operations.
Power	• Maintaining the existing structure of installed capacity of power plants. • Gradual replacement of coal.	• Significant increase in the capacity of nuclear power plants. • Gradual decommissioning of coal-fired power plants. • Slight increase in the capacity of the solar and wind power plants.
Supply	• Projection of fossil fuel production and exports are relevant to the Target scenario of the Russia Energy Strategy 2050.	• Projection of fossil fuel production and exports is driven by domestic demand trends and market conditions in APEC.
Emissions	• CO_2 emissions are calculated at post consumption based on IPCC emission factors.	• CO_2 emissions are calculated at post consumption based on IPCC emission factors.

Note: The base year is 2021. Macro-economic assumptions are constant across scenarios. Historical energy balances are from EGEDA submissions for 2021.

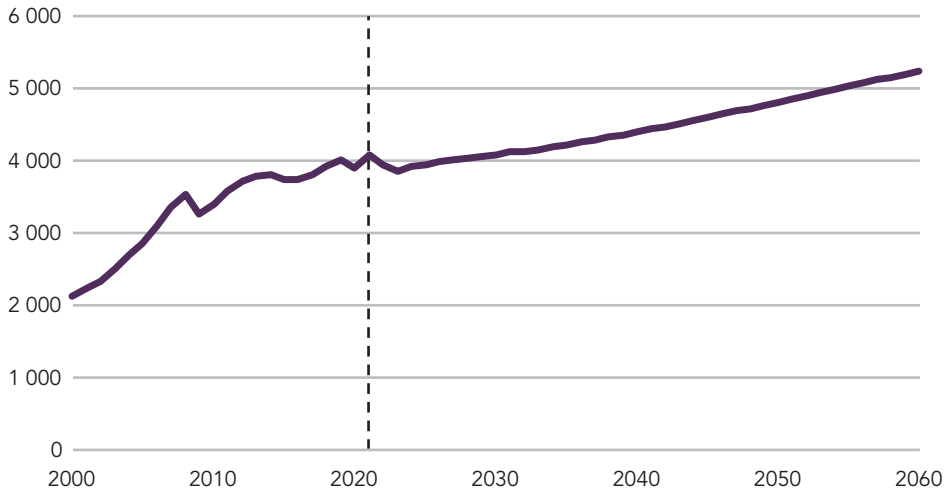
Demographic and Macroeconomic Assumptions

Figure 16-5. Population (thousands)



- The decline in Russia's population, which began in the early 1990s, continued through the 2000s. This decline was due to a combination of two major factors: the small generation of World War II children starting to become parents, and the consequences of the collapse of the Soviet Union and the associated economic and social crises. By 2010, the generation born in the 1980s (baby boomers' children) were beginning to enter adulthood, after which the population started to grow again. Growth peaked in 2016-2017. The positive trend has continued through 2019.
- Looking ahead, the Outlook follows UN DESA population projections. These projections incorporate the demographic impact of the COVID-19 pandemic and anticipate a population decrease of around 10 million by 2060. The expected decline reflects ongoing trends in reduced birth rates and long-term demographic patterns rooted in historical events. Nevertheless, gradual increases in life expectancy are expected to offset some of the downward pressures on population levels.

Figure 16-6. Real GDP (billion 2017 USD, PPP)



- Russia experienced robust economic growth between 2000 and 2008, with an average annual GDP increase of 6.6%. While the 2009 global financial crisis temporarily impacted the economy, Russia demonstrated resilience with a strong recovery during 2010–2012. From 2016 to 2019, the economy steadily expanded, achieving a cumulative GDP growth of 7%. Although challenges such as international sanctions and the global COVID-19 pandemic influenced short-term performance, the economy continued to adapt to evolving global conditions.
- Over the forecast period, this outlook reflects the current trajectory of Russia's economic development, alongside the gradual diversification of its economy. Based on these projections, Russia's GDP is expected to grow by 28% by 2060.

End-use Energy Demand

Figure 16-7. Energy demand by sector in REF & TGT (PJ)

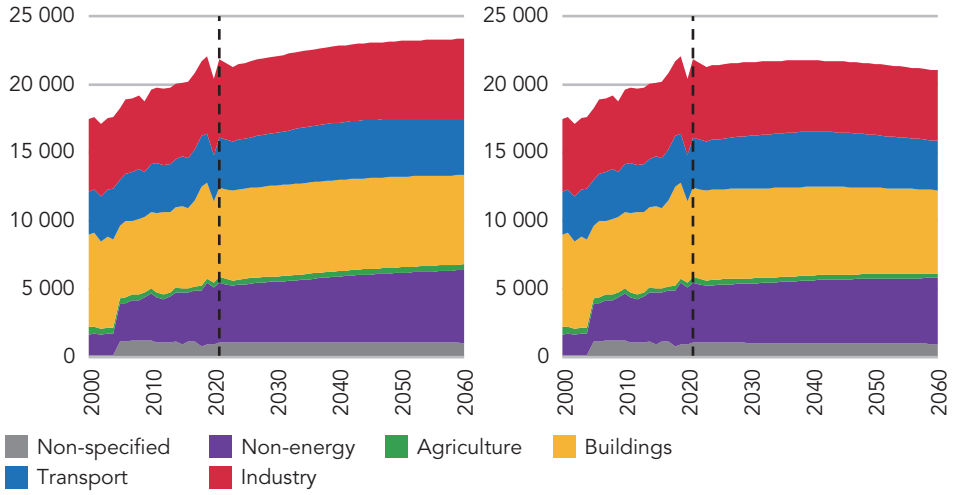
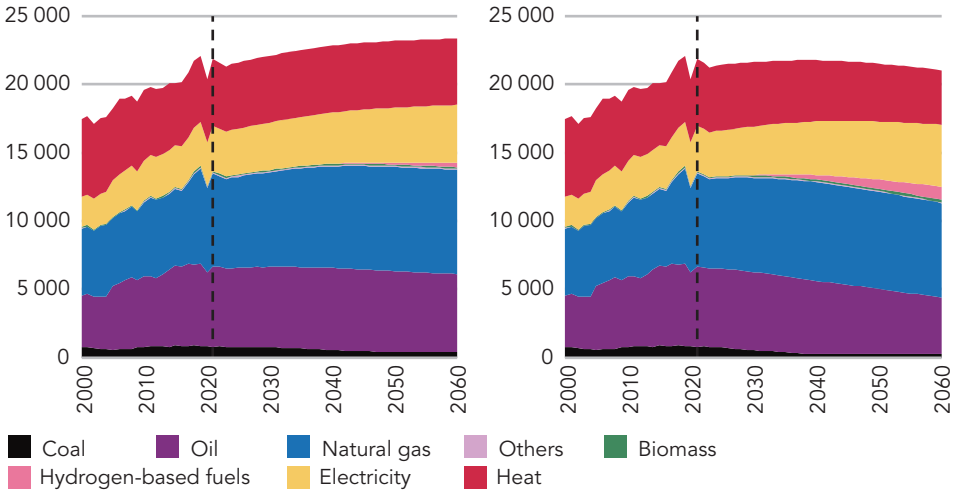


Figure 16-8. Energy demand by fuel in REF & TGT (PJ)



- In REF, total final demand increases by 2060, with industrial energy demand and non-energy fuel use accounting for approximately 70% of the growth. The remaining 30% of the increase is attributed to the transport sector.
- In TGT, final demand in 2060 decreases slightly and is around 10% lower than in REF. Industry and non-energy together account for around 50% of the reduction in fuel demand between REF and TGT by 2060. Breaking this down further, industry alone accounts for 30%, non-energy 23%, buildings 18%, and transport 22%. The remaining decrease comes from reduced demand in the non-specified and agriculture sectors.
- The decline in energy demand is distributed fairly evenly across sectors, with different drivers in each. For example, industry and non-energy improve material and energy efficiency, buildings adopt more energy-efficient measures and retrofits, and transport increases electrification.
- To that end, increased electrification across multiple sectors in TGT causes electricity consumption to be approximately 7% higher than REF in 2060. This transition to electric technologies reduces reliance on fossil fuels, resulting in declines in natural gas, coal, and oil use in TGT compared to REF. The higher electricity use reflects broader adoption in sectors such as transport and industrial processes.
- Hydrogen begins to emerge as an energy carrier in industrial applications and as a non-energy feedstock. Although both scenarios incorporate hydrogen, its use is significantly greater in TGT. By 2060, hydrogen-based fuel consumption in TGT is 225% higher than in REF.

Buildings Energy Demand

Figure 16-9. Buildings energy demand by fuel in REF & TGT (PJ)

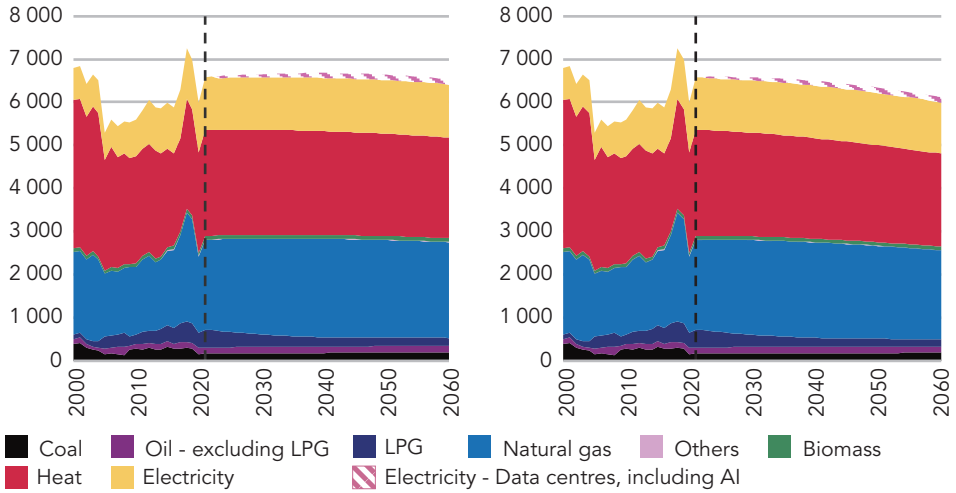
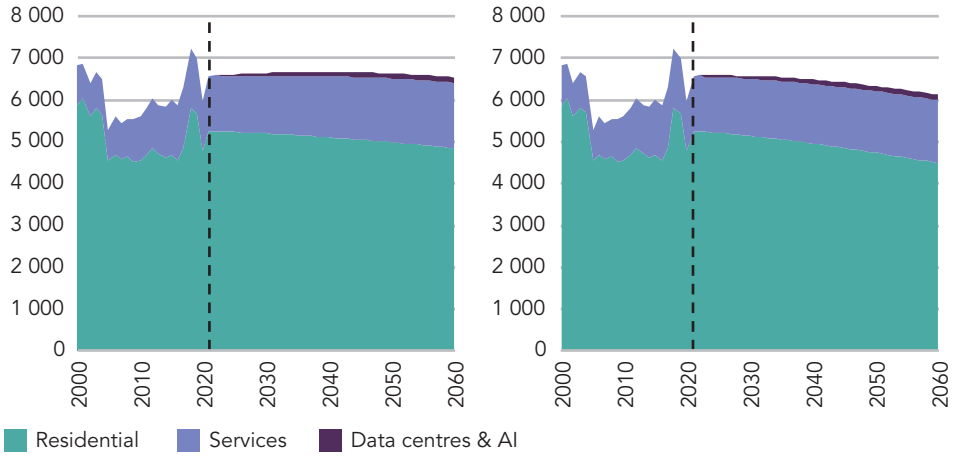


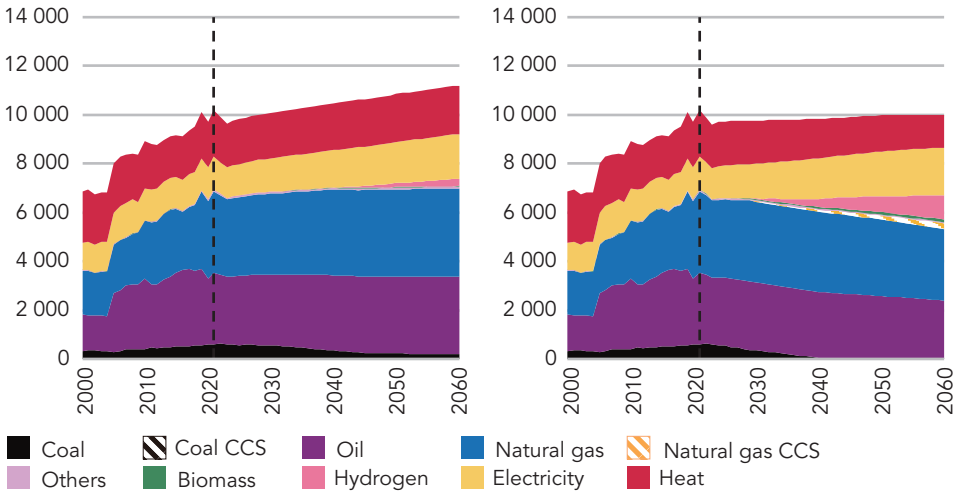
Figure 16-10. Buildings energy demand by sector in REF & TGT (PJ)



- Historically, energy demand in buildings has been satisfied largely through heat, natural gas, and electricity. These fuels are expected to remain the prominent fuels throughout the projection period in both scenarios.
- The share of heat in demand falls by one percentage point in REF and two percentage points in TGT by 2060 compared to 2021. The fall in heat consumption is mainly due to energy savings measures implemented by building occupants. Newly commissioned buildings are also meeting modern energy efficiency standards, contributing to less heat demand.
- In REF, total energy demand is expected to decrease slightly (-0.6%) by 2060 relative to 2021. This decrease arises from population decline, even as residential energy demand per capita increases due to greater adoption of appliances, space cooling, heating, and lighting. Improved living standards contribute to the growth in energy consumption per capita.
- The main factor behind reduced energy use in TGT is improved energy efficiency. Stricter measures are assumed to offset rising end-use demand in residential buildings, resulting in a slight decline in residential energy use per capita. Residential building retrofits are assumed, leading to significant efficiency gains. Total buildings energy consumption in 2060 is 6% lower in TGT than in REF.
- Electricity demand for data centres and AI is included in the projections starting in 2023. Early estimates indicate a moderate rise in electricity demand from AI; however, if adoption accelerates, electricity use could exceed current projections.
- Climatic conditions, characteristics of settlement, and a large district heating role result in the buildings sector being the most challenging sector to decarbonise in the Russian Federation.

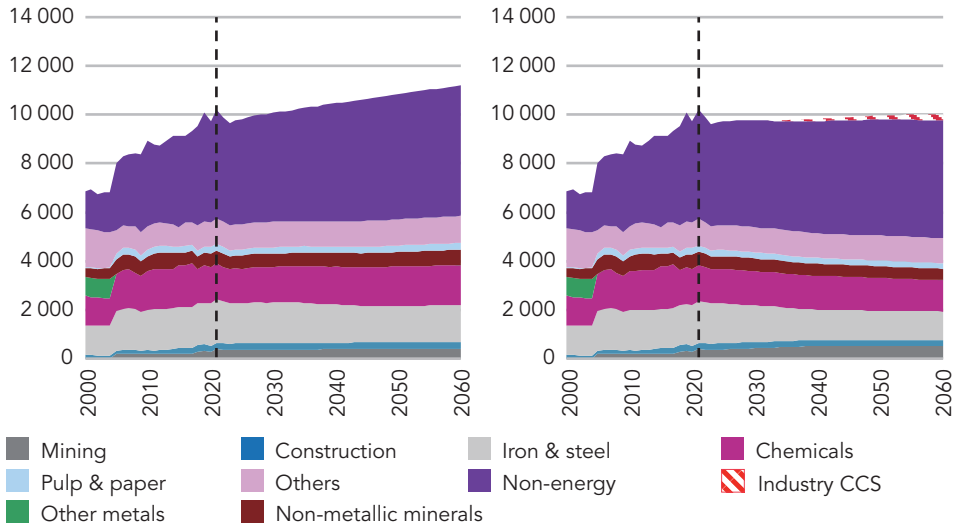
Industry Energy and Non-energy Demand

Figure 16-11. Industry & non-energy demand by fuel in REF & TGT (PJ)



- The industrial and non-energy sectors combined are the largest energy consumers in the Russian Federation. By 2060, industrial energy demand in TGT is 12% lower than REF, driven by material and energy efficiency gains. While non-energy demand grows in both scenarios, reduced feedstock demand and greater material efficiency in TGT make it 10% lower than REF.
- In REF, electricity and heat consumption rise modestly in industrial subsectors, while gas and oil use decline. However, oil and gas demand in non-energy remains strong, sustaining overall oil and gas consumption through 2060. Hydrogen use begins in a limited number of high-temperature processes and as a non-energy feedstock in 2040.
- The TGT scenario incorporates greater technological shifts and material efficiency gains that reduce total demand. Hydrogen is used more widely in iron, steel, and chemical production, while CCS is deployed in steel, cement, and chemical subsectors starting in 2030. Coal is phased out by 2030, ten years earlier than in REF. Hydrogen is also introduced in high-temperature processes and as a non-energy feedstock a decade earlier, beginning in 2030.

Figure 16-12. Industry & non-energy demand by sector in REF & TGT (PJ)



- In TGT, natural gas feedstock demand increases by 4%, reaching about 40% of total non-energy demand by 2060. Hydrogen accounts for 15% of demand in TGT, which is three times the level in REF. Oil and oil products comprise the remainder of non-energy demand.
- Higher electrification rates in TGT across most subsectors, especially mining, raise electricity's share of industrial energy use from 31% in REF to 38% in TGT by 2060.
- Despite slower overall industry growth in TGT, energy demand in mining increases in both scenarios. In TGT, this growth is to support rising global demand for critical minerals needed for low carbon technologies.

Transport Energy Demand

Figure 16-13. Domestic transport energy demand by fuel in REF & TGT (PJ)

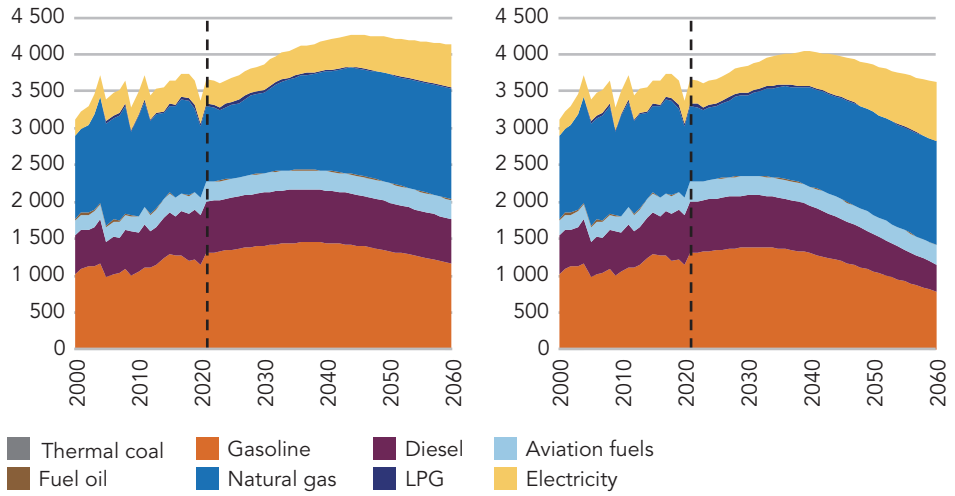
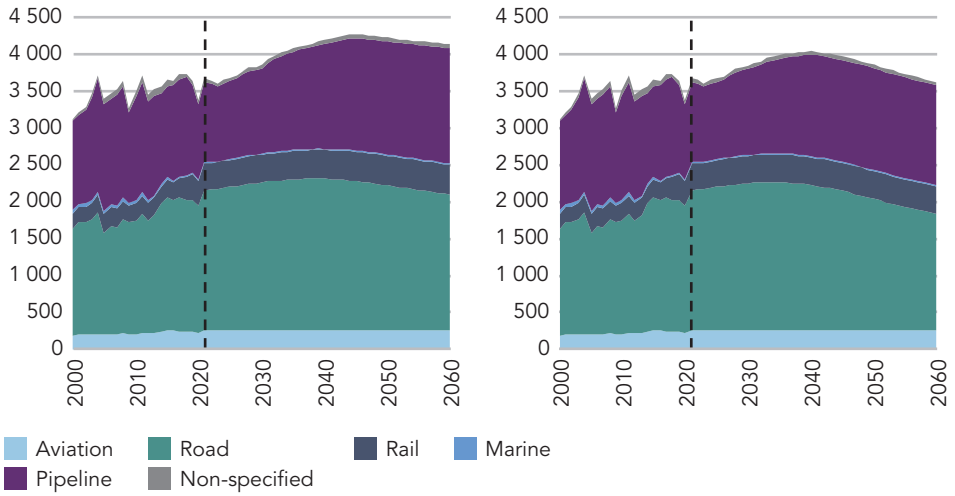


Figure 16-14. Domestic transport energy demand by sector in REF & TGT (PJ)



- Transport energy demand peaks around 2040 to 2045 in both scenarios, then declines in part due to population decrease, as well as increased adoption of electric alternatives for vehicles and decreased pipeline transport.
- Road transport remains the largest energy user in the sector. In REF, battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs) gradually enter the passenger fleet from 2030. Their combined share reaches 28% by 2060. In contrast, TGT assumes earlier and faster adoption, with BEVs and PHEVs reaching 55% of the passenger stock by 2060. As electric vehicles become more common, gasoline use declines while electricity demand rises.
- In REF, there are minimal changes in freight vehicle type. In TGT, some diesel freight vehicles are replaced by BEVs and PHEVs, but compressed natural gas (CNG) plays a more significant role, making up over 22% of the stock by 2060. CNG offers advantages over diesel, including lower emissions, and potentially reduced operating costs.
- Because BEVs and PHEVs are more energy-efficient than ICE vehicles, their adoption contributes to lower overall energy use. By 2060, road transport energy demand in TGT is 14% lower than in REF.
- Russia's transport energy demand is unique within APEC, with a large share used to move natural gas through pipelines. Natural gas remains the primary fuel for gas pipeline operations. In TGT, some pipeline operations switch from gas to electricity, but overall natural gas use stays relatively high due to limited electrification for pipeline transport and its role in CNG freight. The reduced gas production in TGT leads to a 13% decline in the energy used in pipeline transport relative to REF.

Electricity Generation

Figure 16-15. Electricity generation by fuel in REF (TWh)

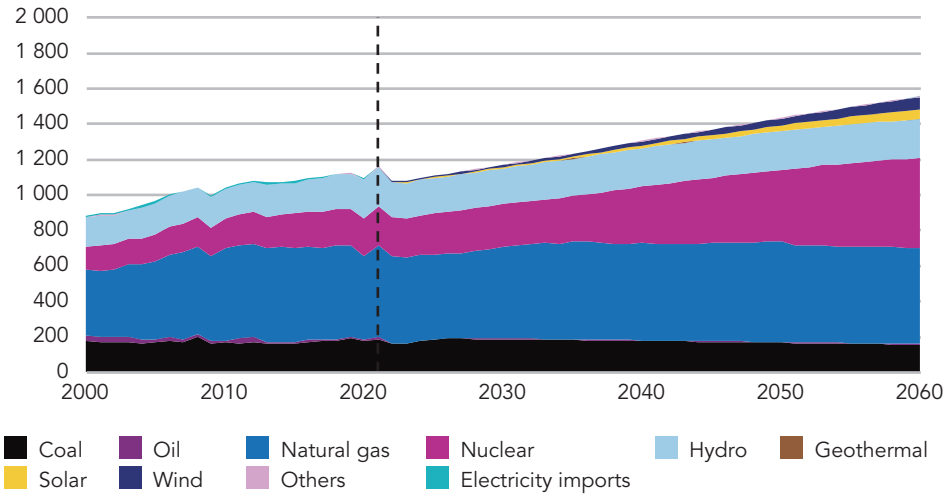
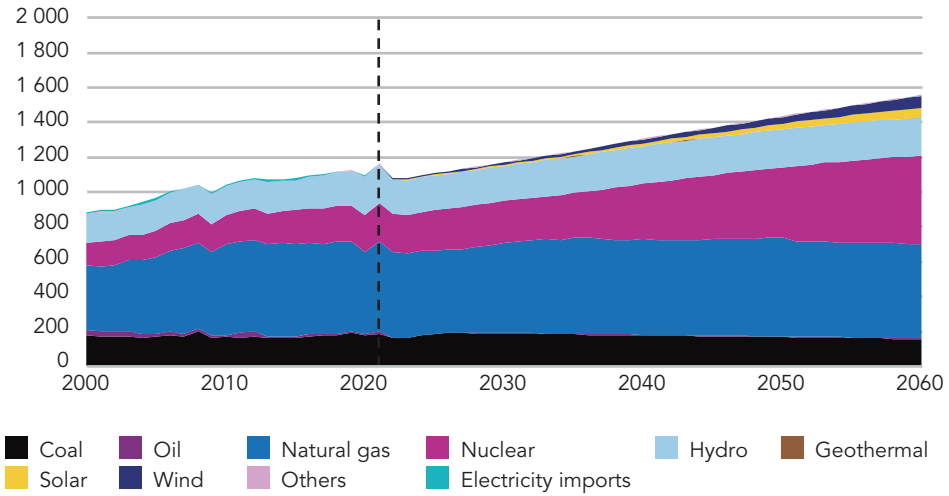


Figure 16-16. Electricity generation by fuel in TGT (TWh)

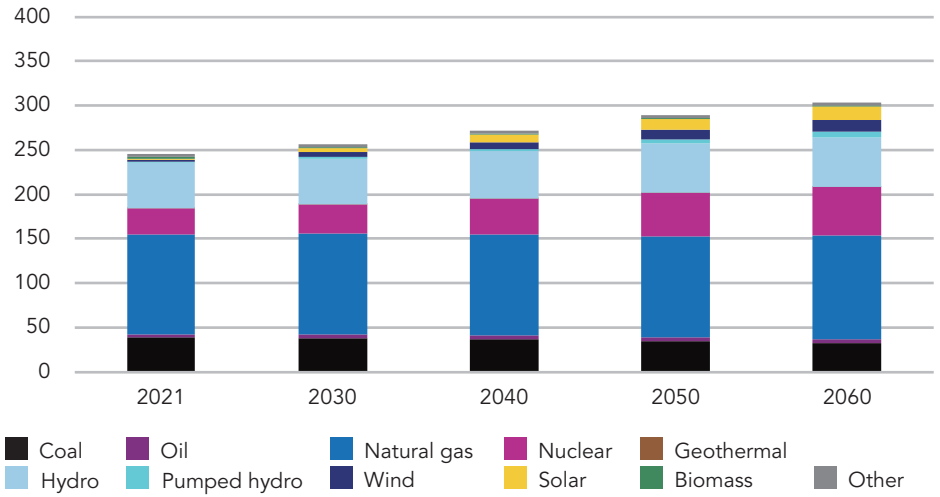


- Russia's electricity generation in REF is projected to increase by 24% from 2021 levels to 1,444 TWh in 2060.
- Nuclear power plants will provide over 70% of the incremental increase in electricity generation, which corresponds to the Russian Federation's Energy Strategy 2050. Gas-fired power plants will continue to account for the highest share of thermal generation.
- In REF, a conservative estimate of the role of renewables in electricity generation is adopted. The share of solar and wind will be around 3.4% by 2060.
- Coal-fired generation increases slightly in the REF scenario due to the existing geographical structure of installed capacity. In TGT, coal-fired generation remains at the existing level.

- In TGT, electricity generation is 8% higher than in REF. Similar to REF, nuclear power plants will provide over 70% of the incremental increase in electricity generation. As TGT adopts the Russian Federation's Energy Strategy 2050 and General Scheme for the Placement of Electric Power Facilities until 2042, it incorporates targets for nuclear generation development, including large conventional reactors and SMRs.
- Wind and solar combined will meet around 30% of the incremental increase in electricity generation in TGT, compared to 16% in REF.
- Thermal generation will remain the foundation of the power system, with a dominant share of gas and a declining share of coal generation. Electricity generation from hydro power plants will increase slightly in both scenarios.

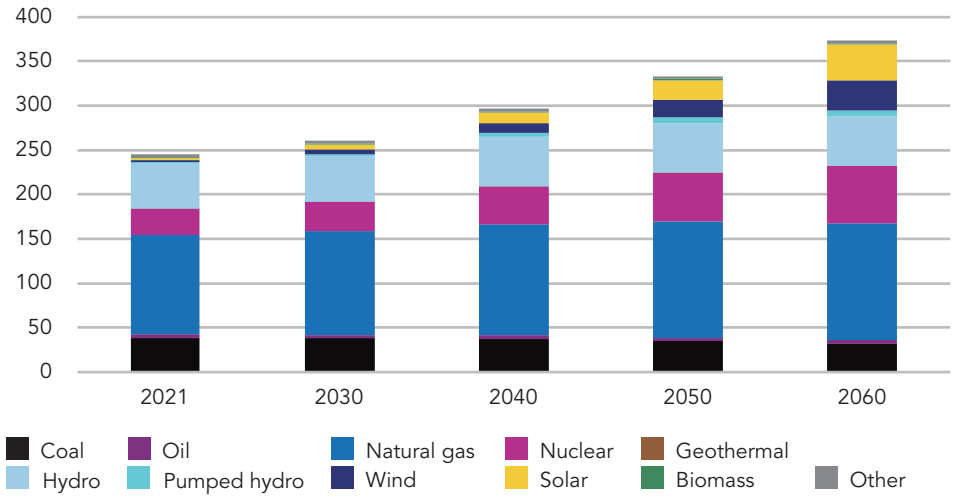
Generation Capacity

Figure 16-17. Generation capacity by fuel in REF (GW)



- In REF, total installed capacity is projected to increase by 24% (59 GW) by 2060. Nuclear power will account for nearly 43% of this growth, while wind and solar will contribute approximately 20% and 23%, respectively. Gas, hydro, and pumped hydro will each contribute around 9%. The decline in coal-fired capacity will partially offset these increases. Notably, nuclear capacity will grow by 85% compared to current levels.
- In REF, the share of thermal generation capacity will decline by around 13% by 2060, primarily due to a reduction in coal-fired power and an accelerated expansion of nuclear and renewable capacity. The share of hydro will fall from 21% presently to 18% in 2060, while the nuclear share will rise to 18%.
- REF projects wind capacity to reach 14 GW and solar capacity to reach 15 GW by 2060, together accounting for 9% of total installed capacity.

Figure 16-18. Generation capacity by fuel in TGT (GW)



- In TGT, total installed capacity is expected to reach 373 GW by 2060.
- Under TGT, nuclear capacity is projected to reach 65 GW by 2060, aligning with the goals set in the Energy Strategy 2050 and the General Scheme for the Placement of Electric Power Facilities to 2042.
- In TGT, gas-fired capacity will increase to replace coal generation and ensure reliability during peak demand periods. This will necessitate the expansion of gas supply infrastructure, particularly in the eastern regions of the economy.
- TGT also outlines more ambitious targets for renewable energy development, with solar and wind capacities rising to 40 GW and 35 GW, respectively, comprising 20% of total installed capacity by 2060.

Note: Figures 16-17 and 16-18 do not include generation capacity for hydrogen production.

Electric Grid Reliability

Figure 16-19. Total generation capacity and peak load (GW)

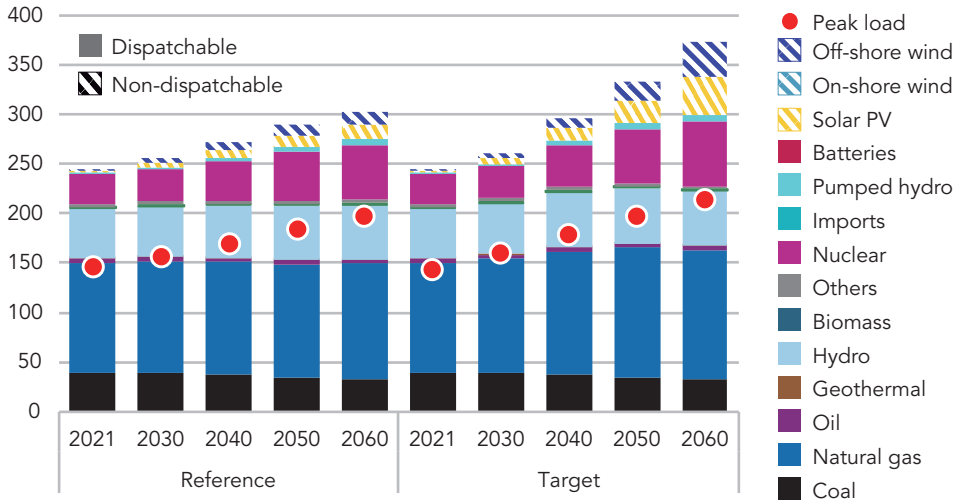
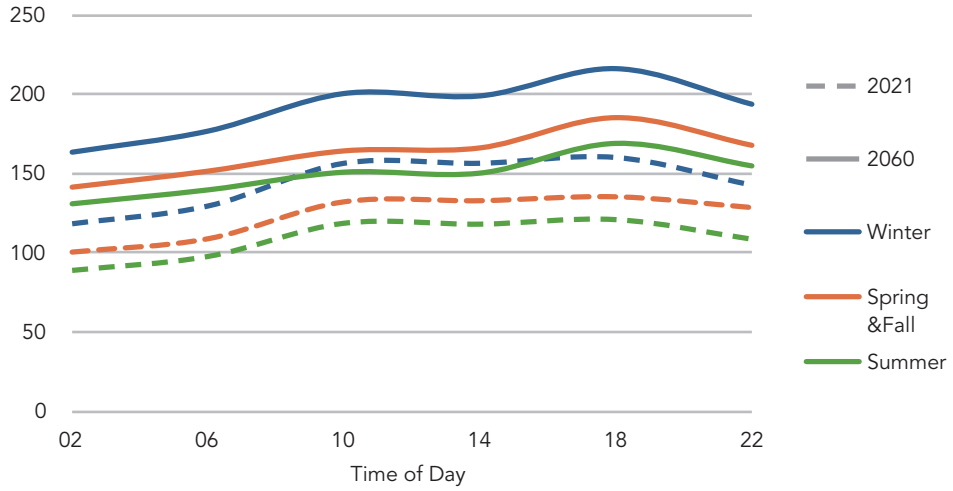


Figure 16-20. Power from dispatchable sources in TGT (GW)



- In REF, the peak electricity load increases by 33%, reaching 194 GW by 2060. In the TGT scenario, greater electrification drives a 42% increase, pushing the peak load to 208 GW.
- Due to the intermittency of solar and wind, which operate at lower capacity factors, total installed generation capacity must grow faster than peak demand to ensure system reliability.
- In REF, total generation capacity rises by 24%, reaching 303 GW by 2060. In TGT, capacity must grow by 53% to 373 GW to accommodate higher electrification and more variable renewables.
- Grid reliability depends on sufficient dispatchable capacity, including thermal plants, hydro, and batteries, to meet demand during periods when solar and wind output is low.

- As of 2020, nearly all electricity demand was met by dispatchable sources. Fluctuations in their output follow daily and seasonal consumption patterns, with winter requiring the highest dispatchable power due to peak heating loads.
- By 2060, dispatchable generation will need to ramp by approximately 40 GW on an average summer day, 45 GW in spring and fall, and up to 55 GW in winter to balance the system.
- Although Russia's current reliance on wind and solar is modest, resulting in lower system variability compared to other economies, regional differences and extreme weather events may lead to greater fluctuations than seasonal averages suggest.

Coal

Figure 16-21. Coal consumption by sector in REF & TGT (PJ)

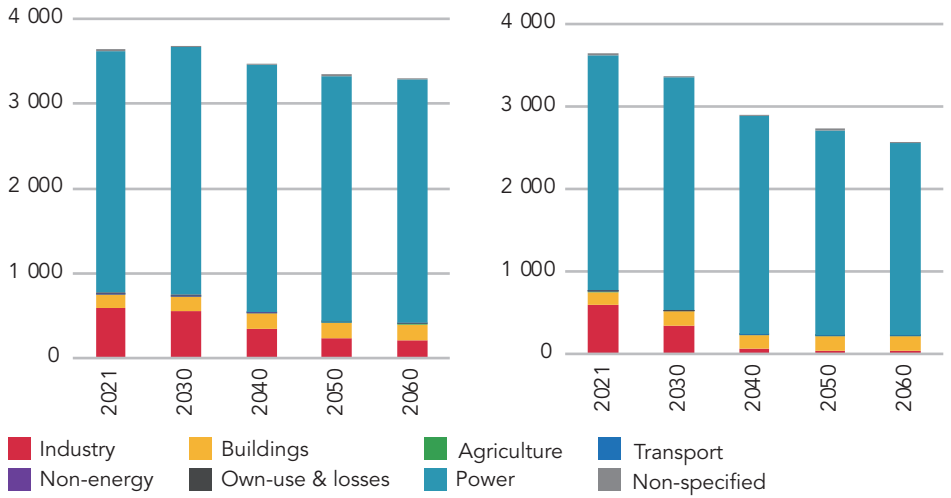
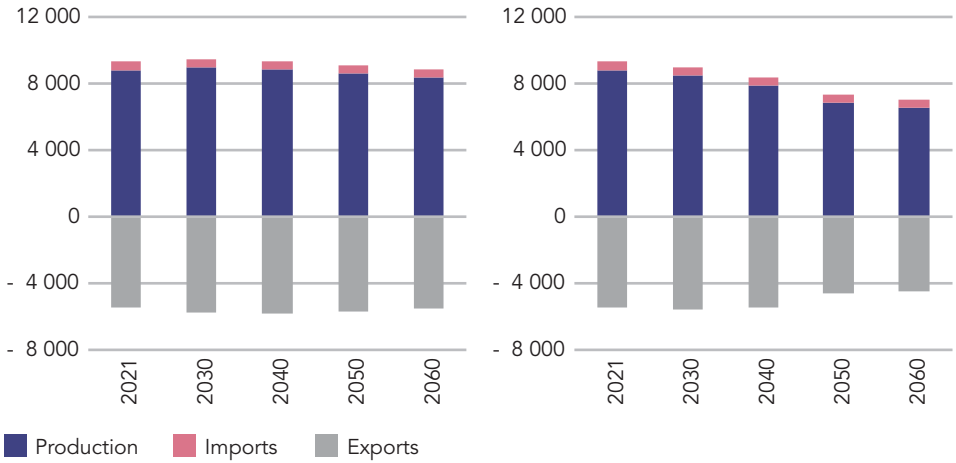


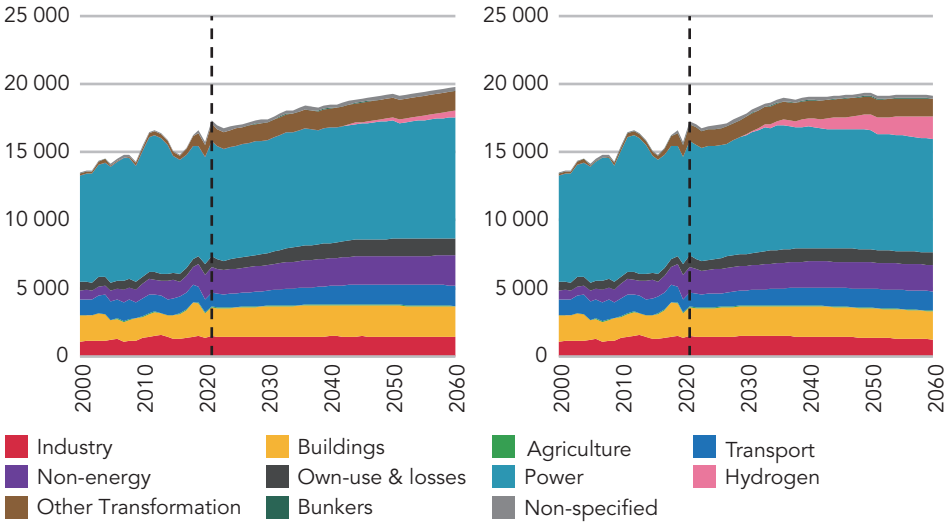
Figure 16-22. Coal production, imports, and exports in REF & TGT (PJ)



- The power sector is the largest consumer of coal in Russia. In REF, coal consumption in the power sector will grow slightly in the coming decade due to increased coal-fired electricity generation and heat production. While in TGT, coal consumption will start to decline, specifically after 2030, due to the replacement of coal with natural gas, the much larger implementation of nuclear generation, as well as solar and wind additions.
- Domestic use of coal will remain important in Siberia and the Far East, especially in Arctic and remote territories. Environmental goals reflected in the Energy Strategy 2050 call for a 25% reduction in GHG emissions from mining and processing by 2050 through innovation and clean coal technologies.
- In REF coal exports are decreasing only slightly, while in TGT they are decreasing quite noticeably due to ongoing global efforts to decarbonise the power sector and electrify end-use sectors in key markets. Combined with declining domestic coal consumption, coal production will decline by over 25% by 2060.
- Russia's Energy Strategy 2050 prioritises new extraction hubs in eastern Russia, expanding infrastructure for exports, especially to the Asia-Pacific region.
- Traditional coal regions, particularly those remote from emerging export markets, face challenges to their long-term economic viability. The strategy addresses this by promoting a shift toward coal processing, advanced coal chemistry, and higher-value industrial applications to support regional resilience and economic diversification.

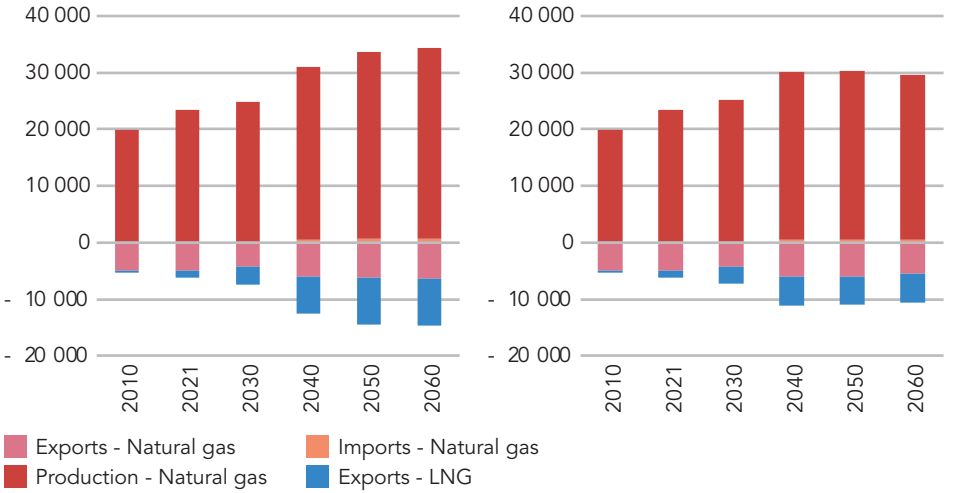
Natural Gas

Figure 16-23. Natural gas consumption by sector in REF & TGT (PJ)



- Natural gas is the largest component of Russia's primary energy supply, with the power sector being the largest consumer, followed by industrial non-energy uses. It also plays a crucial role in the residential heating sector and in high-temperature industrial processes.
- In REF, gas consumption continues to grow steadily, whereas in TGT, it peaks in the mid-2030s, largely due to its declining use in the power and heat sectors driven by improved efficiency.
- Natural gas serves as a transitional fuel, helping to phase out coal in power generation and enabling blue hydrogen production, supported by long-term integration of carbon capture technologies.
- Natural gas is expected to play a growing role in transport, particularly for heavy-duty vehicles and shipping. Gas use in the chemical sector is also encouraged for value-added production.

Figure 16-24. Natural gas production, imports, and exports in REF & TGT (PJ)



- Russia's abundant gas reserves are sufficient to meet both domestic needs and export commitments. However, future production will largely depend on export volumes.
- Pipeline gas exports remain significant, supported by new routes in Eastern Russia, but declining demand in Europe raises concerns about underutilisation of existing infrastructure.
- Expanding LNG capacity, particularly in the Arctic and Far East, is a strategic priority, with a target of reaching 110–175 million tons annually by 2050.
- In REF, global market conditions are assumed to support the full expansion of LNG exports, whereas in TGT, decarbonisation trends in key markets may limit the scale of such developments.

Note: Historical data for LNG is based on JODI gas data.

Crude Oil

Figure 16-25. Crude oil supply in REF & TGT (PJ)

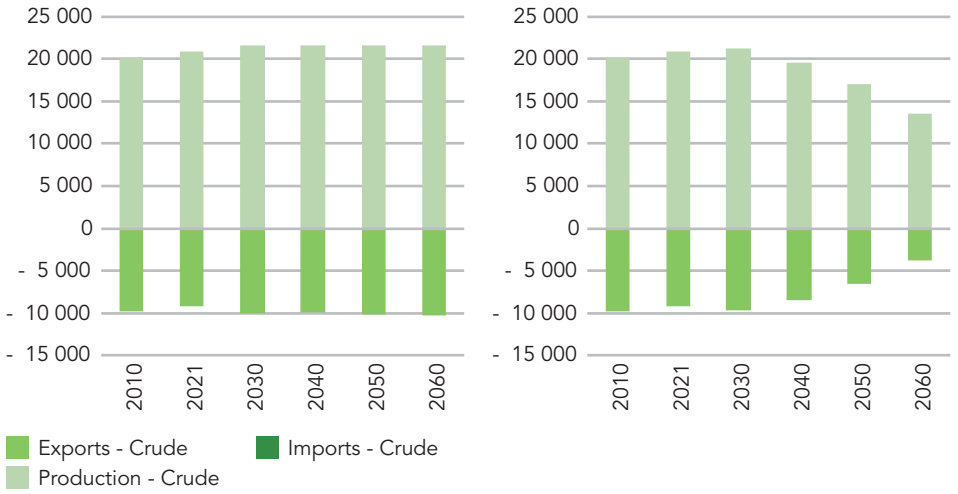
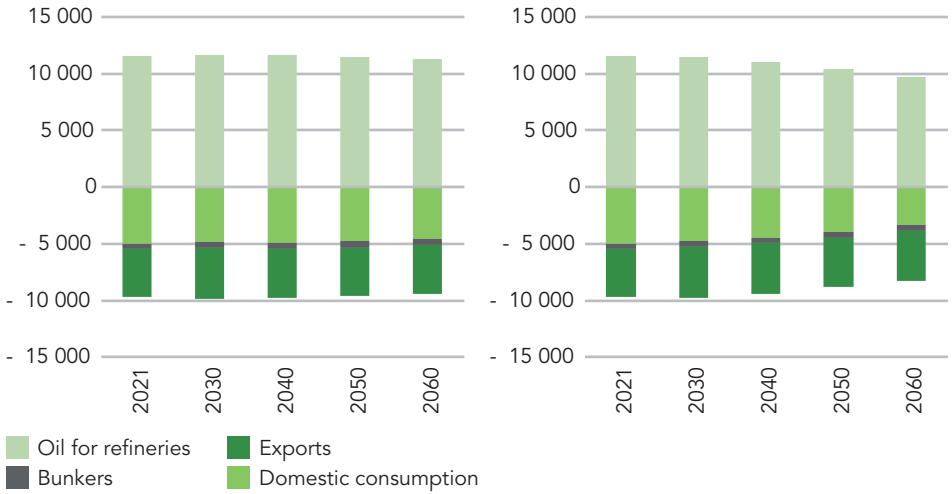


Figure 16-26. Refined products outputs and exports in REF & TGT (PJ)



- Russia possesses substantial oil reserves, with nearly half of its crude oil production currently exported.
- In REF, crude oil production remains relatively stable through 2060, supported by the development of hard-to-recover reserves and the use of enhanced recovery technologies. In TGT, production peaks around 2030 and gradually declines thereafter, reflecting reduced domestic demand for petroleum products and lower exports of crude oil and refined fuels.
- The Energy Strategy 2050 acknowledges increasing uncertainty in global markets due to decarbonisation trends and geopolitical shifts. A strategic pivot toward value-added processing and petrochemical manufacturing is expected to help sustain oil production while decreasing dependence on crude oil and petroleum product exports.
- Russian oil refineries have built competitive advantages through large-scale operations and access to domestically produced crude, enabling them to consistently export around half of their refined products. Key export products include diesel, fuel oil, and naphtha.
- Total refined product consumption, including bunkers, is projected to peak in the late 2020s to mid-2030s in both the REF and TGT scenarios, followed by a modest decline in REF and a more pronounced decrease in TGT.
- Exports of excess refined products, mainly diesel and fuel oil, are maintained in REF with a slight decline in the long term as refinery outputs decline. Exports in TGT decline more rapidly, which aligns with the rapid decline in consumption in the key markets.
- Refining capacity is expected to decline by 17% in REF and by 27% in TGT by 2050, while improving processing efficiency and increasing output of higher-value products such as gasoline, diesel, and petrochemical feedstocks.
- A strategic priority is the expansion of petrochemical production to support import substitution and boost the value of exports.

Refining

Figure 16-27. Refining outputs in REF & TGT (PJ)

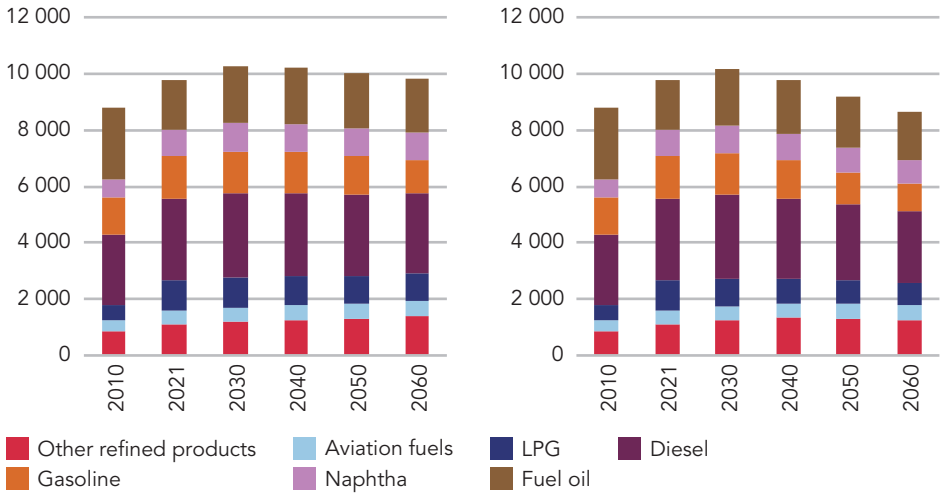
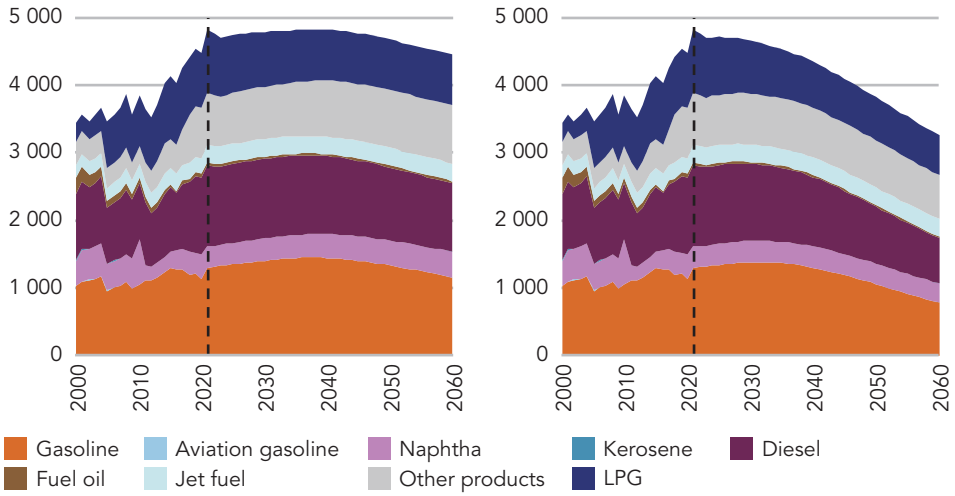


Figure 16-28. Refined products demand in REF & TGT (PJ)



- Total refining output is projected to peak between the late 2020s and mid-2030s in both REF and TGT scenarios.
- Diesel remains the dominant product in the refining mix, followed by fuel oil, gasoline, natural gas liquids (NGLs), and naphtha.
- In REF, gasoline and diesel production gradually decline in line with falling domestic consumption, enabling a shift toward higher yields of jet fuel to meet growing demand.
- In TGT, a steeper decline in the production of gasoline, diesel, and LPG allows for a more pronounced increase in jet fuel output.
- The transport sector remains the primary consumer of refined products. Transport fuel consumption peaks around 2040–2045 in both scenarios, followed by a gradual decline.
- Gasoline use decreases steadily as battery electric vehicles (BEVs) and plug-in hybrids (PHEVs) become more widespread.
- Diesel consumption remains relatively stable in REF but declines in TGT due to increased adoption of BEVs, PHEVs, and compressed natural gas (CNG) in freight transport.
- Improved energy efficiency, particularly through electrification, leads to 14% lower road transport energy use in TGT compared to REF by 2060.

Hydrogen

Figure 16-29. Hydrogen demand by sector in REF & TGT (PJ)

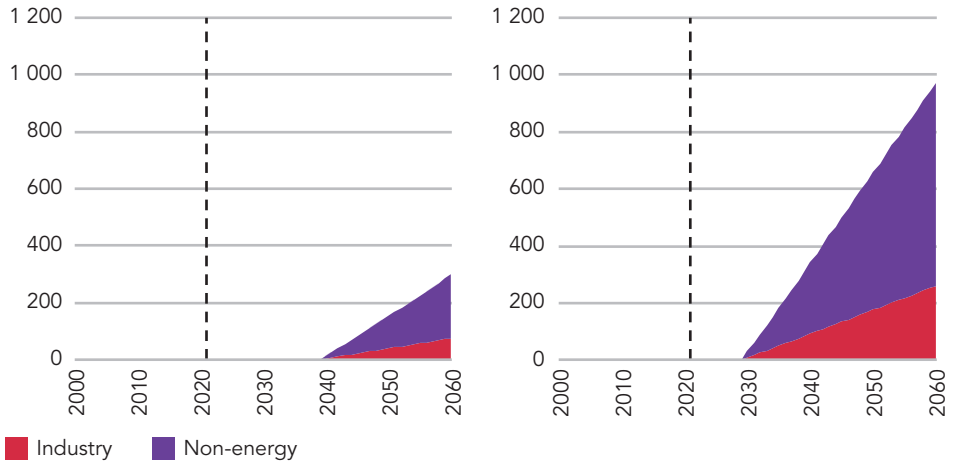
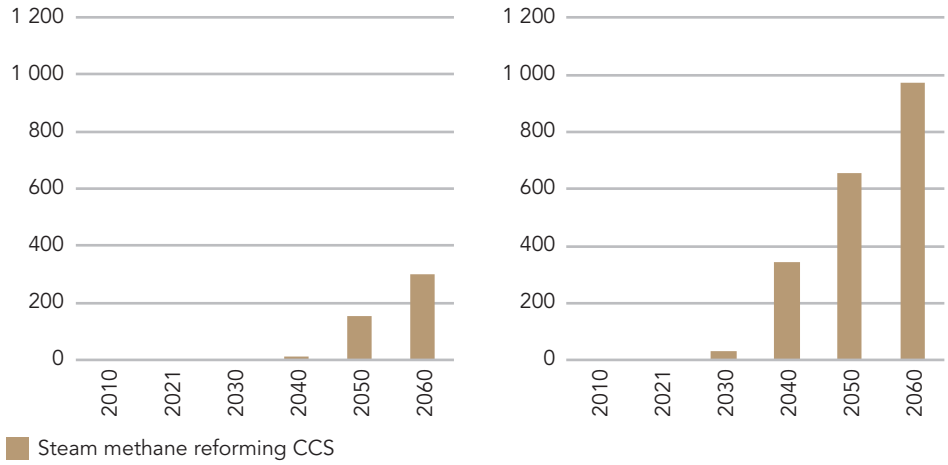


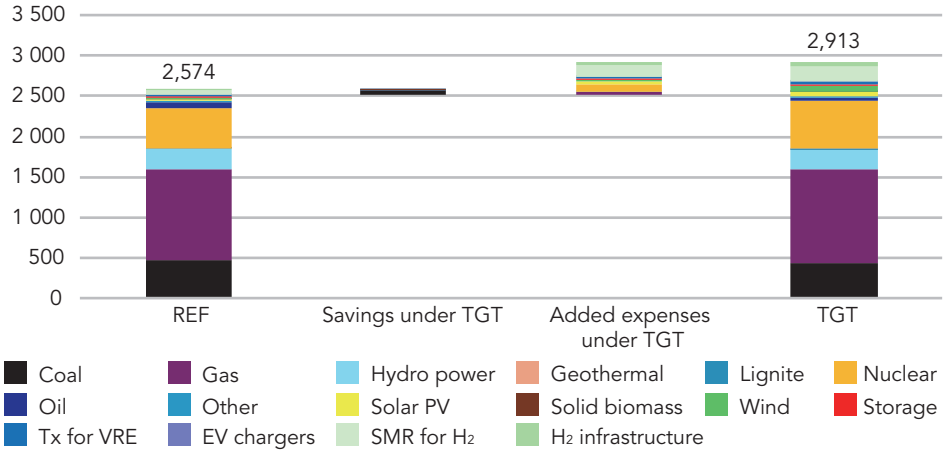
Figure 16-30. Hydrogen production in REF & TGT (PJ)



- In REF, hydrogen use as an energy carrier begins in the late 2030s and remains limited, exceeding 2 million tons annually by 2060. Under this conservative outlook, hydrogen is mainly used by export-oriented chemical producers.
- TGT envisions a significantly wider role for hydrogen in industrial applications, with its share in the industrial fuel mix reaching approximately 10% and total consumption growing to over 7 million tons by 2060.
- In both scenarios, hydrogen is not considered as a fuel for the transport sector.
- Hydrogen is viewed as a strategic pathway for diversifying the gas sector, capitalising on Russia's existing infrastructure, expertise, and natural gas resources.
- Hydrogen's development is closely linked to the decarbonisation of exports, with hydrogen seen as a means to maintain access to carbon-constrained markets in Europe and Asia.
- Given delays in the rollout of hydrogen production and its use as an energy carrier, significant hydrogen exports are not expected by 2060.
- The primary production emphasis is on low-carbon blue hydrogen, based on natural gas with carbon capture and storage.
- Overall, hydrogen development in Russia remains at an early stage and depends heavily on global demand, international partnerships, and the pace of cost reductions from technological advances.

Costs

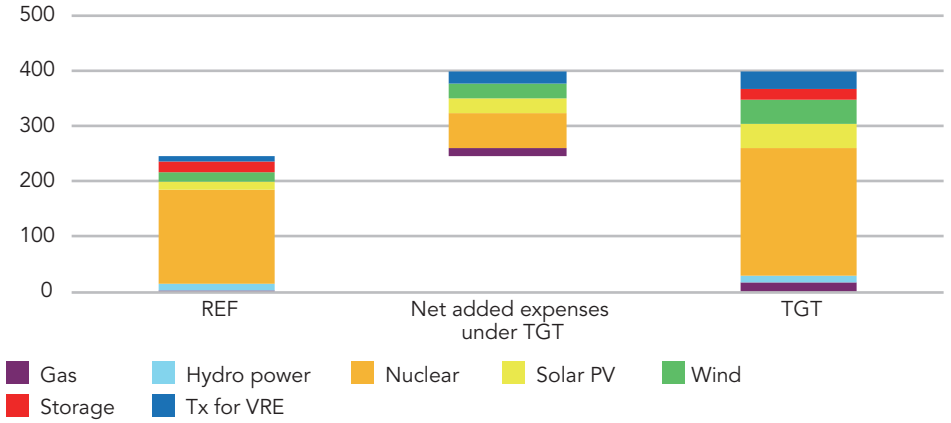
Figure 16-31. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



Note: Tx for VRE is only transmission infrastructure to connect variable renewable capacity to the grid. EV chargers do not cover the cost of associated infrastructure or EV vehicles.
SMR is Steam Methane Reforming used to produce blue hydrogen.

- Meeting Russia's future energy demand is expected to require substantial costs, from 2025 to 2060 in both scenarios. Figure 16-31 includes the total capital, fixed, and variable costs in the power sector, blue hydrogen production costs, transmission for VRE, heat production costs from stand-alone and combined heat and power plants (CHPs) and electric vehicle chargers.
- Gas, nuclear, coal, and hydro power-related costs account for most of the increase in spending from 2025 onward in both scenarios. All four generator types are dispatchable power sources, and their role in providing reliable, on-demand generation helps ensure system stability, especially in TGT as variable renewables expand to comprise 20% of capacity by 2060.
- Although overall costs increase from 2025 onward in both scenarios, the cost difference between the two scenarios remains relatively modest. In 2060, total costs in TGT are only 13% higher than in REF, with most of the additional costs associated with using steam methane reforming to produce blue hydrogen for Russia's industry and non-energy sectors.

Figure 16-32. Total capital investment (CAPEX) from 2025 to 2060 in the power sector (billion USD, undiscounted)

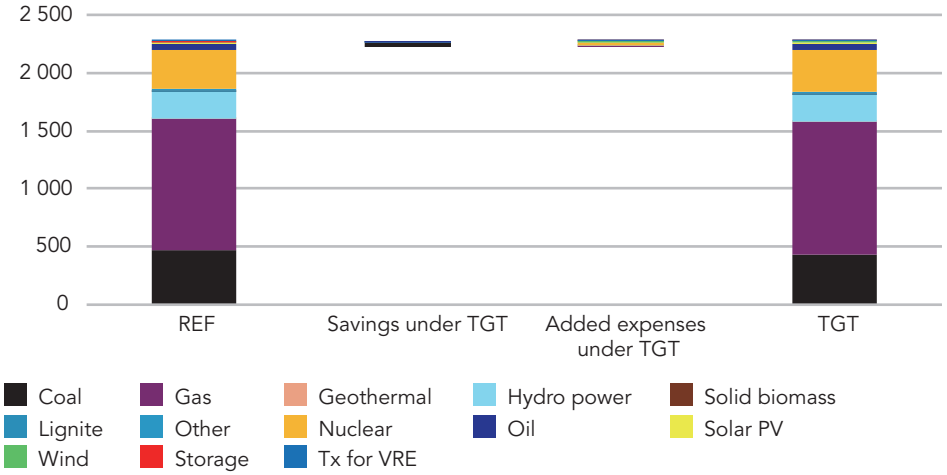


Note: Figure 16-32 only covers power and VRE transmission sector capital investments. Hydrogen and EV capital investments are not included.

- Total capital expenditures in the power sector is an estimated USD 399 billion in TGT, up from an estimated USD 246 billion in REF. Most of the additional expenses under TGT stem from capital expenditures for new nuclear accounting for 42% of the net added expenditure under TGT with additional investments in gas accounting for 9% of the total.
- While additional solar and wind capacity requires further investment in transmission (Tx for VRE) in TGT, additional battery investment is not needed. This is because Russia's electric grids already have sufficient dispatchable capacity and will not rely on battery storage for this flexibility.
- These power sector investments in renewables and the infrastructure needed to support them help drive the 11% reduction in emissions from power in TGT compared to REF by 2060.

Costs

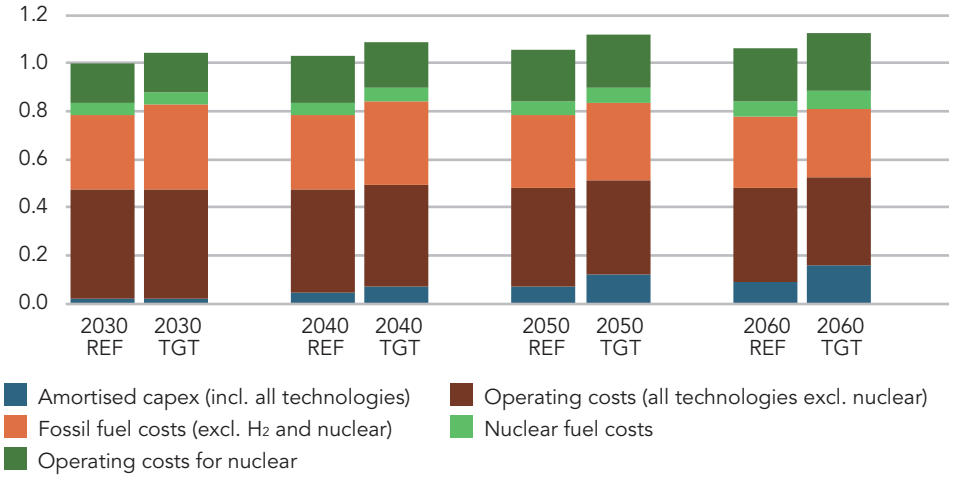
Figure 16-33. Total operating costs from 2025 to 2060 in the power sector (billion USD, undiscounted)



Note: Figure 16-33 only covers power and VRE transmission sector costs. It does not include operating costs associated with blue hydrogen production and EV charger costs.

- Total operating costs are estimated at USD 2.3 trillion in both scenarios and are the largest component in total costs. Operating costs include non-fuel variable expenditures, fixed and fuel costs for the power sector including CHP and heat only power plants. Fixed costs for transmission are also considered.
- The overall difference in operating costs between REF and TGT is relatively minor. In TGT, reduced reliance on coal leads to small operating savings. However, these are largely offset by increased costs associated with additional nuclear generation (and the high fixed costs incurred).
- Significant costs in both scenarios comes from fuel costs linked to heat production reflecting Russia's unique power sector. Due to its cold climate, heat production is necessary to maintain living standards in its cities through its district heating systems. Russia will continue to mostly rely on CHPs to produce heat and electricity as it is the most cost-effective way of producing both.

Figure 16-34. Cost of generating electricity relative to 2025 (2025 cost = 1.0) in the power sector



Note: Based on our assumptions about future capital and operating costs, this chart shows cost compositions over time relative to 2025. It should not be considered an estimate of electricity tariffs and excludes market mechanisms that are too difficult to estimate.

- Figure 16-34 shows the relative cost of generating electricity in selected years indexed to the base year of 2025 for each scenario. To note, it excludes costs related to heat production from CHPs and heat-only plants and electricity used to produce hydrogen.
- Indexed to 2025, REF generation costs are expected to remain relatively stable as cost components do not change significantly over time. TGT features higher shares of amortised CAPEX in its cost components due to the introduction of new generation capacity (mostly nuclear) and the need for additional system components.

CO_2 Emissions

Figure 16-35. CO_2 emissions in REF (million tonnes)

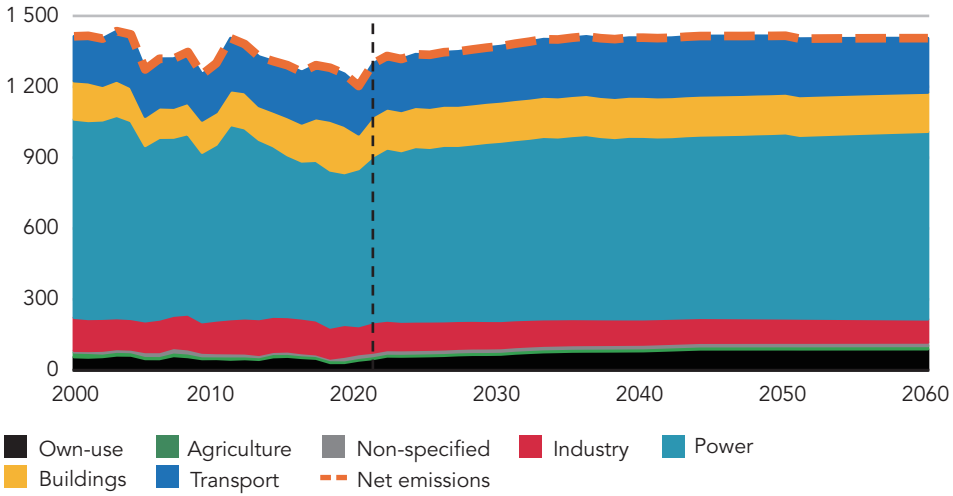
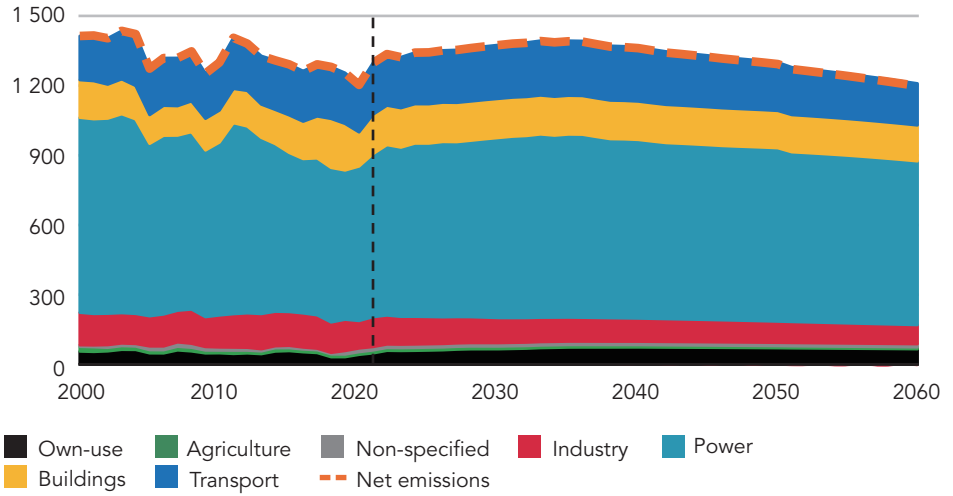
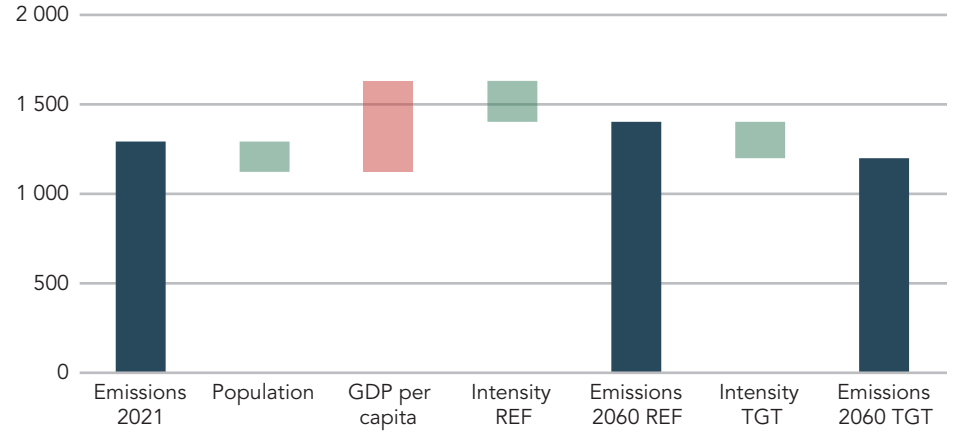


Figure 16-36. CO_2 emissions in TGT (million tonnes)



- Net CO_2 emissions in 2060 are projected to be 15% lower in TGT than REF. The largest contributors to this decrease come from the power sector, which accounts for around 43% of the total reduction, followed by transport at 24%, and industry at 13%.
- In both scenarios, part of the emissions reduction is attributed to a declining population (Figure 16-37). However, this is offset by an increased standard of living (GDP per capita).
- The remaining difference in emissions between REF and TGT is driven by changes in energy and carbon intensity. In TGT, efficiency gains across most sectors reduce overall energy demand, thereby lowering emissions. Despite higher electricity demand, a greater share of non-emitting power generation also contributes to further reductions compared to REF.

Figure 16-37. CO_2 emissions components (million tonnes)



Note: All values represent energy sector combustion CO_2 emissions. Biogenic CO_2 is treated as zero at the point of combustion. Emissions reductions from CCS are comparatively small and do not register in Figures 16-35 and 16-36.

Useful Links

APEC Expert Group on Energy Data and Analysis (EGEDA) – https://www.egeda.ewg.apec.org/

APEC Energy Statistics 2022 – https://www.egeda.ewg.apec.org/egeda/general/info/pdf/APEC_Energy_Statistics_2022.pdf

APEC Energy Overview – https://aperc.or.jp/reports/energy_overview.php

Energy Strategy of the Russian Federation 2050 – http://static.government.ru/media/files/LWYfSENa10uBrrBoyLQqAAOj5eJYlA60.pdf

General Scheme for the Placement of Electric Power Facilities until 2042 – http://static.government.ru/media/files/Rwf9Akjf5FwAnustDEL2m7PEvZ26i7k3.pdf

The Russian Federation Energy Security Doctrine – http://kremlin.ru/acts/bank/44252

The Presidential Decree "On Reducing Greenhouse Gas Emissions" – http://kremlin.ru/acts/bank/45990

The Strategy of Socio-Economic Development of the Russian Federation with Low Greenhouse Gas Emissions 2050 – http://static.government.ru/media/files/ADKkCzp3fWO32e2yA0BhtIpyzWfHaiUa.pdf

Federal Law "On Limiting Greenhouse Gas Emissions" – http://publication.pravo.gov.ru/Document/View/0001202107020031

The concept of the development of hydrogen energy in the Russian Federation 2035 – http://static.government.ru/media/files/5JFns1CDAKqYKzZ0mnRADAw2NqcVsexl.pdf

The concept for the development of production and use of electric vehicles in the Russian Federation 2030 – http://static.government.ru/media/files/bW9wGZ2rDs3BkeZHf7ZsaxnlbJzQbJJt.pdf



17. Singapore

Summary

	Reference			Target		
	2022	2060	% Change	2022	2060	% Change
Macroeconomic						
Population (million)	6	6.2	3%	6	6.2	3%
GDP (billion 2017 USD, PPP)	595	1,177	98%	595	1,177	98%
Energy Demand						
Buildings (PJ)	116	154	33%	116	104	-10%
Industry (PJ)	179	290	62%	179	258	45%
Non-energy (PJ)	284	457	61%	284	419	48%
Transport (PJ)	106	54	-49%	106	44	-59%
Modern renewables share of TFEC (%)	1.8	5.4	200%	1.8	33	1,733%
Energy intensity of TFEC (PJ/GDP, billion USD)	0.67	0.42	-37%	0.67	0.34	-49%
Electricity						
Generation (TWh)	57	72	26%	57	75	31%
Renewables share of generation (%)	3.6	7.1	95%	3.6	42	1,044%
Generation capacity (GW)	13	15	22%	13	19	51%
Total Primary Energy Supply (TPES)						
Coal & coal products (PJ)	17	0	-100%	17	0	-102%
Natural gas (PJ)	441	588	33%	441	387	-12%
Petroleum liquids (PJ)	303	737	143%	303	523	72%
Low-carbon & waste energy (PJ)	33	41	27%	33	266	717%
CO_2 intensity of energy supply ($MtCO_2/PJ$)	0.055	0.032	-42%	0.055	0.024	-57%
Net CO_2 Emissions (million tonnes)	44	47	8%	44	29	-33%

Note: In this publication, the term "modern renewables" refers to all renewable energy sources excluding solid biomass in the buildings sector. The term "low-carbon & waste energy" includes all bioenergy, waste-derived energy, renewables, nuclear, and hydrogen-based fuels. Total primary energy supply (TPES) numbers include international bunkers. Net emissions are calculated as gross energy sector combustion CO_2 minus CO_2 captured and stored through carbon capture and storage (CCS).

Key Takeaways

Emissions

- Singapore's gross CO_2 emissions from fuel combustion are projected to peak in the mid-2030s in the Reference scenario (REF) and decline thereafter, albeit continuing to increase gradually until 2060, reaching 47.2 million tonnes. In the Target scenario (TGT), emissions are projected to decline to 29.3 million tonnes by 2060.
- Emissions reductions in both scenarios are largely driven by electricity imports, increased deployment of solar PV, and adoption of hydrogen in the power sector. In addition, the significant deployment of battery electric vehicles in the transport sector contributes to the decline in emissions.
- Singapore's emissions in 2035 in both scenarios are well under the limit of 45-50 million tonnes of CO_2 equivalent as per its 2035 Nationally Determined Contribution (NDC). However, net-zero emissions are not projected to be achieved by 2050, given Singapore's significant dependence on fossil fuels for its power and industry sectors.

Energy Import Dependence

- Singapore remains a net importer of crude oil and petroleum products, as well as natural gas over the projection period in both REF and TGT. In addition, electricity imports constitute a small share of total imports relative to Singapore's total energy supply.
- Low-carbon fuels, in particular biodiesel and biojet kerosene (SAF), are expected to be produced domestically to meet the low-carbon energy needs of global aviation and marine bunkers. However, this necessitates a significant expansion of Singapore's existing biorefinery facility, requiring a substantial level of investment, infrastructure, and feedstock availability.

Figure 17-1. Net CO_2 emissions (million tonnes)

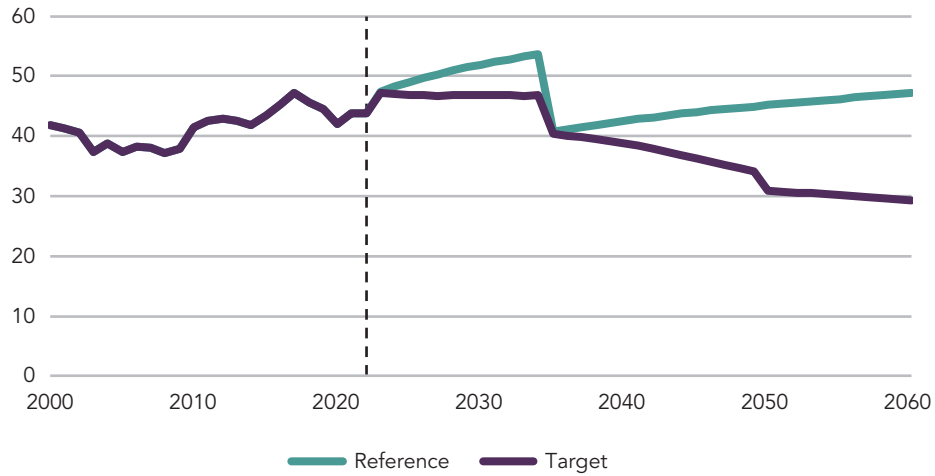
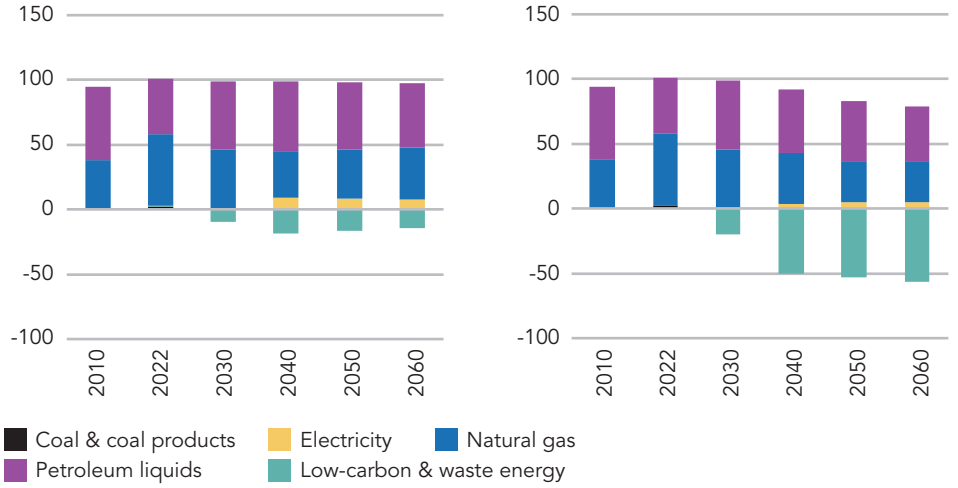


Figure 17-2. Net imports share of TPES in REF & TGT (%)



Note: In Figure 17-2, net imports refer to total imports minus exports and international bunkers.

