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8th ASEAN ENERGY OUTLOOK
2023 - 2050

One Community
for Sustainable
Energy

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ASEAN Centre for Energy
Soemantri Brodjonegoro II Building, 6th fl.
Directorate General of Electricity
Jl. HR. Rasuna Said Block X-2, Kav. 07-08
Jakarta 12950, Indonesia
Tel: (62-21) 527 9332 | Fax: (62-21) 527 9350
E-mail: secretariat@aseanenergy.org
www.aseanenergy.org

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About ACE

Established on 1 January 1999, the ASEAN Centre for Energy (ACE) is an intergovernmental organisation within the Association of Southeast Asian Nations' (ASEAN) structure that represents the 10 ASEAN Member States' (AMS) interests in the energy sector. ACE supports the implementation of the ASEAN Plan of Action for Energy Cooperation (APAEC), a blueprint for better collaboration towards upgrading energy. The Centre is guided by a Governing Council composed of Senior Officials on Energy from each of the AMS and a representative from the ASEAN Secretariat as an ex-officio member.

The three key roles of the ACE:

- *As a catalyst to unify and strengthen ASEAN energy cooperation and integration by implementing relevant capacity-building programmes and projects to assist the AMS develop their energy sector.*
- *As the ASEAN energy data centre and knowledge hub to provide a knowledge repository for the AMS.*
- *As an ASEAN energy think tank to assist the AMS by identifying and surfacing innovative solutions for ASEAN's energy challenges on policies, legal and regulatory frameworks and technologies.*

Keeping the region's energy security, affordability, and sustainability is a fundamental concern of the ASEAN energy sector. Hosted by the Ministry of Energy and Mineral Resources of Indonesia, ACE's office is located in Jakarta, Indonesia. For more information, please visit aseanenergy.org.

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- Workshop I – Data & Scenario and AMS Capacity Building on Technology Roadmap & ICT for Data Analysis (November 2023)
- Country Visits (January-March 2024)
- Workshop II – Model & Result and AMS Capacity Building on Enhancing System, Infrastructure and Societal Resilience (May 2024)
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Forewords

With great pleasure, I am presenting to you the 8th ASEAN Energy Outlook (AEO8), the flagship publication of the ASEAN Centre for Energy (ACE). This publication complements the ASEAN Plan of Action for Energy Cooperation (APAEC) by presenting the ASEAN region's energy landscape and providing potential pathways to achieve regional energy targets, including setting up new targets.

Driven by rapid economic growth, industrialisation and urbanisation, the ASEAN energy demand is projected to increase. Fossil fuels remain a key component to meet the growing demand. Nevertheless, the region is fully committed to ensuring an inclusive energy transition. In balancing the low carbon transition with energy security and economic growth, the "low hanging fruit" efforts of energy efficiency are yet to be fully optimised. A shift to a cleaner supply is crucial not only to decarbonise the energy system but also to improve energy independence.

Amidst these critical issues, AEO8 presents the latest overview of the ASEAN energy sector and assesses its key trends. The report starts exploring the pathways of the energy sector through the Baseline Scenario (BAS) and AMS Targets Scenario (ATS). The previous APAEC Targets Scenario (APS) in AEO7 is now escalated with enhanced constraints and least-cost optimisation in the power sector, delivered under the moniker of the Regional Aspiration Scenario (RAS). Further, a new scenario based on net zero pledges and ambitious decarbonisation efforts by AMS has also introduced: the Carbon Neutrality Scenario (CNS).

The reference year of 2022 shows that ASEAN has reached a 15.6% renewable energy (RE) share in the total primary energy supply (TPES) and 33.6% in installed power capacity, also 24.5% energy intensity (EI) reduction compared to 2005. AEO8 shows the opportunities and challenges for the region in realising the 2025 targets, including 23% of RE share in the TPES and 32% of EI reduction. Based on the ATS, these targets are projected to be achieved by 2030 and 2026, respectively. However, ASEAN is set to overachieve its 2025 target of renewables in installed power capacity-35%-by more than 4%-points.

In secondary analysis, AEO8 features enhancements in two areas: land use for renewables and employment. This report provides an analysis of land use requirements for solar and wind compared to coal –an advancement from AEO7 that only addressed land use for biofuels. With the expected transformation in the workforce, this report also includes an improved analysis of potential job losses due to the shift away from fossil fuels. Thus, robust policy reforms are essential, particularly to mitigate impacts on vulnerable communities.

AEO8 is also timely as ASEAN is designing the next cycle of its energy cooperation blueprint, the APAEC. As the only official energy outlook in the region, new targets and strategies to be introduced in the APAEC Post-2025 will draw inspiration from the AEO8 scenarios. AEO8 is of paramount importance in designing and driving the energy cooperation in ASEAN for the foreseeable future. It also shows how ASEAN develops its energy cooperation blueprint, the APAEC, following the principle of evidence-based policymaking, utilising the data and both quantitative and qualitative analysis produced by the AEO8.

As ASEAN looks ahead, ACE remains fully committed to supporting AMS in achieving the transition to sustainable energy. I extend my deepest gratitude and appreciation to our in-house team, the spirited discussions and collaboration with all the AMS Working Group members, and the support from our partners in developing this report. The AEO8 stands as a step forward, showcasing the joint efforts of friendship and cooperation for the ASEAN people. I hope that this report serves as a valuable reference for AMS and dialogue partners, to fully utilise this publication in a manner of elevating the ASEAN energy sector.

Beni Suryadi
Acting Executive Director
ASEAN Centre for Energy

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EXECUTIVE SUMMARY

The ASEAN Energy Outlook

Since its inception in 2006, AEO has emerged as a cornerstone document supporting ASEAN's energy policy and planning. Guided by the ASEAN Plan of Action for Energy Cooperation (APAEC), especially the Regional Energy Policy and Planning (REPP) Programme Area, the AEO series has consistently provided valuable insights into energy trends and projections across the ASEAN region. It provides regular updates on regional energy trends and delivers strategic reports on essential topics, such as energy access, affordability, efficiency, security, and environmental sustainability. The AEO evaluates whether national and regional energy goals can be achieved and identifies the necessary policies, measures, and technologies.

The AEO stands out from other energy outlooks because it is grounded in rigorous data and modeling, developed through a close partnership between the ASEAN Centre for Energy (ACE) and the ten ASEAN Member States (AMS). The AMS contribute much of the data used in the AEO, and they thoroughly validate the modeling results in each workshop conducted over the years of 2023-2024 to ensure they represent current conditions and align with regional development plans. This cooperative approach promotes a sense of ownership and enhances the relevance and application of the findings for all countries involved further embodying the spirit of "from ASEAN by ASEAN to ASEAN."

The 8th ASEAN Energy Outlook (AEO8) also becomes more important as the findings of this outlook will influence ASEAN energy policymakers gearing up towards its final year of APAEC Phase II: 2021-2025. The next cycle of APAEC 2026-2030 is expected to align with the directives of the new ASEAN Community Vision 2045 and the 5-year timeframe of ASEAN Economic Community Strategic Plans, promoting a more integrated and comprehensive approach.

AEO8 is poised to serve not only as a guiding compass but also as a catalyst for the formulation of visionary regional targets and driving strategic energy policy development for the APAEC 2026-2030 and also for a coming transformative decade.

Modelling Structure

Recent editions of the AEO have adopted a new, bottom-up modelling approach, better suited for examining the implications of national and regional policies and providing a technology-rich picture of how ASEAN's energy systems will grow and change in the coming decades.

The AEO8 builds on its bottom-up modelling approach with more detailed analyses for the commercial and industrial sectors, providing deeper insights into how national and regional targets can be achieved while taking into account the unique characteristics of each Member State. The main AEO model incorporates resource use and conversion flows from the Energy Balance Table (EBT).

For AEO8, the Low Emissions Analysis Platform (LEAP) and the Next Energy Modelling System for Optimisation (NEMO) were employed. LEAP is a scenario-based, demand-driven tool capable of tracking energy consumption, production, and resource extraction across economic sectors, while NEMO optimises the supply side, particularly electricity generation, through mixed-integer linear optimisation. Furthermore, optimisation for the demand side is carried out outside LEAP using the General Algebraic Modelling System (GAMS), a high-level tool designed to solve linear, nonlinear, and mixed-integer optimisation problems. In addition, secondary analysis for emissions is inherited from the LEAP, whereas the energy employment and land use of renewables were calculated separately.

Scenarios

AEO8 projection illustrates four scenarios for 2023 – 2050 based on the historical data from 2005 to 2022. The degree of ambition escalates from the first to the last scenario. The Baseline Scenario (BAS) follows the historical trend without any policy intervention, whilst the AMS Targets Scenario (ATS) considers the energy policies of each AMS, such as power development plans, renewable energy (RE), and energy efficiency and conservation (EE&C). Keeping the 2025 APAEC targets, the Regional Aspiration Scenario (RAS) uses least-cost optimisation (LCO) in the power sector with accelerated targets of each AMS, whilst the Carbon Neutrality Scenario (CNS) serves as an alternative scenario that considers enhanced decarbonisation efforts using the LCO of net-zero technologies.

Charting Multiple Pathways

Energy Demand

National efficiency measures and fuel shifting are projected to reduce the energy demand by 32.7% by 2050 in the ATS, compared to the BAS. By incorporating accelerated national policies, the RAS projects to achieve a 47.9% demand reduction versus the BAS by mid-century, whilst the CNS further boosts this to 36.9% and 18.6% lower than the ATS and RAS, respectively. These savings are accomplished through various strategies, such as enhancing energy efficiency in electric technologies within the residential and commercial sectors (e.g., efficient lighting, cooling systems, and appliances), optimising industrial processes, improving fuel economy, and increasing the use of electric vehicles (EVs) in the transport sector.

The industry is among the major energy-consuming sectors that remain highly reliant on coal, electricity, and natural gas. This mix and trends are projected to be the same from 2022 through 2050 in all scenarios. It indicates that coal and natural gas are indispensable for energy requirements in the ASEAN industrial sector. 'Non-Metallic Minerals' and 'Iron and Steel' consistently emerge as the highest energy-intensive sectors due to their processes, making them the key to decarbonise. While Member States have set targets for reducing energy intensity, achieving these goals will be challenging due to the current scarcity of data, which is often proprietary. This lack of accessible information makes accurate accounting difficult, hindering the implementation and monitoring of effective energy-saving programmes. It is essential to intensify efforts to improve data quality to ensure that energy savings can be properly managed and monitored within the sector.

The second highest is the transport sector. In the RAS, the alignment with the accelerated AMS' biofuel blending mandates and EV penetration targets, as well as the ASEAN Fuel Economy Roadmap, will reduce energy demand by 53.8% by 2050, compared to the ATS. The use of hydrogen and Sustainable Aviation Fuel (SAF) as alternative fuels are expected to be introduced as soon as 2023 and 2024, respectively, to further decarbonise aviation and heavy-duty vehicles. Attainment of EV deployment targets will also be crucial. Although several Member States have set promising strategies for increasing EV uptake, many specify the sales targets rather than penetration, which is more challenging to model in the Outlook. Thus, the scenario with national policies (ATS) is projected to lead to an EV share of only 1.4% of the passenger road transportation fleet by 2030 and 7.4% by 2050 in the ATS. Higher and more specific targets on penetration are required to accelerate EV adoption, coupled with establishing policies in some AMS that have not yet set EV deployment objectives. Despite the low penetration, the deployment of electric passenger vehicles is expected to reduce oil usage, including gasoline and diesel, by 52.1% by 2050 in the ATS, as compared to the BAS.

The residential sector demand is projected to decline due to end-use devices' improved efficiency, by 22.7%, 37.5%, and 44.3% in the ATS, RAS, and CNS, respectively, as compared to the BAS. Generally, the primary contributors to energy consumption in residential are cooking, refrigeration, and air conditioning. With implementing national EE&C efforts, air conditioning and lighting show the highest drops at 38.5% and 33.1%, respectively, as compared to the BAS. Improved policies that promote clean cooking methods and electrification could significantly decrease reliance on traditional fuels, such as wood and charcoal for cooking. Urban households are increasingly switching from LPG stoves to electric alternatives, while rural areas are transitioning from traditional biomass to LPG. These shifts reduce dependence on imported fuels and improve indoor air quality, thereby enhancing residential well-being.

The commercial sector had various effective policies in place to be enhanced. With the adaption of energy efficiency measures in each of the AMS — including Minimum Energy Performance Standards (MEPS) for appliances, building energy codes, and mandatory energy management systems — the ATS projects overall energy consumption to be reduced by 33.6% to 50.4 Mtoe by 2050, as compared to the BAS. The RAS and CNS predict this sector's energy demand would be even lower, which are 37.6 Mtoe and 29.1 Mtoe, respectively.

Primary Energy Supply

The AEO8 modelling finds that national and regional policies can reduce the overall growth in the total primary energy supply (TPES) and make a series of supply shifts to renewables throughout the projection years. By 2050, the ATS and RAS are projected to reduce the fossil fuels share in the TPES by around 18.6%-points and 25.0%-points, respectively, from the 2022 level. In the more ambitious scenario (CNS), RE supply jumped almost seven times in exchange for 48.6%-points reduction in fossil fuel share, accounting for 697.3 Mtoe for existing types of RE, whilst new RE technology like tidal and wave can potentially generate up to 18.0 Mtoe in 2050.

Natural gas is expected to play a crucial role as a transitional energy source, especially in the CNS, where its use rises as coal is phased out. Additionally, CNS highlights the growing importance of advanced technologies such as Carbon Capture and Storage (CCS) and the adoption of new renewable sources like tidal and wave energy. Nuclear energy is also projected to contribute to the energy mix from 2035 onwards in all scenarios except the baseline.

Oil supply increased, maintaining the largest total supply addition between 2022 and 2050 at about 321.3 Mtoe. However, oil supply decreased when compared to ATS, RAS, and CNS, which were 39.5%, 51.8%, and 81.8%, respectively. The percentage of fossil fuel used in transportation has decreased as a result of greater biofuel blending requirements in AMS. The adoption of EVs and the development of hydrogen will also reduce the demand for biofuels to replace fossil fuels.

Import Dependence

Under the BAS, ASEAN is projected to become a net importer of natural gas by 2027. This dependency on fossil fuel imports in the future poses severe energy security risks, potentially affecting energy affordability and increasing price volatility. In contrast, coal exports are expected to continue until at least 2050, though its balance is becoming lower. Public opinion in ASEAN countries shows strong support for halting new coal plant construction immediately, with over half of respondents in favor, and nearly two-thirds backing the phase-out of coal consumption by 2030.

Installed Power Capacity

In 2022, ASEAN's installed power capacity was predominantly reliant on fossil fuels, making up around 66.4% of the energy mix. While fossil fuels will continue to play a significant role without policy interventions, the ATS and RAS are expected to accelerate the shift towards RE, reducing the region's dependency on gas, coal, and oil as electricity demand increases. By 2050, the ATS forecasts a 28.9% decrease in fossil fuel reliance. RE is projected to steadily increase its share in the power capacity across all scenarios, with the most rapid growth in the ATS and RAS, particularly for solar PV and wind energy. Hydro and geothermal energy maintain stable but smaller contributions, while nuclear and other emerging technologies like bioenergy, tidal, and wave remain minor but grow under specific scenarios.

Electricity Generation and Storage

Across all scenarios, there is an expected increase in total power generation in ASEAN by 2050, driven by rising energy demand due to economic and population growth. The projected electricity generation for 2050 is approximately 3,036 TWh under the BAS, 2,769 TWh under the ATS, and 2,920 TWh under the RAS. This growth aligns with the trends in installed capacity, particularly in renewable energy, which is anticipated to play a crucial role in meeting the region's expanding energy needs. The RAS is projected to exceed the ATS in total electricity generation by 2050, balancing energy security, affordability, and sustainability through a diverse mix of electricity generation technologies. Most of the member states are projected to increase power generation by diversifying energy sources and enhancing energy security. The shift towards a cleaner and more diversified energy mix, especially under RAS, reflects substantial growth in renewable technologies such as solar PV and wind, reducing reliance on non-renewable sources. Natural gas remains a stable transition fuel across scenarios, while hydroelectric power, geothermal, and bioenergy continue to support specific regions, underscoring ASEAN's commitment to balancing economic growth, energy security, and environmental sustainability.

Modelling of the ASEAN Power Grid (APG) and battery and energy storage systems were also explored as a part of the RAS and CNS. Battery energy storage system (BESS) facilitates the integration of variable RE, especially solar and wind into the APG, storing excess electricity during peak hours. This integration is crucial for maintaining grid stability and reliability, especially during peak demand periods or when renewable generation is low.

Energy Access

ATS projects that the region's electrification rate will reach 99.9% by 2030 and 100% by 2040. The ASEAN region also faces challenges in providing universal electrification due to many remote and hard-to-reach areas. Indonesia is expected to achieve 100% electrification by 2025, followed by the Philippines in 2028 with an annual average growth rate (AAGR) of 0.65% between 2022 and 2028. Both are archipelagic countries. Policy biases towards large projects, lack of integration with rural development efforts, and dependency on donor assistance for off-grid electrification contribute to concerns about the electrification process. Successful electrification cases in Southeast Asia suggest that grid extensions are preferred, and top-down approaches are effective when supported by strong implementation strategies.

In terms of clean cooking, while ASEAN may not achieve universal access under any of the four scenarios, significant progress is being made. In the ATS, only four out of ten AMS will achieve 100% clean cooking access by 2030. In the RAS, eight AMS are expected to achieve 100% clean cooking access by 2030. Indonesia and Thailand will achieve this by 2026, while Cambodia and Myanmar will follow in 2028, all ahead of the Sustainable Development Goal 7 (SDG7) target year.

ASEAN 2025 Targets

RE is crucial for achieving a sustainable future, with ASEAN targeting a 23% share of renewables in TPES by 2025 under APAEC Phase II. As of 2022, the RE share stood at 15.6%, presenting a challenge to reach the target within three years. While the ATS is projected to meet the target by 2030, and the RAS by 2029, both scenarios show significant increases in RE share by 2050, reaching 38.1% and 50.4%, respectively, driven by supportive policies and technological advancements. ASEAN RE growth is boosted by expanding hydropower, geothermal, and other renewables like solar and wind, particularly under the CNS, where RE share could reach 70.2% by 2050. Despite the progress, ASEAN faces challenges in accelerating the transition away from fossil fuels, balancing ambitious targets with feasibility, and addressing constraints related to biomass reliability and infrastructure investments for emerging technologies.

ASEAN aims for a 35% RE share in installed capacity by 2025. It reached 33.6% in 2022, and the ATS and RAS are on track to surpass this target, reaching 39.6% and 41.3%, respectively, while the BAS is expected to fall short at 34.2%. By 2050, RE shares in the ATS and RAS are projected to rise significantly, reaching 69.4% and 71.7%, driven by strong RE policies and a balanced approach to ambitious targets and cost optimisation.

ASEAN aims for a 32% reduction in energy intensity (EI) by 2025 from the 2005 level under APAEC Phase II. By 2022, a 24.5% reduction was achieved, indicating progress but still short of the target. Projections suggest that the ATS would reach 31% by 2025, slightly missing the target, while the RAS and CNS are on track to meet or exceed it with reductions of 34.2% and 33.7%, respectively. By 2050, the BAS and ATS show substantial gaps, with reductions of 45.0% and 63.2%, respectively, whilst the RAS and CNS project greater reductions of 69.4% and 69.2%, respectively. Achieving further EI reductions will require enhancing national efforts by implementing cost-effective measures in key sectors such as transportation, cooking, and cooling, accelerating the adoption of EVs, improving fuel efficiency, and expanding mass transit. Financial incentives and public-private partnerships should also be leveraged to promote clean technologies and reduce financial risks in energy efficiency projects.

Energy Financing

The high upfront costs and low margins are particularly prominent in the power sector among other sectors since power generation requires significant infrastructure. As the power sector expands across the region, the total financial cost is required to deploy energy generation infrastructure, particularly the implementation of emerging and low-carbon technologies.

The power investment cost across scenarios shows an upward trend by 2050 as the scale of additional installed capacity is projected to increase. All scenarios follow an increasing trend reaching the highest value for the CNS as it integrates net-zero technologies and associates with capital-intensive projects. Moreover, the region will experience massive power investment costs in the longer term for additional capacity infrastructure and to meet the electricity demand. In earlier years (2023-2030), the annual power investment requirement varied from USD 20 billion toUSD 56 billion, while the long-term (2041-2050) ranges from USD 28 billion to USD 371 billion. However, the cost of production shows that the BAS would record as the highest in all projection years, having large externality costs.

Greenhouse Gas Emissions, Job Creation, and Land Use

The GHG emissions reached 2,215.2 Mt CO_2-eq in 2022, increasing almost two times from 1,175.1 Mt CO_2-eq in 2005, covering demand and power sectors. In the demand sector only, the GHG emissions reached 1,080.7 Mt CO_2-eq and will increase to 2,667.7 Mt CO_2-eq by 2050 in BAS. AEO8's modelled policy measures are projected to slow the rate of increase in emissions significantly. ATS will reduce the emissions by 46.9% compared to the Baseline Scenario. The avoided emissions between these two scenarios mostly come from electricity generation, which declines by 71.8%, due to the shift of power sources from fossil fuels to cleaner energy. The emissions gaps are also supported by fuel shifting and fuel economy in transportation, having lower emissions by 53.4% in ATS.

The energy transition in ASEAN is estimated to have a profound impact on the region's energy jobs, gradually shifting the workforce from fossil fuels to RE sectors. During the first decade of the projection (2020-2030), job additions across four scenarios remain consistent, with total jobs ranging from eight to ten million. Fossil fuels dominate employment, although RE jobs show growth. By the second decade (2030-2040), a shift towards RE is evident, especially under the RAS and CNS. Fossil fuels job creation will drop sharply after 2030 due to the smaller capacity installations. Consequently, the bulk of employment will be mainly found in construction and installation (C&I) and operation and maintenance (O&M) jobs, while fuel-related jobs decline sharply as fossil fuels phase out. Between 2040 and 2050, fossil fuels job creation remains significant in the BAS, with over 11.8 million jobs added, comprising 73.7% of total employment, driven by 622 GW of new capacity. In contrast, ATS sees renewable capacity additions ten times higher than fossil fuels, leading to a larger share of RE jobs. Countries such as Vietnam, the Philippines, and Indonesia emerge as major contributors to job creation under the RAS, primarily due to large-scale RE projects. Vietnam is estimated to account for over 1.6 million new jobs between 2045 and 2050, with a significant portion tied to O&M job roles in the solar and wind sectors.

Net employment continues to grow in the BAS, reaching over 6 million jobs by 2045-2050, as fossil fuels remain a dominant energy source. Nevertheless, energy transition leads to considerable job losses in the fossil fuels sector. Total net employment under the RAS and CNS would decline between 2030 and 2040 as fossil fuel jobs rapidly disappear, although RE jobs help stabilise employment by 2050. The CNS projects over 3.2 million job losses by 2050 due to fossil fuel plant decommissioning. These trends highlight the importance of managing workforce transitions through retraining programmes and strategies to support workers affected by the decline of fossil fuels in ASEAN's energy transition.

A shift towards sustainable energy sources is projected to impact environmental loading, particularly concerning land requirements. Biofuels are increasingly integral to the energy mix of AMS, enhancing energy diversification and facilitating decarbonisation efforts. As countries like Indonesia, Malaysia, the Philippines, and Thailand advance biofuel blending mandates for biodiesel and bioethanol in the transportation sector, the total land requirement for biofuel production is projected to reach approximately 11.1 million hectares by 2050 under the BAS, with a substantial allocation of 8.4 million hectares for biodiesel. However, the CNS suggests a reduction in land use, with an estimation of 2.2 million hectares needed, achieved through optimised power supply and the integration of low-carbon technologies. The implications of these trends necessitate careful consideration of land use policies to balance biofuel production with environmental sustainability.

In parallel, the deployment of solar and wind power is rapidly transforming the energy landscape of the region, with installed capacities expected to grow significantly by 2050. As of 2022, solar and wind made up about 10% of the ASEAN energy mix, but this figure is projected to increase substantially, with land requirements anticipated to rise correspondingly. By 2050, the land allocated for solar and wind projects could occupy as much as 1 million hectares under the absence of energy policy interventions, increasing to 4 and 5 million hectares under more aggressive policy frameworks in the ATS and RAS, respectively. Notably, while wind technology demands more land than solar, both energy sources present opportunities to optimise land use. Engaging local communities in decision-making is critical to mitigating socio-ecological impacts, ensuring Free, Prior, and Informed Consent (FPIC), and fostering a sustainable energy transition that respects land rights and local aspirations.

How Should ASEAN Set Its Future Energy Planning?

"To drive a just and sustainable energy transition in ASEAN, it is essential to enhance energy efficiency, diversify renewable energy sources, and integrate advanced technologies like smart grids and hybrid systems. Regional cooperation, supportive policies, and inclusive stakeholder engagement are crucial to ensuring energy security, affordability, and resilience. A comprehensive approach that involves local communities, fosters innovation, and balances geopolitical considerations will enable ASEAN to meet its ambitious clean energy goals."

Future energy planning should adopt a multi-faceted approach, prioritising the following key considerations:

1. **Demand Side**
   - Enhance energy efficiency standards across buildings, appliances, and industrial processes through a harmonised framework to reduce total energy consumption.
   - Invest in energy-efficient machinery, technologies, and optimisation of industrial processes to lower energy intensity and operational costs.
   - Promote smart demand response in the power sector to optimise energy use, improve grid efficiency, and integrate renewable energy sources.
   - Expand electrification efforts to underserved rural communities with a focus on local involvement and capacity building.
   - Promote energy diversification in the industrial and transportation sectors, encouraging the use of biomass, biofuels, and electric vehicles.
   - Explore alternative long-term energy sources, such as hydrogen and sustainable aviation fuels (SAF), for decarbonisation.

2. **Supply Side**
   - Diversify renewable energy sources (hydro, geothermal, bioenergy, solar, wind) to reduce reliance on any single source and promote grid-scale energy storage technologies.
   - Develop hybrid systems that combine renewable energy with conventional fuels to ensure grid stability and reduce emissions.
   - Modernise electrical grids and invest in smart grid technologies to handle variable renewable inputs and improve grid reliability.
   - Balance the shift to cleaner energy sources with energy security by considering natural gas and Carbon Capture, and Storage (CCS) as transitional technologies.
   - Ensure comprehensive compensation and community inclusion when developing renewable energy projects on land occupied by indigenous groups.

- Carbon pricing is an important tool to accelerate decarbonisation efforts, but effective measures need to be deployed to address the anticipated concerns about increasing energy prices and industrial competitiveness.

3. **Regional Cooperation**
   - Develop supportive regulatory frameworks and policies that incentivise investment in clean energy technologies while ensuring energy security and affordability.
   - Foster international cooperation for sharing best practices and accessing global resources and technologies.
   - Engage various stakeholders, including policymakers, businesses, and communities, in the energy transition planning process to ensure broad support and address concerns.
   - Promote international agreements to enhance interconnectivity and flexibility, such as through the ASEAN Power Grid and cross-border gas pipelines.
   - Address geopolitical risks associated with international energy partnerships by prioritising regional solutions and strategic planning for international developments.

Recommendation for AEO Improvements

The AEO has evolved through various editions, each introducing unique approaches to projecting ASEAN's energy future, from AEO6's focus on SDG7 targets to AEO8's combination of regional aspirations and least-cost optimisation, as well as carbon neutrality scenarios. By integrating recent energy developments, regional policies, and global trends, key assumptions are updated, impacting the results and their interpretation. ACE continues to enhance the AEO model to strengthen its relevance and value for future ASEAN energy policymaking. Several potential improvements in the future include:

1. **Optimising All Sectors:**
   - Update cost data for all technologies and countries to account for differences in expenses related to fuel, transmission, CAPEX, OPEX, and other factors.
   - Expand LCO techniques beyond the power sector to include demand sectors, while enhancing model validation and verification to ensure comparability between different models.
   - Address challenges in obtaining detailed technology cost data by accessing industry-specific reports, consulting with technology vendors, or engaging experts with proprietary knowledge.

2. **Incorporating Interdisciplinary Analysis:**
   - Integrate cross-disciplinary data from economics, engineering, environmental science, and sociology to create more comprehensive energy models.
   - Include lifecycle costs, such as material use, disposal, and externalities like pollution impacts, to make models more reflective of real-world scenarios and promote cleaner energy choices.
   - Use diverse data inputs to encourage balanced decision-making, considering technical, economic, environmental, and social factors.

3. **Disaggregating Data:**
   - Improve model accuracy by collecting more granular data, such as industrial sub-sectors, to support targeted policy-making and identify specific areas of need or opportunity.
   - Enhance representations of the commercial sector by focusing on technology adaptation and specific end-use devices, such as data centres, to better tailor efficiency and conservation efforts.
   - Prioritise the collection of gender-disaggregated data to address the under-discussed energy-gender interaction and include gender-specific outcomes in future analyses.

REPORT OUTLINE

CHAPTER 1: Introduction

The introduction section provides an overview of the ASEAN energy landscape based on economic growth, aiming to maintain energy security and resilience in the region. This content overview explores the key drivers behind the growth in the energy consumption of ASEAN Member States (AMS, Efocusing on essential aspects such as safeguarding energy security and resilience, pursuing a just energy transition, and achieving carbon neutrality. It also delves into the critical issue of financing low-carbon energy systems and the importance of regional cooperation. Looking ahead, the discussion will outline the vision for a post-2025 blueprint that aims to address these challenges and harness opportunities for sustainable development.

The document examines the principal factors contributing to the escalation of energy consumption in ASEAN, including demographic aspect, economic development, and industrialisation.

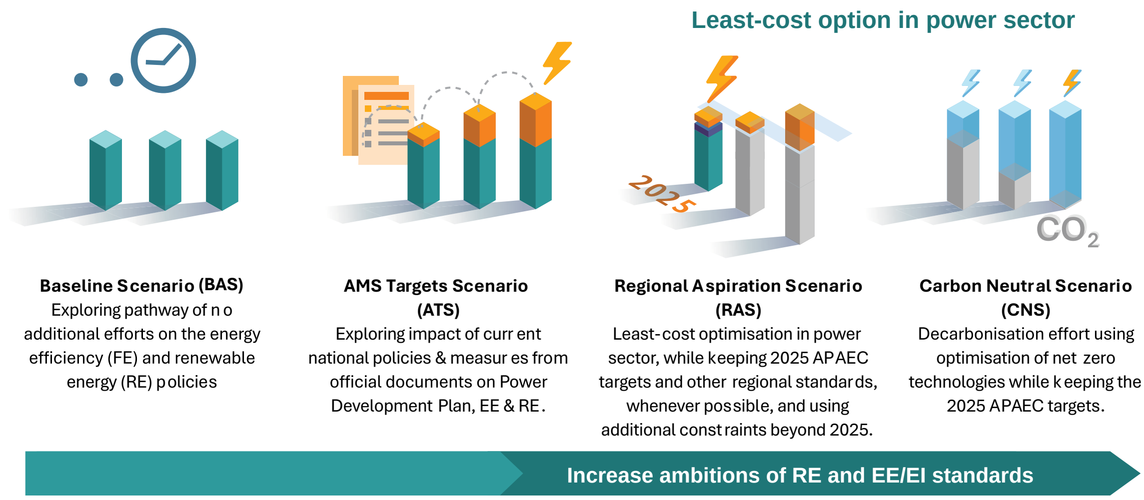
The articulation of the critical objectives and challenges related to ensuring energy security and resilience, achieving a just energy transition, and achieving carbon neutrality and financing low-carbon energy systems.

The role of the ASEAN Plan of Action for Energy Cooperation (APAEC) and the 8th ASEAN Energy Outlook (AEO8) supports in creation of pathways to address the challenges and aimed at fostering sustainable growth and collaboration within the region.

CHAPTER 2: Methodology

This section presents a comprehensive overview of the various scenarios and methodologies utilised to forecast and analyse future energy landscapes within the ASEAN region. It begins with a detailed examination of multiple scenarios, including the **Baseline Scenario (BAS), AMS Targets Scenario (ATS), Regional Aspiration Scenario (RAS)**, and **Carbon Neutrality Scenario (CNS)**. The discussion transitions to the methodologies employed in modeling these scenarios and the steps involved in data processing.

Historical data from 2005 – 2022 are projected out to 2023 – 2050 in four scenarios.



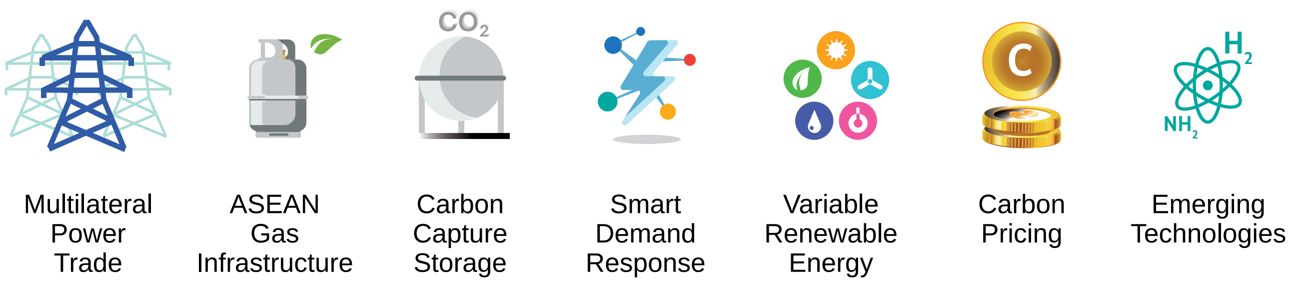
Following this, the discussion transitions to the methodologies employed in modeling the scenarios and the steps involved in data processing. By assessing the scenario frameworks and the technical approaches used, this section aims to present a thorough understanding of the potential pathways and analytical techniques critical for shaping the region's energy future.

CHAPTER 3: Charting Multiple Pathways

This section offers a comprehensive analysis of ASEAN's energy sector, detailing energy demand across industry, transport, residential, and commercial sectors. It explores energy supply, including primary sources, renewable energy share, energy intensity reduction, and trade. The review covers electricity aspects such as installed capacity, power generation, and storage technologies. Additionally, it addresses energy access, employment impacts, greenhouse gas emissions, financing, and land use for renewables, providing a broad overview of current and future energy dynamics in the region.

CHAPTER 4: A Strategic Approach to Energy Regional Blueprint

This chapter elaborates on seven emphasised energy sectors considered essential to attaining secure and reliable energy amidst transition.

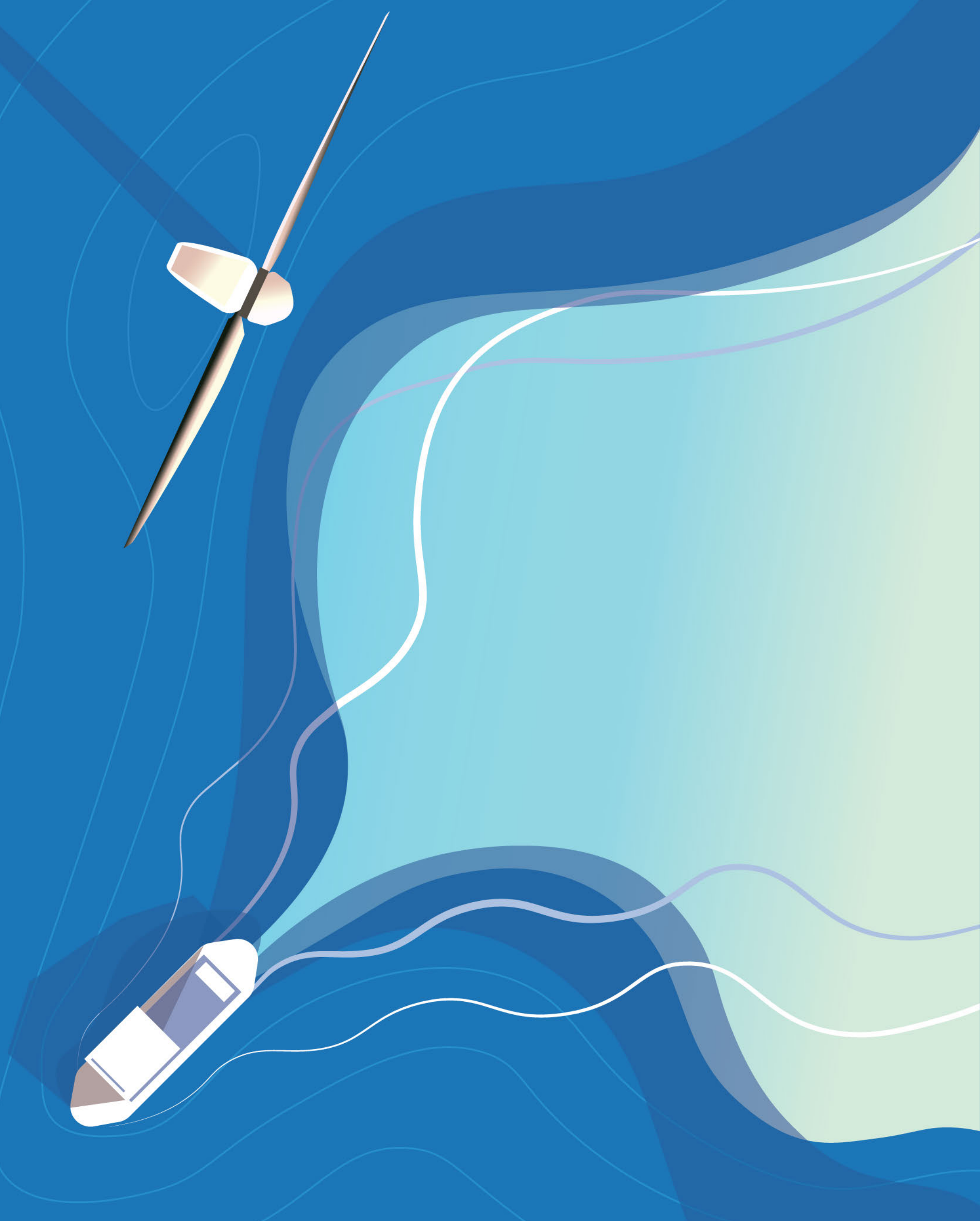


CHAPTER 5: Recommendations and Improvements

This concluding chapter offers key energy policy proposals and strategic steps to address barriers in utilising resources to meet the demand of AMS from end-use and power sectors, and aligning them with the regional targets, in conjunction with institutional, data, and model improvement prospects for the subsequent editions of the ASEAN Energy Outlook.

CHAPTER 1

INTRODUCTION



Chapter 1 - Introduction

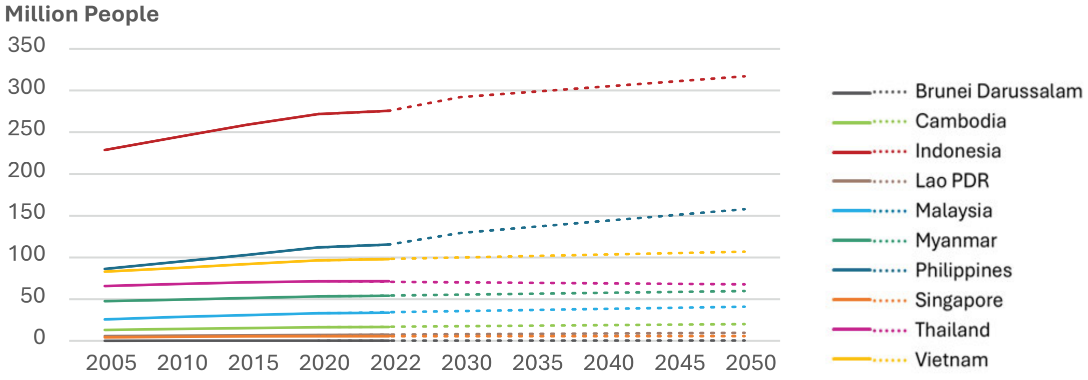
1.1 The Driving Factors of ASEAN Energy Consumption

Total ASEAN population increased 1.2 times in 2022 compared to 2005 level.

ASEAN's population is expanding at an unprecedented rate, although the growth varies amgst its member states. The population collectively reached almost 680 million people in 2022, or about 8.7% of the world's total population. Indonesia's population made up 41% of ASEAN's population, with the Philippines and Vietnam being second and third at 17% and 14% respectively (Figure 1.1). Meanwhile, Brunei's population comprised the lowest share at 0.1%.

The growth rate for the ASEAN population was 0.9% in 2022, as compared to the year before. In the long term, it is expected to gradually decrease to 0.2% by 2050. Almost all ASEAN Member States (AMS) had positive population growth rates during the examined years, with the exception of Singapore in 2020 and 2021. In the long run, the population is expected to continue rising for all AMS, apart from Singapore and Thailand.

Figure 1.1 Population of ASEAN Member States, 2005-2050



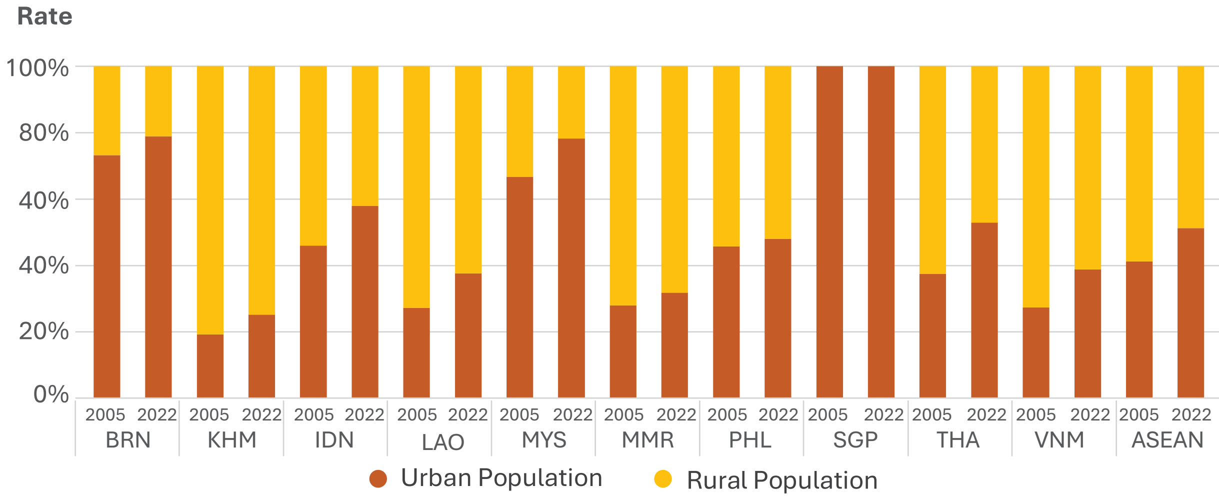
Source: ACE calculations based on population estimates and projections of World Bank DataBank.

ASEAN urban population will grow 1.5 times by 2050 from 2022 level.

ASEAN's growing population places the region in a strategic position. The AMS' youthful and relatively skilled population will ensure that the region has a robust labour force. Combined with the growing market and regional connectivity, consumer demand will also grow, making the region more attractive in terms of business and industry. This fact will open ASEAN to opportunities for becoming an industrial hub. A growing population also means greater demand for residential energy use, including electricity for homes and cooling systems, as well as an increased need for transportation.

The urbanisation rate for the AMS has been rising significantly since 2005. Approximately 231 million people were living in urban areas across ASEAN in 2005, and the number continued to rise to 348 million people in 2022, which accounted for 51% of total AMS population (Figure 1.2). Singapore has a 100% urbanisation rate, followed by Brunei Darussalam (79%) and Malaysia (78%). By 2050, total urbanisation across all AMS is expected to reach 521 million people, or 66% of the population. This implies most of the population increase in ASEAN will take place in urban areas. Cities generally have higher energy demands due to the increased use of transportation, commercial buildings, and energy-intensive infrastructure. As living standards improve, there is greater demand for energy-intensive goods and services, such as air conditioning, electronic appliances, and automobiles. Since most of a country's GDP comes from urban areas, the urban population will contribute to the continued economic growth of ASEAN.

Figure 1.2 Urban Population in ASEAN, 2005 vs 2022



Source: ACE calculations based on population estimates and projections of World Bank DataBank. Note: BRN = Brunei Darussalam, KHM = Cambodia, IDN = Indonesia, LAO = Lao PDR, MYS = Malaysia, MMR = Myanmar, PHL = Philippines, SGP = Singapore, THA = Thailand, VNM = Vietnam.

ASEAN economy is expected to grow faster compared to the world average, with an expected average growth rate of 4% between 2023 and 2050.

The demographic shift towards urbanisation has reshaped economic and market trends in ASEAN. It is accompanied by a significant increase in GDP and GDP per capita in ASEAN. The ASEAN region is becoming one of the fastest-growing economies in the world. In 2019, the total GDP from all AMS reached 2.1 times that of the 2005 level.

Some of the major external factors affecting the ASEAN economy were inflation and global crises, which led to price fluctuations and reduced business confidence. The COVID-19 pandemic caused ASEAN's GDP to decrease by approximately 3% in 2020[1], as compared to 2019. It should be noted that for the first time since the pandemic, GDP growth in 2022, at 5.3%, exceeded the pre-pandemic level of 5% in 2019. This improvement was partly due to various government fiscal stimulus packages at supporting COVID-19 recovery efforts [1].

As the world recovered from the effects of the pandemic, 2022 saw some fluctuations in AMS economic growth compared to 2021. In 2022, all AMS experienced positive economic growth, except for Brunei Darussalam, which contracted by 1.6%. Additionally, several of the AMS, including Cambodia, Indonesia, Malaysia, the Philippines, and Vietnam, enjoyed significantly faster growth in 2022, with rates exceeding 5% compared to 2021. In total, ASEAN's GDP reached USD 3.6 trillion, increasing from USD 3.4 trillion in 2021.

The GDP per capita attained USD 5.3 trillion in 2022 (Figure 1.3), rising from USD 5 trillion in 2021. Having the largest population, Indonesia has contributed the most to ASEAN's GDP since 2005, with a total GDP of USD 1,319 billion in 2022. Thailand and Singapore accounted for the second and third-largest share, reaching USD 495 billion and USD 467 billion, respectively. However, in terms of GDP per capita, Singapore reported the highest with USD 82.8 thousand, followed by Brunei Darussalam (USD 37.2 thousand) and Malaysia (USD 12 thousand). This highlights the economic disparities between countries in the region. With an estimated 4.7% growth rate in 2023, ASEAN grows faster, as compared to the expected global average growth rate of 2.7% [2]. From 2023 to 2050, the average GDP growth rate of ASEAN is projected to be 4%.

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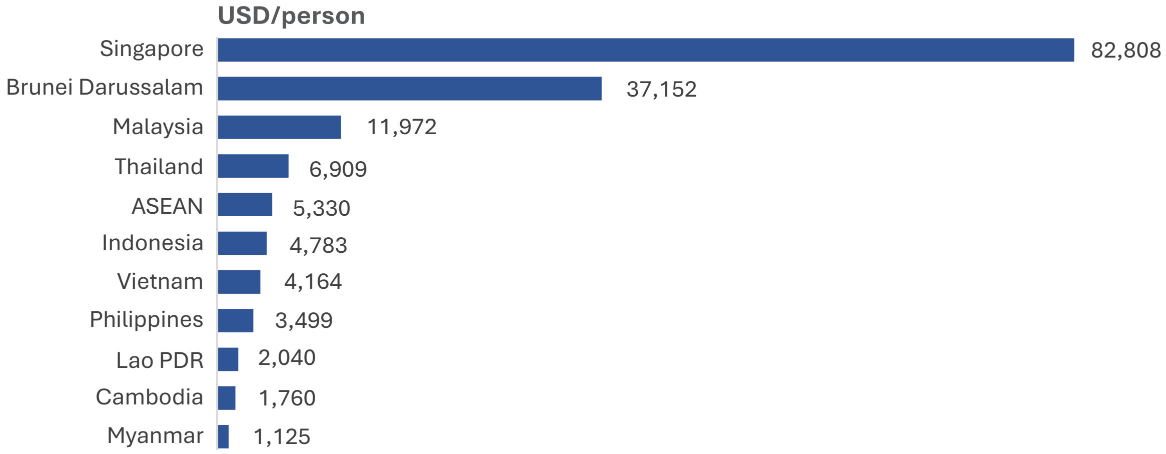
[1] GDP and GDP per Capita in this report use GDP Current Price, while GDP growth rate is calculated based on Real GDP PPP at 2017 Constant Price

Figure 1.3 AMS' GDP per Capita in 2022



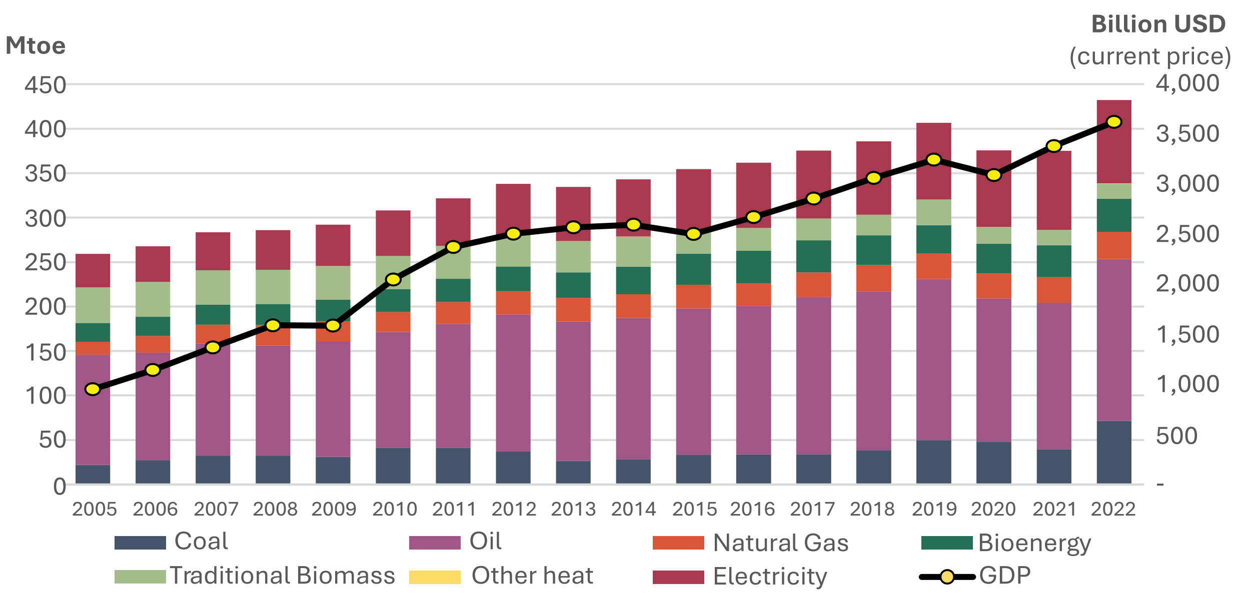
Source: ACE calculations based on data provided by multiple sources (WDI, ADB, IMF, APERC, SSP).

Rapid economic development in ASEAN nations leads to increased industrial activity and higher energy demand. As economies grow, so do the energy needs for infrastructure, transportation, and industrial production.

As a consequence of economic recovery, energy demand exceeded to above the pre-pandemic level. Following an annual decline in ASEAN energy consumption by 7.6% and 0.2% in 2020 and 2021, respectively, 2022 recorded a significant increase of 15.2% in energy demand from 2021 value, reaching 432 million tonnes of oil equivalent (Mtoe) (Figure 1.4). This surging growth in demand was caused by the impacts of positive GDP growth in 2022.

After the plunges in ASEAN energy consumption by 7.6% in 2020 and 0.2% in 2021, 2022 recorded a significant increase in energy demand by 15.2%, returning the value to above the pre-pandemic level.

Figure 1.4 Energy Demand by Fuel and GDP in ASEAN, 2005-2022



Source: ACE. All rights reserved. Note: Other heat includes solar thermal.

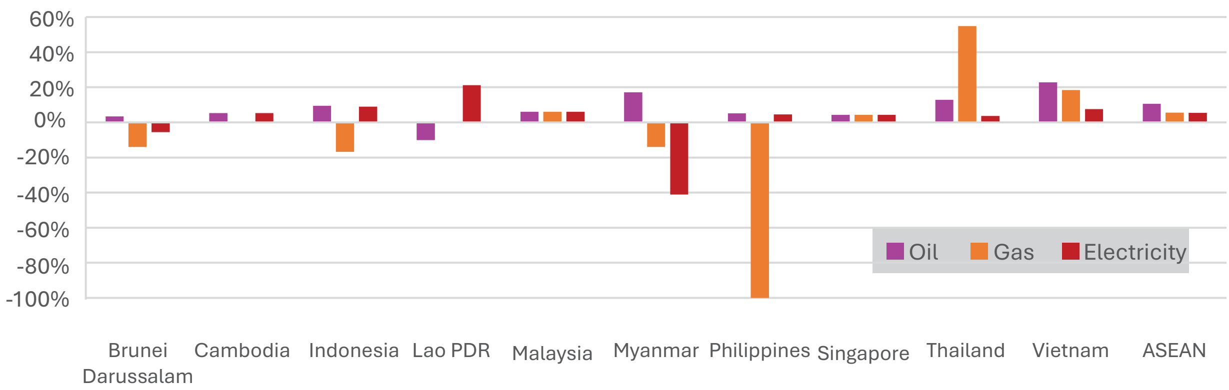
Amongst all fuel types, coal had the greatest demand increases in 2022, rising by 80.5% from 2021 levels. Nearly all the AMS experienced an increase in coal consumption in 2022 as compared to the previous year.

Oil showed the second-highest growth at 10.6% in 2022, reaching 182 Mtoe. Crude oil consumption in ASEAN countries continued to slowly increase, except for Lao PDR (Figure 1.5). Natural gas consumption was impacted not only by the pandemic but also by the 2022 global energy crisis. Brunei Darussalam, Indonesia, and Myanmar recorded a decrease in their gas consumption, whilst the Philippines did not report any gas consumption. The calculation for all ASEAN countries shows an increase of roughly 5.6%, with Thailand contributing the greatest growth at 54.8%.

Almost all AMS experienced an increase in annual coal consumption in 2022. Meanwhile, in sectoral basis, industry and domestic transport saw the most significant growth.

In 2022, overall electricity consumption in ASEAN grew by 5.4% year-over-year. Although Myanmar was still recovering from power shortages, the country experienced a downturn in electricity consumption due to expanding nationwide blackouts in early 2022, resulting in a significant decrease of 41.1% [3]. Brunei Darussalam saw an abrupt decline of 5.6% in electricity demand in 2022, despite having shown increased demand for electricity in 2020.

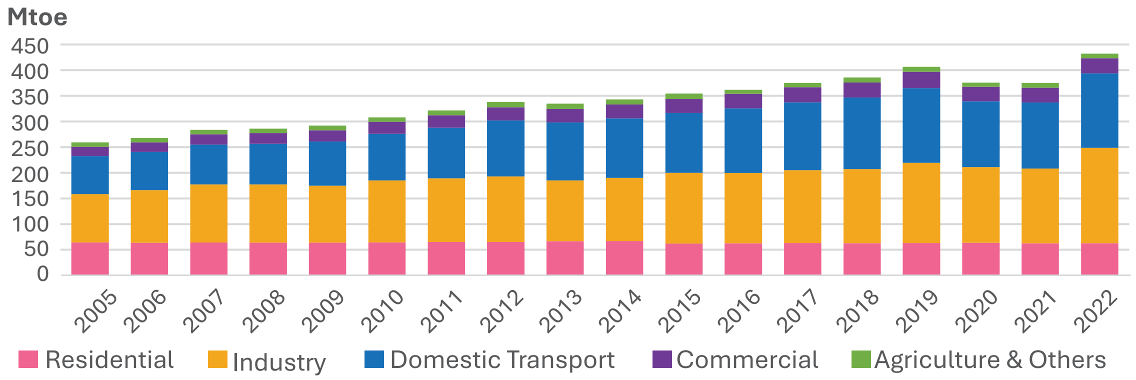
Figure 1.5 AMS Annual Fuel Consumption Growth Rate in 2022



Source: ACE. All rights reserved.

At the sectoral level, industry and domestic transport saw the most significant increase in the total final energy consumption (TFEC) from 2021 levels, rising by 27.4% and 12.8%, respectively (Figure 1.6). The 2022 industrial energy consumption value (185.7 Mtoe) was greater than in 2019 (156.2 Mtoe). This led to a larger share of industry in TFEC, from 38.4% in 2019 to 43% in 2022. As ASEAN countries develop their industrial sectors, the need for energy in production processes, machinery, and logistics rises. Large-scale infrastructure projects, including transport networks, construction, and energy-intensive facilities, contribute to higher energy demands.

Figure 1.6 ASEAN Total Final Energy Consumption by Sector, 2005-2022



Source: ACE. All rights reserved.

The energy demand for domestic transport was on par with its pre-pandemic level. At approximately 145 Mtoe in 2022, its share in ASEAN TFEC was recorded at 33.6%, slightly lower than its 36% proportion in 2019. On the other hand, the share of residential and agricultural energy demand decreased, and commercial remained steady in the same period.

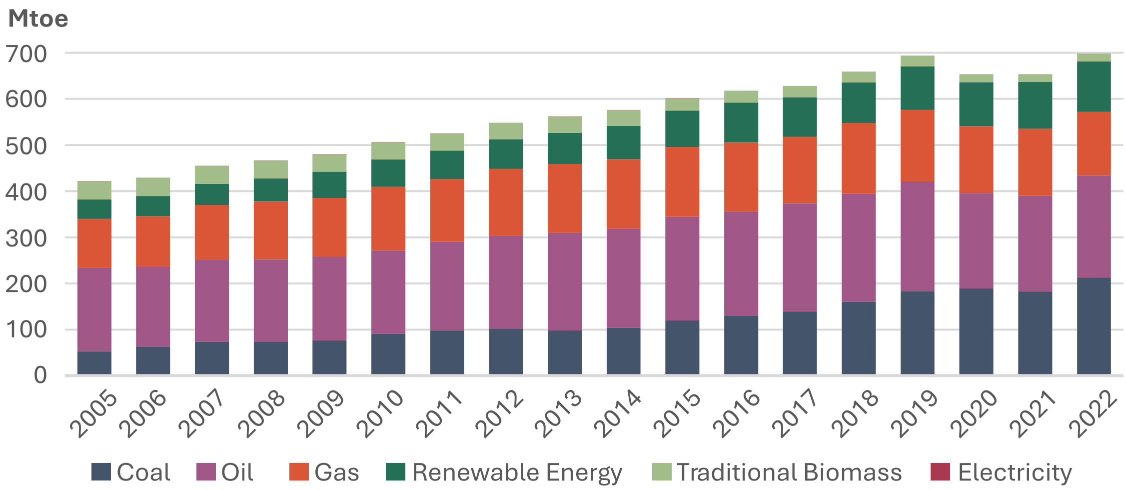
1.2 Safeguarding Energy Security and Resilience

ASEAN's total primary energy supply (TPES) demonstrated a strong recovery in 2022, closely mirroring the growth observed in TFEC. The TPES in 2022 reached approximately 698 Mtoe (Figure 1.7). However, this recovery remains heavily reliant on fossil fuels, with coal experiencing a particularly significant increase of 16.5%, as compared to 2021 levels. Coal dominated the region's energy mix, accounting for 31.5% in 2022.

In contrast, the share of renewable energy (RE) in the TPES comprised only 15.6% of the total supply in 2022, a modest rise from 15.4% in the previous year. Despite the overall recovery, concerns about energy security and resilience in ASEAN persist, as demand grows faster than domestic supply, leading to increased dependency on fossil fuels. Energy resilience for ASEAN is defined as "the capability of an energy system to withstand and recover from high-impact events and reduce the duration, cost and impact of outages on critical services" [4].

Entering the post-pandemic era, ASEAN's TPES gradually increased in just over two years, with rising dependency on oil imports.

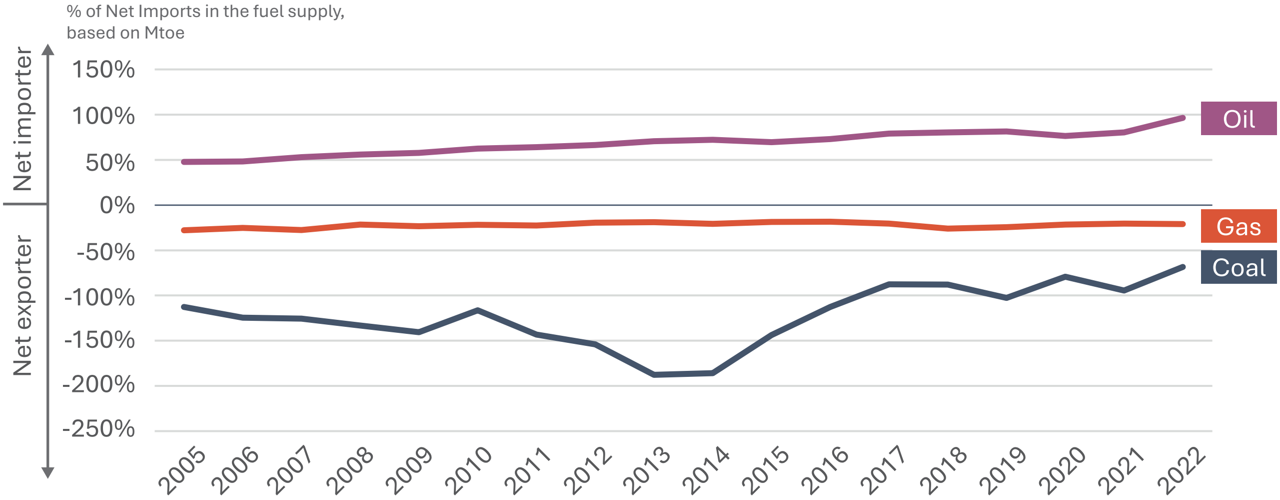
Figure 1.7 ASEAN Total Primary Energy Supply by Fuel, 2005-2022



Source: ACE. All rights reserved. Note: Renewable Energy includes hydro, geothermal, biomass, solar, wind, tidal and wave, excluding traditional biomass used by households.

Oil emerged as the dominant imported energy source in the ASEAN region. The surge in industrial activity, increased vehicle ownership, and improving standard of living have significantly elevated domestic demand for oil in each of the AMS, far exceeding local production capabilities. As a result, ASEAN faced the critical challenge of balancing supply to ensure energy security. Several AMS had experienced a decline in oil production, largely due to the maturation of existing oil fields and insufficient levels of new discoveries or investments in exploration and production. This decline diminished their capacity to satisfy regional demand through local production. Consequently, the AMS had increasingly turned to oil imports to bridge the gap. ASEAN has remained a net importer of petroleum since 2005, and the trend of net imports has generally shown a steady increase, with an annual growth rate of 16%. In 2022, net import dependency reached 96%, up from 81% in the previous year (Figure 1.8), underscoring the region's escalating reliance on external oil sources.

Figure 1.8 ASEAN Fossil Fuel Dependency, 2005-2022



Source: ACE. All rights reserved. Note: This is the weighted average of the import dependence of each ASEAN country. A negative dependency rate indicates a net exporter of energy. Values exceeding 100% indicate an accumulation of stocks. The balance is for the region as a whole; the resources and imports/exports of individual AMS vary significantly.

ASEAN Energy Export-Import Status Quo

Net-importer of oil since before 2005

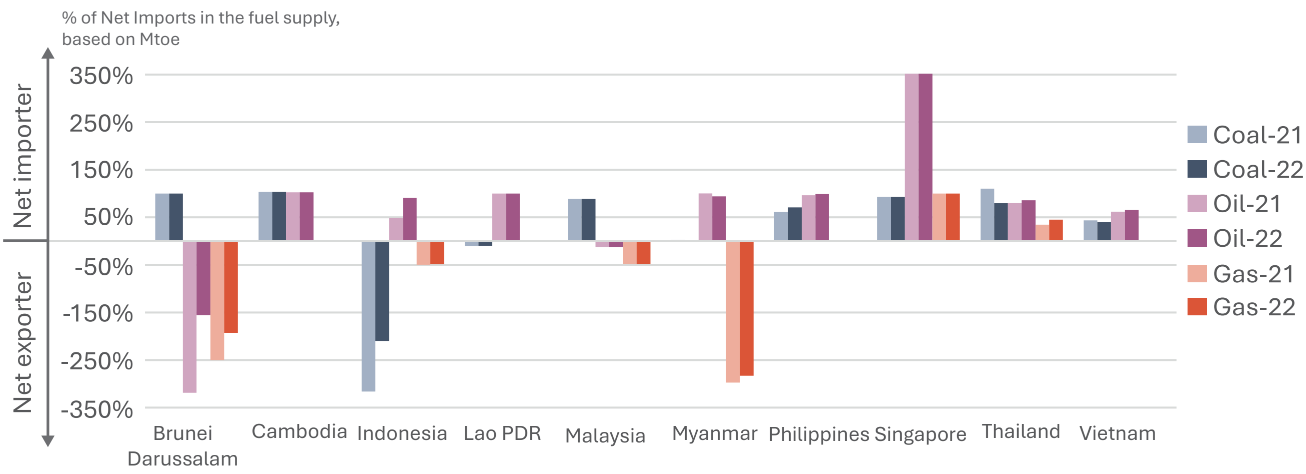
ASEAN is a net exporter of coal and gas of global trade

The ASEAN region is a net exporter of coal, reaching 68% of net export in 2022. Coal export patterns varied sharply several times throughout the historical examined years, due to the fluctuation of global coal prices and market conditions. Regional geopolitical factors and trade policies also impact coal export levels, as with the export surge experienced in 2022. The variable coal export patterns and net import of oil, highlight differing challenges posed, and factors affecting each energy resource on a secured energy supply.

The net export of natural gas is much more stable than coal. The annual variations of growth or decline were relatively low, but the 2005 number (28%) decreased to 21% by 2022. Other than rising domestic demand and declining outputs, this trend might indicate limitations in infrastructure for processing and transporting natural gas, affecting the ability to export. For example, bottlenecks in pipelines or liquefied natural gas (LNG) terminals can hinder export activities.

As each country in ASEAN relies on different primary energy sources, the net imports and exports vary significantly. Most of the AMS are net importers of fossil fuels. Singapore was the largest importer of fossil fuels among ASEAN countries, particularly in oil, this is due to its position as a major global oil trading and refining hub. While Singapore exported some refined oil products, its net oil imports were substantial. Singapore's oil import dependency ratio was 352% in 2022 (Figure 1.9). Brunei Darussalam is the main net exporter in ASEAN, including oil and gas. However, the country's dependency on oil increased by 163%-points in 2022 compared to 2021. Brunei Darussalam is not the only country experiencing a sudden change in energy dependency. Indonesia's net coal export also dropped by 106%-points, whilst its oil imports rose by 42%-points. In addition, Myanmar's net gas exports fell by 14%-points, although the country shifted from being a net importer of coal to a net exporter. When import and export figures are unstable, a country's energy supply becomes increasingly uncertain. These variations in energy trade reflect the diverse economic and resource conditions across the region, influencing both national and regional energy policies.

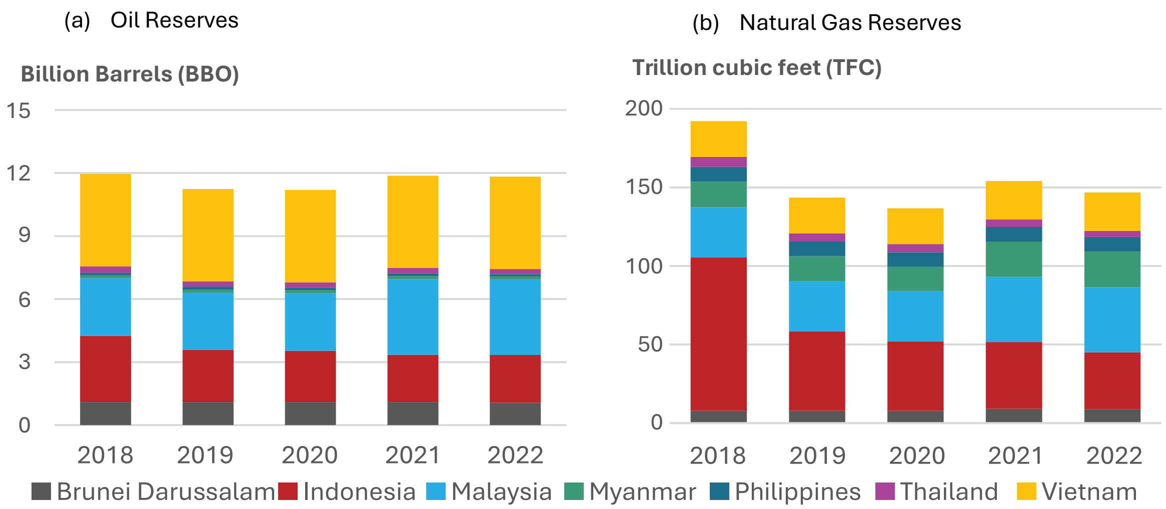
Figure 1.9 ASEAN Fossil Fuel Dependency by Country, 2021 vs 2022



Source: ACE. All rights reserved. Note: A negative dependency rate indicates a net exporter of energy. Values exceeding 100% indicate an accumulation of stocks.

Fuel import dependency is closely tied to a country's reserves. Countries with limited reserves may need to import oil to meet their demand. In 2022, the oil reserves in several ASEAN countries slightly declined, as compared to 2021. The total proved oil reserves in the AMS reached a combined 11.8 billion barrels (BBO), a decrease of 0.4% over 2021. Brunei Darussalam and the Philippines each recorded a decline in oil reserves of 0.03 BBO, whilst Indonesia saw an increase of 0.02 BBO. Meanwhile, the oil reserves of Malaysia and Vietnam—the countries with the largest reserves—remained stable over the past few years (Figure 1.10). In response to declining oil reserves, many of the AMS are undertaking extensive field exploration and development activities. This includes further optimising the production at mature fields and improving oil and gas fiscal terms [5].

Figure 1.10 Oil and Natural Gas Reserves in ASEAN Countries



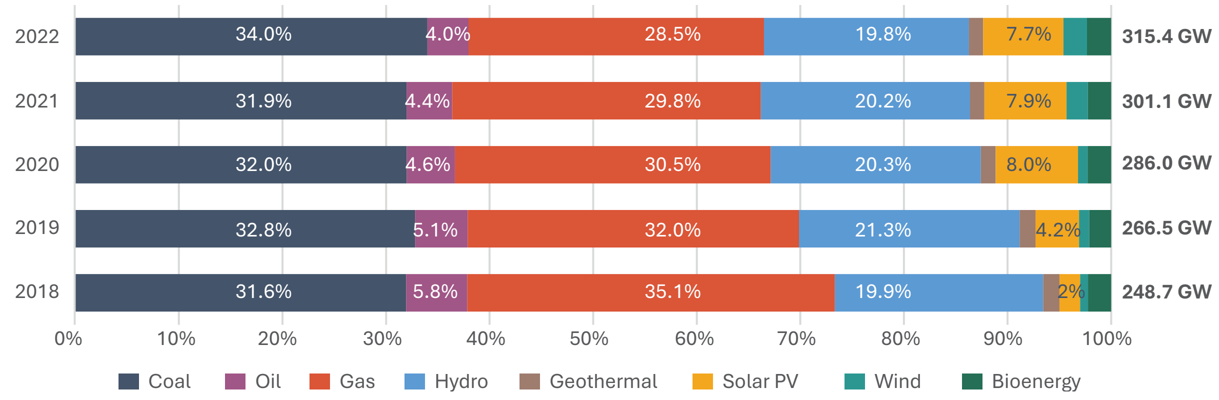
Source: ACE. All rights reserved.

There was a significant reduction in the region's proven gas reserves from 2018 to 2019, due to Indonesia's establishment of a new parameter of the Petroleum Resources Management System, where gas reserves that have not been developed are categorised as contingent resources since 2019. In 2022, the regional natural gas reserves fell slightly, when compared to 2021, decreasing by 4.7% year-over-year, to 146.8 trillion cubic feet (TCF) (Figure 1.10). Thailand had the largest decrease in reserves from 2021 levels, amounting to 20%, followed by Indonesia at 14.4%. On the other hand, the natural gas reserves in Malaysia, Myanmar, and Vietnam remained stable. Declining natural gas reserves in the region can trigger a complex set of economic, environmental, and energy shifts, necessitating strategic adjustments by governments, businesses, and consumers.

In terms of electricity, the installed capacity in 2022 was returning to pre-pandemic levels after the energy downturn due to COVID-19. Total installed capacity grew by 27% from 2018 to 2022, reaching 315.4 GW in 2022. Within that period, solar photovoltaic (PV) had grown sharply, supplementing 19.5 GW in just five years from 2018.

The bioenergy share appears to not have experienced remarkable development, with an average of 2.2% of the total ASEAN installed capacity (Figure 1.11). With the significant increase in solar PV, hydro, and wind, the RE share of ASEAN installed capacity grew from 26.4% in 2018 to 33.6% in 2022. However, this value slightly decreased from the 2021 level of 33.7%, following the additional capacity from coal. Since 2019, the largest share of installed capacity has shifted from natural gas to coal as the reserves of oil and gas have been depleted over the last few years.

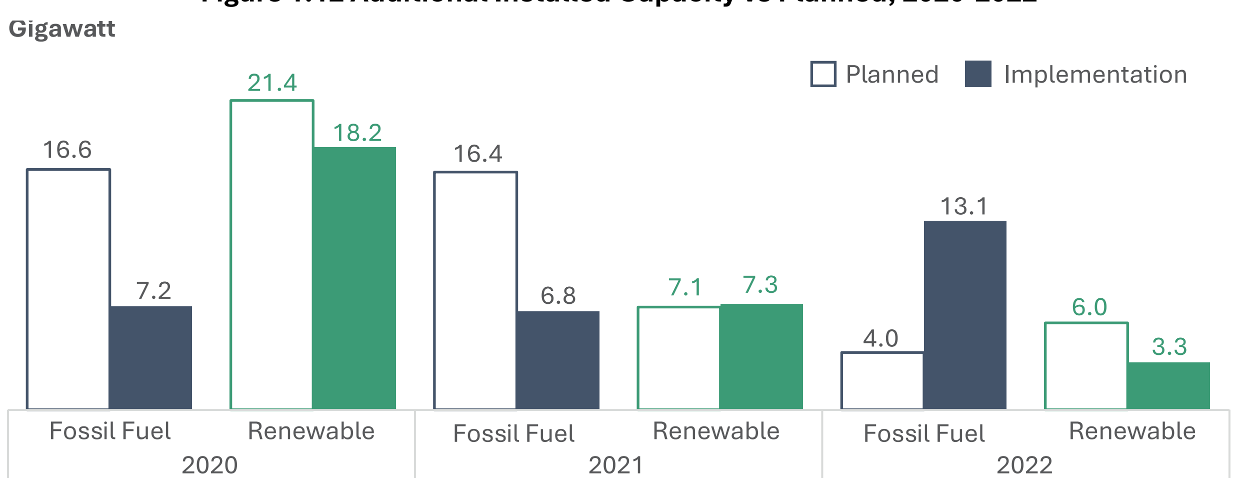
Figure 1.11 ASEAN Installed Capacity by Fuel Type, 2018-2022



Source: ACE. All rights reserved.

Renewable energy appears to be resilient in the additional installed capacity as depicted in Figure 1.12. In 2020-2021, the newly installed RE capacity surpassed fossil fuels because the pandemic delayed fossil fuel-based projects, particularly coal-fired power plants (CFPPs). The renewable addition saw a significant increase due to Vietnam's solar development. However, in 2022, the trend was reversed between fossil fuel and RE. The implemented additional capacity of fossil fuel exceeded 9 GW from the planned one in AMS' power development plans, while RE fell short by 2.7 GW. The very large additions of fossil fuel capacity in 2022 were caused mainly by completion of several delayed fossil fuel-based project due to pandemic and new demands for captive coal power plants in the industrial sectors. AMS have devised several investments and adequate funding to reach the planned RE capacity, through government incentives, private investment, and public-private partnerships (PPP).

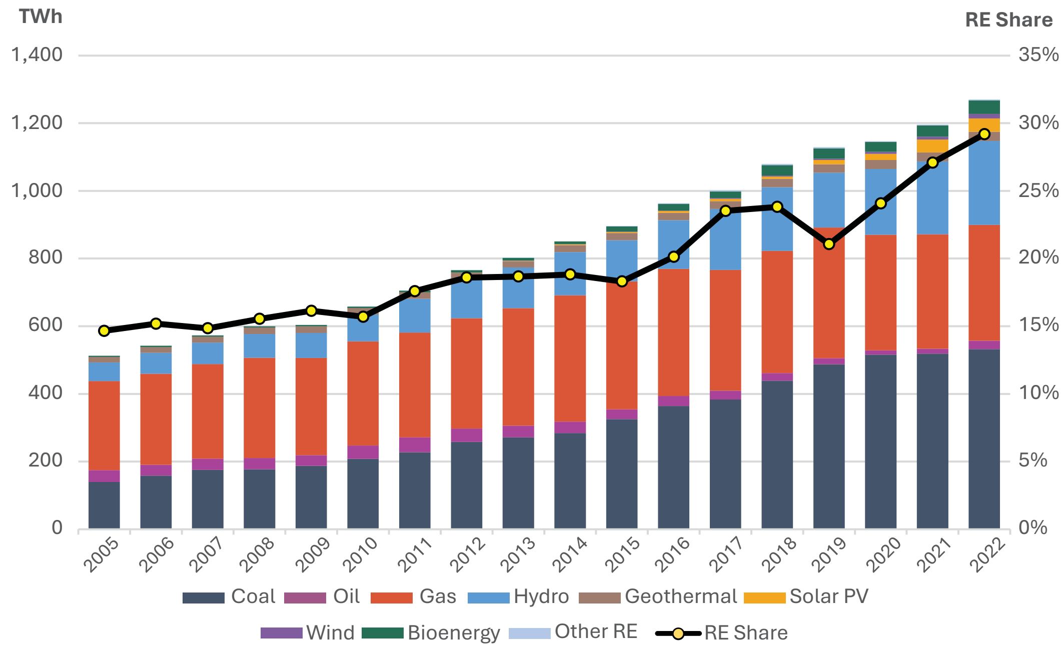
Figure 1.12 Additional Installed Capacity vs Planned, 2020-2022



Source: ACE. All rights reserved. Note: Fossil fuels include coal, gas, oil. Renewable Energy includes geothermal, hydro, solar PV, wind, bioenergy.

