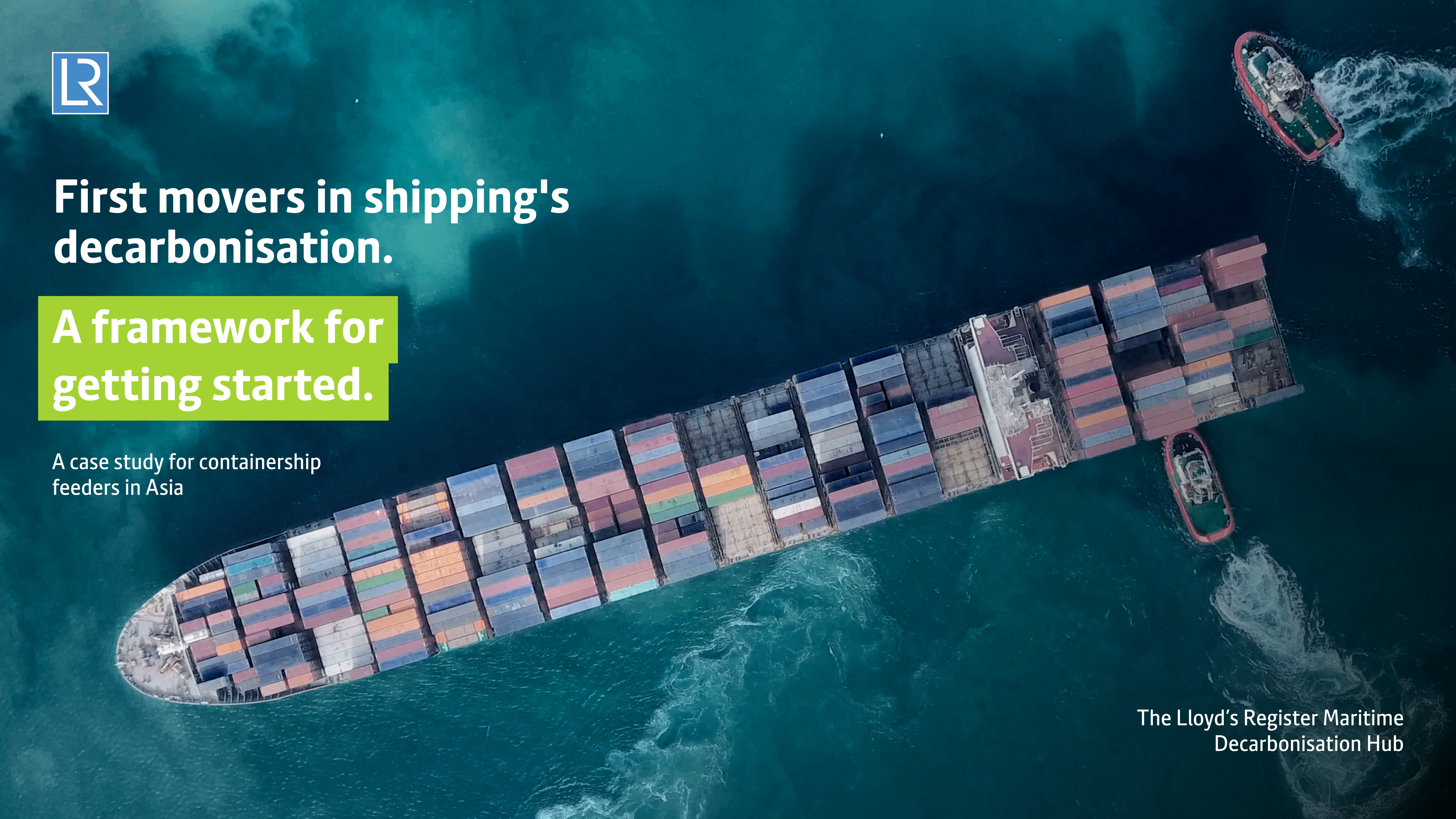


First movers in shipping's decarbonisation.

A framework for getting started.

A case study for containership feeders in Asia

The Lloyd's Register Maritime Decarbonisation Hub

> This is the decade in which zero carbon ships and net zero fuel infrastructure will begin to have real impact. But there is much to learn, and the right decisions require all our collective knowledge. Lloyd's Register is publishing independent evidence and insight, helping steer the industry on the right course.

Nick Brown
CEO, Lloyd's Register

> The challenge is to advance from fossil-based fuels, to net-zero energy sources and technologies in a safe, fair, equitable and just way. Stimulation of investment is critical, which in turn requires an understanding of both supply and demand of zero carbon shipping fuels. The framework presented here delivers the required insight.

Charles Haskell
Programme Manager

Executive Summary

The landscape

Previous studies showed that ships using zero-carbon fuels will need to enter the fleet in 2030 and that the most significant hurdle to overcome would be the zero-carbon fuel costs. More recently, the industry debate has been enhanced by different perspectives, policy makers have set up goals and the industry itself is creating its own targets. The debate is now moving on to global transition strategies and identification of first movers. The urgency is now being addressed by plans to launch Green Corridors where first movers can establish demonstrations that will push shipping beyond a tipping point and onto a path consistent with a net-zero 2050 future.

The challenge

The biggest hurdle to launch first movers now is to convert the ambition into action, given the reality of business cases still being too weak to justify the full uptake of costly zero carbon fuels.

Across the supply chain, zero-carbon fuel solutions are not yet seen as a prospective commercial opportunity, often because they do not yet have a robust business case. Often, there is a need to increase the investment readiness level across the entire supply chain, from their production up to their use onboard ships. Detailed analysis to build real business plans can help stakeholders to better understand the risks both inside and outside of their sphere of control.

Our work

This report sets out a framework to help in converting ambition into actions. The framework allows a detailed comparison of different transition strategies across the entire supply chain (from fuel production to its use onboard vessels). The framework can be applied to specific fleet and this analysis has used a case study of hypothetical first movers. The example chosen is a fleet of containership feeders operating in Asia.

Building on the fuel agnostic framework demonstrated in this analysis, the Lloyd's Register Maritime Decarbonisation Hub aims to steer cross-industry alliances that can unearth and accelerate the most resilient energy transitions and enable pilot projects this decade.

Five factors have influenced our approach

In the quest for a sustainable transition in shipping, we look at five important factors

Fleet-specific analysis

To develop a small-case commercial trial, we need to drill down into the specifics and better understand the techno-economic dynamics for each fleet. Building on the high-level analysis of the global fleet as well as the single ship analysis, it is possible to design and analyse fleet-specific fuel transition strategies. In particular, work should focus on fleets of potential first movers and assess several transitions that might be suitable for that fleet.

Decarbonisation transition of a fleet and its fuel supply

A single transition may require a combination of fuels and different production methods to achieve the decarbonisation goals over time. Comparing one fuel against another fuel limits the debate to the characteristics of individual fuels. In this analysis, we shift the focus from a debate about what is the fuel of choice for the shipping industry to a debate about what is the fuel transition of choice for a specific fleet and its fuel supply.

A long-term assessment

There is a contrast between the short-term business case and the end goal of a new regime where shipping relies on sustainable zero-carbon fuels.

This analysis shows that comparing the potential short- and long-term implications of different transition strategies helps to identify the trade-offs that are inevitably embedded in each case.

A collective understanding of how these transitions could play out in the long term will generate the needed confidence for all stakeholders involved to commit to an actionable plan today.

Evaluate fleet and fuel supply at the same time

Examining the fuel transition for shipping across the entire supply chain means identifying benefits and managing any unknowns. Investments have the best chance of success if based on a system solution. The system in this case is the entire supply chain from fuel suppliers to end-users. This can be done by assessing how the fuel supply may evolve in conjunction with the fleet evolution.

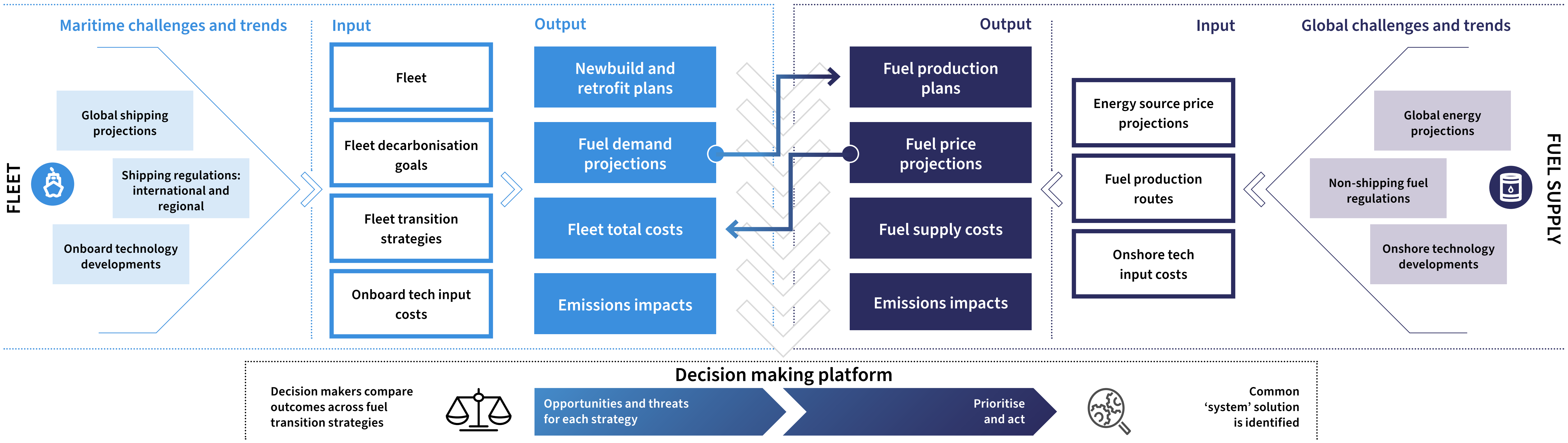
A focus on collaboration to reduce investment risk

The creation of alliances across the supply chain allows for the identification of a system solution with a high chance of success and scalability for a large market, avoiding preconceived solutions that do not work for the entire group of stakeholders.

There is a need for different stakeholders to work together within a framework in which decision making is structured. These alliances should not be limited to technology partners, private shipping and energy supply companies, but should also include financiers and governments within an alliance of stakeholders. The value of a fuel transition can be highlighted, risks can be managed and mitigated, and responsibilities and benefits can be shared across the alliances and beyond members.

The LR Maritime Decarbonisation Hub is engaging with stakeholders to address the actions in this paper to ensure a sustainable transition.

The framework



To overcome the challenges of the first movers and taking into account the factors that influenced our approach, we have set out a framework. The framework allows us to compare different transitions strategies that are selected as inputs based on the collective understanding of a group of stakeholders. It does not look exclusively at the most cost-effective solution, and it does not provide prediction either; it rather allows us to explore the different implications for each strategy. By doing so, it offers new insights, e.g how do transition strategies differ from each other and why. The aim of the framework is to force us to systematically articulate our assumptions, scrutinise and test our conclusions and help to structure decision making.

The framework enables simultaneous assessment of the fleet and fuel supply in order to meet a decarbonisation goal. The major maritime challenges and trends feed into the fleet side of the model (Left hand side) and the major global challenges and trends feed into the fuel supply part of the model (right hand side). These macro drivers are translated into input assumptions on both sides. The macro-elements are used to scope the fleet-specific evaluation by identifying the target fleet and operating route, the most plausible fuel transition strategies, and the potential fuel production routes.

The model generates outputs directly from the input assumptions, as listed in the diagram. The module that generates these outputs works in tandem so that the outputs of the fleet evaluation are used as input for the fuel supply evaluation and vice versa. The outputs are then used to provide answers to a series of specific questions, described in this report. In turn, those answers are used to compare opportunities and risks for each of the transition strategies with the aim of identifying a common 'system solution' that works for all stakeholders involved.

This first version of the framework will be further developed as it evolves over time. This report introduces the new framework and apply it to the case study of containership feeders operating in Asia.

Findings of the case study

In this analysis, our candidate fleet for a scalable commercial trial is a fleet of containership feeders operating in Asia mainly between Singapore and Hong Kong. Different transitions might be suitable for this fleet, based on either methanol, ammonia or hydrogen as fuels, which in turn can be produced from natural gas, renewable electricity, or in some instances, sustainable biomass.

Similar emissions reduction trajectories have different implications for the fuel supply infrastructure. The fleet transitions based on methanol, ammonia or hydrogen can all achieve similar emissions reductions, approximately 79 million tons of net CO_2 emissions cumulatively up to 2050 relative to a fossil fuel case; however, this result is achieved using different infrastructures and at different costs.

The sector must balance early results with long-term planning. This analysis shows a trade-off between early efforts to decarbonise the fleet, which allow for a smoother transition, versus the long-term planning approach, which attempts to find the solution with the lowest overall cost. This balance must be found while providing a growing supply of fuel through different feedstock routes without major price fluctuations.

Both retrofitting and newbuild will be required to meet net zero by 2050. In all cases, approximately 26% (by number of ships up to 2050) of the transition is achieved through retrofitting. This means that replacing vessels near the end of their lives with newbuilds fuelled by zero-carbon fuels is no longer sufficient to meet a net zero 2050 target. Instead, younger vessels in operation today need to be retrofitted to accelerate the uptake of zero-carbon fuels.

Fleet total costs up to 2050 are lowest for the ammonia transition ($44.5 bn), followed by methanol ($51.5 bn) and then hydrogen ($69.4 bn). This compares to the fossil fuel baseline of $42.3 bn including carbon cost.

Voyage costs dominate the fleet's total costs, representing between 71%-82% of the cumulative fleet total costs depending on transition. Improving vessel efficiency and voyage optimisation becomes more and more important to reduce the cost of decarbonisation.

The fleet fuel transition leads to a specific fuel supply. The production location delivering the cheapest fuel production option typically also benefits from being the location with the lowest feedstock prices, except in instances when the cost of transporting that fuel to the fleet becomes too large (e.g. for the hydrogen transition).

Co-location of ng-fuels and re-fuels could deliver further cost reductions. Saudi Arabia and Australia are likely production locations because of relatively lower feedstock prices. There can be key economic advantages in co-location of plants. For example, Saudi Arabia or Australia could likely be the cheapest location to produce ng-fuels and re-fuels (for ammonia and methanol). This would de-risk investments and build long-term security over supply capability and associated costs.

ng-fuels may conceal hidden risks. The pursuit of zero-carbon fuels produced from natural gas (ng-fuels) may conceal hidden risks because they still include residual carbon emissions and methane leakage, and are expected to be less competitive over time given the falling prices of renewable electricity.

Fleet

Fuel supply

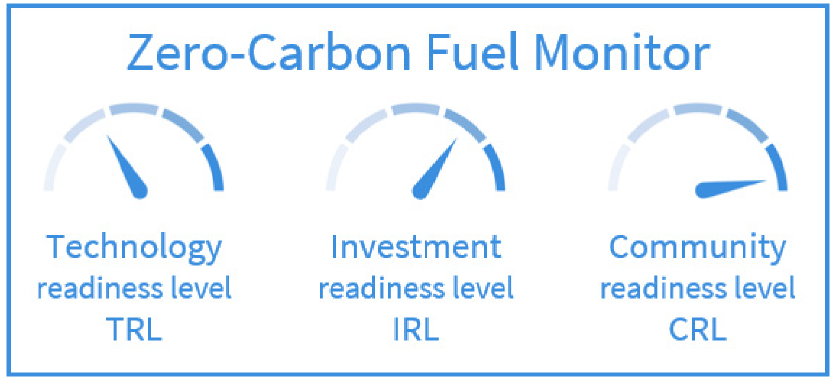
> **First movers in shipping's decarbonisation are working to create green shipping corridors that will kickstart concrete action. This report provides a framework that will help first movers take those initial steps. And by providing a specific case study it shows how to apply the framework to shipping fleets in service today.**

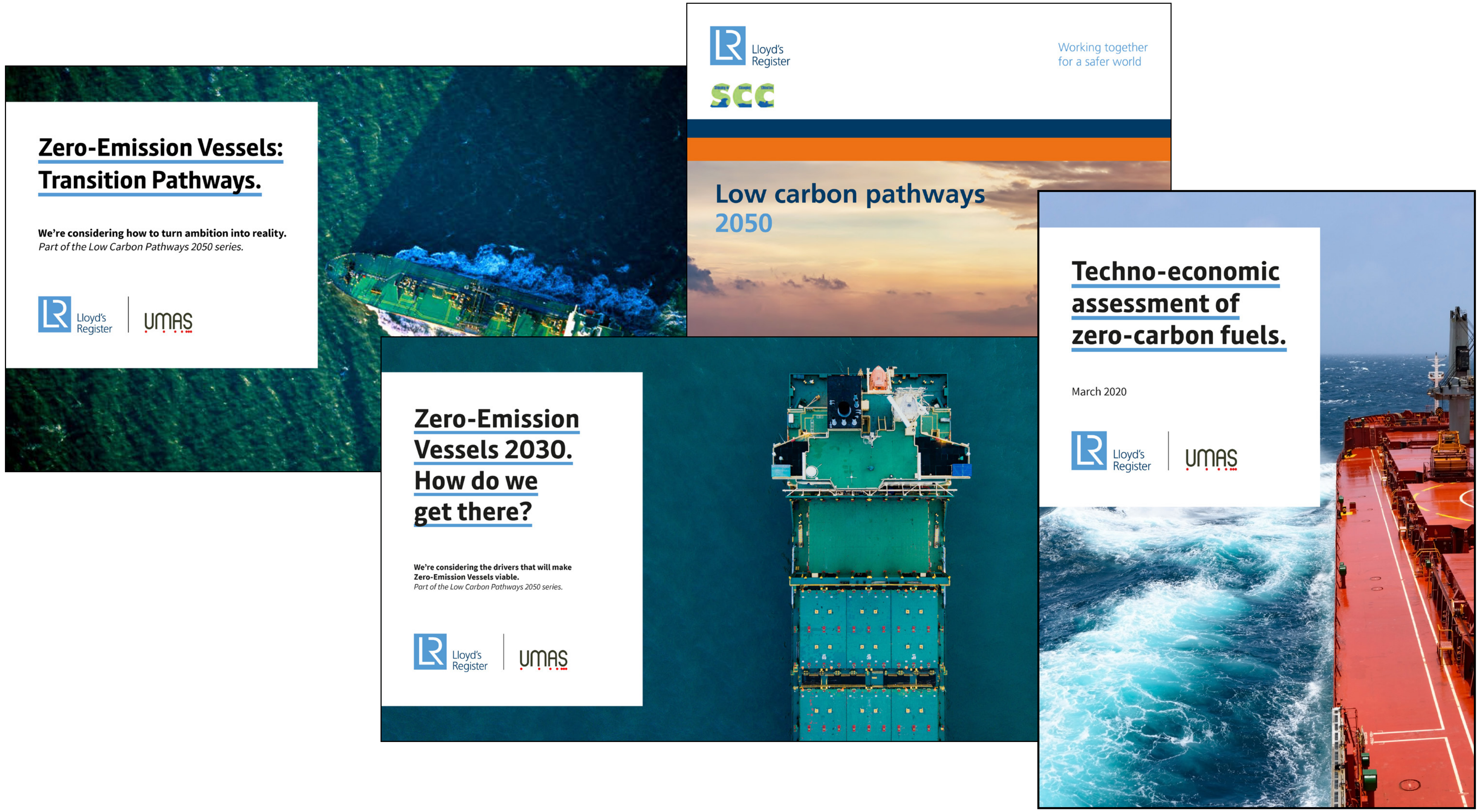
Carlo Raucci
Decarbonisation Consultant

Our journey so far

Our journey so far is telling us that for ZEVs to enter the fleet in 2030, the focus should be on fuel costs as these represent the most significant hurdle to overcome. This will require successful, scalable commercial projects where the global transition can begin and grow.

Zero-emissions vessels (ZEVs) need to be entering the world fleet in 2030 and form a significant proportion of newbuilds from then on. The most significant hurdle is bringing down the ‘voyage cost’, largely driven by fuel cost. Overcoming this hurdle will need regulatory intervention as well as collaborations across the entire supply chain (e.g. shipping companies partnering with fuel suppliers, cargo owners, governments and port authorities). There is a need for action this decade to provide a scalable solution through multiple joint venture demonstration projects, as there is no one production route solution that is continuously the most competitive over time.





Building up momentum

Public and private sectors are now coming together to enable shipping's decarbonisation at a growing pace. Following the outline laid out in the Lloyd's Register Transition Pathways report [1] in 2019, the Getting to Zero Coalition has led the call to action for governments to respond to over 200 leading shipping entities calling for decisive action to fully decarbonise shipping by 2050.

The Mission Possible partnership has further expanded on this idea at COP26, by shortlisting potential “Green Corridors” that provide large scale demonstrations of zero carbon shipping that can push the industry to reach the tipping point of 5% uptake of zero carbon fuels by 2030 [2]. The United Kingdoms' work on the Clydebank Declaration has activated government support for these corridors.

The question now, is how exactly can the Green Corridors be implemented, and how can a first mover fleet mitigate the real world risks associated with new fuels.

Major shipping bodies are now realising that preparation and investment needs to happen this decade, with this sense of urgency also echoed by Maersk Mc-Kinney Møller Centre [3] and the Hydrogen Council [4], given the long life cycles of ships and long lead times for replacements. The Clydebank Declaration co-signed by several governments and the coZEV commitment led by cargo owners are recent demonstrations of early alliances targeted at decarbonising the shipping industry.