Key Takeaways

Grid Reliability

- Electric grid reliability necessitates an instantaneous balance between power supply and demand. Maintaining this balance requires adequate dispatchable power sources, which can include battery storage systems and reliable electricity imports.
- In REF, Singapore continues its reliance on dispatchable natural gas generation together with electricity imports to meet baseload and peak demand. While the share of electricity generation from domestic solar is limited, the presence of battery storage systems helps in stabilising the dispatchable power generation.
- Although gas-fired electricity generation and electricity imports in TGT remain dominant, the gap between maximum and minimum dispatchable generation widens as the share of domestic solar generation increases. This requires scaling-up battery energy storage systems to further minimise supply-demand mismatches.

Cost

- Singapore's power and hydrogen sectors will require significant levels of financial expenditures from 2025 to 2060 in both scenarios.
- Total costs in REF are estimated at USD 243 billion in 2060. An additional USD 210 billion is estimated to be required in TGT, mainly to fund the importation of low-carbon hydrogen-based fuels (hydrogen, ammonia and e-fuels). The total savings of USD 24 billion from reduced gas use in power plants (in line with higher electricity imports) are insufficient to offset the added expenses associated with importing hydrogen-based fuels.
- Overall, managing these costs will be essential to maintaining economic efficiency while charting Singapore's energy transition.

Figure 17-3. Peak load and maximum and minimum dependence on dispatched power (GW)

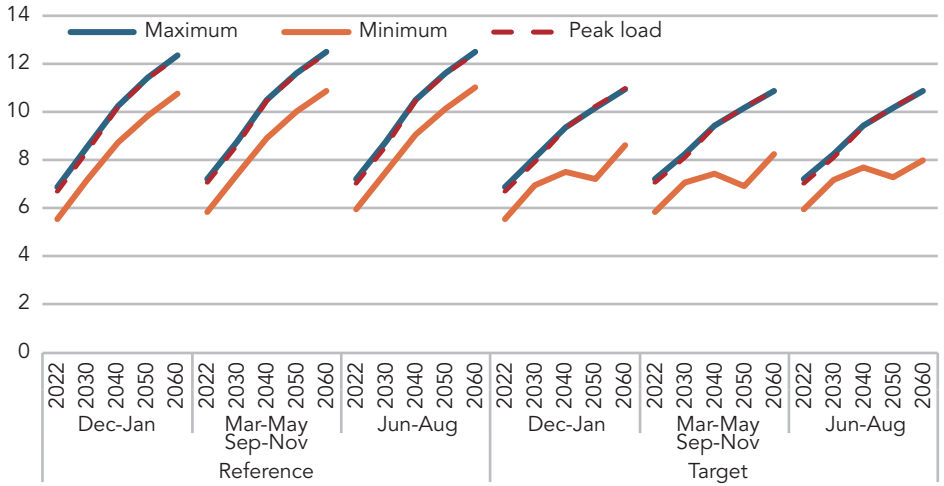
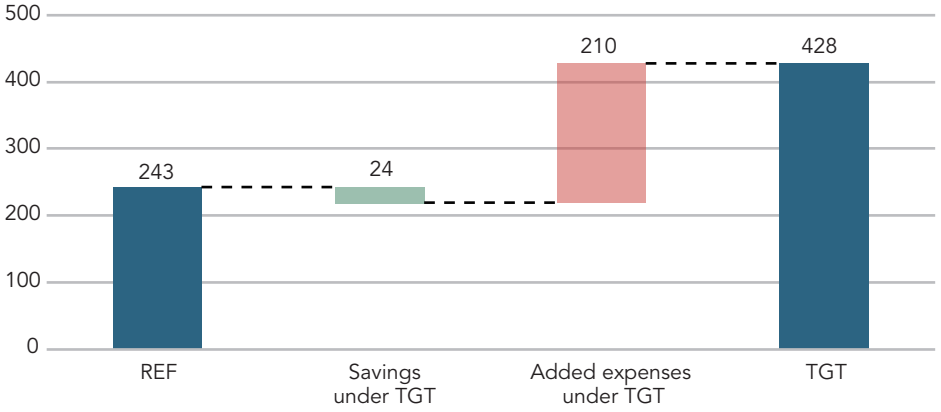


Figure 17-4. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



*Actual costs will differ from estimated costs in the *Outlook* for a variety of reasons including changing commodity prices, manufacturing costs, and unforeseen technical advances. All costs are in 2023 real terms.

About Singapore

Overview

Geographical and Economic Landscape

Singapore is a small island city-state, located between Indonesia and Malaysia. Spanning a total land area of 719.1 square kilometres, Singapore comprises more than 60 islands, with Jurong Island, Pulau Tekong, Pulau Ubin, and Sentosa being amongst the largest. The majority of Singapore is no more than 15 metres above sea level. However, with 30% of its overall land below five metres, the low-lying economy is susceptible to climate change effects, particularly rising sea levels. To future-proof its coastal shores, Singapore has allocated USD 92 million to a coastal protection and flood management research program, which aims to explore and develop innovative solutions for coastal protection, flood management research, and solutioning.

Singapore's economic success emanates from sound policies aimed at maintaining a conducive environment for long-term investments. Leveraging its geographical position, the Port of Singapore has long been a key global trade and logistics centre, with an annual average of 140,000 vessel calls. Combined with its openness policy, Singapore's consistently high trade-to-GDP ratio has made it one of the world's most open economies.

Energy Supply and Consumption

Singapore has successfully transitioned its energy mix, shifting from fuel oil to natural gas over the course of two decades. Natural gas is now the primary fuel for electricity generation, accounting for over 90% of Singapore's total electricity generation. Being a net energy-importing economy, it imported about 6,082 PJ of energy commodities in 2022, of which over 90% was oil (crude oil and petroleum products). Natural gas accounted for over 7% of the total imports, followed by coal and biomass at 0.3% and 0.06%, respectively. The industry and petrochemical sectors have long been the corner-stone of Singapore's economy, and are consequently the dominant energy consumers, accounting for over 67% of Singapore's total consumption.

Energy Security Challenges and Strategies

Singapore considers energy security to be a critical component in securing a stable energy supply while simultaneously working towards its net-zero emissions goal. Natural gas is expected to continue being a vital commodity for addressing potential energy shortages and volatility in electricity prices in Singapore. Some of the main strategies to address Singapore's energy security challenges include: i) establishing a new entity called Singapore GasCo, which will centralise procurement and supply of natural gas to power generation companies with longer and favourable terms, and ii) updating its low-carbon electricity import target from 4 GW to 6 GW by 2035 to meet one-third of Singapore's future energy needs.

Key Energy Initiatives

2035 Nationally Determined Contribution

Singapore has committed to reduce GHG emissions to between 45 and 50 million tonnes CO_2e in 2035, building on its 2030 NDC. This paves the way for Singapore to achieve net-zero emissions by 2050.

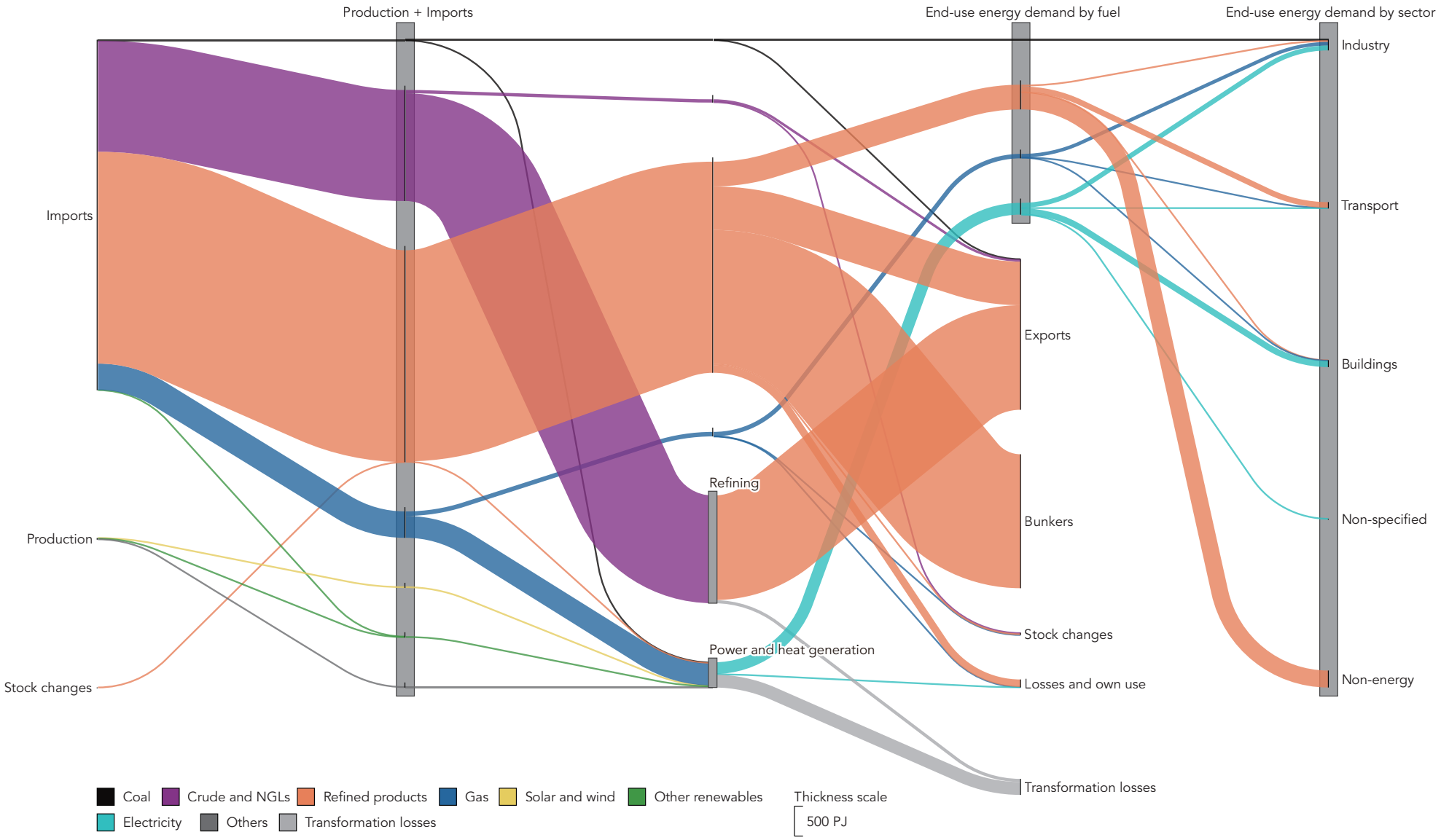
Singapore Carbon Tax

The carbon tax will be raised to SGD 25 per tonne of CO_2 equivalent in 2024 and 2025, and SGD 45 per tonne of CO_2 equivalent in 2026 and 2027, with an aim of reaching SGD 50–80 per tonne of CO_2e by 2030.

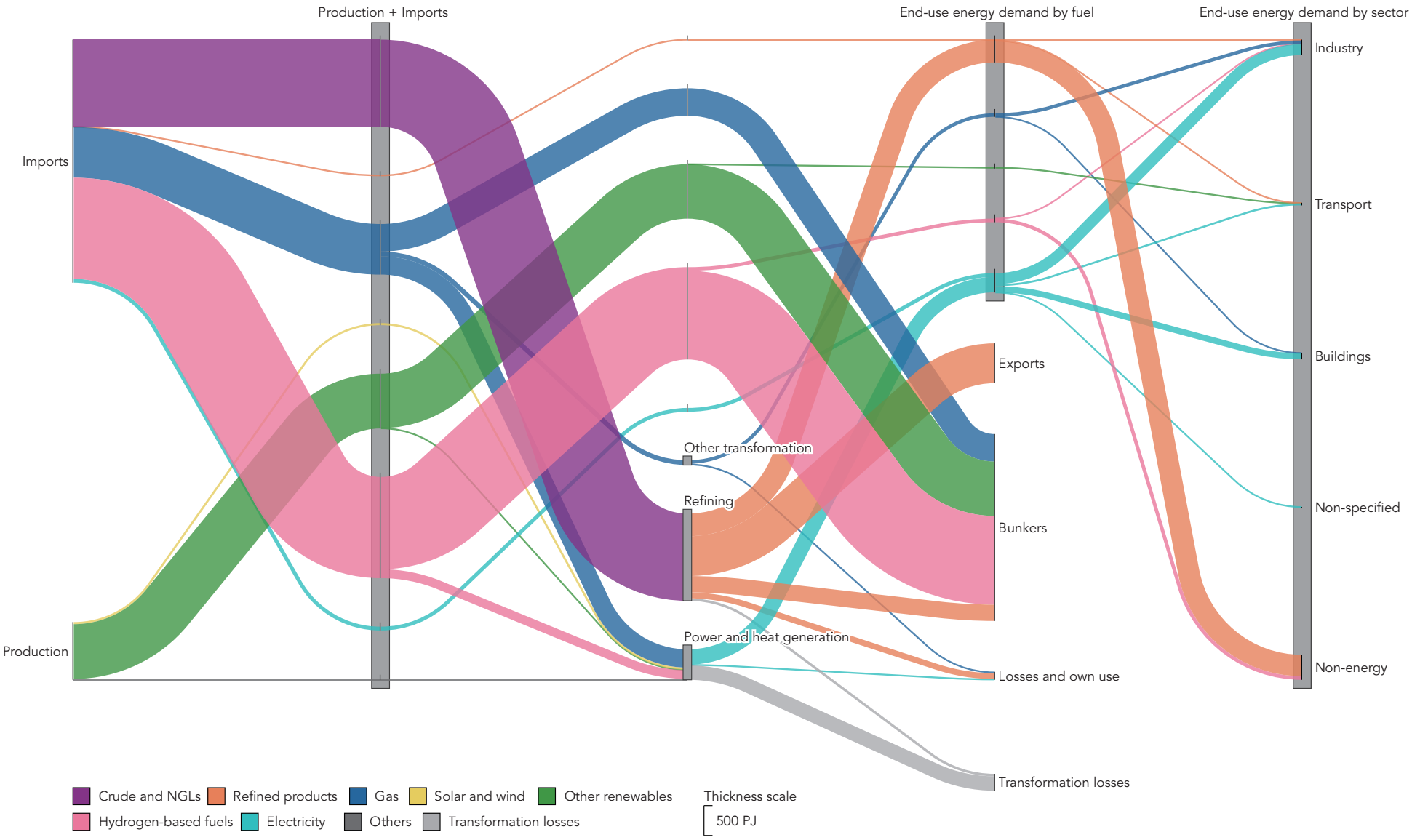
National Hydrogen Strategy

Singapore launched a National Hydrogen Strategy in October 2022 to develop hydrogen as a major decarbonisation pathway to net-zero emissions by 2050. Hydrogen could supply up to half of Singapore's power needs by 2050, subject to technological developments and the development of other energy sources.

Energy Flow (2022)



Energy Flow (2060, Target Scenario)



Scenarios and Assumptions

In *The Outlook*, APERC analyses energy demand, transformation, and supply, as well as emissions. The **Reference Scenario (REF)** offers a projection based on historical trends, recent developments, and APERC's assumptions about the continuation of those trends in each APEC economy, while acknowledging technical restraints. The REF Scenario offers a baseline to compare with the **Target Scenario (TGT)** projections, which explores a hypothetical pathway where each economy achieves energy-related policy targets, assuming implementation regardless of cost-effectiveness. When implementation details are lacking, assumptions are inferred from the targets themselves or emissions-related goals.

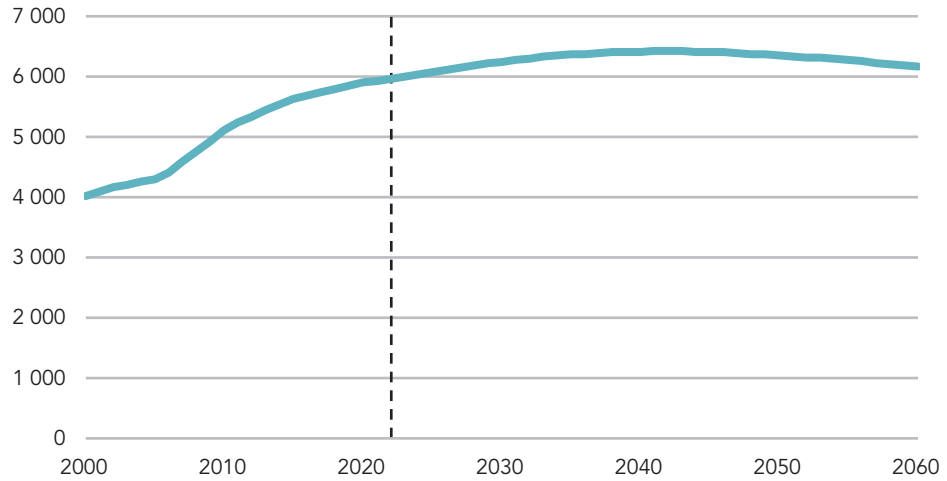
	Reference	Target
General	• Population: UN medium; GDP: APERC model and IMF	• Population: UN medium; GDP: APERC model and IMF
Buildings	• Data centre and AI growth are the same in both scenarios. • Gradual efficiency improvements are assumed, particularly in cooling. • Gas and oil continue to be used to some extent for cooking.	• Improvements in energy efficiency led to a reduction in electricity use in TGT compared to REF. • Cooking is electrified.
Industry	• Industrial activity is assumed to be robust in the coming decades due to a continued role for the economy's export-facing petrochemical industry. • Low-emissions hydrogen is incorporated into the non-energy sector from 2030 onwards. This consumption justifies low-emissions hydrogen production in the modelling. • Electrification makes inroads in petrochemicals production and other non-specified activities.	• Material efficiency: lower end-use consumption of petrochemicals and greater recycling results in chemicals industry consumption being lower in TGT. • Energy efficiency improvements are assumed to be greater for all sectors in TGT. These improvements are dependent on the subsector and energy efficiency potential of industrial processes in each subsector. • Higher penetration of low emissions hydrogen for non-energy sector from 2030 onwards. • Electrification makes greater inroads to become even more dominant in Singapore's energy mix for industry.
Transport	• BEV sales share for passenger and light commercial vehicles increases to 100% by ~2030. • BEV sales share for heavy trucks increases to 75% by 2060. • The share of bus use in passenger road transport remains at around 30%. • There is a 5% decrease in road freight activity from improved routing and other activity efficiency measures.	• The Early Turnover Scheme (ETS) increases the turnover of commercial vehicles, as well as passenger vehicles for scenario contrast. • BEV sales shares are the same as in REF. • The share of bus use in passenger transport increases to 40%. • There is a 20% decrease in road freight activity from improved routing and other activity efficiency measures.
Power	• The capacity of gas-fired power plants remains constant. • Solar PV's installed capacity is assumed to reach 3.42 GW (4.45 GWp) in 2060, with a capacity factor of 17%. • Low-emissions electricity imports of 6 GW start from 2035.	• The capacity of gas-fired power plants declines, in line with increased blending of hydrogen. • Solar PV's installed capacity is assumed to be at a higher level, reaching 6.62 GW (8.6 GWp) in 2060, with a capacity factor of 17%. • Low-emissions electricity imports of 6 GW start from 2035.

	Reference	Target
Supply	• Singapore continues to import crude oil and LNG to meet domestic demands. • Piped gas imports to Singapore are assumed to be terminated in the early 2030s. • Hydrogen is assumed to be imported to meet domestic requirements and bunkering.	• Singapore continues to import crude oil and LNG to meet domestic demands. • Piped gas imports to Singapore are assumed to be terminated in the early 2040s. • Hydrogen, ammonia and e-fuels are assumed to be imported to meet domestic requirements and bunkering.
Emissions	• Only considers CO_2 emissions from fuel combustion. • Guided by Singapore's 2035 Nationally Determined Contributions (NDC).	• Only considers CO_2 emissions from fuel combustion. • Guided by Singapore's 2035 Nationally Determined Contributions (NDC), and Low Emissions Development Strategy (LEDS).

Note: The base year is 2022. Macro-economic assumptions are constant across scenarios. Historical energy balances are from EGEDA submissions for 2022.

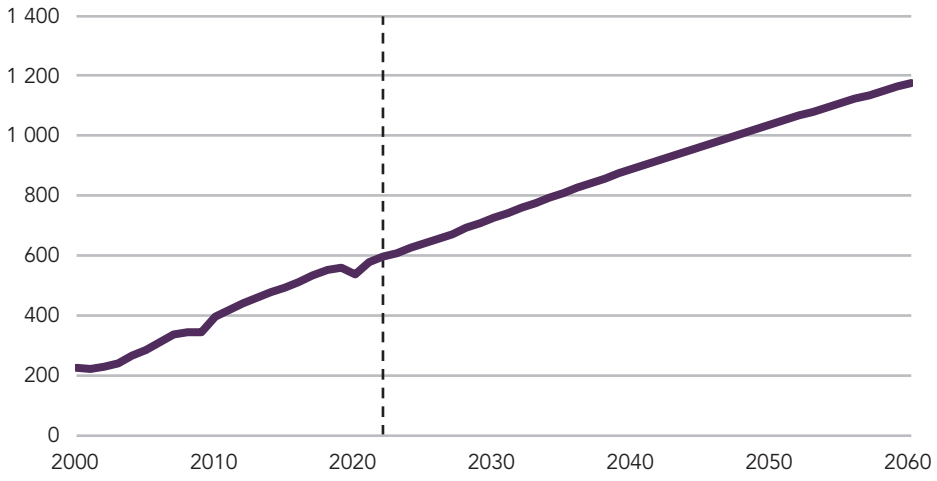
Demographic and Macroeconomic Assumptions

Figure 17-5. Population (thousands)



- Singapore's population stood at 5.96 million in 2022, a 1.8% growth per annum from 2000. According to the Singapore Department of Statistics (SingStat), the highest annual growth between 2000 and 2022 was from non-residents at 3.4%, followed by permanent residents at 2.7%. The growth rate of Singaporean citizens was only 0.8%.
- Beyond 2022, the population continues to grow and eventually reaches its peak in early 2040s at around 6.41 million and declines thereafter to 6.16 million in 2060.
- Singapore is already the oldest economy in ASEAN, with over 18% of the total population comprising of citizens aged 65 and above in 2022. This is primarily driven by a combination of declining total fertility rate and increased life expectancy rate. Assuming the current trend remains, Singapore's population pyramid will transform in such a way that a smaller working-age population will support a larger population aged 65 and above.

Figure 17-6. Real GDP (billion 2017 USD, PPP)



- From 2000 to 2022, Singapore's real GDP grew from USD 225 billion to USD 596 billion, with per capita expanding from USD 56,087 to USD 100,028. This reflects significant transformation into a high-income economy, thanks to its FDI-friendly policies.
- Singapore's real GDP is likely to reach over USD 1 trillion by 2060, amid challenges such as a declining working-age population. Several measures can help mitigate these challenges, such as increasing digitalisation and automation, which can reduce the physical demands of work for older citizens. In addition, Singapore aims to continue attracting foreign talent to support and complement local talent to deliver optimal results.

End-use Energy Demand

Figure 17-7. Energy demand by sector in REF & TGT (PJ)

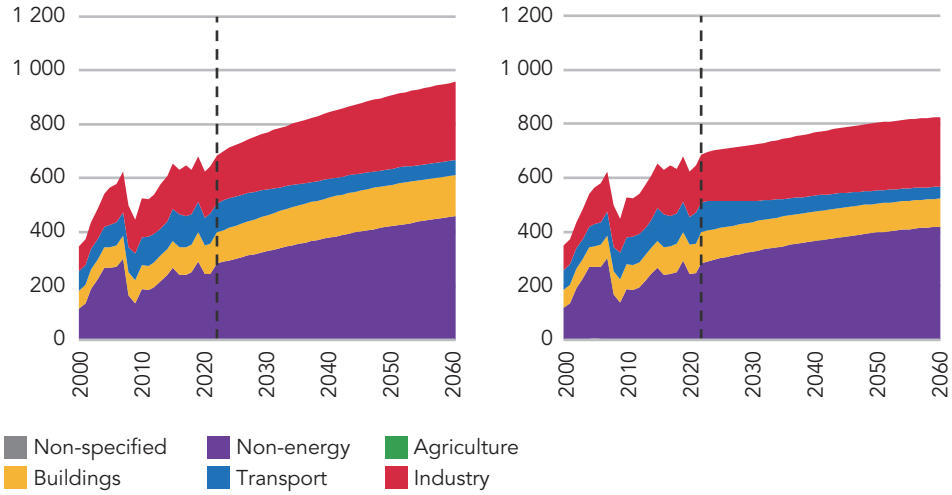
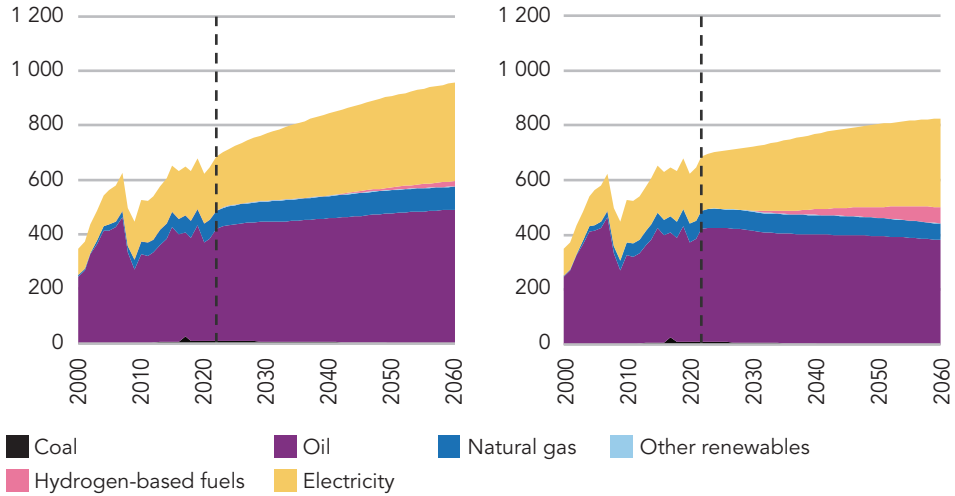


Figure 17-8. Energy demand by fuel in REF & TGT (PJ)



- Singapore's total end use energy demand has doubled in the last 22 years, from 348 PJ in 2000 to 685 PJ in 2022. Of this growth, non-energy and industry sectors stood out as the most dominant, owing to the expansion of Singapore's petrochemical industry to meet global and regional demand.
- By 2060, total end use energy demand is expected to reach over 956 PJ in REF, an increase of 40% from 2022 levels. In TGT, this demand is about 14% lower relative to REF levels in 2060, underpinned by enhanced energy efficiency measures.
- In both scenarios, the non-energy and industry sectors are expected to continue being the primary driver of demand growth. While buildings energy demand continues to grow modestly, transport energy demand is expected to decline, partially offsetting the increases in non-energy and industry uses.
- Oil is expected to continue meeting Singapore's total end use energy needs over the projection period in both scenarios to support its petrochemical industry, accounting for 51% and 46% of the total energy demand in 2060 in REF and TGT, respectively.
- In addition, as Singapore pursues electrification across all demand sectors, electricity demand is expected to increase by 83% and 64% in REF and TGT, respectively, by 2060 from 2022 levels.

Buildings Energy Demand

Figure 17-9. Buildings energy demand by fuel in REF & TGT (PJ)

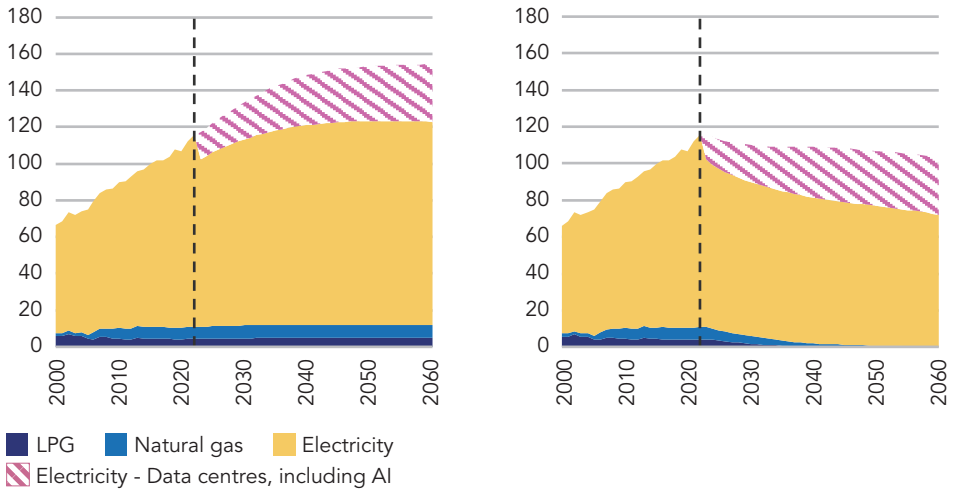
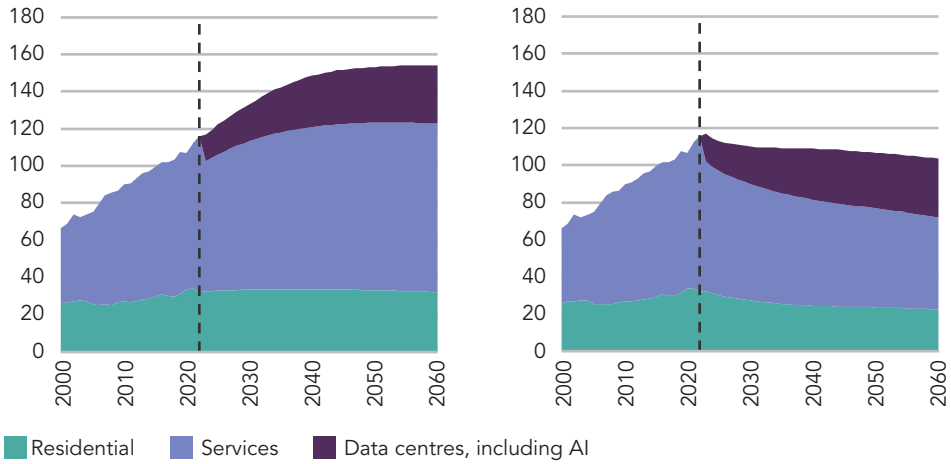


Figure 17-10. Buildings energy demand by sector in REF & TGT (PJ)



- Singapore's buildings are highly electrified and play a significant role in the economy's electricity demand. The buildings sector accounted for roughly half of the economy's total electricity demand in 2022. As a result, reducing energy demand in the buildings sector is one of the priorities for meeting Singapore's net-zero ambitions.
- In REF, energy demand for buildings is expected to continue growing rapidly until 2040, driven by the rising electricity demand for data centres. Due to energy efficiency improvements, buildings' energy demand beyond 2040 grows slower than in the previous decade.
- In TGT, enhanced efficiency improvements, supported by various existing policies such as the Singapore Green Building Masterplan (SGBMP) as well as the newly established Mandatory Energy Improvement (MEI) regime, will result in energy demand declining by 10% in 2060 from 2022 levels. Additionally, the electrification of cooking results in an oil and gas phase-out.
- Singapore has been a hub for data centres since the 2010s. However, the EGEDA database does not explicitly incorporate electricity demand from data centres in Singapore as well as other APEC economies. Hence, APERC estimates data centre electricity demand for each economy in this iteration of the *Outlook* from 2023, given data centres' growing importance in today's digital landscape.
- As Singapore's continues to invest in data centres, its electricity demand is projected to account for 20% and 30% of total buildings energy demand in REF and TGT, respectively, by 2060.
- Singapore unveiled its first National AI Strategy in 2019, followed by the second National AI Strategy in 2023. Five strategic sectors have been identified for AI adoption, including healthcare, smart cities and estates, education, safety and security, and logistics.

Industry Energy and Non-energy Demand

Figure 17-11. Industry & non-energy demand by fuel in REF & TGT (PJ)

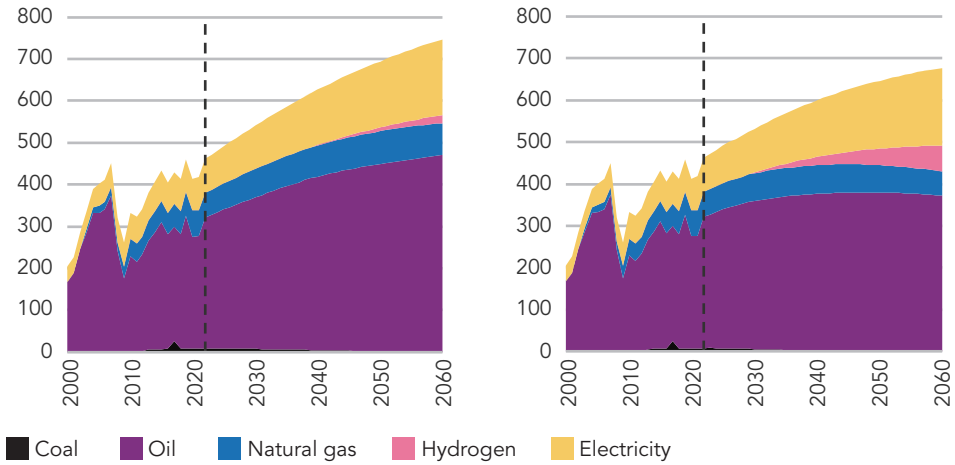
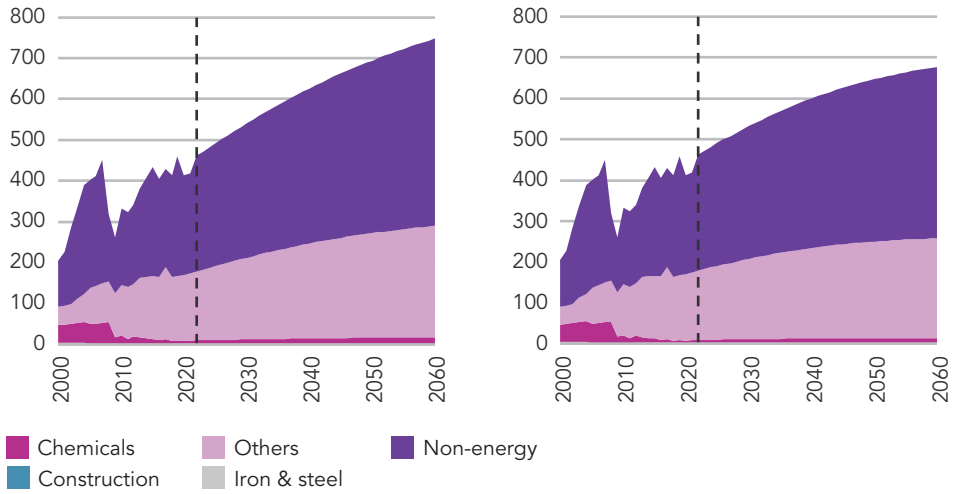


Figure 17-12. Industry & non-energy demand by sector in REF & TGT (PJ)



- Singapore's industry and non-energy (petrochemicals) sectors have been the cornerstone of its economy as these sectors are major sources of export growth. These sectors are anticipated to grow in the coming decades —especially petrochemicals, given expected increasing global demand for these commodities.
- Considering the above, by 2060, energy demand for the industry and non-energy sectors is projected to grow by 62% from 2022 levels in REF. Oil, being a pivotal fuel in the sector, grows by 50%, while electricity is also expected to more than double throughout the projection period. Natural gas demand remains steady with a growth of 20%. Coal, which has been marginal, is expected to be phased out in the 2050s.
- In TGT, energy demand is expected to grow by 47%, assuming greater efficiency gains than in REF, arising from increased resources and investment devoted to efficient industry operations to the extent that it is practically achievable. Electrification progresses at a slightly faster pace than in REF, while hydrogen is expected to be incorporated starting in 2030.
- Aside from petrochemicals, Singapore divides its industry sector into manufacturing and construction. Manufacturing, particularly the electronic cluster, is a major driver of Singapore's economy, while precision engineering contributes significantly to Singapore's manufacturing output. Throughout the projection period, as the manufacturing and petrochemical sectors continue to propel Singapore's economy, energy demand is also expected to grow in both scenarios.

Transport Energy Demand

Figure 17-13. Domestic transport energy demand in REF (PJ)

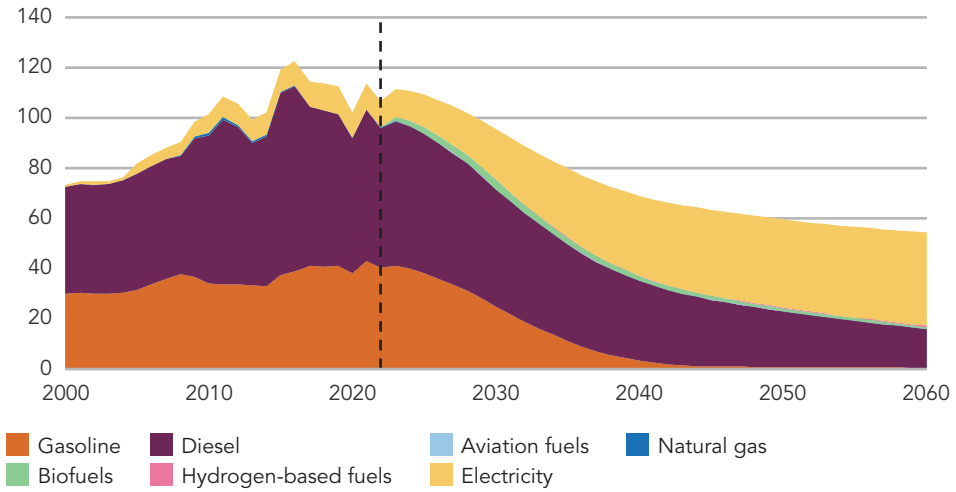
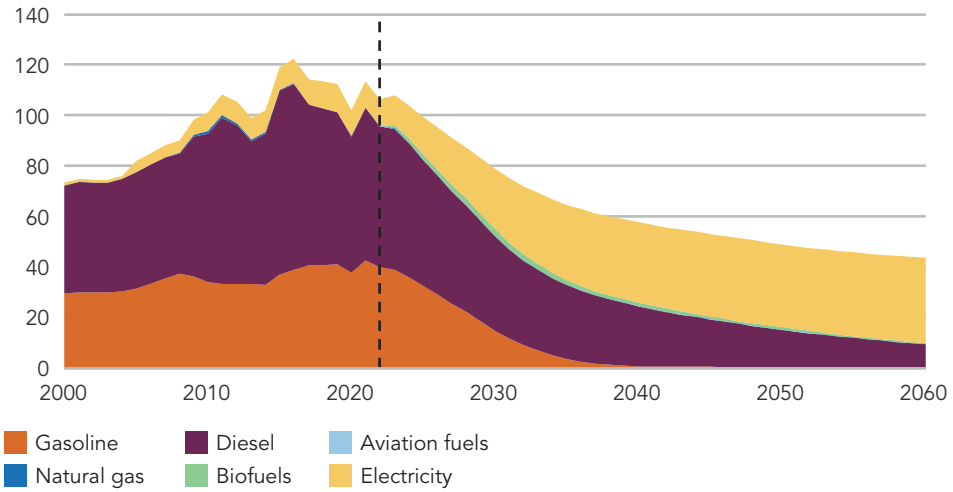


Figure 17-14. Domestic transport energy demand in TGT (PJ)



- Policy plays a key role in Singapore's transport energy use. The Vehicle Quota System (VQS) has helped to limit private vehicles ownership, thereby encouraging growth in public transport use. Efforts to reach the goal to phase-out internal combustion engine vehicles by 2040 have already helped the economy reach a 33% battery electric vehicles (BEVs) sales share in 2023. The early turnover scheme promotes a faster turnover rate for commercial vehicles, thereby helping to speed the uptake of more efficient vehicles.
- The projections in REF and TGT are similar. This is largely because BEVs, which have the largest effect on changes in energy use, are assumed to be adopted at almost the same record pace in both scenarios (for example, 100% sales share for passenger BEVs by 2030). This is assisted by the government's current efforts, such as the Early Turnover Scheme (ETS), to help increase the turnover of old vehicles beyond the normally assumed rate.
- In REF, the overall demand declines by 49% by 2060 from 2022 levels, whereas in TGT, a 59% decline in demand is expected. This difference is due to increased levels of freight optimisation, vehicle turnover, bus use, and a slight increase in the rate of decarbonisation of domestic shipping.
- BEVs sales shares in TGT are the same as in REF, but a more pronounced effect from the ETS results in the stock share for light commercial vehicles being higher in 2040. To note, this same effect was also applied to passenger vehicles for the sake of scenario contrast.

Other Transport Data

Figure 17-15. Transport vehicle stocks in REF & TGT (millions)

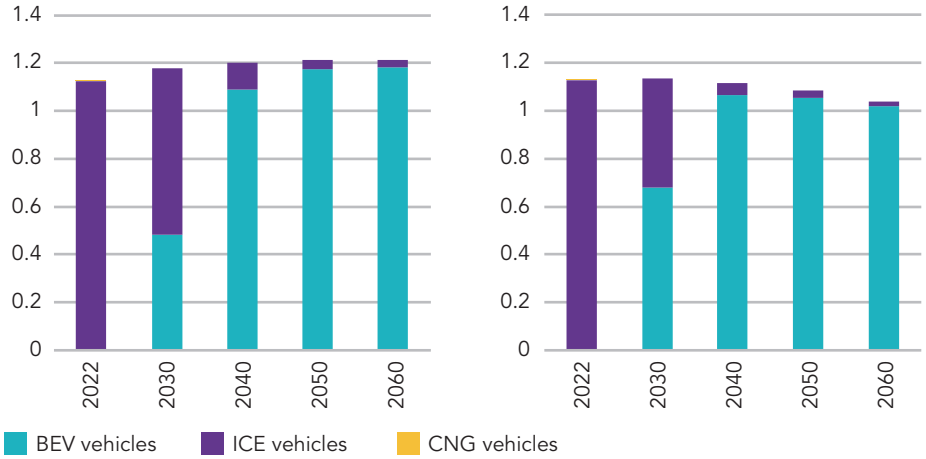
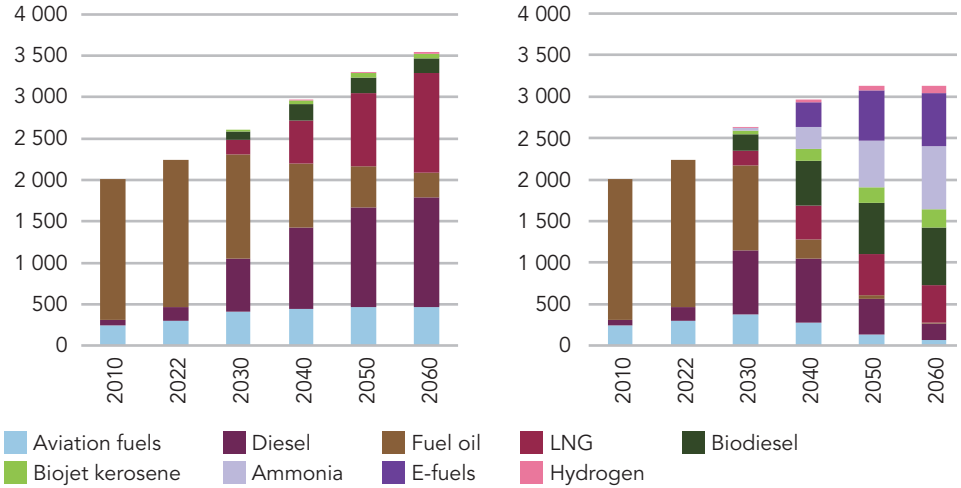
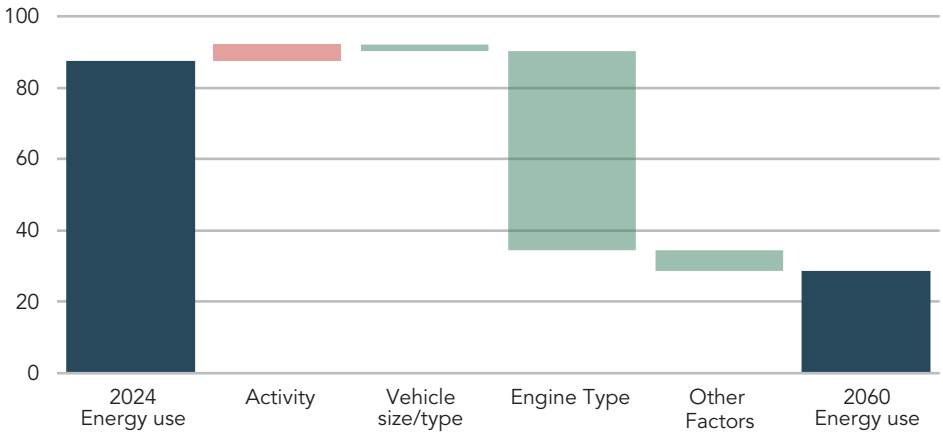


Figure 17-16. International bunker energy demand for shipping and aviation in REF & TGT (PJ)



- In both scenarios, battery electric vehicles are projected to dominate Singapore's stock by 2060 at a 98% share. This is in line with the economy's vision towards a lower emission transportation system.
- Singapore's bunkering activity is expected to increase while simultaneously diversifying bunkering fuels. In TGT, the shift to lower-emission fuels is more pronounced, reflecting decarbonisation targets set by international transport bodies. There is a considerable shift from fuel oil to diesel, which accounts for 37% of the total bunker fuels in 2060 in REF. In addition, LNG is expected to account for about 34%, biodiesel at 5%, and biojet kerosene at over 1%, by 2060. In TGT, by 2060, diesel and LNG intakes reduce significantly, with ammonia, biodiesel, and e-fuels accounting for the bulk of the total, while biojet kerosene rises over 7%.
- The anticipated primary driver of energy demand reduction is the shift of engine types of vehicles, despite an increased freight and passenger activity due to population and economic growth.

Figure 17-17. Components of the change in road energy use in TGT (PJ)



Note: Information on the different drivers in the transport energy decomposition can be found in the *Outlook*'s annex.

Electricity Generation

Figure 17-18. Electricity generation by fuel in REF (TWh)

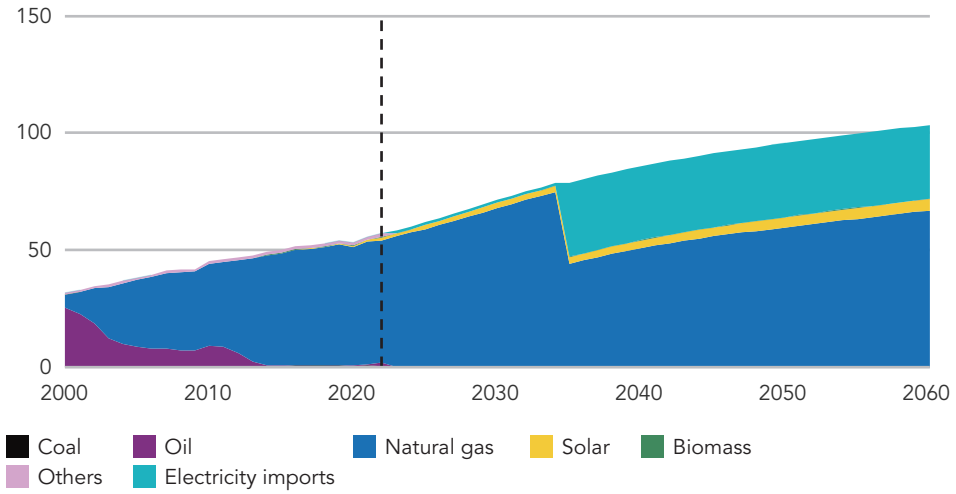
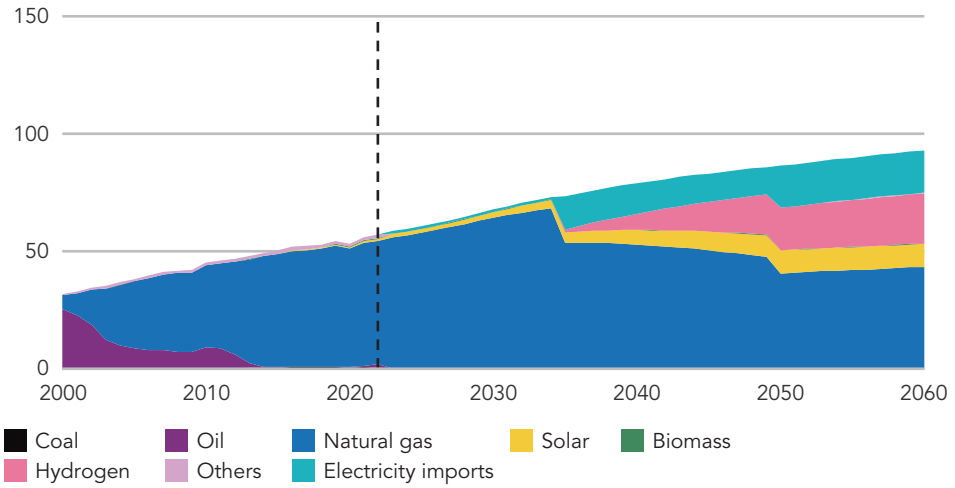


Figure 17-19. Electricity generation by fuel in TGT (TWh)



- Over the projection period, Singapore's electricity generation is expected to continue increasing in both scenarios, driven by economic growth, expansion of data centres, and increased electrification across demand sectors.
- At the same time, Singapore is actively exploring ways to decarbonise its electricity generation in a gradual manner. This is due to the dominance of natural gas in the power sector, providing about 91% of the economy's total electricity generation in 2022.
- Singapore's total electricity generation grows by 81%, reaching 104 TWh in 2060 in REF, with natural gas being a mainstay fuel throughout the projection period. However, its share declines to 65% in 2060 in REF primarily due to imported electricity, which is expected to account for 30% of the total electricity supply in 2060.
- The growth of electricity generation from solar further reduces the reliance on natural gas, as its generation grows fivefold, reaching 5 TWh or accounting for 5% of total electricity generation by 2060.

- In TGT, total electricity generation reaches 93 TWh in 2060, lower than in REF due to reduced electricity demand driven by greater efficiency improvements. The share of natural gas in 2060 is only 47%, due to higher levels of fuel diversification in TGT. While electricity imports continue through 2060, their share is projected to decline to 19% as hydrogen is expected to enter the generation mix, contributing to 23% of the total generation by 2060.
- The inclusion of hydrogen in Singapore's electricity generation is in line with the economy's National Hydrogen Strategy, although the share of hydrogen achieved in 2060 falls short of the Strategy's goal of a 50% share.
- Electricity generation from solar is expected to grow by almost ten times in 2060 from 2022 levels, thus reducing the reliance on natural gas further.

Note: Figures 17-18 and 17-19 do not include electricity generation for hydrogen production.

Generation Capacity

Figure 17-20. Generation capacity by fuel in REF (GW)

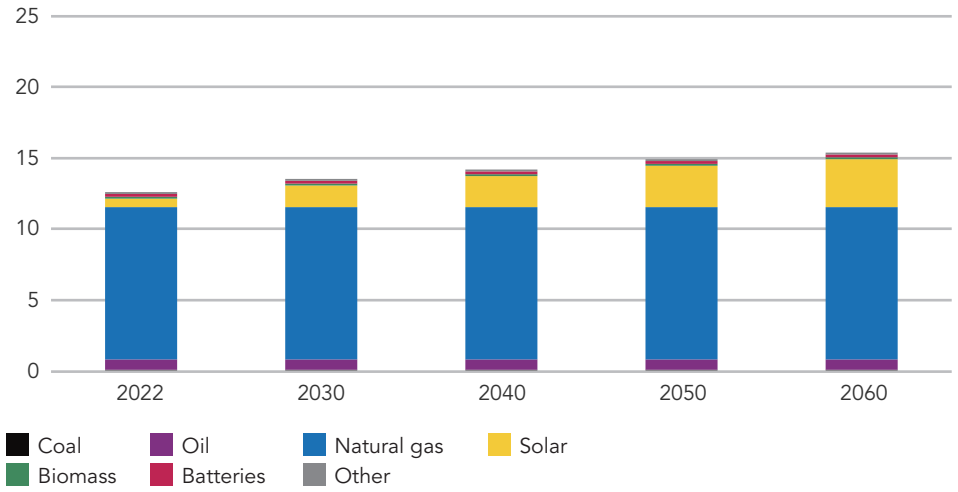
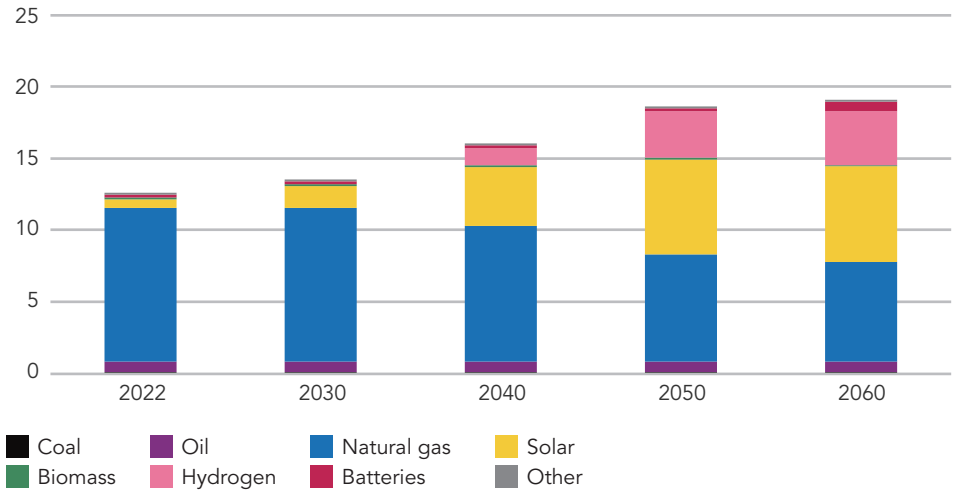


Figure 17-21. Generation capacity by fuel in TGT (GW)



- Singapore's total installed capacity is expected to grow by 22% in REF, reaching 15.4 GW in 2060 from 2022 levels of 12.6 GW. This is primarily driven by the significant expansion of solar PV capacity.
- Singapore is expected to achieve 1.54 GW of solar PV capacity by 2030, which is equivalent to and in line with its 2030 goal of at least 2.0 GWp of capacity in both REF and TGT. Moving forward in REF, by 2060, solar capacity is expected to reach 3.4 GW, which is equivalent to 4.45 GWp.
- The Solar Energy Research Institute of Singapore (SERIS) estimated that Singapore has the technical potential to deploy a maximum of 8.6 GWp of solar by 2050. However, this is not achieved in REF, given continuous constraints in maximising rooftops, reservoirs, and other suitable areas.
- Singapore currently houses a 200 MW battery energy storage system located on Jurong Island. In REF, this level of capacity is assumed to remain constant throughout the projection period.

- In TGT, total installed capacity is expected to reach 19.1 GW by 2060, driven by enhanced deployment of solar PV capacity. By 2060, solar PV capacity is expected to reach 6.62 GW, equivalent to the maximum technical potential of 8.6 GWp as per SERIS estimates.
- In addition, as hydrogen complements natural gas in electricity generation, some 3.7 GW of gas capacity is expected to be repurposed for hydrogen by 2060, while retaining the remaining gas capacity of 6.95 GW.

Note: Figures 17-20 and 17-21 do not include generation capacity for hydrogen production.

Grid Reliability

Figure 17-22. Total generation capacity and peak load (GW)

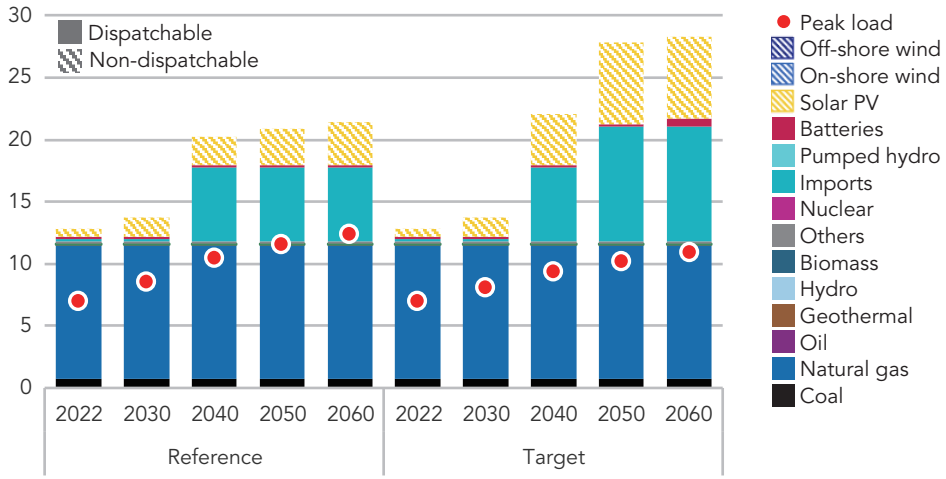
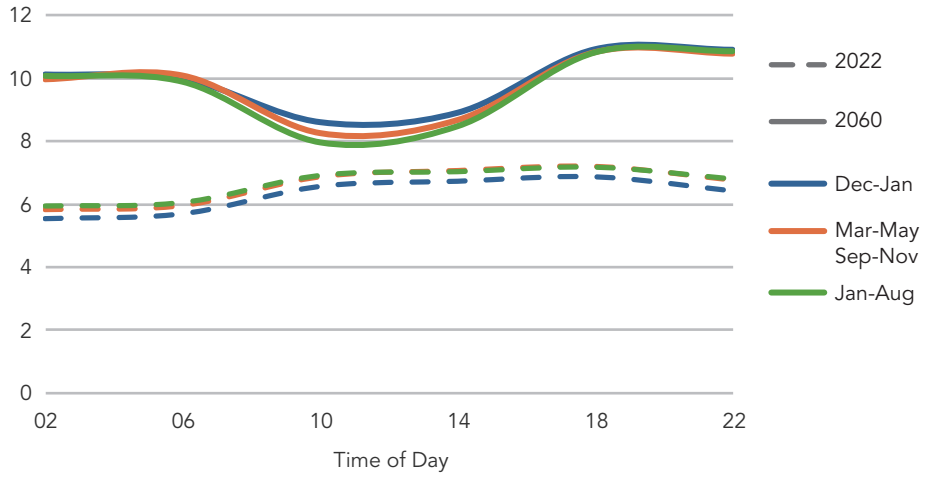


Figure 17-23. Power from dispatchable sources in TGT (GW)



- Singapore's power system is regarded as one of the most reliable in the world, thanks to its robust smart grid infrastructure that minimise outages.
- The economy's peak electricity load is expected to almost double in 2060 from 2020 levels in both scenarios as electrification across the demand sectors gives rise to higher demand for electricity.
- Over the projection period, the future peak loads are assumed to be satisfied by natural gas power plants, which are dispatchable in nature. In addition, large-scale regional electricity imports will help cushion Singapore's peak loads.
- The significant expansion of solar PV capacity in Singapore may affect its grid stability and reliability, given Singapore's frequent cloud cover and high humidity. The presence of battery storage systems, like the 200 MW system in Jurong Island, will help stabilise Singapore's power grid, and provides a buffer against potential outages. However, expanding the current battery storage system is necessary to increase electricity supply security and to reduce reliance on electricity imports.
- Increased reliance on electricity generation from solar generation is expected to increase the variability of generation from dispatchable sources. The variability is prominent during the middle of the day as solar generation is at its maximum, leading to a pronounced dip. A ramping up of dispatchable generation is required between the middle of the day and the evening to meet the evening electricity demand, as solar output declines.
- Singapore has recently developed a Future Grid Capabilities Roadmap, which identifies focus areas to mitigate challenges in grid reliability. These key areas include harnessing the flexibility of distributed energy resources (DERs) such as rooftop solar, strengthening grid planning and operations capabilities with technology, and exploring solutions to provide new system needs during periods of high penetration of renewables.

Coal and Biomass

Figure 17-24. Coal and biomass consumption by sector in REF & TGT (PJ)

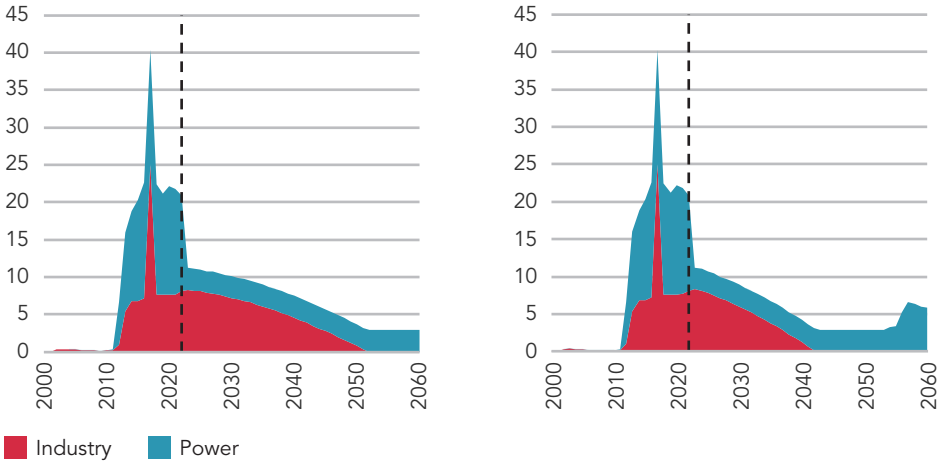
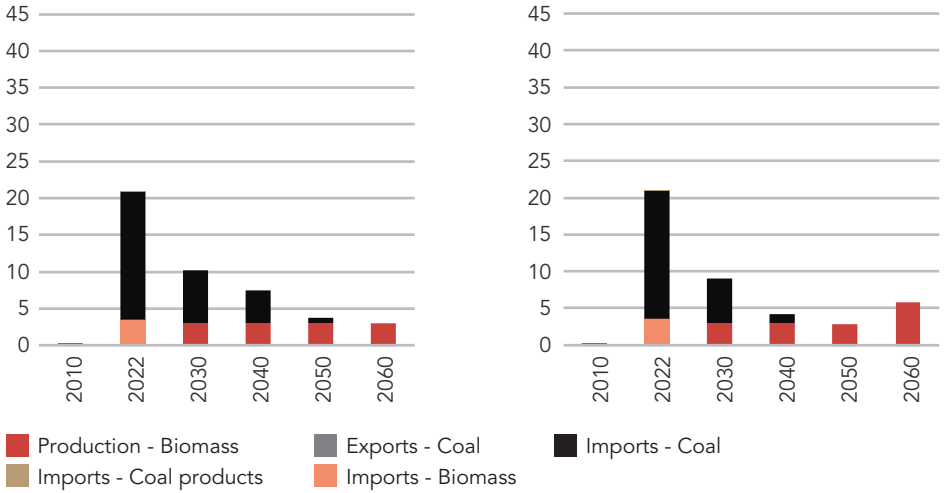


Figure 17-25. Coal and biomass production, imports, and exports in REF & TGT (PJ)



- Singapore currently has only one coal-fired power plant, which has been in operation since 2013. The plant burns at a ratio of approximately 70% coal to 30% biomass, to produce electricity and steam. In addition, there is small coal consumption within Singapore's manufacturing subsector in the industry sector.
- Singapore joined the Powering Past Coal Alliance (PPCA) during COP26 in Glasgow, United Kingdom. In addition, Singapore is a signatory to the Global Coal to Clean Power Transition initiated by the COP26 Presidency.
- In both REF and TGT, coal is expected to be phased out in both power and industry sectors, reflecting the economy's efforts to phase out unabated coal. From 2023 onwards, the power plant is assumed to run completely on biomass in both scenarios. Coal demand in the industry sector remains resilient until the early 2050s in REF, during which coal is expected to be phased out. In TGT, the industry sector's coal phase-out is expected to be in 2040s, one decade earlier.
- While it is possible for the power plant to run completely with biomass, it presents several challenges, including limited biomass availability, higher operational cost to adjust the configuration of the plant, as well as higher volume of biomass required than before to ensure constant electricity generation.
- As Singapore relies entirely on coal imports, import volumes decline to zero in the early 2050s in REF and early 2040s in TGT, in line with declining demand.

Natural Gas

Figure 17-26. Natural gas consumption by sector in REF & TGT (PJ)

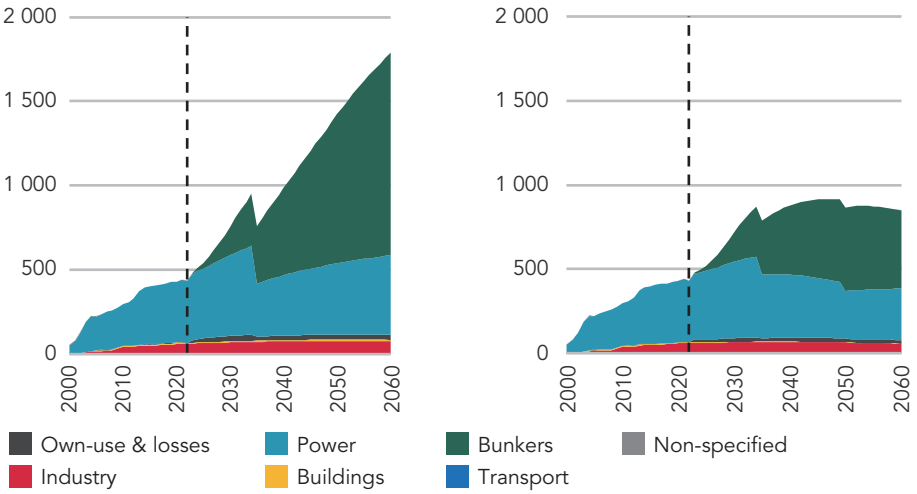
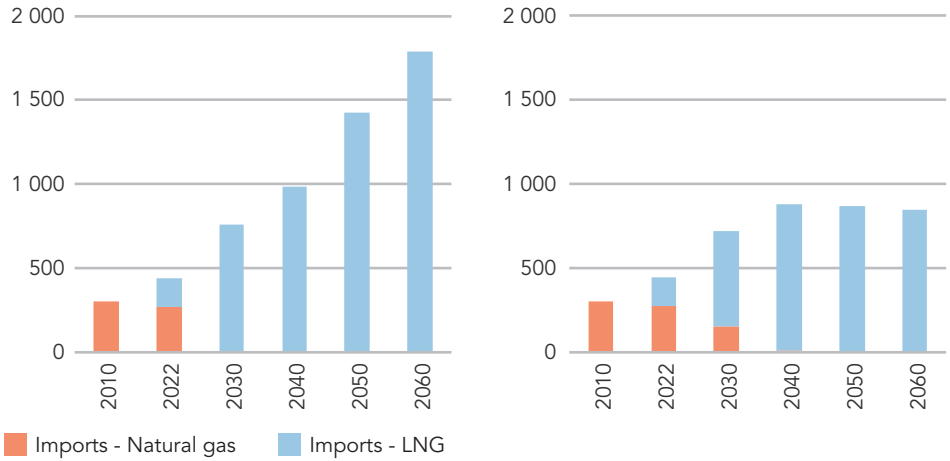


Figure 17-27. Natural gas production, imports, and exports in REF & TGT (PJ)



- Natural gas continues to be an important commodity for Singapore over the projection period in both REF and TGT.
- In REF, natural gas consumption is projected to increase fourfold in 2060 from 2022 levels, reaching 1,786 PJ in 2060. While the power sector continues to be the major consumer of natural gas, its share relative to the total natural gas consumption is projected to decline from 85% in 2022 to 26% in 2060.
- As the Port of Singapore gears-up to provide LNG as a bunkering fuel in the future, LNG sales are expected to increase substantially, driving an increase in natural gas consumption. This contributes to 67% of the total natural gas consumption in 2060 in REF.
- In TGT, the growth of natural gas demand is expected to be lower than in REF between 2022 and 2060. This is driven mainly by a reduction in natural gas demand by the power sector due to the adoption of hydrogen as well as increased solar PV deployment. At the same time, demand for natural gas within Singapore's marine bunkering activities is projected to be limited as broader range of fuel solutions is expected, including hydrogen, ammonia, and e-fuels in 2060.
- Singapore is expected to continue increasing its dependence on LNG imports as piped natural gas reliance from Indonesia and Malaysia declines, given that both neighbouring economies prioritise this gas to meet their respective demands. In REF, piped gas imports are expected to be phased out in 2030s. In TGT, piped gas to Singapore from Indonesia is expected to continue until 2040s, supported by increasing natural gas production in Indonesia.

Note: Historical data for LNG is based on JODI gas data.

Petroleum Liquids

Figure 17-28. Crude oil, NGLs and other hydrocarbon production, imports, and exports in REF & TGT (PJ)

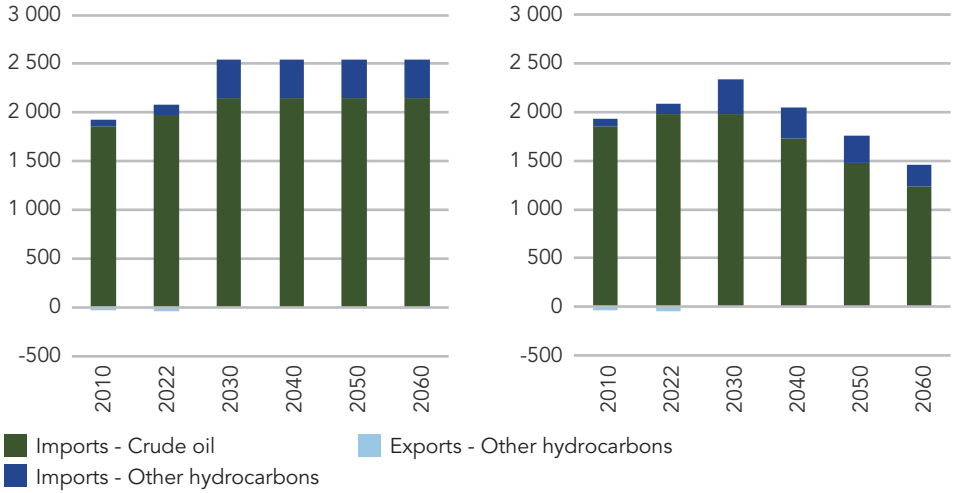
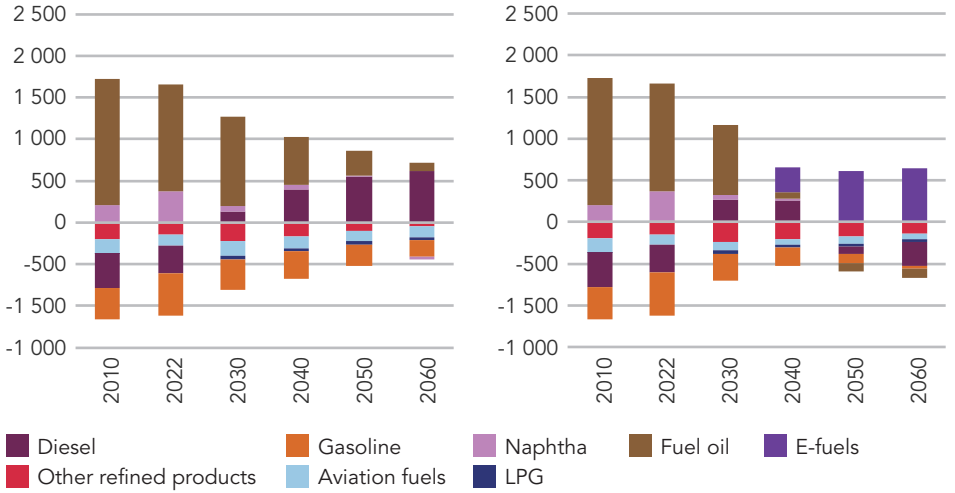


Figure 17-29. Net imports of refined products and low-carbon fuels in REF & TGT (PJ)



- Singapore houses three main refineries: ExxonMobil in Jurong, Shell Bukom, and Singapore Refining Company (SRC) in Jurong. These refineries contribute to a total capacity of 1.3 million barrels per day (mb/d).
- These refineries have been relying solely on imported crude oil to meet their refining and petrochemical requirements. Most of the crude oil imported is from the Middle East and the United States.
- Crude oil and other hydrocarbons imports continue to increase in REF, reaching over 2,500 PJ in 2030, which is then maintained through to 2060. This assumes that the refineries operate at an average utilisation rate of 85%, up from 68% in 2022.
- In TGT, a gradual decline in refining capacity, driven by the closure of the Shell Bukom refinery, as well as reduction in fossil fuels demand, drive the decrease in crude oil and other hydrocarbon import requirements. By 2060, crude oil and other hydrocarbons import levels decline to 1,500 PJ.

- Fuel oil has been the highest net import fuel over the past decade, owing to demands of Singapore's bustling and significant maritime industry.
- Throughout the projection period, Singapore is expected to reduce its fuel oil imports both scenarios, aligning with its Decarbonisation Blueprint as well as meeting the International Maritime Organization (IMO)'s Strategy on Reduction of GHG Emissions from Ships. In parallel, Singapore is expected to increase its diesel imports to displace fuel oil as the main bunkering fuel.
- In TGT, import dependence on fuel oil and diesel is expected to decline rapidly due to enhanced decarbonisation efforts in Singapore's maritime industry. As a result, Singapore is expected to import more e-fuels for its bunkering.

Note: In Figure 17-29, net imports are presented without deducting bunkers.

Refining

Figure 17-30. Refining outputs in REF & TGT (PJ)

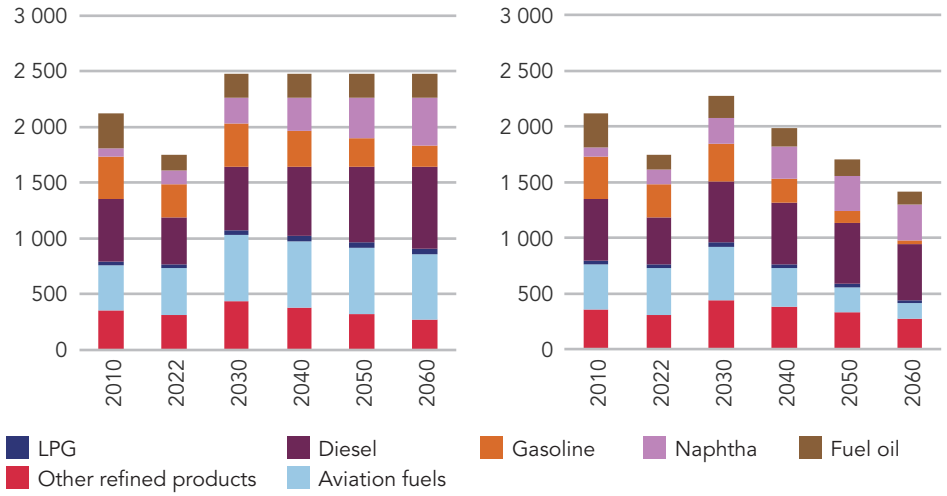
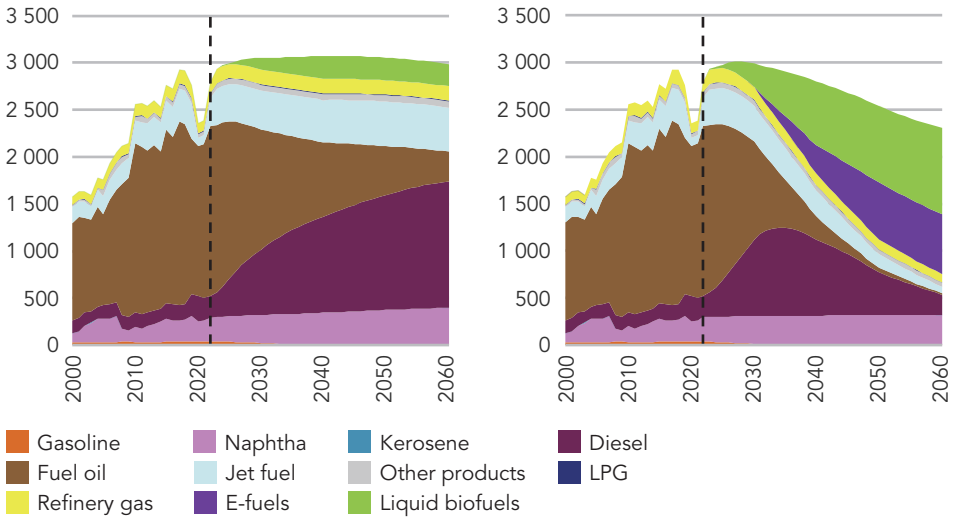


Figure 17-31. Refined products and low-carbon fuels demand in REF & TGT (PJ)



- Singapore's refineries produce a range of petroleum products, with diesel and kerosene jet fuel having the most significant refining yields at 24.1% and 23.7%, respectively, in 2022. Gasoline yielded about 17% of the total refining output, while fuel oil, naphtha, and other products produced yields under a 10% share in the same year.
- In REF, as demand for diesel increases to displace fuel oil as the main bunkering fuel, domestic diesel output is expected to increase to almost 30% yield with respect to the total refining output in 2060. At the same time, the domestic and regional push for electric vehicles is expected to drive down gasoline output to just 7.7% yield in the same year. The growth of global and regional demand for petrochemicals is projected to increase Singapore's naphtha production to over 17% yield by 2060.
- In TGT, total refining output in 2060 is projected to be lower than that in REF. More enhanced efforts on decarbonisation mean outputs of gasoline and kerosene jet fuel are expected to fall significantly to 2.4% and 9.2% yields, respectively, with diesel output stabilising to meet the marine bunkering fuel demand. Naphtha output continues to increase albeit at a slower rate.

- In terms of refined products demand, naphtha is expected to remain dominant throughout the projection period in both scenarios, as domestic demand for petroleum products remain limited.
- Adjusting the refining yields would necessitate significant changes in refinery configuration, which are generally costly due to the technical complexities of refining operations. However, Singapore's advanced refining infrastructure, coupled with government support, provides a foundation for strategic and targeted investments to align with global decarbonisation objectives.

Note: Figure 17-31 includes all demand sector transformation inputs (e.g. power), losses & own use, and bunkers.