Total electricity generation for the AMS steadily increased, reaching a production record of 1,263 TWh in 2022, with significant increases from hydro, solar, and coal (Figure 1.13). Although fossil fuels still dominated ASEAN electricity generation, the share continued to decrease from 85.8% in 2005, to 73.1% in 2021 and 71.2% in 2022. Fuel types showed diverse trends between 2020 and 2022. Specifically, the coal share of electricity generation decreased from 45% in 2020 to 42.1% in 2022. The generation share from natural gas continued to lower by 2.6%-points, but the share of oil expanded by approximately 0.8%-points within the same period.

Figure 1.13 ASEAN Electricity Generation, 2005-2022



Source: ACE.

On the other hand, approximately 29.2% of electricity was generated from RE sources in 2022, up significantly from 2020, encompassing hydro (19.5%), bioenergy (3.2%), solar PV (3.1%), geothermal (2.1%), and wind (1.1%). The overall RE contribution increased by 2.1%-points compared to the previous year. Hydro was the primary contributor, displaying the most rapid growth with 54.1 TWh between 2020 and 2022. It was followed by solar PV, increasing by 20.7 TWh in the same period. These encouraging figures indicate that RE has been steadily replacing fossil fuels in the electricity generation mix, even during the pandemic, balancing energy security.

1.3 Realising Just and Inclusive Energy Transition

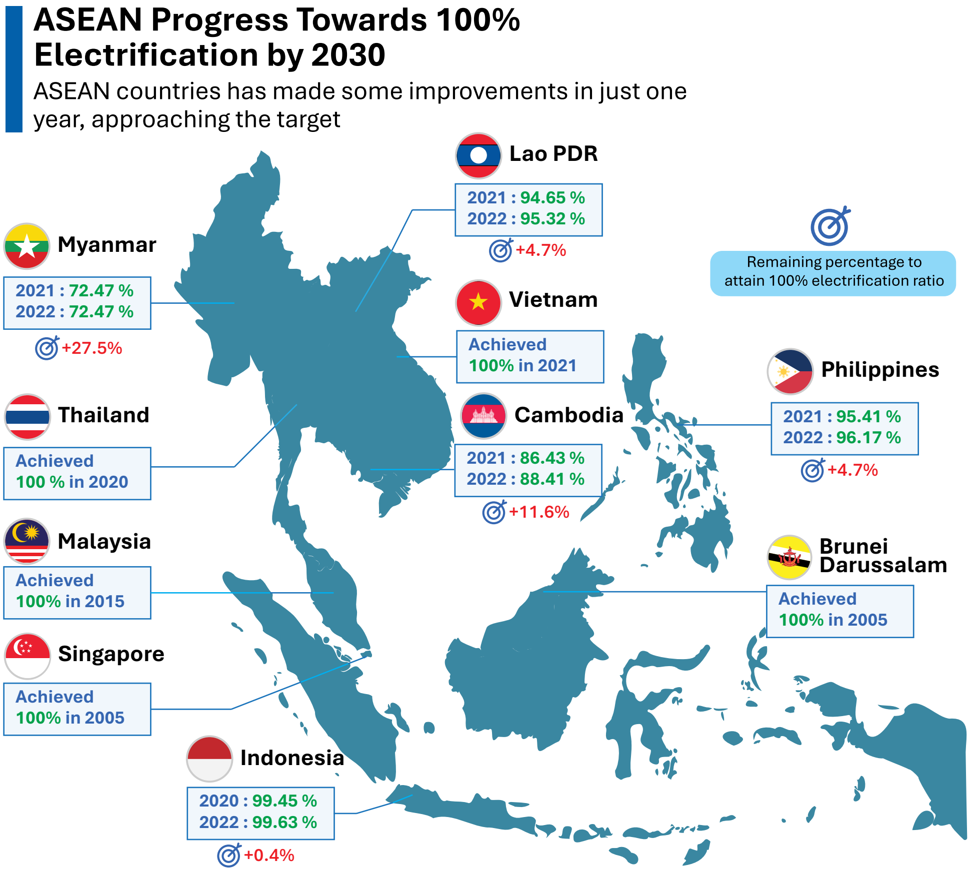
Under the 41st ASEAN Ministers of Energy Meeting (AMEM) in 2023, updating from the 39th AMEM, the political will for just and inclusive energy transitions has been reiterated to emphasise a people-centric approach as the integral element of a successful energy transition. This specific vision is clearly stated in the 41st AMEM Joint Declaration:

"The Joint Declaration, which serves as Indonesia's 2023 ASEAN Chairmanship's Priority Economic Deliverable (PED) on energy, called for greater enhancement of energy interconnectivity among others through the expanded implementation of the ASEAN Power Grid (APG) and the Trans-ASEAN Gas Pipeline (TAGP), including liquefied natural gas (LNG) infrastructure. The Joint Declaration builds on the success of existing ASEAN interconnection projects by pursuing an aspirational regional target for interconnection of AMS towards 2045, in line with the 20-year timeframe of the ASEAN Community's Post-2025 Vision, as well as, to accelerate the just and inclusive energy transitions while ensuring energy security, reliability, accessibility, sustainability, resiliency, and affordability"

The concept of just and inclusive energy transition is closely linked to the parameters outlined in Sustainable Development Goal (SDG) 7, "Affordable and Clean Energy," as well as to the affordability aspect of the energy trilemma—energy security, equity, and environmental sustainability. As of 2022, ASEAN has yet to fully achieve these targets, with progress remaining stagnant in providing universal access to modern energy—encompassing electricity, clean fuels, and technology [6]. Access to modern and clean energy not only involves affordability and reliability but also includes ensuring that individuals and communities fully benefit from and have opportunities to transition to a sustainable and clean energy system [7].

In recent years, progress across the region has varied significantly, with some countries making substantial gains, whilst others have slowed, particularly due to the challenges posed by COVID-19 and its aftermath. As of 2022, the electrification rate has increased (Figure 1.14), yet an estimated 3.4 million households still lacked access to electricity. The number of households without electricity in 2022 decreased by 27 thousand from the previous year.

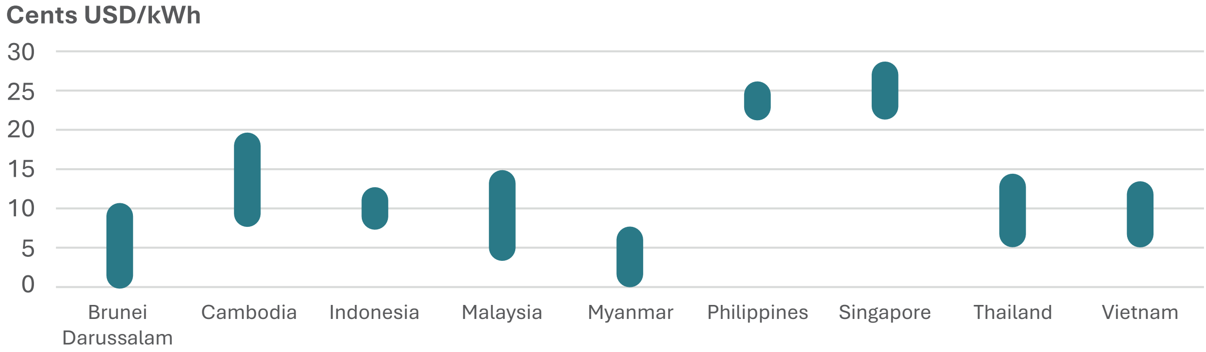
Figure 1.14 Electrification Rate in AMS (% of Households), Latest Available Year



Source: ACE calculations based on data from country consultation and the World Health Organisation (WHO).

Electricity affordability is a key consideration that is as important as energy security. Although ASEAN is recovering from the impact of the pandemic, an unprecedented increase in utility rates occurred post-pandemic in 2022. The electricity price of private utilities in the Philippines increased sharply by 15.7% in 2022 [8], and is amongst the highest in the region. Currently, Cambodia has harmonised the tariff structure under the power-state utilities and private licenses [9], creating a more equitable and affordable energy system for residential consumers. Indonesia and Malaysia have ensured electricity remains affordable and stable, due to allocated subsidies to maintain rates during the pandemic [10], [11], [12]. Myanmar, which in 2022 frequently experienced blackouts nationwide and had the lowest electrification rate in ASEAN, has the cheapest electricity tariff at USD 0.02 to USD 0.06 per kWh (Figure 1.15).

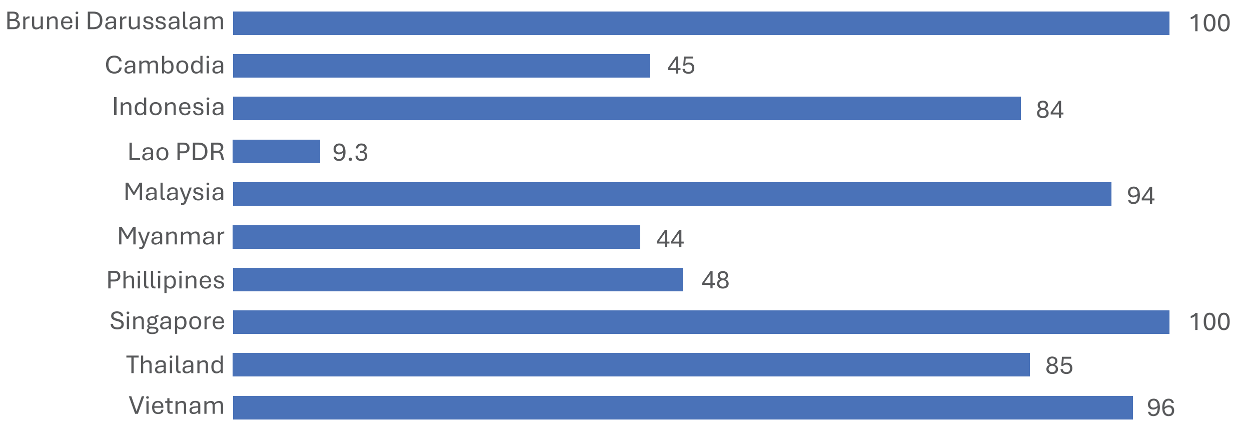
Figure 1.15 Comparison of AMS Household Electricity Tariffs in 2022



Source: ACE calculations based on country data submission. Note: Data for Lao PDR is not available.

Access to clean cooking in Southeast Asia is a significant issue, with considerable variation across the region. As of 2022, 75.4% of the total ASEAN population had access to clean cooking, or approximately 513 million people. It will require more effort to achieve full penetration by 2030, with Cambodia, Lao PDR, Myanmar, and the Philippines having yet to achieve 50% (Figure 1.16).

Figure 1.16 Proportion of Population Using Clean Fuels for Cooking (%) in 2022



Source: ACE calculations based on country consultation and World Bank database.

ASEAN Energy Access Rate by 2023

±3.4 million households lack of electricity access

±167 million people lack clean cooking access

ASEAN countries are progressing towards the target, although they face several challenges. Malaysia has experienced a downward trend for modern cooking energy over the past three years, with a decrease of 0.4% in 2021. Although Lao PDR still has significant room for improvement, the country has experienced a gradual yet consistent rise in access to clean cooking energy over the past decade. Under its current policy setting, about 1 million households will rely on cooking with traditional biomass, and the clean cooking access rate will increase to 20% by 2030 [13]. Additionally, Cambodia showed an outstanding increase of 21.3% share of clean cooking access between 2021 and 2022. The country further committed to tackling this issue through a recent policy for promoting energy-efficient cookstoves under the National Energy Efficiency Policy (NEEP) 2022-2030 [14].

One of the most daunting challenges to 'leaving no one behind' in the spirit of SDGs in the energy transition, is to minimise the gap between rural and urban households. In the Philippines and Vietnam, nearly all the affluent urban households use clean fuels for cooking, whereas the majority of rural households, especially those with lower incomes, rely on traditional biomass. Just 22% of the rural households in Indonesia, and 32% in Thailand use clean fuels [15], [16]. The AMS still commonly utilise harmful fuels like wood, charcoal, or crop waste, particularly impacting the health of women exposed to smoke due to their predominant role in cooking and household activities. Transitioning to clean modern energy supplies has significant implications for employment in the energy and infrastructure sectors. Countries highly reliant on fossil fuels, particularly coal-producing countries, will face job losses risking a deeply negative effect on labour markets without significant adaptive policies. In addition, coal exporting countries must address the task of diversifying their economies in order to mitigate the potential adverse impacts due to this transitioning. The growth of RE holds great potential for remediating the likely job losses in fossil fuel sectors. The previous edition of the ASEAN Energy Outlook (AEO7) projected that RE growth generating almost 850,000 jobs, with Vietnam having the highest number of additional jobs between 2021 and 2050 [17]. Approximately two-thirds of jobs in RE fall into the category of medium-skilled occupations, which call for formal education and skill competencies [18]. Therefore, systemic transitioning to these jobs will require reskilling and upskilling of workforces to match the demands of the green industry [16], [19], [20], [21].

Energy and Gender in ASEAN

The just and inclusive energy transition not only presents opportunities for advancing energy affordability and accessibility, but also empowers all people including women. Historically, women have made up only 8% of the labour force in 2020 across industrial crude, petroleum, and natural gas extraction in the region [18]. Several issues have been identified, including the limited participation of women in high-level policymaking processes within the energy sector, despite more women participate in higher education than men in the region [19]. The disproportionate burdens placed on women by the climate and energy transition and untapped development finance should be addressed to leverage the inclusivity.

In 2022, there has been the establishment of the ASEAN Gender Mainstreaming Strategic Framework (AGMSF) which adapts a whole-of-ASEAN approach to introduce and integrate gender perspectives across the ASEAN Community. The initial realisation in the energy sector is the launched of the ASEAN Renewable Energy – Gender Roadmap which marks the first groundbreaking document to support ASEAN energy policies to reflect articulated approach to women's role and empowerment.

1.4 Achieving Carbon Neutrality

The Paris Agreement sets a global framework for addressing climate change by focusing on both mitigation and adaptation, with the goal of limiting global temperature to 1.5°C [22]. The Intergovernmental Panel on Climate Change, in its Sixth Assessment Report, states that to meet this target, global emissions must be reduced by 45% by 2030, and reach net zero by 2050 [23]. To meet these objectives, it is essential to implement national targets, policies, and action plans that align with international climate action trajectories.

As part of their commitment to reducing greenhouse gas (GHG) emissions, all signatories of the Paris Agreement, including the 10 AMS, are required to develop and implement Nationally Determined Contributions (NDCs) [22]. ASEAN, as one of the region's most vulnerable to the impacts of climate change, is actively working to contribute to these global commitments [24]. Table 1.1 outlines the NDC targets, GHG emissions goals, and net zero targets for each of the AMS.

Table 1.1 AMS Net Zero and NDC Targets in Mitigating Greenhouse Gas Emissions

Country	Net Zero/Carbon Neutrality Target	NDC Target (Reduction of GHG Emission)	
		Unconditional	Conditional
Brunei Darussalam	Net Zero by 2050	-20% from 2030 Business-as-Usual (BAU) scenario	-
Cambodia	Net Zero and Carbon Neutrality by 2050	-	-41.7% from 2030 BAU scenario
Indonesia	Net Zero by 2060 or sooner	-31.89% from 2030 BAU scenario	-43.20% from 2030 BAU scenario

Country	Net Zero/Carbon Neutrality Target	NDC Target (Reduction of GHG Emission)	
		Unconditional	Conditional
Lao PDR	Net Zero by 2050, conditionally	-60% from 2030 BAU scenario	-45.69 $MtCO_2$-eq/yr in 2030-2030
Malaysia	Net Zero by 2050	-45% of carbon intensity from 2005 levels	-
Myanmar	Net Zero from forestry and other land use by 2040	-244.52 $MtCO_2$-eq (sectoral targets)	-414.75 $MtCO_2e$ (sectoral targets)
Philippines	No specific target	-2.71% from 2020 to 2030 cumulative BAU scenario	-75% from 2020 to 2030 cumulative BAU scenario
Singapore	Net Zero by 2050	Peak absolute emissions at 65 $MtCO_2$-eq	-
Thailand	Carbon Neutrality by 2050; Net Zero by 2065	-30% from 2030 BAU scenario	-40% from 2030 BAU scenario
Vietnam	Net Zero by 2050	-15.8% from 2030 BAU scenario	-43.5% from 2030 BAU scenario

Source: ACE compilation from multiple sources.

The AMS recognise the critical role of regional cooperation in ensuring energy security, accessibility, affordability, and sustainability at both national and regional levels. In response to the urgent need for an energy transition, ASEAN has established the ASEAN Plan of Action for Energy Cooperation (APAEC) that is renewed every 10 years. The current cycle spans from 2016 to 2025, with the next phase covering 2026 to 2035. This series of guiding policy documents promotes multilateral energy cooperation and integration, aligning with the broader objectives of the ASEAN Economic Community (AEC) [4]. Whilst these efforts are vital, it is equally important to ensure that regional energy transition initiatives are closely aligned with global climate commitments. Strengthening collaboration between the energy and climate sectors will be key to overcoming existing challenges and fostering a more integrated approach to these shared objectives.

The energy and climate sectors are inextricably linked and mutually dependent and integrating this energy-climate nexus is vital for enhancing long-term energy security, affordability, accessibility, and sustainability. Achieving a carbon-neutral target requires a shared understanding and collaborative efforts between the energy and climate sectors. Additionally, it is essential to explore the synergies between these sectors and to identify the challenges and opportunities that exist for reducing greenhouse gas emissions. Integrating energy and climate efforts will further support national and regional renewable energy policies, helping ASEAN to move toward low-carbon economies and achieve carbon neutrality.

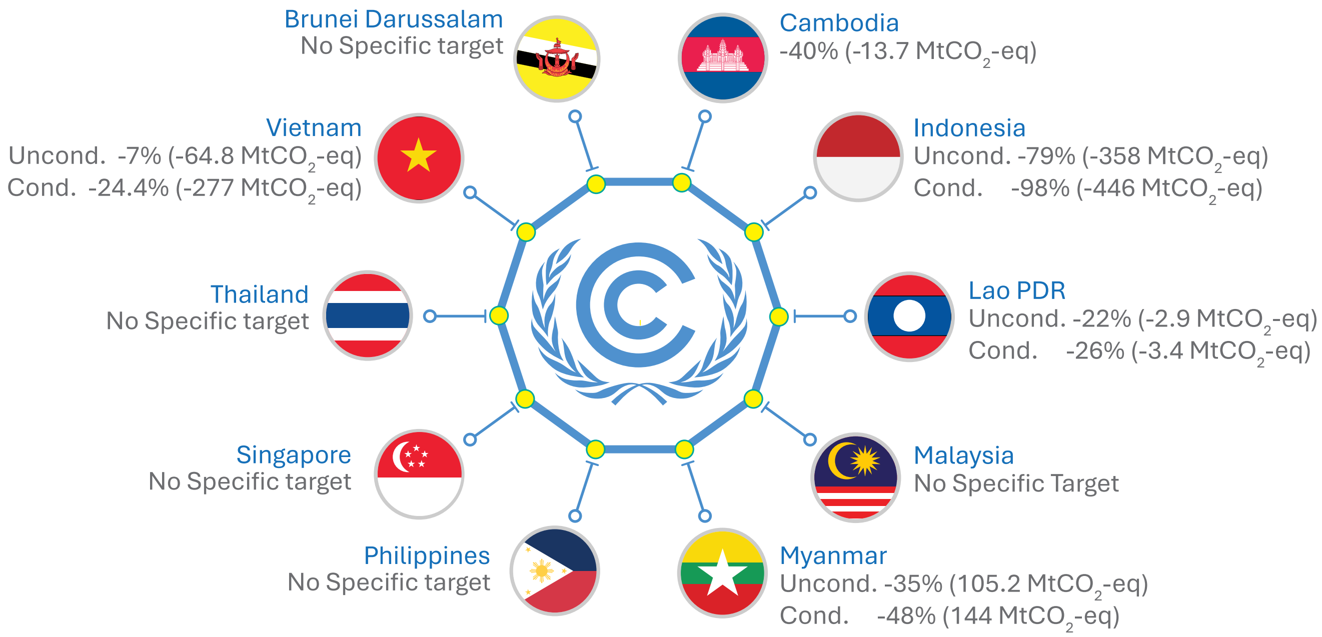
The next phase of the APAEC presents a unique opportunity for AMS to set even more ambitious climate and energy targets. As a regional cooperation framework, APAEC can help AMS align their national policies with a shared vision for a sustainable and resilient future.

With nearly all the AMS pledging to achieve net zero and carbon neutrality targets, the region also acknowledges the critical need for regional cooperation toward achieving carbon neutrality. This initiative has been formalised through the ASEAN Strategy for Carbon Neutrality, a strategic document endorsed by the Joint Ministerial Statement of the 41st AMEM. This strategy emphasises the importance of integrating green infrastructure and markets within the energy sector, ensuring that regional efforts are effectively aligned with carbon neutrality goals [25]. By leveraging existing ASEAN initiatives and global best practices, this strategy aims to drive sustainable development, maintain trade competitiveness, and ensure a just and inclusive transition for the region.

The data indicates that 77% of GHG emissions in ASEAN are primarily generated from the energy, industrial processes, and land use, including land-use change and forestry [25]. With the energy sector being the largest contributor to CO_2 emissions, targeted improvements in these areas are essential for significantly reducing ASEAN's overall emissions and advancing toward the region's carbon neutrality objectives.

Thus, establishing clear targets and pathways to address the energy-climate nexus is necessary to effectively reduce emissions, whilst supporting economic growth and environmental protection [26]. This approach can be reinforced by incorporating specific GHG emission reduction targets in the NDC documents. Only Cambodia, Indonesia, Lao PDR, Myanmar, and Vietnam have currently specified targets for emissions reduction in the energy sector within their NDCs (Figure 1.17). However, other countries have laid out these targets in their other official documents, such as the Philippines in its Energy Plan 2023-2050 who aims for emissions reduction by 54.5-66.4% [27].

Figure 1.17 AMS NDC Targets for Emissions Reduction in the Energy Sector by 2030



Source: ACE, 2023 [23]

Achieving carbon neutrality and environmental sustainability in ASEAN requires a comprehensive approach that integrates socio-economic, technological, and governance strategies. From a policy perspective, clear guidelines are essential for reducing emissions and aligning ASEAN's economic growth with environmentally friendly, low-carbon energy strategies. By adapting comprehensive strategies that incorporate these elements, ASEAN can ensure a sustainable future for the region.

1.5 Financing Low-Carbon Energy Systems

Understanding the challenges outlined in preceding sub-chapters for balancing the region's energy trilemma is essential for accurately identifying the costs and financing requirements necessary to transition to low-carbon energy systems. This shift not only demands competence in technological aspects, but also strong financial schemes to support the advancements.

Significant investments have flowed into fossil fuels in prior years, yet this historical preference has seen a gradual transformation to sustainable investment. Diversifying funding sources with a clear understanding of a country's fiscal landscape is crucial to financing the effective deployment of clean energy solutions. With favourable investment climate and regulatory framework, capital costs will find a functional balance. Thus, aligning a country's economic condition, whilst identifying broad funding sources and schemes will deliver a well-designed strategy to accelerate clean energy technology markets.

By looking at the stability of countries' needs for fossil fuels, it is feasible that investments can be channelled into sectors that provide less risk in return, resulting in a greater number of additional capacities from fossil fuels in 2022. As of 2023, Vietnam and Indonesia have been the largest recipients of international public financing for CFPPs in the region [28]. If the share in RE investments is to be encouraged, policymakers should limit both international public and private funding for unabated CFPPs. There is a need for significant investments in RE infrastructure to fill the void left by coal's economic impact.

Implementing innovative financial measures such as carbon pricing may increase the cost of fossil fuels and channel that into building RE infrastructure. Carbon pricing policies have a pivotal role in ASEAN's shift towards carbon neutrality [29]. Carbon pricing assigns a direct financial value to carbon emissions through mechanisms such as carbon taxes and emission trading systems (ETS), encouraging emissions reductions and innovation, by making emissions costly. The carbon pricing approach holds parties accountable for their environmental impact and promotes sustainable practices.

Singapore and Indonesia have implemented carbon pricing measures, whilst Brunei Darussalam has started the initiatives in this area [29]. Cambodia and Vietnam are making progress, and Thailand and Malaysia are exploring carbon taxes and ETS as part of their efforts to address climate change. These initiatives showcase a diverse range of strategies and ambitions across the region. Challenges such as setting appropriate price levels, ensuring compliance, and managing the significant dependence on fossil fuel industries remain. Addressing these challenges is crucial for the effective implementation of carbon pricing and for achieving significant carbon emission reductions.

Understanding cost trends will guide investment decisions and clean energy policies. Capital expenditure (CAPEX) is one of the major cost drivers for investment, and financing strategies within countries across ASEAN are important in creating a stable investment environment and reducing the stigma associated with the high risk of investing in RE projects. Although the region has a geographical advantage, the capital cost of solar PV is still higher than in other regions, such as China and Europe. An average capital investment of USD 800 to USD 1,200 per kW is needed to build a solar plant [30].

Solar and offshore wind have experienced a significant downward trend in cost since 2011 and 2013, respectively. With more than a 70% decline in cost, solar PV managed to compete with traditional power generation and even surpassing coal and gas costs by 2020. The shift in energy trends has made solar and onshore wind an economically viable power source, potentially influencing future investments in other renewable projects.

Whilst the cost of clean energy systems is key and influences trends in the coming years, funding seems to be the greatest problem for deployment, which stems from three areas: narrow fiscal space, limited financing scheme, and inadequate policy measures. ASEAN relies on public funds to invest in energy projects; however, public funds alone will not fill the gap. The private sector would help with capital investment and expertise.

Insufficient credit ratings in countries across the region pose a significant risk for lenders and investors, making it more difficult to secure the necessary capital required for large-scale projects. Exploring green financing models that align with a country's economic conditions will provide a more stable investment climate. Thus, direct support through policy is important to accelerate the prominence of financing models.

Clear frameworks and guidelines that promote a healthy business environment for investors can aid in the more rapid adoption of green financing practices. Yet, ASEAN countries showed a lack of consistency in policy and regulation towards the RE industry. While some incentives and policies aim for a higher RE share, a robust funding strategy seems to fall short. A firm step from policymakers by embedding green financing schemes in renewable projects would encourage investors to see the energy transition as a business opportunity.

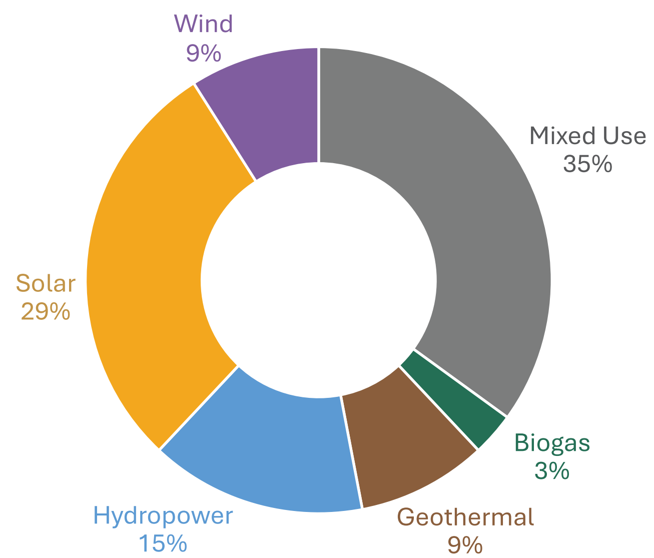
Variable renewable energy projects began to emerge in the early 2000s, with PPPs playing a crucial role in penetrating the RE market. Clear written agreements provided private investors with a secure mechanism for collaboration with the public sector. In return, the private sector contributed capital investment and expertise. Through technological transfers and advancements, solar PV and wind energy became increasingly attractive to private investors, leading to total investments of USD 655 million and USD 252 million, respectively, in 2011 [31].

Hydropower generation has consistently held the highest share of investments, accounting for around 58% of the funds directed to it. From 2012 to 2022, hydropower continued to dominate PPP investments, maintaining a share of approximately 38%. Wind and solar followed, with shares of around 28% and 20%, respectively, of total investments in the AMS [24]. In 2022, solar PV and wind projects saw significant acceleration via international investment, with these two sectors accounting for nearly 90% of all international investment in RE projects. This strong investment trend indicates a promising future for solar and wind energy in the region. In 2022, investments of USD 2.7 billion in the ASEAN region flowed into the RE sector [32].

For underfunded technologies or large-scale projects, the perceived risk of not achieving expected returns could delay investment. In this case, the role of blended finance is important to fill and balance the need for projects to be economically viable. This blended scheme mitigates investment risks by involving various actors to pool the funds, raising capital attractiveness. Rather than a single source, this funding may use a portfolio approach, involving multiple investment sources as part of risk management.

With an established track record, solar and hydropower projects were the recurring targets for blended finance deals between 2019 and 2021, accounting for 29% and 15%, respectively. This reflects a high degree of confidence from investors (Figure 1.18). Although solar and hydropower have become increasingly cost-competitive, blended finance allows for risk-sharing between public and private sectors, unlike PPP, which is more concentrated on revenue-sharing.

Figure 1.18 Blended Finance by Energy Technology in ASEAN 2019-2021



Source: ACE calculations based on IEA and Imperial College London [31]

Geothermal accounted for just a 9% share in blended finance, and yet it is a project that would greatly benefit from the support of this scheme, raising the ability to compete with coal. Geothermal energy has significant potential to serve as a dispatchable power source to balance variable RE, such as solar and wind, but it requires significant investment.

More than one-third of the blended finance investment is used to finance more than one technology within the renewable energy sector with Solar and Hydropower at the forefront.

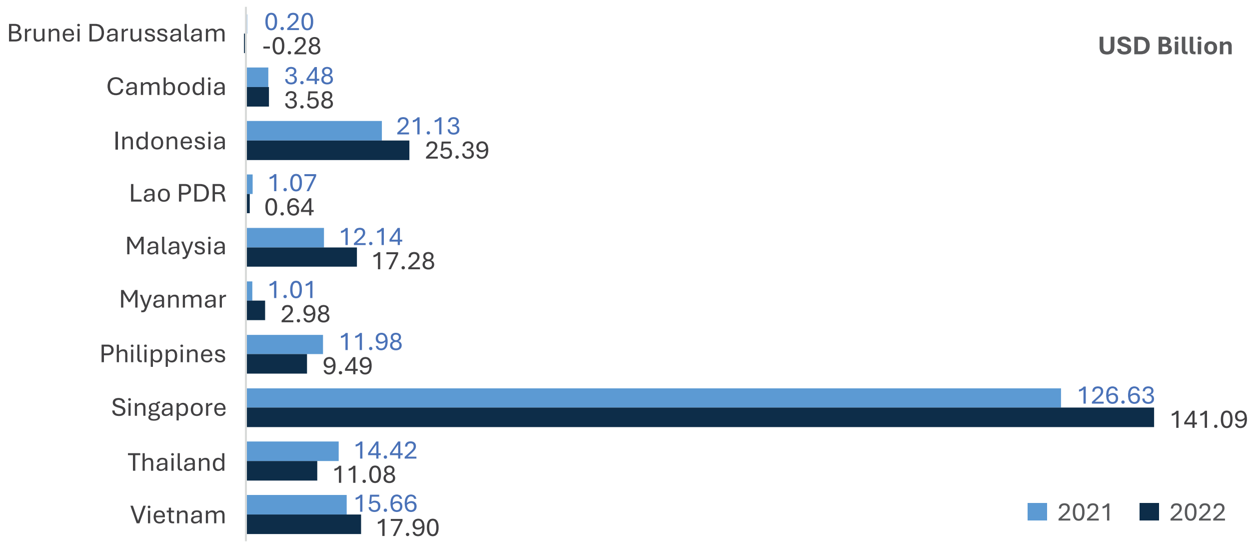
While the cost of clean energy systems is key and affects trends in the coming years, funding seems to be the largest problem for deployment to achieve the 23% regional RE in TPES target.

On the other hand, biogas had a very low share of 3%, showing a large gap with solar that reflects the market maturity. This disparity offers potential growth for biogas by designing policies and regulations that fit the end-use sectors' usage. This would attract more investment.

Both domestic and international actors play a major role in RE projects and are expected to increase over time. Between 2014 and 2018, the private sector contributed over 40% of the financing for large-scale RE projects, with the rest coming from public and multilateral development banks [33]. From 2021-2022, as much as 9% of international investments (including greenfield and international project finance deals) were for RE generation in ASEAN.

Foreign investment, both direct and indirect, is considered a crucial stimulant in helping ASEAN countries move towards a sustainable energy landscape. The limited monetary space of the AMS governments drives the need for Foreign Direct Investment (FDI). As seen in Figure 1.19, six of the AMS received higher FDI than the previous year. Singapore received both the highest value of FDI and the largest increase in FDI, taking in USD 100 billion between 2021 and 2022. Malaysia and Vietnam also had a significant increase, with USD 5 billion and USD 2 billion, respectively. Meanwhile, Myanmar showed a strong potential for FDI with an increase of over USD 1 billion from the previous year. Manufacturing investment in clean energy sectors contributed to a noticeable increase in the region's FDI, including Electric Vehicle (EV) manufacturers, solar PV, wind, and hydropower projects [34].

Figure 1.19 Foreign Direct Investment Flow to ASEAN



Source: ASEAN Stats Data Portal [35]

These strategies can be redirected towards green investments, facilitating a sustainable energy transition. The presence of foreign investors is particularly beneficial in transitioning to cleaner energy. Capital invested through FDI in projects aimed at energy sustainability, especially in RE projects, will have a significant impact on emissions reduction. Furthermore, capacity building and technology transfer gained through indirect investment will enhance environmental stewardship.

A new window of advanced technology and innovation will empower ASEAN countries to create efficiency in energy throughout all sectors, from industry to households. A country's economic growth will also rise as new jobs and industries are created, both through capital and equity investment. Foreign investments not only help the AMS achieve their carbon neutrality or net zero targets, but also enable a just energy transition.

1.6 The Role of Regional Cooperation and the Outlook for Developing Post-2025 Blueprint

In response to the multifaceted energy challenges confronting the region, the AMS are advancing regional cooperation through the APAEC. The APAEC is meticulously aligned with the strategic objectives of the AEC, mirroring the region's core values and high aspirations. Embracing the principles of inclusivity, equity, transparency, and sustainability, the APAEC serves as a guiding star to navigate regional energy cooperation amidst the complexities of the ASEAN energy landscape, to eventually steer the region towards a resilient, interconnected, and sustainable energy future.

Endorsed by the 38th AMEM in 2020, the APAEC Phase II: 2021– 2025 outlines the agenda for energy cooperation and contributions over a five-year period, aiming towards ASEAN's sustainable energy future [4]. In keeping with the theme of "Enhancing Energy Connectivity and Market Integration in ASEAN to Achieve Energy Security, Accessibility, Affordability and Sustainability for All," and the sub-theme of "Accelerating Energy Transition and Strengthening Energy Resilience through Greater Innovation and Cooperation", the APAEC Phase II: 2021– 2025 achieved a mid-term review rating of 4.3 out of 5 in 2023, highlighting a 24.5% reduction in energy intensity, a 15.6% RE share in TPES, and a 33.6% RE share in installed capacity by 2022. Despite this progress, the mid-term review identified critical gaps and future directions necessary for achieving the regional goals by 2025, particularly in energy security and resiliency, just and sustainable energy transition, and cross-sectoral collaboration.

As the final year of APAEC Phase II: 2021 – 2025 approaches, the AMS have initiated preparations for the next cycle of APAEC 2026-2030. The next cycle of APAEC is expected to align with the directives of the new ASEAN Community Vision 2045 and the 5-year timeframe of AEC Strategic Plans, promoting a more integrated and comprehensive approach.

The 41st AMEM has outlined a set of strategic directions focusing on intensifying regional efforts to meet the aspirational targets agreed upon in the APAEC. Addressing these strategic directions will be pivotal for shaping the APAEC 2026–2035 framework and achieving the ASEAN community's long-term objectives of energy security and interconnectivity. Moreover, the new APAEC cycle will address remaining gaps by incorporating the national energy plans of the AMS, global trends, and lessons learned from the existing APAEC. APAEC 2026-2030 will comprehensively consider the findings of several previous key relevant ASEAN energy frameworks and studies, including the findings and recommendations of the AEO8 (Figure 1.20).

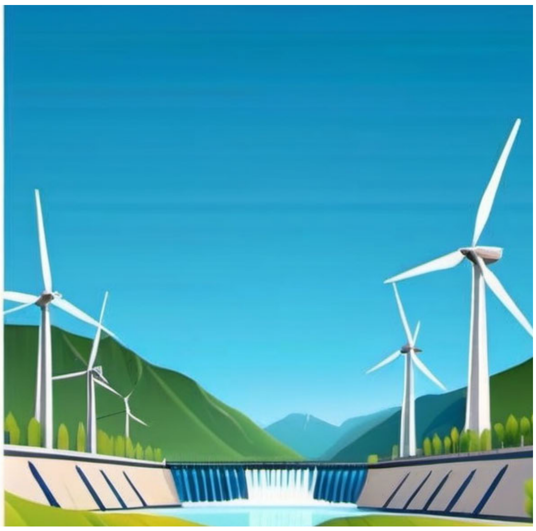
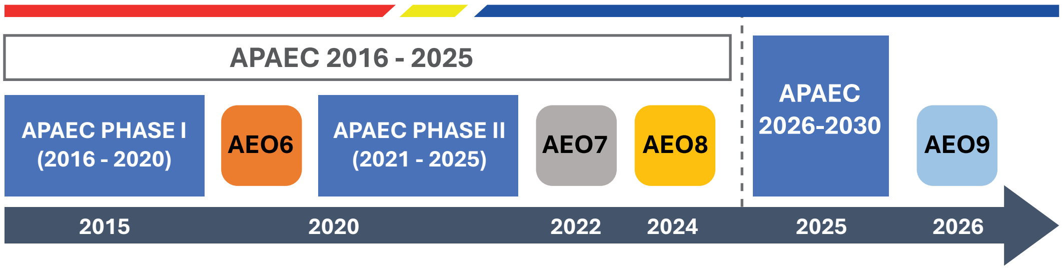


Figure 1.20 ASEAN Energy Outlook and ASEAN Plan of Action for Energy Cooperation



Since its inception in 2006, AEO has emerged as a cornerstone document supporting ASEAN's energy policy and planning. Guided by the Regional Energy Policy and Planning (REPP) programme area, the AEO series has consistently provided valuable insights into energy trends and projections across the ASEAN region. As one of Lao PDR's Chairmanship energy priority deliverables, the publication of AEO8 is poised to serve not only as a guiding compass but also as a catalyst for the formulation of visionary regional targets and driving strategic energy policy development for the APAEC 2026-2030 and also for a coming transformative decade. By providing an overview of the current energy landscape and exploring pathways for achieving regional and national energy targets, AEO8 will be instrumental in the development of the new cycle of APAEC. Providing essential data-driven insights and projections is one of the key roles of the AEO8. These insights will be instrumental in formulating new targets and metrics. By referring to the projections and findings of AEO8, the AMS will be able to identify new targets that are both realistic and grounded in data. For instance, the aspirational energy intensity reduction target for APAEC post-2025 will benefit from well-founded recommendations regarding potential numerical goals and feasible metrics for RE targets, along with suggested measures and regional cooperation strategies.

Additionally, AEO8 encourages the pursuit of an aspirational regional target for the interconnection of the AMS through the ASEAN Power Grid (APG) and the Trans-ASEAN Gas Pipeline (TAGP), including LNG infrastructure, towards 2045, in line with the 20-year timeframe of the ASEAN Community's Post-2025 Vision. Beyond providing data and projections, the AEO8 identifies challenges and opportunities within the ASEAN energy sector. AEO8 helps the AMS anticipate and prepare for potential obstacles, whilst also identifying areas where regional cooperation can yield significant benefits. Key initiatives include the expansion of regional and multilateral electricity trading to enhance energy interconnectivity, the advancement of grid resiliency and modernisation, and the acceleration of RE adaption alongside advanced low-carbon technologies. A significant focus is placed on improving energy efficiency and conservation across both power systems and end-users. Furthermore, the directives advocate for the development of sustainable regional supply chains for diverse renewable energy sources and energy storage systems to expedite the region's energy transition. Additionally, it underscores the necessity of enhanced collaboration with the private sector, international financial institutions, and donors to facilitate the financing and deployment of innovative technologies.

The AEO8 provides strategic policy recommendations that guide the development of APAEC 2026-2030. By aligning national policies with regional goals, AEO8 facilitates a cohesive approach to energy cooperation, ensuring the AMS work together towards ASEAN long-term blueprint that accounts for the energy trilemma.

CHAPTER 2

UNDERSTANDING THE OUTLOOK

Chapter 2 - Understanding the Outlook

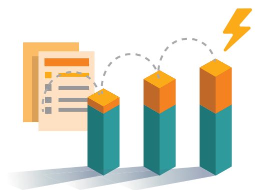
2.1 Overview of Scenarios

This 8th edition of the AEO (AEO8) lays out ASEAN energy prospects by examining four scenarios from 2023 to 2050, using historical data from 2005 to 2022. Similar to the previous AEOs, AEO8 explores the Baseline Scenario (BAS) for business-as-usual, and the ASEAN Member States Target Scenario (ATS) for national targets. The Regional Aspiration Scenario (RAS), now introduced as the third scenario, is the update of the APAEC Targets Scenario (APS) from AEO6 and AEO7, which contains enhanced regional targets and least-cost optimisation. Also new to this edition is the Carbon Neutrality Scenario (CNS), introduced as the fourth scenario to explore the carbon neutrality strategies in the ASEAN region (Table 2.1).

Each scenario assumes different sets of energy targets and policies, with a gradual increase in the level of effort put forth, to predict the impacts on energy consumption, supply, electricity generation, access, CO_2 emissions, and other cross-cutting issues.

Baseline Scenario (BAS)

This scenario follows the historical trend of the AMS energy systems. It assumes a BAU level of effort put forth by each AMS without any modelling interventions to meet existing national energy efficiency (EE) and renewable energy (RE) targets. Hence, it also excludes firm plant capacity additions from power development plans (PDP).

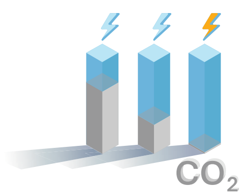


ASEAN Member State Targets Scenario (ATS)

This scenario ensures the attainment of official national policies, especially for EE and RE targets. It includes PDP installation targets and firmed capacity additions and provides modelling interventions to meet energy-related unconditional targets under the various countries' Nationally Determined Contributions (NDCs).

Regional Aspiration Scenario (RAS)

This scenario aims to explore an enhanced version of the national and regional targets outlined in APAEC 2016-2025 by escalating national EE and RE targets. This is crucial to informing the AMS in developing the new phase of APAEC 2026-2030, as the current blueprint will expire in 2025. RAS offers results while implementing least-cost optimisation in the power generation sector, applying RE capacity constraints, optimised electricity storage, and transmission modelling.



Carbon Neutrality Scenario (CNS)

This scenario explores the most ambitious decarbonisation efforts using the least-cost optimisation of net-zero technologies, whilst keeping the 2025 APAEC targets, aligned with ASEAN Strategies for Carbon Neutrality. The scenario offers pathways to reaching carbon neutrality or net zero pledges set by most AMS.

Table 2.1 Summary of AEO8 Energy Scenarios and Key Assumptions

Scenario	Least-Cost Optimisation	Energy Efficiency (EE)	Renewable Energy (RE)	Power Generation Capacity	Energy Targets and Measures in NDCs
Baseline Scenario (BAS)	NO	**Constant** at the level of the last historical year	**Preserving** growth rate from the previous **historical** year	**No installed capacities from the national PDP**	**Not** considered in the projection
AMS Targets Scenario (ATS)	NO	Based on **individual Member States' targets**	Based on **individual Member States' targets**	**Consistent** with PDP, **prioritising RE and more efficient technologies** when adding new capacity	Energy-related items in NDCs (**unconditional**), including EE, RE, and energy access targets
Regional Aspiration Scenario (RAS)	YES	Raise individual Member States' targets with the assumption to reach the 2025 **regional targets and aspiration standards**, and **scale up**	Raise individual Member States' targets and **scale up** where possible based on **accelerated policies**	PDP capacities included with **accelerated deployment of RE capacity** based on each **country's potential**	Energy-related items in NDCs (**conditional**), including EE, RE, and energy access targets, but **scaled up** where possible
Carbon Neutrality Scenario (CNS)	YES	**Accelerate** individual Member States' EE development based on their potential with the assumption of achieving their respective **pledge to carbon neutrality, implementing new net zero measures** if possible to further increase EE	**Accelerate** individual Member States' RE development based on their potential with the assumption of achieving their respective **pledge to carbon neutrality**	The PDP capacity additions are included and the model is allowed to **build additional plants and prioritise dispatch of RE, retirement assumptions for both coal and gas technologies without CCS** to achieve **the lowest carbon emission**	Energy-related items in NDCs (**conditional**), including EE, RE, and energy access targets, and dispatch **emerging technologies to reduce emissions**

2.1.1 Baseline Scenario

The Baseline Scenario (BAS) considers historical trends and excludes any policy interventions, such as RE and EE policies, as well as PDP. Population and economic growth have been the primary drivers for the increase in sectoral energy demand. The population and GDP forecasts are shown in Appendix D.

The share and energy intensity of sub-sectors within the industrial sector are held constant with the latest available data. However, production growth (iron steel, pulp paper, chemicals, non-metallic minerals, textiles, and leather) and value-added products (food, beverages, tobacco, mining, and construction) follow the expected growth in industrial GDP for each country.

In the transport sector, fuel economy, vehicle loading, and vehicle mileage are held constant with the latest available data. The number of vehicles is projected, considering growth in population, urbanisation, and per capita income. The share of vehicle types running with a specific fuel remains the same throughout the years, and biofuel usage follows actual consumption rather than the stated blending mandates. Rail, domestic air, and inland waterway consumption are held constant with the latest historical data since more information would be required to model the growth of these transportation modes.

In the residential and commercial sectors, the efficiency of technologies (cooking, lighting, appliances) is taken as a constant with the latest available data, assuming negligible improvements in efficiency technologies in the absence of energy efficiency and conservation (EE&C) policies. However, access to clean cooking and electrification is assumed to increase following the average annual growth for each country from 2005 to 2022.

The power sector is projected using a simulation approach wherein power sector capacity expansion and dispatch are determined to meet the electricity demand, based on the historical behaviour of consumers. Own-use and losses, as a percentage of electricity, are held constant with the latest available data. In other transformation processes (e.g., biofuel and coal production, oil refining, gas processing), the import and export targets are held constant with the latest historical data, but the production, import, and export projections are estimated based on the demand and availability of indigenously produced resources. The resources considered are only those "proven reserves" from the latest available data and did not consider additional exploration or any potential resources.

2.1.2 AMS Targets Scenario

ASEAN will keep producing and consuming affordable energy, fuelling dynamic economic growth. However, the AMS have realised that continuing the historical energy trend in the BAS is not sustainable. If there are no significant changes in priorities and policies, it will affect their energy security and contribute to more GHG emissions. Hence, each of the AMS has set its own policies for EE/EI and RE, and submitted its NDCs to reduce emissions, in support of the Paris Agreement.

The AMS Targets Scenario (ATS) models the impact of these existing national policies and measures that will lead each AMS to reach their targets. It incorporates more recent information on energy-saving goals, action plans on renewables, and PDPs. All AMS have EE targets in their national energy policies, but not all of them set out the targets for specific sectors. The ATS includes more ambitious energy-saving targets, in addition to rapid advances in low-carbon energy technologies, especially RE. Table 2.2 summarises the AMS official energy targets for access, efficiency/intensity, and renewables.

Table 2.2 Official Energy Targets and Policies of ASEAN Member States

Country	Sector	Official Target
Brunei Darussalam	Demand	• Increase the total share of EVs to 60% of total annual vehicle sales by 2035
	Supply	• Increase the total share of RE to at least 30% of total capacity in the power generation mix by 2035. • 200 MW target for solar capacity by 2025 and more than 600 MW by 2035
Cambodia	Access	• Fully electrified by 2030.
	Demand	• Reduce energy consumption—thermal and electrical—by 19% by 2030 to a BAU trajectory[2] • Public transport will have a 30% share in urban areas by 2050 • Moderate penetration for EVs: 70% for motorcycles, and 40% for cars and urban buses by 2050 • Compressed natural gas (CNG) penetration of 80% for interregional buses and 80% for trucks until 2050
	Supply	• Aiming to achieve a minimum of 70% renewable energy capacity by 2030
Indonesia	Access	• Reach 100% electrification rate by 2025
	Demand	• Reduce energy intensity (TPES per GDP) by 1%/year through 2025 • Achieve 2 million units of electric cars and 13 million units of electric motorbikes by 2030
	Supply	• Increase RE share to 19% in TPES by 2025 and 25% by 2033 • Biodiesel blending ratio targets 30% by 2025 and 50% by 2050; Bioethanol blending ratio of 20% by 2025 and 50% by 2050 • The nuclear power plant is scheduled to commence operations in 2032 with a capacity of 250 MW, gradually increasing to 9 GW by 2060

[2] Refer to its national energy outlook BAU scenario

Country	Sector	Official Target
Lao PDR	Access	• Increase the electricity access rate to 98% of total households by 2025
	Demand	• Reduce TFEC by 10% by 2030 and 20% by 2040 as compared to the Baseline[3] • Introduction of 50,000 energy-efficient cook stoves by 2030 (energy-efficient gasifier cookstoves using biomass pellets)
	Supply	• 30% share of RE in total energy consumption by 2025, including 20% renewable electricity share (excluding large-scale hydro) and 10% biofuel share (blending ratio 5%-10%) • 13 GW total hydropower capacity (domestic and export use) in the country by 2030
Malaysia	Demand	• By 2040, achieve energy savings of 21% compared to the BAU scenario • Elevate the public transport modal share to reach 40% by 2040 and 60% by 2050 • Accelerate the penetration of xEV (4W) share of the vehicle fleet to 80% • Accelerate the penetration of electric two-wheelers' (E2W) share of the vehicle fleet to 80% • Maintain the pathway towards achieving a 5% share of rail freight modal utilisation by the year 2030 • 5% of heavy vehicles utilise hydrogen by 2050
	Supply	• Increase the RE share to 31% in the power capacity mix by 2030 and 40% by 2035 • Increase biodiesel blending targets to 30% (B30) by 2030 • Up to 47% sustainable aviation fuel (SAF) blending mandate by 2050
Myanmar	Access	• Increase electricity access rate to 100% by 2030
	Demand	• Transport: Reduce consumption by 20% by 2030 (raise fuel efficiency and EV share) • Industrial: reduce consumption by 3.6% by 2020, 5% by 2025, 6.6% by 2030 • Commercial/Residential: reduce consumption by 7.4% by 2020, 10% by 2025, 12% by 2030 • 5% reduction by 2025 and 7% by 2030 in traditional biomass use, relative to 2012 levels, via the promotion of energy-efficient cooking stoves
	Supply	• Increase the RE share to 39% in electricity generation by 2030 (28% hydro and 11% other RE)
Philippines	Access	• Achieve a 100% household electrification rate by 2028
	Demand	• Total energy saving by 2040: Transport 25%, Industry 15%, Residential 20%, Commercial 25%, Agricultural 10% • Reach at least a 10% EV share for road transportation (including motorcycles, cars, jeepneys) by 2040
	Supply	• Aim for at least 35% RE share in the power generation mix by 2030, 50% share by 2040, and more than 50% by 2050 • 1,200 MW Nuclear Energy by 2032, 2,400 MW by 2035, and at least 4,800 MW by 2050
Singapore	Demand	• Reduce energy consumption in residential (existing HDB towns) by 15% • Implement green buildings to see an 80% improvement in energy efficiency (over 2005 levels) by 2030 • Achieve 100% cleaner-energy public bus fleet and taxis by 2040 (electric or hybrid vehicles)
	Supply	• Increase solar energy deployment to at least 1.5 GWp by 2025 and 2 GWp in 2030 • 200 MW of deployed energy storage systems beyond 2025

[3] Refer to its national energy outlook BAU scenario

Country	Sector	Official Target
Thailand	Demand	• Decrease energy intensity by 30% of the base year in TFEC compared to 2010 level by 2037 • Achieve 30% EVs manufactured and sales by 2030
	Supply	• Increase the RE share to 30% in TFEC by 2037, which equates to 26.26% renewable electricity in total electricity generation; 39.32% of consumed heating from renewables in total heat consumption; 11.74% consumed biofuel in total oil fuel consumption in the transport sector
Vietnam	Demand	• By 2025, reduce energy intensity in TFEC by 5%-7% and keep power losses under 6.5% • By 2030, reduce energy intensity in TFEC by 8%-10%, keep power losses under 6%, and reduce fuel and oil consumption by 5% in transportation • Energy saving to 10% in 2030 and 20% by 2050
	Supply	• The proportion of RE in the TPES will be 15%-20% by 2030 • Green hydrogen production will reach between 100,000 and 200,000 tonnes annually by 2030 • Renewables are to account for about 30.9-39.2% of Vietnam's electricity supply by 2030 • By 2030, electricity exports should be scaled-up to about 5,000 to 10,000 MW • Increase the absorption area of solar hot water rigs in commercial, service, civil, and industrial production, providing about 3.1 Mtoe by 2030 • Total RE sources for heat production and co-generation of thermal power in 2030 will be about 8 to 9 Mtoe • Biogas is expected to be about 60 million m^3 by 2030

Source: ACE compilation from multiple official documents and consultation with AMS AEO8 Working Group. Note: Countries without 'Access' information has achieved 100% electrification rate as of 2022.

Table 2.3 Translation of National Targets into the ATS Model

Residential and Commercial	Transport	Industrial	Power
Efficiency: Increasing the share of households that utilise efficient air conditioning, refrigeration, and lighting through the replacement of existing appliances after their lifetime with efficient counterparts. **Cooking:** Increasing the share of households utilising modern cook stoves with liquefied petroleum gas (LPG), natural gas, biogas, and electricity as fuels. Overall reduction of households using traditional fuels (kerosene, wood, biomass, charcoal) as a percentage of cooking access is improved throughout the modelling period.	**Efficiency:** Improvements in fuel economy following the global historical trends reduce the fuel required to travel a given distance. **Biofuel:** Reflecting the share of biodiesel and ethanol consumption in transportation fleets as a function of nationally stated biofuel mandates and diesel and gasoline usage, respectively. **EV:** Increasing the share of hybrid/EV in the transportation fleet and/or the targeted number of EVs per type as indicated in national policies.	**Efficiency:** Implementing annual energy intensity reduction to attain the nationally stated total or annual energy saving targets for the whole sector and/or particular sub-sector.	**Renewable and alternative energy:** Firm additions of renewable and alternative energy (such as nuclear and hydrogen) installed capacity based on national power plans and/or prioritising their capacity additions until the country-specific targets are met. **Fossil fuels:** Implement coal phase-down and/or shift to cleaner coal technology for countries with an indicated target.

2.1.3 Regional Aspiration Scenario

The Regional Aspiration Scenario (RAS) includes all key assumptions in ATS with additional RE and EE measures to meet the 2025 regional target under APAEC 2016-2025 Phase II: 2021-2025 [4]. It explores the efforts required to reach the EI and RE targets of APAEC, whenever possible. By adapting a bottom-up approach and Common But Differentiated Responsibilities and Respective Capabilities (CBDR–RC), this scenario also explores accelerated national targets, including the conditional targets in NDCs and the enhanced scenario of the AMS' energy roadmap, if any. For example, in its more ambitious national scenario, the Philippines pushes for 50% EV penetration rate by 2040 [27]. RAS also differs with the BAS and ATS, since it considers the least-cost optimisation which affects the choices of technologies in the energy supply mix.

Table 2.4 Translation of the Accelerated National and Regional Targets into the RAS Model

Residential and Commercial	Transport	Industrial	Power
<u>Efficiency</u>: Increased use of energy-efficient household appliances, such as air-conditioners, refrigerators, televisions, lighting products, and other appliances. **<u>Cooking</u>**: Higher share of clean and more efficient cooking technology, especially electric stoves and biogas.	**<u>Efficiency</u>:** Alignment with the ASEAN fuel economy roadmap by taking the annual average fuel economy improvement rate for the entire region **<u>Biofuel</u>**: Higher biofuel mandates for countries with existing biofuel mandates and setting reasonable blending mandates for countries without existing biofuel policies. **<u>EVs</u>**: Higher share of hybrid/EV in the transportation fleet. **<u>Mass Transport</u>**: Increasing the share of passenger-km served by buses.	**<u>Efficiency</u>**: Higher annual energy intensity reduction relative to nationally stated total or annual energy saving targets for the whole sector and/or particular sub-sector. **<u>Electrification</u>**: Replacing traditional fossil fuel-based furnaces with electric ones, where feasible, can reduce carbon emissions. Utilising heat pumps for industrial heating processes can also be more efficient and less carbon-intensive as compared to conventional heating methods.	**<u>Renewable and alternative energy</u>**: Higher prioritisation with the addition of renewable capacity relative to fossil-based plants in meeting demand. **<u>Fossil fuels</u>**: Reduced utilisation of existing coal, oil, and gas plants in power generation.

2.1.4 Carbon Neutrality Scenario

The Carbon Neutrality Scenario (CNS) outlines a pathway for ASEAN to achieve net-zero carbon emissions by 2050, encompassing both energy and non-energy sources. Unlike zero emissions, which implies eliminating all emissions, net-zero emissions allow for some residual emissions, provided they are offset by negative emissions elsewhere in the economy.

CNS specifies the implementation levels for energy-related mitigation technologies, referred to as "net-zero enabling measures," which are integrated into the AEO model. This scenario builds on the RAS by incorporating emission constraints, adapting low-emission technologies and fuels on the demand side, gradual retirement of some coal and gas technologies, and exploring options for low-emission power generation. It also includes carbon capture and storage (CCS) in the electricity sector and relevant production processes on the supply side, facilitating the production of low-emission fuels. The net-zero enabling technologies were selected from the International Energy Agency's (IEA) Energy Technology Perspectives (ETP) "Clean Energy Technology Guide" [36]. Literature research was conducted to assess the impact of each option on energy consumption and GHG emissions, and assumptions regarding implementation levels for each of the AMS' carbon neutrality roadmaps were developed internally and validated through consultations with AMS stakeholders.

The measures represented in the model generally include technologies related to:

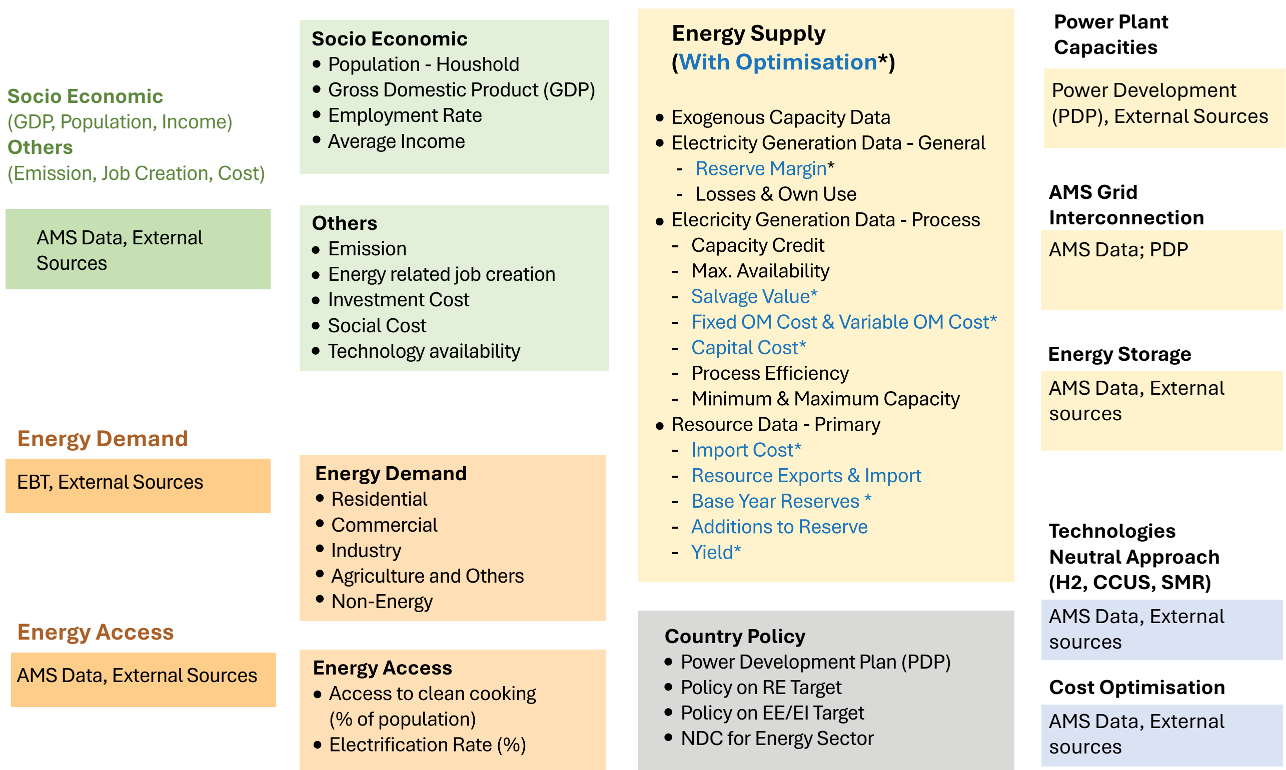
- Energy storage using pumped hydro, lithium batteries, and compressed-air energy storage;
- Electrification and fuel switching to solar energy, biofuels, biomethane, hydrogen, ammonia, methanol, and sustainable aviation fuel for various sectors and applications;
- Cofiring to fuel switching of ammonia and biomass with coal, and hydrogen with natural gas;
- Enhancing energy conservation and efficiency in areas such as lighting, cooking, space cooling, water heating, air and road transport, cement production, and certain manufacturing processes;
- Utilising CO_2 from carbon-intensive industries, such as power plants and iron and steel manufacturing;
- Producing clean electricity from hydro, solar, geothermal, wind, tidal, wave, biofuels, and waste sources; and
- Implementing CCS for thermal power plants, as well as bioenergy with CCS (BECCS).

2.2 Data Overview and Modelling Techniques

2.2.1 Data Overview

The primary data source used in AEO8 is the submitted Energy Balance Table (EBT) by each of the AMS, which provides a detailed accounting of energy flows within a given system of a country over a specific period. It serves as a critical tool for understanding how energy is produced, transformed, and consumed. An EBT may include data on the production, imports, and exports of primary energy sources; information on energy transformation, such as conversion processes and the output of secondary energy sources; a breakdown of end-use consumption by different sectors and fuels; energy losses and adjustments; and energy stocks. In addition, other supporting information is collected, including socioeconomic, energy access, PDP, and energy-related policies (Figure 2.1).

Figure 2.1 Data Requirement in AEO8



Several key factors must be recognised in the energy data processing. Official data sources come in various formats and definitions and are dynamic, being regularly updated with new policies, reference sources, and methodologies. Throughout the AEO series, energy data submissions are standardised; however, bottom-up modelling poses a challenge, as it requires a complex and comprehensive dataset. This approach depends on a limited number of sources that provide detailed disaggregation data and assumes data standardisation.

Timely and accurate data is crucial for modelling outlooks and monitoring national and regional targets, such as energy intensity reduction, RE share in TPES, and RE share in installed capacity. There is a concern regarding the timeliness of the data period. Continuous coordination with AMS focal points is essential to finalise regional data and to improve existing assumptions.

Ensuring the availability of more **granular** data is imperative, including detailed and technology-specific representations of the energy system. Up-to-date, comprehensive data on technology and costs are crucial for accurately reflecting global energy trends and enhancing both modelling accuracy and policy development.

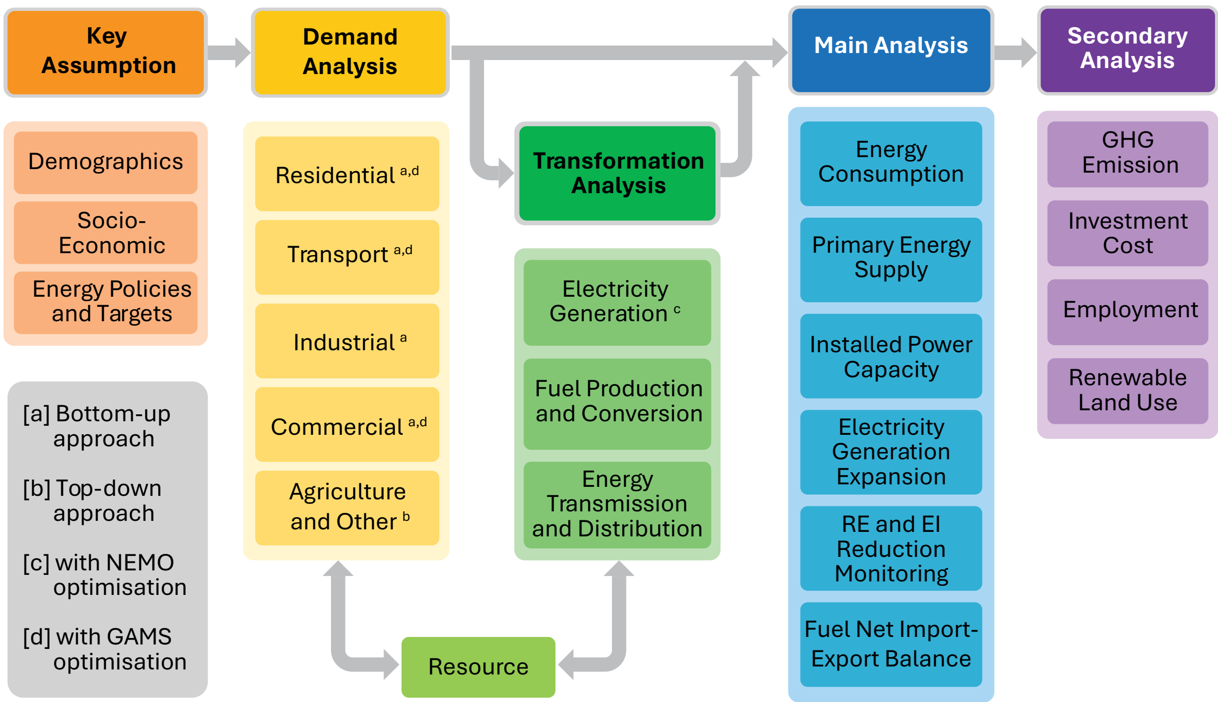
Different agencies are involved in providing energy data, such as ministries of energy, power utilities, and the ministries of transport. Hence, there is a need to **streamline processes** for data collection, verification, synchronisation, and standardisation across institutions.

Having comprehensive, comparable, and timely energy data will greatly enhance understanding of the energy outlook and support the development of evidence-based energy policies.

2.2.2 Modelling Techniques

The main AEO model is designed to incorporate resource use and conversion flows from the EBT. Figure 2.2 provides an overview of the AEO8 model's structure. For AEO8, the Low Emissions Analysis Platform (LEAP)[4] and the Next Energy Modelling system for Optimisation (NEMO)[5] software was used. LEAP is a scenario-based, demand-driven modelling tool capable of tracking energy consumption, production, and resource extraction across all economic sectors. NEMO is a high-performance, open-source energy system tool, that complements LEAP by optimising the supply side, especially electricity generation, using mixed-integer linear optimisation.

Figure 2.2 AEO8 Modelling Structure and Analysis



Another optimisation is applied outside LEAP, specifically for the demand side, using the general algebraic modelling system (GAMS)[6]. GAMS is a high-level modelling system for mathematical optimisation, which is designed for modelling and solving linear, nonlinear, and mixed-integer optimisation problems. Due to disaggregated data availability, GAMS optimisation is implemented for several activity levels in residential, transport, and commercial (exclude industrial sector). It affects the choices of technologies based on costs in these demand sectors, and consequently the supply projection.

[4] https://leap.sei.org/

[5] https://sei-international.github.io/NemoMod.jl/stable/

[6] https://www.gams.com/

Demand Side

As with AEO7, demand-side modelling explores five foundational sectors – Residential, Transport, Industrial, Commercial, and Others (including agricultural and non-energy use). AEO8 utilises a detailed sector-by-sector modelling approach, with additional sub-sectoral or end-use devices where possible, including bottom-up modelling within some sectors. This method is favoured for the demand side as it effectively models energy policies, such as transitions to clean-cooking technologies and efficient appliances, energy savings in specific sub-sectors, the deployment of EVs, and biofuel mandates. By doing so, it enables changes in electricity demand to be factored into electricity sector modelling and fossil fuel demand, incorporating it into non-power process modelling.

The AEO8 differs from the AEO7 for the commercial sector. Instead of disaggregating it by building types, AEO8 uses appliance types, similar to the residential sector. This modification was done to get more robust results in energy-intensive appliances, thus providing better policy recommendations. In the transportation sector fuel switching to emerging fuel types was also implemented including the penetration of hydrogen and ammonia to adapt NDCs for some AMS.

An additional exercise is undertaken in AEO8 to explore the least-cost optimisation impact on modelling end-use applications using GAMS. In the transport sector, the method is employed for optimising road vehicles fuelled by internal combustion engines (ICE), electricity, biofuels, and natural gas. Meanwhile, the residential and commercial sectors cover types of air conditioning (i.e., non-inverter, inverter, and smart inverter), and lighting (fluorescent, light emitting diode (LED), and smart LED). By using the LEAP results in ATS (called BAU in this exercise) as the inputs, and the same assumptions in RAS, the GAMS modelling projects the optimised TFEC and annual costs for these three sectors (called OPT in this exercise).

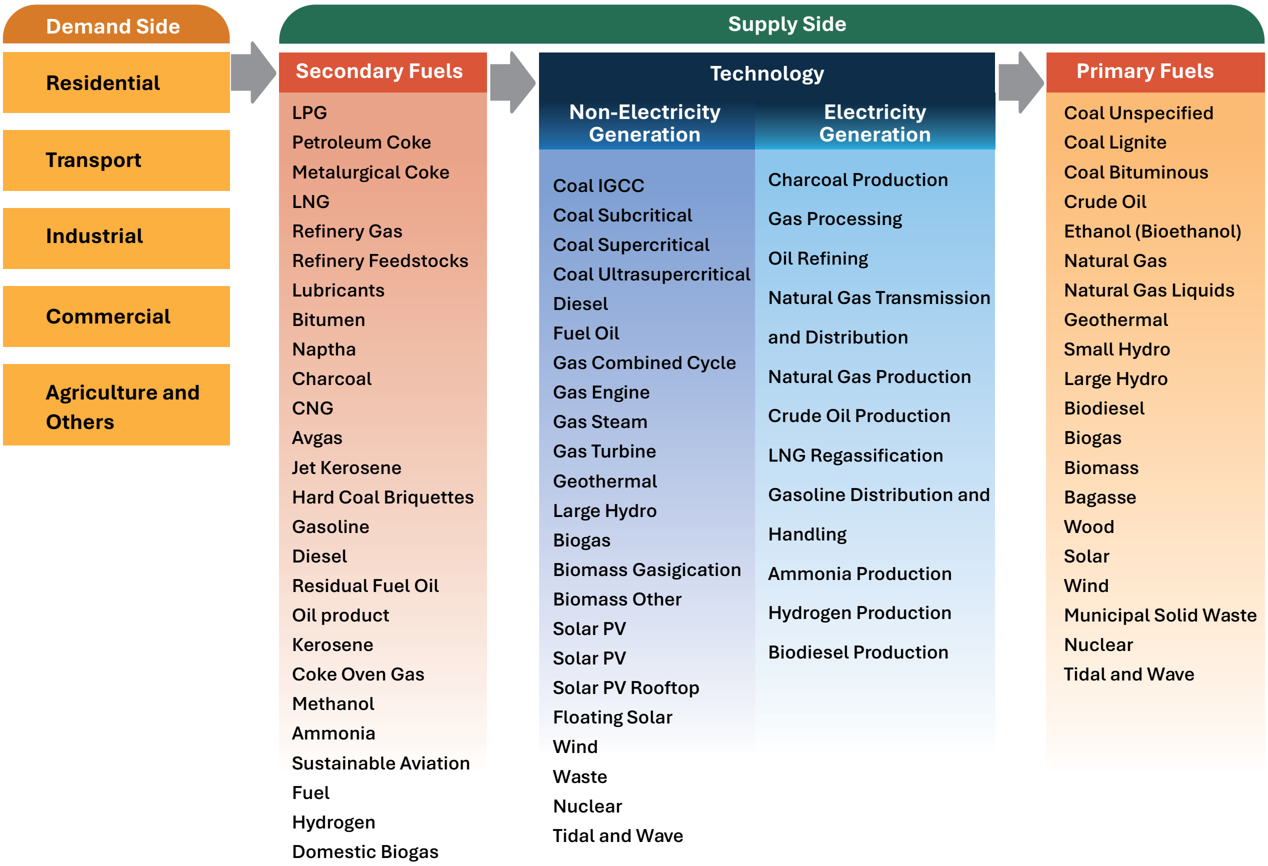
Transformation Side

Transformation or supply-side modelling examines both electricity generation and non-power processes (Figure 2.3). The resource module estimates overall fuel requirements by considering fossil fuel reserves and RE potential. For the non-power transformation, the energy is transformed through "modules", which include coal production/mining, natural gas and crude oil production, gas processing, oil refining, LNG regasification, charcoal production, and hydrogen/ammonia/biofuel production.

The overall final electricity demand and the export targets drive all related transformation modules in power generation modelling to create just the right amount of electricity and capacity to be built in order to meet the requirements. LEAP and NEMO add the capacity expansion requirements defined by each AMS planning reserve margin, and the energy dispatch process adheres to the maximum availability and minimum utilisation of each generation technology type [37]. Several "Technologies" are modelled, representing the type of power plants, such as various types of coal and gas power plants, and all renewables, including solar, wind, geothermal, hydro, and waste, as well as nuclear. The non-power transformation will produce either primary or secondary fuels. "Primary Fuels" include types of coal and natural gas liquids, whilst the "Secondary Fuels" include various petroleum products (LPG, petroleum coke, gasoline, diesel, SAF), CNG, hydrogen, and others.

Electricity generation modelling follows two approaches: Simulation (BAS and ATS) and Optimisation (RAS and CNS). BAS forecasts the power sector capacity expansion and dispatch based on the historical behaviour of consumer production and the type of generation technologies in the last historical year. In ATS, capacity build follows the PDP of each AMS up to the last year specified and allows LEAP to add similar technologies following each country's plan. In both scenarios, energy generation is addressed by merit order dispatch, and the capacity added for each type of technology is distributed according to the historical ratio of non-renewable to renewable technologies.

Figure 2.3 Supply-Side Modelling Structure



By utilising NEMO, RAS and CNS make sure that the electricity demand is satisfied at the lowest possible cost. In addition to reaching the APAEC RE target of 35% by 2025, both scenarios continue to adhere to the capacity build plans for all AMS. Different kinds of energy storage systems are optimised as well for the system based on demand. Transmissions between the different countries are also modelled for both scenarios. Neither approach is superior to the other; therefore, both modelling approaches are examined in the AEO8 to gain a more comprehensive understanding of ASEAN's various energy futures.

Energy Employment

AEO8 explores the energy transition impact on the future of direct employment between 2023 and 2050 in the ASEAN energy sector. This analysis adopted the Employment Factor (EF) approach considering its flexibility, simplicity, and effectiveness in predicting the number of jobs created and lost associated with installed power capacity addition and power generation over time generated from the LEAP model, covering both sectoral and technological variations [38]. This method estimates the number of jobs across several stages of the energy transition, including manufacturing, construction and installation, operation and maintenance, fuel supply, and decommissioning jobs as seen in Table 2.5. The projection of job creation and loss is identified by incorporating several parameters, including EF, decline factor, regional employment multiplier, and local manufacturing factor [39].

Table 2.5 The Category of Direct Employment

Sector	Description
Manufacturing Jobs	These jobs cover the temporary employment required to manufacture equipment and components for power plants, defined as job-years over the plant's lifetime. This analysis only focuses on a local manufacturing factor that adjusts the job creation forecast based on the degree of import dependence on energy equipment and limits the boundary of jobs occurring domestically within the region.
Construction and Installation (C&I)	Jobs in construction and installation entail setting up electricity-generating equipment. These are assessed as the number of job years required to build a power plant, capturing the direct effects on employment throughout the early stages of the project. The length of this work varies based on the technology and is expressed in terms of installed capacity per unit.
Operation and maintenance (O&M) jobs	Unlike manufacturing and C&I jobs, O&M jobs involve the continual employment required to keep power plants working throughout their operational lifespan. The overall number of jobs during the energy transition period is estimated by annualising these occupations, which are quantified per unit of installed capacity. Even if these jobs last longer, advances in technology maturity and operational efficiency and procedures may result in a reduction in the number of workers needed.
Fuel Jobs	These encompass all employment related to the fuel supply for power plants, including fossil, nuclear, and bioenergy. These are calculated as jobs per unit of primary energy, taking into account the varying fuel consumption rates of power plants, depending on the type of fuel used and conversion efficiencies during the transition period.
Decommissioning Jobs	These refer to all employment related to the decommissioning of power plants at the end of their operational life, particularly when plants are repowered or certain components are recycled or reused. These jobs are similar to those in construction and installation and are measured in job years, representing the total number of full-time jobs required for decommissioning over the plant's lifetime. These jobs are further annualised during the transition period to determine the total number of jobs generated.
Jobs Loss	The number of job losses corresponds to the decommissioned and power generation curtailment of conventional power plants until 2050.

