Decarbonizing the Global Shipping Industry: Evaluating Pathways for Alternative Fuels

by

Seoyeon Tara Hong

B.S. Electrical Engineering, Rice University, 2011

SUBMITTED TO THE SYSTEM DESIGN AND MANAGEMENT PROGRAM IN PARTIAL FULFILLMENT OF THE REQUIREMENTS OF THE DEGREE OF

MASTER OF SCIENCE IN ENGINEERING AND MANAGEMENT

AT THE

MASSACHUSETTS INSTITUTE OF TECHNOLOGY

September 2022

Signature of Author: ______________________________

Seoyeon Tara Hong
System Design and Management Program
August 5, 2022

Certified By: ______________________________

Sergey Paltsev
Thesis Supervisor
Deputy Director, MIT Joint Program on the Science and Policy of Global Change
Senior Research Scientist, MIT Energy Initiative

Accepted By: ______________________________

Joan Rubin
Executive Director
System Design and Management Program

(This page intentionally left blank)

Decarbonizing the Global Shipping Industry: Evaluating Pathways for Alternative Fuels

by

Seoyeon Tara Hong

Submitted to the System Design and Management Program

On August 5, 2022, in Partial Fulfillment of the Requirement for the Degree

of Master of Science in Engineering and Management

Abstract

Achieving net-zero emissions across all sectors, including the shipping industry, which relies heavily on fossil fuels and traditional internal combustion engines for propulsion, is critical to mitigating climate change and limiting global temperature rise. This thesis evaluates decarbonizing pathways for the global shipping industry through alternative fuels. The decarbonization pathways for shipping are constructed by considering significant system decisions, including powertrains, fuel types, and feedstock. Each pathway is assessed based on cost and multi-attribute utility using system-level metrics relevant to shipping. For alternative fuels, fuel cost models have been developed to estimate the levelized cost of production based on varying electricity prices, natural gas prices, and capital and operating expenditure assumptions. With the fuel cost model results, the total cost of ownership models of bulk carrier vessels has been developed to calculate and compare the lifetime cost for operating vessels for various alternative fuel pathways. The cost models provide insights into the cost markup of alternative fuel pathways relative to the conventional fuels of maritime ships. The MIT's Economic Projection and Policy Analysis (EPPA) model has been enhanced to represent a low-emission shipping option to assess the economic impact and make projections on the market share of the alternative fuel pathway through 2050. Required investment to enable low-emission shipping to enter the market has been estimated using the EPPA model. Combining findings from the multi-attribute utility, including lifecycle emissions of alternative fuels and economic modeling results, near-term, medium-term, and long-term pathways for low-emission shipping have been proposed.

Thesis Supervisor: Sergey Paltsev
Title: Deputy Director, MIT Joint Program on the Science and Policy of Global Change
Senior Research Scientist, MIT Energy Initiative

Keywords —
Energy Transition, Shipping, Low-emission Shipping, Alternative Fuels, Ammonia, Hydrogen, Methanol

Acknowledgments

I am truly grateful for the opportunity to work with Dr. Sergey Paltsev, my thesis supervisor, on my thesis. It has been my sincere pleasure to have this rare opportunity to learn from his expertise and insights on the energy transition, cost modeling, and economic analysis and projections. I cannot thank him enough for his guidance and mentorship throughout my research and for allowing me to be part of the MIT Joint Program on the Science and Policy of Global Change. I would also like to show my deep gratitude to Dr. Henry Chen in the MIT Joint Program on the Science and Policy of Global Change. He spent his precious time training me on how to use, enhance, and run the EPPA model and interpret the results, which is an integral part of my thesis. The analysis and results in this thesis would not have been possible without his knowledge, expertise, and mentorship.

I would like to express sincere gratitude to Chevron for providing me with the opportunity to study at MIT. I would like to thank Justin Lo, Mary Sailors, and Margery Connor from Chevron, who provided continuous support for my time at MIT. I feel grateful to be part of the Digital Scholar Cohort at Chevron, as I learned so much from them. This special journey has been eye-opening and rewarding and inspired me to learn from the best on energy transition, sustainability, and climate change mitigations.

My journey at MIT has been a family effort, and it would not have been possible without my incredibly supportive husband, Grant Lee. He has become as knowledgeable as I am on my thesis topic by always lending me a listening ear and now shares the same passion for sustainability and energy transition. My 4-year-old daughter, Gia Lee, has continued to inspire me to become a better version of myself, and together we thoroughly enjoyed our time in Boston. I especially thank my mom, Jungsuk Min, who always provides endless support. I give special thanks to Dad, Junbae Hong, my sister, Jooyeon, and brother Yoonseok, who always root for me. I dedicate my thesis to my family.

Table of Contents

Contents

List of Figures

List of Tables

List of Acronyms

CO_2	Carbon Dioxide
DWT	Deadweight Tonnes
EPPA	Economic Projection and Policy Analysis model
FC	Fuel Cell
GHG	Greenhouse Gas
HFO	Heavy Fuel Oil
ICE	Internal Combustion Engine
IEA	The International Energy Agency
IMO	The International Maritime Organization
LH_2	Liquid Hydrogen
LNG	Liquefied Natural Gas
MeOH	Methanol
MMBtu	Million Metric British Thermal Unit
NG	Natural Gas
NH_3	Ammonia
NZE	Net Zero Emission
TCO	Total Cost of Ownership

Chapter 1 – Introduction

Climate change is one of the most urgent and complex problems that the world is facing. Anthropogenic carbon emissions have been accelerated, and so has the global mean surface temperature rise. Figure 1 shows the global mean surface temperature anomaly, which indicates a departure from a reference value relative to the pre-industrial level from 1850 to 1900. At the bottom of Figure 1, atmospheric CO_2 concentrations are illustrated on the same time scale.

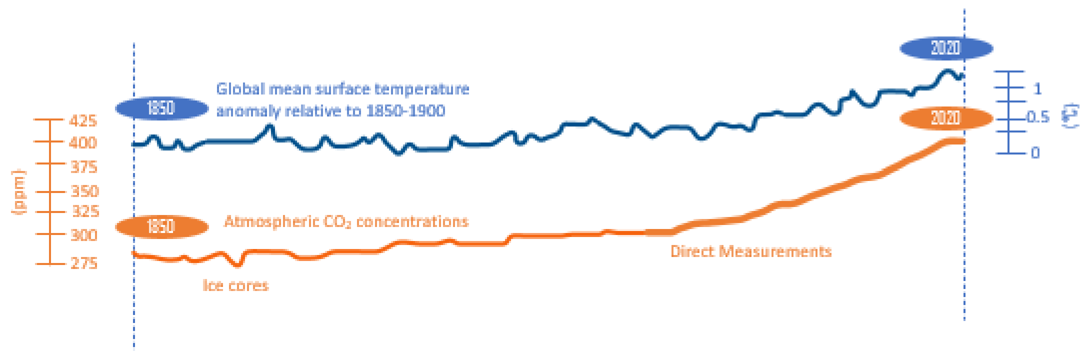


Figure 1 Curves of global surface air temperature anomaly and atmospheric carbon dioxide concentrations, reproduced from (IPCC, 2022a)

The 2015 Paris Agreement set a climate target to limit global temperature rise well below 2°C and preferably to 1.5°C above pre-industrial levels to avoid dangerous climate change (UN, 2015). The global mean surface temperature anomaly indicates that we are already above 1°C from the pre-industrial reference level. All sectors should develop specific plans to limit carbon emissions and create necessary strategies to achieve the Paris Agreement target. The shipping industry, which is indispensable to the global economy by handling more than 80% of global trade volume (Shell, 2020), is also one of the sectors that need the low-carbon energy transition.

Global greenhouse gas (GHG) emissions are presented in Figure 2 to illustrate the scale of the problem. The transportation sector accounted for around 17% of the total global greenhouse gas emissions in 2019. The shipping industry contributed 2-3% of global greenhouse gas emissions (Climate Watch, 2021) (IEA, 2021b). The challenge of decarbonizing the shipping industry stems from a few common characteristics shared by hard-to-abate sectors, such as a long lifetime of vessels, heavy dependency on fossil fuels, high cost of capital, multiple international stakeholders, and the lack of widely available alternative technologies.

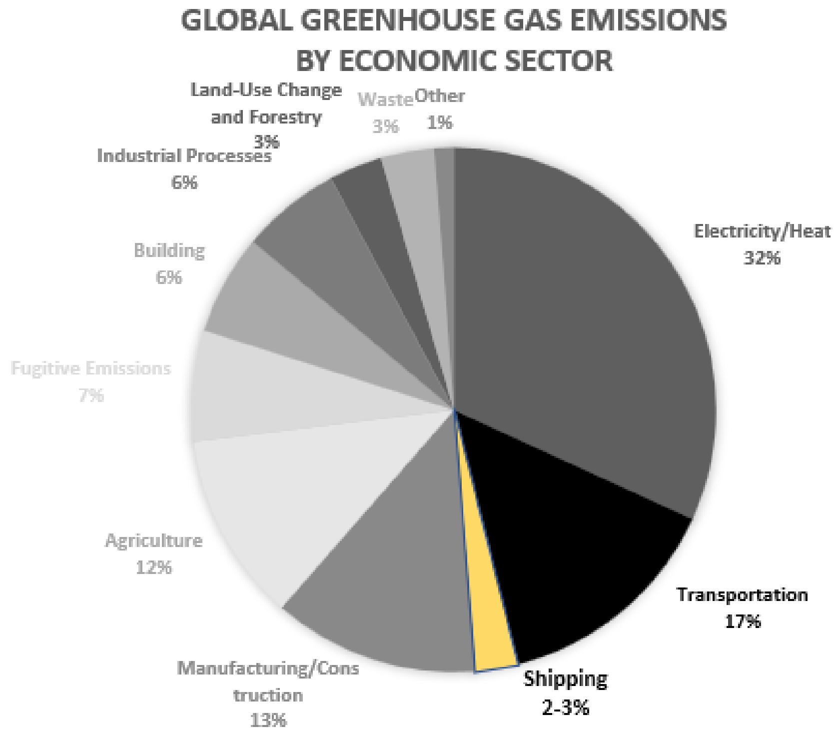


Figure 2 Global greenhouse gas emissions by economic sector in 2019, adapted from (Climate Watch, 2021)

This thesis aims to evaluate alternative pathways and assess economic impacts for the shipping industry to transition toward low-emission shipping to achieve decarbonization. The thesis will start by providing the context of the shipping industry by analyzing stakeholders in the industry, evaluating global greenhouse gas emissions from shipping, and reviewing the current and projected carbon intensity. Then the thesis will survey recent literature to assess characteristics and track progress on alternative fuel pathways. Next, the thesis aims to develop cost models to estimate the cost of alternative fuel production, which will be used in the total cost of ownership model. The cost models will calculate the green premium of low-emission alternative fuel pathways relative to the conventional option. Finally, the results from the cost models will be used in the economic projections and policy analysis (EPPA) tool developed by the MIT Joint Program on the Science and Policy of Global Change, enhanced for this thesis to represent the low-emission shipping pathway. The EPPA tool is used to assess the economic impact of decarbonizing the shipping industry and understand the magnitude of the problem under different scenarios to provide insights to decision makers to plan for the transition toward a low-emission shipping future.

1.1 Motivation and Background

Maritime shipping accounts for more than three-quarters of total freight transport activity, making it a key enabler of international trade. International shipping accounted for ~2% of global energy-related CO_2 emissions in 2020, resulting in 646 Mt CO_2 emissions (IEA, 2021b). The shipping industry is considered one of the hard-to-abate sectors due to its heavy dependence on fossil fuels to traditionally power energy-intensive ship engines and long lifetimes of ships. With increasing global trade demand, maritime trade volume based on the current demand pathway is projected to grow at a compound annual growth rate of 3.6% through 2050 from the 2015 level (International Transport Forum, 2019) (OECD, 2019). Since the early 2000s, CO_2 emissions from international shipping have risen steadily, as shown in Figure 3. The steady rise in CO_2 emissions presents urgent challenges to the shipping industry to reduce greenhouse gas (GHG) emissions to achieve the goal of the Paris Agreement to limit global warming to well below 2°C and preferably to 1.5°C above pre-industrial levels to avoid dangerous climate change (UN, 2015).

The International Maritime Organization (IMO) is the United Nations (UN) specialized agency governing international shipping. The IMO is the regulatory body of the shipping industry with responsibility for the safety and security of shipping and the prevention of marine and atmospheric pollution by ships, also in support of the UN Sustainable Development Goal 13 – to take urgent action to combat climate change and its impacts (Martin, 2019). IMO has committed to reducing GHG emissions from international shipping by setting out visions and ambitions. IMO announced its Initial Greenhouse Gas Strategy in 2018 to reduce emissions from international shipping and phase them out as soon as possible (IMO, 2018). The target is a 50% reduction in GHG emissions by 2050 compared to 2008 levels, then eliminating GHG emissions entirely after 2050. The strategy also aims to reduce the carbon intensity of international shipping (CO_2 emissions per transport work – measured in tonne-miles) by at least 40% by 2030, pursuing efforts towards 70% by 2050 compared to 2008.

The IMO included several short-term (between 2018-2023) measures that can direct its Initial Strategy. The first measure is to implement the energy efficiency design index (EEDI) for new ships to reduce the carbon intensity of the vessels. The second one is to implement operational requirements based on a Carbon Intensity Indicator (CII) that measures grams of CO_2 emitted per cargo-carrying capacity and nautical mile (nm) to reduce the carbon intensity of international shipping (IEA, 2021b). Another measure that aligns well with the goal of this thesis is to initiate research and development activities addressing marine propulsion, alternative low-carbon, and zero-carbon fuels, and innovative technologies to further enhance the energy efficiency of ships (IMO, 2018).

There is more than one scenario to reach the decarbonization goal of the shipping industry. To understand the scale of the problem, I referred to the International Energy Agency (IEA) scenarios to review one of the existing net-zero scenarios. The IEA published the Net Zero Emissions by 2050 Scenario (NZE) in 2021 to outline a global pathway to present what is needed for the global energy sector to achieve net-zero CO_2 emissions by 2050. The NZE scenario is aligned with the goal of limiting global warming to 1.5 °C. Several important developments need to happen, which require increased ambitions toward net zero pledges from the current global climate policies, to achieve this goal. For example, in the NZE scenario, universal access to sustainable energy is achieved by 2030, and there is a 75% reduction in methane emissions from fossil fuel use by 2030, while the global economy more than doubles by 2050 (IEA, 2021c). For the international shipping industry, the NZE by 2050 scenario requires strict measures to achieve a 1.42% average annual reduction in GHG emissions between 2020-2030 and more than 84% reduction from 2020 to 2050, as illustrated in Figure 3 (IEA 2021c).

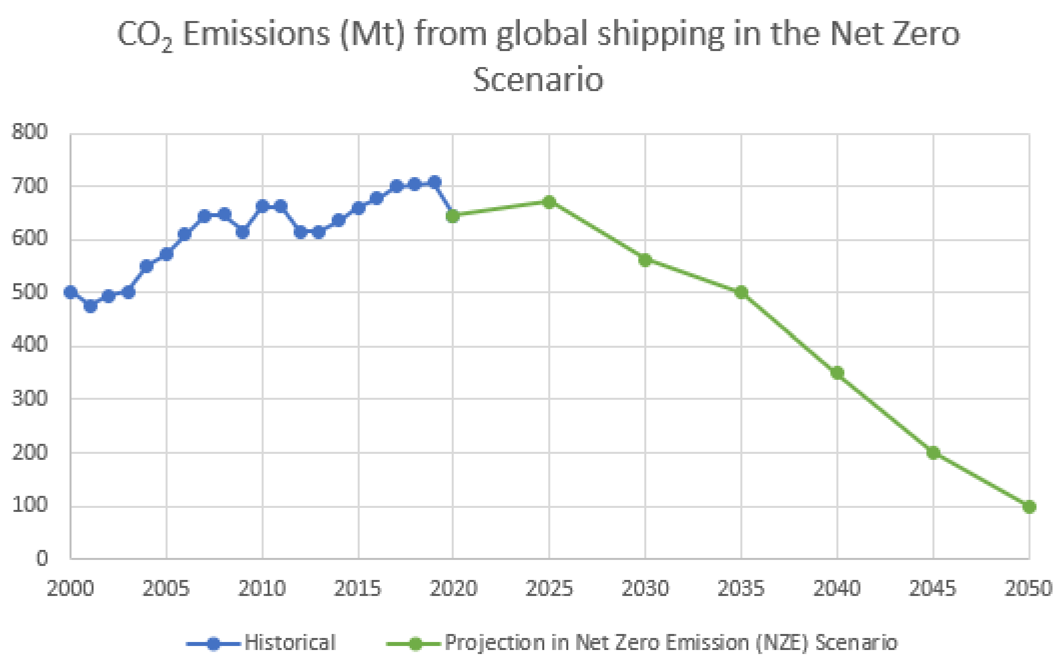


Figure 3 CO_2 Emissions from International Shipping, adapted from (IEA 2021c)

To achieve these targets for Net Zero Emissions by 2050, the introduction of alternative fuels with clean energy sources and technological innovations will all be critical and should happen timely by 2030. The most imminent problem is that almost no low-carbon fuels are currently used in international shipping, as shown in Figure 4. The only non-fossil fuel alternative, biofuels, accounts for 0.1% of final energy consumption in 2020. Low- and zero-carbon fuels are expected to make up around 2% of total energy consumption in international shipping. This is significantly lower to meet the Net Zero Emission target that requires at least 15% of low- and zero-carbon fuel in 2030 (IEA, 2021b). Therefore, developing and deploying low- and zero- carbon alternative fuels globally is critical to achieving the Net Zero Emission goals by 2050 for the shipping industry.

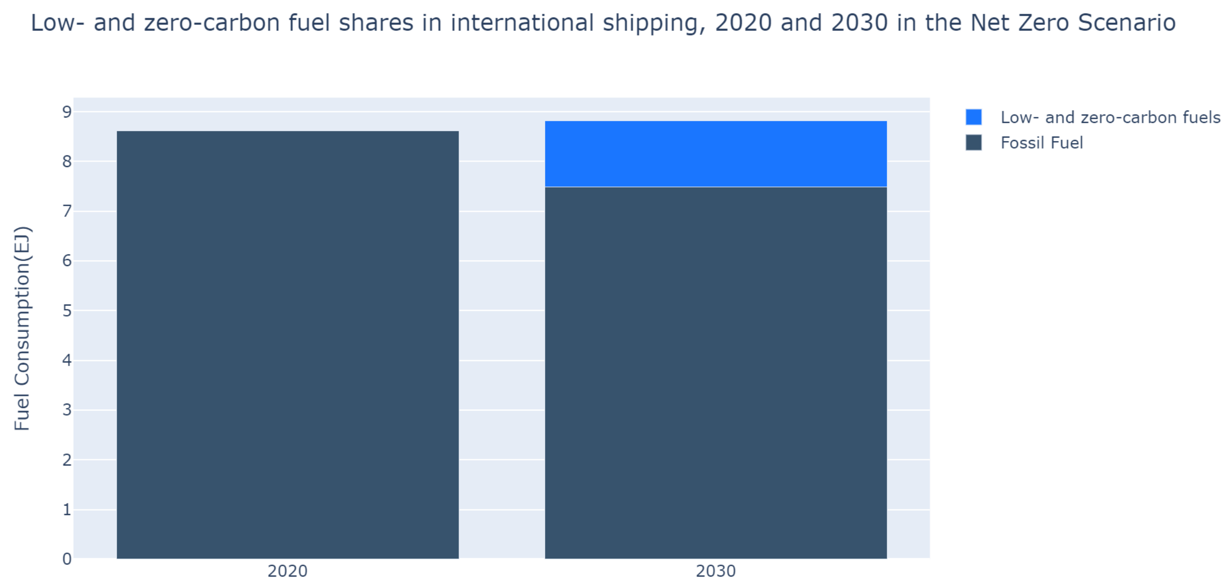


Figure 4 Low carbon fuel shares in international shipping, adapted from (IEA, 2021a)

This thesis will focus on evaluating different pathways for alternative fuels and their economic impact on achieving decarbonization goals. I will use the MIT EPPA model's climate scenarios (Paltsev et al., 2021) that aim to meet the global temperature target of 1.5°C, and I will make projections on the economic impacts through 2050 for a low-emission shipping pathway.

1.2 Research Questions and Objectives

1.2.1 Research Question in System Problem Statement Format

The research question is presented using "To-By-Using" format (Crawley et al., 2016). The main question that this research aims to answer is **to** evaluate different pathways for decarbonizing the shipping industry **by** estimating cost, constructing utility models, and performing economic projections and GHG emission analysis **using** the MIT Economic Projection and Policy Analysis

(EPPA) model and cost of fuel production models. Five primary research objectives have been identified in the following section.

1.2.2 Primary Research Objectives

1. To assess regional demand growth for shipping until 2050
2. To evaluate global emissions from shipping in a business-as-usual (i.e., no climate policy) scenario until 2050
3. To understand the details of the shipping industry's current carbon intensity and its potential future evolution
4. To evaluate different pathways for decarbonizing the shipping industry using different fuels and other options
5. To analyze the cost impacts of alternative pathways for the decarbonizing shipping industry.

1.2.3 Research Scope

The scope of the research is the global shipping industry, its energy use, and emissions up to 2050.

1.3 Thesis Outline & Structure

This thesis is composed of six main chapters:

- Chapter 1 – Introduction

  This chapter introduces the background of the shipping industry and gives the context of the motivation for the research question. The research objectives and questions are stated.

- Chapter 2 – Literature Review

  This chapter synthesizes findings from various literature regarding alternative fuels focusing on hydrogen, ammonia, and methanol. The shipping industry's global demand projection and its carbon intensity in the current state are also discussed. Key metrics to assess alternative fuels are presented, including lifecycle emissions.

- Chapter 3 – Cost Model & Results

  This chapter presents the cost model of alternative fuels and the new power trains required for new fuels. Fuel cost models and methodologies are introduced, and then the total cost of ownership models of alternative fuel shipping vessels is described. Results of cost models are presented. A trade-off analysis of alternative fuel pathways is constructed by combining the results from cost models and key metrics of alternative fuels.

- Chapter 4 – EPPA Model Results

  The EPPA model is introduced as a main tool for the economic analysis. This chapter presents results from the EPPA modeling and analysis to show the economic impacts of alternative fuels under various scenarios. Global and regional sensitivities are illustrated in the water transportation sector in terms of economic output and required investment. Additional investment needed to enable low-emission shipping to enter the market is projected using the EPPA model.

- Chapter 5 – Discussion

  This chapter illustrates different approaches to lowering costs based on the modeling results toward decarbonizing the shipping industry for Net Zero Emission. Near-term, medium-term, and long-term pathways are presented, with key insights for industry experts and decision-makers.

- Chapter 6 – Conclusions.

  This chapter concludes and summarizes key findings and analysis of the thesis. Future work is recommended.

Chapter 2 – Literature Review

There has been growing pressure and an urgent need to reduce CO_2 emissions in all sectors to curb human-induced climate change and limit global warming. The 2022 Intergovernmental Panel on Climate Change (IPCC) report states clearly that human-induced climate change has caused widespread adverse impacts and related losses and damages to nature and people beyond natural climate variability (IPCC, 2022b). The report also emphasizes that energy generation diversification, including renewable energy resources and generation that can be decentralized, and demand side management can reduce vulnerabilities to climate change (IPCC, 2022b). The shipping industry is facing dual challenges to simultaneously meet the fast-growing demand for shipping from economic growth and reducing carbon footprint. Decarbonizing the shipping industry is a complex socio-technical problem due to the industry's capital- and energy-intensive nature with heavy dependence on fossil fuel and the need for necessary infrastructure development with a regulatory framework for alternative fuels. This chapter illustrates the current state of shipping in terms of GHG emissions and carbon intensity. Then three alternative fuels (hydrogen, ammonia, methanol) production and value chain (storage, handling) with infrastructure needs are discussed.