Despite this convergence in industry intent, large uncertainty remains over fuel solutions with no one-size-fits-all solution. What might work for a specific ship type in a certain region might not result in a scalable solution for the rest of the global fleet.

There have been steps towards modelling the energy transition and complexities of the 2050 fuel mix, acknowledging that it will not be a one-fuel and one-feedstock solution for the entire shipping industry [5] [6] [7]. However, investors are still left without a steer to make micro-level investment decisions with analysis conducted on a global and somewhat high level.

The micro-level analysis also needs to go further. The Total Cost of Ownership (TCO) calculation has become an industry standard, but modelling has so far focused on typical ship types or generic fuel supply systems to compare different technologies.

Questions still remain. Will the fuel supply evolve in partnership with vessels' developments? If so, how? Do the characteristics of a ship/fleet and fuel supply along a specified shipping route influence the combined fleet and supply evolution?

Definition of first movers

In a traditional sense, ‘first movers’ are companies with a competitive advantage by simply being the first, which is also true in the case of fleet decarbonisation plans, through technical advantages and early insights to lower costs, as well as financial incentives. However, these entities are also driven by other factors, which may include large risk exposures that need to be mitigated (e.g. shipowners with large and varied fleets that need clarity on scalable solutions) and investor or consumer pressure to decarbonise [8].

Our approach to achieving a sustainable transition

The Zero-Carbon Fuel Monitor

To accelerate the safe and sustainable transition, the Lloyd's Register Maritime Decarbonisation Hub has developed an evidence-based framework to assess the readiness of the most promising zero-carbon fuels and related technologies that could play a role in getting the entire shipping industry to zero emissions by 2050. We use this problem-solving-driven framework to identify where more effort is needed to grow a potential solution into a commercially viable, sustainable, full-scale deployment.

In 2021, we launched our 'Zero-Carbon Fuel Monitor' to compare the readiness levels of the most promising zero-carbon fuels and related technologies, finding that the lack of investment readiness is a case for pushing through small-scale commercial projects to demonstrate a route that can scale.

Try it out here: [Zero-Carbon Fuel Monitor (lr.org)]

Our work [9] has identified low investment readiness level (IRL) ratings for the majority of the zero-carbon fuels across the different stages of the supply chain. We rate IRL on a scale from 1 to 6, where 1 is the lowest level, a hypothetical commercial proposition. Solutions fully ready for investment are given level 6 assessment, bankable asset class. In many cases we see current IRL levels at level 1; in a few cases do we see current IRL levels reach level 2, 'small commercial scale'. Very few fuels currently reach level 3 where commercial scale-up can be demonstrated.

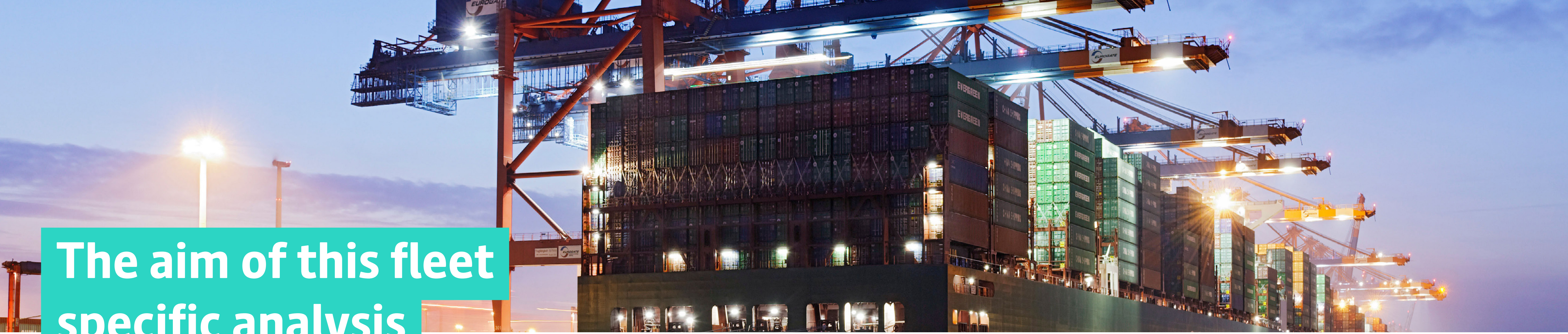
There are different reasons why the IRL ratings of most zero-carbon fuels are currently low, including the potential high price gap with current marine fuels, the uncertainty around the fuel's relative competitiveness in the medium to long term, and the lack of a commercial proposition for specific high-volume applications.

To enable investors to judge the mid- to long-term prospects of a decarbonisation solution, it becomes very important to understand the key cost drivers of a specific application. This can be achieved not merely by focusing the analysis across the entire supply chain, but by analysing a specific fleet, considering plausible fuel transitions for that fleet and potential fuel supply around the geographic area where the fleet operates.

The techno-economic analysis of generic ship or generic fuel supply infrastructure may not be sufficient for investors to build up the required confidence to invest. This is also highlighted in other reports, such as a recent IRENA report [10] which calls for mapping out key stakeholders associated with the shipping sector and engaging with these parties to form strategic partnerships where there are common goals to identify key strategic investments and study the production costs of renewable fuel production.

Among shipowners and charterers, zero-carbon fuel solutions are not yet seen as a prospective commercial opportunity, often because they do not yet have a robust business case. Investors need to understand a specific application identifying a particular target market segment, its short- and long-term size, and the risks within and external to the investor's sphere of control. This includes factoring in policy and regulation that may include market-based measures which could further strengthen the business case.

We have found that there is a need to increase IRL across the entire supply chain by switching the focus from an analysis of generic ship or generic fuel supply infrastructure to a more specific and detailed analysis that provides a 'system solution' and can form the basis of a business plan for a specific application.



The aim of this fleet specific analysis

This new analysis from the Lloyd's Register Maritime Decarbonisation Hub aims to progress IRL levels and eventually unlock small-case commercial trials to demonstrate a route to scale and reach zero-carbon shipping by 2050.

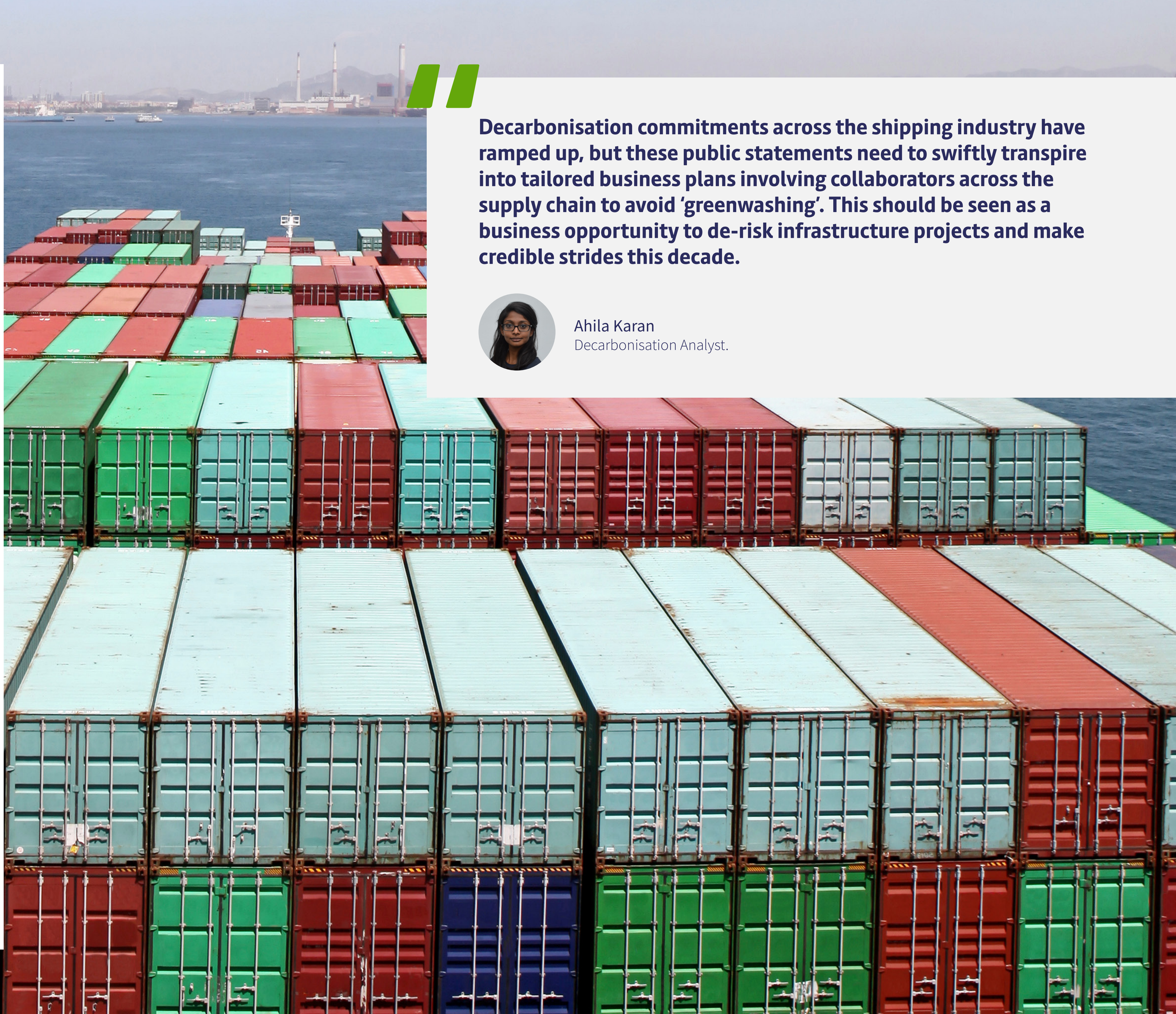
It aims to do so by providing a concrete example of how the decarbonisation of a specific fleet (in this case, feeder-sized container ships operating between Singapore and Hong Kong) can happen in conjunction with the evolution of the regional fuel supply infrastructure. This allows us to focus on what is material as well as on a specific fleet that we have identified as a potential first mover with additional potential for scalability.

The analysis provides detailed, plausible fuel transitions for this specific fleet rather than for global fleet segments. For example, it describes how decarbonisation can be achieved through fleet turnover, giving fleet-specific figures for new builds and retrofits. At the same time, it provides a deeper understanding of the key cost drivers across the entire supply chain.

This analysis is a first step in the reduction of uncertainty around decarbonisation investments. It provides new insights around the opportunities and challenges of each transition, articulating our assumptions and highlighting remaining uncertainties. We hope this new framework will help to structure decision-making and inform public debate, as well as form the basis for other first-mover projects where stakeholders can create fruitful collaborations and enable growth markets with high potential to drive the industry energy transition.

Structure of the case study

The remaining part of this report describes the application of the framework to the selected case study. It is divided into three sections. The first section focuses on the fleet analysis by answering several key questions related to fleet turnover, fuel mix and emissions, as well as providing a breakdown of the fleet total cost. The second section focuses on the fuel supply analysis (see Appendix A for a methodology overview). Key questions include the scaling requirement, the most likely least cost production routes, and the breakdown of the fuel supply total cost. Finally, the third section interprets the results and summarises the key conclusions.



> Decarbonisation commitments across the shipping industry have ramped up, but these public statements need to swiftly transpire into tailored business plans involving collaborators across the supply chain to avoid 'greenwashing'. This should be seen as a business opportunity to de-risk infrastructure projects and make credible strides this decade.

Ahila Karan
Decarbonisation Analyst.

Key questions for the Fleet

3.1
Which fleet can represent the case of a scalable commercial trial?

3.2
Which fleet fuel transitions strategies are the most plausible?

3.3
How is the decarbonisation goal achieved through fleet turnover?

3.4
What is the composition of fleet fuel mix demands?

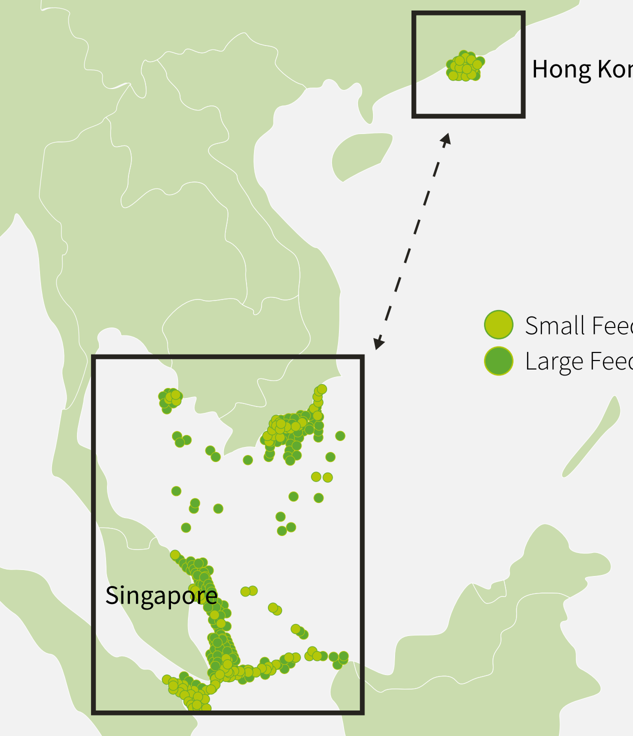
3.5
What are the implications in terms of emissions reduction trajectories?

3.6
What are the key cost drivers and how do they differ among transition strategies?

3.1 Which fleet can represent the case of a scalable commercial trial?

A fleet of containership feeders operating in Asia

There are many potential candidate vessel fleets suitable for a scalable commercial trial. In this analysis, we have undertaken a literature review of existing studies to identify a representative fleet that meets certain criteria. By using AIS data, we identified a fleet composed of feeders (totalling ~360 kTEU capacity) operating regionally between Singapore, Hong Kong and other Asian countries nearby. According to our AIS data analysis, 222 feeder vessels are trading mainly in this area with current fuel consumption estimated at 1.4 million tons of fuel oil equivalent corresponding to 4.7 million tons of CO_2 emitted per year (0.4% of global shipping CO_2 emissions in 2018).



Map of the area where the identified containership feeders fleet mainly operate

222
vessels

1.4mt
fuel oil

4.7mt
CO_2

Today's fleet profile

1,619
Average TEU

359,346
Total TEU capacity

12 years
Average age

15,793 nm
Average annual distance travelled per vessel

22.4 kdwt
Average dwt

3,506,120 nm
Total annual distance travelled

Fleet Selection

Criteria	Candidate Fleet: Singapore-Hong Kong containership feeders
The type of vessels in the fleet should be in the **'first movers'** category.	This candidate fleet and selected shipping route inspires first-mover projects because: • Containerships are used to transport manufactured goods, often sold directly to end consumers that may be willing to absorb the passthrough costs. Consumer pressure to address climate change is more heavily felt in this vessel type segment, unlike bulkers and tankers, which are further down the chain and less subject to consumer pressure. • Shipowners in this fleet also own more vessels outside of this fleet, and therefore are incentivised to prepare for the eventuality of turning over their wider fleets. Gaining an early technical and practical advantage leaves these owners less exposed to sudden decarbonisation policy changes in future. • These feeders can benefit from regional financial support offered by local port authorities.
The fleet mainly operates in a specific geographical area with a fairly high concentration of cargo traffic regularly calling at specific major hubs/ports so that **stable and reliable energy demand** can be inferred or derived.	• By their nature, feeders remain largely region bound, unlike larger containerships on longer-haul voyages, so these feeders mostly call at regional ports, with the majority of activity falling within the South China Sea. As a result, demand is localised, meaning reliable and relatively stable energy demand estimates can be inferred for this particular fleet.
While the transition of this fleet should deliver a **significant potential emissions reduction,** the fleet transition should also act as a **catalyst for other ships** that call at the identified ports, or ships operating nearby, so that it is likely to have a wider impact, spreading beyond this fleet into a larger market.	• The transition of this feeders fleet offers a significant potential impact by targeting approximately 4.7 million tons in current carbon emissions. When placed alongside the 10 shortlisted corridors identified in the study commissioned by GMF [11], this fleet would represent the 5th highest ranking by potential impact (the GMF study's corridor with the 4th highest impact, Brazil-Asia iron ore corridor, is estimated to currently emit 10.4 million tons of carbon, while the 5th highest impact corridor in the GMF ranking is the Transatlantic containerships corridor with an estimated 3.2 million tons of carbon – therefore the fleet in our study would rank between these). • The fleet operates in Singapore, which is a leading container trans-shipment hub and busy trade region, so has potential to act as a catalyst for all the other ships calling in Singapore or Hong Kong. According to the IAP report [12], the use of new fuels could tap into Singapore's position with extensive regional feedering activities and bunkering capabilities and lead to collaboration between Singapore and industry stakeholders, enabling co-sharing of risks of new investments and sharing of knowledge on common issues.

3.2 Which fleet fuel transition strategies are the most plausible?

Transition 1: Methanol (3 stage approach)

	Stage 1	Stage 2	Stage 3
LSHFO →	bio-Methanol →	ng-Methanol →	re-Methanol

Transition 2: Ammonia (2 stage approach)

	Stage 1	Stage 2
LSHFO →	ng-Ammonia →	re-Ammonia

Transition 3: Hydrogen (2 stage approach)

	Stage 1	Stage 2
LSHFO →	ng-Hydrogen →	re-Hydrogen

Fleet fuel transitions considered in this study

The transition based on methanol assumes the use of sustainable bio-Methanol as an interim fuel, followed by a switch to ng-Methanol first and re-Methanol in the long term (a three-stage approach). In contrast, the transition based on ammonia assumes initial use of ng-Ammonia from 2025 followed by a switch to re-Ammonia from 2030 (a two-stage approach). The hydrogen transition also employs a two-stage approach, first to ng-Hydrogen from 2025 and later to re-Hydrogen from 2030.

Selection of fleet fuel transition strategies

Through a literature review of the existing information and data available to LR, we have identified three fleet fuel transition strategies[13]: a transition based on methanol (referred to from here as the “methanol transition”), another based on ammonia (“ammonia transition”), and a final transition based on liquid hydrogen (“hydrogen transition”).

While any of these fleet fuel transition strategies sets an overall direction for the energy transition, actual execution can proceed through a series of steps (changing from one fuel to another) that could involve several fuels. Based on LR’s previous work as well as more recent studies, hydrogen, ammonia and methanol that are derived from renewable electricity (referred to from here as re-Hydrogen, re-Ammonia and re-Methanol respectively) are promising long-term solutions, whereas several sustainable biofuels or fuels derived from natural gas in conjunction with carbon capture and storage (referred to as ng-Hydrogen, ng-Ammonia and ng-Methanol) are promising short- to medium-term solutions.

The use of natural gas fuels with carbon capture and storage

Ultimately, the steps of any transition will depend on the cost, availability and sustainability of the intermediate fuels and feedstocks used to produce the fuels. The inclusion of natural gas-derived fuels, although not entirely net-zero carbon due to the carbon capture rates of current technology, may not necessarily be required as a step in all three of the transitions explored in this analysis. They are nonetheless included as a step in these transitions in the interest of exploring transitions which can scale up to meet demand around the world. Several national governments have indicated pursuit of a dual-track hydrogen economy, where both natural gas and renewable electricity production routes will be required to decarbonise national infrastructure. Consequently, shipping, as a consumer of fuels, would no doubt be coupled to the fuels available globally, particularly in the nearer term where natural gas routes, with more advanced infrastructure, are already being used on land to alleviate the pressure on producing the most sustainable renewable electricity derived fuels.

The development of carbon capture and storage will be necessary for the use of natural gas-derived fuels. For this analysis, the IEA’s carbon capture, utilisation and storage (CCUS) study of Southeast Asia[14], which highlights regional potential for large-scale storage opportunities given the deep saline formations and depleted oil and gas reserves, is particularly relevant. Despite Singapore’s limited storage resources, there is potential for regional storage hubs with neighbouring countries, including Indonesia, which is gaining early experience with CCUS solutions and already developing a legal and regulatory framework for CCUS activities.

Further work

Several other fleet fuel transition strategies can be identified and can be explored as further work. For example, a transition could begin using liquefied natural gas (LNG) and then switch to bio-LNG or re-Methane or ammonia. Other transitions could bypass intermediate steps and rely on fuels derived from renewable electricity from the start, or use compressed hydrogen or use a biogenic source of carbon rather than DAC rather than liquid hydrogen. Another plausible methanol fuel strategy could include the earlier use of ng-Methanol, bypassing bio-Methanol. This study is not an exhaustive examination of all potential transition strategies but rather the first step towards a new approach to evaluating decarbonisation strategies. Nevertheless, the selected transition strategies are considered representative of major trends that the industry is likely to adopt.

3.3 How is the decarbonisation goal achieved through fleet turnover?

Newbuild vs. Retrofit

Investment in newbuilds alone is not sufficient to meet decarbonisation goals; retrofitting is crucial to the decarbonisation strategy in the first 15 years of the transition.

The analysis finds that the split between newbuild and retrofit varies slightly depending on the transition. Around 26% of investments over the period to 2050 are retrofits (80-83 vessels). The remaining ~74% of investments (229 vessels) are newbuilds.

Simulating fleet turnover

The progressive switch from one fuel to another over time is driven by the emissions goal set in any specific year. To meet the goal, the fleet turnover combines zero-carbon-powered newbuild ships with retrofitting the existing fleet for zero-carbon fuels. The simulation also factors in the natural tonnage growth, with additional cargo demand growth set at ~3% over the 30-year transition period.

