International Hydrogen Ramp-Up Programme (H2Uppp)

Study series summary on market development for Green Hydrogen and Power-to-X(PtX) in Thailand

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Preface

Welcome to the concise technical study series exploring market development for Green Hydrogen and Power-to-X (PtX) in Thailand, produced in collaboration with the International Hydrogen Ramp-Up Programme (H2Uppp). This series delves into the potential and challenges of fostering Green Hydrogen and Power-to-X technologies in Thailand, aligning with the objectives of H2Uppp.

As Project Manager of H2Uppp Thailand, I am pleased to present this study, a result of collaborative efforts and a commitment to sustainable energy solutions. With hydrogen's rising importance as a clean and versatile energy carrier, this study holds immense value for policymakers, industries, and researchers invested in Thailand's sustainable energy transition.

Through this study, we explore Thailand's renewable energy landscape, technological capabilities, regulatory frameworks, and potential applications across sectors. By drawing on global best practices and case studies, we provide insights to steer Thai stakeholders towards effective hydrogen integration.

I would like to extend my appreciation to H2Uppp and contributors who have shaped this study series. It is my hope that this endeavour accelerates Thailand's journey towards a greener energy future, driven by the transformative potential of Green Hydrogen and Power-to-X technologies.

Tim Nees
Project Manager, H2Uppp Thailand

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1 BACKGROUND AND SCOPE OF WORK

Thailand aims to be carbon neutral by 2050 and net zero by 2065, which could be achieved through sectoral decarbonisation via related energy plans and policy frameworks. With major GHG emissions in Thailand coming from the power, transport and industry sectors, Thailand has focused on decarbonising these sectors by transitioning towards clean energy. Hydrogen may have a potential role to play in decarbonisation if the costs of production and utilisation are competitive with other options and the challenges of deploying hydrogen can be addressed. Policy measures will be important to support the deployment of hydrogen and to overcome the challenges and bridging of the cost gaps between hydrogen-based fuels and other fuel options. Thailand's Ministry of Energy is in the process of developing guidelines to promote commercial use of hydrogen and production, yet there is still no clear policy roadmap for the power, industry and transport sectors.

The main objective of this study is to assess the potential role of hydrogen in Thailand's power, industry and transport sectors and to establish a policy roadmap to facilitate the transition of these sectors towards decarbonisation in which hydrogen can play a key role. The analysis is conducted by forecasting the growth of hydrogen demand in these key sectors and assessing the cost competitiveness of hydrogen compared to conventional fuel. The study takes into consideration the policy settings, as well as the technical, economics and environmental implications to identify potential barriers and key drivers for hydrogen in Thailand.

This study consists of the following key areas:

- Status quo and projected global hydrogen demand and supply
- Potential for hydrogen in Thailand which includes relevant energy policies, hydrogen resource and demand potential in different regions and the production costs, and potential policy interventions
- Future market size and economics of hydrogen in the power, industry and transport sectors
- Policy recommendations and roadmaps to support the development of hydrogen markets in these sectors

2 OVERVIEW OF GLOBAL HYDROGEN DEMAND AND SUPPLY

The hydrogen value chain commonly includes five different elements, which outline the steps that can be taken between the production and consumption of hydrogen:

- **Production**: Conversion of primary energy (electricity, fossil fuels or heat) into gaseous hydrogen
- **(Re-)conversion**: Optional step to convert between gaseous hydrogen and derivatives used for transport such as ammonia
- **Transport & Storage**: Transport of hydrogen to its destination and storage in case of mismatches between supply and demand. Can be done in gaseous form or liquid form via liquid hydrogen or hydrogen derivatives
- **End-use**: Different use-cases for hydrogen

A typical value chain overview, which outlines how these elements interact, is provided in the figure below.

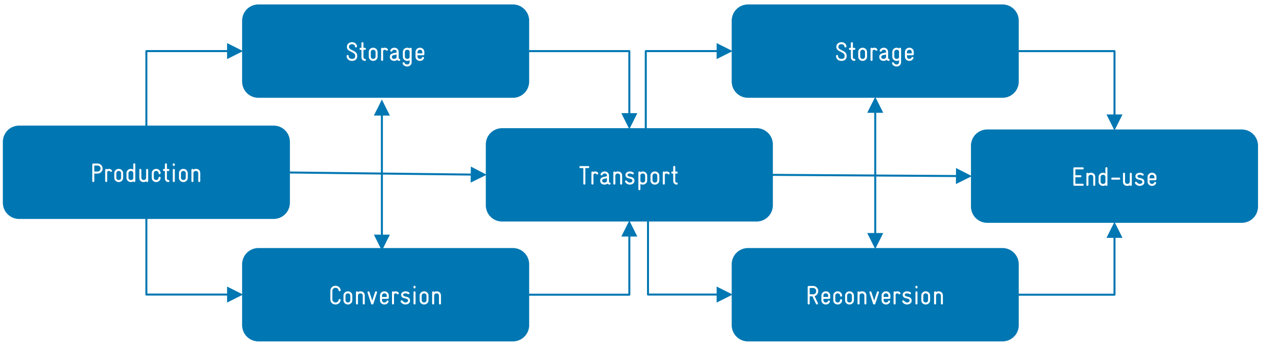


Figure 2-1: Typical hydrogen value chain

Based on DNV's Hydrogen Forecast 2022, hydrogen demand is expected grow steadily until about 2030, after which growth ramps up towards 2050, as shown in Figure 2-2

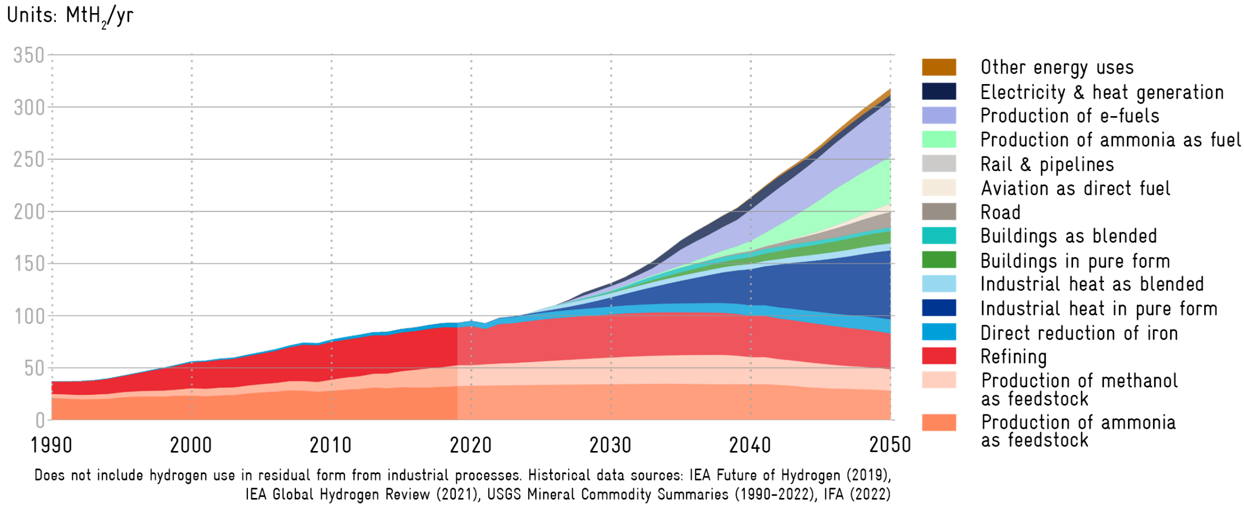


Figure 2-2: Global hydrogen demand by sector 1990-2050

The growth of hydrogen until 2030 will be driven primarily by government incentives and supporting policies, especially in Europe, OECD Pacific, North America and China, with limited new use cases for hydrogen. By 2040, hydrogen is expected to become more commercially attractive, with more applications towards industrial and domestic heating, power generation, and transport. The primary role of hydrogen will still be as a feedstock, but hydrogen will be increasingly used in hard-to-abate sectors to comply with climate goals. By 2050, the cost of hydrogen is expected to decline significantly while conventional alternatives will become more expensive due to carbon taxes, driving further demand growth. Hydrogen Fuel Cell Vehicles (HFCV) will become more widespread in long-distance trucking, and hydrogen derivatives such as ammonia, methanol and e-fuels will see increased usage in the maritime and aviation sectors. The primary global demand for hydrogen will come from Europe, North America, and China, with OECD Pacific also utilising hydrogen for a relatively large share of its final energy demand.

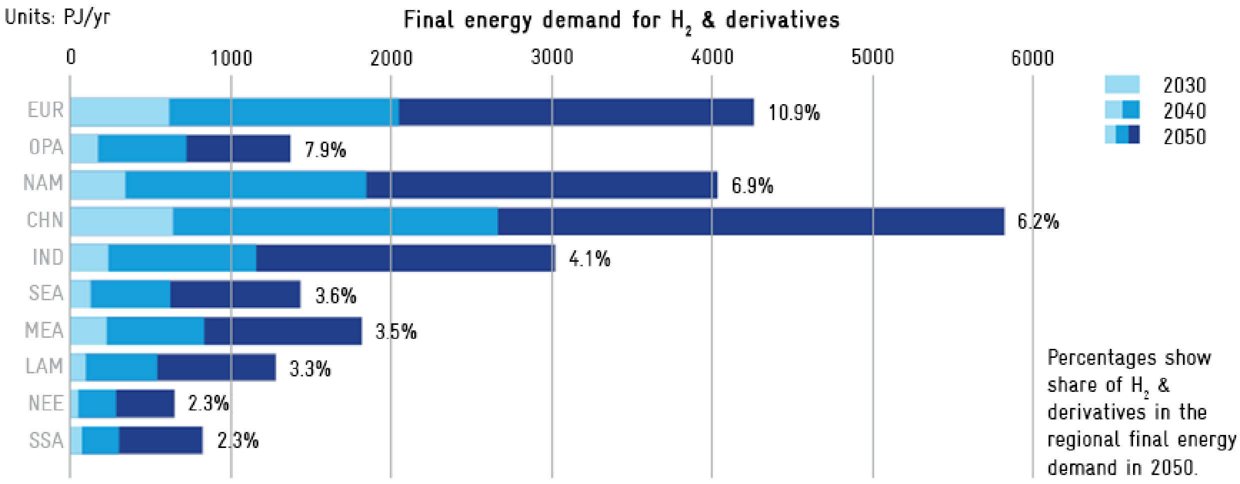


Figure 2-3: Regional comparison of hydrogen uptake

To meet the increasing demand for hydrogen, production is required to step up as well. Hydrogen is expected to play an important role in realising decarbonisation ambitions in which the growth in hydrogen demand (Figure 2-3) will mainly be met through low-carbon means. Low-carbon forms of hydrogen production are also expected to replace conventional alternatives over time through cost reductions and government mandates.

By 2030, about a third of all hydrogen supply is expected to be produced using low-carbon production methods such as electrolysis and conventional production with carbon capture. The production from conventional means without carbon capture is expected to decrease towards 2040, while low-carbon production continues to increase. As carbon capture is generally considered to be a transitionary solution due to residual carbon emissions and limitations in carbon storage, the total volume of hydrogen production from natural gas and coal with carbon capture is expected to decline after 2045. By 2050, it is expected that 85% of all global hydrogen production will be from low-carbon methods, including a mix of grid connected and dedicated electrolysis, with a higher share of solar and wind-based electrolysis and a smaller share of nuclear-based electrolysis.