Bioenergy and Waste

Figure 17-32. Bioenergy and waste demand by sector in REF & TGT (PJ)

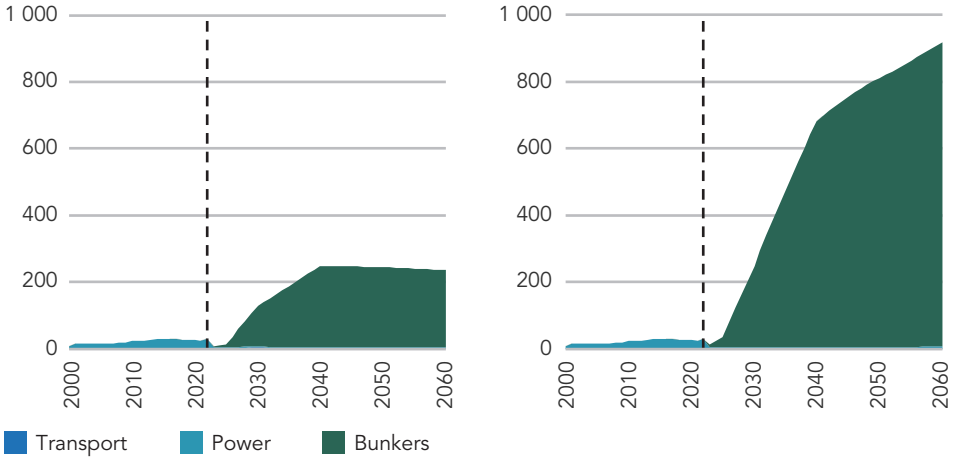
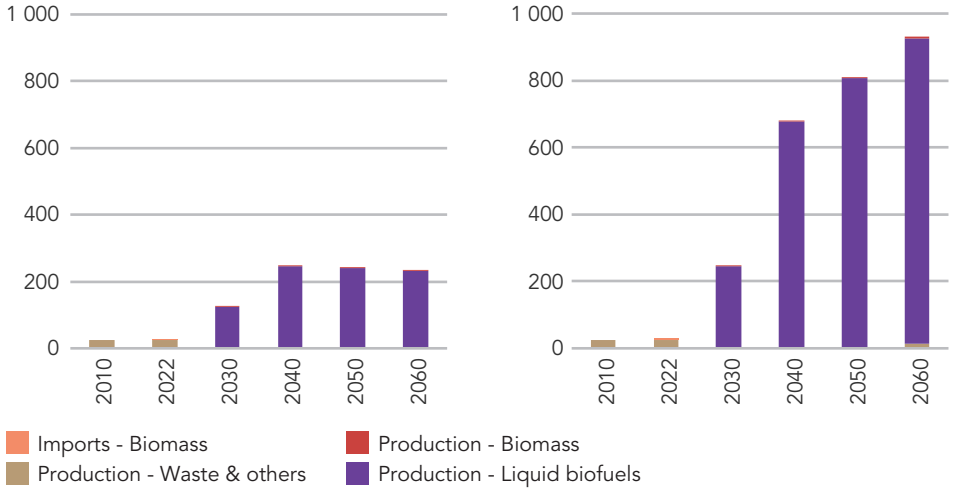


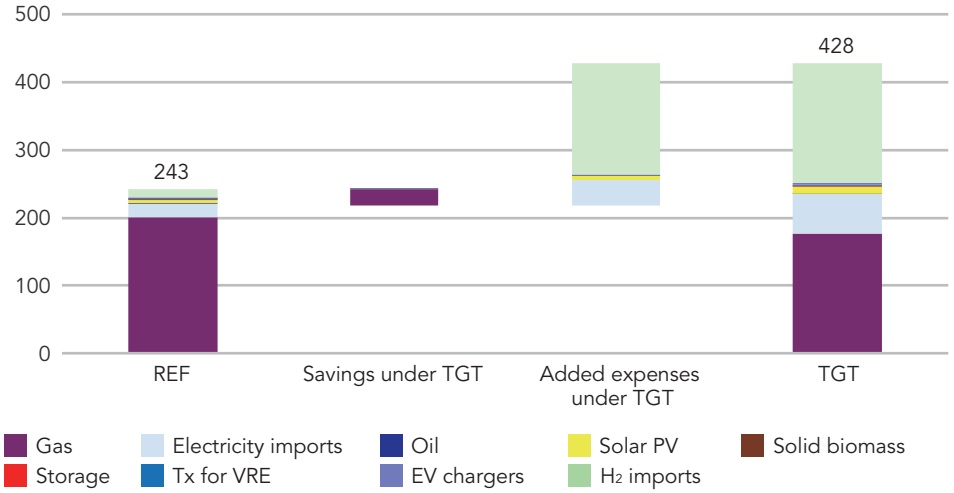
Figure 17-33. Bioenergy and waste production, imports, and exports in REF & TGT (PJ)



- Throughout the historical period, bioenergy demand in Singapore has been small, and confined within its power sector, particularly its domestic waste-to-energy facilities.
- In REF, demand for bioenergy is expected to be the largest in bunkers, as Singapore diversifies its bunkering fuels to include biodiesel. In addition, the demand for biojet kerosene (SAF) is also envisaged to grow as Singapore implements a Sustainable Aviation Fuel (SAF) mandate for flights departing from the economy.
- The collective demand for biodiesel and biojet kerosene in TGT is expected to be over four times higher than REF levels in 2060, assuming a more ambitious blending rate for both fuels within Singapore's marine and aviation bunkers.
- Singapore houses a biorefinery plant owned by Finnish-based Neste, the leading producer of SAF and renewable diesel. Currently, the biorefinery can produce 2.6 million tonnes of SAF and renewable biodiesel, with up to 1 million tonnes dedicated to yielding SAF.
- Throughout the projection period, Singapore is assumed to domestically produce all its bioenergy needs in both REF and TGT. In line with the demand, an estimated total of 6 million tonnes of biofuels (primarily biodiesel and biojet kerosene) is required to be produced by 2060 in REF, while in TGT, this amount is projected to be over four times higher (26 million tonnes).
- Scaling up the current capacity to almost 30 million tonnes would require substantial levels of infrastructure and financial investment, as well as advancements in feedstock availability.

Costs

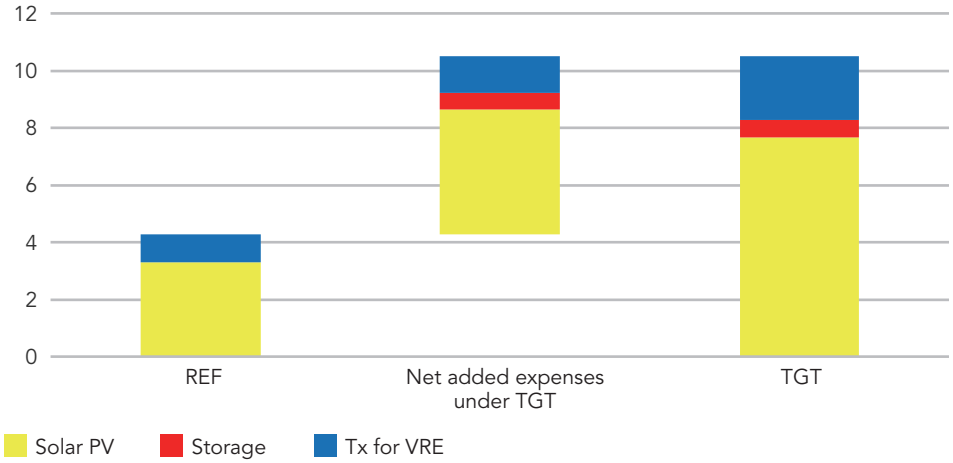
Figure 17-34. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



Note: Tx for VRE is only transmission infrastructure to connect variable renewable capacity to the grid. EV chargers do not cover the cost of associated infrastructure or EV vehicles. Hydrogen costs do not cover costs for bunkering.

- Singapore's energy journey will require a substantial amount of expenditure from 2025 to 2060 in both scenarios. Figure 17-34 includes the total capital, fixed, and variable costs for the power sector, electricity and low-carbon hydrogen imports for domestic use only and spending on EV chargers.
- In REF, total costs are expected to reach an estimated USD 243 billion, noting the uncertainty of future estimates, with gas-related costs being the largest expense.
- The reduction of gas use in TGT is estimated to contribute to savings of USD 24 billion. However, additional costs due to imports offset these savings. Imports of hydrogen-based fuels for domestic use (mostly in the power sector) are expected to account for the majority of added costs (USD 165 billion), while regional electricity imports add USD 37 billion. These raise the total costs to USD 428 billion in TGT. To note, the cost of importing hydrogen-based fuels for bunkering is not included, since cost recovery is assumed from other APEC economies.

Figure 17-35. Total capital investment (CAPEX) from 2025 to 2060 in the power sector (billion USD, undiscounted)

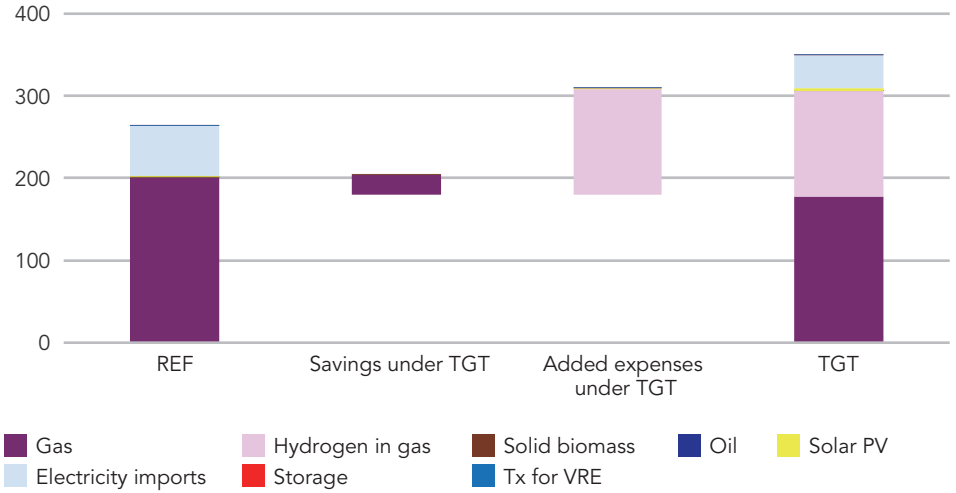


Note: Figure 17-35 only covers power and VRE transmission sector investments. Hydrogen and EV capital investments are not included.

- The total capital investment (CAPEX) alone is projected to reach USD 4.3 billion in REF, with investments in new solar PV deployment accounting for 77% of the total capital investment, or USD 3.3 billion. To accommodate increased adoption of renewable electricity, investments into new transmission lines are needed, which accounts for 23% of the total (USD 1 billion).
- The higher level of deployment of solar PV in TGT adds USD 4.4 billion to the total CAPEX. As a result, this requires greater levels of investment for new transmission lines, which is estimated at USD 1.3 billion. An additional investment of approximately USD 0.6 billion in energy storage systems is also required. Consequently, the total capital investment in TGT is expected to reach an estimated USD 10.5 billion.
- Singapore recently established its Future Energy Fund at the end of 2024 to address the significant financial requirements of its energy transition journey. This initiative will inject a total funding of SGD 10 billion, equivalent to USD 7.4 billion (based on the latest exchange rate), to further strengthen its energy infrastructure.

Costs

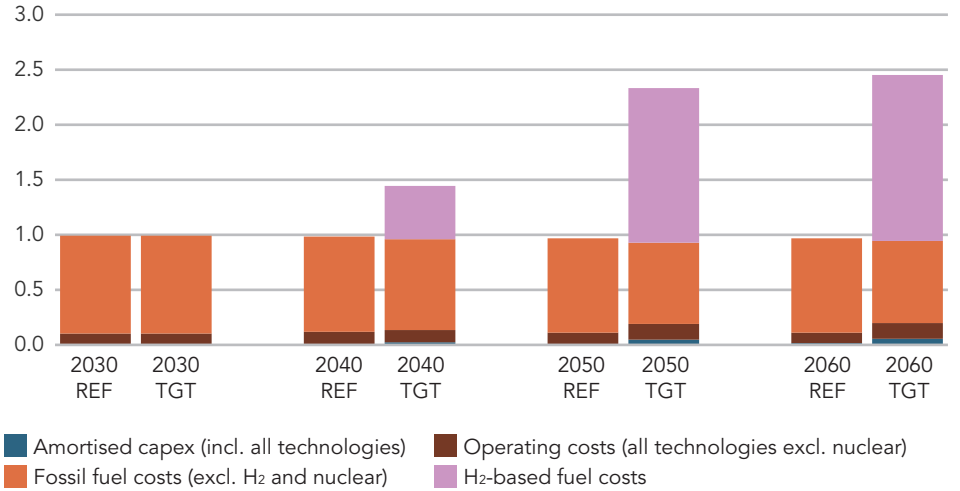
Figure 17-36. Total operating costs from 2025 to 2060 in the power sector (billion USD, undiscounted)



Note: Figure 17-36 only covers power and VRE transmission sector costs. It does not include operating costs associated with hydrogen production and EV charger costs but does include the cost of H_2 blending in power generation.

- Total operating costs are expected to exceed total capital investments in both REF and TGT, reflecting the high fuel expenditures of natural gas and hydrogen in fuelling Singapore's gas-fired power plants.
- In REF, total operating costs are projected to reach USD 264 billion by 2060, driven by natural gas costs. The total operating cost of gas is estimated at USD 201 billion, assuming that the imported gas is priced at USD 12 million per PJ (or equivalent to approximately USD 12.6 per MMBtu).
- In TGT, total operating costs are estimated to increase by 33% from REF levels, reaching USD 350 billion. This is mainly driven by an additional cost of USD 129 billion for low-carbon hydrogen for use in co-firing with gas. As this hydrogen is a nascent technology, high fuel costs are assumed which contributes to the substantial increase in TGT operational costs.

Figure 17-37. Cost of generating electricity relative to 2025 (2025 cost = 1.0) in the power sector



Note: Based on our assumptions about future capital and operating costs, Figure 17-37 shows cost compositions over time relative to 2025. It should not be considered an estimate of electricity tariffs and excludes market mechanisms that are too difficult to estimate.

- Singapore's electricity generation cost (excluding regional electricity imports), indexed to 2025, stays relatively the same in REF. To note, this figure does not reflect the consumer cost of electricity, which includes market mechanisms that are challenging to quantify.
- In TGT, the generation cost is expected to more than double in 2050 and 2060, driven largely by low-carbon hydrogen import expenditures and use within the power sector (co-firing with gas).
- Overall, these projections highlight the sustained financial burden of system operations in a decarbonised pathway. Managing these costs, especially fuel-related ones, will be essential to maintaining economic efficiency while charting Singapore's energy transition.

CO_2 Emissions

Figure 17-38. CO_2 emissions in REF (million tonnes)

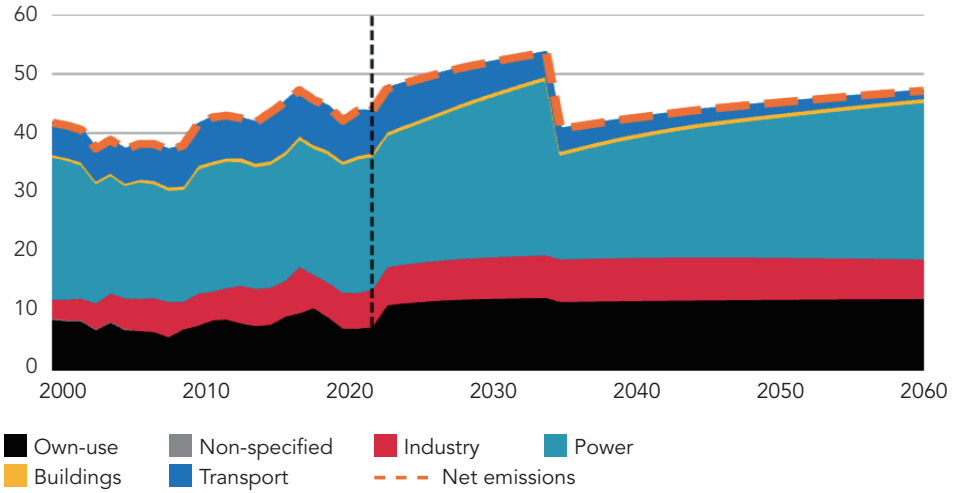
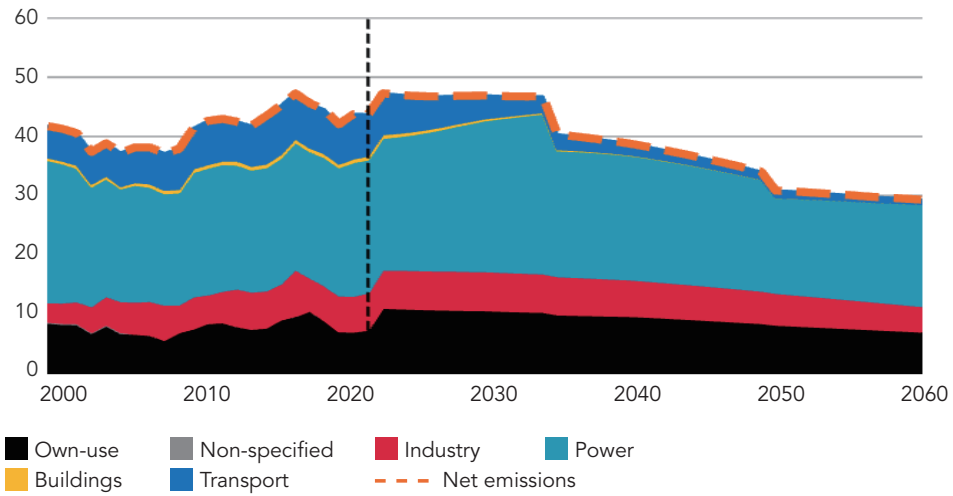
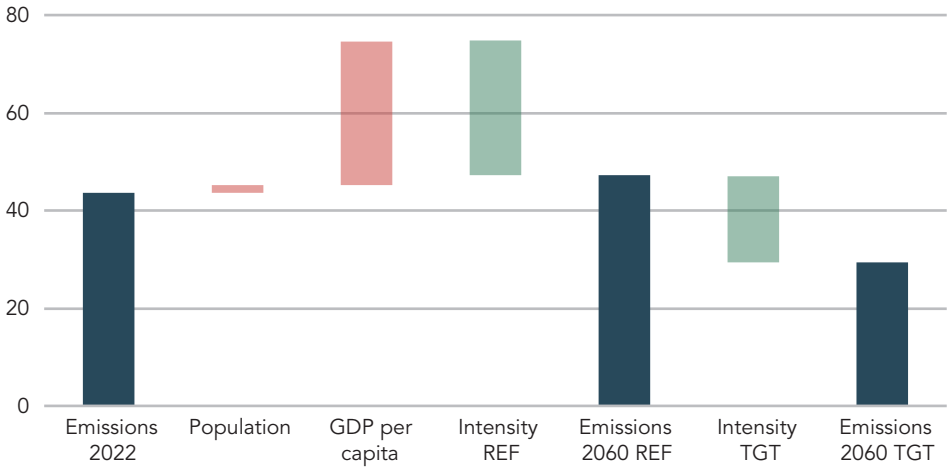


Figure 17-39. CO_2 emissions in TGT (million tonnes)



- Singapore's gross CO_2 emissions from fuel combustion are projected to reach 47.2 million tonnes in 2060 in REF, up from 43.7 million tonnes in 2022. In between those years, emissions from the power sector are expected to peak at over 29 million tonnes in 2034. As electricity imports come online beginning in 2035, power sector emissions are expected to decline substantially due to reduced input of natural gas for combustion in the power sector.
- Conversely, gross emissions in TGT are projected to decline to 29.3 million tonnes in 2060. Hydrogen adoption, increased deployment of solar PV, and electricity imports lower the need for combustion of natural gas in gas-fired power plants. In addition, the adoption of battery electric vehicles contributes to emissions reduction.
- Singapore's emissions in 2035 in both scenarios are well under the limit of 45-50 million tonnes of CO_2 equivalent as per its 2035 Nationally Determined Contribution (NDC). However, net-zero emissions would not be achieved by 2050, given Singapore's significant dependence on fossil fuels for its power and industry sectors.
- Changes in emissions from 2022 to 2060 are largely influenced by improvements in energy and carbon intensities, which help offset the impacts of population and economic growth. In the TGT scenario, continued intensity improvements, underpinned by stronger decarbonisation efforts, are essential for accelerating emissions reductions.

Figure 17-40. CO_2 emissions components (million tonnes)



Note: All values represent energy sector combustion CO_2 emissions. Biogenic CO_2 is treated as zero at the point of combustion.

Useful Links

APEC Expert Group on Energy Data and Analysis (EGEDA) – https://www.egeda.ewg.apec.org/

APEC Energy Statistics 2022 – https://www.egeda.ewg.apec.org/egeda/general/info/pdf/APEC_Energy_Statistics_2022.pdf

APEC Energy Overview – https://aperc.or.jp/reports/energy_overview.php

Department of Statistics Singapore – https://www.singstat.gov.sg

Economic Development Board – https://www.edb.gov.sg/

Energy Efficiency Programme Office – www.e2singapore.gov.sg/

Energy Market Authority – https://www.ema.gov.sg

Ministry of Trade and Industry – https://www.mti.gov.sg

National Environment Agency – https://www.nea.gov.sg

National Climate Change Secretariat – https://www.nccs.gov.sg/

Singapore Department of Statistics – https://www.singstat.gov.sg/

Singapore LNG Corporation (SLNG) – https://www.slng.com.sg/website/index.aspx

Solar Energy Research Institute of Singapore (SERIS) – www.seris.nus.edu.sg/



18. Chinese Taipei

Summary

	Reference			Target		
	2022	2060	% Change	2022	2060	% Change
Macroeconomic						
Population (million)	23.9	18.9	-21%	23.9	18.9	-21%
GDP (billion 2017 USD, PPP)	1,378	2,388	73%	1,378	2,388	73%
Energy Demand						
Agriculture & fisheries (PJ)	30	36	18%	30	32	6%
Buildings (PJ)	493	403	-18%	493	366	-26%
Industry (PJ)	1,044	1,267	21%	1,044	1,092	5%
Non-energy (PJ)	815	805	-1%	815	738	-9%
Transport (PJ)	495	349	-29%	495	196	-60%
Modern renewables share of TFEC (%)	5	22	340%	5	70	1300%
Energy intensity of TFEC (PJ/GDP, billion USD)	1.5	0.9	-40%	1.5	0.7	-53%
Electricity						
Generation (TWh)	288	381	32%	288	378	31%
Renewables share of generation (%)	9	34	277%	9	85	844%
Generation capacity (GW)	62	144	132%	62	206	233%
Total Primary Energy Supply (TPES)						
Coal & coal products (PJ)	1,548	357	-77%	1,548	51	-97%
Natural gas (PJ)	1,008	1,828	81%	1,008	589	-42%
Petroleum liquids (PJ)	1,482	1,204	-19%	1,482	761	-49%
Low-carbon & waste energy (PJ)	396	585	47%	396	1,577	298%
CO_2 intensity of energy supply ($MtCO_2/PJ$)	0.055	0.041	-25%	0.055	0.016	-70%
Net CO_2 Emissions (million tonnes)	242	162	-33%	242	38	-84%

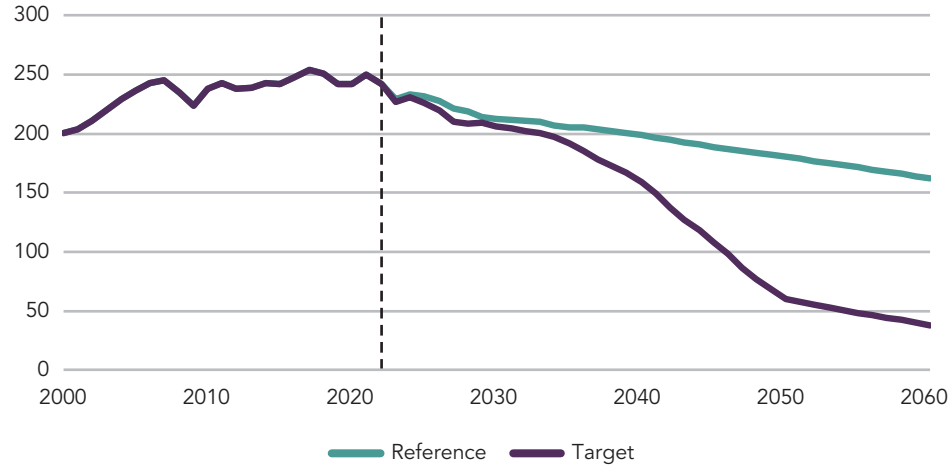
Note: In this publication, the term "modern renewables" refers to all renewable energy sources excluding solid biomass in the buildings sector. The term "low-carbon & waste energy" includes all bioenergy, waste-derived energy, renewables, nuclear, and hydrogen-based fuels. Total primary energy supply (TPES) numbers include international bunkers. Net emissions are calculated as gross energy sector combustion CO_2 minus CO_2 captured and stored through carbon capture and storage (CCS).

Key Takeaways

Emissions

- Emissions in Chinese Taipei peaked in 2017 and have gradually declined since then, though current levels still fall short of meeting climate targets.
- The power sector remains the largest source of CO_2 emissions, followed by the industrial and transport sectors.
- In TGT, emissions decline more rapidly, driven by enhanced energy efficiency, fuel switching, and the accelerated adoption of renewable energy.
- Emission reductions in the transport and industrial sectors are expected to accelerate after 2030 in TGT, compared to more gradual changes in REF.
- Given the power sector's significant contribution to emissions, expanding the deployment of solar, wind, and other low-carbon technologies is essential to achieving deeper decarbonisation.

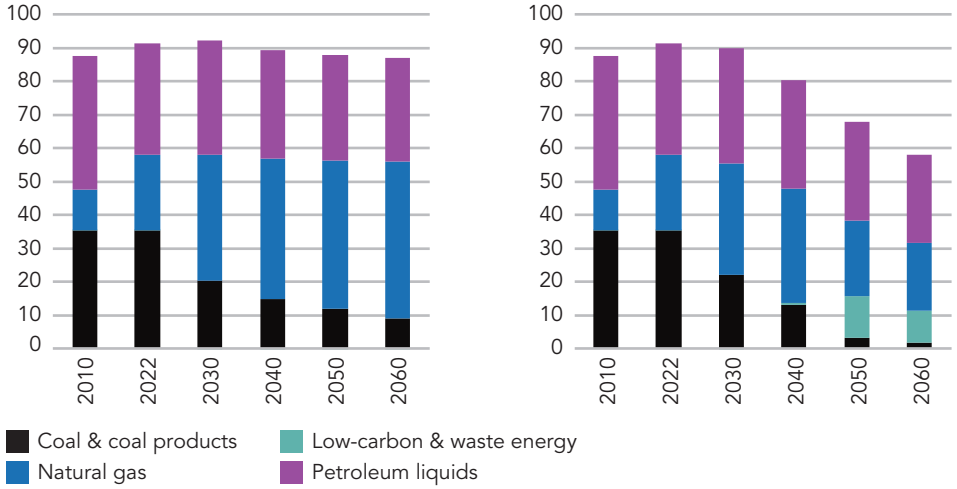
Figure 18-1. Net CO_2 emissions (million tonnes)



Energy Import Dependence

- Chinese Taipei faces energy security challenges due to its limited domestic resources and heavy reliance on imported fuels.
- The transition to a low-carbon energy future involves increased near-term dependence on imported natural gas, raising concerns about supply chain resilience and geopolitical risks.
- The long-term strategy emphasises renewable energy to enhance energy independence by replacing imports of gas, oil, and coal.
- Managing natural gas supply and investing in grid modernisation and energy storage are critical during the transition.
- Balancing energy security with decarbonisation goals and international climate commitments remains a key policy challenge.

Figure 18-2. Net imports share of TPES in REF & TGT (%)



Note: In Figure 18-2, net imports refer to total imports minus exports and international bunkers.

Key Takeaways

Grid Reliability

- Chinese Taipei's dispatchable power are projected to grow significantly, rising from around 40 GW in 2020 to 50 GW by 2050 in REF (summer peak), due to increasing shares of variable renewable energy (VRE).
- Rising shares of VRE increase the need for flexible dispatchable power, especially in summer when peak loads are highest.
- The grid's reliance on dispatchable generation during periods of maximum and minimum dependence. The widening gap between maximum and minimum output suggests dispatchable generators will need greater flexibility over time.
- Ongoing grid infrastructure modernisation will be necessary to accommodate the dynamic interplay between dispatchable and variable renewable energy sources.

Cost

- Chinese Taipei is expected to face significant estimated costs through to 2060 in its power and hydrogen sectors. In TGT, total costs are an estimated USD 461 billion higher than in REF, driven by increased spending on renewable generation (namely offshore wind) and low-carbon hydrogen imports.
- Costs considered include total capital, fixed, and variable costs in the power sector, low-carbon hydrogen imports, transmission for variable renewable electricity, and electric vehicle chargers.
- Energy system costs are primarily influenced by spending on renewables and gas-fired generation. Whilst reduced gas usage in TGT results in savings, this is offset by additional costs in TGT, namely hydrogen co-firing with gas in the power sector.
- These expenditures are integral to support the transition, but they also introduce cost implications for households and industrial sectors.

Figure 18-3. Peak load and maximum and minimum dependence on dispatched power (GW)

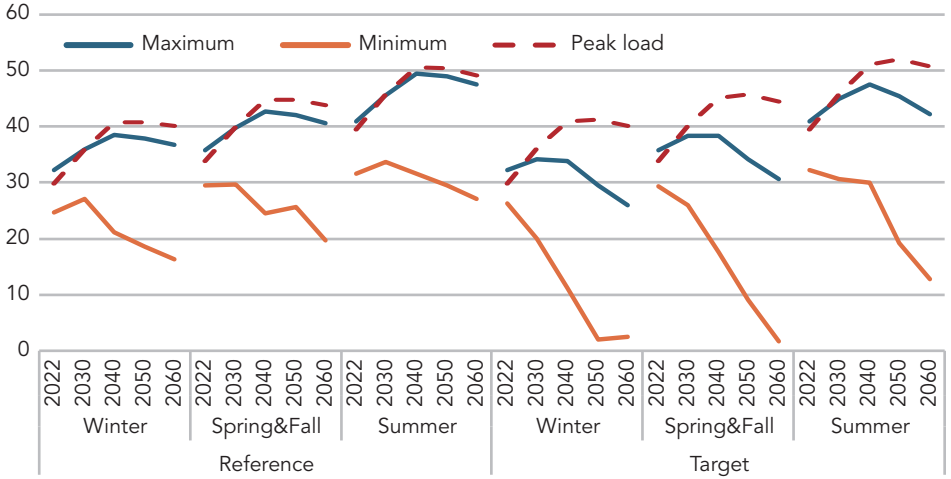


Figure 18-4. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



*Actual costs will differ from estimated costs in the *Outlook* for a variety of reasons including changing commodity prices, manufacturing costs, and unforeseen technical advances. All costs are in 2023 real terms.

About Chinese Taipei

Overview

Geographical and Economic Landscape

Chinese Taipei, situated off the southeast coast of China and southwest of Japan, consists of multiple islands with a diverse topography that includes mountains, hills, and coastal plains. The subtropical climate supports year-round agricultural production, though arable land is limited. Over the past decades, Chinese Taipei has developed into a highly industrialised and trade-driven economy, with key strengths in high-tech manufacturing, including semiconductors, electronics, and precision machinery. While manufacturing remains a pillar of economic growth, the service sector is expected to play an increasingly significant role in shaping Chinese Taipei's future economic landscape.

Energy Supply and Consumption

Chinese Taipei is advancing low-carbon energy development by phasing out coal and nuclear power while increasing reliance on renewable energy and natural gas. Coal-fired generation has been declining since 2021, and nuclear power ceased after its last nuclear reactor was shut down in May 2025 as mandated by law.

In the Reference scenario (REF), natural gas becomes the dominant power source by 2025, supporting both system stability and emissions reduction. Renewable energy capacity continues to expand, notably through solar PV and offshore wind.

In Target scenario (TGT), coal and nuclear power are similarly phased out, but natural gas generation is reduced due to hydrogen co-firing starting in 2035. Hydrogen deployment, along with carbon capture adoption starting from 2045, drives stronger decarbonisation. Post-2040, rapid growth in solar and wind accelerates the shift toward renewables, which become the primary energy sources by 2060.

Electricity demand is projected to grow steadily through 2060 as electrification expands across sectors. The increasing role of renewables and gas-fired generation ensures a lower emissions and more stable energy mix to meet future demand.

Energy Security Challenges and Strategies

Chinese Taipei's power landscape is undergoing a significant transformation. By 2025, natural gas is expected to become the dominant fuel source, overtaking coal and nuclear with the aim of stabilising electricity supply and lowering greenhouse gas emissions.

However, this transition increases reliance on LNG imports due to limited domestic production. Achieving the 50% gas-fired power target by 2025 requires rapid expansion of gas-fired plants and LNG terminals, but these projects face delays tied to environmental impact assessments. Integrating intermittent renewables requires improved grid infrastructure, energy storage, and smart technologies. Additionally, energy storage is key to balancing supply fluctuations and ensuring reliability. To address these challenges, Chinese Taipei is diversifying LNG import sources, expanding storage, and advancing grid modernisation and renewable energy investments.

In summary, to enhance energy security and ensure a smooth energy transition, Chinese Taipei is pursuing a multi-pronged strategy that includes diversifying LNG supply sources, expanding storage capacity, modernising grid infrastructure, and accelerating renewable energy deployment.

Key Energy Initiatives

Net-Zero Emissions by 2050

The "Pathway to Net-Zero Emissions in 2050" was published in 2022. This strategy outlines transitions in energy, industry, lifestyle, and society, emphasising renewable energy expansion, hydrogen development, innovative energy solutions, and carbon capture technologies. It includes 12 action plans targeting key sectors.

To reach this long-term target, Chinese Taipei has also established interim goals:

- By 2030: Reduce net greenhouse gas emissions by 28±2% compared to 2005 levels.
- By 2032: Reduce net greenhouse gas emissions by 32±2% compared to 2005 levels.
- By 2035: Reduce net greenhouse gas emissions by 38±2% compared to 2005 levels.

Nuclear Energy Phase-Out

All nuclear power plants are set to be decommissioned by 2025, with the final reactor scheduled for shutdown that year to achieve a "nuclear-free homeland".

Renewable Energy Targets

Chinese Taipei promotes renewable energy with an emphasis on scaling-up solar photovoltaic (PV) and offshore wind power as central pillars of the energy transition. Offshore wind power capacity is targeted to reach 10.9 GW by 2030, with a long-term ambition of 40 to 55 GW by 2050. Recent planning documents outline a phased capacity trajectory, including 10.9 GW by 2030, 13.9 GW by 2032, and 18.4 GW by 2035, indicating a recalibration of near- to mid-term deployment targets while maintaining a clear long-term growth trajectory.

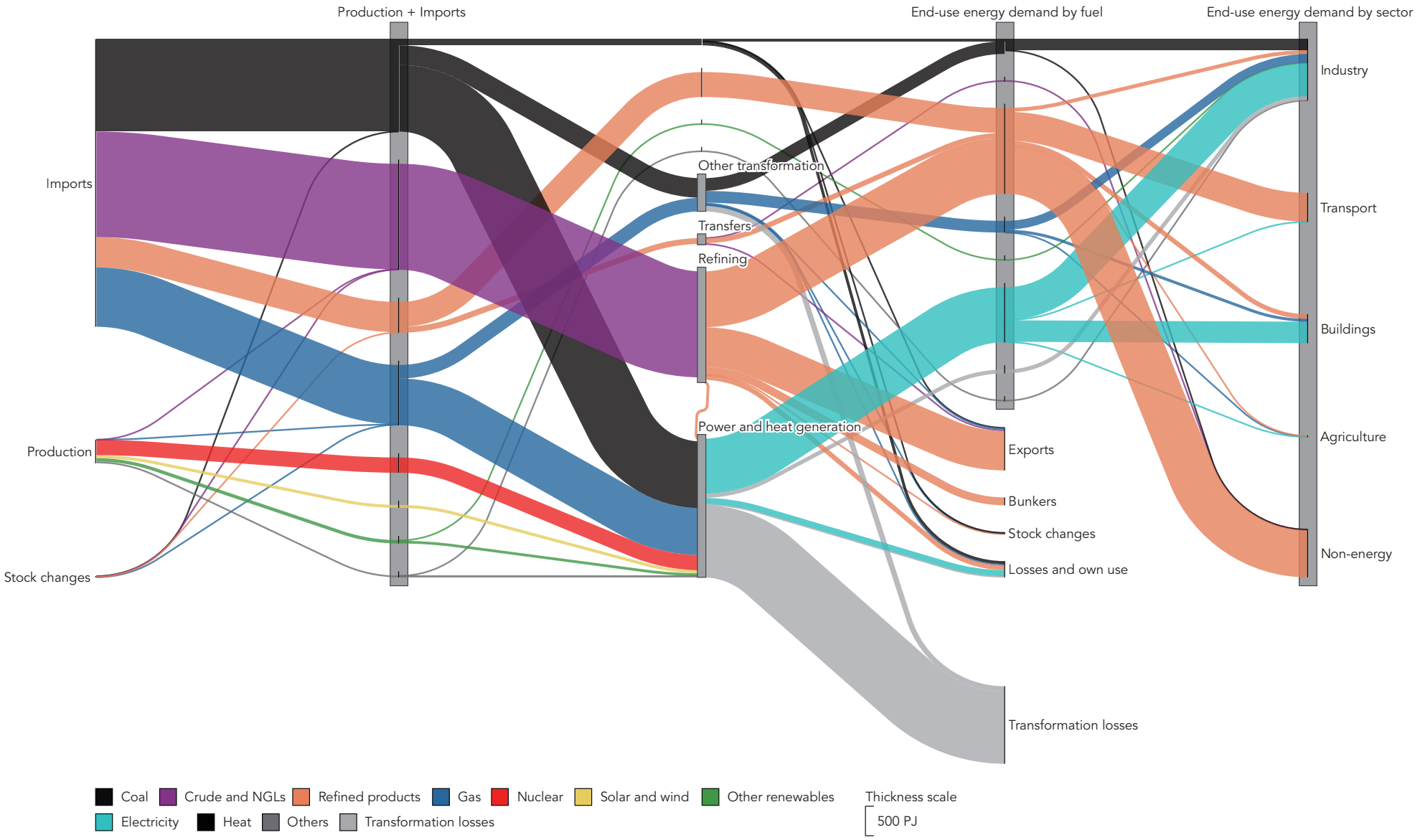
Currently, solar PV development is expected to expand significantly, leveraging diverse land use strategies such as rooftop installations, integration with agricultural land, and deployment on industrial and commercial facilities. The baseline target for solar capacity is 30 GW by 2030 and 40 to 80 GW by 2050, while the latest updates project 31.2 GW by 2030 and 35.02 GW by 2035, reflecting a modest upward revision and reinforcing the role of solar PV in meeting decarbonisation goals.

Energy Transition

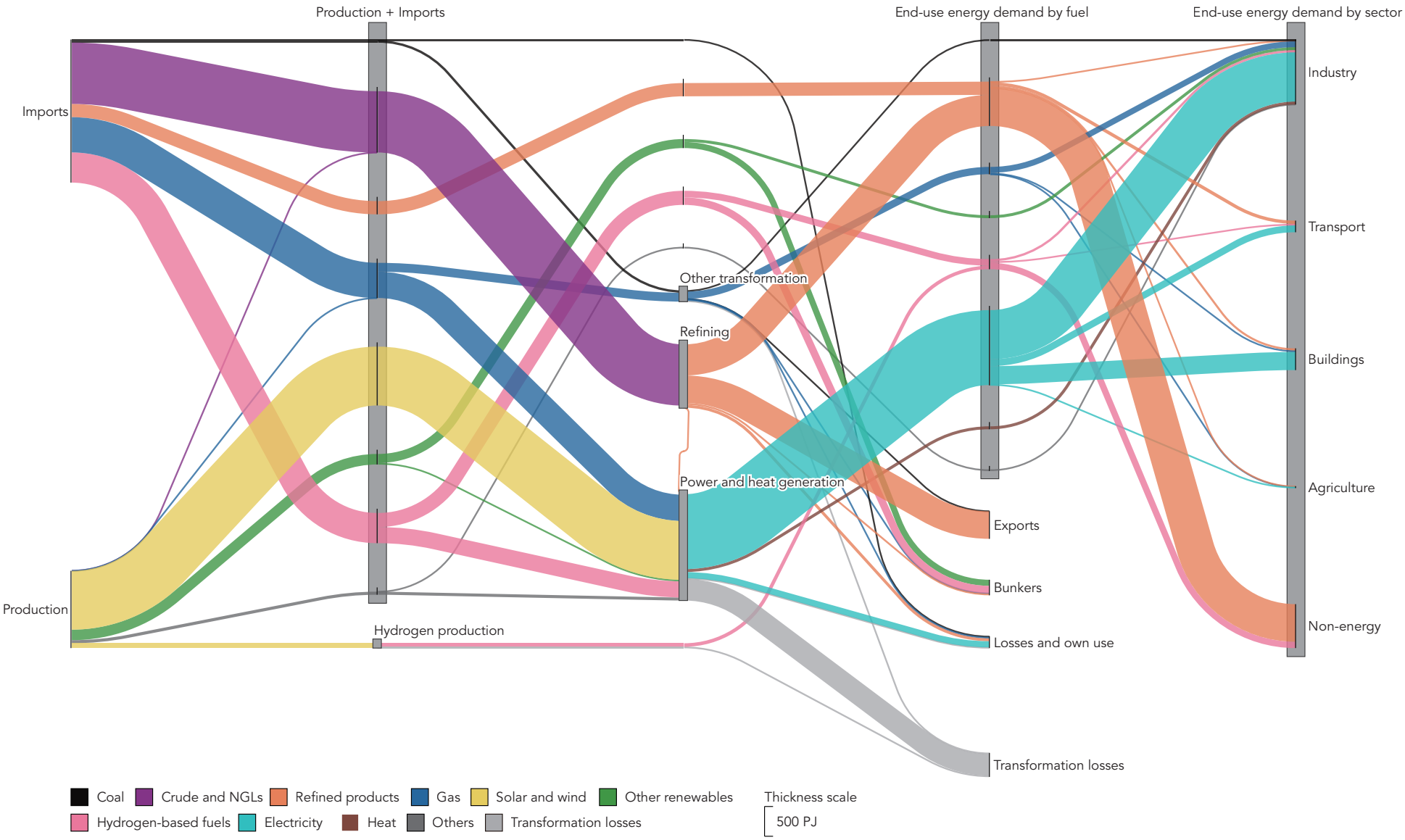
Natural Gas Expansion: Natural gas will account for 50% of the power mix, with increased demand driven by coal-to-gas boiler conversions.

Coal Reduction: No new coal-fired plants will be built before 2025, and existing units will be replaced by gas-fired facilities upon decommissioning.

Energy Flow (2022)



Energy Flow (2060, Target Scenario)



Scenarios and Assumptions

In *The Outlook*, APERC analyses energy demand, transformation, and supply, as well as emissions. The **Reference Scenario (REF)** offers a projection based on historical trends, recent developments, and APERC's assumptions about the continuation of those trends in each APEC economy, while acknowledging technical restraints. The REF Scenario offers a baseline to compare with the **Target Scenario (TGT)** projections, which explores a hypothetical pathway where each economy achieves energy-related policy targets, assuming implementation regardless of cost-effectiveness. When implementation details are lacking, assumptions are inferred from the targets themselves or emissions-related goals.

	Reference	Target
General	• Population: UN DESA's low scenario • GDP: APERC macro model (IMF projections to 2027)	• Population: UN DESA's low scenario • GDP: APERC macro model (IMF projections to 2027)
Buildings	• Efficiency improvements follow historical trends through 2050, contributing to the overall energy demand decline. • LPG use declines slowly. • Data centres and AI grow steadily under both scenarios.	• Faster fuel switching from oil, diesel, LPG, and gas to electricity. • Phase-out of heating oil and fuel oil by 2045. • 25% efficiency improvement in LPG use by 2050. • Broader adoption of green building codes and higher efficiency. • Electricity demand from data centres and AI grows steadily.
Industry	• Industrial activity is expected to remain strong. • Electricity already plays a significant role in the industry sector. • No CCS adoption is assumed for heavy industry. • Hydrogen use in industry is projected to begin in the 2040s. • Low-emission hydrogen will serve as a feedstock by 2040. • Electrification expands across most industrial subsectors.	• Industrial energy demand declines more significantly due to efficiency and lower material demand from recycling and innovation. • CCS deployment in industries begins in the 2030s. • Hydrogen adoption starts in the 2030s. • Electrification expands across more subsectors, reducing coal consumption significantly by 2060.
Transport	• Passenger activity declines in line with population trends. • BEV adoption grows significantly, especially in light passenger vehicles, urban buses, and light commercial vehicles, with an average 40% sales share by mid-century. • PHEVs play a small role for passenger and freight vehicles. • Medium trucks experience higher BEV uptake than heavy trucks, which experience moderate growth in BEVs and slow growth in FCEV adoption.	• BEV adoption reaches 100% for light passenger vehicles, urban buses, and light commercial vehicles by 2040, approaching full stock turnover by 2060. • FCEVs make up most rural buses in 2050, with the remainder as BEVs. • Heavy truck sales are projected to reach 50% and 40% sales share for BEV and FCEVs by 2050 respectively. Since sales of FCEVs only begin after 2030, the earlier adoption of BEVs helps them achieve a 30% stock share by 2050 compared to a 15% stock share for FCEVs by 2050. • Biofuels are adopted in international marine and aviation sectors; hydrogen-based fuels enter after 2030.

	Reference	Target
Power	• Nuclear phase-out in 2025. • Gradually decommission existing coal-fired power plants, with all coal-fired CHP units remaining operational. • Expand gas-fired power generation.	• Nuclear phase-out in 2025. • Gradual decommissioning of existing coal-fired power plants, with coal-fired CHP units remaining operational. Ammonia will be co-fired with coal. • Adopt CCS by 2045 and introduce hydrogen in 2035. • Implement large-scale battery deployment.
Supply	• Fossil fuel projections are influenced by demand trends. • Naphtha production is assumed to increase to meet domestic demand and reduce reliance on imports. • Growing reliance on LNG imports.	• Fossil fuel projections are influenced by demand trends. • Refinery capacity will be reduced to align with declining demand. • Growing reliance on LNG imports.
Emissions	• CO_2 emissions are calculated post-consumption using IPCC factors and are specific to the energy sector. • Emission reductions may vary based on macroeconomic assumptions, technological advancements, and commercialisation timelines.	• CO_2 emissions are calculated post-consumption using IPCC factors and are specific to the energy sector. • Emission reductions may vary based on macroeconomic assumptions, technological advancements, and commercialisation timelines.

Note: The base year is 2022. Macro-economic assumptions are constant across scenarios. Historical energy balances are from EGEDA submissions for 2022.

Demographic and Macroeconomic Assumptions

Figure 18-5. Population (thousands)

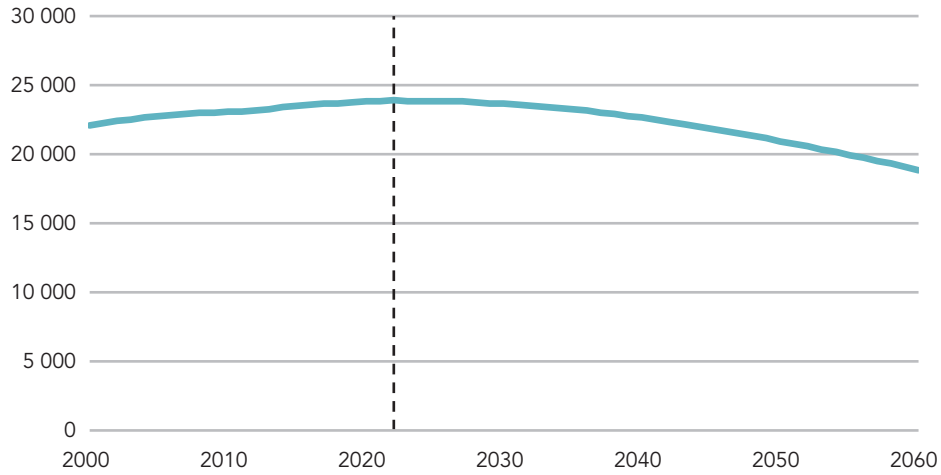
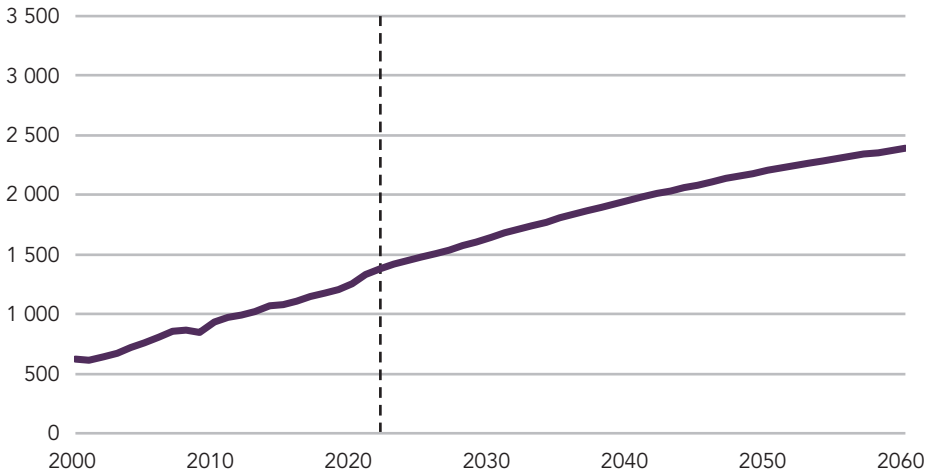


Figure 18-6. Real GDP (billion USD PPP, 2017)



- Chinese Taipei's population is projected to peak at approximately 23.8 million in 2025 before gradually declining over the following decades. By 2060, it is expected to decrease to around 18.8 million, aligning closely with the high-scenario projections published by Chinese Taipei.
- This trend is driven by a persistently low fertility rate, an aging population, which results in a declining population growth rate. In recent years, deaths have outnumbered births, marking the onset of negative population growth. These demographic shifts reflect broader social changes, including evolving lifestyles and family structures.
- With a population density of approximately 647 people per km², Chinese Taipei is one of the most densely populated economies in the APEC region, with population levels remaining highly concentrated in urban areas.
- These changes are likely to impact future energy consumption patterns, particularly in residential buildings and transportation, as household sizes shrink and the population declines.

- Chinese Taipei is a highly developed economy with a steadily increasing GDP, driven by strong exports of IT products and OEM-oriented production methods. Its economic growth has been consistently supported by high-tech manufacturing and a thriving services sector. This robust industrial foundation has enabled the economy to maintain stability even during global downturns.
- GDP is projected to continue its upward trend, with a growth rate of approximately 1.5 % CAGR from 2021 to 2060. Although growth rates are expected to moderate over time due to demographic shifts, particularly a shrinking working-age population, Chinese Taipei remains one of the highest GDP per capita economies in the APEC region, reflecting its economic resilience and industrial strength.
- In the medium to long term, high-tech manufacturing and services are anticipated to remain key drivers of economic growth. Notably, Chinese Taipei's advanced semiconductor industry continues to play a crucial role in global supply chains, further reinforcing its economic stability and growth potential.

End-use Energy Demand

Figure 18-7. Energy demand by sector in REF & TGT (PJ)

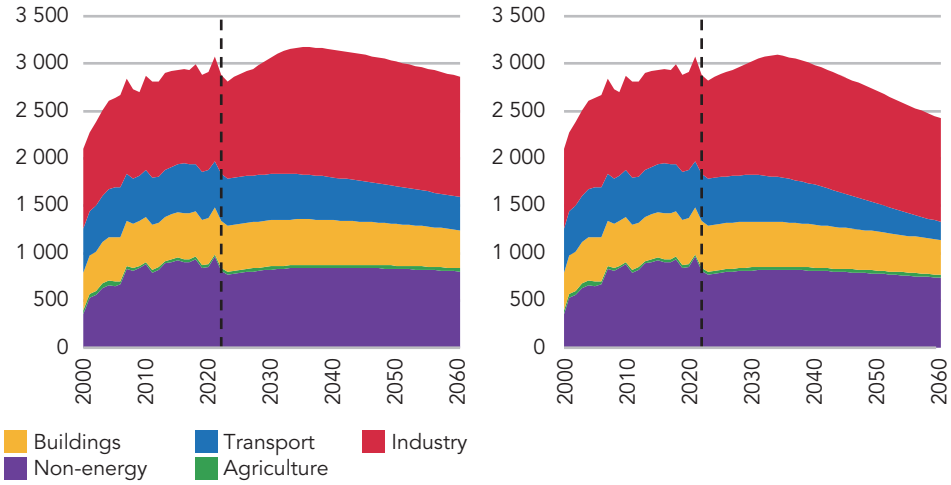
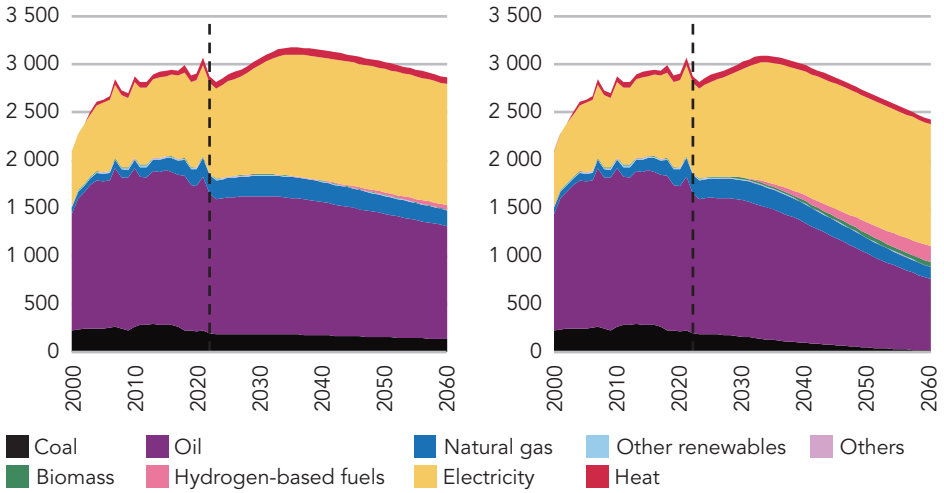


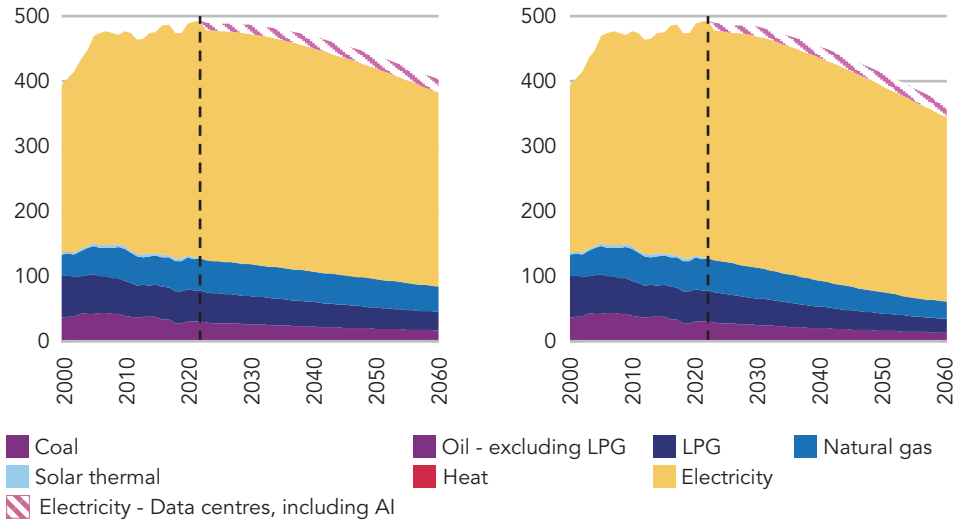
Figure 18-8. Energy demand by fuel in REF & TGT (PJ)



- In 2022 (the base year), industry accounted for the largest share of end-use energy demand at 36%, followed by non-energy use (28%), buildings and transport (both 17%). By 2060, the share of industry is projected to rise significantly to 44%, while transport and buildings decline to 12% and 14% respectively, reflecting shifts in energy demand patterns under the Reference (REF) scenario.
- End-use energy demand is expected to peak in 2035 and then gradually decline, more significantly in the Target (TGT) scenario, which emphasises decarbonisation.
- In both scenarios, the industry sector remains the dominant end-use sector driven by the semiconductor manufacturing industry. After 2035, industrial energy demand is projected to decline, primarily due to energy efficiency improvements and electrification in the machinery subsector, though rising electricity demand from semiconductor production will partially offset reductions in fossil fuel use.
- Transport energy demand drops sharply in TGT, primarily due to reduced gasoline consumption as a result of electrification and stronger decarbonisation policies.
- The TGT scenario emphasises electrification, hydrogen adoption, and reduced fossil fuel reliance for deeper decarbonisation.
- Electricity demand grows steadily, with hydrogen-based fuels emerging after 2040 in TGT. Coal and oil demand decrease notably, particularly in TGT, aligning with decarbonisation efforts. Gas consumption gradually declines, reaching minimal levels post-2040. Biomass continues to play a limited role in the energy mix through 2060.

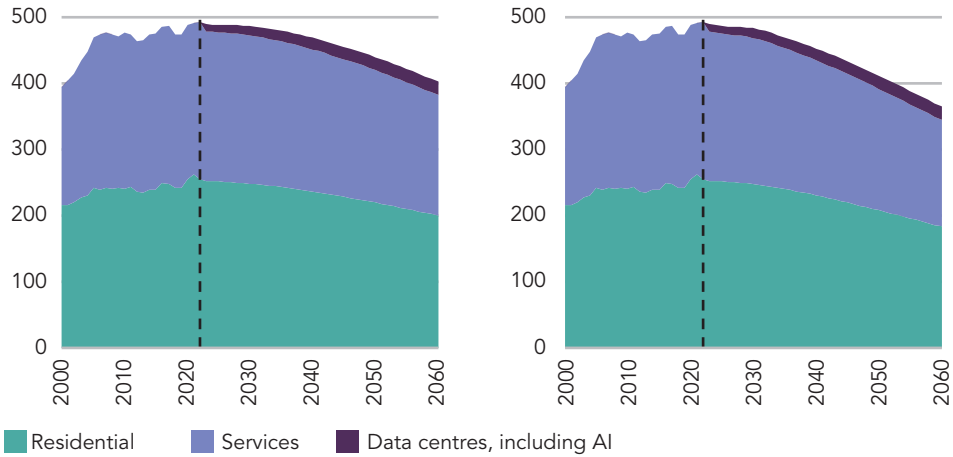
Buildings Energy Demand

Figure 18-9. Buildings energy demand by fuel in REF & TGT (PJ)



- Building energy demand in Chinese Taipei peaked in 2022 and is projected to decline steadily under both REF and TGT scenarios, driven by demographic shifts, rising electrification, and continued improvements in energy efficiency.
- In REF, building energy demand remains relatively stable through 2040 before gradually declining. Electricity's share increases from 73% in 2020 to 79% by 2060, driven by continued electrification and wider adoption of electric appliances and cooling systems, while oil use declines. Gas consumption remains steady over the projection period.
- In TGT, building energy demand decreases more sharply due to accelerated electrification and stricter energy efficiency standards. Electricity's share reaches 83% by 2060, supported by the adoption of green building codes and low-carbon technologies.
- Residential and service sectors dominate total building demand. While residential consumption declines in line with a shrinking population, the service sector's share grows due to urbanisation and stable economic activity. Nonetheless, energy intensity improves, supported by efficiency measures.

Figure 18-10. Buildings energy demand by sector in REF & TGT (PJ)



- Services demand decreases slightly faster than residential, reflecting targeted policies such as mandatory energy audits and subsidies for efficient systems such as electric heat pumps in commercial buildings.
- Although currently modest, electricity demand from data centres and AI is projected to grow steadily and become a more visible component of total consumption by 2060.
- Differences between REF and TGT scenarios in the building sector are not expected to diverge significantly until after 2030, as current policies primarily address near-term goals.

Industry Energy and Non-energy Demand

Figure 18-11. Industry & non-energy demand by fuel in REF & TGT (PJ)

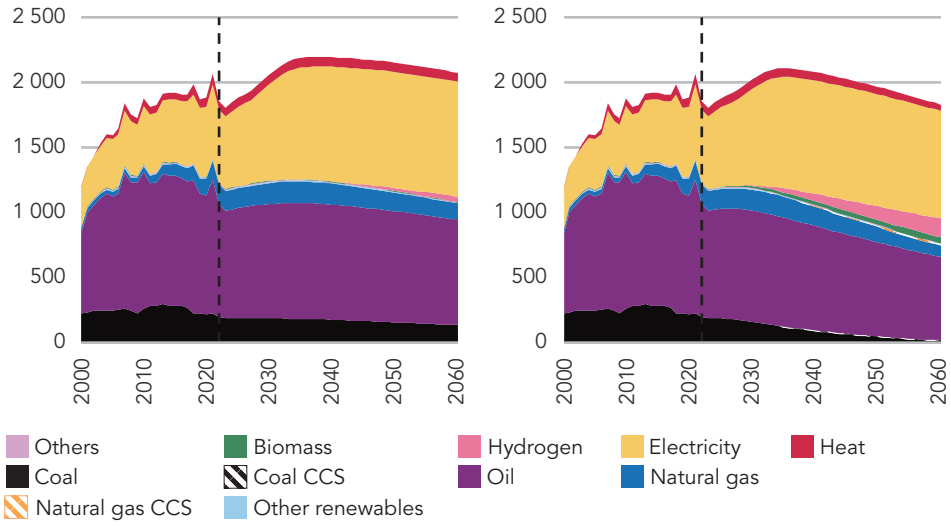
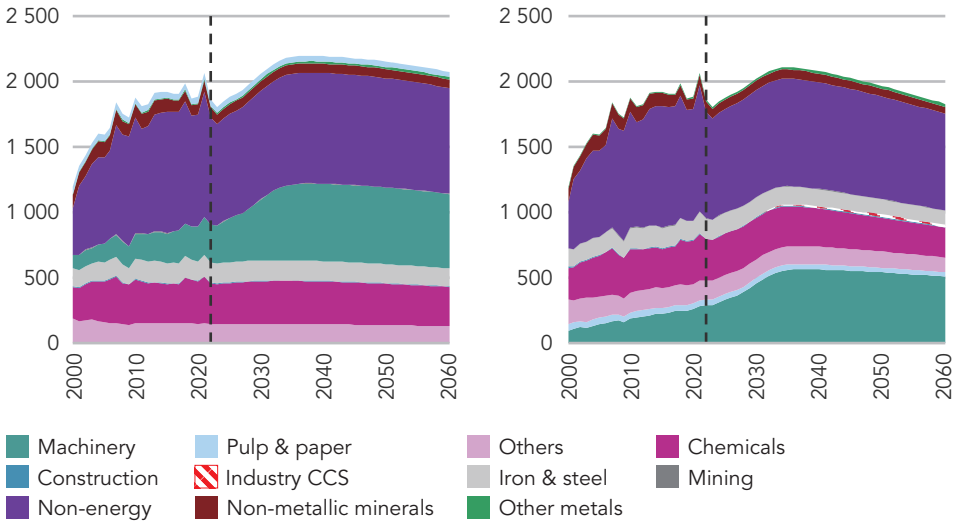


Figure 18-12. Industry & non-energy demand by sector in REF & TGT (PJ)



- Industry and non-energy are major energy consuming sectors in Chinese Taipei, accounting for 36% and 28% of total demand in 2022, respectively. These shares are projected to increase to 44% in industry and to 28% in non-energy by 2060 in REF. Demand is expected to peak in 2035, likely due to efficiency improvements in the semiconductor industry, as well as once data centres and digital networks infrastructure matures.
- Historically, oil has been dominant in the non-energy demand, particularly as a feedstock in the petrochemical industry, accounting for 45% (841.7 PJ) in 2022. Although its share is projected to decline to 38% (787.6 PJ) in REF and to 34% (626.2 PJ) in TGT by 2060, driven by a contraction in the petrochemical sector, oil is expected to remain a key source.
- Electricity plays a crucial role in the industry energy demand. In 2022, it comprised of 53% (555.4 PJ) of total industry energy demand, rising to 70% (884.8 PJ) by 2060 in REF and 76% (825.3 PJ) in TGT.
- Coal use is projected to be nearly phased out in TGT by 2060, reflecting a shift toward electrification in low-temperature industrial processes. Biomass is expected to partially replace coal as an industrial feedstock, particularly in the cement and chemical sectors. However, its contribution remains modest, increasing from 5.3 PJ in 2022 to 47.9 PJ by 2060 in TGT but reducing to 4.1 PJ in REF.
- The energy demand of machinery sector will significantly increase in both scenarios until 2040, driven particularly by semiconductor manufacturing. In TGT, the demand declines across machinery and chemicals after 2040.
- Starting in 2030 in REF and 2040 in TGT, hydrogen is expected to support green steel production and be blended with natural gas for high-heat applications in the cement and chemical sectors. Heavy industry is also projected to adopt CCS from the 2030s in TGT, with steelmakers collaborating with petrochemical firms to turn captured carbon into valuable products.

Transport Energy Demand

Figure 18-13. Domestic transport energy demand in REF (PJ)

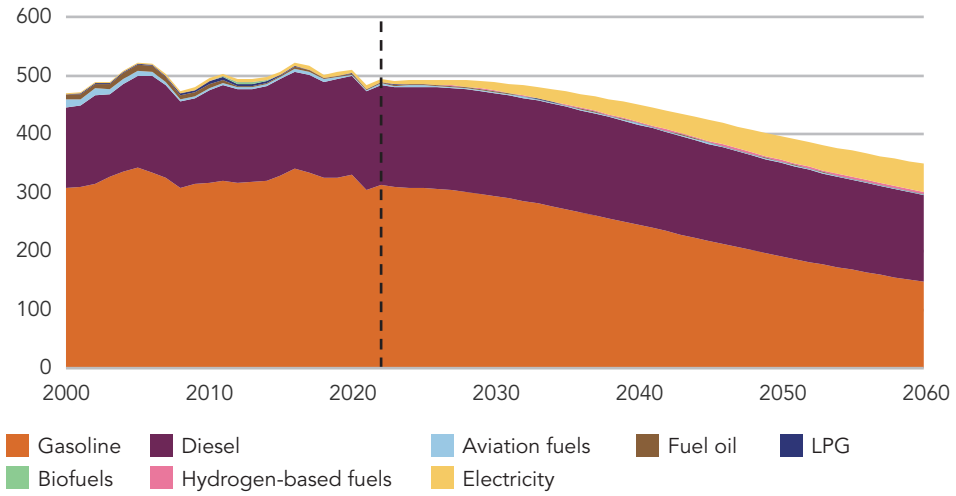
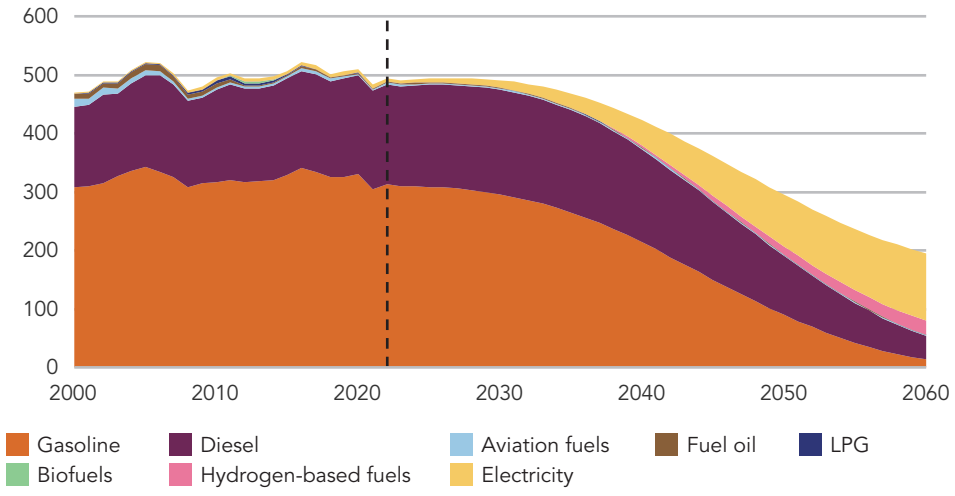


Figure 18-14. Domestic transport energy demand in TGT (PJ)



- Transport energy demand in Chinese Taipei is expected to undergo significant changes, driven primarily by policy targets that phase out sales of fossil fuel-powered motorcycles by 2035, internal combustion engine (ICE) passenger vehicles by 2040, and city buses by 2030. These goals are achieved in TGT.
- The projected decrease in population for Chinese Taipei leads to a reduction in passenger activity, driving a slight decrease in energy use in both scenarios. On the other hand, increasing economic activity leads to steady growth in freight demand.
- In REF, transport energy demand peaks around 2020 and gradually declines. Electricity use expands notably, while hydrogen-based fuels emerge later at a modest scale.
- The TGT scenario shows a more accelerated decline in overall energy demand due to efficiency gains. This is driven by stronger electrification trends and the incremental adoption of fuel cell EVs (which use hydrogen) in heavy freight trucks and a small number of buses.
- The fast adoption of EVs in Chinese Taipei will require special attention to ensure a large amount of public charging stations and associated electricity system upgrades are considered. Notably, there are about twice as many two-wheelers as there are cars. These two-wheelers put relatively less stress on the grid and already have a well-used battery swapping system in place.

Other Transport Data

Figure 18-15. Transport vehicle stocks in REF & TGT (millions)

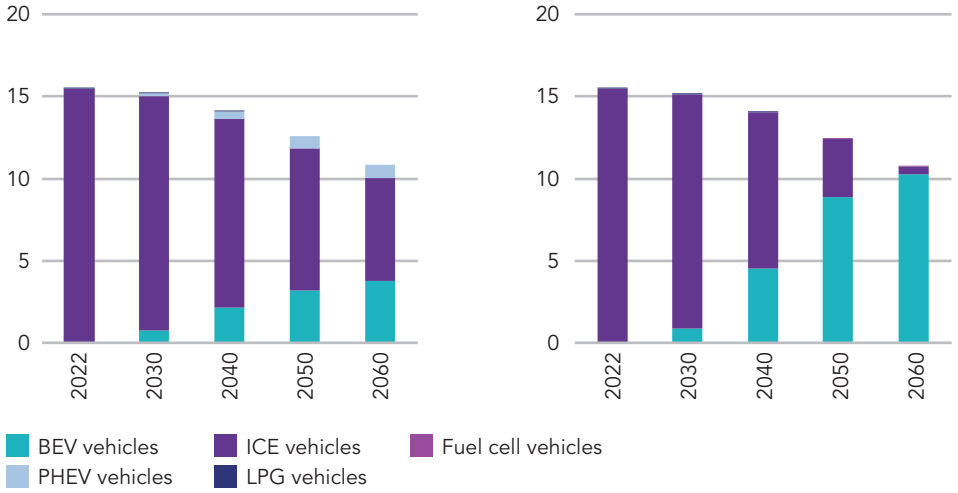
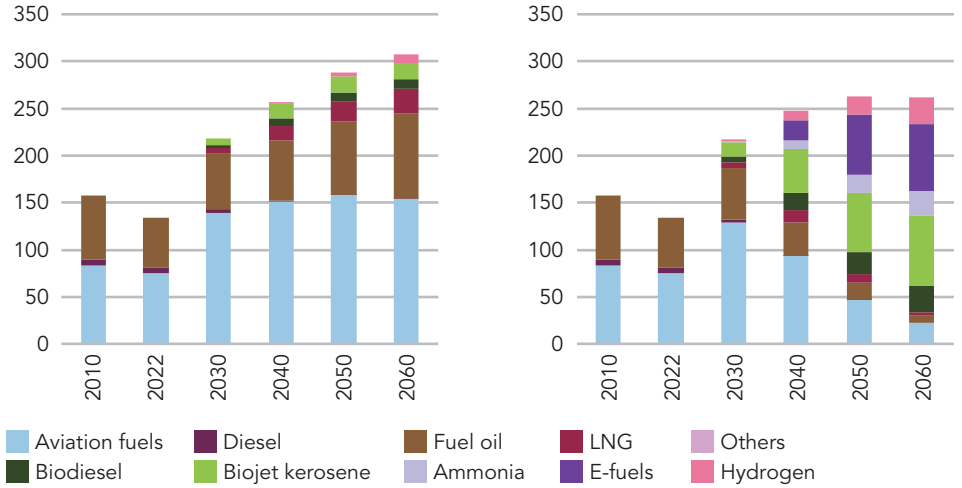
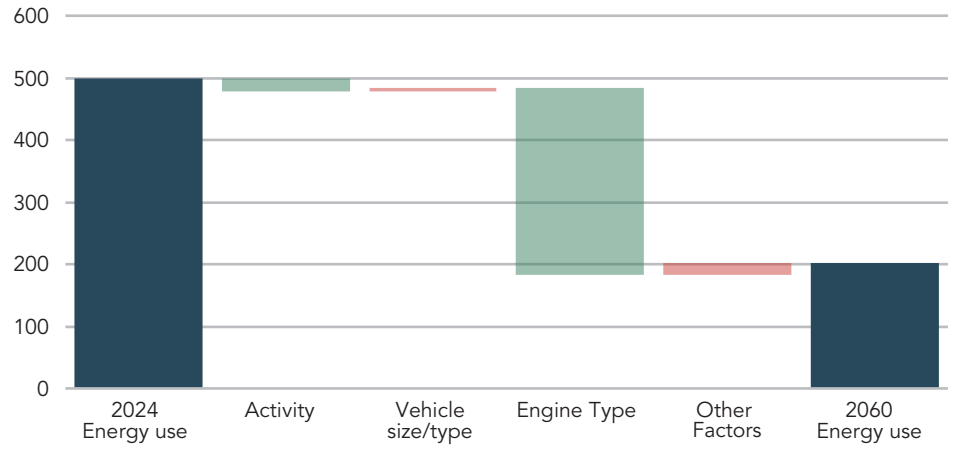


Figure 18-16. International bunker energy demand for shipping and aviation in REF & TGT (PJ)



- By 2060 in TGT, BEVs account for nearly 99% of passenger vehicles and 80% of freight vehicles. The remaining freight vehicles (which are mostly heavy) are split equally between fuel cell and ICE vehicles.
- Bunkers (energy for international transport) transition to lower emissions fuel sources in TGT. The target for this was assumed from the general intentions set out by international transport organisations.
- Figure 18-17 shows that the shift to more efficient engine types is the major cause of the projected decline in transport energy use in TGT between 2024 and 2060. The decreasing population also causes a slight decrease, but this is countered by other factors (such as aging vehicles) and vehicle size/type (such as the shift from motorbikes to cars, and cars to SUVs).

Figure 18-17. Components of the change in road energy use in TGT (PJ)



Note: Information on the different drivers in the transport energy decomposition can be found in the *Outlook*'s annex.

Electricity Generation

Figure 18-18. Electricity generation by fuel in REF (TWh)

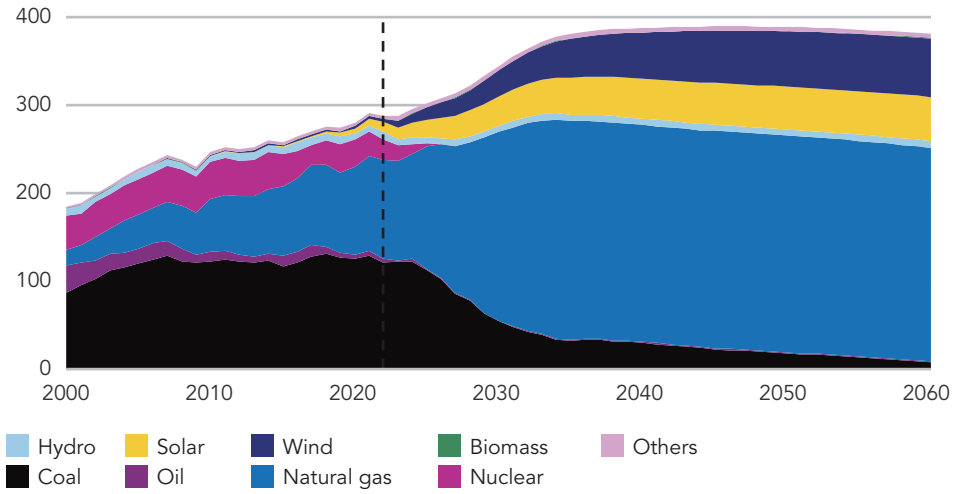
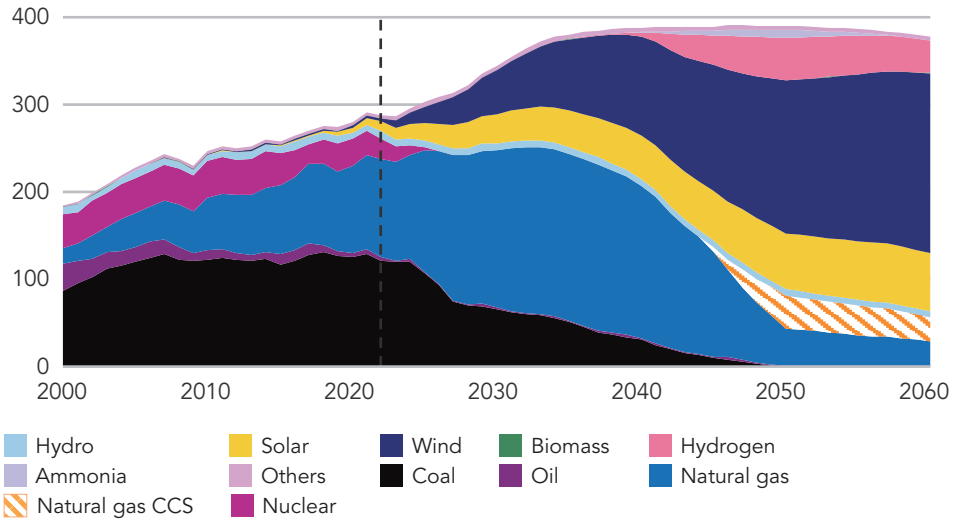


Figure 18-19. Electricity generation by fuel in TGT (TWh)



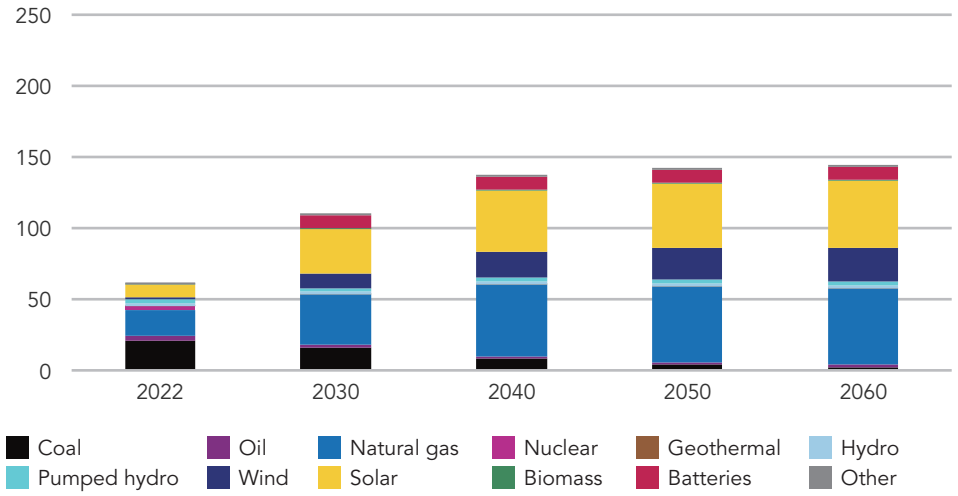
- Chinese Taipei's electricity generation is undergoing a significant transformation, driven by its "Pathway to Net-Zero Emissions in 2050" and the Climate Change Response Act promulgated in 2023. While electricity generation is projected to grow steadily, reaching 381.1 TWh by 2060 in REF, the Target scenario outlines a much more aggressive decarbonisation pathway for the power sector.
- Natural gas-fired generation is expected to rise steadily, increasing from 36% in 2020 to 64% in 2060 in REF. It becomes the primary electricity source from 2025, serving as a transitional fuel to ensure supply stability while reducing coal use and phasing out nuclear. This supports the target of 50% natural gas in the energy mix by 2025.
- In line with Chinese Taipei's nuclear-free policy, nuclear power generation has officially ceased by May 2025, following the disconnection of the last operating reactor at Maanshan from the grid.
- Coal-fired generation is projected to decline gradually, with a full phase-out by 2042 under the TGT scenario.