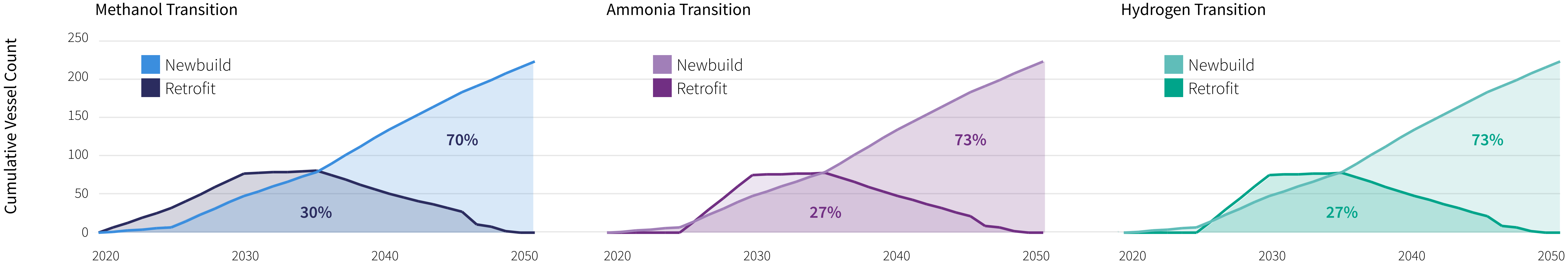
Emissions goals

The decarbonisation goal for the fleet is based on life-cycle (also referred to as 'net' or 'well-to-wake') CO_2 emissions, which includes both upstream emissions from the production of the fuel and operational emissions from use of fuel on board a vessel. Further work shall include other GHG emissions as well as any other air pollutants.

This analysis assumes the decarbonisation goal is broadly in line with a 1.5C trajectory: by 2030, the net CO_2 emissions goal is set at almost 50% of today's baseline CO_2 levels for this fleet.

By 2040, net CO_2 emissions are targeted to reach 28% of today's levels, before falling close to full abatement by 2050. The emissions decarbonisation goal for this fleet is in line with the 1.5C trajectory; however, one can argue that first movers could achieve full decarbonisation earlier than 2050. Further work will include transitions with more stringent decarbonisation goals over time.

Newbuild vs. Retrofit Vessel Count (by fuel transition)



Newbuilds

Low sulphur heavy fuel oil (LSHFO) newbuilds

The newbuilds for the methanol transition are all powered by zero-carbon fuels from vessel delivery, whereas the newbuilds for the ammonia and hydrogen transitions are still powered by conventional fuels up until 2025 due to the combination of potential limited fuel availability and growing cargo demand. However, we only see 7 LSHFO-based ships, delivered before 2025 in each case, which will eventually have to be retrofitted with zero-carbon fuels over 2035-2040. Some retrofits take place as early as 6 years in, highlighting the importance of design flexibility.

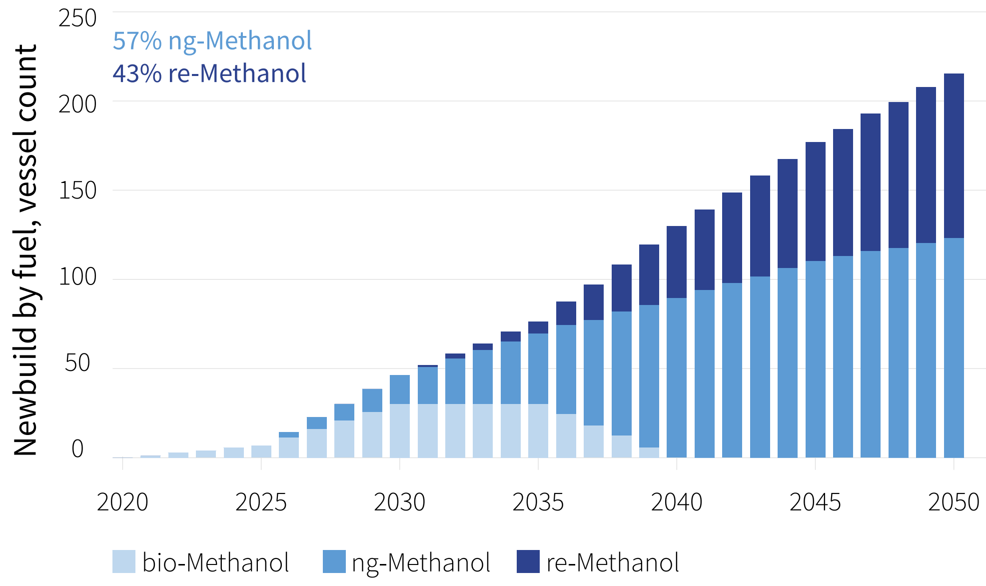
Early adoption of bio-Methanol

In the methanol transition, the use of bio-Methanol allows the transition to begin early in this decade. The construction of methanol vessels in the near term would help to create a demand for methanol in the medium to long term. However, this creates a risk of locking in to a fuel that might not be as competitive as other options in the long term.

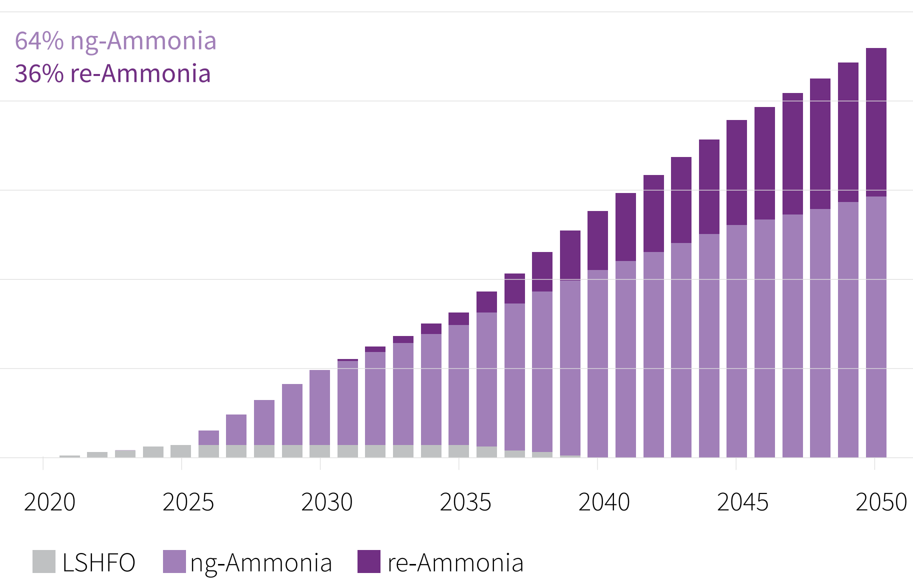
Age profile

The age distribution of the fleet is key to shaping requirements for newbuild vessels to replenish the aging fleet, and this applies to all fuel transitions. In particular, over the 2035-40 period, the natural scrappage rate peaks, driving a greater push for newbuilds over this period.

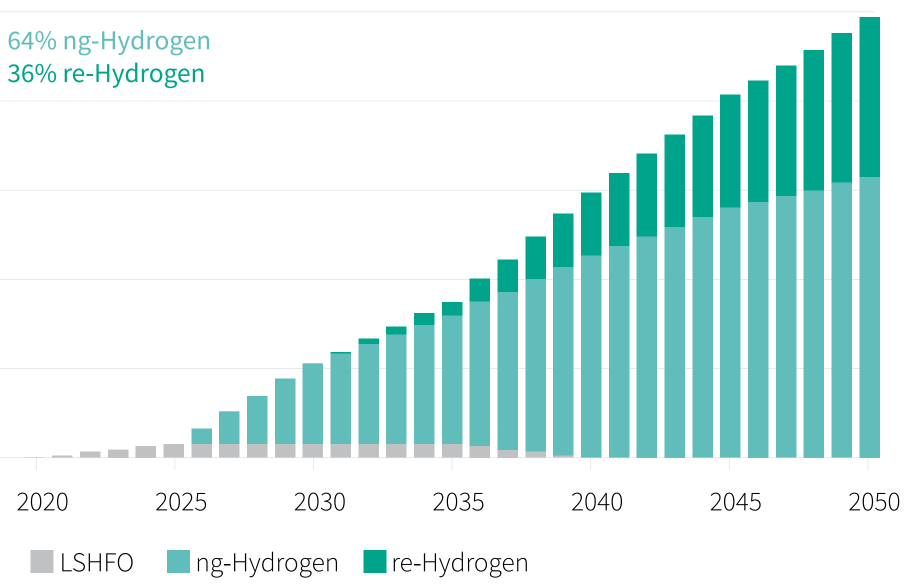
Methanol transition



Ammonia transition



Hydrogen transition



All newbuilds in the fleet simulation are assumed to take the average size of a large feeder container (1,704 TEU), as large feeders make up the majority (92%) of this sample fleet, while only 19 of ships in this sample fleet are small feeders.

Retrofitting

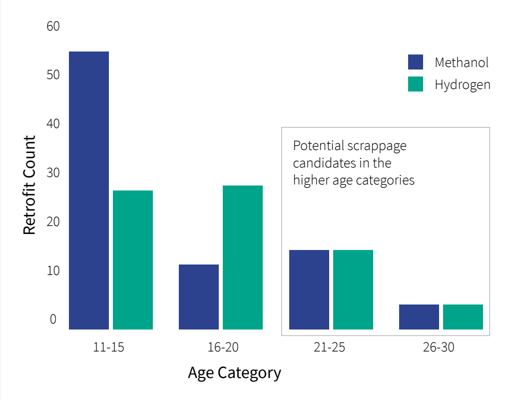
The pace of retrofitting among transitions

The pace and timing of retrofits differs between fuel transitions. For the methanol transition, retrofitting commences almost immediately, due to the early availability of bio-Methanol. Hydrogen and ammonia retrofits ramp up later once ng-derived fuels come online by 2025. The number of ng-retrofitted ships in each of these transitions reaches similar levels to the methanol transition but occurring over a shorter five-year period between 2025-30. The rapid push to retrofit the existing fleet is necessary in the ammonia and hydrogen cases to meet the decarbonisation targets by 2030. However, success will depend on having mature retrofit designs, as well as capacity in the shipyards and equipment manufacturers to deliver successive retrofit projects that could take up to three months each.

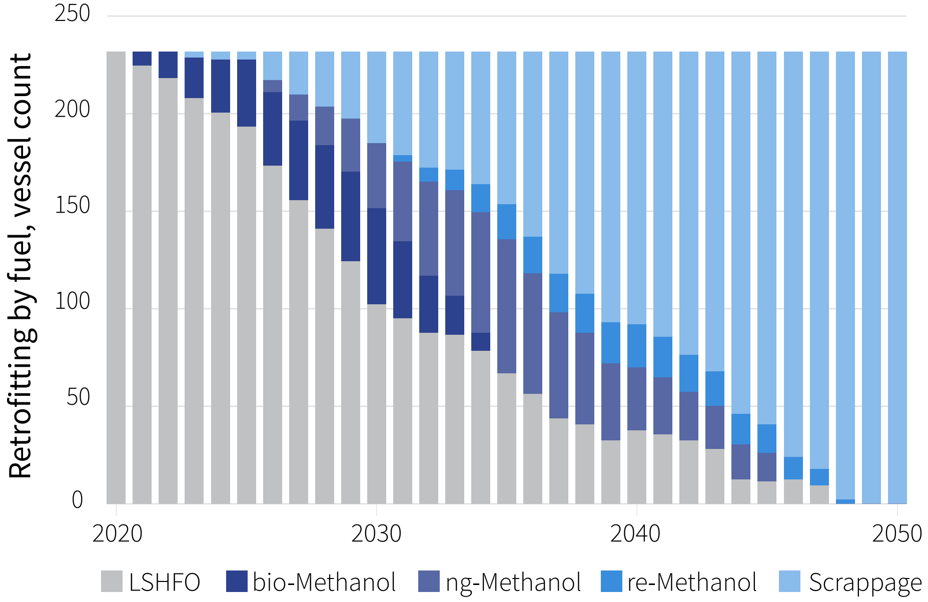
Risk of early scrappage

The analysis of retrofitting can help identify ships at risk of early scrappage.

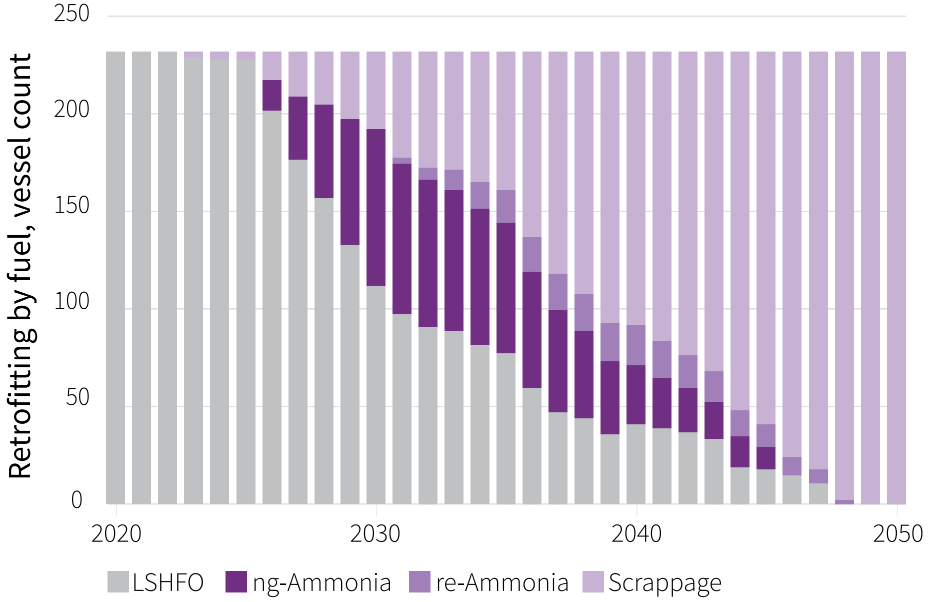
Shipowners may consider early scrappage as retrofitting at a late stage in the vessel's life cycle becomes less economic. Overall, our analysis shows there are 21 retrofitted ships that are over 20 years old (9.4% of the entire fleet), of which five ships are over 25 years old, making these even higher risk for scrappage. This does not vary between transitions – the total number of retrofits needed to meet the decarbonisation goals is similar across all three transitions.



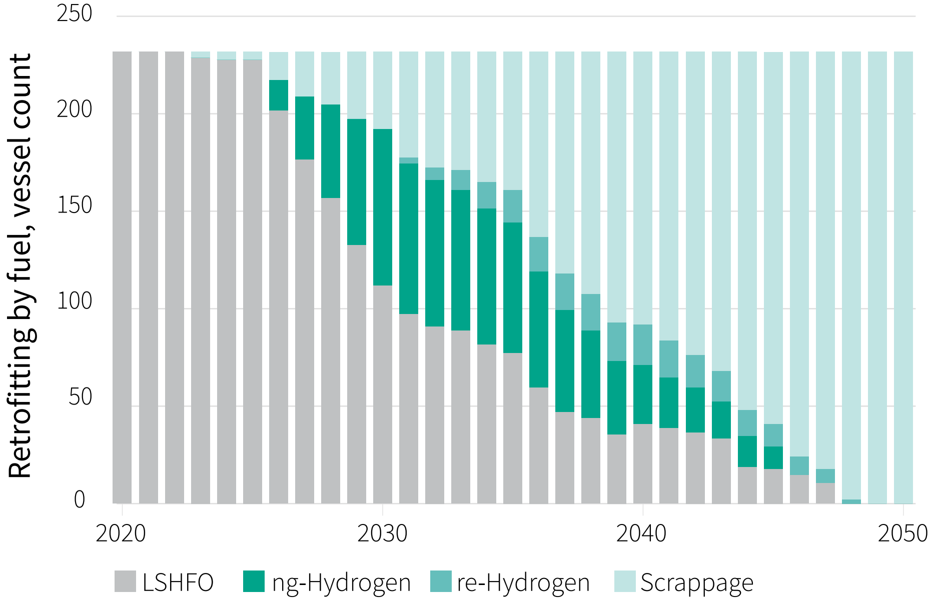
Methanol transition



Ammonia transition



Hydrogen transition



Assumed retrofit cost for a LSHFO-powered ship

Fuel retrofitted	Main engine type	Engine retrofit cost ($/kW)	Storage tank cost ($/kg of fuel stored)
Methanol	Liquid gas/low flash injection	590	Negligible
Ammonia	Gas injection	590	1.3
Hydrogen	Gas injection	590	56

3.4 What is the composition of fleet fuel mix demands?

Methanol Fleet Fuel Transition

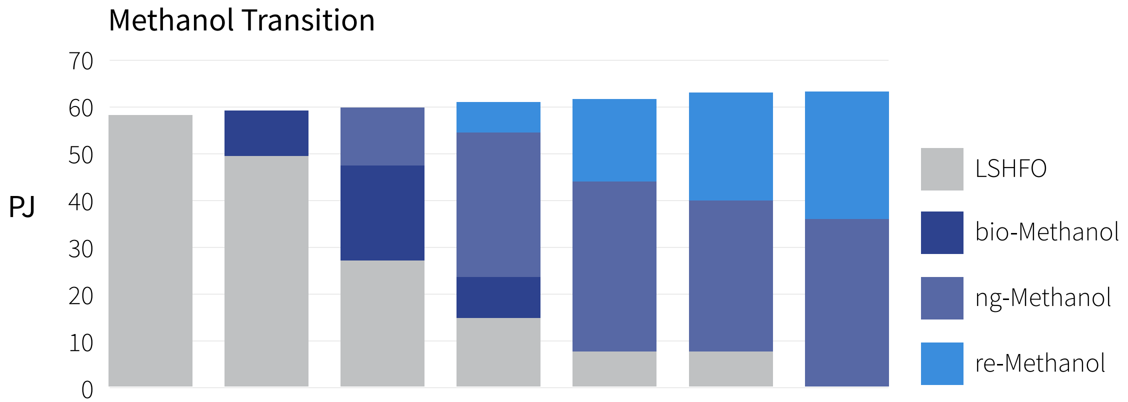
Use of bio-Methanol begins early in the transition, displacing some of the existing LSHFO demand. While bio-Methanol is an option for newbuilds, it is treated as an 'interim fuel' in this analysis as it may suffer from supply constraints and high demand from other sectors, so it is expected to become less economically viable for the shipping sector by 2040, and no longer forms part of the fuel mix from 2040 onwards. Use of ng-Methanol emerges from 2025-2030, and this is followed by re-Methanol growing from 2030-2035. Upon reaching 2050, the majority share (57%) is ng-Methanol, with the remainder (43%) re-Methanol.

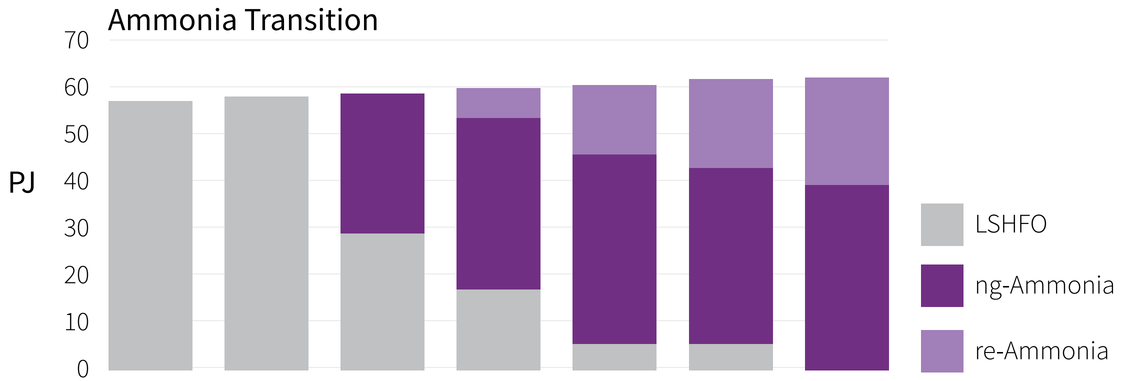
Ammonia Fleet Fuel Transition

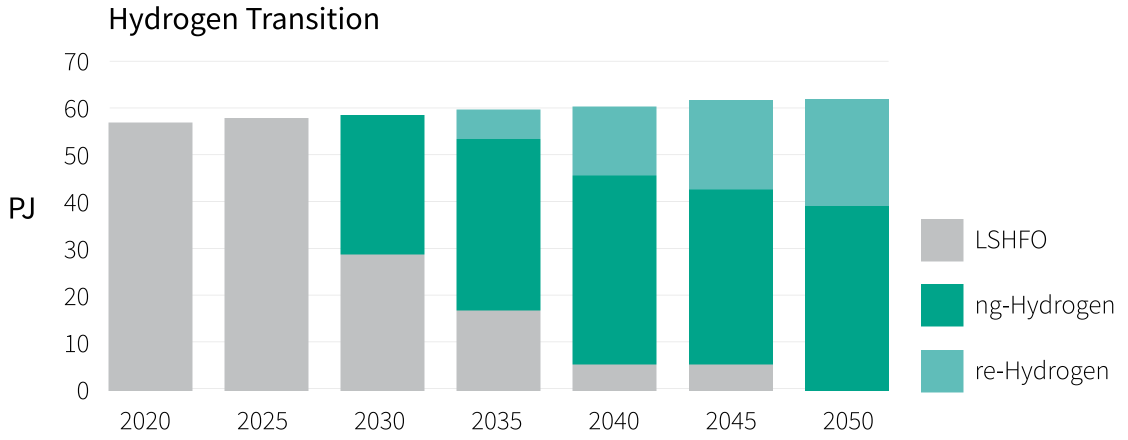
Between 2025-2030, ng-Ammonia starts to form part of the fuel mix and re-Ammonia is introduced over 2030-2035. Prior to 2025, the fuel mix is composed solely of LSHFO, and newbuilds are also LSHFO ships. These newbuilds are then gradually retrofitted for ng-Ammonia when this alternative fuel becomes available. Reaching 2050, ng-Ammonia accounts for the majority of consumption (64%), with the remainder re-Ammonia (36%).