2.1 Global Shipping Industry and CO_2 emissions

Before the COVID pandemic in 2017, global CO_2 emissions from shipping accounted for ~2.7-2.9% of the total global CO_2 emissions (IEA, 2021b). The emissions are concentrated across a few large vessel types: Bulk carriers, oil tankers, and container ships account for 85% of all shipping activity, with ~440 Mt CO_2, ~210 Mt CO_2, and ~140 Mt CO_2 emissions, respectively (Shell, 2020). The breakdown of the global shipping fleet is shown in Table 1. According to the sources, bulk carriers, oil tankers, and container ships account for ~85% of total CO_2 emissions in the global fleet, making up ~30% of the total fleet in 2021. The total fleet in 2021 was 99,800 ships globally. In terms of capacity, deadweight tonnage (DWT) is used as a measure of how much weight a ship can carry, and it represents the sum of the weights of cargo, fuel, passengers, and crew. DWT measures a vessel's weight carrying capacity, not including the empty weight of the ship. DWT of the total fleet in 2021 was 2.1 billion tonnes, in which bulk carriers, oil tankers, and container ships accounted for roughly 85% of total DWT. The three major vessel types, bulk carriers, oil tankers, and container ships, account for 70% of the shipping sector's fuel demand. Large ships with vessel sizes in terms of gross tonnage greater than 25,000 have an average lifespan of 30 years with relatively newer vessels (less than 15 years old). Therefore, it is likely that most of the ships built today will remain in service by 2050 (Gray, 2021). The long lifespan of ships underscores the importance of anticipating and complying with new emission regulations that will only become stricter in the future.

Table 1 Global Shipping Fleet, adapted from (UNCTAD 2021, Shell 2020)

Ship Type	Number of Ships (2021)	Dead Weight Tonnes (DWT) in thousands (2021)	DWT Percentage of Total Fleet	2021 CO_2 Emission eq (Mt CO_2)
Total Fleet	99800	2134640	100	646-930
Bulk Carriers	12325	913032	42.77	440
Oil Tankers	11400	619148	29	210
Container Ships	5434	281784	13.2	140
Other Types of Ships	51235	243922	11.43	100
General Cargo	19406	76754	3.6	40

2.1.1 Stakeholders in the Shipping Industry

The global shipping industry is complex because multiple stakeholders have various needs under different regulatory controls. The main reason is that per international agreements, every merchant ship is required to be registered to a country called Flag State, which exercises regulatory control over a vessel. The regulatory controls include safety standards, environmental protection, emission controls, and labor standards. Some flag states have less strict regulations than others, and it is a common practice for ship owners to register their ships via Open Registry, which allows them to register them in a different country than the owners' country.

Figure 5 illustrates multiple stakeholders and their needs in the shipping industry. Shipowners bear the financial risk of purchasing and operating ships and are ultimately legally responsible for their ships (ICS, 2020a). Operating companies handle the day-to-day operation of ships, and charterers hire ships to transport cargo that they own. Ship brokers negotiate between charterers and shipowners to drive down the cost and improve efficiencies in the process. Ship managers manage a fleet of ships and service ship routes. Manning agents provide skilled labor for the shipowners and operating companies. Bunker operators provide the marine fuels that ships need. Two main regulatory bodies, the International Maritime Organization (IMO), and International Labour Organization (ILO) influence the global shipping industry. The IMO develops regulations to improve safety and security and prevent pollution. One of IMO's tasks is to create up-to-date policies and treaties to reduce greenhouse gas emissions. The ILO develops regulators related to seafarers' labor standards to protect and promote their security. Finally, flag states provide mandatory registration to merchant ships worldwide, ratify treaties and conventions set by the regulatory bodies, and exercise regulatory controls over the ships registered within their flag (HG, 2022).

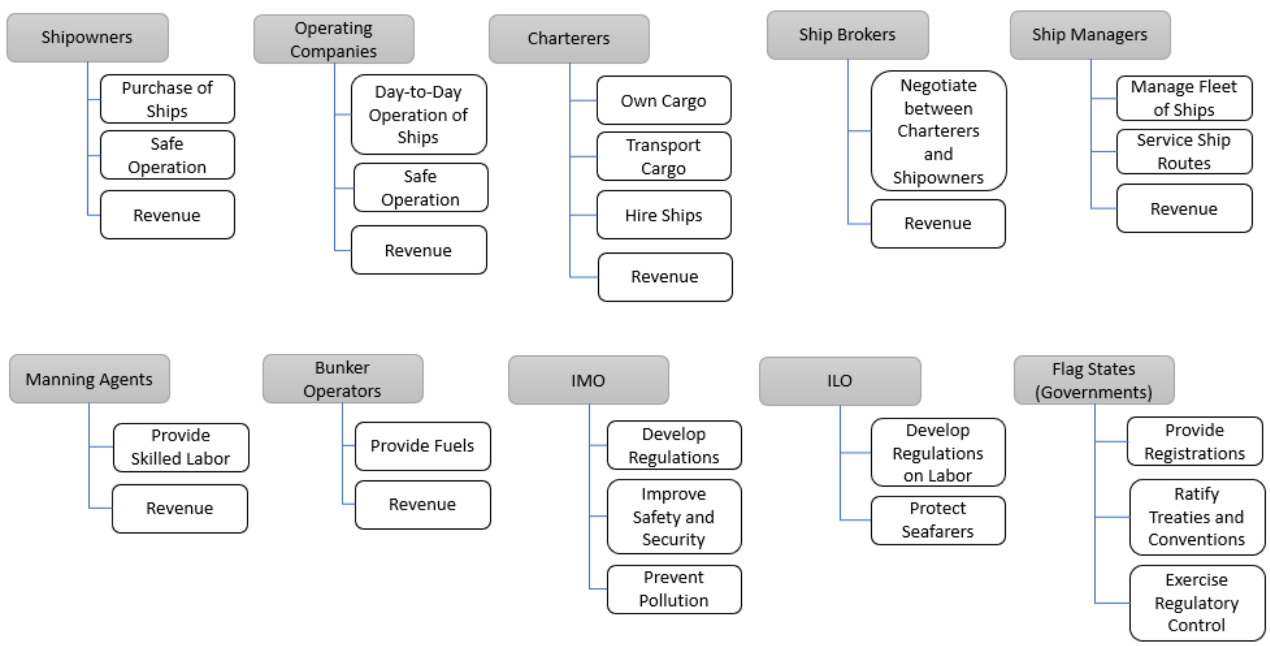


Figure 5 Stakeholders and their needs in the shipping industry

I illustrated the primary stakeholders and their relationships in a system diagram in Figure 6. Shipowners are at the center of the complex chain of the shipping industry. They are responsible for clean energy transitions in the future as they own the ships and are also bound by financial incentives as indicated by green lines representing financial transactions. Shipowners in many countries form a shipowners' association that represents their interests locally and globally. They are part of the International Chamber of Shipping (ICS), the global trade association for shipowners and operators. The ICS influences regulatory policies and treaties implementation and advocates shipowner positions to the IMO, ILO, and other government regulators (ICS, 2020b).

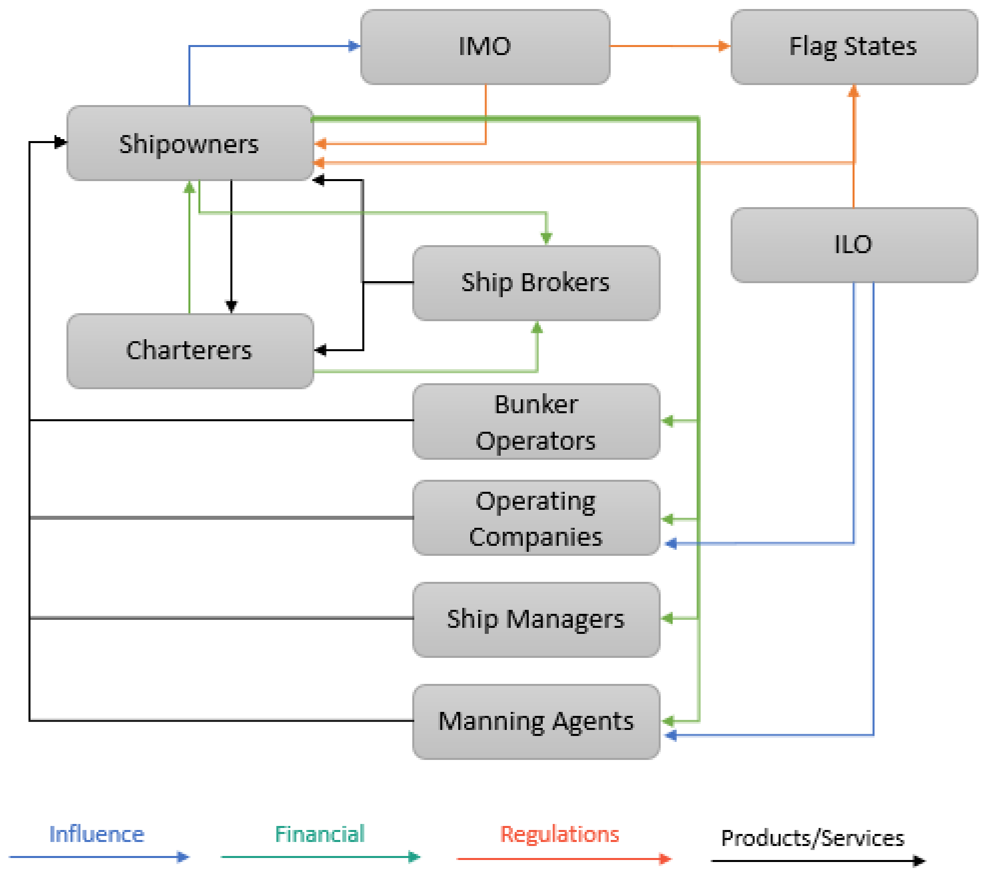


Figure 6 Primary Stakeholders system diagram

Shipowners can register their merchant ships to other countries which allow open registries. The countries with the open registry are often characterized by their relatively lax tax, employment, and environmental protection laws (Hunt and Lee, 2021). As presented in Table 2, Greece owns the ships that have the largest tonnage, followed by China, Japan, and Singapore. Asia owns more than half of the world's fleet tonnage in terms of DWT in 2020, as shown in Figure 7. However, ships are bound by the laws and regulations of their flag states, where they are registered. Table 2 shows that flag states with the most registrations are Panama, Liberia, and the Marshall Islands in terms of tonnage.

Regarding potential emissions reductions and the energy transitions in the shipping industry, I identify three key stakeholders that can play the most critical role. They are the IMO, flag states, and shipowners. The IMO sets the emission-related regulations and treaties. And since flag states exercise regulatory controls over ships under their flags, they should ratify and abide by the latest emission regulations set by the IMO and other regulatory bodies. Shipowners should invest in upgrading their ships to comply with the flag states' emission regulations. All three stakeholders should collaborate, influence each other, and work together on the best path toward the energy transition in the shipping industry.

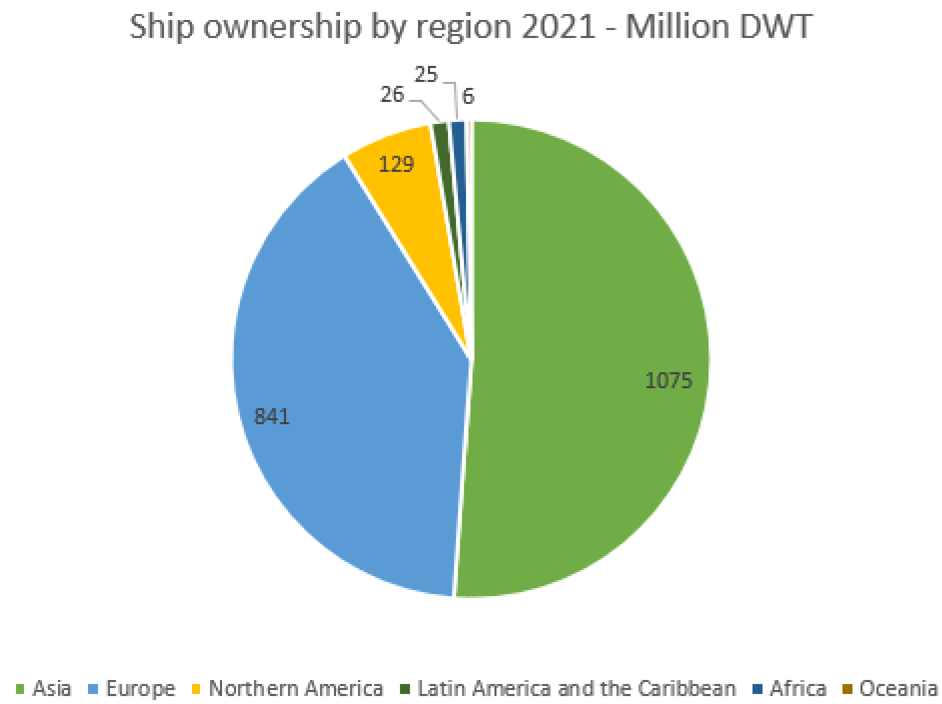


Figure 7 Ship ownership by region, adapted from (UNCTAD, 2021)

Table 2 Ship ownership and flag of registration by country, adapted from (UNCTAD 2021)

	Flag of Registration (Ranked by tonnage registered)								
Economy of Ownership (Ranked by tonnage owned)	Panama	Liberia	Marshall Islands	China, Hong Kong	Singapore	Malta	China	Rest of the World	World
Greece	27,924	94,234	80,325	1,262	1,763	63,639	-	104,270	373,417
China	23,461	11,564	6,505	81,330	4,964	2,951	105,657	8,124	244,556
Japan	136,971	24,099	14,510	3,143	10,130	829	-	52,166	241,848
Singapore	11,884	18,655	8,972	7,248	73,258	3,198	964	14,885	139,064
China, Hong Kong SAR	12,600	5,785	3,528	72,367	4,878	839	135	4,087	104,219
Germany	870	33,112	5,019	1,296	3,844	5,795	-	36,261	86,197
Korea, Republic of	40,042	1,379	26,474	1,089	29	356	2	16,722	86,093
Norway	1,993	5,027	8,384	8,742	4,622	1,339	-	33,936	64,043
Bermuda	1,495	7,500	21,472	8,169	1,247	172	-	23,979	64,034
France	4,400	11,132	17,686	2,700	1,261	7,379	-	12,465	57,023
Rest of the World	81,961	87,589	81,141	17,665	30,168	29,876	121	-	655,907
World	343,601	300,076	274,016	205,011	136,164	116,373	106,879	634,281	2,116,401

2.1.2 Recent GHG Emissions Trend from 2012 to 2018

The GHG emissions from shipping include carbon dioxide (CO_2), carbon monoxide (CO), methane (CH_4), nitrous oxide (N_2O), oxides of nitrogen (NOx), fine particles (PM_{10} and $PM_{2.5}$), Sulphur oxides (SOx), black carbon (BC), and volatile organic compounds (VOC). GHG emissions can be expressed in CO_2-eq (Carbon dioxide equivalent) which represents the number of metric tons of

CO_2 emissions with the same global warming potential as one metric ton of various greenhouse gases. According to the Fourth IMO study, the global shipping industry has increased its GHG emissions by 9.6%, from 962 Mt in 2012 to 1,056 Mt in 2018 (IMO, 2020a). This increase in GHG emissions led to increased contributions of shipping emissions in global anthropogenic emissions from 2.76% in 2012 to 2.89% in 2018, which dropped to around 2% in 2020 mainly due to reduced shipping activities during the COVID year (IMO, 2020a). Table 3 summarizes CO_2 emissions from total and international shipping from 2012 to 2018. In the same study, 2008 CO_2 emissions from international shipping are estimated to be around 794 Mt CO_2-eq, which is the basis for the reduction target in Initial IMO GHG Strategy. The overall GHG emissions trend from 2012 to 2018 is increasing, which makes it essential to have a global CO_2 emission reduction strategy for the shipping industry.

Table 3 Total and International Shipping CO_2 Emissions, adapted from (IMO, 2020)

Year	**Global anthropogenic CO_2 emissions (Mt)**	**Total shipping CO_2 (Mt)**	**Total shipping as a percentage of global**	**International shipping CO_2 (Mt)**	**International shipping as a percentage of global**
2012	34,793	962	2.76%	848	2.44%
2013	34,959	957	2.74%	837	2.39%
2014	35,225	964	2.74%	846	2.37%
2015	35,239	991	2.81%	859	2.44%
2016	35,380	1,026	2.90%	894	2.53%
2017	35,810	1,064	2.97%	929	2.59%
2018	36,573	1,056	2.89%	919	2.51%

2.1.3 Carbon Intensity in the Shipping Industry

As a carbon intensity metric, Energy Efficiency Operational Indicator (EEOI, g CO_2/t/nm) is commonly used in the shipping industry. Other metrics to measure carbon intensity in the shipping industry includes the Annual Efficiency Ratio (AER, g CO_2/dwt/nm), DIST (kg CO_2/nm), and TIME (t CO_2/hr). These metrics are used to estimate the carbon intensity performance of international shipping in the IMO report with slightly different implications. For example, EEOI and AER metrics are more applicable to typical cargo and passenger ships, while DIST and TIME are more suitable for service, working for fishing vessels (IMO, 2020a).

Between 2012 and 2018, international shipping has improved its carbon intensity overall for most ship types. Measured in EEOI (gCO_2/t/nm), the overall carbon intensity as an average across international shipping was 29% better than in 2008. The improvement has been slowed since 2015, with around a 3% improvement between 2015 and 2018. Table 4 presents estimates of the carbon intensity of international shipping and percentage changes compared to 2008 values.

Table 4 Estimates on carbon intensity of international shipping, adapted from (IMO, 2020)

Year	EEOI (gCO_2/t/nm)	EEOI % change from 2008
2008	17.1	-
2012	13.16	-23.10%
2013	12.87	-24.70%
2014	12.34	-27.90%
2015	12.33	-27.90%
2016	12.22	-28.60%
2017	11.87	-30.60%
2018	11.67	-31.80%

One insight that can be drawn from the global emissions data and the carbon intensity data is that although the efficiency of ships has been improving, as shown by decreasing carbon intensity metrics, GHG emissions have been increasing in recent years. This discrepancy stems from increased shipping demand, fleet size, and fuel consumption to power the ships.

2.1.4 Projections for International Shipping

International shipping is projected to increase in transport work measured using tonne-miles metric from 2020 to 2050. Figure 8 presents various projections in transport work from the shipping industry based on long-term socio-economic scenarios and energy scenarios in Table 5 that limit the global temperature rise to 2 °C (RCP 2.6). In terms of economic growth in the socio-economic scenarios, SSP5 has the highest economic growth assumptions until 2050, followed by SSP1, SSP2, SSP4, SSP3, and the OECD long-term economic scenario (IMO, 2020a). There are two methods of modeling approach used in the report to estimate future projections by finding the relationship between the future transport work and its drivers. The first approach uses the logistics curve (S-curve) to fit the historical transport work data to future projections by using global data, which results in higher projections that indicate the upper end of projections (denoted by _L suffix). The other approach uses the gravitational models, which take trade elasticities into account to model the bilateral sea trade as a function of the income of the trading countries (denoted by _G suffix). The gravitational model provides lower projection results than the logistics model, so they represent the lower end of projections (IMO, 2020a). The IMO report interpreted the difference in these two approaches as an inherent uncertainty in future projections. As a lower-end projection, the SSP2_RCP19_G model projected around 34% increase in transport work from 2020 to 2050; as an upper-end projection, the SSP1_RCP19_L model projected around 130% increase in the transport work in the same period. By ship types, bulk carriers accounted for the most transport work in 2020, and the trend continues toward 2050 in all scenarios considered (IMO, 2020a). As such, bulk carriers are the critical ship types in the energy transition.

Table 5 Economic and energy scenarios, reproduced from (IMO, 2020a)

Long-term socio-economic scenarios	Long-term energy scenarios
SSP1 (Sustainability - Taking the Green Road)	RCP 1.9 (1.5°C)
SSP2 (Middle of the Road)	RCP 2.6 (2°C)
SSP3 (Regional Rivalry - A Rocky Road)	
SSP4 (Inequality - A Road Divided)	
SSP5 (Fossil-fueled Development)	
OECD long-term baseline projections	

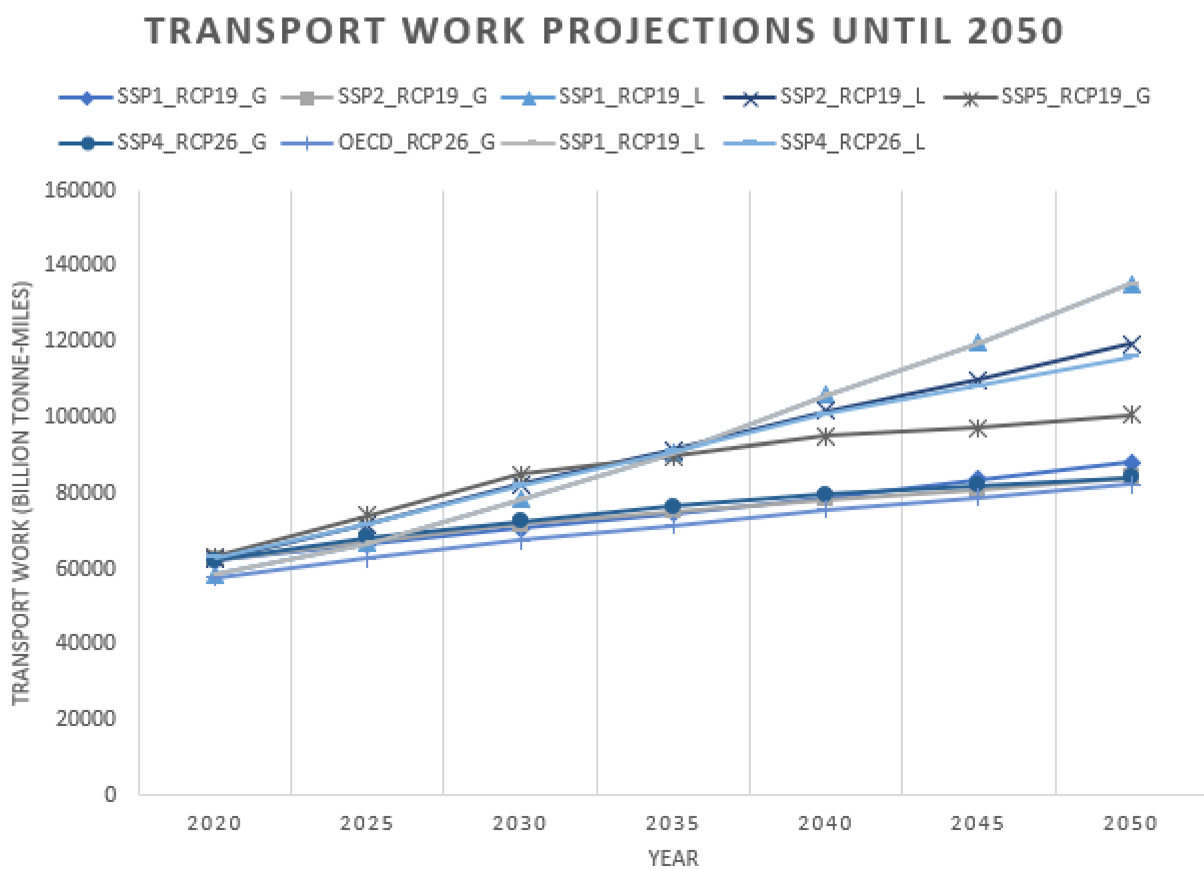


Figure 8 Shipping transport work projections, adapted from (IMO, 2020a)

In terms of emissions, under all economic scenarios considered in the IMO report, CO_2 emissions are projected to increase by 2050. It can be inferred that more aggressive economic development scenarios (SSP1) will result in more carbon emissions than lower economic development scenarios (OECD). In such cases, CO_2 emissions will increase by more than 65% compared to the emissions in 2020 (IMO, 2020b).

