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Carbon Emission Reduction Potential of Hydrogen Production for Large-Scale Industrial Facilities in Southeast Asia

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Abstract: *Making use of hydrogen demand and supply forecasts reported by ERIA (2024) for the oil refining, ammonia, methanol, and steel industries in the Association of Southeast Asian Nations, this paper studies the carbon emission reduction potential of blue and green hydrogen for these large-scale industries until 2050. Future hydrogen supply and demand under the International Energy Agency's announced pledges scenario are examined for each of these four industrial sectors, the corresponding carbon emissions calculated, and their future carbon emission reduction potential estimated. The potential of ammonia fuels and methanol for e-fuels is also considered. Levelised cost of hydrogen estimates and various carbon price scenarios are studied to calculate the government subsidies required to help finance the transition from grey to green and blue hydrogen production in the four industrial sectors in Southeast Asia in the coming decades. The insights gained inform policy strategies for a future industrial hydrogen decarbonisation transition.*

Keywords: hydrogen, industry, carbon dioxide, emission
JEL classification: L20, O14, O25, Q42, Q48

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1. Introduction

Blue and green hydrogen are key contributors to the future decarbonisation of the oil refining, chemical, and steel industries. Within the chemical industry, blue and green ammonia and methanol are not only crucial feedstocks in many downstream processes but also offer the potential to help decarbonise the agriculture, shipping, and road transport sectors and contribute to future energy storage and transport solutions. ERIA (2024) reported its hydrogen demand and supply forecasts for the oil refining, ammonia, methanol and steel industries in the Association of Southeast Asian Nations (ASEAN) region towards 2050. The study examines four distinct future scenarios: the frozen/business-as-usual scenario (Frozen scenario); the Stated Policies Scenario (STEPS) and the Announced Pledges Scenario (APS), both leaning on IEA (2022) with ASEAN region-specific adaptations; and the Likely scenario, following Det Norske Veritas (DNV, 2022) with ASEAN-specific adjustments.

Briefly, in ERIA (2024), the ERIA–Frozen scenario relates to the situation where the trend in the demand and supply of hydrogen during the 2015–2021 period will continue in the future. ERIA–STEPS retains the current and latest ASEAN Member States' (AMS) policies, including those related to the Intended Nationally Determined Contributions. ERIA–APS assumes that all aspirational targets announced by governments are met on time and in full, including their long-term net-zero and energy access goals. Finally, the ERIA–Likely scenario represents the most likely future situation for the supply and demand of hydrogen in the four industrial sectors in ASEAN from the present time to the horizon to 2050.

ERIA (2024) projects that total regional hydrogen demand will steadily grow in all scenarios, with 2020–2050 cumulative average growth rates (CAGR) of 2.7% (Frozen), 2.3% (STEPS), 3.9% (APS) and 2.7% (Likely). Importantly, the composition and sequence of future hydrogen demand growth matter the most. In the Likely scenario, demand for oil refining decreases over the forecast period, driven by the electrification of the mobility sector, whilst demand for ammonia as an energy carrier and methanol for e-fuels overcompensates for the decrease. During the same period, the Frozen scenario's hydrogen demand grows similarly fast as traditional demand for hydrogen, such as in oil refining, increases strongly. Therefore, even though the Frozen and Likely forecasts reach similar levels of aggregate hydrogen demand by 2050, carbon emissions in the Likely scenario will decrease much more significantly than in the Frozen scenario (ERIA, 2024).

Additionally, under STEPS, growth in hydrogen demand in the industrial sector in ASEAN is the lowest, with a CAGR of 2.3% during the 2020–2050 period. This is a consequence of the decreasing use of hydrogen in oil refining due to the limited electrification of mobility, which is not yet offset by the use of hydrogen for the production of methanol for e-fuels and ammonia as a co-fuel for shipping and power generation. In contrast, the APS is expected to have the highest growth in future hydrogen demand. In this scenario, hydrogen demand from oil refining decreases most rapidly over the 2020–2050 projection period, whilst methanol e-fuels and ammonia energy carriers more than compensate and grow even faster than in the Likely scenario (ERIA, 2024).

This study examines the carbon emission volumes under traditional natural gas and coal steam methane reforming (SMR). It analyses the future carbon-reduction potential of blue and green hydrogen for the oil refining, ammonia, methanol and steel industries in the ASEAN region until 2050. In particular, the future hydrogen supply under the APS is examined for each of the four industrial sectors. Since ERIA (2024) reports hydrogen supply from the region's refineries and incumbent ammonia and methanol producers, accounting only for known and announced future growth in production capacity, the remaining demand is assumed to be met by merchant production volumes. These merchant volumes include both regionally produced hydrogen and imported hydrogen from independent industrial gas companies.

Carbon emissions from hydrogen production via the SMR of natural gas, and to a lesser extent coal, i.e. grey hydrogen, are compared with three future production mix scenarios. First is the IEA's future APS production technology mix (IEA, 2023e), where the proportion of grey hydrogen decreases to 91% in 2025, 84% in 2030, 48% in 2040, and 31% by 2050. During the same period the APS forecasts production technology mixes of 2% blue hydrogen and 7% green hydrogen in 2025, 4% blue and 13% green in 2030, 11% blue and 41% green in 2040, and 14% blue and 55% green by 2050. This future production technology mix is compared to a future scenario of 100% blue versus 100% green hydrogen production between 2025 and 2050.

The analysis subsequently estimates the incremental cost of producing hydrogen under APS demand forecasts using the three production technology mix scenarios, compared to the current state of effectively 100% traditional SMR. Incumbent SMR facilities' levelised cost of hydrogen (LCOH) is assumed to be well-established industry standards and economically feasible, whilst the incremental LCOH of transitioning to the future production scenarios and production technology mixes may render future decarbonised hydrogen production capacity economically unfeasible. Thus, the analysis concludes with calculations of potential government subsidies that may be required by incumbent and future hydrogen producers to achieve the emission reduction potential whilst receiving similar returns to their new investments as their past and existing SMR facilities and operations. Concurrently, since the carbon emission reduction potential can generate future carbon credit revenues, the future subsidies for blue and green hydrogen are calculated under different carbon price assumptions.

The results of this study can be summarised as follows. First, as per ERIA (2024), total hydrogen demand will grow from about 4.4 million tonnes per annum (MTPA) in 2025 to 11.7 MTPA by 2050. This is to be satisfied by existing and planned or announced production capacities by incumbent oil refineries and methanol and ammonia producers in the region. For the remaining diversified chemical sub-sectors, the steel industry and future unsatisfied demand growth are to be supplied by merchant production or imports.

Second, the carbon emissions thus projected based on continued production via SMR are estimated to grow to about 37 MTPA of carbon dioxide (CO_2) in 2025 and 100 MTPA of CO_2 by 2050.

Third, the future CO_2 emission reduction potential under the APS demand projections and production technology mix is estimated to reach 52 MTPA by 2050. This compares to potential carbon emission reductions of up to 60 MTPA by 2050 when only blue hydrogen is produced starting in 2025, versus 78 MTPA by 2050 if only green is produced starting 2025. Therefore, compared to the estimated 100 MTPA of CO_2 emissions in an SMR-dominated hydrogen economy, under the APS all blue or green hydrogen scenarios, between half and four-fifths of carbon emissions can be reduced across ASEAN's industrial sectors by 2050.

Fourth, future government subsidies required to provide incumbent and new hydrogen producers the same 8% per annum project returns as their hitherto grey hydrogen production mix are calculated under carbon price assumptions ranging from US$100 to US$500 per tonne of hydrogen produced. Moreover, technology improvements, lower renewable electricity prices, and efficiency increases from higher scale economies are assumed to reduce the relative production costs of blue and green hydrogen in the future (ERIA, 2024; Purwanto et al., 2024a). Thus, aggregate present values of region-wide subsidies in the range of US$20 billion–US$100 billion are estimated for 20-year decarbonised hydrogen projects under the APS with carbon prices between US$100 and US$300 per tonne. Moreover, the present values of these subsidies increase significantly to US$100 billion–US$300 billion when only green hydrogen is considered, whereas almost no subsidies are required to implement an all-blue hydrogen transition, except at very low carbon prices. In contrast, when carbon prices reach US$500 per tonne, only an all-green hydrogen future may require subsidies, whereas the APS and blue hydrogen can largely be self-funded through the monetisation of carbon credits.

Our contribution to the hydrogen literature is as follows. ERIA (2024) is the first attempt to dissect future hydrogen demand and supply across these major industrial sectors and across the eight largest ASEAN economies. To our knowledge, this study is the first to explicitly estimate future carbon emissions and carbon emission reduction potential from hydrogen production across key industrial sectors in ASEAN. Moreover, the carbon emission reduction potential is analysed using future LCOH estimates under several production scenarios and various carbon price assumptions to come up with estimates for the national government or multilateral development agency subsidies required to render the transition towards blue and green hydrogen production economically feasible for private sector incumbents and future entrants.

The analysis reported in this paper can be expanded to study more specific country- and project-level decarbonisation pathways, green and blue hydrogen production and transport economics, and the political economy of promoting, and importantly, financing such large-scale projects requiring significant public sector and multilateral support.

Following this introductory section, a literature review is summarised on hydrogen SMR production, the carbon emission volumes of grey hydrogen versus blue and green hydrogen, and the use of methanol for e-fuels and ammonia as an energy carrier to reduce fossil fuel consumption in transport, shipping, and power generation. The subsequent third section describes the modelling methodology and discusses the carbon emission reduction potential under the various production scenarios. Section 4 estimates and discusses the economic consequences of transitioning to blue and green hydrogen production, and the necessary public sector subsidies such a transition would require. Following that, section 5 summarises the policy implications, whilst section 6 concludes.