Land-use for Renewables

Land-use for renewables analysis extends on the findings of AEO7 by highlighting the estimated land-area requirements for biofuels and applying adjusted methodologies to account for installed capacity and power generation. It further explores the land-use implications of different energy transition scenarios across the ASEAN region, focusing on wind and solar power based on the installed capacity projection produced from LEAP.

The methodology for estimating land use requirements for wind and solar energy considers both direct surface impacts and the total project area, incorporating various environmental and geographical factors. For both types of energy plants, direct surface impacts refer to the land physically disturbed by construction and associated infrastructure. In wind power plants, this includes areas occupied by turbine pads, access roads, substations, service buildings, and other infrastructure that permanently or temporarily alter the land. For solar power, direct impacts primarily involve the installation of solar panels, inverters, wiring, and access roads.

The total project area for wind and solar plants includes the entire footprint of the project, not just the direct impacts. It encompasses land within the project's perimeter, factoring in terrain, equipment size (e.g., turbine height for wind and panel orientation for solar), land-use regulations, and other environmental considerations. This approach involved several assumptions, such as excluding specific configurations of wind and solar power plants and not accounting for the average power output or total energy generated over the footprint area [40], [41], [42], [43].

A systematic review of previous studies on wind and solar land-use requirements was undertaken to examine the average land use per unit of power and the average capacity factor of each technology. By aggregating data from multiple sources, a systematic review captures the variability across different energy projects in various regions, technologies, and environmental conditions, providing a more representative estimate. This data, derived from the systematic review, serves as the multiplying factor to estimate the total land-use, percent of occupied ASEAN land area, and comparison with another technology with higher energy density, such as coal, for more in-depth analysis.

CHAPTER 3

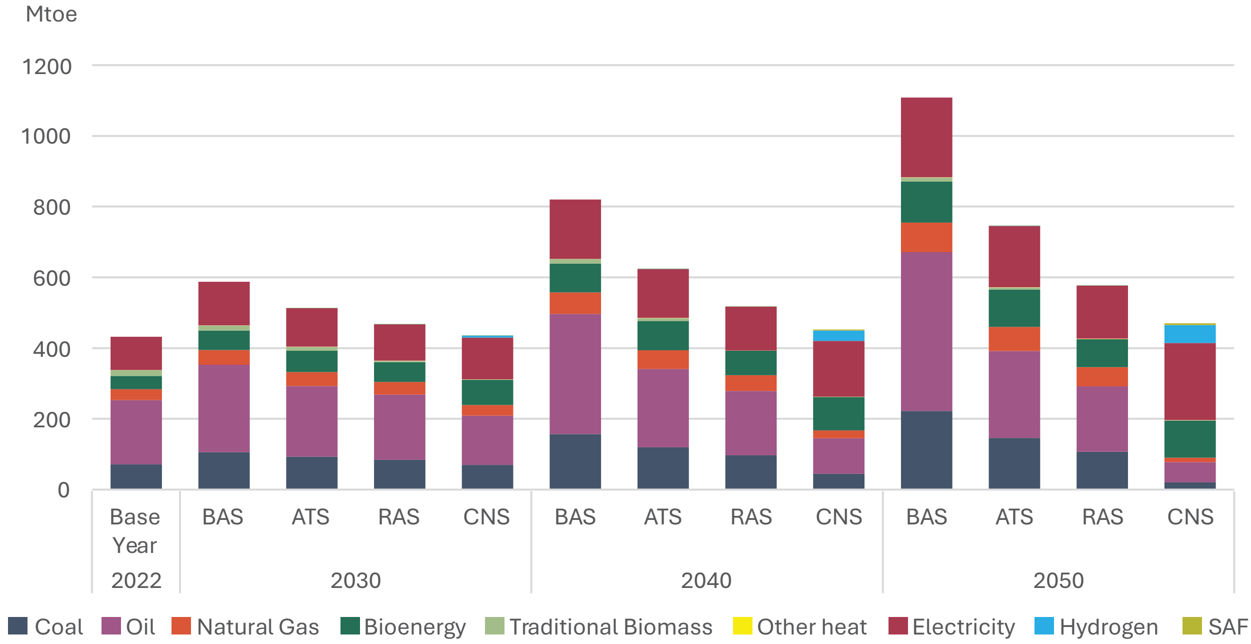
CHARTING MULTIPLE PATHWAYS

Chapter 3 - Charting Multiple Pathways

3.1 Energy Demand

As population and economic growth continue to rise across the AMS, ASEAN's total final energy consumption (TFEC) is projected to consistently increase. By 2050, regional energy consumption is expected to reach 1,107.9 Mtoe in the Baseline Scenario (BAS), representing an approximate 2.6-fold increase from 2022 levels (Figure 3.1). Oil is anticipated to remain the dominant energy source, constituting 40.5% of the TFEC, followed by electricity and coal, each accounting for 20.3%. This continued reliance on oil, electricity, and coal is largely attributed to their availability and the well-established infrastructure supporting these energy sources. Despite bioenergy's lower share, it performs the highest compound annual growth rate (CAGR) between 2022 and 2050 amongst all fuels at 4.1%, along with coal.

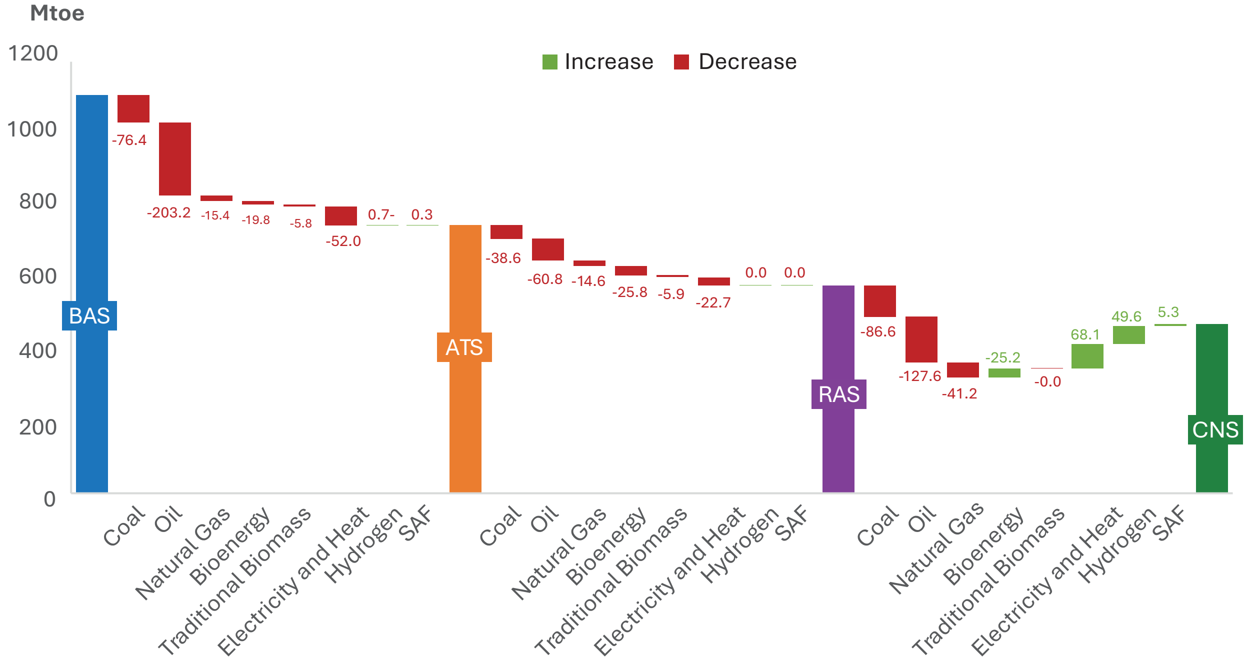
Figure 3.1 ASEAN Total Final Energy Consumption by Fuel Across Scenarios



Note: Other heat includes solar thermal.

The realisation of national energy efficiency and conservation (EE&C) targets in the AMS Targets Scenario (ATS) is predicted to reduce energy demand by 32.7% by 2050, as compared to the BAS. Although the domination of oil demand remains unchanged, its usage would reduce the highest, followed by coal (Figure 3.2). Oil share is expected to decline significantly to 32.9%, whilst the shares of bioenergy and electricity are estimated to increase by 3.7 and 2.8 percentage points, respectively. This trend is evident in the ATS which reflects the widespread adoption of energy efficiency and fuel-shifting measures across various sectors, such as fuel economy standards and the increased deployment of EVs, alongside biofuel mandates in transportation. Additionally, hydrogen in transport is in the mix for some AMS with a 0.09% fuel share by 2050.

Figure 3.2 TFEC Fuel Shifting in 2050 Across Scenarios



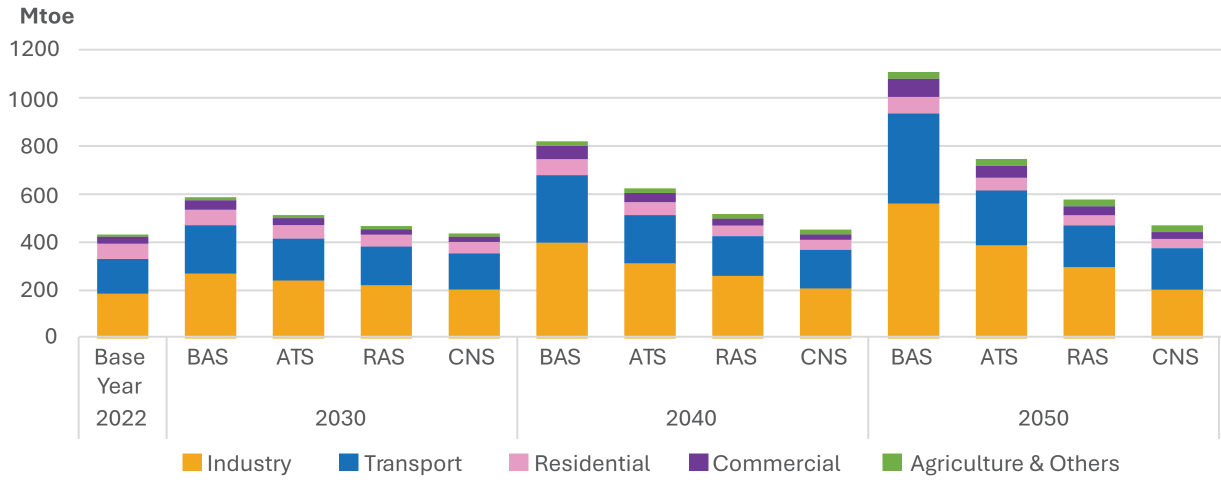
In the Regional Aspiration Scenario (RAS), ASEAN's TFEC is projected to be 577.7 Mtoe by 2050, representing a reduction of approximately 47.9%, as compared to the BAS. In this scenario, the shares of oil and coal remain relatively stable at 32.0% and 18.6%, respectively, but electricity consumption is expected to increase, reaching 25.9%, especially due to the adoption of stringent energy efficiency standards in the various sectors, and the use of electric cooking stoves in residential areas. This shift highlights the role of energy efficiency policy adaption in the projected downward trend for energy demand and displacement of fossil fuel use. Hydrogen in transport is also present in the scenario with a 0.12% share by 2050.

The Carbon Neutrality Scenario (CNS) projects that ASEAN's TFEC would reach 470.5 Mtoe by 2050, which is approximately 36.9% and 18.6% lower than the projections under the ATS and RAS respectively. This scenario projects a significant decline in the consumption of coal and gas by 2050, with a substantial increase in the use of electricity and bioenergy. However, the highest reduction is noted with oil at around 57.2 Mtoe by mid-century, whilst electricity rises sharply to 217.6 Mtoe. Electrification policies and biofuel mandates are the expected drivers of this trend shift. Electrifying sectors traditionally reliant on fossil fuels (e.g., heating, transport) can also lead to increased electricity consumption, even if the overall carbon footprint is reduced. Thus, electricity will become one of the primary fuels aside from bioenergy standing at 46.2%, together with the emergence of hydrogen with a 10.7% share.

In terms of sectoral demand, industry and transport are the most energy-consuming sectors in the region throughout the projection years and scenarios. The gaps with the other sectors are widening, caused by a shift in population areas and economic structures. Under the BAS, industry would contribute to 50.6% of regional energy consumption in 2050 (Figure 3.3). The transport and commercial sectors are growing steadily, with around 33.8% and 6.9% shares, respectively, in all projection years. The residential energy demand would not grow exponentially like the others, from 63.0 Mtoe in 2022, to 68.2 Mtoe in 2050.

Applying each country's EE&C policies in ATS might show the greatest reductions of energy demand in the transport and commercial sectors by 2050, with 39.1% and 33.6%, respectively, when compared to the BAS. More stringent efforts in the RAS will further decrease energy consumption by 53.8% and 50.5% for the same sectors and year, whilst industrial shows a 47% reduction.

Figure 3.3 ASEAN Energy Consumption by Sector Across Scenarios



Although the percentage difference in industrial energy consumption between the scenarios is not as significant as in the other two sectors mentioned, the value reductions are the largest. By 2050, energy consumption in the industrial sector is predicted to decrease by 174.0 Mtoe in the ATS, and 264.7 Mtoe in the RAS, when compared to the BAS. This aligns with the existing policies at the national and regional levels. In the ASEAN Plan of Action for Energy Cooperation (APAEC) 2016-2025 Phase II: 2021-2025, there are specific Outcome-Based Strategies for industry and transport to enhance energy efficiency in these two crucial sectors [4]. Implementation of energy-efficient technologies and practices in the industrial sector may include upgrading machinery, optimising processes, and improving insulation to reduce overall energy consumption.

Inclusive Transition

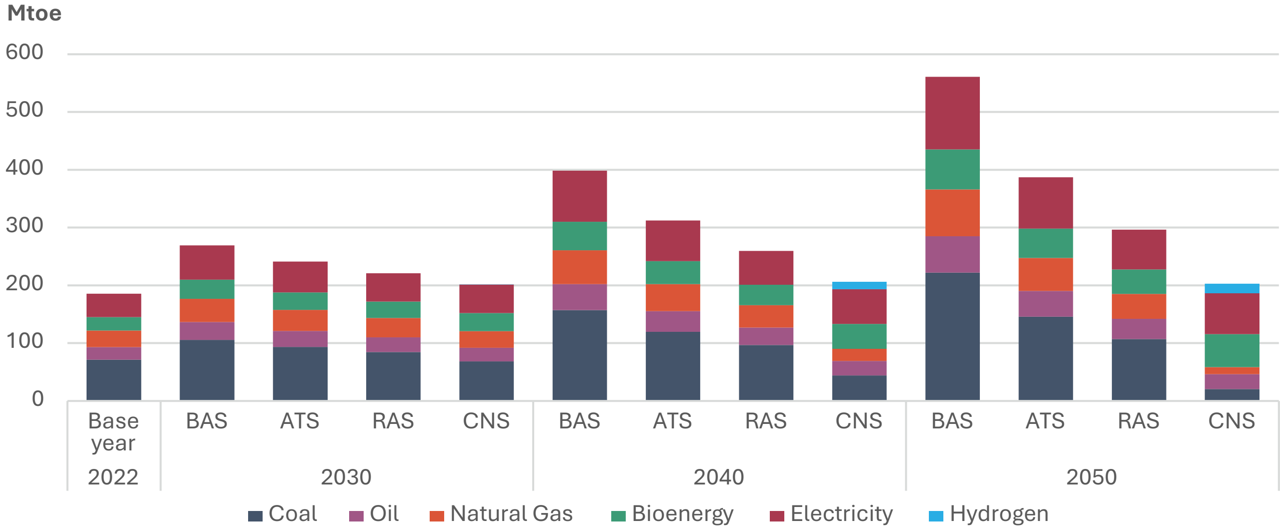
Meeting demand tends to reinforce patterns of increased consumption. Therefore, limiting consumption is likely to create a more sustainable feedback loop by promoting innovations in energy efficiency and reducing energy intensity. Encouraging the use of alternative modes of transport is expected to reduce fuel consumption and increase the adoption of low-energy transportation options. In order to promote responsible consumption, several legislative measures may be deployed to shift costs of adjustment onto the private sector and lessen the burden on society, such as building codes implementation (isolation standards, heat dispersing architecture) and better urban planning (bicycle infrastructure, public transport).

3.1.1 Industry

It is projected in BAS that the TFEC in the industrial sector will reach 214.2 Mtoe and 561.0 Mtoe by 2025 and 2050, respectively, growing from 185.6 Mtoe in 2022 (Figure 3.4). Industries across ASEAN are projected to remain reliant on coal as their primary fuel source, accounting for 39.6% of all fuels, followed by electricity at 22.4% and natural gas at 14.5% by 2050. The energy mix is predicted to be the same from 2022 through 2050 in the absence of policy interventions. Although the total demand will be lower for both ATS and RAS, the trend and projection patterns remain relatively unchanged in 2050, indicating that coal and natural gas are indispensable for energy requirements in the ASEAN industrial sector.

The AMS can integrate several strategies in industries, progressively reducing dependence on coal and natural gas, and moving towards a more sustainable energy future. For instance, industries could replace coal and natural gas-based heating and power systems with electric alternatives powered by RE and other emerging fuels. This may involve using electric boilers, furnaces, or heat pumps. In addition, governments should encourage companies to use by-products or waste from other industries, which can reduce the need for energy-intensive processes and decrease reliance on fossil fuels. There should be more research and development (R&D) in adapting alternative fuels such as biofuels, hydrogen, or synthetic fuels that can replace coal and natural gas in industrial applications.

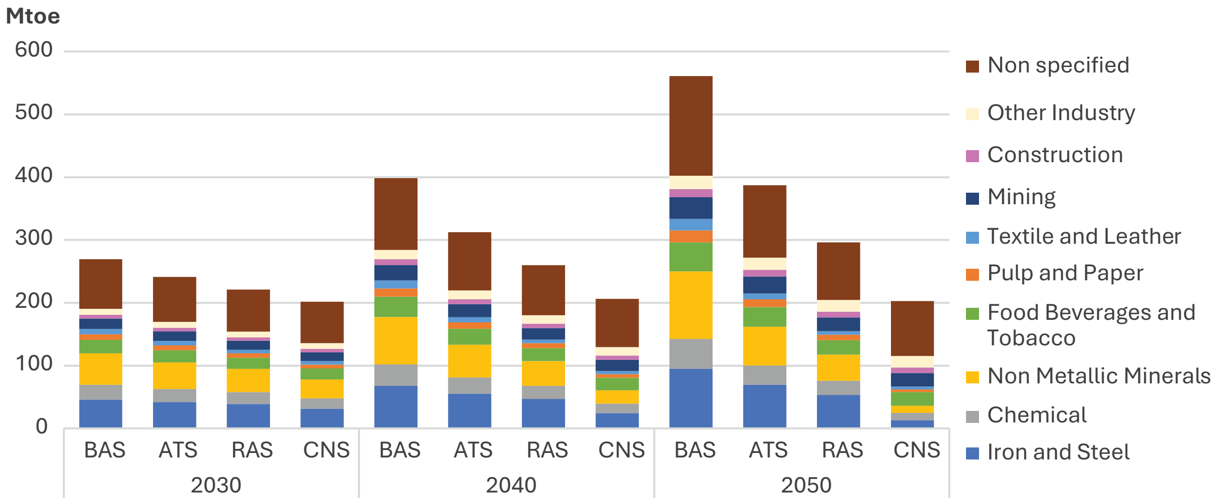
Figure 3.4 Industry Consumption by Fuel Across Scenarios



Among the industry types, the 'Non-Metallic Minerals' and 'Iron and Steel' sectors consistently emerge as the largest energy consumers across all scenarios, followed by 'Chemical', in almost all the projection years (Figure 3.5). These sectors dominate energy use due to their energy-intensive processes, which are central to industrial production. Decarbonisation in these sub-sectors is essential, requiring a shift toward cleaner energy sources.

The ATS, RAS, and CNS show that implementing more sustainable technologies will significantly reduce overall energy consumption. However, the reduced energy use will not substantially affect the 'Iron and Steel' and 'Non-Metallic Minerals' types, indicating the critical importance of targeting these sectors for energy efficiency improvements and the adoption of cleaner technologies.

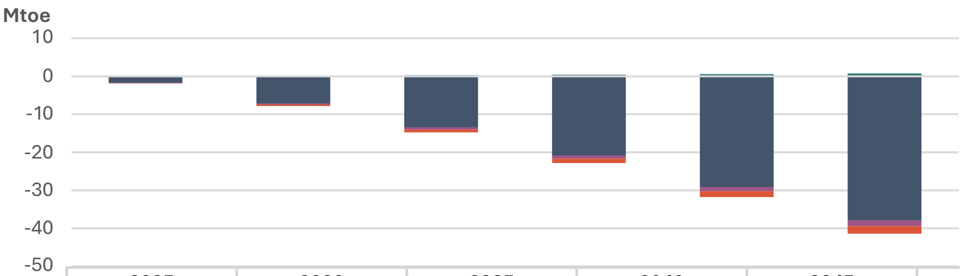
Figure 3.5 TFEC by Industrial Sub-Sector Across Scenarios



Note: Sub-industrial demand cannot be reported for the historical year (2022). These details only appear at the beginning of the projection year (2023) and thereafter.

The ATS, RAS, and CNS show that implementing more sustainable technologies will significantly reduce overall energy consumption. However, the reduced energy use will not substantially affect the 'Non-Metallic Minerals' and 'Iron and Steel' shares, except for the CNS in the long term. Achieving carbon neutrality will require zero emissions from major industries. All sub-sectors, except for mining and construction, have net zero measures implemented in terms of material efficiency and hydrogen displacing coal and gas. As depicted in Figure 3.6, decarbonisation efforts in the 'Non-Metallic Minerals' and 'Iron and Steel' industries are shown by additional utilisation of bioenergy, electricity, and hydrogen in the CNS and the reduction of fossil fuel demand compared to the RAS. These measures resulted in having 'Food Beverages and Tobacco' (10.9%) and 'Mining' (10.7%) as sectors with the highest share by 2050. The category labelled 'Other Industry' and 'Non specified' collectively account for 52.2% in the CNS by 2050, highlighting the need for more granular data to better inform policy decisions and enhance industrial energy management strategies.

Figure 3.6 Fuel Shifting in Iron and Steel Industry Demand, CNS vs RAS

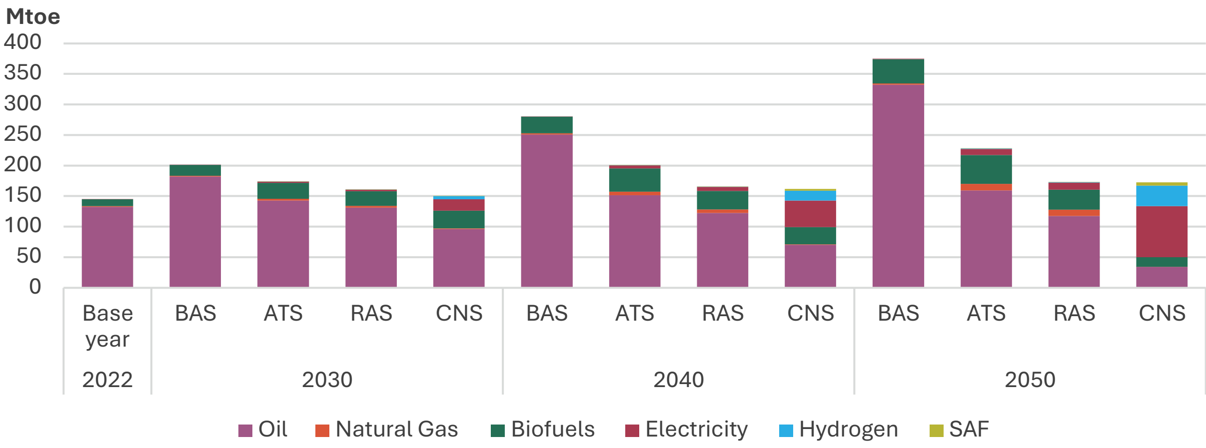


	2025	2030	2035	2040	2045	2050
Hydrogen	0.00	0.02	0.03	0.05	0.07	0.09
Electricity	0.00	0.02	0.03	0.05	0.07	0.09
Bioenergy	0.03	0.11	0.21	0.33	0.46	0.60
Natural Gas	-0.10	-0.38	-0.71	-1.09	-1.52	-1.98
Oil	-0.07	-0.30	-0.56	-0.85	-1.17	-1.49
Coal	-1.76	-7.13	-13.49	-20.86	-29.11	-37.94

3.1.2 Transport

The transport sector is the second largest energy-consuming sector, after industry, with 145.2 Mtoe in 2022. Driven by economic growth, increased population, and vehicle ownership, under the BAS, the energy consumption for the transport sector is expected to grow by 2.6 folds by 2050, from the 2022 value, which amounts to 374.9 Mtoe (Figure 3.7). Oil is expected to continue dominating the fuel mix of the transport sector, with 91.2% in 2022, and it is projected to slightly decline to 88.7% by 2050. Biofuel increases from 7.7% to 10.6%, whilst electricity share remains relatively low, only reaching 0.2% by 2050. It is expected no change in fuel share in the sector under the BAS, given no policy intervention to switch from traditional fuel to more sustainable and emerging transportation.

Figure 3.7 Transport Consumption by Fuel Across Scenarios



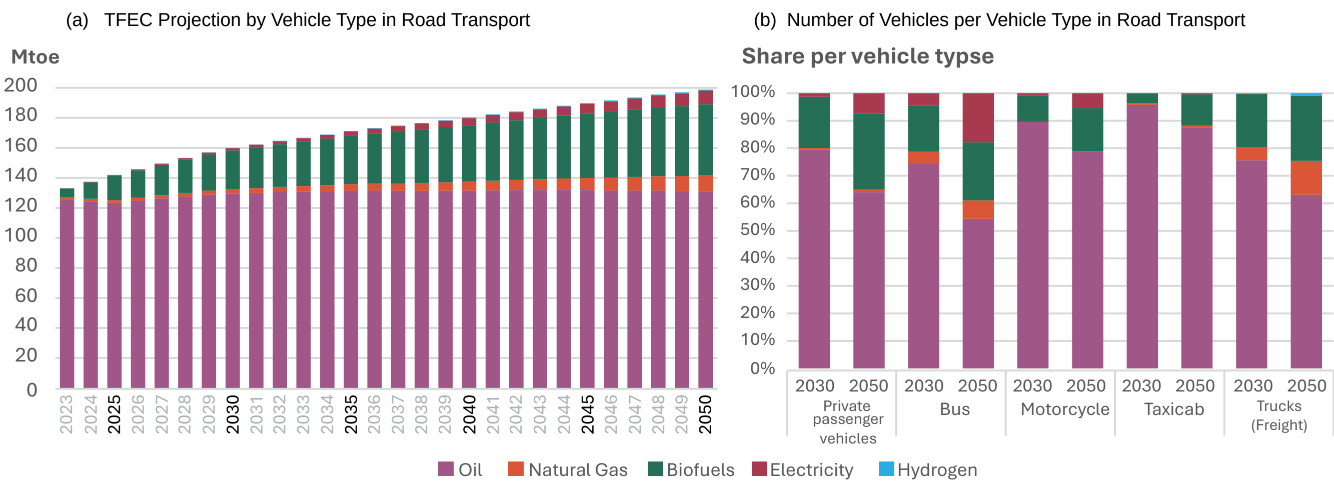
The AMS aim to reduce their dependency on oil imports, by enacting various policies and targets, including biofuel blending mandates and EV share targets. Under the ATS, total energy consumption for the transport sector in 2050 is projected to be reduced by 39.1%, as compared to BAS, down to 228.2 Mtoe. As a result, oil share in total energy consumption for transport also decreases noticeably to a 69.8% share, with an increase in biofuels and electricity up to 20.8% and 4.3%, respectively.

Under the RAS, through the implementation of ASEAN's commitment to increase vehicle efficiency within the ASEAN Fuel Economy Roadmap for light-duty vehicles, the overall consumption will be reduced by 53.8% to 144.0 Mtoe by 2050, as compared to the BAS. As a result, oil and biofuel consumption decreases by approximately 26.3% and 31.0%, respectively, as compared to the ATS in 2050. The use of Sustainable Aviation Fuel (SAF) and hydrogen as alternative fuels are expected to be introduced as soon as 2030 with Malaysia leading ASEAN with a fuel share target by 2050, to further decarbonise aviation and heavy-duty vehicles.

Towards achieving carbon neutrality, the CNS shows a significant increase in electrification with around 48.3% share by 2050. Oil and biofuel shares are expected at 19.8% and 9%, respectively. Hydrogen is also projected to take a significant share up to 19.5% by 2050, mainly for freight transport. SAF development in the region remains limited with a fuel share for the whole region at 3.2% by 2050.

Road transport makes up about 93.5% of the sector's overall energy consumption. In the ATS, oil demand remains the dominant share, with 69.8%, whilst biofuel and electricity are expected to increase their shares up to 20.8% and 4.3%, respectively, of total fuel consumed by the road transport sector in 2050 (Figure 3.8 a). This demonstrates the AMS' commitment to reducing oil demand for road transport in decarbonising the ASEAN transport sector.

Figure 3.8 Road Transport Fuel Consumption in ATS



The significant increase in biofuel share by 2050 under the ATS, as compared to the BAS, results from the growing use of biofuel as an alternative to oil products, particularly diesel (Figure 3.9). This shift is driven by policies supporting biofuel production and its use in the transport sector. Indonesia and Malaysia, the leading palm oil producers in ASEAN, play a pivotal role in biofuel production. Indonesia's biodiesel blending mandate programme has evolved from 2.5% (B2.5) in 2008 to 35% (B35) in 2023, with plans to increase this rate further. Similarly, Malaysia has applied a biodiesel blend of 10% (B10) and aims for 30% (B30) by 2025, with specific regions like Sarawak, Labuan, and Langkawi islands already at 20% (B20). The Philippines has implemented a voluntary scheme in bioethanol blend to 20% (E20), from the current 10% (E10), starting in 2024.

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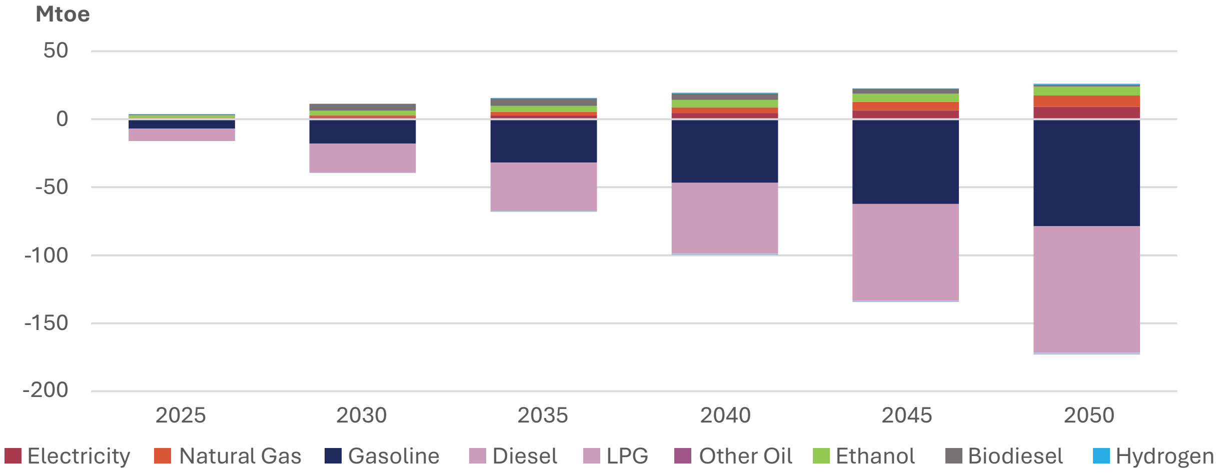
Figure 3.9 Fuel Shifting in Road Transport, ATS vs BAS



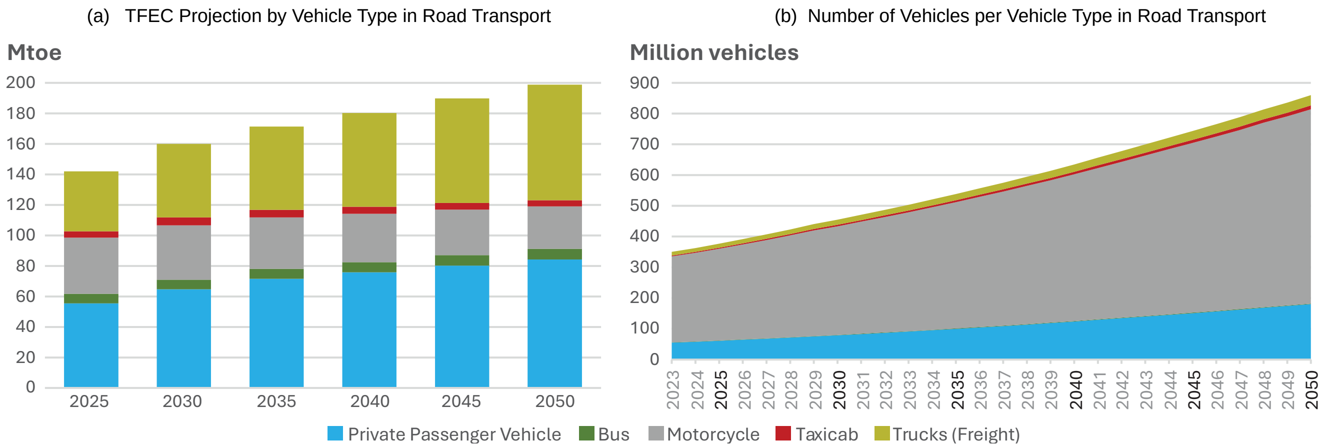
Most of the AMS are targeting a higher EV penetration between 2030 and 2050, with Singapore aiming for an Internal Combustion Engine (ICE) phase-out by 2040. The overall penetration of electricity in passenger vehicles would reach up to 1.4% and 7.4% by 2030 and 2050 respectively (Figure 3.8 b). Despite the low penetration, the deployment of electric passenger vehicles is expected to reduce oil usage by 52.1% in the ATS, as compared to the BAS. To yield more energy savings in the sector, higher penetration of EVs is needed through a combination of mandatory fuel economy standards, higher fuel blending mandates, incentives, and infrastructure readiness improvements.

Faster adoption of EVs can be seen in buses, from 4.4% up to 17.9% in 2050, highlighting the strong potential for electrification due to their relatively fixed driving patterns and lower daily travel distances. Several cities in Southeast Asia, such as Jakarta, Bangkok, and Singapore have increased the uptake of electric buses in their bus rapid transit fleets.

Motorcycles are widely used in the AMS for short-distance urban mobility. Motorcycles can serve as a solution for the first mile and last mile in urban areas. ASEAN is one of the largest two and three-wheeler markets, with a fleet of more than 270 million in 2022, which is expected to more than double by 2050. The energy consumption of motorcycles, however, is projected to decrease from 35.6 Mtoe in 2030 to 27.8 Mtoe by 2050 (Figure 3.10 a), due to the improvement in fuel economy from each AMS, the increase in share for bioethanol (15.7%), and the gradual shift to electrification (5.4%). With technology maturity and affordability compared to passenger vehicles, electrification of motorcycles could be the low-hanging fruit for decarbonisation and curbing oil demand. Government support to facilitate the transition through incentives and policies could lead to rapid market penetration of e-motorcycles.

Trucks and other heavy-duty vehicles are responsible for over 38.1% of road transport fuel consumption, despite only accounting for around 3.9% of overall vehicle fleets, in the ATS by 2050, highlighting their elevated energy intensity (Figure 3.10). Noting the long-haul nature of trucks, biofuels, and natural gas remain a viable alternative to diesel as decarbonisation options, which are projected to increase up to 23.6% and 12.3% share by 2050, respectively. Hydrogen also emerges as a potential fuel for heavy-duty vehicles with Malaysia spearheading the way, albeit at a small scale with 0.9% by 2050. Meanwhile, electric fleets are yet to be commercially mature, particularly regarding concerns related to vehicle weight, and require sufficient infrastructure. Additionally, implementing improved fuel economy standards for trucks will play a significant role in increasing the efficiency of trucks in the short to medium term and in reducing oil demand.

Figure 3.10 Road Transport by Vehicle Type, ATS



Note: End-use details (sectoral demand by vehicle type) cannot be reported for the historical year (2022). These details only appear at the beginning of the projection year (2023) and thereafter.

3.1.3 Residential

In 2022, the residential sector had an energy consumption of 63 Mtoe (Figure 3.11). Electricity, traditional biomass, and oil have been the primary household energy sources, with respective fuel shares of 46%, 27.4%, and 26.1% of 2022 TFEC in the residential sector.

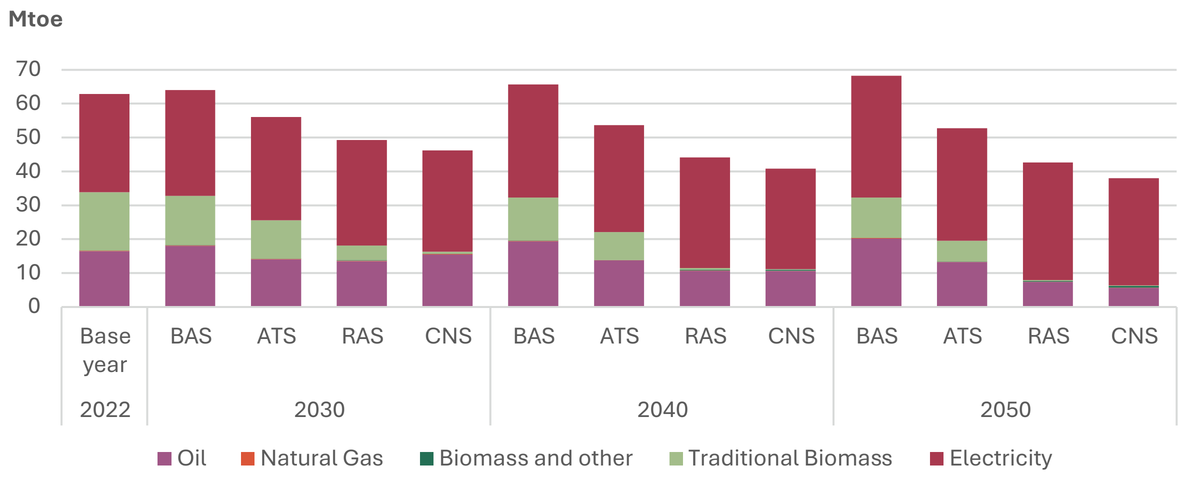
Projections for the residential sector in the BAS are expected to increase gradually by 1.1 times from 2022 to 2050. In this case, electricity and oil share would increase to 52.6% and 29.5%, respectively, whilst traditional biomass is predicted to decrease to 17.5%.

Contrary to the BAS projection, which is expected to increase annually, the ATS and RAS show a decrease in projections from 2022 to 2050. This decline occurs in all end-use devices. Electricity is the dominant fuel type due to improvements in the electrification rate and the growth in clean cooking access, increasing to 33.2 Mtoe by 2050 from 29.0 Mtoe in 2022. However, because of the general advancement in end-use device efficiency in the ATS, there would be a 22.7% decrease in intensity compared to the BAS in 2050.

In the RAS, with more ambitious policies coupled with regional targets in energy efficiency, residential demand in 2050 is projected at 42.6 Mtoe, a 37.5% decrease from the BAS level. Another significant improvement is the traditional biomass share (0.4%) which reflects the improvement in clean cooking access across all AMS compared to BAS.

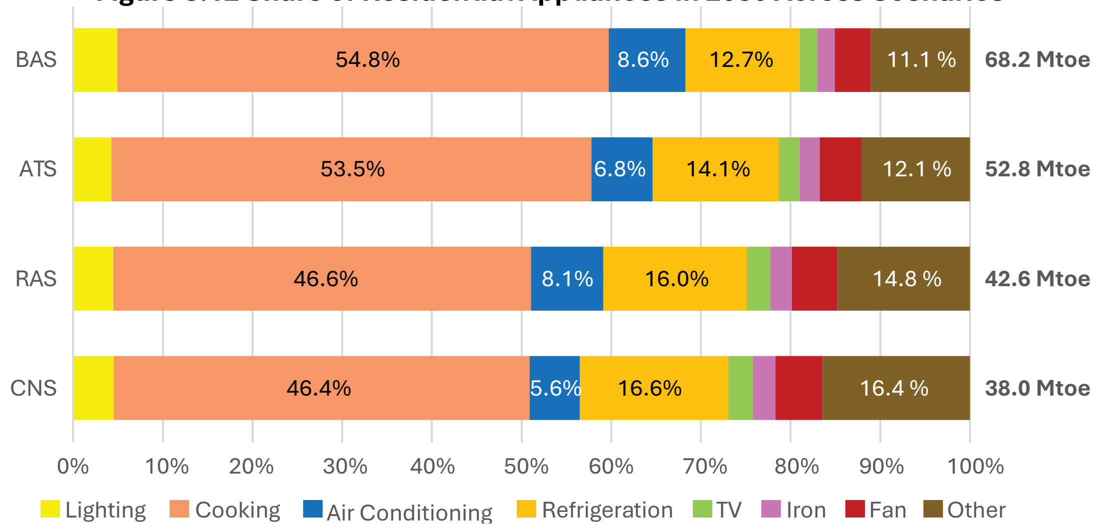
In CNS, demand by residential fuels is expected to be lower by 44.3% in 2050, with a higher rate of electrification and efficient appliances in households, making electricity the dominant share at 83.4%. Biomass and other would also increase 7 times compared to the BAS. By mid-century, traditional biomass is at 0.4% fuel share compared to 17.5% in the BAS, reflecting a sharper improvement in clean cooking access across all AMS.

Figure 3.11 Residential Consumption by Fuel Across Scenarios



By analysing household electrical appliance usage (Figure 3.12), it is anticipated that total end-use energy will rise to 68.2 Mtoe by 2050 without policy interventions. The primary contributors to energy consumption in the residential sector are cooking, refrigeration, and air conditioning which account for 54.8%, 12.7%, and 8.6%, respectively.

Figure 3.12 Share of Residential Appliances in 2050 Across Scenarios

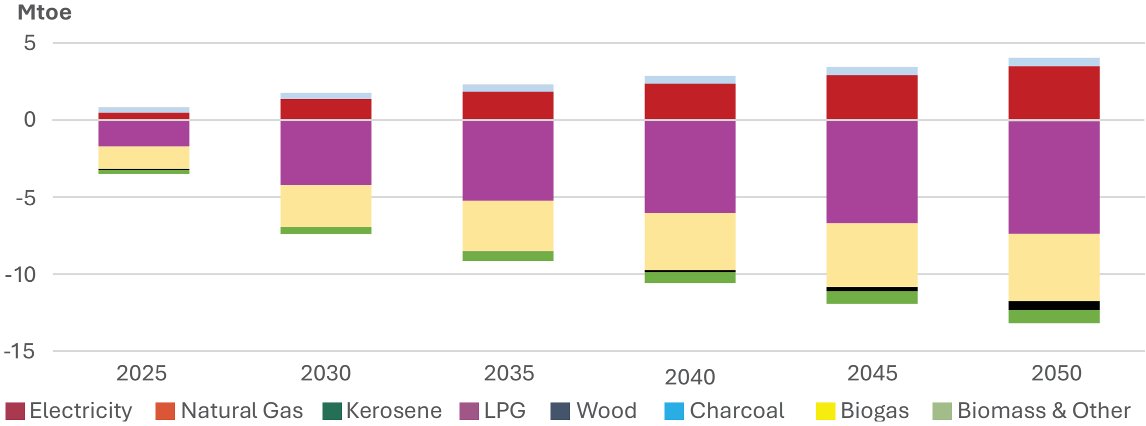


Note: Others include water heating, rice cooker, washing machine, computer/laptop, clothes dryer. End-use details (sectoral demand by appliances) cannot be reported for the historical year (2022). These details only appear at the beginning of the projection year (2023) and thereafter.

In the ATS, with cooking end-user devices having a share of 53.5% in the residential sector, its consumption in 2050 is expected to be 28.2 Mtoe, which is lower than the BAS' 37.4 Mtoe. The availability of electricity as an option for cooking helps reduce the energy intensity in all years. Air conditioning and lighting show the highest drops among end-use devices compared to the BAS, with a 38.5% and 33.1% difference, respectively.

Improved policies that encourage clean cooking methods and electrification could notably decrease reliance on LPG, biomass, and charcoal for cooking. In rural areas, there is a noticeable transition from traditional biomass to LPG, whilst urban households are increasingly switching from LPG to electric stoves (Figure 3.13). This shift not only reduces dependence on imported fuels but also improves residential well-being by lowering indoor air pollution associated with cooking fuel combustion.

Figure 3.13 Fuel Shifting due to Clean Cooking, ATS vs BAS



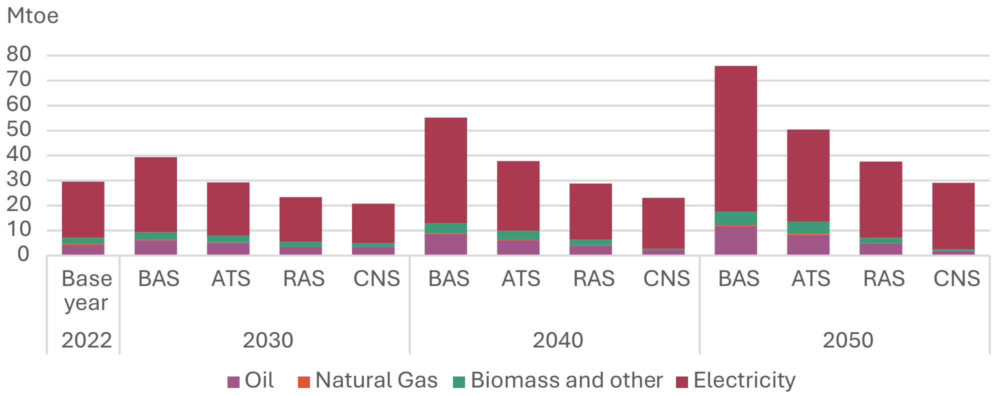
The RAS residential sector shows that the highest improvement was achieved in the cooking end-use devices, with 20 Mtoe by 2050, equivalent to a 47% reduction in demand compared to the BAS. A shift to more efficient devices in the RAS is translated to a 38% reduction in demand in the residential sector by 2050, with lighting and air conditioning devices completing the top three energy intensity improvements observed.

Under the CNS, cooking is projected to reduce by 63.6% compared to the BAS, with 17.6 Mtoe by 2050. Energy intensity improvement in cooking is followed by lighting, for a 52.9% reduction compared to the BAS, with the assumption that all households will be using LED by 2050. Overall, in all household settings, the cooking end-use devices continue to be the largest energy user; however, its fuel share is declining, which is indicative of advancements in energy access and overall efficiency. All end-use devices in the CNS have an average of 35.9% reduction in energy intensity compared to the BAS, due to device switching coupled with the implementation of net zero technologies especially in space cooling that helped improve and make air conditioning more efficient, indicating the possible impact on demand from implementing net zero measures in households throughout the region.

3.1.4 Commercial

Driven by increasing population, economic growth, and urbanisation, energy demand in the commercial sector is projected to grow by 3.3% annually (Figure 3.14), from 29.5 Mtoe in 2022 to 75.9 Mtoe by 2050, within the BAS. Electricity dominates the energy source share, accounting for 77.0% in 2050, due to the increased use of electrical appliances such as air conditioners, lighting, and refrigerators. Oil products, natural gas, and biomass mainly used for cooking will make up the remaining share.

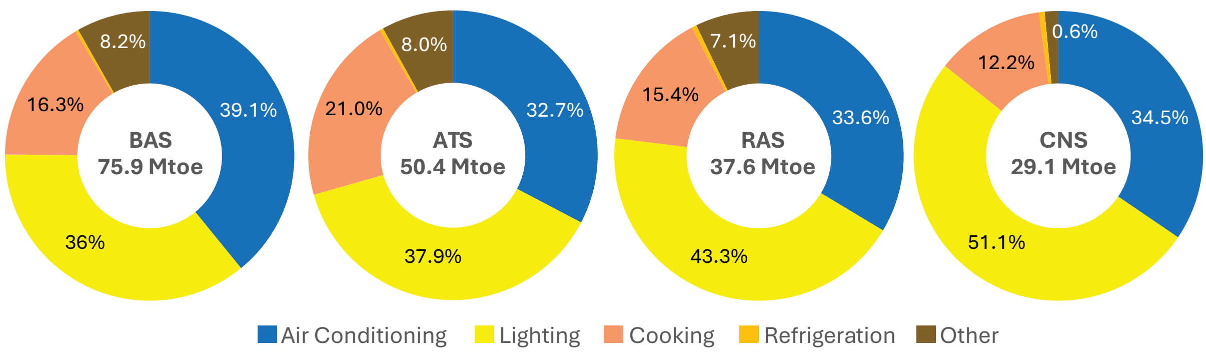
Figure 3.14 Commercial Consumption by Fuel Across Scenarios



With the adaption of energy efficiency measures in each of the AMS — including Minimum Energy Performance Standards (MEPS) for appliances, building energy codes, and mandatory energy management systems — the ATS projects overall energy consumption to be reduced by 33.6% to 50 Mtoe by 2050. The RAS consumption in the sector would be at 37.6 Mtoe, approximately 50.4% lower compared to the BAS, whilst the CNS is projected at 29.1 Mtoe by the same year. Electricity and oil dominate the share at the end of the projection year with a total fuel share of 94% in RAS and 98% in CNS.

Air conditioning dominates commercial sector energy demand, with 12.9 Mtoe in 2025, and is expected to more than double to 29.7 Mtoe by 2050, within the BAS (Figure 3.15). Implementing standards and labelling programmes to encourage the adaption of energy-efficient air conditioners in the ATS is projected to save up to 13.2 Mtoe in energy consumption by 2050. Additional regional efforts in RAS to harmonise and strengthen MEPS for air conditioners through the Regional Policy Roadmap could further reduce energy consumption by 17.1 Mtoe by 2050, as compared to the BAS.

Figure 3.15 Share of Commercial Appliances in 2050 Across Scenarios



Note: End-use details (sectoral demand by appliances) cannot be reported for the historical year (2022). These details only appear at the beginning of the projection year (2023) and thereafter.

Similarly, the adoption of energy-efficient lighting within the ATS, is projected to reduce energy consumption in lighting by as much as 8.2 Mtoe by 2050, compared to the BAS. This reduction is primarily driven by government regulations and the declining cost of LED and energy-efficient light bulbs. More stringent energy performance standards under the regional policy roadmap for lighting could further reduce consumption by up to 11.1 Mtoe by 2050, compared to the BAS. The earlier switch to LED for CNS decreased intensity by 48.6%, resulting in a reduction of half of consumption in BAS from 3.33 Mtoe to 1.72 Mtoe by 2025. Implementing best practices and utilising more efficient space cooling devices, consumption was 63.6% lower at 2.13 Mtoe than it was with BAS. The model will be able to investigate net-zero measures for CNS in the commercial sector with more updated and extensive data.

These projections highlight opportunities to achieve further energy savings through more stringent MEPS for appliances, in addition to the adaption of building energy codes and mandatory energy management systems. Additionally, expanding harmonisation initiatives to other appliances — including refrigerators, cooking stoves, and water heaters — is worth considering, as these make up a significant portion of fuel consumption in the commercial sector.

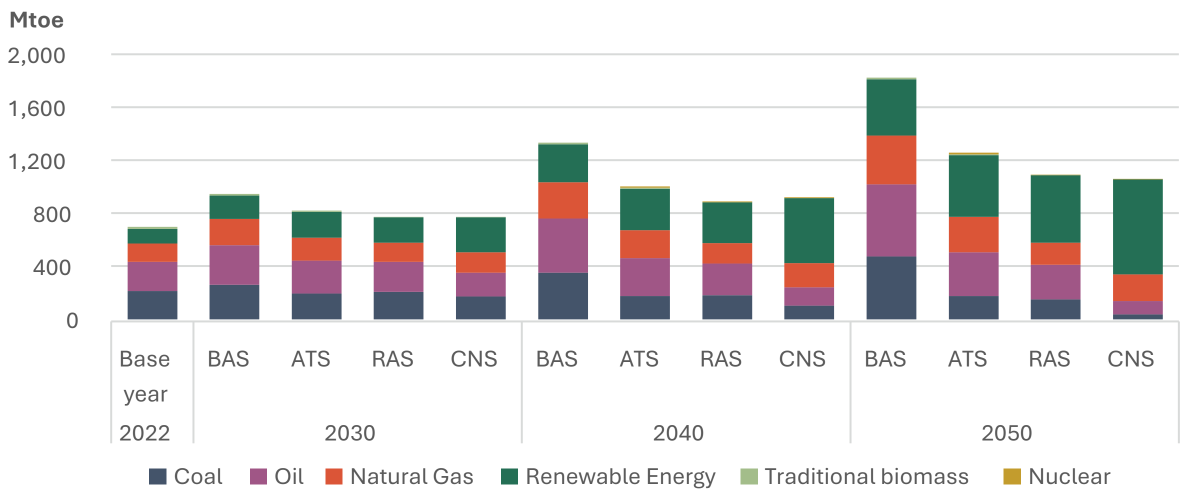
Considering the ASEAN region is experiencing a significant acceleration in digital transformation to boost economic growth, the impact of the data centre expansion on energy demand, which required an extensive cooling system for its optimum operations, may need to be assessed. Policies to encourage an energy-efficient data centre would be required to mitigate the surge of increasing energy demand from this expansion. A key metric for evaluating energy efficiency in data centers is Power Usage Effectiveness (PUE), which measures the ratio of total energy consumption to the energy used solely by IT equipment; lower PUE values signify greater efficiency. Establishing standardised PUE benchmarks across ASEAN can significantly enhance energy efficiency, with Malaysia setting a minimum requirement of 1.9 and Singapore aiming for a target of 1.3. Furthermore, the integration of the best available technology (BAT) for cooling systems and energy-efficient designs, such as modular systems with renewable energy sources with higher MEPS, can improve data centre performance while reducing energy consumption. The BAT for cooling appliances should be prioritised in ASEAN, as the region has established harmonised energy efficiency standards for air conditioning at a Cooling Seasonal Performance Factor (CSPF) of 6.07 by 2030, which can also be applied in data centres.

3.2 Energy Supply

3.2.1 Primary Energy Supply

In 2022, the Total Primary Energy Supply (TPES) was approximately 698.1 Mtoe, with fossil fuels still dominating the overall share at 81.9%, and the remainder from renewables. The highest primary fuel in the energy mix was coal (30.5%), followed by oil (31.7%) and natural gas (19.7%). According to the BAS, by 2050, fossil fuels would remain the primary sources of energy in the region, as they satisfy the rising demand in the upcoming years. Over 20% are recorded from each type of fossil fuel, totalling 1,387.1 Mtoe. Despite the limited uptake of supply from RE, the ATS shows that current policies could reduce the fossil fuels share from 76.1% in the BAS, to 63.4% by 2050 (Figure 3.16). More ambitious efforts could potentially reduce the conventional fuels portion further to 56.9% in the RAS and 33.3% in the CNS.

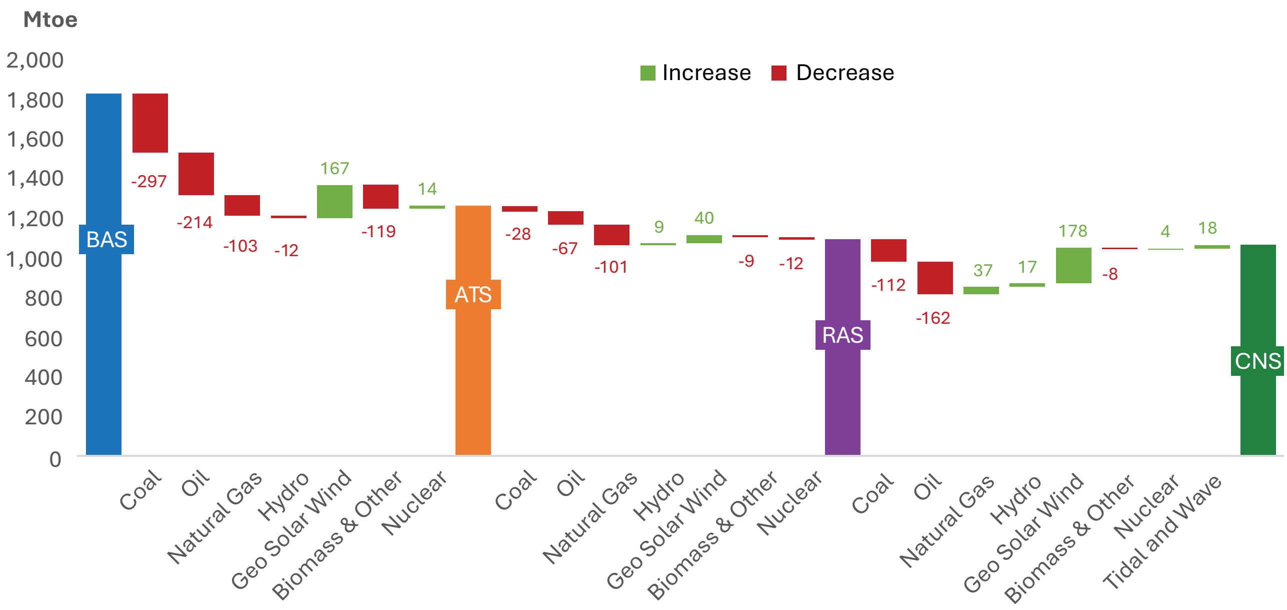
Figure 3.16 Total Primary Energy Supply Across Scenarios



Note: Renewable Energy includes hydro, geothermal, biomass, solar, wind, tidal and wave, excluding traditional biomass used by households.

By 2050, in the ATS, AMS reliance on coal is expected to decrease by 297 Mtoe (Figure 3.17), accounting to 14.4% of the total fuel at 176.2 Mtoe, as more AMS choose to switch to alternative generation technologies. Coal supply declines even more in the RAS, reaching a total of 148.3 Mtoe. It is only allowed to reach 36.8 Mtoe in the CNS owing to the scenario's tighter emission constraints, reducing its use by 82.7% compared to 2022 level.

Figure 3.17 TPES Fuel Shifting in 2050 Across Scenarios



Natural gas, on the other hand, is growing steadily in the BAS and ATS, outpacing coal in the ATS with a 268 Mtoe by 2050. In the RAS, natural gas supply remained the fuel of choice for 16.5% of the TPES, with a total of 166.6 Mtoe. Natural gas will play a significant role in bridging the energy transition from the phase-out of coal to the use of RE sources. Nevertheless, it is interesting to note that natural gas supply has a larger share in the CNS, with 203.4 Mtoe supplying the demand with the rapid decline in coal output. Natural gas combined cycle (NGCC) with CCS is expected to be an option for capacity built. especially in the CNS. but might be limited in generation output due to higher operating costs compared to other types of technology. including new emerging RE.

Oil supply is projected to increase in the BAS, maintaining the largest total supply addition between 2022 and 2050 at about 321.3 Mtoe. However, oil supplies in the ATS, RAS, and CNS are lower than in the BAS, with a reduction of 39.5%, 51.8%, and 81.8%, respectively. The percentage of fossil fuel used in transportation has decreased as a result of greater biofuel blending requirements in AMS; nevertheless, since only Indonesia has a target of 50% biofuel blending by 2050 and other countries have mandates that are lower than 50%, it is anticipated that oil usage will always exceed that of biofuel. In the CNS focuses on cutting emissions from hard-to-abate sectors through net-zero policies. These measures reduced oil supply from the 221.6 Mtoe in 2022 to 99.1 Mtoe by 2050, a 55.3 % drop, while other scenarios showed an increase in oil supply.

Renewable energy sources experience substantial growth across all scenarios. In the BAS, biomass contributed to the largest supply addition among the RE supply, totalling 256.5 Mtoe. Stringent measures in the ATS and RAS are expected to make a series of supply shifts to renewables, covering hydro (large and smaller run-of-river), geothermal, biomass, solar (ground mounted, floating, and rooftop), wind (onshore and offshore). A more prominent role for the RE supply could be achieved with more ambitious regional target with the RAS. The highest supply of RE primary supply comes from the aggregation of all modern biomass from all sectors at 201.7 Mtoe accounting to 18.9% of transport using biofuels, backed by AMS increase biofuel blending mandates. The geothermal supply will rise from 43.3 Mtoe in 2022 to 100.5 Mtoe in 2050, whilst the combined wind and solar supply will rise from 4.8 Mtoe to 168.3 Mtoe.

In the more aggressive CNS, RE supply rises 6.6-fold by 2050 from 2022 level, accounting for 715.3 Mtoe, this number includes new RE technology like tidal and wave, which can potentially generate up to 18 Mtoe. Geothermal energy is even higher in the CNS at 263.1 Mtoe, followed by solar and wind energy at 184.2 Mtoe. Additionally, tidal and wave emerge in the CNS, contributing 18 Mtoe to the overall energy mix. By 2050, the total share of RE in the CNS will be 70.2%. These shifts are indicative of ASEAN's gradual transition towards cleaner energy while maintaining energy security.

Reflecting AMS' PDPs and targets, nuclear energy would exist in all scenarios except the BAS, from 2035 onwards, with the highest supply projected to be around 13.8 Mtoe in the ATS by 2050. This indicates the AMS' resolute commitment to expanding nuclear energy, especially in Indonesia and the Philippines. According to the forecast, alternative energy sources are expected to emerge and improve the future energy supply mix. For all AMS, affordability and energy security remain paramount.

Inclusive Transition

Energy supply considerations range beyond technical considerations and require thinking in terms of regional and geo-political risks. Budding regulations in the European sphere and UN certification processes suggest the possibility that top-firms and investment institutions are likely to start considering scope three emissions accounting. This would in effect mean that relying on carbon intensive technologies for production will obtain risks for prospective investors. This may make carbon intensive energy sourcing less attractive for foreign investment or capital development.

Additionally, the international nature of high-tech energy systems entails international political risks. Contracting with external partners may give their respective governments geo-political leverage by through command of maintenance expertise or monopolies on crucial replacement parts. So far as intra-regional solutions exist, they have the advantage of being mediable within ASEAN formats. So far as ASEAN located solutions are technically undesirable or unavailable, consideration of international developments and geopolitical competition invites careful strategic considerations.

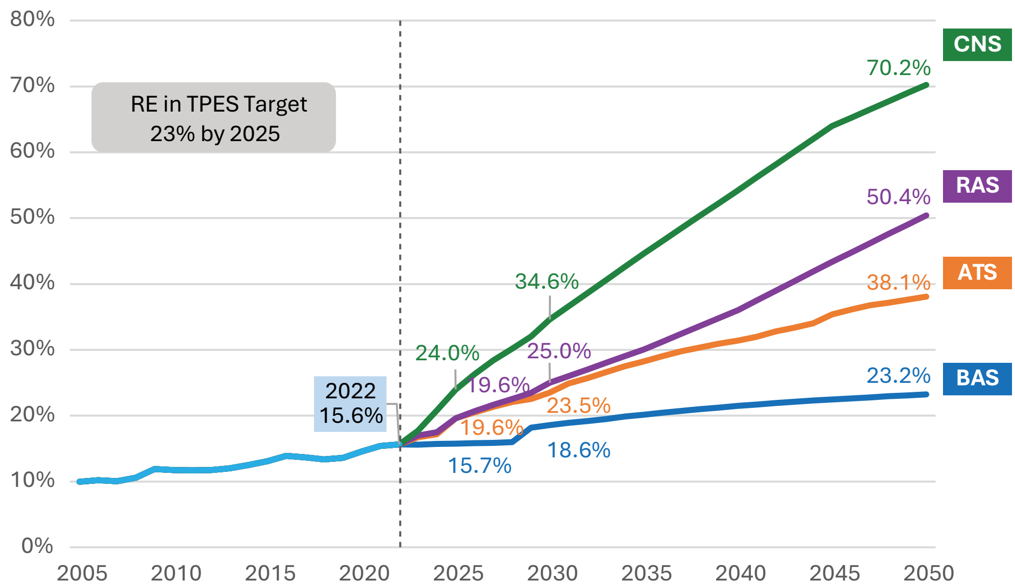
3.2.2 Renewable Energy Share

Renewable energy is key to powering a sustainable future, and the share of it in TPES is important to determining the status and when ASEAN might achieve its goal. Under the APAEC Phase II: 2021-2025, ASEAN aims for a 23% share of RE by 2025. In 2022, the RE share in TPES showed a 0.2% increase from the previous year, for a total of 15.6%. it is challenging for ASEAN to achieve the remaining 7.4%-point within three years. However, close monitoring has galvanised policymakers to enhance RE supply-related policies, with the ATS achieving the regional target by 2030.

In light of the challenges, ASEAN is confronted with critical questions: Should ASEAN raise its ambitions? If so, by how much? It is imperative to balance the potential for more ambitious targets with their feasibility, particularly considering that the current regional targets fall short of both regional and global agendas.

By mid-century, the ATS and RAS are projected to reverse the trend fossil fuel dominance, with the RE share achieving 38.1% and 50.4%, respectively, by 2050 (Figure 3.18). It proves that RE performance has improved, reflecting development in policies that promote supply from clean energy sources. At least two countries (Indonesia and Vietnam) also showed interest in retrofitting and co-firing coal and natural gas plants with targets as early as 2035, coal power plants transition from coal to biomass to ammonia, and natural gas plants from natural gas to hydrogen.

Figure 3.18 Renewable Energy Share in TPES Across Scenarios 2005-2050



	2022	2025	2030	2035	2040	2045	2050
BAS	15.6%	15.7%	18.6%	20.2%	21.5%	22.5%	23.2%
ATS		19.6%	23.5%	28.2%	31.4%	35.4%	38.1%
RAS		19.6%	25.0%	30.1%	36.0%	43.4%	50.4%
CNS		24.0%	34.6%	44.7%	54.2%	64.0%	70.2%

Projecting from the BAS shows a slower growth trend, though still increasing each year. On the other hand, the ATS growth trend indicates a more significant increase, suggesting a promising achievement in the coming years, even though it may not meet the current APAEC target in the near term. The growth trend for the RAS shows similar trend, increasing in share through 2050, whilst the fossil fuel share, especially for coal, continues to decrease. Most AMS, has provided targets for their capacity builds up to 2030 to 2040 with some even pushing it further to 2050 (The Philippines and Vietnam), with significant share from mix of mature and new RE technologies.

With current projections, the average growth of RE in the ATS from 2021 to 2050 has doubled from AEO7, rising from 0.3%/year to 0.6%/year. The share of RE in the ATS by 2050, as compared to the ATS in AEO7, also shows a more promising number of 38.1%, over the previous 23%. Despite the pioneering growth rate, ASEAN still needs a significant transformation to enhance its growth rate. With regard to the 15.6% RE share in 2022, ASEAN will need an annual 3% growth through 2025, to achieve the desired RE share target, meaning a five-fold annual increase. Given the ATS parameters, ASEAN will reach its 23% RE share target by 2031, six years later than the initial target. in contrast to the ATS, the RAS will reach the target a year earlier by 2030 and is projected to incorporate more RE until 2050.

According to the ATS, hydropower will reach its peak contribution to TPES in 2050, taking off from the currently established infrastructure. For instance, Lao PDR has around 26 GW of hydropower potential, yet only 9 GW have been utilised as of 2020 [44]. This shows a potential capacity expansion, leading to hydropower becoming the frontrunner of renewable supply in the short term. On the other hand, the RAS shows a higher supply of hydropower, with supply increasing each year. Compared to 2022, hydropower supply would more than double by 2050, from 19.5 Mtoe to 39.7 Mtoe, and would be at 56.4 Mtoe in the CNS.

Under the BAS, geothermal would increase from 2022, with a projected supply of 25.7 Mtoe in 2030. Geothermal shows a similar trend in the ATS, with an almost doubled supply at 43.9 Mtoe. Furthermore, geothermal presents a supply of more than a 100 Mtoe for both the ATS and RAS, accounting for 8.6% and 9.9% respectively, with a potential share of 25.8% in the CNS. Keeping in mind that the lower efficiency of geothermal technologies will need more fuel compared to wind and solar which have higher efficiencies. This highlights the significant position of RE supply in the region, by closing in on the level of fossil fuels by mid-century.

With existing ambitious policies to increase capacity and supply for solar and wind, the ATS sees a significant rise in share from 12.9% to 14.8% between 2040 and 2050, and increase further with regional targets and policies from 20.9% to 27.2% growth in the RAS. CNS boost the highest increase in RE with AMS road map for carbon neutrality that can see a potential increase of 41.5% to 47.0% by 2040 to 2050. Modern biomass, despite showing constant growth in supply (ATS), will experience constraints related to its reliability as feedstock and for food security. By 2050, modern biomass shows an increased share in the RAS (19.9%), as compared to the ATS (16.8%).

3.2.3 Primary Energy Intensity Reduction

Targeting Energy Intensity (EI) reduction consists of national energy efficiency measures throughout the economy. It indicates how much energy is used to produce one unit of economic output (TPES per GDP). Lower energy intensity indicates greater efficiency, as less energy is needed to generate the same amount of economic activity. APAEC Phase II: 2021-2025 has a target of 32% EI reduction by 2025, as compared to the 2005 level.

Overall, the EI reduction performance within the projection period continues to increase at different rates for each scenario. The 2022 reduction was noted at 24.5%, an improvement of 1.4%-point from 2021. Based on the AEO7 ATS projection (same year), the region still falls short by 2.2%-point. By 2025, the ATS is still insufficient to achieve the target of 31%, delaying the target date into 2026 (Figure 3.19). However, both the RAS and CNS projections will allow the AMS to meet its regional target in 2025 by 34.2% and 33.7%, respectively.

In comparing the different scenarios, the RAS shows the most significant long-term gains by 2050. Each scenario presents a different trajectory for improving energy efficiency, reflecting varying levels of ambition and commitment to reducing energy intensity. The EI reduction targets pose similar challenges as RE in TPES and will expire in 2025. Discussion concerning updates for this target is critical. Based on the trends, improvements in energy efficiency policies and standards may lead to better overall performance throughout the region.

By 2050, the BAS and ATS will have substantial gaps compared to 2025. The policies and measures modelled in these both scenarios will enable respective EI reductions of 45.5% and 63.2%, below 2005 levels. The RAS and CNS offer greater reductions over both the ATS and BAS, up to 69.4% and 69.2%, respectively for the same year. Both will also achieve the APAEC target of reducing EI by 32% in 2025.

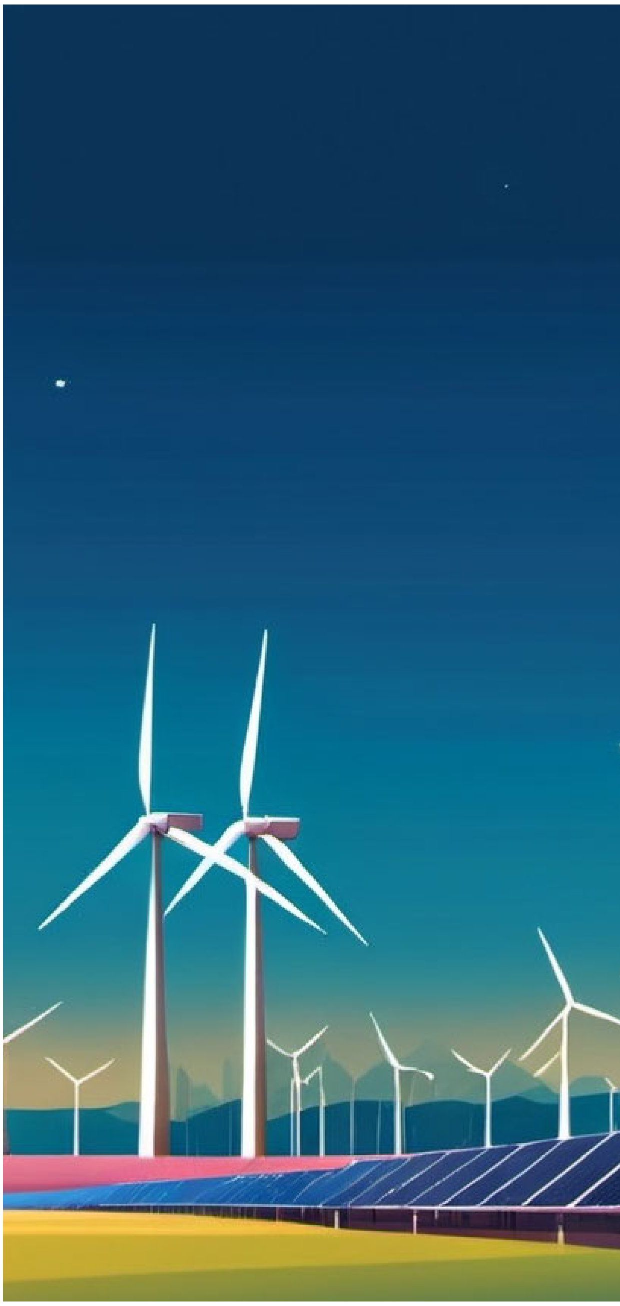
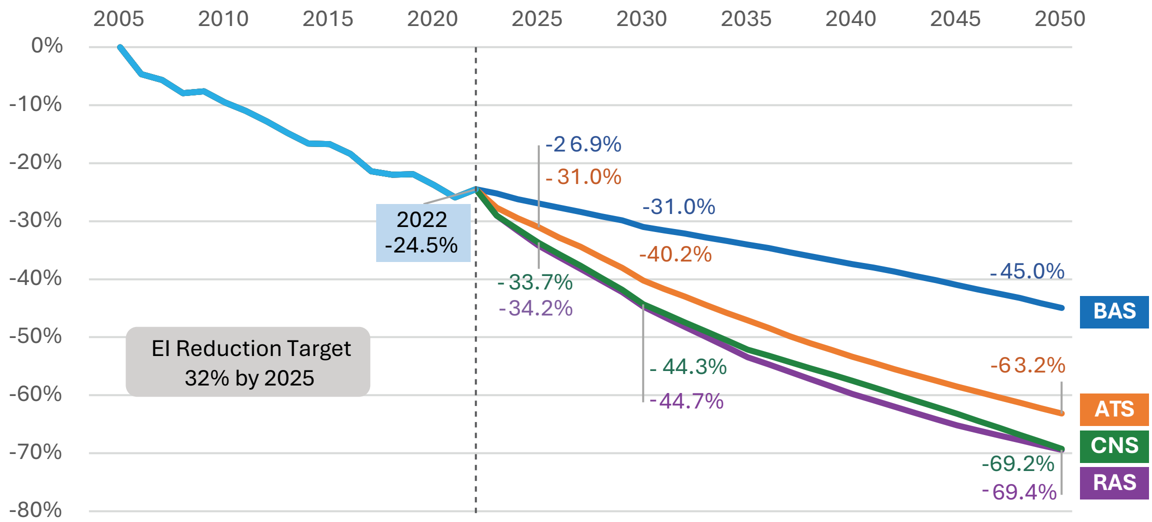


Figure 3.19 Primary Energy Intensity Reduction from the 2005 Level Across Scenarios



	2022	2025	2030	2035	2040	2045	2050
BAS	-24.5%	-26.9%	-31.0%	-34.0%	-37.4%	-41.0%	-45.0%
ATS		-31.0%	-40.2%	-47.1%	-53.4%	-58.5%	-63.2%
RAS		-34.2%	-44.7%	-53.4%	-59.8%	-65.2%	-69.4%
CNS		-33.7%	-44.3%	-52.1%	-57.5%	-63.2%	-69.2%

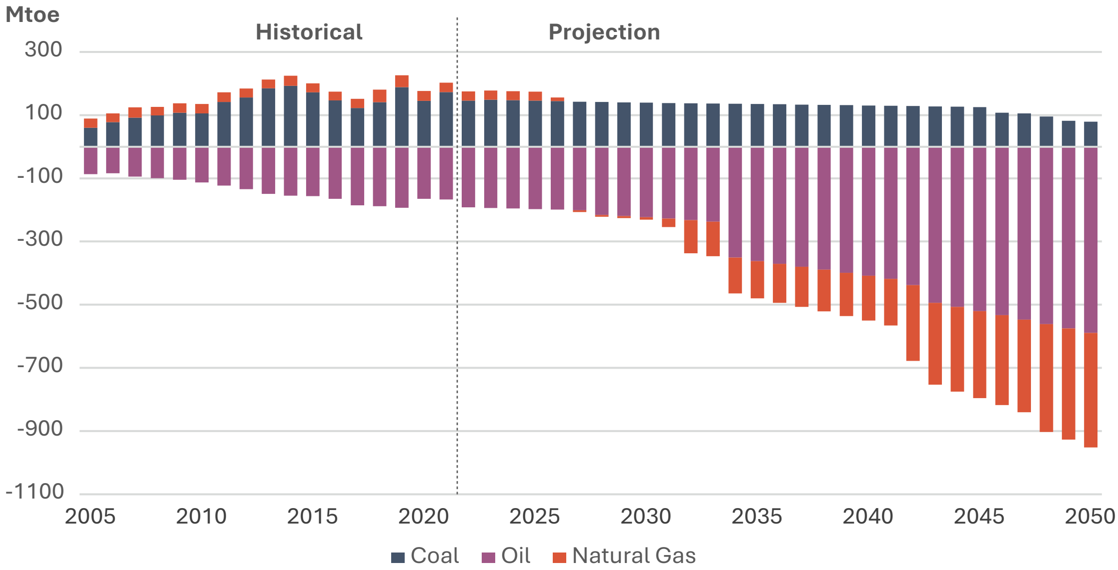
These trends underscore a collective movement toward reducing energy consumption and improving efficiency across all sectors. Enhancing existing national efforts by focusing on the most cost-efficient measures for end-users, particularly in transport, cooking, and cooling, is crucial. Accelerating the deployment of EVs, improving fuel economy, and expanding mass transportation can significantly reduce energy consumption in the transport sector. Additionally, implementing energy efficiency labelling for air conditioning and refrigeration units, along with doubling energy-saving efforts in the industrial and commercial sectors, will contribute substantially to overall energy efficiency.