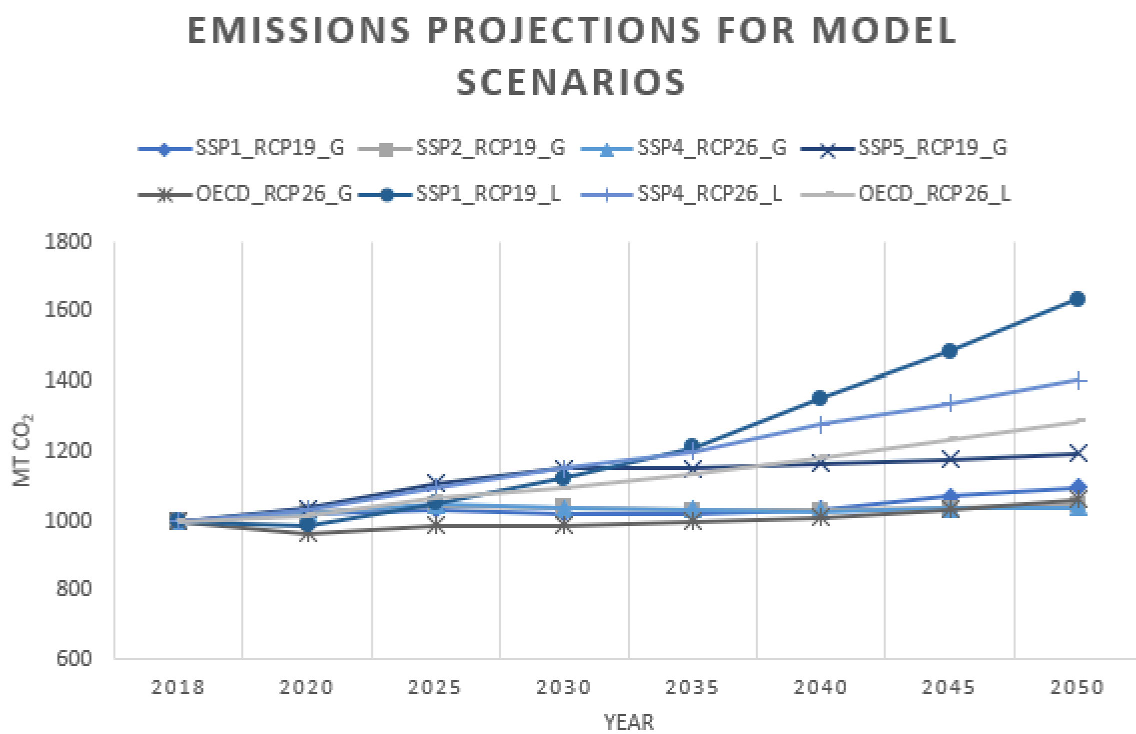


Figure 9 Projections of maritime ship emissions, adapted from (IMO, 2020b)

2.1.5 Regional Demand Growth for Shipping

The current regional demand for maritime trade is shown in Figure 10. Asia accounted for more than 40% of global goods loaded (exports) and more than 60% of global goods discharged (imports). Much of the demand has been in China, and there has been an increase in trade volumes on the Transpacific trade routes linking East Asia to North America (UN, 2022). Other regions, including America and Africa, accounted for 10-20% of the total share of global goods loaded in 2020.

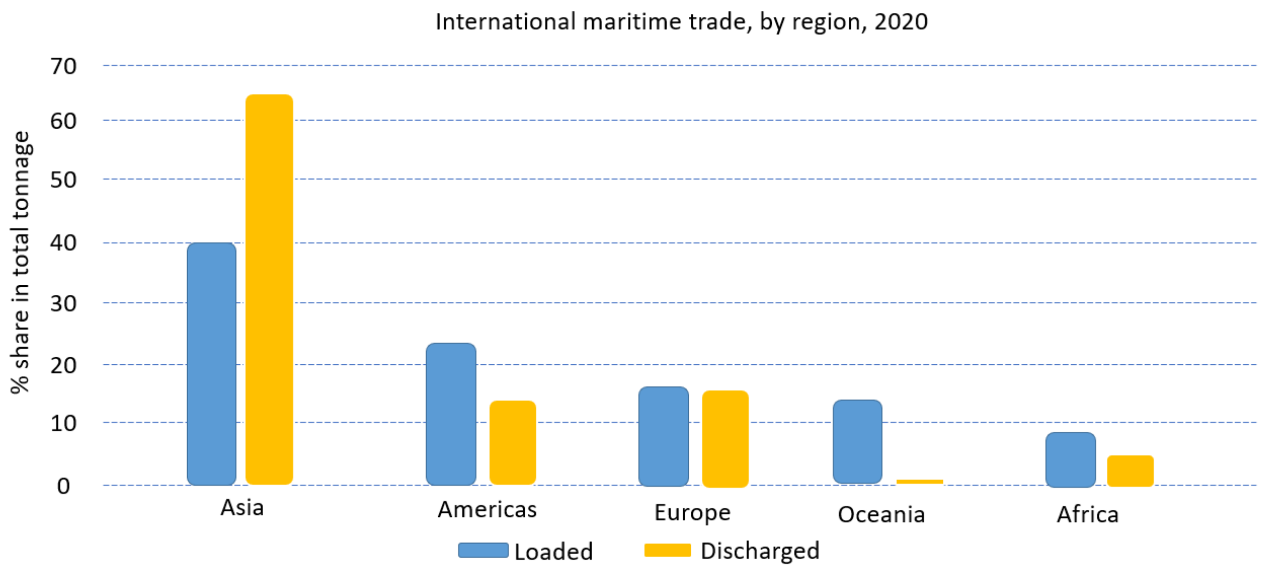


Figure 10 International maritime trade by region 2020, adapted from (UN, 2022)

The regional demand growth for maritime trade from 2015 to 2050 (International Transport Forum 2019) has been projected based on the current demand pathway, as shown in Figure 11. In 2015, more than half of maritime trade demand came from the Indian Ocean and the North Pacific regions. The same trend holds for maritime trade projections in 2030 and 2050, in which the Indian Ocean and the North Pacific remain the highest demanded maritime trade regions. The North Atlantic Ocean is the third busiest trade route with 15% of maritime freight movement projections, leading to 38 trillion tonne-kilometers of transport work in 2050 (International Transport Forum, 2019). Both the Indian Ocean and North Pacific oceans include the shipping routes departing to and from Asia, representing the highest share in global trade tonnage of the current maritime trade by region, as shown in Figure 10.

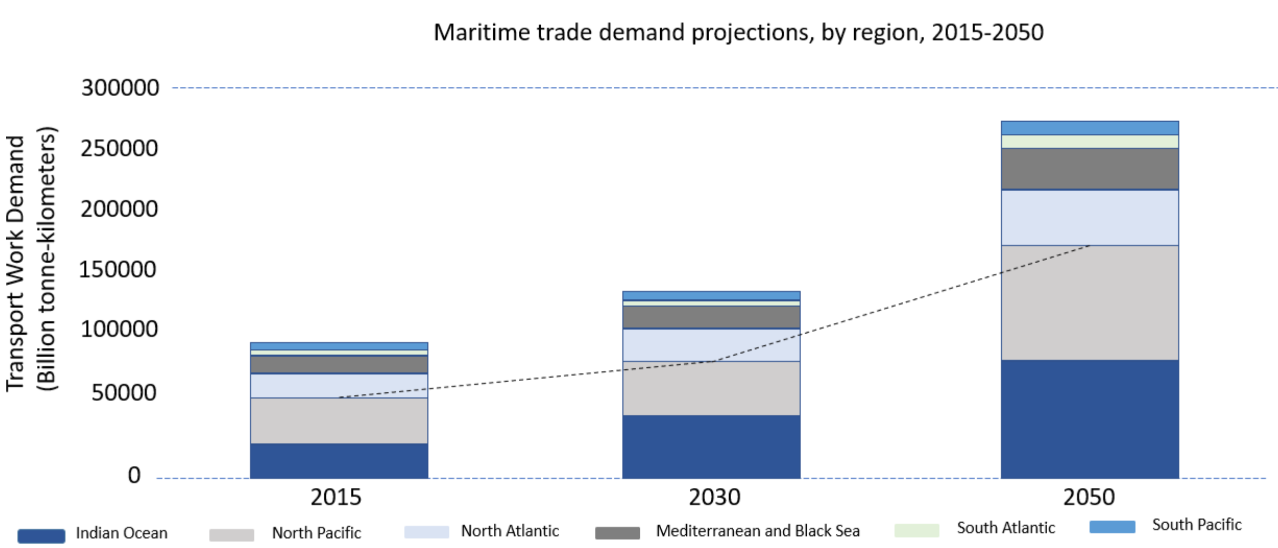


Figure 11 Regional maritime trade demand projections, 2015-2050, adapted from (International Transport Forum, 2019)

2.2 Pathways to Marine Fuels

Figure 12 represents examples of current and potential pathways for various marine fuels. Three primary energy sources include fossil fuel, biomass, and non-biomass renewable energy (solar and wind). Fossil fuel is processed to generate the most commonly used marine fuels, such as heavy fuel oil (HFO) and marine diesel oil (MDO), liquified natural gas (LNG), as well as methanol and hydrogen. Renewable energy can also be used to generate hydrogen through water electrolysis. Currently, internal combustion engines are the most dominant option in maritime propulsion, which depend on fossil fuel-based marine fuels. In the future, there can be different ways to power ship vessels using these fuels, including fuel cell systems.

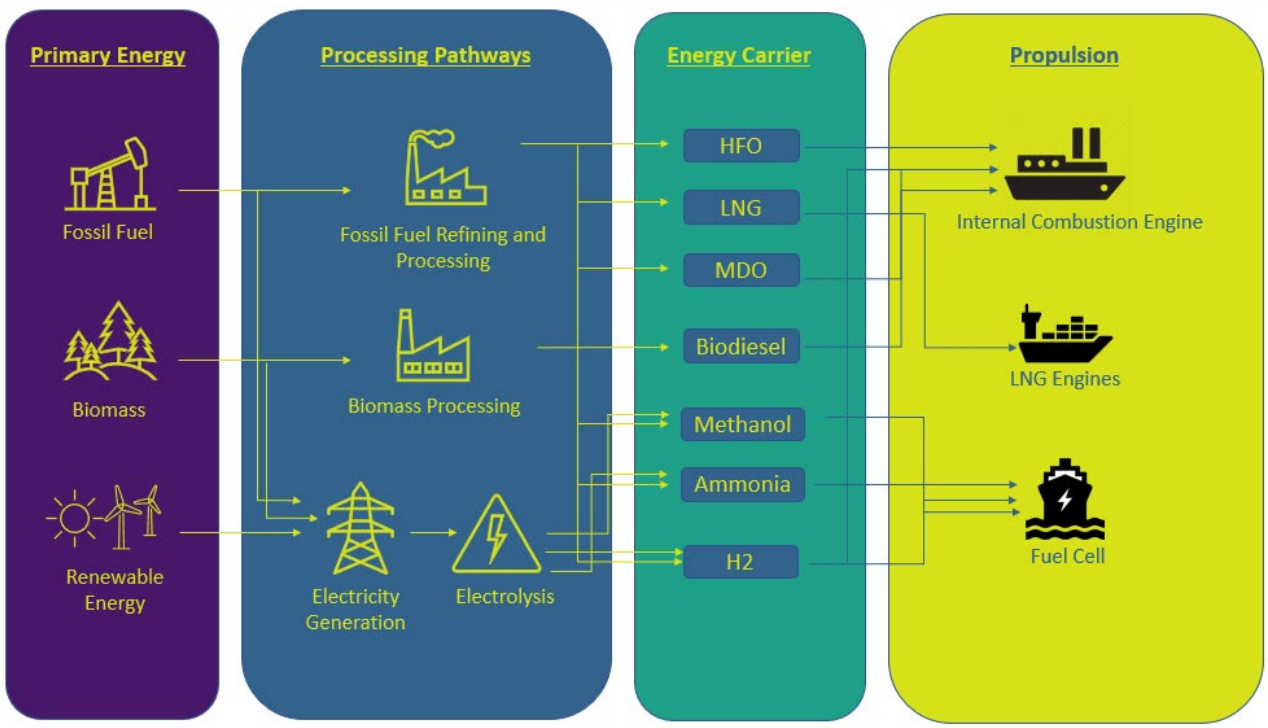


Figure 12 Current and potential pathways to marine fuels

2.3 Heavy Fuel Oil (HFO)

Traditionally, heavy fuel oil (HFO) has been the primary fuel that is cost-efficient for large ships (cargo vessels, bulk carriers, and oil tankers). HFO is produced from Crude Oil after extracting lighter hydrocarbons during the oil refining process. Since HFO is a residual fuel oil with high viscosity, it is often mixed with lighter fuels like Diesel to power ship engines. HFO is also known as IFO 380, Marine Fuel, Bunker Fuel, or just Heavy Oil. HFO has a high density of 0.98 kg/m^3

with a lower heating value (LHV) of 39 MJ/kg, which is lower than that of LNG (48.6 MJ/kg) but higher than that of Methanol (19.9 MJ/kg). In 2015, it was reported that 72% of fuel consumption in the shipping sector came from HFO, 26% from distillate fuels such as marine diesel oil (MDO), and 2% from liquified natural gas (LNG), as shown in Figure 13 (Gray, 2021).

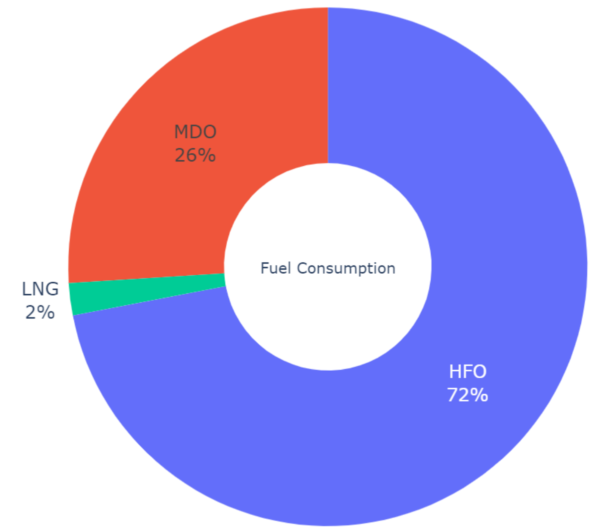


Figure 13 Fuel consumption in shipping, adapted from (ICCT 2015)

In 2018, according to the Fourth IMO GHG report (IMO, 2020b), HFO still remained dominant with a decreasing proportion in the fuel mix overall, with a reduction of approximately 7%. The gap was filled by increased consumption of marine diesel oil (MDO) and liquefied natural gas (LNG) (IMO, 2020b). By ship type, it can be observed that the large ships (bulk carriers, containers, and oil tankers) heavily consumed HFO primarily between 2012 and 2018. Figure 14 illustrates the average international HFO-equivalent fuel consumption per ship type between 2012 and 2018. According to the report, the carbon intensity of bulk carrier ships was the lowest at 7.3 gCO_2/tnm in 2018, and containers demonstrated higher carbon intensity of 15.3 gCO_2/tnm in 2018 (IMO, 2020b), as shown in Figure 15. LNG tankers are practically the only ship type that consumes LNG. This study uses the conventional HFO as a base marine fuel for a reference case.

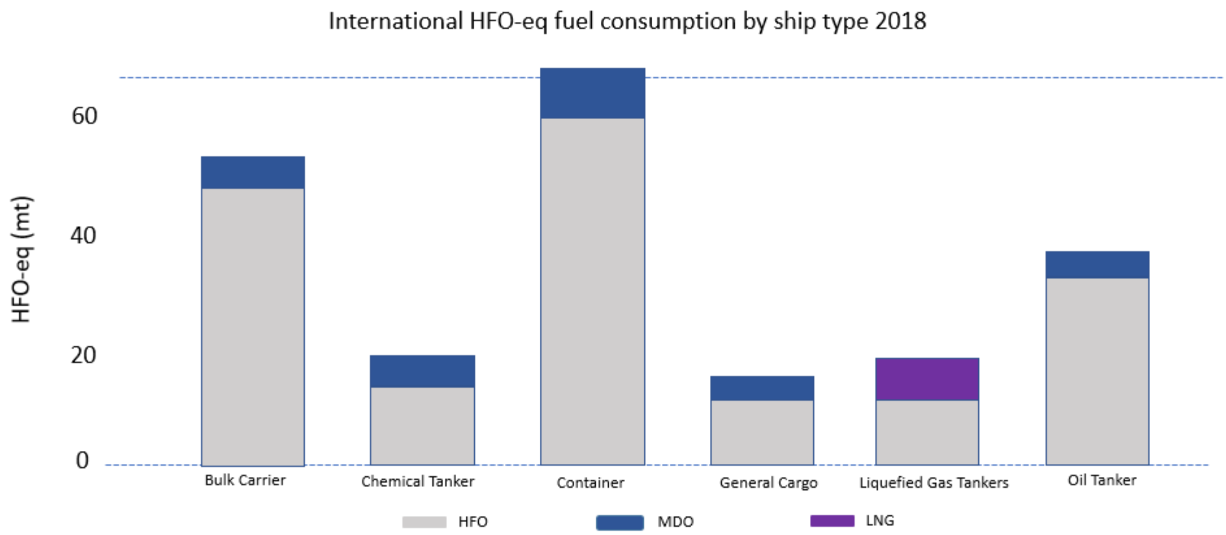


Figure 14 International HFO-eq fuel consumption by ship type, adapted from (IMO 2020)

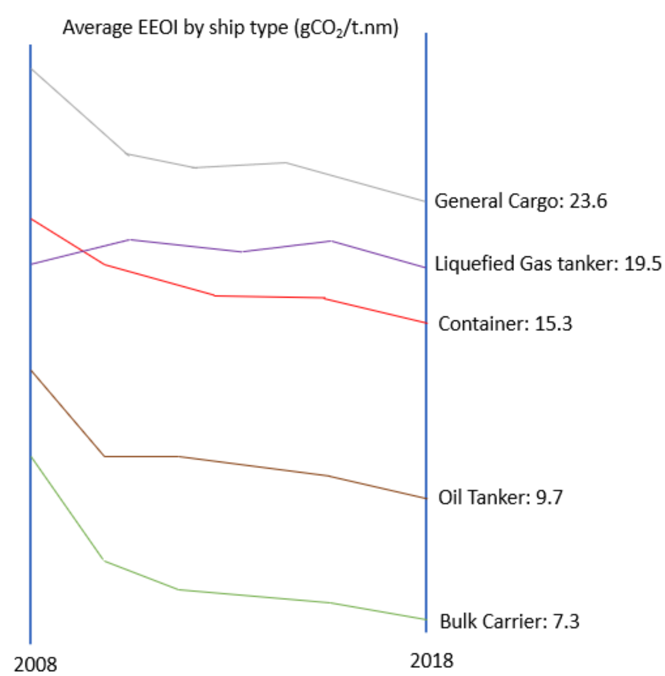


Figure 15 Carbon intensity of each ship type, adapted from (IMO 2020)

2.3.1 Problems with HFO and Regulation Changes

HFO has high direct and indirect GHG emissions, including carbon dioxide, sulfur oxide (SOx), and nitrogen oxide (NOx). HFO also has high particulate matter (PM) emissions that harm the global environment and human health. The international shipping industry accounts for 8-13% of sulfur dioxide emissions, a significant contributor to acid rain and other harmful cardiovascular and respiratory diseases (Degnarain, 2020). The shipping sector emits approximately 1.4 Mt of particulate matter (PM), accounting for ~15% of global NOx emissions. Moreover, in the case of oil spills, HFO poses several problems as it is difficult to assess the quantity due to high viscosity, and it is hard to clean up, fowling natural habitat for a longer time (Ansell et al., 2001). Therefore, decarbonizing the shipping industry necessitates transitioning from HFO to more environmentally friendly low- or zero-carbon alternative fuels.

There has been some recent development in regulations to curb the use of HFO. From the 1st of January 2020, IMO has put a new limit on the sulfur content in fuel oil. This new regulation, known as "IMO 2020", limits the sulfur in the fuel oil used on ships to 0.5% m/m (mass by mass) from the previous limit of 3.5% and further poses a stricter limit of 0.1% in certain emission control areas (ECAs) including the North Sea, the Baltic Sea and North America (IMO, 2020c). Due to this new sulfur limit, HFO is no longer compliant without sulfur scrubbers or intensive desulphurization before use. The vast majority of ships in ECAs are transitioning to very low sulfur fuel oil (VLSFO) (Gray, 2021).

2.4 Hydrogen

Hydrogen is one of the ten most common elements on the surface of the Earth that is accessible to man. Hydrogen is also the lightest and smallest element and the first element in the periodic table. Hydrogen is colorless and odorless but highly combustible. Under ambient temperature and atmospheric pressure, hydrogen exists as a hydrogen molecule (H_2) in gaseous form. Hydrogen has a low density in its gaseous state – 0.089 grams per liter, which is about 14 times lighter than air. Therefore, hydrogen volatilizes quickly in the open air and diffuses into another medium, including metals. This characteristic presents a challenge in storing and transporting hydrogen, as it requires special materials for the storage containers. Hydrogen is compounded with other elements, such as water (H_2O). Hydrogen also commonly forms different compounds combined with carbon, such as natural gas and petroleum (EIA, 2021e). Hydrogen is a highly flammable gas as the minimum ignition energy of 0.02MJ is much lower than that of other fuels.

Hydrogen is an energy carrier that allows energy transport from one place to another. In other words, hydrogen is an energy storage medium, not a primary energy source (Nehrir and Wang, 2016). Various pathways produce hydrogen energy carriers from different primary energy sources. For example, hydrogen can be produced from electrolysis, a conversion process, using electricity, which can come from multiple primary energy sources, such as solar, wind, fossil fuels, or biomass. Hydrogen has the potential for use as a fuel in many applications, including fuel cell power generation and fuel cell vehicles. One unique property of hydrogen is that it has the highest energy content of any common fuel by weight, but it has the lowest energy content by volume (EIA, 2021e). For storage and transportation, hydrogen may be liquified or pressurized. The liquefaction of hydrogen at -253 °C increases hydrogen density by around 800 and reduces the storage volume (Shell, 2017). Hydrogen can be pressurized at 700 bar, which increases the energy density by a factor of 600 (McKinlay et al., 2021). Both methodologies require additional energy costs to maintain the high pressure or low temperature. Another approach is to use metal hydrides which absorb hydrogen into metals using chemical bonding, resulting in a significant increase in energy density of a factor of 1000, with an increase in weight stemming from the weight of metal used (McKinlay et al., 2021). With these technologies to reduce the storage volume, hydrogen is useful as an energy carrier despite the low volumetric density due to its high energy content per weight.

Hydrogen can be produced from various sources. Hydrogen can be categorized based on the sources of energy for its production. For example, hydrogen produced using renewable energy is referred to as green hydrogen. Hydrogen produced from coal is called brown hydrogen. The most common type of hydrogen is produced from natural gas or petroleum, and it is referred to as grey hydrogen. If the carbon capture and storage technique are combined with coal or natural gas hydrogen production, the resulting hydrogen is called blue hydrogen (EIA, 2021b).

2.4.1 Hydrogen as a Fuel

Hydrogen is a clean-burning fuel with zero emissions. Only water is produced when pure hydrogen is burned as a fuel to generate energy, as shown in the following reaction.

$$2H_2 + O_2 \rightarrow 2H_2O$$

The process is carbon-free and does not add any CO_2 to the atmosphere. On the other hand, fossil fuels generate greenhouse gas emissions from burning. The heavy dependence and utilization of fossil fuels have raised environmental concerns and contributed to climate change. Transitioning to cleaner energy, including hydrogen, is essential to reduce greenhouse gas emissions. Therefore, hydrogen is considered one of the promising options for marine fuels.

Hydrogen can be used in fuel cells to produce electricity. One of the benefits of fuel cells is that they can operate at higher efficiencies than combustion engines, with efficiencies capable of exceeding 60%. Fuel cells that use hydrogen as feedstocks separate hydrogen molecules into protons and electrons, which go through an external circuit to create a flow of electricity. The U.S. Department of Energy (DOE) is working with numerous industry partners and universities to overcome the current key challenges with fuel cells – cost, performance, and durability (Hydrogen and Fuel Cell Technologies Office, 2020).

2.4.2 Hydrogen Production

Steam Methane Reforming (SMR): Since hydrogen is commonly found in compounds in chemically bound form, it must be separated from other elements in the molecules in compounds in order to be used for energy purposes. There are various processes to produce hydrogen today. Most of today's global hydrogen production is based on fossil fuel energy sources. The most common method for producing hydrogen is steam-methane reforming (SMR). Only about 5% of hydrogen is produced from electrolysis (Shell, 2017).