Hydrogen Fleet Fuel Transition

The hydrogen transition follows a similar path to ammonia, with ng-Hydrogen entering during 2025-2030, followed by re-Hydrogen in 2030-2035. Any LSHFO newbuilds are retrofitted for ng-Hydrogen by 2040. By 2050, ng-Hydrogen accounts for the bulk of consumption (64%), with the remainder re-Hydrogen (36%).







Fuel mix demand

Factoring in tonnage demand growth and decarbonisation goals, the fuel mix of the existing and newbuild fleet evolves over time for each fleet fuel transition, which ultimately has different implications for the 2050 fuel mix. Irrespective of fuel mix differences, for all three fuel transitions, energy demand starts at 57 PJ in 2020 (by comparison, this is roughly ~70% of the total energy demand of the UK domestic fleet estimated in Frontier et al 2018 [15]), and reaches 62 PJ by 2050, satisfied by a mix of ng- and re-derived net-zero carbon fuels. By 2050, LSHFO is fully phased out.

3.5 What are the implications in terms of emissions trajectories?

Potential emissions savings

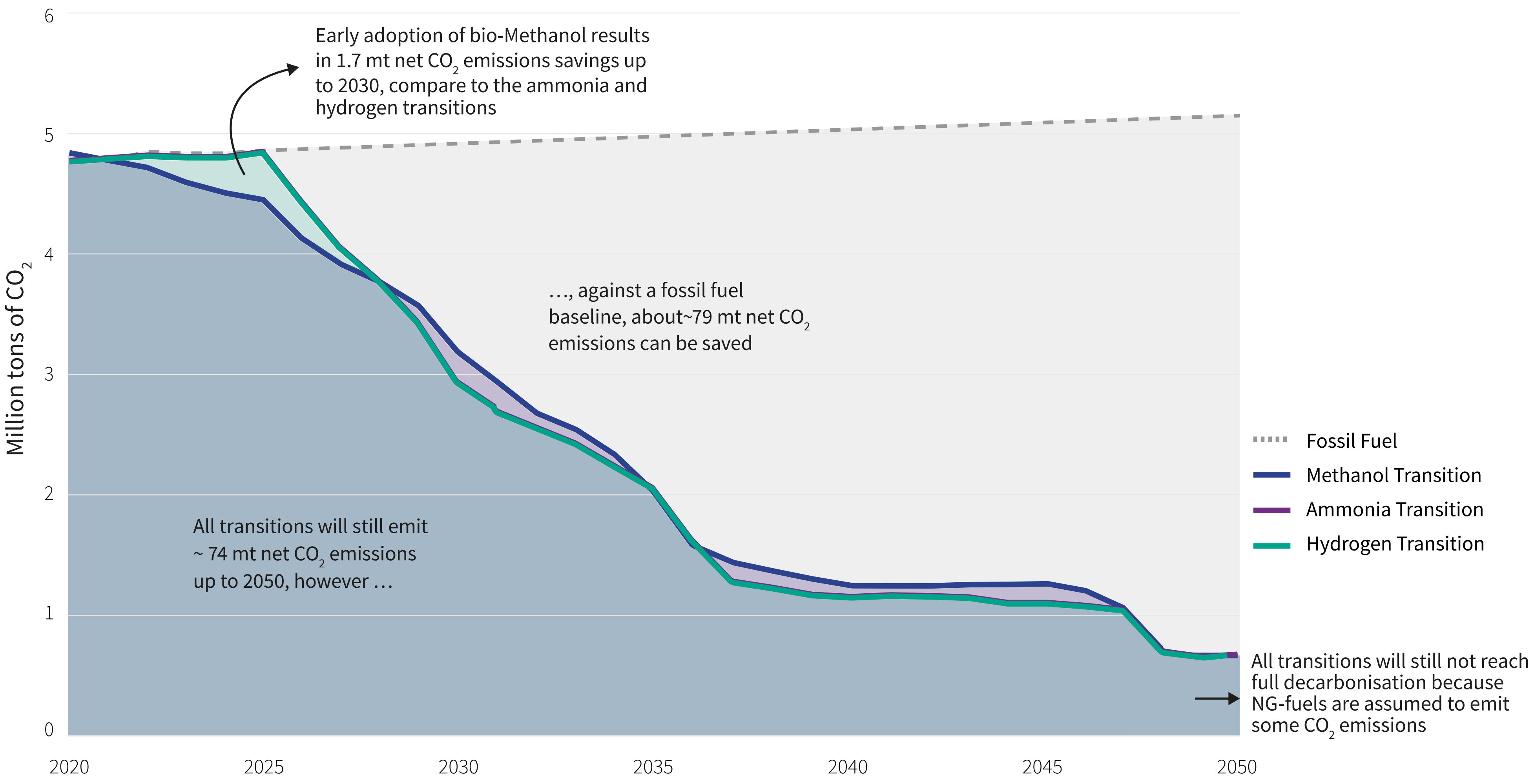
During the transition period, CO_2 emissions will continue, albeit at a decreasing rate, regardLess of the chosen fuel production route. CO_2 emissions are broadly the same for all transitions – about 74 million tons of cumulative net CO_2 emissions given all three are working to the same decarbonisation goals. When compared to a fossil fuel baseline (a scenario where the fleet continues to use LSHFO up to 2050), all three transitions have the potential to save about 79 million tons of net CO_2 emissions. For comparison, this approximates to the combined emissions of Hong Kong and Singapore for one year (80 million tons in 2019).

The impact of early adoption of bio-Methanol

The bio-Methanol transition enables accelerated adoption of alternative fuels relative to the ammonia and hydrogen transitions as bio-Methanol is already available. This would result in about 1.7 million tons of net CO_2 emissions savings up to 2030 compared to the ammonia and hydrogen transitions. For comparison, this is equivalent to saving the emissions of 23 fully-loaded passenger flights between Singapore and Hong Kong every day from today until 2030. However, this early saving is gradually eroded beyond 2030 given that bio-Methanol is assumed to have higher emissions per MJ of energy compared to the ammonia and hydrogen alternatives. It takes 25 years to fully offset the early adoption advantage of bio-Methanol.

Full decarbonisation not achieved

All transitions will still not reach full decarbonisation because ng-fuels are assumed to emit some CO_2 due to the emissions associated with upstream natural gas production and capture rates of carbon capture and storage (CCS). Other GHG emissions are also likely at 2050 as the analysis has not taken into account methane leakage.



(a) Emission factor in net CO_2 ton emissions per ton of fuel: low sulfur heavy fuel oil (LSHFO) = 3.358; bio-Methanol = 0.68; ng-Methanol = 0.34; ng-Ammonia = 0.3; and ng-Hydrogen = 2.
(b) re-Methanol, re-Ammonia and re-Hydrogen have zero carbon emissions.

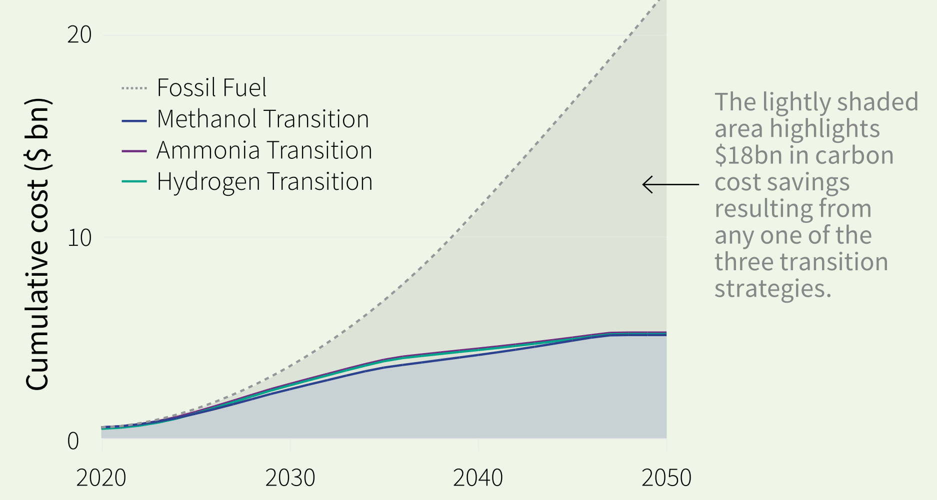
3.6 What are the key cost drivers and how do they differ among transition strategies?

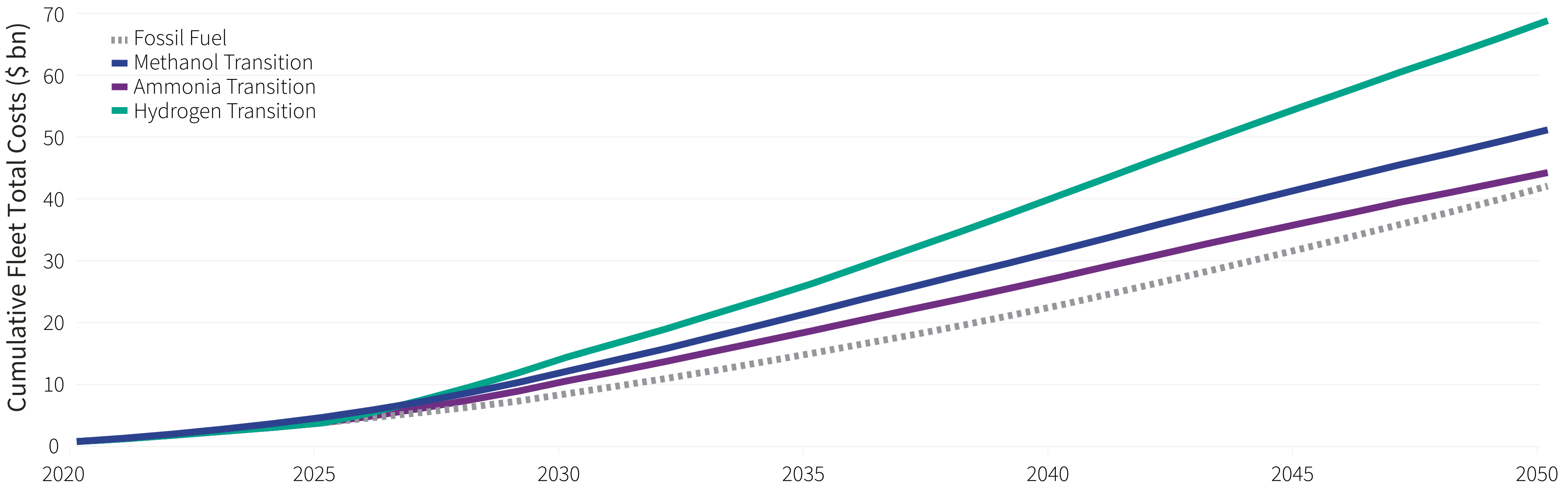
Cumulative fleet total cost

Although the three transitions have the potential to save a similar amount of cumulative net CO_2 emissions up to 2050 (~79 million tons of CO_2), they achieve this at different costs. The ammonia-based transition results in the lowest cumulative fleet total cost (FTC) at $44.5 bn, followed by methanol ($51.5 bn) and then hydrogen ($69.4 bn). *See Appendix A for fleet total cost methodology.*

All three transitions still cost more than the fossil fuel baseline ($42.3 bn) in which all vessels continue to run on LSHFO but pay a carbon price. This means that the assumed carbon price is not sufficient to close the gap with the decarbonisation transitions, but the ammonia transition is the closest, only overshooting the fossil fuel baseline by ~$2bn.

Carbon cost[16]





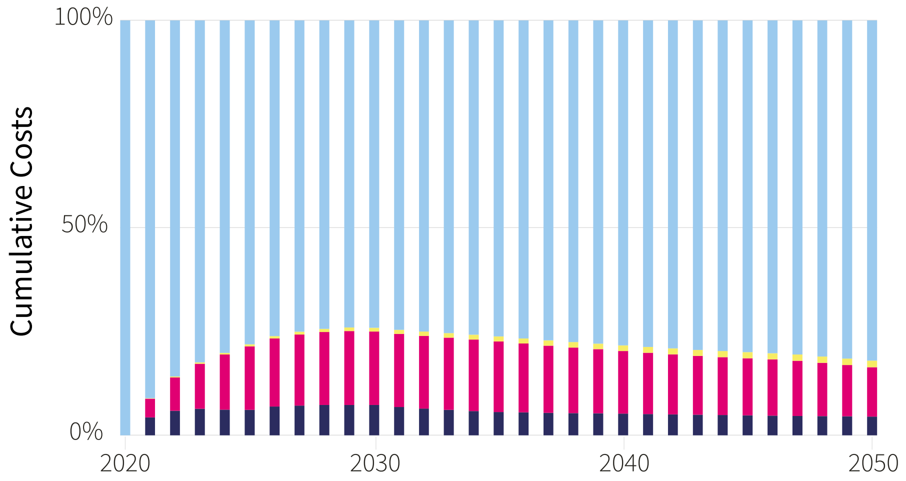
Fleet Total Cost (FTC)

The FTC is the sum of the costs of every vessel in the fleet over a period of one year and is split into several cost categories (voyage costs + CAPEX engine + CAPEX storage + storage impact + carbon costs). It includes the costs of any ships in the fleet that continue to run on LSHFO during the transition.

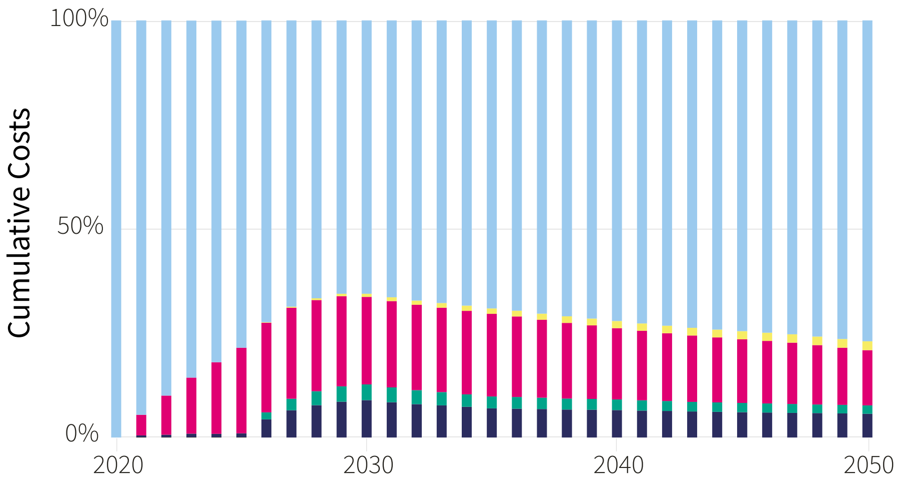
The appetite from end consumers to pay for “green” products should help shipowners pass some of the additional energy transition cost burdens through to the end consumer.

By applying this framework to a fleet-specific case, we can also estimate cargo premiums using the additional fleet costs of each transition relative to a fossil fuel case. These premiums can also change over time as the cost to decarbonise also varies, whereby setting a carbon price that gradually increases also results in cargo premiums declining. In the past, several attempts to quantify these end consumer premiums have been made but this remains an area of uncertainty where further work is required.

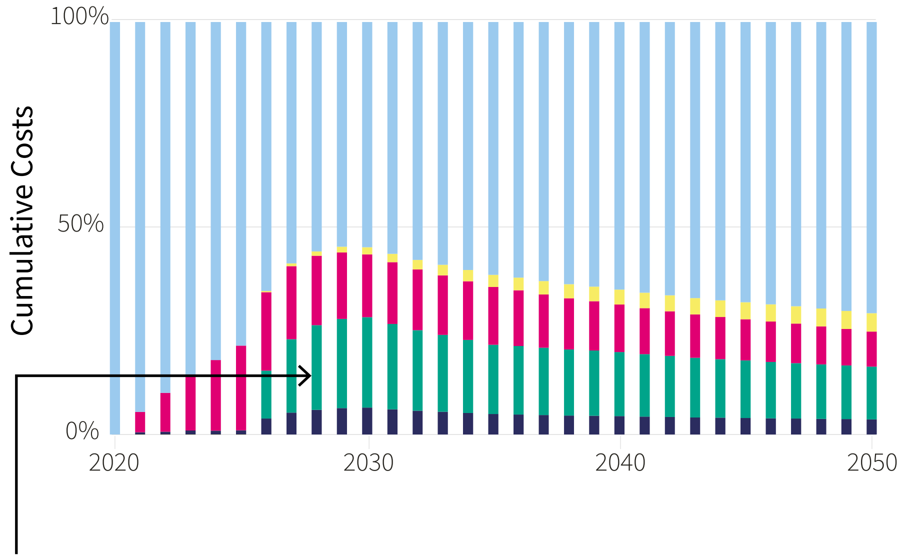
Methanol transition



Ammonia transition



Hydrogen transition

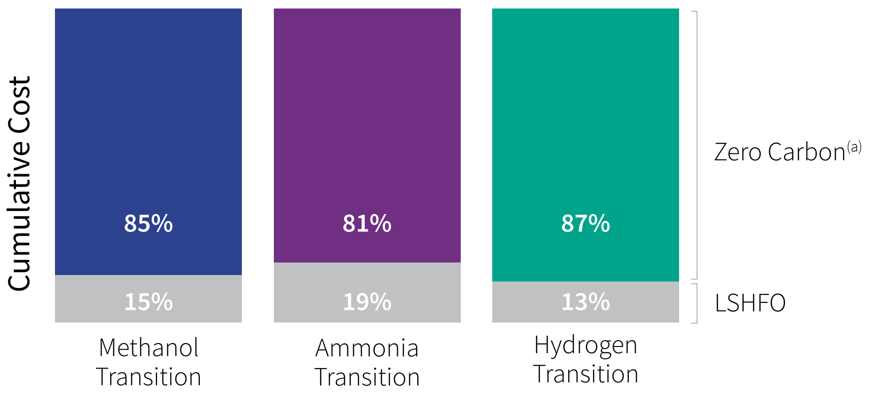


■ CAPEX Engine ■ CAPEX Storage ■ Carbon cost ■ Rev Loss ■ Safety costs ■ Voyage cost

Total voyage cost is the largest cost burden

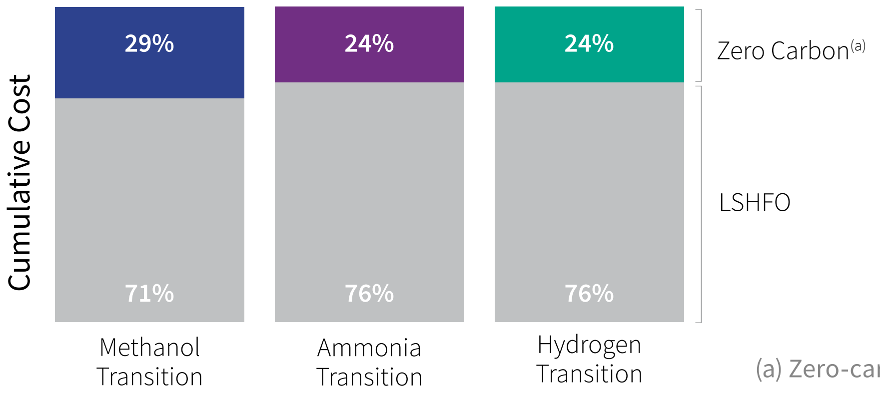
Total voyage cost poses the largest cost burden for all three fuel transitions, representing 82% of methanol fleet transition costs, and 76% and 71% of the ammonia and hydrogen fleet transition costs respectively.

As the zero-carbon fuels are expected to be more expensive, the total voyage costs are predominantly driven by vessels running on zero-carbon fuels, as opposed to LSHFO vessels.



Carbon cost driven by the existing fleet

The carbon cost for each fuel transition is largely driven by the existing fleet that has yet to be retrofitted or scrapped; this accounts for more than 70% of the total carbon cost. The remaining 30% includes other carbon costs associated with the net CO_2 emissions from bio-Methanol and ng-based fuels, subject to 'fugitive' emissions during the CCS process.



(a) Zero-carbon fuels include all transition fuels except LSHFO

The impact of storage costs for hydrogen

The hydrogen transition faces the highest CAPEX costs for storage (e.g. additional insulation and refrigeration costs), reaching $8.9 million over the entire transition period, as well as larger cargo revenue losses (up to $3.1 million) due to the extra storage requirements of liquid hydrogen. These storage-related cost components make up 17% of the cumulative FTC.

Key assumptions: liquid hydrogen storage costs are $56/kg; energy density of hydrogen is 120.97 MJ/kg; and its volumetric density is 60 kg/m^3.

Safety considerations for ammonia- and hydrogen-powered vessels

Several costs fall outside the remit of this study; however, they are considered less material than those included here. One exception could be the potential safety costs – the additional equipment and manpower required to safely operate vessels using more hazardous fuels. Although these have not yet been quantified, they will need to be considered, especially for ammonia- or hydrogen-powered vessels.