Nonetheless, the cost of different hydrogen production methods will determine the pace of the transition to low-carbon methods. Coal gasification and methane reforming are currently the cheapest technologies, but their costs are expected to increase over time due to carbon taxes and fuel prices. Carbon capture with coal gasification is expected to reach break-even by 2030, while carbon capture with methane reforming will not become commercially viable on a global level until 2050. Grid-based electrolysis is currently the cheapest option, but dedicated renewable electrolysis is expected to become competitive by 2030, with completeness through fossil fuel production expected between 2030-2040. The cost of different methods will influence the mix of hydrogen production until low-carbon methods become more affordable.

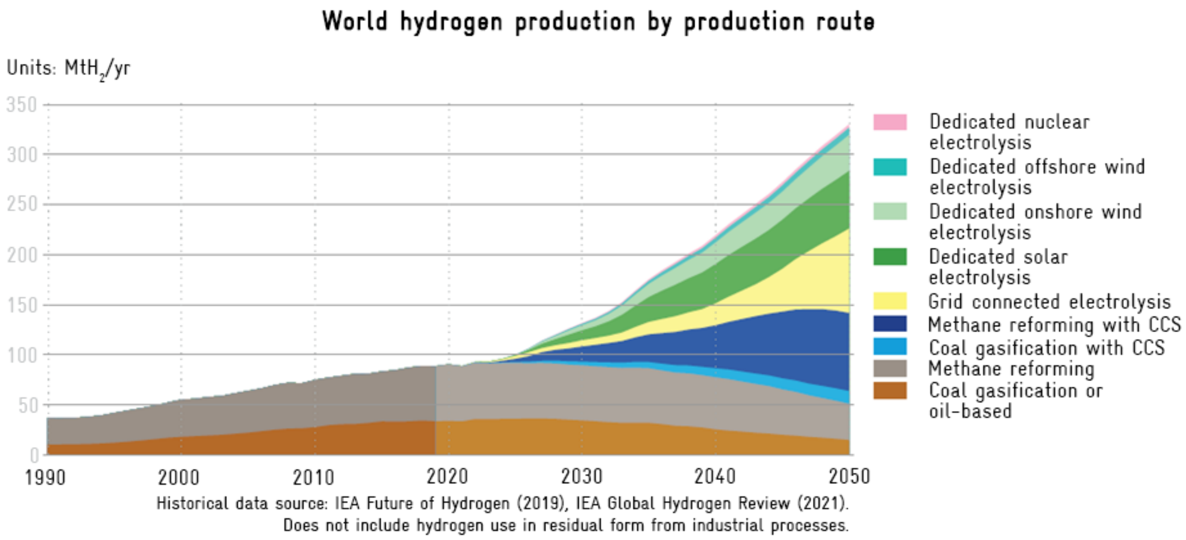


Figure 2-4: World hydrogen production by production route

The most cost-effective option for hydrogen production depends on various factors, such as primary energy cost, equipment costs, and market and regulatory circumstances. For example, Europe will start with a high share of low-carbon hydrogen as early as 2030, while North America and China will support early demand growth using fossil means and pivot towards 2040. Southeast Asia as a region will see limited utilisation of low-carbon hydrogen in 2030 before ramping up blue hydrogen production by 2040 and grid-connected electrolysis towards 2050. Each country in the region will also have its own recommended transition pathway based on local circumstances.

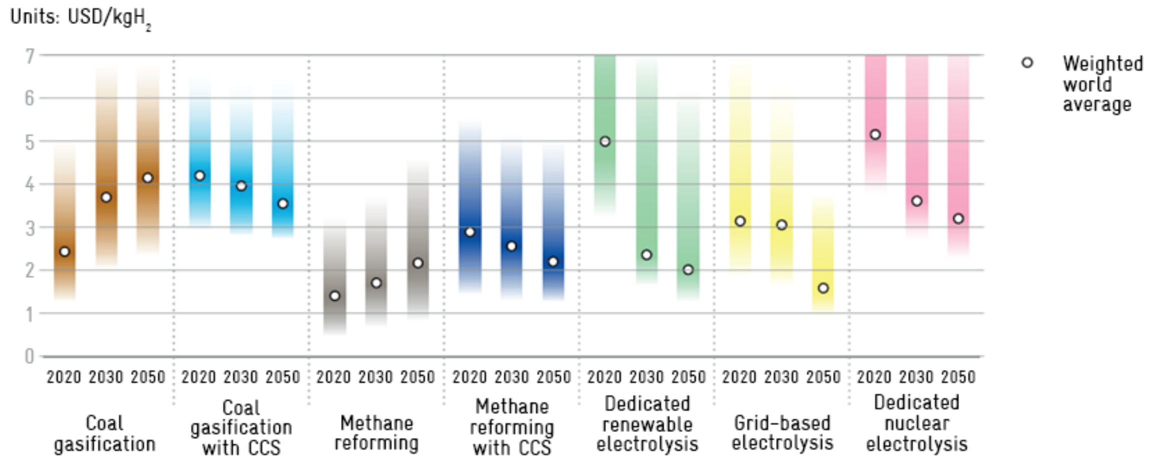


Figure 2-5: Levelized cost range of hydrogen production per production route 2020-2050

3 POTENTIAL OF HYDROGEN IN THAILAND

To achieve the decarbonisation targets set out by Thailand, efforts will be made towards sectoral decarbonisation via related energy plans and policy frameworks. The major contributors of GHG emissions in Thailand are from the power, transport and industry sectors, hence efforts towards decarbonisation involve transitioning to renewable energy resources and improving energy efficiency across all sectors. Also, hydrogen is gaining attention in Thailand as a potential solution, given its long-term storage capabilities and the need for energy storage when solar and wind become the primary energy sources. As 70% of Thailand's total electricity generation comes from thermal sources (coal and gas), including a relatively young gas fleet, low-carbon dispatchable power plants could be a valuable tool in decarbonising the power sector.

3.1 Relevant energy policy for hydrogen development in Thailand

Thailand has developed a Long-Term Low Greenhouse Gas Emission Development Strategy (LT-LEDS) that guides its national development agenda and helps address global climate change. The mid-century LT-LEDS was submitted in late 2021 and revised in 2022. At COP26, Thailand committed to increasing its conditional GHG reduction from 25% to 40% by 2030, in addition to re-confirming a 20% unconditional GHG reduction. To achieve carbon neutrality and net zero emissions targets, efforts will also be made towards decarbonising sectors via energy plans and policy frameworks.

At present, hydrogen is not yet included in Thailand's national plans. Nevertheless, a recent study proposing policy recommendations to advance the commercialisation of hydrogen in Thailand has suggested a Hydrogen Roadmap to be applied across the three sectors described with specific applications in mind:

- **Power sector**: H_2 could be used as direct fuel in fuel cell stacks or blended with natural gas in gas-fired generators
- **Industrial heating sector**: H_2 could be used as direct fuel in combustion chambers or blended with natural gas
- **Transport sector**: H_2 could be used to produce synthetic fuel for the internal combustion engine (ICE) or used in the Fuel Cell Electric Vehicle (FCEV), especially on heavy duty long-haul vehicles including buses and trucks.

The proposed roadmap entails three different timeframes: a short-term plan (2021-2030) which will focus on research and development as well as demonstrations, a medium-term plan (2031-2040) that will prioritise the early adoption of hydrogen in power and heat generation, and a long-term plan (2041 onwards) that will emphasise infrastructure development. In addition to the described cases there are additional applications possible for hydrogen in Thailand, which will be addressed in a later section.

3.2 Hydrogen resource and demand potential in Thailand

Thailand consists of seven main regions: Metropolitan Bangkok; Central-North (referred to as Central in this report); Central-East (referred to as East); Central-West (referred to as West), North, Northeast and South. These regions have varying geographical features, renewable resource potential, energy infrastructure, and demand. The potential for hydrogen production in each region relies on a combination of factors including wind and solar resource potential, existing and planned generation capacity, transmission network and existing natural gas supply infrastructure availability. Potential local demand for hydrogen is assessed based on the current regional demand in power, industry and manufacturing, and transport.

In defining the potential roles of different regions in Thailand in a future energy system that includes hydrogen production and demand, different archetypes have been defined to develop roadmaps for future development. These archetypes depend on each region's characteristics, with the primary drivers being: local availability of energy sources for hydrogen production (Table 3-1), expected local demand for hydrogen (Table 3-2), and the expected cost of hydrogen production in each of the regions (Figure 3-1)

The resulting archetypes defined for the purpose of this study are as follows:

- **Self-sufficient**: Potential for local hydrogen demand and sufficient production potential to meet local demand. Exports may be possible in case of favourable economics
- **Import dependent**: Limited local production potential compared to local demand
- **Export potential**: Surplus local production potential compared to local demand
- **No role in hydrogen**: Limited local demand and supply potential

The availability of energy sources for hydrogen production and expected local demand is first assessed with a traffic light approach.

Table 3-1: Hydrogen resource potential

Region	Solar	Wind	Gas
North (NAC)	High potential	Moderate	Moderate
Northeast (NEC)	High potential	High potential	Moderate
South (SAC)	Moderate	Moderate	High potential
Bangkok (MAC)	Limited	Limited	Limited
Central (CAC-N)	High potential	High potential	High potential
West (CAC-W)	Moderate	Moderate	High potential
East (CAC-E)	High potential	High potential	High potential

Limited Moderate High potential

Table 3-2: Hydrogen demand potential

Region	Power generation	Industry	Transport
North (NAC)	High potential	Moderate	High potential
Northeast (NEC)	Moderate	Moderate	High potential
South (SAC)	Moderate	Moderate	Moderate
Bangkok (MAC)	Limited	High potential	High potential
Central (CAC-N)	High potential	Moderate	High potential
West (CAC-W)	Moderate	Moderate	Moderate
East (CAC-E)	High potential	High potential	High potential

Limited Moderate High potential

Based on the mapping of potential hydrogen resources (Table 3-1), the Northeast, Central and Eastern regions have access to the best wind resource potential. For solar resource potential, all the regions in Thailand have access to excellent solar irradiation though availability of space. Suitable electrical infrastructure and gas networks differ per region which can limit the overall potential. In terms of access to natural gas, the North and Northeast have relatively poor access compared to the rest of the regions, with Bangkok not being the most suitable location for blue hydrogen production.

Looking at Table 3-2, the primary demand potential in power generation can be found in the North, Central and East regions with industrial demand around Bangkok, Central and East. Transportation demand will likely occur in major cities and trade hubs, thus likely being lower in the West and South regions. As a result, the Central, East and Bangkok regions are the most likely future demand centres for hydrogen in Thailand.

Following a hydrogen resource and demand assessment, the expected costs of hydrogen production in each of the regions were calculated. The costs were derived from DNV's hydrogen production cost model for its Hydrogen Forecast to 2050 – adopted with combined regional assumptions for Southeast Asia on hydrogen production assumptions with Thailand-specific data on renewables and fuel pricing.