2. Literature Review

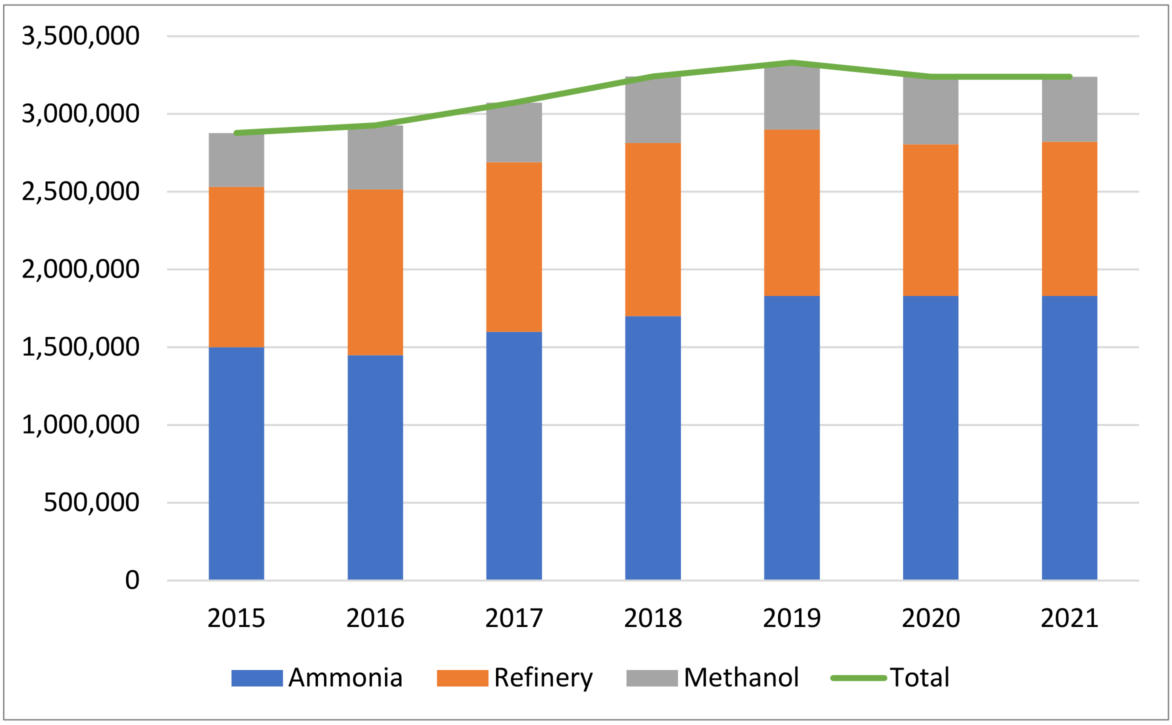
2.1. Literature on Hydrogen Production from Natural Gas and Coal SMR

Across the relevant industries globally, the IEA and IRENA report that most of the hydrogen supply is currently produced through established SMR processes utilising fossil fuels, i.e. natural gas or coal. The IEA (2023a) reports that through 2020–2022, more than 80% of the hydrogen supply was produced from SMR. In 2022, of the 95 MT of hydrogen produced globally, 62% and 21% were produced from natural gas and coal, respectively, whilst low emission hydrogen only amounted to less than 1Mt. IRENA (2022a) reported that 47% of hydrogen production came from natural gas, 27% from coal, and 1% from renewables. Despite the still prevalent use of fossil fuels in the hydrogen production process in recent years, numerous low carbon hydrogen projects have been announced, which are either in early-stage discussions or are undergoing feasibility studies.

In terms of geographic split, according to the IEA (2023a), 30% of hydrogen production currently takes place in China, including a large proportion of the world's coal-based SMR. The other major producers are the United States, the Middle East, India, and Russia. In contrast, the ASEAN region produces around 3% of the total supply of hydrogen. The amount of production is projected to grow, following increasing demand, especially in the industrial sector. Most of the hydrogen currently used as feedstock for ammonia and methanol in Southeast Asia is produced via SMR, similar to the global picture.

In ASEAN's major oil refining centres, SMR hydrogen is produced simultaneously with captive hydrogen from reforming and platforming and as by-products from various refining processes. During the past few years, the hydrogen captive supply in industry sectors in ASEAN grew from around 2.88 MTPA in 2015 to 3.33 MTPA in 2019, before decreasing to 3.24 MTPA in 2021 (ERIA, 2024). Figure 1 shows that ammonia exhibits the highest proportion of captive production, amounting to almost half of the total captive production in ASEAN and making it the only hydrogen self-sufficient sector. The oil refining sector produced 80%–90% of its hydrogen demand on-site, whilst the methanol industry only fulfilled 75% of its hydrogen demand in 2021. In contrast, the other chemical subsectors and the steel industry procure 100% of their hydrogen supply from third-party merchant gas companies.

Figure 1: Total Hydrogen Captive Supply in the Industry Sector in ASEAN, 2015–2021 (MTPA)



Source: ERIA (2024).

Furthermore, following ERIA (2024), total hydrogen production in ASEAN is expected to increase gradually up to 2030 and will exhibit incremental to stagnant growth until 2050, except under the APS. In STEPS, hydrogen production will increase from 3.15 MTPA in 2020 to 4.54 MTPA in 2030, then grow more slowly to 4.77 MTPA in 2050. These projections are based on the NDC of each ASEAN member state (AMS), with the assumption that each of the countries will comply with their announced policy and NDC. The other two scenarios, Likely and Frozen, also show similar trends with STEPS. In the Likely scenario, production grows to 4.47 MTPA and 4.67 MTPA in 2030 and 2050, respectively, and in the Frozen scenario, production grows to 4.55 MTPA and 4.88 MTPA in 2030 and 2050, respectively. However, in the APS, the production trend increases linearly until 2050, when it will reach 5.59 MTPA, almost twice the current production. The dramatic increase is due to the assumption that the demand for hydrogen will grow significantly following the increasing demand for low-carbon hydrogen as a partial substitute for shipping fuel oils, coal-fired electricity generation, and e-fuels.

2.2. Literature on Carbon Emissions from Grey Hydrogen Production

Competitively priced hydrogen is still predominantly derived from steam reforming, i.e. the SMR of natural gas and coal gasification. Although hydrogen production through water electrolysis offers the potential to compete with conventional transport fuels, particularly during periods of elevated oil prices, it is significantly costlier than grey hydrogen, which is commonly employed within industrial applications (Ball and Weeda, 2015). Nevertheless, recent advancements in research and the successful implementation of pilot projects have raised expectations regarding the increasing prominence of technologies such as natural gas reforming coupled with carbon capture (blue hydrogen) and the electrolysis of water using renewable-based electricity (green hydrogen). These developments suggest that these methods may come to dominate hydrogen production in the future (APERC, 2018; IEA, 2021).

SMR has been studied to generate varying carbon emissions estimates. The IEA (2023) reports that the emissions resulting from hydrogen production via SMR are around 10–13 kilogrammes (kg) CO_2 per kg hydrogen, where direct emissions from production account for 9 kg CO_2 per kg hydrogen, and natural gas production (upstream and midstream) accounts for around 2.4 kg CO_2. Sun et al. (2019) also estimate average emissions of 9.01 kg CO_2 per kg of SMR hydrogen. Other studies by Cetinkaya et al. (2012) and Suleman et al. (2016) reported on emission figures within the range provided by the IEA, with estimates ranging from 11.9 kg to 11.95 kg CO_2 per kg hydrogen. In contrast, a few other studies report slightly lower estimates. Bassani et al. (2020) find that each kg of hydrogen production via SMR emits approximately 7 kg of CO_2, whilst Katebah et al. (2022) reported total specific CO_2 emissions of approximately 8.47 kg CO_2 per kg of hydrogen.

2.3. Literature on Carbon Emissions of Blue and Green Hydrogen, Ammonia, and Methanol

An emerging approach to mitigate carbon emissions in hydrogen production is the use of SMR in conjunction with carbon capture and storage (CCS). According to the IEA (2023a), this method shows potential, with emission intensity estimates ranging from 0.8 to 4.6 kg CO_2-eq per kg hydrogen. Notably, IEA's APS and Net Zero by 2050 Scenarios predict emission intensity levels of 3 kg CO_2-eq per kg hydrogen and less than 1 kg CO_2-eq per kg hydrogen in 2050, respectively.

Electrolysis, particularly when powered by renewable energy sources such as wind and solar, offers a more environmentally sustainable alternative. Cetinkaya et al. (2012) estimate that water electrolysis using wind energy results in emissions of approximately 0.97 kg CO_2 -eq per kg of hydrogen. When powered by solar energy, this estimate increased to 2,412 grammes (g) per kg hydrogen. Subsequent research by Suleman et al. (2016) supported these significant emission reductions, reporting significantly lower emissions of approximately 32.5 g per kg hydrogen for wind-powered electrolysis and 370 g per kg hydrogen for solar-powered electrolysis.

The two most important industrial-scale chemical derivatives of hydrogen are methanol and ammonia. There are two types of green methanol that are characterised by two distinct production processes: biomethanol and e-methanol (Nemmour et al., 2023). Biomethanol is produced using energy sources that involve the gasification of sustainable biomass sources. These include livestock, agricultural, and forestry residues, as well as municipal waste gathered from households and businesses. E-methanol is produced by reacting blue or green hydrogen with captured CO_2. The terms ‘electro fuels’ and ‘e-fuels’ refer to fuels that are obtained by the utilisation of collected CO_2 or the separation of nitrogen from the atmosphere via a reaction with hydrogen generated through the process of water electrolysis (Nemmour et al., 2023).

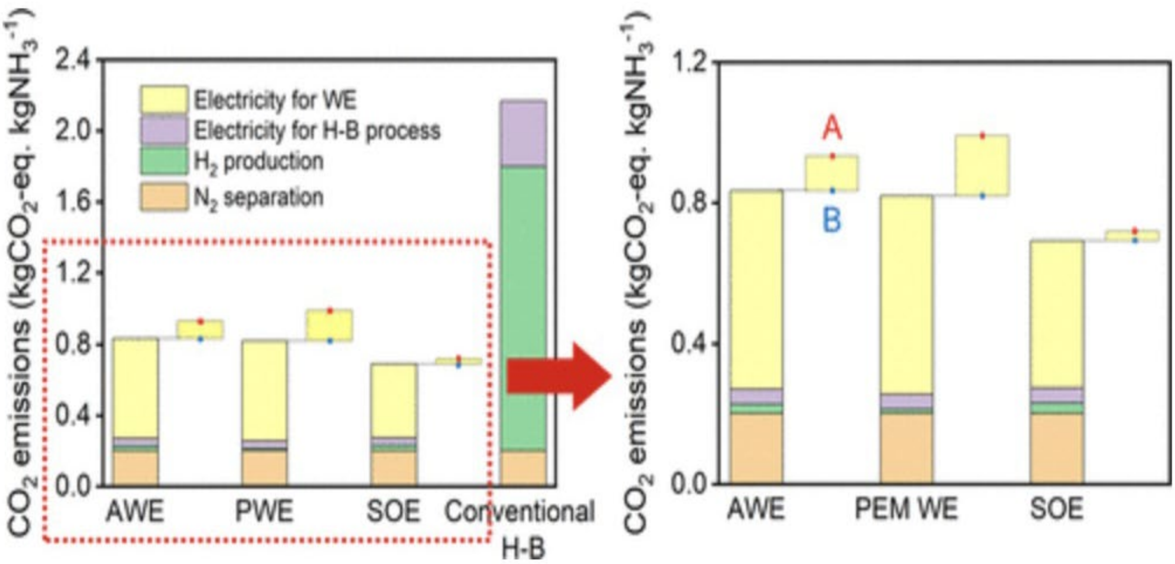
The CO_2 can be obtained through carbon-capture processes like waste gases or captured directly from the air (Siemens Energy, 2020). The CO_2 gas for green methanol production would be derived from three main carbon sources: biomass, industry, and direct air capture (Schorn et al., 2021). This further reduces CO_2 being emitted into the atmosphere. The CO_2 derived from industry could be from the separation of flue gas of a conventional power station (Sollai et al., 2023).