- Renewable energy generation is projected to grow significantly under Chinese Taipei's net-zero strategy, with wind and solar identified as one of the "12 Key Strategies." In TGT, solar and wind generation accelerate notably after 2040, together accounting for 73% of total electricity generation by 2060 (18% from solar, 55% from wind), making them the dominant energy sources. This aligns with Chinese Taipei's long-term goals for renewables, aiming for 60-70% of total electricity generation to come from renewable energy by 2050.
- The Target scenario highlights the adoption of carbon capture technologies starting in 2045, the introduction of hydrogen deployment from 2035, and ammonia co-firing in coal-fired power generation by 2036. These developments mark a significant step in diversifying the electricity mix and decarbonising the power sector.

Note: Figures 18-18 and 18-19 do not include electricity generation for hydrogen production.

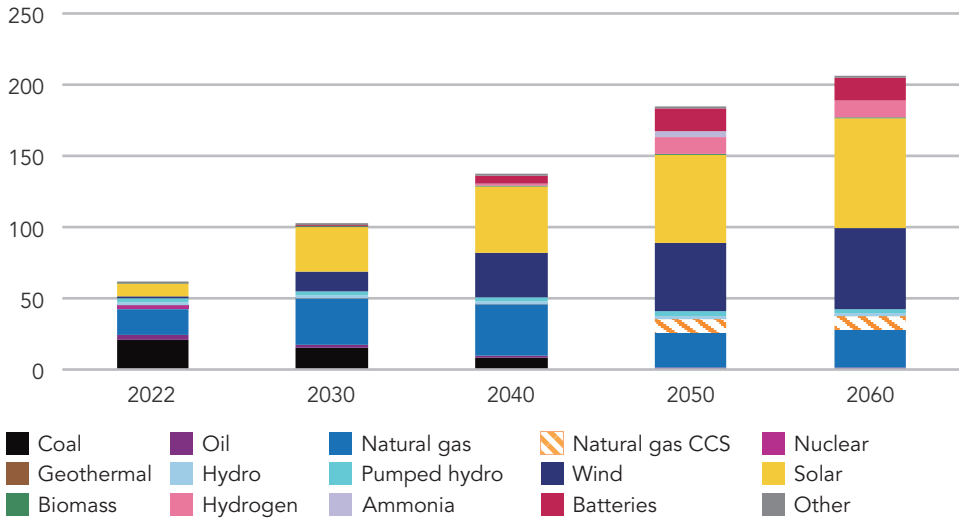
Generation Capacity

Figure 18-20. Generation capacity by fuel in REF (GW)



- Chinese Taipei's commitment to advancing low-carbon energy development and its nuclear-free policy has led to an increase in natural gas and renewable energy, along with the phase-out of coal and nuclear power plants.
- Generation capacity is projected to grow steadily, primarily driven by renewable energies and gas, reaching approximately 145 GW by 2060 in REF.
- Gas-fired generation will continue to increase and become the primary energy source in the power sector from 2025, supporting low-carbon development and power supply stability.
- Nuclear power is phased out in line with the policy requiring all existing nuclear power plants to be decommissioned by 2025.
- In TGT, generation capacity is expected to reach 206 GW in 2060, a faster growth than in the REF scenario, especially after 2040.

Figure 18-21. Generation capacity by fuel in TGT (GW)



- Both scenarios show coal and nuclear phase-out with increased natural gas reliance, while the TGT scenario accelerates renewable energy, energy storage, and hydrogen adoption for stronger decarbonisation.
- The substantial growth in solar, wind, and battery capacity after 2040 reflects a shift toward flexible and resilient power systems. Installed capacity is projected to reach 61 GW for solar and 57 GW for wind by 2060. Battery storage also expands significantly, supporting the integration of variable renewable energy and enhancing grid stability.
- Carbon capture technologies are expected to be adopted from 2045, while hydrogen deployment is anticipated from 2035, contributing to the decarbonisation of the power sector.

Note: Figures 18-20 and 18-21 do not include generation capacity for hydrogen production.

Grid Reliability

Figure 18-22. Total generation capacity and peak load (GW)

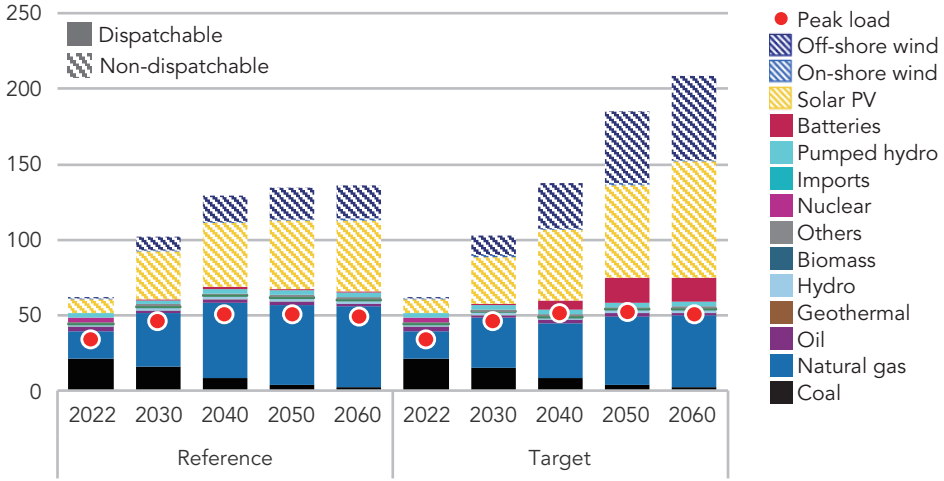
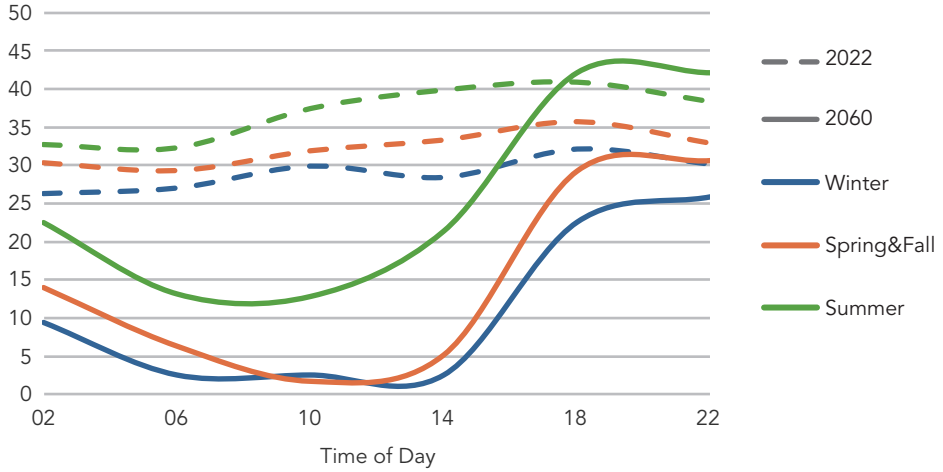


Figure 18-23. Power from dispatchable sources in TGT (GW)



- Chinese Taipei's peak electricity load is projected to rise steadily, reaching around 50 GW in both scenarios in 2040.
- Variable renewable energy capacity, mainly wind and solar, expands significantly, reaching around 70 GW in REF, with a larger buildout in TGT. The growth of capacity between 2020 to 2060 is 3.5%. As the share of renewable energy grows, system operations will face greater challenges.
- The large rise in capacity, mainly from variable renewables, lowers the average capacity factor and increases reliance on dispersed sources, making transmission and coordination more complex.
- To ensure grid reliability, dispatchable capacity including batteries and energy storage should increase to 50 GW in both scenarios by 2050 to provide a critical buffer during periods of low renewable output or outages.

- Dispatched power variability increases significantly by 2060, especially in the summer. The dispatched power plunges to around 10 GW at midday and then surges to nearly 30 GW by early evening. This 20 GW swing reflects a much steeper curve than in 2020, due to higher share of VRE, especially solar.
- Similar patterns appear in 2060 spring and fall. The load rises from 5 GW at noon to 25 GW in the evening. To maintain stability, dispatchable sources must ramp up by over 20 GW within a few hours, which is twice the level required in 2020.
- To manage the steep evening ramp, especially in summer when solar output declines while demand rises, system operators will require fast-ramping generation, storage, and demand-side management, which will increase capital, maintenance, and operational costs.

Coal and Biomass

Figure 18-24. Coal and biomass consumption by sector in REF & TGT (PJ)

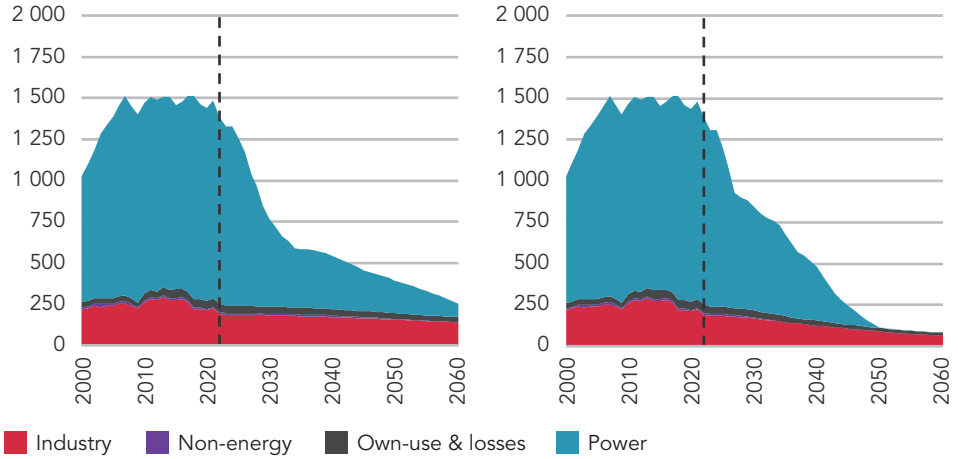
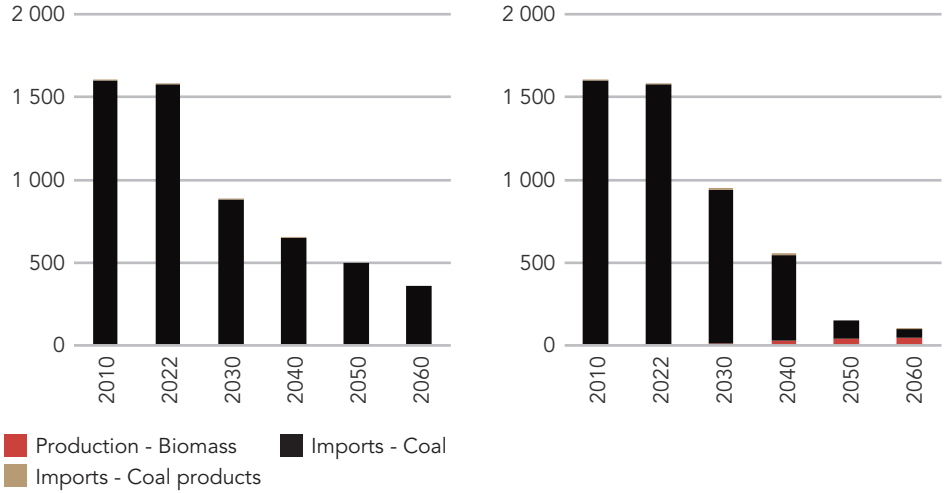


Figure 18-25. Coal and biomass production, imports, and exports in REF & TGT (PJ)



- Coal consumption declines significantly in both scenarios, primarily in the power sector, driven by strengthened decarbonisation. The power sector, historically the largest consumer of coal, experiences a rapid decline in coal use in both scenarios as coal-fired power generation is phased out gradually.
- In REF, total coal and biomass consumption peaked at approximately 1,500 PJ in 2018, dropped sharply after 2020 due to reduced coal use in power generation, and is projected to decline to around 250 PJ by 2060 in REF, with remaining use limited to specific industrial applications.
- In TGT, coal use drops more steeply than in REF, with power sector demand nearly phased out after 2050. After 2036, coal begins to be co-fired with ammonia in small portions, reflecting intensified efforts to reduce emissions.
- In the industrial sector, coal use remains relatively stable through the early 2030s, then gradually decreases as facilities transition to cleaner heat sources, such as through electrification and low-carbon hydrogen.

- Chinese Taipei relies heavily on coal imports due to limited domestic reserves, with imports primarily supporting power generation and industrial activities.
- Coal imports peaked at around 1,600 PJ in 2010, reflecting a strong dependence on coal during that period. From 2022 onward, coal imports decline steadily, falling to 357 PJ by 2060 in REF, in line with energy policies aimed at reducing coal's share in power generation.
- In TGT, coal imports gradually decrease faster, consistent with the target of reducing their share to 30% by 2025 and phasing down thereafter.
- Biomass production remains modest, rising slightly from approximately 6 PJ in 2022 to around 50 PJ by 2060 in TGT. This growth aligns with the Chinese Taipei's net-zero strategy, which includes promoting biogas generation.

Natural Gas

Figure 18-26. Natural gas consumption by sector in REF & TGT (PJ)

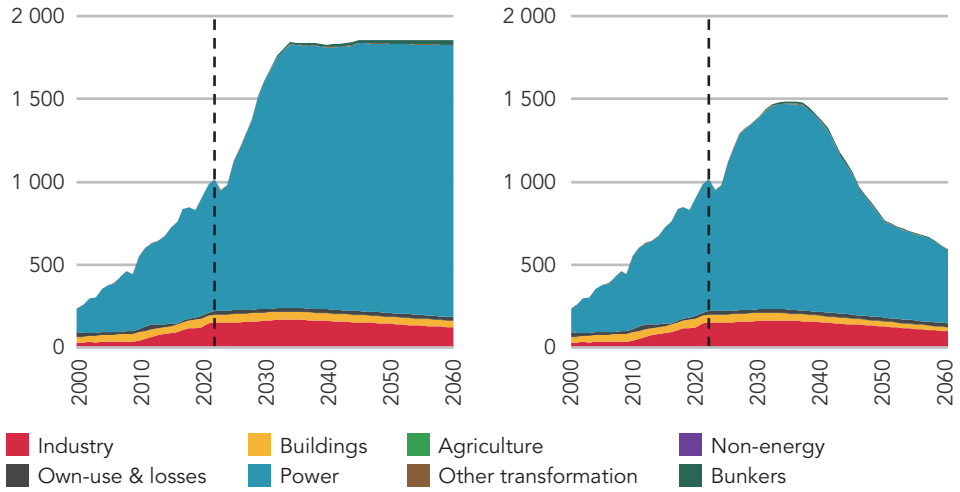
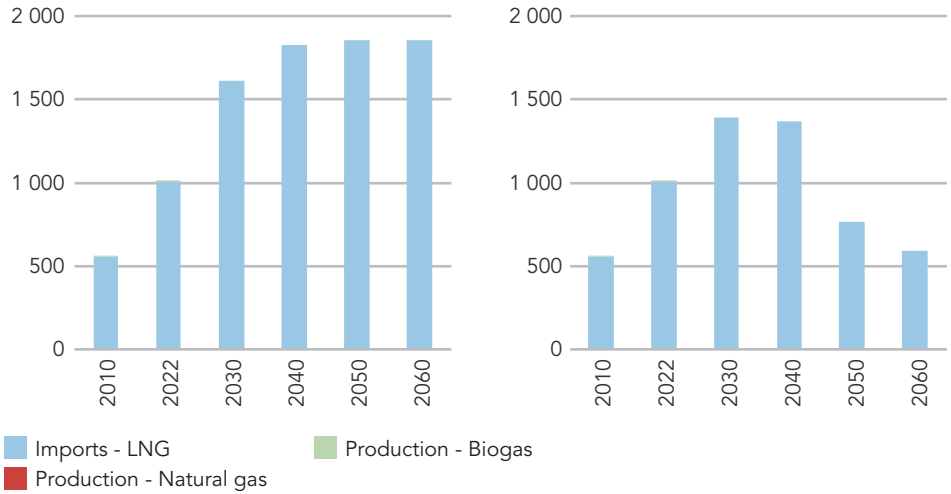


Figure 18-27. Natural gas production, imports, and exports in REF & TGT (PJ)



- Natural gas serves as a transitional fuel in Chinese Taipei's shift to net-zero by 2050, with a policy target of 50% gas-fired power generation by 2025 to replace coal. As a result, both scenarios show a significant increase in natural gas use, from around 900 PJ in 2020 to peak of 1,850 in REF and 1,480 in TGT by 2035. In REF, natural gas use continues to grow until the early 2030s, reaching 1,800 PJ, then remains stable. In contrast, in TGT, it peaks around 2030 and declines as hydrogen is introduced for co-firing to offset natural gas demand.
- The power sector dominates gas consumption, accounting for roughly 80% since 2015, and rising to over 85% from 2030 through 2060, followed by smaller contributions from buildings and industry.
- Due to limited domestic resources, Chinese Taipei relies heavily on LNG imports, which peak at 1,826 PJ in 2040 in REF and 1,391 PJ in 2030 in TGT, before falling to near 600 PJ by 2060. This reliance heightens energy security and price volatility risks, reinforcing the need for diversification and increased domestic renewable energy capacity.
- To meet rising demand, Chinese Taipei is expanding its LNG import infrastructure. Key projects include the operational Guantang terminal, ongoing expansion of the Taichung terminal, and a planned facility in Kaohsiung. Taipower is also developing LNG receiving facilities for the Hsieh-ho power plant. These developments could raise total LNG import capacity to over 37 MTPA by the early 2030s.

Petroleum Liquids

Figure 18-28. Crude oil, NGLs, and other hydrocarbon production, imports, and exports in REF & TGT (PJ)

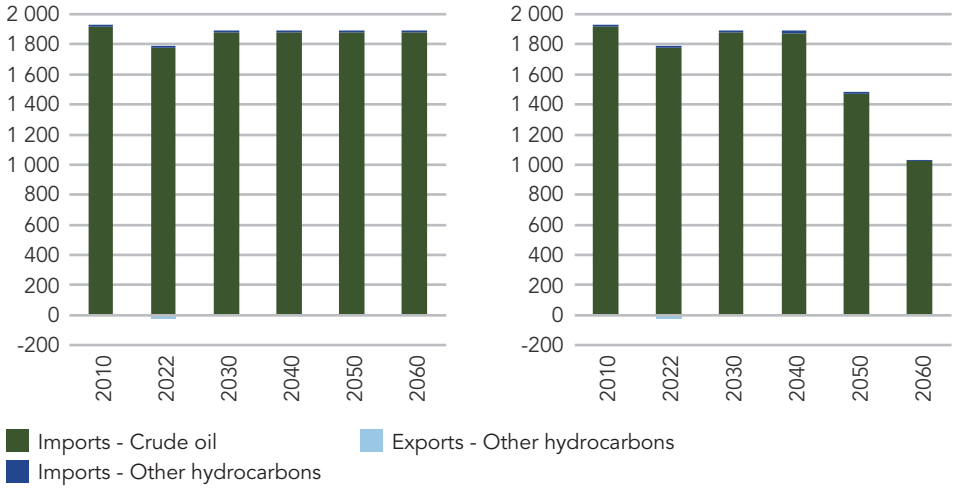
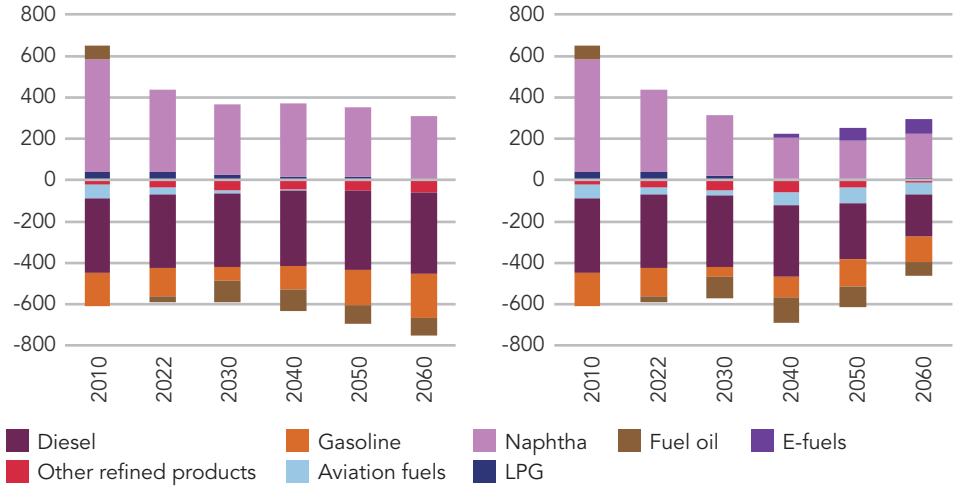


Figure 18-29. Net imports of refined products and low-carbon fuels in REF & TGT (PJ)



- Chinese Taipei relies heavily on crude oil imports due to limited domestic reserves.
- In REF, crude oil imports are projected to remain the same throughout the whole projection period; However, imports are expected to decline significantly after 2050 in TGT, falling from around 1,870 PJ in 2040 to 1,020 in 2050, driven by deep decarbonisation efforts, a contraction of the petrochemical sector, widespread electrification of transport and industrial processes, and the adoption of alternative fuels.
- Domestic crude oil production is negligible and remains unchanged throughout the projection period.
- As of 2022, total refinery capacity was 1.1 mb/d, with a net addition of 627 kb/d between 1,997 and 2,000 to support petrochemical production.
- Refining capacity declines gradually from 2020, especially in TGT, driven by falling domestic demand and increased electrification of transport. Export-oriented refining faces growing pressure as overseas markets transition to low-carbon alternatives.

- Gasoline and diesel outputs decline in both scenarios, with reduced exports due to shrinking external markets and the loss of economies of scale.
- Aviation fuel output remains stable under REF, but shifts from net imports to net exports under TGT, aligned with the global momentum toward SAF adoption.
- LPG and other refined products maintain stable output levels, though their share in the energy mix diminishes over time.

Note: In Figure 18-29, net imports are presented without deducting bunkers.

Refining

Figure 18-30. Refining outputs in REF & TGT (PJ)

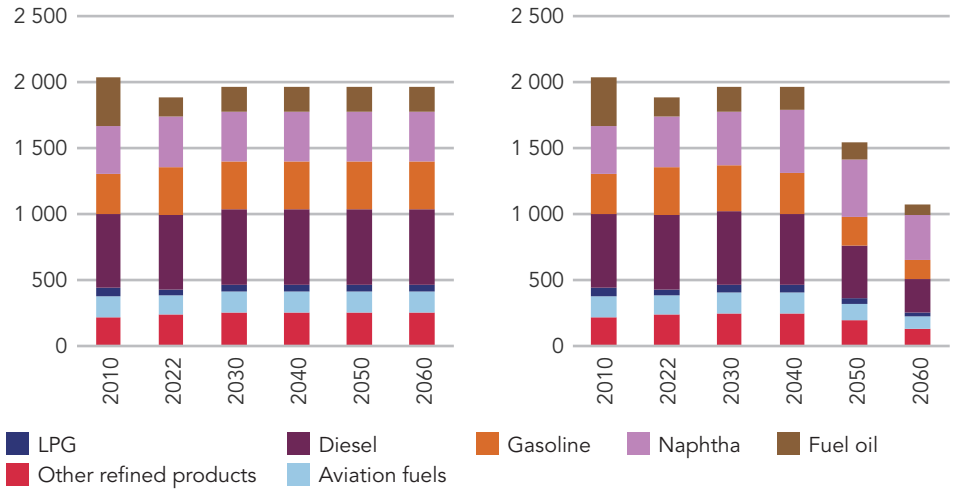
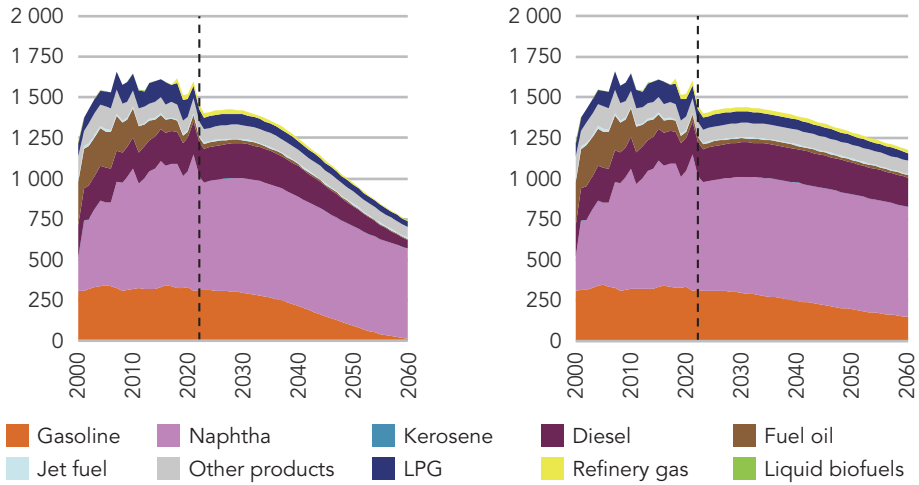


Figure 18-31. Refined products demand in REF & TGT (PJ)



- Refinery outputs historically matched total consumption, including international marine and aviation bunkers, with naphtha imports and diesel and gasoline exports maintaining balance.
- In REF, refining capacity remains stable to meet petrochemical demand. In TGT, refining capacity is projected to decline gradually with decreasing gasoline and diesel consumption due to EV adoption.
- Refined product demand peaked at nearly 2000 PJ in 2007 and began declining gradually from 2021. Future consumption is projected to decline slightly in REF and more significantly in TGT.
- The petrochemical industry faces challenges, including competition from overseas and the rise of EVs, impacting refinery viability.
- Naphtha consumption for petrochemicals remains the dominant refined product, staying robust but decreasing slightly in TGT. The output is expected to rise in the medium term as refineries enhance and upgrade processes to meet growing petrochemical demand, supported by reduced gasoline and diesel yields.
- Naphtha imports remain relatively steady in REF, but decline in TGT due to increased domestic refinery outputs, reflecting a strategic shift towards the production of petrochemical feedstocks.
- Gasoline consumption declines moderately in REF, but drops sharply in TGT. Diesel consumption remains stable in REF, but decreases significantly in TGT.

Hydrogen-based Fuels

Figure 18-32. Hydrogen-based fuels demand by sector in REF & TGT (PJ)

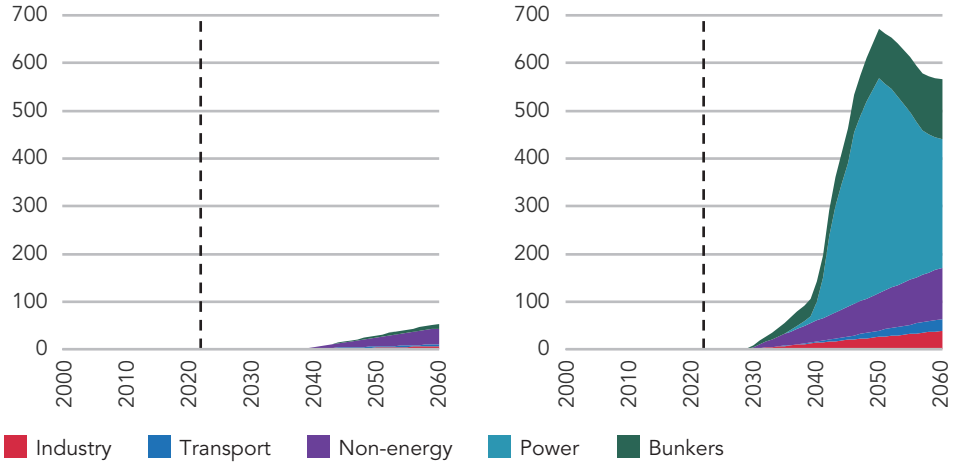
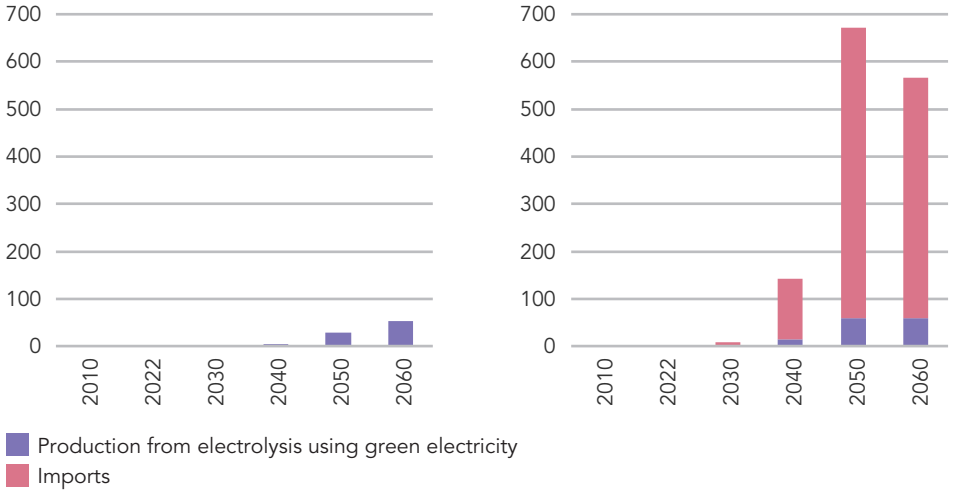


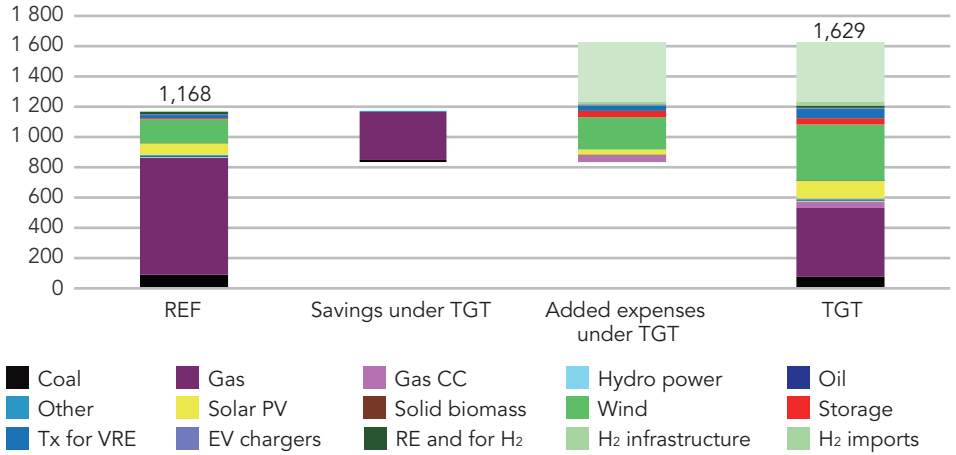
Figure 18-33. Hydrogen-based fuel production method and supply in REF & TGT (PJ)



- The Chinese Taipei government has integrated hydrogen into its 2050 Net-Zero Emissions Pathway as one of the "12 Key Strategies" and supports hydrogen development through multiple initiatives. Hydrogen demand in Chinese Taipei is expected to emerge gradually, with small-scale adoption starting by 2030 in both scenarios, initially in the transport sector.
- Hydrogen demand in Chinese Taipei shows a substantial difference between the two scenarios. In TGT, demand grows significantly after 2040, reaching approximately 4.35 million tons by 2050, driven primarily by hydrogen co-firing in power generation, as well as early-stage use in transport and industry. In contrast, in REF, there is limited hydrogen use, mainly in niche transport applications and shipping fuels.
- Notably, in 2024, Taipower launched a project at the Hsinta Power Plant to co-fire hydrogen with natural gas, aiming to scale from 5% to 15% hydrogen blending. With the power sector becoming the dominant hydrogen consumer by 2041 in TGT, this reflects expectations that hydrogen will be co-fired for power generation as part of broader decarbonisation strategies.
- Hydrogen's adoption in the transport sector remains limited, mostly confined to pilot projects such as hydrogen fuel cell buses.
- In REF, all hydrogen demand is assumed to be met through domestic production, given its limited scale. In contrast, in TGT, it is anticipated that there will be a mix of domestic electrolysis and large-scale imports, especially post-2040, with imports expected to account for around 90% of demand by 2050.

Costs

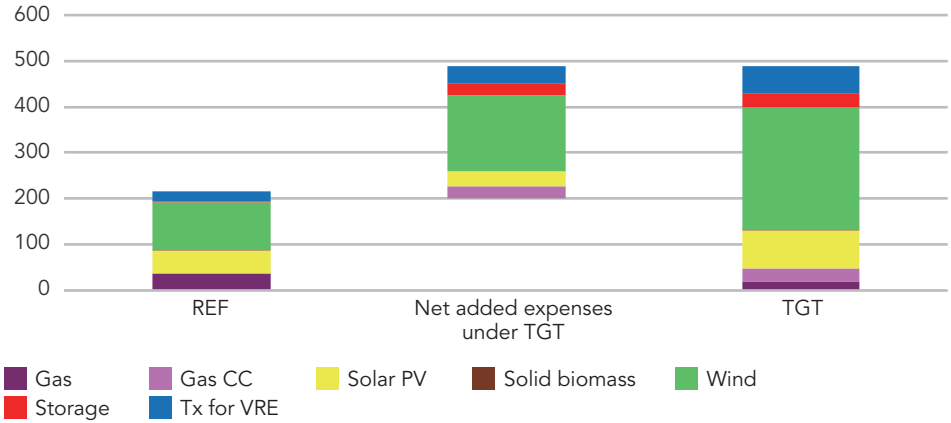
Figure 18-34. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



Note: Tx for VRE is only transmission infrastructure to connect variable renewable capacity to the grid. EV chargers do not cover the cost of associated infrastructure or EV vehicles. Hydrogen costs do not cover costs for bunkering.

- Decarbonisation of Chinese Taipei's energy system requires substantial expenditures, particularly in TGT where from 2025 to 2060, total energy system costs are an estimated USD 461 billion higher than in REF. Figure 18-34 shows capital, fixed, and variable costs in the power sector, costs for low-carbon hydrogen imports (production to a lesser extent), transmission for new variable renewable electricity, and electric vehicle chargers.
- In TGT, fossil fuel expenditures, especially for gas decline with an estimated USD 320 billion worth of savings under TGT, but these savings are offset by low-emissions energy investments such as wind and solar and low-carbon hydrogen imports for use in power, transport, industry, and non-energy. Not counting gas, wind power and hydrogen imports account for the largest shares of expenditure, at 23% and 24% respectively, followed by solar PV (7%) in TGT.
- Hydrogen-related costs total around USD 440 billion, mostly attributed to imports for domestic use (largely in the power sector) with small investments in renewables and hydrogen producing infrastructure (USD 40 billion).

Figure 18-35. Total capital investment (CAPEX) from 2025 to 2060 in the power sector (billion USD, undiscounted)

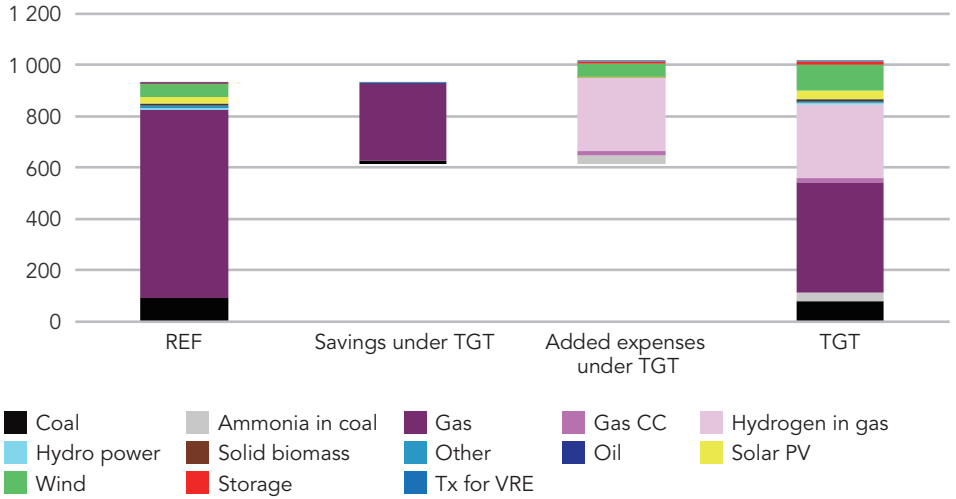


Note: Figure 18-35 only covers power and VRE transmission sector investments. Hydrogen and EV capital investments are not included.

- Investment in transmission (Tx for VRE) for integrating variable renewable energy also rises by an estimated USD 37 billion in TGT, helping to ensure system reliability.
- Figure 18-35 shows that capital investment in TGT is an estimated USD 488 billion between 2025 and 2060, more than double that of REF. This rise is primarily driven by expanded deployment of renewables such as offshore wind, solar, energy storage, as well as the transmission needed to accommodate added variable generation and to accelerate electrification.
- The expanded investment in TGT also extends to advanced dispatchable solutions, including increased carbon capture gas (CC) investments, crucial for ensuring both sufficient firm capacity and reduced emissions while balancing intermittent renewable output and maintaining grid reliability.
- In contrast, capital expenditures in REF remain at USD 215 billion, as this scenario relies more on utilising existing fossil-based infrastructure with more limited expansion in low-emissions energy technologies.

Costs

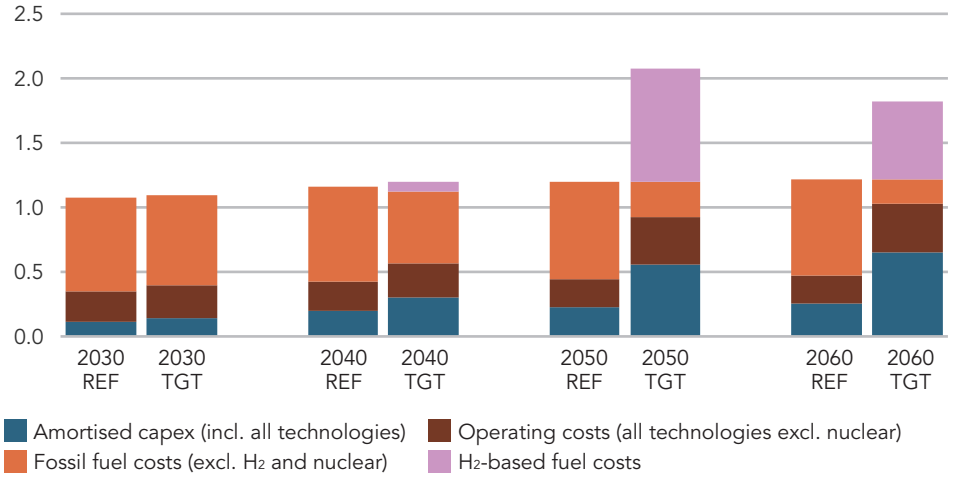
Figure 18-36. Total operating costs from 2025 to 2060 in the power sector (billion USD, undiscounted)



Note: Figure 18-36 only covers power and VRE transmission sector costs. It does not include operating costs associated with hydrogen production and EV charger costs but does include the cost of H_2/ammonia blending in power generation.

- Chinese Taipei's total operating costs in the power sector are projected to reach an estimated USD 930 billion by 2060 in REF. This reflects a continued reliance on fossil fuels, particularly natural gas, which remains the dominant cost driver in generating electricity.
- In REF, gas accounts for 79% of total operating costs due to its critical role in balancing variable renewables and maintaining system reliability. In contrast, under TGT, the cost of natural gas shifts toward a smaller share, dropping to around 40%. Meanwhile, low-carbon hydrogen blended into gas emerges as a significant cost factor, increasing to approximately 30% of total operating expenditures.
- Total operating costs under TGT rise to an estimated USD 1,015 billion by 2060. While gas-related expenses decline by USD 303 billion, this is offset by increased operational spending on low-emission technologies, namely hydrogen blending in gas and to a lesser extent wind.

Figure 18-37. Cost of generating electricity relative to 2025 (2025 cost = 1.0) in the power sector



Note: Based on our assumptions about future capital and operating costs, Figure 18-37 shows cost compositions over time relative to 2025. It should not be considered an estimate of electricity tariffs and excludes market mechanisms that are too difficult to estimate.

- Indexed to 2025, electricity generation costs are projected to stay roughly the same in both scenarios until 2040 but are slightly higher in TGT due to greater renewable investment increasing capital amortised costs, particularly for offshore wind.
- In REF, indexed to 2025, fossil fuel expenditures consistently comprise around 75% of electricity generation costs throughout the projection period, reflecting the continued reliance on natural gas for Chinese Taipei's power generation.
- In TGT, cost increases are more pronounced with the cost of electricity generation doubling relative to 2025 by 2050 as low-carbon hydrogen blending in gas peaks before easing as its use starts to decrease in the power sector.
- Amortised capital costs grow steadily to about a third of total generation costs in TGT by 2060, compared to just half of that in REF, reflecting increased investment in renewables.

CO_2 Emissions

Figure 18-38. CO_2 emissions in REF (million tonnes)

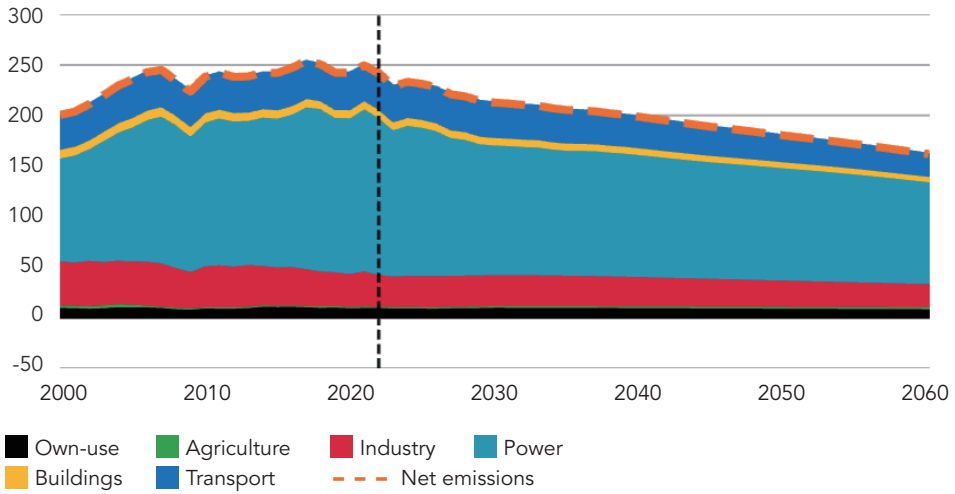
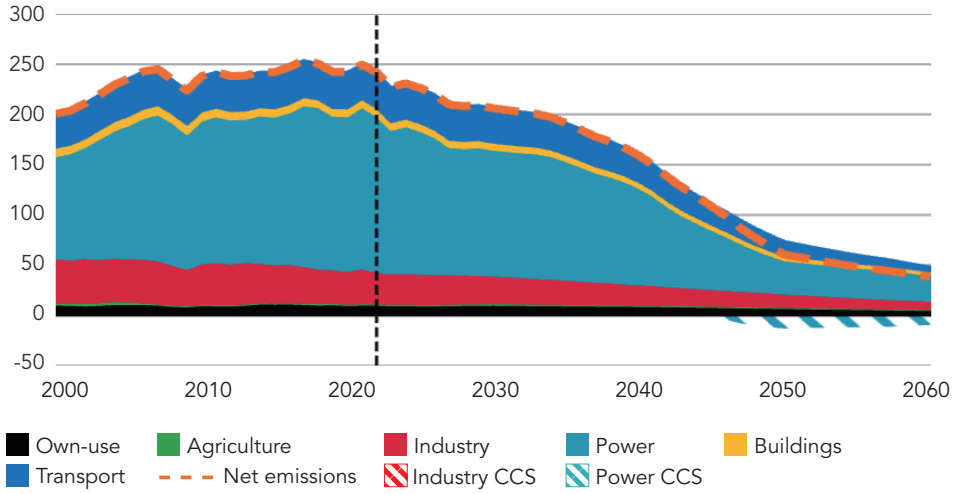
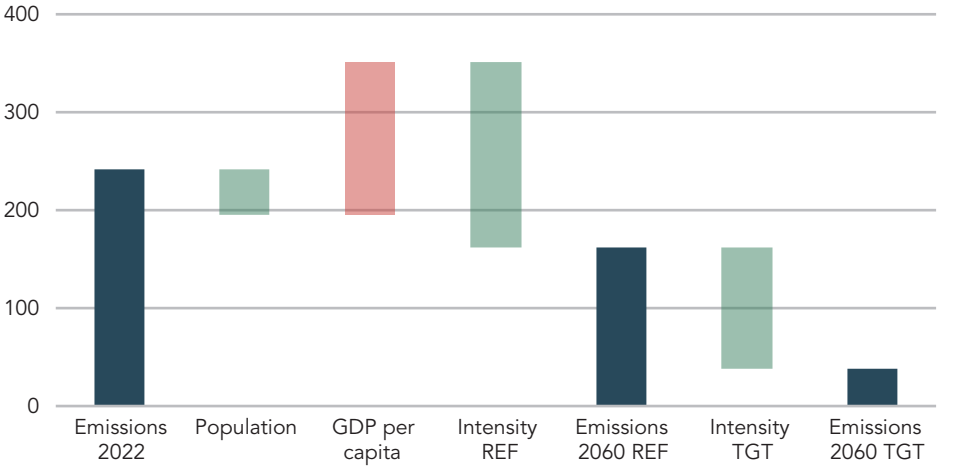


Figure 18-39. CO_2 emissions in TGT (million tonnes)



- CO_2 emissions peak around 2017 and gradually decline in REF, with emissions remaining considerable by 2060.
- The power sector is the largest contributor to CO_2 emissions throughout the period, followed by the transport and industry sectors.
- In REF, power sector emissions are expected to decrease steadily after 2026. Meanwhile, the agriculture and building sectors maintain a smaller share of emissions, with gradual reductions over time.
- In TGT, emissions follow a similar peak pattern around 2020 but decline rapidly after 2030, driven by improved energy efficiency, fuel switching, and expanded deployment of renewable energy generation.
- CO_2 emissions from the transport and industry sectors are projected to decline faster after 2030 compared to REF.

Figure 18-40. CO_2 emissions components (million tonnes)



Note: All values represent energy sector combustion CO_2 emissions. Biogenic CO_2 is treated as zero at the point of combustion.

Useful Links

APEC Expert Group on Energy Data and Analysis (EGEDA) – https://www.egeda.ewg.apec.org/

APEC Energy Statistics 2022 – https://www.egeda.ewg.apec.org/egeda/general/info/pdf/APEC_Energy_Statistics_2022.pdf

APEC Energy Overview – https://aperc.or.jp/reports/energy_overview.php

CPC – https://www.cpc.com.tw/en/

EA (Energy Administration), MOEA – https://www.moeaea.gov.tw/ECW/english/home/English.aspx

Electricity Price and Related Tariff Review – https://www3.moeaea.gov.tw/ele102/Content/Messagess/contents.aspx?MmmID=654246034150461022

Energy labelling website – https://www.energylabel.org.tw/

Energy Statistics Information System – https://www.esist.org.tw/

Feed-in tariffs (FIT) review – https://www.moeaea.gov.tw/ECW/RENEWABLE/news/News.aspx?kind=1&menu_id=767

Formosa Plastics Group – https://fpg.com.tw/tw

Minimum Energy Performance Standards (MEPS) website – https://www.meps.org.tw/

MOE (Ministry of Environment) – https://www.moenv.gov.tw/

MOE Climate Change Talks platform – https://www.climatetalks.tw/

MOEA (Ministry of Economy Affairs) – https://www.moea.gov.tw/Mns/english/home/English.aspx

MOI (Ministry of the Interior) – https://www.moi.gov.tw/english/

MOTE (Ministry of Transportation and Communication) – https://www.motc.gov.tw/ch/index

NDC – https://www.ndc.gov.tw/en/Default.aspx

Renewable Energy Certification Centre (T-REC) – https://www.trec.org.tw/https://www.trec.org.tw/

Taipower – https://www.taipower.com.tw/en/index.aspx



19. Thailand

Summary

	Reference			Target		
	2022	2060	% Change	2022	2060	% Change
Macroeconomic						
Population (million)	71.6	70.3	-2%	71.6	70.3	-2%
GDP (billion 2017 USD, PPP)	1,257	3,501	178%	1,257	3,501	178%
Energy Demand						
Agriculture & fisheries (PJ)	91	106	16%	91	90	-1%
Buildings (PJ)	694	1,300	87%	694	1,086	56%
Industry (PJ)	1,371	2,880	110%	1,371	2,592	89%
Non-energy (PJ)	401	778	94%	401	709	77%
Transport (PJ)	1,224	1,329	9%	1,224	883	-28%
Modern renewables share of TFEC (%)	15	30	100%	15	53	253%
Energy intensity of TFEC (PJ/GDP, billion USD)	2.7	1.6	-41%	2.7	1.3	-52%
Electricity						
Generation (TWh)	191	717	275%	191	780	308%
Renewables share of generation (%)	20.4	40.1	97%	20.4	65.4	221%
Generation capacity (GW)	44	279	531%	44	384	768%
Total Primary Energy Supply (TPES)						
Coal & coal products (PJ)	704	676	-4%	704	482	-32%
Natural gas (PJ)	1,576	4,278	171%	1,576	2,783	77%
Petroleum liquids (PJ)	1,970	2,176	10%	1,970	988	-50%
Low-carbon & waste energy (PJ)	1,021	2,199	115%	1,021	3,629	255%
CO_2 intensity of energy supply ($MtCO_2/PJ$)	0.046	0.041	-11%	0.046	0.028	-39%
Net CO_2 Emissions (million tonnes)	246	385	57%	246	213	-14%

Note: In this publication, the term "modern renewables" refers to all renewable energy sources excluding solid biomass in the buildings sector. The term "low-carbon & waste energy" includes all bioenergy, waste-derived energy, renewables, nuclear, and hydrogen-based fuels. Total primary energy supply (TPES) numbers include international bunkers. Net emissions are calculated as gross energy sector combustion CO_2 minus CO_2 captured and stored through carbon capture and storage (CCS).

Key Takeaways

Emissions

- Thailand's CO_2 emissions continue to grow in the Reference scenario (REF), but are projected to decline steadily through 2060 after their peak in 2036 in the Target scenario (TGT).
- Emissions fall short of Thailand's climate goals in TGT. Total emissions decline from their peak at about 300 $MtCO_2$ to 213 $MtCO_2$ by 2060, driven mostly by reductions in the transport sector. Emissions in the power sector increase 50% from 81 $MtCO_2$ to 121 $MtCO_2$ by 2060 due to higher generation resulting from increasing electricity demand. Emissions in the industry sector increase 13% from 62 $MtCO_2$ in 2022 to 70 $MtCO_2$ by 2060. In REF, emissions continue to increase to 386 $MtCO_2$ by 2060.
- Thailand's Long-term Low Greenhouse Gas Emission Development Strategy (LT-LEDS), submitted in November 2022, aims for about 120 $MtCO_2$ gross emissions in the energy sector and industrial processes and product uses (IPPU) by 2050 to be absorbed by forestation to reach neutrality.

Energy Import Dependence

- Energy security remains vital for Thailand due to its heavy reliance on energy imports. In 2022, net imports accounted for 55% of Thailand's total primary energy supply (TPES), driven by imports of crude oil, coal, and natural gas.
- Thailand's dependence on energy imports is projected to grow amid declining domestic production. In REF, the net import share is projected to grow to almost 75% by 2040, driven by increasing natural gas and crude oil imports. In TGT, net imports peak at less than 70% by 2040, followed by declines of crude oil due to increased electrification in the transport sector.
- Despite scaled-up low-carbon electricity generation in TGT, import reliance on natural gas, particularly in form of LNG imports for the power sector remains high. Ensuring stable and diversified energy imports will be essential to manage external uncertainties and market volatility.

Figure 19-1. Net CO_2 emissions (million tonnes)

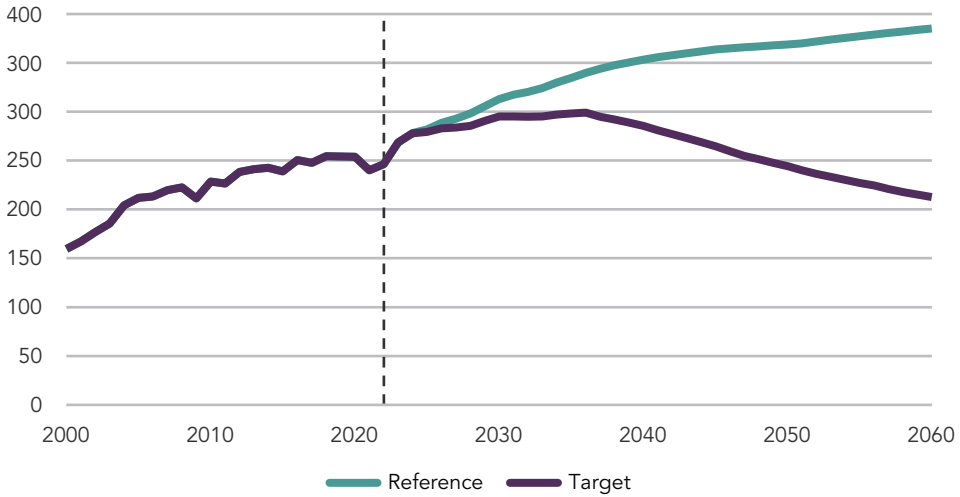
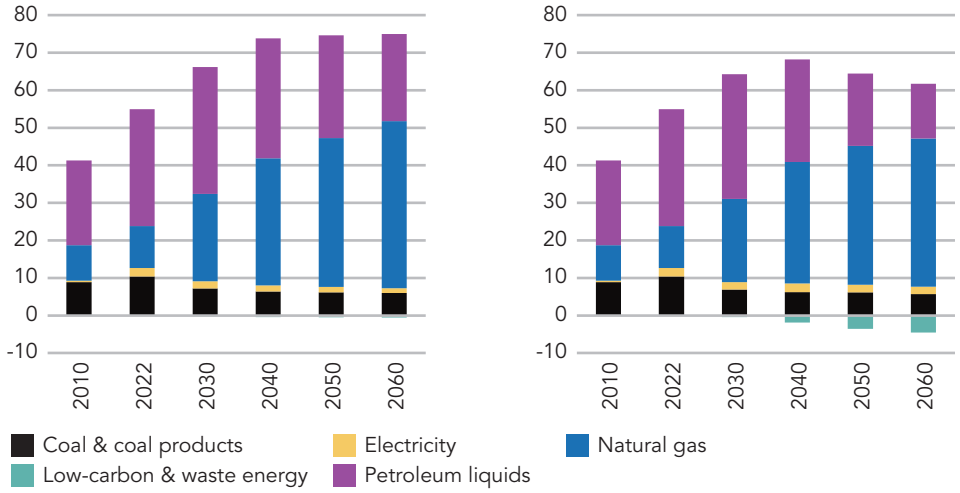


Figure 19-2. Net imports share of TPES in REF & TGT (%)



Note: In Figure 19-2, net imports refer to total imports minus exports and international bunkers.

Key Takeaways

Grid Reliability

- Electric grid reliability requires a near-instantaneous balance between power supply and demand at all times, supported by adequate dispatchable power sources including batteries.
- Figure 19-3 shows the grid's dependence on dispatchable power in the 4-hour period of maximum dependence and 4-hour period of minimum dependence. In 2022, there was a relatively small difference between the minimum and maximum, so dispatchable generators could produce at a fairly constant rate.
- As total electricity demand increases in both REF and TGT, Thailand will require increased dispatchable capacity for those periods when variable renewable energy (VRE) sources, such as wind and solar, are not producing at their maximum level. As the VRE rises, the gap between the minimum and maximum demands on dispatched power increases, which will increase capital, maintenance, and operating costs.

Cost

- The *Outlook* projects substantial total costs for Thailand's power and hydrogen sectors by 2060. Under the TGT scenario, total costs are projected to reach an estimated USD 1.75 trillion, 35% higher than the REF (USD 1.3 trillion). This includes the total capital, fixed, and variable costs in the power sector, costs for green hydrogen production, electricity imports, transmission for VRE, and electric vehicle chargers.
- This increase is primarily driven by the rapid expansion of low-emission power generation (namely solar PV) and green hydrogen production costs. Investments in storage, EV chargers, and transmission also grow significantly under the TGT scenario to support a more electrified and decentralised energy system.

Figure 19-3. Peak load and maximum and minimum dependence on dispatched power (GW)

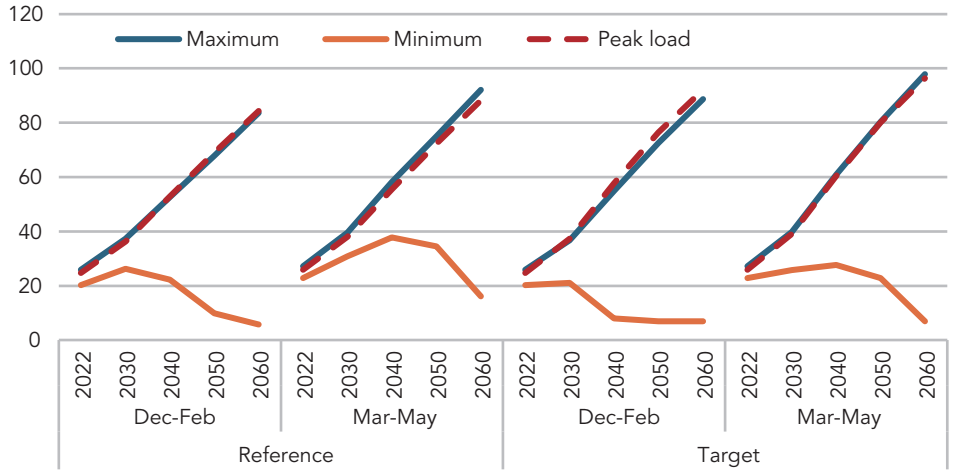
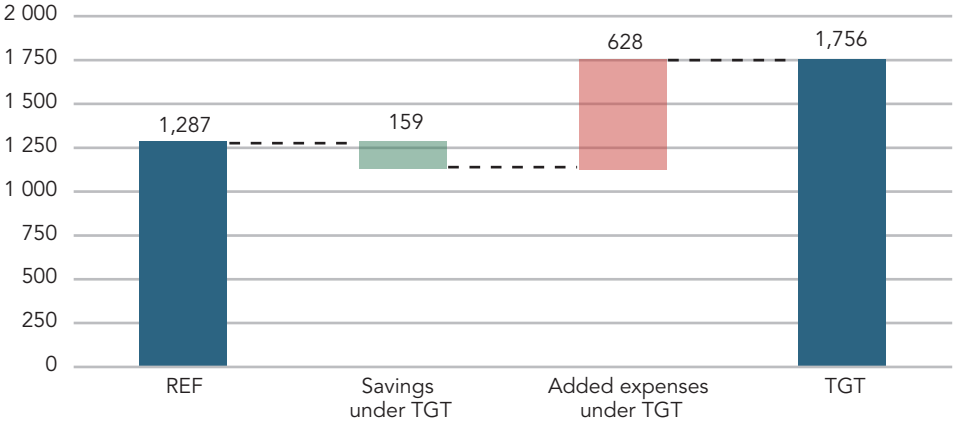


Figure 19-4. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



*Actual costs will differ from estimated costs in the *Outlook* for a variety of reasons including changing commodity prices, manufacturing costs, and unforeseen technical advances. All costs are in 2023 real terms.

About Thailand

Overview

Geographical and Economic Landscape

Thailand is situated in the centre of the Southeast Asia peninsula, surrounded by Cambodia; the Lao People's Democratic Republic (Lao PDR); Malaysia; and Myanmar. Thailand has an area of 513,120 square kilometres and had a population of 71 million in 2022 (UN DESA). It has a monsoon climate with marginal variations in temperature all year round, resulting in modest changes in energy demand patterns. In 2022, the gross domestic product (real GDP) reached USD 1,257 billion (2017 USD purchasing power parity [PPP]), a 2.8% increase from 2021.

Energy Supply and Consumption

Thailand's total energy consumption in 2022 was 3,780 PJ, with the industrial and transport sectors accounting for the largest shares at 36% and 32%, respectively. Over the period from 2000 to 2022, Thailand's total energy supply nearly doubled. Given its declining domestic resources, Thailand is becoming more dependent on energy imports. While oil and natural gas continue to dominate the energy supply, Thailand is on path to increase renewable energy since 2000 to diversify its energy mix.

Economic growth has driven a sharp increase in electricity demand. Between 2000 and 2022, electricity generation more than doubled, from 99 TWh to 226 TWh. With a growing focus on carbon neutrality, renewable generation is expected to increase significantly over the long run, with battery storage, nuclear, and hydrogen-based fuels added.

Key Energy Initiatives

Paris Agreement Commitment

Thailand has committed to reach carbon neutrality by 2050 and net-zero GHG emissions by 2065, with an NDC target of reducing greenhouse gas emissions by 30%-40% by 2030 from its business-as-usual level. These commitments are stated in Thailand's Long-term Low Greenhouse Gas Emission Development Strategy (LT-LEDS) (Revised Version) which was submitted by the Thai Government in November 2022.

Carbon-free Energy Initiatives

Thailand promotes the global deployment of various carbon-free technologies, including renewables, hydrogen, and nuclear, reflecting diverse domestic circumstances and upholding the principle of technology neutrality.

Hydrogen Promotion Study

Thailand has completed its hydrogen development study and policy recommendation study to promote hydrogen in 2021 and 2022, respectively. The studies aim to expand the role of hydrogen as a low-emissions energy option. Key areas include potential of green hydrogen production and its use in power generation, transport, and industrial applications.

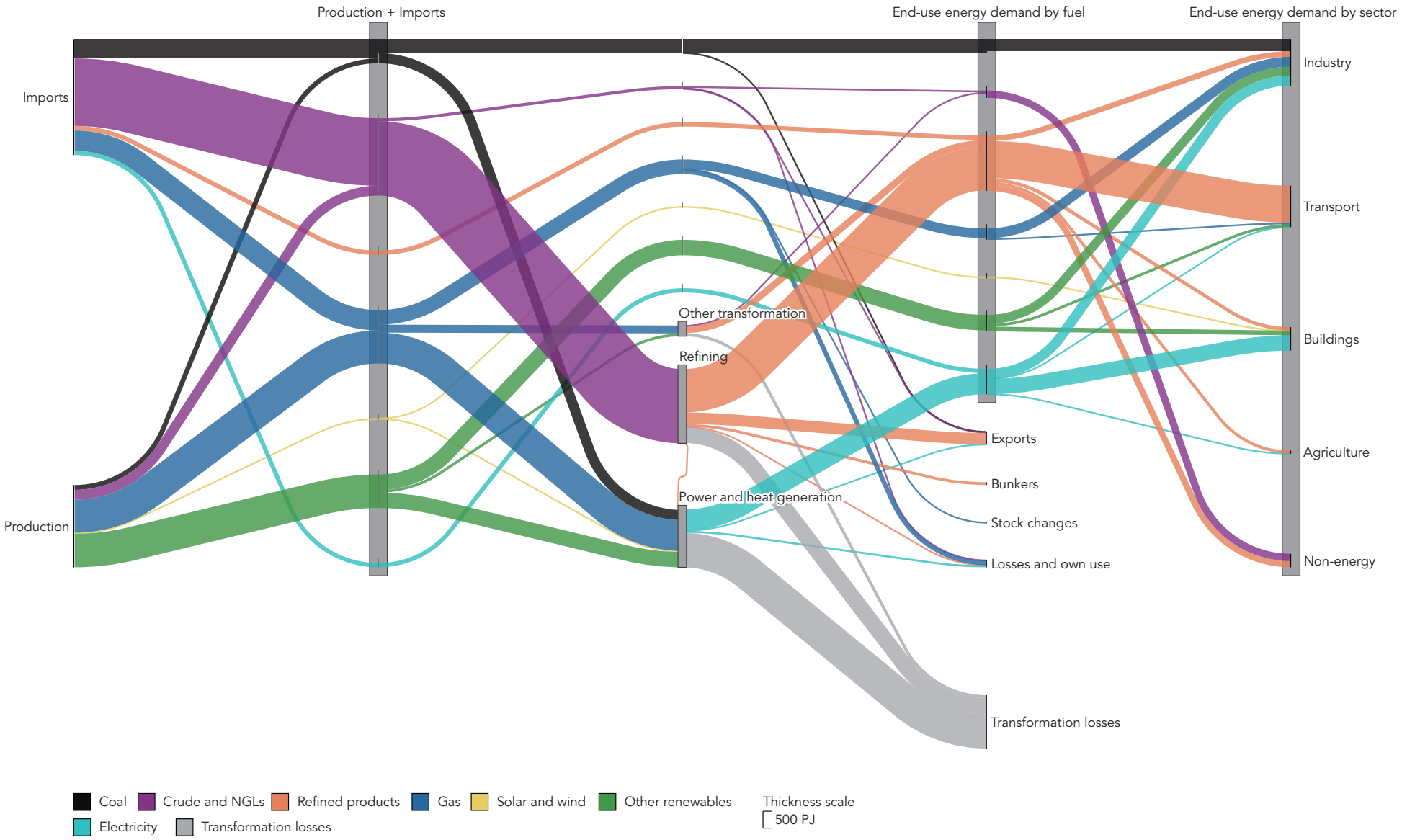
Promotion of Electric Vehicles (known as the 30@30 Policy)

A strategic commitment to accelerate the widespread use of electric vehicles (EVs) with tax and non-tax incentives. The initiative sets a goal that 30% of all vehicles manufactured in Thailand are electric by 2030.

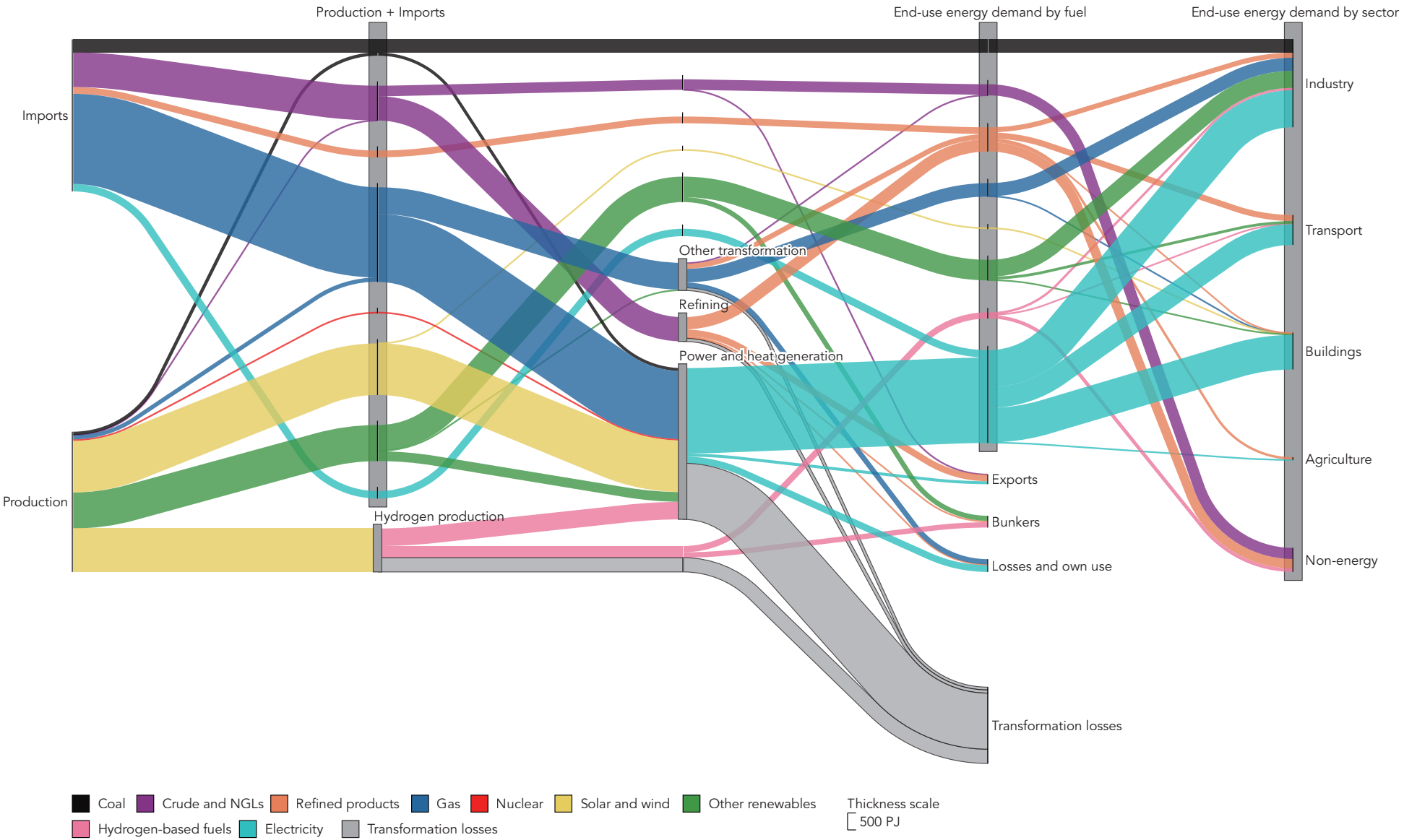
Thailand's Related Energy Plans

Thailand's commitments to reduce GHG are supported by the related energy plans namely Power Development Plan 2018 (PDP-2018, revision 1), Alternative Energy Development Plan (AEDP-2018), Energy Efficiency Plan (EEP-2018), Gas Plan (Gas Plan 2018), and draft Oil Plan 2018. These plans provide details and targets for the respective energy agencies and authorities until 2037.

Energy Flow (2022)



Energy Flow (2060, Target Scenario)



Scenarios and Assumptions

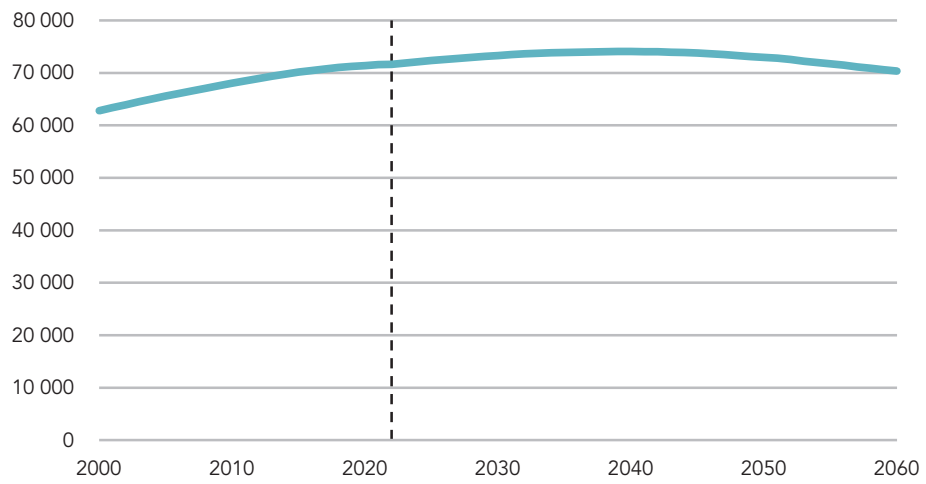
In *The Outlook*, APERC analyses energy demand, transformation, and supply, as well as emissions. The **Reference Scenario (REF)** offers a projection based on historical trends, recent developments, and APERC's assumptions about the continuation of those trends in each APEC economy, while acknowledging technical restraints. The REF Scenario offers a baseline to compare with the **Target Scenario (TGT)** projections, which explores a hypothetical pathway where each economy achieves energy-related policy targets, assuming implementation regardless of cost-effectiveness. When implementation details are lacking, assumptions are inferred from the targets themselves or emissions-related goals. Assumptions in TGT, however, do not guarantee that each economy will meet its NDC-related emission targets. Instead, they serve as references for each economy to consider or to make policy adjustments to reach their emission targets.

	Reference	Target
General	• Population: UN medium; GDP: APERC model and IMF	• Population: UN medium; GDP: APERC model and IMF
Buildings	• Energy efficiency standards and building thermal insulation measures are considered. • AI and data centre growth is the same in both scenarios.	• Stricter efficiency standards and promotion of Zero Energy Building (ZEBs) using renewable electricity and energy-saving measures. • Faster shift from oil and gas to electricity for heating and cooking.
Industry	• Key manufacturing subsectors maintain strong activity. • Hydrogen-based fuels begin deployment in the 2040s in cement and ceramics, petrochemicals, and iron and steel industries. • Electricity use expands considerably and gains a higher share. Coal, natural gas, and biomass continue to grow as main fuels.	• Hydrogen use expands and scales faster than in REF. • Increased electrification, energy and material efficiency, and low-carbon fuel use compared to REF. • Deployment of CCS in hard to abate industry sub-sectors starts in 2030. • Uses of biomass increase in both scenarios as part of decarbonisation.
Transport	• ICE vehicles steadily decline, with a shift toward electrification by 2060. • BEVs gradually increase to account for 30% of new vehicle sales in 2030 and 80% of the total vehicle stock by 2060. • SAF ramps up in 2030; hydrogen ramps up in marine bunkers in 2040.	• BEVs rapidly grow to 95% of new vehicle sales by 2040 and almost fully replace ICE vehicle stock by 2060. • Biofuel mixing rates reach 30% for biodiesel and ethanol by 2060 • Higher uses of SAF, hydrogen, and e-fuels in bunkers.
Power	• Natural gas expands as a flexible backup to support grid reliability. Renewables capacity rises 57–65% by 2060 from 26–28% in 2022. Battery deployment starts in 2040. • No nuclear or hydrogen in REF.	• Renewables capacity gains higher share to 72% by 2060. • Nuclear SMRs start commissioning in 2050 at a total of 600 MW. • Hydrogen use as a fuel starts to be deployed in 2040. • Higher use of batteries alongside increases in renewables. • Natural gas continues to provide a backup role with lower capacity.
Supply	• Reflects current trends of increasing imports of crude oil and LNG due to declines in domestic production.	• Fossil fuel use follows declining domestic demand trends, but import dependency remains high.
Emissions	• CO_2 emissions are calculated at post consumption based on IPCC emission factors.	

Note: The base year is 2022. Macro-economic assumptions are constant across scenarios. Historical energy balances are from EGEDA submissions for 2022.

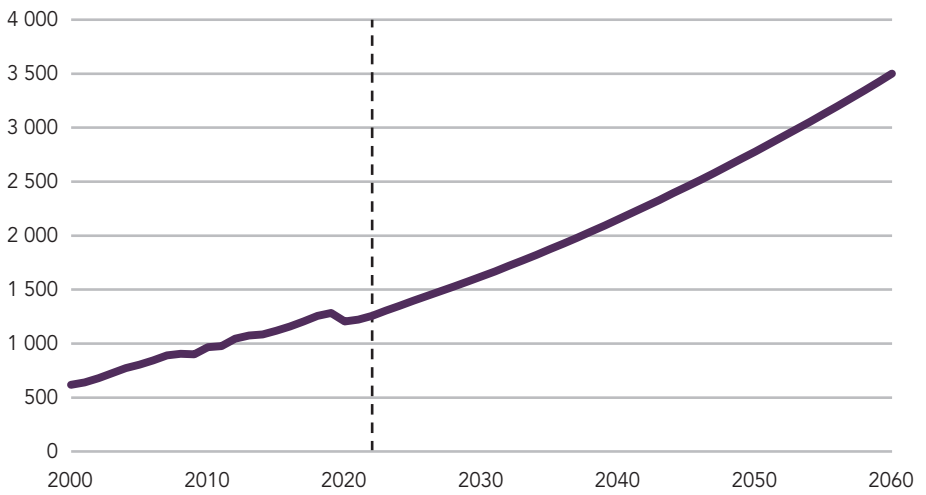
Demographic and Macroeconomic Assumptions

Figure 19-5. Population (thousands)



- Thailand's population is projected to increase slightly and reach a peak of 74 million in 2040, followed by gradual decline.
- The population decline reflects Thailand's persistently low fertility rates and rapidly aging society. The demographic shifts pose long-term structural challenges and are expected to impact energy demand projections, particularly in the buildings and transport sectors.

Figure 19-6. Real GDP (billion 2017 USD, PPP)



- Thailand's GDP is projected to follow a consistent upward trajectory through 2060, despite long-term demographic challenges. After a brief contraction in 2020 due to the COVID-19 pandemic, the economy recovered with annual real GDP growth ranging between 2.5% and 3%.
- In the medium term, the economy is expected to grow at average 3.2% between 2022 and 2030, supported by exports, tourism, and manufacturing activities in particular. Over the long term, however, growth is projected to be modest with a compound annual growth rate (CAGR) of around 2.6% by 2060, reflecting the impact of a rapidly ageing population and the structural maturity of the economy.
- Despite the slowing growth rate, industrial activity is projected to remain strong through 2060, particularly in food and beverages, non-metallic minerals, and high-value subsectors such as machinery and petrochemicals. The services subsector is also expected to expand, driven by sustained growth in tourism and information technology industries.