Financial incentives, such as tax rebates, subsidies, and grants, along with PPPs like Energy Service Companies (ESCOs), should be leveraged to encourage the adoption of clean technologies and reduce financial risks in energy efficiency projects.

3.2.4 Energy Imports and Exports

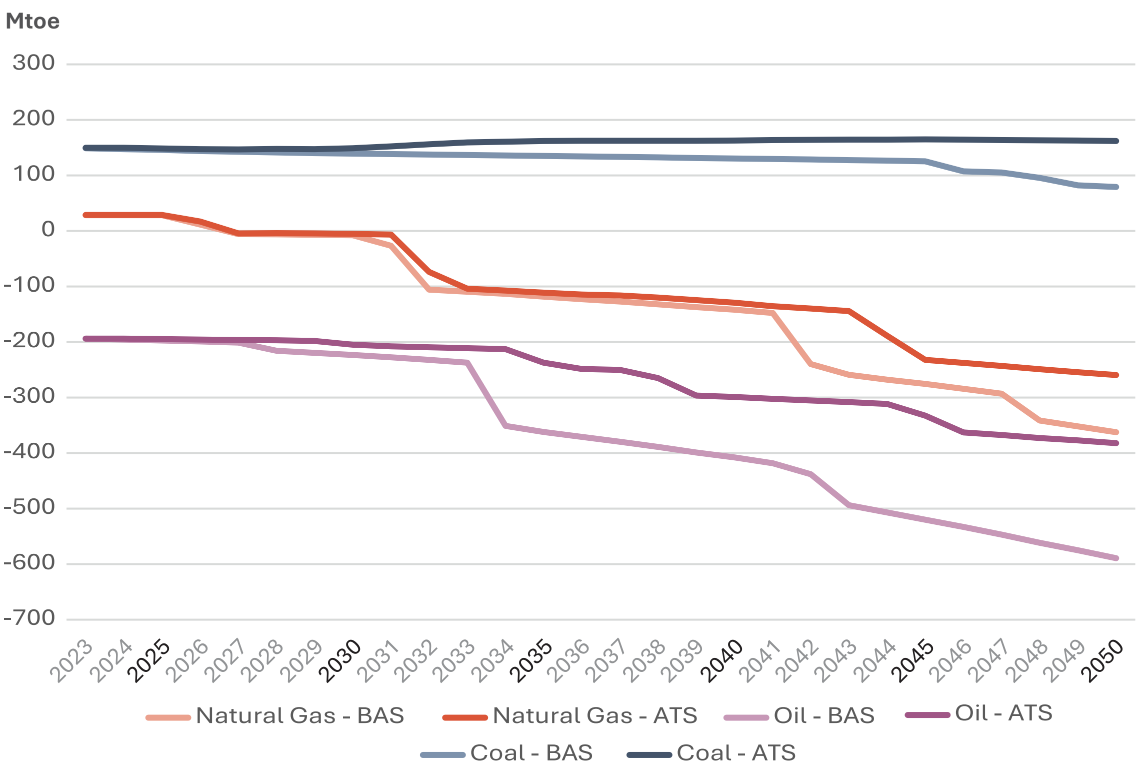
By 2023, natural gas and coal exports exceeded imports, with export values reaching 29 Mtoe and 146 Mtoe, respectively. Under the BAS, ASEAN is projected to become a net importer of natural gas by 2027 (Figure 3.20). This dependency on fossil fuel imports in the future poses severe energy security risks, potentially affecting energy affordability and increasing price volatility. In contrast, coal exports are expected to continue until at least 2050, though its balance declines. This represents a significant improvement from the AEO7 projection, which forecasted net imports starting in 2039 under the BAS. The sustained export status highlights the less reliant on coal within the region.

Figure 3.20 ASEAN Energy Import-Export Balance and Projections in BAS



The ATS indicates a net import of natural gas beginning in 2030 (Figure 3.21). For the RAS, the starting year would be delayed to 2033. Regarding coal imports, both the ATS and RAS predict that ASEAN will not become a net importer by 2050. Public opinion plays a role, with surveys indicating that more than half of respondents in ASEAN countries support stopping the construction of new coal plants immediately, and nearly two-thirds favour phasing out coal consumption by 2030.

Figure 3.21 ASEAN Energy Trade Balance by Fuel, ATS vs BAS

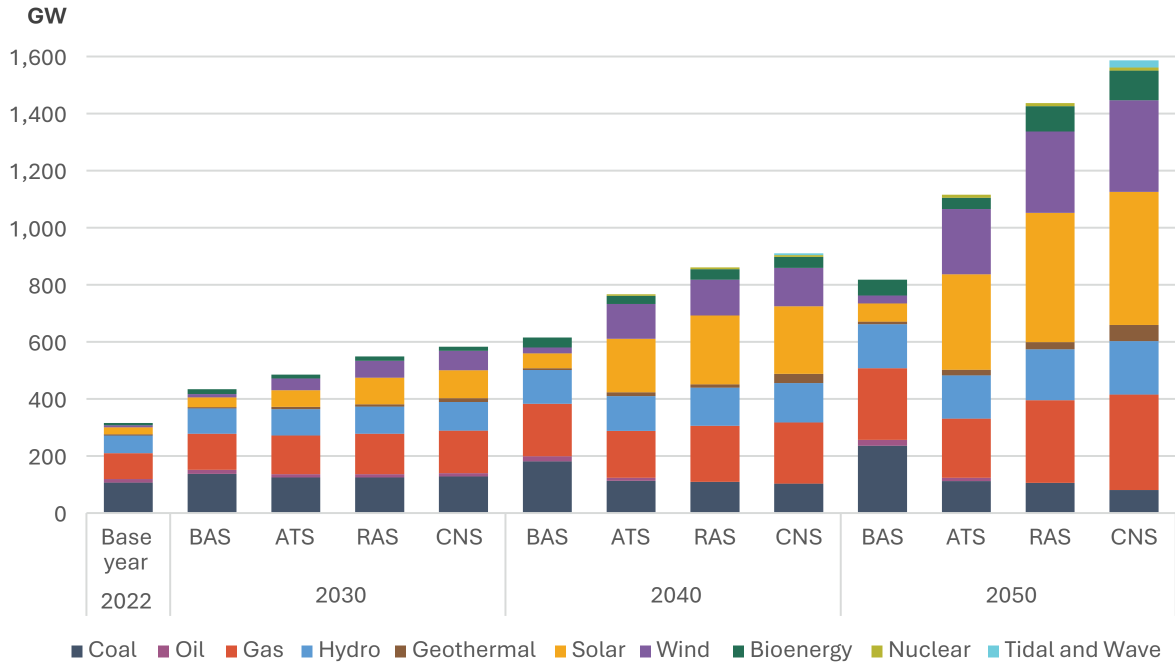


3.3 Electricity

3.3.1 Installed Power Capacity

In 2022, the installed power capacity in ASEAN was heavily reliant on fossil fuels, accounting for approximately 66.4% of the total energy mix. The total installed power capacity is expected to experience steady growth across all scenarios, with the most significant expansion occurring in the RAS by 2050, where the total capacity is projected to exceed 1,200 GW (Figure 3.22). Whilst fossil fuels will continue to play a dominant role and their capacity will increase in the absence of energy policy intervention, the ATS and RAS are anticipated to accelerate the adoption of RE sources, thereby reducing the region's dependency on gas, coal, and oil in response to an increase in electricity demand.

Figure 3.22 ASEAN Installed Power Capacity Across Scenarios

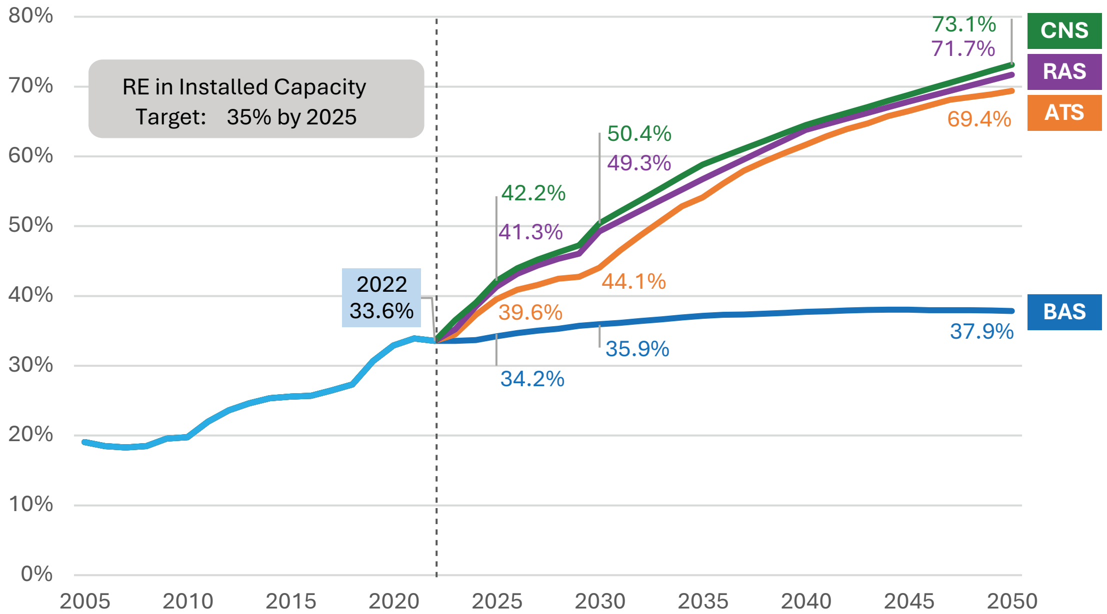


In relation to the energy mix, coal remains a substantial component up to 2050, but a declining share can be observed under the ATS and RAS. Oil also sees a steady decline in its contribution across all scenarios, signalling a regional shift away from oil-based energy generation. Natural gas, whilst initially maintaining a significant share, begins to decrease under the ATS and RAS. The precise decrease in reliance on these fossil fuels can be quantified as 28.9% by 2050, particularly in the ATS.

The general trend throughout all scenarios indicates a steady increase in the share of RE within ASEAN's installed power capacity from 2022 to 2050. However, the pace of growth varies considerably depending on the scenario. With a limited policy intervention, the Baseline Scenario shows a slow and incremental rise compared to the more ambitious ATS and RAS, which demonstrate significantly more rapid growth, especially in the latter half of the projection period. Solar PV and wind energy, however, experience the most significant growth, with solar PV rising from 7.7% in 2022, to around a quarter of the total capacity share by 2050, and wind energy increasing from 2.3% to 20.7% in the ATS, and 16.9% in the RAS over the same period, indicating a major shift toward these renewables. Meanwhile, the BAS shows an insignificant impact on the solar and wind energy proportion by 2050. Bioenergy, nuclear, and tidal and wave technologies contribute smaller shares, with nuclear energy seeing a notable increase from virtually non-existent to 0.9% and 0.8% under the ATS and RAS, driven by cost optimisation and low-carbon goals.

Notably, ASEAN has set a target of achieving 35% RE in installed capacity by 2025. According to the projections, both the ATS and RAS show promising progress toward this goal, with RE shares expected to reach 40.3% and 42.1%, respectively, by 2025, surpassing the target (Figure 3.23). In contrast, the Baseline Scenario is projected to fall short, with the RE share reaching just 34.1% by 2025. Furthermore, the BAS predicts a slow increase in the share of RE from 33.6% in 2022, to 37.5% by 2050, reflecting a continued reliance on fossil fuels. In contrast, the ATS shows a more aggressive rise, with the RE share ramping up to 47.7% by 2025, and reaching 73.1% by 2050, driven by strong RE policies. Similarly, the RAS presents steady and substantial growth, achieving 43.8% by 2025, and 63.3% by 2050, indicating a balanced approach combining ambitious targets with cost optimisation.

Figure 3.23 Renewable Energy Share in Installed Capacity Across Scenarios

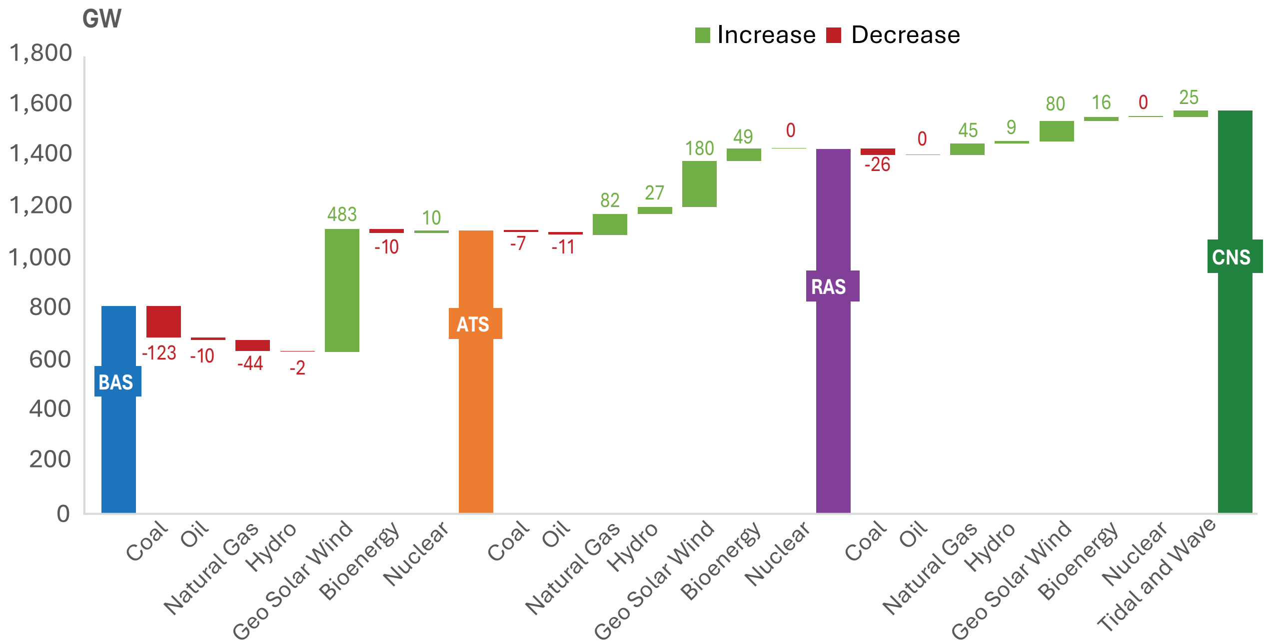


	2022	2025	2030	2035	2040	2045	2050
BAS	33.6%	34.2%	35.9%	37.2%	37.7%	38.0%	37.9%
ATS		39.6%	44.1%	54.1%	61.7%	66.5%	69.4%
RAS		41.3%	49.3%	56.7%	63.8%	67.9%	71.7%
CNS		42.2%	50.4%	58.8%	64.5%	68.8%	73.1%

The fuel shifting in the installed capacity in 2050 highlights notable reductions in fossil fuels and a marked increase in renewable energy capacity (Figure 3.24). Under the BAS, coal experiences the largest reduction, decreasing by 123 GW, while oil and natural gas also see declines of 10.4 GW and 43.6 GW, respectively. Despite the decline in fossil fuels, the renewable energy sector, led by solar, wind, and geothermal, increases significantly by 482.5 GW. Other renewables, such as nuclear and bioenergy, see smaller contributions, with nuclear increasing by 10.5 GW while bioenergy declines slightly.

In the more ambitious RAS and CNS, the shift is even more dramatic, marked by aggressive fossil fuel reductions, with coal dropping by 25.6 GW, and oil being completely phased out by 2050. Natural gas still plays a role, but its capacity increases by only 45.4 GW. Meanwhile, reneweable energy sources see strong growth, with solar, wind, and geothermal increasing by 80.2 GW and new technologies, such as tidal and wave energy, contributing an additional 25 GW. This transition highlights the region's push towards a diversified and low-carbon energy mix by 2050.

Figure 3.24 Installed Capacity Fuel Shifting in 2050 Across Scenarios



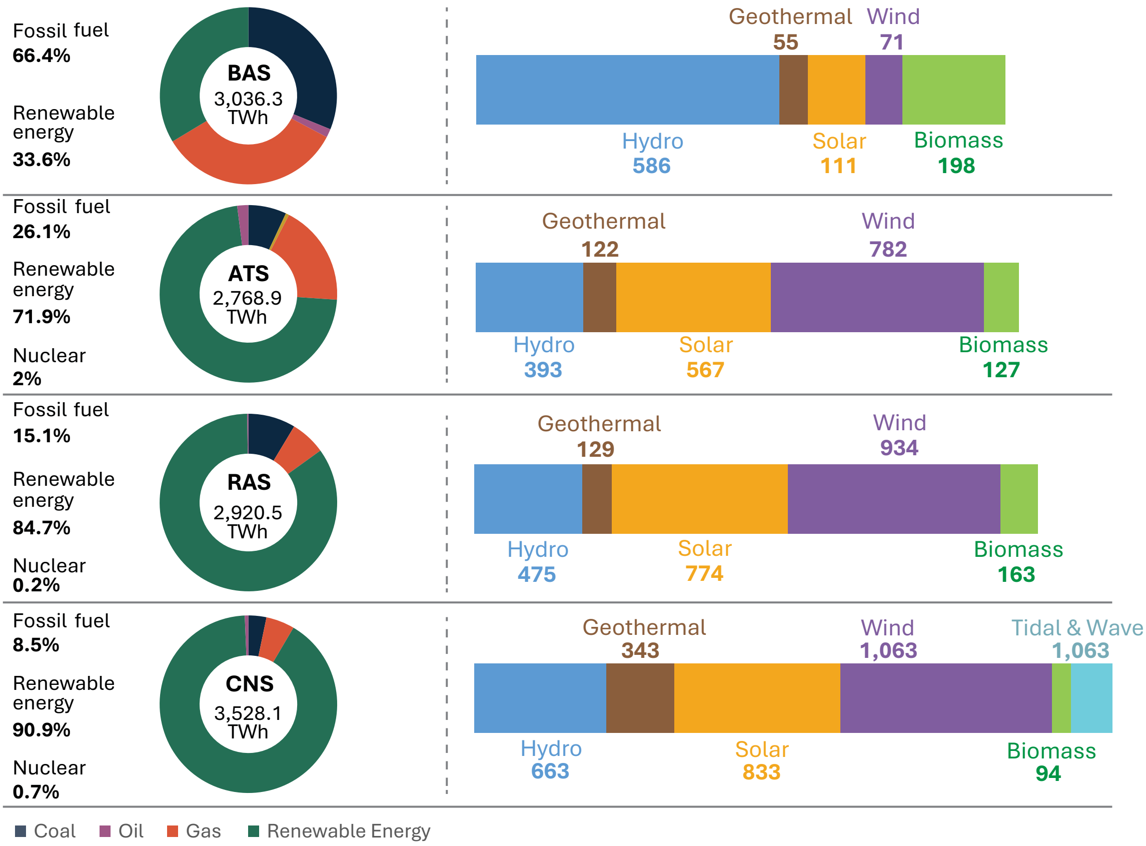
3.3.2 Electricity Generation

Throughout all scenarios, there is an increase in total power generation across the given timeframe, reflecting growing energy demand driven by economic growth and population increases in the region. Total power generation for the year 2050 across the region will reach approximately 3,036 TWh under the BAS, 2,769 TWh in the ATS, and 2,920 TWh in the RAS (Figure 3.25). The projected growth in power generation is closely aligned with the trends observed in installed capacity, where significant expansion, particularly in RE, are anticipated to support the increasing demand. The integration of additional capacity from renewable sources, as discussed in the previous sub-chapter, is expected to play a critical role in meeting the energy needs of a rapidly developing ASEAN region.

The RAS projects will outweigh the ATS in total power generation by 2050, driven by a comprehensive strategy to balance energy security, affordability, and sustainability. This reflects the RAS's emphasis on optimising energy resources across the region, with a focus on leveraging cost-effective and sustainable power generation technologies. Indonesia and Vietnam are expected to continue leading in power generation across all scenarios, with particular increases under the RAS. This growth is attributed to large-scale investments in both renewable and conventional energy infrastructure, guided by cost-optimisation principles. Other AMS such as Thailand, Malaysia and the Philippines, also show marked increases in power generation, reflecting efforts to diversify energy sources and enhance energy security.

Similarly, power generation by technology in the ASEAN region reveals a transformative shift towards a more diversified and cleaner energy mix, especially under the RAS. This transformation is directly linked to the shits in installed capacity, where renewable energy technologies such as solar PV and wind have seen substantial growth. As installed capacity in renewables increases, it naturally leads to higher contributions of these technologies in power generation, reducing reliance on non-renewable sources.

Figure 3.25 ASEAN Electricity Generation Across Scenarios in 2050



Fossil fuels, whilst still significant, show a declining trend, particularly in coal's share, as the region moves toward cleaner alternatives. Natural gas retains a stable and crucial role across all scenarios, acting as a transition fuel due to its flexibility and relatively lower emissions compared to coal. The stability of natural gas in the power generation mix is supported by the consistent capacity levels, where gas continues to be a critical component, particularly in the Baseline Scenario, with slower renewable uptake.

Renewable energy sources, particularly solar PV and wind, experience substantial growth, driven by technological advancements and decreasing costs, making them viable options under the low-cost optimisation framework. The deployment of hydro power remains a constant, particularly in resource-rich countries like Lao PDR and Myanmar, whilst geothermal and bioenergy provide additional support in specific regions. Diversifying power generation by increasing the RE share across all scenarios underscores the region's efforts to balance economic growth, energy security, and environmental sustainability.

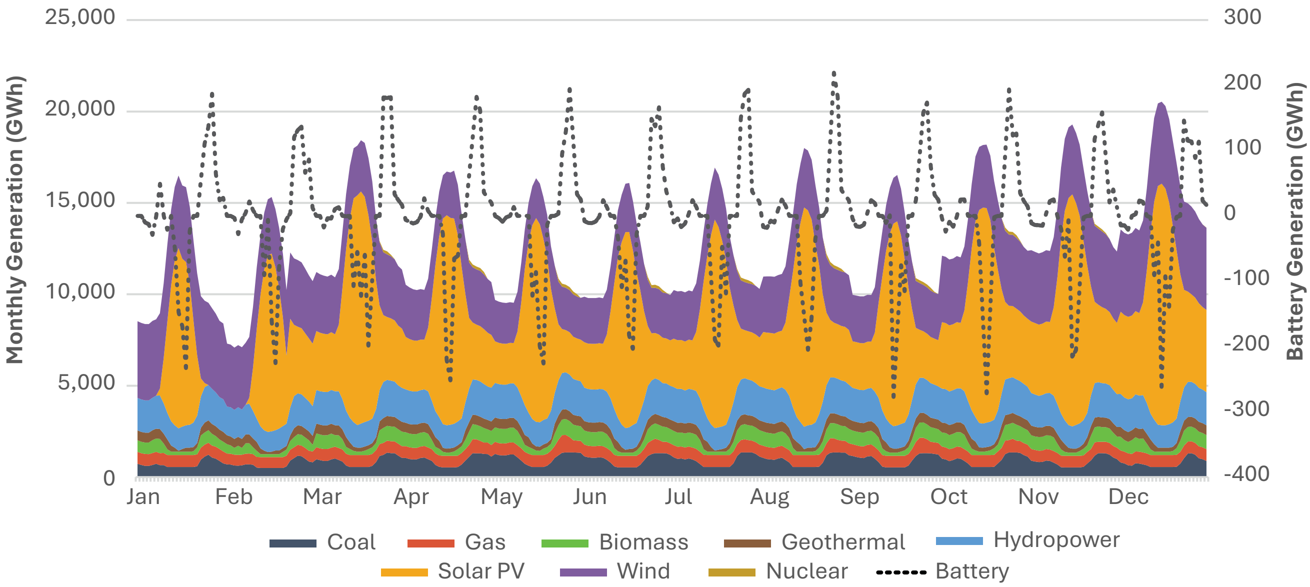
The CNS estimates the highest level of electricity generation among all scenarios by 2050, reaching approximately 3,528 TWh. Strong policy support in net zero target and low carbon technological advancements will drive an accelerated shift towards renewable energy sources, with solar, wind, and bioenergy, experiencing significant expansion. Different from most scenarios, the reliance on coal diminishes substantially, adhering to the commitment to minimising carbon emissions and advancing towards a more sustainable electricity generation mix. The CNS also sees a notable increase in the deployment of nuclear and emerging technologies, such as tidal and wave energy, which are critical for achieving the ambitious carbon neutrality targets.

Moreover, under the CNS, the share of hydrogen and ammonia in total electricity generation is projected to be approximately 2.2% by 2050, which is notably higher than its share under the RAS (nearly 1%). This indicates the CNS's broader adoption of innovative low-carbon technologies, positioning it as the most forward-looking pathway for ASEAN's transition to a clean and resilient energy system.

3.3.3 Battery and Energy Storage Utilisation

Battery Energy Storage Systems (BESS) play a pivotal role in enhancing the APG under the RAS. By enabling the storage of electricity generated from renewable sources, BESS facilitates the integration of variable RE, especially solar and wind, into the APG. This integration is crucial for maintaining grid stability and reliability, especially during peak demand periods or when renewable generation is low. In the RAS, BESS supports the efficient use of renewables, helps balance supply and demand, and reduces reliance on fossil fuels. Figure 3.26 presents the hourly behaviour of batteries installed in conjunction with the construction of future APG networks by 2050.

Figure 3.26 ASEAN Hourly Generation Mix, RAS



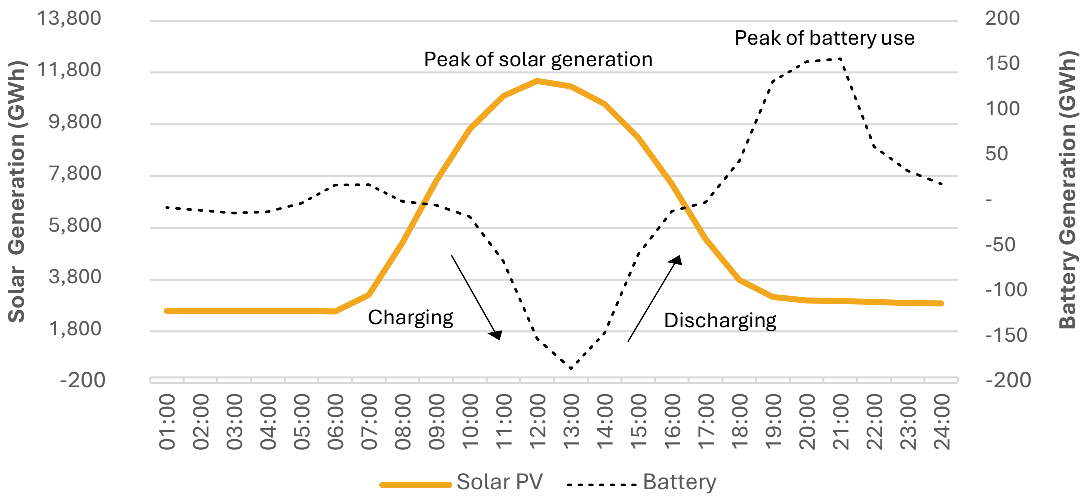
The graph depicts the projected average monthly energy storage and discharge patterns by 2050 at an hourly resolution, with significant contributions from renewable sources such as solar and wind, which display a pronounce seasonal and diurnal variability. Solar and wind energy account for the largest share of renewable generation, characterised by peaks during daytime and reduced generation during the night, alongside seasonal fluctuations that likely correspond to the monsoon patterns prevalent in the ASEAN region.

Coal, gas, and nuclear remain substantial contributors to the energy mix, providing a stable baseline of energy generation. These sources are maintained in the energy mix not only for their energy density but also due to their crucial role in providing grid stability, particularly in the face of variable renewable energy output. Gas and coal plants can be ramped up or down quickly to respond to changes in demand or renewable supply, making them essential for maintaining a stable grid. Similarly, grid stability can also be supported by hydropower and biomass, as they are capable of providing a stable and continuous power output and can even be used for load-following capabilities.

In the Figure 3.27, the behaviour of BESS, as depicted by the black dotted line, showcases its critical role in balancing the variability introduced by renewable energy sources. The battery storage systems are seen actively charging during periods of excess generation, particularly during midday peaks of solar energy. This is evident as the BESS energy flow dips into negative values, indicating energy absorption (charging phase). Conversely, during periods of low renewable generation, such as nighttime or during cloudy and rainy seasons from October to March, the BESS discharges more energy, as indicated by the positive spikes in the battery energy flow, especially between January and February.

Notably, the amplitude of BESS behaviour is synchronised with the variability of renewables generation, particularly solar, demonstrating the system's responsiveness to renewable energy fluctuations. This indicates that BESS is effectively mitigating the intermittency of renewables, ensuring a more stable and reliable power supply across ASEAN region. Furthermore, the integration of BESS with grid-forming inverters enhances grid stability, allowing batteries to play an active role in maintaining grid frequency and voltage stability, traditionally managed by conventional power plants.

Figure 3.27 Hourly Generation of Solar PV and Battery, RAS



Delving deeper into the correlation between solar and wind generation and BESS utilisation reveals a clear interpendence. The graph uniquely illustrates that BESS activity is most pronounced during periods when solar and wind generation exhibit their natural variability. Solar PV generation increases sharply from the early morning, peaks around midday, and declines in the late afternoon. Correspondingly, BESS begins charging as solar generation ramps up, with the highest charging rates occurring during peak solar hours (around 11:00 to 14:00). The BESS then shifts to discharging as solar generation drops off, particularly in the evening and nighttime hours when solar output is zero.

This pattern of BESS operation highlights its role as a buffer system, absorbing excess energy when generation surpasses demand and releasing it when generation falls short. The correlation between BESS activity and renewable energy generation is further evidenced by the timing of these activities—BESS charges during the day when solar generation is abundant and discharges during the night, aligning perfectly with the natural cycle of solar energy availability.

This correlation indicates a well-functioning energy storage system that effectively stabilises the grid by managing the surplus energy and compensating for energy deficits during low generation period. Furthermore, the integration of BESS with other types of energy sources likely follows a similar pattern of charging during high generation and discharging when the production is low. This highlights the importance of BESS in smoothing out fluctuations not only solar, but also other renewables, ensuring a steady and reliable energy supply across the ASEAN region, especially if RAS is adopted.

Inclusive Transition

Electrification is a necessary step towards holistic inclusion in contemporary society and mediate access to global media, education, labor saving devices and many other benefits of contemporary society. Nevertheless, access and usage of electricity is highly differentiated across income levels and degrees of urbanisation.

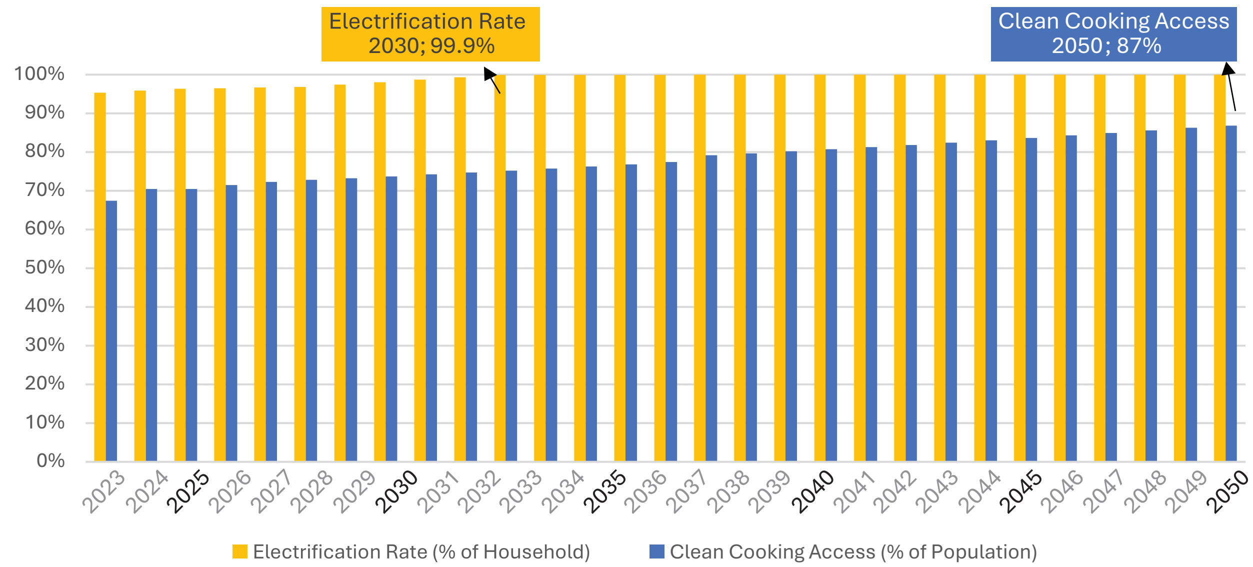
In assessing the inclusivity of electrical systems it is important to systematically attend to informal electricity access. Throughout the region many households, especially in poorer urban areas or remote rural communities access electricity through improvised access points, not officially counted by national electricity. This is often a low-cost way to electrify poor households, and so have unintuitive systemic benefits.

Nevertheless, improvised or poorly executed connections to the grid of this kind poses fire risks and occasionally health hazards. When modernising, maintaining or upgrading grid facilities it is important to consider how best to accommodate such informal setups.

3.4 Energy Access

The SDG7 aims to ensure universal access to affordable, reliable, and modern energy services by 2030, and ASEAN has made notable progress in this regard. There are two key measures of energy access: the electrification rate and clean cooking access for households. With the current policy efforts (ATS), ASEAN will achieve a 100% electrification rate in 2040, but the region has not yet achieved full access to clean cooking fuel, and is not expected to even by the 2050 horizon (Figure 3.28).

Figure 3.28 ASEAN Electrification Rate and Clean Cooking Access, ATS



At the start of the projection year (2022), five of the AMS (Brunei Darussalam, Malaysia, Singapore, Thailand, Vietnam) had a 100% electrification rate (Table 3.1). According to the BAS through 2030, there will be no additional countries achieving the electrification target. However, three countries are expected to come close—Indonesia (99.6%), Cambodia (98.3%), and the Philippines (96%)—whilst Lao PDR and Myanmar will reach 95.3% and 72.5%, respectively.

Table 3.1 Electrification Rate in ASEAN Member States, ATS

Region	2020	2022	2030
Brunei Darussalam	100%	100%	100%
Cambodia	81.1%	88.4%	100%
Indonesia	99.2%	99.6%	100%
Lao PDR	94.3%	95.3%	98%
Malaysia	100%	100%	100%
Myanmar	70.4%	72.5%	100%
Philippines	94.5%	96.2%	100%
Singapore	100%	100%	100%
Thailand	100%	100%	100%
Vietnam	99.8%	100%	100%

The ATS projects that the region's electrification rate will reach 99.9% by 2030. Indonesia is expected to achieve 100% electrification by 2025, followed by the Philippines in 2028 with an AAGR of 0.65% between 2022 and 2028. Myanmar, which had the lowest electrification rate amongst the AMS in 2022, is projected in meeting its universal electrification target by 2030, requiring an AAGR of 4%. The remaining gap in the region's electrification rate could potentially be addressed by focusing on Lao PDR, whose current electrification rate is 95.3%.

It should be noted that for Myanmar, progress may differ from projected scenarios due to the escalation of conflicts and humanitarian situation since 2021 [45]. According to Myanmar's National Electrification Plan (NEP), the next milestone is to achieve a 76% electrification rate by 2025 and 100% by 2030. Closing the 21% gap will undoubtedly require unprecedented and concerted efforts. Currently, Myanmar relies on hydropower systems for electricity, but there is significant potential to utilise solar energy, especially in rural areas [46]. However, achieving this may be challenging due to the current situation affecting infrastructure development and foreign investment, which are essential for ensuring electricity accessibility.

The ASEAN region also faces challenges in providing universal electrification due to having many remote and hard-to-reach areas. Policy biases toward large projects, lack of integration with rural development efforts, and dependency on donor assistance for off-grid electrification contribute to concerns about the electrification process. Successful electrification cases in Southeast Asia suggest that grid extensions are preferred, and top-down approaches are effective when supported by strong implementation strategies [47].

Besides that, the current electrification rate definition that we use simply illustrates the population's ability to consume electricity for the desired service, gathered through household surveys in binary measurements [48]. This means that the current definition may not portray the whole picture of energy access as it does not address some questions such as the sufficiency of electricity accessed, the consumption outside the residential sector, or the price of electricity. There is a need to explore a new threshold to provide a holistic context of the people's livelihoods and economy, such as considering a higher measurement of electrification rate up to 300 kWh for residential and 700 kWh for non-residential [49]. The percentage of household income spent on energy can also be added to the parameter to measure energy affordability.

Regarding clean cooking, while ASEAN may not achieve universal access under any of the four scenarios, significant progress is being made. In 2022, only Brunei Darussalam and Singapore had 100% clean cooking access. Under the Baseline Scenario, Vietnam and Malaysia are expected to achieve universal access to clean cooking by 2024 and 2025, respectively, reflecting promising advancements in the region. In the ATS, these years are accelerated to 2023 and 2024 (Table 3.2). Thus, only four out of ten of the AMS will achieve 100% clean cooking access by 2030 in both scenarios. Indonesia's growth will remain stagnant at around 84% from 2023 until 2030 under both the BAS and ATS.

Table 3.2 Clean Cooking Access in the ASEAN Member States, ATS

Region	2020	2022	2030			
			BAS	ATS	RAS	CNS
Brunei Darussalam	100%	100%	100%	100%	100%	100%
Cambodia	23.5%	44.5%	50.1%	56.4%	100%	100%
Indonesia	82.7%	84.1%	84.1%	84.1%	93.9%	100%
Lao PDR	8.6%	9.3%	10.5%	11.8%	29.5%	84.3%
Malaysia	94.2%	93.8%	100%	100%	100%	100%
Myanmar	39.2%	43.5%	49%	55.1%	100%	100%
Philippines	47.1%	48%	51.9%	51.9%	70.9%	95.6%
Singapore	100%	100%	100%	100%	100%	100%
Thailand	84.2%	85.1%	92.8%	92.8%	100%	100%
Vietnam	94.7%	96.1%	100%	100%	100%	100%

The ATS projects that Thailand will reach 100% in 2037, with an AAGR of 2%. Despite being the second lowest in clean cooking access in 2020, Cambodia is expected to accelerate its progress and become the sixth country to achieve universal access by 2050 under the ATS. The updated ATS projects a higher penetration rate of 86.8%, as compared to the ATS projection from the AEO7 forecast of just 85.2%. Since household access to clean cooking is inherently linked to overall energy demand, there is a correlation between it and the types of cooking fuel used. Currently, the major cooking fuels are LPG and wood. LPG is considered a cleaner fuel due to its lower health risks and time-saving benefits, whilst wood does not share these characteristics [50]. Therefore, efforts are being made to switch from solid fuels, such as wood and coal, to electricity and LPG as the primary cooking fuels, whilst trying to reduce overall energy demand.

In 2021, cooking activities in the residential sector demanded as much as 36.2 Mtoe. Under the Baseline Scenario, this will increase to 37.7 Mtoe by 2030, accounting for 58.8% of residential energy demand. This number can be reduced to 32.2 Mtoe under the ATS, where the share of electricity for cooking fuel increases from 5.1 Mtoe to 6.39 Mtoe in the same year. This is achievable if the use of LPG and wood is reduced as cooking fuels by 4% each.

Moving to the RAS, eight of the AMS are expected to achieve 100% clean cooking access by 2030. Indonesia and Thailand will achieve this target by 2026, whilst Cambodia and Myanmar will follow in 2028, all ahead of the SDG7 target year. The Philippines will not reach the target until 2038, with an AAGR of 9.6%. ASEAN will meet the SDG7 target for universal clean cooking access when Lao PDR achieves it in 2050, with an ambitious AAGR of 34.5%. Energy demand from cooking is projected to be 25.5 Mtoe in 2030, with electricity comprising 8 Mtoe of the total residential energy demand. The use of biomass is expected to be reduced to 1% of the total demand.

Inclusive Transition

Energy access is especially challenging to achieve for distant rural communities, often in mountainous areas. The cost of extending grid connectivity may be untenable for these communities. Public investment is likely needed to electrify such communities.

The technical particulars of providing electricity to these areas will likely pose complicated decisions about balancing concerns of pricing, stability, volume and spatial concerns. Externally imposed decisions on these matters have a history of delivering dysfunctional solutions and generating resentment among affected communities. The best practice is to involve local communities in the decision processes and to train up locals in maintenance needs as possible.

Newly electrified communities are likely to need information about safe use of electricity and support for the uptake of electrified technologies such as induction cooking. Providing such support is likely to further both the uptake of clean energy use and to reduce fire risks to rural communities. Moreover, technological innovations like off-grid renewable systems, microgrids, and smart meters hold significant promise for enhancing energy access in rural and remote areas.

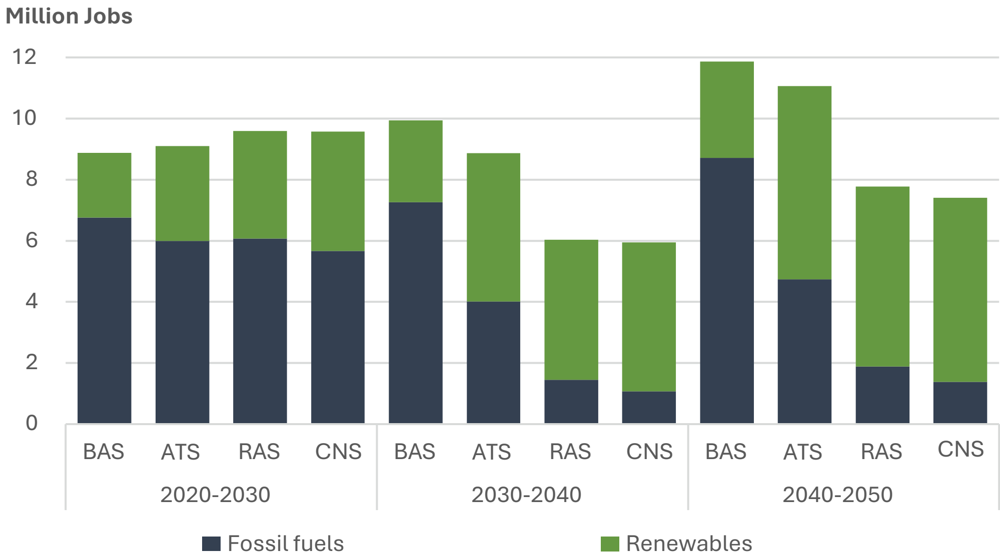
3.5 Employment

The global shift toward clean energy continues to be the primary driver reshaping the energy workforce, with employment in the fossil fuel sector projected to decline, following trends in the global energy landscape [51]. Improving upon the model used in AEO7, the current edition of secondary analysis related to jobs will not only track job creation from RE, but also include fossil fuel-related job creation and losses up to mid-century. The analyses will focus on direct jobs in various technologies, including hydropower, geothermal, solar, wind, hydro, nuclear, as well as jobs related to fossil fuels driven power plants such as coal, oil and gas.

During the first decade of the analysis (2020-2030), job additions across the four scenarios remain relatively similar, with total job counts ranging between 8 to 10 millions jobs. In all scenarios, fossil fuels continue to dominate employment, but renewable energy jobs show noticeable growth. However, by the second decade (2030-2040), a significant shift begins as RE jobs increase, particularly under the CNS and RAS. Under the BAS, fossil fuel job creation remains significant, with over 11.8 million additional jobs anticipated between 2040-2050, comprising 73.7% of total employment during this period (Figure 3.29). This highlights the labour-intensive nature of the fossil fuel power plants, especially with new installed capacity additions projected to reach 622 GW within the period. On the other hand, a regional shift toward renewables and decreased reliance on fossil-based power generation influences the fossil fuel-related jobs in the ATS, RAS, and CNS.

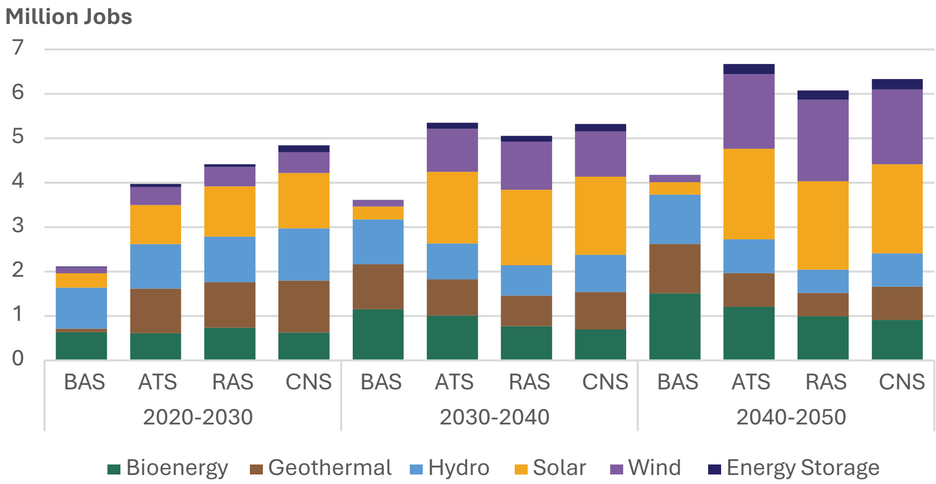
The ATS projects a significant increase in renewable capacity, which is anticipated to be ten times higher than fossil fuel sources, leading to a relatively similar number of new jobs compared to the BAS, but with a higher share of new RE jobs. Under the RAS and CNS, fossil fuel job creation drops drastically after 2030, aligning with a marked reduction in installed capacity additions within the fossil fuel power sector. In these scenarios, the substantial investments in renewable capacities drive continued growth in RE employment, while the role of fossil fuels steadily declines. This shift underscores ASEAN's commitment to reducing environmental impact and enhancing clean energy adoption, with new renewable installations vastly outpacing fossil fuel additions, resulting in a workforce that increasingly supports green energy industries.

Figure 3.29 Total Energy Jobs Created Across Scenarios (2020-2050)



Globally, the COVID-19 lockdowns led to significant layoffs in the energy industry; however, renewable energy jobs remained resilient [51], [52]. The number of RE jobs increased in ASEAN despite disruptions from the COVID-19 pandemic, and will continue to rise through 2050. The same trends were noted in ASEAN, where fossil fuel-related jobs were greatly affected by the pandemic, as jobs created between 2020 and 2025 were small, and will continue to decrease in the period 2030-2040. The number of RE jobs increased in ASEAN despite the disruptions from the COVID-19 pandemic and will continue to hike, potentially reaching around 4.6 million by 2030, and 5.8 million by 2050 under the regional target scenario (RAS). Until 2040, job creation in RAS will be lower than BAS and ATS due to the utilisation of cost-efficient and low-carbon technology which resulted in fewer direct job opportunities. Similarly, under carbon neutrality scenario (CNS), energy job creation will attain 9.5 million in 2030, with high share from renewable sector. As comparison, IRENA's report shows that if the region is following along the similar pathway, the number of jobs in the energy sector could reach 10.3 million in 2030 under a 1.5˚C Scenario [53]. RE job creation is slightly higher than the other two scenarios due to massive renewable capacity deployment which requires significant maintenance and installation.

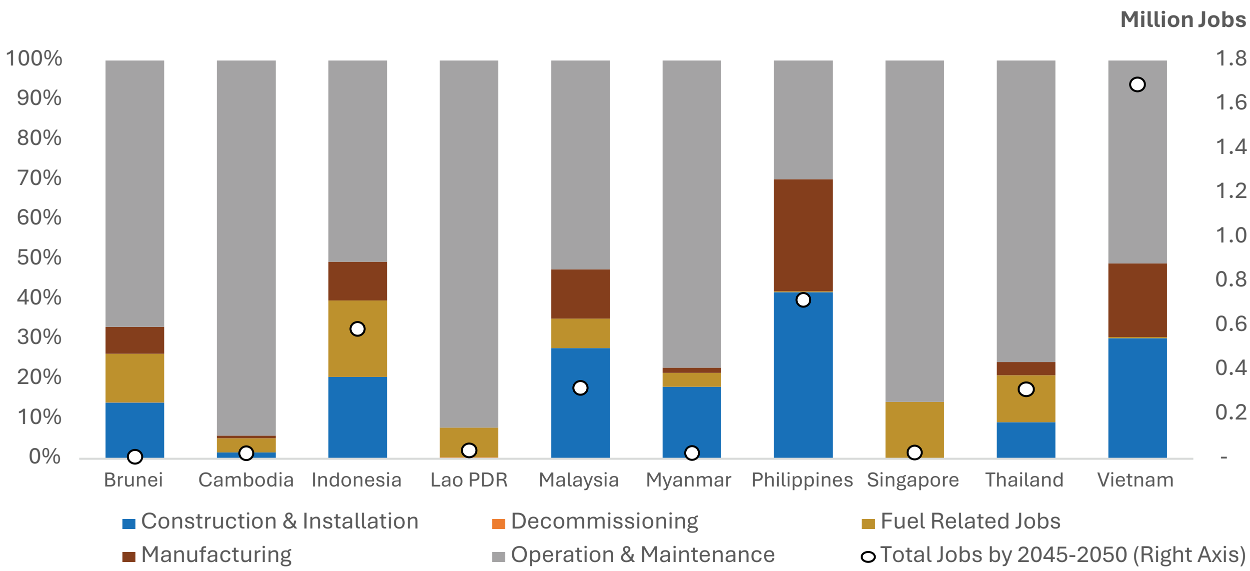
Figure 3.30 New RE Jobs Across Scenarios (2020-2050)



The RE sector shows strong job growth potential across all scenarios from 2020 to 2050, with solar power leading the way (Figure 3.30). By 2050, solar PV jobs are projected to surpass 2 million under the CNS and RAS, over seven times the baseline scenario (BAS) of 276,986. Wind energy jobs also see significant growth, reaching over 1.6 million in the ATS, RAS, and CNS, compared to just 163,502 in the BAS. In contrast, hydropower, while remaining a key job provider, declines in employment growth after 2030, falling to 524,301 in the RAS by 2050, down from its 2020-2030 peak of over 1 million jobs.

Bioenergy, while peaking at 1.5 million jobs in the BAS by 2050, sees lower growth in the more ambitious scenarios. This is due to bioenergy's labour-intensive nature and its reliance on traditional sectors such as agriculture and forestry. In the ambitious pathways like the ATS, RAS, and CNS, the focus shifts toward more technologically advanced, low-carbon energy sources like solar and wind, which are less labour-intensive. Additionally, concerns about land-use changes and environmental sustainability limit bioenergy's role in these scenarios. Geothermal remains a minor player in the job market, contributing around 162,426 jobs in the RAS by 2050. Energy storage, although modest in earlier decades, shows potential for job growth in the later years, with 232,293 jobs projected under the CNS by 2050. Overall, solar and wind will drive employment growth in ASEAN's RE transition, while hydropower, bioenergy, and geothermal play more limited roles in the long-term job market.

Figure 3.31 Job Creation in ASEAN Countries by Type of Jobs 2045-2050, RAS

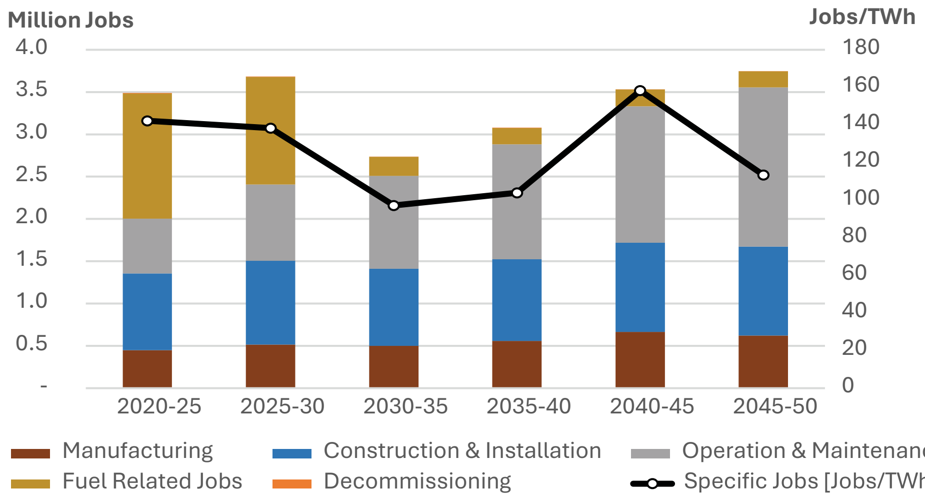


Note: see Table 2.5 for type of jobs definition

The RAS, which involves a cost-optimisation approach to ensure that ASEAN countries can meet energy demand efficiently while minimising costs, also balances the deployment of RE technologies with job creation across various sectors, such as construction and installation (C&I), manufacturing, operations and mainetance (O&M), fuel related jobs, and decommissioning jobs. By 2045-2050, the largest contributors to employment in the RAS are countries like Vietnam, Philippines, and Indonesia, primarily due to their large-scale RE projects and the operational workforce required to maintain these systems (Figure 3.31).

Vietnam leads with over 1.6 million jobs due to significant investments in operation and maintenance, which accounts for the largest share of jobs in the country. The country's heavy reliance on solar and wind power, coupled with a robust manufacturing sector, drives its high employment figures. On the other hand, Indonesia has a substantial workforce in fuel-related jobs and construction, reflecting its focus on large infrastructure projects. Meanwhile, smaller countries like Brunei and Singapore have much lower employment numbers, primarily due to limited land availability and smaller energy markets, which result in fewer large-scale renewable energy projects.

Figure 3.32 Job Creations in ASEAN by Category in 2020-2050, RAS



Following the country-by-country breakdown of job creation under RAS, the broader trends in workforce demand across various job categories over time are also examined. The chart in the Figure 3.32 shows that as the energy transition progresses, job creation patterns shift significantly. While O&M and C&I jobs maintain steady growth due to the need for ongoing maintenance and the installation of renewable energy systems, fuel-related jobs see a marked decline after 2030. This is largely due to the reduced need for fossil fuels in the RAS, aligning with ASEAN's clean energy goals. Additionally, the reduction in workforce demand between 2030-2040, particularly in manufacturing, can be attributed to the completion of large-scale renewable installations, with labour shifting towards O&M for ongoing system maintenance. These trends provide valuable insights into the evolving job market in ASEAN's energy transition.

The workforce demand reduction between 2030 and 2040, particularly in sectors like manufacturing and fuel-related jobs, can be attributed to the shift from the initial ramp-up of renewable energy capacity toward more stable, ongoing operations. The initial surge in job creation comes from building and installing new capacity, but after 2030, the bulk of the workforce shifts towards O&M as the newly installed systems require upkeep, rather than new installations. Meanwhile, C&I jobs remain relatively stable, reflecting ongoing but less rapid expansion. Fuel-related job reductions are also due to energy transition policies favouring clean energy over fossil fuels, aligning with ASEAN's long-term energy goals.

However, while the energy transition in ASEAN promises substantial job creation, particularly in the renewable energy sector, it also raises concerns about significant job losses. These concerns primarily stem from the phase-out of fossil fuel industries, such as coal, oil, and gas, which currently employ a large portion of the workforce.

Figure 3.33 Job Losses in the ASEAN Energy Sector Across Scenarios (2020-2050)

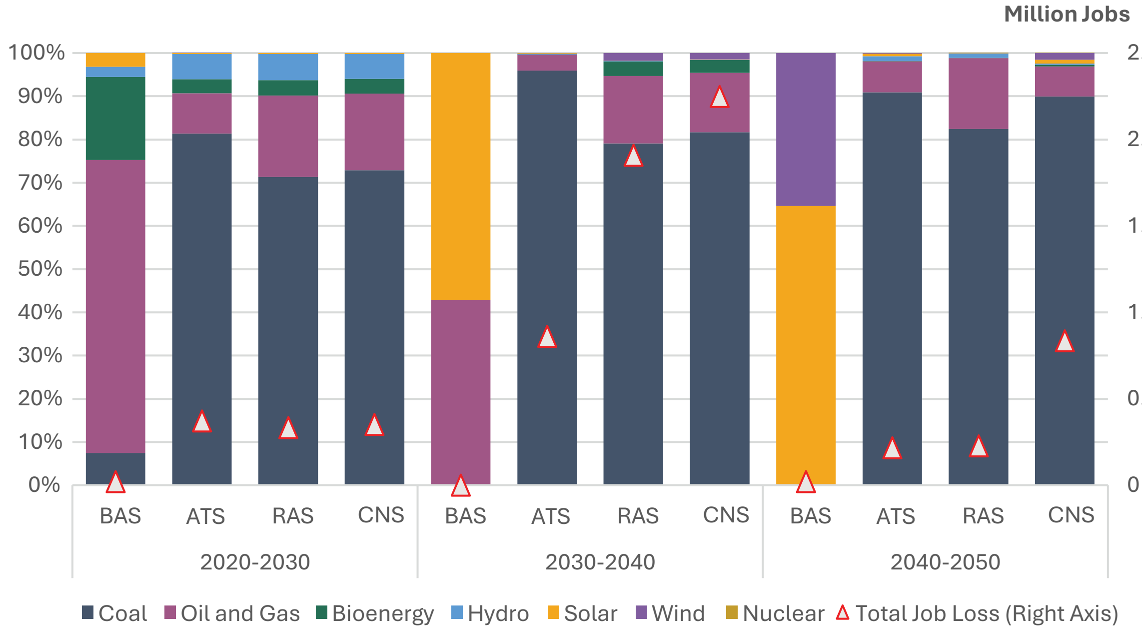


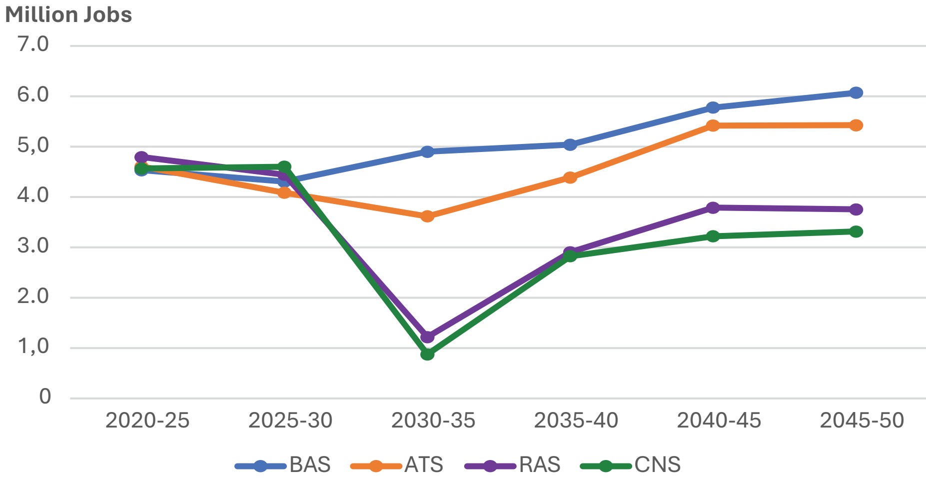
Table 3.3 Cumulative Job Losses Across Scenarios between 2020 and 2050

Parameter	BAS		ATS		RAS		CNS	
	RE	Fossil	RE	Fossil	RE	Fossil	RE	Fossil
Decommissioned Capacity (GW)	21	9	18	9	35	115	48	190
Power Generation Reduction (TWh)	0	70	18	1,554	2,151	4,120	2,446	4,221
Job Loss by 2050	25,230	15,613	41,677	1,407,207	137,799	2,331,126	162,277	3,271,697
Total Energy Jobs Loss	40,843		1,448,883		2,468,926		3,433,974	

Job losses in the energy sector vary significantly across scenarios. In the BAS, job losses are small, with a total of around 40,843 jobs lost by 2050, primarily due to the gradual retirement of fossil fuel plants. The ATS, RAS, and CNS see far greater job losses, especially in fossil fuels, with the CNS experiencing the highest job loss at 3.4 million (Figure 3.33). This is due to the aggressive transition away from fossil fuels, particularly coal, oil, and gas, as decommissioning of fossil fuel plants takes place alongside a shift to renewables. The reduced power generation and retirement of plants play a critical role, particularly in the CNS, which sees the decommissioning of 190 GW of capacity, leading to major workforce reductions in the fossil fuel sector as presented in Table 3.3.

The net employment trends in the energy sector from 2020 to 2050 reveal significant disparities across scenarios, shaped by the pace of the energy transition (Figure 3.34). In the BAS, where fossil fuel industries will remain to exist, net employment steadily grows, reaching over 6 million jobs by 2045-2050. The moderate shift allows the workforce to remain relatively stable, with both renewable energy jobs and some residual fossil fuel jobs contributing to the total. In contrast, the ambitious scenarios, particularly the CNS and RAS, show a sharp drop in net employment between 2030-2040, when rapid fossil fuel decommissioning leads to substantial job losses. For example, the CNS sees net employment decline to 875,411 by 2030-35 before it recovers slightly in the later years.

Figure 3.34 Total Net Employment Creation Across Scenarios (2020-2050)



One of the reasons why the installation of more renewable energy capacity does not directly translate into higher job creation lies in the lower labour intensity of renewables compared to fossil fuels. Fossil fuel power plants, particularly coal, employ a significantly larger workforce, with an average of 13,072 jobs per gigawatt (GW), whereas renewable energy plants such as solar and wind require only around 4,604 jobs per GW. This imbalance explains why, despite the doubling of renewable energy capacity by 2045-2050, particularly in the RAS, the number of jobs created in renewables fails to compensate for the massive loss of jobs in fossil fuels. Additionally, this report does not account for potential job creation in energy transmission and grid infrastructure, which could provide further employment opportunities in the energy transition.

Inclusive Transition

Energy transition will shift labor demands. Low skill, low wage workers are likely to be the losers of this process. Though medium skill labor skills are likely to rise in demand to service new technological setups. Nevertheless, these gains are not likely to minimize the impacts of job loss for the least fortunate nor to minimize its negative knock-on effects.

Legislating and implementing retraining schemes to facilitate laid off laborers' shift to higher skill green industries are more likely to solve the problem. Through legislative action industry partners can be brought into both improve successful reemployment rates and reduce costs on governments. Due care to regulate these training processes is encouraged to ensure private employers re-train in sustainable ways and comprehensive ways that do not create captive employees whose skills are too narrow or specialized to transfer to other plants or situations in the future.

3.6 GHG Emissions

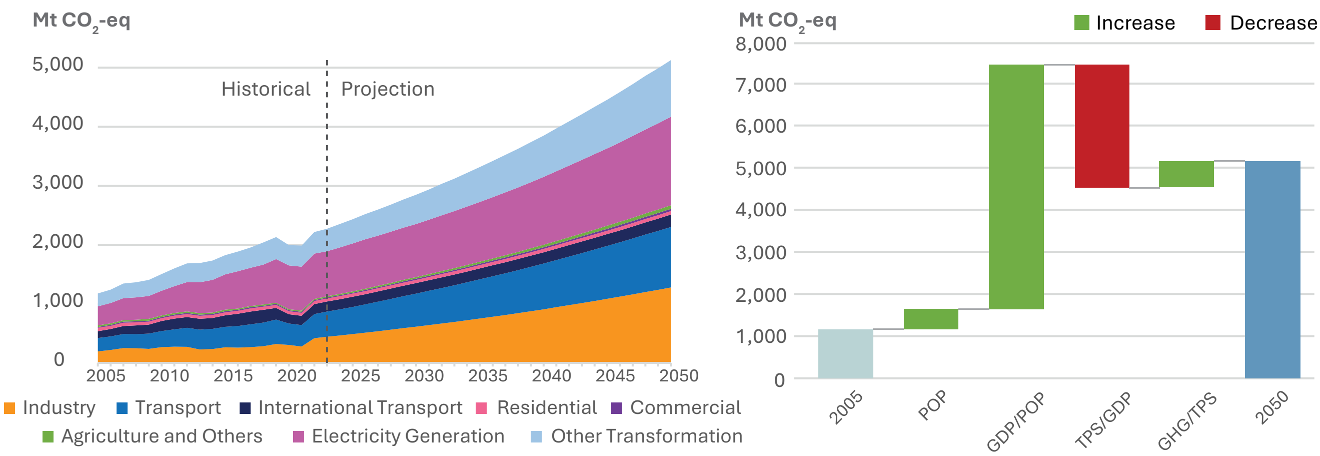
The increase in GHG emissions in ASEAN is driven by a combination of rapid economic growth, heavy reliance on fossil fuels, expanding transport networks, deforestation, and population growth. The GHG emissions reached 2,215.2 $MtCO_2$-eq in 2022, increasing almost two-fold from 1,175.1 $MtCO_2$-eq in 2005, covering demand and power sectors (Figure 3.35 a). The demand sector includes industry, domestic and international transport, residential, commercial, and agricultural. The power sector includes electricity generation and other transformations.

In order to identify the relative importance of various GHG emissions drivers in the scenario analysis, a decomposition analysis was conducted based on the Kaya identity equation (Appendix D.3.3). This makes it possible to quantify the assessment and relative impact on GHGs identified from population growth, income (as GDP per capita), energy intensity (as TPES/GDP), and carbon intensity of energy (as energy GHGs/ TPES). Under the BAS (Figure 3.35 b), the analysis shows that GDP growth is by far the strongest driver of energy emissions growth in 2050, at approximately 5,127.4 $MtCO_2$-eq, with some contributions from increased population and energy supply carbon intensity, accounting for 470 $MtCO_2$-eq and 643 $MtCO_2$-eq, respectively. At the same time, a reduction in the economic energy intensity offsets the emissions increase by about 2,936 $MtCO_2$-eq. However, this is not enough to avoid a sharp overall rise in GHG emissions.

Figure 3.35 GHG Emission, BAS

(a) GHG Emissions Produced by Sector

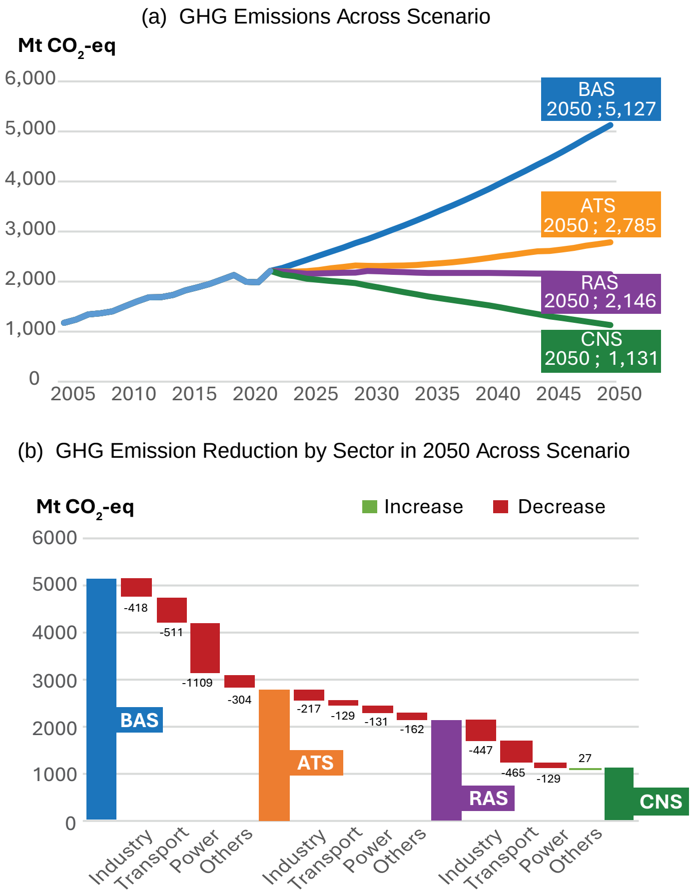
(b) Decomposition Analysis of GHG Emission



In the demand sector alone, the GHG emissions reached 1,080.7 $MtCO_2$-eq, and will increase to 2,668.2 $MtCO_2$-eq by 2050 in the BAS. Applying the national policies of the ATS will reduce the emissions by 36%, as compared to the BAS. The avoided emissions between these two scenarios primarily come from electricity generation, which declines by 74%, due to the shift of power sources from fossil fuels to cleaner energy. The emissions gaps are also supported by fuel shifting and fuel economy in transport, having lower emissions by 26.6% in the ATS.

Given accelerated efforts by each of the AMS in the RAS, the GHG emissions can be further decreased by 23%, as compared to the ATS (Figure 3.36). This trend can be observed with the contribution of EE&C efforts in the residential sector and cleaner energy sources in electricity generation. With these measures, the share of GHG emissions from electricity generation falls significantly from 29.2% in the BAS, to 12% in the RAS.

Figure 3.36 GHG Emissions in All Sectors Across Scenarios



On the other hand, the proportion of emissions generated from industrial and other transformations is the highest in the RAS, which requires more attention to, and R&D in decarbonising these sectors. For example, the AMS could invest in technologies that capture and store carbon dioxide emissions from industrial processes, reducing the carbon footprint of using fossil fuels. In addition, ASEAN countries should advocate for and comply with policies and regulations that promote low-carbon technologies and penalise high-emission practices.

In the CNS, putting net-zero measures into effect further decreased emissions by figuring out how to make industry operations more effective so that they use less raw materials, or by figuring out how to make households less reliant on energy for space cooling end-use devices. In order to significantly reduce energy intensity and hence reduce emissions, fuel switching will be essential in both the energy sector and fuel utilisation. It will also demonstrate that there are ways to reduce the impact on the environment if all AMS attempt to integrate alternative fuels and increase the blending ratio of biofuels. In addition, better understanding of each AMS's existing carbon sinks will be helpful in the transition to net-zero. In this case, reaching net-zero is possible, but our chances of succeeding may be hampered by the continued emissions from different industries without taking into consideration the carbon sink that already exists. We can only strive to further minimize emissions from all sectors until the entire region fully utilises the potential of RE technology with non-RE technologies with CCS or include Direct Air Capture (DAC) systems that can capture the remaining emissions in modelling net-zero scenarios.

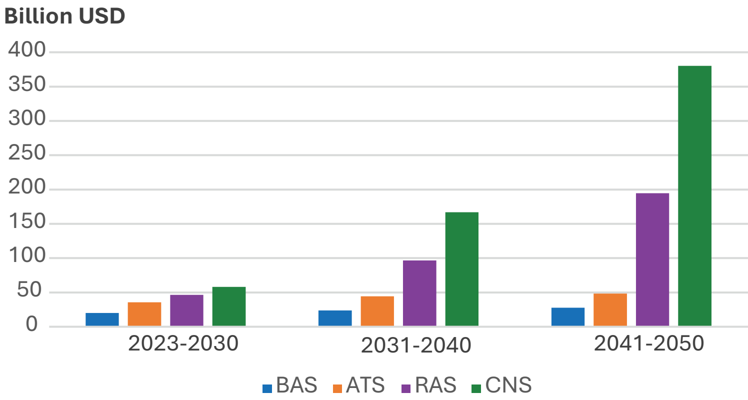
3.7 Energy Financing

The high upfront costs and low margins are particularly prominent in the power sector among other sectors since power generation requires significant infrastructure. As the power sector expands across the region, the total financial cost is required to deploy energy generation infrastructure, particularly the implementation of emerging and low-carbon technologies. The BAS and ATS projected power capacity expansions for ASEAN in 2050 will be 817 GW and 1,115 GW, respectively. Moreover, the power sector investment cost trend is strongly impacted by the implementation of emerging and low-carbon technologies. Under the ATS, the electricity demand will reach 173 Mtoe in 2050, surging by 73% from 2023.

The power investment cost across scenarios shows an upward trend by 2050 as the scale of additional installed capacity is projected to increase. In Figure 3.37, the required investment in ATS is higher than the BAS given the strengthened commitment of AMS under their Power Development Plan (PDP). The annual investment cost in 2050 under BAS would account for USD 27 billion, which is about 16% lower than the ATS. Meanwhile, cost differences between the ATS and RAS are not significantly different, with annual investment costs in 2050 being USD 32 billion and 274 billion, respectively.

The power investment cost in CNS also shows an upward trend as it integrates net-zero technologies and associates with capital-intensive projects. CNS demonstrates the highest power generation investment requirements in the later years, with the growth jump almost 9 folds from 2023 to 2050. Aligning with the carbon neutrality target, the investment cost reach USD 516 billion in 2050, almost two times higher than the RAS. However, if it is in total throughout the projection years (2023-2050), the CNS requires financing costs of USD 6 trillion for clean power sectors to achieve net zero emissions.

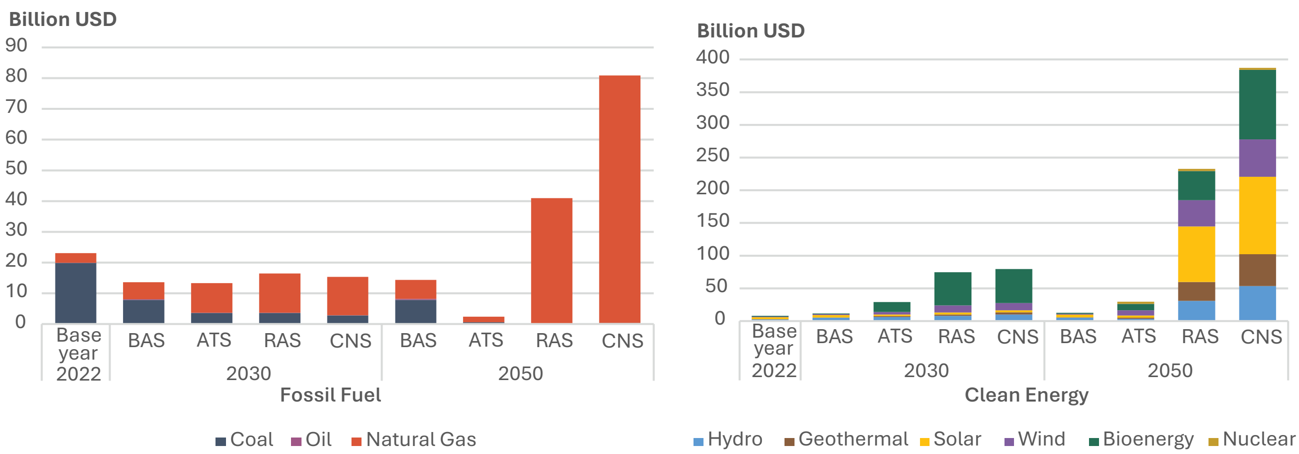
Figure 3.37 Average Annual Power Investment Cost Across Scenarios



All scenarios follow an increasing trend reaching the highest value for the CNS following the carbon neutrality target through clean technology and infrastructure updates. Moreover, the region will experience massive power investment costs in the longer term for additional capacity infrastructure and to meet the electricity demand. In earlier years (2023-2030), the annual power investment requirement varied from USD 20 billion to USD 56 billion, while the long-term (2041-2050) ranges from USD 28 billion to USD 371 billion.

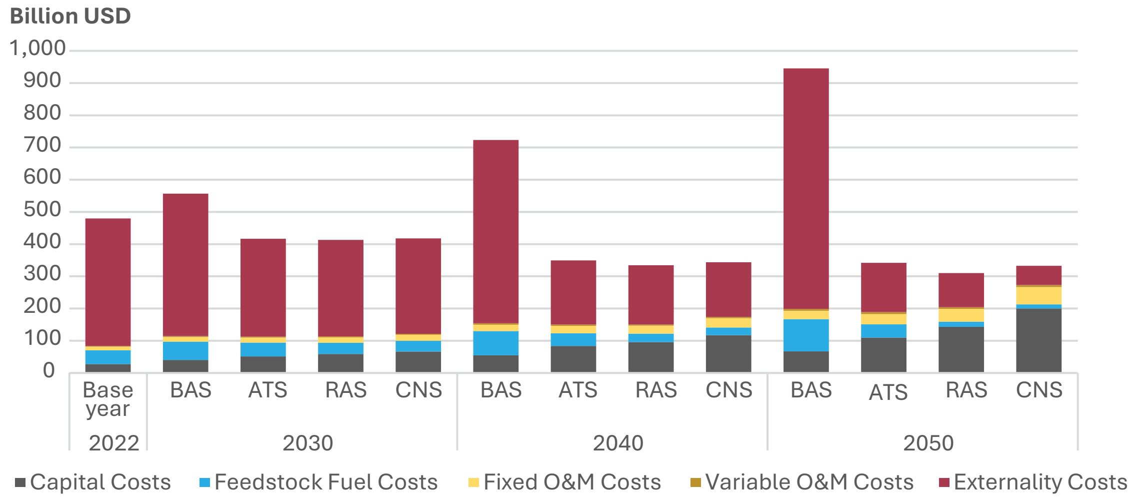
A major effect of the energy diversification policy in ASEAN has been to accelerate the deployment of clean energy technologies. The projected power capacity in RE will be 773 GW by 2030, with the share of solar continuing to dominate the power capacity, while wind accounted only for 8.4% share under ATS. This results in high financing costs in renewable energy due to installation costs, particularly wind which is projected to increase to USD 3.9 and 8.2 billion by 2030 and 2050, respectively (Figure 3.38). In contrast, the financing cost of coal power will decrease gradually until 2050 at USD 580 million, reflecting a similar downward trend observed in oil following ongoing fuel costs and O&M expenses. A notable addition to the investment cost is nuclear energy, which may require up to USD 3 billion investment cost in 2050.