The CO_2 hydrogenation process that produces methanol can reduce greenhouse gas (GHG) emissions by 59% compared to a conventional grey methanol production process (Assen et al., 2013). On the cost side, the near-term e-methanol production costs are estimated between US$120 and US$210/MWh, which are competitive with the current production costs of fossil fuels, where the latter could rise even further with further restrictions on CO_2 emissions (IEA, 2019).

The methanol molecule is an efficient hydrogen carrier. More hydrogen can be found in methanol compared to compressed or liquefied hydrogen per unit volume (Gumber and Gurumoorthy, 2018). Methanol is currently being traded as a base chemical and could be transported using crude oil cargo vessels with minor retrofits (Schorn et al., 2021). Methanol can be used as an energy carrier to reduce emissions released by internal combustion engine (ICE) vehicles or other vehicles that consume fossil fuels like diesel, gasoline, or kerosene.

Industrial ammonia is produced through the Haber-Bosch process. Currently, it produces 235 million tonnes of CO_2 emissions every year, which is 1.8% of global CO_2 emissions (Royal Society, 2020). 80% of these CO_2 emissions are from the hydrogen SMR step (Winter and Chen, 2021). Green ammonia can be synthesised using green hydrogen, which refers to hydrogen produced through renewable electricity. Hydrogen generation can be achieved via electrolysis technology. For synthesising green ammonia through the modified Haber-Bosch process, there are three distinct types of electrolysis processes: alkaline water electrolysis (AWE), polymer electrolyte membrane water electrolysis, and solid oxide water electrolysis (SOE) (Lee et al., 2022). Figure 2 describes the breakdown of CO_2 emissions derived from each green ammonia production process. These range from 0.83–0.93, 0.82–0.99, and 0.69–0.72 kg of CO_2 per kg of ammonia produced, respectively. The range describes different levels of efficiency for the modified Haber-Bosch processes (with upper and lower bounds A and B, respectively). These values generate an average of 2.46, 2.42, and 3.07 times lower CO_2 emissions than for the conventional Haber–Bosch process using SMR or grey hydrogen, respectively.

Figure 2: Breakdown of CO_2 Emissions for Green Ammonia Synthesis



AWE = alkaline water electrolysis, PWE = PEM WE= polymer electrolyte membrane water electrolysis, SOE = solid oxide water electrolysis, WE = water electrolysis.
Source: Lee et al. (2022).

Figure 2 also breaks down the CO_2 emissions associated with the electricity used for water electrolysis and for the modified Haber-Bosch process, as well as for hydrogen production and nitrogen separation. Improvements to the traditional Haber-Bosch process are possible to further reduce or almost eliminate CO_2 production with no CO_2 emitted. First, it has to be decoupled from the SMR process, including by SMR decoupling, the use of electric compressors, and optimised separation processes (Smith et al., 2020).

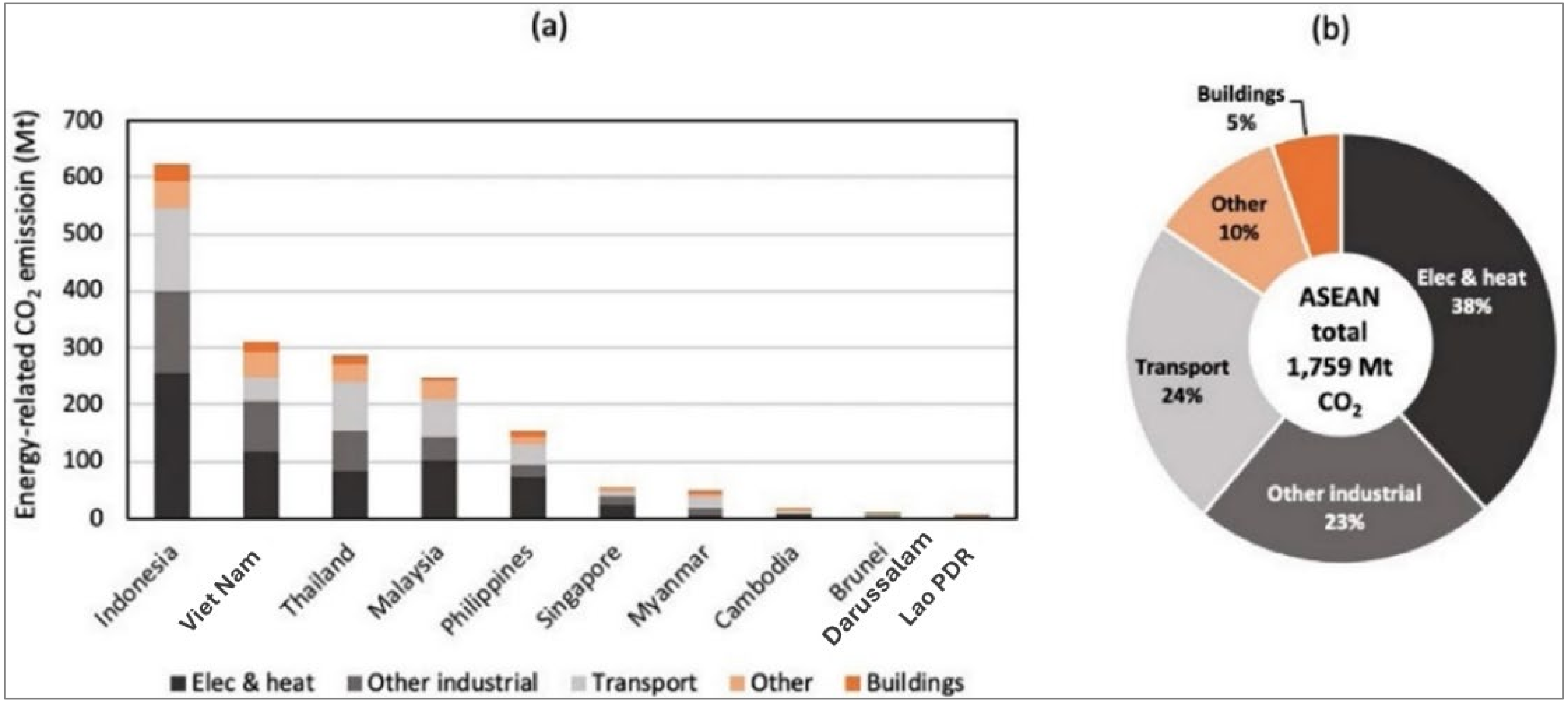
Bareiß et al. (2019) showed that utilising proton exchange membrane water electrolysis for hydrogen generation has the potential to decrease CO_2 emissions in the hydrogen sector by 75% when the electrolysis system is powered exclusively by renewable energy sources. PEM WE has several benefits over traditional AWE, including a higher working current density, greater gas purity, increased output pressure, and a smaller physical footprint (Shi et al., 2023).

Shi et al. (2023) explored three decarbonisation methods for ammonia production: carbon capture technology; renewable energy-based hydrogen production; and electrochemical methods. Adopting carbon capture technology in the ammonia production can result in a significant reduction of GHG emissions by 55%–70% (Shi et al., 2023).

2.4. Literature on Carbon Emissions from Fossil Fuels in Shipping and Transport

The road transportation industry, which includes passenger vehicles, trucks, and buses, predominantly depends on traditional fossil fuels like diesel, gasoline, and liquefied petroleum gas to power ICEs. Approximately 72% of GHG emissions in the transportation sector are attributed to road transportation (IEA, 2020). In the baseline scenario of the 7th ASEAN Energy Outlook (ACE, 2022), the transportation sector produces the second biggest proportion of emissions, behind electricity generation. Considering the relative greenhouse warming potential of all three gases, one can define the CO_2-eq emission. A total of 379 MT CO_2-eq was recorded in 2020. Projections indicate that this figure will rise to 493 MT CO_2-eq in 2025, 621 MT CO_2-eq in 2030, and 1,385 MT CO_2-eq in 2050. As depicted in Figure 3, it can be observed that the transportation sector accounted for 24% of CO_2 emissions in the ASEAN region in 2019.

Figure 3: Energy-related CO_2 Emissions in ASEAN, 2019

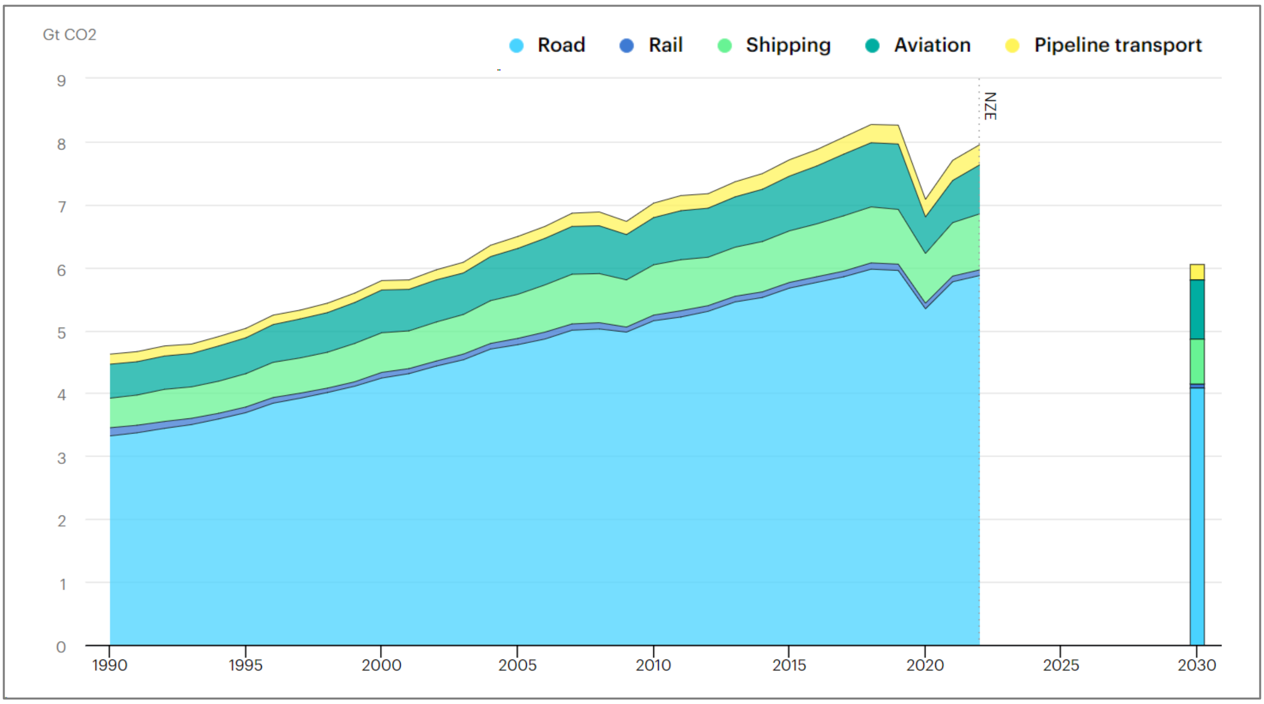


Source: IRENA (2022a) in Lau (2022).