End-use Energy Demand

Figure 19-7. Energy demand by sector in REF & TGT (PJ)

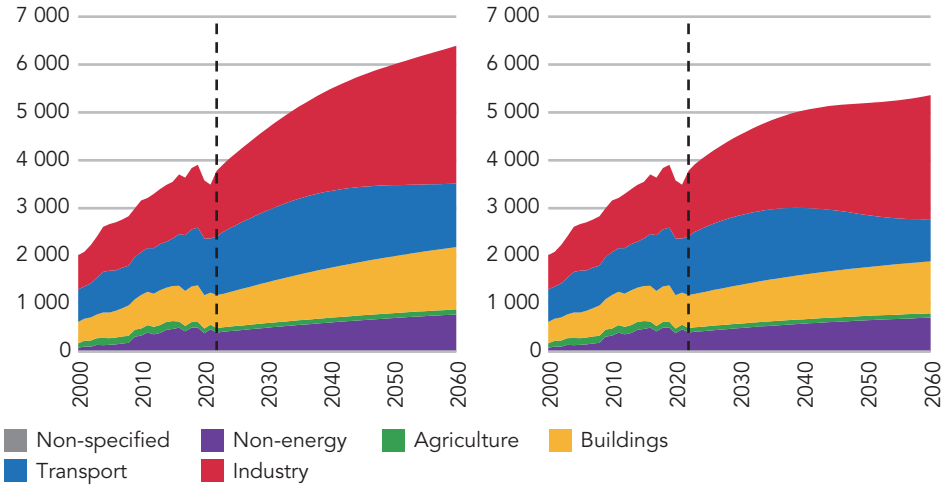
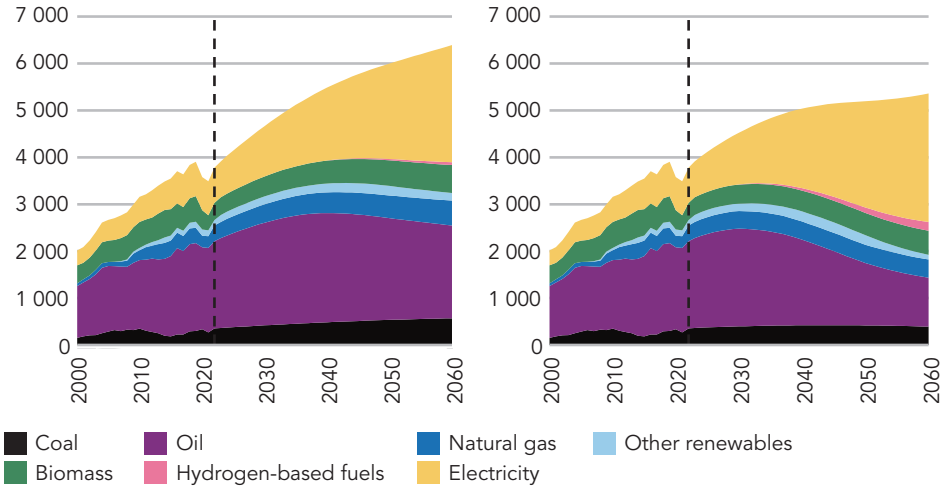


Figure 19-8. Energy demand by fuel in REF & TGT (PJ)



- The major differences in energy demand between the Reference (REF) and Target (TGT) scenarios arise from accelerated electrification with significantly enhanced efficiency.
- Total end-use energy demand continues to grow 70% from 2022 to 2060 in REF. In contrast, TGT sees a more modest growth of 42% in the same period.
- Industry is the largest sector for energy demand in Thailand. This sector is assumed to adopt higher electrification in both scenarios, though efficiency gains are relatively modest due to electricity's limited advantage in process heat applications. The industry sector's share of energy demand increases from 36% in 2020 to 50% by 2060 in both scenarios.
- Transport is the second largest sector by energy demand. In both scenarios, the sector undergoes rapid adoption of battery electric vehicles (BEVs) to gain higher energy efficiency, with even higher adoption in TGT. The transport sector's share of total energy demand declines from 32% in 2022 to 20% in 2060 in REF, and further to 16% in TGT.
- Buildings demand grows in both scenarios, largely due to higher urbanisation in the residential subsector and growth in service subsectors.
- Oil continues to play a vital role in end-use energy demand, accounting for almost 50% of the total in 2022. Oil demand peaks in 2040 and 2035 in REF and TGT, respectively, in line with the declines in the transport sector. By 2060, the share of oil decreases to 30% and 20% in REF and TGT, respectively, due to higher efficiency gains and electrification across all sectors.
- Electricity grows substantially due to higher electrifications across all sectors. Electricity demand grows more than 200% and its share reaches 40% and 50% in 2060 in REF and TGT, respectively.
- Gas and biomass demand remain substantial, in particular in the industry sector. Coal use in the industry sector increases slightly in REF but remains constant in TGT.
- Hydrogen-based fuels are assumed to emerge in 2037 and 2035 in REF and TGT, respectively, with greater use in TGT.

Buildings Energy Demand

Figure 19-9. Buildings energy demand by fuel in REF & TGT (PJ)

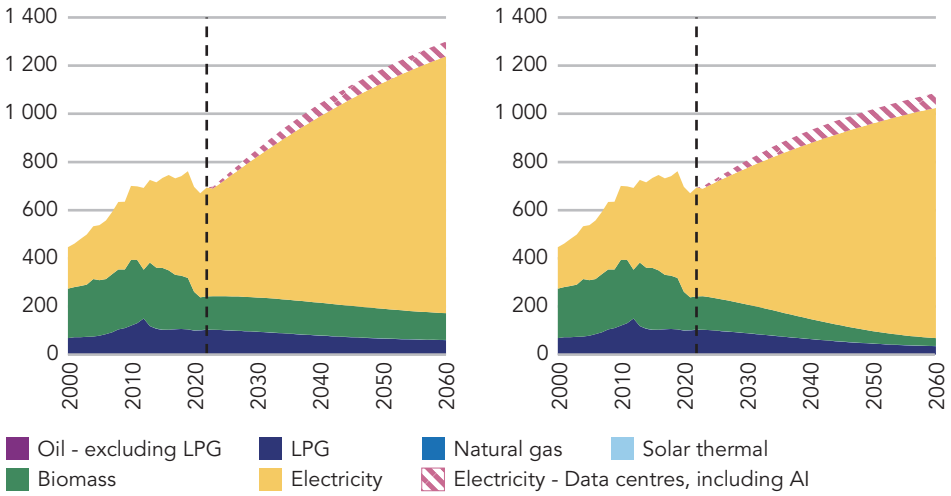
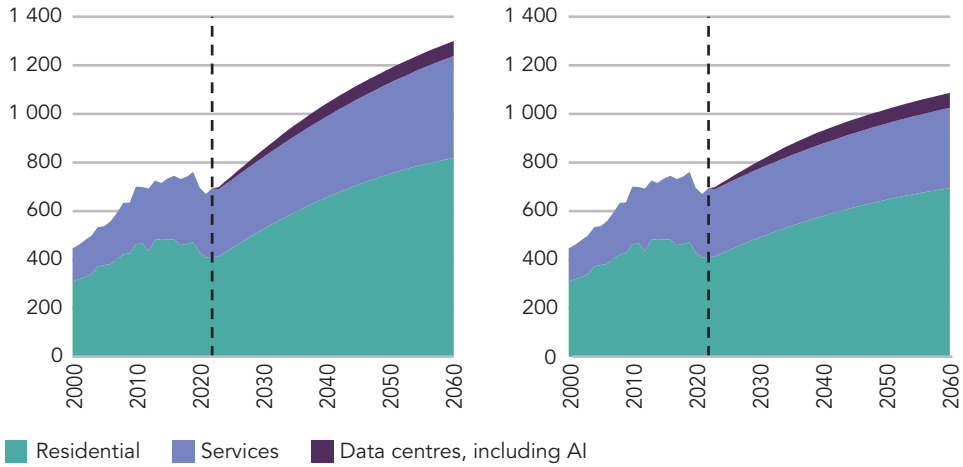


Figure 19-10. Buildings energy demand by sector in REF & TGT (PJ)



- Overall buildings demand is first projected based on population growth, then allocated across end use sectors using best estimates. These estimates are adjusted to reflect broad assumptions as needed. The fuel share for each end use sector is then inferred and fuel switching is incorporated where applicable.
- Thailand's buildings sector is the third largest sector. Demand is expected to grow, driven by increasing urbanisation and rising income levels, as reflected in the GDP per capita growth. These shifts enable greater access to modern energy in the residential subsector, along with wider adoption of appliances and higher energy demand for end uses such as space cooling and lighting. Energy use in the services subsector is also expected to rise, supporting the expansion of economic activity such as tourism.
- Electricity demand more than doubles by 2060 in REF. In TGT, the demand is slightly less than in REF due to efficiency improvements.
- Electricity demand for data centres and AI is included in the projections starting in 2023. This demand is expected to grow more rapidly in the first half of the 2023 to 2060 projection period, before slowing under the assumption that activity levels stabilise and efficiency gains begin to moderate further electricity demand growth.
- Use of biomass and LPG, mostly in residential cooking, declines due to fuel switching to electricity in both scenarios, with a more pronounced shift in TGT.
- The residential subsector accounts for approximately 60% of total building energy demand throughout the projection period in both scenarios.

Industry Energy and Non-energy Demand

Figure 19-11. Industry & non-energy demand by fuel in REF & TGT (PJ)

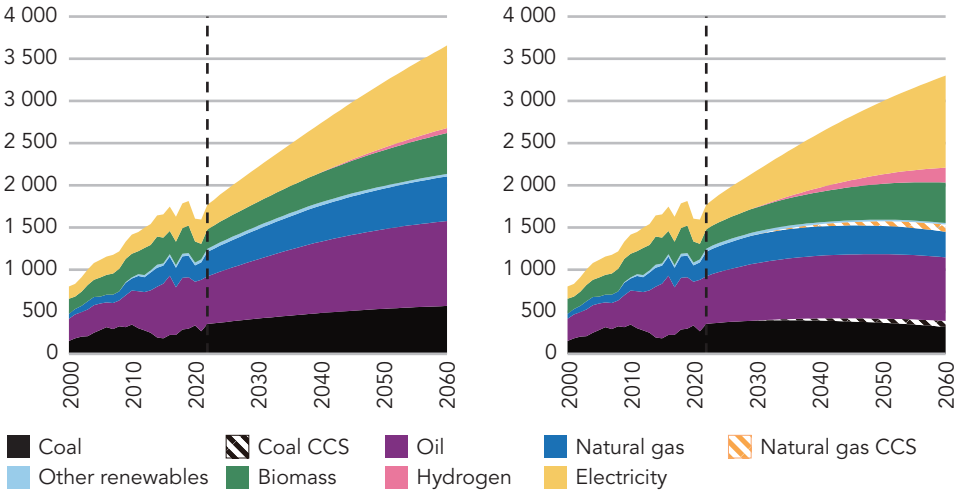
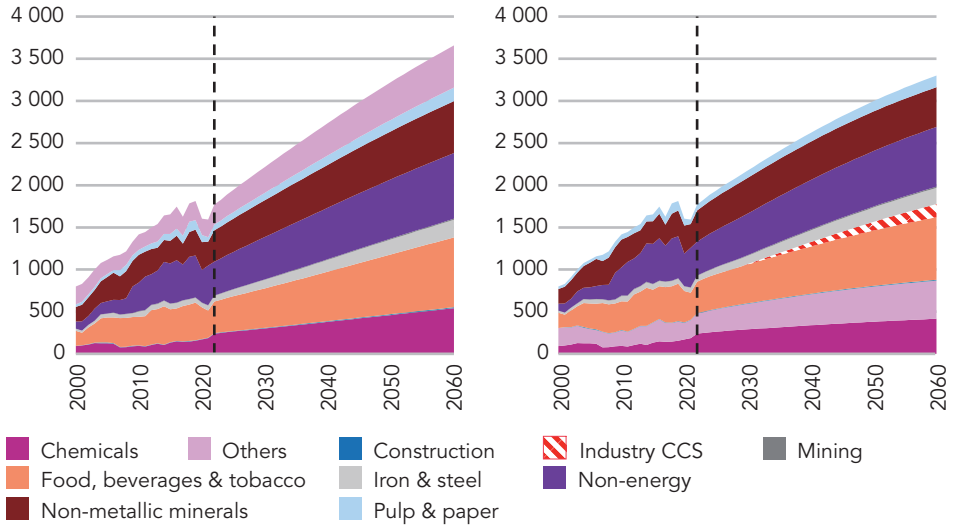


Figure 19-12. Industry & non-energy demand by sector in REF & TGT (PJ)



- Industry and non-energy combined is the largest sector in Thailand. Its strong demand growth continues through 2060 in both REF and TGT to support growing economic activities. In TGT, there is slightly less demand due mainly to energy and material efficiency improvements.
- In 2022, oil had the highest share in industry demand at 33%. However, most of oil was consumed as feedstocks in petrochemical sub-sector. Coal, and gas have almost equal shares of energy demand at about 20% each, followed by electricity and biomass. The three fossil fuels remain major fuel sources in hard-to-abate industries.
- Electricity's share increases as major industry subsectors including food & beverages, chemical & petrochemicals, and iron & steel employ electrification to decarbonise their processes. By 2060, electricity's share reaches about a third of total demand in both scenarios.
- Biomass continues to be an important energy source. The increased use of biomass in the two scenarios is attributed to the higher utilisation of agricultural residues, mostly bagasse, rice husk, oil palm and tapioca residuals in the food and paper industries.
- The adoption of coal with CCS and gas with CCS in TGT takes place starting in 2030 in the cement and chemicals subsectors. The fossil fuels with CCS applications gain a higher share through 2060. Similarly, the adoption of hydrogen applications is assumed to commence in 2030 in both scenarios, with higher adoption in TGT.
- Energy demand is projected to grow in all industry subsectors. Demand in the food & beverages industry continues to be the largest, followed by petrochemicals (shown in the non-energy category). Energy demand in cement and ceramics in non-metallic minerals and chemicals are the third and the fourth largest, respectively.

Transport Energy Demand

Figure 19-13. Domestic transport energy demand in REF (PJ)

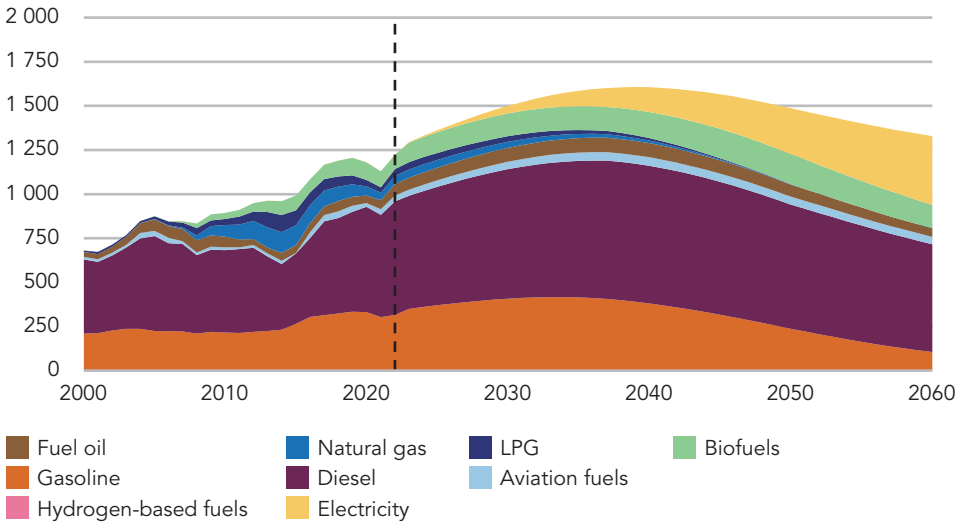
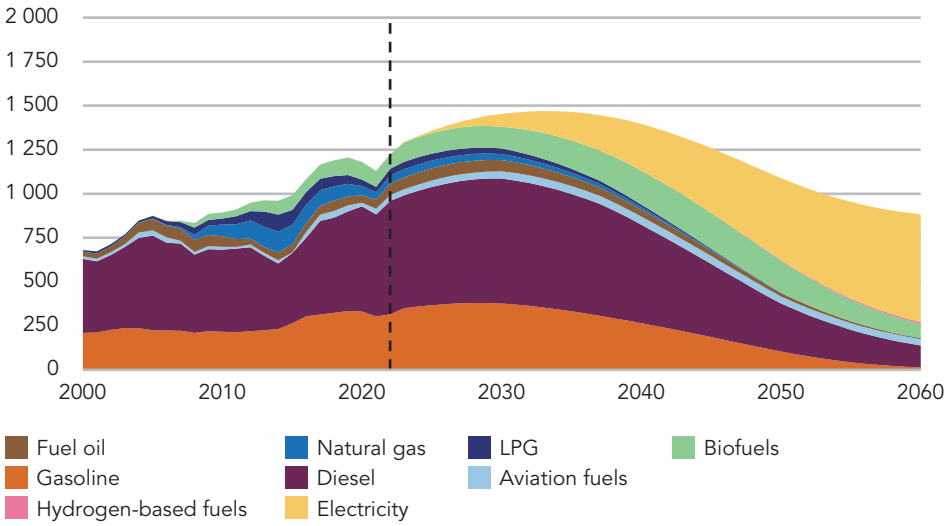


Figure 19-14. Domestic transport energy demand in TGT (PJ)



- Transport is the second largest sector in Thailand. It is heavily dominated by road transport, which accounted for 91% of total transport energy demand in 2022. Reducing energy use in this sector will therefore play an important role in achieving Thailand's decarbonisation goals.
- Passenger transport activity in Thailand is expected to increase rapidly until 2040, after which vehicle ownership levels begin to saturate, leading to a stagnation of growth. Freight activity increases at a steady rate throughout the projection period, which is a direct result of the growth in industrial activity. While energy use initially follows these activity trends in the first decade of the projection, the effect of battery electric vehicle (BEV) adoption starts to have an increasing impact, thereby offsetting the potential increases in energy use.

- The 30@30 policy program of Thailand sets a target for zero-emission vehicles to account for 30% of Thailand's total motor-vehicle production by 2030. To help achieve this, Thailand is encouraging growth in the domestic EV sales share, resulting in an already 12% sales share of BEVs in 2023. Based on this rapid growth we project the sales share for passenger BEVs will be 33% in REF and 70% in TGT by 2030. Sales shares continue to grow after 2030.
- Biofuel mixing rates are expected to increase significantly, reaching ~30% for biodiesel and ethanol by 2060 in TGT. However, high EV adoption counters this growth, leading to a decline in biofuel use after 2045. Similar trends are delayed in REF because of lower biofuel mixing and EV adoption.
- Substantial infrastructure development may be needed to ensure adequate EV charger availability for the growing number of EV users. This includes upgrades to electricity distribution systems and the installation of public chargers along long-distance routes.

Other Transport Data

Figure 19-15. Passenger transport activity in REF & TGT (billions of passenger-km)

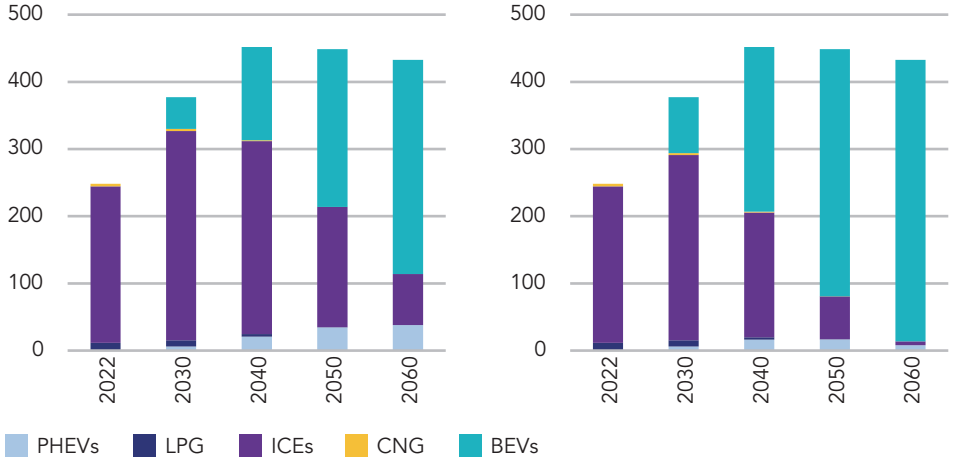
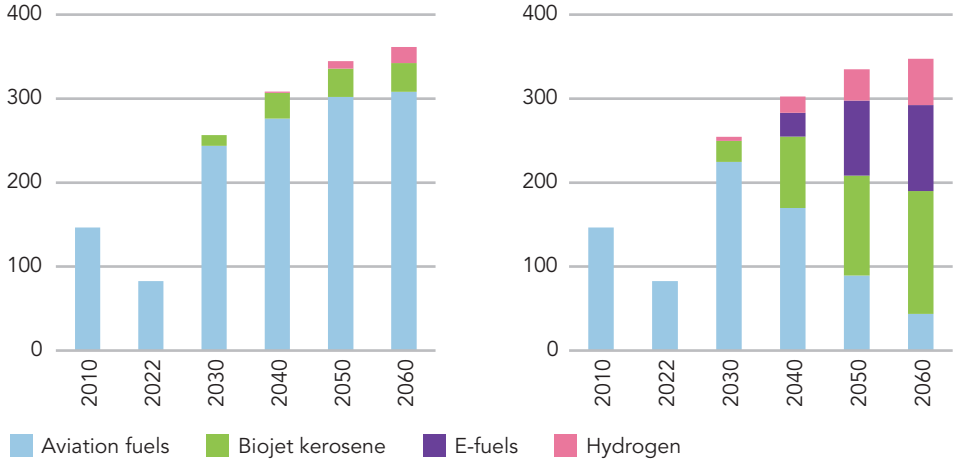
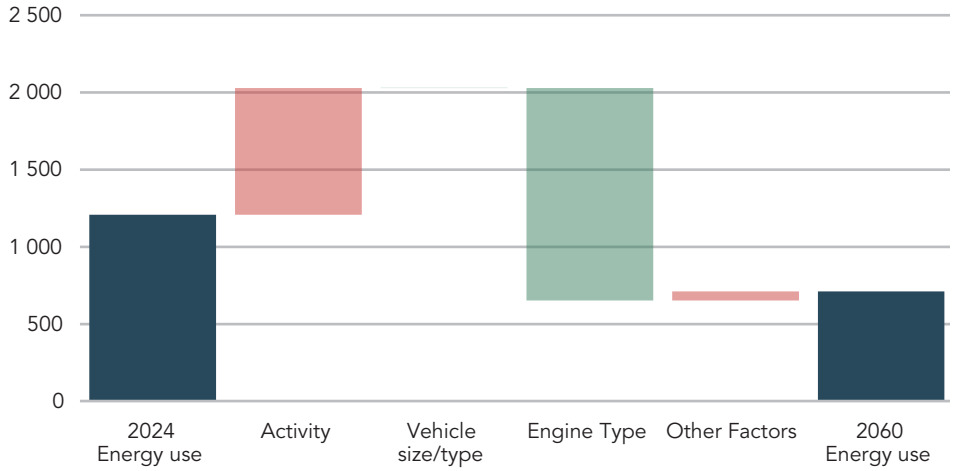


Figure 19-16. International bunkers energy demand for aviation in REF & TGT (PJ)



- The transition to BEVs is the single largest driver of lower transport emissions and energy use, reducing nearly 1,300 PJ of energy use as illustrated in "Engine Type" component in Figure 19-17. However, if all other factors remain unchanged, growth in passenger and freight transport activity alone would add about 750 PJ to energy use.
- Figure 19-15 illustrates that, by 2060, BEVs are projected to account for roughly 74% of total road passenger transport activity in REF and 97% in TGT.
- Bunkers energy demand for aviation is projected to grow steadily through 2060. The adoption of bio-kerosene begins around 2030 and is more pronounced in TGT. The use of e-fuels and hydrogen also becomes more significant in TGT, particularly from 2040 onward. These assumptions are based off targets set by international transport organisations rather than by Thailand.

Figure 19-17. Components of change in road energy use in TGT (PJ)



Note: Information on the different drivers in the transport energy decomposition can be found in the *Outlook*'s annex.

Electricity Generation

Figure 19-18. Electricity generation by fuel in REF & TGT (TWh)

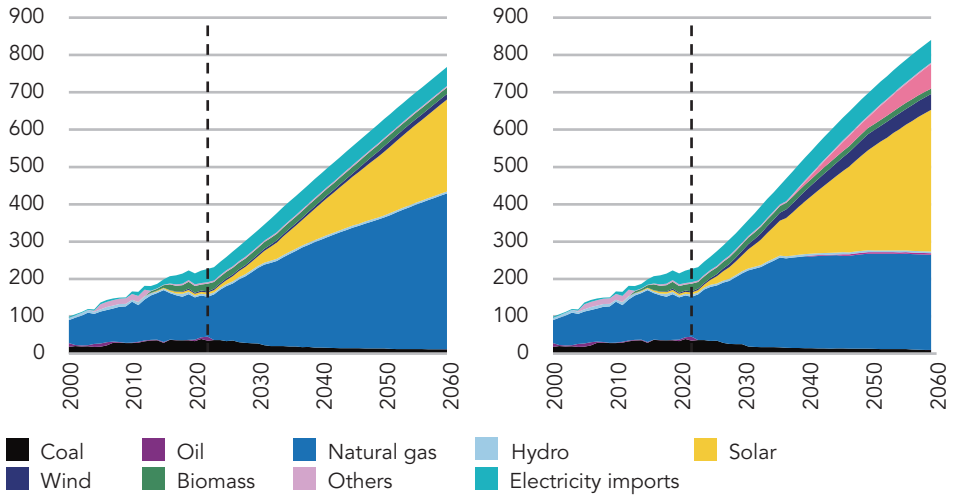
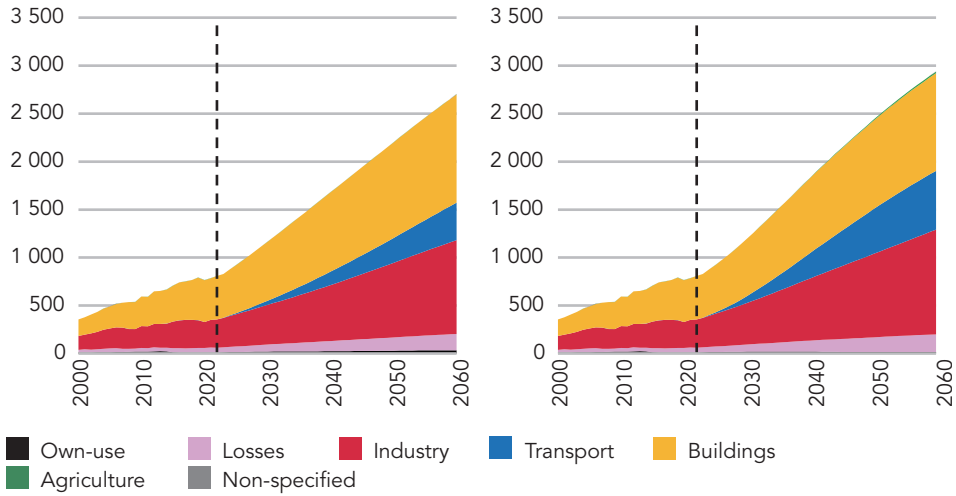


Figure 19-19. Electricity demand by sector in REF & TGT (PJ)

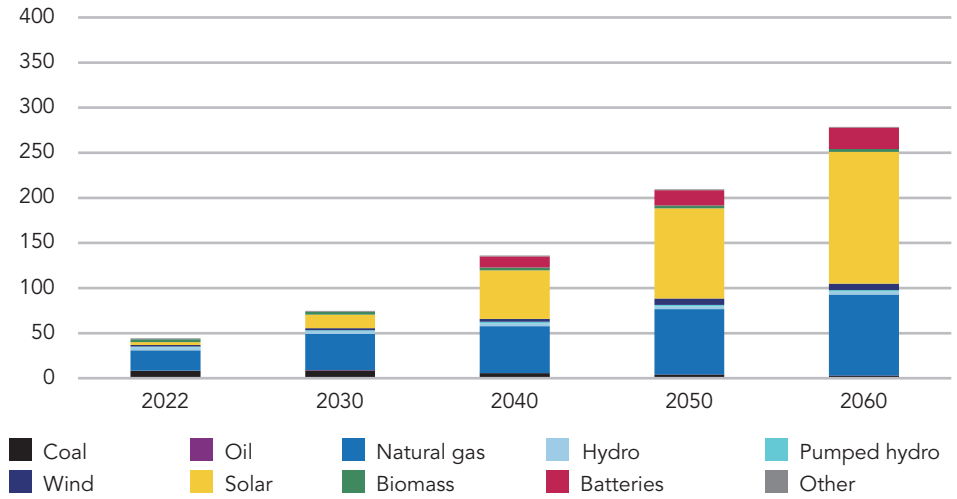


- Electricity generation increases substantially in both REF and TGT, driven by rising electrification in the industry, building, and transport sectors. In REF, total electricity generation increases from 209 TWh in 2022 to 767 TWh by 2060. In TGT, it almost quadruples to 840 TWh by 2060.
- The generation mix shifts progressively towards a higher share of renewables, particularly solar PV. The share of solar in the generation mix increases from 2% in 2022 to 32% and 45% in REF and TGT, respectively, by 2060.
- In response to higher shares of intermittent renewables, gas generation plays an increasingly important role in maintaining grid reliability. Gas generation in REF maintains its share at about 50% through to 2060. In TGT, by 2060, its share declines to 30% due to the higher deployment of battery storage. Generation from nuclear is assumed to start in 2040 in TGT.
- The coal generation mix declines from 15% in 2022 to less than 2% by 2060 in TGT, owing to Thailand's policy to phase down coal.
- Wind and biomass generation increases in TGT, reaching shares of 5% and 2%, respectively, in 2060. Generation from hydrogen-derived fuels is assumed in TGT, with its share reaching 8% by 2060. Electricity imports are assumed to be constant at 60 TWh. Their shares reduce from 16% in 2022 to 7% by 2060.
- Historically, electricity demand in the buildings and industry sectors combined was over 90%. However, with adoption of battery electric vehicles (BEVs), the transport sector's share of electricity demand increases, reaching 14% and 21% in REF and TGT, respectively, by 2060.
- In the revised Long-term Low Greenhouse Gas Emission Development Strategy (LT-LEDS) submitted in November 2022, Thailand aims to achieve 68% and 74% share of renewables generation by 2040 and 2050, respectively. In TGT, the share of renewables generation, which includes solar, wind, biomass, hydro, hydrogen, and nuclear, is 38% in 2040, and 52% in 2050. The combined share of solar and wind in TGT in 2060 is 50%, compared with 65% target in LT-LEDS.

Note: Figures 19-18 and 19-19 do not include electricity generation for hydrogen production.

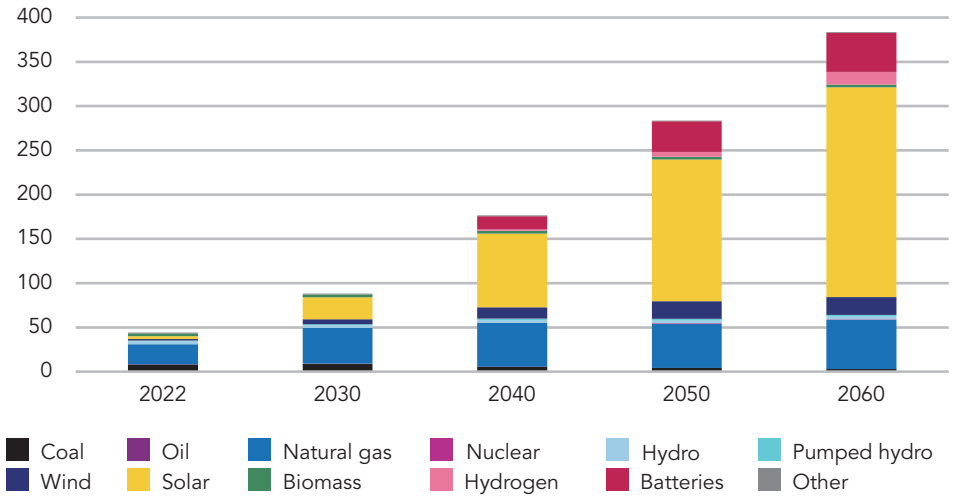
Generation Capacity

Figure 19-20. Generation capacity by fuel in REF (GW)



- Generation capacity increases more than sixfold in REF, from 44 GW in 2022 to 278 GW by 2060. Renewable capacity increases from 11 GW to 159 GW in the same period, leading its share to increase from 26% to 57%.
- Gas capacity increases to continue to provide grid reliability. In REF, it increases to fourfold from 22 GW to 90 GW from 2022 to 2060. However, the share of gas in the capacity mix falls from 51% to 32% during the same period due to the increase of renewables.
- Battery storage capacity is introduced from 2040 onward to support grid reliability, reaching 24 GW in REF. Wind capacity increases to 7 GW but faces limited potential, while biomass capacity remains steady at 3 GW. Coal capacity declines from 8 GW to 3 GW over the projection period.
- Nuclear and hydrogen-based capacity appears in TGT but not in REF.

Figure 19-21. Generation capacity by fuel in TGT (GW)



- Renewable generation capacity grows more rapidly in TGT than in REF as part of Thailand's efforts to decarbonise the power sector. By 2060, total renewable capacity increases 24-fold to 277 GW, led by 237 GW of solar PV and 20 GW of wind capacity. In TGT, renewables account for 72% of total capacity by 2060.
- By 2060, gas-fired capacity increases to 55 GW and battery capacity expands to 44 GW to provide grid reliability in TGT.
- Nuclear and hydrogen-based capacity is added to the system in TGT in 2041 and 2038, respectively. By 2060, nuclear capacity reaches 600 MW and hydrogen reaches 14 GW.
- Coal, biomass, and pumped hydro capacity in TGT is the same as in REF at 3 GW, 3 GW, and 2 GW, respectively, by 2060.
- Thailand's Power Development Plan (PDP-2018 rev.1) aims for 77.2 GW generation capacity and 28.0 GW renewable capacity in 2037. In TGT, total capacity reaches 142.8 GW, and renewable capacity reaches 76.9 GW in 2037.

Note: Figures 19-20 and 19-21 do not include generation capacity for hydrogen production.

Grid Reliability

Figure 19-22. Total generation capacity and peak load (GW)

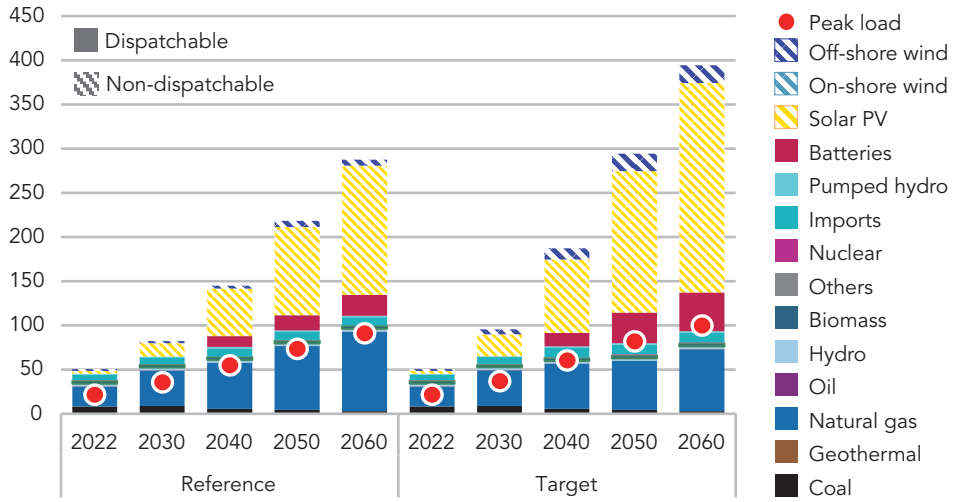
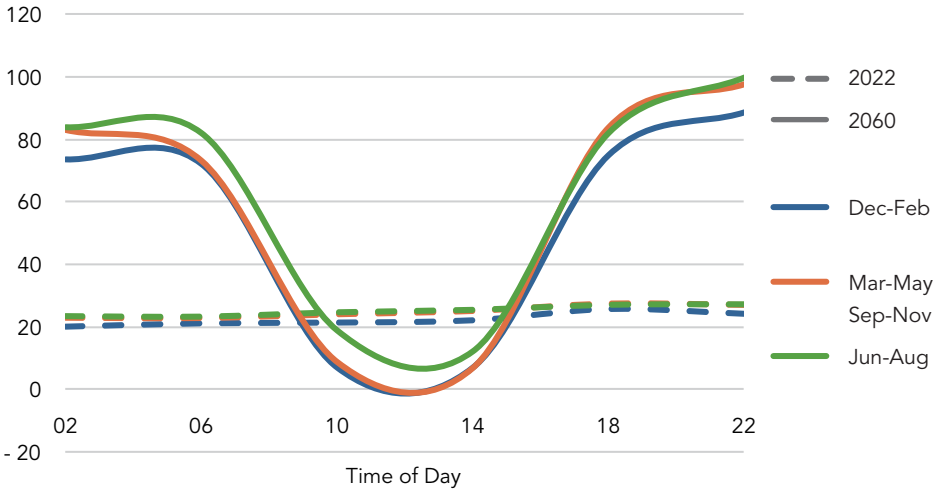


Figure 19-23. Power from dispatchable sources in TGT (GW)



- In REF, the peak electricity load grows by 260% from 26 GW in 2020 to 92 GW by 2060. In TGT, peak load grows to almost fourfold to 100 GW by 2060 due to increased electrification in this scenario.
- Due to the intermittency of solar and wind generation, which results in relatively lower load factors, total system generation capacity must grow faster than peak load.
- In REF, total generation capacity grows by almost sixfold from 44 GW in 2022 to 278 GW by 2060. In TGT, it needs to grow by eightfold to 383 GW by 2060.
- Grid reliability requires that power systems have enough dispatchable generation capacity, including batteries, to meet peak load in those periods when solar and wind generation are at their lowest levels.
- Increased reliance on solar and wind generation will increase the variability of the generation required from dispatchable power sources.
- For Thailand, the *Outlook* projections show the variability of dispatchable power increasing substantially, especially in TGT. As shown in Figure 19-23, the dispatchable generation in 2020 (dashed lines) showed slight variations during specific times of day per season. Looking into the future, however, the generation from dispatchable sources is anticipated to increase from less than 10 GW to higher than 60 GW from noon to 8:00 pm on an average day as solar generation gradually declines as sunlight diminishes.
- The actual variability will be different than this total since the variability will be spread across the entire economy, but it could also be larger since some individual days will experience greater variability than the seasonal averages.
- This variability presents a challenge for system operators across the economy and is expected to increase the capital, maintenance, and operating costs of Thailand's electric grids.

Coal

Figure 19-24. Coal consumption by sector in REF & TGT (PJ)

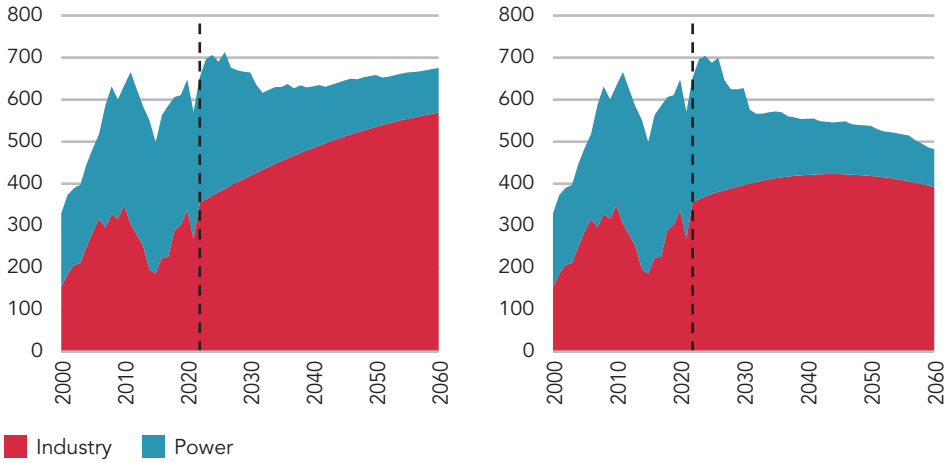
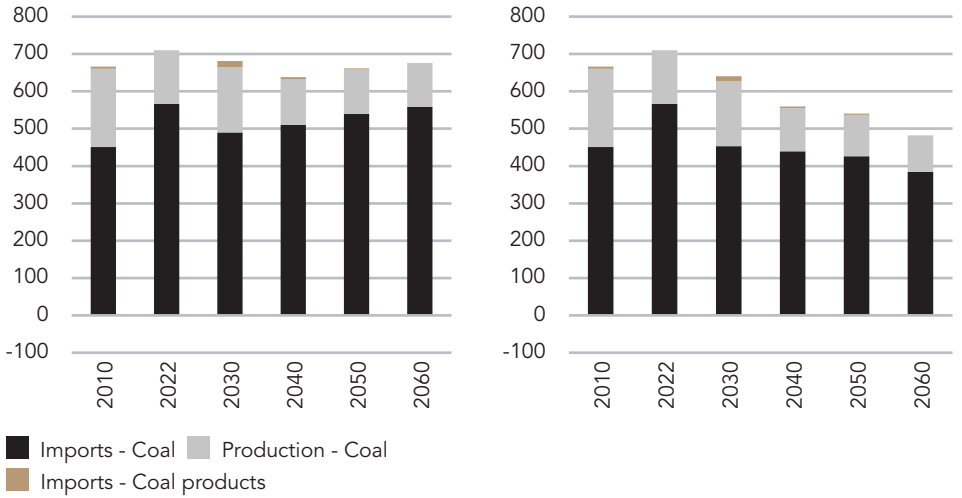


Figure 19-25. Coal production, imports, and exports in REF & TGT (PJ)



- Coal consumption in Thailand is relatively low compared with the APEC average and with other economies in Southeast Asia.
- In 2022, coal consumption in the industry and power sectors was 355 PJ and 298 PJ, respectively.
- Looking into the future, coal continues to play a role in providing process heat for industry. In REF, industrial coal consumption rises from 355 PJ to 569 PJ by 2060. In TGT, it peaks in 2044 and then declines slightly as the industrial sector increasingly adopts electrification.
- Coal consumption in the power sector declines from 298 PJ to less than half at about 100 PJ in both REF and TGT as the sector aims to decarbonise.

- Coal resources are limited in Thailand. Production is expected to decline from 143 PJ in 2022 to 117 PJ and 97 PJ by 2060 in REF and TGT, respectively.
- Currently, the Mae Moh coal mine in the north of Thailand is the only operational mining facility, producing lignite with a lower calorific content compared with other types of coal.
- Thailand relies on imports of coal. The import-dependent ratio increases to over 80% of total consumption by 2060 in both REF and TGT.

Natural Gas

Figure 19-26. Natural gas consumption by sector in REF & TGT (PJ)

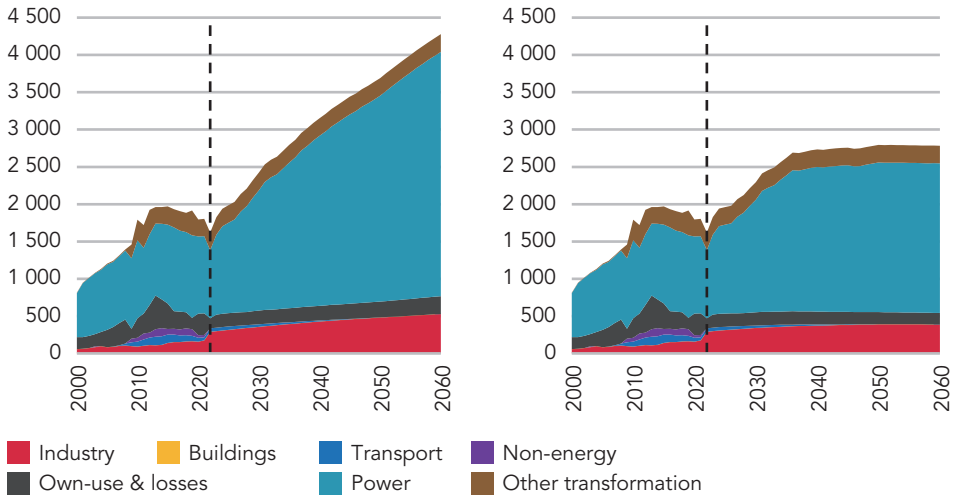
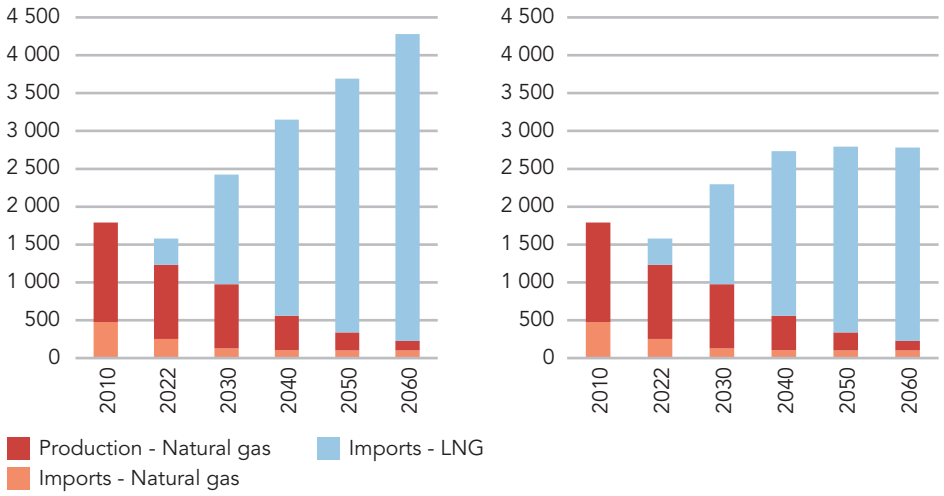


Figure 19-27. Natural gas production, imports, and exports in REF & TGT (PJ)



- Natural gas is a major fuel across all end-use sectors in Thailand, with the power sector being the dominant driver of consumption.
- In 2022, the share of gas consumption from the power sector was 56%, followed by equal shares of industry and gas processing in "other transformation" at 16% each. In REF, the share of the power sector increases to almost 80% by 2060 as gas generates more electricity to supply high demand and to follow larger net load swings created by increasing VRE generation. In TGT, the share of gas in the power sector declines to 73% by 2060, reflecting greater adoption of battery storage and other technologies, as well as other fuel types.
- In 2022, the official report of domestic production of natural gas in Thailand was 980 PJ (2,648 mmscfd), with total imports of 601 PJ (1,626 mmscfd). Domestic production is assumed to decline 44% to 550 PJ in 2040, and further decline to 124 PJ by 2060. Thailand's Gas Plan 2018 expects that domestic production will decline to about 1,500 mmscfd (590 PJ) by 2037.
- Thailand is expected to become increasingly reliant on gas imports as demand grows and domestic production declines. The share of natural gas imports, mostly LNG, rises from 38% in 2022 to over 90% by 2050, and by 2060 Thailand is almost fully import-dependent for gas in both scenarios.
- In REF, LNG imports are projected to reach about 1,447 PJ (32 MTPA) in 2030 and 2,590 PJ (58 MTPA) in 2040. In TGT, LNG imports plateau at around 2,500 PJ (55 MTPA) from the medium term onward. By 2060, LNG imports in TGT are 40% lower than in REF due to lower gas consumption in the power sector.
- Thailand is well positioned with LNG receiving capacity to ensure medium-term gas security. Thailand's Gas Plan-2018 targets a total of 34.8 MTPA by 2027, close to the expected 32 MTPA in REF by 2030. However, even with an expandable capacity of 47.5 MTPA, LNG terminals may potentially fall short of meeting projected 2040 demand of 58 MTPA in REF and 55 MTPA in TGT.

Note: Historical data for LNG is based on JODI gas data.

Petroleum Liquids

Figure 19-28. Crude oil, NGL, and other hydrocarbon productions, imports, and exports in REF & TGT (PJ)

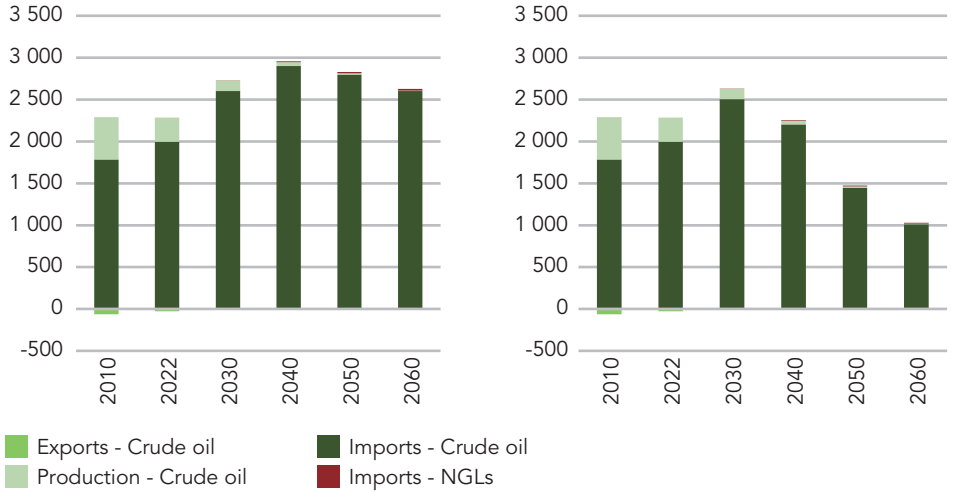
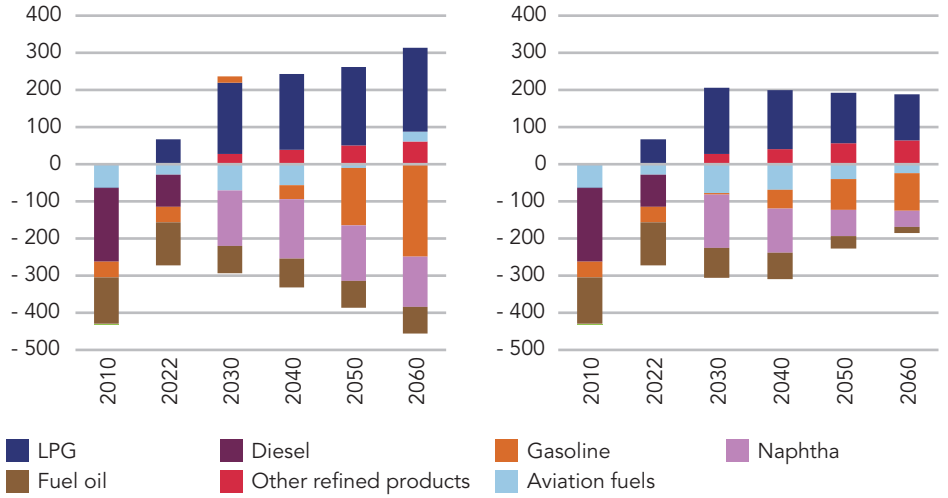


Figure 19-29. Net imports of refined products in REF & TGT (PJ)



- Thailand's crude oil supply remains largely import-dependent, with domestic production declining. Total crude oil supply peaks around 2040 and 2030 in REF and TGT, respectively, before declining through 2060, reflecting reductions in transport demand.
- The refining sector is assumed to meet most changes in demand under both scenarios. However, Thailand's refined product trade is expected to adjust as transport fuel demand declines.
- Imports of LPG and ethane (shown in "Other refined products" in Figure 19-29) for petrochemical feedstocks are partly met by additional supply from domestic gas processing. Over the longer term, however, imports of LPG and ethane for feedstocks may be needed as output declines from gas processing alongside decreasing gas production.
- In the medium to longer term, excess gasoline and fuel oil are exported as transport sector consumption declines. Diesel exports, however, decrease to zero, reflecting rising consumption in the medium term and declining refinery outputs over the medium and longer term.
- To note, naphtha is shown as an export, but, in reality, the output of naphtha from refineries is transferred to be used as feedstocks to the domestic petrochemical sector.

Note: In Figure 19-29, net imports are presented without deducting bunkers.

Refining

Figure 19-30. Refining outputs in REF & TGT (PJ)

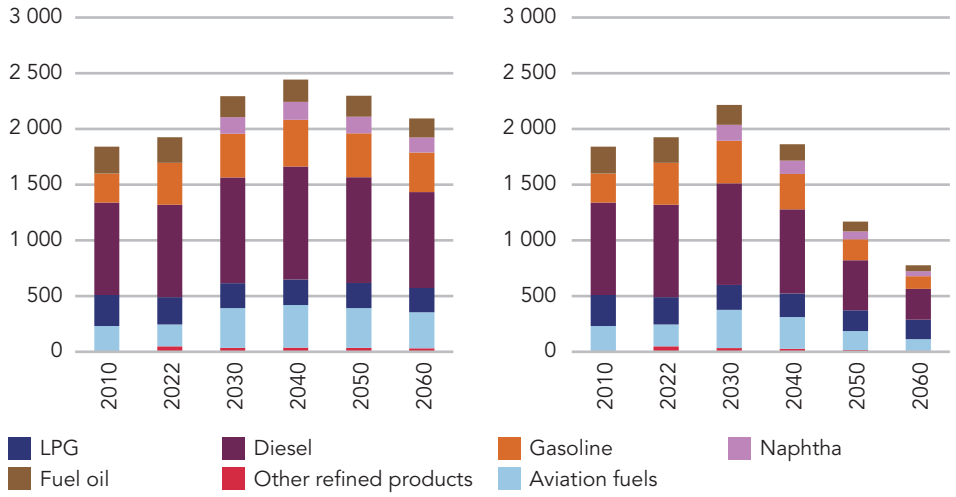
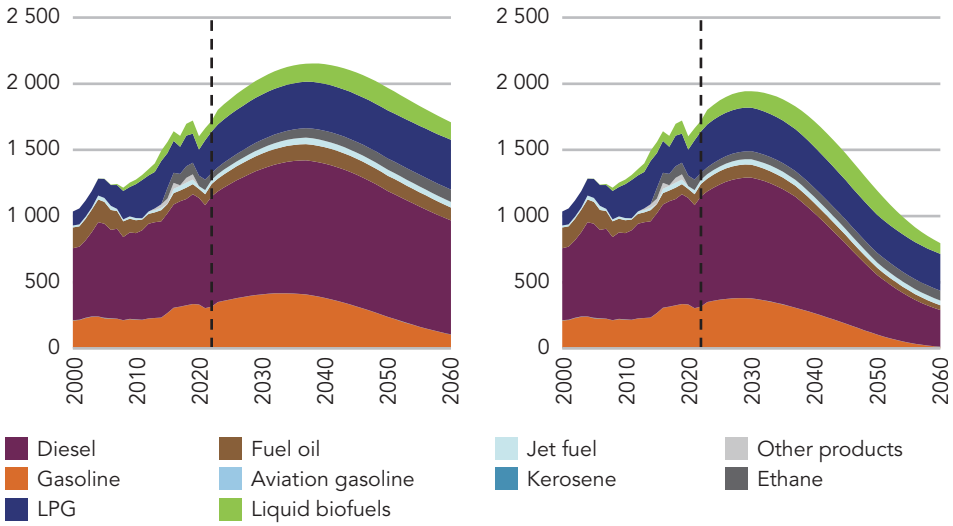


Figure 19-31. Refined products and low-carbon fuels demand in REF & TGT (PJ)



- Thailand's refining output is shaped to meet the evolving demand in both the REF and TGT scenarios.
- Historically, refinery output is led by diesel at about a 40% output ratio, followed by gasoline, naphtha, jet fuel, and other products, including LPG. Total refining output peaks in 2040 and 2030 in the REF and TGT, respectively, following the demand trends.
- In REF, total refining capacity including the new unit of Thai Oil is assumed to be constant through 2060, with a slight decline in refinery utilisation rates after the peak. In TGT, refining capacity and total outputs are assumed to decline in line with the declines in consumption.
- On the demand side, diesel demand is prominent in both scenarios followed by gasoline and LPG, with a greater decline in TGT. LPG is consumed both in building and residential sectors, as well as in the petrochemical sector as a key feedstock.
- The demand for liquid biofuels increases in transport sector, especially further out in the projection period to assist both aviation and marine bunkers with decarbonisation. To note, liquid biofuels are shown as refined product demand even though they are not produced from oil refineries.
- Diesel demand is met by output from refineries throughout the projections in both scenarios. Similarly, gasoline demand is met by refinery output, with excess amounts to be exported in the long term.
- Demand of LPG is prominent throughout both projections despite its declining role in buildings. This is due to its increasing consumption as a non-energy feedstock in the petrochemical sector, which is a key industrial sector in Thailand. LPG non-energy demand is partly met by additional supply from Thailand's domestic gas processing.

Bioenergy and Waste

Figure 19-32. Bioenergy & waste demand by sector in REF & TGT (PJ)

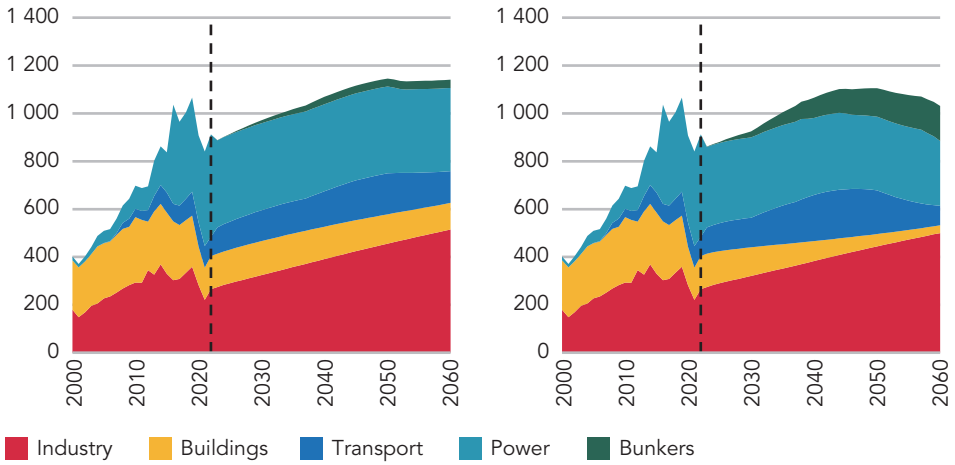
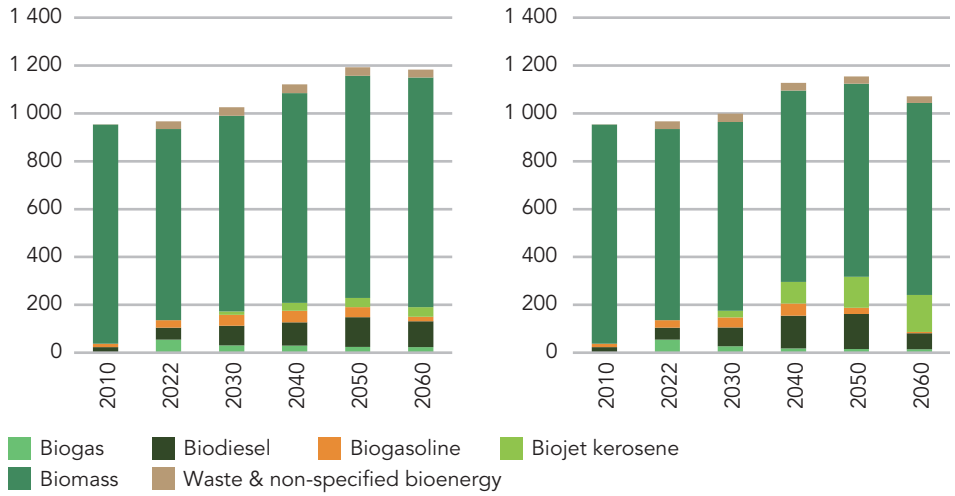
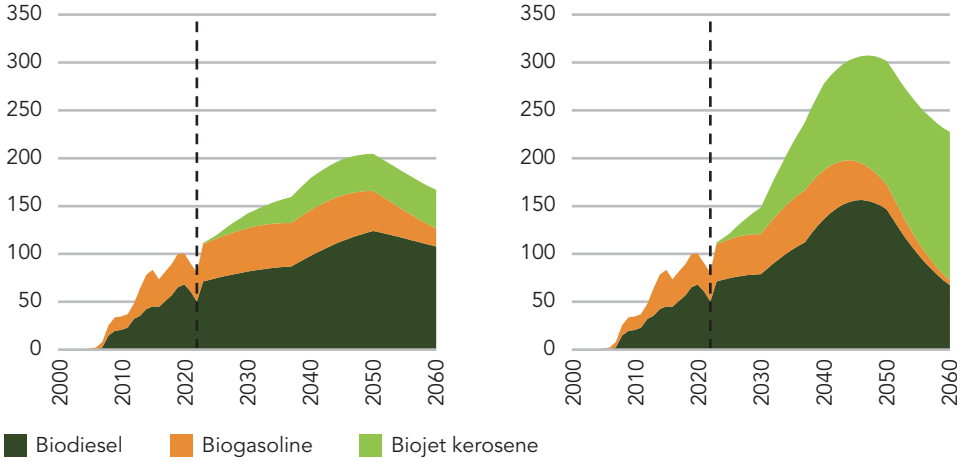


Figure 19-33. Bioenergy production by fuel in REF & TGT (PJ)



- Bioenergy is an important fuel source for industry, household, transport, and power sectors in Thailand, with a significant potential for bunkers.
- Biomass from agriculture residues, which include rice husk, bagasse, tapioca and oil palm residues, contribute to the future demand growth in industry and power. Biofuels demand in transport continues to grow in REF, but peaks and declines in TGT due to the greater adoption of EVs. Demand for firewood and charcoal in households declines in TGT due to increasing electrification.
- Biodiesel for marine transport and biojet for aviation and bunkers are projected to increase, particularly under TGT, reflecting higher decarbonisation efforts. Bio-gasoline continues to be used in REF but declines in TGT.
- Thailand's Alternative Energy Development Plan (AEDP-2018) targets 33 Mtoe (1,394 PJ) uses of bioenergy in all sectors in 2037. In the *Outlook*, bioenergy productions reach 1,050 PJ and 1,065 PJ in REF and TGT, respectively, in 2037, which are short compared to AEDP consumption target.

Figure 19-34. Biofuels production in REF & TGT, 2000-2060 (PJ)



Hydrogen-based Fuels

Figure 19-35. Hydrogen-based fuels demand by sector in REF & TGT (PJ)

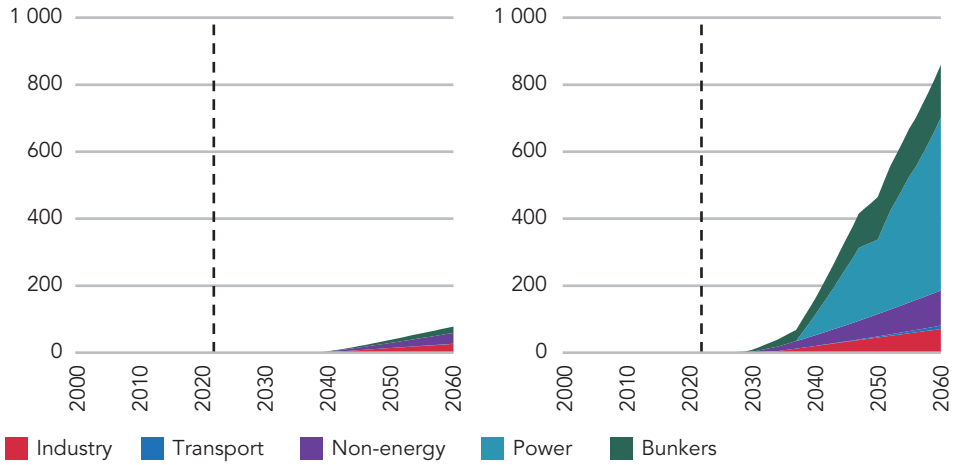
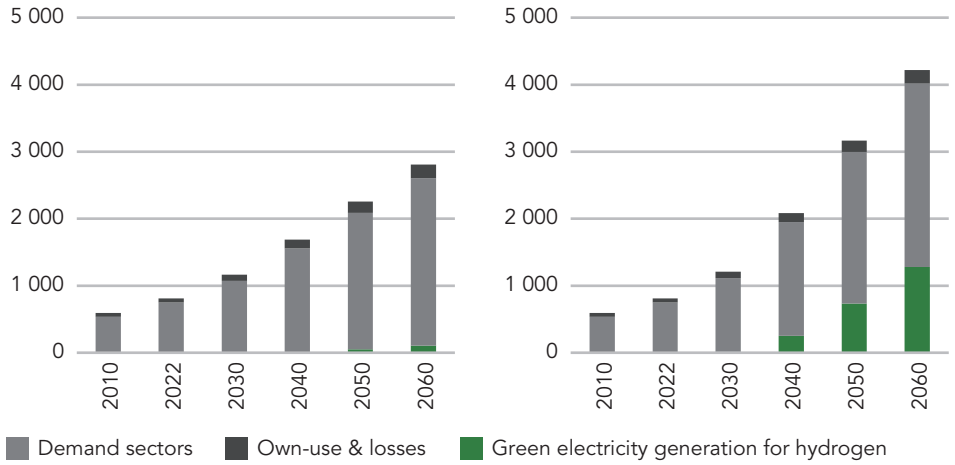


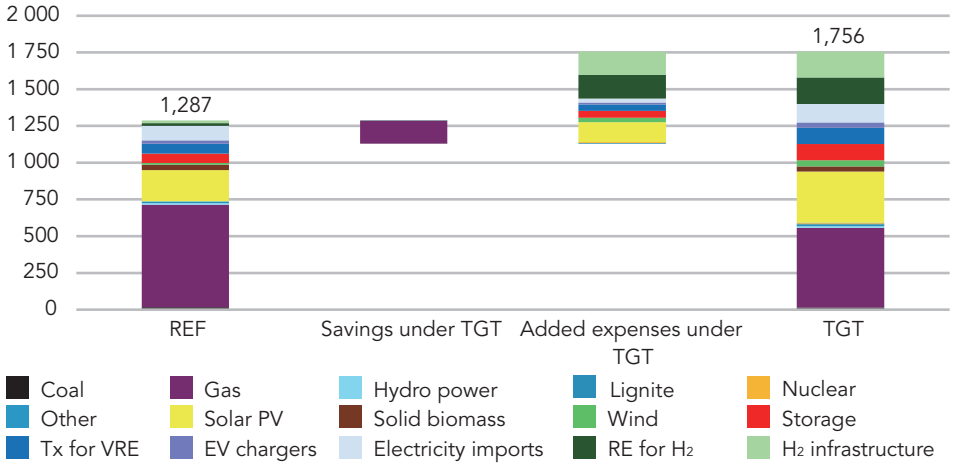
Figure 19-36. Electricity for electrolysis vs other sectors (PJ)



- Thailand is on a path to promote hydrogen use, as evidenced by the 2021 Study to Promote Hydrogen Production and Uses as Renewable Energy, and the 2022 Policy Recommendation Study to Promote Commercial Uses of Hydrogen by the Energy Planning and Policy Office-EPPO, Ministry of Energy.
- Thailand's projected hydrogen-based fuel demand shows a marked contrast between the two scenarios. In REF, demand is assumed to begin in 2040, reaching 78 PJ (approximately 2 million tons of oil equivalent [Mtoe]) by 2060, in line with the Thailand's estimate of 10% blending in the gas pipeline. In TGT, demand is assumed to start earlier, in 2030, driven by accelerated adoption of gas-blending in power generation, non-energy uses in petrochemicals, and hydrogen-based fuels in cement and steel, as well as in bunkering. Hydrogen demand in TGT reaches 860 PJ (19 Mtoe) by 2060, exceeding the long-term potential demand estimated in the Thailand's study. This sharp rise in TGT is assumed to reflect Thailand's more ambitious decarbonisation pathway with higher utilisation of hydrogen production capability, which was estimated at 45 Mtoe in the Thailand's study.
- Thailand is assumed to produce its own hydrogen. In both REF and TGT, hydrogen production is projected to be solely from electrolysis with green electricity. This assumption is in line with Thailand's estimation that 96% of total hydrogen supply could potentially be produced using green electricity generation mostly from solar PV.
- In REF, the demand for green electricity in hydrogen production substantially increases to 106 PJ by 2060. In TGT, the demand of green electricity to produce hydrogen is significantly larger, reaching almost 1,300 PJ by 2060.
- In REF, the demand of green electricity for the generation of hydrogen is small compared to the demand sectors and own use. However, in TGT, its share of total electricity demand reaches 30% by 2060.

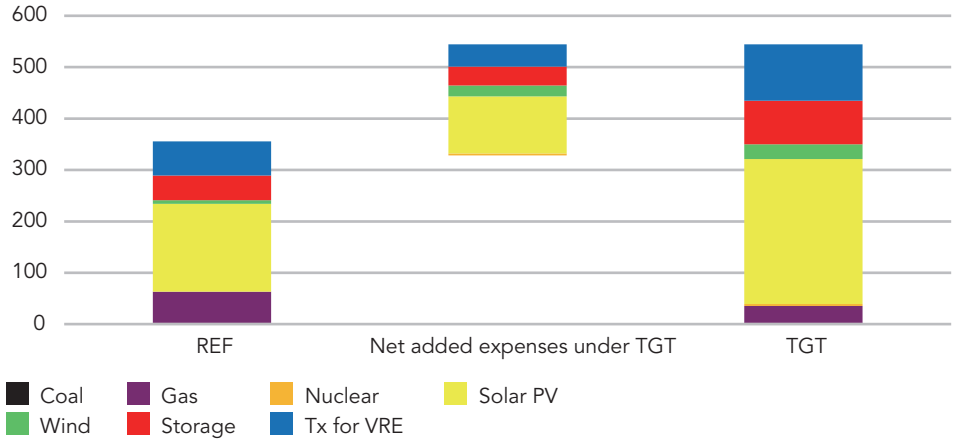
Costs

Figure 19-37. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



Note: Tx for VRE is only transmission infrastructure to connect variable renewable capacity to the grid. EV chargers do not cover the cost of associated infrastructure or EV vehicles. H_2 costs to meet bunkering obligations are not included in Figure 19-37.

Figure 19-38. Total capital investment (CAPEX) from 2025 to 2060 in the power sector (billion USD, undiscounted)

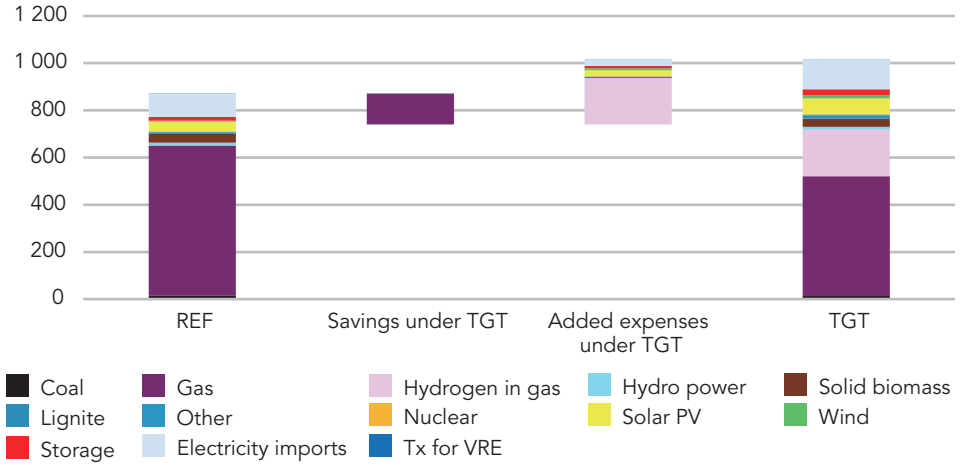


Note: Figure 19-38 only covers power and VRE transmission sector investments. Hydrogen and EV capital investments are not included.

- Decarbonisation will require significant expenditures in Thailand, with total costs rising substantially in both scenarios from 2025 to 2060. Total capital, fixed, and variable costs in the power sector are considered, as well as costs for green hydrogen production, transmission for variable renewable electricity, electricity imports, and electric vehicle chargers.
- In REF, estimated costs reach USD 1.3 trillion, driven largely by investments in higher gas expenditures to provide system stability and added solar PV capacity. Other investments include battery storage and transmission expansion to accommodate more renewable capacity and added EV chargers.
- In TGT, total costs reach an estimated USD 1.8 trillion. The additional cost is driven largely by adding more solar PV and renewables capacity and infrastructure (such as electrolyser plants) dedicated for green hydrogen production. There are notable savings from less expenditure on natural gas, as TGT employs other technologies such as battery storage to provide system reliability. In TGT, twice as much solar and battery capacity is added compared with REF to meet rising electricity demand. Total costs of adding 600 MW of nuclear as well as a higher number of EV chargers are also added in TGT.
- Total capital investment (CAPEX) for Thailand's power sector is an estimated USD 544 billion in TGT, up from USD 355 billion in REF.
- Additional CAPEX in REF is driven by capacity additions in gas and solar PV, expanded transmission, and storage deployment to accommodate a growing share of variable renewables.
- The key additional CAPEX costs in TGT compared to REF are driven largely by adding more solar PV, as well as wind and storage. Additional CAPEX in transmission infrastructure increases even more, relative to REF, to accommodate added renewable capacity. The CAPEX of additional nuclear capacity is also included in TGT but is relatively minor compared to other expenses given the relatively small amount of capacity added.

Costs

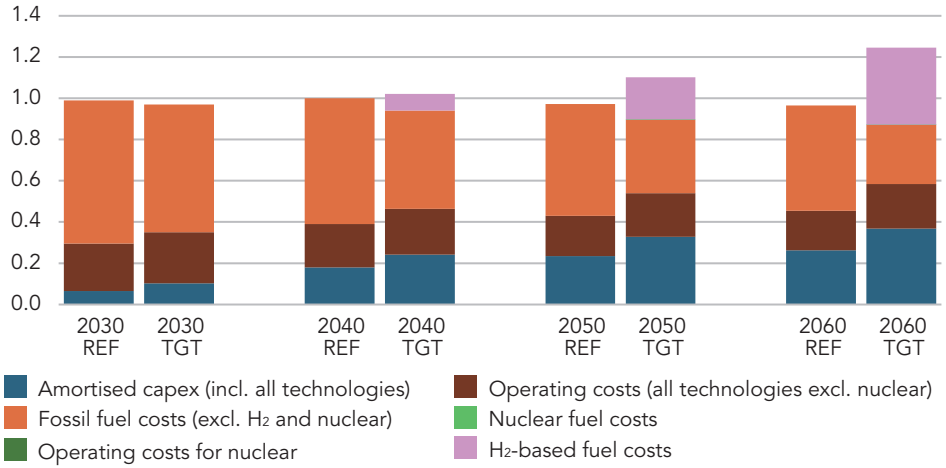
Figure 19-39. Total operating costs from 2025 to 2060 in the power sector (billion USD, undiscounted)



Note: Figure 19-39 only covers power and VRE transmission sector costs. It does not include operating costs associated with hydrogen production and EV charger costs but does include the cost of H_2 blending in power generation.

- Total operating costs for the power sector are projected to exceed an estimated USD 1015 billion in TGT, compared to USD 871 billion in REF. These costs primarily reflect variable fuel and non-fuel expenditures, electricity imports as well as fixed costs for the power sector and transmission to 2060.
- In REF, the highest operating costs are for gas, due to the fuel expenditures to maintain the large volumes of natural gas required for gas fired generation. While some of these gas-related costs are reduced in TGT, there are added operational expenses associated with deploying low-emission technologies, driven largely by introducing green hydrogen blending in gas, as well as maintenance costs of higher solar PV and battery storage.
- Higher usage of hydrogen blending in gas reflects Thailand's policy ambitions to continue relying on dispatchable generation whilst pursuing its decarbonisation objectives.

Figure 19-40. Cost of generating electricity relative to 2025 (2025 cost = 1.0) in the power sector



Note: Based on our assumptions about future capital and operating costs, Figure 19-40 shows cost compositions over time relative to 2025. It should not be considered an estimate of electricity tariffs and excludes market mechanisms that are too difficult to estimate.

- Thailand's electricity generation cost (not the cost of electricity), indexed to 2025, stays relatively steadily in REF and TGT in 2030 and 2040, as the share of amortised capital costs (reflective of additional renewable capacity investment) offset proportional decreases in the share of fossil fuel expenditures as the power sector decarbonises. REF generation costs, relative to 2025, stay generally flat until 2060 due to this offsetting effect.
- Generation costs in TGT start to increase in 2050, being primarily driven by the rising costs of hydrogen blending in gas fired generation and amortised capital costs growing as a cost component due to additional solar PV and storage being added. Both factors continue to push up costs past 2050 and by 2060 electricity generation costs are roughly 20% higher in TGT compared to 2025.
- To note, Figure 19-40 estimates the cost of electricity generation only and does not reflect the consumer cost of electricity which will depend on market design and could include other costs, like distribution costs.