Figure 3.38 Investment Costs by Fuel Across Scenarios



The RE cost has become more affordable than fossil fuels over the past ten years, there has been a shift in the use of technology, particularly in light of the continuous geopolitical turmoil that has increased the price of fossil fuels. RAS and CNS projected investment costs in natural gas and renewable energy at their peak in 2050 due to the adaption of emerging clean technology equipment with higher capital expenditure (Figure 3.39). While this leads to higher initial capital costs, the improved efficiency in technology can lower long-term operational costs.

Figure 3.39 Comparison of Production Cost Across All Scenarios



The capital cost across all scenarios shows an upward trajectory with reduced O&M costs as the region still expects power plant construction and equipment installation. The capital cost will attain USD 114 billion and 79 billion, respectively in the BAS and ATS. A cost-optimised energy system posits a production cost of USD 414 billion in 2050 under RAS, including the cost of developing APG and energy storage. The capital cost is at its peak in 2040 under CNS. On the contrary, the externality costs or indirect costs show different trends across all scenarios since CNS looks for sustainable power technology, resulting in lower costs in social, environmental, and health aspects. However, production cost in BAS high share of externality costs.

Developing and expanding RE projects in the region will lead to an increase in supply. It is well-known that shifting to clean energy sources will be costly. With large investments previously directed towards fossil fuels, investing in renewable sources may seem less appealing. For growing markets like hydropower, solar and wind, increasing private sector participation through Power Purchase Agreements (PPA) will stimulate investment flows. To further accelerate market growth, feed-in-tariffs and tax incentives will enhance competitiveness within the local industry and attract domestic investors, ultimately driving economic growth. Designing regulations and financing schemes that are favourable to the business environment is crucial for facilitating renewable infrastructure development at a competitive cost. This is a key role of the public sector.

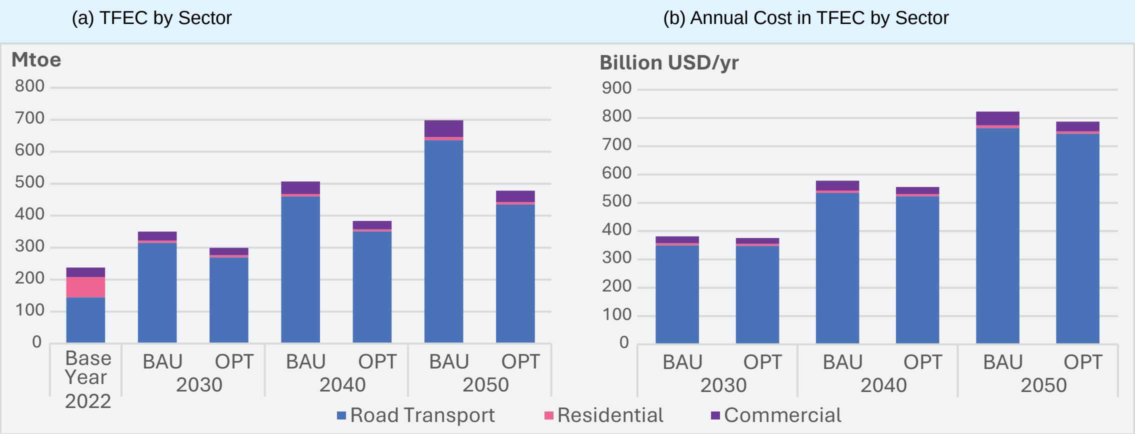
Reflecting on the increase of geothermal supply in the upcoming years, the realisation requires proper financing tools to address the high capital requirements. In launching a seemingly unviable project, grants could provide a great support mechanism. With international aid, grants could flow from a blended finance scheme, eventually making the project more feasible in the long term. Similarly, green bonds are an alternative green financing instrument that could reinforce large-scale projects by pooling funds, ranging from multilateral institutions to philanthropic funds. Thus, close monitoring of each country's targets and potential is important in creating suitable and supportive policies to achieve ASEAN's shared goals.

Least Cost Optimisation in Demand and Supply

An additional exercise using GAMS was conducted to check the effect of applying the least-cost optimisation method in the demand sector for specific end-use technologies. The optimal technological choice based on least-cost optimisation (OPT) could reduce energy demand compared to without optimisation (BAU). In 2030, the TFEC of three sectors – Road Transport, Residential, Commercial [7] – is projected at 350.2 Mtoe in BAU and reduced to 299.1 Mtoe in OPT. The TFEC in OPT further decreases in the long term, by approximately 24% in 2040 and 32% in 2050 compared to BAU. It indicates the selection of EE&C policy measures while considering the cost of technologies available in the region would foster the reduction of energy demand. Although the transport sector accounts for the largest share in the TFEC of the region in 2050, the reduction of energy consumption in commercial is found to be the largest, which is approximately 33% lower than its BAU value (Figure 3.40).

The effect of cost optimisation on annual cost reduction is not as large as the TFEC reduction. Compared to BAU, OPT could decrease the annual cost of the three sectors by 2%, 3.9%, and 4.4% in 2030, 2040, and 2050, respectively (Figure 3.40 b). It is due to the cost assumption applied in the current GAMS model, on which fossil fuel cost is assumed to be constant while the RE cost is assumed to be reduced gradually. Added to this, the different fuel consumption factor for different types of transport is also applied. As a results, the reduction of TFEC is higher than the cost reduction after optimisation.

Figure 3.40 Projection in Energy Demand

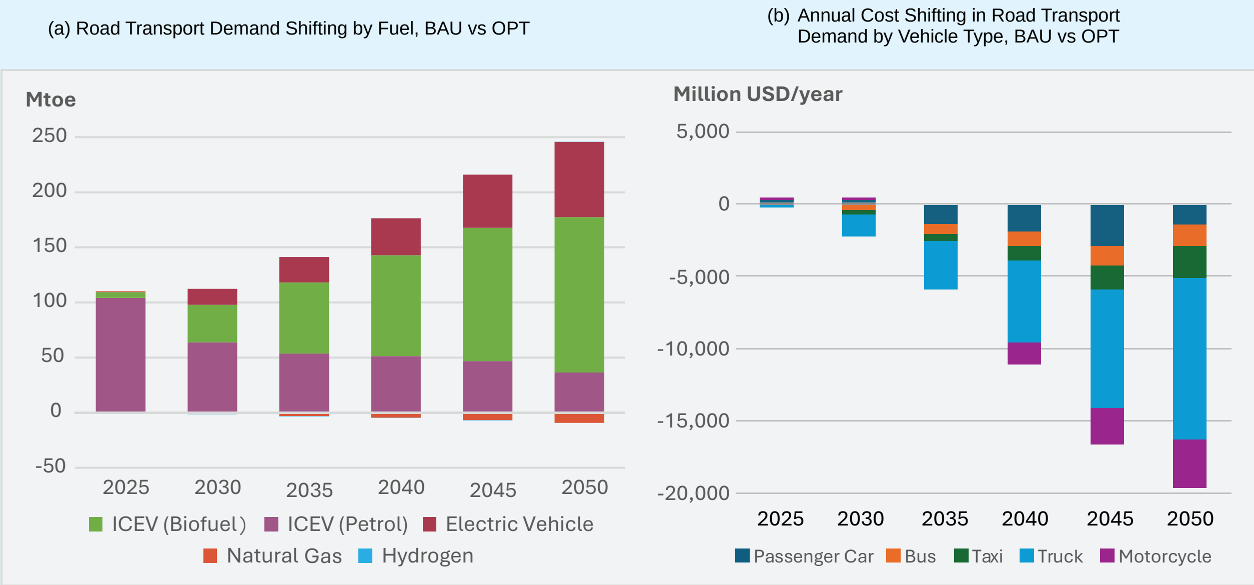


[7] Appliances measured in the Residential and Commercial sectors include only air conditioning and lighting

The cost optimisation applied in road transport demand results in a significant decrease in the usage of petroleum-based ICEV throughout the projection years. On the other hand, the energy consumption from biofuel-based ICE and electric vehicles are expected to grow significantly from 2030 to 2050. In 2030, the increase in TFEC resulting from the utilisation of biofuel and EVs in ASEAN is projected at 34 Mtoe and 15 Mtoe, respectively (Figure 3.41 a). By 2050, the demand for these two vehicle types would multiply by 4 and 4.6 times, respectively, compared to the 2030 values. This predicted shifting trend from petroleum is driven by the implementation of biofuel mandates and EV policies of AMS (Table 2.2). Hydrogen-type transport is found to be at smallest share among others. Policy measures, such as tax incentives and subsidies, could make electric and hydrogen vehicles cost-competitive, thus increasing market demand for these types of road transport in ASEAN.

Following the reduction in the TFEC of road transport, the cost optimisation method also decreases its total annual cost. In 2030, the difference in the cost of road transport demand after optimisation is nearly USD 1.7 billion per year and would increase by 2.2 times in 2050 (Figure 3.41 b). Among transport demand, trucks and passenger cars account for the two largest shares of total annual cost-shifting between 2030 and 2050 from non-optimised levels.

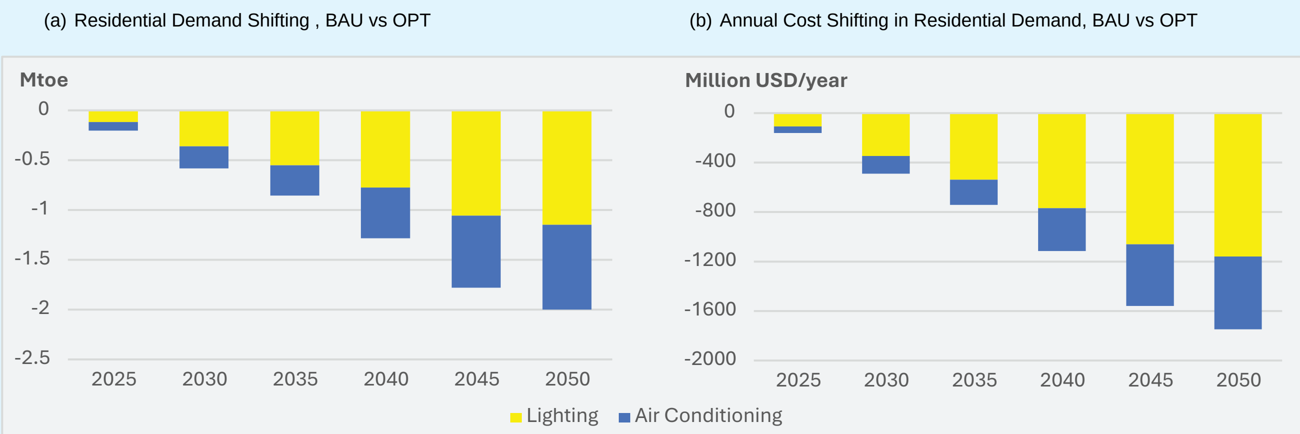
Figure 3.41 Projection in Road Transport Demand



With cost optimisation, the TFEC of the residential sector can be reduced by nearly 1 Mtoe in 2030, 1.3 Mtoe in 2040, and 2 Mtoe in 2050 (Figure 3.42 a). This reduction can be observed due to the policy measures on utilisation of more efficient lighting and air conditioning appliances, such as MEPS. The reduction of energy consumed by lighting in residential is higher than by air conditioning, which indicates the need for strengthening energy efficiency measures for air conditioning in the region.

As a result of the reduction in the energy consumption of the residential, the total annual cost for this sector has also decreased. In 2030, the reduction in total annual cost for the residential sector after optimisation is approximately USD 490 million, and would increase to USD 1.1 billion and USD 1.8 billion USD, in 2040 and 2050, respectively (Figure 3.42 b). The share of annual cost reduction of lighting is also found to be higher than air conditioning. This can indicate that utilisation of more efficient appliances including lighting and air conditioning saves more cost in the long run than could also benefit from shifting the income spending of the residential sector to be used for other purposes.

Figure 3.42 Projection in Residential Demand by Appliances



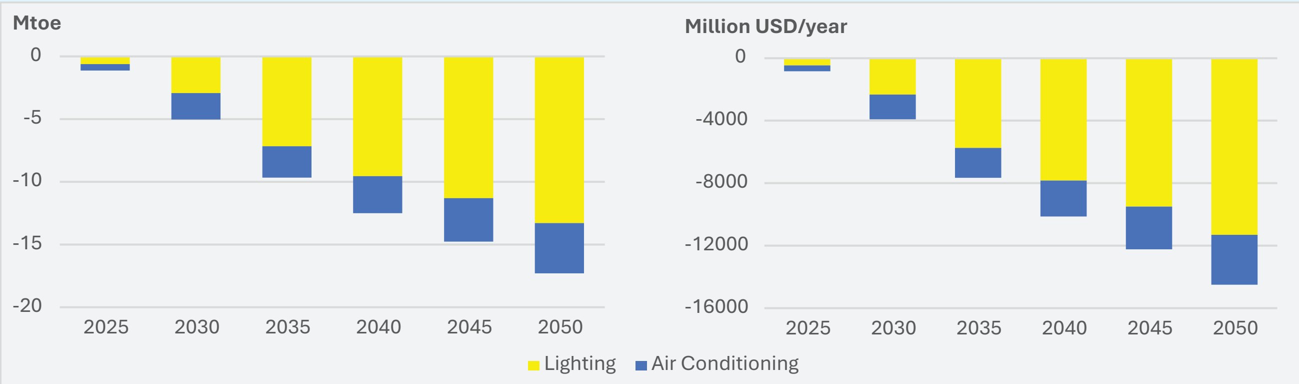
The commercial demand shows the same reduction trend in terms of TFEC and annual cost as the residential sector, although higher. In 2030, the total reduction of energy consumed after optimisation in the commercial sector is nearly 5 Mtoe (Figure 3.43 a), five times larger than the TFEC reduction in the residential sector for the same year. It is projected to continue increasing to nearly 13 Mtoe and 17.5 Mtoe, in 2040 and 2050, respectively. It would be easier for the governments to mandate the commercial sector than residential to use more efficient technologies.

The reduction of final energy consumed by commercial after optimisation also reduces its total annual cost in the projection years. The optimised total cost of commercial in 2030 is approximately USD 3.9 billion per year, and increases to approximately USD 10.1 billion and USD 14.5 billion, in 2040 and 2050, respectively (Figure 3.43 b). The largest share of annual cost reduction is from the utilisation of more energy-efficient lighting in the commercial, similar pattern to the residential demand.

Figure 3.43 Projection in Commercial Demand by Appliances

(a) Commercial Demand Shifting , BAU vs OPT

(b) Annual Cost Shifting in Commercial Demand, BAU vs OPT

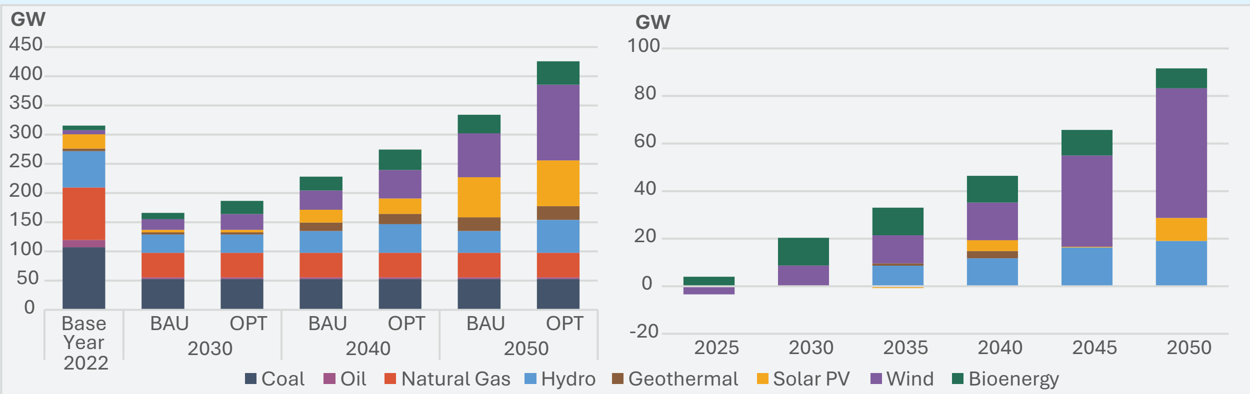


The total installed capacity after cost optimisation in 2030 is nearly 190 GW, 12% of the value without cost optimisation. It increases by 20% and 27% of the values without cost optimisation in 2040 and 2050, respectively (Figure 3.44 a). The share of fossil fuel before and after cost optimisation from 2030 to 2050 is reduced due to the increasing total installed capacity of RE, due to decreasing RE cost in the long run. In 2050, the share of fossil fuel accounts for approximately 23% of the total installed capacity, which is 29% lower than its share in 2030, with the highest reduction comes from coal and natural gas. The proportion of coal and gas in the total installed capacity in 2050 decrease by 16% and 13%, respectively, from the shares in 2030. As a result, the RE share in the installed capacity by 2050 after cost optimisation reaches 77%, which is nearly 30% higher than its share in 2030. Amongst RE technologies, solar and wind increase by 15% in 2050 compared to their share in 2030 (Figure 3.44 b).

Figure 3.44 Installed Capacity, BAU vs OPT

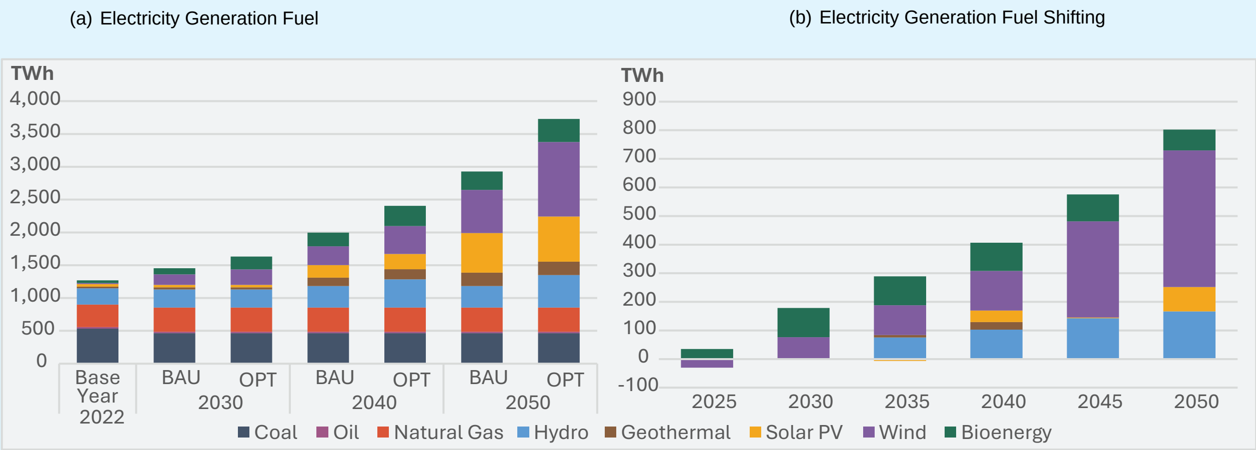
(a) Installed Capacity by Fuel

(b) Installed Capacity Fuel Shifting

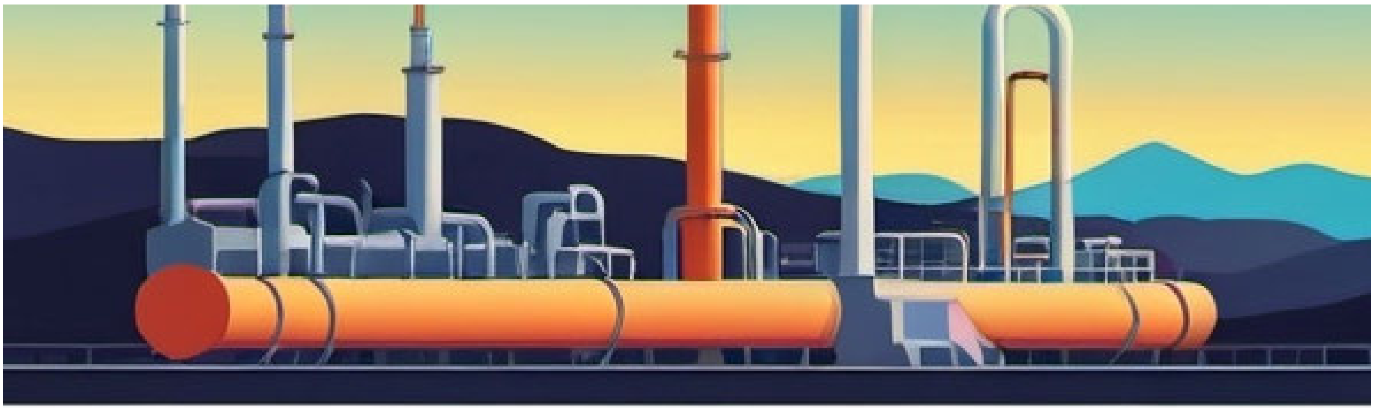


The same findings are also found under the electricity generation without and with cost optimisation from 2030 to 2050. In 2030, the total electricity generation of fossil fuel is nearly 856 TWh with coal contributing as the largest source (464 TWh). Natural gas accounts for the second largest portion of total electricity generation from 2030- 2050, which is nearly 370 TWh. The total electricity generation of RE sources is found to increase under the cost optimisation scenario, from 599 TWh to almost 777 TWh in 2030, and continue to increase to 1,549 TWh and 2,874 TWh in 2040 and 2050, respectively. As a result of the significant increase in RE electricity generation, the total electricity generation under cost optimisation also increases to 2,404 TWh and 3,730 TWh in 2040 and 2050, respectively (Figure 3.45 a). However, it is worth noting that the cost reduction is only assumed on RE cost, not fossil fuel generation cost.

Figure 3.45 Electricity Generation, BAU vs OPT



The significant increase in RE electricity generation with cost optimisation results in the growth of its RE share. In 2030, the rise of bioenergy and wind electricity generation with cost optimisation is projected to be nearly 102 TWh and 77 TWh higher than its values under no-cost optimisation. The increase of wind electricity generation continues in 2040 and 2050 to be nearly 140 TWh and 480 TWh, respectively. Differently, the increase of bioenergy slows down in 2040 and 2050 to be nearly 99 TWh and 73 TWh, respectively. Other electricity generation sources are also found to increase significantly from 2040 and 2050, including hydropower and solar PV. Geothermal electricity generation is expected to grow only by nearly 30 TWh compared to its value under no-cost optimisation in 2040, and no further increase in 2050 (Figure 3.45). While the cost optimisation results are also subject to assumptions applied in the current model, it also shows the necessity to design supporting regional measures on cost reduction of RE and phasing down of fossil fuel electricity generation with maintaining energy security level in the region.

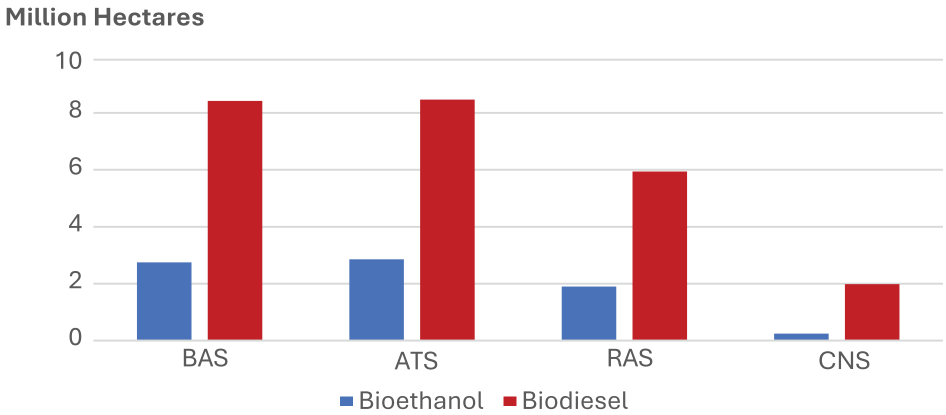


3.8 Land Use for Renewables

3.8.1 Land Use for Biofuels

Biofuels play a crucial role in the energy mix of AMS, contributing significantly to energy diversification and providing essential pathways toward decarbonisation. Biodiesel is prominently used in Indonesia, Malaysia, the Philippines, and Thailand, whilst bioethanol is widely adopted in Thailand, the Philippines, and Vietnam. The dominant position of Indonesia and Malaysia as the largest global producers of palm oil is closely tied to biofuel production, raising concerns about increased land use intensity and the environmental impacts of expanding biofuel feedstock cultivation. As the ASEAN region is advancing towards biofuel blending policies, such as Indonesia's B35 mandate and Thailand's E20 and B10 targets, biofuel consumption is projected to rise, necessitating a closer examination of the associated land use implications by 2050 as seen in Figure 3.46.

Figure 3.46 Land-use Requirement for Biofuels by 2050



Under the BAS, by 2050 the total land required for biofuel production is estimated at 11.1 million hectares. Biodiesel production comprises the largest share of land use requirement at 8.4 million hectares. In a similar trajectory, the ATS presents a similar amount of land required by 2050, with only an incremental increase in total land required at 11.3 million hectares. This can be attributed to the stringent demand for the implementation of energy efficiency policies and blending targets by AMS. RAS indicates a decrease in total land requirement for biofuel production, at 7.8 million hectares. A sharp decline in land requirement is projected in the CNS, with a land requirement for biofuel production totalling 2.2 million hectares. The total land requirement in the CNS is comprised of 2.2 million hectares for biodiesel production and 240,000 Ha for bioethanol production respectively.

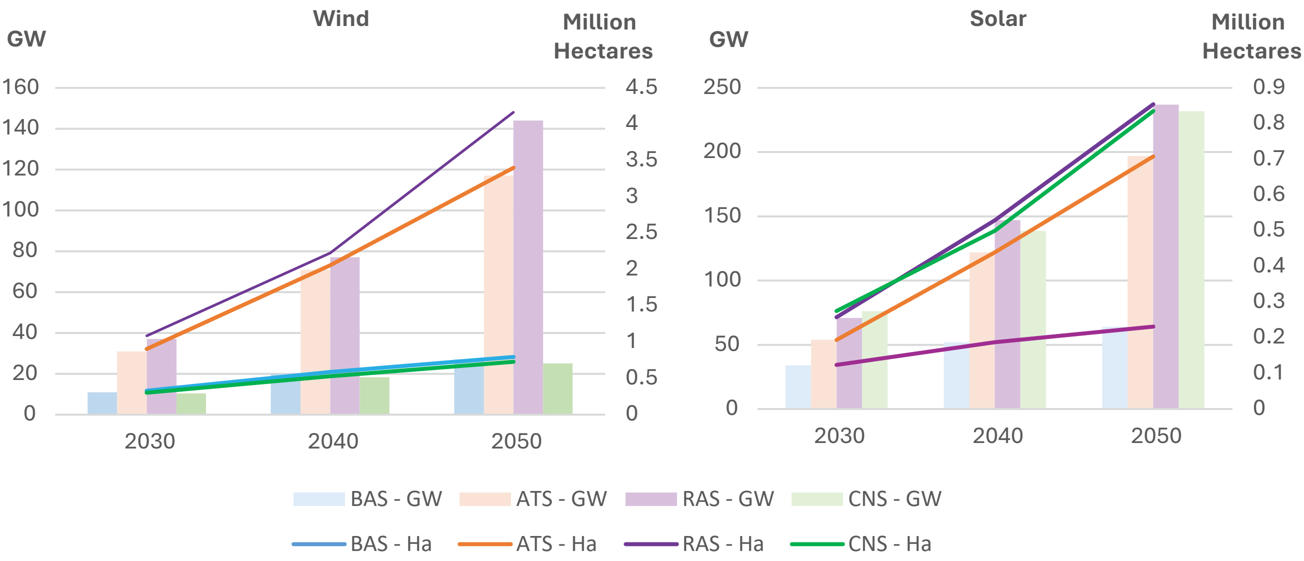
A small area of land requirement is observed under CNS, where total land for biofuel production is projected to be only 2.2 million hectares, including 1.98 million hectares for biodiesel and 239,780 hectares for bioethanol production. This reduction reflects the optimising land use and integrating low-carbon technologies, ultimately contributing to a more sustainable and balanced energy system.

3.8.2 Land-use for Solar and Wind Projects

Solar and wind power have emerged as the most cost-effective energy sources for all AMS, positioning them as pivotal energy sources for accelerating the region's energy transition. As of 2022, the installed capacity of solar and wind in ASEAN has increased to 31.57 GW, comprising 10% of energy mix. The deployment of solar and wind technologies is evident in Indonesia, Malaysia, the Philippines, Thailand, and Vietnam, highlighting these countries' key roles in ASEAN's total electricity generation. As the AMS continue to increase capacity for solar and wind to meet RE targets, the associated land use requirements are also expected to rise across various scenarios. For context, ASEAN's total land area encompasses 450 million hectares.

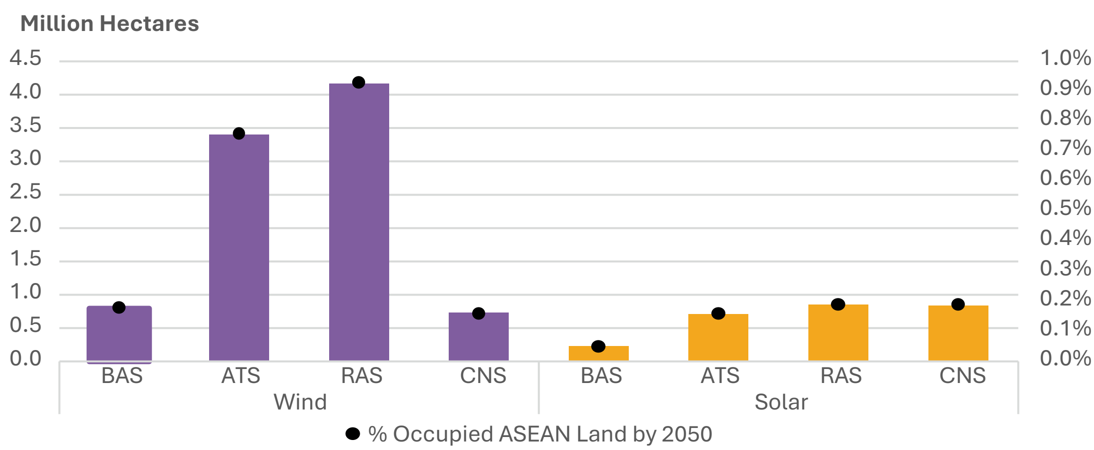
Figure 3.47 provides information on land use requirements for solar and wind energy, accounting for ground-mounted solar panels and land occupied by wind turbine pads, access roads, substations, service buildings, and associated onshore infrastructure. In total, this implies a greater amount of land use requirements by 2050, than noted in the AEO7 results when calculating land use requirements for biofuel. The projection data shows that the required land for solar and wind power is expected to ramp up by 2050 across all scenarios.

Figure 3.47 Land Use for Wind and Solar Projects Across Scenarios



In 2023, the installed power capacity for wind and solar PV across various scenarios exhibited relative consistency, initiating from approximately 7.3-7.9 GW for wind energy and 24-28 GW for solar energy. Moving towards 2050, the absence of comprehensive energy policy interventions under the BAS is likely to slow the rate of wind and solar adoption, subsequently leading to a reduced share of these renewables in the total installed capacity. Consequently, this will not give a significant impact on the overall land usage dedicated to renewable energy infrastructure. Meanwhile, more ambitious scenarios are estimated to use more land space, with ATS and RAS presenting a comparable upward trend, projecting even higher than CNS (Figure 3.48).

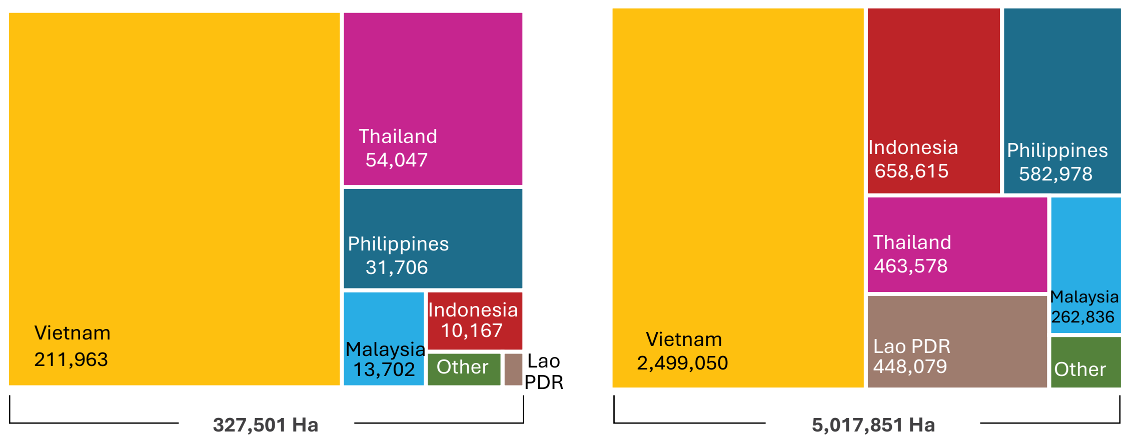
Figure 3.48 Land Requirement for Renewables by 2050 and Comparison to Total ASEAN Land Area



The land use required to deploy wind technology is substantially higher than for solar. According to the BAS, by 2050, the total land requirement for wind is expected to be 794,860 hectares by 2050, accounting for 0.18% of ASEAN's total land area. Under the ATS, the land requirement by 2050 is projected to increase sharply to 3.4 million hectares, amounting to 0.76% of ASEAN's total land area. This significant increase aligns with the assumption that wind installation capacity will be spurred by supportive policies from the AMS. The RAS indicates a marginal decrease in land use for wind, projected at 4.1 million hectares, which amounts to 0.93% of ASEAN's total land area. Similar to the projections for solar, the scale of expansion in wind land use under the ATS and RAS is particularly notable in Vietnam, the Philippines, Thailand, Indonesia, and Malaysia. The substantial increase observed in the RAS may be attributed to the adoption of least-cost technologies, which optimally balance renewable energy deployment with capacity expansion.

Under the RAS, Vietnam is projected to experience the most significant impact in terms of land use for RE installations, particularly for wind and solar power by 2023 (Figure 3.49). As a key destination for RE investment within ASEAN, Vietnam will likely continue to concentrate a significant portion of land use, with approximately 2.5 million hectares dedicated to wind and solar power plants by 2050. Despite being the largest AMS geographically, Indonesia is expected to allocate only 658,615 hectares for these RE installations, which would constitute 13% of ASEAN's total land use for renewables by 2050. The Philippines is projected to follow closely, with a 12% share. Thailand and Lao PDR are expected to contribute 9% each to the total land use for renewables, while Malaysia's contribution is projected to be half of this percentage. The remaining AMS, including Brunei, Cambodia, Myanmar, and Singapore, are expected to experience minimal or negligible impacts on land use due to their relatively smaller power capacities and geographical constraints.

Figure 3.49 Land Used for Wind and Solar Projects by ASEAN Countries in 2023 and 2050, RAS



As coal remains an important energy source in ASEAN due to its supply stability and affordability, comparing its land use requirements with those of solar and wind provides insights into the land-energy nexus faced by the AMS. According to the Baseline Scenario, the land requirement for coal by 2050 is projected to double to 7.7 million hectares, amounting to 0.26% of ASEAN's total land area. Under the ATS and RAS scenarios, the land requirement for coal-fired power plants is expected to decrease by half, reducing to 0.12% of ASEAN's total land area by 2050. Although the total installed capacity of coal is projected to be 22% lower than that of wind by 2050, the total land use for coal is estimated to be 87% smaller than wind with the implementation of the RAS. This stark contrast underscores the spatial efficiency of coal compared to wind energy, albeit with significant exchange in terms of environmental and social impacts.

When compared to coal, the annual land use requirement for wind technology is approximately 18 times larger than that for coal across all scenarios. In contrast, the land use requirement for solar is only twice as large as that for coal-fired plants. It is crucial to consider the trade-offs between the land use requirements of renewables and the GHG emissions and land degradation resulting from coal-fired plants. The scenarios for land use requirements indicate a positive trajectory, suggesting that the AMS are making significant progress towards achieving RE capacity targets. In the long term, this underscores the concerted effort required to reduce dependence on coal, whilst navigating the challenge of extensive land use requirements through supportive land use policies.

Socio-Ecological Considerations and Community Participation of Land-use for Renewables Development

The increased land use intensity associated with renewable energy projects necessitates careful consideration of socio-ecological impacts and community participation. Historical evidence from fossil fuel-based energy systems has shown that the exclusion of communities from decision-making processes often leads to social conflict and financial repercussions. Therefore, there is a compelling business and economic rationale for ensuring that renewable energy developers and financiers secure Free, Prior, and Informed Consent (FPIC) from affected communities [54]. This approach is not only a matter of respecting land rights but also a strategic measure to mitigate potential conflicts and ensure the long-term sustainability of renewable energy projects.

Furthermore, communities should be viewed as integral partners in the energy transition rather than as obstacles to development. By involving local civil society organizations (CSOs) and grassroots movements, communities can play a crucial role in shaping the direction of renewable energy projects [55]. These organisations can facilitate community engagement, helping to define and communicate local development priorities and ensuring that renewable energy projects align with the aspirations of the communities they impact.

Lastly, it is important to note that the modular nature of renewable energy technologies, such as wind and solar, offers distinct advantages over centralised coal plants. For instance, wind and solar installations can be deployed in diverse locations, including offshore areas and reservoirs, thereby reducing the pressure on land resources. However, the challenge lies in ensuring that these installations are compatible with existing transmission systems and grid infrastructure, which may require significant upgrades to accommodate the intermittent nature of renewable energy sources [56].

Inclusive Transition

The land required for developing RE generation is likely to be occupied by indigenous groupings who are often members of religious or ethnic minorities. These groups typically have long-standing livelihood dependencies on the land in question. Appropriating said land for development risks dismantling the communities in question. This is likely to drive worsening poverty and exacerbate illegal substance use along with unsustainable migration patterns.

Comprehensive compensation schemes must therefore be implemented and enforced. The inclusion of local communities in every phase of the project is crucial. Short-term concerns of re-location, fiscal compensation, and livelihood adjustment must be holistically considered.

In the longer term, the international best practice is Benefit Sharing. This is a process by which affected communities are given a direct stake in the project through a community foundation that owns and benefits from a share of the ownership of the complex in question.

CHAPTER 4

A STRATEGIC APPROACH TO ENERGY REGIONAL BLUEPRINT

Chapter 4 - A Strategic Approach to Energy Regional Blueprint

The theme of this chapter is to provide viable strategies for ASEAN policymakers as they prepare for the new cycle of the ASEAN Plan of Action for Energy Cooperation (APAEC), focusing on balancing the energy trilemma whilst emphasising energy transformation. The strategies outlined in this chapter are designed to support energy resilience in ASEAN by considering the capabilities of each of the ASEAN Member States (AMS).

Energy resilience is defined as the ability of an energy system to withstand and recover from high-impact events, as well as to minimise the duration, cost, and impact of outages on critical services. This chapter, supported by insights from various external experts, covers several topics that align with the APAEC programme areas.

4.1 Multilateral Power Trade

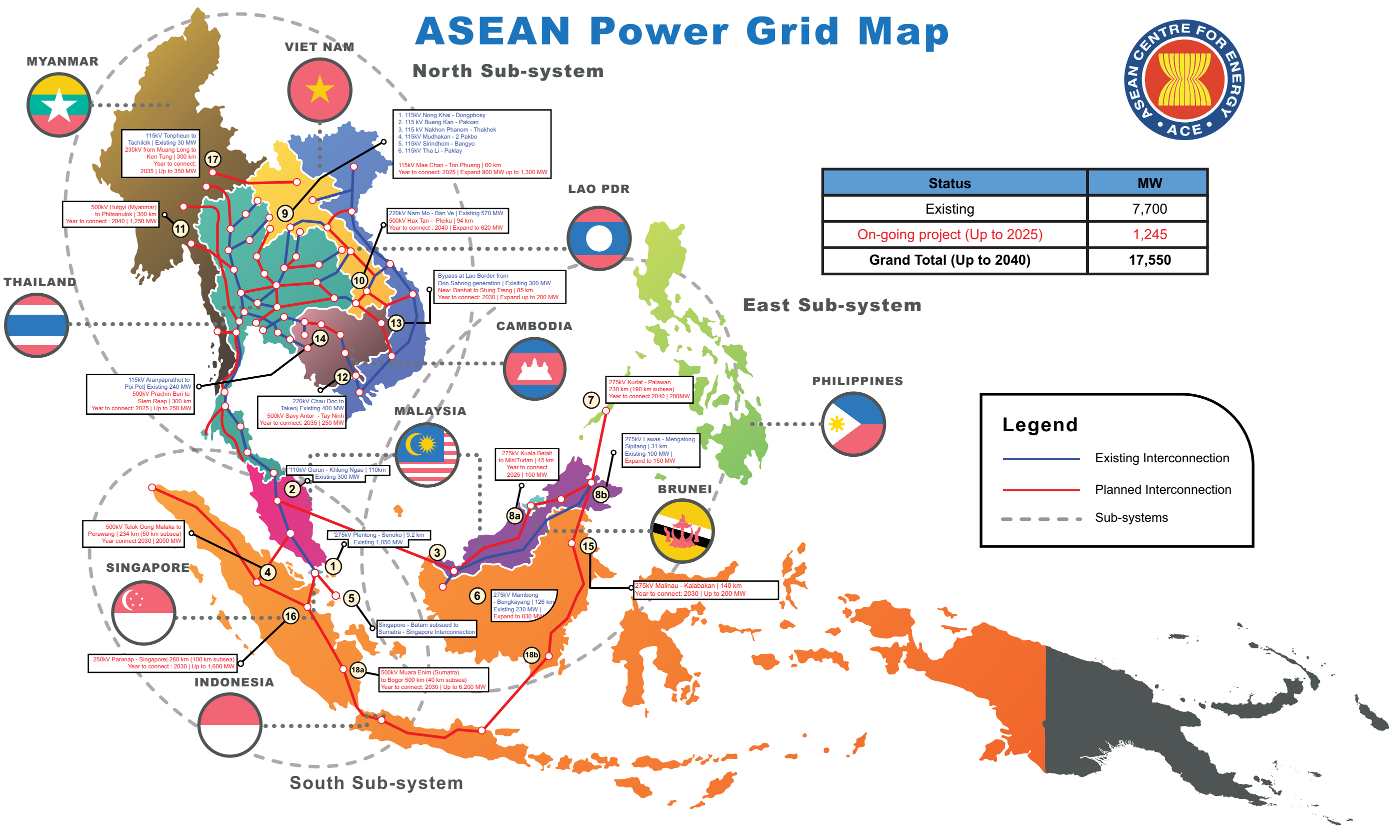
4.1.1 Background

The ASEAN Power Grid (APG) has been one of the key programme areas of the APAEC since 1999 [57]. The APG envisions energy integration through the development of infrastructures, markets, and institutions. This includes the construction of cross-border interconnections, the integration of electricity markets, harmonisation of regulations, and the establishment of regional institutions.

As shown in Figure 4.1, the APG is divided into three geographic areas: the North System (Cambodia, Lao PDR, Myanmar, Thailand, Vietnam), the South System (Indonesia, Malaysia, Singapore), and the East System (Brunei Darussalam, Indonesia, Malaysia, the Philippines).

The APG is expected to progress in three stages: starting with bilateral trade, followed by subregional trade, and finally into an integrated regional system.

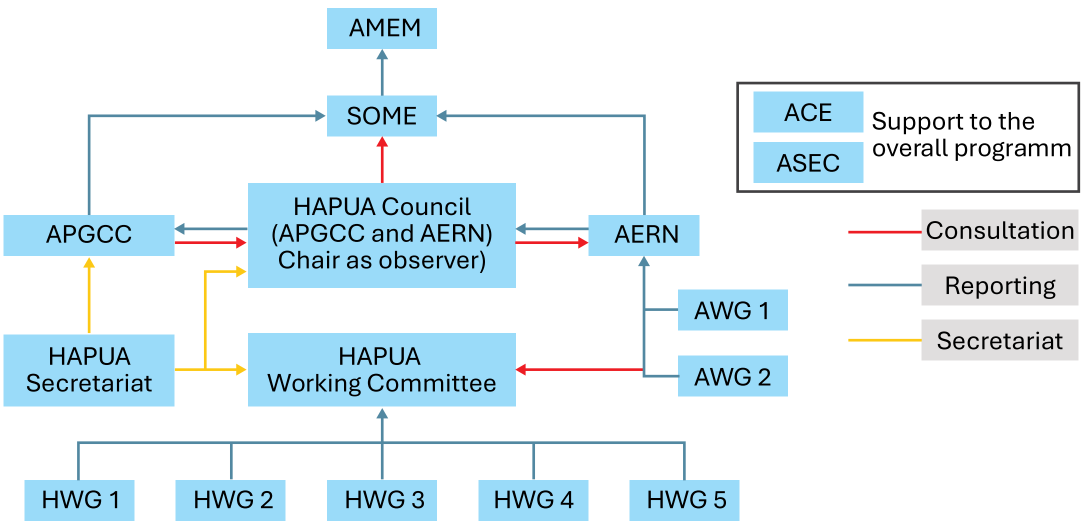
Figure 4.1 ASEAN Power Grid



The APG project is spearheaded by several regional energy groups and committees (Figure 4.2). The primary coordinator of the APG is the Heads of ASEAN Power Utilities and Authorities (HAPUA), which plays a crucial role in promoting the development of interconnections, enhancing private sector participation, and ensuring the reliability of electricity systems. HAPUA reports to the Senior Officials' Meeting on Energy (SOME) and is supported by the ASEAN Power Grid Consultative Committee (APGCC) and the ASEAN Energy Regulators Network (AERN).

As of now, nine out of the 18 key interconnection projects envisioned under the APG have been completed, resulting in a total installed regional electricity capacity of 7.7 GW, which includes 4.7 GW of dedicated Independent Power Producer (IPP) generation exports (generation to grid). Most of these interconnections are bilateral, with energy trade conducted through long-term power purchase agreements. Ongoing projects currently at various stages of implementation include subsea cables between the Indonesian island of Sumatra and Peninsular Malaysia, overland grids between Kalimantan and Sabah, and upgrades to the interconnections between Thailand and Malaysia.

Figure 4.2 ASEAN Power Grid Governance Structure



The completion of the APG will have significant benefits for energy security, decarbonisation costs, and emissions reductions. The ASEAN Interconnection Masterplan Study (AIMS) III Phases 1 and 2 demonstrate that cross-border interconnections will facilitate the utilisation of 62 VRE projects – 42 solar projects with a capacity of 8,119 GW and 20 wind projects with a capacity of 342 GW.

Regional interconnections will optimise energy systems, thereby reducing the need for 1.2 TWh of electrical storage, 16 TWh of hydrogen storage, and 600 GW of solar generation capacity by 2050. Overall, the APG is expected to reduce the economic cost of decarbonisation in Southeast Asia by USD 0.8 trillion, and the carbon footprint of the energy transition by 13% by 2050 [58].

The acceleration of the APG will require very high levels of political trust, increased levels of technical harmonisation and data sharing, and large infrastructure investments. Despite these challenges, there has been steady progress toward the realisation of several multilateral interconnection projects.

4.1.2 Contemporary Developments

The region's first multilateral power project, the Lao PDR-Thailand-Malaysia-Singapore Power Integration Project (LTMS-PIP) commenced operations in June 2022. The LTMS-PIP facilitates the import of up to 100 MW of hydroelectric power from Lao PDR to Singapore via Thailand and Malaysia, using existing interconnections. The project facilitated the trade of a total of 266 GWh of electricity as of February 2024 [59]. After the expiration of the initial agreement in June 2024, energy trade via the LTMS-PIP was expected to be increased to 300 MW, and the project timeline extended from two years to five years [58] [60].

The Brunei Darussalam-Indonesia-Malaysia-Philippines Power Integration Project (BIMP-PIP), announced at the 41st AMEM in August 2023, aims to build upon the experiences of the LTMS-PIP. The BIMP-PIP envisions as many as 17 interconnections between the four countries, and is expected to reduce the price of electricity as well as the use of fossil fuels [61]. USAID is currently supporting a USD 2 million feasibility study on the BIMP-PIP. Whilst the LTMS-PIP facilitates unidirectional energy trade using existing overland grids, the BIMP-PIP will foster a higher level of energy integration through the development of new overland and subsea cables that will enable bidirectional energy trade.

In addition to the BIMP-PIP, several bilateral interconnections that were not part of the original APG plan are now at various stages of discussion, including subsea cables between Singapore and Vietnam, Singapore and Cambodia, and overland interconnection between Lao PDR and Vietnam [62].

4.1.3 The Road Ahead

The successful implementation of proposed multilateral and bilateral interconnections will require the development of institutional, market, and technical capacities, which are expected to be reflected in the succeeding APG agreement, following the expiration of the current Memorandum of Understanding (MoU) in 2025. The ASEAN Framework Agreement for Power Trade, which is a key component of the upcoming APG MoU, is expected to facilitate the development of protocols on regional institutions, market development, and infrastructure planning. Several key considerations for these three groups of protocols are highlighted in the following sections.

Regional Institutions

A regional institution is essential for enhancing multilateral power trade in ASEAN. The LTMS-PIP Working Groups and Task Forces offer valuable insights into viable models for regional cooperation on specific projects. However, experiences with grid management in Europe and Southern Africa demonstrate the necessity of a regional institution for the development of long-term generation and transmission plans, as well as the coordination of technical issues such as the harmonisation of grid codes and other regulations—prerequisites for an integrated energy market.

For instance, the European Network of Transmission System Operators (ENTSO-E) facilitates cooperation between transmission system operators (TSOs) from 36 countries across Europe, ensuring the security and optimal functioning of the region's electricity markets, and accelerating the energy transition. ENTSO-E is responsible for implementing grid codes and standards, developing data-sharing platforms, and coordinating regional infrastructure planning.

Similarly, the Southern African Power Pool (SAPP) coordinates the planning and operation of electricity trade amongst 12 member countries, by sharing data, developing environmental guidelines, and advocating for energy integration. These examples underscore the importance of a regional institution in ASEAN to achieve similar levels of cooperation and integration.

Legislative mandates are important tools that allow regional institutions to fulfil their goals more effectively. For example, Regulation (EU) No. 5, 43/2013 requires energy stakeholders in Europe to provide data on electricity generation, transmission, and balancing, for publication on the ENTSO-E Transparency Platform. The ENTSO-E itself is mandated by a variety of legislation that guides its responsibilities for enhancing energy cooperation.

Note that binding legislation is not required for the development of regional institutions. The SAPP was formed through an Inter-Governmental MoU, which then led to multiple other MoUs and agreements on specific issues related to energy cooperation.

In the case of the APG, developing a regional institution based on binding mandates is necessary for driving energy integration with confidence, despite possible difficulties posed by political challenges. A regional energy institution based on legal mandates, rather than a non-binding agreement, will protect the interests of all AMS, and encourage investment and cooperation. The upcoming APG MoU should thus develop procedures to facilitate discussion between policymakers on developing binding legislation to assist the functions of a regional energy institution, based on international best practices. It should also direct resources and allocate frameworks for the development of a regional institution.

Market Development

Currently, only the electricity markets of the Philippines and Singapore have been liberalised, whereas state institutions in other ASEAN countries continue to monopolise much of the generation, transmission and distribution capacity. The LTMS-PIP demonstrates that multilateral energy projects can be undertaken despite market differences. However, enhancing multilateral power trade will require the reform of domestic electricity markets, including addressing the crucial issues of state subsidies, third-party access, and direct Power Purchase Agreements (PPAs). In the context of the APG, the creation of a regional energy market requires the mitigation of risks and challenges through the development of standardised wheeling charges and dispute resolution mechanisms, as well as maximising the opportunities in green finance such as Renewable Energy Certificate (REC) markets.

The development of a standard regional wheeling charge methodology is an important step in energy market integration. This is important for addressing the economic and energy security concerns of all parties involved in multilateral trading. The coordinating bodies of the APG, such as HAPUA and APGCC, can bring together multiple stakeholders in the energy sector to develop a regional wheeling charge methodology based upon international best practices, namely the four principles of: (1) promoting efficiency; (2) recovering costs; (3) ensuring transparency, fairness, and predictability; and (4) promoting non-discriminatory behaviour.

For example, the wheeling charge utilised by the SAPP is based on three considerations: (1) the proportion of the country's network capacity used (based on thermal rating); (2) the age of the assets and current replacement cost of the assets; and (3) allowances for the operational and maintenance costs of assets involved in wheeling [63].

A dispute resolution mechanism enhances investor confidence and facilitates the timely resolution of cross-border energy-related conflicts. Studies have pointed toward the importance of a dispute resolution mechanism for the smooth functioning of a regional market [63]. Traditionally, conflicts related to energy have been resolved through unofficial discussions between energy officials and mechanisms embedded in PPAs.

An important part of the upcoming APG MoU will be to direct resources toward developing a dispute resolution mechanism that includes the drafting of rules and procedures for facilitating negotiations, and provision of third-party mediation, conciliation, and good offices, as well as to identify legal processes for further escalation of intractable disputes. Dispute resolution mechanisms will boost investor confidence in new energy generation projects, including those in distribution and transmission systems.

A reference case is the Dispute Resolution and Negotiation Centre set up by the Energy Community (EC) in 2016 to address conflicts in the European energy market in a systematic and transparent manner.

In addition, RECs are becoming increasingly relevant in Southeast Asia's electricity markets, due to the growing demand by corporations for RE. All AMS except Myanmar have REC markets. In 2023, almost 12.5 million RECs were issued by solar and wind project owners in Southeast Asia, up from 7 million in 2022 [64].

In 2020, Thailand suggested the development of a regional REC market at the SOME, which was then included in the BIMP East ASEAN Growth Area (BIMP-EAGA) agenda at the 9th BIMP-EAGA Power and Energy Infrastructure Cluster (PEIC) Meeting in 2023. This endorsement provided an opportunity to develop a regional REC market, along with cross-border interconnection projects such as the BIMP-PIP.

A regional REC market can enhance investment in infrastructure, increase RE trade, and improve regional cooperation on energy transition. However, such an initiative is impeded by the absence of a set of unified guidelines, limited cross-border transactions, and shortfalls in meeting international standards. The upcoming APG MoU can direct energy stakeholders to develop common REC market rules and guidelines, and regional REC instruments, through research on international best practices.

Infrastructure Planning and Operations

The development of cross-border grids are complex, protracted projects, which require long-term energy plans and operational coordination. Three important requirements for infrastructure planning and operations are: (1) the sharing of accurate and reliable data; (2) the harmonisation of grid codes; and (3) the identification of priority projects.

Developing long-term plans for the commissioning of new physical infrastructure requires the sharing data on generation, transmission, distribution, demand, and system performance. Despite the current momentum towards interconnections, the sharing of accurate real-time data on energy demand and consumption remains a challenge. Timely energy data is shared by several AMS, though regional planning is impeded by the lack of uniform data, sensitivity attached to some types of data, and the absence of regional data-sharing guidelines and standards, as well as the high investment costs of setting up a data-sharing platform [65].

The lack of uniform and transparent data not only constrains planning and negotiations for interconnections, but also prevents state-owned and private utilities from recognising new market trends, enhancing risk management, and increasing revenues. The LTMS-PIP has developed a platform that shares data on sales, purchases, electricity wheeling, and system constraints.

Developing the APG will require a much higher level of data sharing and standardisation. ACE has proposed the development of "Data-Sharing Framework and Governance Guidelines" which aim to facilitate discussion on identifying the type, use and timeliness of data exchange in ASEAN. AMEM and SOME endorsement of this framework and subsequent implementation by national-level utilities and regulators will be crucial to developing a platform and procedures for data sharing.

Grid codes facilitate coordination among utilities, system operators, power producers, and consumers, ensuring that energy trade is conducted according to specific regulations and standards. Whilst countries in the region have made significant progress in updating their grid codes to align with international standards, several Southeast Asian nations have yet to fully address the challenges posed by RE and distributed systems [66].

At the regional level, harmonising grid codes is hindered by the lack of standardisation in national documents, procedures, and terminology. For instance, in Indonesia and Malaysia, grid codes vary between different systems and operators, which complicates regional harmonisation efforts [66]. Whilst some of these differences were addressed by the Task Forces of the LTMS-PIP, future projects like the BIMP-PIP are more complex and will demand a higher level of coordination across generation, transmission, distribution, and other sectors.

Accelerating the APG will therefore require the development of a regional grid code. The ASEAN Grid Code Committee could bring together officials from across the region to share best practices for harmonisation at both the national and regional levels. Additionally, there is a need to update grid codes to accommodate greater integration of RE into grids and the use of distributed generation. The Greater Mekong Subregion Regional Grid Code serves as an example of how diverse grid codes can be aligned to facilitate regional energy trade [63], [66].

Developing new infrastructure requires the collective prioritisation of key ‘backbone’ projects that can accelerate the energy integration process and facilitate the alignment of national infrastructure development with regional goals. Southeast Asia will need to invest as much as USD 200 billion into upgrading both domestic and regional energy infrastructure by 2030, to accelerate interconnections and energy transition.

Given the limited funding for infrastructure development, the AMS will need to prioritise the projects that will bear the greatest dividends in terms of energy integration and transition. This has already been achieved to some extent, through the identification of key projects within the AIMS III. Another international example is the EU’s Projects of Common Interest (PCI) initiative, which prioritises the implementation of projects that have a substantial impact on energy transition and interdependence.

An ASEAN Projects of Common Interest (APCI) categorisation for critical regional interconnections can encourage the pooling of financial resources for projects that could form the backbone of the APG. The first step in developing the APCI is consultations with energy stakeholders to develop criteria for inclusion, followed by collaborative research on the benefits and costs of particular interconnections. The APCI should be developed through an open and transparent process to increase its acceptance and impact, as well as generate interest from investors [63].

The technical feasibility of the 18 key interconnections of the APG has been substantiated in AIMS II and AIMS III, yet the implementation of cross-border projects is impeded by a number of political, economic, and technical issues. Despite these challenges, Southeast Asia has made considerable progress towards realisation of the APG, through the commissioning of the LTMS-PIP in 2022, and the announcement of the BIMP-PIP in 2023, which was accompanied by new plans for proposed bilateral subsea and overland projects.

The upcoming APG MoU will provide an opportunity for policymakers to generate consensus on the development of regional institutions, markets, and infrastructure planning. This can be done through protocols on creating a regional energy institution, underpinned by legislative mandates, the development of a harmonised wheeling charge methodology and dispute resolution mechanisms, the creation of a regional REC market, and collaboration on data sharing, grid harmonisation and prioritisation of backbone projects.

The new APG MoU can encourage collaborative approaches to address these policy priorities, thereby contributing to an integrated, energy-secured, and sustainable Southeast Asia.

Inclusive Transition

Integrating regional power grids entails complicated legal and socio-practical challenges as well as technical and administrative investments. These have long-term consequences and their social patterns are crucial to consider in the context of a just and inclusive energy transition. Equitable and fair regulation requires the multilateral build-up of technical, regulatory, and administrative expertise across all member states participating in integrated grids. It is also necessary to consider training standards as a means of building technical, administrative, and regulatory vocabulary and comparable skillsets. Staff mobility schemes and regional training schemes may allow such capacities to develop more evenly across AMS.

Regional integration may also generate counterintuitive situations wherein regions producing electricity may end up lacking electricity themselves - underserved in favor of distant metropolitan centers that have higher purchasing power. The long-term social viability of grid integration necessitates consideration of how to protect rural and marginal populations from electrical instability and under-prioritization compared to national centers. Politically and economically including rural communities and ethnic minorities in the benefits and strategic processes of grid integration and renewable expansion will be crucial to ensuring a just and inclusive transition.

Special consideration may be necessary for border-dwelling communities. These communities are often split across two or more AMS. Further, the land holdings of these communities are likely to be important real estate for integrative grid infrastructure. Finding cooperative frameworks with these communities and the involved AMS will likely be necessary. Aligning policies regionally may serve to provide transparency and standards for how to justly include and compensate border communities.

4.2 ASEAN Gas Infrastructure

The integration of the ASEAN gas market is a key element in the region's broader energy strategy, especially as Southeast Asia faces the dual challenges of meeting rising energy demand and transitioning towards more sustainable energy systems. Natural gas occupies a central role in this context, often referred to as a "bridge fuel" due to its ability to support the transition from high-emission fossil fuels like coal, to cleaner energy sources [67].

This is particularly relevant given the global push to accelerate energy transition and reduce greenhouse gas (GHG) emissions. Natural gas offers a combination of lower GHG emissions relative to coal and oil, fewer non-carbon air pollutants, and a high degree of operational flexibility, making it indispensable in the short- to mid-term energy mix of ASEAN countries [68].

One of the significant benefits of natural gas is its ability to complement the intermittent nature of renewable energy sources like solar and wind. Unlike coal or nuclear power plants, natural gas-fired power plants, particularly peaking combustion turbines, can swiftly ramp production up or down — within less than an hour—allowing them to adjust to fluctuations in both demand and supply. This dynamic ramping ability makes natural gas a critical enabler for integrating renewables into the grid [69].

For example, Thailand, which heavily relies on natural gas for electricity generation, has successfully integrated utility-scale solar power into its energy system, thanks to the flexibility provided by its natural gas infrastructure [70]. Similarly, Brunei Darussalam and Singapore, also reliant on natural gas, are poised to invest in offshore wind power generation, bolstered by their existing gas infrastructure [69]. This adaptability not only supports current energy needs, but also lays the groundwork for future transitions to fully RE systems.

The existing infrastructure for natural gas, including storage, transportation, and distribution networks, can also be repurposed to facilitate the integration of renewable gaseous fuels like biogas, further enhancing the region's energy resilience and sustainability [71].

The increasing demand for natural gas in ASEAN is accompanied by a growing dependence on imports. In 2020, natural gas imports accounted for 21.6% of the total gas-based primary supply in the region, a significant rise from 13.8% in 2005 [37]. This trend, whilst necessary to meet the region's energy needs, poses potential risks to energy security, particularly in times of global crises such as pandemics, geopolitical conflicts, and economic downturns. The region's reliance on imports could make it vulnerable to supply disruptions and price volatility in the global gas market.

Despite the growth in demand, natural gas's share of ASEAN's installed power capacity has declined from 47% in 2005, to 30% in 2020, reflecting a broader shift towards coal, which now holds the largest share. Nevertheless, natural gas remains a critical component of the region's energy mix, with a narrow gap of just 2% between coal (32%) and natural gas (30%) in the installed capacity, as of 2020 [37]. This underscores the continued importance of natural gas, particularly in countries like Indonesia, Malaysia, and Thailand, which are amongst the top producers of natural gas in Southeast Asia. Notable production fields in the region include: Tangguh in West Papua, Indonesia; Block A-18 in the Malaysia-Thailand Joint Development Area; and the Corridor PSC in South Sumatra, Indonesia [72]. These fields significantly contribute to the region's gas supply, but they may be insufficient to meet future demand [37].

Table 4.1 Ten Largest Natural Gas-Producing Fields in Southeast Asia as of 2022

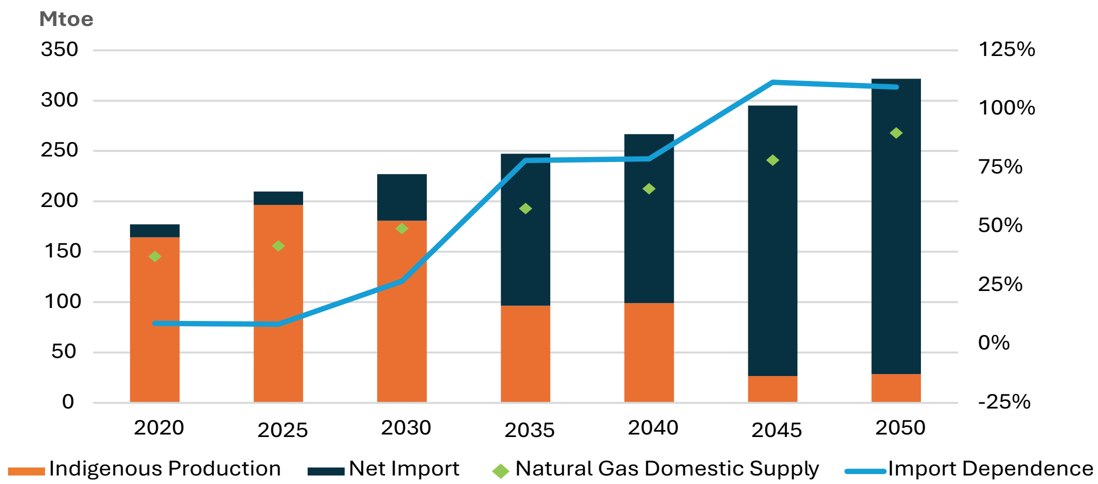
Gas Field's Name	Location	Total Production (mmcfd)	Recoverable Natural Gas Reserves (%)
Tangguh	West Papua, Indonesia	1,149.75	25.39
Block A-18	Gulf of Thailand, Malaysia – Thailand Joint Development Area	978.55	52.99
Corridor PSC	South Sumatera, Indonesia	860	44.73
Mahakam PSC	East Kalimantan, Indonesia	717.3	94.63
Yadana Project	Gulf or Martaban, Myanmar	717	69.79
MLNG PSC	Sarawak, Malaysia	611.03	94.78
Shwe Complex	Bay of Bengal, Myanmar	608	43.29
Bongkot	Gulf of Thailand, Thailand	539.5	72.45
Bongkot South	Gulf of Thailand, Thailand	437.06	45.25
Kebabangan Cluster	Sabah, Malaysia	414	31.33

Source: Global Data's Upstream Fields database as referred to by Offshore Technology [72]

[8] All the quantities of gas that are considered technically feasible and economically viable to extract from a field.

Looking ahead, the ASEAN region is expected to see a substantial increase in natural gas demand. According to the RAS, demand is projected to rise by 8% by 2030, and by 34% by 2050, as compared to 2022 levels. This growth will be particularly pronounced in Indonesia and Malaysia, where annual demand is expected to increase by 4.5% and 5.2%, respectively. By 2050, natural gas is anticipated to account for more than one-fifth (22%) of the total energy demand in Southeast Asia. Despite this rising demand, the region's domestic production is expected to decline, leading to an increased reliance on imports. By 2025, it is projected that domestic supply and imports will be at parity, after which ASEAN is expected to become a net importer of natural gas. This shift is particularly significant for countries like Singapore, which already meets its entire natural gas demand through imports, and for Thailand, where declining indigenous production is expected to increase import dependency. Similarly, Malaysia and Indonesia, which are currently net exporters, are projected to become net importers by the 2030s and 2040s, respectively, as their domestic production falls short of national demand.

Figure 4.3 Natural Gas Domestic Supply and Import Dependence in ASEAN



Without significant discoveries or expansions of existing production infrastructure, the region's growing reliance on imports could pose challenges for energy security. This situation is further complicated by the expected rate of fossil fuel utilisation, which if maintained, will see ASEAN's natural gas supply increasingly dominated by imports. By 2050, installed power capacity in the region is projected to reach 959 GW, with natural gas making up 26.1% of the mix, second only to coal. Under the ATS, natural gas is expected to comprise 25.3% of the power mix, closely following hydropower at 27.9% [37]. These projections highlight the critical role that natural gas will continue to play in the region's energy future, even as ASEAN seeks to balance its growing energy needs with the imperative of reducing carbon emissions and enhancing energy security.

4.2.1 Domestic Gas Infrastructure of Each ASEAN Member State

The domestic gas infrastructure across the AMS reflects the varying degrees of natural gas development, usage, and dependency, with each nation having unique challenges and opportunities. This section provides an overview of the current infrastructure, outlining the production capabilities, existing facilities, and plans of each of the AMS.

Brunei Darussalam

Beginning with an AMS where 90% of its economy is accounted for by oil and gas, Brunei Darussalam's natural gas sector is primarily concentrated around its offshore fields, particularly the Southwest Ampa and Champion Fields. In these areas, gas is often produced in conjunction with oil extraction.

The gas from these fields is processed at the liquefaction terminal in Lumut, which has a capacity of 9.8 billion cubic meters per year (bcm/y). This terminal is a critical component of Brunei Darussalam's energy exports, with LNG traditionally being shipped to major markets in Japan and South Korea. The infrastructure is well-established, supporting Brunei Darussalam's position as a key LNG supplier in the region [73], [74].

Cambodia

Cambodia's natural gas infrastructure is still in its infancy. The country's gas consumption was almost non-existent until January 2020, when Cambodia received its first LNG imports via small-scale tanks from China's CNOOC, marking the start of a nascent gas market. This small-scale LNG supply, benchmarked to the domestic price of Chinese LNG transported by trucks, was one of CNOOC's first ventures outside of China and was part of the Belt and Road Initiative (BRI).

Despite plans to build a floating storage and regasification unit (FSRU) and a domestic pipeline network, these projects have been delayed, largely due to the COVID-19 pandemic. Cambodia's LNG strategy is intertwined with its plans for a gas-fired power plant, which remains stalled. Future infrastructure development is expected to focus on the Phnom Penh and Preah Sihanouk provinces, where LNG is initially targeted for use in hotels and restaurants, before expanding to industrial and power sectors [75].

Indonesia

Indonesia boasts a diverse and expansive gas infrastructure, reflecting its position as one of Southeast Asia's largest gas producers. Whilst historical gas fields are nearing depletion, new projects such as Eni's Jangkrik (2017) and Merakes (2021) Fields have been launched. Additionally, significant opportunities for future gas production are presented by the Saka Kemang Field by Repsol in South Sumatra and potential resources in East Natuna.

Indonesia is globally recognised as a major LNG exporter, with key markets including Japan, South Korea, Taiwan, and more recently, China. Unique to Indonesia is its use of LNG for domestic transport, moving gas from production regions in Central-Eastern islands like Sulawesi, Kalimantan, and New Guinea to consumption hubs in Java and Bali.

Recent developments, such as the Tangguh Train 3 and Abadi LNG, inaugurated in November 2023, further demonstrate Indonesia's commitment to bolstering domestic gas infrastructure as part of its National Strategic Plan. Future plans include exploring small-scale LNG in remote areas and enhancing energy access across the archipelago.

Lao PDR

Distinct from other AMS, Lao PDR currently does not have any domestic natural gas infrastructure, reflecting its limited involvement in the gas sector [76]. The country relies on other energy sources and has not yet developed significant infrastructure for natural gas production, importation, or consumption.

Malaysia

Malaysia is a significant player in the regional gas market, with its production largely based offshore Sarawak, feeding the Bintulu Liquefaction Terminal with a capacity of 30 bcm/y. Despite being a net gas exporter, Malaysia imports small quantities of gas, primarily via pipelines from Indonesia, and as LNG from Brunei Darussalam and Australia.

Malaysia's gas infrastructure includes two regasification terminals at Lekas and Pengerang, integrated with downstream petrochemical and refining activities. Like Indonesia, Malaysia uses LNG to transport gas within the country, particularly from Borneo to Peninsular Malaysia. The country also has international pipeline connections to Thailand, Singapore, and Indonesia. In addition to the Bintulu Terminal, Malaysia operates a floating liquefaction facility and plans to establish another nearshore facility in Sabah, tied to significant investments. These developments aim to enhance Malaysia's role as a key gas hub in Southeast Asia [75].

Myanmar

Myanmar has been an important gas producer since the 1990s, with offshore fields such as Yadana and Yetagun historically contributing to its output. More recently, production has been bolstered by the Shwe and Zawtika Fields.

Myanmar exports two-thirds of its gas, primarily to Thailand, with China also receiving piped gas since 2014. Despite significant exports, Myanmar's domestic infrastructure has faced challenges, including the deterioration of the North-South pipeline. The country's 2017 Natural Gas Master Plan envisioned the development of four LNG terminals, yet progress has been slow. However, the urgency for LNG imports grew following widespread power cuts in 2019, leading to the importation of LNG in 2020 to support new gas-fired power plants.

Looking forward, pipeline exports are expected to continue until 2025, with LNG imports anticipated to rise to 5 to 10 bcm/y by 2030, necessitating the construction of additional terminals and FSRUs. Multilateral organisations and foreign companies are exploring these opportunities, with China actively participating through the Belt and Road Initiative [77], [78].

The Philippines

The Philippines' gas infrastructure is mostly concentrated around Batangas, where all gas-fired power plants are located near landfall of the pipeline from the Malampaya Field. Despite plans for an extensive pipeline network, including the Batangas-to-Manila (BatMan) pipeline, these projects have yet to materialise.

Recently, two LNG projects are soon expected to start commercial operation: one by Linseed Field Corp. in Ilijan, Batangas; and another by FGEN LNG Corp. in Batangas Bay. These developments mark a significant step forward for the Philippines, aiming to enhance its energy security and diversify its energy mix [75].

Singapore

Singapore imports pipeline gas from Malaysia and Indonesia, and LNG via the Singapore LNG (SLNG) terminal. The SLNG terminal, supported by imports mainly from Australia, also positions Singapore as a key LNG trading and bunkering hub in Asia.

To further bolster energy security, Singapore is developing a Second LNG Terminal, exploring a Floating Storage and Regasification Unit (FSRU) concept, expected to be operational by the end of the decade. This terminal will connect to Singapore's gas pipeline grid, further strengthening the nation's energy infrastructure [75].

Thailand

Thailand's gas infrastructure is extensive, with most production occurring offshore in the Gulf of Thailand, within the Joint Development Area shared with Malaysia. The country has diversified its gas imports by bringing in piped gas from Myanmar and LNG from countries such as Qatar, Nigeria, and Malaysia. The national gas pipeline system connects these offshore fields to power plants, gas separation plants, and industrial users.

In 2021, Thailand imported 9.2 bcm of LNG, with the largest volumes coming from Qatar. Thailand's first LNG regasification terminal, Map Ta Phut, began operations in 2011, and has a current capacity of 11.5 million tonnes per annum (Mtpa). The development of the second terminal at Nong Fab was completed and began operations in 2022. These facilities underscore Thailand's commitment to securing and diversifying its energy sources [75].

Vietnam

Vietnam is steadily developing its natural gas infrastructure, with three LNG terminals currently under construction. The Cai Mep Terminal, operated by AG&P LNG in partnership with Hai Linh Company Limited, commenced commissioning in May 2024. The Thi Vai Terminal began operations in October 2023, receiving its first cargo in July 2023. Another terminal in Northern Vietnam, owned by ExxonMobil, is set to significantly bolster the country's LNG capacity, supporting a 4,500 MW power plant.

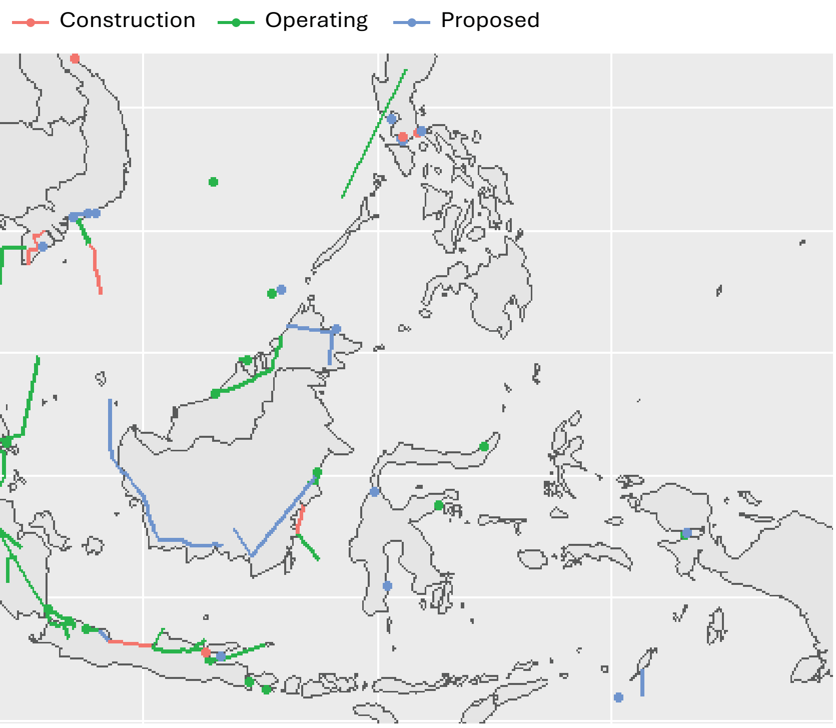
Vietnam's domestic gas production is also poised for expansion, with ongoing projects in the Su Tu Trang field and new developments in the Ca Voi Xanh and Block B fields. Additionally, a significant gas discovery in the northern Block 114, announced by Eni in mid-2020, promises future production, further integrating Vietnam into the regional gas market [75].

4.2.2 Gas Pipeline Across Southeast Asia

The Trans-ASEAN Gas Pipeline (TAGP) represents a strategic initiative to bolster energy security and accessibility within Southeast Asia. It is designed to enhance regional connectivity through an integrated network of gas pipelines and regasification terminals. Spearheaded by the ASEAN Council on Petroleum (ASCOPE), the TAGP Project aims to create a seamless energy grid across the ASEAN region, fostering greater cooperation and interdependence amongst member states.