A study conducted by Quiros et al. (2017) examined the levels of GHG emissions generated by heavy-duty on-road trucks that operate on natural gas, hybrid, and conventional diesel fuels during the transportation of freight. The study measured seven vehicles whilst they were in operation on public roads. The trucks included in the study were powered by diesel, hybrid diesel, and natural gas. It has been shown that the emissions of nitric oxides from diesel trucks equipped with selective catalytic reduction (SCR) are 10 times higher than those from diesel trucks without SCR. Based on that calculation, natural gas and hybrid diesel vehicles exhibited reduced CO_2-eq emissions, but only for specific routes.

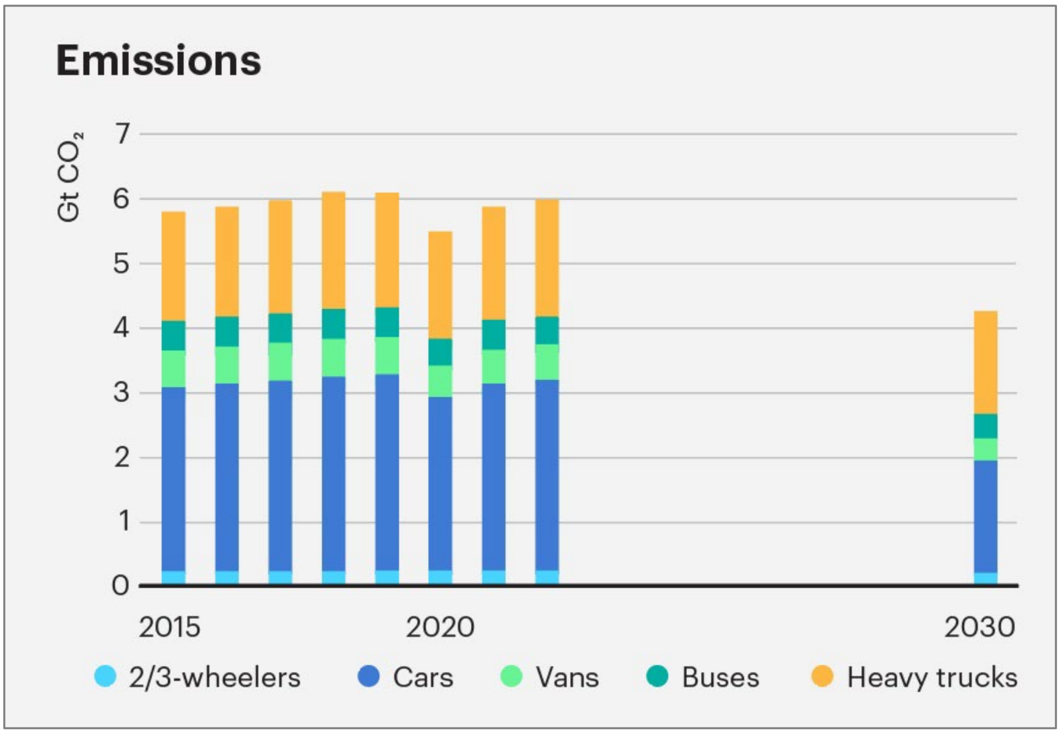
The CO_2 emissions resulting directly from the burning of fossil fuels in the road sector experienced a notable increase of 200 MT during 2015. To adhere to the IEA Net Zero Emissions by 2050 Scenario (NZE Scenario), it is imperative that emissions be reduced by around 30% by the year 2030. The road sector CO_2 emissions accounted for 5.87 Gt CO_2 in 2022 (Figure 4). To achieve the objective of achieving net zero emissions, it is imperative that emissions stemming from vehicle transport are reduced by approximately 30% by 2030 (IEA, 2023b).

Figure 4: Global CO_2 Emissions from Transport in the Net Zero Scenario, 2000–2030



Source: IEA (2023b).

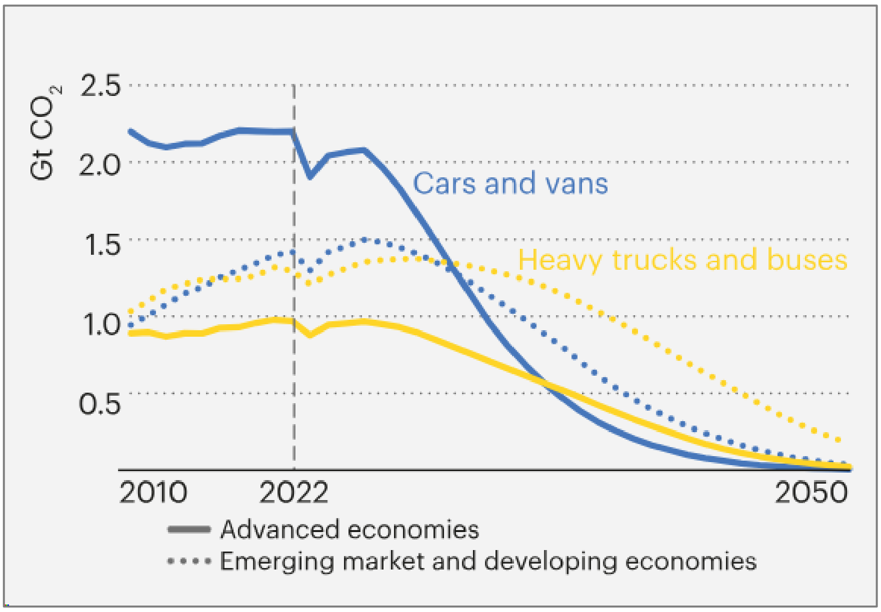
Figure 5: Emissions by Vehicle Type



Source: IEA (2023c).

Figure 5 illustrates a significant reduction in emissions resulting from road transport, particularly in industrialised economies, by the year 2030 (IEA, 2023c). Total transport emissions increase by 2.1% (or 137 MT), also driven by growth in advanced economies. Nonetheless, emissions would be even higher without the accelerated deployment of low-carbon vehicles. Electric car sales surpassed 10 million in 2022, making up over 14% of global sales. If all new electric cars on the road had been typical diesel or gasoline cars, global emissions in 2022 would have been 13 MT higher (IEA, 2023d).

Figure 6: Projected CO_2 Emissions



Source: IEA (2023d).

Lindstad et al. (2021) reported that the use of low-emission green ammonia as a shipping fuel results in a 95% decrease in GHG emissions and a 75% increase in well-to-wake (WTW) energy consumption compared to the use of standard marine gas oil. Additionally, green hydrogen leads to a 100% reduction in GHG emissions but doubles the WTW energy consumption. Furthermore, hydrocarbon-based e-fuels burned in dual-fuel diesel engines also achieve a nearly 100% GHG reduction, but their WTW energy consumption nearly triples (140%–200% increase) compared to marine gas oil. However, the intriguing aspect of hydrocarbon-based e-fuels is their ability to be mixed with traditional fossil fuels, allowing for a progressive reduction in GHG emissions in the shipping industry (Lindstad et al., 2021).

2.5. Literature on Future Hydrogen Economics

SMR facilities produce most of the hydrogen that is currently utilised as feedstock for ammonia and methanol in Southeast Asia. SMR hydrogen is produced concurrently with captive hydrogen from reforming and platforming, as well as being a by-product from several refining operations in the major refining centres of the region. By contrast, the steel industry continues to primarily rely on conventional, antiquated oxygen furnace technology. Some studies have discussed the cost competitiveness of various hydrogen production pathways.

Compared to SMR-based production costs of roughly US$960 per tonne in 2020, Neuwirth and Fleiter (2020) estimated that the cost of producing green ammonia in Germany will be approximately €1,250 per tonne assuming electricity prices of €0.05 per kWh and on-site alkaline electrolysis technology. Due to economies of scale and learning gain traction, it is predicted that the cost of green ammonia will drop to US$1,030 per tonne in 2050. The cost of producing ammonia based on green and blue hydrogen is estimated by the IEA's Ammonia Technology Roadmap (IEA, 2021b) to be highly dependent on electricity costs and technology capital expenditures, as well as future carbon prices. A carbon price of roughly US$30 per tonne is required for the US$600 per tonne production cost of blue hydrogen-based ammonia to be able to break even with SMR hydrogen. Furthermore, to match the price of grey hydrogen, electrolyser costs must decrease by 60% to roughly US$400 per kW of electrolyser capacity. In a more recent study by Egerer et al. (2023), the cost of ammonia produced in Australia using a hybrid solar photovoltaic (PV) and wind-powered electrolyser, and its transportation to Germany, is estimated at approximately €509 per tonne, consisting of €458 per tonne of solar PV and wind electricity generation plus €51 per tonne of ammonia synthesis costs.

Meanwhile, according to Neuwirth and Fleiter (2020) the production cost of green methanol will continue to be higher than SMR-based production until 2050, estimated in the range of €1,120–€1,340 per tonne. According to research by IRENA and Methanol Institute (2021), the cost of producing green methanol is now estimated to be between US$800 and US$1,600 per tonne. Following ammonia and methanol, the investment and running expenses for direct reduction iron (DRI) steelmaking are projected by IRENA (2022b) to be 30%–50% greater than those for the conventional SMR process. The primary issue influencing the future competitiveness of green hydrogen-based DRI will be the cost of energy. Even with CCUS, the cost of producing steel for 50%–100% direct reduced iron–electric arc furnace (DRI-EAF) would be about twice as high as it was previously for SMR-based production (IEA, 2019).