CO_2 Emissions

Figure 19-41. CO_2 emissions in REF (million tonnes)

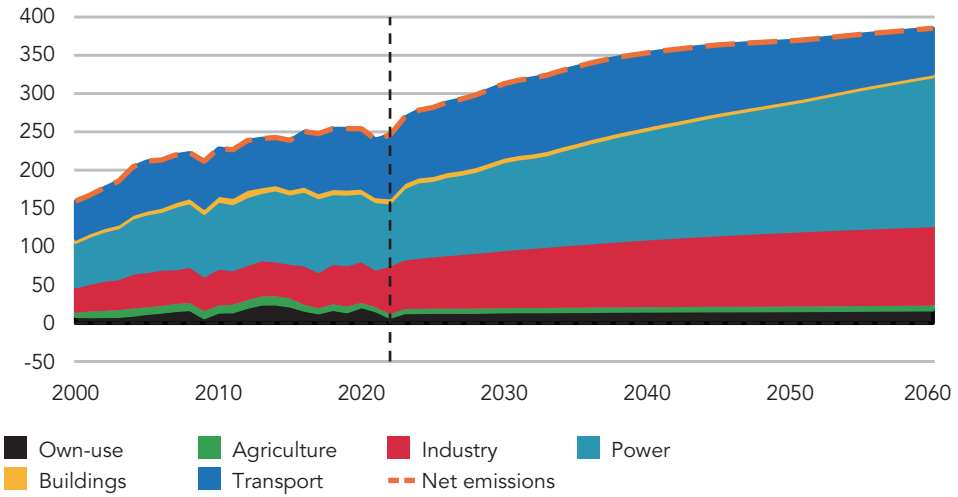
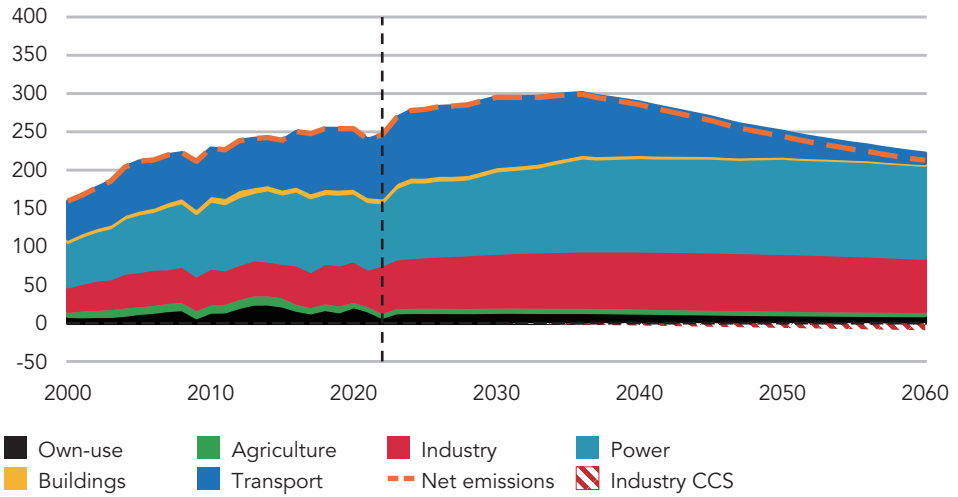
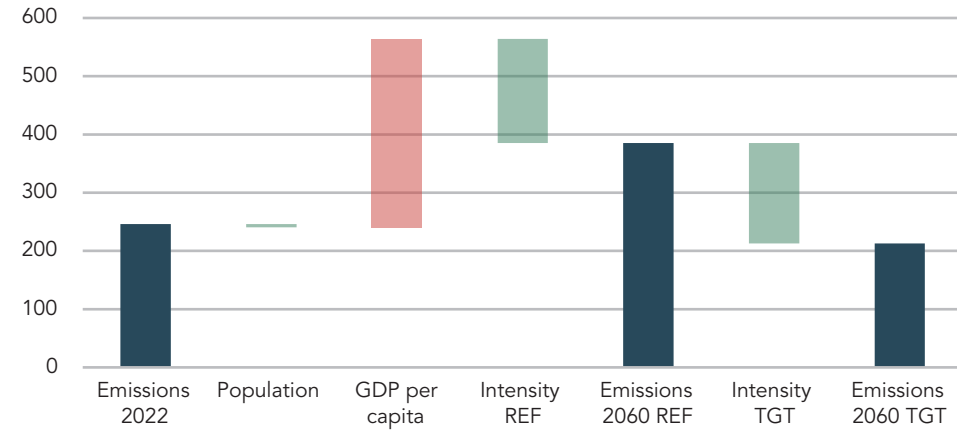


Figure 19-42. CO_2 emissions in TGT (million tonnes)



- Despite various decarbonisation efforts, Thailand's CO_2 emissions are projected to increase to 385 million tonnes by 2060 in REF from 246 million tonnes in 2022, driven by economic growth.
- In TGT, CO_2 emissions peak in 2036 at 300 million tonnes and later decline to 244 million tonnes by 2050 and 213 million tonnes by 2060.
- Thailand's 2022 Long-Term Low Greenhouse Gas Emission Development Strategy sets a carbon neutrality goal that allows around 120 million tonnes of emissions from the energy sector and industrial process and product use to be offset through land-based absorption in 2050. In comparison, TGT emissions remain much higher at 244 million tonnes, mainly due higher emissions in the power sector from increased gas-based generation to maintain reliability in a system with higher shares of intermittent renewables.
- The CO_2 emissions components analysis suggests that increasing GDP per capita largely drives emissions growth to 2060, partly offset by energy and emissions intensity improvements in REF. In TGT, further intensity improvements are essential for accelerating additional emissions reductions.

Figure 19-43. CO_2 emissions components (million tonnes)



Note: All values represent energy sector combustion CO_2 emissions. Biogenic CO_2 is treated as zero at the point of combustion.

Useful Links

APEC Expert Group on Energy Data and Analysis (EGEDA) – https://www.egeda.ewg.apec.org/

APEC Energy Statistics 2022 – https://www.egeda.ewg.apec.org/egeda/general/info/pdf/APEC_Energy_Statistics_2022.pdf

APEC Energy Overview – https://aperc.or.jp/reports/energy_overview.php

Ministry of Energy – Ministry of Energy

Thailand's Energy Statistics – https://www.eppo.go.th/index.php/en/

Thailand Long-Term Low Greenhouse Gas Emission Development Strategy (LT-LEDS), Second Revision, November 2022 – https://unfccc.int/sites/default/files/resource/Thailand%20LT-LEDS%20(Revised%20Version)_08Nov2022.pdf

National Energy Plan – แผนพลังงานชาติ (National Energy Plan)

Power Development Plan 2018 Revision 1 (PDP-2018 Rev.1) – https://policy.asiapacificenergy.org/sites/default/files/Thailand%E2%80%99s%20Power%20Development%20Plan%20%28PDP%29%20%282018%E2%80%932037%29%20%28TH%29.pdf

Alternative Energy Development Plan 2018 (AEDP-2018) – Alternative Energy Development Plan 2018-2037 - Climate Change Laws of the World

EI (Energy Institute) (2024), *Statistical Review of World Energy*. – https://www.energyinst.org/statistical-review

EPPO (Energy Policy and Planning Office) (2023), *Energy Statistic of Thailand 2023*. – https://anyflip.com/qivjx/nvxn/

Promotion of electric vehicles (known as the 30@30 policy) – ITA



20. United States

Summary

	Reference			Target		
	2022	2060	% Change	2022	2060	% Change
Macroeconomic						
Population (million)	337.5	380.6	13%	337.5	380.6	13%
GDP (billion 2017 USD, PPP)	21,276	40,928	92%	21,276	40,928	92%
Energy Demand						
Agriculture & fisheries (PJ)	887	1,101	24%	887	1,101	24%
Buildings (PJ)	20,577	24,902	21%	20,577	28,344	38%
Industry (PJ)	11,762	16,268	38%	11,762	16,327	39%
Non-energy (PJ)	6,191	10,780	74%	6,191	10,780	74%
Transport (PJ)	25,903	24,593	-5%	25,903	26,484	2%
Modern renewables share of TFEC (%)	10	23	130%	10	16	60%
Energy intensity of TFEC (PJ/GDP, billion USD)	2.8	1.7	-39%	2.8	1.8	-36%
Electricity						
Generation (TWh)	4,473	7,920	77%	4,473	8,614	93%
Renewables share of generation (%)	21	49	133%	21	32	52%
Generation capacity (GW)	1,232	2,887	134%	1,232	2,628	113%
Total Primary Energy Supply (TPES)						
Coal & coal products (PJ)	10,016	502	-95%	10,016	5,219	-48%
Natural gas (PJ)	32,292	47,434	47%	32,292	38,448	19%
Petroleum liquids (PJ)	31,722	31,005	-2%	31,722	33,188	5%
Low-carbon & waste energy (PJ)	16,800	28,374	69%	16,800	51,366	206%
CO_2 intensity of energy supply ($MtCO_2/PJ$)	0.05	0.04	-20%	0.05	0.03	-40%
Net CO_2 Emissions (million tonnes)	4,560	4,002	-12%	4,560	4,302	-6%

Note: In this publication, the term "modern renewables" refers to all renewable energy sources excluding solid biomass in the buildings sector. The term "low-carbon & waste energy" includes all bioenergy, waste-derived energy, renewables, nuclear, and hydrogen-based fuels. Total primary energy supply (TPES) numbers include international bunkers. Net emissions are calculated as gross energy sector combustion CO_2 minus CO_2 captured and stored through carbon capture and storage (CCS).

Key Takeaways

Energy Imports and Exports

- The United States has significantly reduced its dependence on foreign energy imports, becoming a net-energy exporter in 2019. This shift is attributed to increased domestic production of oil and natural gas. The primary United States energy exports are gas, via pipelines and liquefied natural gas (LNG) tankers; crude oil; and refined petroleum products.
- The United States is import-dependent for numerous key critical minerals that are necessary for renewable energy technologies, which exposes the United States to supply chain risks. The United States is seeking to address this vulnerability through a combination of domestic production, international partnerships, recycling initiatives, and technological innovation.

Grid Reliability

- Electric grid reliability requires a near-instantaneous balance between power supply and demand at all times. Maintaining this balance requires adequate dispatchable power sources, which can include batteries.
- Figure 20-2 shows the grid's dependence on dispatchable power in the 4-hour period of maximum dependence and 4-hour period of minimum dependence on average summer and winter days. In 2022, there was a relatively small difference between the minimum and maximum need for dispatchable power, so dispatchable generators could produce at a fairly constant rate.
- The dashed line in Figure 20-2 shows the system's peak load in each year. In both REF and TGT, total electricity consumption is projected to increase. Because of this increase, the United States will require an increased amount of power generation capacity and also increased dispatchable capacity for those periods when variable renewable energy (VRE) sources, such as wind and solar, are not producing at their maximum levels.
- The increasing share of VRE over the decades will cause the gap between the minimum and maximum demands on dispatchable power to increase, which will increase capital, maintenance, and operating costs in the U.S. power system.

Figure 20-1. Net imports share of TPES in REF & TGT (%)

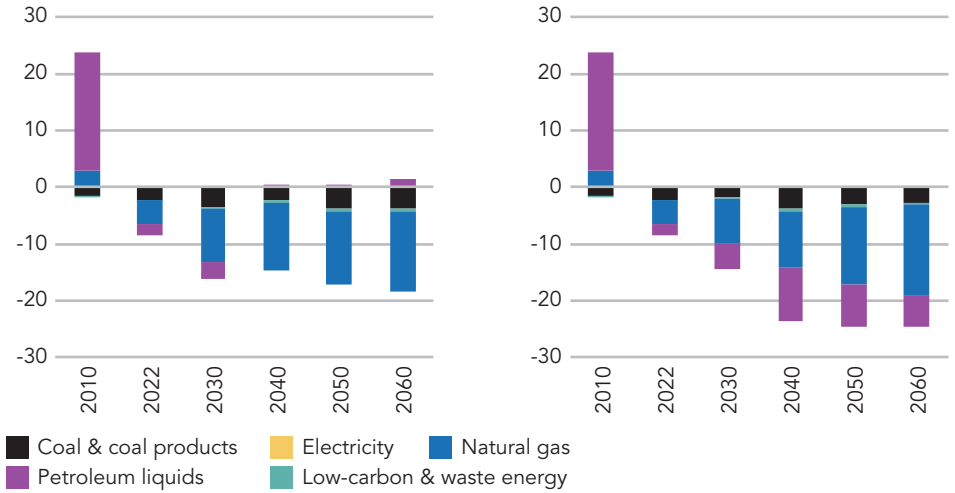
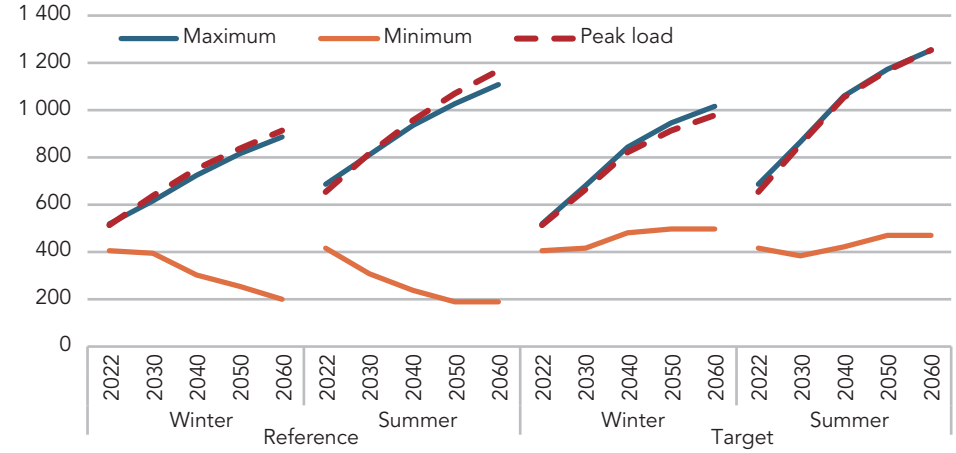


Figure 20-2. Peak load and maximum and minimum dependence on dispatched power (GW)



Note: In Figure 20-1, net imports refer to total imports minus exports and international bunkers.

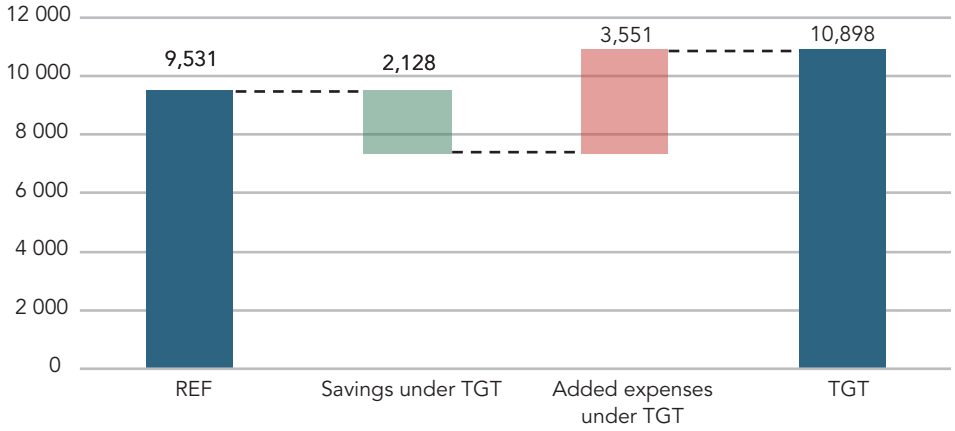
Key Takeaways

Cost

- The cost of expanding the power and hydrogen sectors from 2025 to 2060 is an estimated 9.5 trillion in REF and 10.9 trillion in TGT. These costs include the total capital, fixed, and variable costs in the power sector, costs for hydrogen production, transmission for variable renewable energy (VRE) sources, electric vehicle chargers, and electricity imports.
- The U.S. goal of adding an additional 300 GW of nuclear by 2050 results in overall greater costs in TGT. Coal's continual operation in TGT also brings added costs—mostly in the form of fuel costs. There is less expenditure on VREs in TGT relative to REF, but this is offset by increases in coal and nuclear.

*Actual costs will differ from estimated costs in the *Outlook* for a variety of reasons including changing commodity prices, manufacturing costs, and unforeseen technical advances. All costs are in 2023 real terms.

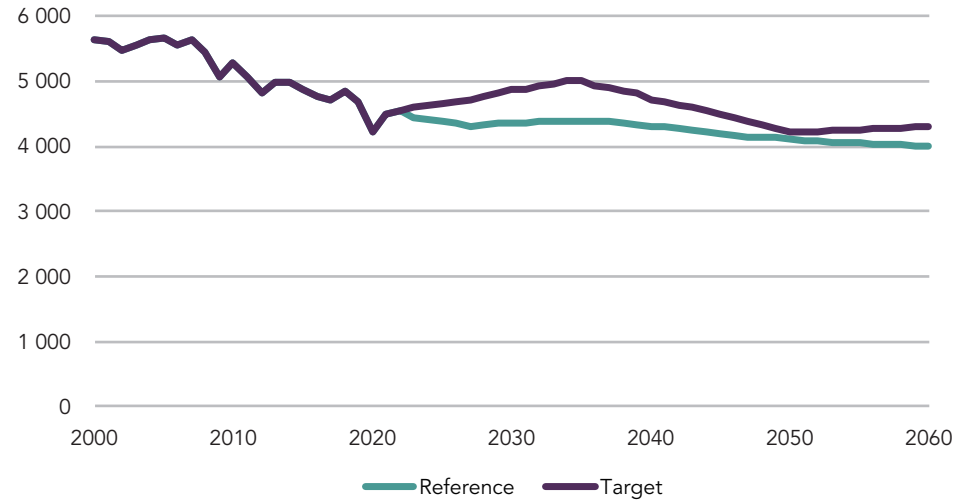
Figure 20-3. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



Emissions

- U.S. CO_2 emissions peaked in the early 2000s and began to decline thereafter, primarily due to significant changes in the electricity generation sector. This shift involved a decreased reliance on coal and an increased usage of natural gas, followed by a further adoption of renewable energy sources.
- In both scenarios, the power and transportation sectors are the greatest contributors to CO_2 emissions due to their usage of fossil fuels. In TGT, transportation contributes more to CO_2 emissions relative to REF as a result of reducing EV tax credits and continued reliance on internal combustion engine (ICE) vehicles.
- In the TGT projection period, CO_2 emissions peak around 2035 before declining, driven by new nuclear power generation capacity coming online.

Figure 20-4. Net CO_2 emissions (million tonnes)



About the United States

Overview

Geographical and Economic Landscape

The United States is a geographically varied and resource-rich economy and is a major energy producer and consumer. The United States encompasses 50 states plus the District of Columbia, a federal district designated as the economy's capital. The United States has a dynamic, knowledge-based economy fuelled by cutting-edge technology and innovative entrepreneurship.

Energy Supply and Consumption

The United States is historically one of the world's largest energy consumers and, of the APEC economies, the United States has the second highest share of primary energy consumption at close to 16%. Relative to other APEC member economies, the United States had the third highest level of total primary energy supply (TPES) per capita in 2022. The United States' TPES in 2022 was 273 gigajoules per capita, representing a 19% decrease compared to its TPES in 2000.

Energy Security Challenges and Strategies

In 2019, the United States became a net exporter of energy for the first time in over six decades thanks to a significant increase in domestic energy production. This shift has enhanced U.S. energy security by reducing reliance on foreign energy sources and bolstering resilience against global supply disruptions.

Key Energy Initiatives

Trump Administration

Unleashing the Golden Era of American Energy Dominance

On 5 February 2025, the U.S. Secretary of Energy announced the "9 Pillars for American Energy Dominance", a comprehensive strategy focused on expanding energy supply, accelerating innovation, and strengthening domestic security. Key priorities include boosting advanced nuclear R&D, streamlining LNG exports and permitting, promoting energy affordability and consumer choice, refilling the Strategic Petroleum Reserve, enhancing grid reliability, and unleashing the full potential of commercial nuclear power.

One Big Beautiful Bill Act

On 4 July 2025, the "One Big Beautiful Bill Act" was signed into law. While the Act contains many non-energy provisions, its energy-related measures include the accelerated phase-out of renewable energy and EV tax credits, and expanded support for fossil fuel development through reduced royalties, mandated offshore leasing, and streamlined permitting.

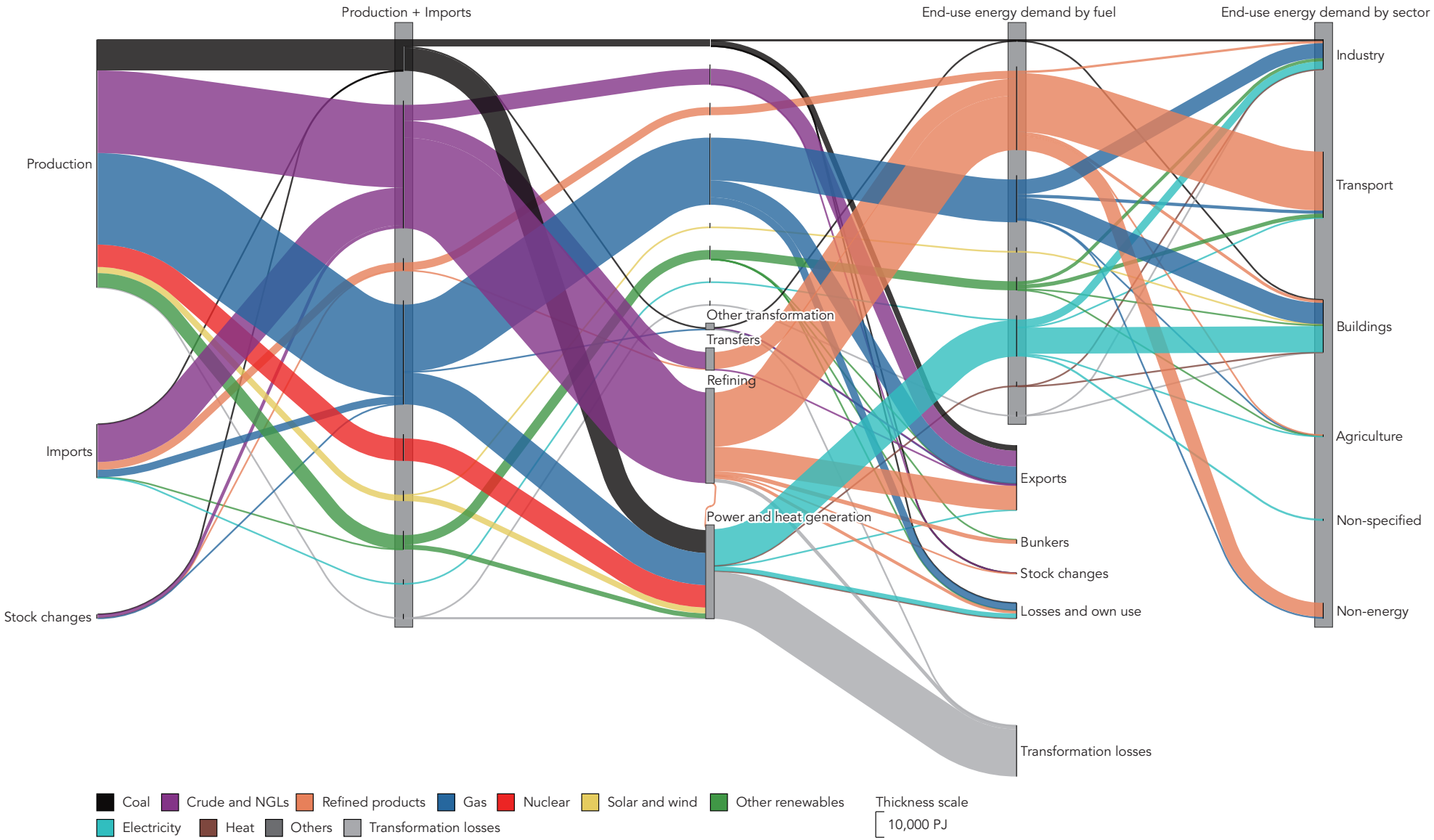
America Nuclear Renaissance

The Trump Administration aims to expand U.S. nuclear energy capacity from 100 GW to 400 GW by 2050 through executive actions focused on innovation, security, regulation, and industry. The plan includes accelerating reactor testing at U.S. Department of Energy labs, building reactors on federal land for security, reforming the Nuclear Regulatory Commission (NRC) to speed up licensing, and revitalising the domestic nuclear fuel cycle through renewed uranium mining and enrichment.

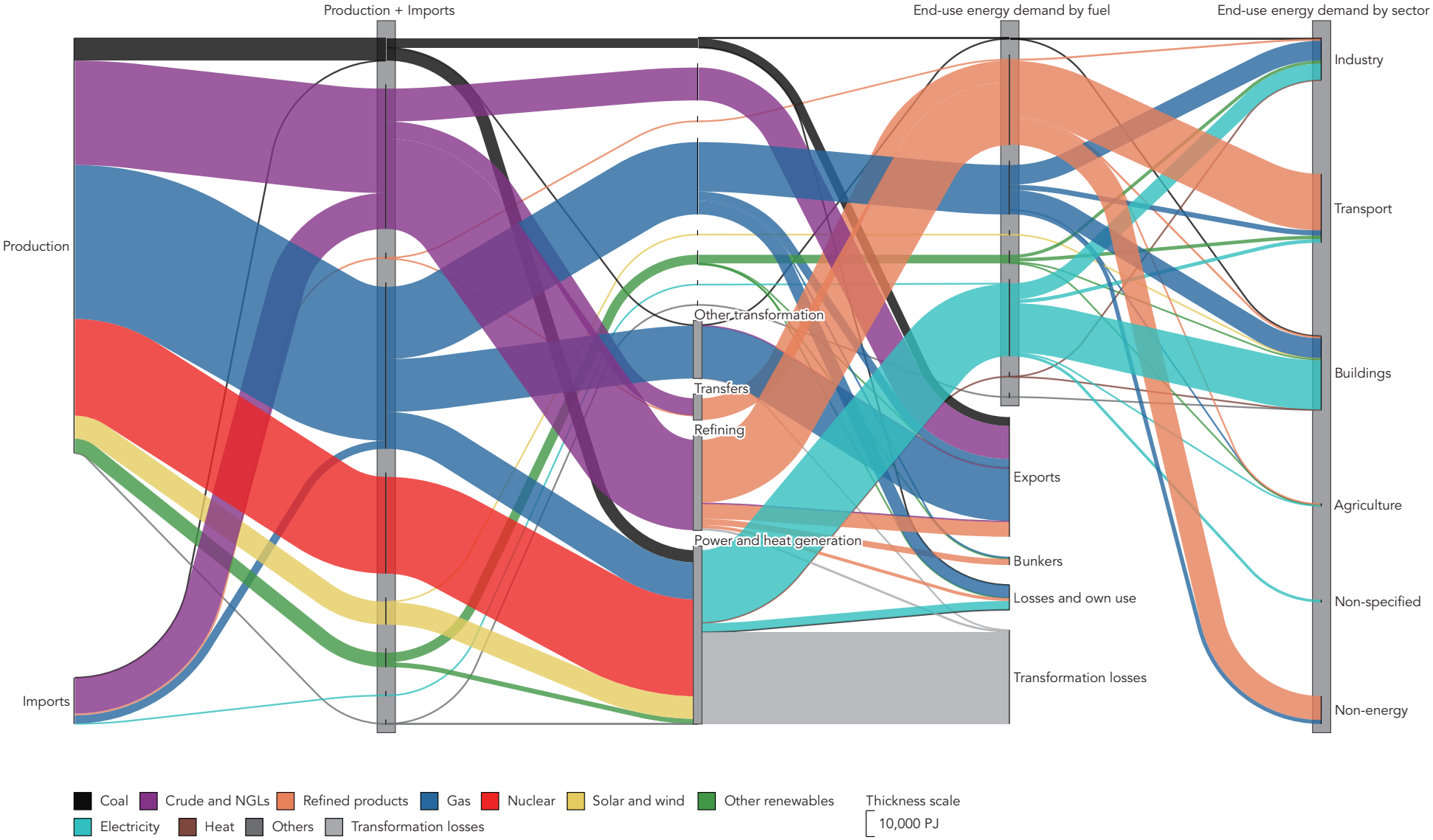
Additional Updates

On climate, in late January 2025, the Trump Administration signed an Executive Order that starts the process of withdrawing the United States from the Paris Agreement. In addition, the U.S. Environmental Protection Agency is considering revoking the "endangerment finding", which is the legal basis for the regulation of greenhouse gas emissions. The Trump Administration has also stated its intent to open more federal land for oil and gas exploration.

Energy Flow (2022)



Energy Flow (2060, Target Scenario)



Scenarios and Assumptions

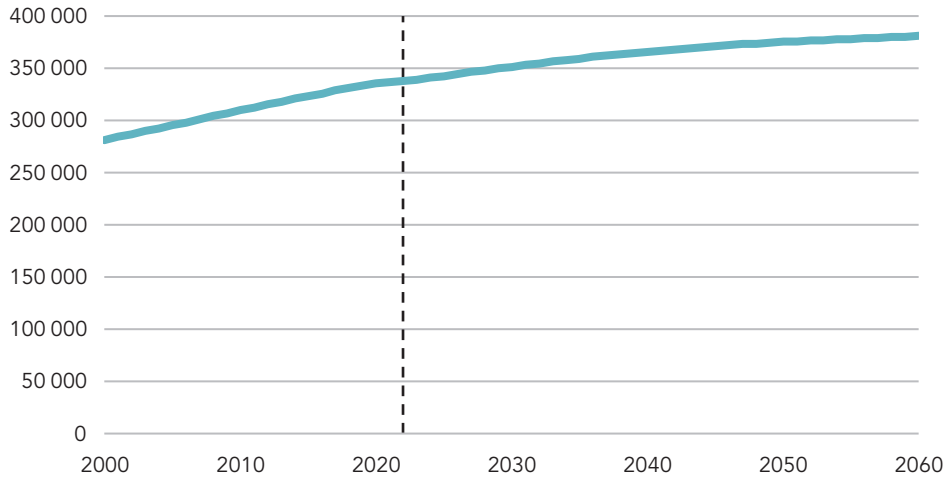
In *The Outlook*, APERC analyses energy demand, transformation, and supply, as well as estimated costs and CO_2 emissions. The **Reference Scenario (REF)** offers a projection based on historical trends and APERC's assumptions about the continuation of those trends in each APEC economy, while acknowledging technical constraints. The REF Scenario offers a baseline to compare with the **Target Scenario (TGT)** projections, which explores a hypothetical pathway where each economy achieves energy-related policy targets, assuming implementation regardless of cost-effectiveness. In this chapter, TGT is based on U.S. energy policies as of October 2025.

	Reference	Target
General	• Population: UN medium; GDP: APERC model and IMF	• Population: UN medium; GDP: APERC model and IMF
Buildings	• Moderate building envelope improvements and equipment efficiency gains are assumed. • New buildings incorporate energy efficiency measures, but retrofits of existing stock are not widespread. • AI and data centres electricity use incorporated as a projection.	• Building envelope and equipment efficiency improvements are based on energy cost savings and are the same as REF. • Data centre electricity use increases compared to REF. In this scenario: - Data centres account for 16% of total U.S. electricity demand by 2030. - Data centre electricity demand continues to increase after 2030, but at a slower rate.
Industry	• Hydrogen and CCS for both gas and coal are deployed in the 2040s.	• Fossil fuels are maintained in hard-to-abate sectors. • CCS is not implemented, and low-carbon hydrogen is not utilised in industry due to high costs.
Transport	• EVs grow steadily (e.g. 30% BEV sales share for passenger vehicles by 2060).	• Stock share of EVs is reduced by 50% compared to REF.
Power	• Coal is phased out by the end of the projection period. • Gas replaces coal as the baseload generation source.	• Coal stays flat throughout the projection period. • Nuclear adoption is increased to reach the goal of 400 GW by 2050. • Wind is approximately 50% of REF; offshore wind is reduced due to elimination of subsidies. • Solar is 80% of REF. • Gas-fired generation is assumed to meet electricity demand that exceeds the contributions from other sources.
Supply	• No new coal-fired power plants are assumed to come online. • The United States remains an LNG exporter. Gas production increases independently from oil production. • Slowing growth in world oil demand, combined with comparative expensive oil production leads to a 2030 peak in production. • Refining capacity is reduced by 15% in REF by 2060.	• No new coal-fired power plants are assumed to come online, but coal plant lifetimes are extended. • More acreage is opened for oil exploration, which leads to higher oil production. • Refining capacity is reduced by 4% in TGT by 2060. • Gas production increases to meet total domestic consumption plus export demand. Share of gas from associate versus non-associated fields depends on field economics.
Emissions	• CO_2 emissions are calculated at post consumption based off IPCC emission factors.	

Note: The base year is 2022. Macro-economic assumptions are constant across scenarios. Historical energy balances are from EGEDA submissions for 2022.

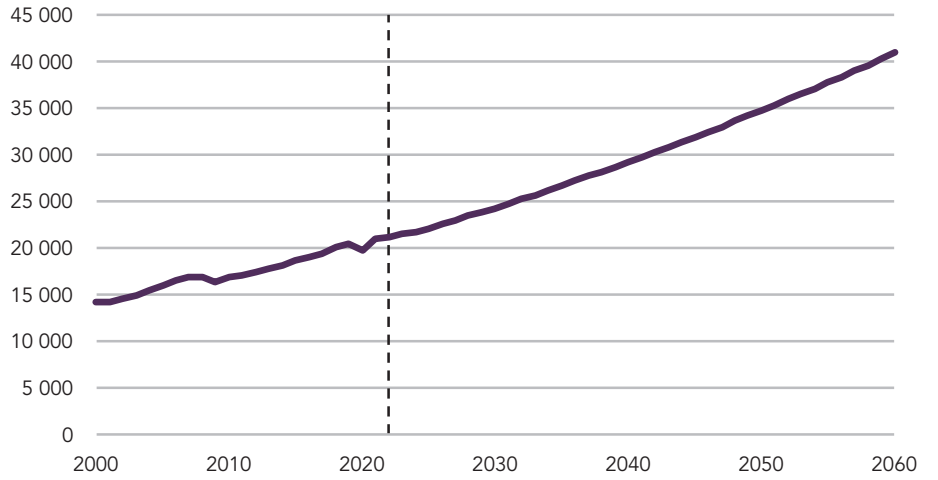
Demographic and Macroeconomic Assumptions

Figure 20-5. Population (thousands)



- The United States' population is expected to steadily increase from approximately 337 million (2022 data) to 381 million (2060 projection).
- The United States is one of the most diverse economies in the world, and immigration has historically been a significant contributor to its population growth. Future contributions from immigration will depend on domestic policies and global dynamics.
- Over 80% of the United States' population lives in metropolitan areas, an increase of approximately 20 percentage points since the 1950s. Urbanisation is projected to increase further driven by factors such as economic opportunities, infrastructure development, and lifestyle preferences.

Figure 20-6. Real GDP (billion 2017 USD, PPP)



- The United States' GDP is assumed to grow steadily at 1.5-2.0% per year through 2060. This growth rate is consistent with recent history, aside from the 5.6% bump from 2020 to 2021 following the resumption of economic activity after the first year of the pandemic.
- The U.S. GDP is the largest in the world based on market exchange rates. However, based on producer price parity (PPP), the United States economy is the second largest, after China, in both APEC and the world.

End-use Energy Demand

Figure 20-7. Energy demand by sector in REF & TGT (PJ)

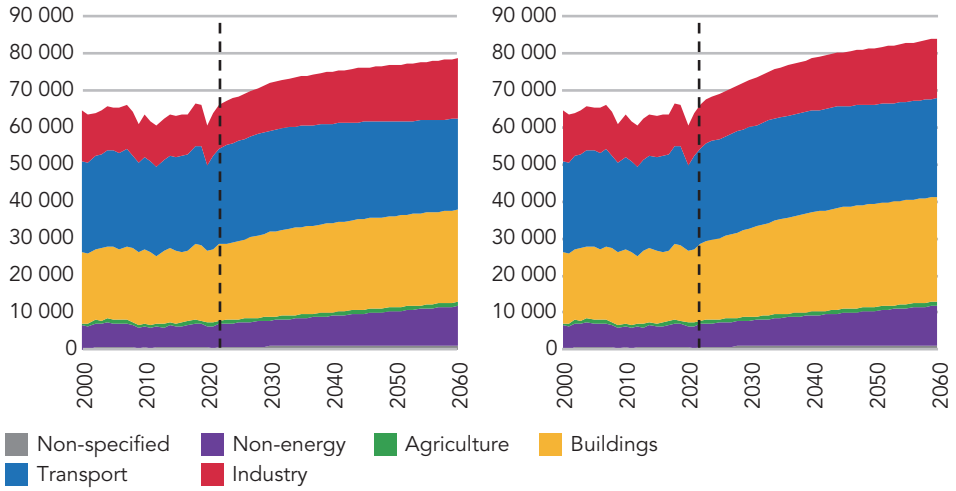
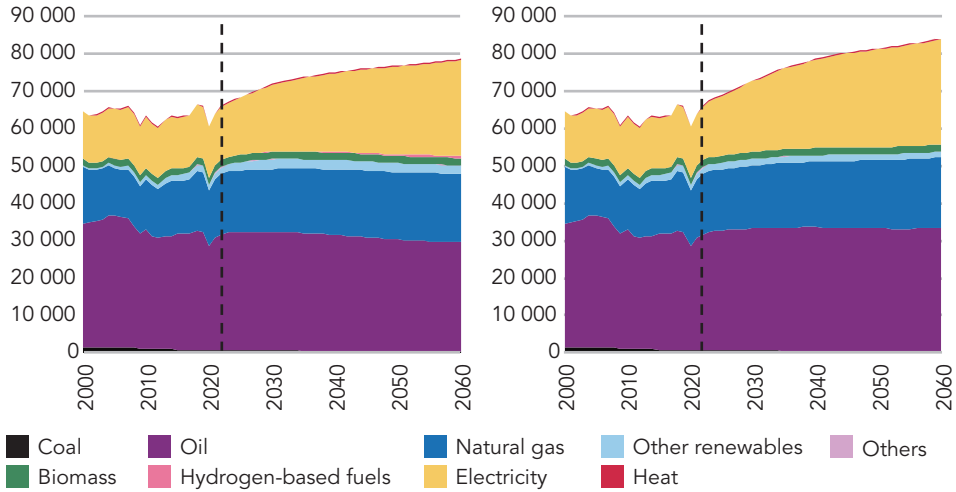


Figure 20-8. Energy demand by fuel in REF & TGT (PJ)



- The United States is the world's second-largest consumer of energy, and total final energy consumption is projected to rise in both the Reference scenario (REF) and Target scenario (TGT), reaching 78,600 PJ in REF and 84,100 PJ in TGT by the end of the projection period in 2060. This increase is driven by steady economic and population growth, increasing electrification of end-uses, and the expansion of energy-intensive services such as data centres.
- In the United States, the buildings and transportation sectors account for the majority of energy demand. Growth in the buildings sector is driven in part by the rapid expansion of data centres. Meanwhile, the transportation sector exhibits elevated energy consumption due to widespread personal vehicle ownership and the prevalence of larger vehicles compared with those in other APEC economies.
- The industrial, non-energy, and agriculture sectors experience moderate growth due to economic expansion, increased demand for manufactured goods and feedstocks, and continued mechanisation and electrification in agriculture, partially offset by improvements in energy efficiency, structural shifts toward less energy-intensive industries, and other innovation advances.

- By fuel source, oil constitutes the plurality of energy demand in the United States, followed by electricity and natural gas. Oil's predominance is largely attributable to its central role in the transportation sector, where liquid fuels power the majority of personal vehicles, freight trucks, and aviation. Electricity represents the second-largest share, reflecting its widespread use across multiple sectors, including the increasing demand from data centre operations. Natural gas accounts for a substantial portion of energy consumption due to its versatility and efficiency in residential and commercial heating, industrial processes, and baseload electricity generation.

Buildings Energy Demand

Figure 20-9. Buildings energy demand by fuel in REF & TGT (PJ)

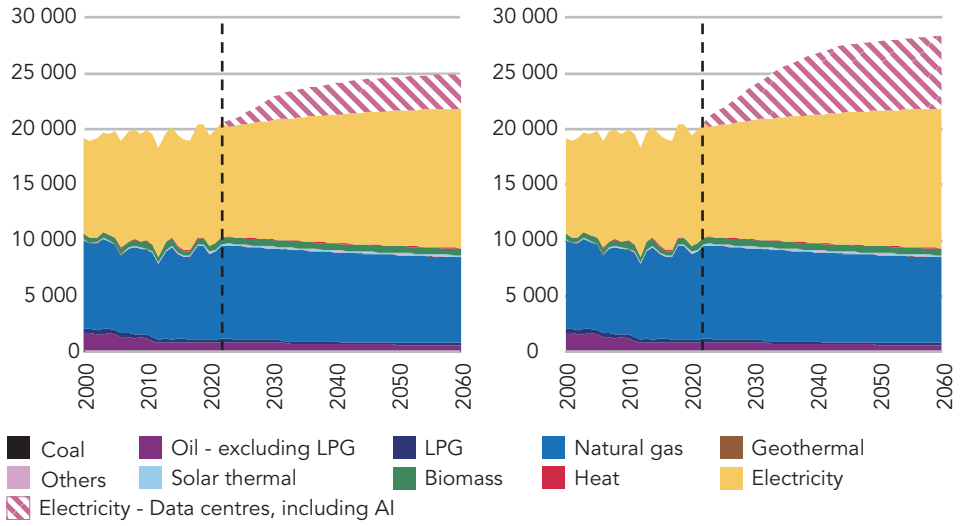
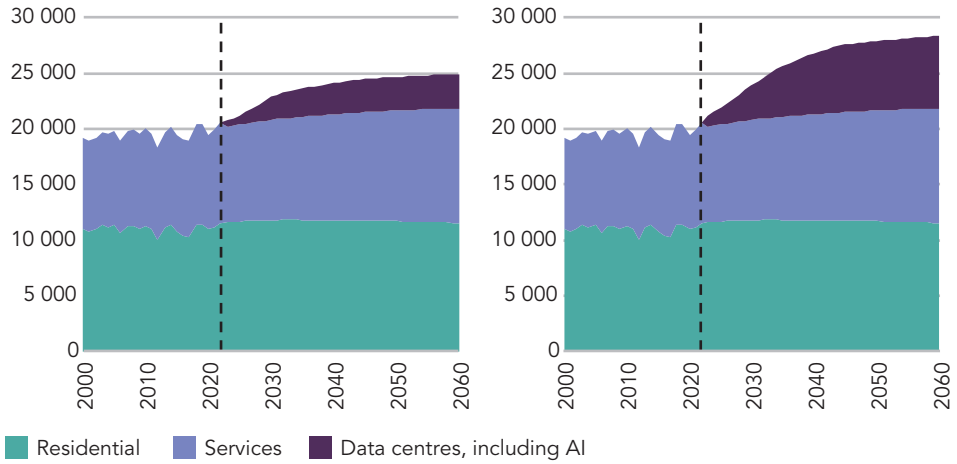


Figure 20-10. Buildings energy demand by sector in REF & TGT (PJ)



- The buildings sector encompasses a wide range of energy demand sources across both residential and commercial facilities. Key end uses include space heating and cooling, water heating, lighting, cooking, refrigeration, and increasingly, electrical loads associated with appliances, office equipment, and data centre operations. Residential buildings primarily rely on natural gas for space and water heating, while electricity supports lighting, appliances, and emerging electrified heating and cooling systems such as heat pumps. Commercial buildings exhibit significant electricity demand for lighting, heating, ventilation, air conditioning (HVAC), and office/industrial equipment, while natural gas is primarily used for space heating and cooking.
- In both REF and TGT scenarios, the buildings sector accounts for the highest total final consumption by 2060 (~24,900 PJ, 32% in REF; ~28,300 PJ, 34% in TGT). Electricity and natural gas are the dominant sources, with electricity consumption projected to increase due to the electrification of building end-uses and the continued growth of electricity demand from data centres and other digital infrastructure.
- This edition of the *Outlook* explicitly models data centre energy consumption, including the effects of increased artificial intelligence (AI) usage. Projections for electricity demand in data centres is estimated to increase in REF to 3,100 PJ and in TGT to 6,500 PJ by 2060. Of total electricity consumption for the United States, data centres are projected to comprise 11% in REF and 16% in TGT by 2030. This additional electricity demand may strain local power systems unless there is adequate investment to accommodate this emerging demand source.

Industry Energy and Non-energy Demand

Figure 20-11. Industry & non-energy demand by fuel in REF & TGT (PJ)

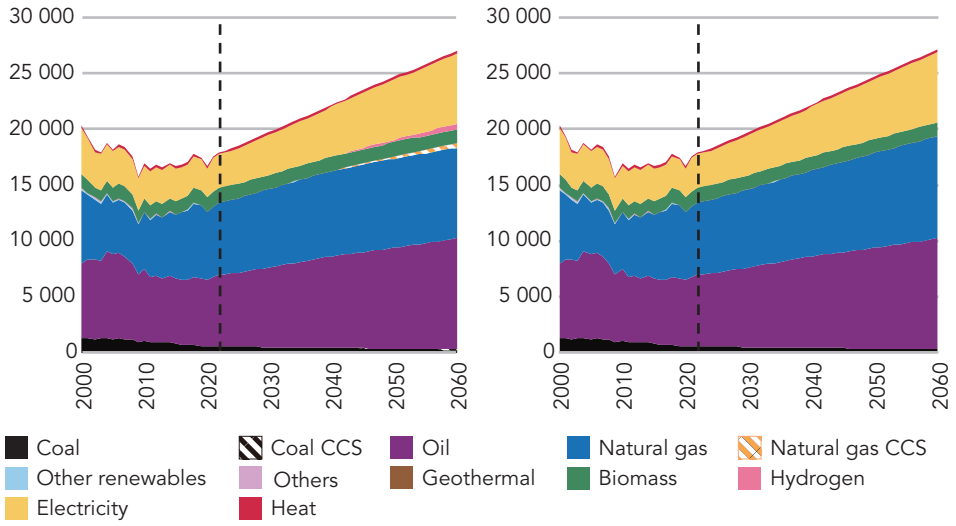
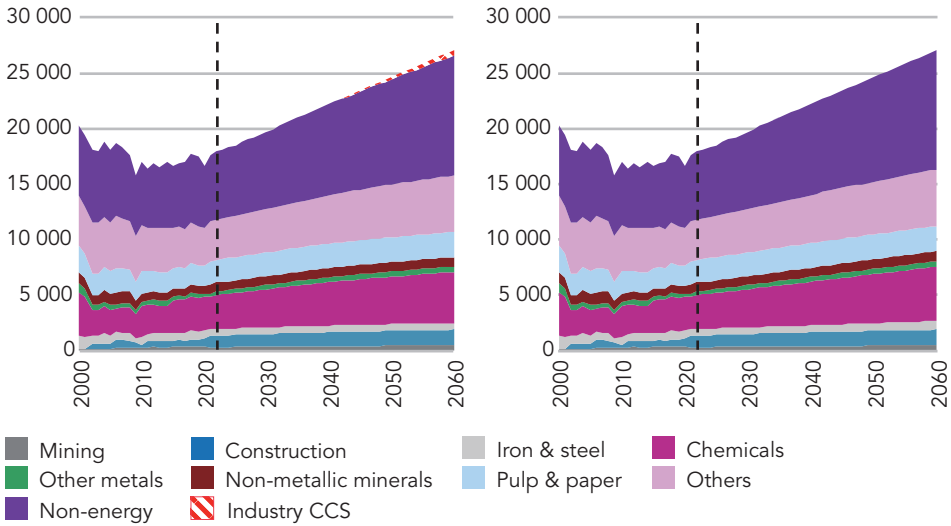


Figure 20-12. Industry & non-energy demand by sector in REF & TGT (PJ)



- The U.S. industrial sector represents a critical component of the economy, comprising subsectors such as chemicals, metals, pulp and paper, and mining. These industries are responsible for the production of essential materials and intermediate goods that underpin manufacturing, construction, and technological development. Characterised by complex, capital-intensive production processes, the sector increasingly integrates advanced technologies to enhance operational efficiency and product quality.
- U.S. industry energy plus non-energy demand is projected to grow in both scenarios, exceeding 27,000 PJ by 2060. Gas, oil, and electricity are the main sources for the industrial & non-energy sectors. These fuels and electricity are used for heating in industrial processes, space heating, boiler fuel for generating steam and/or hot water for industrial heating and power generation. In addition, natural gas and oil serve as feedstocks or raw materials in the production of chemicals and plastics, with natural gas playing a particularly important role in supporting growth in the petrochemical subsector and other non-energy applications.
- The chemicals sector accounts for approximately 30% of industrial energy demand and the pulp & paper industry accounts for 14% in both scenarios. "Others", which includes the food, textiles, machinery, and transport equipment sub-sectors, is another major source of energy demand.
- Non-energy demand grows and reaches two-fifths of industry demand by 2060 in both REF and TGT, driven by U.S. production of petrochemical feedstocks, asphalt, and lubricants. Petrochemical feedstocks, such as ethane, naphtha, and NGLs, continue to rise due to growing production of plastics, fertilisers, and industrial chemicals, which is supported by low-cost U.S. shale gas.

Transport Energy Demand

Figure 20-13. Domestic transport energy demand in REF (PJ)

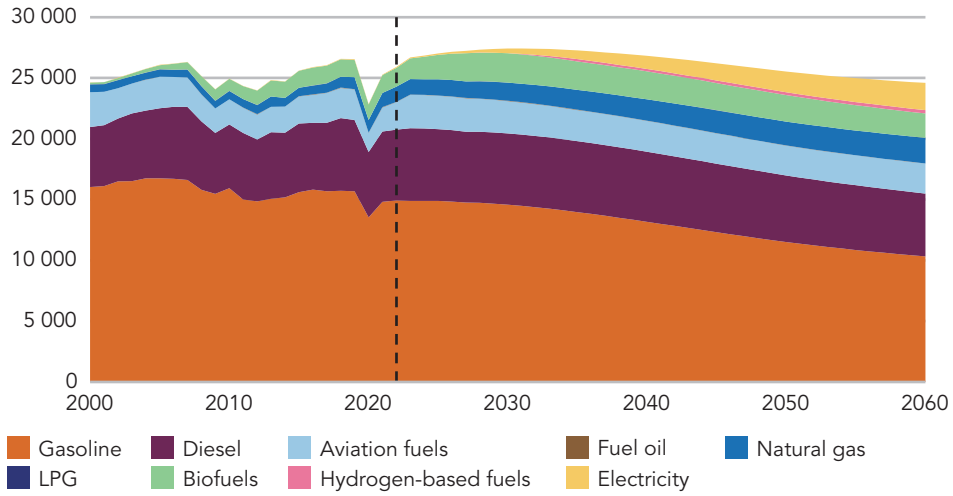
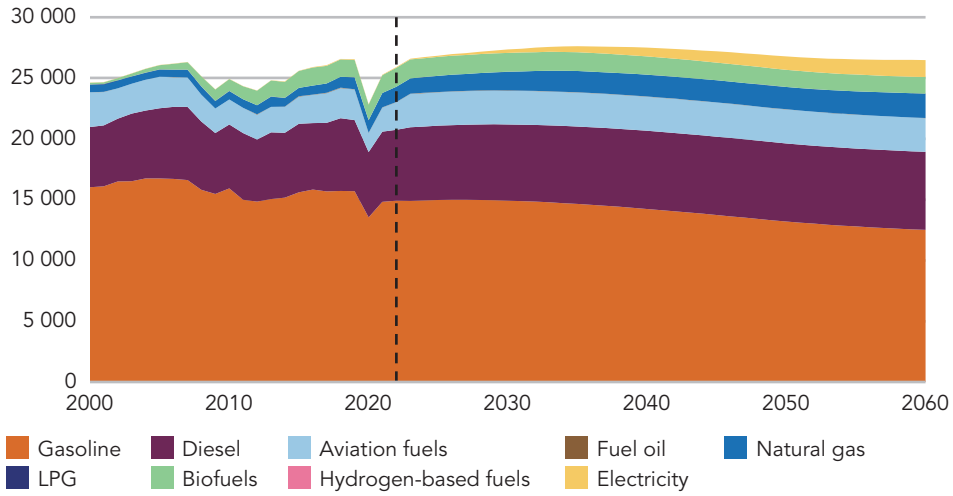


Figure 20-14. Domestic transport energy demand in TGT (PJ)



- The transport sector is a major component of U.S. energy demand, encompassing road, rail, aviation, and maritime transportation. Private vehicles are the predominant means of travel for Americans, with millions commuting daily, while public transportation systems, including subways and buses, play a key role in urban mobility. Road transport accounts for 83% of domestic energy use in the transport sector in 2022; it declines to 76% and 79% in 2060 in REF and TGT, respectively. This small decline in road transport's share of total domestic energy consumption within the transport sector is due to efficiency improvements.
- The U.S. transport sector is characterised by high reliance on petroleum-based fuels. This is driven by several structural factors: (1) the predominance of light-duty vehicles powered by gasoline, (2) heavy trucks and freight operations that rely on diesel/distillate fuels, (3) aviation's use of jet fuel (a petroleum derivative), and (4) longstanding infrastructure and fleet investments oriented toward liquid fuels. While alternatives such as biofuels, natural gas, and electricity are increasing, they represent only a small portion of transport energy.
- In REF, domestic transportation energy use peaks in 2030 and declines 10% from that peak by 2060. From 2022 to 2060, gasoline's share of domestic transport energy use declines from 58% to 42% as it is replaced by electricity and a small amount of hydrogen-based fuels.
- In TGT, the sales share of electric vehicles (EVs) is reduced by 50% to reflect the termination of federal subsidy programs for this engine type. Consequently, total energy demand in the domestic transport sector remains relatively stable over the projection period, averaging around 27,000 PJ. Gasoline represents approximately half of transport energy demand through-out the projection period. Hydrogen use in transport is not incorporated in this scenario, consistent with the suspension of federal support for many hydrogen development and deployment projects.

Other Transport Data

Figure 20-15. Transport vehicle stocks in REF & TGT (millions)

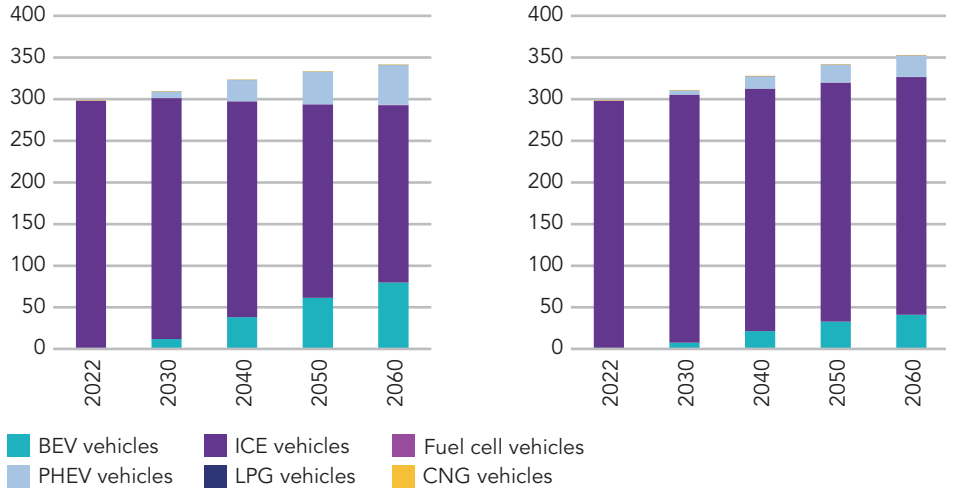
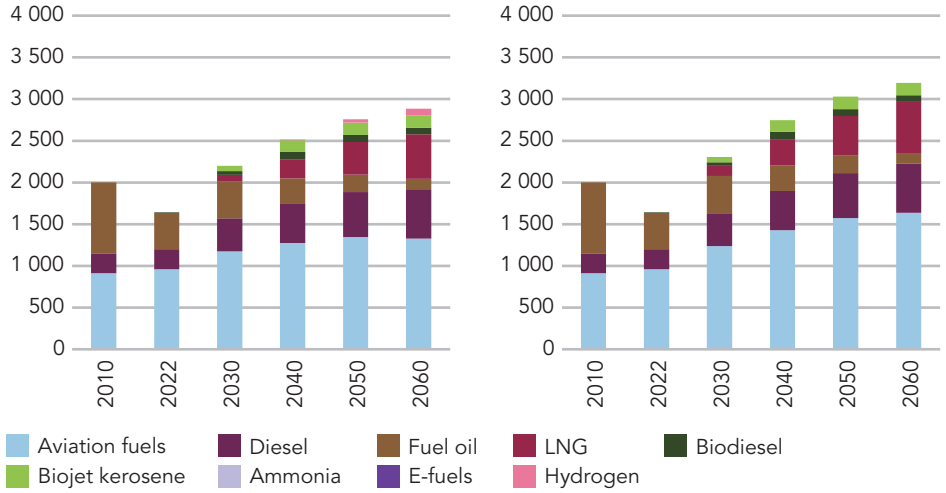
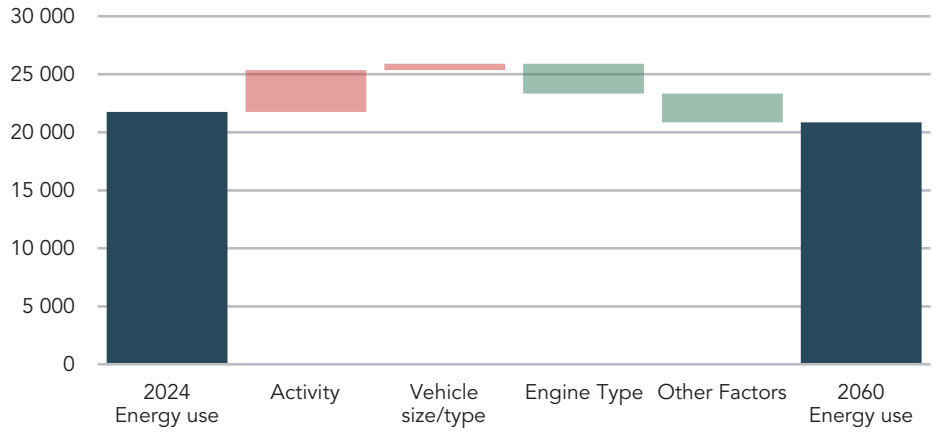


Figure 20-16. International bunker energy demand for shipping and aviation in REF & TGT (PJ)



- With respect to the number of vehicles (stocks), the share of internal combustion engine (ICE) vehicles declines in REF and is displaced by a growing share of battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs). In TGT, this shift is delayed, resulting in a greater share of ICE vehicles.
- International bunker fuel demand is projected to increase in the United States, driven by growth in international trade volumes, maritime shipping activity, and aviation traffic. Both marine and aviation bunkering contribute significantly to total petroleum consumption, reflecting the United States' role as a global trade hub and a major centre for international air transport. Although improvements in vessel and aircraft efficiency are expected, rising freight movement and passenger travel more than offset these gains.
- Figure 20-17 illustrates why energy use remains largely flat in TGT. A small increase in energy use from continued growth in freight and passenger km (Activity bar) and a shift to larger vehicles (Vehicle size/Type bar) is balanced by efficiency gains from electrification (Engine Type bar) and continued improvements in ICE vehicle efficiency (Other Factors bar).

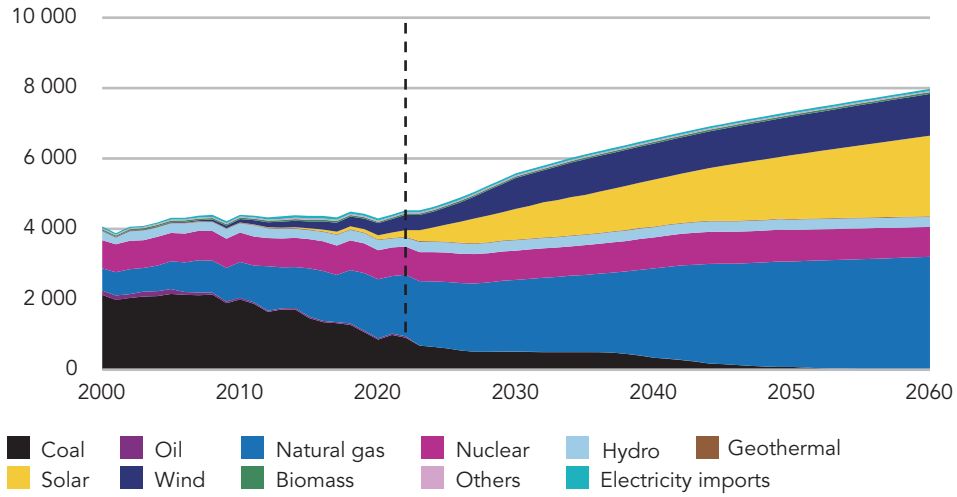
Figure 20-17. Components of the change in road energy use in TGT (PJ)



Note: Information on the different drivers in the transport energy decomposition can be found in the *Outlook*'s annex.

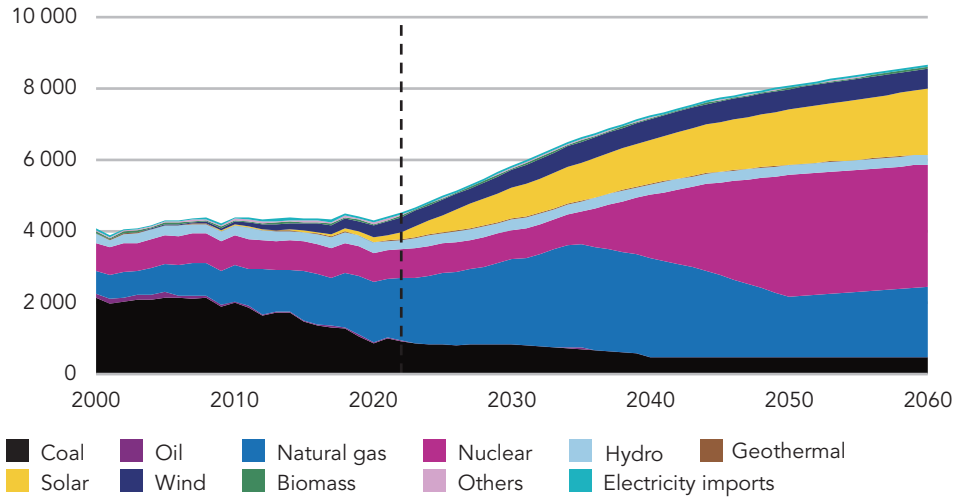
Electricity Generation

Figure 20-18. Electricity generation by fuel in REF (TWh)



- U.S. electricity generation in REF is projected to grow from approximately 4,500 TWh in 2022 to close to 8,000 TWh by 2060. This is driven by increased electrification across all sectors in the United States.
- In REF, the integration of renewable energy is expected to increase, driven by technological advancements and declining costs of renewable energy infrastructure.
- Coal previously dominated electricity generation in the United States, but its share has declined significantly due to the availability of low-cost natural gas, federal and state environmental regulations, and shifting consumer preferences. In this scenario, coal-fired power plants are projected to be phased-out in line with efforts to reduce CO_2 emissions.

Figure 20-19. Electricity generation by fuel in TGT (TWh)



- In TGT, U.S. electricity generation is projected to almost double, increasing from approximately 4,500 TWh in 2022 to nearly 8,700 TWh by 2060.
- In TGT, the composition of U.S. electricity generation shifts to include a greater share of nuclear in line with the current U.S. administration's goal of achieving 400 GW of nuclear capacity by 2050. Expansion of solar and wind are more moderate than in REF with offshore wind not increasing due to the elimination of incentives. Generation from coal is maintained to align with domestic policy.
- Due to a higher proportion of generation met by nuclear power, domestic natural gas demand for power generation is reduced compared to REF. This results in increased volumes of U.S. natural gas available for export.

Note: Figure 20-18 (REF) does not include electricity generation for hydrogen production, which occurs in this scenario.

Generation Capacity

Figure 20-20. Generation capacity by fuel in REF (GW)

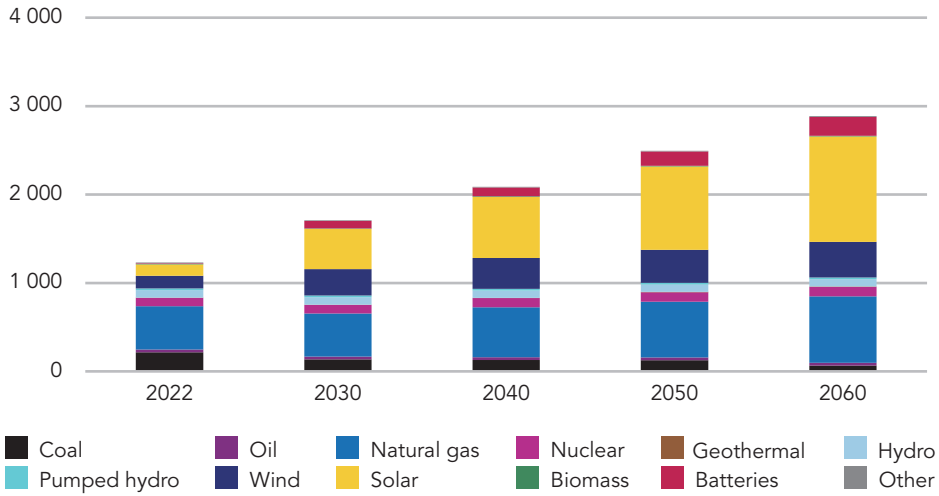
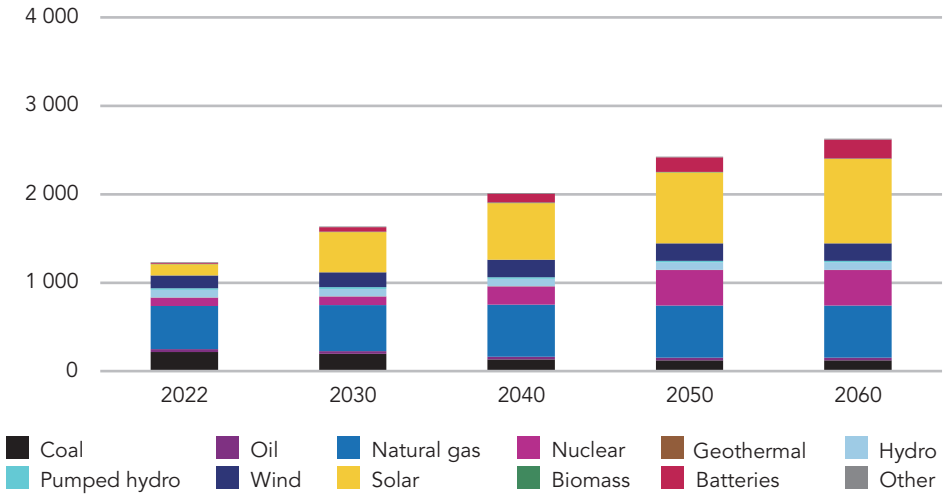


Figure 20-21. Generation capacity by fuel in TGT (GW)



- In REF, U.S. installed generation capacity is projected to more than double from 2022 to 2060, reaching approximately 2,900 GW. Both wind and solar capacity are expected to grow throughout this period as the United States transitions to a greater usage of renewables. Given that the average capacity factor of solar power is low, high solar deployment is required in both scenarios to meet demand. Gas capacity also increases, driven by the need for dispatchable generation and the abundance of U.S. gas supplies.
- All existing gas-fired power plants are expected to continue operations in REF. However, coal-fired power plants start to be decommissioned, with the exception of coal-fired combined heat and power (CHP) facilities, which will continue to operate.

- In TGT, total installed capacity in the United States is projected to double between the base year 2022 and 2060, reaching approximately 2,600 GW. The expansion in dispatchable capacity is driven primarily by an increase in nuclear capacity, which reaches 400 GW by 2050, reflecting U.S. executive directives supporting a nuclear renaissance.
- Key initiatives to achieve this growth include collaboration with industry to facilitate approximately 5 GW of power uprates to existing reactors; leveraging loan programs to support reactor restarts and complete partially constructed projects; strengthening domestic supply chains; and advancing the construction of ten new large reactors with fully approved designs by 2030.

Grid Reliability

Figure 20-22. Total generation capacity and peak load (GW)

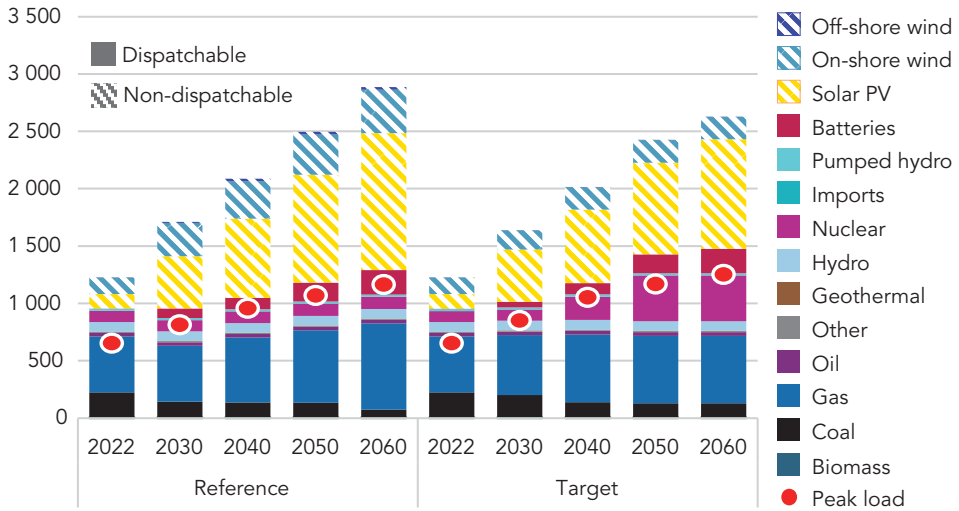
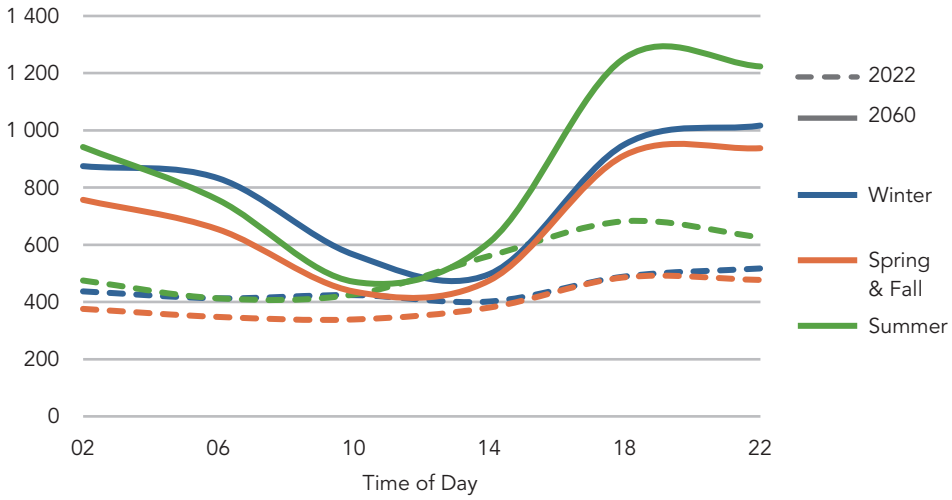


Figure 20-23. Power from dispatchable sources in TGT (GW)



- In REF, the peak electricity load grows by 78% from 653 GW in 2022 to 1,165 GW in 2060. In TGT, peak load grows by 92% to 1,254 GW by 2060.
- Due to the intermittency of solar and wind generation, which results in relatively lower load factors, total system generation capacity must grow at a higher rate than peak load.
- In REF, total generation capacity grows by 134% from 1,232 GW in 2022 to 2,887 GW by 2060. In TGT, it grows by 113% to 2,628 GW by 2060.
- Grid reliability requires that power systems have enough dispatchable generation capacity, including batteries, to meet peak load in those periods when wind and solar generation are at their lowest levels.
- Generally, as wind and solar capacity increases, the load factor for dispatchable sources declines, which increases total system cost.
- APERC's Power Model uses 36 time slices calculated as 3 seasons × 2 day types × 6 four-hour daily segments to represent temporal variations throughout the year. The three seasons are Winter (Dec–Feb), Summer (Jun–Aug), and Intermediate (other months), with two-day types: weekdays and holidays.
- In the United States, the variability of dispatchable power increases the most during the summer season. As shown in Figure 20-23, by 2060, the generation from dispatchable sources must increase from approximately 470 GW in the mid-morning to over 1,250 GW in the evening on an average summer day.
- Increased reliance on wind and solar generation will heighten the variability of the generation required from dispatchable power sources. However, the actual variability experienced will differ from the total variability, as it will be distributed across the entire power system in the economy. In most cases, this variability will be smaller, although it may be greater on days when renewable resource fluctuations exceed typical seasonal patterns.
- This variability will present a challenge for system operators across the economy and meeting this challenge will increase the capital, maintenance, and operating costs of the electric grids in the United States.

Coal

Figure 20-24. Coal consumption by sector in REF & TGT (PJ)

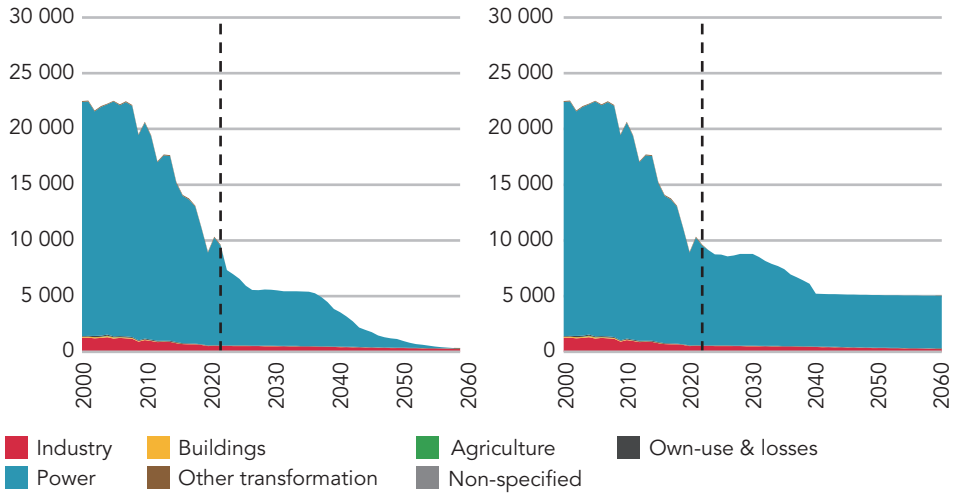
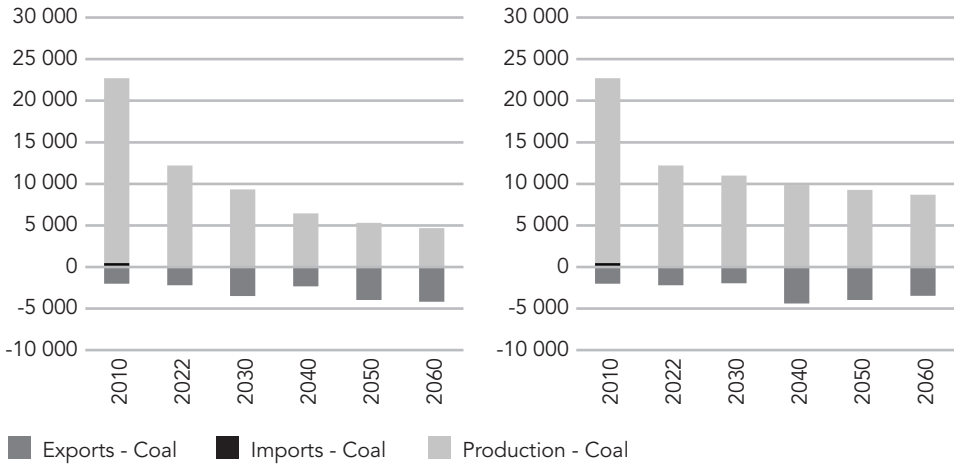


Figure 20-25. Coal production, imports, and exports in REF & TGT (PJ)



- The U.S. power sector has historically been the primary consumer of coal, accounting for approximately 80% of domestic coal use at the turn of the century. Since then, coal's share of the electricity generation mix has declined sharply, driven by an increased reliance on natural gas, decarbonisation policies, declining costs of renewable energy technologies, and other domestic policies. Technological advancements in hydraulic fracturing have further reduced natural gas costs, accelerating coal's displacement. In REF, coal consumption in the power sector declines to near zero by 2060, but is sustained in TGT to reflect domestic policies.
- Coal is utilised domestically in the industrial sector for industrial coke plants and industrial combined heat and power, as well as for other industrial uses. Coal usage is prominent in steelmaking and concrete-making, which require high heat levels.
- While domestic consumption has fallen overtime, the United States has experienced fluctuations in coal exports. Some coal producers have turned to international markets, particularly Asia, although global demand may decline in the future.
- In REF, thermal coal production declines due to the absence of new coal-fired power plants and decarbonisation policies, and continues to fall through 2060 as more mines close and usage is limited to facilities with CCS. Metallurgical coal production remains stable until the late 2030s, then gradually declines. Coal exports continue through 2060 with thermal coal exports rising after 2038 as domestic consumption drops, and metallurgical coal exports increasing slightly until 2038 before gradually declining.
- In TGT, thermal coal production declines more slowly than in REF due to domestic policy plans to expand and reinvigorate America's coal industry. Coal exports are expected to rise until 2040 and then remain at a high plateau thereafter. Metallurgical coal production and exports align with REF over the projection period.

Note: Figure 20-24 excludes coal for transformation into coal products.

Natural Gas

Figure 20-26. Natural gas consumption by sector in REF & TGT (PJ)

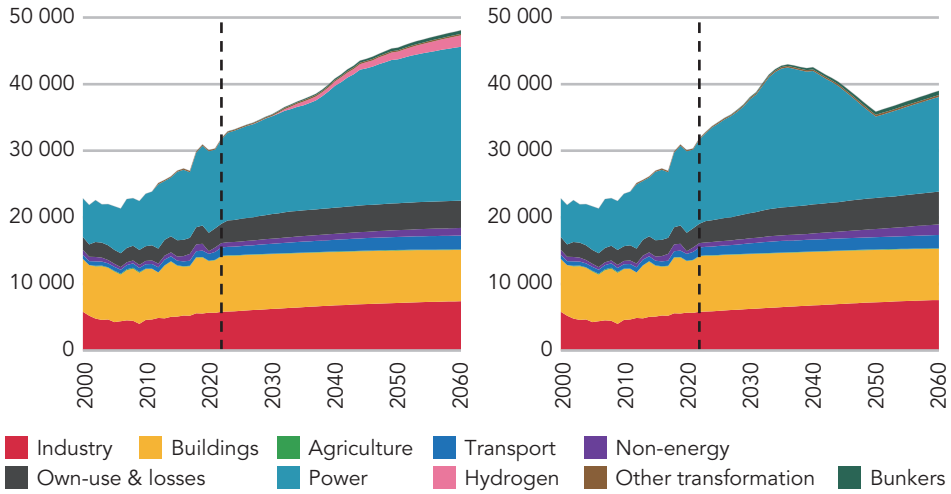
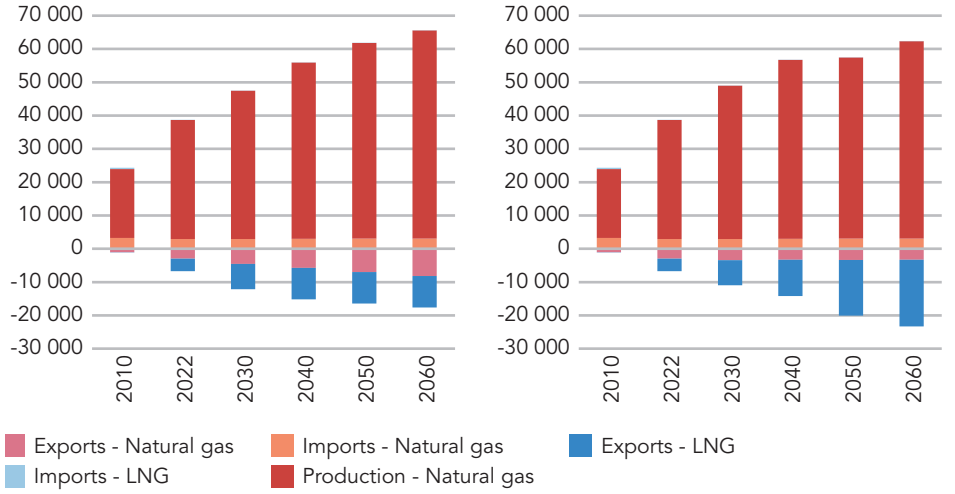


Figure 20-27. Natural gas production, imports, and exports in REF & TGT (PJ)



- Natural gas is primarily consumed in the U.S. power sector, followed by the buildings and industrial sectors. In the buildings sector, natural gas is used for heating, cooking, and water heating. Industry is the third largest consumer of gas, utilising it for process heat and as a feedstock for chemicals, fertilisers, and plastics.
- The United States is a net-exporter of gas and currently the world's largest exporter of LNG. The United States has eight LNG export facilities in service with a total nameplate capacity of approximately 118 Mtpa. Once all under construction facilities reach operation status, this amount is set to rise to 213 Mtpa (~10,200 PJ). The United States exports approximately half of its LNG to Europe, one-third to Asia, and the rest to other regions.