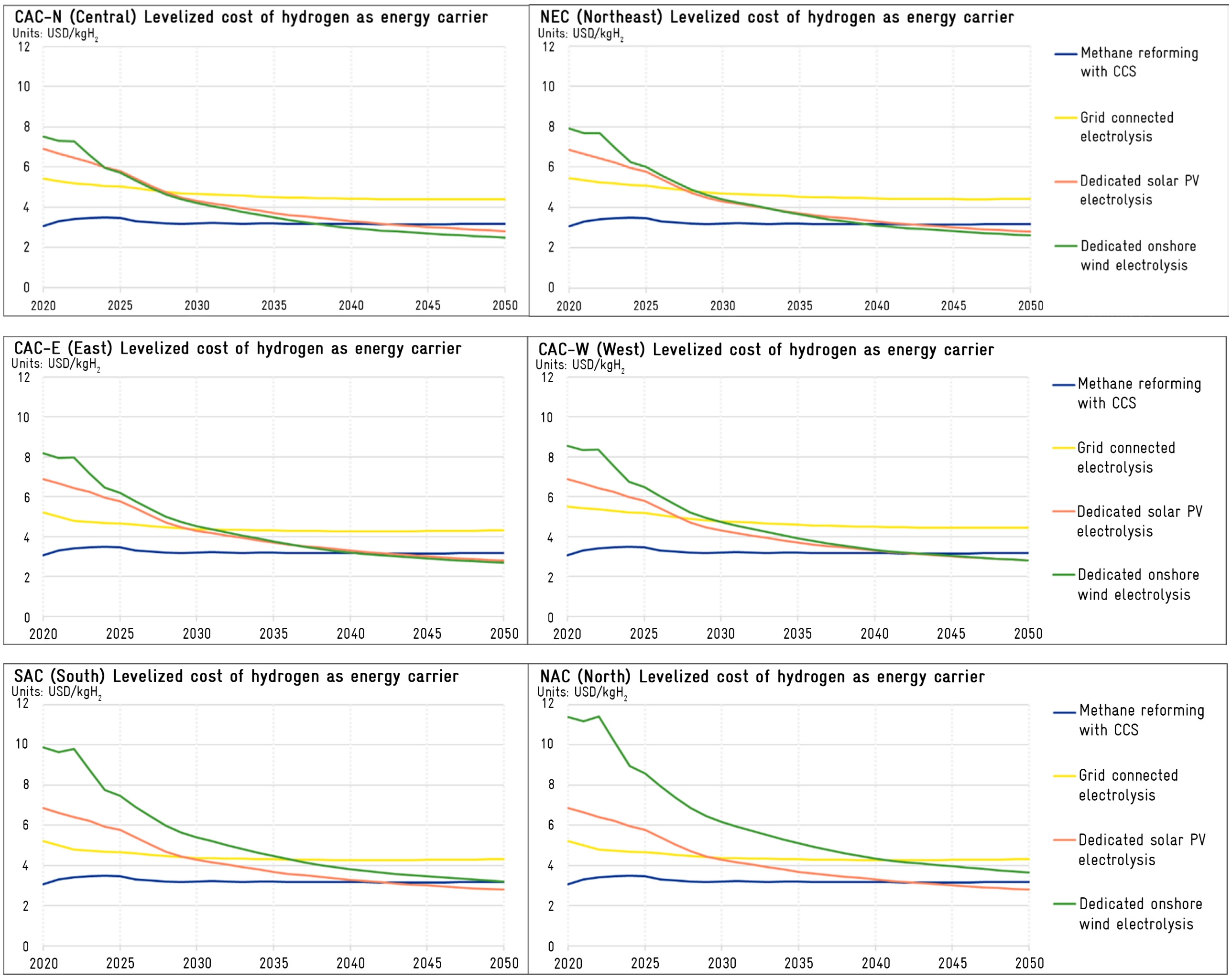


Figure 3-1: Hydrogen production cost as energy carrier in Thailand

From Figure 3-1, it can be observed that grey hydrogen production is the lowest cost production technology at around 2 USD/kg H_2 at present and is expected to increase in the next few years due to rising natural gas costs to reach around 2.5 USD/kg H_2. For green hydrogen production, the lowest cost technology varies with different timelines:

- Short-medium term (2025-2030): solar PV electrolysis, which is estimated to be around 5.7 - 5.8 USD/kg H_2 in 2025 and 4.3 - 4.8 USD/kg H_2 in 2030 across all regions – with minimal differences across regions, but significant differences in production cost from wind.
- In medium to long-term (2030-2050): onshore wind in the central and northeast regions, which is estimated to be around 3.6 - 3.7 USD/kg H_2 in 2035 and 2.5 – 2.6 USD/kg H_2 in 2050.

The Central, East, and Northeast regions are therefore likely to have the highest potential for hydrogen production due to access to both solar and wind, potentially followed by solar resources in the North.

Table 3-3: Regional archetypes

Region	Supply	Demand	Resulting archetype
North (NAC)			**Self-sufficient**
Northeast (NEC)			**Export potential**
South (SAC)			**No role in hydrogen**
Bangkok (MAC)			**Import dependent**
Central (CAC-N)			**Self-sufficient**
West (CAC-W)			**No role in hydrogen**
East (CAC-E)			**Self-sufficient**

Having assessed the hydrogen resources potential, demand, and expected costs in each region, the initial mapping of supply and demand expectations and resulting archetypes have been outlined in Table 3-3. Key findings from the mapping show that:

- **Self-sufficient regions** – the North, Central and East regions are classified as self-sufficient though demand and supply potential in the Central and East regions are higher. Should sufficient low-cost renewables be available in both regions, it may be possible to export to other regions in a cost-effective manner.
- **Export potential regions** – This export potential likely exists for the Northeast region as well, due to access to low-cost wind but with limited domestic demand.
- **Import dependent** – Import dependency will mostly exist in the Bangkok area, with a large potential demand in Industry and Transport but with limited access to local hydrogen production – especially green hydrogen from local renewables.

4 HYDROGEN DEMAND FORECAST FOR THAILAND

The expected future market size of hydrogen has been estimated based on hydrogen's potential role and economics in Thailand's transport, industry, and power sectors. Hydrogen has the potential to play diverse roles across these sectors, depending on the energy requirements and availability of alternatives. In the power sector, hydrogen can be a fuel for power generation as well as a storage medium, especially for long-duration storage purposes when there is excessive surplus. For the industry sector, hydrogen's role would be as feedstock, replacing grey hydrogen, and fuel alternative for heating, while for the transport sector its role is limited to fuel but has the potential to replace other different types of conventional fuels. The future market size of hydrogen has been estimated based on energy demand forecasts for 2037[1] and 2050 for each sector by conducting the following analysis:

- Assessment of the potential role of hydrogen in the power, industry, and transport sectors to identify where hydrogen could play a role and what alternative pathways to decarbonization are available (Section 4.1),
- Analysis of the economics of hydrogen through a cost comparison between hydrogen and alternative fossil fuels, determining when cost parity is expected to be reached which will unlock demand without policy intervention (Section 4.2),
- Determining the potential and expected future market size of hydrogen for 2037 and 2050 based on the available decarbonisation pathways and cost comparison per sub-sector (Section 4.3),
- Analysis of the role and economics of hydrogen as a storage mechanism in the power sector compared to pumped hydro and battery energy storage to capture excess renewables for use when renewable generation is limited (Section 4.4).

Following the assessment of hydrogen demand and cost competitiveness, a policy roadmap was outlined to facilitate the transition of the industry, transport and power sectors. This will be discussed in the next Section.

4.1 Potential role of hydrogen in the power, industry and transport sectors

The feasibility of green hydrogen in replacing existing conventional fuels, as well as its competitiveness among future fuel alternatives in

[1] The year 2037 is selected to represent the medium term as it is the target year in the later Power Development Plan (2018 PDP Rev.1)

each sector is assessed using a traffic light approach.

Table 4-1 provides an overview of the potential roles of hydrogen on the power, industry, and transport sectors. Where hydrogen or hydrogen derivatives have the potential to be used as low-carbon fuel in the future they are classified as green or yellow. When considering the potential demand for hydrogen, green will represent guaranteed demand as hydrogen is the only pathway to decarbonisation while yellow represents uncertain demand due to competition with other decarbonisation routes.

Table 4-1: Potential role of hydrogen and derivatives on power, industry, and transport sector

Sector	Role	Current (BAU)	Role for hydrogen and derivatives	Comment
Power generation	Fuel	Coal		• Co-firing ammonia is possible in existing coal-fired power plants. In the longer term, a transition to firing 100% hydrogen or ammonia is the most sensible route. • For natural gas and oil, hydrogen is the most feasible route.
		Gas		
		Oil		
	Storage	PSH/Battery		• Hydrogen as long-term storage solution for seasonal and interannual flexibility
Industry	Feedstock	Grey H_2		• Green hydrogen is the only decarbonisation pathway for grey hydrogen feedstock
	Fuel (High temperature heat)	Coal		• Replacement with a low carbon fuel in the same state of matter would allow continued use of existing equipment and save costs, e.g. biomass for coal and biofuel for oil. • However, those sources do not scale as well, so for larger scale applications e.g. in cement manufacturing, hydrogen is the preferred route. • Natural gas will almost always be replaced with hydrogen.
		Gas		
		Oil		
Transport	Fuel	Electricity		• Electrification is the preferred route for almost all land-based transport. • Hydrogen use for longer distance trucking and rail are a potential niche application, but even there, electrification and biofuels appear the frontrunners. • For long distance marine and aviation, electrification is not possible and hydrogen-based fuels (e.g. ammonia/methanol for maritime and e-fuel SAF) are the most likely pathways.
		Diesel		
		Gasoline		
		CNG		
		LPG		
		Marine Fuel		
		Aviation Fuel		

Hydrogen will not play a role for decarbonisation

Hydrogen based fuels are an option, but face competition from other routes to decarbonisation

Hydrogen based fuels are the only pathway to decarbonisation

To fully decarbonise the power sector, a transition from coal and natural gas to low-carbon fuels in power generation will be necessary. The backbone for this will be a transition to as much renewables as possible, but a certain amount of dispatchable power generation will still be required to provide balancing of supply and demand as well as system stability. In the long term, these remaining dispatchable power plants will also have to be decarbonised, for which hydrogen and ammonia (as hydrogen derivative) are the most suitable alternatives. For existing power plants, a limited amount of co-firing ammonia in coal power plants or blending of hydrogen in gas plants is possible. In the longer term, a transition to firing 100% hydrogen or ammonia is the most plausible route. The availability of low-cost renewables for hydrogen production and the possibility of underground hydrogen storage in Thailand further increases the favourability of hydrogen as a replacement for conventional fuels used in the power sector. The next few sections will focus on the expected demand for hydrogen to decarbonise the different sectors, while the role of hydrogen as a storage mechanism for the power sector compared with other storage options (battery and pumped storage) will be discussed further in Section 4.4.