In the Southeast Asian context, IESR (2022) compared the economics of producing green hydrogen in Indonesia using three different types of electrolysis technology, assuming solar PV electricity rates of US$60– US$100 per MWh. According to the authors' calculations, the cost of producing solar PV-based green hydrogen will drop to US$2.6– US$4.7 per kg for alkaline, US$2.8– US$5.7 per kg for PEM, and US$3.1– US$5.3 per kg for solid oxide electrolyser cell electrolysis by 2050. These prices will only be roughly

US$2.0– US$3.2 per kg when the electricity stems from lower cost geothermal and location-constrained hydropower. Li and Taghizadeh-Hesary (2020) conducted a cost comparison between lithium batteries and pumped hydropower in comparison to the generation and supply of green hydrogen for use as a fuel for road transport. Li et al. (2023), investigating hydrogen production and supply for power generation via hydrogen fuel cells or mixed combustion in coal or gas power plants, noted similar cost comparison results with the renewable electricity cost as the most significant factors. Both studies examined the use of solar PV, wind, and geothermal energy with the electricity grids of a few selected nations for electrolysis to estimate the production cost of hydrogen.

Selected assumptions from Li and Taghizadeh-Hesary (2020), IESR (2022b), Chang and Han (2021) and Li et al. (2023) on solar PV, electricity, and electrolyser cost are used by ERIA (2024) to estimate the effective cost of delivering green hydrogen to industrial sites. Using similar assumptions, Purwanto et al. (2024a) calculate the costs of green hydrogen generation in Southeast Asia in different locations, whether remotely or on-site at the hydrogen-consuming industrial facilities. The authors consider domestic renewable electricity costs, upfront electrolyser investments, and ongoing operational expenditures and anticipate the cost of electricity transmission infrastructure or hydrogen transport and storage facilities. The relevant results are discussed in section 4.

3. Modelling Carbon Emissions and Carbon Reduction Potential

The modelling approach can be summarised as in Table 1.

Table 1: Modelling Approach

Step	Source
1. Hydrogen production forecasts by industry, usage and country; by scenario (APS vs. STEPS)	**ERIA Greening Hydrogen for Industry in ASEAN (2024)**
2. Carbon emission forecasts of hydrogen production by industry, usage and scenario	Bassani et al. (2020), IEA Future of Hydrogen (...) Status quo production technology-mix (IEA)
3. Carbon emission reduction potential by industry, merchants, shipping and road transport	IEA Future of Hydrogen ... Future production technology mix (IEA: increasing blue, green vs. decreasing grey) by industry and usage
4. H2 economics and required subsidies by production technology-mix and carbon prices	Function of carbon prices and IEA's future production technology mix
5. Country-breakdown of carbon emissions and reduction potential, economics and subsidies	Same country-split of hydrogen usage and production technology-mix as region

First, ERIA's hydrogen supply and demand forecasts are utilised (ERIA 2024). In particular, the APS is analysed. The four industrial sectors under study are split in accordance with the applications and sources of hydrogen inherent in their technologies. These include ammonia for power generation, maritime fuel, non-fertiliser feedstocks, non-urea and urea fertilisers, methanol for feedstock, a conventional fuel mix, and low-carbon energy. In oil refining, both captive hydrogen produced in reformers and platformers and coming out of isomerisation processes as well as hydrogen produced from SMR are considered. Merchant hydrogen production is assumed to represent hydrogen independently produced by gas companies like Air Products, Air Liquide, Linde, or any other regional gas company. These primarily serve independent chemical producers and the DRI steel producers in the ASEAN region. Concurrently, the volumes of power generation fuel, maritime and shipping, and road transport to be displaced by ammonia and methanol in the future are estimated.

Source: Authors' elaboration.

Second, carbon emission estimates resulting from the projected hydrogen production volumes are derived across the four key industries studied. Here the diversified chemical sectors, the regional steel industry, and any projected shortfall of future incumbent supply within the four key industries are assumed to be supplied by independent gas producers and merchants.

Third, the carbon emission reduction potential across the four industrial sectors in the region are estimated under the assumption that the future production technology mix for non-captive or non-by-product hydrogen consists of either 100% blue, 100% green, or the projected global mix of grey, blue, and green hydrogen under the APS.

Fourth, making use of ERIA's (2024) estimated per-tonne LCOH based on the current, 2030, and 2050 states of development in electrolyser technology, unit costs, and regional renewable electricity costs, the aggregate incremental costs for the ASEAN region are calculated. The base case's existing SMR production costs and future hydrogen production mix under these scenarios, i.e. APS, 100% blue and 100% green are estimated. Furthermore, these regional aggregate incremental costs of decarbonising hydrogen across the region's industrial sectors, which may require public subsidies and innovative financing solutions with the help of member states and other friendly governments and multilaterals, are calculated under different carbon price assumptions. The latter analysis supposes that the decarbonisation efforts across the region's industries can simultaneously benefit from selling carbon credits to other high-emission sectors in the region and internationally.

In the fifth step the regional estimates of carbon emission reductions and required aggregate regional subsidies are divided into the corresponding estimates for each country and industrial sector. Again, the same future hydrogen production technology mix of 100% blue, 100% green, and the APS are examined.

3.1. Scenario Definition

The ERIA (2024) report defined four future scenarios of hydrogen production in industrial sectors in the ASEAN Member States in the horizon to 2050: the APS, STEPS, Frozen scenario, and Likely scenario. This paper concentrates solely on the APS, in which hydrogen consumption grows fastest in the following decades. It does not include the Frozen scenario or STEPS, which involve limited decarbonisation potential. The ERIA-APS, however, is expected to witness the emergence of alternative applications of low-carbon hydrogen feedstocks, such as blue or green ammonia for shipping and power generation fuels and e-methanol for road transport. Nor is the Likely scenario examined in this study, since it constitutes a more conservative projection of such alternative ammonia and methanol applications.

The APS defined globally by the IEA (2022) assumes all aspirational targets announced by governments are met on time and in full, including their long-term net zero and energy access goals. The scenario fills the 'implementation gap' that needs to be bridged for countries in STEPS to achieve their announced decarbonisation targets. The APS examined by ERIA (2024) also includes some assumed policy measures implemented in three industrial sectors, the ammonia production, methanol, and iron and steel industries, of the IEA's NZE scenario. Since the NZE scenario differs from the APS and most of the policy measures and trends are given at the global level, interpretation of the assumptions for the ERIA-APS is conducted specifically for the ASEAN region.

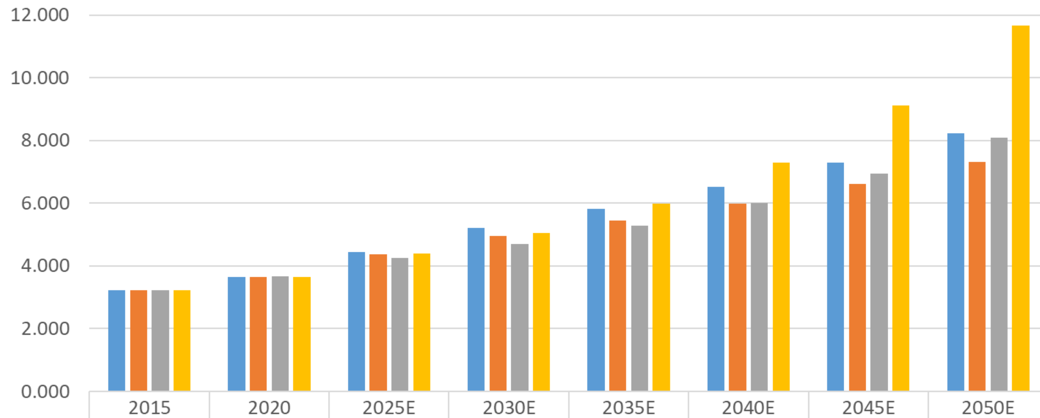
Inspired by IEA's NZE scenario, ERIA's (2024) APS assumes that global demand for low-emission hydrogen – both produced on-site and off-site – rises to 11 MT in 2030 for use in the production of ammonia, steel, and methanol. Over 25% of the hydrogen produced in 2050 is converted to hydrogen-based fuels, such as ammonia, methanol, and synthetic hydrocarbons. The remainder is used directly in industry, transport, and buildings. Ammonia and hydrogen co-firing, respectively in coal-fired and natural gas-fired power plants, provides 2%–3% of global electricity generation from 2030 to 2050. By 2050, ammonia will meet around 45% of demand for shipping fuel. Global unabated coal use is estimated to drop by 99% over this period, whilst around half of the remaining 60 MT of unabated coal consumption in 2050 is used in the iron and steel industry. Without new coal mine lifetime extensions, thermal coal production falls by 50% by 2030 as coal is rapidly eliminated from the power sector in all countries. Coking coal production falls by about 30% by 2030, a more gradual decline compared to thermal coal since the steel industry has fewer readily available alternatives. The APS is projected to have the lowest average emissions factor or carbon intensity by 2050, followed by the Likely scenario and then STEPS. This is due to the APS being projected to the have the highest penetration of low-carbon hydrogen.

3.2. Estimation of industrial and merchant hydrogen production

The industrial and merchant hydrogen production estimation utilised in this paper is discussed in this section. ERIA (2024) reports and discusses the hydrogen supply-demand balance for each of the scenarios, including the modified APS. The report also includes the growing discrepancy between estimated demand and announced or known production growth in the forthcoming years. This reflects the increasing role of merchants within hydrogen trade in the region, which nevertheless will be diminished when new captive production capacities are announced and implemented in the future. For now, merchant hydrogen is assumed to also capture the entire volume of demand from steel DRI and other chemicals due to the industries' projected lack of captive hydrogen production.

The APS appears to be the scenario where total hydrogen demand for the industry sector in ASEAN will increase the fastest during the simulated 2020–2050 period, as shown in Figure 7. In this scenario, hydrogen demand for the industry sector in ASEAN increases from around 3.7 million tonnes per annum (MTPA) in 2020 to 11.7 MTPA in 2050 with a compounded annual growth rate of 3.9%. The use of hydrogen as an energy carrier and as a feedstock to produce e-methanol, ammonia fuels, and e-kerosene is the main driving factor of this fast growth. Note that the hydrogen produced in this scenario gradually transitions to low emission i.e. low carbon-intensity hydrogen, as only the latter leads to net zero emissions.