- In REF, U.S. natural gas production is projected to increase steadily, driven by domestic demand and the continued expansion of LNG exports. LNG exports are expected to continue rising through the early 2030s as additional liquefaction projects commence operation. Pipeline natural gas exports to Mexico also remain an outlet for U.S. gas production, with Mexico projected to become increasingly dependent on U.S. imports to meet its growing natural gas demand.
- In TGT, U.S. natural gas production is projected to increase and then stabilise from around 2035 to 2050, followed by another period of growth thereafter. While domestic demand declines due to nuclear displacing gas in the power sector, the share of gas available for export increases. Natural gas exports growth is expected to be driven by LNG exports, which more than offset the projected decline in natural gas pipeline exports to Mexico. In TGT, U.S. gas exports to Mexico decline as Mexico meets incremental end-use demand with electrification and relies increasingly on renewables for power generation.

Note: Historical data for LNG is based on JODI gas data.

Petroleum Liquids

Figure 20-28. Crude oil, NGLs, and other hydrocarbon production, imports, and exports in REF & TGT (PJ)

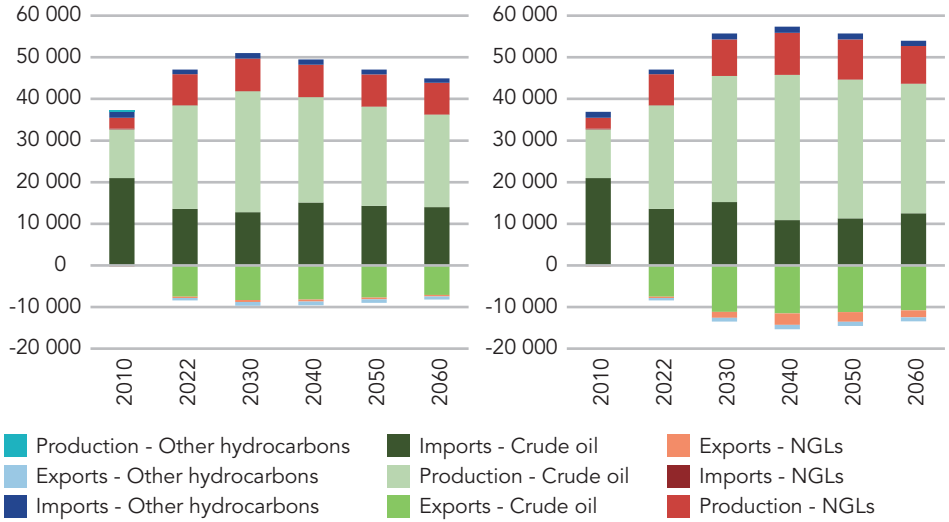
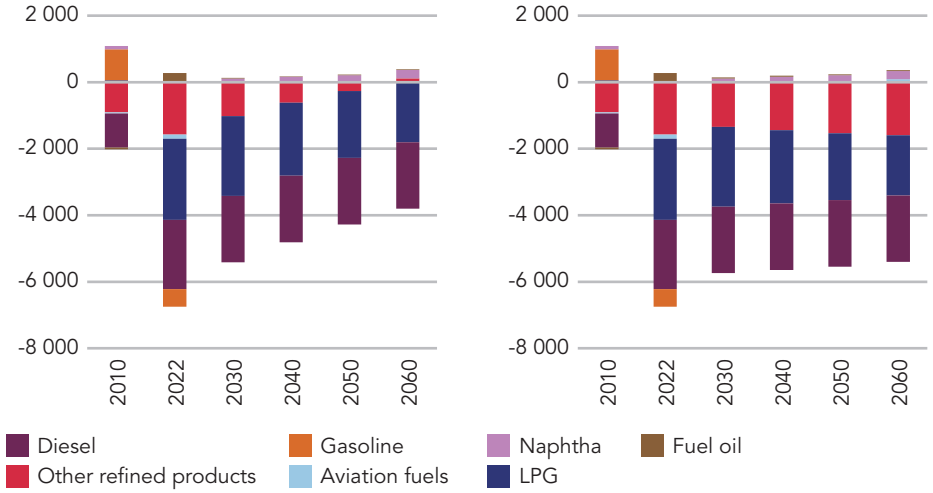


Figure 20-29. Net imports of refined products in REF & TGT (PJ)



- The United States is the world's largest crude oil producer, primarily extracting light crude oil, which is well suited to produce gasoline. However, many U.S. refineries, especially those along the Gulf Coast, are optimised to process heavier crude oils, which are less expensive than light oils and more suitable for producing diesel, jet fuel, and petrochemicals. As a result, the United States exports light crude oil and imports heavy crude oil.
- In REF, U.S. oil production increases in the short term (until ~2030) as current investments in shale and other domestic resources bear fruit. However, in the long term, production gradually declines due to the depletion of reserves. In addition, the ratio of NGLs to crude oil will gradually increase to 40%. Exports remain relatively flat through 2040 and decline slightly thereafter. To note, NGLs in the United States largely come from the production and processing of natural gas.
- In TGT, production is expected to peak later than REF—around 2038—due to greater demand from the transport sector. Oil imports (crude oil, NGLs, and other hydrocarbons) are expected to be maintained at historic levels, assuming no development of new refineries. Export levels are expected to increase from the current level of approximately 4 million barrels per day to over 6 million barrels per day as policy changes allow for more federal area to be available for oil exploration. Similar to REF, the ratio of NGLs to crude oil increases.
- Since the shale revolution, the United States has been exporting substantial quantities of diesel and other petroleum products (such as heavy distillates). The United States is the leading exporter of diesel in APEC, with Europe being a key customer. In both scenarios, diesel exports are expected to be maintained at 2,000 PJ and other petroleum products at 1,000 PJ, following a historical average over the past five years.
- The competitiveness of U.S. refining sector, driven by its high efficiency and the low cost of energy and crude oil input from U.S. shale gas and shale oil, enables the sector to remain a major exporter of petroleum products to economies with smaller, less profitable refineries. These economies are projected to continue to require petroleum products over the long term.

Note: In Figure 20-29, net imports are presented without deducting bunkers.

Refining

Figure 20-30. Refining outputs in REF & TGT (PJ)

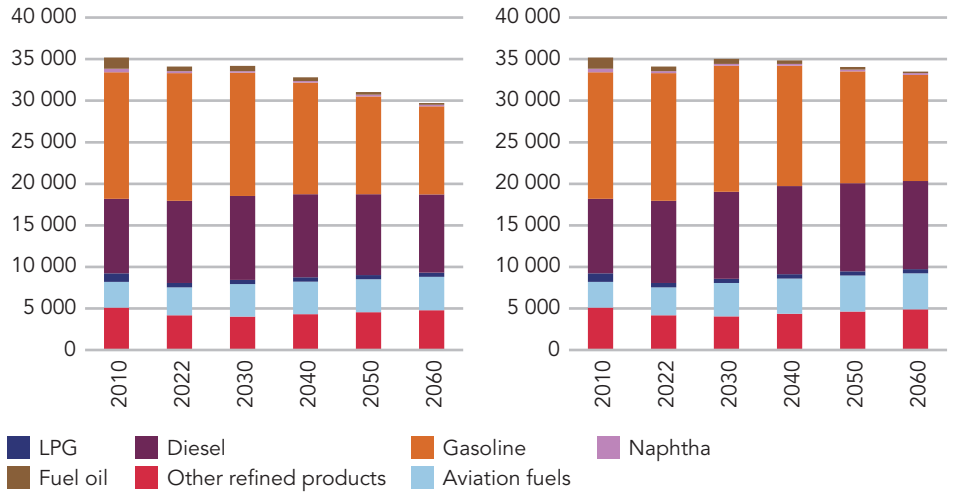
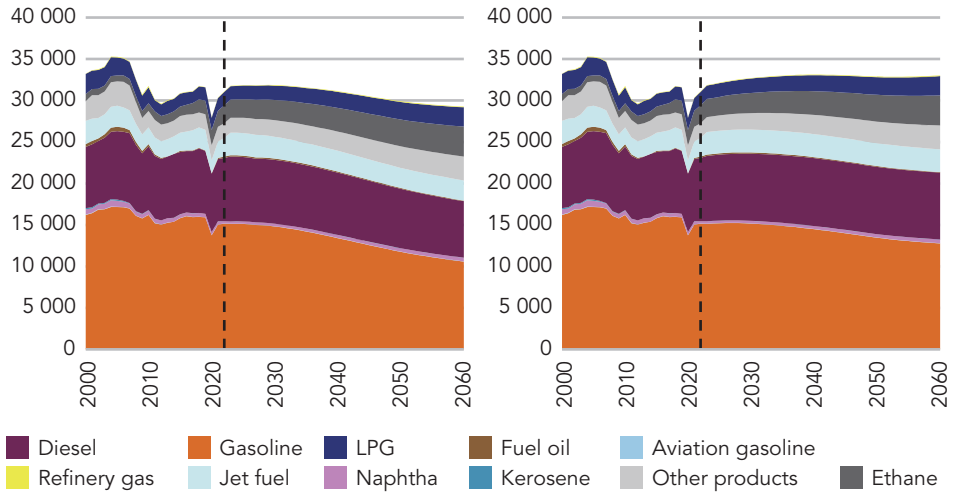


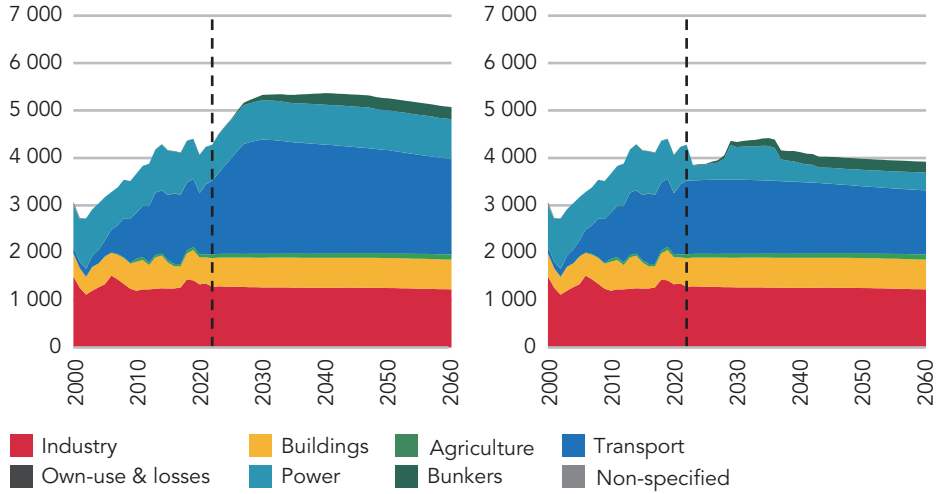
Figure 20-31. Refined products demand in REF & TGT (PJ)



- The U.S. petroleum refining sector is comprised of 132 refineries with an operable atmospheric distillation capacity of 18.4 mb/d, as of January 2025.
- By 2060, U.S. refining capacity declines by 15% in REF and slightly by 4% in TGT. In REF, total distillation capacity is projected to decline slightly from 18.1 mb/d in 2022 to 15.3 mb/d in 2060 and remain constant thereafter as consumption of refined products declines marginally. In TGT, the capacity declines slightly to 17.3 mb/d due to higher consumption mainly in the transport sector
- In both REF and TGT, the United States is expected to maintain exports of diesel and other products based on the international competitiveness of the U.S. industry.
- In both scenarios, gasoline and jet fuels consumption is roughly equal to refinery production and net exports of diesel are maintained at historic levels. The growing consumption of LPG and ethane, presumably as non-energy feedstocks for petrochemicals, is met partly by refineries and partly by natural gas processing plants. Domestic jet fuel demand and supply is roughly balanced in the medium and long term, with some marginal exports in the near term.
- Consumption of refined products in buildings, agriculture, and industry gradually declines in both REF and TGT due to improved efficiency and fuel switching (for instance, to electricity). On the other hand, the non-energy sector's consumption of refined products, such as liquid petroleum gases (LPG), continues to grow in both scenarios driven by increased global demand and U.S. oil and gas competitiveness. In TGT, refined product demand in the transportation sector continues due to the delayed adoption of electric vehicles.

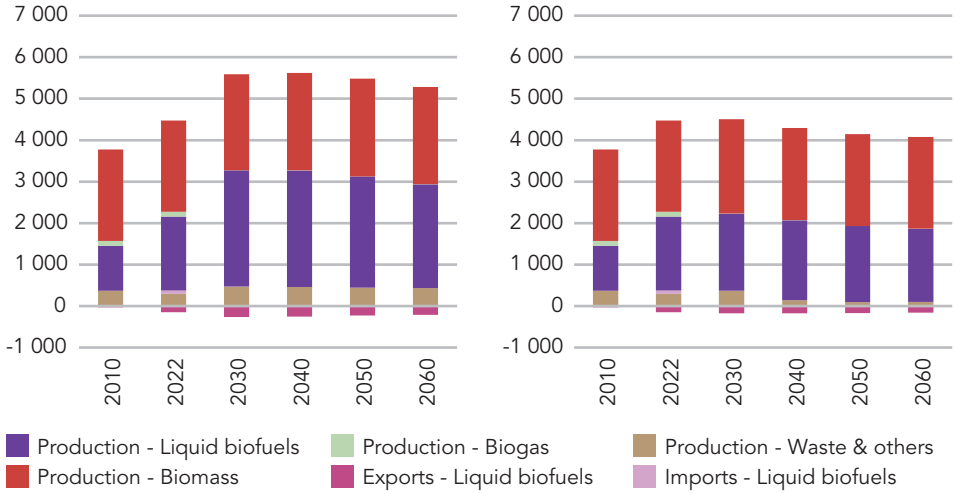
Bioenergy and Waste

Figure 20-32. Bioenergy and waste demand by sector in REF & TGT (PJ)



- The United States is a major producer of biofuels, particularly ethanol—a form of biogasoline derived primarily from corn. Aside from fuel ethanol, the United States also produces biodiesel, renewable diesel, and other types of biofuels, though in smaller quantities.
- Bioenergy and waste are mainly utilised by demand sectors (85% in the base year), with smaller quantities going towards power and bunkers. The transport sector is the largest consumer as most gasoline in the United States is blended with a portion of ethanol. Additionally, the agricultural sector uses biodiesel in machinery, and the industrial sector (mainly manufacturing) uses solid biomass for process-heating and other energy uses.

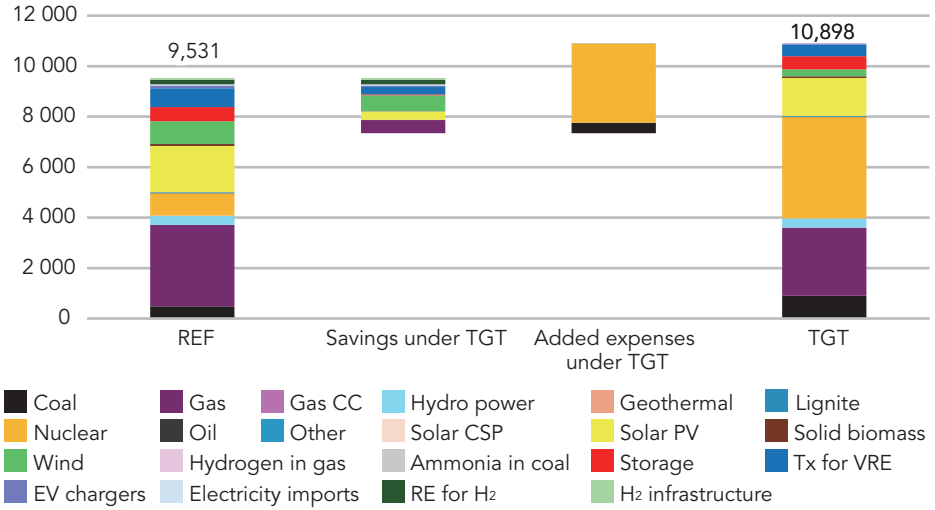
Figure 20-33. Bioenergy and waste production, imports, and exports in REF & TGT (PJ)



- In TGT, bioenergy bunker demand growth is more limited as conventional aviation fuels, diesel and LNG are still preferred over biodiesel and biojet kerosene within the United States' marine and aviation industries.
- In both scenarios, bioenergy bunker demand increases later in the projection period (2030 onwards) as the maritime shipping industry transitions to low-emission alternatives in response to stricter global climate regulations and decarbonisation targets. Bioenergy comprises 8% of total bunker demand in REF and in 7% in TGT by 2060.
- The United States exports a portion of its bioenergy supply, mainly to Canada, in the forms of ethanol and biodiesel.

Costs

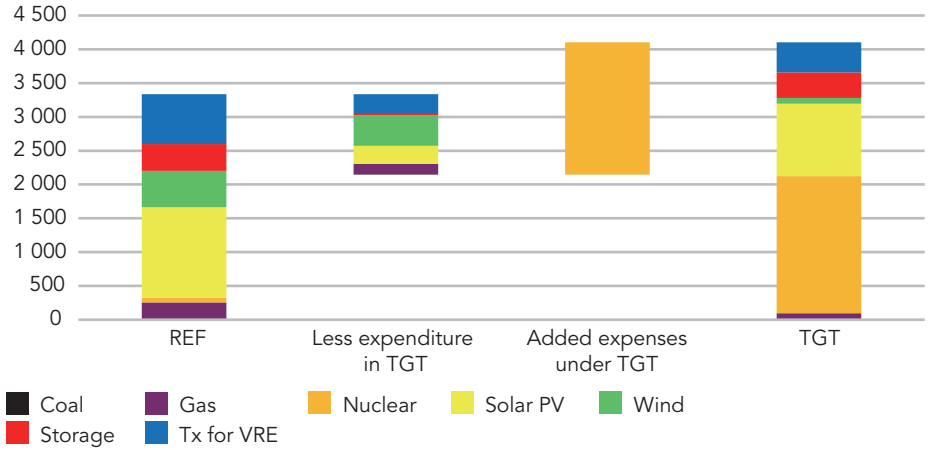
Figure 20-34. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



Note: Tx for VRE is only transmission infrastructure to connect variable renewable capacity to the grid. EV chargers do not cover the cost of associated infrastructure or EV vehicles. SMR is Steam Methane Reforming used to produce blue hydrogen. Hydrogen costs do not cover costs for bunkering.

- In REF, estimated total costs reach USD 9.5 trillion, which rises to 10.8 trillion in TGT. To note, in these cost projections, the total capital, fixed, and variable costs in the power sector are considered, as well as costs for hydrogen production for domestic use, transmission for variable renewable electricity, electricity imports, heat produced from combined heating plants, and electric vehicle chargers.
- Expenses associated with nuclear are the key driver of increased costs in TGT in line with the rapid expansion of nuclear in this scenario. These expenses include both the CAPEX and OPEX necessary to build and operate 400 GW of nuclear capacity by 2050. Notably, approximately two-thirds of the total nuclear-related costs are attributed to CAPEX. Coal's continued operation in TGT results in additional costs, mostly in the form of fuel costs.

Figure 20-35. Total capital investment (CAPEX) from 2025 to 2060 in the power sector (billion USD, undiscounted)

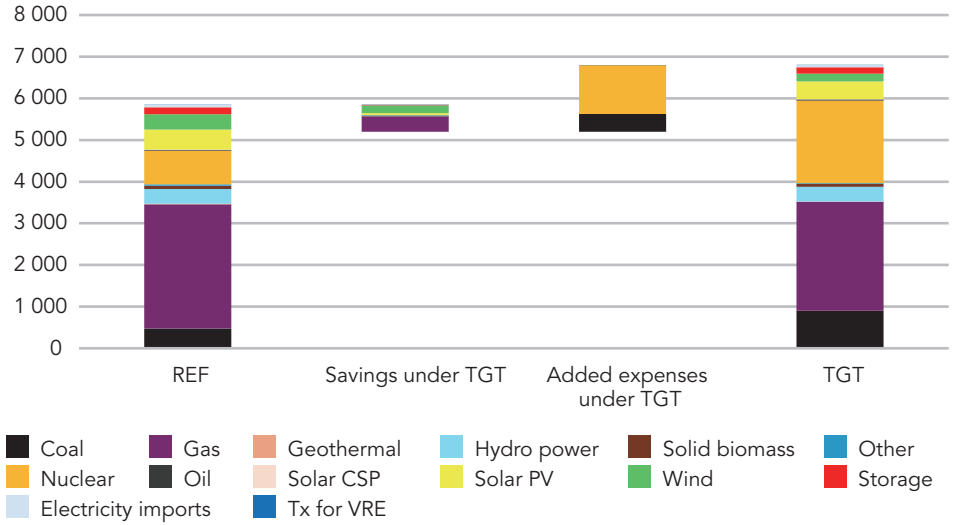


Note: Figure 20-35 only covers power and VRE transmission sector investments. Hydrogen and EV costs are not covered.

- There is less spending on VRE in TGT, which results in reduced spending on associated transmission infrastructure. While this is shown as "Savings under TGT", it is outweighed by higher spending on nuclear.
- To ensure evening peak demand is met in TGT, storage still plays a role in the energy mix in TGT resulting in small costs differences between the two scenarios.
- Total CAPEX for the U.S. power sector exceeds USD 4 trillion in TGT, up from USD 3.3 trillion in REF.
- The major additional CAPEX in TGT, relative to REF, is from nuclear, with reduced CAPEX on VRE and its associated storage and transmission infrastructure. Nuclear CAPEX is prominent, reflecting the goal of quadrupling nuclear capacity to 400 GW by 2050. Capital costs for nuclear are relatively high due to complex designs and safety systems, long construction periods, regulatory and safety requirements.

Costs

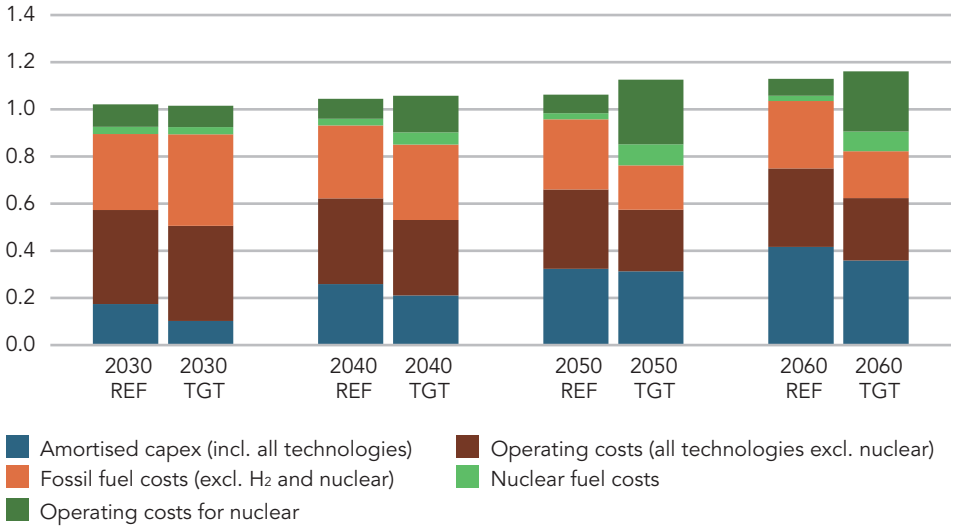
Figure 20-36. Total operating costs from 2025 to 2060 in the power sector (billion USD, undiscounted)



Note: Figure 20-36 only covers power and VRE transmission sector costs. It does not include operating costs associated with hydrogen production and EV charger costs

- Total operating costs for the U.S. power sector are projected to be an estimated USD 6.8 trillion in TGT, compared to an estimated USD 5.8 trillion in REF. These costs incorporate variable fuel expenditures for power, fixed costs for the power sector, and transmission infrastructure to 2060. Heat production costs from CHPs are also considered.
- In REF, the primary contributor to operating costs is fuel expenditure for gas-fired power generation. In TGT, these gas-related costs are slightly reduced due to a greater share of nuclear generation in the power mix. However, the resulting savings are largely offset by higher nuclear fixed operating costs, which include expenses for highly qualified personnel, regulatory compliance and inspections, security, maintenance decommissioning trusts and costs associated with refuelling. In TGT, there are additional coal expenditures, mostly fuel costs, as coal plants continue to operate throughout the projection period.

Figure 20-37. Cost of generating electricity relative to 2025 (2025 cost = 1.0) in the power sector



Note: Based on our assumptions about future capital and operating costs, Figure 20-37 shows cost compositions over time relative to 2025. It should not be considered an estimate of electricity tariffs and excludes market mechanisms that are too difficult to estimate.

- The costs of electricity generation (not the price of electricity for consumers) gradually increases in TGT as rising nuclear operating and amortised capital costs grow with additional nuclear deployment, reaching nearly 20% above 2025 levels. However, by the end of the projection period, electricity generation costs are only marginally higher than in the REF case, as this scenario does not involve large-scale renewable investment.

CO_2 Emissions

Figure 20-38. CO_2 emissions in REF (million tonnes)

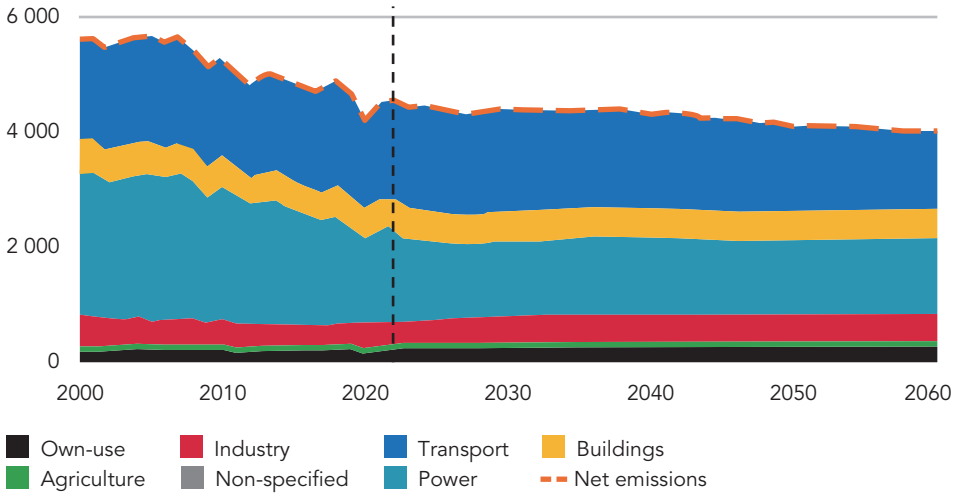
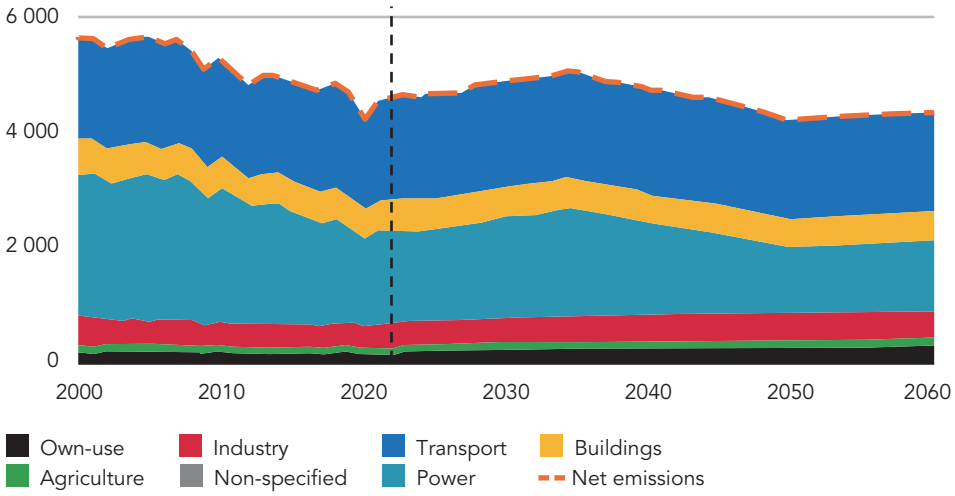
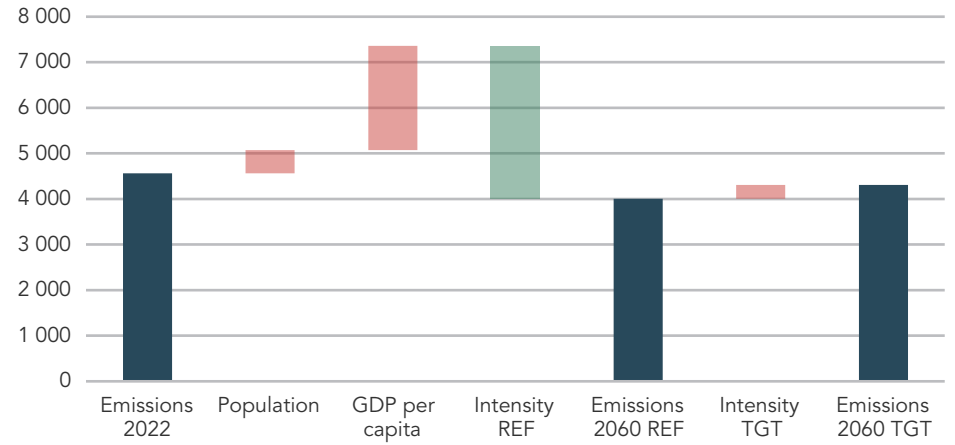


Figure 20-39. CO_2 emissions in TGT (million tonnes)



- In REF, net CO_2 emissions are projected to decrease only 12%, from 4560 million tonnes in 2022 to 4000 million tonnes in 2060. The power and transportation sectors are the main contributors to CO_2 emissions, and oil and gas are the primary fuel sources of these CO_2 emissions.
- In TGT, emissions in 2060 are projected to experience even less of a decline (5.5%) to 4300 million tonnes. This is due in part to extended utilisation of internal combustion engine (ICE) vehicles in the transport sector and extended coal usage in the power sector in this scenario.
- As shown in Figure 20-40, in REF, despite economic and population growth, improvements in energy and carbon intensity reduces emissions. TGT shows less improvement in carbon intensity than REF.

Figure 20-40. CO_2 emissions components (million tonnes)



Note: All values represent energy sector combustion CO_2 emissions. Biogenic CO_2 is treated as zero at the point of combustion.

Useful Links

APEC Expert Group on Energy Data and Analysis (EGEDA) – https://www.egeda.ewg.apec.org/

APEC Energy Statistics 2022 – https://www.egeda.ewg.apec.org/egeda/general/info/pdf/APEC_Energy_Statistics_2022.pdf

APEC Energy Overview – https://aperc.or.jp/reports/energy_overview.php

Energy Institute Statistical Review of World Energy – https://www.energyinst.org/statistical-review

The White House Statements and Releases – https://www.whitehouse.gov/briefing-room/statements-releases/

U.S. Census Bureau – https://www.census.gov/

U.S. Department of Energy – https://www.energy.gov/

U.S. Energy Information Administration – https://www.eia.gov/

World Bank Open Data – https://data.worldbank.org/



21. Viet Nam

Summary

	Reference			Target		
	2022	2060	% Change	2022	2060	% Change
Macroeconomic						
Population (million)	97.8	106.2	9%	97.8	106.2	9%
GDP (billion 2017 USD, PPP)	1,105	6,208	462%	1,105	6,208	462%
Energy Demand						
Agriculture & fisheries (PJ)	151	256	70%	151	169	12%
Buildings (PJ)	543	1,486	174%	543	1,305	140%
Industry (PJ)	1,542	4,267	177%	1,542	3,835	149%
Non-energy (PJ)	141	463	229%	141	422	200%
Transport (PJ)	627	1,150	84%	627	826	32%
Modern renewables share of TFEC (%)	23	42	83%	23	81	252%
Energy intensity of TFEC (PJ/GDP, billion USD)	2.59	1.15	-56%	2.59	0.99	-62%
Electricity						
Generation (TWh)	268	967	261%	268	1,042	289%
Renewables share of generation (%)	50	83	66%	50	100	100%
Generation capacity (GW)	79	556	603%	79	653	726%
Total Primary Energy Supply (TPES)						
Coal & coal products (PJ)	1,808	1,979	9%	1,808	361	-80%
Natural gas (PJ)	287	1,840	540%	287	471	64%
Petroleum liquids (PJ)	1,162	2,138	84%	1,162	706	-39%
Low-carbon & waste energy (PJ)	873	3,441	294%	873	7,214	726%
CO_2 intensity of energy supply ($MtCO_2/PJ$)	0.061	0.042	-31%	0.061	0.009	-86%
Net CO_2 Emissions (million tonnes)	253	402	58%	253	71	-72%

Note: In this publication, the term "modern renewables" refers to all renewable energy sources excluding solid biomass in the buildings sector. The term "low-carbon & waste energy" includes all bioenergy, waste-derived energy, renewables, nuclear, and hydrogen-based fuels. Total primary energy supply (TPES) numbers include international bunkers. Net emissions are calculated as gross energy sector combustion CO_2 minus CO_2 captured and stored through carbon capture and storage (CCS).

Key Takeaways

Emissions

- Viet Nam's CO_2 emissions are projected to continue rising and peak in the mid-2040s in the Reference scenario (REF); however, in the Target scenario (TGT), this peak is expected to occur ten years earlier due to the likely adoption of more aspirational energy policies and measures.
- In REF, CO_2 emissions are projected to peak at 446 Mt by 2044 before declining steadily through the end of the projection period. By 2060, emissions will still remain at around 400 Mt. Despite planned reductions in the coal-power sector, coal will continue to be extensively used in industrial applications due to challenges in substituting it with alternative fuels.
- In TGT, CO_2 emissions are expected to drop 72% over the 2022-2060 period. With a clear commitment to achieve net zero by 2050, Viet Nam's government has issued backbone policies such as the Power Development Plan (PDP8) and the National Energy Master Plan, which aim to boost renewable energy deployment and phase out coal in the power sector.

Energy Import Dependence

- Viet Nam has been a net energy importer since 2015, with import dependency projected to increase in the coming decades. The economy currently imports coal, crude oil, petroleum products, and LNG, making energy security a top priority for the Vietnamese Government.
- In the REF scenario, net import dependency is forecast to rise significantly from approximately 35% in 2022 to about 51% by 2060, primarily driven by coal and crude & petroleum products imports. This dependency is expected to stabilise at this level throughout the remainder of the projection period.
- The TGT scenario presents a different trajectory, with net import share peaking at around 42% by 2030 before declining substantially to 8.3% by 2060. This reduction in the net import share will largely result from increased renewable energy adoption.

Figure 21-1. Net CO_2 emissions (million tonnes)

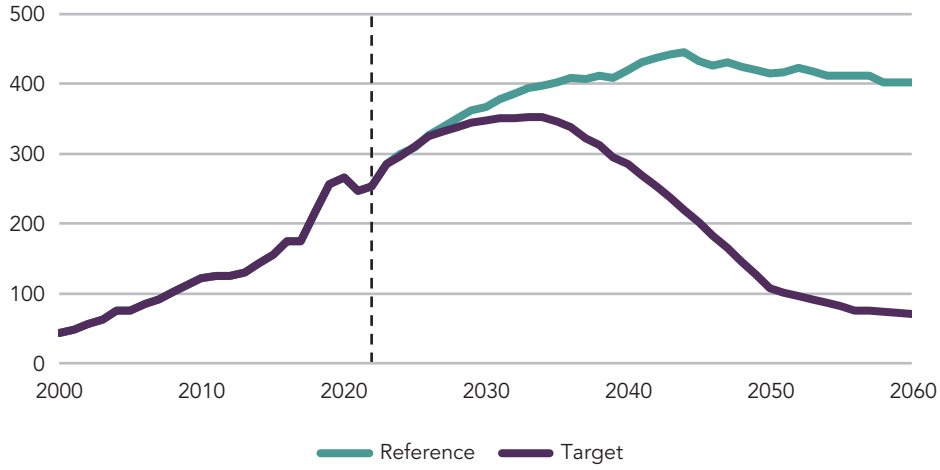
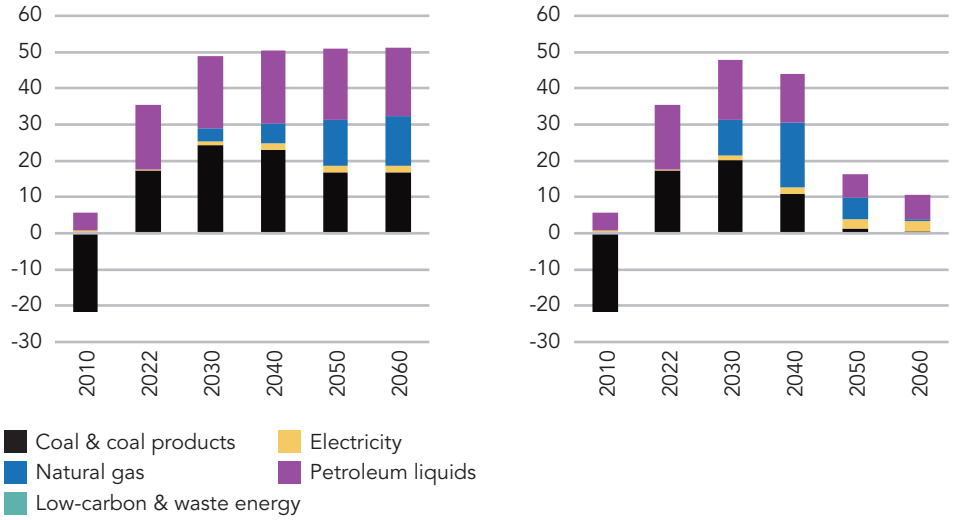


Figure 21-2. Net imports share of TPES in REF & TGT (%)



Note: In Figure 21-2, net imports refer to total imports minus exports and international bunkers.

Key Takeaways

Grid Reliability

- Electric grid reliability requires a near-instantaneous balance between power supply and demand at all times. Maintaining this balance requires adequate dispatchable power sources, which can include batteries.
- Figure 21-3 shows the dispatchable power that is necessary in the periods of maximum and minimum dependence across all power grids. In 2022, the gap between the minimum and maximum was relatively small, allowing dispatchable generators to produce at a fairly consistent rate.
- Viet Nam will require an increased amount of dispatchable power capacity over the coming decades for periods when variable renewable energy (VRE) sources are not producing at their maximum level. In addition, the increasing share of VRE will cause the gap between the minimum and maximum requirements for dispatchable power to increase, which will increase capital, maintenance, and operating costs of the system.

Cost

- There are significant estimated costs for Viet Nam's power and hydrogen sectors through to 2060. In TGT, total costs are an estimated USD 3.6 trillion, USD 1.8 trillion higher than in the REF case. Total costs consider total capital, fixed, and variable costs in the power sector, costs for green hydrogen production, transmission for VRE, electricity imports, and EV chargers.
- The added expenses in TGT are driven primarily by Viet Nam's ambitions to expand its wind, solar, and dispatchable storage. Costs for additional transmission needed to accommodate more VRE capacity further increase costs in TGT relative to REF.
- In line with ambitions to accelerate its green hydrogen sector, green hydrogen production costs are considered. This further drives costs in TGT, as hydrogen production and use in REF is assumed to be minimal.

Figure 21-3. Peak load and maximum and minimum dependence on dispatched power (GW)

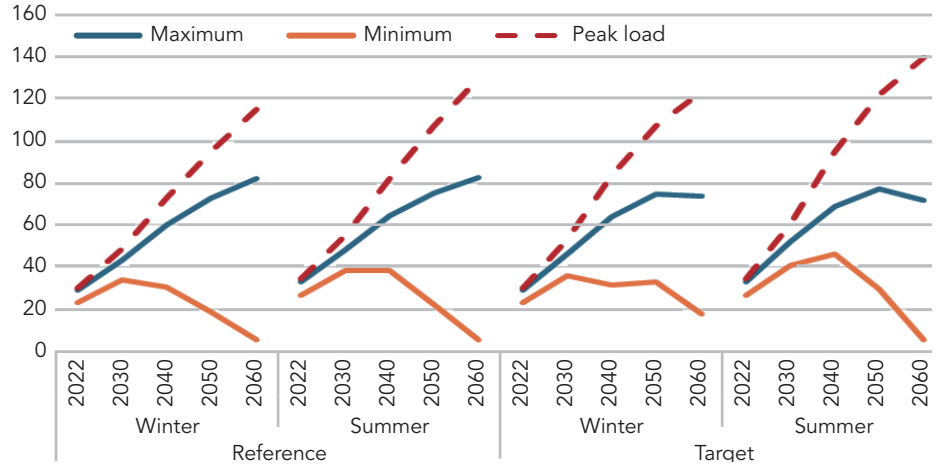
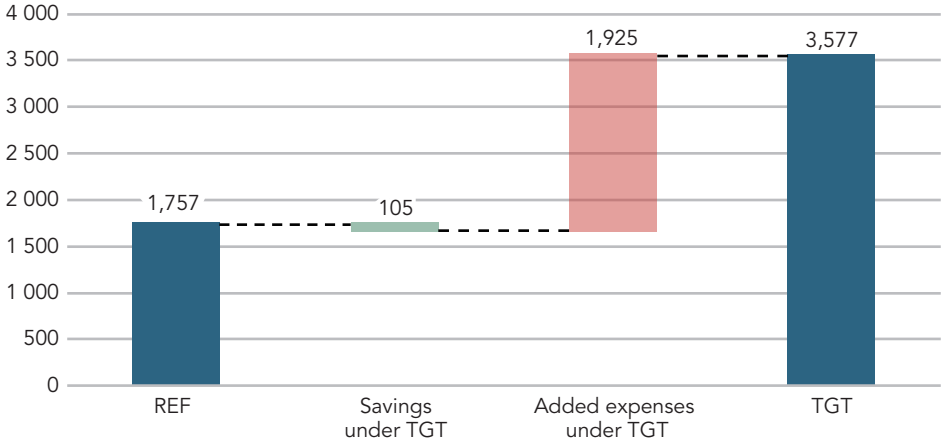


Figure 21-4. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



*Actual costs will differ from estimated costs in the *Outlook* for a variety of reasons including changing commodity prices, manufacturing costs, and unforeseen technical advances. All costs are in 2023 real terms.

About Viet Nam

Overview

Geographical and Economic Landscape

Viet Nam is a geographically long and narrow economy, located in Southeast Asia. It boasts diverse terrain, including mountainous regions in the north and central highlands, fertile deltas in the Red River and Mekong River regions, and a coastline that extends over 3,200 km.

As a rapidly developing economy, Viet Nam has transitioned from agriculture to industrialisation and services.

Energy Supply and Consumption

Energy supply rose an average of 9% per year from 2000 to 2022, reaching 4,139 PJ in 2022. Viet Nam has coal resources in the northern provinces, producing around 50 million tonnes of coal annually. Crude oil and natural gas are mainly extracted offshore in the south.

The total final consumption grew 8.5% annually from 2000 to 2022 due to significant growth in GDP and population. The total final consumption in 2022 was 3,003 PJ, an increase of 8.3% compared to the previous year.

Energy Security Challenges and Strategies

Viet Nam has been a net energy importer since 2015, and its dependence on energy imports is projected to rise significantly over the next decade, potentially reaching 43% of total primary energy supply by 2030.

Currently, Viet Nam imports coal, crude oil, petroleum products, and liquefied natural gas (LNG). Therefore, energy security has become one of the top priorities for the Vietnamese government.

Key Energy Initiatives

Paris Agreement (The second updated NDC in November 2022)

Viet Nam is committed to reducing greenhouse gas emissions by 15.8% below 2005 levels by 2030 with domestic resources and 43.5% with financial support from international organisations.

The Politburo's Resolution No. 70-NQ/TW dated 20 August 2025

The new resolution defines energy security as a core pillar of domestic security that is directly linked to political stability, economic growth, domestic defence and global integration.

The National Energy Master Plan (Decision No. 893/QD-TTg dated 26 July 2023)

To ensure domestic energy security, reduce carbon emissions to meet Viet Nam's net zero target by 2050, and ensure the energy industry is independent and self-sufficient.

National Energy Development Strategy (Decision No. 215/QD-TTg dated 1 March 2024)

To ensure domestic energy security for socio-economic growth, prioritize sustainable energy development, adapt to climate change, meet the net-zero emissions target by 2050, and promote efficient, eco-friendly energy use.

The Power Development Plan (Decision No. 768/QD-TTg dated 15 April 2025

The adjusted Power Development Plan aims to ensure energy security for the government's economic growth target.

National Strategy on Climate Change by 2050 (Decision No. 896/QD-TTg dated 26 July 2022)

Total GHG emissions will reach net zero by 2050, with the peak emission year set at 2035.

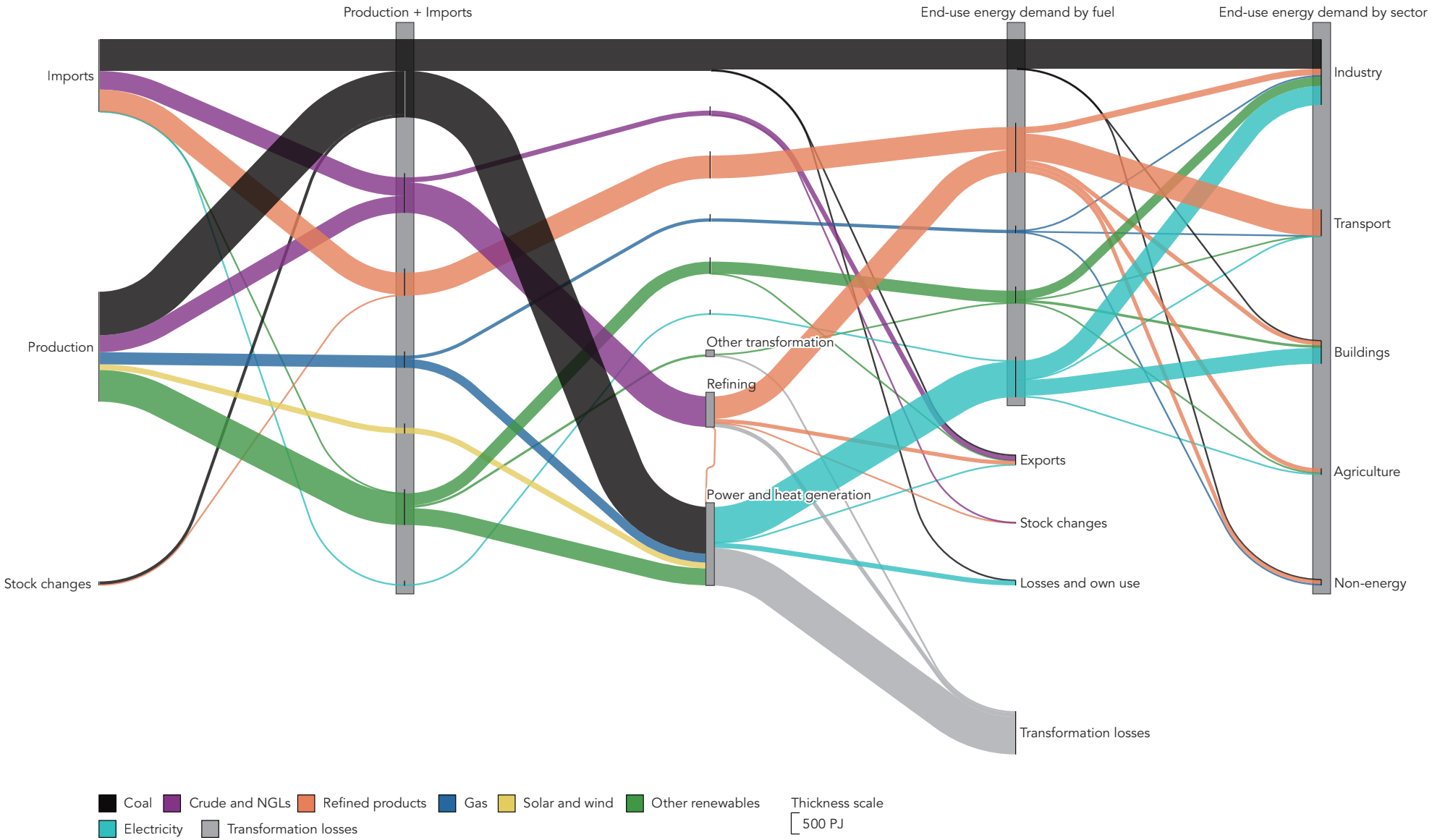
Hydrogen Energy Development Strategy (Decision No. 165/QD-TTg dated 7 February 2024)

The share of hydrogen energy and hydrogen-based fuels is expected to reach about 10% of the final energy consumption demand.

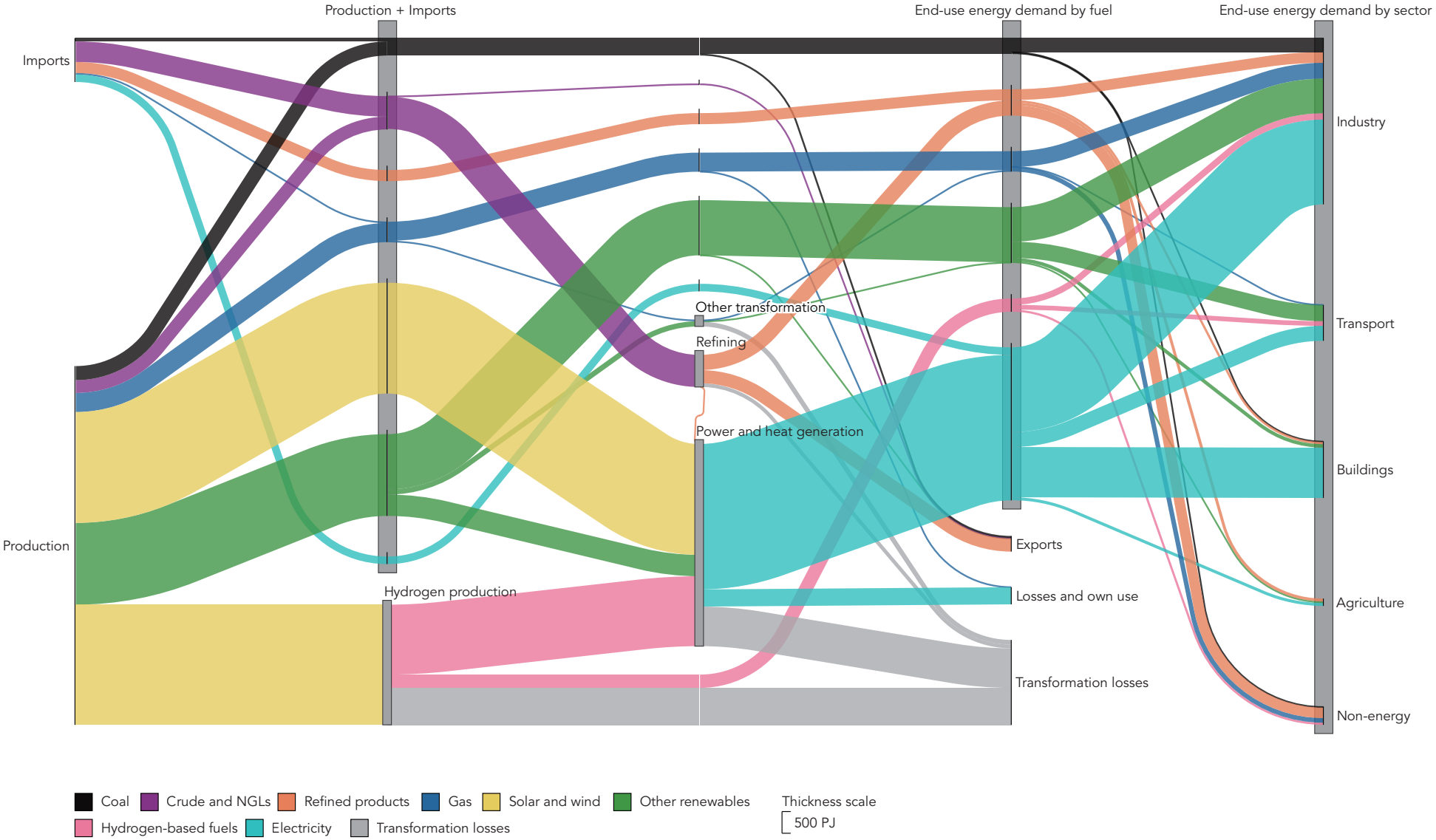
Coal Industry Development Strategy until 2030, with a vision to 2045 (Decision No. 55/QD-TTg dated 17 January 2024)

Coal output is expected to be between 45 and 50 million tonnes by 2030, and between 38 and 40 million tonnes in 2031-2045.

Energy Flow (2022)



Energy Flow (2060, Target Scenario)



Scenarios and Assumptions

In *The Outlook*, APERC analyses energy demand, transformation, and supply, as well as emissions. The **Reference Scenario (REF)** offers a projection based on historical trends, recent developments, and APERC's assumptions about the continuation of those trends in each APEC economy, while acknowledging technical restraints. The REF Scenario offers a baseline to compare with the **Target Scenario (TGT)** projections, which explores a hypothetical pathway where each economy achieves energy-related policy targets, assuming implementation regardless of cost-effectiveness. When implementation details are lacking, assumptions are inferred from the targets themselves or emissions-related goals.

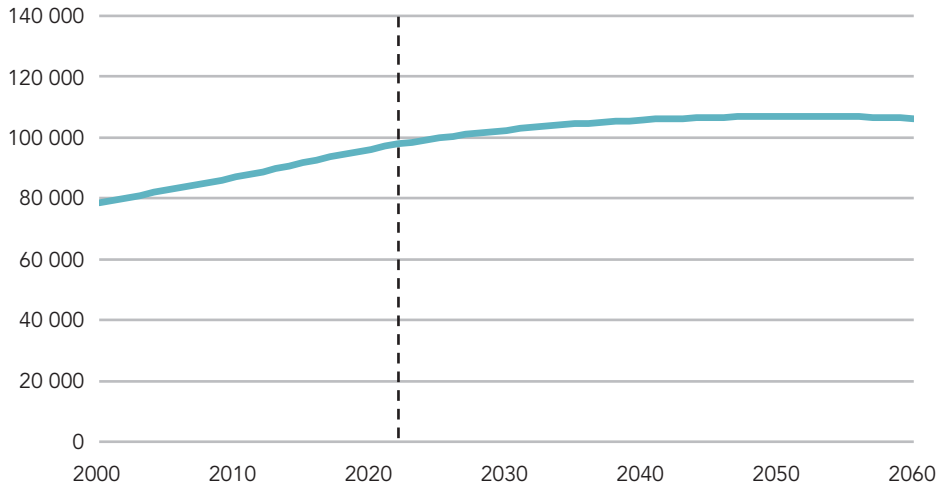
	Reference	Target
General	• Population: Use medium projection from the United Nations Department of Economic and Social Affairs (UN DESA). • GDP projections are from the International Monetary Fund (IMF) to 2027. • Beyond 2027, the APERC macroeconomic model is used.	
Buildings	• Energy-saving measures are guided by the National Energy Efficiency Program during the 2019-2030 period. • Data centre and AI energy use projections are assumed to be the same in both scenarios.	• Additional 20% for energy saving measures by 2050. • More switching from traditional biomass to LPG and electricity.
Industry	• Industrial activity increases significantly, driven by GDP and population growth. • Mining expands due to the global demand for low-carbon technology. • Electrification advances moderately across subsectors. • Gradual energy efficiency improvements.	• Industrial growth is moderated by energy and material efficiency improvements, including increased recycling. • Mining expands further, but growth slows after 2040. CCS and low-emission hydrogen will be adopted from the 2030s in hard-to-abate subsectors. • Stronger electrification of industrial processes across all subsectors. • Biomass plays a role in decarbonising the cement, pulp, and paper sectors.
Transport	• Viet Nam reaches an average ~33% sales share for BEVs in passenger vehicles and light commercial vehicles (LCVs) by 2035 and ~66% by 2060. • BEV sales share for heavy trucks is 20%, and FCEV is 7% by 2060. • Biodiesel, biojet, and biogasoline (or ethanol) mixing increases to 5% of the original fuel by 2040 and remains constant after.	• Viet Nam reaches an average ~60% sales share for BEVs in passenger vehicles and LCVs by 2035 and ~100% by 2060. • BEV sales share for heavy trucks is 60%, and FCEV is 20% by 2060. • Biodiesel mixing slowly grows to 5% in 2030 and then rapidly grows to replace 100% of the original fuel use by 2050. • Electric ships and rail grow to replace most diesel ships/rail and fuel oil ships by 2050. Remaining fuel oil ships have 100% of their fuel oil use replaced with e-fuels by 2050.
Power	• No new coal-fired power plants after 2030. • The PDP8 and the implementation plan for PDP8 are used as guidelines through 2030. • Coal and gas-fired units are used as baseload generation.	• No new coal-fired power plants after 2030. • More adoption of solar and wind projects than in REF. • The PDP8 is used as a guideline through 2050. • Use ammonia and hydrogen in thermal power plants.

	Reference	Target
Supply	• Crude oil production is to reach 6 to 9.5 Mtpa by 2030, and 7 to 9 Mtpa from 2031 to 2050. • Natural gas production is expected to reach 5.5 to 15 bcm/year by 2030. From 2031 to 2050 that number is expected to reach 10 to 15 bcm/year. • Coal production is to reach about 41 to 47 Mtpa by 2030, decrease to about 39 Mtpa by 2045, and about 33 Mtpa by 2050.	• Fossil fuels production is expected to be lower than in REF.
Emissions	• Reduce greenhouse gas (GHG) emissions by 15.8% below 2005 levels by 2030 with domestic resources and by 43.5%, with the financial support from international organisations.	• Net-zero emissions by 2050.

Note: The base year is 2022. Macro-economic assumptions are constant across scenarios. Historical energy balances are from EGEDA submissions for 2022.

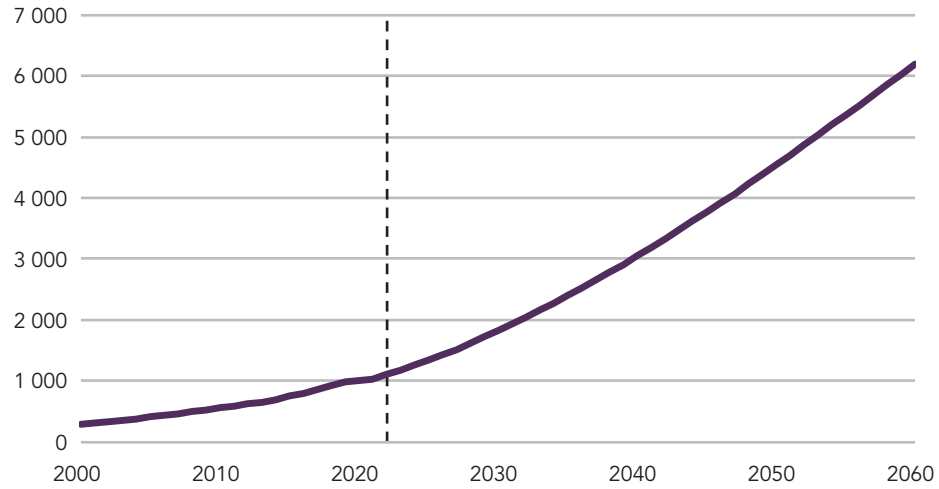
Demographic and Macroeconomic Assumptions

Figure 21-5. Population projections (thousands)



- Population projections provide critical information for planning and budgeting within Viet Nam's socioeconomic development strategy.
- In 2022, Viet Nam's population reached approximately 98 million people with an urban population share of 38.1%. According to the United Nations Population Fund in Viet Nam, urban residents are projected to constitute 50% of the total population by 2030.
- The APERC model incorporates the UN DESA medium projection scenario, indicating that Viet Nam's population will peak at approximately 107 million by 2050 before experiencing a gradual decline throughout the remainder of the projection period.

Figure 21-6. Real GDP (billions 2017 USD, PPP)



- GDP projections through 2027 are derived from IMF data. Beyond 2027, the APERC Solow-Swan macroeconomic model employs population as a labor input proxy while incorporating assumptions regarding labor productivity, depreciation, and savings rates—all converging toward a steady state aligned with global economic development patterns.
- With projected population and economic growth, Viet Nam's real GDP is expected to reach USD 6.2 trillion by 2060 on a purchasing power parity (PPP) basis (2017 USD). GDP per capita will correspondingly increase to USD 58,000 (2017 USD PPP) by 2060.
- Annual GDP growth rates are projected at 6.5% during 2021-2030 and 4.6% for 2031-2050, falling below the Vietnamese government's more optimistic projections (7% for 2021-2030 and 6.5%-7.5% for 2031-2050) for the economy.

End-use Energy Demand

Figure 21-7. Energy demand by sector in REF & TGT (PJ)

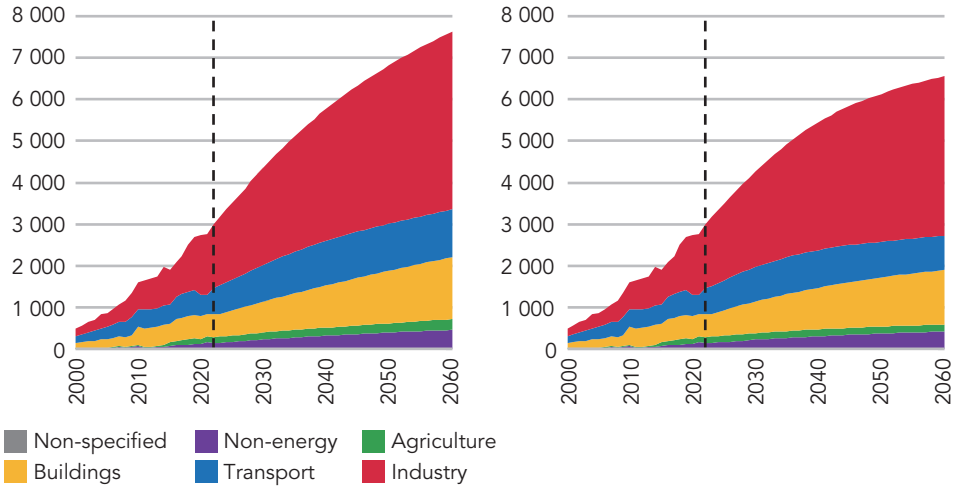
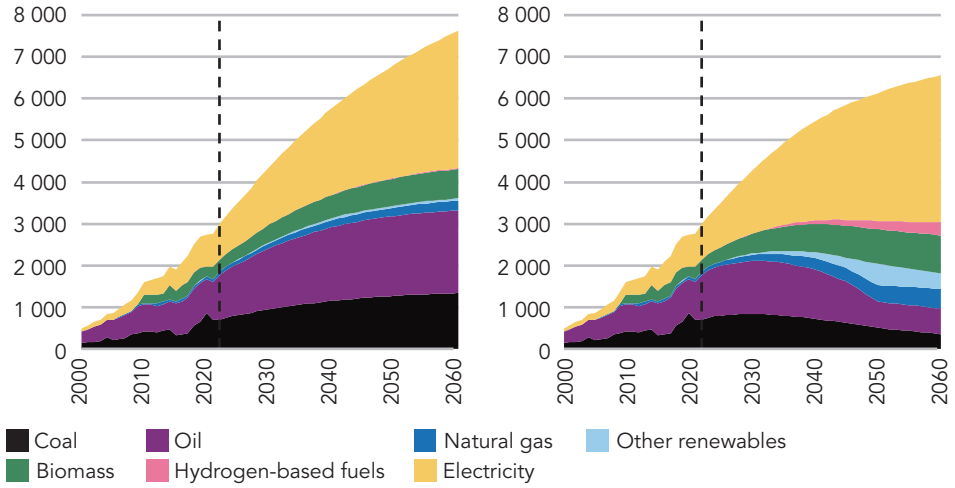


Figure 21-8. Energy demand by fuel in REF & TGT (PJ)



- Viet Nam's energy demand is projected to increase significantly in the coming decades, driven by industrialisation and urbanisation strategies. Industry accounts for nearly 50% of this demand, largely due to industrialisation over the past two decades. This share of demand will remain steady until 2060, comprising of 56% in REF and 57% in TGT.
- The energy demand in buildings is projected to increase significantly as more modern electric appliances will be used in households, accounting for 20% in both scenarios by 2060.
- Transport energy use increases by 1.8 times in the REF scenario and by 1.3 times in the TGT scenario between 2022 and 2060, accounting for 15% and 12.6% of total end-use demand, respectively. The reduced growth in energy consumption in TGT results from the increased adoption of EVs in the coming decades.
- In REF, demand for fossil fuels continues to rise, with their share expected to be approximately 47% by 2060. Electricity will account for 43% of the total energy demand by 2060, reflecting a significant shift in the energy mix. Alternatives such as biomass, gas, and hydrogen-based fuels are expected to expand.
- In TGT, demand for hydrogen-based fuel is expected to rise in industrial processes involving steel-making, chemicals, and cement plants, as well as in heavy transport vehicles. Electricity demand is projected to increase continuously, while demand for coal and oil is anticipated to decline to meet the 2050 net-zero target.
- The 14% reduction in energy demand in TGT reflects the accelerated adoption of low-carbon fuels and more effective energy-saving solutions.

Buildings Energy Demand

Figure 21-9. Buildings energy demand by fuel in REF & TGT (PJ)

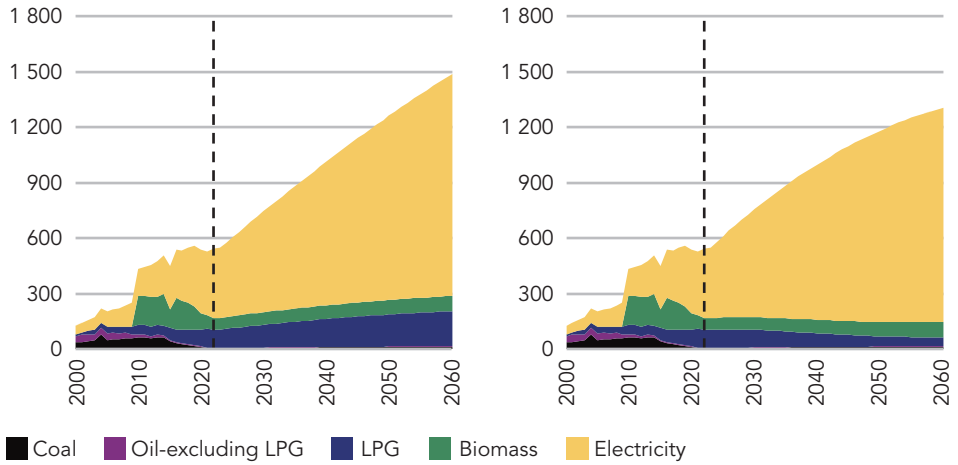
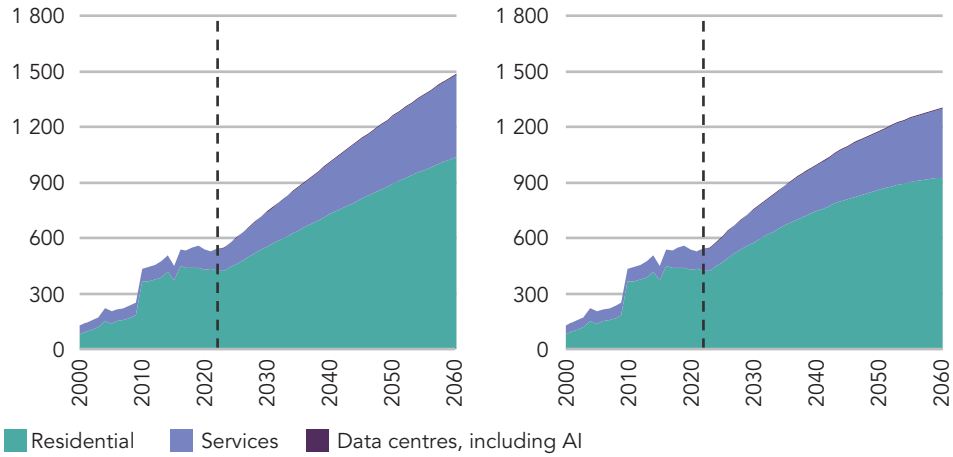


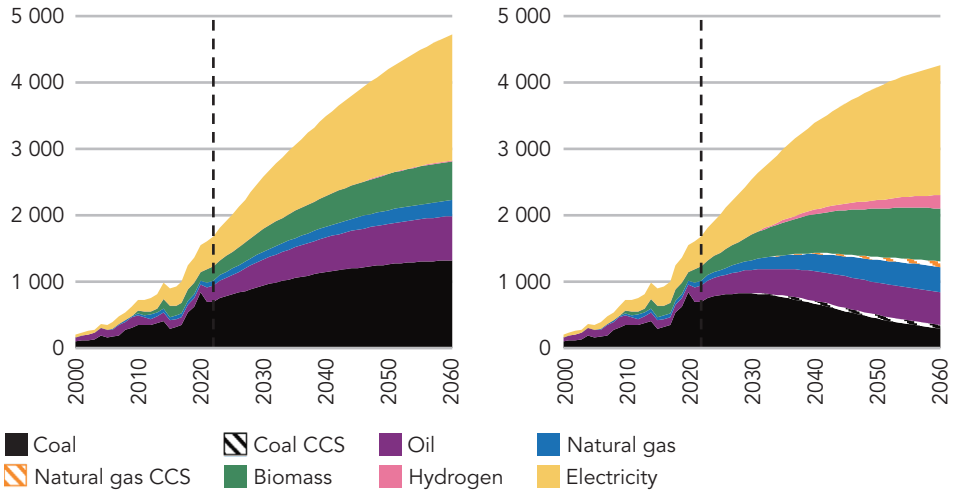
Figure 21-10. Buildings energy demand by sector in REF & TGT (PJ)



- By fuel, energy demand in buildings sector has increased rapidly over the past decades and continues to rise in the coming years, in line with rising household incomes and urbanisation. Despite modest population growth, rising quality of life is expected to drive higher energy demand in both scenarios through factors like the popularisation of home electric appliances.
- Significant buildout of electricity capacity and associated infrastructure would likely be needed to meet the growing electricity demand in either scenario.
- In REF, energy demand in buildings rises 2.7 times from the 2022 base year to above 1,486 PJ in 2060. Most of this increase comes from electricity, which grows over threefold. Energy consumption for space cooling increases alongside the growth in commercial space. Gas is projected to increase significantly over the projection period due to its advantage as a clean cooking fuel.
- In TGT, energy demand is projected to decline by 13% relative to the REF scenario due to the use of more highly efficient appliances and advanced energy management systems in buildings. Electricity is expected to be the most prominent energy source, followed by biomass and gas by 2060.
- By sector, residential buildings dominate energy demand, with the residential subsector projected to account for around 70% of total buildings demand by 2060. Energy demand in the service subsector is projected to represent approximately 29% of total demand by 2060, with data centres and AI comprising the remaining share in both scenarios.
- The National Energy Efficiency Program (VNEEP) phase 3 aims to reduce overall energy demand. VNEEP also seeks to decrease overall energy demand by 8-10% from 2019 to 2030. As such, energy efficiency in TGT is assumed to be higher than in REF.

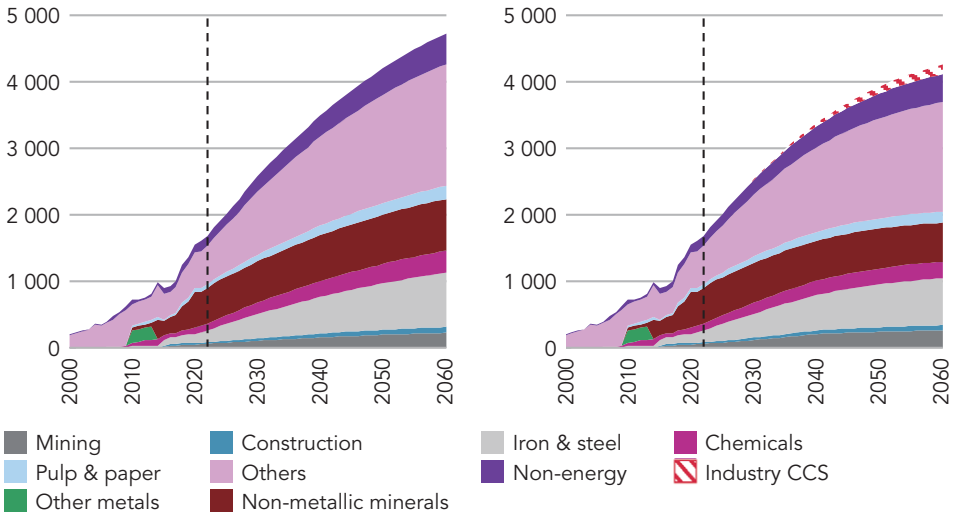
Industry Energy and Non-energy Demand

Figure 21-11. Industry & non-energy demand by fuel in REF & TGT (PJ)



- Electricity is projected to be the largest source of final energy consumption in 2060 under both scenarios.
- Coal's share is expected to decline dramatically in the TGT due to Viet Nam's aspiration to achieve net-zero emissions by 2050. However, coal still remains at around 8% by 2060, as it is hard to replace in the iron & steel industry.
- Hydrogen will be gradually introduced in TGT, starting in 2030, to partially substitute fossil fuel-based processes.
- Additionally, CCS technology is expected to be adopted after 2030 to decarbonise heat processes in industrial subsectors such as iron & steel, cement, and chemicals. This technology will require the readiness of CCS full-chain components, including CO_2 capture, transportation, and storage.

Figure 21-12. Industry & non-energy demand by sector in REF & TGT (PJ)



- By sector, non-metallic minerals dominate energy demand because of Viet Nam's significant potential in non-metallic minerals, including coal, cement raw materials, apatite, limestone, and clay. These minerals are being mined to support economic growth in both scenarios. The energy demand for non-metallic minerals is projected to increase 1.47-fold in REF and 1.24-fold in TGT from 2022 to 2060.
- The energy demand for iron and steel will grow dramatically from 2022 to 2060. As an energy-intensive and hard-to-abate sector, exporting steel will be challenging due to the carbon tax mechanisms, such as CBAM in the EU.
- Energy demand for mining is expected to rise between 2022 and 2060. The Minerals Development Plan sets specific figures for each mineral in the exploration and mining stages, indicating the significance of key minerals for the energy transition.

Non-energy Demand

Figure 21-13. Non-energy demand in REF (PJ)

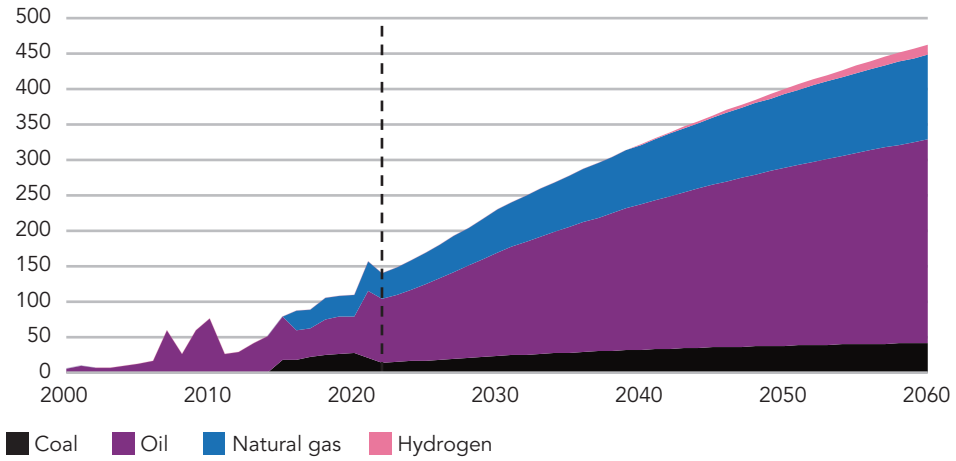
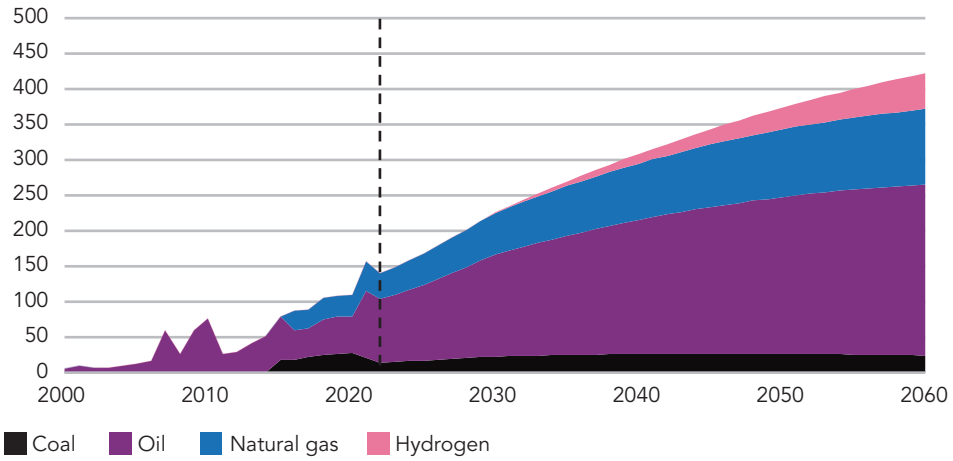


Figure 21-14. Non-energy demand in TGT (PJ)



- In the REF scenario, total non-energy demand increases significantly over the projection period, from about 140 PJ in 2022 to 463 PJ by 2060. Most fuels for the non-energy sector come from fossil fuels, while a minor share of hydrogen is expected to be used after 2040.
- In Viet Nam, oil, specifically petroleum products, is used for non-energy purposes in various sectors, including the production of plastics, lubricants, and solvents. Oil is a significant fuel and is projected to constitute the largest share of non-energy demand, accounting for approximately 62% by 2060.
- Gas demand demonstrates a substantial increase throughout the projection period, indicating a growth factor of 3.2 from 2022 to 2060. Natural gas is mainly used as a feedstock for fertiliser production, where demand is increasing for both domestic and export markets. Viet Nam has 841 fertiliser plants with a total capacity of 30 Mtpa, which are expected to consume more gas in the coming decades.
- Under the TGT scenario, total non-energy demand is expected to increase continuously until the end of the projection period. However, total demand is projected to be slightly lower (-9%) than that in the REF. This decline reflects the improvement of energy efficiency, energy savings, and the penetration of low-carbon emissions technologies in industrial processes.
- Oil and gas demand are expected to grow significantly over 2022-2060, while coal demand shows a slight increase to the early 2040s before plateauing to the end of projection period.
- The use of hydrogen starts earlier than in REF, beginning from 2030 with only 0.9 PJ in 2030, then increasing to 50.3 PJ by 2060. Assuming that hydrogen will be produced from renewable energy sources, the incorporation of hydrogen in this sector will contribute to reducing CO_2 emissions.