In the industry sector, hydrogen can play a role in both the decarbonisation of grey hydrogen used as feedstock and as replacement for conventional fuels for high heating applications. While low-carbon hydrogen is the only pathway to decarbonise grey hydrogen as industrial feedstock, the application in other sectors is less straightforward. Key considerations for hydrogen use in industry include:

- For low temperature heating, which forms a significant portion of the industrial energy demand, electrification is the most suitable pathway. This is because direct electricity use is generally more efficient than converting the electricity into hydrogen first, especially in cases where highly efficient heat pumps can be utilised.
- In high temperature heating (>400 degrees) there are significant challenges regarding the use of electricity and alternatives for decarbonisation are required. In general, alternative fuels that do not require equipment replacement are preferred, which can generally be achieved by replacing a solid fuel such as coal with a new solid fuel such as biomass. As a result, the easiest use case for hydrogen will be the replacement of natural gas for heating as this does not require any changes to the combustion process or equipment replacements.
- Biomass is the most practical resource for replacing coal for the reasons mentioned above. However, biomass does have limitations that can lead to hydrogen being favoured in certain sectors. Biomass is an inherently decentral resource with inconsistent quality, which means it is primarily suitable for small-scale local applications. In sectors that require larger installations, such as cement manufacturing, biomass is therefore less suitable and replacement of combustion equipment is more acceptable. In these cases, hydrogen would be a better alternative, especially for larger installations. Similarly, in the replacement of oil, there will be competition with biofuels, but large installations would favour hydrogen over biofuels.
- In certain sectors and applications, electrification may still play a role even at higher temperatures as the technical challenges are easier to resolve, which means that electrification will compete with hydrogen and it will be a question of cost. This is primarily applicable to subsectors such as machinery and equipment manufacturing.

In the transport sector, there are three main modes of transportation: i) land-based; ii) maritime; and iii) aviation. Hydrogen could have some role to play in these segments as summarised below:

- Most land-based transport, short-distance marine and aviation hauls will likely be electrified in the long term due to the ease of developing charging infrastructure and cost competitiveness of electricity.

- Hydrogen may only play a role in niche cases such as long-distance buses, heavy trucks and rail lines that have not yet been electrified, where electrical infrastructure is more difficult to develop and the weight of the batteries might not be suitable based on travel distance. There are several pilots ongoing on the use of hydrogen in both road and rail transport although electrification (directly or via batteries) currently appears to be the most promising option long-term.
- For maritime and aviation segments, there is potential for hydrogen-based fuels in long distance hauls where electrification is not suitable. This will primarily be in the form of hydrogen derivatives, though liquid hydrogen may be an alternative (at least for medium distances) but requires infrastructure for production and bunkering, which can be expensive and necessitates strategic locations for refuelling. For longer distance flights, hydrogen derivatives such as Sustainable Aviation Fuels (SAF) will play a key role as they require minimal modifications to existing aircraft and engine technologies. At present, SAF blending is only up to 50% but it is likely to have 100% pathways without blending with fossil fuel in the future. In the maritime sector, ammonia and methanol are the most likely low-carbon fuels for long-distance shipping.

4.2 Economics of hydrogen

The economics of hydrogen have been assessed through a production cost comparison between hydrogen and fossil fuel alternatives which are used in three main applications, and which is dependent on the fossil fuel alternative with which hydrogen competes: i) industrial feedstock; ii) industrial heat and power generation; and iii) transport.

For the industrial heat and power generation sectors, different carbon pricing scenarios are considered: no carbon price, low and high carbon prices. Low carbon price is based on the current EU pledge: 65 USD/tCO_2 in 2030, 75 USD/tCO_2 in 2040 and 90 USD/tCO_2 in 2050. High carbon price is based on IEA scenario for Net Zero Advanced Economies: 130 USD/tCO_2 in 2030, 205 USD/tCO_2 in 2040 and 250 USD/tCO_2 in 2050. The other sectors are not currently subject to carbon taxation.

The costs of hydrogen as feedstock under different carbon pricing scenarios are compared in

Figure 4-1. The transition from grey hydrogen to green hydrogen as industrial feedstock will typically be easier to achieve than the transition for fuel usage because grey hydrogen will always be more expensive than the natural gas it uses as a feedstock. Key observations are:

- **No carbon price** – by 2050 green hydrogen will be almost equal in cost to grey hydrogen without the introduction of any carbon tax. This is the result of natural cost declines in green hydrogen and cost increases in the natural gas used to make grey hydrogen.
- **Low carbon price** – the introduction of a carbon tax significantly accelerates this transition. In the low carbon tax scenario, cost parity will be reached around 2040.
- **High carbon price** – in a high carbon price scenario this parity can be reached as early as 2034.

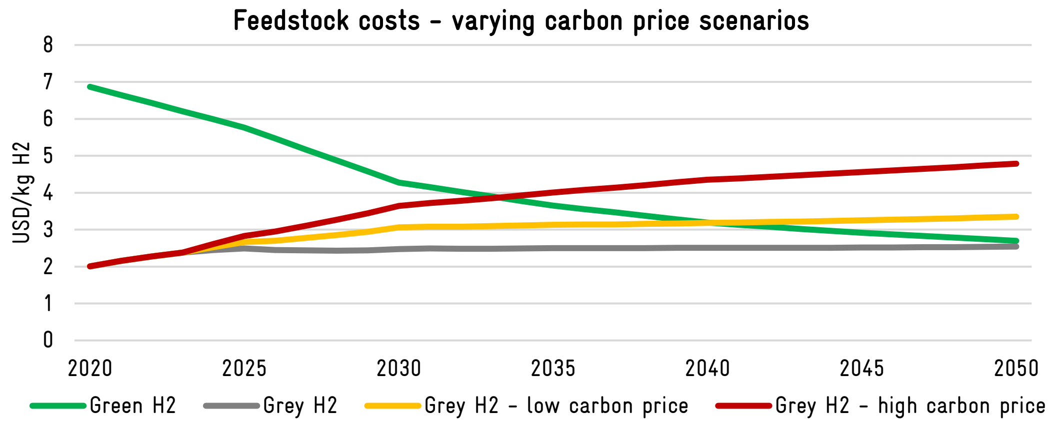


Figure 4-1: Cost comparison green and grey hydrogen under different carbon price scenarios

The cost of hydrogen as fuel for industrial heat applications and power generation under different carbon pricing scenarios are compared with fossil fuels in Figure 4-2. The cost competitiveness of hydrogen is largely dependent on the carbon price utilised as well as the fuel with which it competes, with the following key observations:

- **Coal** – only under the high carbon price scenario can cost parity be reached between 2045 – 2050.
- **Oil** – cost parity with oil naturally occurs around 2035, where introducing a low carbon price would accelerate the cost parity to around 2030 and a high carbon price to somewhere before 2029.
- **Natural Gas** – similar to coal, cost parity is only reached in the high carbon price scenario between 2045 – 2050; with low carbon price the parity by 2050 is close but is not reached yet.

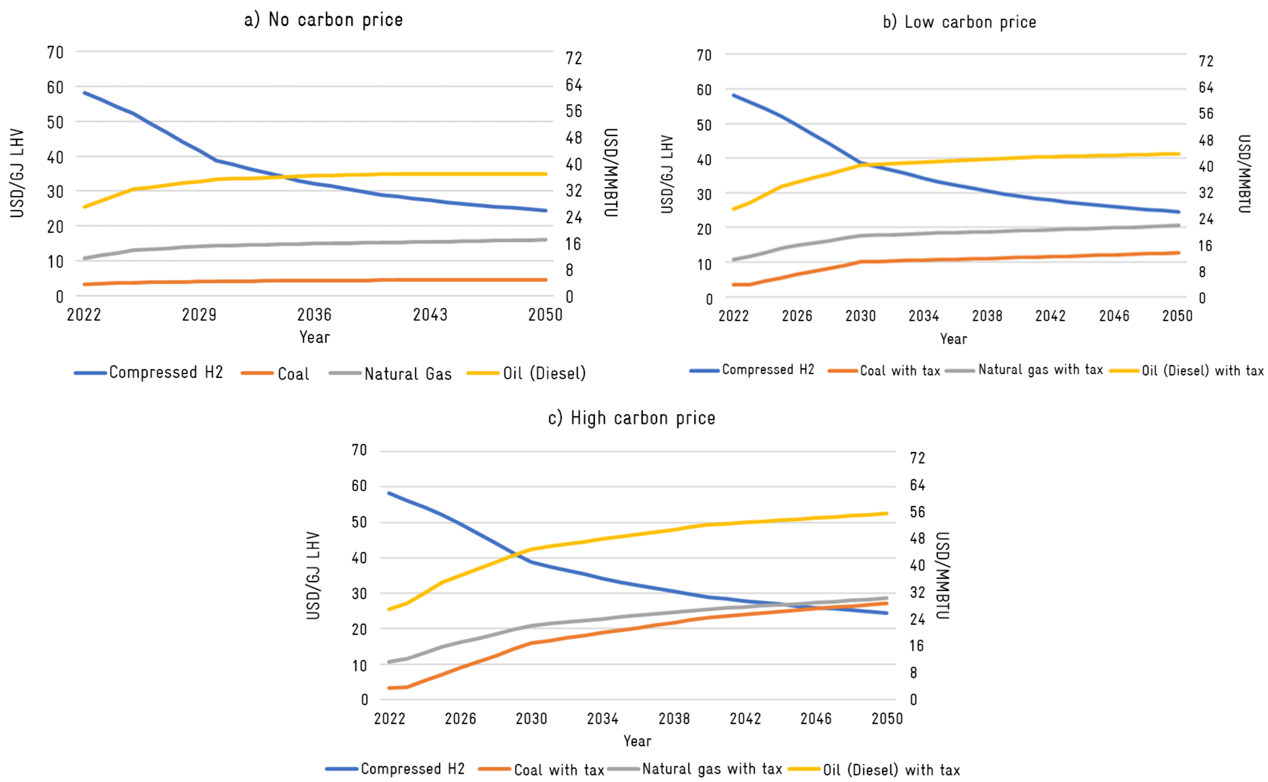
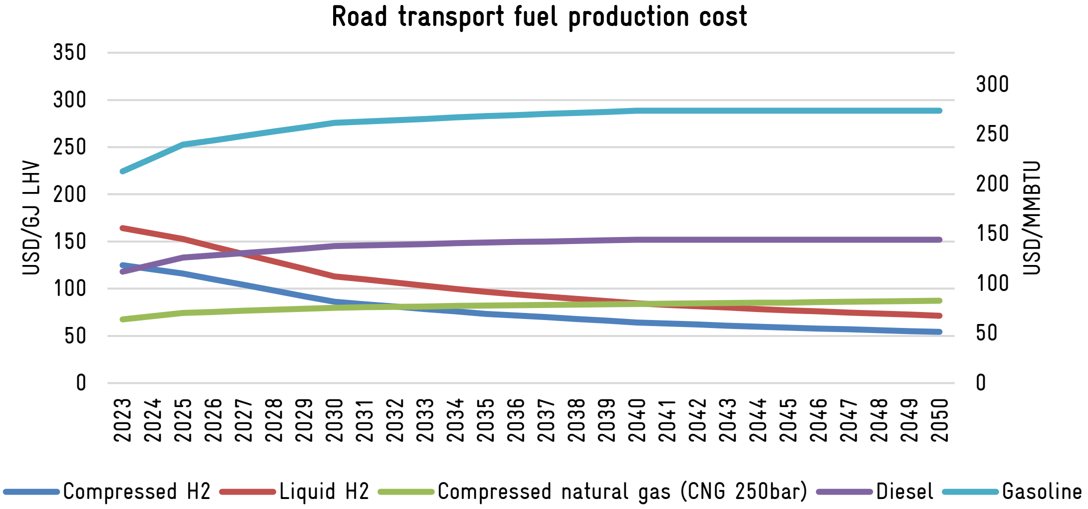


Figure 4-2: Cost comparison for hydrogen as fuel; (a) no carbon price (b) low carbon price (c) high carbon price

For the transport sector, a different set of fuel alternatives are compared on a production cost basis. Costs of infrastructure and vehicles are currently not considered. The costs of compressed and liquid hydrogen are compared with BAU fuels for heavy trucks, shown in Figure 4-3. The cost comparison between the hydrogen-based fuels and BAU fuels leads to several key observations:

- **CNG** – presents as the cheapest fuel per unit but will be overtaken by compressed hydrogen by 2030 and liquid hydrogen by 2040.
- **Compressed hydrogen** – appears as cheaper than liquid hydrogen on a cost of fuel basis but faces challenges in infrastructure development. Liquid hydrogen can be supplied using trucks similar to existing fuels.
- **Diesel** – presents as the second cheapest but is almost on par with compressed hydrogen and likely to reach cost parity with liquid hydrogen by 2030. Gasoline is more expensive than either compressed or liquid hydrogen.