Work is currently being undertaken by LR and other partners to guide the use of ammonia as a fuel for shipping. This includes developing a mature and detailed understanding of risk and safety concerns, which will be assessed through a quantitative risk assessment (QRA) methodology. Once a full QRA is concluded, further work should include the acceptability of such risks and the quantification of the associated safety costs. Safety concerns and potential risk mitigation measures identified thus far are summarised below.

Ammonia

In gaseous form, ammonia is a colourless and toxic substance which has a distinct, pungent odour. The release of large quantities of ammonia can lead to the formation of a large ammonia gas cloud that is toxic when inhaled, even at considerable distances from the source of release. Exposure to high concentrations of gaseous ammonia can result in lung damage and death. Adequate safety measures must therefore be implemented to limit the exposure of toxic vapours to those on board an ammonia-powered vessel.

When exposed to liquid ammonia or concentrated vapours, tissue damage can occur rapidly. Suitable protective equipment that covers all exposed skin would be required for crew members in locations with ammonia-containing equipment. In the event of an evacuation, respiratory and eye protection equipment should also be available to everyone on board. A system that can detect leakages of gases and liquid would be necessary to warn crew members against entering contaminated spaces and of discharges from ventilation.

To protect ammonia tanks against overpressure, a pressure safety release system must be installed. This would typically be designed with pressure relief valves (PRV) and a vent mast; however, a traditional vent mast may not provide an adequate level of safety due to the toxicity of ammonia. New solutions such as scrubbers may therefore be necessary to reduce the release to air as much as possible. Ammonia is also very toxic to aquatic life with potential long-lasting effects. Although the release of ammonia to the sea is preferable to keeping the ammonia on board in the event of a leak, a release to water can have catastrophic consequences and should not be underestimated.

Hydrogen

Hydrogen can be stored on a ship cryogenically (-253°C) as a liquified gas or as a compressed gas at very high pressures. Hydrogen has key safety-related properties in its gaseous and liquid form which differ from natural gas and LNG. Hydrogen gas has a low-density, low-ignition energy, wide flammability range and ignites easily. In the selection of materials, it is critical to consider these properties to ensure compatibility with hydrogen and minimise the risk of hydrogen embrittlement and frequency of leaks.

Explosion and fire risks can be reduced through safe layout and process design at an early stage. Storage of high-pressure storage tanks above deck can help to disperse leaks in the open air, reduce cloud size and reduce the severity of explosions. As leaks in contained areas are susceptible to fire hazards, proper ventilation and hydrogen gas detection is required. Selection of suitable hydrogen fire detection technology is also necessary due to low thermal radiation levels from small hydrogen fires and the invisibility of hydrogen flames in daylight.

Hydrogen has an extremely low boiling point, which makes storage in liquid form more challenging and energy-consuming compared to natural gas. Liquid hydrogen stored at cryogenic temperatures is particularly susceptible to pressure build-up from boil-off gas, meaning significantly thicker insulation layers are required for cryogenic tanks. Fast evaporation of liquid hydrogen leaking into a confined space may also lead to a sudden pressure increase if venting is ineffective.

> **Shipping is under pressure to decarbonise this decade, but until now the risk of acting alone to solve a public goods problem is simply too high for any individual company to address. This analysis sheds new light on how collaboration between supplier and consumer can not only lower the risk to an acceptable level, but also open up opportunities for significant commercial reward.**

Shane Balani
Decarbonisation Consultant

Key questions for the fuel supply

4.1
How must fuel production scale to meet demand?

4.2
What are the potential fuel production routes?

4.3
What are the most likely production routes?

4.4
What are the projected fuel costs?

4.5
What are the key cost drivers for each fuel supply transition?

4.1 How must fuel production scale to meet demand?

Two-stage or three-stage transitions

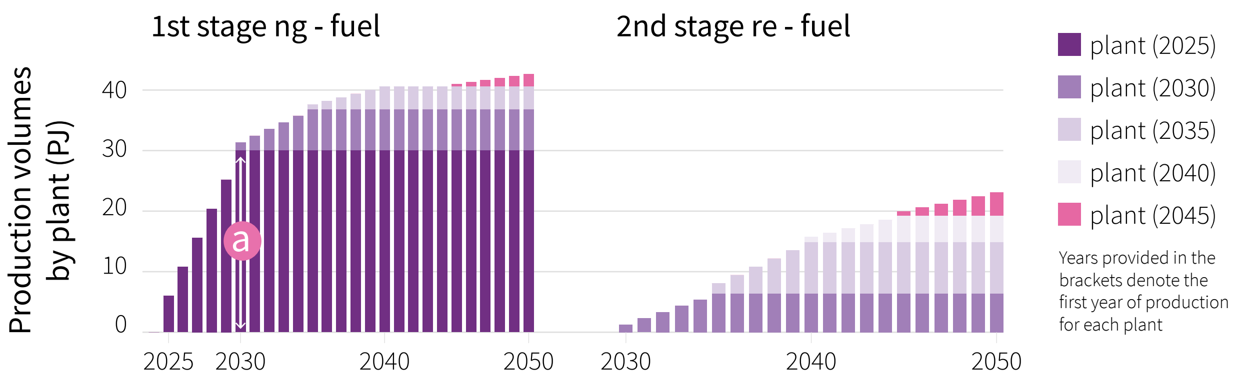
The number of fuels in the fuel mix dictates the type of fuel supply infrastructure development (i.e. two-stage or three-stage transitions). The ammonia transition (a two-stage approach) leads to the construction of ng-Ammonia supply infrastructure first, followed by adding re-Ammonia supply infrastructure at a later stage. The same two-stage approach applies to the hydrogen transition. We assume that every five years, the different fuel type production plants scale up to meet growing demand.

In contrast, the methanol transition has three stages. The transition begins earlier with supply infrastructure necessary to produce the interim fuel bio-Methanol, followed by ng-Methanol and then re-Methanol.

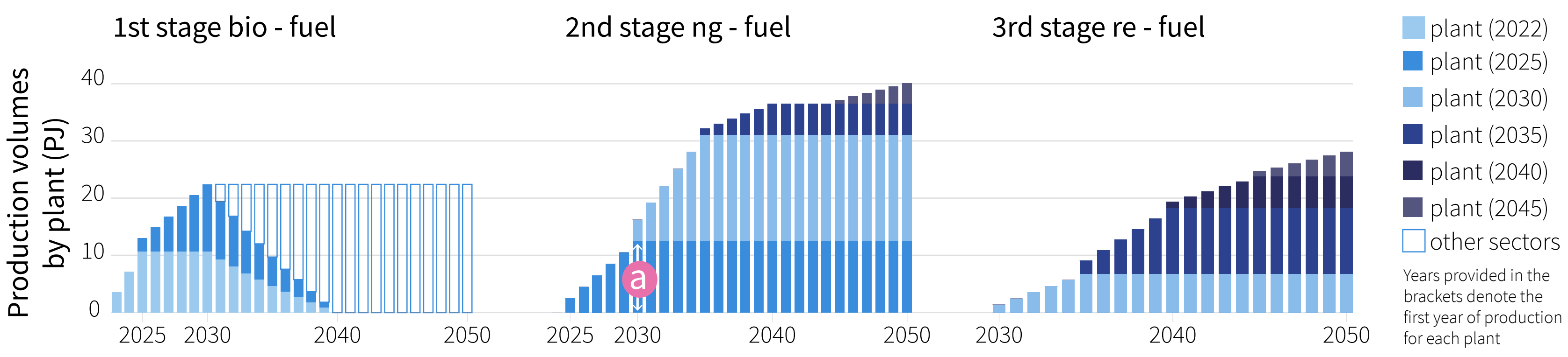
The use of bio-Methanol in this fleet is assumed to decrease from 2025 onwards and so the production plants begin to produce surplus bio-Methanol, beyond the requirements of the fleet, from 2025 onwards. The surplus bio-Methanol is assumed to be diverted to and used in other non-shipping sectors. However, uncertainty around exactly which non-shipping sectors will consume this excess bio-Methanol may impact shipowner confidence when signing offtake agreements with fuel suppliers. This situation is not present in either the ammonia or hydrogen transitions, which are instead more straightforward as demand for each of the zero-carbon fuels in these two transitions only increases over time.

How does the production of the fuel need to scale to meet the required demand?

Two stages –ammonia transition



Three stages –methanol transition



a The first ng-Ammonia plant has a production volume ~2.5 times higher than the first ng-Methanol plant.

Deployment and scaling of the fuel supply infrastructure

The overall fleet fuel transition strategy is closely intertwined with the development of the fuel supply infrastructure. As zero-carbon vessels are built or retrofitted, the fuel demand mix changes. The fuel supply chain responds to this changing demand by building production and distribution infrastructure, beginning in key locations and then scaling that infrastructure as fuel demand grows over time. These charts illustrate the incremental growth in capacity as new plants are introduced and scaled up year by year.

The pace of deployment and pressure to scale

In the three-stage methanol transition, the construction of bio-Methanol supply infrastructure puts less pressure on the development of ng-Methanol infrastructure after 2030. In contrast, the ammonia and hydrogen transitions (two-stage approaches) begin building supply infrastructure five years after the methanol transition in the absence of an 'interim fuel' stage, but to a larger scale. Therefore, the success of the two-stage ammonia and hydrogen approaches depends on the ability to construct a much larger plant at the first attempt in order to keep pace with decarbonisation goals. This adds pressure to scale the infrastructure quickly, and to secure more investment, materials and construction capability in a shorter timeframe.

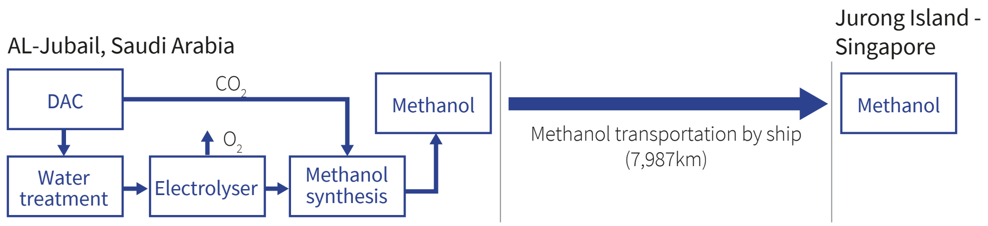
4.2 What are the potential fuel production routes?

Fuel production route and fuel price

This analysis assesses several fuel production routes [17], taking into account the type of fuel supply infrastructure, the sizing of the plants, and the pace of the development required to meet fuel demand. A production route includes the locations for the new plants and where and how feedstock, byproducts and fuels are transported.

The analysis of the fuel production costs is one way to estimate how fuel prices may change in the future. Fuel price is a key factor in driving fleet costs, and therefore also in the selection of the decarbonisation strategy.

Through a literature review of the existing information and data available to LR, this analysis considers 56 plausible fuel production routes for each fuel in each transition.



* see Appendix B for full details

Centralised and decentralised production

Each production route is a fuel production journey. There are multiple production route configurations, varying by both production process and geography. Key factors to consider include where the end product will be produced, the transportation method and route, and whether the feedstock energy source is transported prior to use in production.

For example, one production route may assume that hydrogen is produced and stored in a neighbour country and then transported to and within Singapore; we call this centralised production (C). Another production route may assume that instead of transporting hydrogen, natural gas is transported from a low-cost country before it is stored and transformed into hydrogen in Singapore; we call this decentralised production with import (DI). Finally, another production route may assume that the production is completely decentralised (D), with all production and storage facilities located at the point of use, e.g. re-Hydrogen in Singapore.

To ensure that upstream emissions are kept at a very low level, the use of CCS is assumed in production routes where facilities emit CO_2, e.g. SMR and natural gas liquefaction. The captured carbon is then assumed to be transported and stored permanently in nearby carbon storage basins.

The selected production routes are deemed to be representative examples of those likely to be used in practice, although other possibilities exist.

56 Total production routes

22 Methanol production routes

17 Ammonia production routes

17 Hydrogen production routes

8 Number of countries

19 Supply hubs

8 Carbon storage basins

4.3 What are the most likely production routes?

The levelised cost of marine fuel

We have assumed that the emergence and development of production routes will be driven largely by the anticipated total costs of potential routes, taking into account resources, production, storage transportation and carbon costs. To establish the most likely least cost production route, this analysis uses the levelised cost (LC).

The LC of a marine fuel is the fuel price at which an investor would break even after paying the required rates of return on capital, given the costs incurred over the lifetime of the fuel production route (assumed to be 30 years).

The LC is a straightforward metric for comparison of different production routes, although it does not account for all costs at a system level, e.g. the impact of a plant on the electricity system as a whole.

The LC was estimated for each production route according to the required deployment timing and sizing described previously.

The cost inputs in the LC calculation are broken down by expenditure type, such as costs of direct air capture, renewable electricity costs, transportation, etc. With this breakdown of LCs, we can reveal the key cost drivers for each production route.

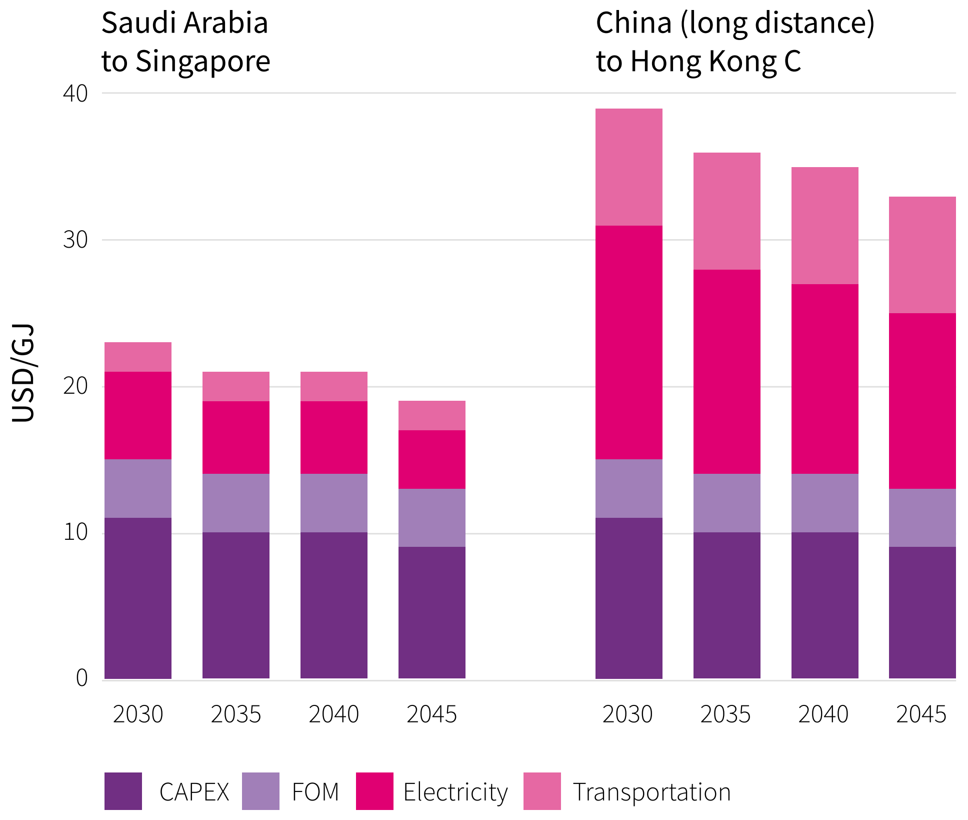
Example of LC breakdown

Facilities built at different times will have different LCs and therefore a different LC value. For example, each fuel production route for re-Ammonia has four different LCs, one for each time the production level scales up.

The breakdown of the LCs by cost category can bring additional insight, such as the potential impact of transportation costs, which depends on the distance travelled and the transportation modes used (ships, trucks, pipelines).

Carbon cost due to CO_2 emissions (such as natural gas) is not accounted for in the fuel supply analysis because a carbon price is applied to the net emissions on the fleet analysis. This avoids the potential double-counting of emissions.

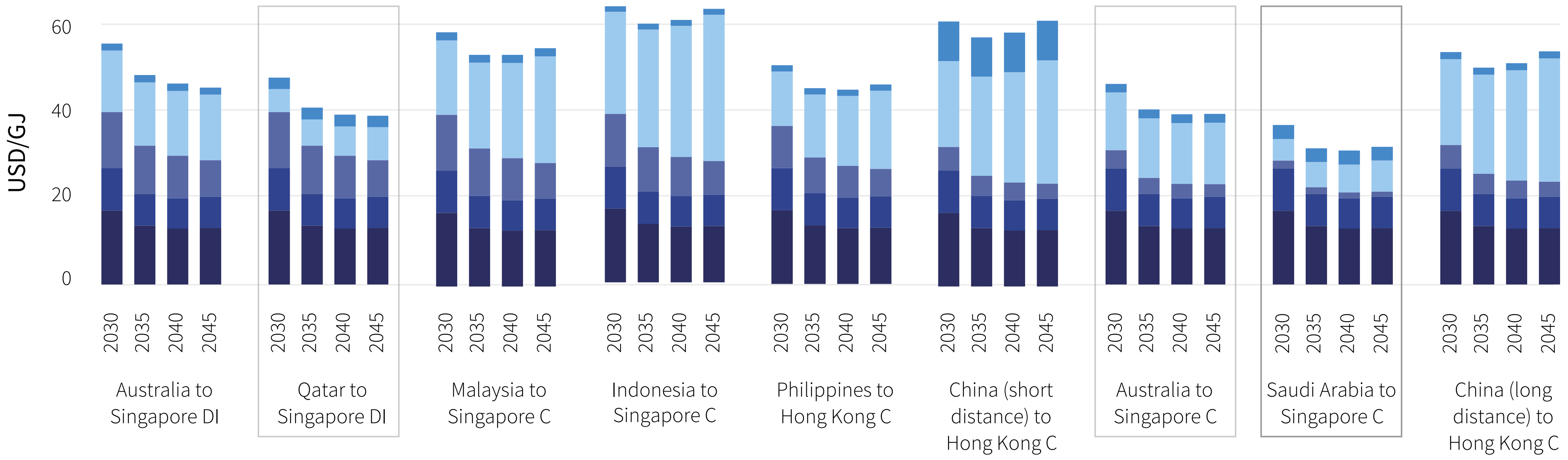
LC of re-Ammonia



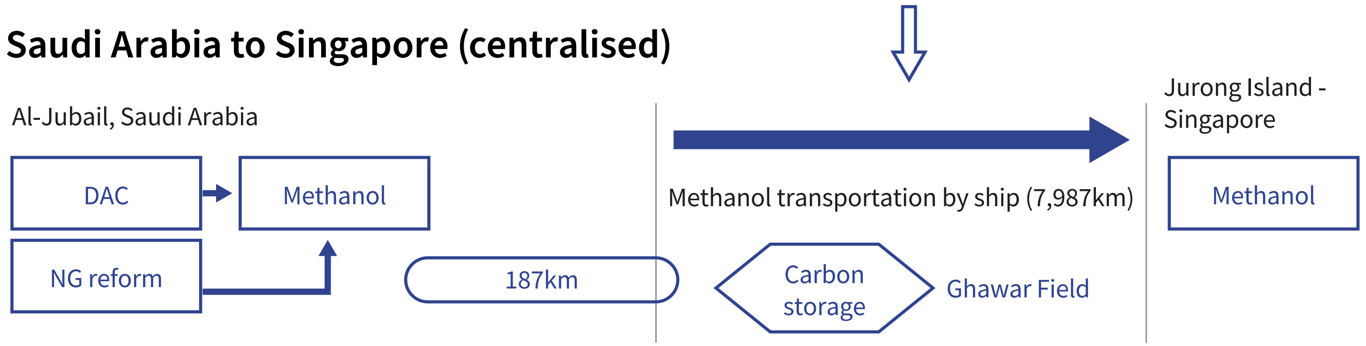
(a) FOM = fixed operating and maintenance costs
(b) See Appendix B for underlying fuel supply cost assumptions

The most likely production routes for ng-Methanol

Levelised cost breakdown for ng-Methanol[18]



Saudi Arabia to Singapore (centralised)



Cost of ng-Methanol production routes

For ng-Methanol, the production route with the lowest LC uses centralised production in Saudi Arabia and methanol transported to Singapore.