SMR accounts for nearly all commercially produced hydrogen in the United States. During this process, high-temperature steam (1,300F to 1,800F) under 3-25 bar pressure reacts with methane in the presence of a catalyst to produce hydrogen, water, carbon monoxide, and carbon dioxide (EIA, 2021b). Globally, this process is responsible for about 1% of CO_2 emissions. Notably, natural gas is the primary methane source (68%) for hydrogen production by industrial facilities and petroleum refineries. Reforming requires an oxidant for the reaction, which supplies the necessary oxygen. The types of oxidants used for the reforming process can be used to decompose the reforming process. For Steam reforming, pure water vapor is used as the oxidant, and the reaction is endothermic as it requires heat. After the raw materials (natural gas and water) are pre-processed, mainly to remove sulfur, methane and water are converted into hydrogen by the following reactions:

$$CH_4 + H_2O \rightarrow CO + 3H_2$$

$$CH_4 + 2H_2O \rightarrow CO_2 + 4H_2$$

As the next step, carbon monoxide and remaining water are further converted to H_2 by a process called water gas shift reaction (Ratnasamy and Wagner, 2009):

$$CO + H_2O \rightarrow CO_2 + H_2$$

Electrolysis: A process that splits hydrogen from water using an electric current is called electrolysis (EIA, 2021b). This process takes place in an electrolyzer. Electrolyzers consist of an anode and a cathode separated by an electrolyte. There are different types of electrolyzers with varying materials of electrolyte involved in the process. In the case of an alkaline electrolyzer, the process starts when the cathode loses electrons to the aqueous solution. The water is dissociated and forms hydrogen and hydroxide ions. The charge carriers move in the electrolyte towards the anode, where the electrons are absorbed. The negative OH- anions are oxidized to form water and oxygen, which rise at the anode. The reactions at cathode and anode are as follows:

$$2H_2O + 2e^- \rightarrow\ H_2 + 2OH^-$$

$$2\ OH^- \rightarrow\ H_2O + {}^1\!/_2\, O_2 + 2e^-$$

The equation shows electrolysis is a promising hydrogen production pathway free of carbon emissions. Hydrogen production via electrolysis can result in zero GHG emissions if renewable energy (wind, solar, hydro, geothermal) is used to generate electricity for the process.

2.4.3 Hydrogen Infrastructure

One of the challenges to expanding hydrogen production in the future is the concern about building the hydrogen infrastructure. Hydrogen infrastructure is an essential aspect of the so-called "Hydrogen Economy." The hydrogen economy is an economy that relies on hydrogen as the commercial fuel that would deliver a substantial fraction of a nation's energy and services. The hydrogen economy's vision can be achieved if hydrogen can be produced cost competitively using domestic energy sources in a low-carbon manner (Nehrir and Wang, 2016), reducing the dependence on fossil fuels. Figure 16 depicts the simplified pathways of hydrogen production and distribution networks.

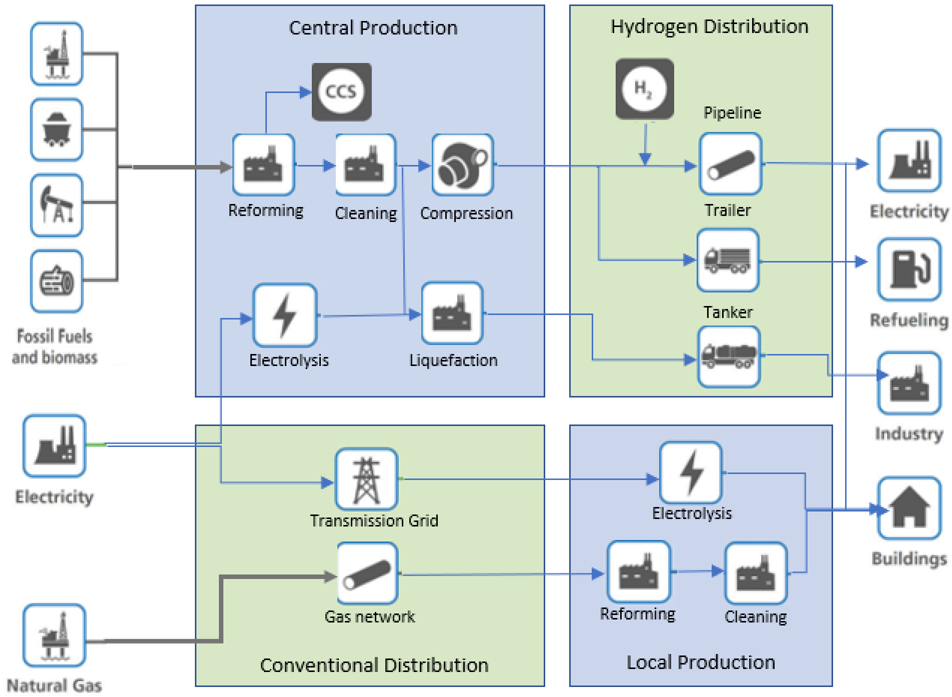


Figure 16 Hydrogen delivery pathways, reproduced from (Staffell et al., 2019)

The primary sources of energy to generate electricity are abstracted away in Figure 16. Assuming the electricity is generated from renewable sources, electrolysis can be used to produce hydrogen in centralized and decentralized methods. The upper half of Figure 16 describes the central production methods that rely on new hydrogen distribution networks, shown in blue lines. Once hydrogen is produced from central electrolysis facilities, hydrogen will need to be liquefied for distribution and delivered in tankers for long/short distances until it arrives at the end-user applications. As this centralized distribution method will require a new hydrogen distribution infrastructure, it will be costly. The lower half of Figure 16 illustrates a simplified model of decentralized or local distribution routes. This method is less intrusive in terms of infrastructure, as it can utilize existing electricity networks such as the transmission grid. After renewable electricity is transmitted to the local electrolysis production facility, hydrogen can be generated closer to end-user applications to reduce distribution costs. This method can avoid high up-front costs at the expense of efficiency (Staffell et al., 2019). A less intrusive pathway to distribute hydrogen leveraging existing electricity networks and infrastructure can be technically and economically challenging, especially in the early stages of the hydrogen economy. They can be a potential barrier to expanding green hydrogen production in the future.

2.4.4 Hydrogen Storage

One of the challenges in using hydrogen as a fuel is effectively storing hydrogen due to its unique properties. First, hydrogen is gaseous in ambient temperature with low volumetric energy density (0.003MWh/m^3 at 1 bar), which makes the volume required much greater than storing HFO, whose volumetric density is 11.7 MWh/m^3. Hydrogen should be pressurized at 700 bar, increasing the volumetric energy density to 2.1MWh/m^3 to reduce the volume required to meet the energy demand to power ships, but this will necessitate additional infrastructure and structural modifications. As such, storing hydrogen as a liquid is considered a more viable option, increasing the energy density to between 2.2 and 2.8 MWh/m^3 at a lower temperature between 13.8 K and 33.2 K (McKinlay et al., 2021). Second, hydrogen is highly flammable, with a broad flammability range of between 4% to 75% in air. Hydrogen requires only 0.02 millijoules of energy to ignite the hydrogen-air mixture (Hord, 1978). This characteristic makes hydrogen very explosive, and to add to the complexity of storing and handling hydrogen, it is colorless and odorless, making leaks difficult to detect (Mazloomi and Gomes, 2012). Therefore, additional safety rules, proper training, and hydrogen storage systems must be carefully designed if hydrogen is widely used as an alternative fuel for the shipping industry.

2.4.5 Hydrogen-Based Power Propulsion System

Currently, most ships are powered by internal combustion engines (ICE). There are two ways of using hydrogen to power propulsion systems. First, hydrogen can be directly used to power ICEs with significant retrofit and modifications due to the different burning rates of hydrogen and other marine fuels. Second, hydrogen can be used as fuel to power fuel cells to generate electricity that can power ships. Fuel cells can operate at higher efficiencies than combustion engines, with efficiencies around 55-60%, making them the most efficient method of converting hydrogen to energy (McKinlay et al., 2021). The use of hydrogen in a combustion engine yields efficiencies of 40% (Goldmann et al., 2018). Currently, fuel cell systems using hydrogen are a more commercialized approach than ICEs, as demonstrated by fuel cell vehicles developed by Toyota and Hyundai in selected markets with more than 6500 units sold as of June 2018 (Manoharan et al., 2019). The advantages of hydrogen ICEs to fuel cell systems include a higher tolerance to fuel impurities and a more straightforward transition from conventional ICEs. More advanced hydrogen ICEs such as direct injection and dual-fuel methods are still in the conceptual stage. The most common type of hydrogen ICE prototype is Port Fuel injection (PFI) system, as illustrated in Figure 17(Yip et al., 2019).

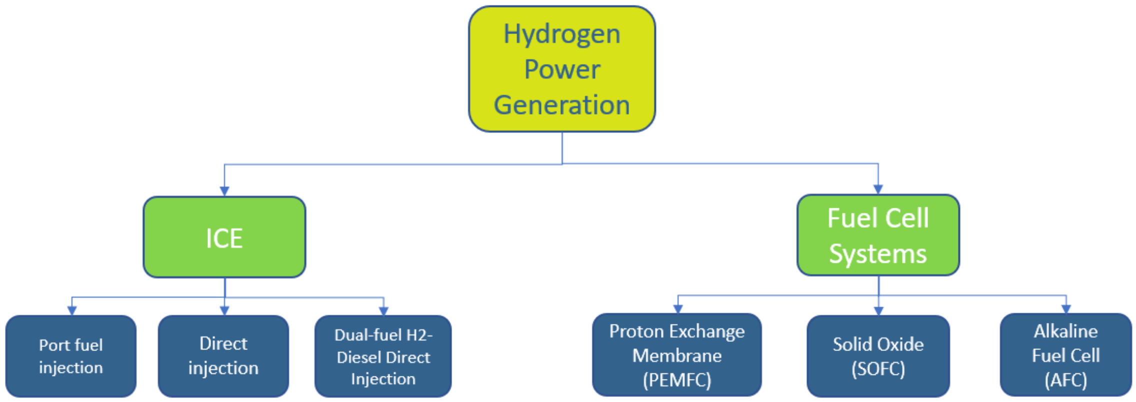


Figure 17 Hydrogen-based power propulsion generation options

2.5 Ammonia

Ammonia is a chemical compound of hydrogen and nitrogen (NH_3) with no carbon content. Ammonia is mainly used for the production of fertilizers and various industrial applications such as plastics, synthetic fibers, and explosives (IEA, 2021d). Ammonia is a colorless, poisonous gas with a noxious odor. Ammonia occurs naturally, but ammonia is commercially produced via nitrogen and hydrogen catalytic reactions at high temperatures and pressure. In 2020, the actual ammonia production was 187 Mt, of which 85% is used directly or indirectly in agriculture as various chemical fertilizers variants (ACS, 2021).

2.5.1 Ammonia as a Fuel

Recently, ammonia has been gaining attention as an alternative fuel due to its favorable characteristics as a clean energy carrier. Most importantly, ammonia has no carbon content and thus, can be combusted in an environmentally friendly way exhausting only water and nitrogen. Using ammonia as fuel does not generate CO_2, SOx, or PM emissions. However, the combustion of ammonia via ICEs will generate NOx emissions that harm humans. DeNOx systems can be utilized to reduce NOx emissions (de Vries, 2019) to mitigate this effect. In addition, ammonia has a lower cost per volume of stored energy than hydrogen, and a widely used distribution infrastructure already exists to deliver around 100 million tons of ammonia yearly, making it an attractive option for potential fuel (Zamfirescu and Dincer, 2008).

2.5.2 Ammonia Production

Ammonia is produced based on the Haber-Bosch process (Guo et al., 2019), where ammonia is synthesized from nitrogen and hydrogen at high temperatures and pressure, as shown in the following chemical reaction.

$$3H_2(g) + N_2(g) \rightleftharpoons 2NH_3(g)$$

This production process is both energy- and carbon emissions-intensive. As shown in the reaction, ammonia is synthesized from hydrogen, and natural gas via SMR forms 72% of the total feedstock for hydrogen required for ammonia production, generating a high amount of carbon emissions. Overall, ammonia production contributes 2% of global energy consumption (8.6 EJ) and 1% of CO_2 emissions, which amounts to 450 Mt CO_2 (Zincir, 2022). Therefore, with a system boundary that includes the production process for accounting for carbon emissions, the use of ammonia has a high carbon footprint. However, ammonia itself does not have any carbon content.

Like hydrogen production categories, ammonia production paths are classified under different terms by the colors. For example, brown ammonia is fossil-based ammonia produced from coal or natural gas that generates the highest amount of CO_2 emissions. Blue ammonia is produced with fossil fuel but with a carbon capture and storage (CCS) system, which can significantly reduce CO_2 emissions. Lastly, green ammonia is a carbon-free production process that uses renewable energy (solar, wind) to power electrolysis to get pure hydrogen and direct-air capture for nitrogen. With clean hydrogen and nitrogen acquired from renewable energy, they are combined via the Haber-Bosch process, which is powered entirely by renewable electricity to form ammonia compounds (Zincir, 2022). Since 90% of carbon emission from brown ammonia production is from the SMR process to generate hydrogen, it is essential to use low-carbon hydrogen when making ammonia compounds (The Royal Society, 2020). Figure 18 describes one simplified pathway toward green ammonia production.

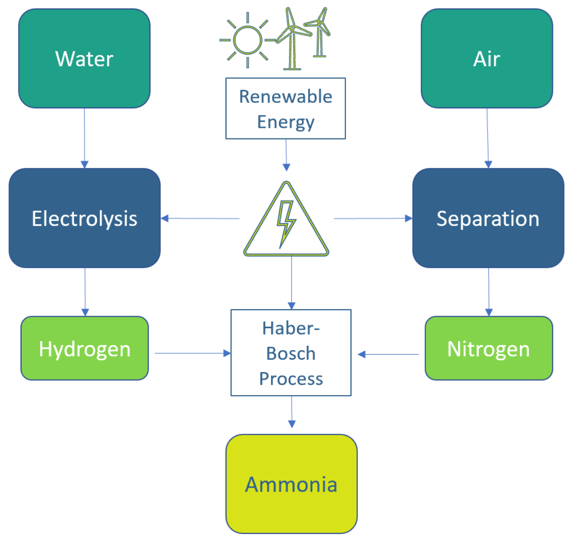


Figure 18 Example pathway to green ammonia production

With the deployment of green hydrogen production technologies, green ammonia production has the potential to expand as it shares the same process of generating hydrogen using renewable electricity.

2.5.3 Ammonia Infrastructure

Ammonia has existing infrastructure globally as it is already stored and handled in 120 ports around the world, with the capacity to deliver around 100 million tons of ammonia yearly (Zamfirescu and Dincer, 2008). Thanks to its globally traded history, ammonia also has storage tanks infrastructure available. However, in addition to its existing distribution network, ammonia would require the development of bunkering (fueling) facilities as currently, ammonia is not used as fuel in the shipping industry. The current infrastructure must be massively scaled up to meet the energy demand for shipping (IEA, 2019a).

2.5.4 Ammonia Storage

Ammonia is easier to store than hydrogen as it can be stored as a liquid at ambient temperature by applying 10 bar or at ambient pressure with a temperature of -34°C (McKinlay et al., 2021). However, ammonia's high toxicity must be carefully addressed for the storage process, as relatively low levels of exposure (100 µmol /L) can lead to the loss of consciousness (University College of London, 2020). Therefore, like hydrogen, ammonia requires additional safety protocols, storage system designs, and training to be safely used as fuel.

2.5.5 Ammonia-Based Power Propulsion System

Ammonia can power propulsion systems in two ways, as shown in Figure 19.

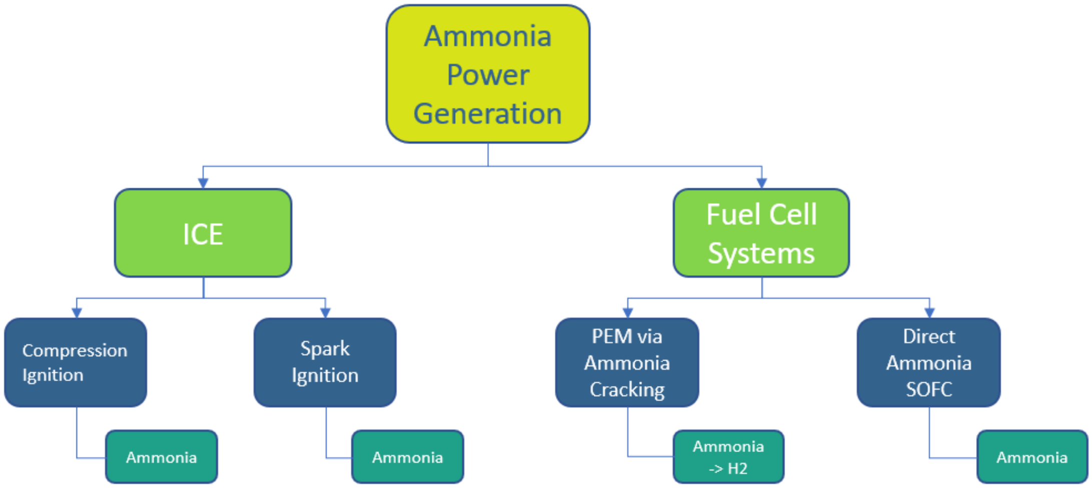


Figure 19 Possible power propulsion systems to be fueled with ammonia

The first approach is to fuel ICEs, but ammonia would require secondary ignition promoters to overcome its lower ignition energy because ammonia's flame speed is too slow and engine modifications (IEA, 2019a). In this case, an efficiency of around 40% can be achieved (Zamfirescu and Dincer, 2008).

The second option is to use ammonia to power fuel-cell systems. Solid oxide fuel cells have been considered the most commonly studied type of ammonia-fed fuel cell technology due to their high energy conversion efficiency and flexibility (Jeerh et al., 2021). There have been some recent developments for direct ammonia fuel-cell systems in which ammonia can be directly used as feedstock for solid oxide fuel cells with efficiencies as high as 55%, but actual overall system efficiencies of around 40% due to the cooling effect. The reason for this gap is that the efficiency of fuel cells is highly dependent on the optimum operating conditions of temperature. For example, a temperature drop of 100°C degrades the power density by about 66% (Zamfirescu and Dincer, 2008). Although there are many research developments to improve the efficiencies of ammonia fuel cells, the study by Jeerh et al (Jeerh et al., 2021) concluded that progress in the commercialization stage of direct ammonia fuel cells is still underway due to several technical challenges, such as stability and power density.

Another way is to use Proton Exchange Membrane (PEM) fuel cell systems using ammonia as a hydrogen carrier. PEM fuel cell systems are commercially available and have been applied in other transportation modes such as cars and buses. However, PEM fuel cell systems can only use hydrogen as fuel. In this case, ammonia is used as a hydrogen carrier, which can be converted to hydrogen through ammonia cracking that requires a high temperature (~1000 °C) (de Vries, 2019). The energy cost to provide high-temperature operating conditions for ammonia cracking is not negligible. Several experimental research still have not been proven for large-scale marine applications (McKinlay et al., 2021). Therefore, in the foreseeable future, ICEs would be the most reasonable and promising option to use ammonia as fuel to power the ship's propulsion systems with proper NOx emission control systems to mitigate NOx emissions.

2.6 Methanol

Methanol (CH_3OH) is a versatile and essential chemical building block for various applications with a long history of being commercially shipped, handled, and stored. Methanol is clear, colorless, biodegradable, and liquid at ambient temperature (Methanol Institute, 2022a). Methanol is widely used for chemical derivatives such as construction materials, consumer products, and industrial products. Methanol is used as a liquid fuel today to power industrial boilers, cooking stoves, cars, buses, trucks, and ships (Methanex Corporation, 2020). In terms of molar mass, the carbon content of methanol is lower than that of natural gas. For methanol, the molar mass is 32 g/mol, and the carbon content per 1 mol is 12/32 *100 = 37.5 %. For natural gas (methane), the carbon content is 12 / 16 * 100 = 75%. Taking into specific energy content (kWh/kg) of each fuel and the ratio of the molecular weight of CO_2 to the molecular weight of carbon, the specific CO_2 emission amount at the point of use can be calculated per energy basis using this equation (Engineering Toolbox, 2022):

$$qCO_2 = \frac{Cf}{Hf} * \frac{MCO_2}{MC}$$

where

qCO_2 = specific carbon dioxide emission (kg CO_2/kWh)

Cf = specific carbon content in the fuel (kg Carbon/kg fuel)

Hf = specific energy content in the fuel (kWh/kg fuel)

Mc = molecular weight of Carbon (kg/kmol Carbon)

MCO_2 = Molecular weight of Carbon Dioxide (Kg/kmol CO_2)

Using the above equation, the specific CO_2 emission for methanol is 70 kg CO_2/GJ, whereas that of heavy fuel oil and natural gas is 75 kg CO_2/GJ and 50 kg CO_2/GJ, respectively. Specific CO_2 emissions only represent Tank-to-Wake emissions, and the life cycle emissions should also be considered when comparing alternative fuels, which will be discussed in Section 2.7.4. Despite its carbon content, methanol is a relatively clean-burning fuel compared to HFO with the potential to be used as an emission-free fuel without any nitrogen or sulfur content (McKinlay et al., 2021). In terms of CO_2 emission, if methanol is produced from renewable hydrogen synthesized with a CO_2 feedstock from bioenergy or direct air capture, the life cycle emissions can achieve net zero (Gielen, 2022). As such, in recent years, methanol has been gaining traction as an alternative marine fuel. According to the Fourth IMO GHG study, methanol is estimated to be the fourth most significant fuel in the shipping industry, with approximately 130,000 tonnes of consumption in 2018 (IMO, 2020a).

2.6.1 Methanol as a Fuel

Recently, the fuel transition in shipping is gaining momentum with the increased alternative fuel uptake in the number of ships in order, according to the DNV report in 2022. In 2019, 6% of total ships on order had alternative fuel systems, and 0.08% of the new vessels utilized methanol as fuel, as shown in Figure 20. In 2021, the number increased to 11.84%, with 0.3% using methanol. Specifically, 13 tankers are under order, and 13 tankers are in operation (DNV, 2022).

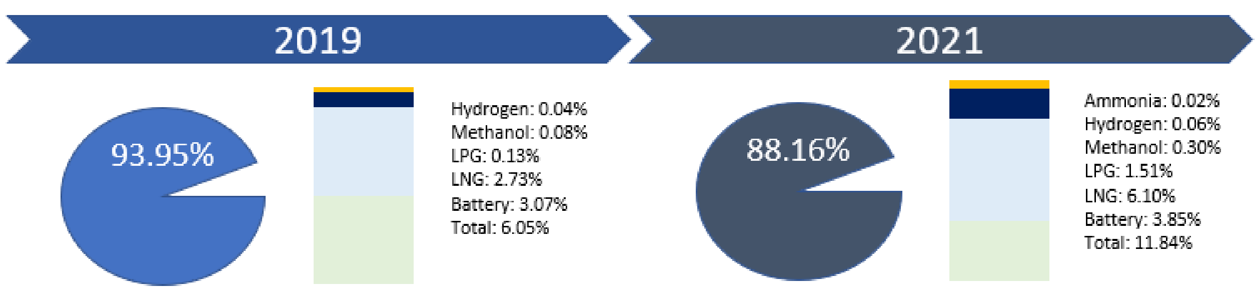


Figure 20 Alternative Fuel Ships on order, reproduced from (DNV 2022)

When methanol is used for combustion, it will have slightly higher CO_2 emissions than LNG for the equivalent energy output with reduced CO_2 emissions by 15% compared to HFO (Methanex Corporation, 2020), depending on the production pathways. Methanol has no sulfur content, so it can reduce SOx emissions by 95%-99%, making it an attractive, environmentally friendly fuel option. NOx can still be produced due to nitrogen in the air, but several sources indicate that NOx emissions would be around 60% of HFO (McKinlay et al., 2021), with an annual NOx reduction of approximately 30% (DNV, 2022). In addition, methanol can help improve air quality and human health by reducing Particulate Matter emissions by 95% (Methanex Corporation, 2020). These low-emission characteristics of methanol will help meet the stringent IMO 2020 regulations toward transitioning to low sulfur fuel and meeting Tier III NOx standards while reducing CO_2 emissions.

2.6.2 Methanol Production

Currently, methanol is globally produced at 70-98 Mt per year (McKinlay et al., 2021) (IRENA, 2021). Most methanol today is primarily produced from fossil fuel feedstock such as natural gas or coal (Collodi et al., 2017). Other feedstocks include biomass and agricultural waste. Similar to hydrogen production, there is a wide range of emission variations depending on methanol production pathways. If fossil fuel is used as the primary feedstock, the process is highly energy intensive and generates high CO_2 emissions. The current methanol production has 0.3 Gt of life-cycle CO_2 emissions per annum that contributes to 10% of total chemical sector emissions. This number if projected to grow as the production could increase to 500 Mt per annum by 2050 which would be equivalent to 1.5 Gt of CO_2 emissions based on fossil fuel feedstock (IRENA, 2021).

Methanol production can also be decarbonized using renewable energy. Methanol produced from renewable sources such as biomass and renewable electricity is called renewable methanol, and they make up less than 0.2 Mt methanol production annually. There are sub-categories in renewable methanol: Bio-methanol and green e-methanol. Bio-methanol is a more common type of renewable methanol, and it is produced from biomass feedstocks such as forestry and agricultural waste. Green e-methanol is made by using CO_2 captured from renewable sources such as bioenergy with carbon capture and storage (BECCS) and direct air capture (DAC) and green hydrogen with renewable electricity (IRENA, 2021). Figure 21 illustrates possible pathways to green methanol production.