Note: The percentage efficiency tank to wheels (TTW) for heavy trucks has been assumed and is accounted in the fuel costs using the efficiencies of drivetrains. Gasoline has the lowest % TTW of 15%.

Figure 4-3: Road transport fuel cost (USD/GJ LHV and USD/MMBTU

The estimated fuel costs of liquid hydrogen, green methanol, green ammonia, and marine fuel (MGO) for the maritime sector are shown in Figure 4-4, with some key observations as follows:

- **Green ammonia** – Likely winner due to lowest overall production costs among all decarbonised fuels but faces Health, Safety, and Environment (HSE) challenges due to its toxic and corrosive nature. Expected cost parity will not be reached until early 2040s.
- **Methanol** – May be easier than ammonia to convert existing ships to methanol-ready ships to extend lifetime of existing fleet, which will likely lead to methanol demand rising earlier than ammonia demand. Expected cost parity will not be reached until late 2040s.
- **Liquid hydrogen** – Similar cost to methanol but faces challenges from low energy density and boil-off issues. May face competition from methanol and electricity for domestic ships, and not suitable for longer distances. Expected cost parity will not be reached until late 2040s.

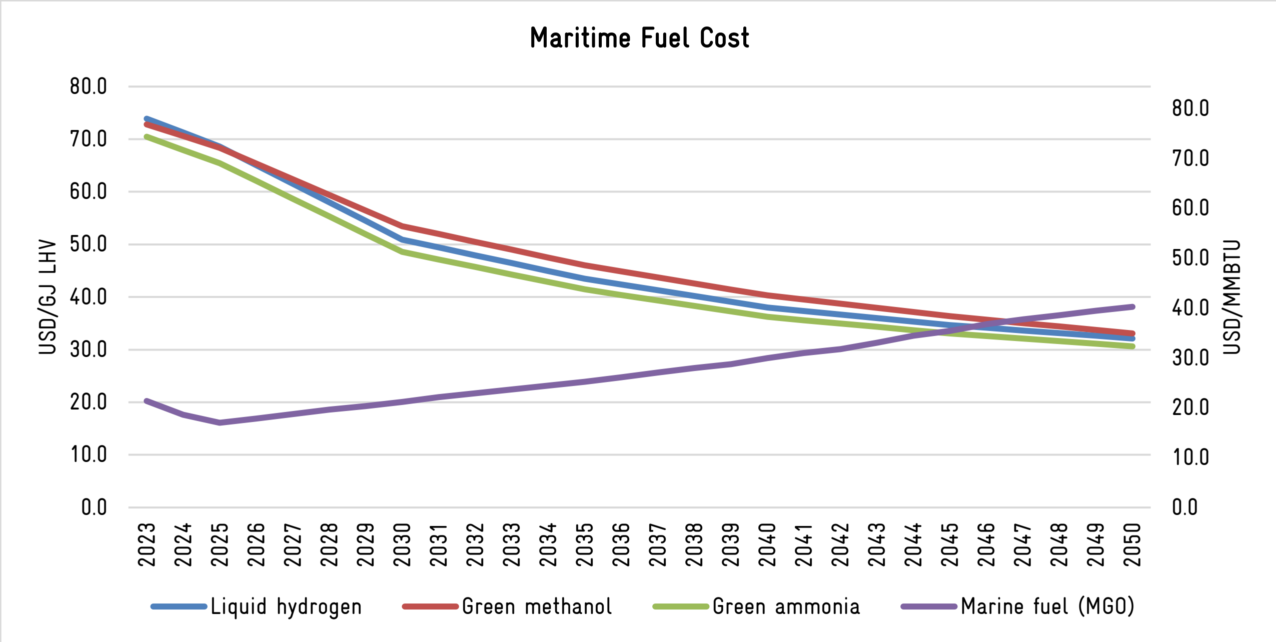


Figure 4-4: Maritime fuel costs comparison (USD/GJ LHV and USD/MMBTU)

The costs of jet fuel are compared with liquid hydrogen and SAF for aviation (Figure 4-5). Key observations are:

- **Jet fuel** – expected to remain as most cost-effective option in near future.
- **Liquid hydrogen** – break-even point to be reached only in early 2040s. Could potentially play a niche role in the medium haul segment only if infrastructure pre-conditions are met and with a regulatory push.
- **(E-fuel) SAF** – expected to remain more costly than liquid hydrogen due to inefficiency and multiple processing steps to produce liquid hydrocarbon but able to use as a drop-in fuel that is compatible with existing aircrafts. Not expected to break-even with jet fuels until 2050. The future cost reduction in e-fuel SAF is expected to be derived predominately from progressive reduction in the cost of green hydrogen feedstock (60-70% of e-SAF production cost), with the secondary driver being the cost of CO2 feedstock. Comparatively, the scaling of e-fuel production facilities is expected to have a relatively insignificant effect on the e-SAF production cost reduction. It is assumed in this context that the e-fuel SAF production facilities already reach a commercialised scale in the 2030s, whereby further increases in plant size/economies of scale have limited benefit.

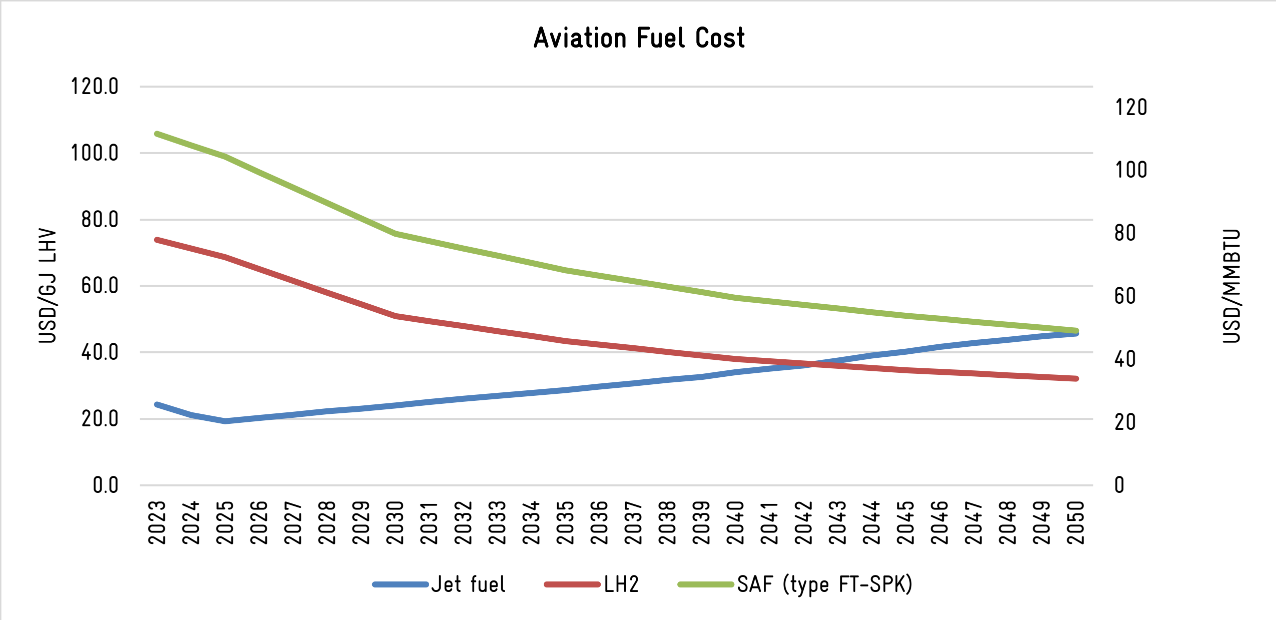


Figure 4-5: Aviation cost comparison (USD/GJ LHV and USD/MMBTU)

4.3 Potential future market size for hydrogen

The cost analysis identifies when hydrogen transition would naturally be expected to occur and for each scenario based on hydrogen becoming the lowest cost option. When combining the traffic light methodology, which helps determine the expected role of hydrogen per sub-segment, with the cost analysis insights, the expected timing of the transition to hydrogen can be derived. This is done on the assumption that the regulatory and policy framework put in place would ensure that no additional cost would have to be borne by the consumer compared to the current situation. This analysis was combined with demand forecasts for each of the different sectors provided by CASE to estimate the market size for hydrogen and when this is expected to be unlocked.

Figure 4-6 illustrates the potential market size under no carbon, low carbon, and high carbon price scenarios in 2037 and 2050. Low refers to lower bound of the market and high refers to the higher bound of the projected demand. From the analysis the following key takeaways are found:

- **Power** – green hydrogen is expected to be cost competitive with natural gas between 2040 – 2050 under the high carbon price scenario. In this scenario demand is expected to grow, and it is assumed that the hydrogen blending rate is 100%.
- **Industry** – the demand for hydrogen as fuel greatly depends on carbon pricing. In the no carbon price and low carbon price scenarios, the uptake is relatively low, with only oil-based demand potentially transitioning towards hydrogen from the industry sector (specifically non-metallic minerals). In the low carbon scenario, an additional feedstock demand occurs in 2050 as cost parity is reached between grey and green hydrogen. Only in the high carbon price scenario is the uptake of hydrogen significantly higher, with green hydrogen becoming competitive with grey hydrogen by 2037. Demand for hydrogen as fuel is largely driven by the non-metallic minerals industry sub-sector.
- **Transport** – demand in the transport sector comes from trucking, domestic maritime freight and domestic aviation hauls. Demand in international shipping and aviation will be higher, but no data are available to quantify this potential in

Thailand. With the uptake in electrification, technology improvement and increased efficiency, overall energy demand in the transport sector decreases, which also reduces the hydrogen market size (from the truck sector) between 2037 and 2050. For maritime and aviation segments that are hard to abate and where electrification is less feasible, the market size of hydrogen remains similar from 2037 to 2050.