Transport Energy Demand

Figure 21-15. Domestic transport energy demand in REF (PJ)

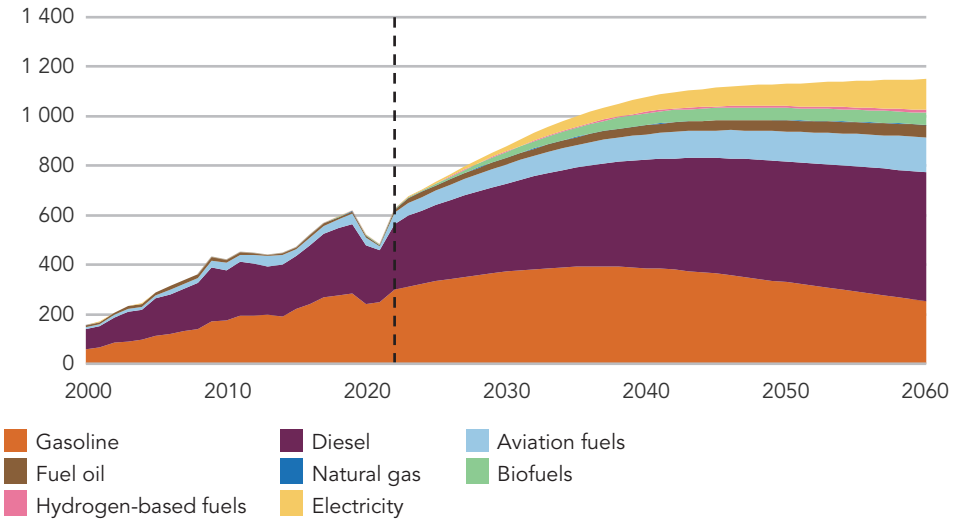
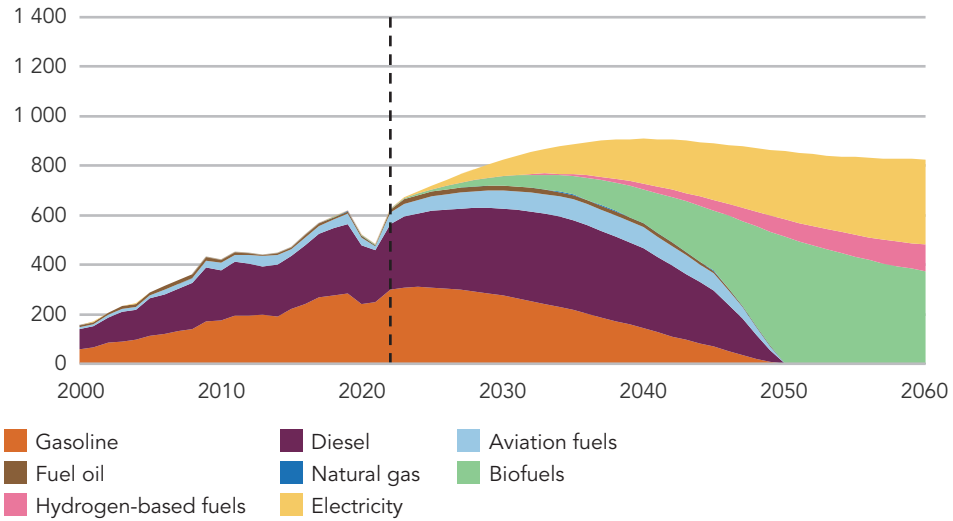


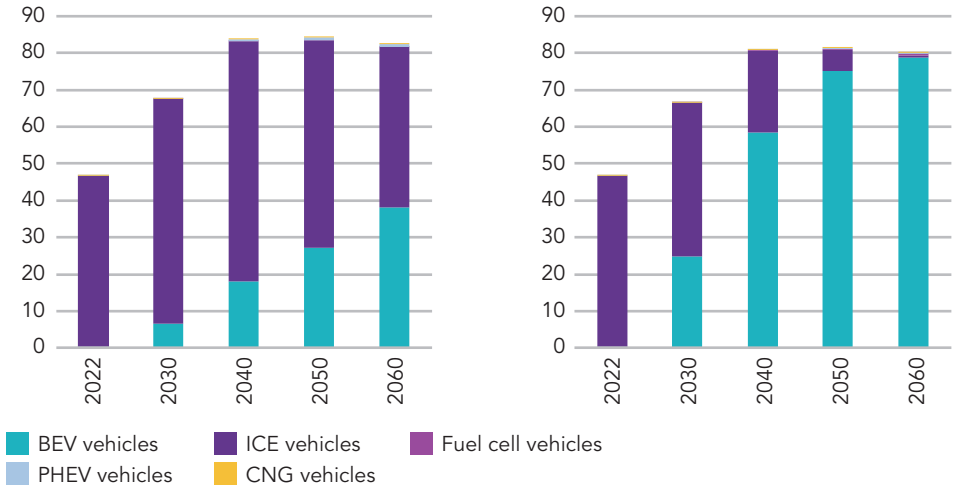
Figure 21-16. Domestic transport energy demand in TGT (PJ)



- In REF, diesel and gasoline are the dominant fuels in Viet Nam's transport sector. Gasoline is expected to peak in the mid-2030s and then gradually decline toward 2060 due to electrification, adoption of alternative fuels, and slowing activity growth. In contrast, diesel demand is projected to continue rising, as it remains essential for trucks and ships, which are difficult to electrify and for which substituting diesel with alternative fuels is highly challenging.
- In both scenarios, passenger activity in Viet Nam is projected to grow until around 2040, when vehicle ownership reaches saturation. Thereafter, passenger activity growth stagnates in line with population trends, leading to energy use stabilising around 2040 instead of continuing to increase.
- Freight activity, on the other hand, is projected to grow steadily, nearly tripling by 2060 in line with the expansion of the industry sector.
- In TGT, the potential of utilising 100% green energy in the transport sector was examined, in line with Viet Nam's target stated in Decision No. 876/QD-TTg dated July 2022.
- Based on these assumptions, by 2050, all road vehicles are anticipated to utilise electricity or low-carbon fuels. This necessitates balancing the growth of electric vehicles (EVs) with the use of liquid biofuels and hydrogen-based fuels. However, low-carbon fuels are not currently produced at scale, and expanding production would be costly. Meanwhile, battery electric vehicles (BEVs) are expected to be price competitive with internal combustion engine (ICE) vehicles and benefit from lower fuel costs. As such, modelling assumptions prioritised maximising EV deployment, with residual emissions addressed through the use of these more expensive low-carbon fuels.
- Vinfast, a Vietnamese EV manufacturer, announced a plan in December 2024 to build its second domestic production plant, which will double its annual output capacity to 600,000 units.

Other Transport Data

Figure 21-17. Transport vehicle stocks in REF & TGT (millions)



- Figure 21-17 highlights the technological shifts in the transport sector from ICE vehicles to BEVs. The transition is faster under TGT, where strong policy support leads BEVs to surpass ICE vehicles by 2040. In contrast, ICE vehicles remain dominant in REF, with only a gradual uptake of low-emission vehicles.
- In TGT, an aggressive adoption of BEVs was assumed to reduce reliance on higher-cost low-carbon fuels. The assumed targets include 95% BEV sales for motorcycles by 2030, 90% for cars by 2040, and 80% for light commercial vehicles by 2040. Trucks are anticipated to transition more slowly.
- Figures 21-18 and 21-19 show that transportation activity significantly contributes to energy consumption growth in both scenarios. In contrast, engine type plays the largest role in reducing energy use in TGT, driven by the substantial adoption of BEVs in Viet Nam over the coming decades.

Figure 21-18. Components of the change in road energy use in REF (PJ)

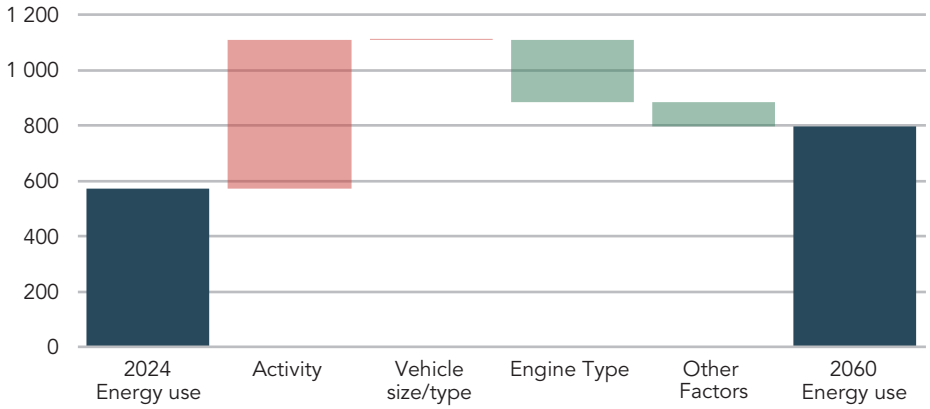
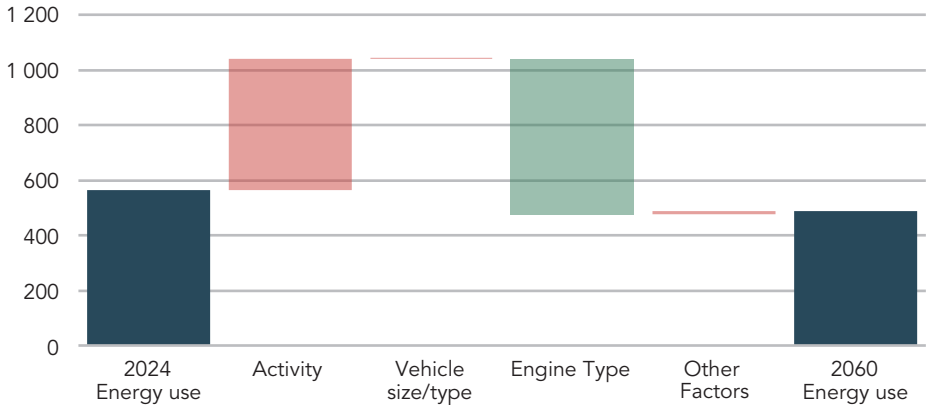


Figure 21-19. Components of the change in road energy use in TGT (PJ)



Note: Information on the different drivers in the transport energy decomposition can be found in the *Outlook*'s annex.

Electricity Generation

Figure 21-20. Electricity generation by fuel in REF (TWh)

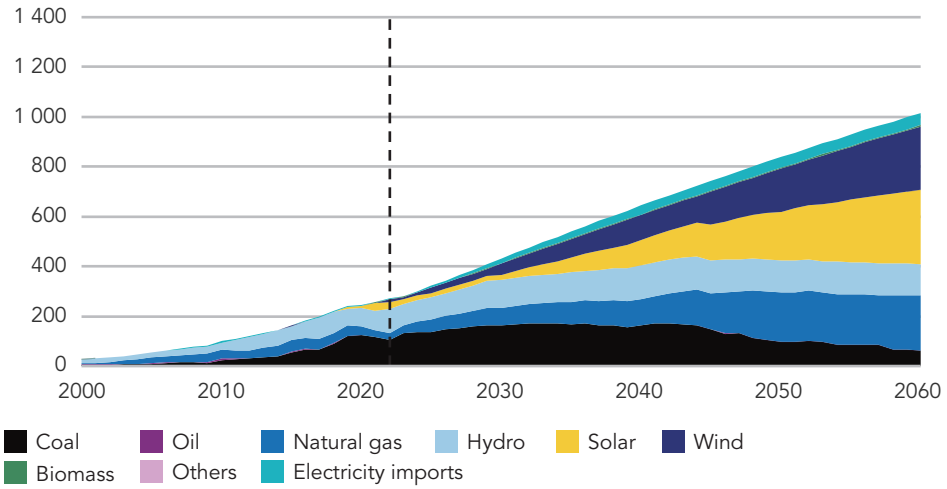
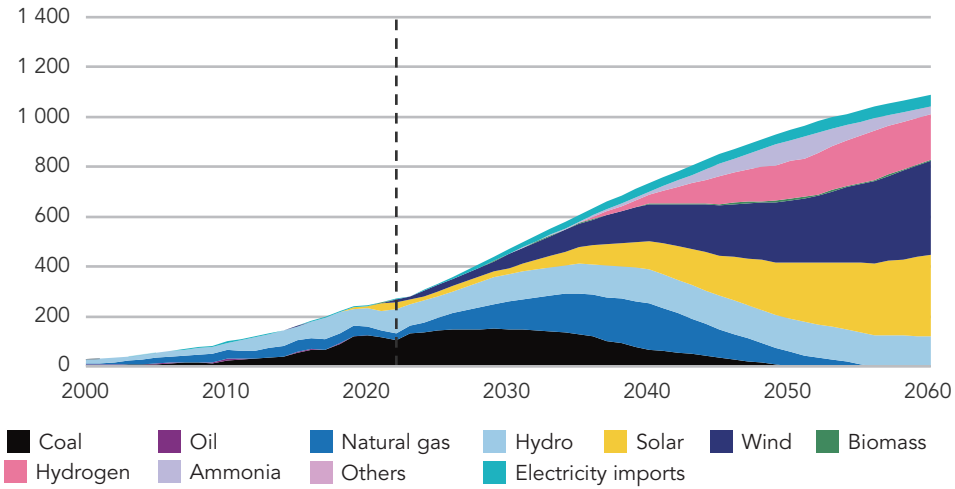


Figure 21-21. Electricity generation by fuel in TGT (TWh)



- In REF, electricity generated from coal is projected to decline after 2043, while natural gas grows substantially to compensate for this reduction in coal-generated electricity and maintain the baseload power supply. This shift though creates a need for expanded LNG import infrastructure, as Viet Nam is expected to require around 15 Mtpa of imported LNG by 2030, compared with only 1 Mtpa currently available.
- Electricity production from hydropower is only expected to rise slightly as large-scale dams have already approached their maximum technical capacity.
- The future electricity generation mix in Viet Nam is expected to shift from a reliance on coal and hydropower to a more diversified mix dominated by solar, wind, and gas. Nuclear power was not considered in this projection as modelling work was finalised prior to the issuance of the revised PDP8.
- In TGT, electricity generated from coal is expected to decline more rapidly than in REF, reaching its peak in 2030 and decreasing thereafter. This trend aligns with Viet Nam's net-zero commitment at COP26.
- Coal and gas will be substituted by ammonia and hydrogen, respectively. Despite the addition of these new fuels, existing coal and gas-fired power plants will continue to be in use.
- Renewables, including solar and wind, are expected to increase by 21-fold between 2022 and 2060.
- As the share of variable renewable energy continues to grow, maintaining the power system's grid stability becomes increasingly important. Enhancing system flexibility will be essential, including a significant expansion of the transmission network, particularly High-Voltage Direct Current (HVDC) connections, to integrate renewable energy sources located far from demand centres.

Note: Figures 21-20 and 21-21 do not include electricity generation for hydrogen production.

Generation Capacity

Figure 21-22. Generation capacity by fuel in REF (GW)

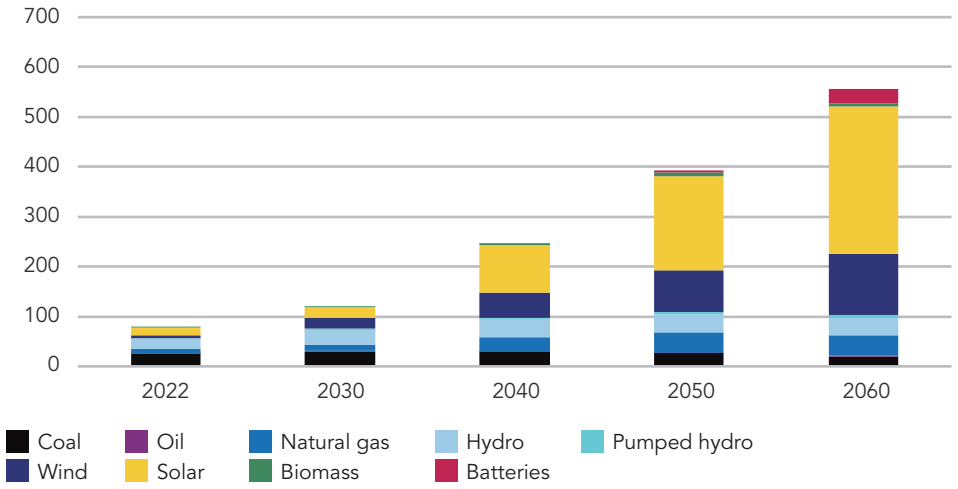
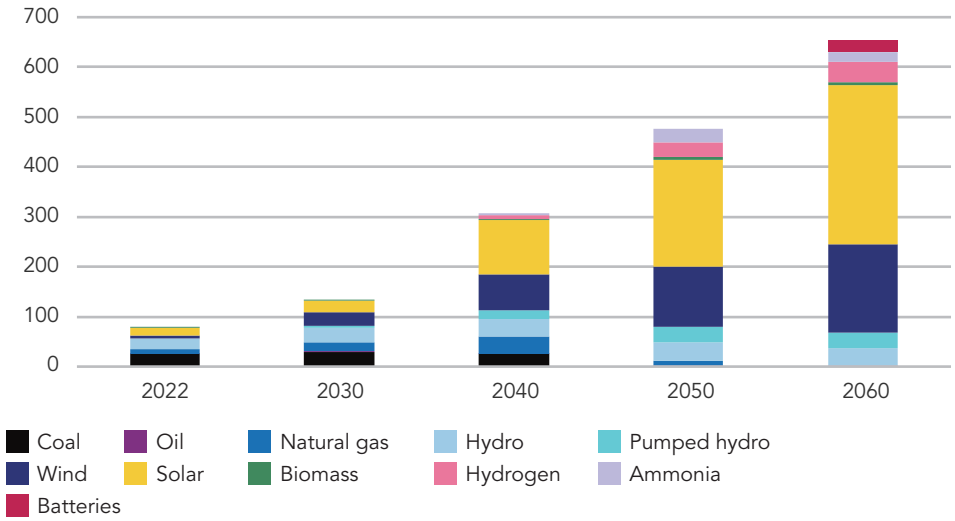


Figure 21-23. Generation capacity by fuel in TGT (GW)



- Total generation capacity is projected to increase dramatically from approximately 79 GW in 2022 to 556 GW by 2060, representing a sevenfold increase over four decades.
- Solar and wind power experience the most dramatic growth, becoming the dominant generation technologies by 2040 and continuing to expand through 2060.
- Coal power is gradually declining, while gas power is on the rise due to its lower CO_2 emissions and reliability as a base-load generation source.
- Battery capacity begins to appear in the later decades, reflecting the growing need for energy storage as variable renewable sources increase.
- The REF scenario demonstrates a major shift toward renewable energy in generation capacity, particularly solar and wind, while conventional sources remain present but do not expand substantially over the four-decade projection period.

- In the TGT scenario, the total generation capacity is projected to increase dramatically from 79 GW in 2022 to 653 GW in 2060, representing a more than eightfold increase over the 2022-2060 period.
- Solar experiences the most dramatic growth of any energy source, skyrocketing from 16.7 GW in 2022 to 317.7 GW by 2060. Wind capacity shows remarkable growth, increasing from just 5 GW in 2022 to 177.4 GW by 2060.
- In the PDP8, the installed capacity is projected to reach 150 GW by 2030 and 490-573 GW by 2050, with a renewable energy generation share of 31-39% in 2030 and 67.5-71.5% in 2050. This TGT projection is to a certain degree in line with Viet Nam's aspirational target.

Note: Figures 21-22 and 21-23 do not include electricity capacity for hydrogen production.

Grid Reliability

Figure 21-24. Total generation capacity and peak load (GW)

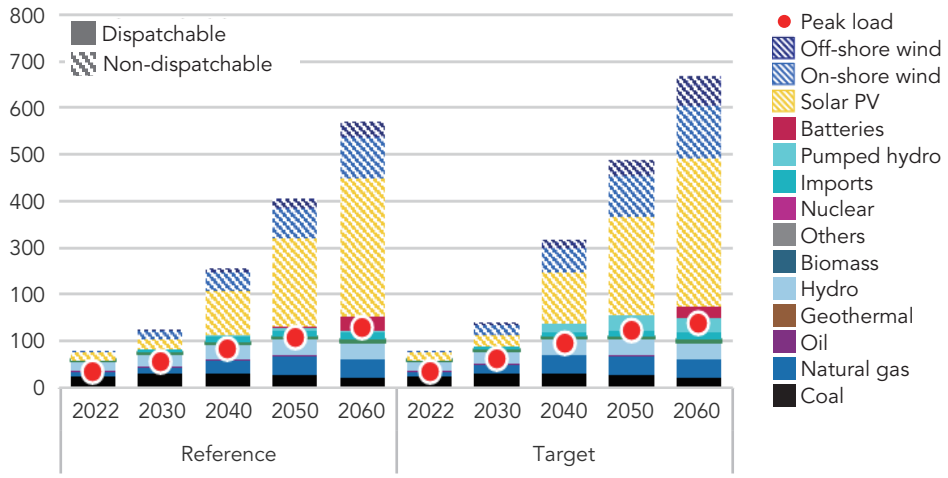
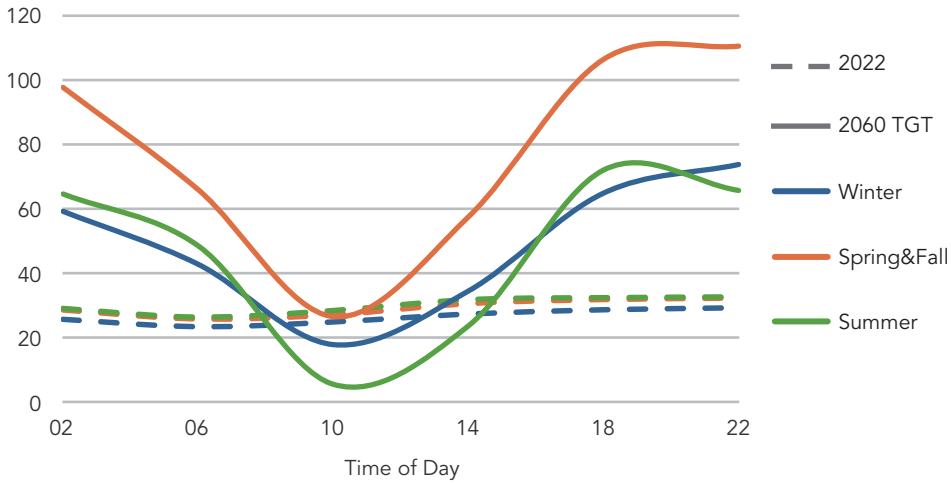


Figure 21-25. Power from dispatchable sources in TGT (GW)



- In REF and TGT, the peak electricity load grows substantially to 130 GW and 140 GW by 2060, respectively, from around 33 GW in 2022.
- In REF, wind plus solar capacity grows to 418 GW by 2060, or 19 times its value in 2022.
- In TGT, wind plus solar capacity will grow even higher by 2060, reaching approximately 23 times its value in 2022.
- To maintain grid reliability, dispatchable generation capacity (including batteries) will need to grow to at least 77 GW in REF and 74 GW in TGT by 2060.

- Increased reliance on wind and solar generation will increase the variability of generation required from dispatchable power sources.
- In Viet Nam, the variability of this net load curve increases substantially, especially in TGT. Actual variability on the power system will be larger than what is shown in Figure 21-25, as the APERC model only captures seasonal averages. Even so, these averages indicate that dispatchable power sources will need to increase by 64 GW from the early afternoon to the evening.
- This variability could be a challenge for system operators and will likely increase the capital, maintenance, and operating costs of the electrical grid.

Coal

Figure 21-26. Coal consumption by sector in REF & TGT (PJ)

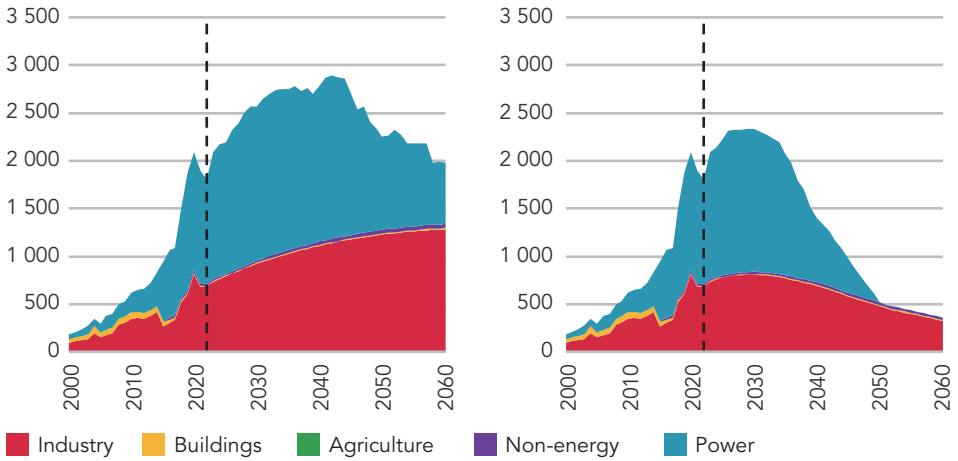
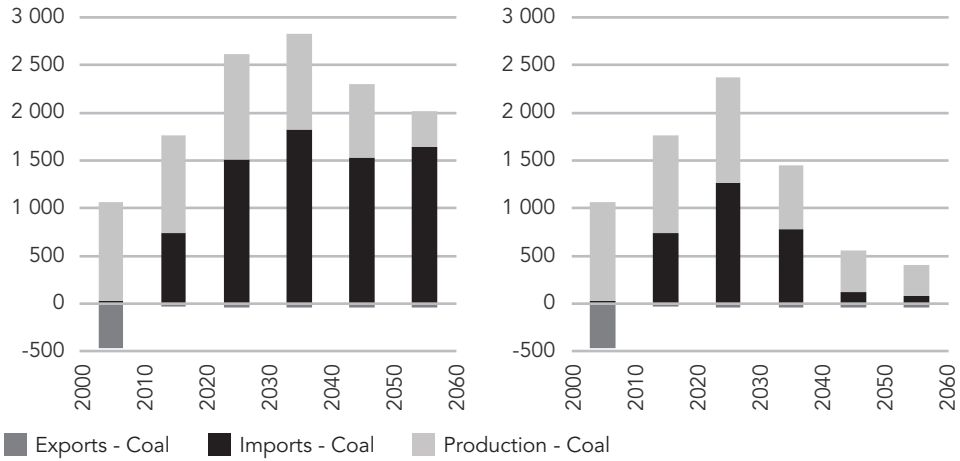


Figure 21-27. Coal production, imports, and exports in REF & TGT (PJ)



- In both scenarios, power generation is the largest consumer of coal from 2022 to 2040. There is a continued heavy reliance on coal for power until 2040 in REF, while TGT demonstrates a rapid coal phase-down after 2030.
- The industry sector's use of coal demonstrates greater persistence in both scenarios compared to other sectors. Even in TGT, industry remains the predominant consumer of coal by 2060, indicating that certain processes are harder to abate.
- The substantial difference between the REF and TGT scenarios highlights the significant policy and technology choices required to reduce coal dependence. The TGT scenario represents a pathway aligned with climate goals, requiring rapid deployment of low-emission energy alternatives, particularly in the power sector.
- Coal production rises slightly until 2030 and then declines throughout the remainder of the projection period in both scenarios. This reduction in domestic coal production results from geological constraints in mining as coal mines need to be deeper, as well as rising production costs.
- In REF, coal imports begin increasing significantly around 2022, peaking around 2040. The high levels of imports persist through 2050 and 2060, remaining above 1,500 PJ, which raises concerns about energy security.
- In TGT, imports peak at 1,260 PJ by 2030 before declining significantly through the end of the projection period. By 2050-2060, imports stabilise at around 100 PJ, which is roughly 90% lower than in the REF scenario, as Viet Nam will not use coal in the power sector after 2050. This suggests that implementing decarbonisation policies would require significantly deploying alternative energy sources.

Natural Gas

Figure 21-28. Natural gas consumption by sector in REF and TGT (PJ)

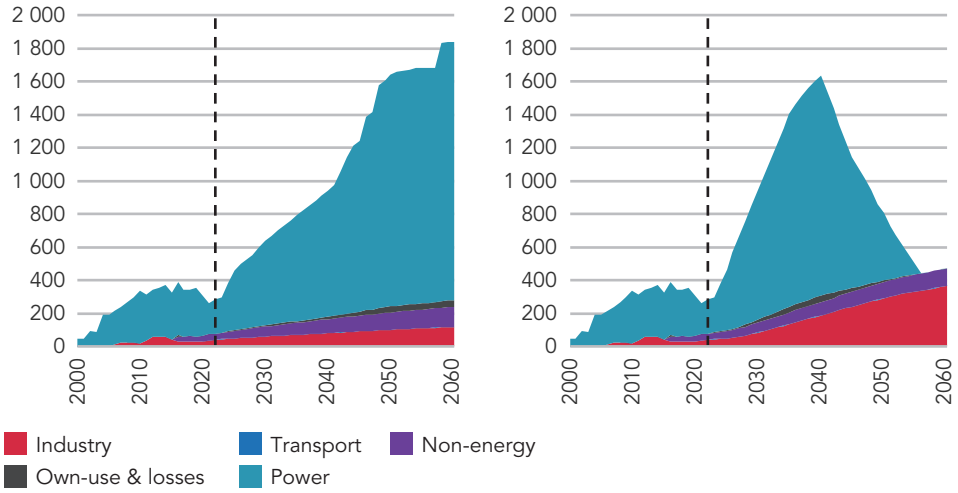
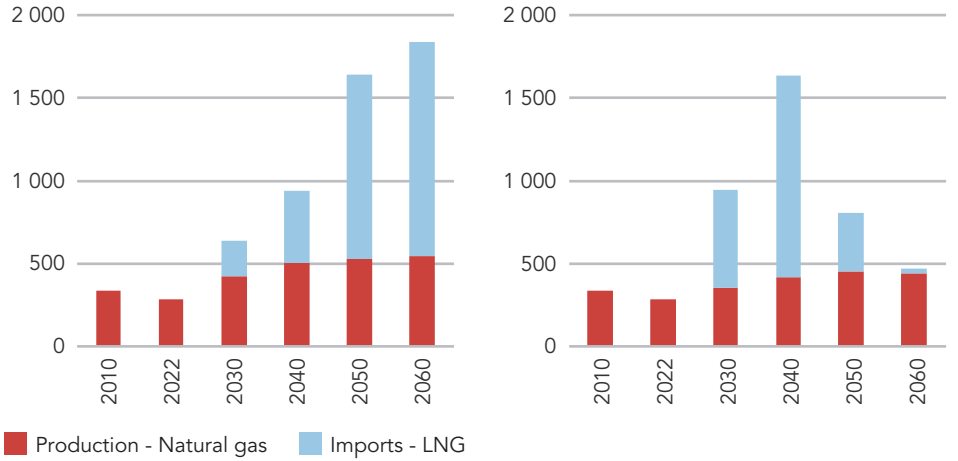


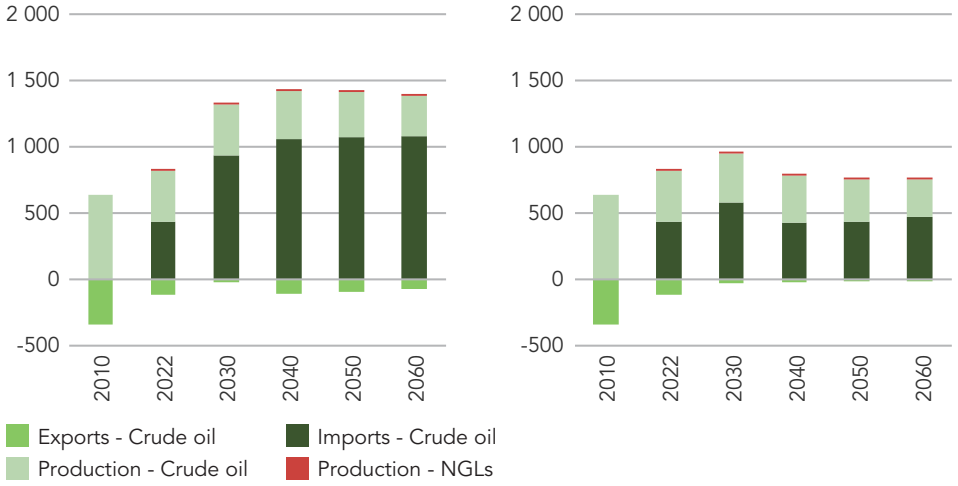
Figure 21-29. Natural gas production, imports, and exports in REF and TGT (PJ)



- In REF, there is a significant increase in total natural gas consumption from 2022 to 2060, reaching over 1,800 PJ by 2060. The power sector demonstrates exponential growth, becoming the primary consumer, while the industrial sector shows steady growth.
- In the coming decades, most of the gas supply will come from imported LNG, requiring significant investments in in-land LNG infrastructure and Floating Storage Regasification Units. This indicates that the cost of gas within Viet Nam will be impacted by the international LNG market.
- In TGT, gas surges sharply and peaks at 1,600 PJ by 2040 before declining to about 400 PJ by 2060, driven by the power sector. A sharp decrease in gas consumption for power after peaking is due to fuel switching from gas to H_2, bringing a new challenge of stranded assets of LNG-related infrastructure.
- In both scenarios, production is projected to steadily increase, reaching 587 PJ in REF and 439 PJ in TGT by 2060. However, growth in domestic natural gas production is outpaced by the high growth in demand in the coming years. As a result, any extra supply will need to come from imported LNG. This represents a significant increase in import dependency.
- In TGT, LNG imports are projected to start very high at 574.9 PJ in 2030, and are expected to surge dramatically, more than doubling to a peak of 1179.4 PJ in 2040. However, after this peak, imports are projected to decrease sharply to 351.6 PJ in 2050 and fall significantly further to only 31.2 PJ by 2060. The decline in LNG imports is due to fuel switching from gas to hydrogen in the power sector by 2050.

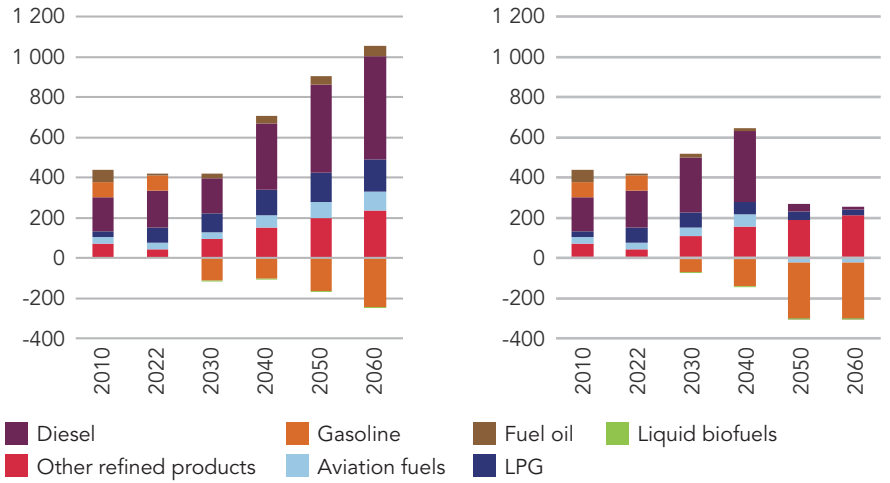
Petroleum Liquids

Figure 21-30. Crude oil, NGLs, and other hydrocarbon production, imports, and exports in REF & TGT (PJ)



- In REF, the supply of crude oil and other hydrocarbons is dominated by imports, accounting for around 46% of the total crude oil and oil products supply. The Dung Quat oil expansion project is under construction to raise its capacity to 171,000 barrels per day, up from 148,000 barrels, which will require more crude oil imports in the coming decades. Crude oil production remains plateaued over the projection period due to the limited development of oil reserves and technological limitations in deepwater exploration.
- In TGT, crude production and imports will be lower than in REF. Higher EV adoption in TGT compared to REF contributes to this lower demand. By 2060, total supply of crude oil and other hydrocarbons is projected to decrease by 43% in TGT relative to REF, driven by the shift from fossil-based fuels to low-carbon alternatives in the transport sector.

Figure 21-31. Net imports of refined products and low-carbon fuels in REF & TGT (PJ)



- In REF, product imports are driven by diesel, gasoline, and LPG. Diesel imports continue to rise over the projection period due to high demand in the transport sector.
- In TGT, diesel imports decline after peaking around 2040, followed by a sharp decline until 2050. This substantial drop is projected due to the Vietnamese government's aspiration to use low-carbon fuels in the transport sector.
- Exports of gasoline are anticipated to rise in the longer term in both scenarios as consumption declines sharply.

Note: In Figure 21-31, net imports are presented without deducting bunkers.

Refining

Figure 21-32. Refining outputs in REF & TGT (PJ)

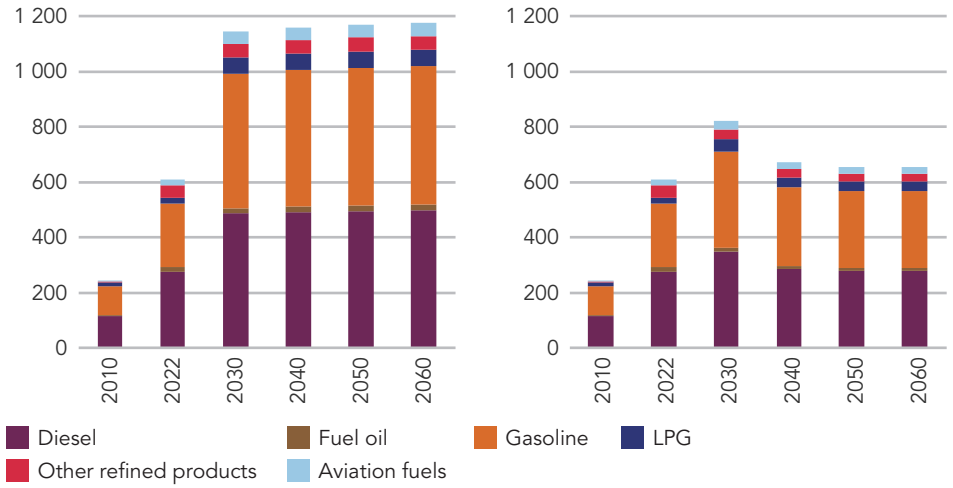
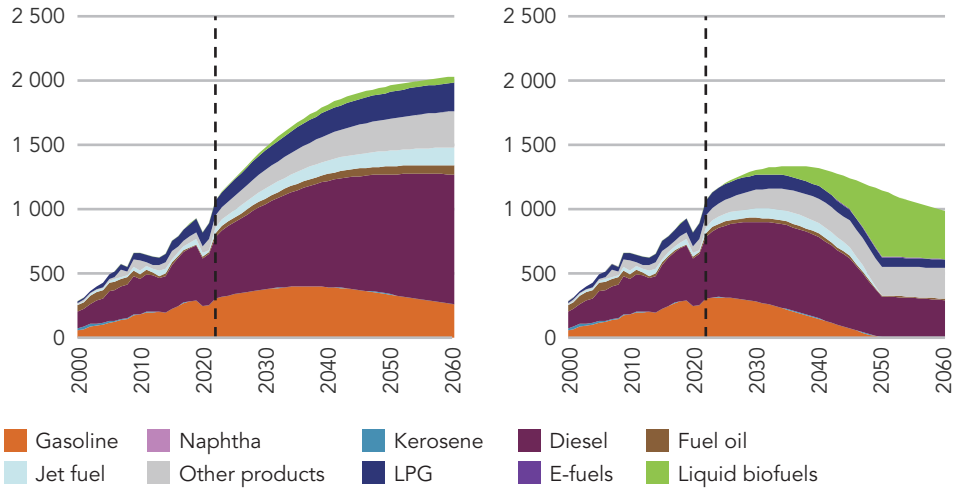


Figure 21-33. Refined products and low-carbon fuels demand in REF & TGT (PJ)



- In REF, gasoline and diesel are the major outputs from refineries, growing significantly between 2022 and 2030, and then plateauing at a high level and remaining stable through 2060. LPG, aviation fuels, and other refining products peak by 2030 and maintain a plateau over the projection period.
- In TGT, total refinery capacity is assumed to peak at 367 kb/d to align with a more rapid consumption decline than in the REF scenario. Gasoline and diesel output is projected to decline after peaking but will remain stable for the remainder of the projection period. The amount of exported gasoline is based on this output minus demand.
- The utilisation rate is assumed to improve to meet the 70% self-sufficiency target in the medium term, from 85% to 90% in REF and to 100% in TGT due to no additional capacity by 2030.

- In REF, the demand for refined products and biofuels continues to grow, reaching about 2,000 PJ by 2060. Diesel consumption continues to rise over the projection period, while gasoline consumption peaks around 2040, then declines gradually. Alternative fuels (particularly liquid biofuels) increase in the future mix.
- In TGT, total refined products and biofuels demand are projected to peak around 2040, and then gradually decline until the end of the projection period. Gasoline will peak around 2025, while diesel will peak in 2030. The share of liquid biofuels is expected to rise dramatically due to an aspirational target to use low-carbon energy in the transport sector, in line with the target stated in Decision No 876/QD-TTG dated July 2022.

Bioenergy and Waste

Figure 21-34. Bioenergy and waste demand by sector in REF & TGT (PJ)

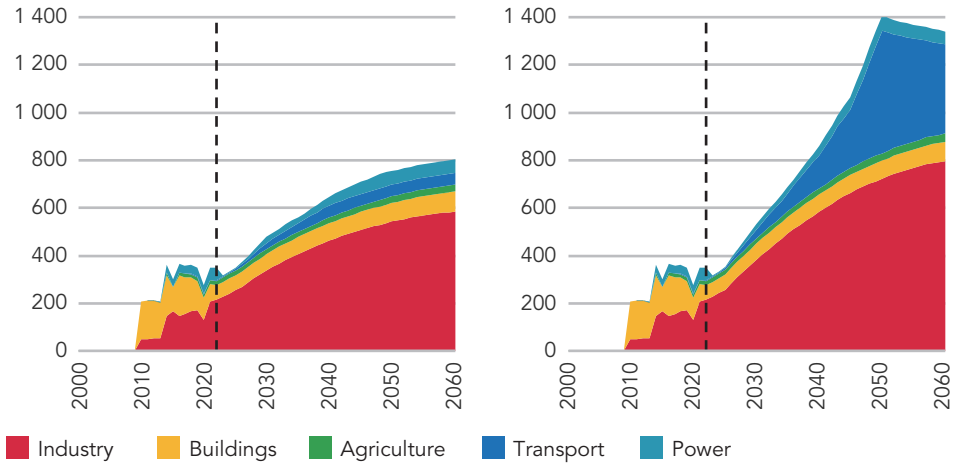
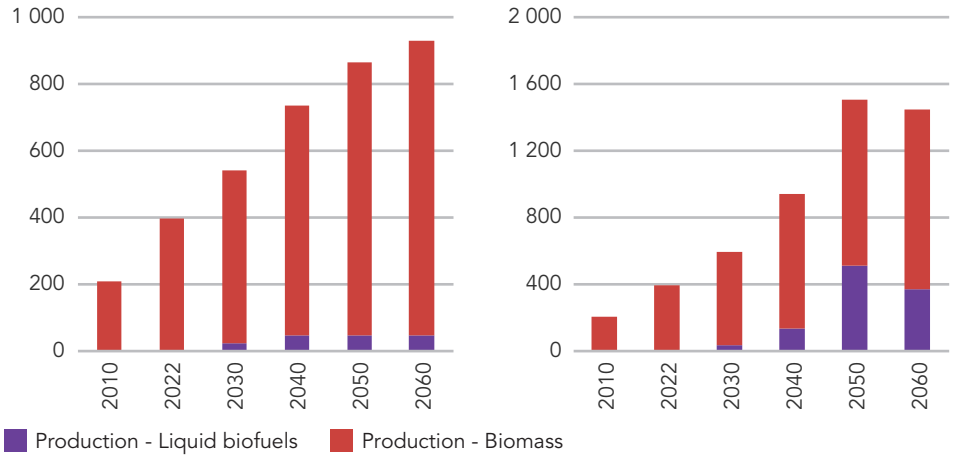


Figure 21-35. Bioenergy and waste production in REF & TGT (PJ)



- In REF, bioenergy and waste demand increases steadily from approximately 350 PJ in 2022 to around 800 PJ by 2060, representing roughly a 2.3-fold increase over the projection period. Industry dominates the total bioenergy and waste demand, followed by buildings and power. The transport sector shows notable growth, particularly between 2030 and 2060.
- In TGT, bioenergy and waste demand increases significantly from approximately 350 PJ in 2022 to about 1,400 PJ by 2050, and then slightly declines to around 1,340 PJ in 2060. Bioenergy and waste demand for transport experiences substantial growth from 2030 to 2050, becoming the sector with the fastest growth. The industrial sector shows steady growth throughout the period, making it the largest consumer of bioenergy.

- In REF, bioenergy and waste production steadily increase from around 400 PJ in 2022 to roughly 930 PJ by 2060, more than doubling bioenergy production capacity.
- In TGT, bioenergy and waste supply are projected to increase 3.5-fold over the 2022-2060 period.
- The supply of bioenergy is sourced from domestic production in both scenarios, leveraging abundant feedstock resources, with reserves estimated at around 200 million tonnes of oil equivalent (515 million tonnes).
- By 2060, it is estimated that between 54 to 66 million tonnes of solid biomass will need to be produced domestically. For biofuels, in REF and TGT, approximately 1,500 million litres and 8,400 million litres respectively are needed by 2060.

Hydrogen-based Fuels in the Target Scenario

Figure 21-36. Hydrogen-based fuels production methods and supply [left]; Inputs for hydrogen production [right] (PJ)

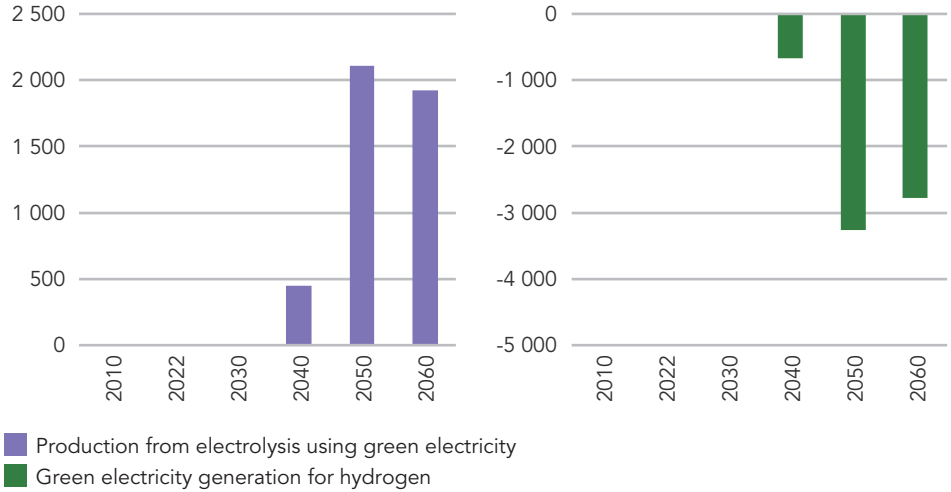
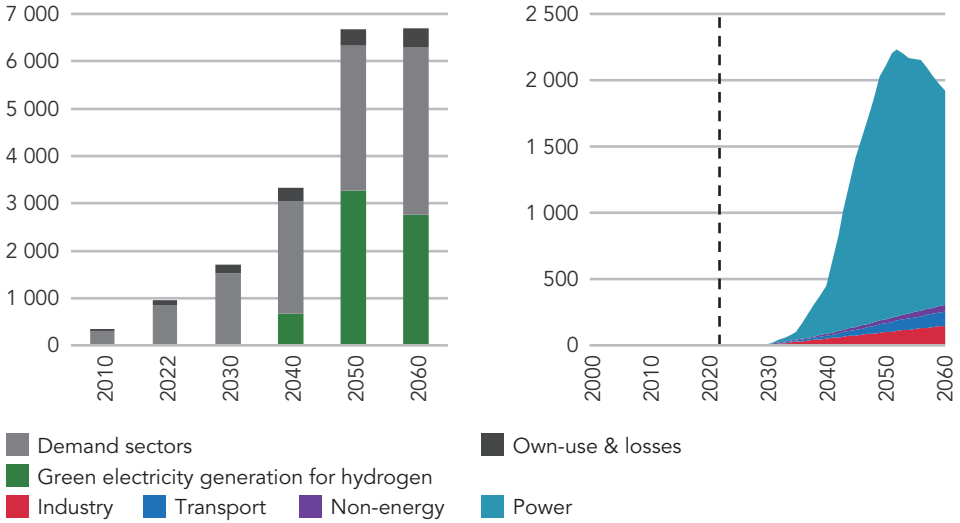


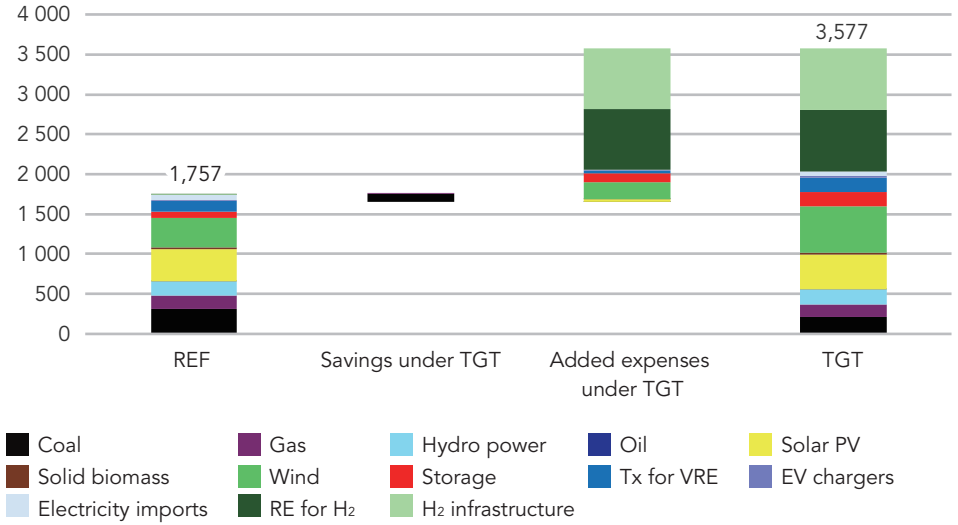
Figure 21-37. Electricity for electrolysis vs other sectors [left]; Hydrogen-based fuels demand by sector [right] (PJ)



- In TGT, hydrogen-based fuel production begins in 2040, peaking at 2,050 PJ before dropping to 1,900 PJ by 2060. This increase results from switching fuel sources from gas to hydrogen and coal to ammonia in the power sector.
- According to the Hydrogen Energy Development Strategy to 2030 and Vision to 2050, Viet Nam has ambitious plans for green hydrogen production, targeting annual production of 100,000 to 500,000 tonnes (12 to 60 PJ) by 2030 and 10 to 20 million tonnes (1,200 to 2,400 PJ) by 2050. These production goals are aligned with TGT.
- Hydrogen-based fuel demand is assumed to be greater in TGT than in REF. In the PDP8, Viet Nam plans to introduce hydrogen co-firing with natural gas starting in the 2040s with the goal of transitioning to 100% hydrogen-fuelled turbines in the power sector by the 2050s.
- With significant potential in renewable energy, Viet Nam aims to utilise electrolysis to produce green hydrogen from domestic sources. This will satisfy all demand requirements without having to rely on imports. This approach though will require a significant increase in electricity demand for electrolysis by 2050, representing roughly half of the total.
- In TGT, most hydrogen-based fuels are projected to be used in the power sector, co-firing hydrogen in gas-fired plants and ammonia in coal-fired plants. This is particularly relevant given that Viet Nam is expected to rely on electrolysis-based hydrogen production, which will require significant additional renewable electricity capacity to support hydrogen generation. Additionally, hydrogen is anticipated to be utilised in industry, transportation, and the non-energy subsector in the TGT scenario.

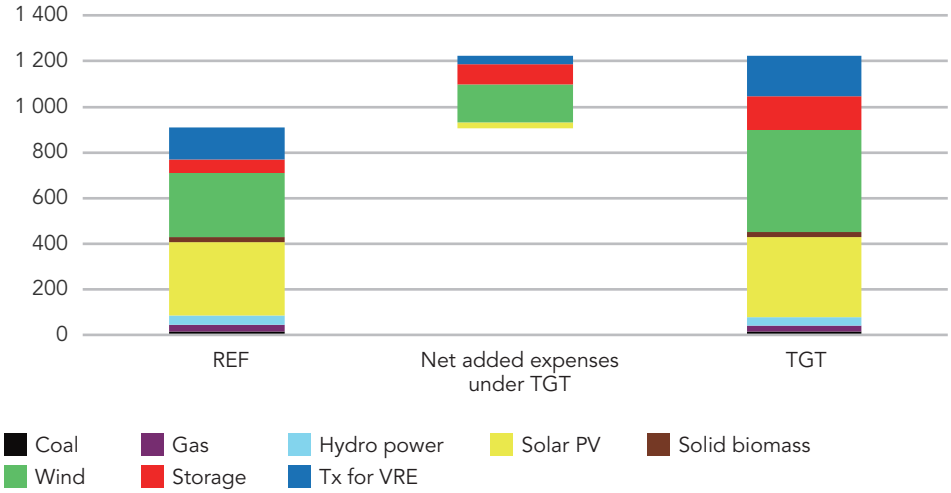
Costs

Figure 21-38. Costs in the power and hydrogen sectors, 2025 to 2060 (billion USD, undiscounted)



Note: Tx for VRE is only transmission infrastructure to connect variable renewable capacity to the grid. EV chargers do not cover the cost of associated infrastructure or EV vehicles.

Figure 21-39. Total capital investment (CAPEX) from 2025 to 2060 in the power sector (billion USD, undiscounted)

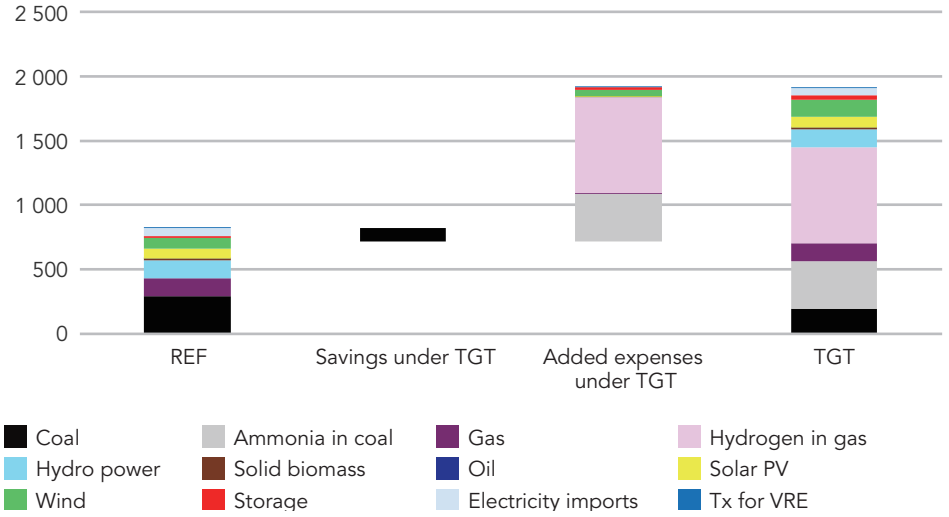


Note: Figure 21-39 only covers power and VRE transmission sector investments. Hydrogen and EV capital investments are not included.

- Viet Nam's power and hydrogen sectors will demand significant new investment and expenditures in the coming years, with total costs rising markedly in both scenarios from 2025 to 2060. The total capital, fixed, and variable costs in the power sector are considered, as well as costs for green hydrogen production, transmission for variable renewable electricity, electricity imports, and electric vehicle chargers.
- In REF, total costs reach an estimated USD 1,757 billion, primarily driven by renewables (solar, wind, and hydro), followed by investments and maintenance of thermal generation, especially coal and LNG.
- In TGT, total costs rise to an estimated USD 3,577 billion. A significant portion of the budget is allocated for investing in low-emission energy technologies, including green hydrogen production, renewables, and energy storage.
- Total costs of hydrogen (renewables for H_2 and H_2 infrastructure) represents a major component, accounting for 79% of additional expenses under TGT. Most of this hydrogen is used in the power sector to co-fire with coal and gas, with some being used directly. According to the revised PDP8, at least 43 GW of generation capacity will be allocated for co-firing, and 15 GW will be used in dedicated ammonia/hydrogen-fuelled power plants by 2050.
- A reduction in coal use results in cost savings of USD 101 billion, reflecting the transition away from fossil fuels.
- The total capital investment is projected to be USD 1,225 billion in TGT, compared to roughly USD 911 billion in REF. The largest CAPEX investment under TGT is anticipated to be wind (both onshore and offshore), followed by solar PV, transmission for additional VRE, and storage.

Costs

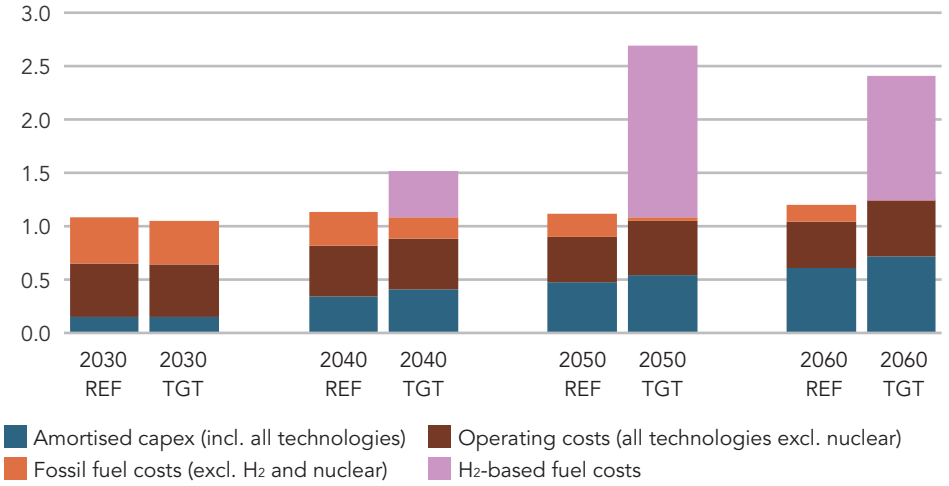
Figure 21-40. Total operating costs from 2025 to 2060 in the power sector (billion USD, undiscounted)



Note: Figure 21-40 only covers power, electricity imports, and VRE transmission sector costs. It does not include operating costs associated with hydrogen production and EV charger costs, but does include the cost of H_2/ammonia blending in power generation.

- The total operating costs for the Viet Nam power sector are projected to be an estimated USD 1,912 billion in TGT, compared to USD 821 billion in REF. In REF, the largest cost component will be the continued operation of coal and gas plants and the fuel costs involved.
- In TGT, additional operating costs arise from expansion into low-emission technologies such as using hydrogen and ammonia in power generation. However, reduced coal use, due to the transition away from fossil fuels, leads to cost savings of USD 101 billion.
- Overall, these projections highlight the sustained financial burden of system operations on a decarbonised pathway and the trade-offs policy makers will face when balancing sustainability, security/reliability, and affordability.

Figure 21-41. Cost of generating electricity relative to 2025 (2025 cost = 1.0) in the power sector



Note: Based on our assumptions about future capital and operating costs, Figure 21-41 shows cost compositions over time relative to 2025. It should not be considered an estimate of electricity tariffs and excludes market mechanisms that are too difficult to estimate.

- Viet Nam's electricity generation costs, indexed to 2025, increase steadily in REF but rises much faster in TGT. The cost gap between the two scenarios reflects deeper decarbonisation efforts in TGT, driven primarily by green ammonia and hydrogen blending in the power sector.
- Hydrogen-based fuel costs dominate the total cost of electricity generation in the last two decades. Carbon-free fuels will lead to an almost threefold increase in electricity costs in 2050 relative to 2025, bringing into focus the challenge of the energy trilemma.
- Amortised CAPEX rises steadily in both scenarios due to ongoing investment in renewable generation, with a marginally higher increase in TGT. However, fossil fuel costs as a share of total costs decline in both scenarios as a greater share of renewable and other carbon-free fuels are used in the coming decades in the energy mix.

CO_2 Emissions

Figure 21-42. CO_2 emissions in REF (million tonnes)

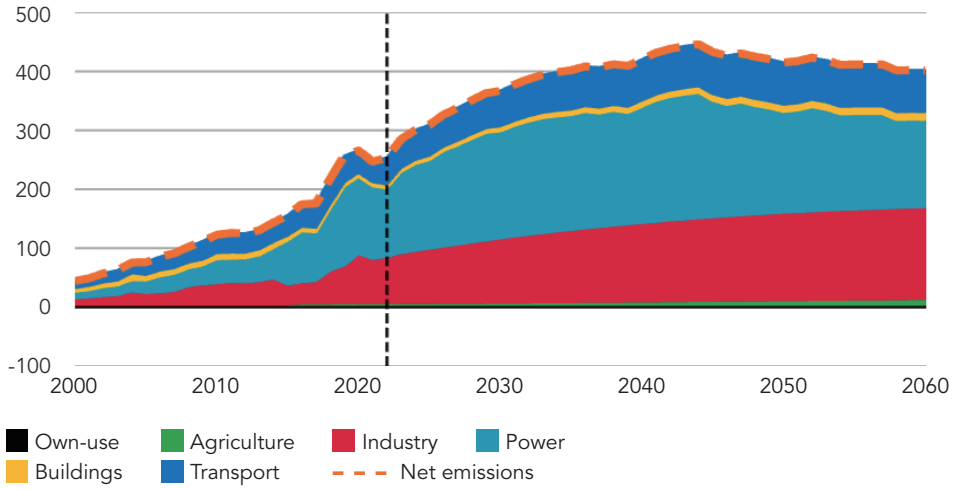
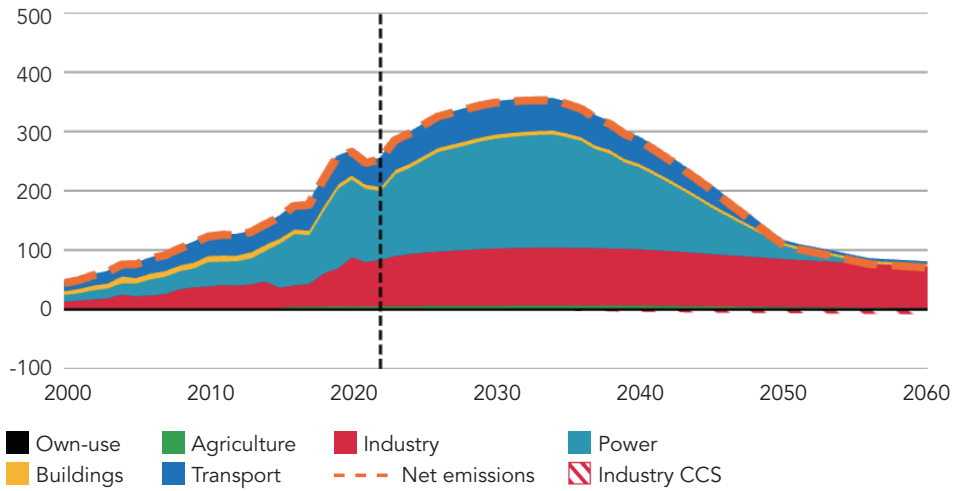
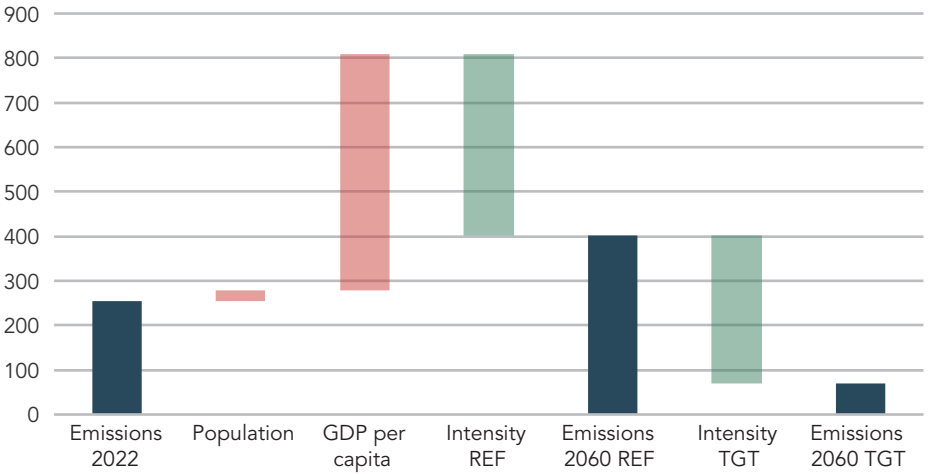


Figure 21-43. CO_2 emissions in TGT (million tonnes)



- In REF, CO_2 emissions are expected to grow significantly, peaking in 2044 before gradually declining until the end of the projection period. Power and industry are major contributors, accounting for approximately 75% of total CO_2 emissions by 2060. CO_2 emissions from transport are projected to increase slightly, comprising of 17% by 2060.
- In TGT, robust policies aim to achieve the net-zero target, with CO_2 emissions expected to peak around the mid-2030s. Significant reductions in CO_2 emissions are anticipated in the power and transport sectors, where carbon-free and low-carbon fuels, such as hydrogen/ammonia and biofuels, can replace fossil fuels.
- The change in CO_2 emissions from 2022 to 2060 is primarily driven by enhancements in energy intensity and emissions intensity. TGT projections indicates that CO_2 emissions will decrease by 72% by 2060.

Figure 21-44. CO_2 emissions components (million tonnes)



Note: All values represent energy sector combustion CO_2 emissions. Biogenic CO_2 is treated as zero at the point of combustion.

Useful Links

APEC Expert Group on Energy Data and Analysis (EGEDA) – https://www.egeda.ewg.apec.org/

APEC Energy Statistics 2022 – https://www.egeda.ewg.apec.org/egeda/general/info/pdf/APEC_Energy_Statistics_2022.pdf

APEC Energy Overview – https://aperc.or.jp/reports/energy_overview.php

Government of Viet Nam – http://chinhphu.vn/portal/page/portal/chinhphu/trangchu

Ministry of Industry and Trade – www.moit.gov.vn/

National Energy Efficiency Program (VNEEP) – http://vneec.gov.vn/

Viet Nam Electricity (EVN) – www.evn.com.vn

Energy Savings – https://tietkiemnangluong.evn.com.vn/

Viet Nam Energy – http://nangluongvietnam.vn

Viet Nam Oil and Gas Group (PVN) – www.pvn.com.vn

Viet Nam National Petroleum Group (Petrolimex) – https://petrolimex.com.vn/

Viet Nam National Coal and Mineral Industries Holding Corporation Ltd (Vinacomin) – www.vinacomin.vn/

Viet Nam Economic Times – https://vneconomy.vn/

Viet Nam News Agency – https://vietnamnews.vn/

General Statistics Office – https://www.gso.gov.vn/



Annex

Conversion Factors

From Petajoule (PJ) to		Multiply by:
Trillion British thermal units	TBTU	0.948
Million tonnes of oil equivalent	MTOE	0.024
Million barrels of oil equivalent	MMBOE	0.164
Million tonnes of coal equivalent	MTCE	0.017
Million tonnes per annum of LNG	Mtpa	0.020
Billion cubic meters of natural gas	bcm	0.028
Billion cubic feet of natural gas	bcf	0.981
Terawatt-hour	TWh	0.028
Million gigacalorie	Million GCal	0.239
Million tonnes of hydrogen	MM tonne H_2	0.008

Regional Groupings

China	
Northeast Asia	Hong Kong, China; Japan; Korea; Chinese Taipei
Oceania	Australia; New Zealand; Papua New Guinea
Other Americas	Canada; Chile; Mexico; Peru
Russia	
Southeast Asia	Brunei Darussalam; Indonesia; Malaysia; the Philippines; Singapore; Thailand; Viet Nam
United States	

Commonly Used Abbreviations

AI	Artificial intelligence
AFOLU	Agriculture, forestry, and other land use
APEC	Asia-Pacific Economic Cooperation
APERC	Asia Pacific Energy Research Centre
ASEAN	Association of Southeast Asian Nations
bcm	Billion cubic metres
B20/B30	Diesel fuel with 20%/30% biodiesel blending
BEV	Battery electric vehicle
CAPEX	Capital expenditure
CC	Carbon capture
CAGR	Compound annual growth rate
CCS	Carbon capture and storage
CCUS	Carbon capture, utilisation, and storage
CHP	Combine heat and power
CNG	Compressed natural gas
CO_2	Carbon dioxide
COP	Conference of the Parties
COVID-19	Coronavirus disease 2019
EE	Energy efficiency
EGEDA	Expert Group on Energy Data and Analysis
EV	Electric vehicle
EWG	APEC Energy Working Group
FCEV	Fuel cell electric vehicle
FIT	Feed in tariff
GDP	Gross domestic product
GHG	Greenhouse gas
GW	Gigawatt
HVDC	High voltage direct current
ICE	Internal combustion engine
IEA	International Energy Agency
IMF	International Monetary Fund
IPCC	Intergovernmental Panel on Climate Change
IPPU	Industrial processes and product use
kV	Kilovolt
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
Mtpa	Million tonnes per annum
MW	Megawatt
MTOE	Million tonnes of oil equivalent
MEPS	Minimum energy performance standards
NDC	Nationally determined contribution
NGL	Natural gas liquids
OECD	Organisation for Economic Co-operation and Development
OPEC+	Organisation of the Petroleum Exporting Countries Plus
PHEV	Plug-in hybrid electric vehicle
PJ	Petajoule
PPP	Purchasing power parity
PV	Photovoltaic
REF	The Reference scenario
SAF	Sustainable aviation fuel
SMR	Small modular reactor (nuclear)
SMR	Steam methane reforming (blue hydrogen production)
TGT	The Target scenario
TFEC	Total final energy consumption
TPES	Total primary energy supply
TWh	Terawatt-hour
Tx for VRE	Transmission for variable renewable energy
VPP	Virtual power plant
VRE	Variable renewable energy
UNFCCC	United Nations Framework Convention on Climate Change
ZEB	Zero energy building

Commonly Used Terms

Ammonia/hydrogen co-firing	Combusting ammonia and hydrogen with another fuel (e.g., coal or gas) in the same boiler/turbine to displace part of the fossil fuel and reduce overall emissions.
Amortised capex	The upfront capital expenditure (CAPEX) for constructing an energy asset, expressed as an equivalent annual cost over the asset's expected lifetime (using a discount rate). This annualised figure enables direct comparison with other yearly costs, such as fixed O&M, variable O&M, and fuel costs.
Biofuels	Fuels (liquid, gas, or solid) derived from biological materials instead of fossil fuels.
Biodiesel	In this publication, this is diesel-range fuel derived from biogenic oils and fats (e.g., used cooking oil, animal fats, palm-derived by-products). For modelling purposes, use is represented based on the projected share in total diesel: either as a drop-in blendstock or as a fully drop-in fuel that can be used neat or blended when the projected share exceeds blend limits.
Biogasoline	In this publication, this is gasoline-range fuel derived from biomass (e.g., ethanol and other oxygenates, and renewable hydrocarbon gasoline from upgraded bio-oils or co-processing). For modelling purposes, use is represented based on the projected share in total gasoline: either as a drop-in blendstock or as a fully drop-in fuel that can be used neat or blended when the projected share exceeds blend limits.
Biojet-kerosene	In this publication, this is aviation turbine fuel derived from renewable or waste feedstocks. For modelling purposes, use is represented based on the projected share in total aviation fuel: either as a drop-in blendstock or as a fully drop-in fuel that can be used neat or blended when the projected share exceeds blend limits.
Biomass	Organic material from plants, animals, or microbes (including residues and waste) used for energy or materials.
Bunkers	Fuels supplied to international aviation and maritime navigation. These are reported separately from domestic consumption in energy statistics.
Capital expenditure (CAPEX)	Investment outlays to build new capacity or replace existing long-lived energy assets that have been retired. CAPEX is presented as overnight costs (total upfront build cost, excluding financing) or amortised costs (annualised over the asset's lifetime).
Capacity factor	Actual generation over a period divided by generation at continuous rated output for the same period (%).
Carbon intensity	Greenhouse-gas emissions per unit of energy supply, demand, or economic activity (e.g., gCO_2/kWh, gCO_2/PJ, $MtCO_2$/USD GDP), as the context specifies.
Carbon neutrality	Residual greenhouse-gas emissions balanced by removals over a stated period.
Carbon capture	Separation of CO_2 from point sources or air.
Dispatchable capacity/ generators/power	Generation that can be scheduled and adjusted on request to meet demand.
E-fuels (synthetic fuels)	Fuels made with renewable electricity, water and captured CO_2—including e-diesel, e-gasoline and e-kerosene—treated in this publication as drop-in and blendable with their conventional equivalents.
Electrification	Substituting electricity for direct fuel combustion in end-uses (e.g., heat pumps, electric vehicles, electric arc furnaces).
Energy intensity	Final (or primary) energy use (or supply) per unit of economic output (e.g., PJ/USD, GDP).
Fuel switching	Process of replacing one fuel with another. Often used in the context of replacing a carbon-intensive fuel with a lower-carbon or zero-carbon alternative fuel.

Fixed costs	Expenses that remain constant in the use of an energy asset and do not vary based on electricity generation. Common examples include staff salaries, insurance, and routine inspections.
Low-carbon & waste energy	Low-carbon & waste energy includes all bioenergy, waste-derived energy, renewables, nuclear, and hydrogen-based fuels.
Low-emission technologies	Technologies that significantly reduce emissions relative to incumbent options (especially greenhouse gases).
Hydrogen-based fuels	In this publication, this includes hydrogen, ammonia, and e-fuels, used as energy carriers.
Clean hydrogen	Hydrogen produced through processes that generate minimal direct carbon emissions during production. This primarily refers to hydrogen produced via electrolysis using electricity from renewable energy sources (solar, wind, hydroelectric, etc.), commonly known as green or renewable hydrogen. Clean hydrogen may also include hydrogen produced using nuclear-powered electrolysis (pink hydrogen) and other carbon-free production methods. For classification purposes clean hydrogen is a subset of low-carbon hydrogen.
Low-carbon hydrogen	In the context of the Outlook, low-carbon hydrogen is used as a catch-all term for clean hydrogen that was exported and blue hydrogen that was produced or imported. Low-carbon hydrogen refers to clean hydrogen produced and exported to hydrogen importing economies as emissions would be incurred during transportation and distribution. It was assumed that most hydrogen traded amongst APEC economies would be of this form (specifically green hydrogen) with a small proportion being blue hydrogen. Additionally, in the context of hydrogen-producing economies, low-carbon hydrogen specifically refers to hydrogen being produced using fossil fuels with technologies such as CCS or methane pyrolysis that cut lifecycle emissions by at least 90% compared to unabated production. A key example is blue hydrogen made from natural gas via SMR or ATR with CCS.
Unabated hydrogen	This includes hydrogen produced from natural gas via steam methane reforming (SMR) or auto thermal reforming (ATR) without CCS, also known as grey hydrogen, hydrogen from coal gasification without CCS, also known as black or brown hydrogen, and hydrogen produced via electrolysis using electricity from fossil fuel-dominated power grids, also known as yellow hydrogen.
Grid modernisation	Upgrades that enhance electricity networks' efficiency, resilience, and flexibility (e.g., digitalisation, advanced controls, storage integration).
Modern renewables	In this publication, "modern renewables" includes all renewable energy sources except solid biomass in the buildings sector.
Modal share	Also called modal split, it is the percentage distribution of travel or trips made using different modes of transportation (e.g., bus, car, boat, plane) within an economy or area.
Non-energy demand	Refers to the use of energy resources, primarily fossil fuels, as raw materials or feedstocks for producing goods, rather than for combustion or power generation (e.g., oil used in petrochemicals).
Net-zero emissions	Economy-wide balance between anthropogenic emissions and removals of greenhouse gases by a target date.
Sustainable aviation fuels (SAF)	Alternative aviation fuel derived from liquid biofuels or e-fuels , instead of fossil petroleum.
System flexibility	Refers to the ability of an energy system, such as an electrical grid, to dynamically adjust both power generation and consumption to maintain a stable and balanced supply-demand relationship under varying conditions.
Petroleum liquids	All fuels within the categories of refined petroleum products, crude oil, natural gas liquids, and other hydrocarbons.
Variable cost	Costs that fluctuate in direct proportion to the electricity produced by the asset. Common examples include fuel costs, maintenance, and cleaning that scale with operation.

Guidance on Figures

This report follows a standard layout to support comparison between scenarios. All charts are arranged so that, when two appear side by side, the left chart always represents REF, and the right chart always represents TGT.

Drivers in the transport energy decomposition chart:

This chart is a log mean divisia index (LMDI) decomposition showing the drivers of changes in energy use in the road sector.

- Activity: The change in energy use caused by growth in passenger-km and freight tonne-km, with all other effects held constant.
- Vehicle size/type: The change in energy use caused by changes in the type of vehicle used (such as from car to bus, car to SUV, etc.).
- Engine Type: The change in energy use caused by changes in the type of engine used in vehicles. Most of this effect is caused by shifts from ICE (internal combustion engines) to BEVs (battery electric vehicles).
- Other Factors: The change in energy use caused by all other modelled factors, which include the degradation of pre-existing vehicle efficiency due to age and improvements in overall ICE vehicle efficiency, which is not captured by the engine type effect since that captures changes in the engine type distribution compared to the base year.

CO_2 emissions components:

This chart also uses the LMDI decomposition method to represent the Kaya identity, which employs the following formula:

$$CO_2 \text{ emissions} = \text{Population} \times \frac{\text{GDP}}{\text{Population}} \times \frac{\text{Energy supply}}{\text{GDP}} \times \frac{CO_2 \text{ emissions}}{\text{Energy supply}}$$

- Population: The change in emissions caused by population growth or decline.
- GDP per capita: The change in emissions caused by an increase or decrease in GDP per capita $\left(\frac{\text{GDP}}{\text{Population}}\right)$.
- Intensity REF: The change in emissions caused by improvements or decreases in energy and carbon intensity $\left(\frac{\text{Energy supply}}{\text{GDP}} \times \frac{CO_2 \text{ emissions}}{\text{Energy supply)}}\right)$ in REF.
- Intensity TGT: The change in emissions caused by further change in intensity in TGT compared to REF.


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