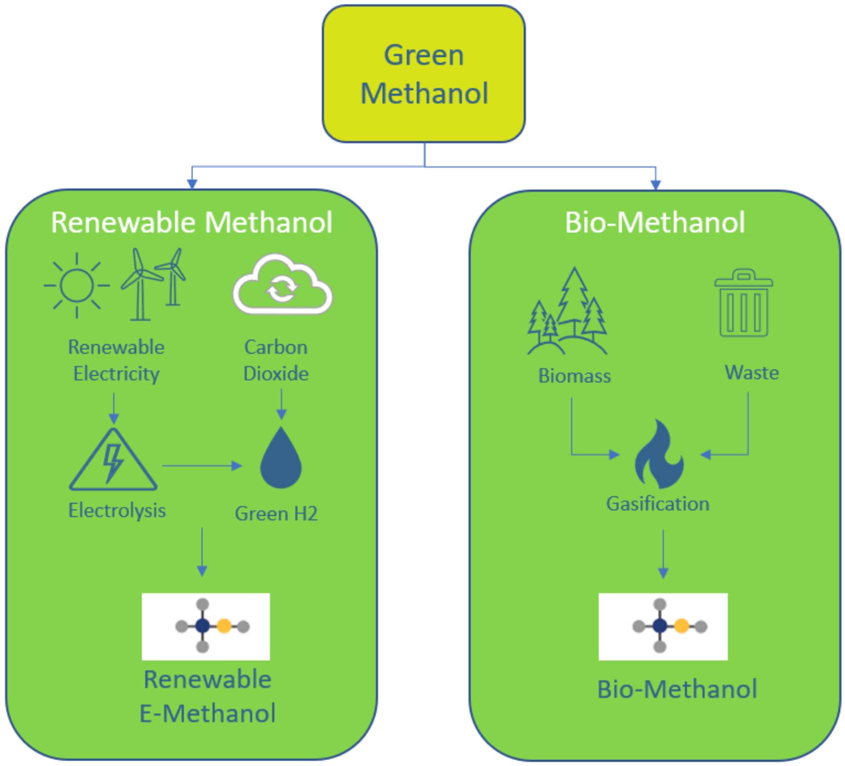


Figure 21 Green methanol production pathways

2.6.3 Methanol Infrastructure and Storage

Methanol has a well-established infrastructure with global availability. Methanol has been globally traded and available in almost 90 of the world's top 100 ports (Methanex Corporation, 2020). To be used as marine fuels on a large-scale, only minor modifications to existing bunkering and storage infrastructure will be needed as methanol is liquid at ambient temperature and pressure with a boiling point of 65 °C (McKinlay et al., 2021). This characteristic makes storing methanol relatively easier than hydrogen or ammonia. Due to its characteristics similar to conventional fuels, methanol is subject to the same bunkering guidelines (Methanol Institute, 2020).

However, from acute exposure, methanol has toxic properties for humans (Kavet and Nauss, 1990). As such, additional monitoring systems to enhance safety would be required. Methanol has over 100 years of history as being handled in various applications. Recently, IMO and other risk classification societies have developed standards and guidelines for methanol as a marine fuel. In September 2019, the IMO's CCC5 sub-committee completed interim guidelines covering the safety of ships using methanol as fuel, and it is expected to be added to the International Code of Safety for ships (Methanol Institute, 2020).

2.6.4 Methanol-Based Power Propulsion System

Several sources indicate that methanol is a cost-effective alternative fuel considering the low fuel cost and the existing infrastructure. It is also known that the cost to convert existing vessels to run on methanol is significantly less than other alternative fuel conversions and ship upgrades, thanks to dual-fuel engines (Methanex Corporation, 2020). The fuel cost and the total cost of ownership model will be discussed in more detail in the next chapter. In this section, the main methanol-based power generation options are illustrated.

Figure 22 illustrates simplified options for a methanol-based power propulsion system. The main method of powering propulsion using methanol is using a dual-fuel engine. Methanol dual-fuel engines are commercially available and have already been operated at sea for many years. MAN Energy Solutions developed the ME-LGIM (Liquid Gas Injection Methanol) dual-fuel engine for operation on methanol and conventional fuel. These engines are based on the traditional diesel engine principles and allow the easy switch between methanol and conventional fuel. The ME-LGI dual-fuel engines have accumulated more than 110,000 dual-fuel running hours (MAN Energy Solutions, 2021).

Methanol can also be used to feed fuel cell systems for power generation. For example, methanol can feed fuel cells directly via Direct Methanol Fuel Cell (DMFC), a subcategory of proton exchange fuel cells, with low energy conversion cost (Mekhilef et al., 2012). Reformed Methanol Fuel Cell (RMFC) or Indirect Methanol Fuel Cell (IMFC) systems reform methanol to generate hydrogen fed to the fuel cell. In the latter case, methanol is used as a hydrogen carrier because of its higher volumetric energy density than hydrogen gas. Methanol-based fuel cell systems have primary applications for portable electronic devices that can be an alternative solution for rechargeable batteries (Kamarudin et al., 2009). More recently, methanol fuel cells have expanded their applications for charging batteries for forklifts and camper vans and provisioning off-grid or grid-support power as a backup power supply to telecom towers, remote communities, and off-grid mining (Methanol Institute, 2021b).

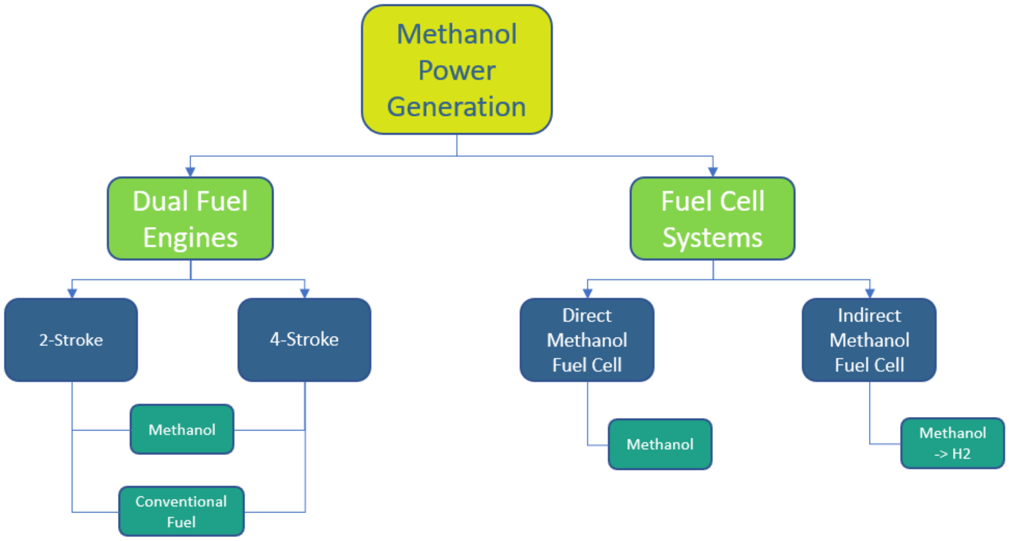


Figure 22 Examples of methanol power propulsion pathways

2.7 LNG

In 2020, natural gas demand hit around 4000 billion cubic meters globally, with OECD countries accounting for 45% of the total demand, and the trend has been increasing since 1975 (IEA, 2020b). In 2020, natural gas constituted 34% of the U.S. primary energy consumption, about 31.53 quadrillion British thermal units (EIA, 2021d), making it the second largest energy source after petroleum (35%). Liquified Natural Gas (LNG) is natural gas in a liquefied form. LNG is used for storage, transport, and shipping natural gas at a liquid state (-162 °C), where the volume becomes about 600 times smaller than its volume in its gaseous form (Energy.gov, 2022). With the compact volume footprint, LNG can provide access to natural gas to places even where the primary mode of delivery, pipelines, cannot reach.

2.7.1 LNG Production and Infrastructure

LNG is exported to many countries and traded globally. Special ocean-going LNG ships or LNG tankers exist to transport LNG. Most LNG is transported by tankers called LNG carriers equipped with large, cryogenic tanks to maintain the liquified state of LNG. In 2019, the U.S. was the largest producer of natural gas, followed by Russia, Iran, China, Canada, Qatar, and Australia (EIA, 2021a). In 2020, the U.S. exported around 2,400 billion cubic feet of natural gas in the form of LNG primarily via large LNG tanker ships, which delivered LNG to 40 countries as of August 2021 (Energy.gov, 2022). Other major LNG exporters are Qatar and Australia.

2.7.2 LNG as a Fuel

LNG has been used as an alternative to HFO as a marine fuel mainly because LNG has no sulfur emissions and emits fewer NOx emissions. This characteristic makes LNG an attractive fuel in the four IMO-designated Emission Control Areas (the Baltic Sea, the North Sea, North America, and the U.S. Caribbean) where sulfur and nitrogen oxide emissions regulations have become more stringent (Pavlenko, 2020). LNG is considered to have a relatively low environmental impact compared to conventional HFO, as LNG emits almost no Particulate Matter and emits less CO_2 than HFO (about 25% reduction) when burned (Mitsui O.S.K. Lines, 2021). Even with the IMO's Energy Efficiency Design Index (EEDI) regulations which only limit the amount of CO_2 emitted from shipping, LNG can help shipowners meet these regulations. However, LNG consists of methane, a greenhouse gas with higher global warming potential than CO_2. The carbon content of LNG and HFO is 75% and 85%, respectively (Engineering Toolbox, 2022). Since the EEDI regulations do not regulate GHGs, including methane, LNG remains an effective and practical solution. In addition, the price of LNG has been less high than conventional fuels (MGO, HFO, and recently VLSFO). As such, the number of ships using LNG as fuel has increased, and there were more than 750 LNG-powered ships in 2019 (Pavlenko, 2020).

2.7.3 Renewable Natural Gas (RNG)

Renewable natural gas (RNG) can potentially substitute natural gas and refers to treated biogas, or bio-methane, which can be produced from a variety of sources, including municipal solid waste landfills, livestock farms, and agricultural waste (US EPA, 2018). RNG can be injected into the existing natural gas pipeline or transported via trucks. RNG can be used as a "drop-in" fuel as the chemical properties are identical to methane in natural gas. RNG's potential use cases include vehicle fuels, generating electricity, and heating for various sectors, similar to natural gas. In terms of GHG emissions, RNG is less carbon-intensive than other fossil fuels, including natural gas, especially if the organic waste is used to produce RNG, which reduces methane emissions (EPA, 2021).

The current barriers to RNG include both economic and technical ones. From the fuel production perspective, RNG has a cost range of USD 7/MMBtu to USD 25/MMBtu (Williams, 2016), according to a study published by the Environmental Protection Agency (EPA), resulting in about 2-10 times more expensive than LNG from fossil fuels (excluding their recent price spike). In addition, there is a high additional cost to implement pipeline interconnection for RNG projects in local production sites. Technically, RNG faces challenges such as meeting varying specifications regarding the heating value and treating biogas with sub-optimal quality with lower methane concentrations (EPA, 2021). In addition to these current barriers, RNG demonstrates higher lifecycle GHG emissions (between 40 to 80 g CO_2e/MJ (EPA, 2021)) than other clean-burning alternative fuels, making RNG a less attractive alternative fuel pathway. For this study, RNG is not considered in the analysis as the focus is on clean-burning alternative fuels and because of limited RNG availability.

2.7.4 Life-cycle Emissions of LNG

To better account for the actual carbon footprint of using LNG as a marine fuel, it is essential to evaluate the life-cycle emissions of LNG, as there is upstream methane leakage and downstream methane slip, which can pose a severe threat to global warming (Pavlenko, 2020). For example, the extraction, processing, and transport of LNG also emit GHG, which increases the life-cycle emissions of LNG. For LNG export options, the life-cycle emissions of LNG are estimated to be 700-900 g CO_2 equivalent/kWh comparable to that of coal (1000 g CO_2e/kWh) (Abrahams et al., 2015). Moreover, leaks of methane during the extraction and transport of LNG can constitute up to 14% of LNG's life-cycle emissions (Alvarez et al., 2018), which can be a threat to limiting global warming to 1.5 °C due to methane's high global warming potential, unless the leaks are strictly controlled.

The International Council on Clean Transportation (ICCT) recently conducted a study to compare the life-cycle emissions of LNG and other traditional fuels to assess the climate implications of using LNG as marine fuels (Pavlenko, 2020). In the report, ICCT used the GREET (Greenhouse gases, Regulated Emissions, and Energy use in Transportation) model developed by Argonne National Laboratory in 2018. The breakdown of well-to-wake emissions is shown in Figure 23.

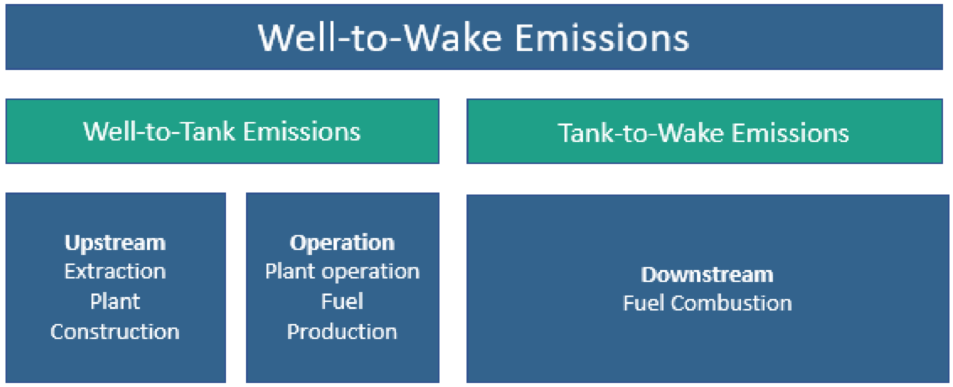


Figure 23 Maritime Life-cycle Emission, adapted from (GREET, 2018)

Based on the GREET model, the well-to-tank emissions, which include upstream and operation for LNG and other conventional fuels, are shown in Table 6. LNG has higher CO_2 equivalent emissions (methane) than traditional fuels such as HFO or MGO.

Table 6 Well-to-Tank emissions (g/MJ), reproduced from (GREET, 2018)

	HFO	VLSFO	MGO	LNG
CH_4	0.1	0.1	0.1	0.1
N_2O	0.0	0.0	0.0	0.0
CO_2	10.7	12.9	13.5	11.0
CO_2e (100-year)	14.3	16.8	17.4	21.5
CO_2e (20-year)	19.2	22.0	22.7	35.6

For downstream tank-to-wake emissions, the results are summarized in Table 7. The CO_2 emissions from the combustion of LNG are lower than those of other conventional fuels. As expected, HFO emits the most amount of CO_2 during combustion. The methane emissions in this table are from combustion only, and the methane slip amount per engine type is added separately for the life-cycle emission estimation.

Table 7 Tank-to-Wake combustion emissions (g/MJ fuel), reproduced from (GREET, 2018)

	HFO	VLSFO	MGO	LNG
CH_4	$7.5x10^{-4}$	$7.4x10^{-4}$	$7.5x10^{-4}$	$1.8x10^{-2}$
N_2O	$3.9x10^{-3}$	$3.8x10^{-3}$	$3.9x10^{-3}$	$1.6x10^{-3}$
CO_2	80.1	75.6	73.6	56.5
CO_2e (100-year)	81.2	76.6	74.7	57.5
CO_2e(20-year)	81.2	76.7	74.7	58.4

The ICCT then compared the life cycle GHG emission using LNG as marine fuels by considering commonly used engines for 20-year GWP. HDPF (High-pressure injection dual-fuel), and LDPF (low-pressure injection dual-fuel) engines have been included in the analysis.

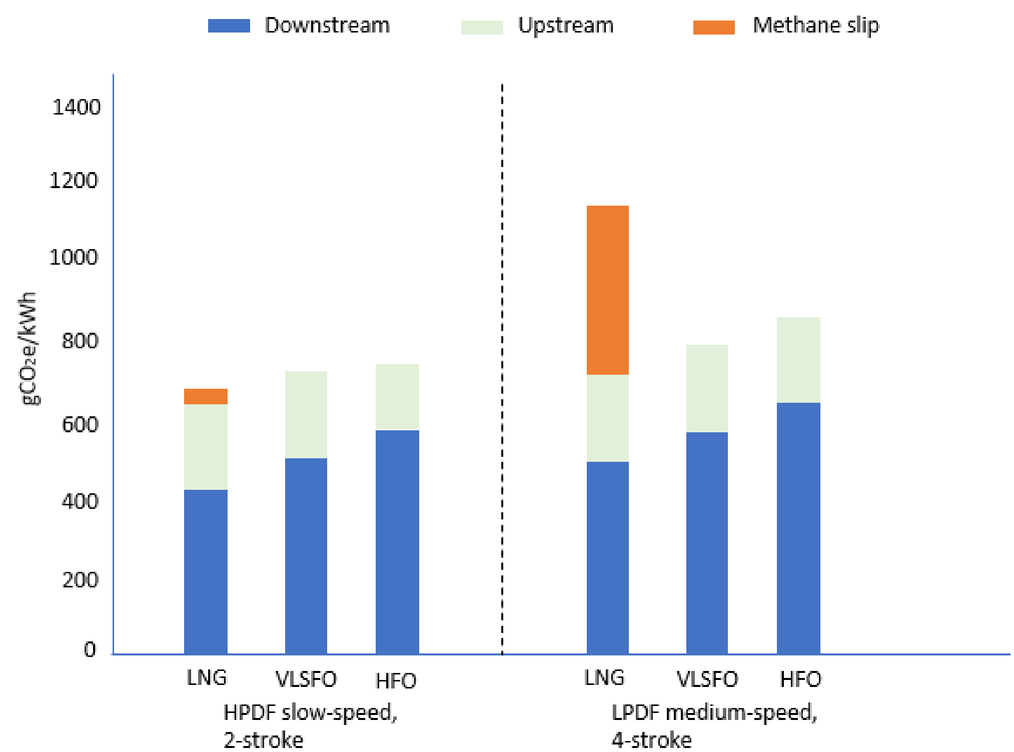


Figure 24 Life-cycle GHG emissions by engine and fuel type, 20-year GWP, adapted from (Pavlenko, 2020)

Except for HPDF engines, where LNG emissions are about 3% lower than VLSFO, LNG has much higher life-cycle GHG emissions than other conventional fuels for LPDF engines. This high emission is notable because methane slip constitutes a significantly large portion of the total GHG emissions. For LPDF 4-stroke engines, methane slip accounted for more than downstream emissions from fuel combustion. IMO's policy and regulation only concern the downstream emissions, so the need for using life-cycle emissions is evident when evaluating LNG as a marine fuel.

LNG also requires the installation of engines that can use LNG fuel and heavy capital investments and infrastructure development such as bunkering facilities and liquefaction facilities (Swanson et al., 2020). Such heavy investment decisions need to be holistically and conservatively reviewed because the environmental impact will be irrevocable in the near term, considering the long lifespan of marine vessels (~25 to 30 years). For this study, due to the high life cycle GHG emissions, LNG is not considered as a potential alternative fuel solution but will be used for comparison.

2.8 Well-to-Wake Emissions of Alternative Fuel Pathways

This section compares the lifecycle well-to-wake emission factors for alternative fuel options. The emissions factors are compiled from various sources ((Pavlenko, 2020), (Gray et al., 2021), (Olmer et al., 2017)) and they generally align, except for the methane slip estimation from LNG, which has vast variations. In a recent publication (Gray et al., 2021), the emission factors for green ammonia, methanol, and H_2 are extracted, and the well-to-wake emissions are presented in Figure 25. It needs to be noted that LNG's methane slip emissions are not included, but if methane slip accounts for 14% of total emissions as presented in the previous section, then LNG's lifecycle emission is comparable to that of HFO. Moreover, according to the report, if grid electricity is used for electrolysis, the process can lead to very high carbon intensities if the electrical grid is still reliant on fossil fuels. In other words, electric fuels produced from grid relying on fossil fuels can have a greater carbon intensity than HFO, making them inviable alternative fuel options to meet environmental imperatives. RNG also demonstrates higher lifecycle GHG emissions (between 40 to 80 g CO_2e/MJ (EPA, 2021)) than green ammonia, methanol, or hydrogen. Therefore, in the next chapter for cost modeling, all alternative fuels are assumed to be produced using renewable electricity from clean energy sources that minimize lifecycle emissions.

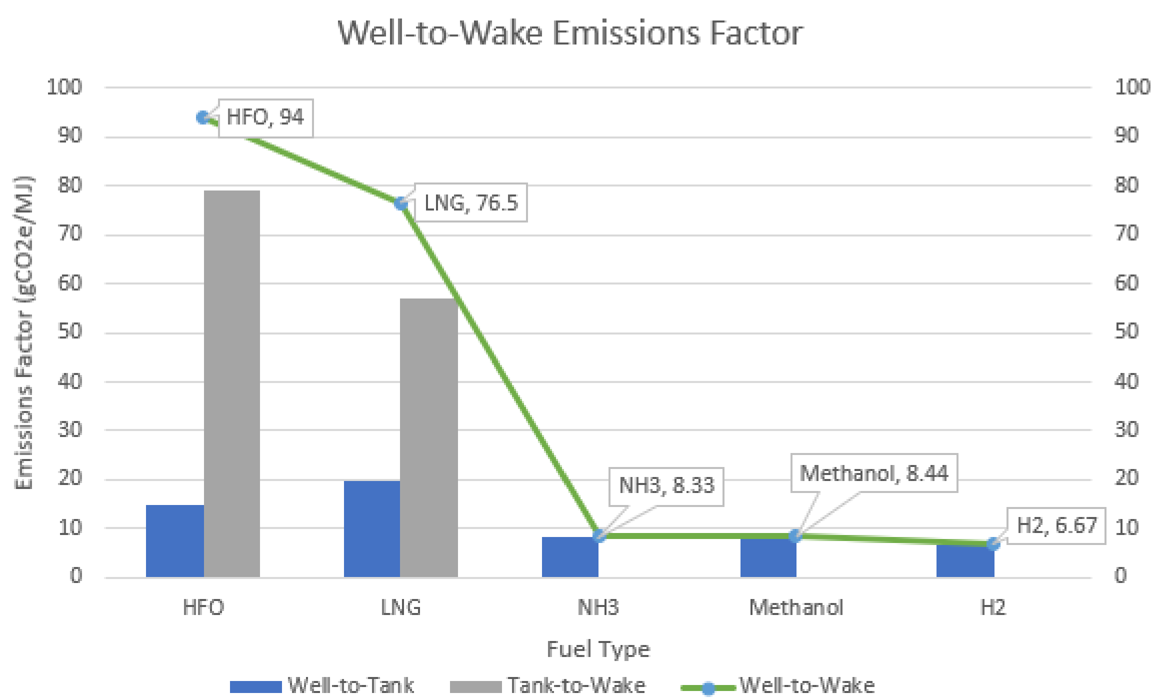


Figure 25 Well-to-Wake emissions factor of conventional and green alternative fuels, adapted from (Gray et al., 2021)

Chapter 3 – Cost Model

It is necessary to provide cost estimations associated with various alternative marine fuel technologies to assess the future economic impact of alternative marine fuel pathways. In this chapter, I developed simplified levelized cost of energy (sLCOE) models to estimate the fuel production cost for each pathway. After I developed the models, I validated the results with various sources and presented sensitivity analyses. Next, I developed the total cost of ownership models of alternative fuel pathways and the reference pathway to estimate the lifetime cost of vessels. For modeling the economic competition between alternative and conventional fuels, I use a *markup* approach (Morris et al., 2019) that represents the cost of technology relative to the price of traditional fuel. If the markup is greater than one, technology is not economical unless supported by other means, such as subsidies, standards, or requirements. I also use the same approach for the total cost of ownership of vessels. The results from the cost models are used in Chapter 4 to assess the economic implications for alternative fuels using the EPPA model. Figure 26 conceptually represents the process of developing a cost model for alternative marine fuel technologies.