Figure 7: Total Hydrogen Demand in the Industry Sector in ASEAN by Scenario
(million tonnes per annum)

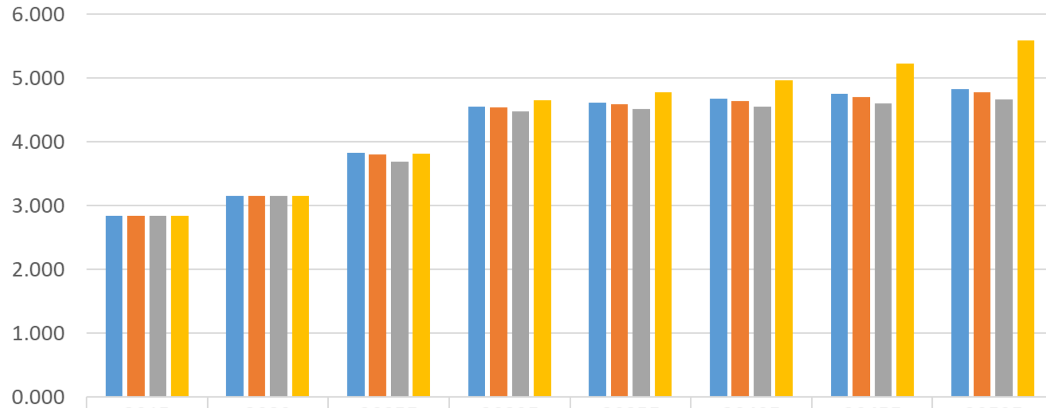


	2015	2020	2025E	2030E	2035E	2040E	2045E	2050E
ERIA-Frozen Scenario	3.216	3.657	4.445	5.212	5.830	6.520	7.302	8.227
ERIA-STEPS	3.216	3.657	4.367	4.961	5.444	5.990	6.610	7.319
ERIA-Likely Scenario	3.216	3.675	4.245	4.687	5.272	6.009	6.933	8.088
ERIA-APS	3.216	3.657	4.406	5.060	5.978	7.292	9.130	11.669

APS = Announced Pledges Scenario, E = estimate, STEPS = Stated Policies Scenario.
Source: Authors.

Captive hydrogen production will increase in all four scenarios, with the APS being the scenario where hydrogen produced in the four sectors increases at the fastest rate from around 3.2 MTPA of hydrogen in 2020 to 5.6 MTPA of hydrogen in 2050 (Figure 8). The produced hydrogen in the APS follows the growth of demand, which is also the fastest. For STEPS, the ASEAN ratio of on-site and/or captive production to total hydrogen demand of around 86% in 2020 grows to 91.5% by 2030 and decreases to around 65.2% in 2050. The relatively low on-site and/or captive hydrogen production after 2030 compared to the APS is presumably caused by the need to produce low-carbon hydrogen to meet higher hydrogen demand in the industry sector. The need for hydrogen feedstock to produce e-fuels and ammonia carriers in the STEPS scenario starts to kick in after 2030, but the quantity is less than in the APS, so the economy of scale of producing low-carbon hydrogen is not high enough to decrease the low-carbon hydrogen prices. Therefore, the on-site and/or captive (low-carbon) hydrogen production in the STEPS scenario becomes lower.

Figure 8: Captive Hydrogen Production in the Industry Sector in ASEAN by Scenario
(million tonnes per annum)



	2015	2020	2025E	2030E	2035E	2040E	2045E	2050E
ERIA-Frozen Scenario	2.844	3.148	3.826	4.554	4.612	4.677	4.750	4.833
ERIA-STEPS	2.844	3.148	3.805	4.542	4.591	4.645	4.706	4.773
ERIA-Likely Scenario	2.844	3.148	3.696	4.474	4.509	4.554	4.608	4.671
ERIA-APS	2.844	3.148	3.812	4.658	4.782	4.968	5.229	5.587

ERIA-Frozen Scenario ERIA-STEPS ERIA-Likely Scenario ERIA-APS

APS = Announced Pledges Scenario, E = estimate, STEPS = Stated Policies Scenario.
Source: ERIA (2024).

The role of hydrogen merchants in the ASEAN industry sector will become more important after 2030 as the demand for hydrogen grows, whilst new supply from on-site and/or captive production and by-products is yet to be identified. The first source of growth is the ammonia sector, where supply from on-site production and by-products increases only until 2030 and then remains at the same level between 2030 and 2050, regardless of the scenarios. The oil refining sector is generally less dependent on hydrogen supplied by merchants, whilst the methanol sector shows an important increase only in the APS. The iron and steel and chemical industries, on the other hand, are often dependent on the supply of hydrogen from merchants. The decarbonisation imperative grows from STEPS to the APS, which is followed by an increasing share of supply from merchants. The increasing merchant supply, therefore, indicates the important roles expected from the hydrogen merchants to supply low-carbon hydrogen.

As mentioned above, this analysis focuses on the APS and compares it to future carbon emissions and subsidy forecasts under the 100% blue and 100% green hydrogen scenarios, respectively.

3.3. Forecasting Carbon Emission from Industrial and Merchant Hydrogen Production

To estimate the carbon emission volumes of the major industries in the ASEAN region, the region's hydrogen production forecasts are broken down into their key sub-segments, i.e. applications. Ammonia is divided by its various applications, including urea fertiliser, non-urea fertiliser, and non-fertiliser feedstocks, plus its use as a maritime fuel and as a mixed fuel in power generation. The production of hydrogen in oil refineries is split into by-products and captive SMR. Next, methanol is split according to its main uses, including as chemical feedstock, for mixing into conventional fuels i.e. gasoline in road transport, and for future lower-carbon energy. Next, the production of hydrogen by independent third-party merchants and gas companies, which generally sell to diversified chemical customers and the steel industry, is listed and studied separately. The resulting hydrogen production forecast under the APS is shown in Table 2.

Table 2: ASEAN Hydrogen Production Forecasts by Source and Application
(TPA)

	2015	2020	2025E	2030E	2035E	2040E	2045E	2050E
H2 Industrial SMR Production	**3.215.605**	**3.656.888**	**4.405.967**	**5.060.337**	**5.978.410**	**7.291.755**	**9.129.937**	**11.668.710**
Ammonia - Power Generation	0	0	13.075	28.701	165.095	257.424	324.072	374.445
Ammonia - Maritime Fuel	0	0	32.688	71.752	350.466	539.133	675.324	778.259
Ammonia - Non-Fertiliser	437.632	530.979	614.536	717.520	599.557	519.705	462.064	418.498
Ammonia - Non-Urea-Fertiliser	358.062	434.437	523.010	631.418	611.143	597.418	587.511	580.023
Ammonia - Urea-Fertiliser	716.124	868.875	961.030	1.076.280	799.409	611.989	476.699	374.445
Merchant production	371.682	508.846	653.824	402.654	1.196.708	2.323.874	3.901.274	6.081.637
Refinery ex Captive H2	477.656	476.505	593.938	748.787	718.021	690.352	665.469	643.091
Refinery captive byproducts	499.137	497.934	629.964	803.630	780.504	761.827	743.593	727.194
Methanol as Feedstock	260.711	248.971	265.133	282.344	300.673	320.191	340.977	363.112
Methanol for Conventional Energy	94.602	90.342	92.669	95.056	97.505	100.017	102.594	105.237
Methanol for Low-Carbon Energy	0	0	26.099	202.194	359.329	569.823	850.361	1.222.769
Steel (included in merchant production)	0	0	0	0	0	0	0	0
Relevant Fuel Volumes*	**41.939**	**40.051**	**76.867**	**186.390**	**482.246**	**730.106**	**967.667**	**1.220.240**
Power generation (coal)	0	0	10.133	22.243	127.949	199.504	251.156	290.195
Maritime and shipping (marine fuel oil)	0	0	25.651	122.006	311.070	486.263	671.030	883.392
Transport (diesel)	41.939	40.051	41.082	42.141	43.226	44.340	45.482	46.654

* Volumes to be displaced by Ammonia Energy Carrier & Fuel or Methanol e-Fuels in future

Source: ERIA (2024), Bassani et al. (2020), IEA (2023a), authors' estimates.

As depicted in Table 2, the use of ammonia for power generation and as substitute for maritime fuel, and methanol for low-carbon transport fuel, is not anticipated to start until 2025 onwards. Starting from a low base, the growth rates for these applications are expected to accelerate between 2035 and 2050. In contrast, ammonia use as a chemical feedstock and as the basis for urea- and non-urea fertilisers, and methanol use for chemical processing and conventional transport fuel mixtures, have been standard around the world for a long time. In the case of refineries, the captive SMR production is separated from the hydrogen by-products of platformers, reformers, and other processes. Additionally, there is a rapid increase in merchant production, serving other chemical and processing industries and direct reduced iron in the steel industry.

Using these forecasts, future carbon emission volumes are calculated using several assumptions. First, refinery sector hydrogen production via natural gas SMR and coal gasification are estimated to emit about 7–11.5 tonnes, respectively, with 23 tonnes of CO_2 per tonne of hydrogen produced, using calculations from Bassani et al. (2020) and IEA (2023a). Second, blue ammonia is estimated to still emit 3.6 tonnes of CO_2 per tonne of hydrogen. Third, green ammonia produces 2.5 tonnes of CO_2 using conventional electricity generation, which, however, decreases to 0.5 tonnes of CO_2 per tonne of hydrogen produced when the electricity is generated using renewable solar or wind, or nuclear. Concurrently, grey methanol is estimated to emit 6.6 tonnes of CO_2 per tonne of hydrogen, whilst methanol's use for conventional energy produces both 6.6 tonnes of CO_2 in the production stage plus an additional 11.0 tonnes of CO_2 per tonne of hydrogen resulting from the combustion of the methanol (Methanol Institute, 2022). In contrast, blue methanol is estimated to emit between 6.0 tonnes of CO_2 per tonne of hydrogen produced, whilst green methanol i.e. the use of methanol for low-carbon energy, emits about 3.6 tonnes of CO_2 per tonne of hydrogen produced (IRENA and Methanol Institute, 2021).

It is also noteworthy that the equivalent volumes of CO_2 produced by burning 1 tonne each of coal, maritime fuel oil, diesel, and gasoline are estimated to be around 2.8 tonnes, 3.2 tonnes, 3.2 tonnes and 3.2 tonnes (Marine Benchmark, 2020; EIA, 2024). Multiplying these emission estimates by the various fuel types' energy densities per equivalent tonne of hydrogen allows us to calculate the carbon emissions originating from burning these fossil fuels. Additionally, carbon emissions from the relevant fossil fuel volumes can be estimated for future scenarios where blue or green ammonia replaces coal for power generation and marine fuel oil for shipping, and where blue or green methanol replaces diesel for transport.