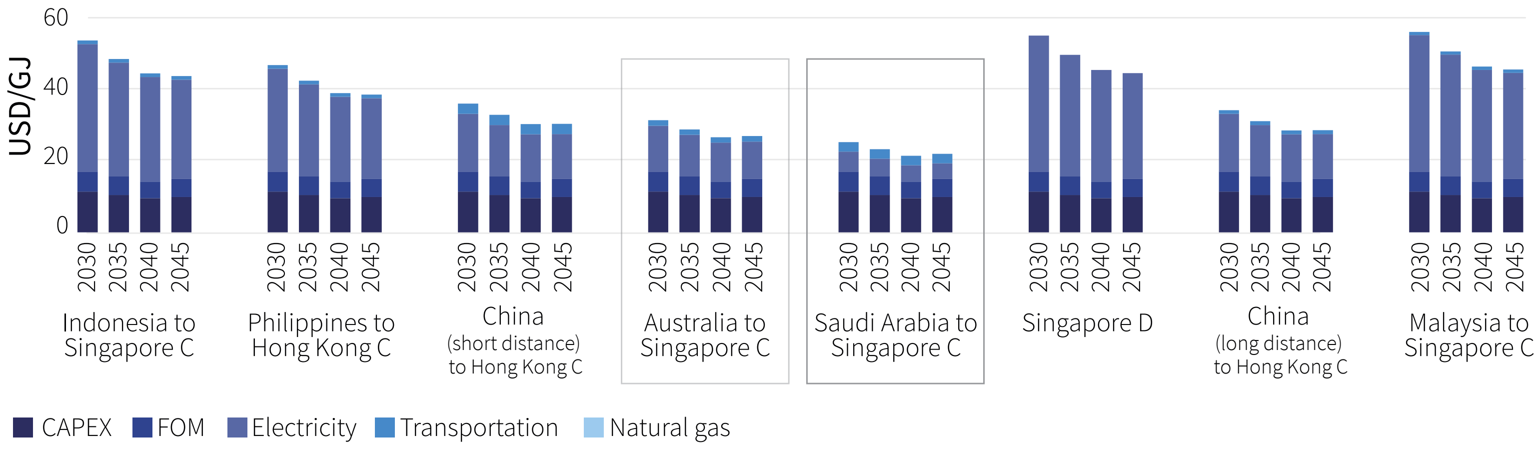
Due to the projected low cost of natural gas in Saudi Arabia, CAPEX on production facilities becomes the major contributor to the LC. The LC of the other production routes is mainly driven by the cost of natural gas.

Other likely competitive production routes include:

- decentralised production in Singapore using natural gas imported from Qatar that is used to make ng-Methanol in Singapore; and
- centralised production in Australia with ng-Methanol transported to Singapore.

The most likely production routes for re-Methanol and bio-Methanol

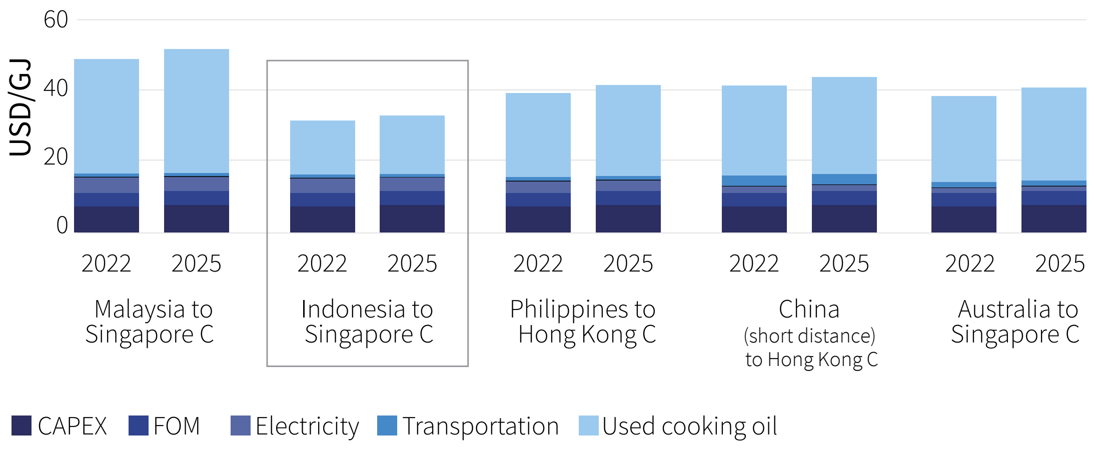
Cost of re-Methanol production routes



The lowest LC for re-Methanol is also the production route using centralised production in Saudi Arabia given the low projected cost of renewable electricity (from 22.8 USD/MWh to 8.5 USD/MWh).

Another likely production route is centralised production in Australia with re-Methanol transported to Singapore.

Cost of bio-Methanol production routes



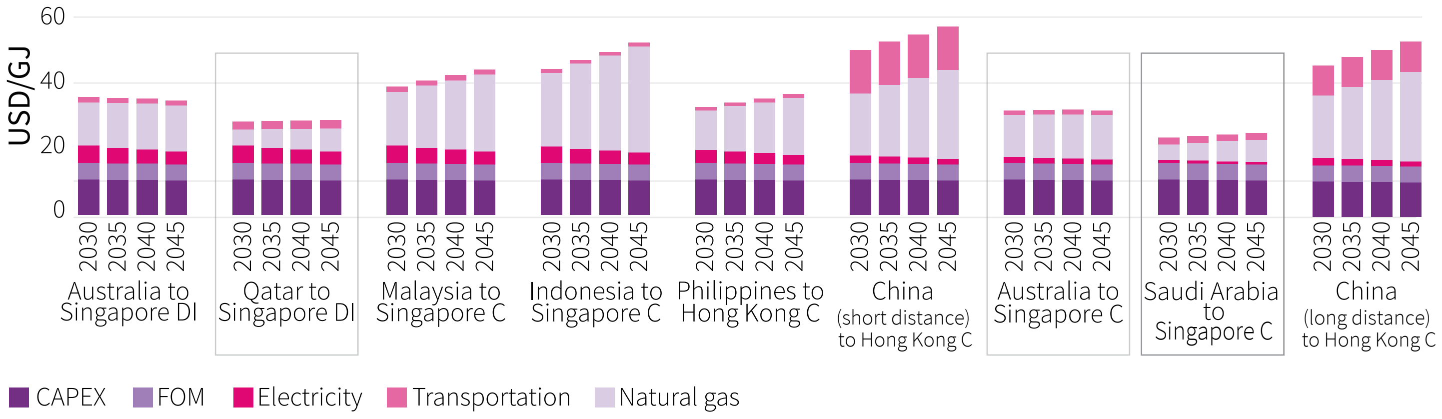
The LC of bio-Methanol production routes is mainly driven by the feedstock cost, in this case used cooking oil (UCO).

The production route from Indonesia to Singapore has the lowest LC, driven by the relatively low feedstock cost of UCO in Indonesia.

Bio waste cost expected to increase from 11.8 USD/GJ to 28.9 USD/GJ in 2050

The most likely production routes for ammonia

Cost of ng-Ammonia production routes



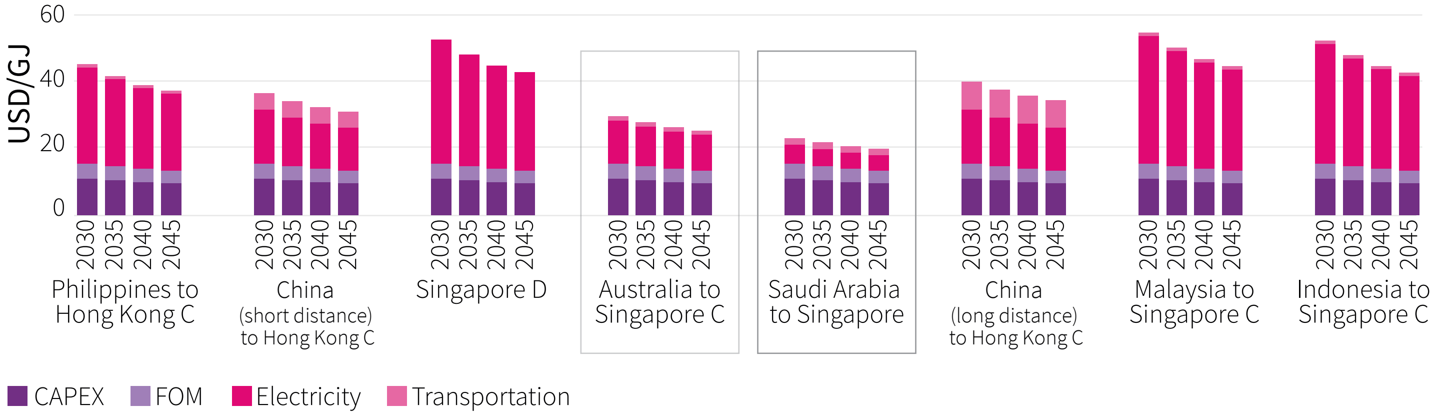
The ng-Ammonia production routes have a similar pattern to those of ng-Methanol.

The lowest LC production route for ng-Ammonia is centralised production in Saudi Arabia with the final fuel transported to Singapore.

Other likely competitive production routes include:

- decentralised production in Singapore using natural gas imported from Qatar; and
- centralised production in Australia with the resulting ng-Ammonia transported to Singapore.

Cost of re-Ammonia production routes



As for re-Methanol, the lowest LC for re-Ammonia is centralised production in Saudi Arabia, given the low projected cost of renewable electricity. Another likely production route is centralised production in Australia with fuel transported to Singapore.

Co-location opportunity for ng-fuels and re-fuels

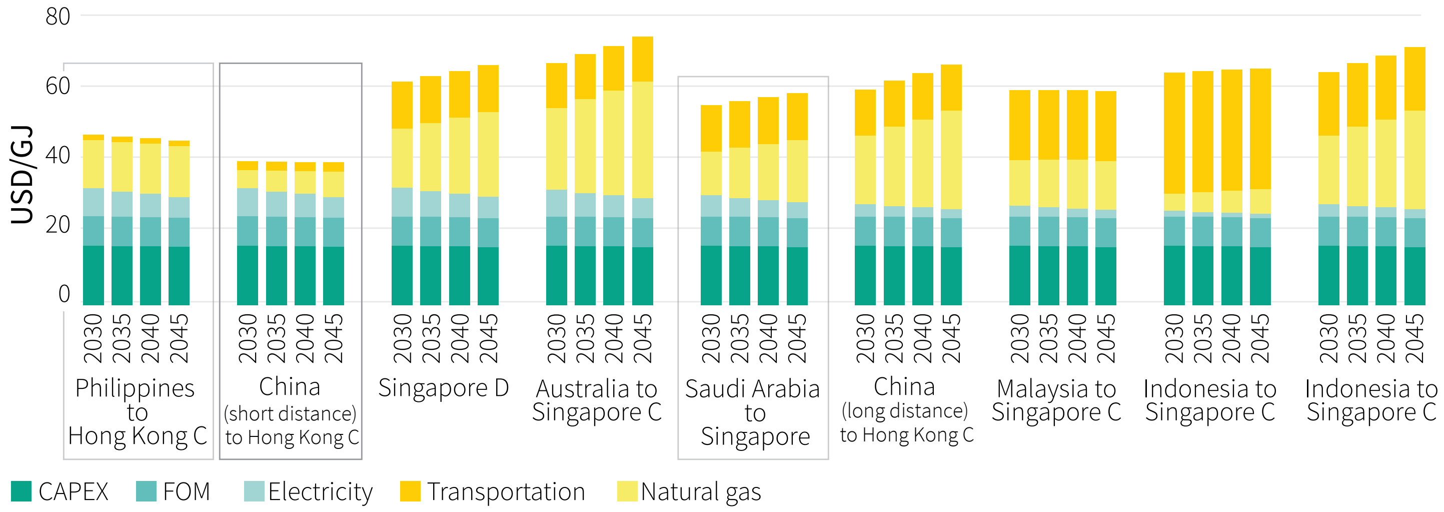
The least cost production routes for ng-Methanol, ng-Ammonia, re-Methanol and re-Ammonia all share the same production location, Saudi Arabia. This could create an opportunity to co-locate production, potentially leading to further synergies and cost reductions.

The most likely production routes for hydrogen

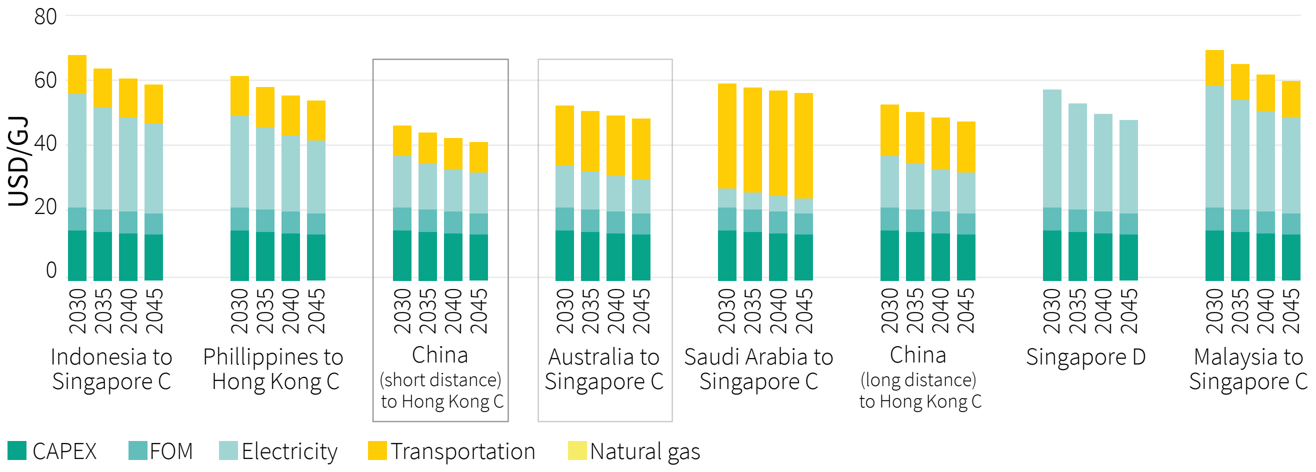
The impact of transportation cost

The ranking of the hydrogen production routes is different to ammonia and methanol due to transportation costs having a higher contribution to the LC.

Cost of ng-Hydrogen production routes



Cost of re-Hydrogen production routes



For ng-Hydrogen, decentralised production in Singapore using imported natural gas from Qatar is the lowest LC option. This implies that the reforming of natural gas to hydrogen (with CCS) would need to be located in Singapore. As a result of potential space limitations in Singapore, this production route may have scalability limits.

The least cost production routes with centralised production are from the Philippines to Hong Kong and Australia to Singapore.

For a low LC of re-Hydrogen, both low electricity costs and low transportation costs are required.

The production route with the lowest LC is centralised production in China with transport to Hong Kong. Although this route does not have the lowest electricity cost, the transportation costs are lower than for other production routes. Another likely production route is centralised production in Australia with fuel transported to Singapore.

4.4 What are the projected fuel costs?

Fuel cost projections

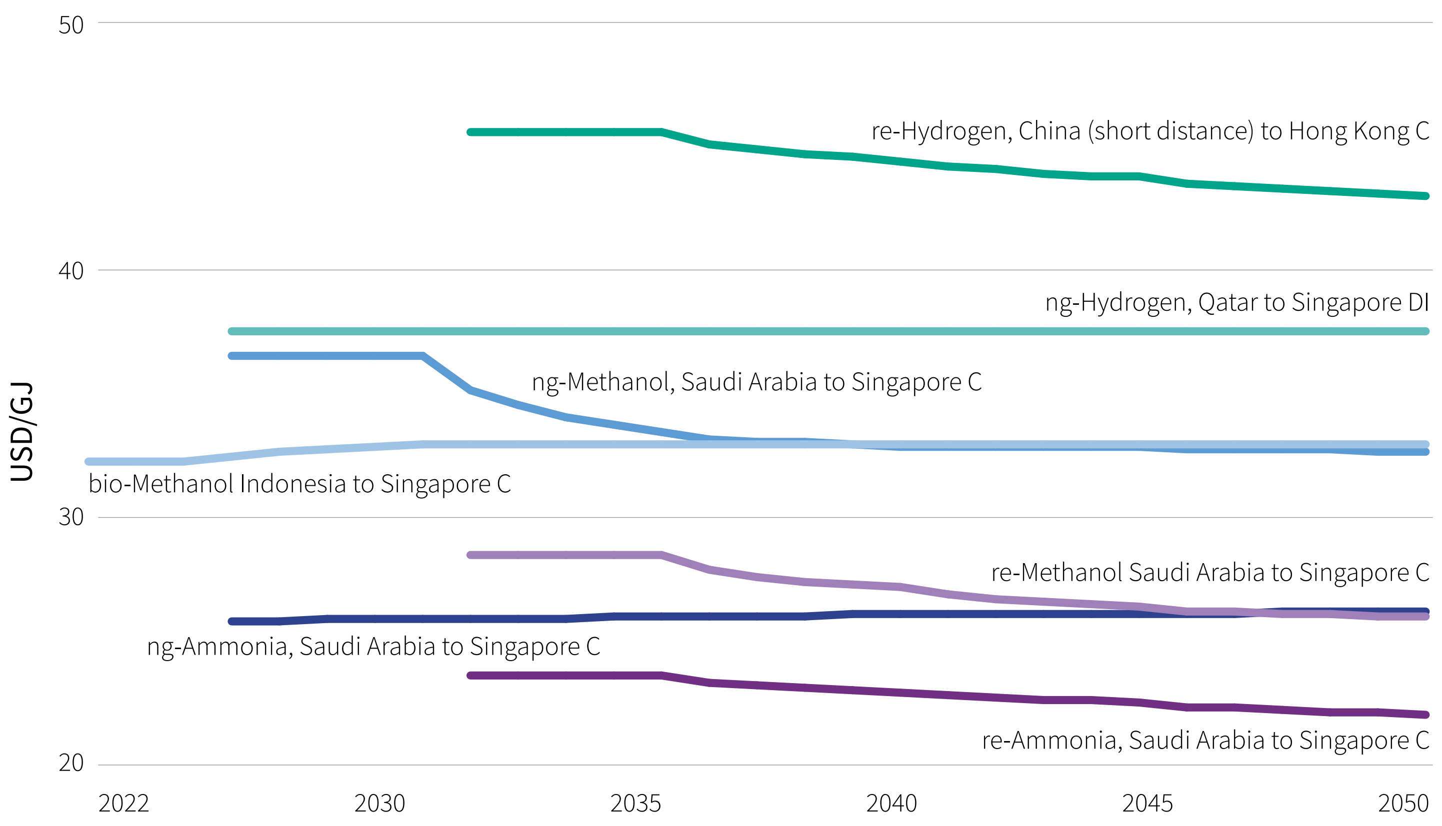
Local energy sources (renewable electricity, natural gas, UCO) are the key cost driver and the source of the main uncertainty. Nevertheless, we observe the following results.

The LC of bio-Methanol is fairly constant from 31 to 32 USD/GJ, as it is derived from production plants going live in 2022 and 2025. These are production costs; therefore, they do not take into account any supply-demand dynamics, and in the case of bio-Methanol, this could include demand-side competition emerging from other sectors that can tighten this market and risk higher prices over time.

The LC of ng-Methanol decreases from 36 to 32 USD/GJ. The LC of ng-Ammonia decreases from 28 to 25.5 USD/GJ, whereas ng-liquid hydrogen remains constant at just below 37 USD/GJ.

Fuels derived from renewable electricity have a lower LC than ng-fuels because the least cost production routes involve locations where the cost of renewable electricity is very low. Re-Methanol varies from 27 to 25 USD/GJ, re-Ammonia from 23 to 21 USD/GJ, and re-liquid hydrogen from 45 to 42 USD/GJ.

The cost effectiveness of re-fuels also depends on the assumption used to deal with the intermittent supply of renewable electricity. In contrast with ng-fuels which would essentially be steady state, re-fuels need to account for additional costs to deal with such intermittent supply. This analysis assumes a hypothetical hydrogen buffer storage for re-fuels, however, this is an area of uncertainty which would require more detailed analysis



Method highlights

The LC is estimated for each production route according to the development of production plants over time. For example, the LC was estimated for the ng-Methanol plant in 2025, and again in 2030 as capacity is increased, and so on.

Fuel cost projections are a function of these LCs. The fuel cost production is a weighted average of the LCs of all plants over time per unit of fuel produced. The fuel cost projection is specific to the selected fuel production routes and their development (i.e. the production routes yielding the lowest LCs). Since this fuel cost is specific to the 'most likely' production routes, they are not meant to represent a global average.