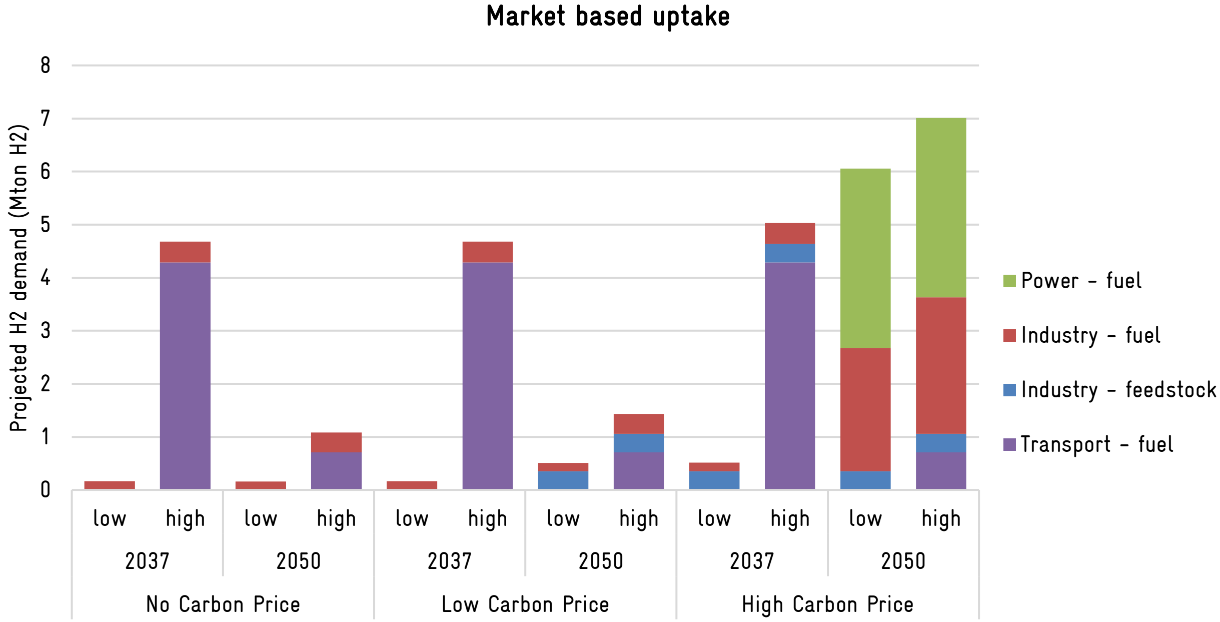


Figure 4-6: Market based uptake of hydrogen under different carbon price scenarios

4.4 Role of hydrogen in the power sector as storage medium

Having addressed hydrogen's role as future feedstock and fuel, another important area to discuss is hydrogen's role as a storage medium in the power sector. Low carbon fuels such as hydrogen and ammonia can serve a dual purpose, as fuel in power generation and as a storage mechanism to better integrate renewables in a high penetration scenario with large surpluses that do not fully align with demand, either on a day-to-day or seasonal basis.

As solar is expected to represent the largest share of the electricity mix in Thailand, the electricity system will experience long periods of surplus during the daytime and shortfalls at night. Figure 4-7 illustrates the potential challenge in Thailand's power system in 2037 which is expected to be dominated by solar generation, resulting in surplus and deficits across a typical week in addition to variations in supply and demand across seasons.

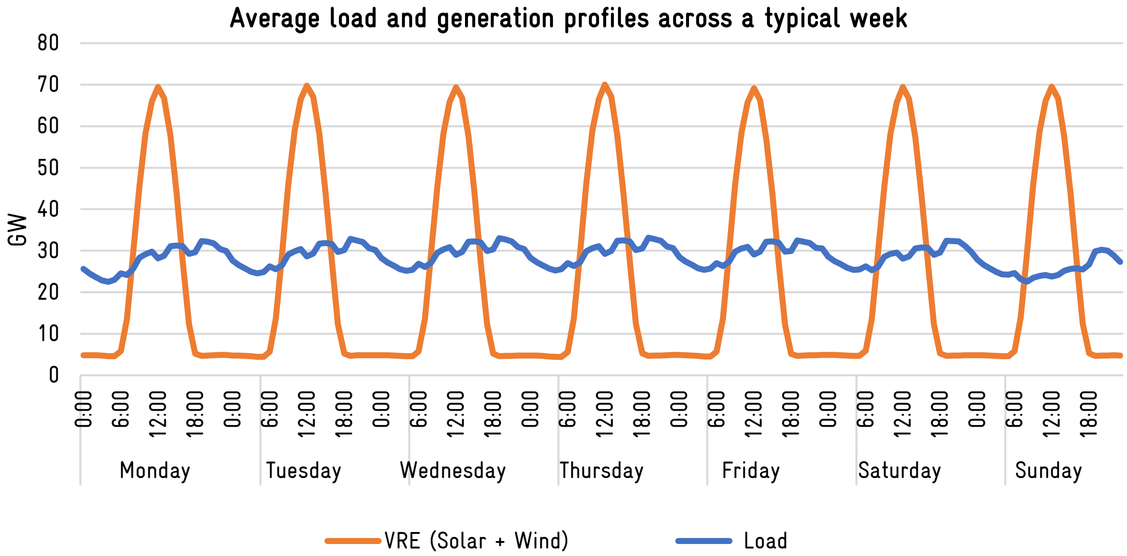


Figure 4-7: Average generation and demand profiles and surplus across a typical week

Energy storage will play an important role in providing flexibility to the system from the short-term duration to maintain system stability, to long-term to balance seasonal and inter-annual variability. The main storage technologies include pumped storage hydro (PSH) and battery energy storage systems (BESS), both of which have been widely used in many countries. Storage technologies have different characteristics which can vary based on size, response time, charging and discharging times. The applications and services that different storage options can provide to the power system are shown in Table 4-2.

Table 4-2: Capability of different storage technologies to provide a range of support to the system

Supply chain	Application	Description	PSH	Lithium-ion	Hydrogen
Generation	RE integration – Bulk	Time-shifting RE output to optimise for grid integration and minimise curtailment			
	RE integration – Ramp	Optimising short-term RE output to improve power quality and avoid imbalance payments			
Energy capabilities and System services	Inertial response	Providing instantaneous response to maintain the rate of change of frequency (RoCoF)			
	Frequency regulation	Maintaining supply and demand balance via continuous, short-term power supply/reduction			
	Reserve	Maintaining supply and demand balance via sustained and fast power supply during contingency			
	Blackstart	System restoration after outages without external power supply			
	Voltage support	Maintaining voltage levels in the networks via reactive power supply			
	Intraday flexibility including storage	Providing flexibility services during the day including charging and discharging duration			
	Seasonal and interannual flexibility	Providing flexibility services across the seasons and year including storage			

Market	Peak reduction / energy shifting	Reducing demand supplied by the network during peak hours to reduce system stress and network charges			
	Energy arbitrage	Purchasing power in low and selling in high price periods on wholesale or retail market			
	Ancillary services	Through reserve market or bilateral contact depending on types of markets			

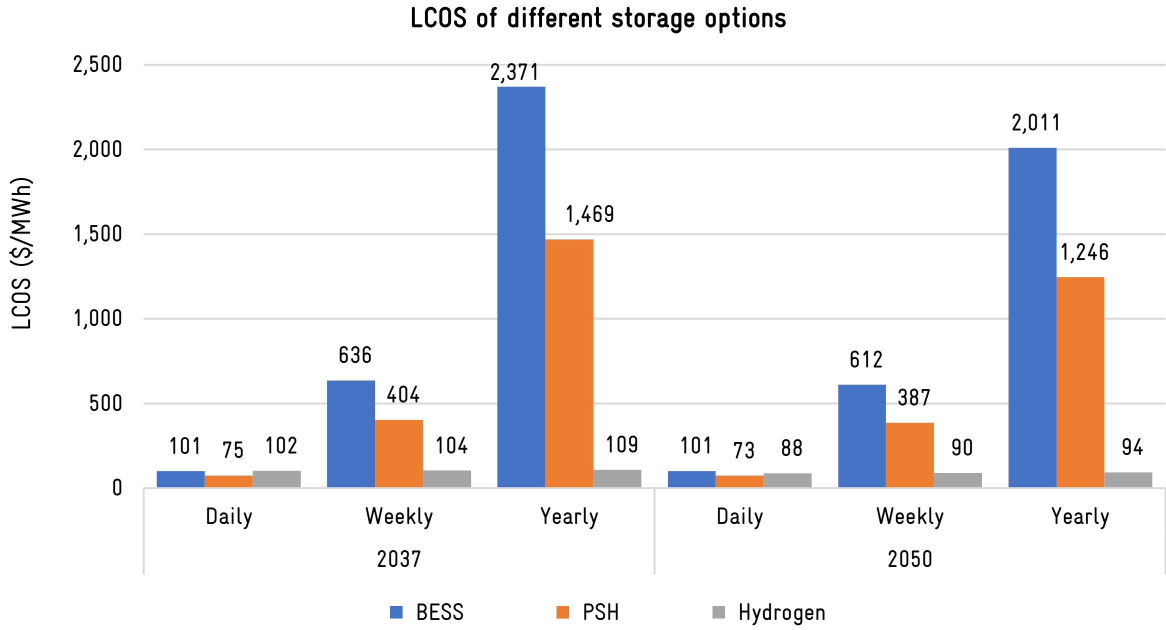
Low capability   Moderate capability   High capability

When wind and solar generation accounts for most of the electricity generation resulting in excessive surplus, hydrogen storage represents a plausible future option for long-term duration storage. One of the cost-effective and safest options for large-scale and long-duration storage of pure hydrogen is underground in salt caverns, as it is considered the most-ready technology and less challenging compared to gas fields. The main advantages of salt caverns include low operational and investment costs, low risk of contamination and significant economies of scale. The drawback of hydrogen-based storage options is the low round-trip efficiency in converting electricity through electrolysis into hydrogen and then back into electricity, which is around 40% compared to around 80%-85% for BESS and PSH. There are a number of ongoing and planned demonstration projects of underground salt caverns in Denmark, France, Germany, Netherlands, Poland, Spain and Canada with storage capacity ranges from 1.5 GWh to 670 GWh.

A cost analysis is conducted to understand the economics of underground hydrogen storage technology against other storage options in the power sector, namely BESS and PSH. The levelized cost of storage (LCOS) of these storage options is used as the metric for cost comparison.[2] The main objective of the cost analysis is to obtain the LCOS of each storage technology (BESS, PSH, and H_2) for different time frames (daily, weekly, and yearly) and in different years (2037 and 2050) based on key assumptions such as discharge duration, round-trip efficiencies, and lifetime. Refer to Task 4 – Power sector report for the details.