The resulting CO_2 emission forecast can thus be summarised in Table 3.

Table 3: CO_2 Emissions from SMR Hydrogen Production

(TPA)

	2015	2020	2025E	2030E	2035E	2040E	2045E	2050E
CO2 from gas SMR & coal gasification	**26.845.979**	**30.925.407**	**36.970.112**	**41.256.965**	**49.871.865**	**61.671.801**	**77.899.575**	**100.125.837**
Ammonia - Power Generation	0	0	120.946	265.482	1.527.132	2.381.173	2.997.665	3.463.619
Ammonia - Maritime Fuel	0	0	302.365	663.706	3.241.808	4.986.984	6.246.747	7.198.894
Ammonia - Non-Fertiliser	4.048.092	4.911.556	5.684.462	6.637.059	5.545.902	4.807.273	4.274.090	3.871.103
Ammonia - Non-Urea-Fertiliser	3.312.075	4.018.545	4.837.840	5.840.612	5.653.069	5.526.117	5.434.477	5.365.213
Ammonia - Urea-Fertiliser	6.624.150	8.037.091	8.889.531	9.955.588	7.394.536	5.660.901	4.409.469	3.463.619
Merchant production	3.438.059	4.706.829	6.047.873	3.724.554	11.069.547	21.495.835	36.086.781	56.255.146
Refinery ex Captive H2	4.418.316	4.407.669	5.493.928	6.926.281	6.641.692	6.385.756	6.155.588	5.948.594
Refinery captive byproducts	1.497.410	1.493.801	1.889.891	2.410.891	2.341.512	2.285.481	2.230.778	2.181.583
Methanol for Feedstock	1.710.262	1.633.247	1.739.271	1.852.178	1.972.413	2.100.454	2.236.807	2.382.012
Methanol for Conventional Energy	1.664.993	1.590.017	1.630.978	1.672.994	1.716.093	1.760.302	1.805.650	1.852.166
Methanol for Low-Carbon Energy	0	0	93.938	727.760	1.293.338	2.050.972	3.060.715	4.401.126
Steel	0	0	0	0	0	0	0	0
CO2 from relevant Fuel Volumes*	**132.624**	**126.651**	**239.089**	**579.860**	**1.474.823**	**2.230.554**	**2.960.807**	**3.742.763**
Power generation (coal)	0	0	28.373	62.281	358.257	558.610	703.236	812.546
Maritime and shipping (marine fuel oil)	0	0	80.802	384.318	979.872	1.531.728	2.113.743	2.782.684
Transport (diesel)	132.624	126.651	129.914	133.261	136.694	140.215	143.828	147.533

* Volumes to be displaced by Ammonia Energy Carrier & Fuel or Methanol e-Fuels in future

Source: ERIA (2024), IEA (2023a), Methanol Institute (2022), IRENA and Methanol Institute (2021), authors' estimates.

Assuming grey hydrogen, ammonia, and methanol CO_2 emissions in the ASEAN region increase rapidly over the next 25-year projection period, the region's industrial hydrogen production is estimated to emit more than 100 million tonnes of CO_2 by 2050. Recall that the large share of merchant production is a result of the assumption by ERIA (2024) to only consider announced and known hydrogen production volume growth rates by incumbent refiners and ammonia and methanol producers, disregarding any yet to be announced hydrogen capacity expansion plans throughout the region.

The estimated CO_2 emissions in Table 3 include roughly 3.7 million tonnes of CO_2 produced by the equivalent fossil fuel volumes, which can be gradually or partially eliminated if the corresponding blue and green hydrogen production forecasts are considered. Specifically, the forecasted CO_2 volumes assume coal combustion for power generation, maritime fuel oil for shipping, and diesel and gasoline for road transport.

3.4. Carbon Emission Reduction Potential

Under the APS, the future hydrogen production technology mix can be summarised as shown in Table 4.

Table 4: Projected Hydrogen Production Technology Mix under the APS

	2015	2020	2025	2030	2035	2040	2045	2050
Fossil Fuel	100.0%	100.0%	90.7%	83.8%	62.4%	48.4%	38.5%	31.1%
Fossil Fuel with CCUS	0.0%	0.0%	2.1%	3.8%	7.9%	10.7%	12.6%	14.0%
Electrolysis	0.0%	0.0%	7.1%	12.5%	29.7%	41.0%	49.0%	54.9%

CCUS = carbon capture, utilisation, and storage.
Source: IEA (2023e).

According to the IEA (2023a), starting with historical fossil fuels-based SMR production, blue and green hydrogen start coming into the picture by 2025. As the proportion of grey hydrogen decreases steadily from then on, the share of blue and green hydrogen continues increasing. By 2050, the APS hydrogen production mix reaches 31% natural gas and coal SMR, 14% natural gas or coal with carbon capture, and 55% green hydrogen utilising various electrolysis technologies. Note that this study assumes the same production technology mix for industries in the ASEAN region as per the IEA's global estimates under the APS.

Using this APS production technology mix, the carbon emission potential can be estimated as shown in Table 5.

Table 5: Carbon Emission Reduction Potential under the APS

(TPA)

	2015	2020	2025E	2030E	2035E	2040E	2045E	2050E
CO2 Reduction Potential (APS)	132.624	126.651	2.716.232	5.269.523	14.540.655	24.421.742	36.531.081	52.386.737
Ammonia - Power Generation	0	0	8.891	34.154	457.200	979.477	1.470.108	1.902.365
Ammonia - Maritime Fuel	0	0	22.228	85.385	970.547	2.051.358	3.063.515	3.953.934
Ammonia - Non-Fertiliser	0	0	417.885	853.849	1.660.357	1.977.436	2.096.089	2.126.172
Ammonia - Non-Urea-Fertiliser	0	0	355.647	751.387	1.692.442	2.273.127	2.665.163	2.946.800
Ammonia - Urea-Fertiliser	0	0	653.501	1.280.773	2.213.810	2.328.569	2.162.481	1.902.365
Merchant production	0	0	444.600	479.159	3.314.051	8.842.150	17.697.596	30.897.685
Refinery ex Captive H2	0	0	403.878	891.057	1.988.420	2.626.733	3.018.809	3.267.217
Refinery captive byproducts	0	0	0	0	0	0	0	0
Methanol for Feedstock	0	0	114.064	212.570	528.351	773.524	982.347	1.171.765
Methanol for Conventional Energy	0	0	56.449	101.331	240.655	338.813	414.164	475.671
Methanol for Low-Carbon Energy	0	0	0	0	0	0	0	0
Steel	0	0	0	0	0	0	0	0
Power generation	0	0	28.373	62.281	358.257	558.610	703.236	812.546
Maritime and shipping	0	0	80.802	384.318	979.872	1.531.728	2.113.743	2.782.684
Transport	132.624	126.651	129.914	133.261	136.694	140.215	143.828	147.533

Source: ERIA (2024), IEA (2023a), Methanol Institute (2022), IRENA and Methanol Institute (2021), authors' estimates.

An aggregate of over 52 million tonnes of CO_2 can be eliminated using the APS' mix of hydrogen production technology as per Table 5. Note that it is assumed that captive refinery by-products of hydrogen will continue as before, and their CO_2 emissions are unaffected by switching to blue and green hydrogen. Furthermore, methanol for low-carbon energy is already considered to be low-emission and will not experience any change. Since under the APS approximately half of the amount of hydrogen is still produced using SMR or fossil fuels with carbon capture, the long-term carbon reduction potential also amounts to roughly half of the original emission levels.

By comparison, if future production processes were to comprise only natural gas and coal SMR with carbon capture and produce only blue hydrogen from 2025E onwards, the emission reduction potential increases slightly from the APS (Table 6). If this 100% blue scenario is assumed, approximately half of the carbon emissions from hydrogen production across industrial sectors in ASEAN can be eliminated compared to the APS, starting already in 2030. In the long-term, three-fifths of carbon emissions from industrial hydrogen production can be eliminated (Table 6).

Table 6: Carbon Emission Reduction Potential Assuming 100% Blue Hydrogen
(TPA)

	2015	2020	2025E	2030E	2035E	2040E	2045E	2050E
CO_2 Reduction Potential (APS)	132.624	126.651	21.711.482	23.804.717	29.277.972	36.599.870	46.573.595	60.176.059
Ammonia - Power Generation	0	0	77.144	169.335	974.063	1.518.802	1.912.024	2.209.227
Ammonia - Maritime Fuel	0	0	192.860	423.337	2.067.747	3.180.887	3.984.412	4.591.727
Ammonia - Non-Fertiliser	0	0	3.625.765	4.233.367	3.537.386	3.066.261	2.726.176	2.469.136
Ammonia - Non-Urea-Fertiliser	0	0	3.085.758	3.725.363	3.605.741	3.524.767	3.466.315	3.422.136
Ammonia - Urea-Fertiliser	0	0	5.670.080	6.350.051	4.716.515	3.610.737	2.812.526	2.209.227
Merchant production	0	0	3.857.562	2.375.661	7.060.576	13.710.857	23.017.514	35.881.661
Refinery ex Captive H2	0	0	3.504.235	4.417.844	4.236.322	4.073.077	3.926.267	3.794.238
Refinery captive byproducts	0	0	0	0	0	0	0	0
Methanol for Feedstock	0	0	851.076	906.325	965.160	1.027.814	1.094.535	1.165.588
Methanol for Conventional Energy	0	0	607.913	623.574	639.638	656.116	673.018	690.356
Methanol for Low-Carbon Energy	0	0	0	0	0	0	0	0
Steel	0	0	0	0	0	0	0	0
Power generation	0	0	28.373	62.281	358.257	558.610	703.236	812.546
Maritime and shipping	0	0	80.802	384.318	979.872	1.531.728	2.113.743	2.782.684
Transport	132.624	126.651	129.914	133.261	136.694	140.215	143.828	147.533

Note: 100% grey hydrogen based on natural gas and coal SMR is assumed until 2024.
Source: ERIA (2024), IEA (2023a), Methanol Institute (2022), IRENA and Methanol Institute (2021), authors' estimates.

Lastly, in an ideal future scenario with maximum decarbonisation, where future hydrogen production is entirely green, the carbon reduction potential increases to more than three-quarters starting in 2030 and reaches almost four-fifths by 2050 (Table 7).