Central to this initiative is the development of multiple physical pipeline interconnections and regasification terminals (RGTs). The latter facilities are crucial for converting LNG back into its gaseous state for distribution and consumption. By 2018, ASEAN had successfully commissioned 13 bilateral gas pipeline interconnection projects, stretching approximately 3,631 km in total. These pipelines connect six of the AMS—Singapore, Malaysia, Myanmar, Thailand, Vietnam, and Indonesia—demonstrating the region's significant progress in establishing a robust and interconnected gas network [68]. These interconnections not only facilitate the efficient transfer of natural gas across borders, but also reinforce energy security by ensuring a more stable and reliable supply of gas within the region. The challenges posed by global gas developments, such as those associated with the East Natuna Gas Field, have prompted a strategic shift in focus. Recognising the limitations of pipeline infrastructure

Figure 4.4 ASEAN's Gas Pipelines



Data Source: Asia Gas Tracker, Global Energy Market (GEM) [79] alone, the TAGP initiative is expanding its scope to increasingly incorporate LNG as a key component of the region's gas supply strategy. This shift reflects the evolving dynamics of the global energy market and ASEAN's proactive approach to adapting to these changes, ensuring that the region remains well-equipped to meet its future energy needs.

4.2.3 Liquefied Natural Gas Terminals Across Southeast Asia

Southeast Asia's LNG infrastructure is an essential component of the region's energy landscape, with a wide array of operational and proposed projects across various countries. These terminals are critical for meeting the growing energy demands, enhancing energy security, and supporting economic growth:

Currently, the region boasts a total regasification capacity of 57.8 Mtpa, spread across 14 terminals. This substantial capacity emphasises ASEAN's commitment to diversifying its energy sources and enhancing its infrastructure to meet rising energy demands. What follows is an elaboration of the data on LNG terminals throughout the region, according to the ASEAN Oil & Gas Updates 2023.

Brunei Darussalam is home to the Brunei LNG Terminal, one of the oldest in the region, having been operational since the early 1970s. This facility, with a capacity of 7.4 Mtpa, is operated by the Government of Brunei Darussalam in partnership with Mitsubishi and Shell. Its longevity and capacity highlight Brunei Darussalam's established role in the global LNG market.

Indonesia has emerged as a key player in the LNG market, with multiple operational and proposed terminals. The Arun LNG Import Terminal in Aceh, operated by Pertamina and the Government of Aceh, has been in operation since 2015, with a capacity of 3 Mtpa. Another significant facility is the Teluk Lamong LNG Terminal, operated since its commissioning in 2019 by PT Pelindo and PT PGN, with a capacity of 0.3 Mtpa. The Bontang LNG Terminal stands out with an impressive capacity of 11.85 Mtpa, making it one of the largest in the region. It has been in operation since 1990, with expansions completed in 1998, and is operated by a consortium that includes Pertamina, JILCO, BP, Eni, and TotalEnergies.

Other notable terminals include the Donggi Senoro LNG Terminal, operated since 2015 by Mitsubishi, Pertamina, KOGAS, and MedcoEnergi, with a capacity of 2 Mtpa, as well as the Tangguh LNG Terminal, with a capacity of 11.4 Mtpa. The Tangguh terminal, operated by a consortium led by BP, has been operational since 2009, with an expansion completed in 2020. The Hua Xiang-Zaynep Sultan LNG Terminal in North Sulawesi, a smaller facility with a capacity of 0.1 Mtpa, has been operational since 2020 by Karadeniz Holdings.

Several proposed projects in Indonesia also hold significant potential. The Sengkang LNG Terminal, proposed by Energy World, and the Palu LNG Terminal, proposed by the Government of Central Sulawesi and LNG Alliance, are notable, though specific capacity and start year details are not yet available. The Abadi LNG Terminal, a major project proposed by INPEX, Pertamina, and Petronas, aims to bring a substantial capacity of 9.5 Mtpa online by 2030.

Table 4.2 Completed LNG Terminals in Southeast Asia

Countries	Capacity (Mtpa)
Indonesia	10.3
Malaysia	7.3
Myanmar	0.9
Philippines	8.26
Singapore	11
Thailand	19
Vietnam	1
Total Capacity	57.76

Data Source: ASCOPE

Table 4.3 Under Development LNG Terminals in Southeast Asia

Countries	Capacity (Mtpa)	Start Date
Philippines	10.72	2025, 2026, 2028
Singapore	5	By 2030 (TBC)
Thailand	10.8	2028
Vietnam	6.6	Sep 2024 & after 2026
Malaysia	2	2026

Data Source: ASCOPE

Malaysia has a robust LNG infrastructure. The **Pangerang Johor LNG Terminal**, which began operations in 2017, is operated by Petronas, Dialog Group Berhad, and the Government of Johor, with a capacity of 3.5 Mtpa. Additionally, Malaysia has several other key terminals, including the **Malaysia LNG Terminal**, operational since 2016 with a capacity of 3.6 Mtpa, and the **Tiga Malaysia LNG Terminal**, which began operations in 2003 with a capacity of 7.2 Mtpa. Both of these terminals are operated by Petronas in collaboration with various partners, including ENEOS Holdings, PTT, and Mitsubishi.

In **Myanmar**, the **Thilawa LNG Terminal** is a proposed project expected to start operations by 2026. This terminal is a collaboration between Eden Group, Marubeni Corporation, Mitsui Group, and Sumitomo Corporation, though its capacity details are still under discussion.

The LNG sector is rapidly developing In the **Philippines**, with a mix of operational, under-construction, and proposed projects. The **Philippines LNG Terminal**, operated by **Linseed Field Corporation**, is currently under testing and commissioning with a capacity of 3 MTPA. Similarly, the **FGEN Interim Floating Storage and Regasification Unit (FSRU) LNG Terminal**, is expected to start commercial operation by October 2024 and can provide 5.26 MTPA of capacity. Additional proposed LNG projects include those by **Energy World Gas Operations Philippines** in Quezon Province, **Luzon LNG Terminal** Inc. and **Shell Energy Philippines, Inc.**, both in Batangas, and **Samat LNG Corporation** in Bataan.

Singapore plays an important role in the regional LNG market with its **Singapore LNG Terminal**, which has a total capacity of 11 Mtpa. This facility, operated by Singapore LNG Corporation, has been expanded in stages, with phases completed in 2013, 2014, and 2018. Singapore's strategic position and advanced infrastructure make it a key LNG trading hub in Southeast Asia.

Thailand continues to enhance its LNG infrastructure with the **Map Ta Phut LNG Terminal 1**, which has been operational since 2011 and expanded in 2019, boasting a capacity of 11.5 Mtpa. The **Map Ta Phut LNG Terminal 2**, operational since 2022, adds another 7.5 Mtpa. Both terminals are operated by PTT, Thailand's state-owned oil and gas company. The **Gulf MTP LNG Terminal**, a proposed project by Gulf Energy Development and PTT, is expected to add another 10.8 Mtpa by 2025.

Vietnam is also expanding its LNG infrastructure, with several projects in various stages of development. The **Thi Vai LNG Terminal**, operated by PetroVietnam, has been operational since 2022 with a capacity of 1 Mtpa. The terminal's second unit, expected to add another 3 Mtpa, is proposed to start operations by 2023. Other significant projects include the **Hai Lang LNG Terminal**, under construction and expected to begin operations by 2026 with a capacity of 1.5 Mtpa, and the **Son My LNG Terminal**, a proposed project by AES Corporation and PetroVietnam, expected to add 3.6 Mtpa by 2026. The **Bac Lieu LNG Terminal**, proposed by Delta Offshore Energy, is also slated for a 2023 start, contributing an additional 2 Mtpa to Vietnam's LNG capacity. Another proposed project, the **Thanh Hóa LNG Terminal**, is being developed by Gulf Energy Development Public Company Limited, though specific capacity details are not yet available.

These LNG terminals, both operational and proposed, highlight the significant investments Southeast Asian countries are making in their energy infrastructure. This expansion is crucial for meeting the growing energy demands, ensuring energy security, and supporting the region's economic development.

4.2.4 Natural Gas Trade Flow

Course of Natural Gas Imports

The total global imports of natural gas amount to 45.8 Mtpa, with non-ASEAN countries contributing a substantial 40.8 Mtpa, whilst ASEAN countries account for 4.7 Mtpa. This highlights a clear dominance of non-ASEAN nations in the global natural gas trade, reflecting their significant roles in the global energy market.

China and Japan have emerged as the two largest importers of natural gas. China, with an impressive 7.6 Mtpa, leads the global importers, highlighting its immense energy requirements driven by its large population and industrial base. Japan follows with 10.8 Mtpa, indicating its reliance on imported natural gas to meet its energy needs, particularly in light of its limited domestic fossil fuel resources.

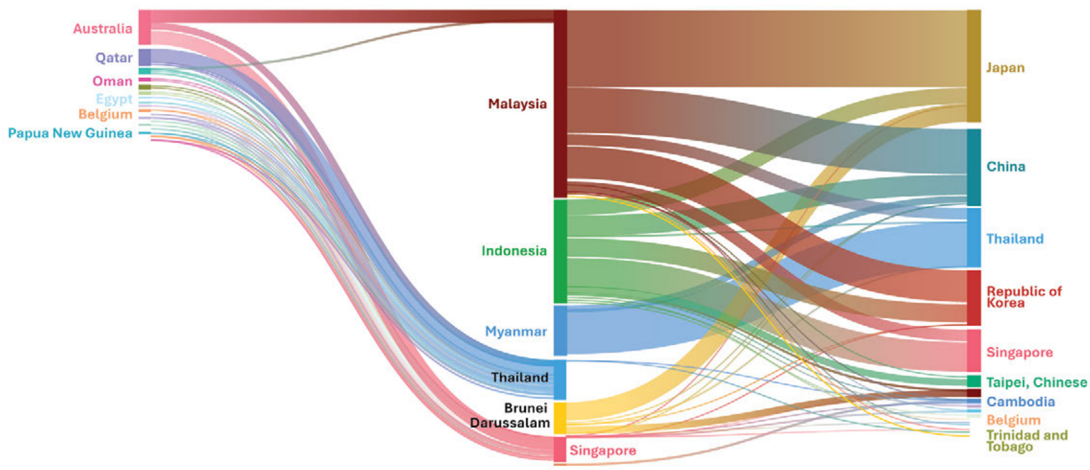
Within the ASEAN group, the largest importers are Thailand and Singapore. Thailand imports 4.7 Mtpa, which includes substantial volumes from various sources, reflecting its strategic position as a major regional player in natural gas. Singapore also shows a significant import volume of 4 Mtpa, emphasising its role as a key hub for natural gas trade in Southeast Asia. Conversely, other ASEAN countries, such as Malaysia, Myanmar, and the Philippines, have relatively lower import volumes but still contribute to the regional total.

Non-ASEAN countries, particularly those in the Middle East and Africa, show significant contributions to the global natural gas trade. For instance, Qatar and Russia are notable for their substantial exports, though their import figures are not detailed in the provided data. Countries like Kuwait, with 67,784 tpa, and Angola, not specifically detailed, play crucial roles in supplying natural gas to various regions, including ASEAN countries.

The high import volumes in China and Japan indicate their strategic need to secure energy supplies from diverse sources to ensure energy security and stability. Meanwhile, ASEAN's role as a significant import hub underlines the region's growing energy needs and the increasing importance of energy trade within Asia. The concentration of imports in specific countries also highlights the influence of energy policies and market dynamics in shaping global trade patterns.

Whilst major exporters such as Australia and the United States are not prominent in the import data, their roles as suppliers to various regions, including ASEAN, are critical. The data points to a relatively lower import volume from countries like Mozambique and Croatia, suggesting a more niche role in the global natural gas market. The sparse import data from some countries could indicate either limited trade activity or the presence of more specialised trade agreements.

Figure 4.5 LNG Trade Flow, 2023



Data Source: ASEAN Oil & Gas Updates 2023 [5]

Natural Gas Exports

Total global natural gas exports amount to 21.6 Mtpa. According to the data, non-ASEAN countries are the predominant exporters, contributing 20 Mtpa, whilst the AMS collectively export 1.4 Mtpa units. Australia stands out as a major exporter with a total of 2.7 Mtpa, making it one of the largest suppliers in the global market. Its significant export figures reflect its extensive natural gas resources and its role as a key player in the Asia-Pacific energy sector. Qatar is another major exporter with substantial volumes, totalling 4.1 Mtpa. This positions Qatar as a leading supplier, particularly to regions with high energy needs.

Among ASEAN countries, Brunei Darussalam is a notable exporter with 2.3 Mtpa, demonstrating its importance in the regional and global natural gas market. Malaysia also contributes significantly with 2 Mtpa. This showcases the ASEAN region's role as a crucial supplier in the natural gas trade, despite its lower total export volume compared to major non-ASEAN exporters.

Non-ASEAN countries, including major exporters such as the United States, Russia, and various Middle Eastern countries, dominate global natural gas exports. The United States, with exports totalling 1.6 Mtpa, and Russia, with 69,487 Mtpa, showcase their roles in global supply chains, though their contributions are relatively smaller compared to leading exporters like Australia and Qatar. Additionally, countries like Trinidad and Tobago, and Mozambique play important roles, with exports of 313,353 tpa and 574,327 tpa, respectively.

Non-ASEAN countries primarily serve as major exporters to regions like ASEAN and beyond. The AMS, whilst significant in their own right, export comparatively less and primarily serve regional markets. For example, Malaysia's and Brunei Darussalam's exports contribute substantially to ASEAN's total exports, illustrating the region's reliance on its members for natural gas supplies.

Several countries, such as Equatorial Guinea and Mozambique, emerged as specialised exporters. Equatorial Guinea, with 196,683 tpa, and Mozambique, with 574,327 tpa, highlight the diverse sources of natural gas in the global market. Their contributions, whilst smaller in comparison to giants like Qatar and Australia, are still crucial for balancing the global energy supply.

The cited data emphasises the strategic importance of natural gas exports in global energy markets. Non-ASEAN countries, particularly those with vast natural resources and advanced extraction technologies, play a pivotal role in meeting global energy demands.

ASEAN countries, whilst important, have a more regional focus, with their export figures reflecting their roles in supporting energy needs within their geographic vicinity.

4.2.5 Gas Market Integration Recommendation

With surging natural gas imports for the region as soon as 2027, an unexpected supply disruption could threaten the AMS gas supply. In this regard, an integrated gas market may improve the region's natural gas supply security, as it fosters interconnection networks, and competition expands the gas pool, lowering business costs, and enhancing resource allocation efficiency – an advantage that the bilateral approach does not offer.

A comprehensive approach to establishing an integrated gas market within ASEAN is essential in addressing economic, regulatory, and infrastructural aspects. The initial step involves crafting an economic framework tailored to the diverse conditions of each member state. This framework should include defining the most effective gas market structure, with regard to each country's unique economic and environmental circumstances.

Policies must be formulated to guide infrastructure development, including the construction and maintenance of pipelines and other critical facilities. Additionally, each nation should develop country-specific pricing policies that align with regional integration goals, whilst efforts to integrate domestic markets internally should focus on aligning regulations and practices across borders.

Encouraging competition through deregulation is crucial to drive market efficiency and innovation, and a well-defined timetable for sector reforms should be established to facilitate the transition toward a more integrated regional market.

Nevertheless, several significant challenges impede the development of a unified gas market in ASEAN. A major issue is the variation in natural gas prices, which is influenced by the complex infrastructure required for its transportation. Unlike crude oil, which benefits from a more integrated global market, natural gas markets remain fragmented, resulting in regional price discrepancies. For example, the recent geopolitical crisis starkly illustrated this fragmentation. Whilst European gas prices soared due to disrupted pipeline supplies; US prices remained comparatively stable due to its separate market dynamics.

The technological and logistical requirements for LNG further complicate market integration. Natural gas must be converted into a liquid form to facilitate transport, which involves substantial investment in specialised facilities. The fixed capacity of LNG export and import infrastructure, combined with the high costs associated with constructing and operating these facilities, can lead to regional price fluctuations and present barriers to market integration.

In Southeast Asia, several specific obstacles must be addressed to create a unified gas market. The high capital requirements for developing gas pipelines and LNG terminals pose significant challenges, particularly in a region where investment often prioritises immediate domestic needs. Additionally, ensuring that infrastructure development benefits all areas, including rural and low-income communities, adds complexity to the integration process.

Securing financing for new LNG terminals presents its own set of challenges. These projects typically require long-term sales contracts to obtain bank financing, with construction costs ranging from USD 10 billion to USD 15 billion, and completion times of two to four years. Without long-term contracts, financing becomes more difficult, and some projects may never come to fruition.

To address these challenges, a strategic approach focusing on enhancing regional cooperation and infrastructure development is essential. The TAGP initiative offers a promising solution to several of these issues. By expanding and optimising the TAGP network, ASEAN can improve cross-border gas flows, mitigate regional price disparities, and support a more integrated market.

Strengthening this network will also promote greater competition and reduce reliance on individual national infrastructures, facilitating a more cohesive regional market. Recommendations to tackle the challenges include [80]:

Update the TAGP Masterplan
The TAGP Masterplan, initially developed and approved in 2001, was a pioneering effort in laying the groundwork for the long-term development of a regional energy network. However, the energy landscape in ASEAN has experienced substantial changes since then, driven by rapid technological advancements, shifting geopolitical dynamics, market fluctuations, and evolving energy policies. These changes have introduced new challenges and opportunities that necessitate a comprehensive reassessment of the natural gas sector. To address these evolving needs, it is imperative to update the TAGP Masterplan. This updated plan should incorporate a thorough evaluation of current trends, future scenarios, and emerging issues in the ASEAN gas market. By doing so, it will provide a more accurate and relevant framework to guide the development of a cohesive and integrated regional gas market.

Address Key Issues Impeding Market Integration
One of the primary challenges hindering the realisation of a common gas market in ASEAN is the lack of detailed information on potential gas infrastructure projects and the broader regional gas landscape. To address this, there is a need for a more granular analysis of various factors including trends and future scenarios in the gas sector, available gas development options, and strategies for market integration. This includes a comprehensive outlook on supply and demand, infrastructure and strategic planning requirements, political and regulatory frameworks, gas pricing mechanisms, third-party access (TPA), and financial mechanisms. By systematically addressing these issues, ASEAN can better identify and overcome the barriers to market integration and develop more effective strategies to synchronise the regional gas market.
Revise Traditional Commercial Structures
Existing commercial structures associated with Power Purchase Agreements (PPAs), Production Sharing Agreements (PSAs), and LNG procurement contracts often include rigid take-or-pay clauses that limit the flexibility of gas markets. These traditional arrangements may restrict the ability of investors to fully capitalise on the benefits of natural gas, such as enhanced energy security and lower emissions compared to coal-fired generation. To address this limitation, it is crucial to revisit and revise these commercial structures to allow for greater flexibility and adaptability. This could involve negotiating more dynamic contract terms that better align with the evolving needs and opportunities within the natural gas market, thereby maximising the potential benefits of gas.
Enhance Cross-Border Collaboration Through MoU Refinements
With the current Memorandum of Understanding (MOU) on TAGP expiring in May 2024, there is a significant opportunity to bolster cross-border collaboration and advance the integration of the regional gas market. A key step in this process is to refine the objectives of the MOU. The current objective is primarily focused on providing a broad framework for cooperation to achieve regional energy security. This objective should be expanded to explicitly include cross-border and interconnecting developments related to natural gas. By broadening the scope of the MOU, AMS can more effectively address the complexities of regional gas integration and foster closer collaboration on shared projects and initiatives.
Incorporate Detailed Cross-Border Collaboration Provisions
The new MOU should include a dedicated section outlining specific cross-border issues and collaboration opportunities. This could involve exploring the implementation actions recommended in the Gas Advocacy White Paper 2018 or identifying potential business opportunities related to piped natural gas and LNG. By clearly defining areas for collaboration and setting out actionable steps, the new MOU can facilitate more targeted and effective cross-border initiatives. This will help ensure that ASEAN member countries are working together to address common challenges and seize opportunities for mutual benefit.
Promote Multilateral Collaboration
The previous MOU language, which encourages individual or joint studies and actions, may limit the scope and effectiveness of regional collaboration. To enhance cooperative efforts, the new MOU should replace such language with terms that explicitly promote multilateral collaboration. By emphasising a multilateral approach, the MOU will encourage all ASEAN countries to participate in studies and initiatives, fostering a more integrated and cohesive effort towards regional gas market integration.
Implement Additional Modalities for MoU Adherence
Given that ASEAN MOUs, including the TAGP MOU, are non-legally binding, it is essential to implement additional modalities to ensure their relevance and adherence. This could involve establishing mechanisms for monitoring progress, evaluating outcomes, and addressing non-compliance. By introducing these supplementary measures, ASEAN can enhance the effectiveness of the new MOU and ensure that its objectives are met.
Increase Public Awareness and Support
Public perception and awareness of the benefits of natural gas play a crucial role in influencing policymakers and industry players. With the growing emphasis on net-zero agendas and renewable energy, it is important to balance energy transition goals with energy security considerations. Increasing public awareness of the advantages of natural gas, such as its role in enhancing energy security and reducing emissions compared to coal, can help garner support for gas market integration initiatives and drive more informed policy decisions.
Enhance the Role of Regional Energy Institutions
To effectively support the implementation of these recommendations and facilitate cross-border collaboration, the role of the ASEAN Centre for Energy (ACE) should be strengthened. As the official regional energy think tank, ACE should work closely with the ASEAN Council on Petroleum (ASCOPE) and each AMS' governments to coordinate efforts and drive progress. By increasing the involvement of these institutions, ASEAN can leverage their expertise and resources to support the development of a more integrated and efficient regional gas market.

4.3 Accelerating of Carbon Capture and Storage Hubs in ASEAN

4.3.1 Role of CCS Technologies and CCS Hubs in ASEAN

Fossil fuels have dominated the total energy supply of ASEAN. They are projected to account for approximately 88% of TPES in the region by 2050. The high regional dependency on fossil fuels raises significant concerns about its environmental impacts, such as GHG emissions, air quality, and public health. ASEAN's total GHG emissions in 2050 are projected to surpass 5,000 $MtCO_2$-eq in the BAS, which is 4.4 times the 2022 level.

In 2023, the region announced the ASEAN Strategy for Carbon Neutrality as its commitment to strengthening energy transition efforts towards carbon neutrality (CN) [25]. Amongst the key measures to meet the CN target by 2050, carbon capture and storage (CCS) technologies are expected to play a crucial role in ensuring energy security and gradually reducing the region's dependency on fossil fuels. In particular, the CCS technologies are expected to reduce the speed of emission growth in power and heavy industries like cement, iron, and steel in ASEAN.

In line with this effort, the deployment of CCS technologies is projected to bring spillover effects on accelerating hydrogen and ammonia production [81]. In 2019, the emissions caused by power and heavy industries accounted for approximately 40% of ASEAN's total emissions [25]. Thus, emission reduction efforts in these sectors would be crucial for meeting the regional CN target.

The CCS technologies are projected to account for approximately 8% of the electricity supply in the region by 2050. To accelerate the deployment of CCS technologies, the region aims to also strengthen the ongoing initiatives and policies toward the deployment of CCS technologies and hub infrastructure by 2050. ASEAN is seen as able to be self-sufficient in storage capacity, and the CCS hubs are viewed as one of the alternative low-cost economic options for the region to accelerate the deployment of CCS technologies. The region is estimated to be self-sufficient in CCS storage with a fully utilised total of 130 Gt of storage potential, of which approximately 62% is located in Malaysia and 17% is located in the Philippines [25].

Based on our desk research, at least eight out of ten ASEAN countries have identified geological storage potential up to an effective level, which is one step beyond the preliminary theoretical assessment, for saline aquifers and hydrocarbon fields. The potential storage capacity of the major basins in ASEAN is detailed in Table 4.4. Whilst these estimates are still uncertain and require further evaluation, they indicate a substantial preliminary capacity that could potentially exceed the needs of each country.

Table 4.4 Storage Capacity of Major Basins in Southeast Asia

Country	Basin	Type	Capacity	Source
Brunei Darussalam	Baram Delta	Oil & gas reservoir	778 Mt	[73]
		Saline aquifer	28,000 Mt	[73]
Cambodia	Kampong Saom	Oil & gas reservoir	1 Mt	[74]
		Saline aquifer	33 Mt	[74]
Indonesia	Kutai	Saline aquifer	152,950 Mt	[75]
	Northeast Java	Saline aquifer	100,830 Mt	[75]
Malaysia	Malay Pennisular	Saline aquifer	84,000 Mt	[74]
	Sarawak	Oil & gas reservoir	2,033 Mt	[73]
Myanmar	Moattama	Saline aquifer	7,000 Mt	[73]
		Oil & gas reservoir	2,652 Mt	[73]
Philippines	Palawan	Saline aquifer	16 Mt	[73]
		Oil & gas reservoir	3 Mt	[73]
Thailand	Pattani	Saline aquifer	23,000 Mt	[73]
		Oil & gas reservoir	1,081 Mt	[73]
Vietnam	Nam Con Son	Saline aquifer	23,000 Mt	[73]
		Oil & gas reservoir	239 Mt	[73]

Source: Author's compilation from various sources [73-75]

4.3.2 CCS Hub Potential in ASEAN

CCS projects are costly, and they might not yield much income in the absence of utilisation plans. Approximately USD 1 billion is required as an average annual investment for CCS technologies in ASEAN through 2030 [81]. Considering that most of the AMS are still developing, relying on individual national economic capacity would put the development of CCS technologies in the region at high risk. ASEAN nations have the chance to create shared networks and infrastructure for Carbon Capture and Storage Hubs (CCS Hubs) because of Southeast Asia's compact geographic size and the presence of oil and gas infrastructure close to favourable geological locations [83].

Hub-and-cluster networks for CCS offer economies of scale and significantly lower CO_2 transportation and storage unit costs. A network is more suited to draw capital and lower individual investors' financial risk [25]. By generating multiple operators and customers, a network also improves operational flexibility by allowing storage sites to switch in the event of planned or unplanned outages. Additionally, the area can grow into a significant offshore operations supplier of CCS services for its member nations or even those that are adjacent [84].

To connect capture and storage clusters amongst ASEAN countries, there is a plan to build an extensive hydrocarbon pipeline connecting Brunei Darussalam, Cambodia, Indonesia, Malaysia, Singapore, Thailand, and Vietnam [84]. Under certain conditions, carbon shipping via maritime routes may also have potential for development. Several recommendations for CCS hubs and network schemes within the ASEAN region are summarised in Table 4.5.

CCS projects are costly, thus relying on each AMS economic capability would hinder the development and scale-up of CCS technologies. CCS Hubs offer better opportunities for ASEAN to deter the potential risks.

Table 4.5 Proposed CCS Hubs & Networks Within the ASEAN Region by Studies

CCS hubs Type	Capture	Storage	Transport Mode
1st Type [84]	**Singapore**	**Indonesia:** Minas oil field in Central Sumatera Basin	Ship
	Indonesia: power plants and refineries in Central Sumatera		Pipeline
	Singapore	**Malaysia**: Jerneh, Dulang, Tapis, and Seligi oil fields in the Malay Basin	Ship and pipeline
	Malaysia: cement, steel, and iron industry, power plants and refineries in Peninsular Malaysia		Pipeline
	Singapore	**Indonesia**: Arun gas condensate field in North Sumatera Basin	Ship
	Indonesia: power plants and refineries in North Sumatera		Pipeline
2nd type [86]	**Singapore**	**Indonesia**: Cepu Block in East Java	NA
3rd type [87]	**Singapore**	**Indonesia**: North Sumatera, Central Sumatera, South Sumatera Basin	Pipeline
		Indonesia: East Java, Central Sulawesi	Ship
		Malaysia: Peninsular Malaysia, Sabah and Sarawak	Ship
		Brunei Darussalam	Ship and pipeline
		Vietnam	Ship
		Myanmar	Ship

Source: Author's compilation from various sources [83], [85], [86]. NA is not available.

Indonesia, Malaysia and Singapore are indeed ambitious in becoming CCS hubs in ASEAN. Singapore is aiming for a capture hub, whilst Indonesia and Malaysia are aiming for a capture and storage hub. Indonesia is establishing itself as a potential regional centre for carbon capture and storage (CCS) due to its abundance of sedimentary basins, vast saline aquifers, and oil and gas reservoirs, all of which are supported by rapidly advancing CCS programmes and infrastructure. Indonesia is also the most advanced country for the legal and regulatory frameworks related to CCS. The most recent updates permit CCS operators in Indonesia to reserve 30% of their storage capacity for CO_2 imports, and are noteworthy for being the first in the region to enable cross-border CCS, demonstrating Indonesia's leadership for the regional CCS initiative [82]. Currently, there are 15 CCS/CCUS projects in the country, expected to be operational by 2030 [87].

Malaysia is forming international collaborations to establish a regional hub for CCS, catering to the country's industries with high emissions along with those of other Asian countries, especially those that are ASEAN members. Their state-run corporation, Petronas, is spearheading the initiative. They have agreement outlines in place to pursue CCS activation projects in Malaysia, with several leading private companies [88].

Petronas's Malaysian Petroleum Management has identified 46 trillion cubic feet of potential carbon storage capacity across 16 depleted fields, exceeding Malaysia's upstream CO_2 emissions forecast [89]. This opens the possibility of serving as storage sites for imported emissions from neighbouring countries. For example, the Kasawari project, for which Petronas has finalised its investment decision, is the world's largest offshore carbon capture project by volume, capable of capturing up to 3.3 million tonnes of CO_2 annually, and being the world's largest offshore platform for carbon capture and storage [90].

Singapore is actively exploring the feasibility of establishing a cross-border CCS project. Singapore via S Hub, a consortium including Shell and ExxonMobil, aims to investigate potential CO_2 storage sites in cooperation with foreign partners [91]. Recently, Singapore and Indonesia also signed a Letter of Intent (LOI) on Cross-Border CCS, paving the way for a workgroup to discuss CCS cooperation [92].

4.3.3 Key Challenges

As ASEAN is still at the early stage of market development for CCS technologies, the region faces several key challenges in accelerating the deployment of CCS technologies including the full exploration of CCS storage capacity and CCS hubs in the region. Among the key challenges that need to be tackled, the region identified four main areas: economic viability, long lead times, project complexity, and innovation gaps.

Highlighted Challenges:

- The technical assessment of capture, storage, and practical capacity, including potential projections
- Data availability
- Comprehensive risk assessment
- Limited technicalities under the existing regulations
- Limited knowledge sharing platform
- High upfront cost

The economic viability of CCS projects in ASEAN is a major concern, primarily due to the high upfront costs associated with these technologies. These high costs are driven by limited experience, high perceived risks, and the absence of cost reduction measures and revenue support mechanisms. Emerging economies like Indonesia face significant financial burdens that cannot be shouldered by government funding alone. Moreover, the financial regulatory frameworks in many ASEAN countries are not yet mature enough to support the level of investment required, making it difficult to attract the necessary funding for CCS projects. The unavailability of specific enabling legislation, such as CCS-specific incentives, carbon pricing, and carbon tax, adds to the perceived risks, further complicating investment decisions.

Long lead times represent another major challenge in the deployment of CCS technologies in ASEAN. The extensive time required to plan, develop, and execute CCS projects, particularly those related to CO_2 storage infrastructure, significantly slows down progress. Additionally, the lack of comprehensive risk assessments, including those related to CO_2 leakage during initial injection and transportation, further extends project timelines. The complexity of these projects adds to the delay, making it difficult to accelerate the deployment of CCS technologies in a region where time is of the essence in combating climate change.

Project complexity is a critical hurdle for CCS deployment in ASEAN. These projects involve a high degree of coordination across various stages of the value chain, including CO_2 capture, transport, and storage. The complexity is further heightened by the need to manage cross-border CO_2 transport and storage, integrate new infrastructure, and navigate evolving legal and regulatory frameworks. For example, Indonesia, while the most advanced among ASEAN Member States (AMS) in developing a legal and regulatory framework for CCS projects, still lacks several key elements such as the classification and purification of CO_2, ownership of pore space, and transitioning from CO_2 Enhanced Oil Recovery (EOR) to permanent storage. Additionally, AMS are non-participation in the London Protocol, which governs the export of CO_2 through cross-border transport, adds another layer of complexity, particularly for cross-border CCS projects. The intricate nature of these projects, combined with the need for comprehensive knowledge sharing among ASEAN countries, makes them difficult to manage and execute, posing significant challenges for the successful deployment of CCS technologies.

Finally, the innovation gap in CCS technology development is a substantial challenge in ASEAN. Most countries in the region are still in the early stages of CCS technology development, with limited experience and few pilot projects to draw upon. The lack of operational commercial or demonstration projects, coupled with the absence of a robust storage database and comprehensive investigation into potential CO_2 storage resources, exacerbates this gap. This innovation shortfall hinders the region's ability to advance its CCS capabilities, delaying the broader adoption of these technologies that are crucial for achieving climate goals. Closing this innovation gap will require increased investment in research and development, capacity building, and knowledge sharing to support the successful implementation of CCS projects across the region.

4.3.4 Conclusion and Ways Forward

The region must implement several key action plans to mitigate the primary challenges hindering CCS development. ASEAN needs to focus on key factors for CCS deployment: policy development, legal and regulatory frameworks, and storage capacity assessment.

A significant factor contributing to the challenge of financial and economic viability in the region is the high cost of CCS projects. This is particularly pressing in emerging economies within ASEAN, where financial resources are constrained. To enhance financial and economic viability, ASEAN must take immediate actions, including providing financial support through the acceleration of carbon pricing mechanisms, subsidies, and the establishment of favourable contracts and procurement processes. These measures are crucial to reducing the overall cost of CCS projects, thereby making them more competitive compared to other carbon reduction technologies. Additionally, leveraging existing financial instruments and introducing new ones can help to attract private sector investment and reduce the perceived risk associated with CCS projects.

The readiness of supportive policy and regulatory frameworks for CCS projects in ASEAN remains limited. Currently, only Indonesia and Malaysia (Sarawak) have established specific regulations governing CCS projects. These existing frameworks provide valuable examples for other AMS in developing their own legal and regulatory structures for CCS. However, even in Indonesia and Malaysia (Sarawak), the frameworks can be enhanced by addressing additional parameters that are currently overlooked. These include industrial regulations, environmental impact assessments, carbon storage assessment methodologies, transboundary emissions, and the classification and purification of CO_2. Moreover, the interaction with pressure fronts across international borders and the transition from CO_2-enhanced oil recovery (EOR) to dedicated storage are also critical issues that need to be incorporated into the legal frameworks.

The method applied for assessing potential CO_2 sources and sinks requires urgent attention. Most current assessments are limited to theoretical and effective capacities, which do not fully capture the practical challenges associated with CCS deployment. A shift towards practical capacity assessment models is needed, which would consider technical, legal, regulatory, infrastructure, and economic barriers. This approach would enable a more accurate estimation of the volume of CO_2 that can be economically stored within a geological formation. Additionally, this effort should be complemented by the establishment of a comprehensive and open storage database. Such a database would list all potential storage sites in ASEAN, including detailed seismic data, well logs, and other geological information, facilitating collaboration among AMS for the development of CCS hub infrastructure across the region. The involvement of state-owned and private companies operating in closely related sectors, such as oil and gas, is essential to ensuring the robustness and comprehensiveness of this database.

The establishment of a CCS Working Group consisting of relevant stakeholders from across ASEAN is a timely and crucial step towards accelerating CCS deployment in the region. This Working Group would play a pivotal role in fostering regional collaboration, knowledge sharing, and capacity building. It would also be responsible for coordinating efforts to develop a robust legal and regulatory framework, ensuring alignment with international standards and best practices. Furthermore, the Working Group would work on establishing a platform for multi-level cooperation among governments, private sectors, research institutions, and universities, facilitating the smooth implementation of CCS projects. The Group would also play a key role in securing international support from dialogue partners, ensuring that the region has access to the latest technological innovations and best practices. The establishment of this Working Group would significantly contribute to the transition of CCS projects in ASEAN from the early stage to mature, commercial-scale operations, ultimately helping the region achieve its carbon neutrality goals.

CCS and CCS Hubs

Key Recommendations:

- *Enhancement of storage capacity assessment method for inclusion of wider coverage risk assessment of CCS projects and enable more robust estimation of financial or investment.*
- *Establish single database platform.*
- *Organise a multi-level stakeholders' platform that led to quadruplex helix cooperation. Stakeholder mapping will be crucial to develop a more comprehensive of specific legal and regulatory framework to guide stakeholders' involvement in CCS projects.*
- *Enabling policy and financial support scheme to reduce the high risk and cost of the CCS projects at the early market phase through leveraging financial support scheme, including catalysing carbon pricing.*

4.4 Smart Demand Response

Demand response has been offered by electric utilities for decades across the world, and can be characterised as utilities interacting with energy consumers through creative and time-varying pricing, behavioural programmes, or direct load control technologies to motivate consumers to change their energy usage patterns for optimising grid operations. Smart demand response has emerged as a pivotal thread, weaving together historical concepts from legacy load management programmes, to integrated demand-side management that includes efficiency, sustainability, adaptability, and the integration of new customer technology and automation.

SMART DEMAND RESPONSE *is a proactive strategy employed within energy grids to balance supply and demand in real-time by motivating consumers to adjust their electricity usage patterns. Through the integration of advanced technologies like smart thermostats, building energy systems, load control switches, sensors, smart meters, and communication networks, demand response programs enable utilities to remotely monitor and manage energy consumption, thereby enhancing grid stability and reliability.*

Why Smart Demand Response is Important in the Modern Energy Systems?

Utilities are experiencing unprecedented changes in grid operations due to changes with both generation and load. The rise of intermittent renewables such as solar and wind power have caused a shift in the generation load profile, introducing variability in energy generation that poses challenges to grid operators in maintaining equilibrium between supply and demand. Concurrently, the load characteristics and profiles are changing with the adaption of decarbonisation initiatives that have accelerated transportation, building, and industrial electrification. Additionally, the new developments in artificial intelligence and the corresponding heavy computing resources have created a wide scale development of high energy use data centres. All of these changes make smart demand response a crucial tool to mitigate the challenges to maintain reliability and normal grid operations by empowering consumers to actively participate in the optimisation of energy usage, thereby reducing strain on the grid and fostering a more resilient energy infrastructure.

4.4.1 Demand vs Supply Response

Demand response focuses on adjusting electricity consumption in response to fluctuations in supply or grid conditions. There are several demand response objective functions, including peak load management, ancillary services, frequency response, transmission and distribution asset deferral, and others. To achieve these objectives, demand response leverages creative rate design, consumer messaging, or direct load control mechanisms to shift non-essential electricity usage to off-peak hours, or temporarily reduce power consumption during peak periods.

Supply response pertains to the capability of energy suppliers to adjust the production or distribution of electricity in response to changes in demand. Whilst demand response empowers consumers to modulate their energy usage, supply response involves the management of generation sources and grid infrastructure by utilities and grid operators to match supply with demand in real time. Supply response can be complicated by generation contracts that may impose specific requirements that affect generation, or dictate specific economics associated with the use of that generation.

4.4.2 Elements of a Successful DR Program

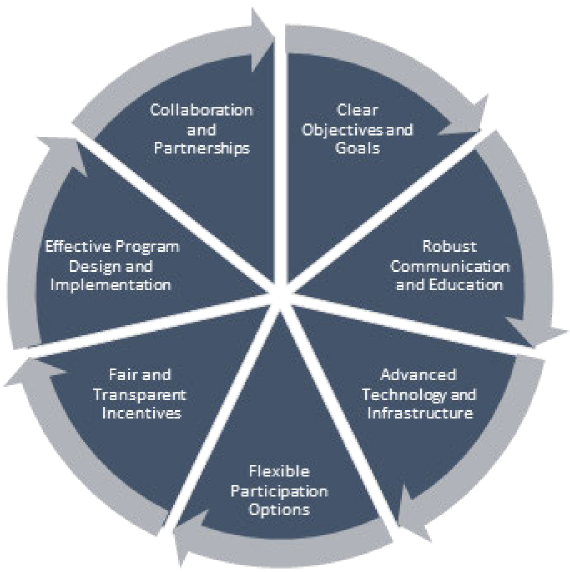


Figure 4.6 Key Elements of a Successful Demand Response Programme

A successful demand response programme encompasses several key elements to effectively engage consumers, optimise grid operations, and achieve the desired outcomes. As demand response leverages multiple distributed energy resources, some of which may be customer-owned, successful programme design must consider: (1) clear objectives for the utility and the customer that leverage detailed analytics and outlines specific value propositions for both the customer and the utility; (2) robust customer communication and engagement strategies; (3) advanced technologies and infrastructure; (4) flexible participation options; (5) fair and transparent incentives; (6) effective programme design and implementation; and (7) collaboration and partnerships.

Clear Objectives and Goals: Utilities should start with detailed planning to define clear, measurable objectives for their demand response programme. This includes a market potential study, utility objectives, and customer value propositions aligned with broader utility strategies and local energy targets. A data-driven approach is essential for successful programme design.

Robust Communication and Education: Customers must be central to programme design. Utilities should educate consumers on demand response, its benefits, and participation options. Clear information about incentives, event timeframes, and benefits should be provided through various channels. Technology and automation can reduce participation barriers.

Advanced Technology and Infrastructure: Smart demand response programmes require advanced technologies like smart meters and sensors for real-time monitoring and control. Utilities need to invest in internal systems and infrastructure to support communication between grid operators and consumers.

Flexible Participation Options: Programmes should offer flexible participation options for residential, commercial, and industrial sectors. Customers can choose from various designs and technologies, including event overrides and multiple participation channels.

Fair and Transparent Incentives: Programmes are evaluated based on cost-benefit analysis to ensure fairness and transparency. Customer incentives, technology, and measure life are key inputs. Utilities determine appropriate financial incentives to deliver demand reduction value.

Effective Programme Design and Implementation: Programmes should be simple, transparent, and scalable. Clear rules, eligibility criteria, and performance metrics are necessary. Robust evaluation, measurement and verification plans are needed to monitor effectiveness and identify improvements.

Collaboration and Partnerships: Utilities should foster collaboration amongst stakeholders, including grid operators, regulators, and technology vendors. Engaging with customers and stakeholders is crucial for feedback and buy-in.

Regulatory and Policy Support: Utilities must seek regulatory and policy support at local, state and national levels, to enable demand response deployment. Supportive policies and market mechanisms are needed to incentivise investment and reward grid flexibility.

Continuous Innovation and Adaptation: Utilities should embrace innovation and adapt to emerging technologies, market trends, and consumer behaviours. Staying updated with industry developments and best practices is essential for refining strategies and enhancing programme efficiency.

4.4.3 Case Studies from Around the World

France, Italy, the Netherlands, and the United States	United Kingdom
Electric Vehicle-to-Grid (V2G) Charging: These countries are experimenting with V2G technology, which allows electric vehicles to both draw from and supply electricity to the grid. In France, the EDF Group is deploying 800 V2G charging stations across Europe, including France, as part of the EVVE project, creating a virtual battery with a capacity of 8.36 MW [93]. In the Netherlands, V2G technology is being integrated into smart grids to enhance energy efficiency and stability [94]. The United States is also advancing V2G technology, with several pilot projects aimed at reducing grid stress and enhancing renewable energy integration [95].	**Energy Smart Appliances Programme (2022)**: The UK launched a programme to test interoperable demand response through smart meters and energy management systems. This initiative is part of the broader Smart Secure Electricity Systems Programme, which aims to create a smart and secure electricity system by regulating energy smart appliances and improving the security of the electricity system [96].

Australia	United States
Tesla Virtual Power Plant (VPP): Tesla has been expanding its VPP from South Australia to other states, including Victoria, New South Wales, South-East Queensland, and the Australian Capital Territory. This expansion aims to help stabilise the grid and reduce electricity costs for low-income households by aggregating Powerwalls to provide grid services [97].	**Tesla VPP Expansion**: In California, Tesla's VPP with PG&E compensates Powerwall owners for contributing to grid stability during peak demand periods [98]. In Texas, Tesla has received approval for two new VPPs, further expanding its grid services [99]. **GridRewards Platform**: More than 9,000 consumers in New York are enrolled in the GridRewards platform, which helps reduce demand by 20 MW during peak times. Participants receive cash payments for their contributions, averaging USD 80 during the summer peak season [100]. **Vistra Demand Response**: Vistra's TXU Energy Connected Conservation programme in Texas enables customers with smart thermostats to participate in demand response, helping to balance supply and demand during peak periods [101].
Chile **Stem Inc. VPP**: Stem Inc. has developed South America's first VPP in Chile, in partnership with Copec and Chilquinta Energía. This project uses Stem's Athena software to optimize energy storage and provide grid services [102].	**India** **Tata Power Demand Response**: In February 2023, Tata Power launched a demand response programme in Mumbai, targeting 55,000 residential consumers and 6,000 large commercial and industrial consumers. The programme aims to achieve a peak reduction of 75 MW, scaling up to 200 MW by summer 2025 [103].
Japan **Itochu Residential Energy Storage Systems**: In January 2023, Itochu announced a pilot project to test the use of residential energy storage systems for demand response. This initiative aims to optimise the balance between electricity supply and demand, and reduce electricity procurement costs [104].	

4.4.4 Status of DSM and DR in ASEAN

Cambodia	Indonesia
Cambodia is in the early stages of designing and implementing a National Energy Efficiency Plan. Even though the plan has aggressive targets, it does not lay out a role for the national electric utility, EdC, to design and implement DSM or DR programmes to help achieve this potential. Nonetheless, EdC can benefit from the South-to-South exchange of experience related to DSM and DR technologies and initiatives, as well as from technical assistance from international experts.	Even though Indonesia recognises DSM as a key element of its energy conservation initiative, very minimal action has been taken to implement any programmes—in large part because the overcapacity on the Java-Madura-Bali grid. Like many other countries in the region, lack of information and understanding of the required actions and benefits of DSM is a key barrier that needs to be overcome to initiate DSM and DR programmes in Indonesia.
Lao PDR Lack of reliable demand-side information is a barrier to formulating DSM and DR programs. EdL's conventional business model, focused on sales and revenues, does not create motivation for DSM and DR. A possible exception is load-shedding or load control to minimize the importation of expensive power during the hot dry season. The absence of an integrated planning approach is also a barrier to incorporating DSM and DR in power development planning.	**Philippines** The DR activity is limited due to the situation of potential power outages, known as the interruptible load programme. In addition, the Philippines utilities are hesitant to initiate large-scale DSM and DR programmes, as they are concerned about perceptions of government energy restrictions on the industry, as well as the impact on sales and revenues. There could be scope for utilities to participate in DSM schemes such as on-bill financing and repayment, which could help customers overcome the first payment barrier for purchases of high-efficiency appliances and equipment.

Thailand	Singapore
Thailand recently wrapped up its 50 MW pilot DR programme, and the distribution utilities, MEA and PEA acted as load aggregators for this programme. However, as EGAT scales up its DR programmes, it will need to estimate the achievable DR potential for the country and develop a model for aggregating load for its DR programmes. The electric utilities (EGAT, MEA, PEA) do not have a dedicated, rate-based budget for implementing the scale of DSM and DR needed to meet Thailand's national net-zero targets. EGAT currently sees changes in customer demand only at a systemic level. With more widespread implementation of smart metering, they will be able to have better visibility of demand profiles at the customer level, and will be better able to design and implement their DSM schemes.	Singapore is actively advancing its Demand Response (DR) programmes to enhance energy efficiency and grid stability. The Energy Market Authority (EMA) and SP Group are targeting the launch of a residential pilot programme in late 2024, enabling households with smart meters to reduce electricity usage during peak periods for financial incentives. For commercial and industrial consumers, EMA has introduced measures to encourage voluntary electricity reduction during high wholesale price periods. Additionally, a regulatory sandbox has been established to streamline participation in DR programmes, supporting Singapore's broader efforts towards a sustainable and efficient energy ecosystem.
Vietnam	
Vietnam has been actively developing and implementing DR programmes as part of its broader DSM strategy. This includes initiatives aimed at both residential and commercial customers. Vietnam Electricity (EVN) executed some DSM strategies focusing on energy efficiency and load management. Key initiatives included a Load Research (LR) programme that installed electronic meters for 1,000 customers to analyse load patterns, and a Time of Use (TOU) metering programme that deployed over 470,000 meters to promote off-peak energy usage. Additionally, a Direct Load Control (DLC) programme was piloted in major cities; however, it was discontinued due to insufficient customer incentives.	

4.4.5 Recommendations to Scale up Smart DR Programs

Several key needs must be addressed in order to bridge the gaps and scale up demand response programmes in the ASEAN region. Enhanced policy and regulatory frameworks are essential to incentivise participation and infrastructure investment.

Capacity-building initiatives are needed to equip utilities, regulators and stakeholders with the skills to manage these programmes. Financial incentives and support mechanisms, such as grants and subsidies, can promote the adoption of advanced technologies.

Public awareness and engagement through targeted communication campaigns are crucial for driving participation. Regional collaboration and knowledge sharing can help ASEAN countries learn from each other's experiences and best practices.

> Smart demand response programs shall be put as a key strategy for achieving energy efficiency and grid reliability goals.

The ASEAN Plan of Action for Energy Cooperation (APAEC) should be updated to explicitly include smart demand response programmes as a key strategy for achieving energy efficiency and grid reliability goals. ACE and HAPUA need to join hand-in-hand to champion this agenda in the new phase of APAEC. The update should outline:

- **Clear Targets and Objectives**: Establish clear targets and objectives for the adoption and scaling of demand response programmes across the AMS.
- **Strategic Actions and Milestones**: Define strategic actions and milestones to guide the implementation of demand response initiatives, including timelines and responsible entities.
- **Monitoring and Evaluation Framework**: Develop a robust monitoring and evaluation framework to track progress, measure outcomes, and identify areas for improvement in demand response programmes.

- **Building on Existing Initiatives**: The Efficient Grid-Interactive Buildings (EGIB) programme, introduced by ACE and the International Energy Agency (IEA), provides a solid foundation for promoting DR in building operations in the ASEAN region. However, to maximise its impact, the programme should be expanded to include:
  - More comprehensive technical assistance for implementing DR technologies in diverse building types; and
  - Development of standardised measurement and verification protocols for DR performance;
  - Creation of a regional platform for sharing success stories and lessons learned.
- **Integration with Other Energy Initiatives**: Ensure the integration of demand response with other energy initiatives, such as RE deployment and smart grid development, to maximise synergies and benefits.

Inclusive Transition

Demand response reflects patterns of consumer behavior. Therefore, it is crucial to consider what means are available for shaping and affecting consumer behavior as well as the diversity of needs and concerns end consumers have. Whereas high-volume consumers can effect greater demand response shifts, focusing on these populations risks neglecting lower-income consumers. cLower-income consumers are likely to be more sensitive to price changes but are also likely to require greater efforts to engage. High volumes are more likely to respond to capital-intensive high-benefit options like domestic behind-the-meter battery systems or subscription-based time-specific vehicle charging services. Lower-income consumers are more likely to respond to immediate response cost-saving measures based on variable electricity costs. Appropriate price incentives for demand responses are likely to drive low-income consumer responses. Nevertheless, it will be crucial to leverage compensation schemes and thoughtful subsidies to ensure that poorer citizens have reliable and affordable access to energy. Providing timely information has been successfully done via digital platforms. Legislative interventions may offer relatively cheap solutions to proffering systemic demand offsets. Building standards for heat and cooling compensating architecture may ensure new capital investments in buildings contribute to demand response adaption. Likewise, regulating the use of smart metering and daily variable pricing will build systemic incentives to adapt demand response practices.

4.5 Dispatchability of Renewable Energy

The integration of growing variable renewable energy (VRE) sources in ASEAN, notably wind and solar – necessitates enhanced grid dispatchability and flexibility. This can be assisted through three key technical enablers: energy storage, distributed energy resources, and digital technology. This chapter will explore these technologies, their potential applications in Southeast Asia, and the enabling factors supporting their adoption.

4.5.1 Energy Storage

Energy storage is an effective solution for variable renewable energy (VRE) integration, whilst enhancing energy system flexibility and reliability. Battery energy storage and pumped hydro storage are the two most deployed storage technologies to date.

Battery energy storage systems (BESS) can provide high energy density and fast response in milliseconds, and thus are suitable for a wide range of applications at both transmission and distribution levels. This may include RE integration through energy shifting and capacity firming, load levelling, peak shaving, black start, voltage and frequency regulation, and network and system ancillary services.

Pumped hydro storage (PHS) can currently be built to provide high energy with lower unit costs, ranging from a couple of hundred MWs to thousands of MWs, depending on the size of the site. Its feasibility depends on the physical and site conditions, suitable locations can be old mine sites, elevated reservoir, and seawater sites. The development and construction time can be prolonged, but the infrastructure developed can last for 50 to 100 years.

Energy storage can play several roles in the electricity system, such as:

Bulk energy shifting Storing excess energy for later use, capturing market value through economic arbitrage.	**Network support and ancillary services** Alleviating congestion and system constraints, reducing the need for new infrastructure investments.	**Grid stability and reliability** Providing backup power and supporting remote areas or microgrids.

Wider deployment of storage technologies faces certain challenges, such as high cost, operational challenges in sizing and optimisation, lack of standardisation, lack of policy support and market design, innovation, and overcoming critical mineral and supply chain constraints [105].

Plug and Play Solutions for ASEAN's VRE Integration: Focus on Battery Energy Storage System

The growth of wind and solar energy will require a significant expansion of energy storage capacity. This presents substantial growth opportunities for the energy storage market, which is expected to be worth around USD 3.32 billion in 2024, and USD 4.61 billion by 2029 [106].

Whilst 2021 data (Table 4.6) show high installation costs for Lithium Iron Phosphate (LFP) battery storage, prices are projected to decline by around 25% by 2030, to around USD 284-399/kWh for 1 MW, and USD 267-363/kWh for 10 MW power capacity. However, wider adoption of battery storage in Southeast Asia has faced significant hurdles, due to relatively high costs for its acquisition and deployment, lack of revenue streams due to inadequate market pricing, and low RE penetration.

Table 4.6 The 2021 Total Installed Cost Data for Lithium Iron Phosphate (LFP) Battery Energy Storage

	1 MW				10 MW			
	2 hr	4 hr	10 hr	24 hr	2 hr	4 hr	10 hr	24 hr
Total installed cost (USD/kWh)	518.59	448.34	402.25	380.32	461.15	410.70	376.67	359.62
Total installed cost (USD/kW)	1,037	1,793	4,023	9,128	922	1,643	3,767	8,631

Source: Pacific Northwest National Laboratory: 2022 Grid Energy Storage Technology Cost and Performance Assessment [107]

Battery physical and operational and market parameters are key factors to be considered for the deployment of storage technology. Market parameters may include Technology Readiness Level, material resource availability, the potential for cost reduction, market potential that is closely tied to RE growth, electricity consumption growth, fuel prices, and supportive policies [108]. Operational parameters such as sizing, capital cost of power and energy, operating and maintenance costs, and technological maturity are crucial for selecting appropriate battery systems for both grid-connected and off-grid applications. A holistic planning approach, considering both market dynamics and technical requirements, is essential for the effective deployment and integration of battery storage and maximising its benefits for regional economic development.

Business Models and Procurement Strategies

The business model for energy storage involves three key aspects: the application of a storage facility, the market role of a potential investor, and the revenue stream from its operation [109]. Eight distinct applications and four revenue streams are listed in Table 4.7, including frequency containment, short-/long-term frequency restoration, voltage control, black start and backup energy, energy trading between prosumers[9], infrastructure investment deferral, and peak demand shaving. Each offers distinct economic benefits; however, the complexity and diversity of revenue streams necessitate a thorough assessment of the "value-stack" to identify profitable investment opportunities. This involves evaluating transaction costs and potential benefits, such as network value, voltage control, frequency control, customer savings, and energy trading value.

Table 4.7 Applications for Energy Storage and their Revenue Stream

Application	Cost Avoidance	Investment Deferral	Capacity Payment	Arbitrage
Provide frequency regulation	X			
Provide short-/ long-term frequency restoration	X		X	
Provide voltage control		X	X	
Provide black start energy	X	X	X	
provide backup energy		X	X	
Meet selling/buying forecast	X		X	
Shave supply/demand peaks	X	X		
Sell at high/buy at low prices	X			X

In the ASEAN context, whilst energy storage is recognised as crucial for power system development, appropriate business models and deployment mechanisms are still under development. Innovative support schemes, flexible market roles, and clear regulatory frameworks can incentivise investment and address diverse stakeholder interests.

Several procurement strategies (Table 4.8) exist for BESS, each with advantages and disadvantages. Turnkey contracts offer simplicity but may be costly, whilst EPC contracts provide more control but require careful contract management and quality management. PPAs shift operational risks to providers, and leasing offers flexibility but potentially higher long-term costs. Other strategies include BOO/BOOT models, competitive bidding, collaborative procurement, and local sourcing, each catering to specific project needs and resources.

Choosing the right procurement and asset acquisition strategy requires careful consideration of project goals, financing and risk preferences, local capabilities, and regulatory frameworks. By aligning these factors, stakeholders can maximise the benefits of energy storage and accelerate Southeast Asia's transition towards a more sustainable and resilient energy system.

[9] Prosumer is defined as "an energy user who generates renewable energy in its domestic environment and either stores the surplus energy for future use or vends to the interested energy buyers"

Table 4.8 Summary of Procurement Strategy for Energy Storage

Procurement Strategies	Description	Advantages	Disadvantages
Turnkey Contracts [110], [111]	A single contractor is responsible for the complete process, including design, supply, installation, and commissioning of the BESS.	Simplifies project management by providing a single point of accountability, thus transferring most of the risk to the contractor	Potentially higher costs due to the contractor's risk premium
Engineering, Procurement, and Construction (EPC) Contracts [112]	The EPC contractor handles the design, procurement of equipment, and construction	Streamlines the integration of design and construction, which can lead to cost and time savings.	Requires careful contract management to ensure quality and adherence to schedules
Power Purchase Agreements (PPA) [112]	A third-party provider installs, owns, and operates the BESS, selling the energy output to the off taker under a long-term contract	Reduces upfront costs for the buyer and shifts operational risks to the provider	Long-term commitment and potentially higher costs over the duration of the contract
Leasing [113], [114]	The BESS is leased from a provider, typically over several years	Lower initial capital expenditure and flexibility to upgrade or change technology as it evolves	Total costs over the lease period may be higher than outright purchase
Build-Own-Operate (BOO) / Build-Own-Operate-Transfer (BOOT) [115], [116]	The developer builds, owns, and operates the BESS, with an option to transfer ownership to the customer after a specified period (BOOT)	Reduces initial investment and operational risk for the buyer	Complex contractual arrangements and potentially higher long-term costs.
Competitive Bidding [117], [118]	Multiple suppliers bid to provide the BESS, with the contract awarded to the most competitive offer	Promotes cost-efficiency and innovation through competition	Can be time-consuming and requires thorough bid evaluation
Collaborative Procurement [119]	Multiple stakeholders collaborate to procure BESS, sharing costs and benefits	Economies of scale and shared risk among stakeholders	Coordination challenges and potential conflicts among participants
Local Sourcing and Cost Fixing [120]	Sourcing batteries from local suppliers and fixing costs early through contractual agreements	Reduces transportation costs and logistical complexities, and helps manage financial risks associated with volatile material prices	Limited to available local suppliers and potential higher initial costs

Case studies

Singapore's approach to BESS procurement centres on public-private partnerships and government initiatives, exemplified by the 200 MW/285 MWh Sembcorp Industries project on Jurong island, which utilises lithium iron phosphate technology [121]. The project involved collaboration with international technology providers like Envision and Huawei, and was constructed by China Energy Engineering Group Shanxi Electric Power Engineering Co. The Energy Market Authority (EMA) actively facilitates BESS deployment through regulatory support, fostering innovation through calls for proposals, and establishing frameworks to accelerate the deployment of energy storage systems.

In the Philippines, large-scale private sector investments drive BESS procurement, with companies like San Miguel Corporation and Aboitiz Power developing projects exceeding 1,000 MW capacity, often in partnership with international players [122], [123], [124], [125]. Supportive government policies, aiming for 35% RE by 2030, and 50% by 2040, coupled with regulatory adjustments, further stimulate market growth [124], [126].

Australia's battery storage market has experienced significant growth, with 5,955 MW of existing, committed and anticipated battery installations, representing 19% of peak demand [127]. This expansion is facilitated by a market design recognising the flexibility of battery technology and supportive policies aimed at improving energy system resiliency, reliability, and sustainability [128], [129], [130].

Recommendations

To effectively deploy energy storage systems such as BESS, AMS should consider several strategic recommendations:

Regulatory and Policy Framework	• Establish clear, consistent policies to encourage investment and development. • Create frameworks for market integration and set standards for safety and performance. • Offer incentives for utility-scale and distributed storage solutions.
Market Development	• Encourage public-private partnerships and the private sector investment to drive innovation and project development. • Develop local manufacturing and supply chains for battery components.
Grid Integration and Modernisation	• Enhance system operation capacity with advanced management systems and smart grid. • Develop standards and protocols for seamless integration.
Research and Development	• Support research, pilot projects, and demonstrations to gain valuable insights.
Consumer and Stakeholder Engagement	• Raise awareness and educate stakeholders about energy storage benefits. • Engage stakeholders in planning and decision-making processes.

4.5.2 Distributed Energy Resources

Distributed energy resources (DERs) refer to a range of supply- and demand-side resources, including RE technologies, such as solar (hot water and photovoltaic systems), energy storage, EVs, and smart devices, which may be accompanied by demand-side measures designed to reduce or shift energy consumption. This will enable more efficient energy management at the building, district, and community levels, increasing system efficiency and utilisation through local supply and demand optimisation.

Distributed Energy Resources can bring multiple benefits, including increased energy security and system resilience, and postponing the need to develop new energy infrastructure, such as centralised generation, transmission and distribution networks.

The barriers to significant DER adaption vary by ASEAN member states and can be generally classified as policy and regulatory frameworks, financial/technical/infrastructure, market, and bureaucratic and administrative [131], [132], [133].

Consumer readiness can be hindered by inadequate technical knowledge of DER products and services, as well as limited understanding of their cost-benefits. Furthermore, difficult permitting and connection processes, the system's perceived high upfront cost, low electricity price, and shifting legislation all further deter adoption.

To overcome these obstacles, ASEAN nations must adopt comprehensive policy reforms, provide financial incentives, invest for grid modernisation, and educate consumers on the benefits of DERs. Such a multi-facetted approach can unlock the full potential of distributed energy resources in the region.

Accelerating Distributed Energy Resource Adaption in ASEAN: Focus on Untapped Rooftop Solar PV Implementation

There is large technical and market potential for DER adoption in ASEAN that is largely untapped to date. For example, despite the vast potential for rooftop solar PV in countries like Indonesia, Malaysia, and Vietnam, actual implementation lags far behind targets. This is due to a combination of policy, financial, technical, market, and bureaucratic barriers. Indonesia has the potential for between 194 GWp and 655 GWp; only 140 MW was installed by 2023, falling short of the 2025 target of 3.6 GW. Similarly, Malaysia and Vietnam possess vast untapped rooftop solar potential, with 34 GWp and 370 GWp respectively, exceeding their current power generating capacities and underscoring the considerable room for growth in solar energy adoption across the region [134], [135].

Whilst feed-in tariffs have proven successful in driving rooftop solar adoption in the ASEAN context, tailored approaches are necessary due to the region's diverse socio-economic and market conditions. For example, in Indonesia, a low net-metering rate and high costs have hindered uptake, necessitating location-specific incentives and adjusted tariffs [136].

The increasing rooftop solar PV installed capacity worldwide is driving the development of innovative decentralised energy solutions. Locations for distributed storage can be identified in neighbourhoods and communities to provide local grid support and optimise local electricity supply and demand, benefitting communities and wider electricity systems.

More advanced platforms, such as peer-to-peer trading and virtual power plants (both will be discussed in the Digital Technology section), can enhance the economics of DERs, asset utilisation and system efficiency, whilst encouraging prosumer participation in energy trading. However, their successful implementation depends on the country's level of DER deployment, the availability of enabling technologies and services, and the structure of the power industry.

Collaboration between government and industry is critical to facilitate technological and social innovations, financing and investment options, consumer awareness, as well as to ensure product quality and installation standards in promoting DER adoption.

Case Studies

Electricity systems in a number of jurisdictions have experienced significant DER growth, and many lessons can be learned from these experiences.

Australia, for example, promotes DER integration through a multi-facetted approach. The country's approach aimed to maximise the benefits of DER for both consumers and the grid. The Distributed Energy Integration Programme (DEIP) fosters collaboration amongst stakeholders, to identify challenges and accelerate reforms, focusing on areas like dynamic operating envelopes, access, pricing, and EV integration [137], [138]. Additionally, efforts are underway to implement flexible demand management through demand response mechanisms, updated appliance standards, and prioritised behind-the-meter storage solutions, to enhance grid stability and reduce costs [139], [140].

Other countries, such as Germany, have implemented feed-in tariffs and market premiums to encourage the adoption of RE sources. The United States, through various state-level initiatives and federal programmes, supports the integration of DER with incentives for solar PV, battery storage, and smart grid technologies. Japan has focused on promoting DER through subsidies for residential solar and battery storage systems, coupled with smart meter deployments to facilitate energy management [137].

Recommendations

The barriers to significant rooftop solar PV adoption vary by ASEAN member states. Whilst some may be country-specific, they can be generally classified as policy and regulatory frameworks, financial, technical and infrastructure, market, and bureaucratic and administrative [131], [132], [141]. To encourage the adoption of DERs requires strong governmental support by orchestrating policies within all layers of power systems and amongst stakeholders, namely

Strong Government Support	• Orchestrate policies and market rules at all levels of the power system. • Pre-match policies, incentives, and financing to overcome barriers.
Policy and Financial Incentives	• Implement effective policies: feed-in tariffs, net-metering, tax rebates, exemptions, grants/subsidies, renewable energy certificates, special leasing, self-consumption, peer-to-peer trading. • Facilitate accessible financing for consumers and businesses.
Consumer Awareness and Education	• Improve consumer knowledge about rooftop solar PV and other DER systems, regulations, and financial benefits. • Ensure consumers receive adequate information before making decisions.
Grid Integration	• Strengthen power system infrastructure to allow seamless DER integration. • Address cost-reliability trade-offs for grid connected rooftop solar PV.
Local and Regional SUpply Chain Development	• Develop strong PV, battery, EV industries, expand manufacturing, and establish supply chains beyond assembly. • Regional and international collaboration on research and development, technology and knowledge transfer.

4.5.3 Digital Technology

Digital technology refers to modern means of utilising digital data to convert, process, transmit, store, display, and apply information. It includes a variety of technological fields such as computers, networks, communications, digital image processing, and digital signal processing. The use of digital technologies, referred to as digitalisation [142], changes business operations and/or business models to improve operational and economic efficiency, and provide new revenue and value-producing opportunities.

Overview of Digital Technology Applications

Digital technologies, such as artificial intelligence (AI), machine learning, big data, blockchain, Internet of Things (IoT), and cloud computing, are crucial for optimising RE integration and grid efficiency. They enable more accurate forecasting, improved efficiency of traditional and renewable energy generation and storage, emission monitoring, intelligent and remote control of grid stations, system diagnostics, fault detection and correction, and congestion alleviation [143].

Digitalisation is pivotal in smart grid development, allowing utilities to manage complex energy systems with both centralised and decentralised sources. Digital tools help to capture and analyse vast amounts of data to optimise resource assessment, electricity flow, reduced costs, and improved asset management through predictive maintenance [144], [145].

Furthermore, digital technologies empower consumers by providing tools for monitoring and controlling their energy usage. Smart home energy management and automation systems enable consumers to optimise energy consumption, reduce costs, and foster a more sustainable energy ecosystem [146], [147].

Digital technology enables the development of a number of emerging distributed and decentralised energy infrastructures and models, such as microgrids[10], Virtual Power Plants (VPPs)[11] and Peer-to-Peer (P2P) trading[12]. These new business models improve grid security, facilitate the integration of variable renewables, and optimise supply and demand. They offer cost-effective alternatives to traditional power plants and provide financial incentives for customers who participate.

This in turn fosters joint value creation amongst communities, service providers, and the wider energy market, delivering economic benefits and social cohesion [148]. These platforms require coordination between technology, utilities, and customers, and may necessitate regulatory changes.

Implementing digital technologies requires addressing challenges, such as inadequate communications infrastructure, regulatory lags, misaligned financial incentives, data accessibility issues, and connectivity problems. Cybersecurity and privacy concerns further highlight the need for robust measures to mitigate risks associated with increased digitalisation in the energy sector.

Digital Transformation of ASEAN's Power Sector: Opportunities, Challenges, and Innovations

Digitalisation holds great potential for transforming the ASEAN power sector, particularly in integrating RE, DERs, and enhancing grid and system operational efficiency. Digital technologies like smart meters and wireless communication networks are key technologies for managing DERs and establishing smart grids.

Blockchain technology has further expanded the possibilities, enabling innovative business models like P2P energy trading, which can increase rooftop solar PV adoption and improve grid reliability. P2P energy trading, which is being developed in many countries, has been identified as one of the innovative community-based energy trading platforms for improving rooftop solar PV ownership and variable renewables penetration in the power grid. including microgrids.

ASEAN countries have begun implementing digital solutions, including utility-scale battery storage control systems, solar PV energy management, and P2P pilot projects. For example, to control the utility-scale BESS in the Philippines and Singapore, manage the energy generated by the floating solar PV systems in Indonesia, manage the border-grid power flow between Thailand and its neighbouring countries and other ASEAN power grid interconnection projects, and run P2P pilot projects in Thailand and Malaysia. As the region embraces RE, the scale and economic impact of digitalisation in the power sector are expected to grow.

Smart grid development is a key focus, with initiatives like the ASEAN Power Grid (APG) aiming to integrate regional power networks and facilitate RE integration. This strategy is expected to save USD 1.87 billion by 2025, by improving integration and reducing new capacity costs. However, the implementation confronts obstacles, including high investment costs, technical barriers, distributional effects, and the necessity for large modifications to transmission infrastructure to handle fluctuating variable RE sources [149], [150].

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[10] Micorgrid is defined as a self-contained and self-sufficient local electricity supply system, either standalone or connected to a centralized grid of regional or national scale, comprising residential and other electric loads, and can be supported by high penetrations of local distributed renewables, other distributed energy and demand-side resources.

[11] VPPs aggregate distributed energy resources like wind and rooftop solar PV, and electric vehicles, and act as brokers between these resources and the wholesale electricity market

[12] P2P trading platforms enable energy transactions between consumers with and without DERs.

Conducive Policy Environment

Several countries have established supportive policy environments for digitalisation in their energy systems. The UK's comprehensive strategy focuses on utilising digital technologies like IoT and AI to enhance RE integration and decarbonise the energy system. The EU's action plan emphasises empowering consumers, enhancing cybersecurity, and promoting research and innovation for digital energy services, ultimately facilitating greater RE integration and grid flexibility [147], [151].

Germany and Denmark showcase successful digitalisation efforts for RE integration. Denmark's widespread smart meter deployment enables real-time energy management and supports the integration of wind power. Germany's data platforms and smart meter mandates for large consumers enhance data-driven energy management, contributing to increased RE shares in both countries [152].

These examples highlight the importance of supportive policy frameworks, data sharing, and advanced digital technologies in facilitating the transition to a more sustainable and efficient energy system.

Recommendations

Keys to an effective application of digital technology in the ASEAN integrated variable renewables power sector are elaborated as:

Well-Designed Programs	• Develop comprehensive programs with clear objectives and targets for digital technology deployment in the energy sector.
Supporting Infrastructure and Capability	• Invest in robust information and communication technology (ICT) infrastructure to enable seamless data exchange and communication. • Build technical capacity and expertise within the energy sector to effectively utilise digital tools and platforms.
Technology Standards	• Establish and enforce standardised protocols and interfaces for digital technologies to ensure interoperability and compatibility across different systems and devices.
Regulatory Framework	• Create a supportive regulatory environment that fosters innovation, encourages investment, and addresses potential barriers to digital technology adoption.
Security and Cybersecurity	• Priorities robust security measures and protocols to protect critical energy infrastructure and data from cyber threats. • Establish cybersecurity and privacy regulation
Incentives and Grid Rules	• Develop approproate financial incentives and grid rules to encourage the adoption of digital technologies by both energy providers and consumers.

4.6 Progress of Carbon Pricing in ASEAN to Support the Shift Towards Carbon Neutrality Target

4.6.1 Positioning of Carbon Pricing in ASEAN

ASEAN is striving to align its economic growth with sustainable, low-carbon energy practices in adherence to the Paris Agreement's carbon neutrality and net-zero emissions objectives. Most of the AMS have pledged to achieve net-zero or carbon neutrality, underscoring their commitment to reducing greenhouse gas emissions. [26].

In 2023, the AMS introduced the ASEAN Carbon Neutrality Strategy, outlining the regional plan to meet carbon neutrality targets by 2050. One of the key strategies highlighted in this plan is the interoperability of carbon markets. Market-based solutions, particularly carbon pricing, are central to ASEAN's strategy for achieving carbon neutrality by 2050.

Carbon pricing, which assigns a cost to carbon content, raises the cost of using fossil fuels, thereby making low-carbon alternative energies and technologies more cost-competitive. Generally, carbon pricing is divided into two forms: carbon taxes and Emissions Trading Schemes (ETS), both of which are considered government regulations. These measures are expected to induce behavioural changes toward decarbonisation through price signals and to allow for the reallocation of tax revenues generated by carbon pricing into research and development of low-carbon technologies, as well as providing grants and incentives for businesses and households.

Additionally, carbon credits serve as a mechanism for financing decarbonisation projects. Governments, international organisations, and the private sector are institutionalising schemes to certify emission avoidance, reduction, or carbon removal efforts by one entity, which can then be traded with other entities.

The carbon market is broadly divided into two main types: a mandatory compliance market aimed at achieving Nationally Determined Contributions (NDCs), and a voluntary market that supports the decarbonisation goals of the private sector. In the compliance market, governments impose a tax or cap on carbon emissions from carbon-intensive industries through a carbon tax or ETS, thereby encouraging emission reductions. This system also allows for cost-efficient emission reductions by enabling the trading of surplus emission caps and carbon credits issued outside the regulated sector when targets are exceeded. The voluntary market, on the other hand, facilitates the trading of carbon credits, allowing companies to meet their decarbonisation targets without legal enforcement.

4.6.2 Progress in Forming Carbon Markets in ASEAN

In ASEAN, carbon pricing is increasingly being adopted as a key climate change policy measure across most of the AMS. With growing momentum for decarbonisation in the private sector, including commitments to net-zero targets and net-zero supply chains, voluntary carbon markets are leading the way. Initiatives, such as the development of carbon exchanges, are being implemented to enhance transaction efficiency and transparency.

At the same time, the AMS are beginning to explore the introduction of carbon taxes and ETSs. Indonesia currently operates the region's only ETS, launched in February 2023, which specifically targets emissions from coal-fired power plants. Additionally, a significant milestone in the region's carbon pricing efforts was Singapore's introduction of a carbon tax in 2019. Carbon prices in Indonesia's ETS range from IDR 30,000 to IDR 50,000 (approximately USD 2 to USD 3) per tonne of CO_2. Another significant step in the region's carbon pricing initiatives was Singapore's introduction of a carbon tax in 2019, initially set at SGD 5/tCO_2e (approximately USD 3.70/tCO_2e). Singapore's carbon tax is scheduled to increase progressively to SGD 25/tCO_2e (approximately USD 19.25/tCO_2e) in 2024, SGD 45/tCO_2e (approximately USD 34.65/tCO_2e) by 2026 and 2027, with a view to reach SGD 50-80/tCO_2e (approximately USD 38 – 61/tCO_2e) by 2030.

Table 4.9 Status of Carbon Market in ASEAN

Countries and Current Status	Carbon Pricing in Climate Change Policy	Carbon Tax and Emission Trading System (ETS)	Carbon Crediting
Brunei Darussalam: Carbon Pricing as a Strategy to Mitigate Climate Change	National Climate Change Policy (BNCCP), with Strategy 6 focusing on carbon pricing	ETS or carbon tax undecided. To be started in 2025	Considering collaboration with carbon exchange in other countries
Cambodia: The Journey Towards Carbon Pricing	-	-	International carbon credit can be traded.
Indonesia: Leading the Region with Carbon Trading	Comprehensive approach to carbon pricing through the enactment of the Ministry of Environment and Forestry (MoEF) Regulation No. 21/2022	Implementation of a carbon tax, initially planned for 2022 but postponed to 2025. Coal-fired power plant under ETS starts in 2023	Carbon credit can be traded on government-authorised carbon exchange
Lao PDR: Navigating Carbon Markets	Under development supported by international donors		International carbon credit can be traded.
Malaysia: Exploring Carbon Tax and ETS	The 12th Malaysia Plan in 2021, signalling the consideration of Carbon Pricing Instruments (CPIs)	Malaysia Partnership for Market Implementation (MyPMI) aimed at finalising carbon pricing mechanisms by 2025	Domestic carbon exchange starts operation in 2022, and international carbon credit can be traded.
Myanmar: Developing Policy and Inventory	-	-	International carbon credit can be traded.
Philippines: On the Path to Implementing Carbon Pricing	Government is exploring compliance market, including the potential implementation of a carbon tax and ETS, favoured by the Department of Finance	Low-Carbon Economy Act of 2023, which is currently undergoing a legislative deliberation, aims to establish a national ETS	International carbon credit can be traded.
Singapore: From Initial Steps to Future Ambitions	Carbon pricing is key enabler to achieve revised 2030 NDC target and net zero emission by 2050.	The Carbon Pricing Act 2018 imposing a carbon tax on facilities emitting over $25ktCO_2e$ annually.	Eligible International carbon credits to offset up to 5% of their taxable emissions.
Thailand: Imposing a Carbon Tax on the Energy, Transport and Industrial Sectors	Strategies outlined in its national development plan to use economic instruments for emissions reduction	The carbon tax currently under study for its potential implementation and concurrent preparations include laws for GHG reporting and an ETS	Domestic credit scheme T-VER start in 2013, and Premium T-VER (High quality credit) in 2023.
Vietnam: National Crediting Programme and ETS	Revised Law on Environmental Protection (Decree No.08/2022) enables the creation of carbon pricing	The pilot ETS is scheduled to start voluntarily in 2026, moving to full, mandatory operation by 2028	Pilot NCM targeting the transport and waste sectors and set to launch in 2024, aiming for full operation of Article 6 crediting mechanisms by 2026

Source: ACE. "Progress of Carbon Pricing in ASEAN to Support the Shift Towards a Low Carbon Economy" [153]

In the regulatory framework for carbon pricing, a key consideration is the operational policy across short-, medium-, and long-term timelines, particularly concerning the targeted sectors, facilities under regulation, and the stringency of regulatory levels. For instance, Singapore's carbon tax allows emissions-intensive, trade-exposed (EITE) sectors to utilise transitional allowances under the current legislative framework. The direction of the Global Stocktake (GST) under the Paris Agreement and the Carbon Border Adjustment Mechanism (CBAM) is expected to significantly influence the operational policies of each country. Therefore, nations must periodically review the operation of their compliance markets to adapt to increasing targets and regulatory demands.