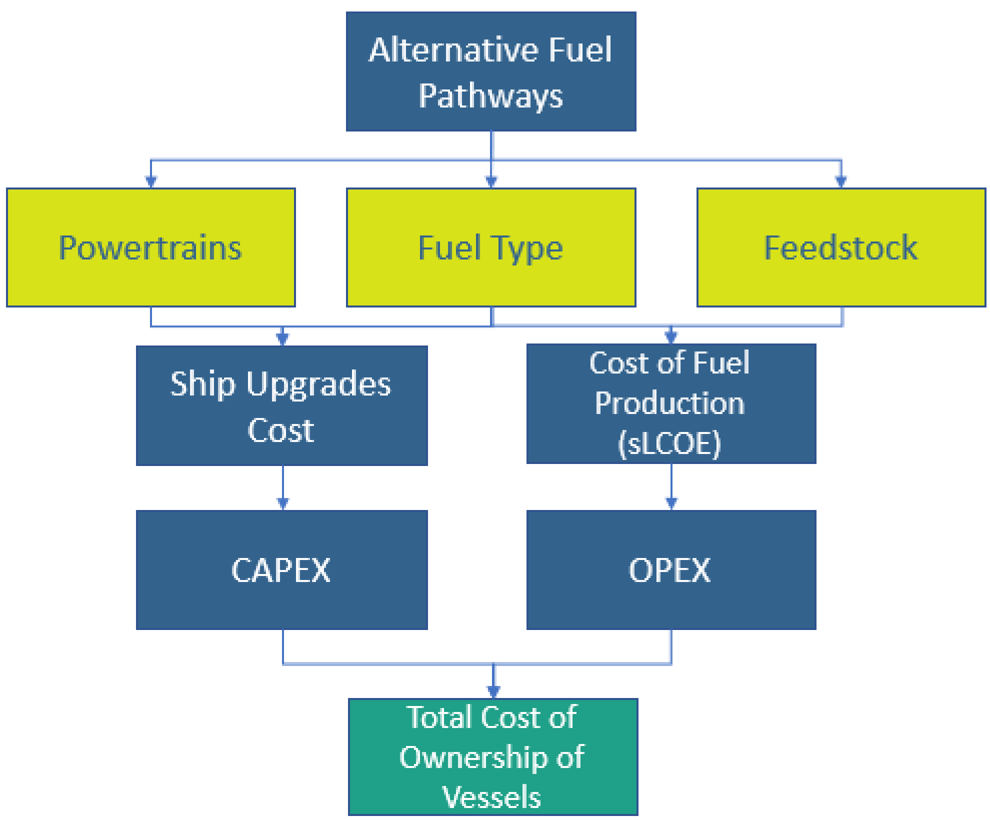


Figure 26 Process of developing cost models for maritime vessels

Based on the literature review from Chapter 2, several promising alternative marine fuel pathways have been selected. Marine vessels can be framed as a system, which is defined as a set of interrelated entities whose functionalities are greater than the sum of the parts (Crawley et al., 2016). Ships are comprised of several sub-systems such as powertrains, storage, fuels, and payload space with interfaces connected to components outside the system boundary, such as infrastructure and bunkering facilities. All these sub-systems constitute the ship system.

Several system decisions and options have been identified for alternative maritime fuel pathways, as shown in Table 8. The carbon capture, utilization, and storage (CCUS) decision is abstracted away and not included in the scope of this study. Instead, alternative fuels generated from fossil fuels with high carbon emissions and renewable energy sources with low carbon emissions are analyzed. For feedstock, fossil-fuel energy sources and renewable energy sources are considered. For fuel types, HFO is used as a reference fuel, and LNG is used for comparison. Alternative fuel types are liquid hydrogen (LH_2), ammonia (NH_3), and Methanol (MeOH). Finally, for powertrain options, internal combustion engines (ICE), dual-fuel engines for methanol, and fuel cell systems for hydrogen and ammonia have been included in the analysis.

Table 8 Alternative fuel system design decisions – options for the analysis are highlighted in black

System Decisions	Option 1	Option 2	Option 3	Option 4	Option 5
Feedstock	Fossil-Fuel	Renewable Energy	Biomass		
Processing	CCUS	No CCUS			
Fuel Type	HFO	LNG	LH2	Ammonia	Methanol
Powertrain	ICE	Dual-Fuel Engines	Fuel Cell Systems	Multi-Fuel Engines	Steam-Turbines

Next, various sources, as shown in Table 9 have been used to compile the cost data for each pathway. I used a bottom-up approach to develop the cost model, starting from the cost of production of alternative fuels based on different feedstocks. As there are different powertrain options with varying system efficiencies, I calculated the energy cost to model the cost of energy used for propulsion (USD/MJ shaft output). This energy cost is then used as a significant component of operating expenditures (OPEX), and capital expenditures (CAPEX) required to implement the new systems. Finally, based on OPEX and CAPEX estimations, the total cost of ownership (TCO) model has been developed for a few common vessel types.

3.1 Fuel Cost Modeling

I synthesized data from various literature, developed fuel cost models, and converted cost results to USD_{2020}/MJ shaft output metric to represent fuel cost and to compare costs of different energy carriers. This metric has a system boundary that includes the system efficiency of converting energy and the specific energy content of the fuel. For alternative fuels such as ammonia, hydrogen, and methanol, the levelized cost of production is used as an estimate of the price of delivered fuel. For existing commercial HFO and LNG, the current market price is used for a cost comparison.

3.1.1 Data Sources

For levelized costs of production of alternative fuels, the IEA's Future of Hydrogen report (IEA, 2019a) has been selected to provide base assumptions for the model, which used a detailed bottom-up analysis. In the annex of the report, various assumptions have been made, and relevant ones are summarized in this chapter. To validate green ammonia production costs from the IEA report, I used Zhang's study (Zhang et al., 2020) of the techno-economic comparison of the green ammonia production process. For methanol production cost, I used a detailed analysis of methanol production pathways for validation (IRENA, 2021). For hydrogen production cost, I selected the IEA's global average levelized cost of hydrogen production by energy source and technology for cross-reference. For the current market price of globally traded HFO, I used Ship and Bunker's global average price (Ship and Bunker, 2022) for IFO 380 since 2019. For LNG price, I used U.S. Energy Information Administration (EIA)'s LNG price since 2019 (EIA, 2021c). To validate the results from the cost models, I used several sources (de Vries, 2019) (ISPT, 2017) (Methanol Institute, 2022b) to compare the cost results.

Table 9 Data sources for cost models

Data	Reference
CAPEX & OPEX assumptions	(IEA, 2019a) (IEA, 2020a)
Green Ammonia Production Costs for Validation	(Zhang et al., 2020) (de Vries, 2019)
Green Methanol Production Costs for Validation	(IRENA, 2021) (Methanol Institute, 2022b)
Green Hydrogen Production Costs for Validation	(IEA, 2020c)
HFO price	(Ship and Bunker, 2022)

LNG Price	(EIA, 2021c)
Fuel Properties	(de Vries, 2019) (McKinlay et al., 2021)

3.1.2 Energy Density of Fuels

Marine fuels have a wide range of different energy densities. To properly compare the cost of marine fuels, it is necessary to convert the cost or price of the fuel per unit of energy. For the energy units, mega-joules (MJ) or megawatt hours (MWh) are commonly used in various literature. The energy densities are usually reported in MJ/volume of fuel or MWh/volume of fuel, and they are also called volumetric energy densities. Other common units for energy densities are called specific energy or gravitational energy, and they represent the energy density of a fuel per unit mass (MJ/kg or MWh/kg). In this study, for energy units, MJ is used. Table 10 presents the energy density and specific energy of five marine fuels – HFO (reference fuel), LH_2 (Liquid hydrogen), NH_3 (Ammonia), Methanol, and LNG (Liquefied Natural Gas). For unit conversions, 1 MWh = 3,600 MJ, and 1 tonne (metric ton) = 1,000 kg is used.

Table 10 Energy densities of marine fuels, adapted from (de Vries, 2019)

Fuel	Volumetric Density (MJ/m^3)	Volumetric Density (MWh/m^3)	Gravitational Density (MJ/kg)	Gravitational Density (MWh/kg)	Gravitational Density (MJ/tonne)
HFO	34920	9.7	41.76	0.0116	41760
LH_2	8496	2.36	119.88	0.0333	119880
NH_3	17352	4.82	18.72	0.0052	18720
Methanol	17964	4.99	19.8	0.0055	19800
LNG	20988	5.83	51.912	0.01442	51912

Figure 27 compares volumetric energy densities and gravitational densities of the fuels. Liquid hydrogen has the highest gravitational energy, meaning it has the highest energy content per unit mass. However, liquid hydrogen has the lowest volumetric density, making it challenging to store and handle. HFO has the highest volumetric density, although its gravitational density is lower than that of LNG or LH_2. Ammonia and methanol share similar energy densities, with methanol having slightly higher gravitational density and volumetric density than ammonia. LNG, one of the most used fuels, has around 60% volumetric energy density compared to HFO, leading to higher storage space on vessels.

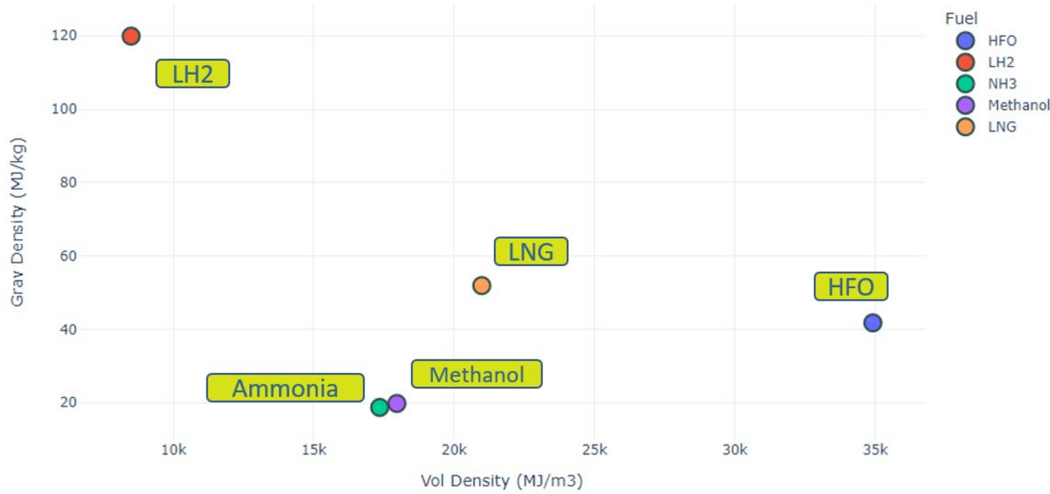


Figure 27 Comparison of energy densities of fuels

3.1.3 Simplified Levelized Cost of Energy (sLCOE) Model for Alternative Fuels

To estimate fuel cost, I have developed levelized cost of production models for alternative fuels – hydrogen, ammonia, and methanol for this study. I synthesized the recent market prices from various sources for commercially available marine fuels, such as HFO and LNG. The levelized costs of production for alternative fuels include Capital Expenditures (CAPEX), Operating Expenses (OPEX), and feedstock/fuel prices but do not include distribution cost or profit margin. Specifically, CAPEX includes core process equipment, and OPEX includes fuel, feedstock costs, and the cost of electricity for electrolysis. The list of assumptions for calculating production costs is listed in Table 11.

Table 11 List of assumptions for levelized costs, reproduced from (IEA, 2020a)

Fuel Type	Technology	Parameter	Units	2017
	Electricity Price	U.S. Grid	USD/MWh	70
	Renewable Electricity Price	100% Renewable Electricity	USD/MWh	31
Hydrogen	Water Electrolysis	CAPEX	USD/kW	900
		Annual OPEX	% of CAPEX	1.5
		Operating Hours	hours	95000
	SMR	CAPEX	USD/kW	910
		Annual OPEX	% of CAPEX	4.7
Ammonia	Natural Gas	CAPEX	USD/tNH_3	905
		Annual OPEX	% of CAPEX	2.5

		Gas consumption	GJ/t	42
		Electricity consumption	GJ/t	0.3
		CAPEX	USD/tNH_3	1160
		Annual OPEX	% of CAPEX	1.5
	Electrolysis	Electricity consumption	GJ/t	37.8
		CAPEX	USD/t	310
		Annual OPEX	% of CAPEX	2.5
		Gas consumption	GJ/t	33.9
	Natural Gas	Electricity consumption	GJ/t	0.3
		CAPEX	USD/t	790
		Annual OPEX	USD/t	1.5
Methanol	Electrolysis	Electricity consumption	GJ/t	25.4

Next, I calculated the levelized cost of energy (LCOE) for the production of each fuel in $/kg fuel. The levelized cost of energy measures lifetime costs divided by energy production and allows the comparison of different technology's costs over their lifetime ("Levelized Cost of Energy (LCOE)," 2022). For this study, I adapted the simple levelized cost of energy formula (NREL, 2022) developed by the National Renewable Energy Laboratory (NREL), which calculates the levelized cost of energy in $/kW metric. I modified the formula to construct the cost of fuel production models to estimate the levelized cost of fuel production in $/kg metric of each alternative fuel as shown in the following equation: ***Simplified Levelized Cost of Energy (sLCOE)***.

$$Simplified\ Levelized\ Cost\ of\ Energy\ (sLCOE) = \frac{\{Overnight\ Capital\ Cost * Capital\ Recovery\ Factor + Fixed\ O\&M\ Cost\}}{Capacity\ Factor} + Fuel\ Cost + Variable\ O\&M\ Cost$$

where

- Overnight Capital Cost: $/kg
- Capital Recovery Factor: the ratio of a constant annuity to the present value of receiving that annuity for a given length of time with i = interest rate, n = the number of annuities received

$$Capital\ Recovery\ Factor\ (CRF) = \{i * (1+i)^n\}/\{[(1+i)^n] - 1\}$$

- Fixed O&M Cost: $/kg per year

- Capacity Factor: Fraction between 0-1 representing a portion of a year that the power plant is operating
- Fuel Cost: $/kg
- Variable O&M Cost: $/kg

This formula provides a framework that allows the comparison of the combination of capital costs, operation and maintenance, performance, and fuel costs. The LCOE is the minimum price at which energy must be sold for an energy project to break even (NREL, 2022). The simplified formula abstracted a few detailed financial components, such as financing issues and future replacement or degradation costs, which would be needed for a more complex financial analysis (NREL, 2022). However, the core idea is still the same. For comparing alternative fuels with high uncertainties in the future cost estimates, the simplified LCOE would be suitable if used as a common framework to assess the production costs of various fuel types.

Table 12 presents the simplified levelized cost of energy model for ammonia production using natural gas feedstock using the assumptions from IEA as shown in Table 11.

Table 12 Simplified Levelized Cost of Production for ammonia using natural gas

Simplified Levelized Cost of Production for NH_3 with NG & Renewable Electricity

	Periods (yrs)	25.00
	Discount Rate	0.08
	CRF	**0.09**
	Capacity Factor	**0.97**
	Electricity Consumption (GJ/tNH_3) (IEA, 2019a)	0.30
	Natural Gas Consumption (GJ/tNH_3) (IEA, 2019a)	42.00
	Renewable Electricity Price ($/MWh)	31.00
	Natural Gas Price ($/Mbtu)	3.30
	Electricity Price ($/GJ) - Conversion	8.61
Input	Natural Gas Price ($/GJ) - Conversion	3.13
	Overnight Capital Cost ($M)	N/A
CAPEX	Overnight Capital Cost ($/kg NH_3) (IEA, 2019a)	**0.91**
	Fixed O&M Cost (% of CAPEX) (IEA, 2019a)	2.50
Fixed OPEX	Fixed O&M Cost ($/ kg NH_3 -yr)	**0.02**
	Variable O&M Cost Multiplier	1.50
Variable OPEX	Variable O&M Cost ($/kg NH_3)	**0.03**

	Natural Gas Cost ($/kg NH_3)	0.13
	Electricity Cost ($/kg NH_3)	0.0026
	Total Feedstock Cost ($/kg NH_3)	**0.13**
	sLCOE ($/kg NH_3)	**0.28**
	sLCOE ($/tonne NH_3)	**278.61**
Output	Validation from IEA (IEA, 2019a) ($/t NH_3)	200-500

In the model, the output sLCOE is calculated by taking the inputs highlighted in bold in the table (CRF, capacity factor, overnight capital cost, fixed O&M cost, variable O&M cost, feedstock cost) using the sLCOE formula described above. With the natural gas price of $3.3/MMBtu and renewable electricity price of $31/MWh, the sLCOE for ammonia production using natural gas with renewable electricity is estimated to be $278.61/tonne NH_3.

Similarly, the simplified LCOE model is used to calculate the production cost for ammonia via electrolysis. The sLCOE is estimated to be $482.97/tonne NH_3, ssing the same assumptions from Table 11.

Table 13 Simplified Levelized Cost of Production for ammonia via electrolysis

Simplified Levelized Cost of Production for NH_3 via Electrolysis

	Periods (yrs)	25.00
	Discount Rate	0.08
	CRF	**0.09**
	Capacity Factor	**0.90**
	Electricity Consumption (GJ/tNH_3) (IEA, 2019a)	37.80
	Natural Gas Consumption (GJ/tNH_3) (IEA, 2019a)	0.00
	Renewable Electricity Price ($/MWh)	31.00
	Natural Gas Price ($/MMBtu)	3.30
	Electricity Price ($/GJ) - Conversion	8.61
Input	Natural Gas Price ($/GJ) - Conversion	3.13
	Overnight Capital Cost ($M)	N/A
CAPEX	Overnight Capital Cost ($/kg NH_3) (IEA, 2019a)	**1.16**
	Fixed O&M Cost (% of CAPEX) (IEA, 2019a)	1.50
Fixed OPEX	Fixed O&M Cost ($/ kg NH_3 -yr)	**0.02**
	Variable O&M Cost Multiplier	1.00
	Variable O&M Cost ($/kg NH_3)	**0.02**
	Natural Gas Cost ($/kg NH_3)	0.00
Variable OPEX	Electricity Cost ($/kg NH_3)	0.33

	Total Feedstock Cost ($/kg NH_3)	**0.33**
	sLCOE ($/kg NH_3)	**0.48**
	sLCOE($/tonne NH_3)	**482.97**
Output	Validation from IEA (IEA, 2019a) ($/t NH_3)	330-500

Next, using the same framework, the levelized cost of production of methanol from natural gas has been calculated as shown Table 14. The sLCOE for methanol from natural gas is estimated to be $161.12/tonne MeOH.

Table 14 Simplified Levelized Cost of Production for Methanol using NG

Simplified Levelized Cost of Production for Methanol using NG

	Periods (yr)	25.00
	Discount Rate	0.08
	CRF	**0.09**
	Capacity Factor	**0.90**
	Electricity Consumption (GJ/tMeOH) (IEA, 2020a)	**0.30**
	Natural Gas Consumption (GJ/tMeOH) (IEA, 2020a)	**33.90**
	Renewable Electricity Price ($/MWh)	31.00
	Natural Gas Price ($/MMBtu)	3.30
	Electricity Price ($/GJ) - Conversion	8.61
Input	Natural Gas Price ($/GJ) - Conversion	3.13
	Overnight Capital Cost ($M)	N/A
CAPEX	Overnight Capital Cost ($/kg MeOH) (IEA, 2020a)	**0.31**
	Fixed O&M Cost (% of CAPEX) (IEA, 2020a)	2.50
Fixed OPEX	Fixed O&M Cost ($/ kg MeOH -yr)	**0.01**
	Variable O&M Cost Multiplier	1.50
	Variable O&M Cost ($/kg MeOH)	**0.01**
	Natural Gas Cost ($/kg MeOH)	0.11
	Electricity Cost ($/kg MeOH)	0.00
Variable OPEX	Total Feedstock Cost ($/kg MeOH)	**0.11**
	sLCOE ($/kg MeOH)	**0.16**
	sLCOE($/tonne MeOH)	**161.12**
Output	Validation from IEA (IEA, 2019a) ($/t MeOH)	120-310

Table 15 presents the sLCOE results for methanol from electrolysis (green methanol). For green methanol production, the cost is highly dependent on the two raw materials: CO_2 and Hydrogen. CO_2 must be extracted from renewable sources such as biomass or via direct air capture. Hydrgoen must be produced from renewable sources via electrolysis. The methanol synthesis cost is assumed to be USD 50/tonne of MeOH. 0.188 tonne of H_2 and 1.373 tonnes of CO_2 are needed to produce 1 tonne of methanol (IRENA, 2021). The total feedstock cost includes the CO_2 and hydrogen cost. The renewable electricity price is assumed to be USD 31/MWh to be consistent with other LCOE calculations. The green hydrogen cost with renewable electricity of USD 31/MWh is estimated to be USD 3.14/kg H_2, using the sLCOE model for hydrogen production. The sLCOE for green methanol via electrolysis is around USD 885/tonne MeOH.

Table 15 Simplified Levelized Cost of Production for Methanol via electrolysis

Simplified Levelized Cost of Production for Methanol via electrolysis

Input	Periods (yr)	25.00
	Discount Rate	0.08
	CRF	**0.09**
	Capacity Factor	**0.90**
	Electricity Consumption (GJ/tMeOH) (IEA, 2020a)	**25.40**
	Natural Gas Consumption (GJ/tMeOH) (IEA, 2020a)	**0.00**
	Renewable Electricity Price ($/MWh)	**31.00**
	Natural Gas Price ($/Mbtu)	3.30
	Electricity Price ($/GJ) - Conversion	8.61
	Natural Gas Price ($/GJ) - Conversion	3.13
	Methanol Synthesis Cost ($/tonne) (IRENA, 2021)	50.00
	Green Hydrogen Cost ($/kg) @$31/MWh electricity	3.14
	CO_2 feedstock ($/tonne CO_2) from Renewable sources	10.00
CAPEX	Overnight Capital Cost ($M)	N/A
	Overnight Capital Cost ($/kg MeOH) (IEA, 2020a)	**0.79**
Fixed OPEX	Fixed O&M Cost (% of CAPEX) (IEA, 2020a)	1.50
	Fixed O&M Cost ($/ kg MeOH -yr)	**0.01**
Variable OPEX	Variable O&M Cost Multiplier	1.00
	Variable O&M Cost ($/kg MeOH)	**0.01**
	Natural Gas Cost ($/kg MeOH)	0.00
	Electricity Cost ($/kg MeOH)	0.22
	Hydrogen Cost ($/kg MeOH)	0.59
	CO_2 Feedstock Cost ($/kg MeOH)	0.14
	Methanol Synthesis Cost ($/kg MeOH)	0.05
	Total Feedstock Cost ($/kg MeOH)	**0.78**
Output	sLCOE ($/kg MeOH)	**0.89**
	sLCOE ($/tonne MeOH)	**885.73**
	Validation from IRENA (IRENA, 2021) ($/t MeOH) with varying CO_2 cost	820-1600

The levelized cost of production for hydrogen using natural gas feedstock has been calculated. For hydrogen, the list of assumptions such as plant output, overnight capital cost, and O&M cost came from NREL's report on analyzing the levelized cost of hydrogen production (Ramsden et al., 2009). Using the sLCOE model, I converted the inputs to match the units and calculated the output sLCOE. The estimated sLCOE for hydrogen using natural gas feedstock is $1347.9/tonne of H_2 at USD 6.6/MMBtu of natural gas price. The NREL (Ramsden et al., 2009) used the same natural gas price, and the result was USD 1320/tonne of H_2, which is closely aligned with the sLCOE model result.

Table 16 Simplified Levelized Cost of Production for Hydrogen using NG

Simplified Levelized Cost of Production for Hydrogen using NG

Assumptions	Plant Output (kg H_2/year) (Ramsden et al., 2009)	125000000.00
	Periods	40.00
	Discount Rate	0.08
	CRF	**0.08**
	Capacity Factor	**0.90**
	Fuel Heat Rate (m^3/MJ) (Ramsden et al., 2009)	0.03
	Feedstock Natural Gas Use (m^3/kg H_2) (Ramsden et al., 2009)	4.50
	Lower Heating Value (MJ/m^3) (Ramsden et al., 2009)	36.60
	Natural Gas Cost ($/$m^3$)	0.24
	Natural Gas Cost ($/MMbtu)	6.6
CAPEX	Overnight Capital Cost ($M) (Ramsden et al., 2009)	180.50
	Overnight Capital Cost ($/kg H_2)	**1.44**
Fixed OPEX	Fixed O&M Cost($M-yr) (Ramsden et al., 2009)	6.90
	Fixed O&M Cost($/ kg H_2 -yr)	**0.06**
Variable OPEX	Variable OPEX Cost ($M) (Ramsden et al., 2009)	144.00
	Variable O&M Cost ($/kg)	**1.15**
	Other Variable O&M Cost (Ramsden et al., 2009)	9.00
	Feedstock Cost - NG ($M)	135.00
Output	sLCOE ($/kg H_2)	**1.35**
	sLCOE ($/tonne H_2)	**1347.88**
	Validation ($/kg H_2) – NREL (@Natural gas $6.6/MMBtu)	1.32

Finally, the simplified LCOE for hydrogen via electrolysis is presented in Table 17. The plant output capacity has been adjusted to match the same assumptions used in the NREL study for validation purposes. The renewable electricity price was assumed to be USD 55/MWh. The sLCOE for hydrogen via electrolysis is estimated to be USD 4876/tonne of H_2, and the NREL result is estimated at around USD 4500/tonne of H_2. The sLCOE calculates that green hydrogen production cost is about 3.6 times more expensive than grey hydrogen production.