Table 7: Carbon Emission Reduction Potential Assuming 100% Green Hydrogen
(TPA)

	2015	2020	2025E	2030E	2035E	2040E	2045E	2050E
CO2 Reduction Potential (APS)	132.624	126.651	28.477.365	31.129.708	38.048.952	47.441.030	60.325.364	77.961.051
Ammonia - Power Generation	0	0	101.333	222.431	1.279.489	1.995.036	2.511.557	2.901.951
Ammonia - Maritime Fuel	0	0	253.333	556.078	2.716.109	4.178.284	5.233.761	6.031.506
Ammonia - Non-Fertiliser	0	0	4.762.658	5.560.779	4.646.567	4.027.715	3.580.994	3.243.357
Ammonia - Non-Urea-Fertiliser	0	0	4.053.326	4.893.486	4.736.355	4.629.990	4.553.210	4.495.179
Ammonia - Urea-Fertiliser	0	0	7.447.986	8.341.169	6.195.422	4.742.917	3.694.420	2.901.951
Merchant production	0	0	5.067.136	3.120.572	9.274.486	18.010.024	30.234.871	47.132.690
Refinery ex Captive H2	0	0	4.603.020	5.803.100	5.564.661	5.350.228	5.157.385	4.983.957
Refinery captive byproducts	0	0	0	0	0	0	0	0
Methanol for Feedstock	0	0	1.341.572	1.428.661	1.521.404	1.620.168	1.725.342	1.837.344
Methanol for Conventional Energy	0	0	607.911	623.572	639.636	656.114	673.016	690.354
Methanol for Low-Carbon Energy	0	0	0	0	0	0	0	0
Steel	0	0	0	0	0	0	0	0
Power generation	0	0	28.373	62.281	358.257	558.610	703.236	812.546
Maritime and shipping	0	0	80.802	384.318	979.872	1.531.728	2.113.743	2.782.684
Transport	132.624	126.651	129.914	133.261	136.694	140.215	143.828	147.533

Note: 100% grey hydrogen based on natural gas and coal SMR is assumed until 2024.
Source: ERIA (2024), IEA (2023a), Methanol Institute (2022), IRENA (2021), authors' estimates.

4. Future Subsidy Requirements

According to Purwanto et al. (2024a), the base case hydrogen production capacities of 173 tonnes per day for alkaline electrolysers and 198 tonnes per day for PEM electrolysers are used to determine the costs of green hydrogen generation in Southeast Asia. Different to the analysis in ERIA (2024), the cost of renewable electricity is not included, whereby it is assumed that a 2 GW solar PV farm will require additional upfront investment of US$1.0 billion–US$1.2 billion. The capital expenses comprise the investment necessary for electrolyser facilities, plus either the cost of electricity transmission if only the solar PV facility is located remotely, or the cost of hydrogen transport and storage if both the solar PV farm and the electrolyser are located far from the hydrogen-consuming industrial facility. These costs are higher than the current SMR infrastructure. It is anticipated that in 2050, the cost of infrastructure for transmitting energy and hydrogen will have more or less stabilised. However, the price of compressed hydrogen trailer trucks is still subject to change, and by 2050, it is conservatively estimated that costs could only be reduced by roughly 10%.

Table 8: Incremental Capital Expenditures

Incremental Capex (US$ million)	SMR	SMR+CCS		Alkaline Electrolyser		PEM Electrolyser	
		2019	2050E	Today	2050E	Today	2050E
Grey	0						
Blue		172	91				
Solar PV green on-site*				1,470	400	2,400	530
Green H_2 pipeline 200 km				1,760	690	2,690	820
Green CH_2 truck 200 km				1,880	770	2,810	900
Green power transmission 200 km				1,690	620	2,620	750

* Electrolyser capex only, excl. Solar PV
Source: Purwanto et al. (2024a).

As can be seen in Table 8, Although it is anticipated that the cost of electrolysers will drop dramatically by 2050, green hydrogen projects will necessitate initial investments of US$400 million–US$620 million for alkaline electrolysers and US$530 million–US$750 million for PEM electrolysers. These are about 4–8 times higher than the additional cost of CCS investment. Green hydrogen will always be more expensive than blue hydrogen, even with the most promising new electrolyser technologies, whose economic viability and efficiency are still to be determined.

In line with the LCOH calculated in ERIA (2024), decreases in regional renewable electricity prices and electrolyser unit costs can be achieved through advancements in electrolyser technology and increased economy of scale. Assuming ERIA's (2024) incremental per tonne LCOH estimates for blue and green hydrogen above the costs of grey hydrogen and using the above hydrogen production volume forecasts, the nominal and present values of the total production costs of 100% blue hydrogen, 100% green hydrogen, and the APS production technology mix over 20-year project lifetimes are calculated. Unit cost and technology assumptions as well as project starting dates of 2030, 2040, and 2050 are assumed. Furthermore, the potential carbon emission reduction estimates are used to calculated possible carbon credits that the sponsors of decarbonised hydrogen production projects under the blue hydrogen, green hydrogen, or APS assumptions may be able to benefit from. Taking all these trade-offs into account, the present value of future decarbonised hydrogen production across the ASEAN region and across the four main industries can be summarised as shown in Table 9.

Table 9: Incremental Cost of the Aggregate Regional Subsidy over Grey Hydrogen and PV

(US$ billion)

Carbon prices → Production technology mix ↓	Technology and costs status; project start	US$100/ tonne CO_2	US$200/ tonne CO_2	US$300/ tonne CO_2	US$500/ tonne CO_2
100% blue H_2	2030	24.7	3.6	-17.6	-59.9
	2040	12.9	-29.0	-70.8	-154.6
	2050	-1.1	-54.2	-107.3	-213.6
100% green H_2	2030	291.6	270.5	249.3	207.0
	2040	295.9	254.0	212.2	128.4
	2050	217.9	164.8	111.6	5.4
APS tech. mix H_2	2030	19.7	-1.5	-22.7	-65.0
	2040	102.4	60.5	18.7	-65.1
	2050	102.9	49.8	-3.4	-109.6

Source: Purwanto et al. (2024a).

Several observations are noteworthy. First, increasing the carbon prices reduces the present value of subsidies required for industrial hydrogen to become economically viable. This can be observed across the range of carbon prices. In fact, blue hydrogen will generally become economically viable on its own starting at carbon prices above US$200 per tonne of CO_2. Second, 100% green hydrogen can only break even and may not require subsidies when technology advancement, electrolyser, and renewable electricity costs decrease to the levels forecasted in 2050 and a very high carbon price of US$500 per tonne of CO_2 is enforced. Third, under a future APS with production technology comprising of gradually decreasing grey hydrogen and sequentially increasing blue and green hydrogen, subsidies may not be critical anymore starting at carbon prices above US$300 per tonne of CO_2. It should be noted that under APS conditions, projects initiated in 2040 and particularly 2050 already start at higher proportions of green and blue vis-à-vis grey hydrogen, resulting in lower cost decreases and, thus, increasing (or more slowly decreasing) subsidies compared to 2030 cost levels. This trend reversal continues until carbon prices are high enough to overcompensate the more severe incremental costs of blue and green hydrogen versus grey hydrogen.

5. Policy Recommendations

Given the entrenched SMR-based hydrogen production infrastructure, the large investments and high switching costs, and, thus, the enormous public sector subsidies required to decarbonise hydrogen production across ASEAN industries, AMS must initiate selected blue and green development projects by (i) introducing supportive industry regulations and incentive and subsidy schemes, (ii) leveraging the regional state-owned energy and construction companies, (iii) encouraging investment by private domestic and international energy and industrial companies and financial institutions, (iv) collaborating in particular with regional and international research institutions and industrial companies at the frontiers of CCS and electrolyser technologies, and (v) collaborating with other AMS, friendly governments, and multilateral development agencies (Purwanto et al., 2024b).

Given the initially lower incremental investments and costs of CCS and the potentially lower resistance from relevant energy and oil incumbents, a sequential decarbonisation process starting with blue hydrogen is recommended. However, lessons must be learned from the US shale gas boom in the US, which brought short-run decarbonisation benefits as US power generation reduced its dependency on coal but eventually led to a decline in renewable energy investments and R&D (Acemoglu et al., 2023). In this context, blue hydrogen must be considered solely an interim catalyst solution, whilst significant efforts must be made to accelerate subsequent green hydrogen project investments (Purwanto et al., 2024b). Too much emphasis on and a possible entrenchment into a blue hydrogen infrastructure may raise the risk of reducing incentives to invest in much costlier and more disruptive green hydrogen in the long run. This is particularly important given the inclination of several regional power monopolists not to rapidly expand renewable electricity capacity as well as, importantly, the possible reluctance of incumbent oil companies to aggressively shift away from grey or blue hydrogen as needed (Purwanto et al., 2024b).

Finally, the heavy involvement of AMS and industry regulators and the huge fiscal incentives and subsidies involved necessitate strict, corruption-proof industrial policies and public procurement and co-financing schemes that ensure competitive project bidding, rigorous project planning and control, transparency and accountability (Purwanto et al., 2024b).

6. Conclusions and Future Questions

Under the APS, aggregate hydrogen demand in the oil refining, ammonia, methanol, steel, and chemical industries across ASEAN is anticipated to grow continuously until 2050. In this scenario, hydrogen demand from oil refining decreases fastest over the 2020–2050 projection period, whilst methanol e-fuels and ammonia energy carriers grow even faster than in the Likely scenario (ERIA, 2024).

In this study, CO_2 emissions from hydrogen production via the SMR of natural gas, and to a lesser extent coal, i.e. grey hydrogen, are compared for three future production mix scenarios. The future APS production technology mix for 2025–2050 is contrasted with future scenarios of 100% blue hydrogen production versus 100% green hydrogen production between 2025 and 2050. Compared to the estimated 100 MTPA CO_2 emissions in an SMR-dominated hydrogen economy, under the APS, for all blue or green hydrogen scenarios, between half and four-fifths of carbon emissions can be reduced across ASEAN industrial sectors by 2050.

Significant future government subsidies are required to provide incumbent and new hydrogen producers the same project returns as with the hitherto grey hydrogen production mix. Thus, aggregate present values of region-wide subsidies in the range of US$20 billion–US$100 billion are estimated under the APS with carbon prices between US$100 and US$300 per tonne. These subsidies increase significantly to US$100 billion–US$300 billion when only green hydrogen is contemplated, whereas almost no subsidies are required to implement an all-blue hydrogen transition, except at very low carbon prices. In contrast, when carbon prices reach US$500 per tonne, only an all-green hydrogen future may require subsidies, whereas the APS and blue hydrogen would be self-funded through the monetisation of carbon credits.

The analysis reported in this paper can be expanded to study more specific country- and project-level decarbonisation pathways, green and blue hydrogen production and transport economics, and the political economy of promoting, and importantly, financing such large-scale projects requiring significant public sector and multilateral support.

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