Designing and implementing carbon pricing policies in ASEAN is expected to encounter resistance from industry sectors, primarily due to concerns over anticipated energy price increases and the subsequent impact on industrial competitiveness. Given that ASEAN is poised for rapid economic growth in the near future, it is vital to balance economic development with environmental sustainability. Strategic efforts are necessary to build on global carbon pricing knowledge and experiences to develop an effective mechanism for the region.

4.6.3 Impacts on Industrial Competitiveness and Required Measures

The introduction of carbon pricing is a crucial tool for accelerating decarbonisation efforts. However, there are legitimate concerns regarding the potential adverse effects on industrial competitiveness due to rising energy costs. Thus, the detailed design of a carbon pricing system must carefully consider these aspects, ensuring thorough deliberations.

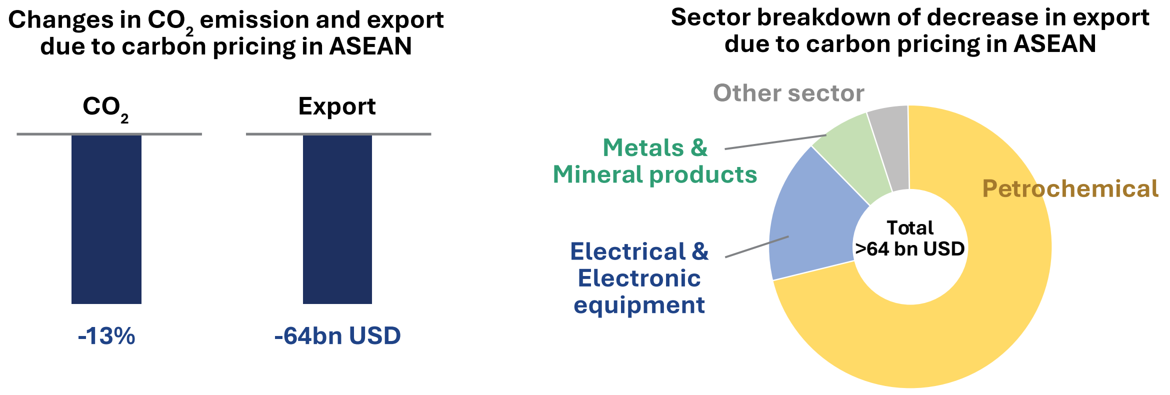
A quantitative evaluation of the impact of carbon pricing in the AMS can be carried out using the Global Trade Analysis Project (GTAP) model. This analysis divides the world into 18 regions, including nine ASEAN countries, and defines 33 industry sectors. For a more detailed assessment of the impact on power composition, the GTAP-E-Power model, which disaggregates the electricity sector, is utilised. Using macroeconomic data, such as population and GDP projections for 2035, the analysis explores the potential impact of applying a uniform carbon price of SGD 80 across ASEAN countries.

As illustrated in Figure 4.7, the introduction of carbon pricing results in a 13% reduction in CO_2 emissions across the AMS. However, the GTAP analysis also reveals notable negative impacts on sectors such as petrochemicals in Thailand and Singapore, as well as on industries including electrical and electronic equipment, metals, and mineral products.

The analysis further indicates that the introduction of carbon pricing would lead to approximately a 15% increase in electricity costs within ASEAN. To maintain industrial competitiveness, it is crucial to ensure that energy costs remain affordable. Thus, an additional analysis was conducted on a scenario where the increase in electricity costs is mitigated by approximately 10%. Under this scenario, ASEAN's industrial competitiveness is enhanced compared to the scenario without mitigation, particularly through increased export volumes in high-value-added sectors such as electrical and electronic equipment.

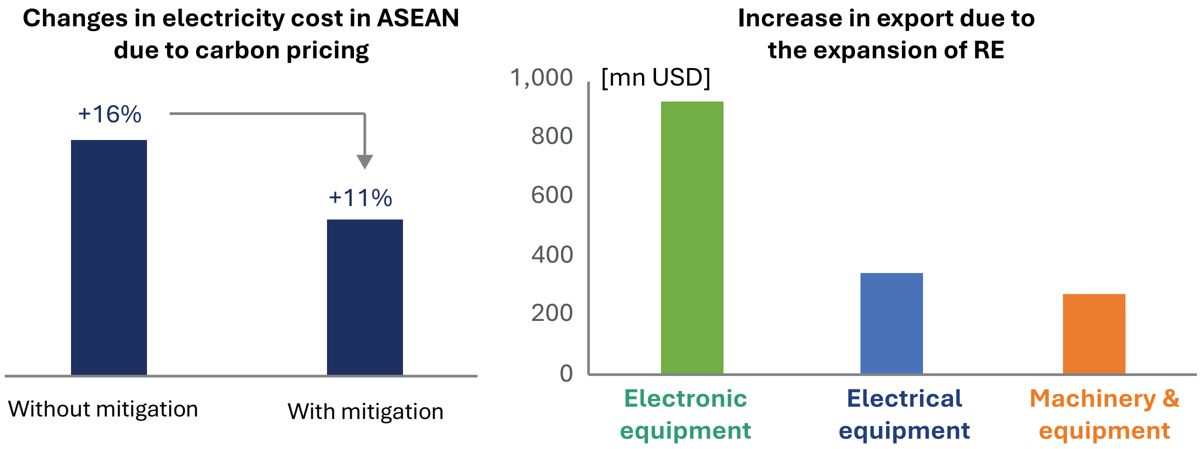
These findings underscore the importance of maintaining affordable energy costs for ASEAN industries, when introducing carbon pricing, ensuring that economic development and environmental goals are harmoniously aligned.

Figure 4.7 Impact of Additional Carbon Pricing in ASEAN Countries



Source: ACE and MRI analysis with GTAP model

Figure 4.8 Impact of Competitive Renewable Energy Expansion in ASEAN Countries



Source: ACE and MRI analysis with GTAP model

4.6.4 Required Measures to Maintain and Enhance Industrial Competitiveness in ASEAN

Based on the GTAP analysis, there are three key strategies to simultaneously achieve CO_2 reduction and economic growth in ASEAN:

1. Detailed Consideration in Carbon Pricing Design: The GTAP analysis highlights the significant impact of carbon pricing on the petrochemical industry, particularly in Thailand and Singapore, where export volumes are expected to decline sharply. Given the higher carbon intensity of chemical products, targeted mitigation measures are crucial. For instance, the European Union's Carbon Border Adjustment Mechanism (CBAM) currently targets fertilisers and hydrogen, but is considering including organic compounds and polymers, which could affect ASEAN economies. Singapore's carbon pricing model, which accounts for carbon leakage in the chemical sector, serves as a useful reference for other countries facing similar challenges.

2. Expansion of Decarbonised Energy: Early expansion of decarbonised energy is essential to reduce energy costs and mitigate the impact on industries. As illustrated in Figure 4.8, maintaining low energy costs is critical for improving industrial competitiveness, particularly in high-value-added sectors. To promote decarbonisation without increasing costs, it is advisable to implement measures with low marginal abatement costs, such as on-site solar power generation and energy efficiency improvements. Additionally, integrating international linkages, such as the ASEAN Power Grid and a trading platform for RE credits, can optimise the use of renewable energy within ASEAN.

3. Industrial Transformation Aligned with Decarbonisation: Transforming the industrial structure to align with decarbonisation is vital for future economic growth. The negative impact on energy-intensive industries indicated by the GTAP analysis underscores the need for institutional frameworks that promote industrial diversification and the development of new industries in line with decarbonisation goals. One approach could involve using carbon pricing revenues to fund the development of new industries and workforce re-skilling. Furthermore, attracting foreign investment is crucial. For global companies, the availability of decarbonised energy is a key factor in investment decisions, making it important for governments to establish favourable procurement environments, such as Power Purchase Agreements (PPA) for RE and renewable value trading schemes.

The analysis indicates that if carbon pricing is introduced without accompanying structural changes in the energy system, there will be negative impacts on trade balances, raising concerns about industrial competitiveness and economic security. Furthermore, the effectiveness of these measures can be enhanced through greater cooperation with ASEAN countries and neighbouring regions, rather than being implemented in isolation. Leveraging existing cooperative frameworks like ASEAN+3 and actively discussing carbon pricing will help promote decarbonisation, whilst supporting economic growth.

Inclusive Transition

Carbon pricing and carbon credit trading have significant potential for raising public revenues in ASEAN and incentivizing reduced carbon emissions for comparatively little cost. Nonetheless, major scandals in the last few years have caused investor confidence in carbon offset trading to drop. It therefore remains a significant challenge to assure investor confidence in these assets. Currently, standards are being developed in the UN to set internationally recognised standards. Early implementation and establishment of rigorous monitoring agencies will likely be crucial for success.

Typically, carbon offset frameworks sell the carbon savings from preserving primary forests and reclaiming former agricultural land into free-growth forests. Several AMS have significant territory of this kind. These territories are inhabited by forest communities and ethnic minorities. These communities hold significant knowledge about how to protect these areas. Community proximity to and familiarity with the territories make them uniquely capable of monitoring these forests. However, these forest communities often rely on the forest for subsistence, cultivating part of the land for agricultural production. Accordingly for these communities to be properly included in this aspect of energy transition, they must be considered and compensated. Training and directly employing local communities in monitoring setups will give these communities a meaningful role in the process. Implementing a gender-equitable hiring ratio is recommended. Hiring should be done in consultation and collaboration with the community. This will ensure that monitoring practices are respectful of local cultural, religious, or social practices, and provide social incentives for community monitors. Secondly, the community must be given a collective stake of ownership in the benefits of carbon offset trading. This can be accomplished by establishing state-of-the-art frameworks for economic benefit sharing.

4.7 Emerging Technologies

4.7.1 Hydrogen and Ammonia

4.7.1.1 Supply and Demand for Hydrogen and Ammonia

As the global demand for cleaner energy options grows, hydrogen is emerging as a promising alternative to enhance energy security. By 2023, the global supply of clean hydrogen increased from 800 ktpa to 860 ktpa [154]. Despite the current high cost and limitation of infrastructure, hydrogen's versatility is evident in its production from various resources and its consumption across multiple sectors. In 2022, global hydrogen consumption reached approximately 95 Mt, predominantly derived from natural gas [155]. The refining industry, which is the largest consumer, utilises around 41 Mt of hydrogen, with over 95% sourced from grey hydrogen [155].

Driven by the goal of achieving net-zero emissions, the global market is increasingly shifting towards clean hydrogen projects to replace fossil fuels and reduce emissions, particularly in hard-to-decarbonise sectors. Currently, electrolysis, especially from renewable sources, accounts for only 4% of hydrogen production. However, this sector is showing promising growth, with a 550 MW increase in electrolysis capacity and a total of 12 GW capacity that reached final investment decisions in 2023 [154], [156]. China leads the electrolysis market, followed by Europe, with installed capacities of 200 MW and 170 MW, respectively [154]. Beyond its role as a feedstock, hydrogen is anticipated to evolve as a reducing agent and, to some extent, as a fuel [155]. The demand for clean hydrogen is expected to rise across various sectors, including transport.

In the near term, blue hydrogen, produced by retrofitting existing infrastructure with Carbon Capture and Storage (CCS) technology, will play a significant role due to its lower production costs as compared to green hydrogen. With an expanding pipeline of projects, the global supply of clean hydrogen is projected to reach 45 Mt per annum by 2030, contributing significantly to carbon emission reductions through technological adaptation [154].

Despite the global momentum, ASEAN's contribution to hydrogen demand remains relatively small, accounting for up to 3.7 Mtpa [157]. Hydrogen production in the region predominantly relies on natural gas, which results in CO_2 emissions as a by-product. Following the global trend, ASEAN's hydrogen demand is primarily directed towards industrial applications, with natural gas playing a significant role in its production [158]. Singapore, Thailand and Indonesia are key players in the refining sector, with daily capacities of 1.13 and 1.10 million barrels in Thailand and Indonesia, respectively, driving significant hydrogen demand [159].

Projections suggest that under a scenario where hydrogen constitutes 10% of the fuel mix in natural gas and hydrogen-fired power plants, ASEAN's hydrogen demand could reach 6.6 Mtoe by 2040. This could result in a 1.5% reduction in total CO_2 emissions, potentially increasing to 2.7% with a 10% to 30% hydrogen share in electricity generation [160]. Hydrogen's utilisation in the region's total final energy consumption is projected to reach 0.1% by 2050, under the RAS, increasing to approximately 1.2% under the CNS.

To accelerate the clean hydrogen market in ASEAN, the region must overcome significant challenges, particularly related to the early stage of hydrogen development and the higher capital investment required. The installation of CCS or Carbon Capture, Utilisation, and Storage (CCUS) technologies, which are classified as blue hydrogen, is expected to bolster the hydrogen economy in the coming years [161]. Amongst the AMS, Malaysia and Indonesia, with their high natural gas production, could utilise flared gas—amounting to 2 bcm and 2.37 bcm, respectively—to produce clean hydrogen and stabilise supply [162].

As the levelised cost of renewables continues to decline, the production cost of green hydrogen is also expected to decrease, particularly during the early market phase. Hydropower, which is prevalent across ASEAN countries, offers a significant opportunity for green hydrogen production. With a levelised cost of USD 0.019/kWh, hydropower in ASEAN, with over 60 GW of capacity, could be leveraged to produce hydrogen through electrolysis, potentially making Lao PDR a hydrogen exporter to meet regional demand [163], [162].

ASEAN's hydrogen production, currently dominated by fossil fuels, is expected to gradually shift towards clean hydrogen as supportive policies are implemented during the market creation phase. Globally, the production of ammonia—an industry closely tied to hydrogen—is projected to reach approximately 688 Mt by 2050, under the IRENA 1.5-degree scenario [164]. ASEAN is a major player in ammonia production, with countries such as Indonesia, Vietnam, Myanmar, Brunei, and Singapore operating ammonia plants for agricultural and chemical purposes, collectively producing around 11.6 Mtpa [157]. Whilst ammonia's primary use remains in production, it could evolve as an energy carrier, providing a clean energy supply solution in the future.

In the hydrogen supply chain, Brunei has been exporting grey hydrogen to Japan since 2019, leveraging its existing gas reserves. Meanwhile, some ASEAN countries are exploring green hydrogen production through existing infrastructure. For instance, the Philippines is exploring the co-firing of natural gas and hydrogen in a 1,000 MW Combined Cycle Plant located in Batangas. Thailand is planning to produce it using a 1 MW electrolyser in Nakhon Ratchasima. Hydrogen adoption in the transport sector is also advancing, with Malaysia developing a hydrogen production plant integrated with a refuelling station and hydrogen fuel cell buses. Singapore followed suit by introducing hydrogen fuel cell buses in 2022 [165].

4.7.1.2 Key Challenges in the Development of Hydrogen and Ammonia in ASEAN

As hydrogen and ammonia utilisation in ASEAN moves through the market creation and growth stages, two primary challenges emerge: (i) financial or economic constraints, and (ii) technological limitations. These challenges span the entire hydrogen value chain, from production (upstream) to transmission or infrastructure (midstream) and demand (downstream).

Financial and Economic Constraints: The cost of producing low-carbon hydrogen, particularly green hydrogen, presents a significant financial challenge. Whilst grey hydrogen production remains cost-effective at USD 1.0–2.2/kg, green hydrogen is considerably more expensive, ranging from USD 3.3–6/kg, depending on technology capacity and utilisation. Blue hydrogen, although cheaper than green hydrogen at USD 2.8–3.5/kg, still costs more than grey hydrogen [166]. The electrolyser stack alone constitutes 33% to 45% of the production cost, with electricity costs accounting for about 50%. Therefore, locating hydrogen facilities in areas with high RE potential is crucial to reducing the Levelised Cost of Energy (LCOE). For blue hydrogen, the fluctuating prices of natural gas or coal, which contribute 50% to 65% of production costs, further complicate financial planning.

Ammonia production in ASEAN faces similar economic challenges, with costs estimated at USD 381/t-NH_3 to USD 489/t-NH_3 by 2030 [167]. High production costs, coupled with limited investment due to uncertainty and long payback periods, hinder market growth. A 3% increase in capital costs could drive up total project costs by more than 30%, further discouraging investment. In blue ammonia production, natural gas costs make up about 50% of total operational costs, adding another layer of financial risk [155].

Technological Limitations: The technological readiness levels of hydrogen and ammonia technologies vary significantly, with many not yet at commercial or mature stages. This affects the availability of upstream technologies and presents challenges in the deployment of midstream infrastructure [168]. **Limited access to RE power plants and end-use sectors, combined with inadequate infrastructure for hydrogen transport**—such as pipelines, refuelling stations, and port facilities—further complicates the situation [169]. The reactive nature of hydrogen, which is unstable and chemically active, poses additional challenges for containment and distribution.

Currently, hydrogen is typically stored and transported as Liquid Organic Hydrogen Carriers (LOHC) due to their low toxicity and chemical stability. However, the process of converting hydrogen to LOHC is costly, requiring high atmospheric pressure and elevated temperatures for hydrogenation and dehydrogenation. Given these challenges, the AMS must enforce strict safety regulations, enhance technical standards for hydrogen facilities, and improve technical literacy concerning hydrogen and ammonia [169].

On the demand side, the limited availability of commercial technologies for end-user sectors, such as industry, transport, and power, is a significant barrier [169]. This **unfamiliarity with hydrogen and ammonia technologies** amongst end-users and project developers leads to perceptions of h**igh investment risks and uncertainty**. To overcome these challenges, it is crucial to accelerate demand for hydrogen and ammonia, which would, in turn, drive supply chain scaling and infrastructure development [155]. This approach would also help mitigate the high investment risks associated with hydrogen and ammonia projects in ASEAN.

In the ASEAN context, a set of enabling policies is needed to stimulate demand for hydrogen and ammonia, aligned with the characteristics of end-user sectors. These demand-driven policies should be combined with supportive measures to **reduce production costs and improve infrastructure access** [170]. In essence, prioritising market-pull policies, complemented by technology-push initiatives, is essential for advancing the hydrogen and ammonia markets in ASEAN.

4.7.1.3 Policy Measures for Hydrogen and Ammonia Utilisation in ASEAN

Measures to accelerate demand for hydrogen and ammonia in ASEAN can be effectively implemented through a combination of market-pull policies, including both incentive or pricing schemes (e.g. tax incentives, feed-in tariffs, guaranteed off-takers, public procurement) and regulatory schemes (e.g. quota targets and standards). Incentive schemes aim to achieve market efficiency, whilst regulatory measures focus on expediting the utilisation of hydrogen and ammonia. A combined approach is highly recommended.

Step 1 Establishing Market Stability: During the market creation stage, ensuring long-term market stability and demand certainty for hydrogen and ammonia in key end-use sectors—such as transport, industry, power, and refining—is critical [169]. This can be achieved by setting clear emission reduction targets to be met through hydrogen utilisation and developing specific strategies for hydrogen and ammonia deployment. Whilst ASEAN has made strides in this direction, there remains a need for a more defined regulatory framework and additional incentives to support hydrogen uptake [171].

Step 2 Selecting Market-Pull Measures: The next step involves selecting a suite of **market-pull policy measures** tailored to the characteristics of key end-user sectors in ASEAN. Whether the region prioritises cost competitiveness or large-scale deployment will determine the appropriate measures. Feed-in tariffs or subsidies are commonly used in market-pull policies for clean technology deployment [172]. For example, Malaysia has used feed-in tariffs to accelerate RE deployment since 2011, similar to Indonesia [169]. Thus, **prioritising incentives** for key end-user sectors is likely to be effective in other areas of ASEAN. Another innovative approach is the **Carbon Contract for Differences (CCfDs)**, which provides subsidies or incentives based on the carbon emissions reduced by using hydrogen or ammonia. The primary goal of these incentives at the market creation stage is to bridge the gap in the initial capital costs faced by key end-users of hydrogen.

Step 3 Enhancing Deployment Speed: Whilst market pull-through incentive measures are effective, they may have limitations in terms of deployment speed and implementation. Therefore, they should be complemented by measures such as **public procurement and quota setting** [156]. These measures do not reduce initial capital costs, but instead aim to achieve specific demand targets for hydrogen usage in key sectors. Under the quota setting approach, governments could **guarantee a certain level of demand for existing hydrogen suppliers**, ensuring a stable market.

Step 4 Addressing Supply-Side Challenges: On the supply side, **technology-push policies** are needed to address upstream (production) and midstream (infrastructure) challenges in hydrogen and ammonia deployment. **Incentives or subsidies** applied on the demand side can also be extended to **producers and infrastructure developers**. These could be combined with **special tax reductions** for key end-user sectors that adopt hydrogen and ammonia. The objective is to lower production costs, **making hydrogen and ammonia more competitive with other fuels**.

Step 5 Leveraging Monetary Policy: **Monetary policy** can play a crucial role in supporting the upstream and midstream segments of hydrogen and ammonia markets. By **lowering interest rates**, the initial capital expenditure (CAPEX) and operational expenditure (OPEX) can be reduced, thereby lowering the investment risk present during the market creation stage. Additionally, creating **demand and supply clusters** can further reduce overall costs and investment risks.

4.7.1.4 Ways Forwards and Potential International Collaboration

ASEAN holds significant potential for hydrogen and ammonia to contribute to its carbon neutrality target by 2050. However, the region faces considerable challenges due to its nascent stage of development in this sector, characterised by high levels of uncertainty. This uncertainty stems from **unstable demand, high production costs, and investment risks,** which are further compounded by limited technological capacity. To address these challenges, ASEAN must design policy measures that leverage **regional energy cooperation** with neighbouring countries and dialogue partners.

Given the limited domestic demand during the market creation stage, one strategic approach is **to export hydrogen to ASEAN's neighbouring countries, which have higher demand**. For example, Japan is expected to increase its hydrogen consumption to around 3 Mtpa by 2030, and 20 Mtpa by 2050. South Korea also projects significant demand, particularly for fuel-cell EVs, with an estimated 2.9 million vehicles by 2040 [156], [173]. ASEAN has already engaged in international collaborations on hydrogen, such as **the Advanced Hydrogen Energy Chain Association for Technology Development (AHEAD)**, which in 2020 marked a milestone by exporting 210 tonnes of grey hydrogen from Brunei Darussalam to Japan [174]. Additionally, the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE) serves as a knowledge-sharing platform for stakeholders, focusing on technology assessment, regulation, and capacity building [175].

International collaboration is crucial for **securing the investment needed** to accelerate hydrogen and ammonia development in ASEAN. Policy measures designed to stimulate demand and reduce production costs require **substantial financial support**, which can be sourced from both domestic and international avenues. Notable examples include Germany's Hydrogen Core Network Financing Act, South Korea's New Deal Fund, and Japan's Climate Transition Bond, all of which represent significant public investments in hydrogen [176], [177], [178]. Furthermore, multilateral development banks like the Asian Development Bank (ADB) and the World Bank offer specific financial instruments aimed at de-risking investments in hydrogen, providing additional sources of funding to accelerate progress in ASEAN.

4.7.2 Nuclear

4.7.2.1 Reconsidering the Nuclear Option

Nuclear energy plays a crucial role in global decarbonisation and the energy transition. It is widely regarded as a low-carbon and reliable energy source, contributing about 10% of the world's electricity supply. At COP28 in December 2023, leaders from 24 countries committed to tripling nuclear power capacity by 2050, aiming to meet rising electricity demands, whilst adhering to the 1.5-degree climate target [179]. This commitment was further solidified during the First Nuclear Energy Summit in Brussels, where national leaders, industrial stakeholders, and international organisations gathered to support innovation, ensure a skilled workforce, develop necessary infrastructure, and facilitate investment mobilisation for future Nuclear Power Plant (NPP) deployment [180].

According to the World Nuclear Association's 2023 Nuclear Performance Report, nuclear power generated a total of 2,545 TWh globally, with an average capacity factor of 80.5%. The Asia region, in particular, saw significant growth, with a 37 TWh increase in nuclear electricity generation. This positive trend is reflected in the construction of around 40 new NPPs and plans for more than 50 additional units across Asia [181]. Beyond electricity generation, nuclear energy's applications are expanding to include hydrogen production, water desalination, and district heating, with various stages of research, prototyping, and operational technology being explored. Additionally, the concept of repurposing retired coal power plants into nuclear power facilities, particularly using Small Modular Reactors (SMRs), is under pre-feasibility assessment [182].

Safety remains a paramount concern in nuclear power deployment, especially in the wake of the Fukushima accident, which significantly impacted global nuclear safety standards. The incident prompted a shift from merely preventing design basis accidents (DBAs), to preventing severe accidents and mitigating their consequences.

This has led to extensive global efforts to enhance the safety of nuclear facilities, including robust and diverse systems to respond to accidents and extreme events. Japan and the international community have made considerable progress in nuclear safety over the past years. The International Atomic Energy Agency (IAEA) has emphasised that nuclear power is now safer than ever, reflecting the industry's ongoing commitment to safety improvements [183], [184].

4.7.2.2 Nuclear Energy in the ASEAN Context

The AMS are signatories of the International Atomic Energy Agency (IAEA) safeguard agreement and the additional protocol under the Non-Proliferation Treaty (NPT), demonstrating the region's commitment to the peaceful use of nuclear energy. Furthermore, nuclear safety, security and safeguards (3S) are being effectively implemented in the region, with some AMS incorporating 3S principles into their national legal and regulatory frameworks.

The AEO8 predicts that nuclear energy will be introduced in the region after 2030, starting with an initial capacity of 3.4 GW, and potentially increasing to around 10 GW by 2050. Although there are currently no operational nuclear power plants in ASEAN, nuclear energy remains an attractive option for many countries in the region as they plan to achieve carbon neutrality or net-zero emissions targets.

Indonesia's Nuclear Ambitions

Indonesia is considering including nuclear power in its energy mix as part of its Net Zero Emissions (NZE) 2060 target. Plans are underway to develop an initial 320 MW of nuclear capacity by 2035, which could expand to 9 GW by 2060 [185]. The country is currently establishing the Nuclear Energy Programme Implementing Organisation (NEPIO), an ad hoc body designed to coordinate stakeholders and prioritise activities related to the deployment of nuclear power plants (NPPs). Indonesia has also developed relevant legal and regulatory frameworks, addressing issues such as safety criteria, licensing, siting, and waste management for NPPs. In support of these efforts, the state electricity company, PLN, signed an MoU with Korea Hydro & Nuclear Power (KHNP) and the U.S. Trade and Development Agency (USTDA) in 2023, to conduct a pre-feasibility study on Small Modular Reactor (SMR) applications in Indonesia [186], [187]. Additionally, the U.S.-based Thorcon Power intends to develop a thorium-fuelled advanced nuclear reactor using molten salt reactor (MSR) technology in the Bangka Belitung region [188].

The Philippines' Nuclear Considerations

The Philippines plans to commission its first NPP by 2032, with an initial capacity of 1,200 MW. The country aims to gradually increase this to 4,800 MW by 2050, alongside RE sources, to diversify its clean energy portfolio. To enhance national coordination, the Nuclear Energy Programme Inter-Agency Committee (NEP-IAC) was established, initially comprising 11 agencies, with 13 more invited under Executive Order 116, making a total of 24 agencies involved. NEP-IAC is divided into six sub-committees focusing on the 19 nuclear infrastructure issues identified by the IAEA. In 2024, NEP-IAC's priorities include assessing and developing nuclear energy plans, engaging with stakeholders, completing a nuclear energy roadmap, and continuing to develop siting assessments, legal and regulatory frameworks, and emergency preparedness plans.

Singapore's Exploration of Advanced Nuclear Technology

In its Energy Committee 2050 report, Singapore identifies nuclear energy as a potential long-term energy option, alongside other clean energy sources. Although a 2012 pre-feasibility study concluded that conventional large nuclear reactors were unsuitable for deployment in Singapore, advancements in nuclear technology suggest that newer designs, such as SMRs, could play a significant role in the future. Singapore should establish the necessary enablers to adopt these technologies quickly if it decides to deploy them [189].

Thailand's Interest in Small Modular Reactors

Thailand is also considering the inclusion of SMRs in its revised Power Development Plan (PDP). Whilst the final version of the PDP is still under review, the country's interest in nuclear energy is noteworthy. In line with national nuclear energy planning, Thailand's Global Power Synergy Public Company Limited (GPSC) signed an MoU with Denmark's Seaborg Technologies to assess the technical feasibility and commercial viability of constructing a floating SMR in Thailand [190].

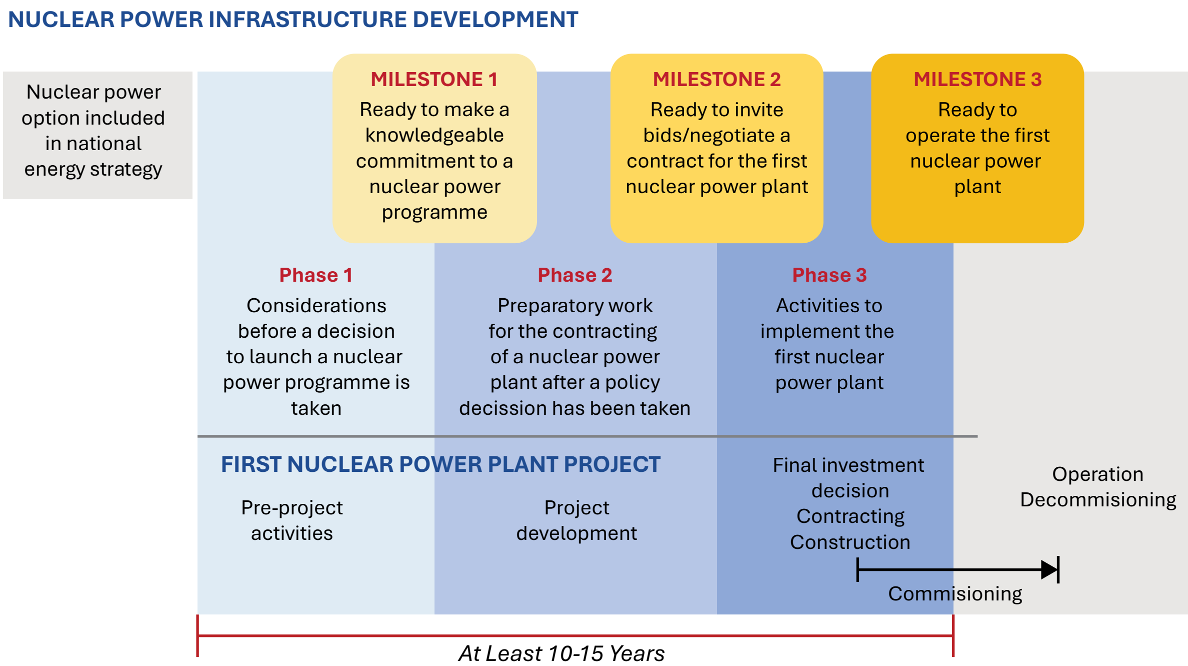
Vietnam's Renewed Interest in Nuclear Energy

After halting its nuclear power programme in 2016, Vietnam appears to be reconsidering nuclear energy as part of its strategy to achieve a 2050 NZE target. Nuclear power is included in the 2024 Vietnam Energy Outlook, with plans to begin supplying electricity by 2040, and potentially increasing capacity to 28 GW by 2050, under an ambitious net-zero scenario (NZ+) [191]. Vietnam has a long history of nuclear planning, dating back to 1995, and has already established regulations on NPP licensing, safety standards, and siting, integrating them into the national legal framework [192].

4.7.2.3 Pathway to Nuclear: What are the Priorities?

To assist the embarking countries in their nuclear project preparation, the IAEA has developed important guidelines, namely Milestone in the Development of a national Infrastructure for Nuclear Power [193]. It compasses three milestones, three phases, and 19 key infrastructure issues that require specific actions:

Figure 4.9 Development of the Infrastructure for a National Nuclear Power Programme



Source: IAEA [193]

Figure 4.10 Infrastructure Issues in NPP development

The 19 infrastructure issues			
1. National position	2. Nuclear safety	3. Management	4. Funding and financing
5. Legal framework	6. Safeguards	7. Regulatory framework	8. Radiation protection
9. Electrical grid	10. Human resource development	11. Stakeholder engagement	12. Site and supporting facilities
13. Environmental protection	14. Emergency preparedness and response	15. Nuclear security	16. Nuclear fuel cycle
17. Radioactive waste management	18. Industrial involvement	19. Procurement	

Source: IAEA [193]

Whilst the guidelines are based on best practices from years of global experience in NPP development, they are not meant to be prescriptive or universally applicable. However, the AMS may wish to consider the following key issues before taking action:

1. National Position on Civilian Nuclear Energy

NPP projects involve long life cycles, from preparation and construction through to operation, dismantling, and decommissioning, potentially spanning multiple generations. The decision to construct an NPP will impact not only the current population but also future generations, requiring a strong political commitment from the national government grounded in scientific and informed approaches, as well as careful long-term planning. It is essential to conduct comprehensive feasibility studies that examine electricity supply-demand outlooks, grid expansion, NPP siting, socio-economic and environmental impacts, nuclear technology options, and workforce requirements, amongst other considerations. Another critical government role in the early stages is to foster strong coordination amongst relevant nuclear stakeholders, including government bodies, regulatory authorities, and industrial players, to avoid conflicting roles, functions, and authorities in NPP development. Once a decision is made to pursue nuclear energy, the government must ensure the creation of supportive policies and the designation of a competent authority to establish the necessary legal and regulatory framework for nuclear energy.

2. Safety Aspect: Technology Maturity vs Advanced Technology Challenges

The safety of the nuclear industry is closely linked to the maturity of its technology. Past nuclear accidents, such as those at Chernobyl, Three Mile Island (TMI), and Fukushima, have set new safety benchmarks and higher safety requirements for NPP technology. Mature technologies, such as Light Water Reactors (LWRs), Pressurised Water Reactors (PWRs) and Boiling Water Reactors (BWRs), have undergone significant safety improvements following incidents like TMI and Fukushima. However, these enhancements, which include additional passive systems and more safety components, have led to higher costs for Generation III/III+ NPPs, despite their longer operational lifetimes (80+ years). Countries must conduct thorough cost-benefit analyses of NPP projects across their entire life cycle, from preparation to decommissioning and waste management.

Advanced technologies, such as Small Modular Reactors (SMRs), offer potential benefits in terms of enhanced safety parameters and greater economic competitiveness due to their modularity and smaller size compared to conventional large-scale NPPs. However, challenges exist for countries interested in adopting novel technologies like SMRs, as they require new approaches to licensing and regulatory frameworks for safety assessments, given the limited operational experience with these technologies compared to conventional NPPs. The AMS may refer to IAEA or other international safety standards when developing national regulations related to NPP safety requirements, encompassing all phases from siting, design, and construction, to operation and waste management. Additionally, governments must support the necessary funding to develop national competence in regulatory authorities responsible for overseeing nuclear energy programmes.

3. Bankability of Nuclear Project: Attracting Investment and Other Source of Funding

Nuclear energy projects present unique risks and challenges, characterised by high technical complexity, stringent regulatory requirements, long construction durations, high capital costs, low and stable operating costs, and very long operational lifetimes. As depicted in Figure 4.11, it is possible to identify and estimate project focus and cost percentages at every step of the nuclear power project. Due to these characteristics, market-based mechanisms alone are insufficient to finance nuclear projects, necessitating the involvement of national governments. Creating the right economic conditions and attracting sufficient capital to successfully plan, build, operate, and eventually dismantle NPP projects will be challenging [194].

Figure 4.11 Indicative Duration and Cost of Various Stages in the Lifecycle of a Nuclear Power Plant in OECD Countries

	Development	Construction	Commissioning	Operations	Decommisisioning
Duration (Years)	6 to 8	7 to 10	1 to 2	60 to 80	20 to 30
Share of Cost (%)	~10	~50	~2-3	~35-40	~1-5
Key Activities	Design, tendering, and permitting	Materials, labour, and civil works	Non-nuclear tests, fuel loading, and nuclear tests	Fuel, operations, maintenance, and waste management	Reactor shutdown, removal nuclear material, and plant demolition

Source: Baringa Report [195]

Initial funding for NPP infrastructure development is likely to come from government sources. Financing for the first NPP can be pursued through various avenues, typically involving a combination of debt and equity from several sources, including the host government. The availability and scale of such financing will depend on the country's economic situation, and some nations may face significant constraints. Export financing is often a crucial source of debt funding for NPPs, though it will only cover part of the total investment. Local or foreign commercial debt may also be required, potentially supported by government guarantees. These guarantees could be direct, such as loan repayment assurances to lenders, or indirect, such as power purchase agreements or market regulations that secure sufficient revenue from electricity sales [193].

Multilateral development banks (MDBs) and multilateral infrastructure banks (MIBs) have proven capable of mobilising public and private investments in the energy sector. These institutions offer various financial mechanisms, including loans, equity investments, public-private partnerships, and blended finance. However, most MDBs and MIBs currently exclude nuclear power projects from their financing portfolios. A potential future solution is the proposed International Bank of Nuclear Infrastructure (IBNI), which would provide funding not only for nuclear construction, but also for nuclear fuel production, waste management, plant life extensions, supply chain development, and R&D on advanced nuclear technologies. The bank's specific focus on nuclear would allow it to deploy its technical expertise to assess programmes, manage risk, and implement effective financing strategies. Establishing the IBNI would work alongside efforts to encourage policy changes within existing MDBs and MIBs to include nuclear projects in their financing portfolios. Such policy shifts would greatly benefit economic development and climate change mitigation efforts [194].

4. Developing Human Resources for Nuclear Power Project

Having sufficient skilled and trained human workforces is important factor in ensuring safe operation nuclear power plants. The unique aspects of nuclear power related to **safety, security and safeguards** requires an organizational culture and individual attitudes that ensure these issues are given the highest priority. However, developing the culture takes time and effort for all the key organizations, particularly the owner/operator and regulatory body. The time from recruiting an individual with suitable educational background for a position to when that individual is fully qualified to work in the nuclear sector can be longer than for many other fields. The lead-time for certain positions in the owner/operator can be five to ten years (e.g. licence engineer, operational planning, shift supervisor, emergency planning engineer, and plant manager). Therefore, the workforce plan needs to identify when these individuals need to be recruited, considering training lead times, and when they are needed to perform their job function. The AMS need to anticipate and conducting the supply-demand analysis, i.e. demand from the nuclear industry and stakeholders; supply from the education and training institutes, then formulate strategy to avoid the gap on the issues. Another important step in the human workforce strategy are the outreach and engagement programmes with educational institutions — from primary school to university — which will help to attract suitable candidates and will also foster greater public understanding regarding nuclear power technologies. These programmes need to be included in the national stakeholder involvement and public communication plans [196].

CHAPTER 5

RECOMMENDATIONS AND IMPROVEMENTS

Chapter 5 - Recommendations and Improvements

5.1 Policy Recommendations

As part of the action plan under the APAEC REPP Programme, the ASEAN Energy Outlook (AEO) aims to support the AMS in strengthening regional energy cooperation by providing insights into the current energy landscape, outlining pathways to achieve regional targets, and analysing future energy scenarios. The modelling in AEO is highly dependent on key assumptions and methodologies detailed in the relevant chapters and appendices. As such, the results should be interpreted as potential future scenarios rather than definitive forecasts, as they reflect the current context, modelling assumptions, and projections. Despite this, the AEO8 modelling exercises are a useful tool for evaluating the effects of policy actions or inaction. Recommendations are based on analysis of recent statistics, policy frameworks, national priorities, scenario results, technology developments, and other trends in the energy sector.

5.1.1 Demand Side

The total final energy consumption (TFEC) in ASEAN is projected to increase by 1.7 times by 2050, as compared to 2022 levels. Even with the implementation of national targets and policies, there is room for further progress. The AMS should not only enhance national energy efficiency standards for buildings, appliances, and industrial processes, but also work towards a harmonised regional framework that can further reduce overall energy consumption and ease the strain on the energy system. Energy efficiency and conservation (EE&C) is often regarded as the "first fuel" for the energy transition.

In the industrial sector, which is the largest consumer of energy in the region, energy efficiency improvements can be achieved by upgrading equipment. The AMS should invest in energy-efficient machinery and technologies, such as high-efficiency motors and variable frequency drives, to reduce energy consumption and operational costs. Optimising industrial processes through the implementation of energy management systems, waste heat recovery, and improved insulation can also significantly reduce energy intensity.

In the power sector, smart demand response (SDR) can contribute to energy efficiency by optimising energy use, reducing consumption, and enhancing grid efficiency, particularly as more RE sources are integrated. SDR works by adjusting energy usage based on grid conditions and availability. Through real-time adjustments, automated controls, and consumer engagement, SDR helps lower energy bills, reduce infrastructure costs, and promote long-term sustainability. By improving overall energy management, SDR plays a crucial role in creating a more efficient and environmentally friendly energy system.

5.1.2 Supply Side

Addressing energy security during the transition to cleaner energy involves balancing the shift to renewable sources with the need for reliable, affordable, and stable energy supplies. As ASEAN countries host many relatively new coal power plants, phasing out coal immediately poses challenges. Transitional technologies, such as natural gas and Carbon Capture and Storage (CCS), offer potential solutions. Natural gas, with lower emissions than other fossil fuels, can act as a bridge to cleaner energy, particularly through the utilisation of existing infrastructure. For example, gas infrastructure can be upgraded to transport, store and distribute hydrogen, with pipelines and storage facilities adapted to accommodate hydrogen's properties.

By integrating CCS technologies, industries and power plants can continue operating with a reduced carbon footprint, supporting the transition to cleaner energy and contributing to global climate goals. Despite challenges, such as cost and scalability, advancements in CCS technology could enhance its role in climate change mitigation and sustainable development.

Diversifying energy sources, particularly through RE, is crucial for reducing dependence on any single source and improving overall stability. Renewable sources like hydro, geothermal, bioenergy, solar, and wind are key to this approach. Hybrid systems that combine RE with traditional fuels can ensure stable energy supply despite the intermittency of renewables. For instance, solar PV systems combined with diesel generators can provide RE during the day, whilst diesel serves as a backup at night or during periods of low solar output. These systems are particularly beneficial in remote or off-grid areas, improving access to electricity throughout the AMS. Biomass-coal hybrid systems are another option, where biomass is co-fired with coal, lowering emissions whilst leveraging renewable resources.

Hybrid systems play a vital role in bridging the gap between the variability of RE and the need for reliable power. They offer flexibility, enhance energy security, and reduce overall emissions, as compared to conventional fossil fuel systems. These systems are particularly valuable in ASEAN, where the reliance on variable renewable resources and limited energy storage solutions make energy diversification crucial.

To maximise the benefits of energy diversification, the AMS must upgrade their energy infrastructure. “There is no transition without transmission.” Modernising electrical grids is essential for integrating renewable sources and improving transmission efficiency. Investments in smart grid technologies, which can better manage supply and demand, are necessary to enhance grid reliability and seamlessly incorporate RE sources.

Energy diversification should extend beyond the power sector to other sectors, particularly industry and transport, which remain heavily reliant on fossil fuels. In the industrial sector, biomass from agricultural residues and wood waste can be used as a fuel for heat generation. Thermal storage systems can store excess heat from industrial processes for later use.

In the transport sector, ASEAN has significant experience in fuel shifting, particularly from oil to biofuels and electricity. Biofuel mandates, such as those in Indonesia and the Philippines, provide lessons for other countries. Whilst many of the AMS have EV policies, they are primarily focused on increasing sales or production, rather than significantly boosting EV penetration in local markets. This may limit the impact of EVs on electricity consumption in the transport sector, as some produced vehicles are likely to be exported.

Looking ahead, alternative energy sources like hydrogen and Sustainable Aviation Fuel (SAF) offer promising avenues for decarbonising transport. Hydrogen fuel cell vehicles (FCVs), for example, offer longer ranges and faster refuelling times, as compared to battery EVs (BEVs), making them ideal for long-distance travel and heavy-duty applications such as buses, trucks and trains. SAF, produced from renewable feedstocks, provides a cleaner alternative to conventional jet fuel, with ongoing advancements expected to improve its cost and availability.

Investing in these emerging technologies, alongside established measures like biofuels and EVs, will be crucial for supporting decarbonisation in ASEAN’s transport sector.

5.1.3 Regional Cooperation

To implement the recommended measures in both the demand and supply sectors, it is essential to establish supportive regulatory frameworks and policies that promote investment in clean and efficient energy technologies, whilst also ensuring energy security and affordability. Governments must offer financial incentives, subsidies, and funding opportunities for infrastructure upgrades and innovations, which are crucial for a successful transition to cleaner energy sources.

International cooperation can significantly contribute by enabling countries to share best practices, technologies, and resources. At the regional level, ASEAN has already benefitted from its ASEAN Plan of Action for Energy Cooperation (APAEC), which outlines a firm blueprint for regional energy cooperation. This plan includes many action points, such as collaborations with international organisations and dialogue partners. The AMS should ensure the involvement of various stakeholders—including policymakers, businesses, and communities—throughout the energy transition planning process. This approach will help garner broad support and address concerns related to energy security. Public education campaigns will also play a crucial role in informing people about the benefits and challenges of transitioning to cleaner energy, whilst promoting energy efficiency and conservation.

Additionally, international agreements aimed at enhancing energy interconnectivity and flexibility will be key to achieving these goals. The ASEAN Power Grid can help address both energy security and sustainability challenges by promoting regional energy sharing and cooperation. Furthermore, the AMS should invest in cross-border infrastructure like pipelines and interconnectors to improve the flexibility and resilience of gas supply, facilitating the efficient transport of renewable gases across the region.

Collaboration with a wide range of stakeholders—such as utilities, regulators, and industry experts—is essential to ensuring that infrastructure improvements are aligned with energy transition objectives. Engaging stakeholders from diverse disciplines ensures that various perspectives are considered, leading to solutions that are more effective, widely accepted, and responsive to local needs and concerns.

5.2 AEO Enhancements

The ASEAN Energy Outlook (AEO) has evolved through multiple editions, each providing a unique perspective on potential energy pathways for the region. No edition is deemed superior, as each addresses specific themes and projections. For instance, whilst AEO6 explored pathways to achieving SDG7 targets, and AEO7 focused on least-cost optimisation (LCO) in the power sector, AEO8 integrates regional aspirations and LCO scenarios, as well as carbon neutrality goals. By incorporating recent energy developments and global trends, key assumptions are regularly updated, which can affect results and their interpretation compared to earlier studies. The continuous refinement of ACE's AEO model lays the groundwork for future analyses, providing a strong basis for ASEAN energy policymaking.

5.2.1 Optimising All Sectors

In terms of sectoral optimisation, AEO8 builds on the foundation laid in previous editions by expanding the application of the LCO method. AEO7 applied this method to the power sector for the first time, and AEO8 extends it to two scenarios. The optimisation process considers a wide range of costs, such as fuel, transmission, CAPEX, and OPEX, which vary across technologies and countries. Updating these data for each AMS is critical, as the costs can differ significantly.

Beyond electricity supply, AEO8 applies the LCO approach to the demand sector using a different tool, although this method has limitations that require further refinement. Despite efforts to harmonise assumptions, models built using two different software programmes may produce varying outcomes. Both models have undergone testing to assess the impact of changing input parameters, but additional validation is necessary to ensure that results from the two models are comparable.

Optimising sectoral energy consumption involves even more complexities, particularly due to the diverse types and brands of end-user appliances across the AMS. The sheer variety of products, such as cars and light bulbs, can lead to the omission or generalisation of purchase costs in calculations. Acquiring technology cost data for specific sectors, such as industrial boilers, is especially difficult due to market sensitivities, confidentiality, and complex pricing structures. These prices often account for factors like installation, maintenance, and warranties, making direct cost comparisons challenging. To overcome these issues, access to private industry reports, direct engagement with technology vendors, and consultation with experts are necessary to obtain accurate and reliable data for optimising energy consumption across different sectors.

5.2.2 Incorporating Interdisciplinary Analysis

Integrating cross-disciplinary information into energy modelling enhances the accuracy, depth and utility of such models by incorporating insights from diverse academic and professional fields. Data from economics, engineering, environmental science, and sociology, for instance, contribute to a more holistic understanding of energy systems. This interdisciplinary approach allows models to better capture the complex interactions between technological advancements, economic policies, and social behaviours, offering a nuanced picture of how these factors influence energy consumption and production. By considering the impact of economic policies on energy use or the influence of societal behaviour on energy efficiency, the model can provide more realistic projections.

A key area for incorporating cross-sectoral insights is in cost data, where projections must account for a wider array of lifecycle factors, including materials, end-of-life disposal, and non-technical elements like regulatory or societal influences. This process requires considering the externality costs of using certain energy sources, such as pollution of air, water and land resulting from emissions and waste in both end-use and power generation. These environmental impacts, particularly their effects on public health and societal well-being, should be quantified and incorporated into the modelling process. By including these externalities, energy models may favour cleaner, more sustainable options, shifting the outcomes toward lower-carbon solutions.

By integrating interdisciplinary data, energy models not only become more robust, but also more reflective of real-world complexities. This leads to decision-making that balances technical feasibility, economic viability, environmental sustainability, and social acceptability. A model built with this approach supports more informed and balanced energy policies, which are crucial for sustainable development and addressing global energy challenges.

5.2.3 Disaggregating Data

AEO8 has enhanced its modelling framework by providing a more detailed and technology-rich depiction of the energy system, which allows for a more in-depth analysis of policies and scenarios. However, these advancements have also highlighted several challenges, particularly due to the lack of more granular data. Access to disaggregated data is essential for improving the accuracy of the model and aiding the development of more targeted policies. Such data would allow for more precise identification of areas of need or opportunity, supporting better decision-making by providing insights into the impacts and effectiveness of different strategies.

One of the improvements in this Outlook is its representation of the commercial sector, which is now segmented based on technology adoption, similar to the residential sector, rather than by building types. This approach helps identify the appliances contributing most to energy consumption and GHG emissions in the commercial sector. As a result, energy efficiency and conservation efforts can be directed toward specific end-use devices. Nevertheless, further improvements are possible. For example, with the rise of digitalisation, many commercial buildings, such as offices, now include data centres. These facilities, which house computing and networking equipment, consume substantial energy, particularly for network switches, power supplies, and cooling systems [197].

In the industrial sector, further refinements could involve a more accurate representation of specific processes, especially within the subsectors covered in AEO8. Overcoming the current data limitations, which prevent a finer disaggregation of these subsectors, is critical for improving the model. Regular updates to the existing assumptions are also necessary to stay aligned with evolving global energy markets and trends.

Disaggregating data beyond the energy system is also crucial to support interdisciplinary analysis, enabling more informed decision-making. For instance, indicators such as electricity expenses relative to income and gender-related metrics should be incorporated to ensure a holistic understanding of energy systems and their societal impacts. Currently, there is a scarcity of consolidated data on energy-gender interactions, which results in this aspect being underexplored. Gender-disaggregated data is essential for supporting this nexus, yet this Outlook has not yet modelled gender-specific outcomes. Therefore, it is imperative that future analyses prioritise improvements in this area.

Appendix A - Abbreviations

AAGR	Annual Average Growth Rate
ACCEPT	ASEAN Climate Change and Energy Project
ACE	ASEAN Centre for Energy
ADB	Asian Development Bank
AEC	ASEAN Economic Community
AEDS	ASEAN Energy Database System
AEO	ASEAN Energy Outlook
AEO6	The 6th ASEAN Energy Outlook
AEO7	The 7th ASEAN Energy Outlook
AEO8	The 8th ASEAN Energy Outlook
AERN	ASEAN Energy Regulators Network
AHEAD	Advanced Hydrogen Energy Chain Association for Technology Development
AI	Artificial Intelligence
AIMS	ASEAN Interconnection Masterplan Study
AMS	ASEAN Member States
AMEM	ASEAN Ministers of Energy Meeting
APAEC	ASEAN Plan of Action for Energy Cooperation
APERC	Asia-Pacific Energy Research Centre
APG	ASEAN Power Grid
APGCC	ASEAN Power Grid Consultative Committee
ASCOPE	ASEAN Council on Petroleum
ASEAN	Association of Southeast Asia Nation
ATS	AMS Target Scenario
BAS	Baseline Scenario
BAT	Best Available Technology
BAU	Business as Usual
BECCS	Bioenergy with CCS
BESS	Battery Energy Storage System
BEV	Battery EV
BNCCP	Brunei National Climate Change Policy
BOO	Build-Own-Operate
BOOT	Build-Own-Operate-Transfer
BRI	Belt and Road Initiative
BWR	Boiling Water Reactor
C&I	Construction and Installation
CAGR	Compound Annual Growth Rate
CAPEX	Capital Expenditure
CBAM	Carbon Border Adjustment Mechanism
CBDR–RC	Common But Differentiated Responsibilities and Respective Capabilities
CCfD	Carbon Contract for Difference
CCS	Carbon Capture and Storage
CCUS	Carbon Capture Utilisation and Storage
CFPP	Coal-Fired Power Plant
CN	Carbon Neutrality
CNG	Compressed Natural Gas
CNOOC	China National Offshore Oil Corporation
CNS	Carbon Neutrality Scenario
CO_2	Carbon Dioxide
COP28	The 2023 United Nations Climate Change Conference of Parties
CPI	Carbon Pricing Instrument
CSPF	Cooling Seasonal Performance Factor
DAC	Direct Air Capture

DBA	Design Basis Accident
DEIP	Distributed Energy Integration Programme
DER	Distributed Energy Resources
DF	Decline Factor
DLC	Direct Load Control
DOE	Department of Energy
DR	Direct Response
DSM	Demand Side Management
EBT	Energy Balance Table
EDC	Electricite du Cambodge
EdL	Electricite du Laos
EE	Energy Efficiency
EE&C	Energy Efficiency and Conversation
EF	Employment Factor
EGAT	Electricity Generating Authority of Thailand
EGIB	Efficient Grid-Interactive Buildings
EI	Energy Intensity
EITE	Emissions-Intensive Trade-Exposed
ENTSO-E	European Network of Transmission System Operators
EPC	Engineering, Procurement and Construction
ESCO	Energy Service Company
ETP	Energy Technology Perspectives
ETS	Emissions Trading Schemes
EV	Electric Vehicle
EVN	Vietnam Electricity
FCV	Fuel Cell Vehicle
FDI	Foreign Direct Investment
FPIC	Free, Prior, and Informed Consent
FSRU	Floating Storage And Regasification Unit
GAMS	General Algebraic Modelling System
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GPSC	Global Power Synergy Public Company Limited
GST	Global Stocktake
GTAP	Global Trade Analysis Project
HAPUA	Heads of ASEAN Power Utilities/Authorities
IAEA	International Atomic Energy Agency
IBNI	International Bank for Nuclear Infrastructure
ICE	Internal Combustion Engine
IEA	International Energy Agency
IoT	Internet of Things
IPHE	International Partnership for Hydrogen and Fuel Cells in the Economy
IRENA	International Renewable Energy Agency
KHNP	Korea Hydro & Nuclear Power
LCO	Least-Cost Optimisation
LCOE	Levelised Cost of Energy
LEAP	Low Emissions Analysis Platform
LED	Light Emitting Diode
LFP	Lithium Ferro-Phosphate
LNG	Liquified Natural Gas
LOHC	Liquid Organic Hydrogen Carriers
LOI	Letter of Intent
LPG	Liquefied Petroleum Gas
LR	Load Research

LTMS-PIP	Lao PDR-Thailand-Malaysia-Singapore Power Integration Project
LWR	Light Water Reactor
MDB	Multilateral Development Bank
MEPS	Minimum Energy Performance Standards
MIB	Multilateral Infrastructure Bank
MoEF	Ministry of Environment and Forestry
MoU	Memorandum of Understanding
MSR	Molten Salt Reactor
MyPMI	Malaysia Partnership for Market Implementation
NDCs	Nationally Determined Contribution
NEEP	National Energy Efficiency Policy
NEMO	Next Energy Modelling System for Optimisation
NEP	National Electrification Plan
NEP-IAC	Nuclear Energy Programme Inter-Agency Committee
NEPIO	Nuclear Energy Programme Implementing Organisation
NPP	Nuclear Power Plant
NPT	Non-Proliferation Treaty
O&M	Operation & Maintenance
OECD	Organisation for Economic Co-operation and Development
OPEX	Operational Expenditure
P2P	Peer to Peer
PCI	Projects of Common Interest
PED	Priority Economic Deliverable
PDP	Power Development Plan
PHS	Pumped Hydro Storage
PLN	National Electricity Company / Perusahaan Listrik Negara
PPA	Power Purchase Agreement
PPP	Public-Private Partnership
PPP	Purchasing Power Parity
PUE	Power Usage Effectiveness
PV	Photovoltaic
R/P	Reserves-to-Production
PWR	Pressurised Water Reactor
R&D	Research and Development
RAS	Regional Aspiration Scenario
RADPLAN	Radiological Emergency Preparedness and Response Plan
RE	Renewable Energy
REPP	Regional Energy Policy and Planning
REC	Renewable Energy Certificate
RE-SSN	Renewable Energy Sub-Sector Network
RF	Regionality Factor
SAF	Sustainable Aviation Fuel
SAPP	Southern African Power Pool
SDG	Sustainable Development Goal
SDR	Smart Demand Response
SLNG	Singapore LNG
SMR	Small Modular Reactor
SOME	Senior Officials' Meeting on Energy
SPP	Smart Power Program
SSN	Sub-Sector Network
SSP	Shared Socioeconomic Pathways
TAGP	Trans-ASEAN Gas Pipeline
TFEC	Total Final Energy Consumption
TMI	Three Mile Island

TOU	Time of Use
TPA	Third-Party Access
TPES	Total Primary Energy Supply
TSO	Transmission System Operator
UN	United Nations
USD	United States Dollar
USTDA	U.S. Trade and Development Agency
V2G	Vehicle to Grid
VPP	Virtual Power Plant
VRE	Variable Renewable Energy
WDI	World Development Indicator
WHO	World Health Organisation
YoY	Year on Year
3S	Safety, Security And Safeguards

Units

°C	Degrees Celsius
BBO	Billion Barrels of Oil
bcm	Billion Cubic Meters
BTU	British Thermal Unit
BTU/h	British Thermal Unit per hour
BTU/h/W	British Thermal Unit per hour per watt
CO_2-eq	Carbon dioxide equivalent
GJ	Gigajoule
Gt CO_2-eq	Gigatonnes (billion tonnes) of CO_2 equivalent
GW	Gigawatt
Km	Kilometre
Km/litre	Kilometre per litre
kV	Kilovolt
kW	Kilowatt
MJ	Megajoule
Mt CO_2-eq	Megatonnes (million tonnes) of CO_2 equivalent
Mtoe	Million tonnes of oil equivalent
MW	Megawatt
MWp	Megawatt peak
PJ	Petajoule
TCF	Trillion Cubic Feet
TCM	Trillion Cubic Meters
t CO_2-eq	Tonnes of CO_2 equivalent

Appendix B - Reference

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Appendix C - Data by Scenario

C.1 TPES by Fuel (Mtoe)

Fuel	Historical		Baseline Scenario						Share of TPES			CAGR		
	2005	2022	2025	2030	2035	2040	2045	2050	2022	2030	2050	2022-2030	2022-2050	2030-2050
Coal	53.3	212.8	223.0	258.9	301.2	350.8	408.9	473.6	30.5%	27.3%	26.0%	2.5%	2.9%	3.1%
Oil	181.1	221.6	251.2	300.7	353.9	410.7	474.5	543.0	31.7%	31.8%	29.8%	3.9%	3.3%	3.0%
Natural Gas	105.4	137.5	165.6	197.1	231.6	272.0	318.4	370.5	19.7%	20.8%	20.3%	4.6%	3.6%	3.2%
Hydropower	4.7	19.5	21.7	25.9	29.4	33.8	38.4	43.3	2.8%	2.7%	2.4%	3.6%	2.9%	2.6%
Geothermal	14.2	23.3	23.1	25.7	29.7	34.3	39.6	45.0	3.3%	2.7%	2.5%	1.2%	2.4%	2.8%
Modern Biomass	23.2	61.6	77.3	115.9	157.6	205.4	258.0	318.1	8.8%	12.2%	17.5%	8.2%	6.0%	5.2%
Traditional Biomass	39.9	17.2	15.4	14.5	13.3	12.7	12.4	11.9	2.5%	1.5%	0.7%	-2.1%	-1.3%	-1.0%
Solar and Wind	0.0	4.8	6.1	8.2	10.6	13.2	15.9	17.1	0.7%	0.9%	0.9%	6.9%	4.6%	3.8%
Nuclear	-0.6	-0.1	0.3	0.2	-0.1	0.0	-0.1	0.0	0.0%	0.0%	0.0%	-	-	-6.2%
Electricity	421.2	698.1	783.7	947.0	1,127.2	1,333.0	1,566.1	1,822.6	100.0%	100.0%	100.0%	3.9%	3.5%	3.3%
Total	421.2	698.1	739.6	820.4	904.4	992.3	1,101.6	1,219.5	100.0%	86.6%	66.9%	2.0%	2.0%	2.0%

Fuel	Historical		ATS						Share of TPES			CAGR		
	2005	2022	2025	2030	2035	2040	2045	2050	2022	2030	2050	2022-2030	2022-2050	2030-2050
Coal	53.3	212.8	193.2	192.3	173.7	174.7	171.2	176.2	30.5%	23.4%	14.4%	-1.3%	-0.7%	-0.4%
Oil	181.1	221.6	231.7	250.7	267.9	285.6	306.7	328.5	31.7%	30.6%	26.9%	1.6%	1.4%	1.4%
Natural Gas	105.4	137.5	155.9	173.1	193.0	212.7	240.9	268.0	19.7%	21.1%	22.0%	2.9%	2.4%	2.2%
Hydropower	4.7	19.5	23.9	26.9	29.0	28.9	28.1	31.2	2.8%	3.3%	2.6%	4.1%	1.7%	0.7%
Geothermal	14.2	23.3	31.3	43.9	61.8	72.1	86.9	104.3	3.3%	5.3%	8.6%	8.2%	5.5%	4.4%
Modern Biomass	23.2	61.6	77.9	99.1	122.9	142.9	174.0	204.4	8.8%	12.1%	16.8%	6.1%	4.4%	3.7%
Traditional Biomass	39.9	17.2	13.6	11.3	9.4	8.1	7.2	6.1	2.5%	1.4%	0.5%	-5.1%	-3.6%	-3.0%
Solar and Wind	0.0	4.8	11.8	23.0	41.7	67.8	100.7	124.4	0.7%	2.8%	10.2%	21.7%	12.3%	8.8%
Nuclear	0.0	0.0	0.0	0.0	6.3	9.2	11.2	13.8	0.0%	0.0%	1.1%	-	-	-
Electricity	-0.6	-0.1	0.3	0.1	-1.3	-9.8	-25.1	-37.4	0.0%	0.0%	-3.1%	-	23.0%	-
Total	421.2	698.1	739.6	820.4	904.4	992.3	1,101.6	1,219.5	100.0%	86.6%	66.9%	2.0%	2.0%	2.0%

Fuel	Historical		RAS						Share of TPES			CAGR		
	2005	2022	2025	2030	2035	2040	2045	2050	2022	2030	2050	2022-2030	2022-2050	2030-2050
Coal	53.3	212.8	194.8	205.4	188.3	179.7	163.5	148.3	30.5%	27.1%	14.7%	-0.4%	-1.3%	-1.6%
Oil	181.1	221.6	218.0	226.0	232.6	239.3	250.0	261.5	31.7%	29.8%	25.8%	0.2%	0.6%	0.7%
Natural Gas	105.4	137.5	151.7	147.1	150.6	155.0	162.2	166.6	19.7%	19.4%	16.5%	0.8%	0.7%	0.6%
Hydropower	4.7	19.5	23.9	26.1	31.6	35.9	37.1	39.7	2.8%	3.4%	3.9%	3.7%	2.6%	2.1%
Geothermal	14.2	23.3	30.6	40.1	39.9	55.8	68.7	100.5	3.3%	5.3%	9.9%	7.0%	5.4%	4.7%
Modern Biomass	23.2	61.6	70.3	90.1	113.5	133.3	166.5	201.7	8.8%	11.9%	19.9%	4.9%	4.3%	4.1%
Traditional Biomass	39.9	17.2	9.1	4.3	1.4	0.5	0.3	0.2	2.5%	0.6%	0.0%	-15.9%	-14.9%	-14.5%
Solar and Wind	-	4.8	13.4	33.3	54.2	83.4	127.9	168.3	0.7%	4.4%	16.6%	27.4%	13.5%	8.4%
Nuclear	-	-	-	-	2.0	4.6	1.6	1.6	0.0%	0.0%	0.2%	-	-	-
Electricity	-0.6	-0.1	-6.6	-14.2	-18.4	-31.2	-54.7	-76.3	0.0%	-1.9%	-7.5%	82.9%	26.2%	8.8%
Total	259.3	432.2	438.8	467.2	491.0	517.6	548.2	577.7	100.0%	100.0%	100.0%	1.0%	1.0%	1.1%

Fuel	Historical		CNS						Share of TPES			CAGR		
	2005	2022	2025	2030	2035	2040	2045	2050	2022	2030	2050	2022-2030	2022-2050	2030-2050
Coal	53.3	212.8	186.7	173.0	129.9	101.0	62.8	36.8	30.5%	22.6%	3.6%	-2.6%	-6.1%	-7.4%
Oil	181.1	221.6	200.2	178.1	161.0	139.5	119.5	99.1	31.7%	23.3%	9.7%	-2.7%	-2.8%	-2.9%
Natural Gas	105.4	137.5	151.1	154.5	168.6	181.6	192.7	203.4	19.7%	20.2%	20.0%	1.5%	1.4%	1.4%
Hydropower	4.7	19.5	26.2	32.3	43.2	49.7	53.6	56.4	2.8%	4.2%	5.5%	6.5%	3.9%	2.8%
Geothermal	14.2	23.3	45.6	74.5	109.8	174.0	232.7	263.1	3.3%	9.8%	25.8%	15.6%	9.0%	6.5%
Modern Biomass	23.2	61.6	80.9	112.9	143.0	166.9	188.8	193.7	8.8%	14.8%	19.0%	7.9%	4.2%	2.7%
Traditional Biomass	39.9	17.2	7.6	0.5	0.2	0.2	0.2	0.2	2.5%	0.1%	0.0%	-35.1%	-15.2%	-5.7%
Solar and Wind	-	4.8	17.7	44.8	67.3	95.8	139.4	184.2	0.7%	5.9%	18.1%	32.2%	13.9%	7.3%
Nuclear	-	-	-	-	2.1	6.8	5.0	5.4	0.0%	0.0%	0.5%	-	-	-
Tidal and Wave	-	-	-	-	2.0	4.4	10.1	18.0	0.0%	0.0%	1.8%	-	-	-
Electricity	-0.6	-0.1	-5.3	-6.6	-8.9	-15.0	-28.4	-41.9	0.0%	-0.9%	-4.1%	66.1%	23.5%	9.7%
Total	421.2	698.1	710.8	764.1	818.1	904.8	976.4	1,018.4	100.0%	80.7%	55.9%	1.1%	1.4%	1.4%

C.2 TFEC by Fuel (Mtoe)

Fuel	Historical		Baseline Scenario						Share of TFEC			CAGR		
	2005	2022	2025	2030	2035	2040	2045	2050	2022	2030	2050	2022-2030	2022-2050	2030-2050
Coal	21.9	71.4	82.9	105.7	129.7	157.3	188.5	222.2	16.5%	18.0%	20.1%	5.0%	4.1%	3.8%
Oil	124.0	182.1	204.8	247.1	291.8	339.1	391.9	448.8	42.1%	42.1%	40.5%	3.9%	3.3%	3.0%
Natural Gas	14.6	30.5	34.5	42.1	50.9	60.8	71.9	84.0	7.1%	7.2%	7.6%	4.1%	3.7%	3.5%
Bioenergy	21.2	37.0	43.0	54.5	67.1	81.4	97.7	115.3	8.6%	9.3%	10.4%	4.9%	4.1%	3.8%
Traditional Biomass	39.9	17.3	15.4	14.5	13.3	12.7	12.4	11.9	4.0%	2.5%	1.1%	-2.2%	-1.3%	-1.0%
Other heat	0.0	0.3	0.3	0.3	0.4	0.5	0.6	0.7	0.1%	0.1%	0.1%	3.7%	3.5%	3.4%
Electricity	37.8	93.7	104.0	123.0	143.8	167.9	195.3	225.0	21.7%	20.9%	20.3%	3.5%	3.2%	3.1%
Hydrogen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0%	0.0%	0.0%	-	-	-
SAF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0%	0.0%	0.0%	-	-	-
Total	259.3	432.2	484.9	587.3	697.1	819.7	958.3	1,107.9	100.0%	100.0%	100.0%	3.9%	3.4%	3.2%

Fuel	Historical		ATS						Share of TFEC			CAGR		
	2005	2022	2025	2030	2035	2040	2045	2050	2022	2030	2050	2022-2030	2022-2050	2030-2050
Coal	21.9	71.4	79.2	93.5	106.2	119.5	133.0	145.8	16.5%	18.2%	19.5%	3.4%	2.6%	2.2%
Oil	124.0	182.1	186.0	199.5	211.1	221.5	233.9	245.6	42.1%	38.9%	32.9%	1.1%	1.1%	1.0%
Natural Gas	14.6	30.5	33.7	39.6	46.1	53.1	60.7	68.5	7.1%	7.7%	9.2%	3.3%	2.9%	2.8%
Bioenergy	21.2	37.0	44.6	59.6	71.3	82.7	94.2	105.5	8.6%	11.6%	14.1%	6.1%	3.8%	2.9%
Traditional Biomass	39.9	17.3	13.6	11.3	9.5	8.2	7.2	6.1	4.0%	2.2%	0.8%	-5.1%	-3.6%	-3.0%
Other heat	0.0	0.3	0.3	0.4	0.5	0.6	0.7	0.9	0.1%	0.1%	0.1%	4.9%	4.6%	4.5%
Electricity	37.8	93.7	99.6	109.1	122.5	137.9	155.0	172.7	21.7%	21.3%	23.2%	1.9%	2.2%	2.3%
Hydrogen	0.0	0.0	0.0	0.1	0.2	0.4	0.5	0.7	0.0%	0.0%	0.1%	-	-	8.7%
SAF	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.3	0.0%	0.0%	0.0%	-	-	10.4%
Total	259.3	432.2	457.0	513.1	567.6	624.0	685.4	746.2	100.0%	100.0%	100.0%	2.2%	2.0%	1.9%

Fuel	Historical		RAS						Share of TFEC			CAGR		
	2005	2022	2025	2030	2035	2040	2045	2050	2022	2030	2050	2022-2030	2022-2050	2030-2050
Coal	21.9	71.4	76.2	84.6	90.8	96.8	102.4	107.2	16.5%	18.1%	18.6%	2.1%	1.5%	1.2%
Oil	124.0	182.1	181.6	183.7	183.2	181.8	183.3	184.8	42.1%	39.3%	32.0%	0.1%	0.1%	0.0%
Natural Gas	14.6	30.5	32.6	36.4	40.6	44.9	49.4	53.9	7.1%	7.8%	9.3%	2.3%	2.1%	2.0%
Bioenergy	21.2	37.0	43.3	55.2	62.5	68.7	74.5	79.7	8.6%	11.8%	13.8%	5.1%	2.8%	1.9%
Traditional Biomass	39.9	17.3	9.1	4.3	1.4	0.5	0.3	0.2	4.0%	0.9%	0.0%	-15.9%	-14.9%	-14.5%
Other heat	0.0	0.3	0.3	0.4	0.6	0.7	0.9	1.2	0.1%	0.1%	0.2%	6.5%	5.7%	5.3%
Electricity	37.8	93.7	95.5	102.4	111.6	123.7	136.6	149.7	21.7%	21.9%	25.9%	1.1%	1.7%	1.9%
Hydrogen	0.0	0.0	0.0	0.1	0.2	0.4	0.5	0.7	0.0%	0.0%	0.1%	-	-	8.7%
SAF	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.3	0.0%	0.0%	0.0%	-	-	10.4%
Total	259.3	432.2	438.8	467.2	491.0	517.6	548.2	577.7	100.0%	100.0%	100.0%	1.0%	1.0%	1.1%

Fuel	Historical		CNS						Share of TFEC			CAGR		
	2005	2022	2025	2030	2035	2040	2045	2050	2022	2030	2050	2022-2030	2022-2050	2030-2050
Coal	21.9	71.4	74.0	70.2	57.8	45.1	32.6	20.6	16.5%	16.1%	4.4%	-0.2%	-4.3%	-5.9%
Oil	124.0	182.1	164.3	139.2	122.0	100.0	78.9	57.2	42.1%	31.9%	12.2%	-3.3%	-4.1%	-4.3%
Natural Gas	14.6	30.5	31.4	30.2	26.2	21.9	17.4	12.8	7.1%	6.9%	2.7%	-0.1%	-3.1%	-4.2%
Bioenergy	21.2	37.0	50.3	71.0	85.2	95.1	102.0	104.8	8.6%	16.3%	22.3%	8.5%	3.8%	2.0%
Traditional Biomass	39.9	17.3	7.6	0.5	0.2	0.2	0.2	0.2	4.0%	0.1%	0.0%	-35.1%	-15.2%	-5.7%
Other heat	0.0	0.3	0.3	0.4	0.6	0.8	1.0	1.4	0.1%	0.1%	0.3%	5.3%	6.2%	6.5%
Electricity	37.8	93.7	100.6	118.2	135.0	157.0	185.3	217.6	21.7%	27.1%	46.2%	3.0%	3.1%	3.1%
Hydrogen	0.0	0.0	0.2	5.9	17.6	29.6	40.7	50.3	0.0%	1.3%	10.7%	-	-	11.3%
SAF	0.0	0.0	0.0	0.6	1.7	2.9	4.2	5.6	0.0%	0.1%	1.2%	-	-	11.9%
Total	259.3	432.2	428.7	436.1	446.2	452.5	462.2	470.5	100.0%	100.0%	100.0%	0.1%	0.3%	0.4%

C.3 TFEC by Sector (Mtoe)

Fuel	Historical		Baseline Scenario						Share of TFEC			CAGR		
	2005	2022	2025	2030	2035	2040	2045	2050	2022	2030	2050	2022-2030	2022-2050	2030-2050
Industry	93.9	185.6	214.2	269.3	329.5	398.5	476.6	561.0	43.0%	45.9%	50.6%	4.8%	4.0%	3.7%
Transport	74.2	145.2	164.8	201.6	240.4	280.8	326.1	374.9	33.6%	34.3%	33.8%	4.2%	3.4%	3.1%
Residential	64.5	63.0	62.9	64.0	64.6	65.7	67.1	68.2	14.6%	10.9%	6.2%	0.2%	0.3%	0.3%
Commercial	18.1	29.5	32.9	39.4	46.8	55.2	65.0	75.9	6.8%	6.7%	6.9%	3.7%	3.4%	3.3%
Agriculture and Others	8.6	8.8	10.1	12.8	15.9	19.4	23.5	27.8	2.0%	2.2%	2.5%	4.8%	4.2%	3.9%
Total	259.3	432.2	484.9	587.3	697.1	819.7	958.3	1,107.9	100.0%	100.0%	100.0%	3.9%	3.4%	3.2%

Fuel	Historical		ATS						Share of TFEC			CAGR		
	2005	2022	2025	2030	2035	2040	2045	2050	2022	2030	2050	2022-2030	2022-2050	2030-2050
Industry	94	186	205	241	276	312	350	387	43.0%	47.0%	51.9%	3.3%	2.7%	2.4%
Transport	74.2	145.2	152.8	173.8	188.3	200.9	214.6	228.2	33.6%	33.9%	30.6%	2.3%	1.6%	1.4%
Residential	64.5	63.0	59.4	56.0	54.4	53.6	53.4	52.8	14.6%	10.9%	7.1%	-1.5%	-0.6%	-0.3%
Commercial	18.1	29.5	29.3	29.3	33.2	37.8	43.8	50.4	6.8%	5.7%	6.8%	-0.1%	1.9%	2.7%
Agriculture and Others	8.6	8.8	10.1	12.8	15.9	19.4	23.5	27.8	2.0%	2.5%	3.7%	4.8%	4.2%	3.9%
Total	259.3	432.2	457.0	513.1	567.6	624.0	685.4	746.2	100.0%	100.0%	100.0%	2.2%	2.0%	1.9%