Table 17 Simplified Levelized Cost of Production for Hydrogen via electrolysis

Simplified Levelized Cost of Production for Hydrogen via electrolysis

	Plant Output (kg H_2/year)	**19000000.00**
	Periods	40.00
	Discount Rate	0.08
	CRF	0.08
	Capacity Factor	0.97
	Fuel Heat Rate (m^3/MJ) (Ramsden et al., 2009)	0.03
	Feedstock Natural Gas Use (m^3/kg H_2) (Ramsden et al., 2009)	4.50
	Lower Heating Value (MJ/ m^3) (Ramsden et al., 2009)	36.60
	Electricity Use (kWh/per kg H_2) (Ramsden et al., 2009)	53.40
	Renewable Electricity Price ($/kWh)	**0.055**
Assumptions	Electricity Consumption (MWh)	1014600.00
	Overnight Capital Cost ($M) (Ramsden et al., 2009)	123.50
CAPEX	Overnight Capital Cost ($/kg H_2)	6.50
	Fixed O&M Cost($M-yr) (Ramsden et al., 2009)	5.40
Fixed OPEX	Fixed O&M Cost ($/ kg H2 -yr)	0.28
	Feedstock Cost ($M) – Electricity	75.41
	Other Variable O&M Cost ($M) (Ramsden et al., 2009)	1.00
	Electrolyzer efficiency (LHV) (Ramsden et al., 2009)	0.74
	Variable OPEX Cost ($M) (Ramsden et al., 2009)	76.41
Variable OPEX	Variable O&M Cost ($/kg)	4.02
	sLCOE ($/kg H_2)	**4.88**
Output	sLCOE ($/tonne H_2)	**4876.50**
	Validation ($/kg H_2) – NREL @ $0.055/kWh electricity	**4.50**

3.1.4 Validations of the Simplified LCOE Model Results

For validation of ammonia and methanol LCOE, the levelized costs (USD/t) for ammonia and methanol as a function of electricity cost are used as shown in Figure 28, which is extracted from the IEA's Future of Hydrogen report (IEA, 2019a).

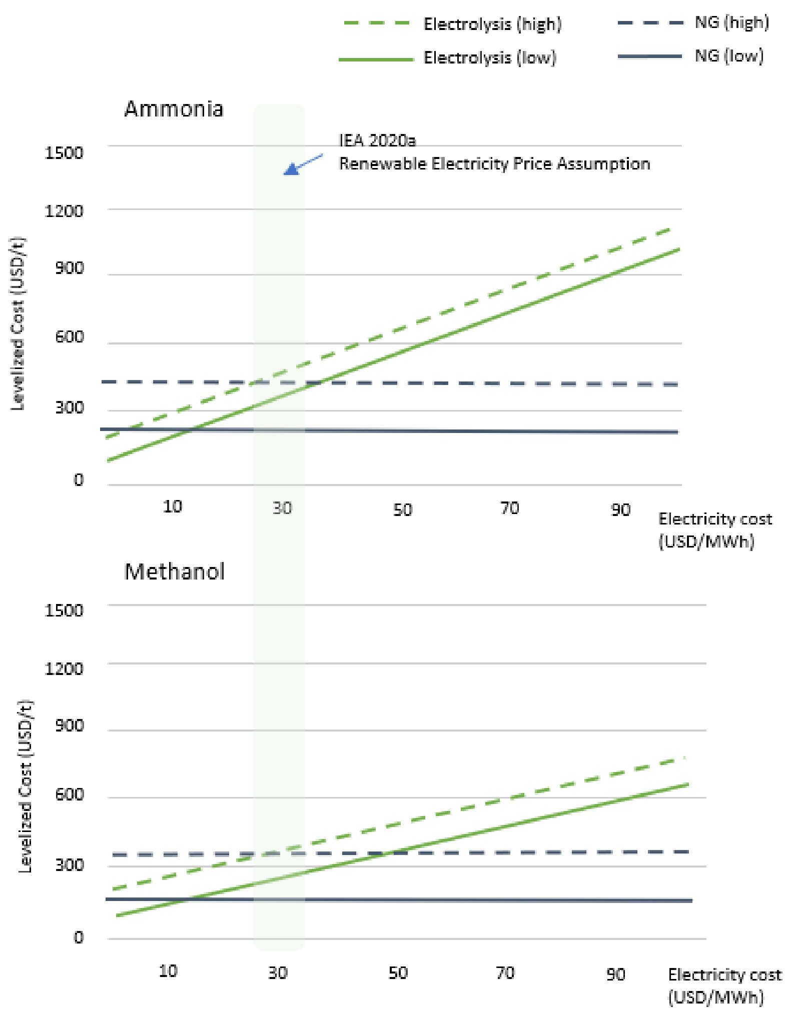


Figure 28 Levelized cost for ammonia and methanol with varying electricity prices for validation, adapted from (IEA, 2019a)

As discussed in Chapter 2, various production pathways exist for alternative fuels, which lead to widely different production costs. For cost modeling, fossil fuel and renewable energy-based feedstock have been considered in the production pathways for hydrogen, ammonia, and methanol. For green ammonia and methanol production pathways, 100% renewable electricity from renewable energy sources is assumed to be used. The price of renewable electricity is assumed to be $31/MWh based on (IEA, 2020a), as highlighted in Figure 28. While some renewable projects are reported at that price, current electricity price for industrial users is higher. Hence, I will perform a sensitivity analysis in the forthcoming sections. Green ammonia and green methanol production costs are slightly higher than fossil-fuel-based production costs at this price. In the IEA report, costs are based on the 2017 data. Based on the IEA report, ammonia's production cost from renewable electricity can be estimated to be around USD 330-500/tonne of NH_3, and methanol produced from renewable electricity is estimated at around USD 250-330/tonne of methanol. For ammonia, the simplified LCOE model developed for this study generated cost estimations that are aligned with the IEA result, as shown in Table 9 and Table 10, closer to the upper limit of the IEA ranges, with USD 482/tonne of NH_3 from renewable sources.

As shown in Figure 21, the production of e-methanol is highly dependent on the two main raw materials: CO_2 gas and hydrogen. However, the IEA report did not include the cost of CO_2 in the breakdown of OPEX. It stated explicitly that CO_2 cost was assumed to be 0 (IEA, 2020a), although it was noted that 100% renewable electricity is used for electrolysis for hydrogen production. Therefore, I reviewed a more detailed approach to methanol production cost calculation for better validation for green methanol cost estimation. The International Renewable Energy Agency (IRENA) is an intergovernmental organization that supports the transition to a sustainable energy future and serves as the principal platform for policy, technology, and financial knowledge on renewable energy. In 2021, IRENA published a report called Innovation Outlook – Renewable Methanol (IRENA, 2021), presenting production costs of e-methanol from multiple works of literature. The report stated that the estimated production cost for e-methanol is roughly between USD 820 and USD 1620/tonne of e-methanol, assuming USD 50/tonne synthesis cost with USD 4000-8000/tonne of green hydrogen and USD 10-50/tonne of CO_2 (IRENA, 2021). As the IEA report did not include the CO_2 cost in the LCOE calculations, and the IRENA report and the sLCOE model developed for this study included the cost of CO_2, the result from the IRENA report more accurately represented the actual cost of green methanol production. Therefore, I selected the IRENA report result for validation, and the result from the sLCOE model (USD 885/tonne of methanol) is within the validation ranges of the IRENA report (USD 820-1600/tonne of methanol) using the lower-end of CO_2 cost at USD 10/tonne CO_2. With a projection of a lowering cost for CO_2 acquisition in the future, the cost model's result would be lower. However, the future trajectory of CO_2 prices is quite uncertain and will depend on policies and regulations in different parts of the world.

For validations of the LCOE of hydrogen production, the NREL study (Ramsden et al., 2009) has been used. In the simplified LCOE model, the same input assumptions have been used for a fair comparison of the results. The NREL's calculation of LCOE of hydrogen from natural gas was $1.32/kg, and the result from the LCOE model developed for this study estimated $1.35/kg of hydrogen. The NREL's estimation of LCOE of hydrogen from electrolysis was $4.5/kg of hydrogen, and the result from the cost model for this study estimated $4.88/kg of hydrogen. As the results are closely aligned and validated, the estimations from the cost model developed for this study will be used for fuel cost.

Figure 29 presents fuels' levelized cost of production from the sLCOE model with the lower and upper ranges used for validation with various sources mentioned above (IEA, IRENA, NREL). For ammonia and methanol production costs, IEA's Future of Hydrogen report (IEA, 2019a) has been used to extract lower and upper ranges, as shown in Figure 29. For hydrogen production cost validations, NREL's data only provided one data point without ranges, so IEA's global average levelized cost of production data (IEA, 2020c) has been used for lower and upper ranges. The wide range reflects the variations in the current and future cost of electrolysis for hydrogen production (USD 872/kWe - 2019 and USD 269/kWe - 2050). I confirmed that the sLCOE model produced reasonable cost results within the validation ranges.

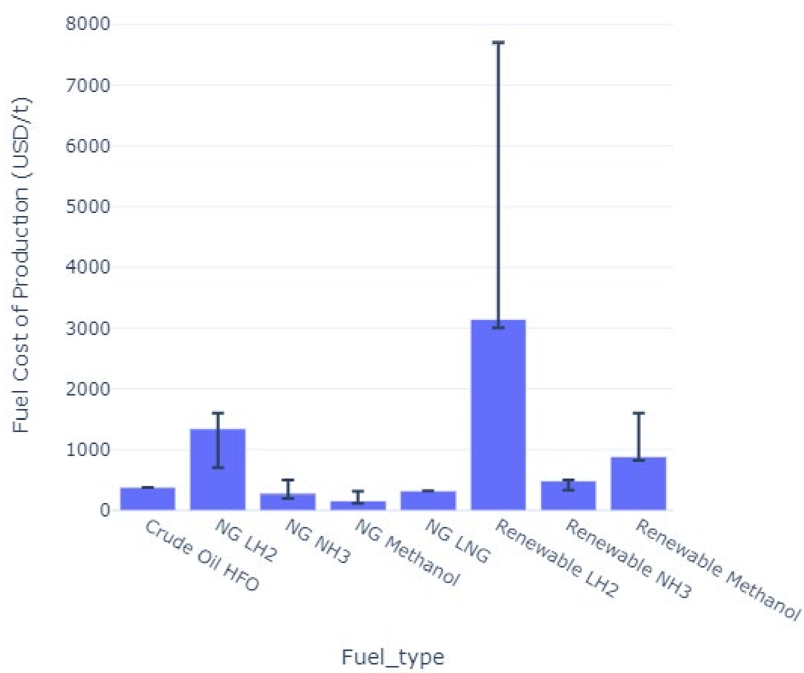


Figure 29 sLCOE model validation results with IEA, IRENA

3.1.5 Fuel Cost Estimation Per Energy Unit by Feedstocks

Table 18 summarizes the levelized cost of production (USD/tonne) by feedstock type calculated using the sLCOE model in the Fuel Cost of Production (USD/t) column. As fuels have varying energy densities, it is essential to compare the cost of fuels per unit of energy. Therefore, the fuel cost per production (USD/t) is converted to USD/GJ using the gravitational density of each fuel. For conventional fuels with existing markets, such as HFO and LNG, their recent average market prices between 2019 and 2022 from (Ship and Bunker, 2022) (EIA, 2021c) were used. Table 18 shows the fuel costs in USD/GJ based on different feedstocks.

Table 18 Combined fuel cost estimates for marine fuels @ $31/MWh Renewable Electricity, adapted from sources below

Sources: (IEA, 2019a) (Zhang et al., 2020) (IEA, 2020c) (DNV, 2021) (Methanol Institute, 2022b)

Feedstock	**Fuel**	**Vol Density (MJ/m^3)**	**Gravitational Density (MJ/tonne)**	**Cost of Fuel Production (USD/t)**	**Fuel Cost (USD/GJ)**
Crude Oil	HFO	34920	41760	376.00 (Ship and Bunker, 2022)	9.00
NG	LH_2	8496	119880	1363.63	11.37
NG	NH_3	17352	18720	278.61	14.88
NG	Methanol	17964	19800	161.12	8.14
NG	LNG	20988	51912	318.00 (EIA, 2021c)	6.13
Renewable	LH_2	8496	119880	3144.61	26.23
Renewable	NH_3	17352	18720	482.97	25.80
Renewable	Methanol	17964	19800	885.73	44.73

Figure 30 compares combined fuel costs (USD/GJ) categorized by feedstocks. Green or renewable hydrogen has the highest fuel cost, followed by green ammonia. Ammonia produced from natural gas feedstock has a higher estimated cost per unit of energy than grey hydrogen produced from natural gas without carbon capture. The cheapest fuel in terms of USD per energy unit is LNG produced from natural gas (NG), followed by the conventional HFO.

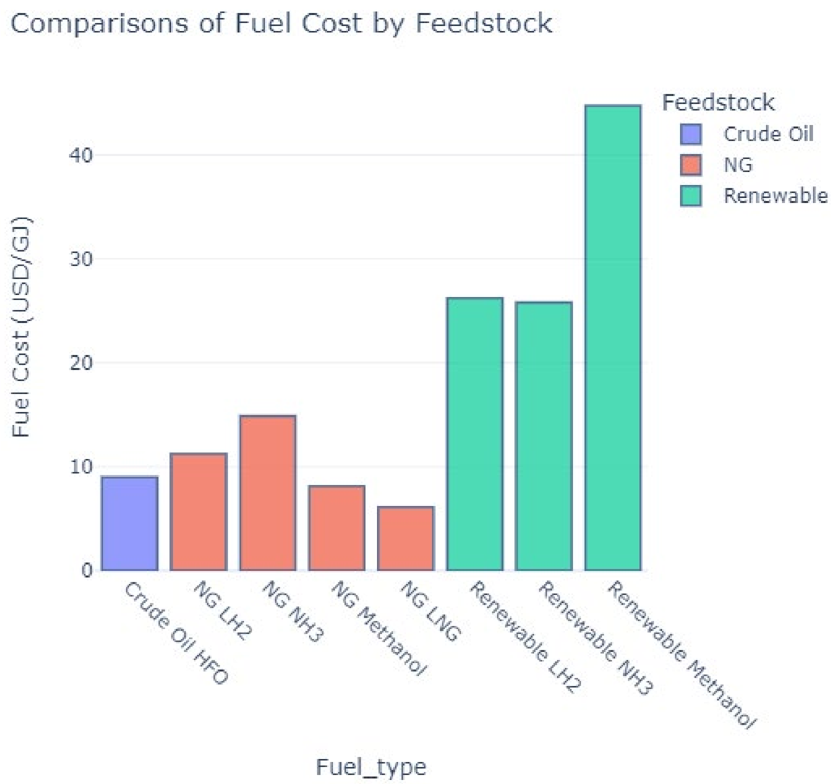


Figure 30 Comparisons of fuel cost by feedstock @ USD 31/MWh renewable electricity

3.1.6 Sensitivity Analysis using sLCOE Models

The levelized costs of production for alternative fuels are sensitive to the price of renewable electricity and natural gas. Both have demonstrated fluctuations over time, so it is worthwhile to run a sensitivity analysis to see the implications of changing renewable electricity and natural gas prices on the levelized cost of production of ammonia, methanol, and hydrogen. The IEA report (IEA, 2019a) assumed USD 31/MWh for variable renewable electricity prices and USD 3.3/MMBtu for natural gas prices. Therefore, the sLCOE models were validated using the same price assumptions in the previous sections.

In this section, I present three sensitivity analyses. The first one is to demonstrate the result of the sLCOE model calculations for alternative fuels with varying renewable electricity price. The second one is to illustrate the sLCOE results with varying natural gas prices for fuels that use natural gas feedstocks. The third one is to present the sensitivity of green methanol cost on two main feedstock variables – the cost of green hydrogen and renewable CO_2.

To determine the reasonable ranges of renewable electricity for the sensitivity analysis, a report published by IEA and NEA (Nuclear Energy Agency), Projected Costs of Generating Electricity, which analyzed the Levelized cost of electricity of various low-carbon technologies across regions, has been used. According to the report, the utility-scale solar PV and onshore wind are the least cost options, with USD 56/MWh and USD 50/MWh of median LCOE, respectively (IEA and NEA, 2020). There is uncertainty around the LCOE, as indicated by the min/max ranges depending on various assumptions. Another source by IRENA reported that the LCOE of onshore wind in 2019 was USD 53/MWh (IRENA, 2019), which is close to the IEA estimation. For the utility-scale solar PV, the upper quartile for LCOE is USD 73/MWh, and the lower quartile is USD 47/MWh. For the onshore wind, the upper quartile for LCOE is USD 60/MWh, and the lower quartile is of USD 45/MWh with the minimum USD 30/MWh. Hydropower LCOE is about USD 70/MWh for electricity generation.

It should be noted that LCOE does not provide the full cost because it does not reflect the ability of energy sources to meet demand for electricity at different times of the day. Although LCOE calculation does not factor in costs of integration or intermittency, it is an informative tool for comparing different electricity generation methods. However, the results should be properly interpreted recognizing its limitations. Based on current numbers and to reflect the uncertainties in future pricing, the ranges of renewable electricity prices for the sensitivity analysis are selected to be between USD 0/MWh – 110/MWh. The ranges for the natural gas price have been selected to be between USD 0.5/MMBtu to USD 13/MMBtu.

Sensitivity of Ammonia on Renewable Electricity Price and Carbon Pricing on Natural Gas: Natural gas feedstock is not used for green ammonia production via electrolysis. As such, only the sensitivity analysis on renewable electricity price was run, shown in Figure 32. The sLCOE of green ammonia is highly sensitive to the renewable electricity price, varying from USD 478/tonne to almost USD 900/tonne when the renewable electricity changes from USD 30/MWh to USD 75/MWh. The sLCOE of ammonia from natural gas is not sensitive to renewable electricity prices. The sLCOE of ammonia only slightly increased from USD 278 to USD 282 with the same renewable electricity price range, as most of the production cost comes from natural gas and is relatively less dependent on the electricity price.

Carbon Pricing on Natural Gas: Another scenario has been explored in which carbon pricing is implemented on natural gas prices. With USD 100/tonne carbon pricing, the added cost to natural gas price is USD 1.49/tcf (thousand cubic feet) (U.S. Climate Change Science Program, 2007). As such, the natural gas price with carbon pricing can be calculated as follows:

$$\text{Added Cost}\ \left(\frac{\$}{\text{tcf}}\right) = \frac{\text{Carbon Dioxide Price Input}\left(\frac{\$}{\text{tcf}}\right)}{\text{Carbon Dioxide Price per}\frac{\$100}{\text{tC}}\left(\frac{\$}{\text{tcf}}\right)} * \$100/\text{tC Added Cost } (\$/\text{tcf})$$

Cost with Carbon Price ($/tcf) = Fuel Cost ($/tcf) + Added Cost ($/tcf)

Cost with Carbon Price ($/MMBtu) = Cost with Carbon Price ($/tcf) / 0.941

- $100/tc Added Cost ($/tcf) is assumed to be USD 1.49/tcf
- CO_2 Price at $100/t Carbon Price = $100 * (12/44) = $27.27/tonne CO_2
- 1 tcf = 0.941 MMBtu

This results in increasing natural gas price with carbon price as shown in Figure 31.

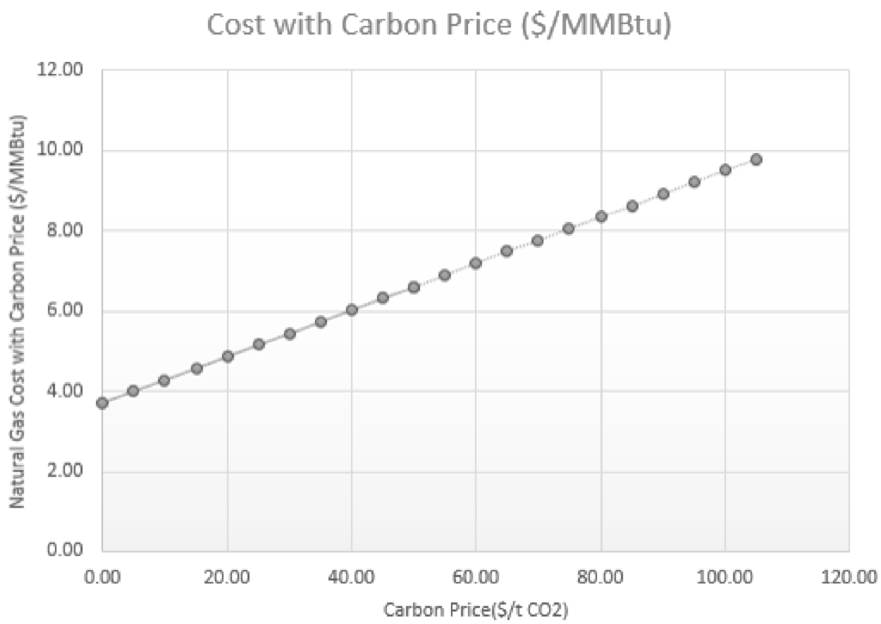


Figure 31 Natural gas price with carbon pricing

Factoring in carbon price in the scenarios, I used the corresponding natural gas price as an input to the sLCOE model to calculate the cost of ammonia production using natural gas feedstock in USD/tonne NH_3. As USD 3.7/MMBtu as a baseline price for natural gas with no carbon pricing, the cost of grey ammonia is USD 296/tonne NH_3. With USD 50/tonne CO_2 carbon pricing, the cost of grey ammonia goes up to USD 453/tonne NH_3. With USD 70/tonne CO_2 pricing, the cost of grey ammonia becomes USD 458/tonne NH_3 and becomes at par with the cost of green ammonia at USD 31/MWh renewable electricity price. With USD 105/tonne CO_2 carbon pricing, the cost of grey ammonia becomes USD 539/tonne NH_3, comparable to the green ammonia produced with renewable electricity at USD 40/MWh.

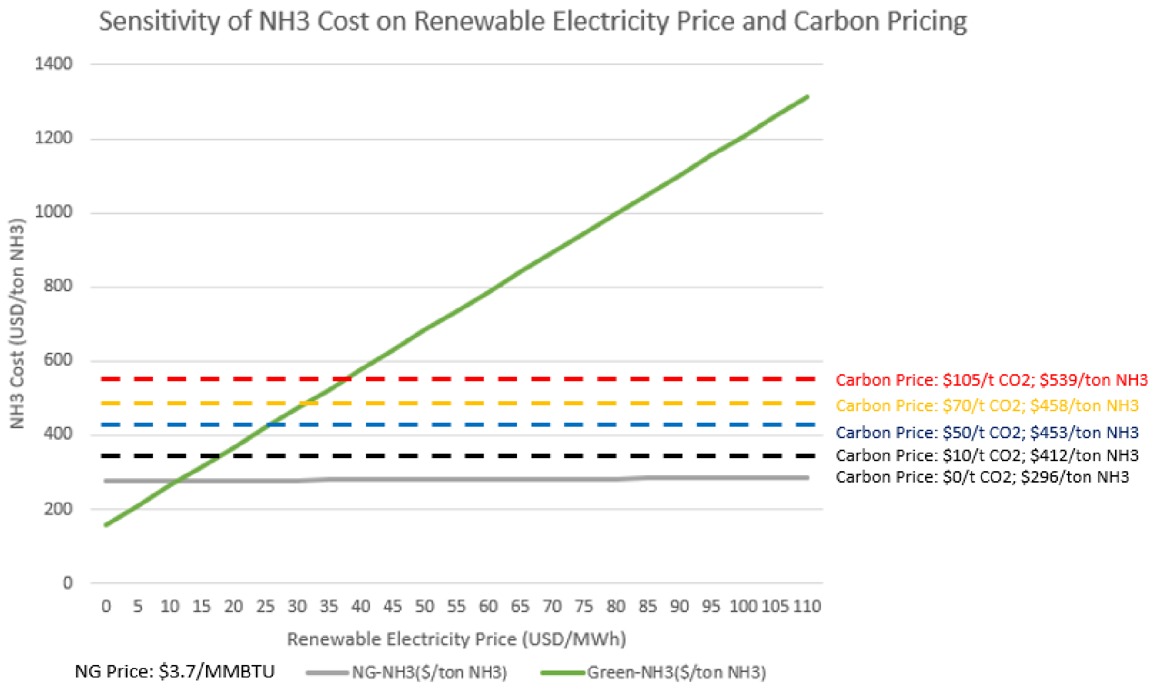


Figure 32 Sensitivity analysis of NH_3 on Renewable Electricity and Carbon Pricing

Sensitivity of Hydrogen on Renewable Electricity Price: A sensitivity analysis has been run for hydrogen on renewable electricity prices. Green hydrogen is highly sensitive to renewable electricity pricing as electrolysis is an energy-intensive process that requires (renewable) electricity. In Figure 33, the ranges of hydrogen from natural gas feedstock are illustrated in grey, with the lower bound of $0.8/kg H_2 at $2.5/MMBtu and the upper bound of $2.2/kg H_2 at $10/MMBtu. Over time, renewable electricity prices are expected to decrease (assuming a successful resolution of intermittency issues). In many parts of the world, solar PV and onshore wind electricity is cost-competitive with fossil-fuel-based electricity. According to IRENA's 2020b report, the cost of green hydrogen is expected to be around USD 2.5-5.0/kg of H_2 in 2030 (IRENA, 2021).