4.5 What are the key cost drivers for each fuel supply transition?

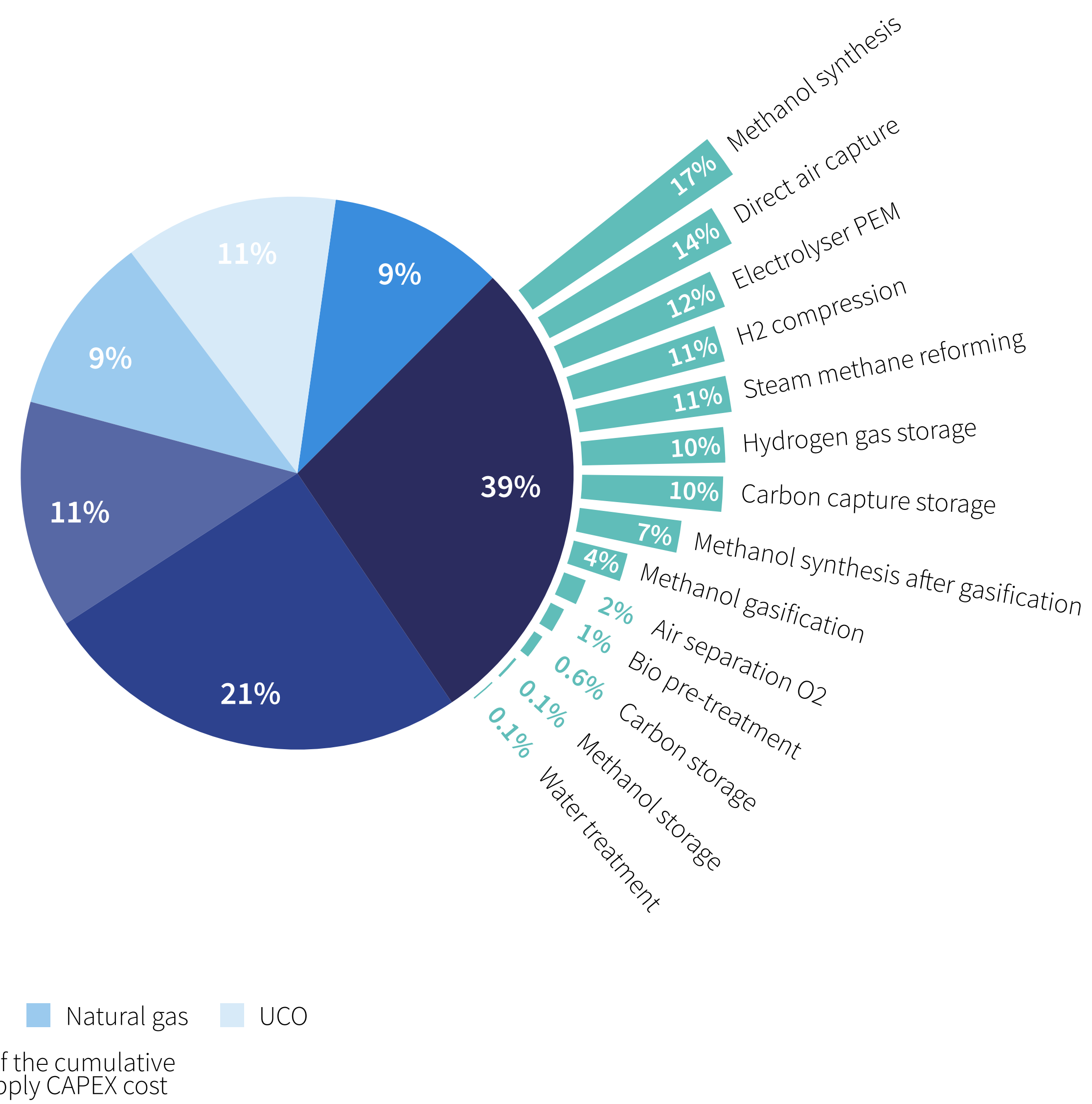
Closing the gap with policy and 'targeted' technological development

The fleet analysis has highlighted that the voyage costs associated with zero-carbon fuels are the major challenge for the economic viability of such fuels. These fuels are likely to be more expensive than the current marine fuels even with strong policy intervention.

The use of energy efficiency technologies on board ships is one way to reduce the voyage costs; however, it is crucial to understand the key cost drivers for the identified least cost fuel production routes to further close the gap with current marine fuels. Several factors can potentially reduce the gap in the short and long term. The analysis of the cost drivers of the identified production routes can highlight where effort should go into technology scale-up and development to reduce the overall fuel production costs. The cost drivers depend on the characteristics of the specific fuel production route.

Fuel supply total cost for the methanol transition

Breakdown of the cumulative methanol supply total cost (up to 2050) based on the identified three least cost production routes



Methanol supply cost

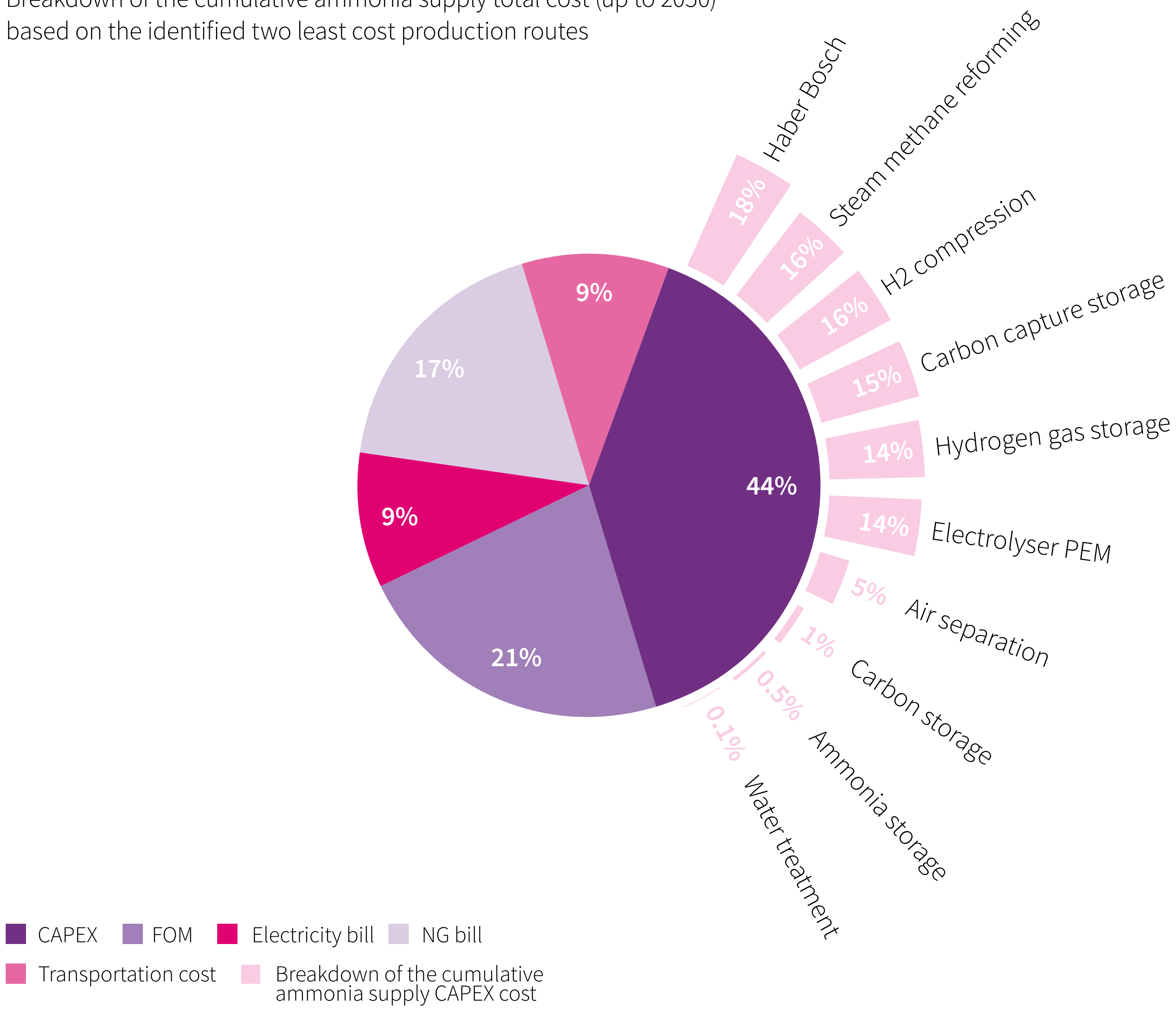
The cumulative fuel supply total transition costs (up to 2050) are estimated to be 41.4 bn USD. The methanol transition relies on ng-Methanol and then on re-Methanol in the medium to long term, and these fuels would be produced in locations where the cost of the energy sources (natural gas and renewable electricity) is expected to be very low (such as Saudi Arabia). In addition to keeping track of the expected costs of the energy sources, further fuel supply cost reduction opportunities could come from focusing on reducing the CAPEX of key technologies and processes.

The cumulative CAPEX represents about 39% of the total cumulative cost. Looking at the breakdown of cumulative CAPEX, we estimate that methanol synthesis, DAC, electrolyser and SMR equipment would represent over 54% of the cumulative fuel supply CAPEX of this transition.

Production process	unit	2020	2030	2040	2050
Electrolyser	USD/GJ/yr	37.48	30.62	25.02	20.67
Methanol synthesis	USD/GJ/yr	24.80	21.31	18.52	15.74
Direct air capture	USD/teCO_2/yr	1273.35	503.11	295.62	186.94
Carbon capture storage	USD/teCO_2/yr	207.81	199.91	192.30	184.99

Fuel supply total cost for the ammonia transition

Breakdown of the cumulative ammonia supply total cost (up to 2050) based on the identified two least cost production routes



Ammonia supply cost

The cumulative fuel supply total transition costs (up to 2050) are estimated to be 26.9 bn USD. The ammonia transition relies on ng-Ammonia and re-Ammonia. As for the methanol transition, ammonia fuels are produced in locations with a very low expected cost of the energy sources (natural gas and renewable electricity). By reducing the CAPEX of key technologies and processes, we could further bring down the ammonia supply cost and therefore its potential future price.

For ammonia, Haber-Bosch and SMR represent about 36% of the cumulative CAPEX, followed by hydrogen compression and storage and CCS.

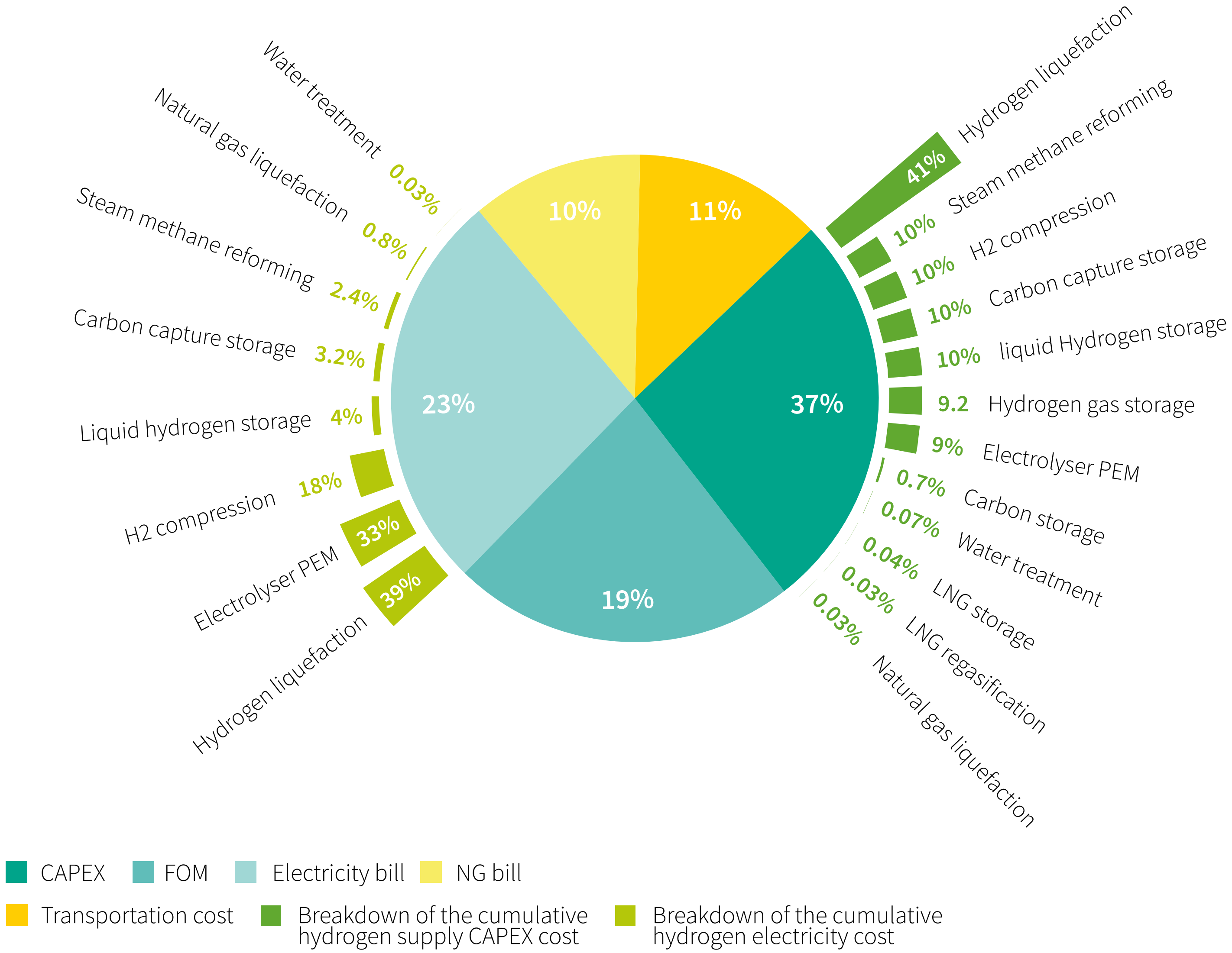
The technologies and processes associated with ng-Ammonia have a major impact because ng-Ammonia represents about 75% of the cumulative overall demand of ammonia.

As per the analysis of the FTC, there are several costs that fall outside the remit of this analysis; however, they are considered less material. One exception could be the potential safety costs for storing and bunkering ammonia and hydrogen at ports.

Production process	unit	2020	2030	2040	2050
Electrolyser	USD/GJ/yr	37.48	30.62	25.02	20.67
Hydrogen gas storage	USD/GJ	3909	3800	3581	3472
Haber Bosch	USD/GJ/yr	14.44	14.44	14.44	14.44
Carbon capture storage	USD/teCO_2/yr	207.81	199.91	192.30	184.99

Fuel supply total cost for the hydrogen transition

Breakdown of the cumulative hydrogen supply total cost (up to 2050) based on the identified two least cost production routes



Hydrogen supply cost

The cumulative fuel supply total transition costs (up to 2050) are estimated to be 43.7 bn USD.

In the hydrogen transition, in addition to CAPEX, the cost of renewable electricity is one of the main drivers, accounting for 23% of the cumulative fuel supply cost.

The least cost production route is based on sourcing both relatively low electricity costs (but not the lowest) and relatively low transportation costs. The breakdown of the electricity costs suggests that hydrogen liquefaction, together with the electrolyser and hydrogen compression and storage, could represent about 94% of the cumulative electricity costs. Improving the efficiency of these processes would bring the hydrogen supply cost down further.

Reducing CAPEX could reduce the future price of hydrogen. Cumulative CAPEX represents about 37% of the total cumulative cost. Breaking down CAPEX, liquefaction of hydrogen is the process that by far contributes the most, namely 41% of cumulative CAPEX.

Production process	unit	2020	2030	2040	2050
Electrolyser	USD/GJ/yr	37.48	30.62	25.02	20.67
Hydrogen gas storage	USD/GJ	3909	3800	3581	3472
Hydrogen liquefaction	USD/GJ/yr	44.87	44.87	44.87	44.87
Carbon capture storage	USD/teCO_2/yr	207.81	199.91	192.30	184.99

"We would like to thank the Lloyd's Register Foundation for making this work possible and the many experts that have reviewed and commented on the work. Your comments and suggestions were of great value, although the conclusions given may not represent every view expressed."

Andrew Keevil
Strategic Propositions Manager

Conclusions

The combined analysis of the evolution of a fleet and the required fuel supply for different plausible transitions allows us to switch the focus away from debating the fuel of choice for the entire shipping industry, and instead delve deeper into understanding the fuel transition of choice for a specific fleet.

Comparing fuel versus fuel limits the debate to the characteristics of individual fuels and by doing so, the industry remains hugely uncertain around which fuel to invest in to achieve decarbonisation. Instead, an analysis focused on transitions for both the fleet and the fuel supply has the potential to highlight the costs involved, but also a series of considerations and steps needed to reach the end decarbonisation goal and to flag any risks and opportunities along the way. Different fuels may also be required at different points along a specific transition, with multiple fuels working in tandem to achieve the end goal of decarbonisation. An understanding across the supply chain of how these transitions could play out will generate the needed confidence for all stakeholders involved to commit to a long-term decarbonisation plan.

Key findings from containership feeders case study

Coordinate efforts between the fleet and the fuel supply side

This analysis has focused on a specific fleet and it has given a concrete example of how the fleet energy transition can take place in conjunction with the development of the required fuel supply. To unlock decarbonisation, it is important to understand what the cost drivers are and how material they are across the entire supply chain so that a system solution that works for the specific ecosystem can be identified.

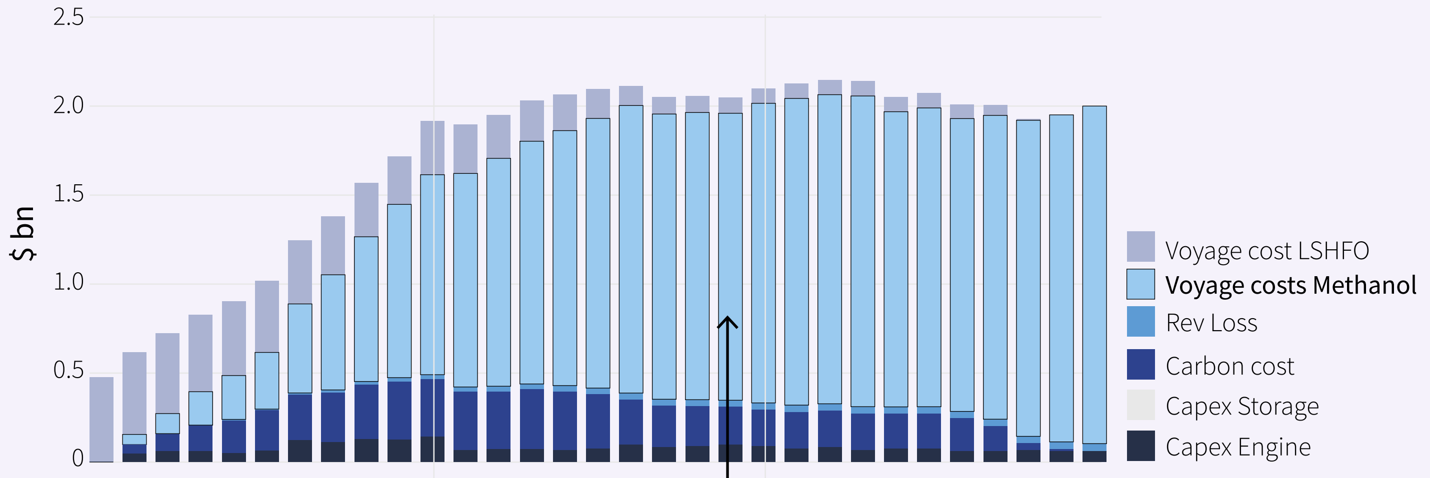
Focusing on a specific fleet allows us to analyse how the Fleet Total Cost (FTC) may evolve. This example (upper chart) for the methanol transition shows how the voyage cost associated with the use of net-zero methanol gradually increases over time. This highlights the importance of improving the technical and operational efficiency of zero-emissions vessels; however, it also highlights the impact of fuel supply cost. As the transitions consider different fuel production routes, this analysis allows us to identify what to focus on in the fuel supply to reduce the overall cost of the transition.

Ensuring that the costs of the chosen energy sources are in line with the forecast (e.g. decreasing trend of renewable electricity costs) is the first step. However, this analysis has identified that where energy sources are relatively low cost, CAPEX becomes one of the major contributors to the total cost of fuel supply (lower chart). Therefore, targeting effort on reducing both CAPEX and OPEX of key technologies and processes can significantly reduce the fuel production costs, fleet voyage costs, and, ultimately, the cost premium for the customers.

The analysis of the costs involved in both the fleet and fuel supply side gives the order of magnitude of the investment required over time. Understanding how these costs may evolve in the long term for all transitions provides further insights to build confidence and therefore reach coordinated commitment across the stakeholders involved. This analysis can form the basis of a more detailed business case where the uncertainty associated with each transition can be further analysed to identify the most resilient energy transition.

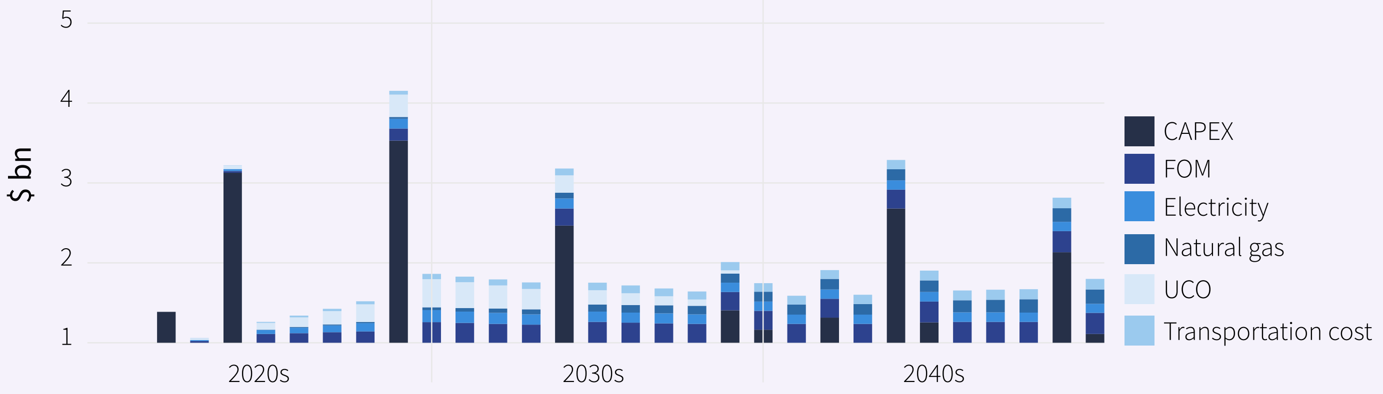
Example for the Methanol transition[19]

Fleet total cost breakdown



Fuel supply total cost breakdown

Fuel supply costs make up methanol voyage cost



Different fuel supply options may yield similar emission reductions

Overall, the three transitions analysed have similar emissions reduction trajectories (approximately 79 million tons of net CO_2 emissions up to 2050). The main difference is that the use of bio-Methanol allows for earlier emissions reduction in the methanol transition (approximately 1.7 million tons of net CO_2 emissions saving up to 2030 compared to the ammonia and hydrogen transitions).