Fuel	Historical		RAS						Share of TFEC			CAGR		
	2005	2022	2025	2030	2035	2040	2045	2050	2022	2030	2050	2022-2030	2022-2050	2030-2050
Industry	93.9	185.6	198.6	220.9	240.3	259.7	278.9	296.4	43.0%	47.3%	51.3%	2.2%	1.7%	1.5%
Transport	74.2	145.2	149.5	160.7	163.8	165.5	169.2	173.3	33.6%	34.4%	30.0%	1.3%	0.6%	0.4%
Residential	64.5	63.0	55.1	49.3	45.7	44.1	43.5	42.6	14.6%	10.5%	7.4%	-3.0%	-1.4%	-0.7%
Commercial	18.1	29.5	25.5	23.4	25.2	28.8	33.1	37.6	6.8%	5.0%	6.5%	-2.9%	0.9%	2.4%
Agriculture and Others	8.6	8.8	10.1	12.8	15.9	19.4	23.5	27.8	2.0%	2.7%	4.8%	4.8%	4.2%	3.9%
Total	259.3	432.2	438.8	467.2	491.0	517.6	548.2	577.7	100.0%	100.0%	100.0%	1.0%	1.0%	1.1%

Fuel	Historical		CNS						Share of TFEC			CAGR		
	2005	2022	2025	2030	2035	2040	2045	2050	2022	2030	2050	2022-2030	2022-2050	2030-2050
Industry	93.9	185.6	196.0	203.7	206.6	207.5	206.5	202.8	43.0%	46.7%	43.1%	1.2%	0.3%	0.0%
Transport	74.2	145.2	143.4	150.6	157.8	161.7	166.8	172.8	33.6%	34.5%	36.7%	0.5%	0.6%	0.7%
Residential	64.5	63.0	54.1	46.6	43.2	40.8	39.4	38.0	14.6%	10.7%	8.1%	-3.7%	-1.8%	-1.0%
Commercial	18.1	29.5	25.2	22.4	22.7	23.1	26.1	29.1	6.8%	5.1%	6.2%	-3.4%	-0.1%	1.3%
Agriculture and Others	8.6	8.8	10.1	12.8	15.9	19.4	23.5	27.8	2.0%	2.9%	5.9%	4.8%	4.2%	3.9%
Total	259.3	432.2	428.7	436.1	446.2	452.5	462.2	470.5	100.0%	100.0%	100.0%	0.1%	0.3%	0.4%

C.4 Installed Capacity by Fuel/Feedstock (GW)

Fuel	Historical		Baseline Scenario						Capacity Share			CAGR		
	2005	2022	2025	2030	2035	2040	2045	2050	2022	2030	2050	2022-2030	2022-2050	2030-2050
Coal	22.3	107.1	114.4	137.1	158.6	181.6	211.2	235.7	34.0%	31.6%	28.8%	3.1%	2.9%	2.7%
Oil	14.4	12.5	12.9	14.2	15.7	17.4	19.4	21.2	4.0%	3.3%	2.6%	1.6%	1.9%	2.0%
Natural Gas	52.1	89.9	98.4	126.9	154.5	183.8	219.3	251.1	28.5%	29.2%	30.7%	4.4%	3.7%	3.5%
Hydro	17.3	62.3	69.2	88.4	104.3	118.7	137.5	153.8	19.8%	20.3%	18.8%	4.5%	3.3%	2.8%
Geothermal	2.8	4.3	4.3	4.8	5.6	6.5	7.6	8.7	1.4%	1.1%	1.1%	1.4%	2.5%	3.0%
Solar	0.0	24.4	26.8	34.2	42.8	51.8	61.1	64.2	7.7%	7.9%	7.9%	4.3%	3.5%	3.2%
Wind	0.0	7.2	8.1	11.3	15.4	20.2	24.8	27.4	2.3%	2.6%	3.4%	5.9%	4.9%	4.5%
Biomass, Biogas, Waste	0.8	7.6	9.1	17.4	26.2	34.9	45.1	55.3	2.4%	4.0%	6.8%	10.9%	7.3%	6.0%
Total	109.7	315.4	343.1	434.2	523.1	614.9	726.0	817.5	100.0%	100.0%	100.0%	4.1%	3.5%	3.2%

Fuel	Historical		ATS						Capacity Share			CAGR		
	2005	2022	2025	2030	2035	2040	2045	2050	2022	2030	2050	2022-2030	2022-2050	2030-2050
Coal	22.3	107.1	112.8	124.8	112.1	112.9	113.7	112.7	34.0%	25.7%	10.1%	1.9%	0.2%	-0.5%
Oil	14.4	12.5	11.8	11.3	10.9	10.9	10.9	10.9	4.0%	2.3%	1.0%	-1.3%	-0.5%	-0.2%
Natural Gas	52.1	89.9	101.3	135.3	155.3	164.5	189.9	207.5	28.5%	27.9%	18.6%	5.2%	3.0%	2.2%
Hydro	17.3	62.3	73.1	92.6	108.7	121.7	137.9	151.4	19.8%	19.1%	13.6%	5.1%	3.2%	2.5%
Geothermal	2.8	4.3	5.7	7.9	11.1	13.5	16.6	19.6	1.4%	1.6%	1.8%	7.9%	5.6%	4.6%
Solar	0.0	24.4	39.6	58.8	122.6	187.6	262.3	334.8	7.7%	12.1%	30.0%	11.6%	9.8%	9.1%
Wind	0.0	7.2	17.9	40.7	67.9	121.7	189.7	228.4	2.3%	8.4%	20.5%	24.3%	13.2%	9.0%
Biomass, Biogas, Waste	0.8	7.6	11.4	13.7	21.9	28.6	33.6	39.4	2.4%	2.8%	3.5%	7.6%	6.0%	5.4%
Nuclear	0.0	0.0	0.0	0.0	3.4	5.8	8.1	10.5	0.0%	0.0%	0.9%	-	-	-
Total	109.7	315.4	373.6	485.2	613.9	767.1	962.5	1115.3	100.0%	100.0%	100.0%	5.5%	4.6%	4.2%

Fuel	Historical		RAS						Capacity Share			CAGR		
	2005	2022	2025	2030	2035	2040	2045	2050	2022	2030	2050	2022-2030	2022-2050	2030-2050
Coal	22.3	107.1	112.9	124.8	110.1	109.7	108.9	106.0	34.0%	22.8%	7.4%	1.9%	0.0%	-0.8%
Oil	14.4	12.5	12.2	11.8	11.5	0.0	0.0	0.0	4.0%	2.2%	0.0%	-0.7%	-100.0%	-100.0%
Natural Gas	52.1	89.9	100.5	141.7	166.2	196.1	242.9	289.9	28.5%	25.8%	20.2%	5.9%	4.3%	3.6%
Hydro	17.3	62.3	73.6	95.0	112.8	133.8	151.9	178.3	19.8%	17.3%	12.4%	5.4%	3.8%	3.2%
Geothermal	2.8	4.3	5.7	8.2	8.3	11.5	16.8	24.7	1.4%	1.5%	1.7%	8.3%	6.4%	5.7%
Solar	0.0	24.4	49.4	92.8	153.7	241.3	328.2	453.0	7.7%	16.9%	31.5%	18.2%	11.0%	8.2%
Wind	0.0	7.2	18.8	59.4	83.6	125.3	212.2	285.3	2.3%	10.8%	19.9%	30.3%	14.1%	8.2%
Biomass, Biogas, Waste	0.8	7.6	11.4	15.0	23.7	37.3	50.7	88.7	2.4%	2.7%	6.2%	8.8%	9.2%	9.3%
Nuclear	0.0	0.0	0.0	0.0	3.4	5.8	8.1	10.5	0.0%	0.0%	0.7%	-	-	-
Total	109.7	315.4	384.4	548.7	673.2	860.8	1119.7	1436.3	100.0%	100.0%	100.0%	7.2%	5.6%	4.9%

Fuel	Historical		CNS						Capacity Share			CAGR		
	2005	2022	2025	2030	2035	2040	2045	2050	2022	2030	2050	2022-2030	2022-2050	2030-2050
Coal	22.3	107.1	117.9	128.4	107.8	102.9	92.9	80.4	34.0%	22.0%	5.1%	2.3%	-1.0%	-2.3%
Oil	14.4	12.5	12.2	11.8	11.5	0.0	0.0	0.0	4.0%	2.0%	0.0%	-0.7%	-100.0%	-100.0%
Natural Gas	52.1	89.9	104.0	149.0	176.5	214.4	272.1	335.3	28.5%	25.5%	21.1%	6.5%	4.8%	4.1%
Hydro	17.3	62.3	76.9	99.7	123.5	138.7	151.4	187.2	19.8%	17.1%	11.8%	6.0%	4.0%	3.2%
Geothermal	2.8	4.3	8.5	14.0	20.4	31.9	45.2	56.3	1.4%	2.4%	3.5%	15.8%	9.6%	7.2%
Solar	0.0	24.4	51.9	98.0	165.4	237.0	330.8	466.3	7.7%	16.8%	29.4%	19.0%	11.1%	8.1%
Wind	0.0	7.2	21.8	67.4	91.6	133.8	222.9	320.6	2.3%	11.6%	20.2%	32.4%	14.5%	8.1%
Biomass, Biogas, Waste	0.8	7.6	11.8	15.0	23.8	39.4	59.2	104.5	2.4%	2.6%	6.6%	8.8%	9.8%	10.2%
Nuclear	0.0	0.0	0.0	0.0	3.4	5.8	8.1	10.5	0.0%	0.0%	0.7%	-	-	-
Tidal and Wave	0.0	0.0	0.0	0.0	2.8	6.1	14.0	25.0	0.0%	0.0%	1.6%	-	-	-
Total	109.7	315.4	405.0	583.3	726.6	909.9	1196.5	1586.0	100.0%	100.0%	100.0%	8.0%	5.9%	5.1%

C.5 Electricity Generation by Fuel/Feedstock (TWh)

Fuel	Historical		Baseline Scenario						Generation Share			CAGR		
	2005	2022	2025	2030	2035	2040	2045	2050	2022	2030	2050	2022-2030	2022-2050	2030-2050
Coal	139.8	532.5	509.3	563.0	635.2	720.2	825.3	946.3	41.9%	33.9%	31.2%	0.7%	2.1%	2.6%
Oil	34.9	24.5	43.9	42.9	44.1	44.7	46.4	47.5	1.9%	2.6%	1.6%	7.3%	2.4%	0.5%
Natural Gas	263.2	342.5	441.5	534.6	628.8	740.3	871.0	1,021.6	27.0%	32.2%	33.6%	5.7%	4.0%	3.3%
Hydro	55.0	248.0	269.1	329.4	383.4	445.9	512.8	585.8	19.5%	19.9%	19.3%	3.6%	3.1%	2.9%
Geothermal	16.5	27.1	27.1	30.6	35.4	41.2	47.8	54.7	2.1%	1.8%	1.8%	1.5%	2.5%	3.0%
Solar	0.0	39.4	46.3	59.1	74.0	89.3	105.3	110.6	3.1%	3.6%	3.6%	5.2%	3.8%	3.2%
Wind	0.0	13.4	22.4	29.8	39.7	52.1	63.8	71.3	1.1%	1.8%	2.3%	10.5%	6.1%	4.5%
Biomass, Biogas, Waste	3.7	42.9	41.8	69.4	99.6	130.7	162.5	198.5	3.4%	4.2%	6.5%	6.2%	5.6%	5.4%
Total	513.1	1,270.3	1,401.4	1,658.8	1,940.2	2,264.6	2,635.0	3,036.3	100.0%	100.0%	100.0%	3.4%	3.2%	3.1%

Fuel	Historical		ATS						Generation Share			CAGR		
	2005	2022	2025	2030	2035	2040	2045	2050	2022	2030	2050	2022-2030	2022-2050	2030-2050
Coal	139.8	532.5	410.7	360.8	258.0	225.0	194.9	192.2	41.9%	24.5%	6.9%	-4.8%	-3.6%	-3.1%
Oil	34.9	24.5	43.4	39.1	29.6	23.5	18.6	17.1	1.9%	2.7%	0.6%	6.0%	-1.3%	-4.0%
Natural Gas	263.2	342.5	395.5	413.8	427.7	435.1	475.9	512.2	27.0%	28.1%	18.5%	2.4%	1.4%	1.1%
Hydro	55.0	248.0	291.5	328.4	357.9	360.9	354.7	393.0	19.5%	22.3%	14.2%	3.6%	1.7%	0.9%
Geothermal	16.5	27.1	36.7	51.9	72.9	84.9	101.7	121.9	2.1%	3.5%	4.4%	8.5%	5.5%	4.4%
Solar	0.0	39.4	67.1	98.9	207.9	315.4	442.0	567.3	3.1%	6.7%	20.5%	12.2%	10.0%	9.1%
Wind	0.0	13.4	53.5	129.9	218.5	406.5	649.1	781.7	1.1%	8.8%	28.2%	32.8%	15.6%	9.4%
Biomass, Biogas, Waste	3.7	42.9	43.6	49.1	72.4	89.4	107.0	127.2	3.4%	3.3%	4.6%	1.7%	4.0%	4.9%
Nuclear	0.0	0.0	0.0	0.0	26.2	37.7	45.2	56.2	0.0%	0.0%	2.0%	-	-	-
Total	513.1	1,270.3	1,342.0	1,471.7	1,671.0	1,978.2	2,389.1	2,768.9	100.0%	100.0%	100.0%	1.9%	2.8%	3.2%

Fuel	Historical		RAS						Generation Share			CAGR		
	2005	2022	2025	2030	2035	2040	2045	2050	2022	2030	2050	2022-2030	2022-2050	2030-2050
Coal	139.8	532.5	456.9	457.1	376.4	334.7	297.0	251.8	41.9%	29.5%	8.6%	-1.9%	-2.6%	-2.9%
Oil	34.9	24.5	0.0	0.0	0.0	0.0	0.0	0.0	1.9%	0.0%	0.0%	-62.0%	-100.0%	-100.0%
Natural Gas	263.2	342.5	397.1	314.6	284.7	254.4	235.2	187.8	27.0%	20.3%	6.4%	-1.1%	-2.1%	-2.5%
Hydro	55.0	248.0	292.0	320.9	388.4	435.8	449.5	475.2	19.5%	20.7%	16.3%	3.3%	2.4%	2.0%
Geothermal	16.5	27.1	35.9	47.3	47.1	69.1	87.5	128.8	2.1%	3.1%	4.4%	7.2%	5.7%	5.1%
Solar	0.0	39.4	82.7	154.5	259.6	409.7	558.6	774.0	3.1%	10.0%	26.5%	18.6%	11.2%	8.4%
Wind	0.0	13.4	56.4	197.8	276.5	411.6	730.4	933.5	1.1%	12.8%	32.0%	40.0%	16.4%	8.1%
Biomass, Biogas, Waste	3.7	42.9	43.3	56.1	85.3	105.7	125.8	162.9	3.4%	3.6%	5.6%	3.4%	4.9%	5.5%
Nuclear	0.0	0.0	0.0	0.0	7.1	18.3	6.5	6.4	0.0%	0.0%	0.2%	-	-	-
Total	513.1	1,270.3	1,364.4	1,548.3	1,725.2	2,039.3	2,490.4	2,920.5	100.0%	100.0%	100.0%	2.5%	3.0%	3.2%

Fuel	Historical		CNS						Generation Share			CAGR		
	2005	2022	2025	2030	2035	2040	2045	2050	2022	2030	2050	2022-2030	2022-2050	2030-2050
Coal	139.8	532.5	441.3	407.8	291.8	243.7	159.0	115.5	41.9%	24.5%	3.3%	-3.3%	-5.3%	-6.1%
Oil	34.9	24.5	2.4	0.8	0.0	0.0	0.0	0.0	1.9%	0.0%	0.0%	-34.6%	-100.0%	-100.0%
Natural Gas	263.2	342.5	399.1	337.6	312.3	268.4	224.6	183.7	27.0%	20.3%	5.2%	-0.2%	-2.2%	-3.0%
Hydro	55.0	248.0	319.0	391.0	519.9	595.0	638.3	663.5	19.5%	23.5%	18.8%	5.9%	3.6%	2.7%
Geothermal	16.5	27.1	53.8	89.1	133.5	216.4	296.5	342.5	2.1%	5.3%	9.7%	16.0%	9.5%	7.0%
Solar	0.0	39.4	86.8	162.7	287.5	419.9	590.1	833.2	3.1%	9.8%	23.6%	19.4%	11.5%	8.5%
Wind	0.0	13.4	66.0	223.2	302.0	444.2	771.2	1,063.4	1.1%	13.4%	30.1%	42.1%	16.9%	8.1%
Biomass, Biogas, Waste	3.7	42.9	44.2	52.6	75.0	91.8	103.1	93.7	3.4%	3.2%	2.7%	2.6%	2.8%	2.9%
Nuclear	0.0	0.0	0.0	0.0	8.0	28.3	20.2	23.3	0.0%	0.0%	0.7%	-	-	-
Tidal and Wave	0.0	0.0	0.0	0.0	23.6	51.2	117.6	209.4	0.0%	0.0%	5.9%	-	-	-
Total	513.1	1,270.3	1,412.6	1,664.9	1,953.4	2,358.8	2,920.6	3,528.1	100.0%	100.0%	100.0%	3.4%	3.7%	3.8%

C.6 Emission by Sector ($MtCO_2$-eq)

Fuel	Historical		Baseline Scenario						Generation Share			CAGR		
	2005	2022	2025	2030	2035	2040	2045	2050	2022	2030	2050	2022-2030	2022-2050	2030-2050
Coal	139.8	532.5	509.3	563.0	635.2	720.2	825.3	946.3	41.9%	33.9%	31.2%	0.7%	2.1%	2.6%
Oil	34.9	24.5	43.9	42.9	44.1	44.7	46.4	47.5	1.9%	2.6%	1.6%	7.3%	2.4%	0.5%
Natural Gas	263.2	342.5	441.5	534.6	628.8	740.3	871.0	1,021.6	27.0%	32.2%	33.6%	5.7%	4.0%	3.3%
Hydro	55.0	248.0	269.1	329.4	383.4	445.9	512.8	585.8	19.5%	19.9%	19.3%	3.6%	3.1%	2.9%
Geothermal	16.5	27.1	27.1	30.6	35.4	41.2	47.8	54.7	2.1%	1.8%	1.8%	1.5%	2.5%	3.0%
Solar	0.0	39.4	46.3	59.1	74.0	89.3	105.3	110.6	3.1%	3.6%	3.6%	5.2%	3.8%	3.2%
Wind	0.0	13.4	22.4	29.8	39.7	52.1	63.8	71.3	1.1%	1.8%	2.3%	10.5%	6.1%	4.5%
Biomass, Biogas, Waste	3.7	42.9	41.8	69.4	99.6	130.7	162.5	198.5	3.4%	4.2%	6.5%	6.2%	5.6%	5.4%
Total	513.1	1,270.3	1,401.4	1,658.8	1,940.2	2,264.6	2,635.0	3,036.3	100.0%	100.0%	100.0%	3.4%	3.2%	3.1%

Fuel	Historical		ATS						Generation Share			CAGR		
	2005	2022	2025	2030	2035	2040	2045	2050	2022	2030	2050	2022-2030	2022-2050	2030-2050
Coal	139.8	532.5	410.7	360.8	258.0	225.0	194.9	192.2	41.9%	24.5%	6.9%	-4.8%	-3.6%	-3.1%
Oil	34.9	24.5	43.4	39.1	29.6	23.5	18.6	17.1	1.9%	2.7%	0.6%	6.0%	-1.3%	-4.0%
Natural Gas	263.2	342.5	395.5	413.8	427.7	435.1	475.9	512.2	27.0%	28.1%	18.5%	2.4%	1.4%	1.1%
Hydro	55.0	248.0	291.5	328.4	357.9	360.9	354.7	393.0	19.5%	22.3%	14.2%	3.6%	1.7%	0.9%
Geothermal	16.5	27.1	36.7	51.9	72.9	84.9	101.7	121.9	2.1%	3.5%	4.4%	8.5%	5.5%	4.4%
Solar	0.0	39.4	67.1	98.9	207.9	315.4	442.0	567.3	3.1%	6.7%	20.5%	12.2%	10.0%	9.1%
Wind	0.0	13.4	53.5	129.9	218.5	406.5	649.1	781.7	1.1%	8.8%	28.2%	32.8%	15.6%	9.4%
Biomass, Biogas, Waste	3.7	42.9	43.6	49.1	72.4	89.4	107.0	127.2	3.4%	3.3%	4.6%	1.7%	4.0%	4.9%
Nuclear	0.0	0.0	0.0	0.0	26.2	37.7	45.2	56.2	0.0%	0.0%	2.0%	-	-	-
Total	513.1	1,270.3	1,342.0	1,471.7	1,671.0	1,978.2	2,389.1	2,768.9	100.0%	100.0%	100.0%	1.9%	2.8%	3.2%

Fuel	Historical		RAS						Generation Share			CAGR		
	2005	2022	2025	2030	2035	2040	2045	2050	2022	2030	2050	2022-2030	2022-2050	2030-2050
Coal	139.8	532.5	456.9	457.1	376.4	334.7	297.0	251.8	41.9%	29.5%	8.6%	-1.9%	-2.6%	-2.9%
Oil	34.9	24.5	0.0	0.0	0.0	0.0	0.0	0.0	1.9%	0.0%	0.0%	-62.0%	-100.0%	-100.0%
Natural Gas	263.2	342.5	397.1	314.6	284.7	254.4	235.2	187.8	27.0%	20.3%	6.4%	-1.1%	-2.1%	-2.5%
Hydro	55.0	248.0	292.0	320.9	388.4	435.8	449.5	475.2	19.5%	20.7%	16.3%	3.3%	2.4%	2.0%
Geothermal	16.5	27.1	35.9	47.3	47.1	69.1	87.5	128.8	2.1%	3.1%	4.4%	7.2%	5.7%	5.1%
Solar	0.0	39.4	82.7	154.5	259.6	409.7	558.6	774.0	3.1%	10.0%	26.5%	18.6%	11.2%	8.4%
Wind	0.0	13.4	56.4	197.8	276.5	411.6	730.4	933.5	1.1%	12.8%	32.0%	40.0%	16.4%	8.1%
Biomass, Biogas, Waste	3.7	42.9	43.3	56.1	85.3	105.7	125.8	162.9	3.4%	3.6%	5.6%	3.4%	4.9%	5.5%
Nuclear	0.0	0.0	0.0	0.0	7.1	18.3	6.5	6.4	0.0%	0.0%	0.2%	-	-	-
Total	513.1	1,270.3	1,364.4	1,548.3	1,725.2	2,039.3	2,490.4	2,920.5	100.0%	100.0%	100.0%	2.5%	3.0%	3.2%

Fuel	Historical		CNS						Generation Share			CAGR		
	2005	2022	2025	2030	2035	2040	2045	2050	2022	2030	2050	2022-2030	2022-2050	2030-2050
Coal	139.8	532.5	441.3	407.8	291.8	243.7	159.0	115.5	41.9%	24.5%	3.3%	-3.3%	-5.3%	-6.1%
Oil	34.9	24.5	2.4	0.8	0.0	0.0	0.0	0.0	1.9%	0.0%	0.0%	-34.6%	-100.0%	-100.0%
Natural Gas	263.2	342.5	399.1	337.6	312.3	268.4	224.6	183.7	27.0%	20.3%	5.2%	-0.2%	-2.2%	-3.0%
Hydro	55.0	248.0	319.0	391.0	519.9	595.0	638.3	663.5	19.5%	23.5%	18.8%	5.9%	3.6%	2.7%
Geothermal	16.5	27.1	53.8	89.1	133.5	216.4	296.5	342.5	2.1%	5.3%	9.7%	16.0%	9.5%	7.0%
Solar	0.0	39.4	86.8	162.7	287.5	419.9	590.1	833.2	3.1%	9.8%	23.6%	19.4%	11.5%	8.5%
Wind	0.0	13.4	66.0	223.2	302.0	444.2	771.2	1,063.4	1.1%	13.4%	30.1%	42.1%	16.9%	8.1%
Biomass, Biogas, Waste	3.7	42.9	44.2	52.6	75.0	91.8	103.1	93.7	3.4%	3.2%	2.7%	2.6%	2.8%	2.9%
Nuclear	0.0	0.0	0.0	0.0	8.0	28.3	20.2	23.3	0.0%	0.0%	0.7%	-	-	-
Tidal and Wave	0.0	0.0	0.0	0.0	23.6	51.2	117.6	209.4	0.0%	0.0%	5.9%	-	-	-
Total	513.1	1,270.3	1,412.6	1,664.9	1,953.4	2,358.8	2,920.6	3,528.1	100.0%	100.0%	100.0%	3.4%	3.7%	3.8%

C.7 Energy Financing

C.7.1 Average Annual Power Sector Investment Cost (Billion USD)

Fuel	2023 - 2030				2031 - 2040				2041 - 2050			
	Baseline	ATS	RAS	CNS	Baseline	ATS	RAS	CNS	Baseline	ATS	RAS	CNS
Coal	6.2	6.3	6.3	7.3	7.2	2.1	1.8	2.0	8.7	2.5	2.2	3.4
Oil	0.2	0.2	0.2	0.2	0.3	0.0	0.0	0.0	0.3	0.0	0.0	0.0
Natural Gas	4.2	5.6	6.5	8.1	5.2	2.7	22.6	32.1	6.0	3.8	39.4	80.5
Hydropower	5.0	7.2	7.6	10.1	4.7	4.0	10.5	24.6	5.4	3.8	18.6	30.4
Geothermal	0.2	1.6	1.7	4.8	0.6	1.8	4.5	27.3	0.7	2.0	21.8	52.3
Biomass and Other	2.5	2.8	3.2	3.2	3.4	3.9	9.9	13.2	3.9	3.0	43.5	69.5
Solar	1.0	3.8	8.1	8.6	1.3	9.8	16.5	23.7	1.4	9.9	29.4	41.4
Wind	0.7	7.3	12.1	13.5	1.1	13.9	23.9	24.3	1.3	17.9	32.0	56.1
Nuclear	0.0	0.0	0.0	0.0	0.0	4.6	3.9	3.9	0.0	3.4	3.4	3.4
Tidal and Wave	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.1	0.0	0.0	0.0	34.1
Total	20.0	34.8	45.6	55.8	23.7	42.9	93.7	160.3	27.7	46.3	190.3	371.1

C.7.2 Cost of Production in the Power Sector (Billion USD)

Fuel	2030				2040				2050			
	Baseline	ATS	RAS	CNS	Baseline	ATS	RAS	CNS	Baseline	ATS	RAS	CNS
Capital Costs	40.1	51.1	58.6	66.3	54.9	84.0	96.0	117.5	67.1	109.7	143.2	199.9
Feedstock Fuel Costs	57.2	43.0	34.8	33.7	75.2	39.0	26.1	23.5	100.3	41.4	15.8	12.7
Fixed O&M Costs	14.2	15.6	16.9	18.6	19.7	23.0	24.6	28.9	25.9	31.9	40.1	54.1
Variable O&M Costs	3.2	3.1	2.9	3.0	4.3	4.2	3.6	4.1	5.7	5.9	4.9	6.4
Externality Costs	442.2	304.1	300.1	296.1	569.4	199.0	184.2	169.4	746.7	153.3	106.3	59.4
Total	556.9	416.8	413.3	417.6	723.5	349.2	334.5	343.5	945.7	342.1	310.3	332.5

C.7.3 Annual Cost in TFEC by Sector (Billion USD)

Fuel	2030		2040		2050	
	BAU	OPT	BAU	OPT	BAU	OPT
Capital Costs	40.1	66.3	54.9	117.5	67.1	199.9
Feedstock Fuel Costs	57.2	33.7	75.2	23.5	100.3	12.7
Fixed O&M Costs	14.2	18.6	19.7	28.9	25.9	54.1
Total	556.9	417.6	723.5	343.5	945.7	332.5

C.7.4 Annual Cost in Road Transport Demand (Million USD)

Fuel	2030		2040		2050	
	BAU	OPT	BAU	OPT	BAU	OPT
Passenger Car	203,188.0	203,508.6	320,177.3	318,239.3	465,570.1	464,241.3
Bus	13,066.5	12,788.7	17,270.9	16,347.9	22,556.9	20,931.3
Taxi	19,607.4	19,314.7	33,377.9	32,403.2	50,840.5	48,634.6
Truck	60,927.7	59,248.5	91,861.2	86,111.7	129,796.9	118,756.0
Motorcycle	53,151.0	53,388.6	72,249.0	70,791.9	95,454.1	92,063.3
Total	349,940.6	348,249.1	534,936.3	523,894.1	764,218.4	744,626.4

C.7.5 Annual Cost in Residential Demand (Billion USD)

Fuel	2030		2040		2050	
	BAU	OPT	BAU	OPT	BAU	OPT
Lighting	3,933.0	3,585.7	4,046.2	3,277.4	4,107.9	2,948.5
Air Conditioning	3,516.8	3,374.4	4,088.9	3,742.7	5,485.4	4,896.9
Total	7,449.8	6,960.1	8,135.0	7,020.2	9,593.3	7,845.5

C.7.6 Annual Cost in Commercial Demand (Billion USD)

Fuel	2030		2040		2050	
	BAU	OPT	BAU	OPT	BAU	OPT
Lighting	13,244.6	10,919.7	19,357.6	11,521.9	27,431.9	16,126.2
Air Conditioning	11,231.6	9,649.3	15,698.2	13,400.3	21,400.4	18,215.8
Total	24,476.2	20,569.0	35,055.8	24,922.2	48,832.3	34,342.0

C.8 Energy Indicators

	Historical 2022	Baseline Scenario (BAS)		AMS Targets Scenario (ATS)		Regional Aspiration Scenario (RAS)		Carbon Neutrality Scenario (CNS)	
		2030	2050	2030	2050	2030	2050	2030	2050
Population (million people) - constant across scenarios	679.7	722.8	787.4	722.8	787.4	722.8	787.4	722.8	787.4
GDP (billion 2017 USD PPP) - constant across scenarios	8,788	12,565	25,952	12,565	25,952	12,565	25,952	12,565	25,952
Total final energy consumption (TFEC, in Mtoe)	432	587	1,108	513	746	467	578	436	471
% Electricity in TFEC	21.7%	20.9%	20.3%	21.3%	23.2%	21.9%	25.9%	27.1%	46.2%
Total primary energy supply (TPES, in Mtoe)	698	947	1,823	820	1,220	758	1,012	764	1,018
% Coal in TPES	30.5%	27.3%	26.0%	23.4%	14.4%	27.1%	14.7%	22.6%	3.6%
% Oil in TPES	31.7%	31.8%	29.8%	30.6%	26.9%	29.8%	25.8%	23.3%	9.7%
% Gas in TPES	19.7%	20.8%	20.3%	21.1%	22.0%	19.4%	16.5%	20.2%	20.0%
% Renewable Energy (RE) in TPES	15.6%	18.6%	23.2%	23.5%	38.1%	25.0%	50.4%	34.6%	70.2%
EI reduction from 2005 level	-24.5%	-31.0%	-45.0%	-40.2%	-63.2%	-44.7%	-69.4%	-44.3%	-69.2%
Installed power capacity (GW)	315	434	818	485	1,115	549	1,436	583	1,586
% RE in installed power capacity	33.6%	35.9%	37.9%	44.1%	69.4%	49.3%	71.7%	50.4%	73.1%
Electricity generation (TWh)	1,270	1,659	3,036	1,472	2,769	1,548	2,920	1,665	3,528
% RE in electricity generation	29.2%	31.2%	33.6%	44.7%	71.9%	50.2%	84.7%	55.2%	90.9%
Energy-related GHG emissions (Mt CO_2-eq)	2,215	2,847	5,127	2,315	2,785	2,211	2,146	1,921	1,131

	Primary energy per capita (TPES/Pop; ktoe/1000 persons)			Final energy per capita (TFEC/Pop; ktoe/1000 persons)			Electricity consumption per capita (kWh/1000 persons)		
	2022	ATS		2022	ATS		2022	ATS	
		2030	2050		2030	2050		2030	2050
Brunei Darussalam	11,876.37	13,213.39	10,868.88	2,202.13	1,960.82	1,463.53	10,921	10,266	8,915
Cambodia	471.96	512.76	818.91	407.40	504.37	772.37	742	776	1,087
Indonesia	888.45	1,027.22	1,481.23	586.45	667.21	901.77	1,055	1,194	1,757
Lao PDR	943.02	572.47	647.30	537.17	532.87	569.71	1,289	1,552	2,133
Malaysia	2,944.50	3,179.21	4,116.96	1,404.75	1,651.61	1,659.92	4,835	5,029	6,742
Myanmar	306.95	212.94	262.21	241.24	209.22	223.94	250	263	463
Philippines	518.47	486.54	454.81	299.16	306.82	346.72	790	882	1,101
Singapore	5,564.87	12,207.06	14,279.63	2,242.04	2,031.83	2,149.37	9,861	9,108	11,324
Thailand	1,757.73	1,758.72	3,052.79	1,144.02	1,204.37	1,996.20	2,880	3,066	5,191
Vietnam	1,007.06	1,066.80	1,615.53	698.56	902.92	1,435.44	2,446	2,916	4,734

	Primary energy per capita (TPES/Pop; ktoe/1000 persons)			Final energy per capita (TFEC/Pop; ktoe/1000 persons)			Electricity consumption per capita (kWh/1000 persons)		
	2022	ATS		2022	ATS		2022	ATS	
		2030	2050		2030	2050		2030	2050
Brunei Darussalam	11,876.37	13,213.39	10,868.88	2,202.13	1,960.82	1,463.53	10,921	10,266	8,915
Cambodia	471.96	512.76	818.91	407.40	504.37	772.37	742	776	1,087
Indonesia	888.45	1,027.22	1,481.23	586.45	667.21	901.77	1,055	1,194	1,757
Lao PDR	943.02	572.47	647.30	537.17	532.87	569.71	1,289	1,552	2,133
Malaysia	2,944.50	3,179.21	4,116.96	1,404.75	1,651.61	1,659.92	4,835	5,029	6,742
Myanmar	306.95	212.94	262.21	241.24	209.22	223.94	250	263	463
Philippines	518.47	486.54	454.81	299.16	306.82	346.72	790	882	1,101
Singapore	5,564.87	12,207.06	14,279.63	2,242.04	2,031.83	2,149.37	9,861	9,108	11,324
Thailand	1,757.73	1,758.72	3,052.79	1,144.02	1,204.37	1,996.20	2,880	3,066	5,191
Vietnam	1,007.06	1,066.80	1,615.53	698.56	902.92	1,435.44	2,446	2,916	4,734

Appendix D - Modelling Approach and Key Assumptions

D.1 Socio-economics

The key drivers at the macroeconomic level are consistent across the four scenarios. GDP, which is presented in constant 2017 purchasing power parity (PPP) dollars, is strongly correlated with energy demand projections. Considering the Covid-19 pandemic, AEO8 reflects the expected impact on GDP growth, as estimated by the Asian Development Bank [105]. The slowdown in economic activities has led to declining energy demand. Other drivers of energy demand projections include population, GDP per capita, and urbanisation, which, in turn, correlate with the projections of clean cooking access, electrification rate, and the number of vehicles.

D.1.1 Population Projections

Population growth is one of the key factors for deriving energy projections. The projection of population by country is shown in Table D.1.

Table D.1 ASEAN Population Historical and Projection 2005-2050 (Million People)

Country	2005	2022	2025	2030	2035	2040	2045	2050	CAGR (2022-2050)
Brunei Darussalam	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.4%
Cambodia	13.2	16.8	17.3	18.1	18.8	19.4	19.9	20.3	0.7%
Indonesia	228.8	275.8	282.0	292.2	300.9	308.2	313.7	317.2	0.5%
Lao PDR	5.9	7.5	7.8	8.3	8.8	9.1	9.5	9.8	0.9%
Malaysia	25.9	33.9	35.0	36.7	38.1	39.3	40.2	41.0	0.7%
Myanmar	47.7	54.2	55.3	57.0	58.2	59.1	59.7	59.9	0.4%
Philippines	86.3	115.6	120.9	129.5	137.6	145.0	151.8	157.9	1.1%
Singapore	4.3	5.6	5.7	5.9	6.0	6.0	6.0	5.9	0.2%
Thailand	65.8	71.7	72.0	72.1	71.7	70.9	69.6	67.9	-0.2%
Vietnam	83.1	98.2	100.1	102.7	104.6	105.9	106.7	107.0	0.3%
ASEAN	561.4	679.7	696.6	722.8	745.2	763.5	777.5	787.4	0.5%

D.1.2 Gross Domestic Product (GDP)

GDP is a factor affecting energy demand projections. The projection of GDP by country is shown in

Table D.2 Real GDP PPP at 2017 Constant Price (Million USD)

Country	2005	2022	2025	2030	2035	2040	2045	2050	CAGR (2022-2050)
Brunei Darussalam	25,480	26,343	28,478	32,353	33,285	33,818	34,350	34,750	1.0%
Cambodia	28,098	75,964	89,409	113,148	129,548	148,570	169,809	192,464	3.4%
Indonesia	1,515,974	3,418,886	3,959,551	5,021,165	6,087,988	7,299,891	8,650,156	10,099,058	3.9%
Lao PDR	20,664	63,100	70,774	84,035	95,809	110,310	128,858	151,898	3.2%
Malaysia	465,290	960,973	1,089,069	1,331,375	1,628,002	1,959,121	2,331,630	2,731,733	3.8%
Myanmar	83,824	253,719	264,512	288,208	332,429	383,962	444,299	517,199	2.6%
Philippines	436,313	991,720	1,178,561	1,579,504	1,997,608	2,477,654	3,019,641	3,608,083	4.7%
Singapore	273,324	622,833	661,398	751,700	860,119	977,211	1,097,193	1,225,850	2.4%
Thailand	804,907	1,255,209	1,351,455	1,577,416	1,907,239	2,280,083	2,710,287	3,183,512	3.4%
Vietnam	407,009	1,118,970	1,322,629	1,785,673	2,266,937	2,840,246	3,497,711	4,207,772	4.8%
ASEAN	4,060,884	8,787,717	10,015,836	12,564,579	15,338,965	18,510,867	22,083,935	25,952,320	3.9%

Sectoral GDP is used to project the energy demand in the Type II category in the industrial sector. The sectoral GDP available data are for industry, service, and agriculture. The projection of sectoral GDP by country is shown in Table D.3, Table D.4, and Table D.5.

Table D.3 Real GDP Industry at 2017 Constant Price (Million USD)

Country	2005	2022	2025	2030	2035	2040	2045	2050	CAGR (2022-2050)
Brunei Darussalam	15,100	15,597	18,117	20,005	22,113	24,447	27,026	29,878	2.3%
Cambodia	9,225	25,028	33,390	46,445	64,381	89,188	123,545	171,134	7.1%
Indonesia	621,341	1,401,363	1,324,602	1,448,389	1,580,432	1,723,885	1,880,266	2,050,821	1.4%
Lao PDR	7,206	22,039	25,919	35,967	49,812	68,971	95,498	132,225	6.6%
Malaysia	180,088	371,617	324,171	327,990	330,807	333,477	336,146	338,834	-0.3%
Myanmar	29,499	89,421	153,369	230,667	346,912	521,740	784,675	1,180,119	9.7%
Philippines	131,511	298,648	262,492	264,603	265,051	265,214	265,340	265,461	-0.4%
Singapore	68,542	155,971	128,533	129,567	129,786	129,866	129,928	129,987	-0.6%
Thailand	281,848	439,555	366,897	350,715	334,366	318,641	303,638	289,341	-1.5%
Vietnam	158,500	436,152	394,141	554,730	779,812	1,095,974	1,540,267	2,164,662	5.9%
ASEAN	1,502,861	3,255,391	3,031,630	3,409,077	3,903,473	4,571,404	5,486,327	6,752,463	2.6%

Table D.4 Real GDP Service at 2017 Constant Price (Million USD)

Country	2005	2022	2025	2030	2035	2040	2045	2050	CAGR (2022-2050)
Brunei Darussalam	10,106	10,462	11,107	11,389	11,672	11,959	12,253	12,555	0.7%
Cambodia	11,881	32,057	30,375	34,155	38,253	42,814	47,915	53,623	1.9%
Indonesia	687,281	1,550,040	1,685,575	2,009,347	2,390,284	2,842,375	3,379,792	4,018,798	3.5%
Lao PDR	9,676	29,512	27,029	31,323	36,205	41,827	48,319	55,818	2.3%
Malaysia	244,627	505,512	489,852	552,757	621,466	698,269	784,493	881,357	2.0%
Myanmar	33,512	101,475	169,984	253,762	378,838	565,560	844,315	1,260,461	9.4%
Philippines	260,310	592,171	594,726	652,226	711,745	776,034	846,031	922,331	1.6%
Singapore	204,692	466,658	439,069	481,520	525,461	572,924	624,600	680,930	1.4%
Thailand	455,365	710,072	771,211	806,983	841,467	876,904	913,760	952,158	1.1%
Vietnam	190,586	523,870	434,299	570,958	749,564	983,799	1,291,187	1,694,613	4.3%
ASEAN	2,108,035	4,521,829	4,653,226	5,404,420	6,304,955	7,412,465	8,792,665	10,532,644	3.1%

Table D.5 Real GDP Agriculture at 2017 Constant Price (Million USD)

Country	2005	2022	2025	2030	2035	2040	2045	2050	CAGR (2022-2050)
Brunei Darussalam	274	284	341	389	446	511	586	672	3.1%
Cambodia	6,992	18,880	15,263	15,668	16,078	16,498	16,929	17,371	-0.3%
Indonesia	207,352	467,483	486,726	566,573	659,118	766,696	891,820	1,037,362	2.9%
Lao PDR	3,783	11,549	9,645	10,759	12,006	13,397	14,950	16,684	1.3%
Malaysia	40,575	83,844	75,297	76,753	78,146	79,546	80,968	82,416	-0.1%
Myanmar	20,813	62,822	58,484	59,686	60,941	62,225	63,536	64,874	0.1%
Philippines	44,493	100,901	93,627	98,411	103,370	108,565	114,021	119,750	0.6%
Singapore	90	204	177	186	196	206	216	227	0.4%
Thailand	67,694	105,582	106,513	109,107	111,505	113,910	116,362	118,865	0.4%
Vietnam	57,923	158,947	128,723	146,794	167,387	190,866	217,638	248,165	1.6%
ASEAN	449,989	1,010,497	974,797	1,084,328	1,209,192	1,352,421	1,517,026	1,706,386	1.9%

D.1.3 GDP per Capita Projection

Based on GDP and population data, the projected trends of GDP per capita show growth through 2050 across all Member States (Figure D.1). The GDP per capita has been used as the dependent variable to forecast the household penetration rate of home appliances (%) and the number of vehicles per capita.

Figure D.1 GDP per Capita Growth Trends, 2005 - 2050

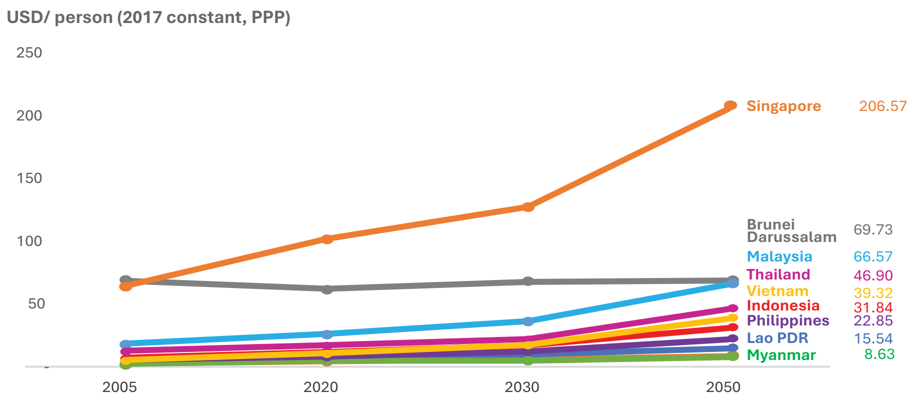


Table D.6 GDP per Capita Projection by Country (2017 Constant, PPP)

Country	2005	2022	2030	2040	2050	CAGR (2022-2050)
Brunei Darussalam	69,482	58,670	68,355	68,595	69,726	0.6%
Cambodia	2,121	4,530	6,257	7,660	9,500	2.7%
Indonesia	6,626	12,397	17,187	23,688	31,836	3.4%
Lao PDR	3,531	8,380	10,099	12,062	15,539	2.2%
Malaysia	17,949	28,315	36,290	49,876	66,575	3.1%
Myanmar	1,756	4,683	5,057	6,493	8,630	2.2%
Philippines	5,058	8,582	12,201	17,085	22,852	3.6%
Singapore	64,074	110,490	127,480	162,537	206,569	2.3%
Thailand	12,229	17,507	21,890	32,152	46,899	3.6%
Vietnam	4,895	11,396	17,387	26,823	39,320	4.5%

D.1.4 Number of Households and Household Size

The number of households is the population divided by household size. Household size is projected as a function of the urbanisation rate and GDP per capita.

Table D.7 Number of Households in the ASEAN Member States (millions)

Country	2005	2022	2025	2030	2035
Brunei Darussalam	0.06	0.08	0.08	0.08	0.08
Cambodia	2.63	3.87	3.87	3.87	3.87
Indonesia	55.12	70.84	70.84	70.84	70.84
Lao PDR	0.96	1.33	1.33	1.33	1.33
Malaysia	5.85	8.56	8.56	8.56	8.56
Myanmar	10.85	12.60	13.25	13.75	13.94
Philippines	17.08	22.98	22.98	22.98	22.98
Singapore	1.02	1.40	1.40	1.40	1.40
Thailand	18.99	23.58	23.58	23.58	23.58
Vietnam	23.98	29.74	29.74	29.74	29.74
ASEAN	136.55	174.99	175.64	176.14	176.32

Table D.8 Household Size in ASEAN Member States (people/HH)

Country	2005	2022	2025	2030	2035
Brunei Darussalam	6.12	5.36	5.65	5.88	5.95
Cambodia	5.03	4.33	4.67	5.01	5.23
Indonesia	4.15	3.89	4.12	4.35	4.48
Lao PDR	6.09	5.67	6.27	6.89	7.37
Malaysia	4.43	3.96	4.29	4.59	4.79
Myanmar	4.40	4.30	4.30	4.30	4.30
Philippines	5.05	5.03	5.63	6.31	6.87
Singapore	4.16	4.03	4.21	4.30	4.24
Thailand	3.47	3.04	3.06	3.01	2.88
Vietnam	3.47	3.30	3.45	3.56	3.60
ASEAN	46.37	42.91	45.65	48.20	49.70

D.1.5 Energy Access

Table D.9 Electrification Rate in the ASEAN Member States, BAS (%)

Country	2022	2025	2030
Brunei Darussalam	100.0	100.0	100.0
Cambodia	88.4	95.2	98.3
Indonesia	99.6	99.6	99.6
Lao PDR	95.3	95.3	95.3
Malaysia	100.0	100.0	100.0
Myanmar	72.5	72.5	72.5
Philippines	96.2	96.2	96.2
Singapore	100.0	100.0	100.0
Thailand	100.0	100.0	100.0
Vietnam	100.0	100.0	100.0

Table D.10 Electrification Rate in the ASEAN Member States, ATS (%)

Country	2022	2025	2030
Brunei Darussalam	100.0	100.0	100.0
Cambodia	88.4	95.7	100.0
Indonesia	99.6	100.0	100.0
Lao PDR	95.3	98.0	98.0
Malaysia	100.0	100.0	100.0
Myanmar	72.5	84.7	100.0
Philippines	96.2	98.1	100.0
Singapore	100.0	100.0	100.0
Thailand	100.0	100.0	100.0
Vietnam	100.0	100.0	100.0

Note: ATS, RAS, and CNS have the same value

Table D.11 Clean Cooking Access in the ASEAN Member States, BAS (%)

Country	2022	2025	2030	2035	2040	2045	2050	CAGR (2022-2050)
Brunei Darussalam	100.0	100.0	100.0	100.0	100.0	100.0	100.0	0.0%
Cambodia	44.5	46.5	50.1	54.0	58.2	62.7	67.5	1.5%
Indonesia	84.1	84.1	84.1	84.1	84.1	84.1	84.1	0.0%
Lao PDR	9.3	9.7	10.5	11.3	12.2	13.1	14.1	1.5%
Malaysia	93.8	98.1	100.0	100.0	100.0	100.0	100.0	0.2%
Myanmar	43.5	45.5	49.0	52.8	56.9	61.3	66.0	1.5%
Philippines	48.0	49.4	51.9	54.6	57.3	60.2	63.2	1.0%
Singapore	100.0	100.0	100.0	100.0	100.0	100.0	100.0	0.0%
Thailand	85.1	87.9	92.8	97.9	100.0	100.0	100.0	0.6%
Vietnam	96.1	100.0	100.0	100.0	100.0	100.0	100.0	0.1%

Table D.12 Clean Cooking Access in the ASEAN Member States, ATS (%)

Country	2022	2025	2030	2035	2040	2045	2050	CAGR (2022-2050)
Brunei Darussalam	100.0	100.0	100.0	100.0	100.0	100.0	100.0	0.0%
Cambodia	44.5	48.6	56.4	65.3	75.8	87.8	100.0	2.9%
Indonesia	84.1	84.1	84.1	84.1	84.1	84.1	84.1	0.0%
Lao PDR	9.3	10.2	11.8	13.7	15.8	18.4	21.3	3.0%
Malaysia	93.8	100.0	100.0	100.0	100.0	100.0	100.0	0.2%
Myanmar	43.5	47.5	55.1	63.9	74.1	85.9	99.5	3.0%
Philippines	48.0	49.4	51.9	54.6	57.3	60.2	63.2	1.0%
Singapore	100.0	100.0	100.0	100.0	100.0	100.0	100.0	0.0%
Thailand	85.1	87.9	92.8	97.9	100.0	100.0	100.0	0.6%
Vietnam	96.1	100.0	100.0	100.0	100.0	100.0	100.0	0.1%

Table D.13 Clean Cooking Access in the ASEAN Member States, RAS (%)

Country	2022	2025	2030	2035	2040	2045	2050	CAGR (2022-2050)
Brunei Darussalam	100.0	100.0	100.0	100.0	100.0	100.0	100.0	0.0%
Cambodia	44.5	68.3	100.0	100.0	100.0	100.0	100.0	2.9%
Indonesia	84.1	87.8	93.9	100.0	100.0	100.0	100.0	0.6%
Lao PDR	9.3	16.9	29.5	42.1	54.8	67.4	80.0	8.0%
Malaysia	93.8	100.0	100.0	100.0	100.0	100.0	100.0	0.2%
Myanmar	43.5	66.0	100.0	100.0	100.0	100.0	100.0	3.0%
Philippines	48.0	55.6	70.9	90.5	100.0	100.0	100.0	2.7%
Singapore	100.0	100.0	100.0	100.0	100.0	100.0	100.0	0.0%
Thailand	85.1	98.5	100.0	100.0	100.0	100.0	100.0	0.6%
Vietnam	96.1	100.0	100.0	100.0	100.0	100.0	100.0	0.1%

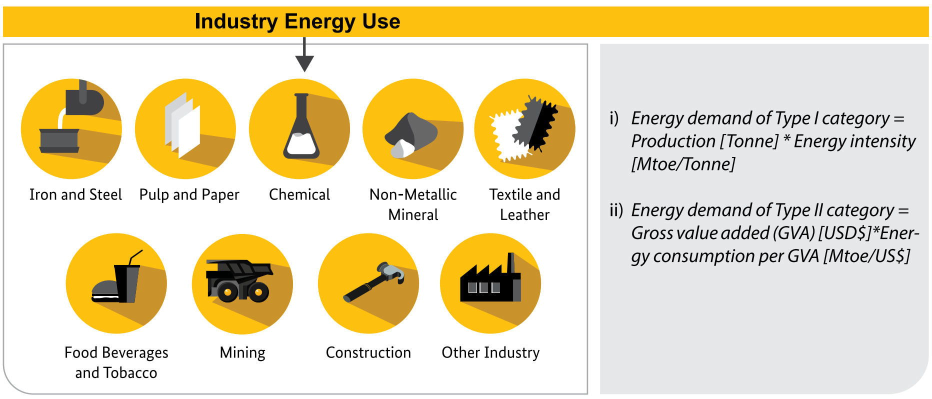
Table D.14 Clean Cooking Access in the ASEAN Member States, CNS (%)

Country	2022	2025	2030	2035	2040	2045	2050	CAGR (2022-2050)
Brunei Darussalam	100.0	100.0	100.0	100.0	100.0	100.0	100.0	0.0%
Cambodia	44.5	68.3	100.0	100.0	100.0	100.0	100.0	2.9%
Indonesia	84.1	100.0	100.0	100.0	100.0	100.0	100.0	0.6%
Lao PDR	9.3	37.4	84.3	84.3	84.3	84.3	84.3	8.2%
Malaysia	93.8	100.0	100.0	100.0	100.0	100.0	100.0	0.2%
Myanmar	43.5	66.0	100.0	100.0	100.0	100.0	100.0	3.0%
Philippines	48.0	62.2	95.6	100.0	100.0	100.0	100.0	2.7%
Singapore	100.0	100.0	100.0	100.0	100.0	100.0	100.0	0.0%
Thailand	85.1	100.0	100.0	100.0	100.0	100.0	100.0	0.6%
Vietnam	96.1	100.0	100.0	100.0	100.0	100.0	100.0	0.1%

D.2 Demand Sector Modelling

D.2.1 Industrial

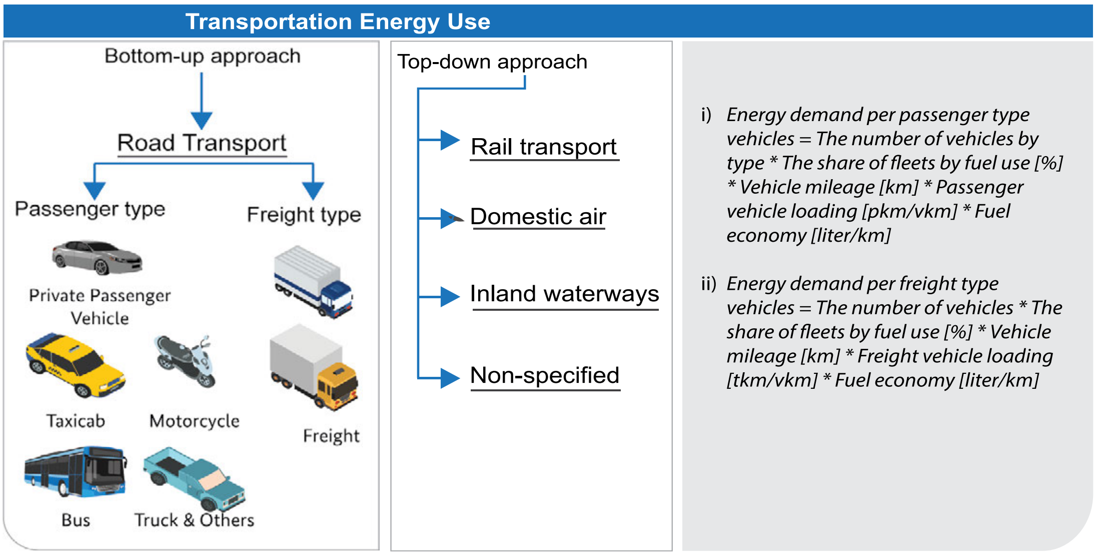
The industrial sector's bottom-up approach was calculated similarly to AEO7, wherein the sector was disaggregated into two types of sub-sectors. Type I includes Iron and Steel, Pulp and Paper, Chemical, Non-Metallic Mineral, and Textile and Leather. Type II includes Food, Beverages and Tobacco, Mining, Construction, Other Industry, and Non-specified. Other Industry is defined as sectors consisting of smaller sectors, such as machinery and woodworking. Whereas, Non-Specified demands are difficult to allocate to a single sector as indicated in country-submitted energy balances. In the Type I category,



historical production, which served as a benchmark for projection years, was calculated from the energy consumption of a specific sector divided by the average energy intensity of the sector per AMS, where data is available. In the Type II category, energy consumption was estimated based on the gross historical value added to certain sub-sectors, as these industries are difficult to quantify based on a physical unit. Most countries in the region lack a share of specific sub-subsectors in the total industrial consumption, energy intensity and fuel usage. Hence, regional data still shows a large percentage of non-specified despite implementing estimates of consumption for expected sub-sectors, such as FBT and 'construction'.

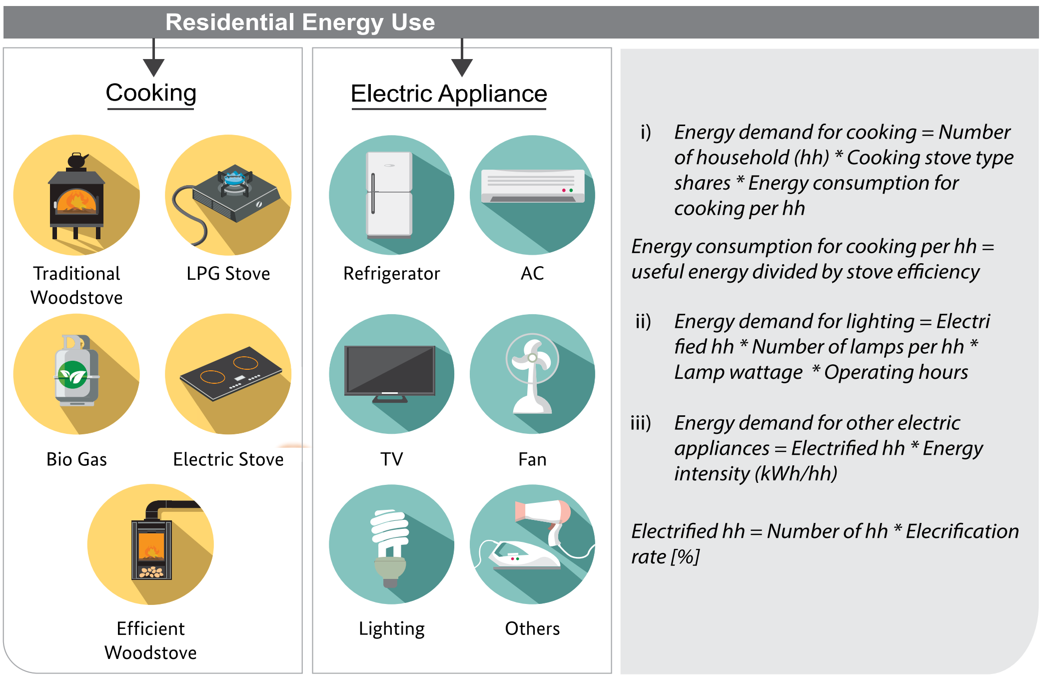
D.2.2 Transport

The transport sector projections were built with a combination of top-down and bottom-up approaches. The transport sector was disaggregated into sub-sectoral levels. The sectoral energy consumption was disaggregated into the type of transport (road, rail, domestic air, inland waterways, and non-specified transport). Road transport was then broken down into passenger vehicles consisting of private passenger vehicles, buses, motorcycles, trucks and others, and taxis; and freight vehicles. The number of registered vehicles by type, the share of fleets by fuel use, travel distance and fuel economy were collected from various national reports, such as national transportation roadmaps, the ASEAN-Japan Transport Partnership, and Ministry of Transportation sources. Apart from road transportation, the other sub-sector transportation demand was built using the top-down approach due to the limited availability of broken-down data.



D.2.3 Residential

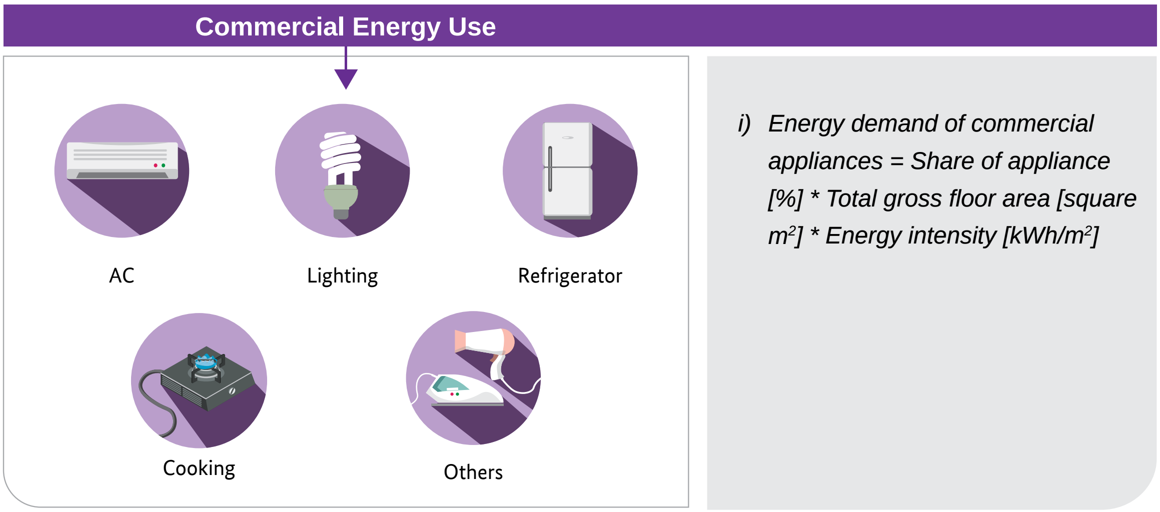
For the residential sector, the structure was broken down into cooking, lighting and several home appliances: air conditioning, washing machines, clothes dryers, refrigerators, kettles, water heating,



televisions (TV), computers, irons, fans, and other appliances. The energy consumption of each appliances was calculated with an approach similar to AEO7, as shown in the following figure. In the Type I category, historical production, which served as a benchmark for projection years, was calculated from the energy consumption of a specific sector divided by the average energy intensity of the sector per AMS, where data is available. In the Type II category, energy consumption was estimated based on the gross historical value added to certain sub-sectors, as these industries are difficult to quantify based on a physical unit. Most countries in the region lack a share of specific sub-subsectors in the total industrial consumption, energy intensity and fuel usage. Hence, regional data still shows a large percentage of non-specified despite implementing estimates of consumption for expected sub-sectors, such as FBT and 'construction'.

D.2.4 Commercial

The commercial sector's bottom-up approach was an improvement in the current edition, wherein the sector was disaggregated into several appliances similar to the residential sector: air conditioning, lighting, cooking, refrigeration, and other appliances, as presented in the following figure.



D.3 Cost Data

Cost is an integral input to optimisation modelling. A summary of the costs considered in the model includes capital cost, fixed operating and maintenance (O&M) costs, variable operating and maintenance (O&M) cost, provided in this table.

Table D.15 Cost Summary

Technology		Capital Cost (Thousand USD/MW)	Fixed Operating and Maintenance (O&M) Cost (Thousand USD/MW)	Variable Operating and Maintenance (O&M) Cost (USD/MWh)
Coal	Coal Subcritical	1,513	30.3	2.3
	Coal Supercritical	1,806	32.1	2.3
	Coal Ultrasupercritical	1,934	42.9	2.0
	Coal Supercritical CCS	3,802	75.3	5.5
	Coal Ultrasupercritical CCS	4,072	100.7	4.8
	Coal IGCC	2,730	68.4	13.7
	Coal IGCC with CCS	4,770	123.0	22.0
	Coal average	2,947	67.5	7.5
Oil	Diesel	910	9.1	7.3
	Fuel Oil	910	9.1	7.3
	Oil average	910	9.1	7.3

Technology		Capital Cost (Thousand USD/MW)	Fixed Operating and Maintenance (O&M) Cost (Thousand USD/MW)	Variable Operating and Maintenance (O&M) Cost (USD/MWh)
Gas	Gas Turbine	616	23.1	3.6
	Gas Engine	949	23.2	1.0
	Gas Steam	1,062	23.2	1.0
	Gas Combined Cycle	918	29.2	2.2
	Gas Combined Cycle with CCS	2,080	38.5	3.4
	Gas average	1,125	27.4	2.2
Nuclear	Nuclear LWR	9,000	75.3	5.1
	Nuclear SMR	9,600	110.0	2.2
	Nuclear SFR	5,953	211.9	0.0
	Nuclear average	8,184	132.4	2.4
Hydro	Large Hydro	1,500	37.3	0.6
	Small Hydro	1,350	38.0	0.5
	Hydro average	1,425	37.7	0.6
Geothermal	Geothermal	3,560	18.4	0.3
	Geothermal ORC	4,640	20.5	0.4
	Geothermal average	4,100	19.5	0.3
Solar	Solar PV	970	8.8	0.0
	Solar PV Rooftop	1,200	4.9	0.0
	Solar CSP	6,308	64.3	3.4
	Solar Floating	1,200	9.0	0.0
	Solar average	2,419	21.8	0.8
Tidal & Wave	Tidal	5,480	272.4	11.4
	Wave	10,360	457.0	15.8
	Tidal & Wave average	7,920	364.7	13.6
Wind	Wind Onshore	1,570	39.9	4.1
	Wind Offshore	3,390	78.7	3.6
	Wind average	2,480	59.3	3.9
Bioenergy	Biomass Other	1,986	46.8	3.0
	Biomass Gasification	2,900	142.5	15.4
	Bioenergy with CCS	5,299	146.2	6.3
	Biogas	2,450	110.6	0.1
	Waste	4,901	232.7	24.0
	Bioenergy average	3,507	135.8	9.7
Energy Storage	Lithium Ion Batteries	515	15.0	2.0
	Pumped Hydro	950	8.3	1.4
	Energy Storage average	733	11.7	1.7

D.4 Secondary Analysis

D.4.1 Employment

Job analysis projects direct employment in the job creation from the RE sector and the job losses from the coal phase-down during the energy transition period over the BAS, ATS, RAS, and CNS. The RE is from four technologies: Utility-Scale Solar PV, Onshore Wind, Hydropower, and Geothermal, while fuel jobs include coal, oil and gas, and bioenergy. The analysis is limited to three different job types: manufacturing, construction and installation (C&I), as well as O&M. Some examples of these job types include manufacturing, construction and installation, operation and maintenance, fuel jobs, and decommissioning jobs. The model is built by calculating the installed capacity against four factors, given in Figure D.2.

Figure D.2 Formulas to Calculate the Employment

Total Jobs

Manufacturing Jobs (Local) = Installed Capacity per year * Manufacturing EF * Decline Factor based on Capex * Local Manufacturing Factor * Regional Employment Multiplier

Construction and Installation Jobs = Installed Capacity per year * Construction and Installation EF * Decline Factor based on Capex * Regional Employment Multiplier

Operation and Maintenance Jobs = Cummulative Capacity * Operation and Maintenance EF * Decline Factor based on Opex * Regional Employment Multiplier

Fuel Jobs = Primary Energy Generation * Fuel EF * Regional Employment Multiplier

Decommissioning Jobs = Decommisioned Capacity per year * Decommissioning EF * Regional Employment Multiplier

The calculation involves the following parameters:

- **Employment Factor (EF)** – number of jobs per unit of installed capacity divided into manufacturing, C&I and O&M. Manufacturing and C&I represent the number of jobs to generate a unit of power capacity over the plant's lifetime, particularly in the start-up phase. Manufacturing could include imported shares as limited production occurs, whilst C&I and O&M are assumed to absorb all local workforces. Duration of construction is also considered based on each technology, with solar having a one-year period whilst the others are constructed over two years. O&M is interpreted as jobs to run operational activities and maintain standardised conditions for a power plant to generate capacity for a relatively long period. The unit used for O&M is jobs per capacity of power generation. The factors were derived from Rutovitz et al. (2015) [107].

Table D.16 Employment Factor

EF	Wind	Solar	Hydro	Geothermal	Coal	Oil, Gas, Diesel, and Bioenergy	Battery Storage
Construction Time (years)	2	2	2	2	5	1	1
Manufacturing (Job-years/MW)	4.7	6.7	3.5	3.9	5.4	0.93	16.9
C&I (Job-years/MW)	3.2	13	7.4	6.8	11.2	1.3	10.8
O&M (Job/MW)	0.3	0.7	0.2	0.4	0.14	0.21	0.4
Fuel (Jobs/PJ)	-	-	-	-	39.7	15.1	-
Decommissioning (Job-years/MW)	0.72	0.8	2.22	0.21	1.65	0.44	0.8

- **Decline Factor (DF)** – gradual deceleration of job creation due to increasing experience and volume of the energy industry, leading to the maturation of technologies over time. Two learning factors are adapted to reflect the decline: Capital Expenditures (Capex) used in Manufacturing and C&I, and Operational Expenditures (Opex) used in O&M. The YoY factors were compiled and interpolated from Ram et al. (2019) [108], based on the cost assumptions developed by Lappeenranta-Lahti University of Technology (LUT) for the Energy System Transition model (Table D.13).

Table D.17 Declining Factor

		2020	2025	2030	2035	2040	2045	2050
Wind	**Capex**	0.08	0.15	0.2	0.23	0.25	0.27	0.28
	Opex	0.08	0.16	0.2	0.24	0.24	0.28	0.28
Solar PV	**Capex**	0.45	0.55	0.63	0.68	0.71	0.74	0.76
	Opex	0.35	0.46	0.54	0.6	0.64	0.68	0.71
Bioenergy	**Capex**	0.15	0.21	0.26	0.32	0.35	0.38	0.41
	Opex	0.15	0.21	0.26	0.32	0.35	0.38	0.41
Hydro	**Capex**	0	0	0	0	0	0	0
	Opex	0	0	0	0	0	0	0
Geothermal	**Capex**	0.05	0.1	0.15	0.19	0.23	0.27	0.31
	Opex	0	0	0	0	0	0	0
Coal	**Capex**	0	0	0	0	0	0	0
	Opex	0	0	0	0	0	0	0
Oil and Gas	**Capex**	0	0	0	0	0	0	0
	Opex	0	0	0	0	0	0	0
Energy Storage	**Capex**	0.33	0.55	0.67	0.73	0.77	0.81	0.83
	Opex	0.63	0.79	0.84	0.88	0.9	0.91	0.92

- **Regionality Factor (RF)** or regional employment multiplier – lower average labour intensity and cost to produce a unit of output (productivity) associated with lower GDP per capita than in OECD countries. The factor is derived from Ram et al. (2019) [108]. The interpolated RF values for 2020-2050 can be found in Table D.14.

Table D.18 Regional Factor

	2020	2025	2030	2035	2040	2045	2050
RF	2.2	1.93	1.77	1.63	1.58	1.52	1.47

- **Local Manufacturing Factor** –renewable and storage technologies are still growing in the region as certain import proportions contribute to the market. Consequently, the factor will eliminate employment not absorbed by local labours in an optimistic scenario of 90% for local manufacturing. The value is adapted from Rutovitz et al. (2015) [107].

D.4.2 Land Use for Renewables

Biofuels

The production of biofuel requires crops as its feedstock. To understand the energy and land use nexus, the model calculates the required land use to produce crops, driven by the demand for biofuel. Two types of biofuels are commonly used and modelled: bioethanol and biodiesel. These biofuels are generally blended with gasoline and diesel, respectively.

The land requirements (in Ha) are estimated based on the specified "environmental loading" (Ha per TJ of energy produced) and biofuel production, which is driven by the demand for biofuels. It must be noted that the land requirements are estimated assuming that there is no export-import of biofuel, meaning only domestically produced biofuels that fully satisfy domestic demand. Environmental loading is derived from region-specific crop yields (kg of crop/Ha), biofuel production process yield (litres of biofuel produced per tonne of the crop), and energy content of the biofuel (GJ per litre of biofuel). An alternative equation would require energy density (tonnes per litre of biofuel) if the energy content is denoted as per mass (GJ per tonne of biofuel).

$$
\begin{aligned}
&Environmental\ Loading\ \left[\frac{Ha}{GJ}\right] \\
&= 1 \\
&/\left\{Crop\ yield\ \left[\frac{tonne_{crop}}{Ha}\right] \times Biofuel\ production\ yield\ \left[\frac{L_{biofuel}}{tonne_{crop}}\right]\right. \\
&\left.\times\ Biofuel\ energy\ content\ \left[\frac{GJ_{biofuel}}{L_{biofuel}}\right]\right\}
\end{aligned}
$$

The biofuel parameters are based on the FAO report [109]. For bioethanol, the global value is utilised for both the crop yield and biofuel production yield, where sugarcane is selected as the crop. As for biodiesel, specific values are used for Indonesia and Malaysia, which were reported in the study (Table D.15). Oil palm is chosen as the crop. For other Member States, the average values of Indonesia and Malaysia are used. Biofuel energy content uses the LEAP default value.

Table D.19 Biofuel Parameters

Country	Bioethanol			Biodiesel		
	Crop Yield (Sugar Cane)	Biofuel Production Yield	Biofuel Energy Content	Crop Yield (Oil Palm)	Biofuel Production Yield	Biofuel Energy Content
Indonesia	65	70	0.0211	17.8	230	0.0376
Malaysia	65	70	0.0211	20.6	230	0.0376
Other AMS	65	70	0.0211	19.2	230	0.0376

Wind and Solar

The land requirements (in Ha) for wind and solar energy projects are calculated by incorporating the land-use requirement per unit of power capacity and total installed capacity projection in the ASEAN region as seen in the following equation:

$$A = L \times C$$

A: Total land-use (Ha)
L: Land-use requirement per Gigawatt of power capacity (Ha/GW)
C: Installed power capacity (GW)

The average land-use requirement per unit of power capacity was obtained from a systematic review as observed in Table D.16. The number came from the average of total land-use, involving permanent impact, temporary impact, and all areas associated with the renewable energy projects within the site boundary.

Table D.20 Average Land-use per Gigawatt of Different Types of Energy Source

Energy Source	Average Land-use per Gigawatt (Ha/GW)
Wind	28,971
Solar	3,601
Coal	4,940

Furthermore, the ratio between the impacted area and the total ASEAN region land area was evaluated by using the following formula:

$$\% \text{ Occupied ASEAN Region} = \frac{A}{Total\ ASEAN\ Area}\ x\ 100\%$$

A: Total land-use (Ha)
Total ASEAN Area: 450,000,000 Hectares

Lastly, the ratio of total area required to build the whole power plants between renewables (wind and solar) power and conventional power plants (coal) was derived from energy density comparison quantified using the following equation:

$$ED = \frac{(C * cf * H)}{A}$$

ED: Energy density (TWh/Ha)
C : Installed power capacity (GW)
cf : Capacity factor
H : Hours over a year (hours)
A : Total land-use (Ha)

Similar to the average land-use per gigawatt, the capacity factor was gathered from a systematic review of previous studies as presented in Table D.17.

Table D.21 Average Capacity Factor of Various Energy Source

Energy Source	Average Capacity Factor
Wind	20.13%
Solar	17.92%
Coal	54.70%

D.4.3 GHG Emissions

Decomposition Analysis

Decomposition analysis was conducted based on the Kaya identity equation. The Kaya identity is a useful equation for quantifying the total emissions of the GHG carbon dioxide (CO_2) from human sources. The simple equation is based on readily available information and can be used to quantify current emissions and how the relevant factors need to change relative to each other over time to reach a target level of CO_2 emissions in the future. The identity has been used, and continues to be important, in the discussion of global climate policy decisions. The Kaya identity states the total emission level of CO_2 as the product of four factors:

$$F = P \times \frac{G}{P} \times \frac{E}{G} \times \frac{F}{E}$$

where:

F = Global CO_2 emissions from human sources
P = Global population
G = Global Gross Domestic Product (GDP)
E = Energy consumption

Emission Factors

The emission factors used to project sectoral energy demand and electricity generation were collected from the AEO6 [2].

Appendix E - Definitions

Clean Cooking: The use of electricity, liquefied petroleum gas (LPG), natural gas, biogas, solar, and alcohol fuels for cooking. Charcoal, coal, crop waste, dung, kerosene, and wood used for cooking are not considered clean fuels.

Electrification Rate: The share of households with access to electricity in a country.

Energy Dependency Rate: The proportion of energy that an economy must import. It is defined as net energy imports divided by gross available energy, expressed as a percentage. A negative dependency rate indicates a net exporter of energy, while a dependency rate in excess of 100% indicates that energy products have been stocked. It can be defined for the total of all products, as well as for individual fuels (for example, crude oil and natural gas).

Energy Intensity (EI): The ratio of TPES to GDP, which can be considered an approximation of the energy efficiency of a country's economy and shows how much energy is needed to produce a unit of GDP. For APAEC's EI target calculation, the annual GDP is converted into a 2017 constant price PPP, adjusting the effects of inflation and eliminating price level differences across countries created by fluctuations in currency exchange rates.

Renewable Energy (RE): Includes bioenergy (bagasse, biofuel, biogas, biomass, and waste), hydro all scale, geothermal, solar, and wind. It is further categorised as modern and traditional RE. Traditional RE refers to the use of solid biomass in the residential sector, typically for cooking or heating. Uses of RE in other end-use sectors and electricity generation are considered modern RE. Traditional RE is not considered when calculating the share of RE in TPES for purposes of meeting the APAEC target.

Total Final Energy Consumption (TFEC): The sum of energy consumption by end-use sectors, excluding non-energy use and international transportation. The end-use sectors include agriculture, commercial, industrial, residential, and transportation.

Total Primary Energy Supply (TPES): The sum of energy production and imports, subtracting exports. It includes non-energy uses and stock changes but excludes international transportation. In the projection years, energy supply is the sum of energy use inputs to transformation and energy demand, after accounting for the balance of energy exports and imports. There are differences in calculating primary energy supply from the electricity generation process. For fossil fuel, combustible RE (bagasse, biomass, and waste), and geothermal, the feedstock is the primary supply, calculated by dividing the generated electricity by the efficiency of the power plant. For non-combustible RE (hydro, solar, wind), the amount of electricity generated is considered the primary energy equivalent.

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