The results of the LCOS analysis are shown in Figure 4-3. For daily storage, the PSH option is the lowest cost alternative. For weekly and yearly storage however, it should be noted that hydrogen storage is the cheapest option by a significant margin. The LCOS comparison between BESS, PSH and underground hydrogen storage suggest that the economic attractiveness of each storage option depends largely on the sizing of the storage system in terms of required storage volume as the total volume charged and discharged does not materially change, leading to significantly higher LCOS for weekly and yearly storage. This is in accordance with a number of studies as explained in Task 4 of the main report.

[2] LCOS quantifies the discounted cost of electricity per unit of discharged electricity, referred to as electrical energy ($/MWh). LCOS accounts for all technical and economic parameters influencing the lifetime cost of storing and discharging electricity



Note: The storage size (MWh) for each storage duration (daily, weekly, yearly) are different as longer storage duration requires larger storage size. CAPEX and losses increase with larger storage sizes resulting in higher LCOS for the same storage technologies.

Figure 4-3: LCOS of BESS, PSH and hydrogen in 2037 and 2050

The cost of hydrogen storage remains similar for any storage duration (daily/weekly/yearly) since its LCOS is less sensitive to CAPEX increases from additional scale. In contrast, the LCOE of BESS and PSH increase significantly as the storage duration increases, resulting in a large cost gap for yearly storage between hydrogen and other storage options. Between 2037 and 2050, the costs of all storage options are expected to drop. This is driven by a decrease in the underlying LCOE as a result of technology improvements, which is used to compensate for losses. Due to the higher losses incurred by hydrogen and PSH, the costs decline faster than the cost of BESS.

5 POLICY ROADMAP TO SUPPORT GREEN HYDROGEN AND PTX IN THAILAND

5.1 Early market development for green hydrogen and Power-to-x

Early market development of green hydrogen and Power-to-X in Thailand will be influenced by both global progress and national approaches. Supportive policies and regulations are needed at national, regional, and international levels to encourage investment and cooperation across the hydrogen value chains. Key barriers to hydrogen production, transportation, storage, and use should be addressed through appropriate early market interventions.

- **Costs and financial support** with measures to address the lack of confidence in investing in new technologies and the absence of carbon cost internalisation in pricing.
- **Demand and competition** such as forming new trade partnerships or using markets or policy interventions to close the profitability gap between hydrogen and incumbent hydrocarbons.
- **Technology and manufacturing** by offering support for technologies with low-rated Technology Readiness Levels to encourage market entrants.
- **Safety and hazards** to ensure the market can develop sufficiently as well as safely, and here, the establishment of regulatory sandboxes to test safety legislation and regulation may be a suitable approach.
- **Infrastructure** to ensure renewable buildout continues with sufficient network infrastructure to accommodate and provide for whole energy system integration, as well as rules for common use infrastructure.
- **Standards and certification** to establish Guarantee of Origin traceability and lifecycle analysis requirements.

There are various policy tools that can be used to achieve decarbonisation objectives and overcome barriers related to the hydrogen value chain in Thailand. The tools are categorized into national hydrogen strategies; technology-push measures; demand-pull measures: and fiscal measures.

- **National hydrogen strategies** exist for around 70 countries that complement net zero emissions commitments. These strategies may contain targets and timelines specific to hydrogen production or use. However, Thailand and other Southeast Asian countries, except for Singapore, do not have such strategies.
- **Technology-push interventions** such as grants or loans to support capital expenditure and focus on demonstration projects often with low-rated Technology Readiness Levels. Examples of such interventions could include Feed-in Tariff programmes for renewable and low-carbon hydrogen production or for projects switching to hydrogen-based fuels. Thailand has FiT schemes for renewables but not for hydrogen.
- **Demand-pull interventions** aim to create new sources of demand for hydrogen such as mandating road transport fuel suppliers to reduce their GHG emissions or introducing hydrogen blending into gas network infrastructure. These measures could help switch from fossil fuel-produced hydrogen to low-carbon hydrogen pathways.
- **Fiscal measures** aim to encourage and support low-emission alternatives to unabated fossil fuels. Carbon pricing passes on to the cost of emitting GHGs to emitters or a proxy to it. Energy taxation can include high grid-connection costs and taxes on grid-connected power consumption to signal desired behaviours.

Looking solely at CO2 equivalent emissions, power generation and transport sectors may have the highest potential for hydrogen to reduce emissions, although significant opportunities exist in industry and agriculture as well. However, when assessing and suggesting suitable early market interventions, it is crucial to consider and weigh other objectives and criteria to determine the appropriate approach to be taken in different parts of the economy.

We have developed an evaluation framework to allow different possible interventions to be compared. At the highest level are three objectives, namely:

- **Strategic fit**: where decarbonisation, cost and investment, and energy security are balanced.
- **Societal impact**: where interventions are assessed for the impacts they have on the broader economy.
- **Deliverability**: where implementation and administration considerations of different options are determined.

The Assessment Criteria consists of several themes, each with a multicriteria analysis objective and criterion. The criteria are prioritised by weighing them to ensure that the most important considerations are given more weight. To enable a clear comparison, potential measures to support early market development are evaluated using this approach. The assessment itself is informed by the outputs from the analysis of status quo of hydrogen in Thailand as well as the sectoral analysis. To aid further discussion and implementation, commentary on the different intervention options and the analysis of them have been included in the full report. This includes reference to other states where similar interventions have been made and associated reasoning.

5.2 Policy roadmap for Thailand

Reduction of greenhouse emissions to meet Thailand's decarbonisation targets will require a systematic approach to policy selection, design and implementation. Policy mechanisms from the categories of strategies and targets, technology-push measures, demand-pull measures, will all be needed as will fiscal policies. Different policies will need to be introduced at different times for the different sectors of transport, industry and power. Regular review will be required to respond to market developments both global and localised, including interactions between the sectors considered. This will be important both in terms of developing the emerging hydrogen economy in Thailand and in respect of attaining a suitable balance between regulation-driven growth and that which is market driven.

From consideration of the sectors of transport, industry and power, several commonalities can be observed in respect of policy as well as cross-cutting measures. In summary, recommended policy development has three phases:

1. **Low regret, capital funding (early to mid-2020s).** Capital funding is recommended to support initial green hydrogen and power-to-X in the transport and power sector. Within the transport sector, grants are recommended to support the establishment of a refuelling station backbone, with loans for fleet operators to support purchasing of hydrogen vehicles in the heavy goods subsector. Similarly low regret are the grants recommended for the maritime subsector in the late 2020s to support technology implementation. Aviation practices in Thailand are expected to follow global developments with airlines expected to introduce SAF through international agreements. For the power sector, capital for the trialling of hydrogen or ammonia turbine conversion could come in the form of government-backed loans. Industry equipment change to be hydrogen ready is costly and investment cycles are long. Caution is advised here with limited capex if any since there is considerable progress on decarbonisation of industry that can be achieved through electrification, with those subsectors that cannot requiring robust carbon pricing to support the business case.
2. **State investment in backbone infrastructure (mid 2020s onwards).** Decision making on the role of hydrogen within the power sector needs to take

place to inform how to proceed on state-backed development of a transport and storage network in Thailand. Policy optioneering needs to take place from the mid-2020s at the latest to ensure sufficient time to consult stakeholders, develop detailed plans and then proceed to establish assets. Similar decision making during this phase, though smaller in scale, needs to take place in the transport sector, with the government to consider developing a backbone of hydrogen refuelling stations, particularly if the private sector has not seized the opportunity of capital funding provided in the first phase. The first policy phase also informs decision making for the maritime sub sector, providing clarity on the technologies and fuel production pathways that are more likely to have long-terms roles in Thailand's decarbonisation and future economy.

3. **Subsidy and carbon tax to address hydrogen cost disparity with fossil alternatives (2030s to 2050 onwards).** This third policy phase is the greatest intervention and correspondingly requires considerable state spending. Proceeding phases enable informed decision making on which sectors to focus support and the extent of support suitable. For all three sectors considered, a combination of subsidy linked to operational productions cost and carbon taxation is required to bridge the difference in cost between green hydrogen and oil, natural gas and coal. Policy should be designed so that the subsidy decreases over time and the latter increases over time, reflecting a transition from regulation-driven change to market-driven change and the establishment of a new, low carbon energy market.

Summaries of transition roadmaps recommended for transport, industry and power sectors are set out below.

5.2.1 Power sector

Similar to the industry sector, policy introduction is required to address cost disparity with fossil alternatives. The following are observed for the decarbonization of power sector:

- Renewables will be more efficient and cheaper for Thailand than use of hydrogen in combined cycle gas turbines (CCGTs). Hydrogen in the power sector is well suited to a role in whole system balancing. Policy may be required to achieve Thailand's ambitious decarbonisation targets as part of the energy transition.
- Policy optioneering is suggested to commence immediately for both loans and the state- backed transportation and storage network.
- The timing of policy introduction for hydrogen should align with the assessment of hydrogen demand and cost competitiveness.
- As with other sectors, a combination of a high subsidy for hydrogen used coupled with the introduction of a low carbon tax is required to deliver decarbonisation at scale. The subsidy would be introductory only and should be designed to decrease over time whereas carbon pricing should increase over time.

A suggested policy roadmap towards 2035 for the power sector from results in this study is shown in Figure 5-1.

5.2.2 Industry sector

Policy is necessary to facilitate the energy transition in the industry sector. The primary reason for this is the cost disparity with fossil alternatives, which is unlikely to be achieved under the existing policy framework. Key takeaways from the policy analysis for the industry sector are:

- The recommended policy tools (industry fuel cost competitiveness, subsidy, carbon taxation, carbon border adjustment) aim to accelerate the cost competitiveness of hydrogen, enabling support for hydrogen as an alternative for "green" use cases and providing flexibility for "yellow" use cases where the role of hydrogen and alternative decarbonization pathways is uncertain.

- The timing of policy introduction for hydrogen should align with the assessment of hydrogen demand and cost competitiveness.
- A combination is recommended of a high subsidy for hydrogen use in industry, coupled with the introduction of a low carbon tax. The subsidy would be introductory only and could be limited to first movers or time limited; it could reduce over time. The fiscal measure would impinge more over time.

A suggested policy roadmap towards 2035 for the industry sector from results in this study is shown in Figure 5-2.

5.2.3 Transport sector

The energy transition in the transport sector would occur through two different routes: either driven by market conditions or government push through regulations. The former will occur in a natural way as the cost of decarbonised alternatives is lower than fossil alternatives while the latter will require mandates due to decarbonised options being more costly than fossil alternatives. Some conclusions can be drawn from the study:

- In trucking, the cost of the fuel will reach parity in the short term, hence policy should be focused around ensuring enabling infrastructure and the removal of regulatory barriers.
- In shipping and aviation, cost parity will not occur until the 2040s, which is relatively late and may mean the segments will not be decarbonised fully by 2050 without acceleration and intervention.

A suggested policy roadmap towards 2035 for the transport sector from results in this study is shown in Figure 5-3.