Each transition requires a complete supporting fuel infrastructure to be in place. The types and number of fuels in the fuel mix dictates how the fuel supply will need to scale. Both the ammonia and hydrogen transitions would use a two-stage approach that begins with the development of ng-fuels infrastructure and then moves to the development of re-fuels infrastructure.

In contrast, the methanol transition uses a three-stage approach: bio-Methanol followed by ng-Methanol followed by re-Methanol. The three-stage approach has the benefit of allowing the fleet to begin the transition earlier via a more gradual transition; however, this is more costly and complex. In the three-stage methanol transition, the investment case is less clear, as investors must find a balance between confidence in the longevity of a transition and the need to decarbonise earlier.

Balance the benefits of early results with long-term planning

A trade-off exists between efforts to start to decarbonise the fleet earlier along with a smoother transition versus the long-term planning approach that attempts to find the solution with lowest overall cost. This balance must be found while providing a growing supply of a fuel through different feedstock routes without major price fluctuations.

In the case of the three-stage methanol transition, the prompt availability of sustainable bio-Methanol makes up most of the fuel produced in the first decade. This enables an immediate drop in the fleet's emissions while allowing ng-Methanol and re-Methanol to absorb the entire demand of the fleet more gradually as the transition continues.

Although the first decade of the methanol transition requires a relatively high investment in the bio-Methanol plants, for a much smaller volume of fuel produced compared to later decades, this investment is evenly shared between OPEX and CAPEX. Later decades see similar levels of overall investment, albeit weighted more towards OPEX in order to focus on procuring the feedstock rather than pressure to build the plants to keep up with growing demand.

This limits the investment shock down the line, in both the fuel supply infrastructure and also for the fleet where a sudden drive to build or retrofit vessels and the associated potential overload on shipyards can be avoided.

The benefits of early decarbonisation, however, are balanced by the exposure in the short term to high OPEX costs – specifically through the impact of the expensive and constrained bio-waste feedstock needed to feed the sustainable bio-Methanol production routes.

In contrast, the two-stage ammonia and hydrogen transitions require the construction of a larger plant in the first decade, with more pressure to scale quickly. Delaying investments to later in the transition like this may result in competition for energy sources that may have a stronger market elsewhere, e.g. hydrogen for heating or renewable electricity for the power sector. The benefit, however, for the ammonia transition in particular is that should risks be successfully avoided, this would likely be the lowest cost transition overall.

Different transition strategies unlock specific supply investments

A given fuel transition (e.g. ammonia, methanol or hydrogen), is likely to determine the fuel production routes with the lowest cost. For re-Methanol and re-Ammonia, the least cost production route will originate in locations with very low costs of renewable electricity, whereas the lowest cost production route for re-Hydrogen requires both low electricity costs and low transportation costs.

After analysing several fuel production routes, we have concluded that for each fuel, the likely least cost production route is mainly driven by two factors: 1) the cost of local energy sources, and 2) transportation costs.

Middle East countries and Australia are among the locations with good potential for low cost production of methanol and ammonia, while for nghydrogen, it is important to reduce the cost of hydrogen transportation in one of two ways: either by locating production close to consumption (e.g. producing in China or the Philippines) or by importing the energy feedstock and converting to fuel close to consumption (e.g. producing in Qatar or Australia).

Identify co-location fuel supply synergies to cut costs

The development of a fuel supply infrastructure, including the production plant, pipelines, distribution networks, expertise and workforce, represents a large part of the overall energy transition commitment. This study found that the least cost production routes for ng-methanol, ng-Methanol, ng-Ammonia, re-Methanol share the same location (i.e. Saudi Arabia or Australia). This creates an opportunity to co-locate production, potentially driving further synergies and cost reductions. Therefore, in locations where both natural gas and renewable electricity are forecast to be competitive, there may be significant economic advantages realised in co-location.

Co-location can also contribute to the longevity and resilience of the investment in a particular plant, absorbing a large amount of the risk of potential failure should the feedstock fuel become uncompetitive. This is a known risk, as the fossil fuel industry has experienced cyclic downturns and periods of price volatility. Reducing the reliance on any single feedstock could also lower the investment risk of the fleet transition, where a narrowed range of fuel price projections would increase the confidence level behind fleet investment decisions.

ng-fuels may conceal hidden risks

For the ng-fuels production routes, the natural gas feedstock price drives the overall cost. This may conceal hidden risks because the expected trend is that the price of natural gas may increase over time, making ng-fuels less attractive. In addition, ng-fuels may still produce residual carbon emissions and methane leakage inherent in the production process, risking the achievement of net zero.

On the upside, ng-fuels could alleviate pressure on creating supply infrastructure for zero-carbon fuels produced from renewable electricity as these would otherwise need to develop at scale more quickly. Conversely, this could unduly lock in shipowners to a fuel that still includes more residual carbon emissions and methane leakage and an increasing reliance on a feedstock which is expected to increase in price. This is slightly more relevant for the ammonia and hydrogen transitions rather than the methanol transition because the ammonia and hydrogen transitions use more ng-fuels than the methanol transition.

Additional work to compare transitions without ng-fuels (e.g. leapfrogging directly to re-fuels) could enhance our understanding of these risks in terms of both GHG emissions and costs.

Voyage costs dominate fleet costs

Fuel total costs (FTC) up to 2050 are lowest for the ammonia transition ($44.5 billion), followed by methanol ($51.5 bn) and then hydrogen ($69.4 bn). This is equivalent to 5%-64% more than the fossil fuel baseline ($42.3 bn including carbon cost). Voyage costs dominate the fleet's total cost, representing between 71%-82% of the cumulative FTC depending on transitions – the cost of zero-carbon fuels outweighs all other main cost components.

Among the transitions, the ammonia transition has the lowest total voyage cost driven by its lower estimated fuel price. The dominance of the voyage costs means that improving vessel efficiency and voyage optimisation becomes more and more important to reduce the cost of decarbonisation.

Both retrofits and newbuilds needed to meet 1.5C trajectory

To meet a net-zero target by 2050 and achieve a smooth transition that both fuel supply and shipbuilding capacity can meet, the analysed fleet cannot fully decarbonise through natural scrappage and renewal strategies alone. Even if all age-driven renewals adopt zero-carbon fuels as they become available, considerable fossil fuels-related emissions would remain in 2050.

Retrofitting is therefore necessary to cut emissions in line with the target. Approximately 30% of the transition is achieved through retrofitting. For a methanol transition, this is spread out over a slightly longer period, whereas for ammonia and hydrogen, it must be met over a shorter time frame. This highlights that vessels built in the 2020s based on conventional fuel may need to be designed for early retirement or to be retrofit ready.

The required fleet turnover and the fleet age profile put constraints on the candidate vessels for retrofitting. Examination of the age distribution of candidate vessels for retrofitting reveals that some vessels could be at risk of early scrappage in cases where retrofitting happens late in the vessel's life.

APPENDIX A

Note: Total Cost = Voyage Costs + CAPEX Engine + CAPEX Storage + Revenue Losses + Carbon Costs

For the purposes of this study, the Total Cost (TC) is estimated **over the entire course of the 30-year transition for each fuel transition strategy**, unlike the previous LR studies that analysed the Total Cost of Ownership (TCO) relative to a reference ship.

Total Cost Breakdown	Description	Additional Assumptions
Voyage Cost	Total cost of running existing fleet on a combination of LSHFO and alternative marine fuels, plus the voyage costs of any newbuilds over the entire 30-year transition, factoring in the differing energy densities and fuel prices.	
Capex Engine	One-off costs for each vessel in the fleet to retrofit (or replace) an existing LSHFO engine or the cost of installing a new engine in a newbuild.	LSHFO – 2-stroke diesel engine (ICE) Methanol – liquid gas/low flash injection Ammonia – gas-injection Hydrogen – gas-injection
Capex Storage	One-off cost of installing a fuel tank designed for a specific alternative fuel.	Methanol – low flash point storage Ammonia – Type B & Type C Hydrogen – Liquid Hydrogen Type A
Revenue Loss	Cargo revenue losses caused by bigger storage tanks needed by vessels running on alternative fuels with lower volumetric densities. These bigger tanks displace potential cargo holding space onboard.	Assumes only 80% of today's energy demand is required for storage onboard, which reduces the revenue loss burden.
Carbon Cost	Total carbon cost bill over the entire transition for the existing and newbuild fleet.	Carbon prices start at $0/mt today and linearly increase to $288/mt in 2050 in line with LR/UMAS study assumptions.

APPENDIX B

Table B1: Feedstock prices

	Unit	2020	2030	2040
Renewable Electricity Singapore	$/MWh	155.94	91.73	75.22
Solar Electricity Malaysia	$/MWh	155.94	91.73	75.22
Solar Electricity Indonesia	$/MWh	145.87	85.80	70.36
Solar Electricity Philippines	$/MWh	116.80	68.70	56.68
Solar Electricity China	$/MWh	66.01	38.83	31.84
Solar Electricity Australia	$/MWh	46.49	29.77	24.87
Solar Electricity Saudi Arabia	$/MWh	22.8	13.41	10.99
Natural Gas Australia	$/million BTU	6.72	8.02	9.14
Natural Gas Middle East	$/million BTU	1.2	2.28	3.48
Natural Gas Malaysia	$/million BTU	4.13	7.86	12.02
Natural Gas Indonesia	$/million BTU	5.68	10.79	16.51
Natural Gas Philippines	$/million BTU	3.04	5.78	8.84
Natural Gas China	$/million BTU	4.78	9.1	13.91
Biowaste Malaysia	$/GJ	25.27	33.96	45.64
Biowaste Indonesia	$/GJ	11.86	15.94	21.42
Biowaste Philippines	$/GJ	18.56	24.95	33.53
Biowaste China	$/GJ	19.72	26.51	35.63
Biowaste Australia	$/GJ	18.95	25.47	34.23

Table B2: Fuel supply capex assumptions

Production process/storage	unit	2020	2030	2040	2050
Haber Bosch	USD/GJ/yr	14.44	14.44	14.44	14.44
H2 compression	USD/GJ/yr	10.91	10.91	10.91	10.91
Electrolyser	USD/GJ/yr	37.48	30.62	25.02	20.67
Methanol synthesis	USD/GJ/yr	24.80	21.31	18.52	15.74
Direct air capture	USD/teCO_2/yr	1273.35	503.11	295.62	186.94
Carbon capture storage	USD/teCO_2/yr	207.81	199.91	192.30	184.99
Steam methane reforming	USD/GJ/yr	28.10	28.10	28.10	28.10
Hydrogen liquefaction	USD/GJ/yr	44.87	44.87	44.87	44.87
Ammonia storage	USD/GJ	45.98	45.98	45.98	45.98
Hydrogen storage	USD/GJ	3909.51	3800.13	3581.38	3472.01

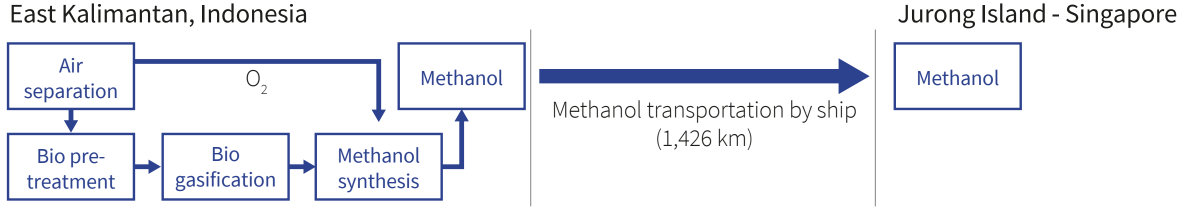
Table B3: Most likely production routes

Transition	Fuel Type	No. production routes analysed	'Most likely' / 'low cost' production routes	Centralised energy source?	CO_2 carbon storage locations	Transportation cost for each production route including the distances USD/ton of fuel transported
Methanol	bio-Methanol	5	Indonesia-Singapore	Yes	-	22
	ng-Methanol	9	Saudi Arabia-Singapore	Yes	Ghawar Field	53
			Singapore	No – import NG from Qatar	Central Sumatra basin	-
			Australia-Singapore	Yes	Northern Carnarvon basin	33
	re-Methanol	8	Saudi-Arabia-Singapore	Yes	-	53
			Australia-Singapore	Yes	-	33
Ammonia	ng-Ammonia	9	Saudi-Arabia-Singapore	Yes	Ghawar Field	35
			Singapore	No – import NG from Qatar	Central Sumatra basin	-
			Australia-Singapore	Yes	Northern Carnarvon basin	24
	re-Ammonia	8	Saudi-Arabia-Singapore	Yes	-	35
		9	Australia-Singapore	Yes	-	24
Hydrogen	ng-Hydrogen	9	Singapore	No – import NG from Qatar	Central Sumatra basin	-
			Philippines-Hong Kong	Yes	NW Palawan basin	1393
			Australia-Singapore	Yes	Northern Carnarvon basin	2091
	re-Hydrogen	8	China-Hong Kong	Yes	-	1070
			Australia-Singapore	Yes	-	2091

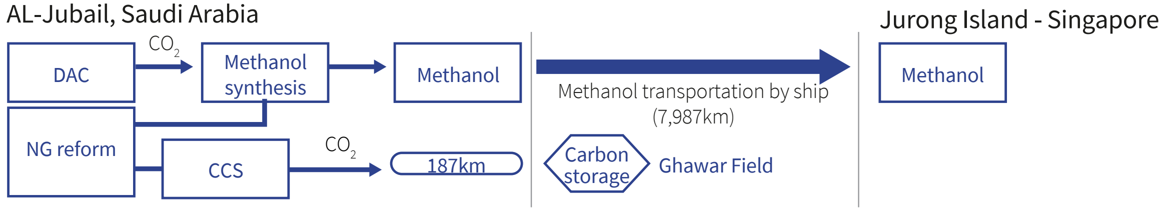
Graphical representations of the most likely/least cost production routes for each fuel transition, capturing 7 production routes out of the 56 routes analysed for this study. Multi-sourced routes can also be considered for more resilient production route options.[20]

Most likely Methanol production routes:

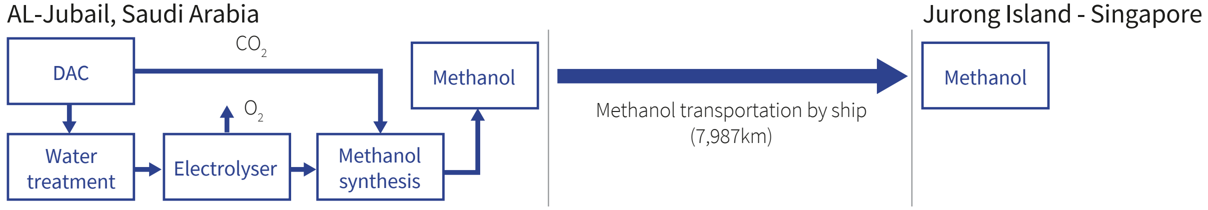
bio-Methanol — Indonesia to Singapore (centralised)



ng-Methanol — Saudi Arabia to Singapore (centralised)

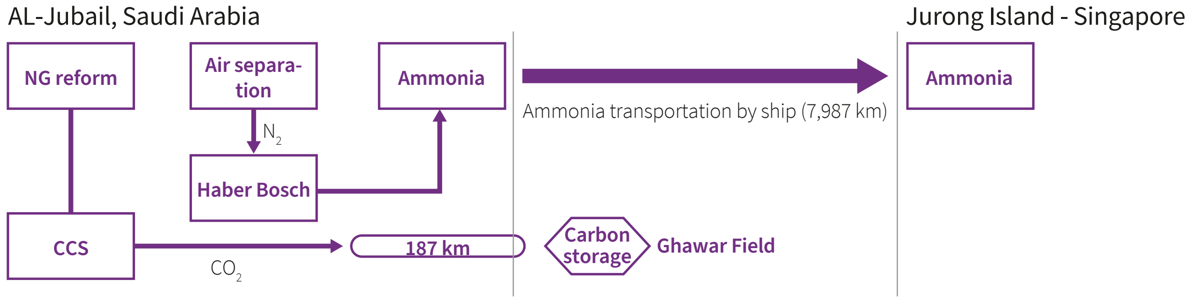


re-Methanol — Saudi Arabia to Singapore (centralised)

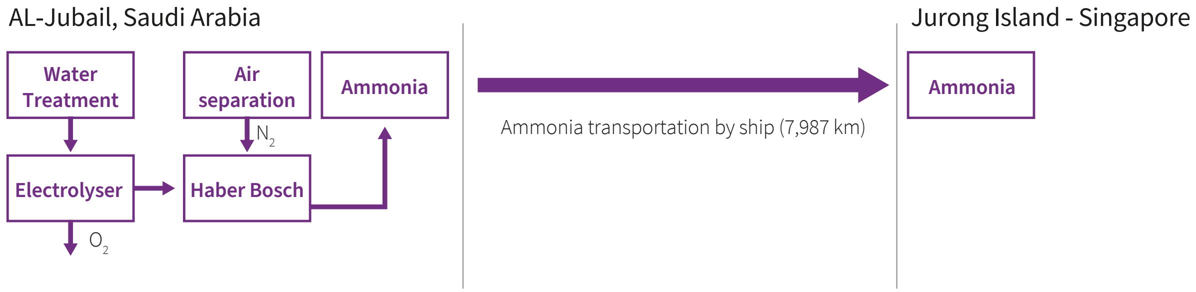


Most likely Ammonia production routes:

ng-Ammonia — Saudi Arabia to Singapore (centralised)



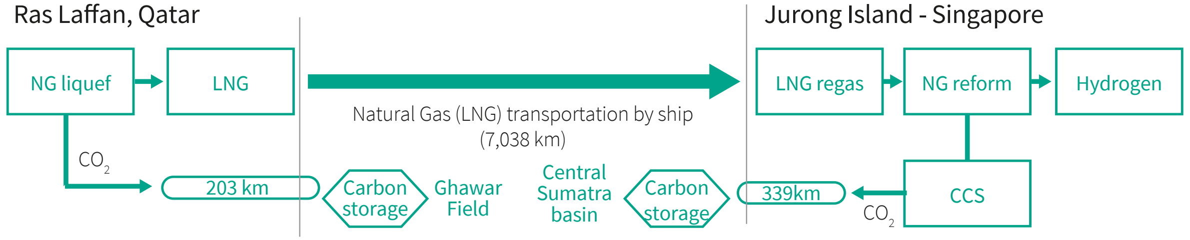
re-Ammonia — Saudi Arabia to Singapore (centralised)



Most likely Hydrogen production routes:

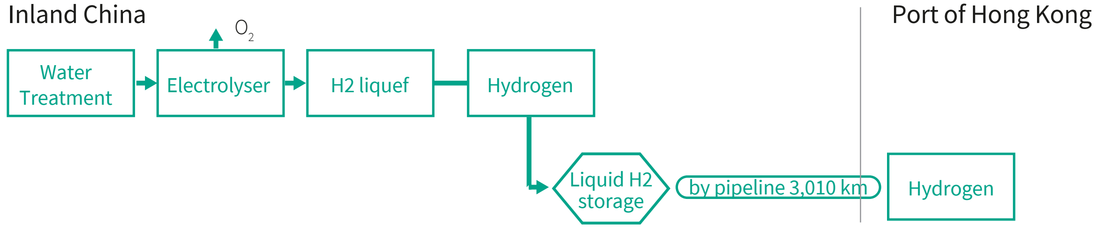
ng-Hydrogen — Qatar to Singapore (decentralised, LNG import)

Qatar to Singapore (decentralised, LNG import)



re-Hydrogen — China to Hong Kong (centralised)

China to Hong Kong (centralised)



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(13) 'Fleet Fuel Transition' definition = the way a fleet executes the energy transition through a series of steps (changing from one fuel to another) that could involve several fuels

(14) https://www.iea.org/reports/carbon-capture-utilisation-and-storage-the-opportunity-in-southeast-asia t

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(16) (a) The cumulative FTC includes a carbon price increasing linearly over the period, starting at $0/mt today, increasing to $101/mt by 2030, $194/mt by 2040 and $288/mt in 2050 (b) "Fossil Fuel" Transition: this is a comparative transition assuming no decarbonisation efforts were made, for use as a cost benchmark against each fleet fuel transition. It assumes there are no retrofits, and all newbuilds are LSHFO ships

(17) Fuel production route = How a fuel is produced, where, and how it is distributed

(18) (a) Natural gas in Saudi Arabia and Qatar is priced at $1.2 per million BTU, and increases to $4.7/million BTU by 2050. Saudi Arabia is seen to have the biggest carbon storage potential in the Middle East, with the CCUS storage assumed to be located in Ghawar Field for these production routes

(b) Natural gas prices in Australia start at $6.72 per million BTU, which increases to $9.14/million BTU by 2050. Northern Carnarvon has been identified as a potential basin for carbon storage, selected due to proximity to existing LNG plants in NW shelf

(19) Voyage costs are a function of fuel production costs. Over 2025-2030, 71% of the total fleet cost is driven by voyage costs, and this share ramps up to 95% of total fleet costs over 2045-2050

(20) Notes: DAC = direct air capture; NG reform = natural gas steam reformer; NG liquef = natural gas liquefaction plant; LNG regas = LNG regasification unit. Hydrogen and nitrogen compression processes included in electrolyser, NG reforming and air separation processes

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Get in touch

Please visit www. lr.org/maritime-decarbonisation-hub
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December 2021

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