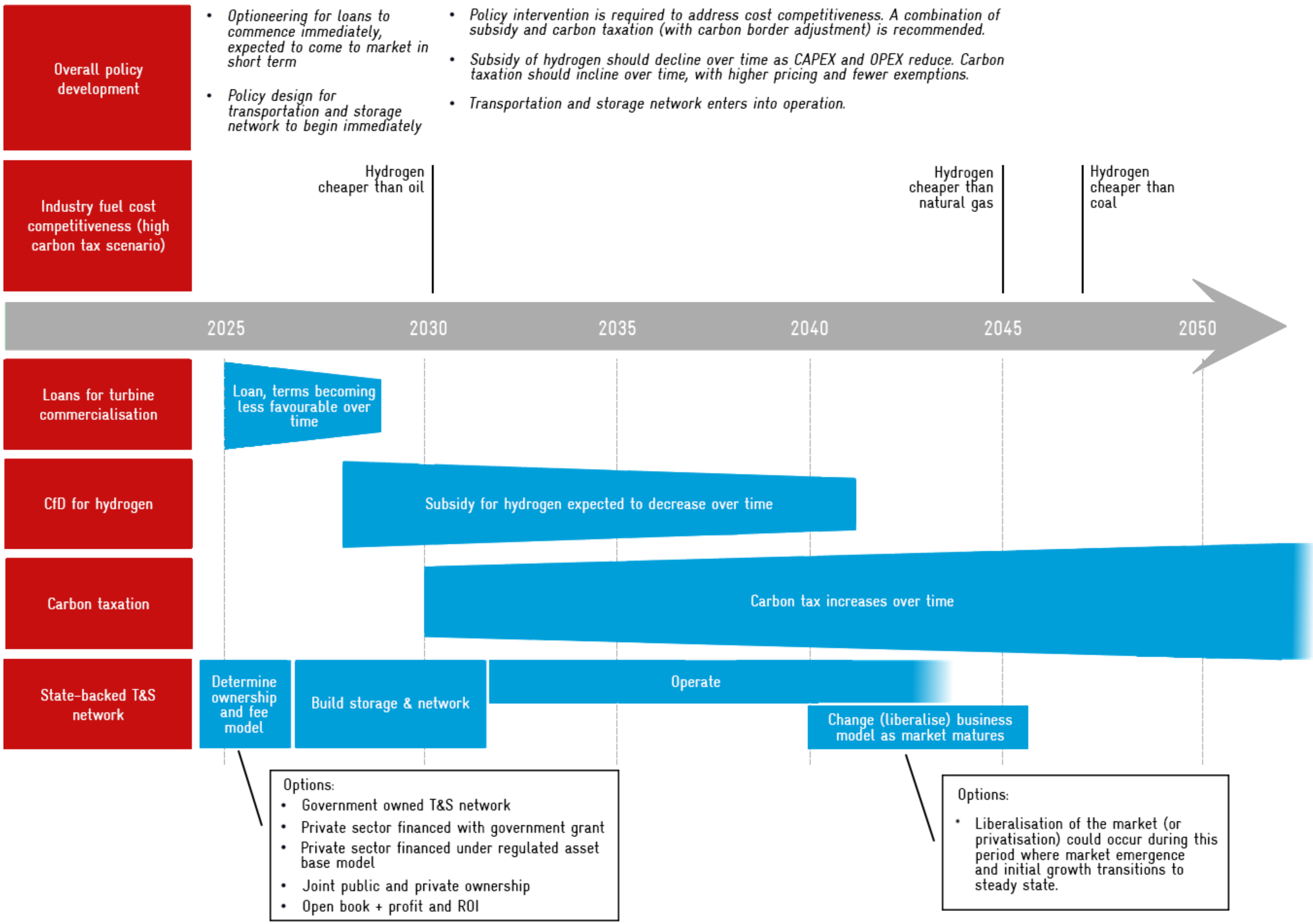


Figure 5-1: Policy roadmap for power sector

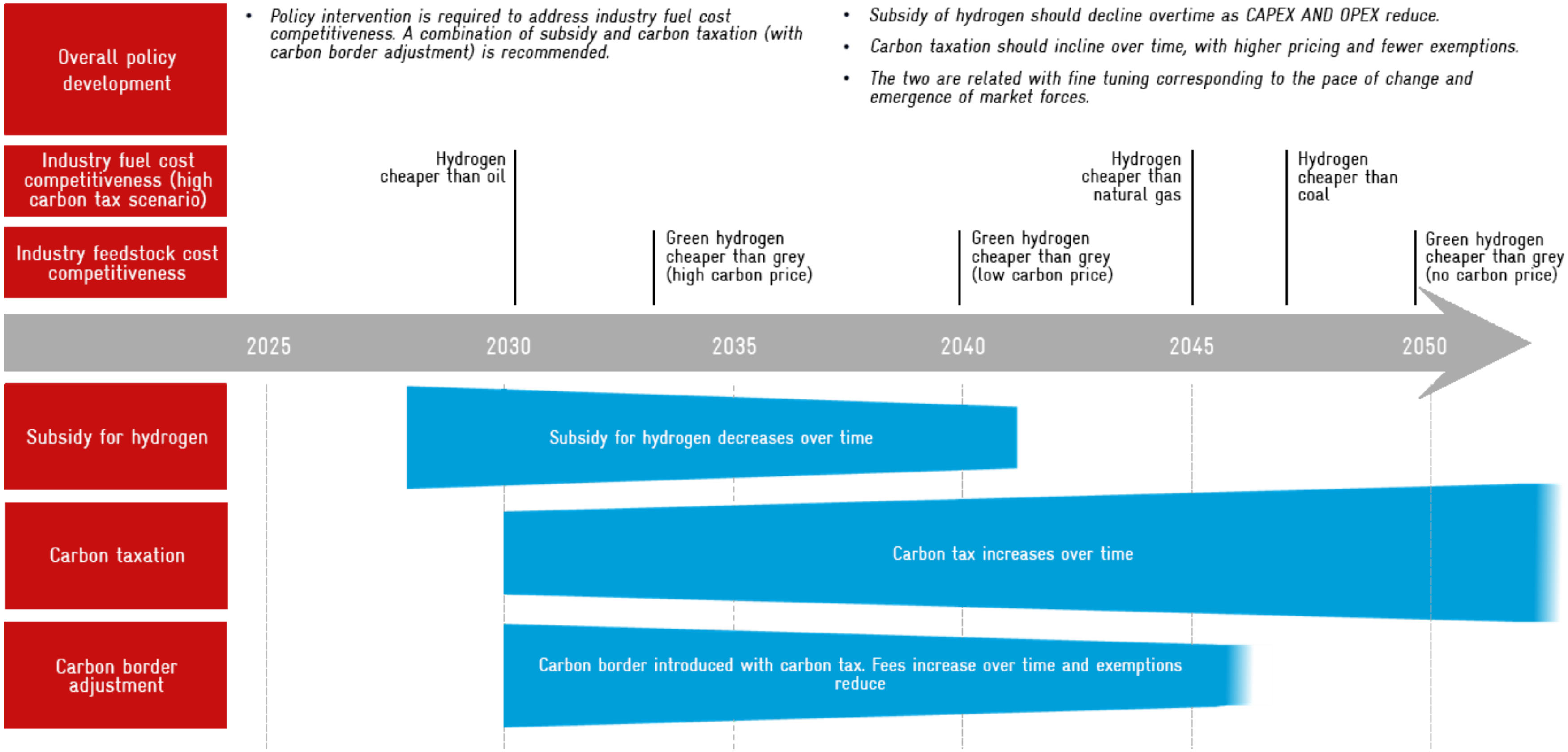


Figure 5-2: Policy roadmap for industry sector

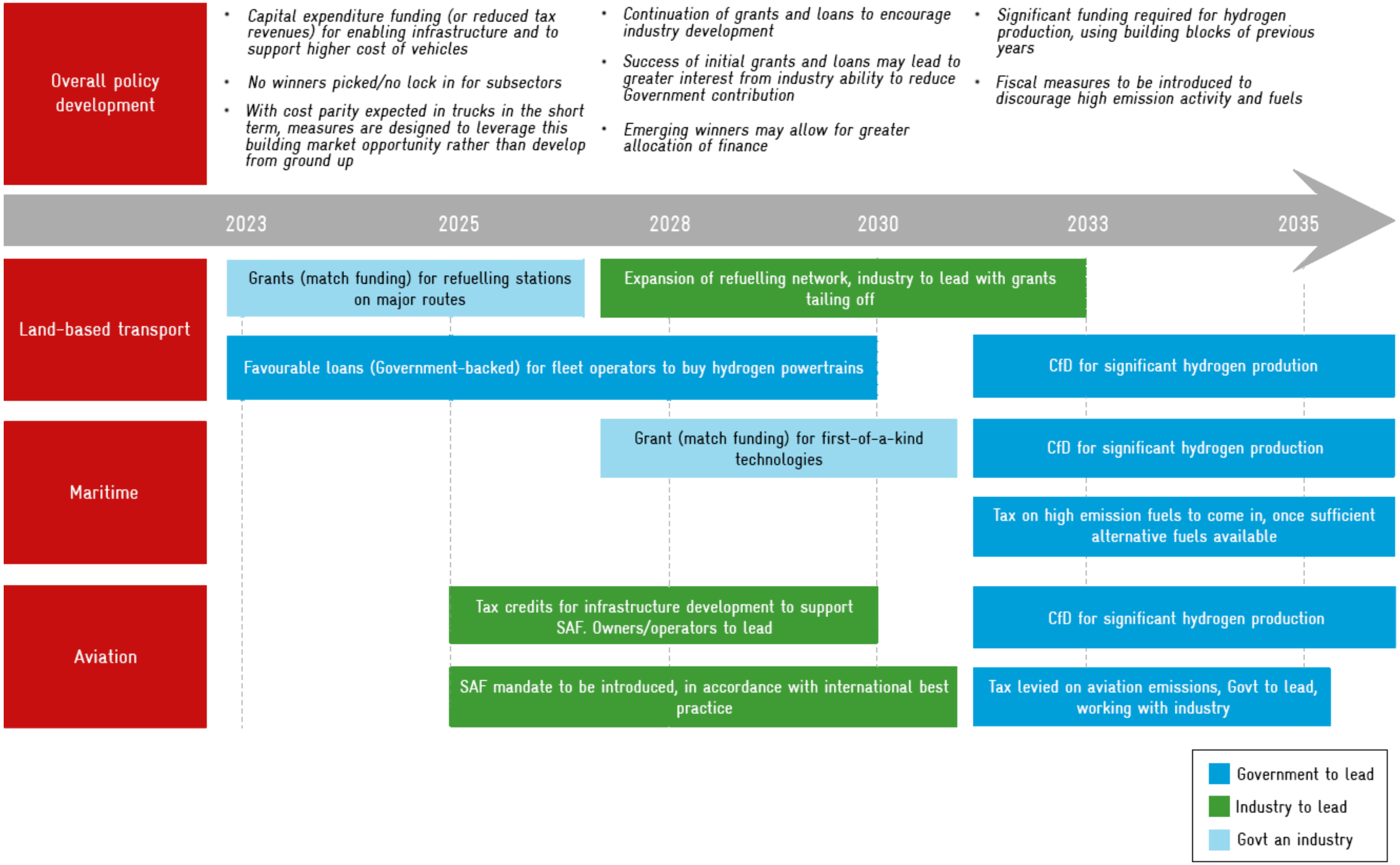


Figure 5-3: Policy roadmap for transport sector

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