Figure 33 Sensitivity analysis of Hydrogen in Renewable Electricity

Sensitivity of Fuels on Natural Gas Price: The sensitivity analysis has been run for the three alternative fuel pathways (from natural gas feedstocks) on the natural gas price. The natural gas price has recently fluctuated, and the monthly average natural gas price for May 2022 was USD 8.14/MMBtu (U.S. EIA, 2022). The sensitivity results are shown in Figure 34. From USD 2.5/MMBtu and USD 9.5/MMBtu of natural gas price ranges, ammonia production cost from natural gas changes from USD 250/tonne to more than USD 500/tonne. In the same range, hydrogen costs change from USD 679/tonne H_2 to more than USD 1800/tonne H_2, and methanol costs change from USD 135 tonne/MeOH to USD 360 tonne/MeOH.

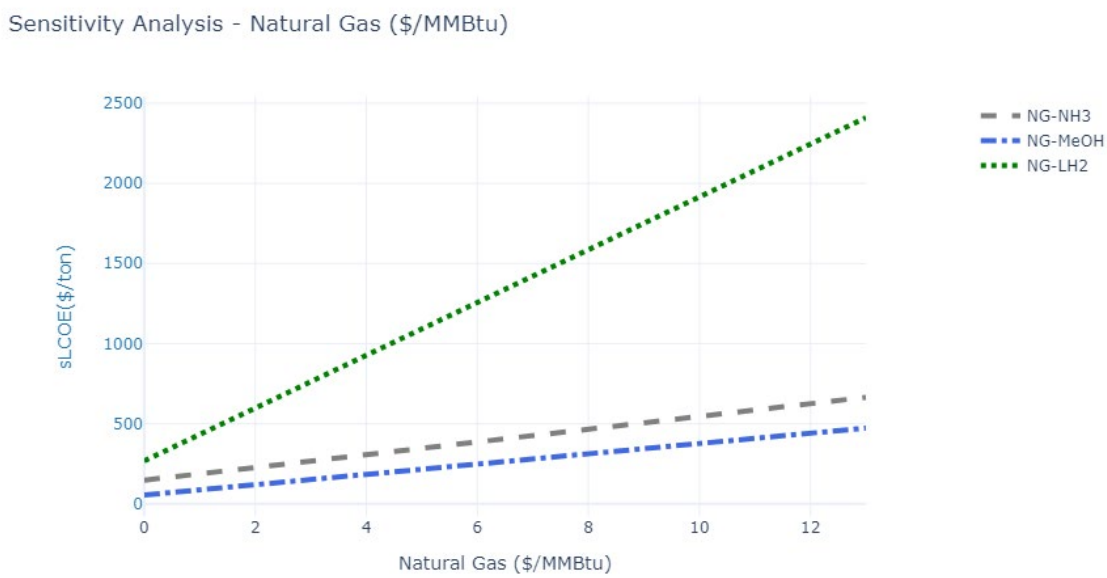


Figure 34 Sensitivity Analysis of Alternative Fuel Cost on Natural Gas Price

Sensitivity of Methanol on Hydrogen and CO_2 Cost: Green e-methanol production requires two main feedstocks – green hydrogen and renewable CO_2. The cost of green hydrogen is sensitive to renewable electricity prices, as described in the previous section. The cost of CO_2 depends on the sources. Through a process called bioenergy with carbon capture and storage (BECCS), biomass, among other things, can be the source of renewable CO_2. With Direct Air Capture (DAC) technologies, air can be another source of CO_2 but at a higher cost (IRENA, 2021). The costs of acquiring CO_2 from these two sources are still quite high as they are nascent in the development phase. DAC costs are in the order of USD 300 to USD 600/t CO_2 range. Biomass can provide CO_2 in the order of USD 10 to USD 100/tonne CO_2 (IRENA, 2021). The result of sensitivity analysis using the sLCOE model on the two variables, the cost of green hydrogen and CO_2, is shown in Figure 35 as a heatmap. Assuming the lower end of CO_2 cost at USD 10/tonne CO_2 and around USD 3.5/tonne H_2, the cost of green methanol is estimated to be USD 950/tonne MeOH.

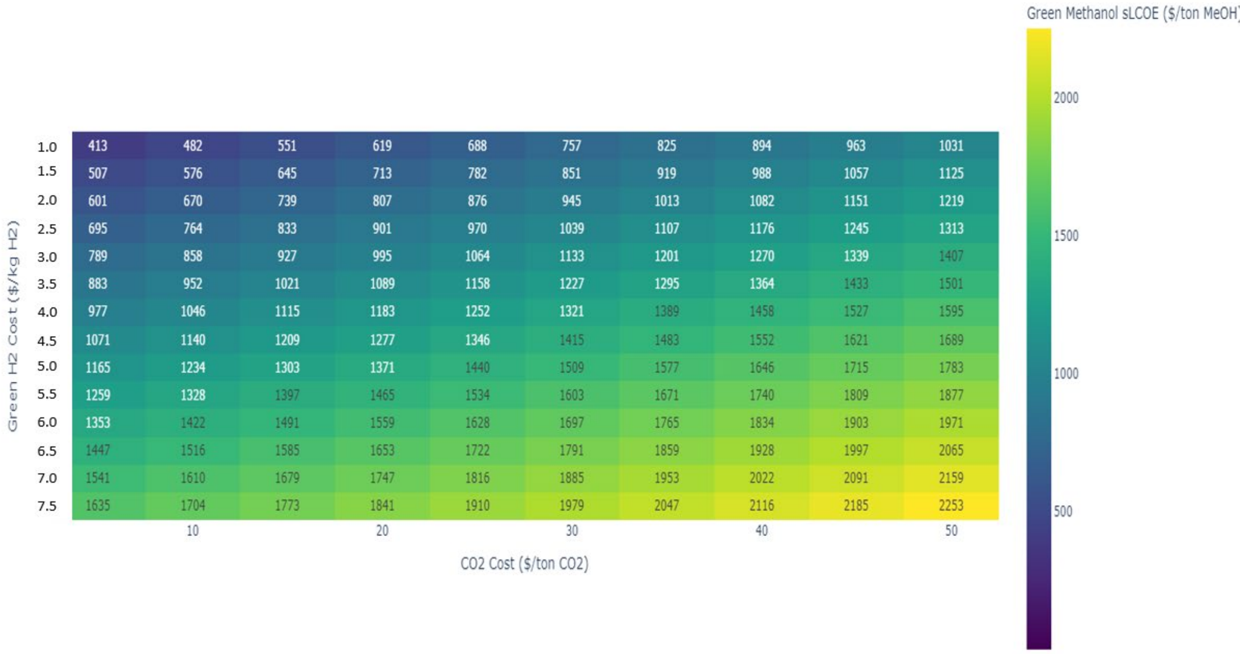


Figure 35 Sensitivity Analysis of Green Methanol Cost on Green H_2 and CO_2 Cost

Another view of the sensitivity analysis is shown in Figure 36. The two cost drivers (Green Hydrogen and CO_2 Cost) are shown on the X-axis with upper and lower ranges with the corresponding green methanol production costs. The blue dashed line indicates the current green methanol cost estimate based on USD 4.52/kg H_2 and USD 10/tonne CO_2 cost.

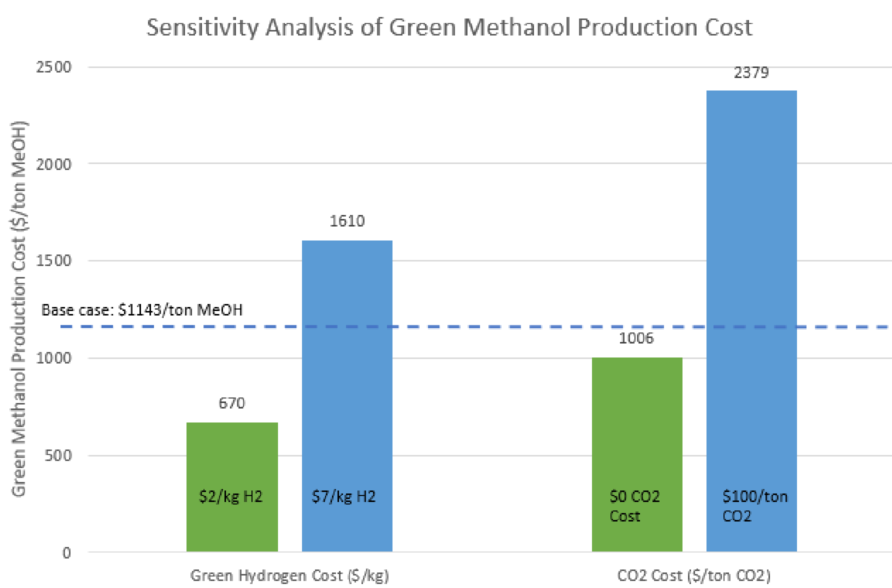
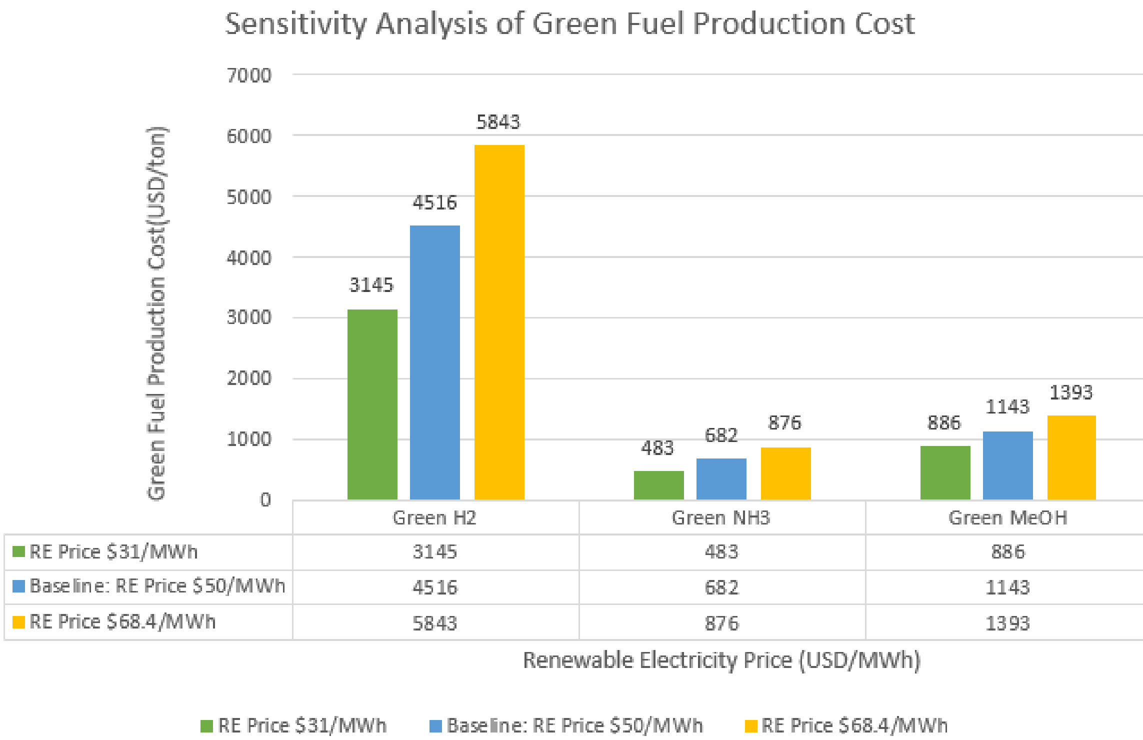


Figure 36 Sensitivity Analysis with the current estimates

Sensitivity of Alternative Fuels on Renewable Electricity Price: As shown above, alternative fuels from renewable energy sources highly depend on renewable electricity prices. Figure 37 summarizes the sensitivity analysis.



	Green H2	Green NH3	Green MeOH
RE Price $31/MWh	3145	483	886
Baseline: RE Price $50/MWh	4516	682	1143
RE Price $68.4/MWh	5843	876	1393

Figure 37 Sensitivity Analysis of Green Fuels

At USD 50/MWh of renewable electricity, green hydrogen costs USD 4516/tonne, green ammonia costs USD 682/tonne, and green methanol costs USD 1143/tonne. The average U.S. industrial electricity price on the grid was USD 68.4/MWh from 2010-2020, which is used as the upper bound in the sensitivity analysis. The IEA's Future Hydrogen Report used USD 31/MWh as the long-term variable renewable electricity price, chosen as the lower bound in the sensitivity analysis.

3.1.7 Energy Cost with Powertrain Efficiency

One of the key system design decisions of utilizing alternative fuels in maritime applications is the type of powertrains used for the propulsion of vessels. In Chapter 2, various powertrain options for each fuel have been reviewed. Each powertrain has varying efficiency in converting the energy from the input fuel to actual power for propulsion. For example, if an ICE has 50% efficiency, then the input fuel to the ICE can generate only 50% of the fuel's energy content to the propulsion shaft. To properly account for the overall system efficiency in calculating the energy cost, the powertrain options in Figure 38 have been included in the analysis.

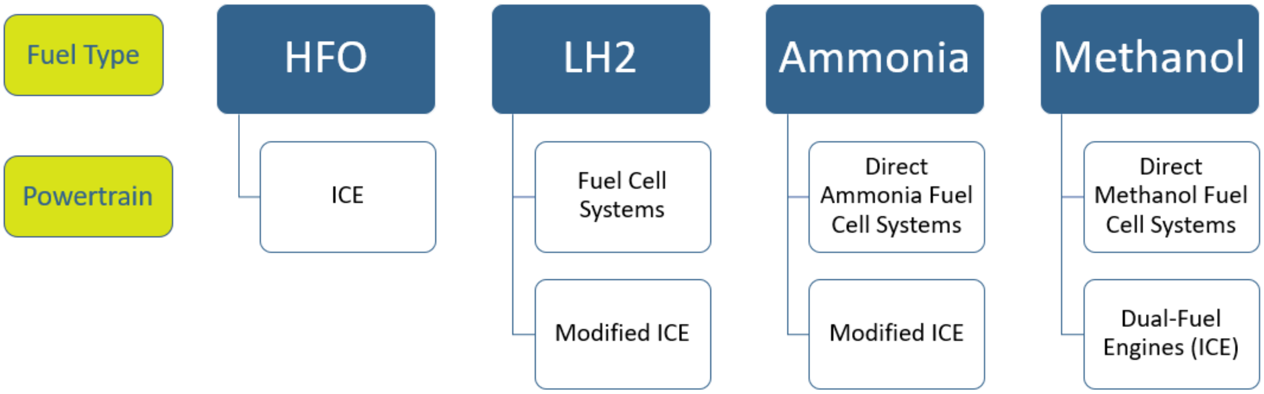


Figure 38 Possible powertrains for vessels for each fuel

The efficiency of various powertrains for each fuel type has been extracted from a DNV's alternative marine fuel study (DNV GL AS Maritime, 2019). The combined fuel cost from Section 3.1.4 is then adjusted by including the powertrain's efficiency to provide a more accurate estimation called energy cost, measured in USD/GJ shaft output. Figure 39 illustrates the powertrain efficiency of vessels where the energy is utilized to compare fuel costs.

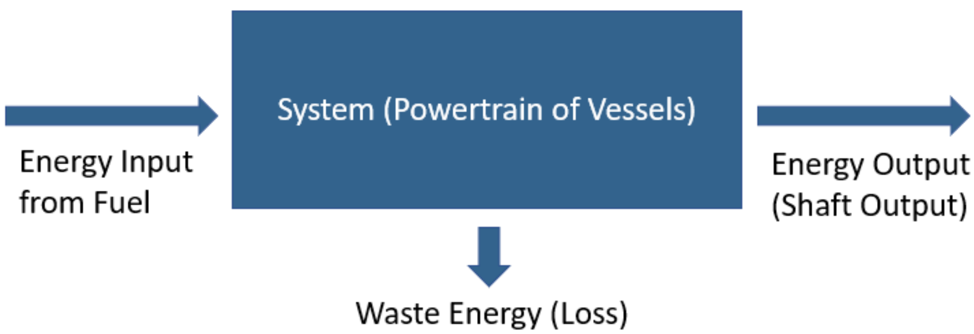


Figure 39 Illustration of powertrain efficiency, adapted from (Frazier, 2017)

$$Efficiency = \frac{Useful\ Energy\ Output}{Total\ Energy\ Input} = \frac{Total\ Energy\ Input - Waste\ Energy}{Total\ Energy\ Input}$$

If the powertrain has higher efficiency, less energy (fuel) is lost in the system, and the energy cost will be lower. Therefore, the final energy cost (USD/GJ shaft output) incorporates the energy density of fuels, feedstock types, and powertrain efficiency. Table 19 summarizes the final energy cost in USD/GJ shaft output with a renewable electricity price of USD 31/MWh, along with the relative mark-up above the reference (HFO-ICE).

Table 19 Summary Table of Comparisons of energy cost per shaft output (Efficiency ranges adapted from (DNV GL AS Maritime, *2019) (de Vries, 2019))*

Feedstock	Fuel	PowerTrain	Fuel Cost of Production (USD/t)	Fuel Cost (USD/GJ)	Efficiency (PowerTrain) Low %	Efficiency (PowerTrain) AVG %	Efficiency (PowerTrain) High %	Energy Cost per shaft output (USD/GJ)	Mark-up above Reference (HFO-ICE)
Crude Oil	HFO	ICE	376.00	9.00		50		18.01	1
NG	LH2	ICE	1347.88	11.24		42		26.77	1.49
NG	NH3	ICE	278.61	14.88	50	50	50	29.77	1.65
NG	Methanol	ICE	161.12	8.14	50	52	53	15.65	0.87
NG	LNG	ICE	318.00	6.13	40	45	49	13.61	0.76
NG	LH2	FC	1347.88	11.24	50	50	80	22.49	1.25
NG	NH3	FC	278.61	14.88	50	50	80	29.77	1.65
Renewable	LH2	ICE	3144.61	26.23		42		62.46	3.47
Renewable	NH3	ICE	482.97	25.80	50	50	50	51.60	2.87
Renewable	Methanol	ICE	885.73	44.73	50	52	53	86.03	4.78
Renewable	LH2	FC	3144.61	26.23	50	50	80	52.46	2.91
Renewable	NH3	FC	482.97	25.80	50	50	80	51.60	2.87
Renewable	Methanol	FC	885.73	44.73	40	46	50	97.25	5.40

Figure 40 illustrates energy cost per shaft output (USD/GJ shaft output). Among renewable feedstock pathways, the green methanol-FC option has the highest energy cost due to the lower high levelized cost of production of green methanol under current assumptions. Due to higher powertrain efficiency, the green methanol-ICE pathway (using Dual-Fuel engines) has a lower energy cost than the methanol-FC option. The green ammonia pathways have a lower cost compared to other renewable pathways. Including natural gas feedstocks, LNG with ICE has the lowest energy cost. The reference pathway (HFO-ICE) has a comparable energy cost to NG-Methanol using dual-fuel engines pathway. Overall, renewable feedstock pathways are more expensive than fossil-fuel-based feedstock pathways.

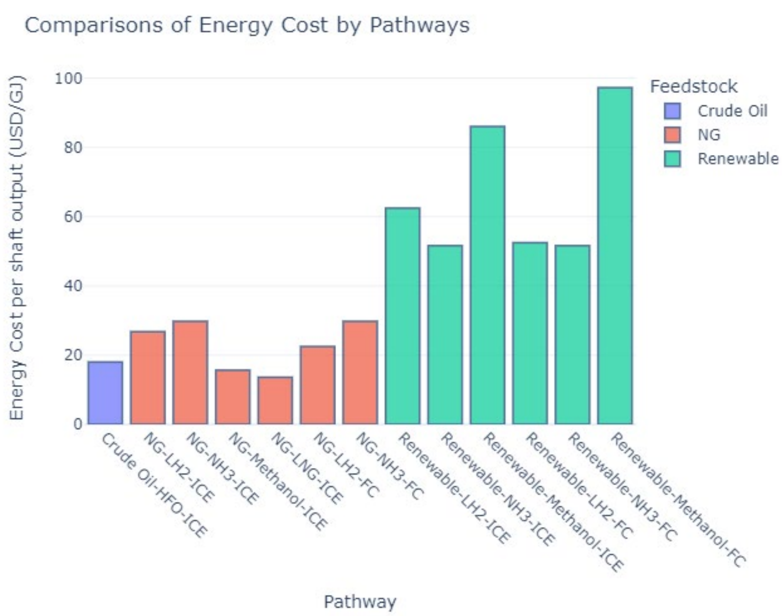


Figure 40 Comparisons of energy cost by feedstock @ USD 31/MWh of Renewable Electricity

3.1.8 Validations of Energy Cost Estimations

I validated the energy cost comparison results with DNV's alternative fuel report (DNV GL AS Maritime, 2019). In the report, DNV presents fuel cost (USD/MWh shaft output) categorized by fuel type. I extracted the powertrain efficiencies from the report with additional sources combined for methanol fuel cell efficiency. I calculated the energy cost for different pathways based on the energy densities of each fuel and levelized costs of production based on different feedstock. For easier comparisons, I grouped the energy cost from the previous section by fuel type in Figure 41.

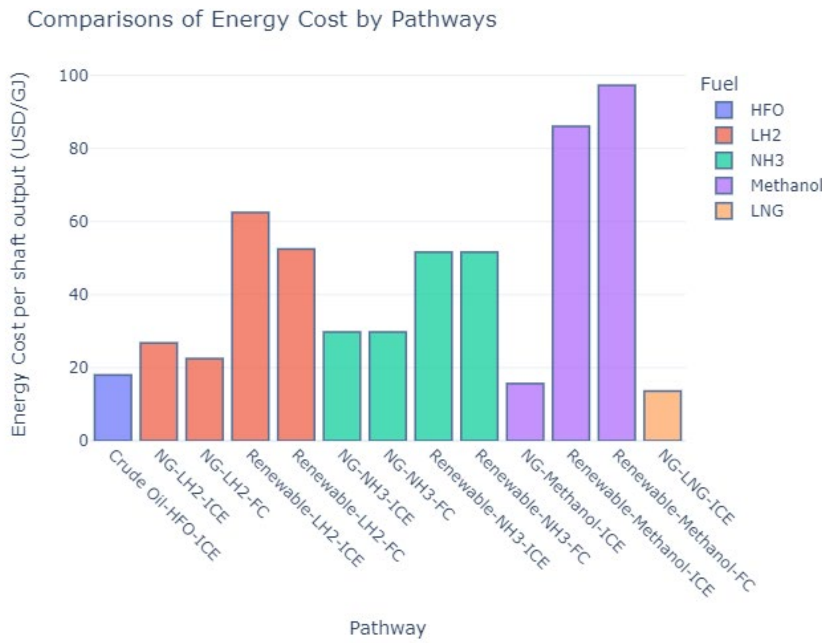


Figure 41 Comparisons of energy cost by fuel type @ USD 31/MWh of Renewable Electricity

There is a subtle limitation to using the DNV report for the purpose of validation. In the DNV report, the reference fuel (HFO) and green methanol pathways are excluded from the comparisons, which makes it difficult to compare the relative multiplier above the reference fuel (HFO). However, despite the stated limitation, most alternative fuel pathways' relative energy costs can still be compared at a high level for validation. The energy cost (USD/GJ shaft output) has been converted to the same units (USD/MWh shaft output) as used in the DNV report for a direct comparison. Figure 42 compares the energy cost ranges (USD/MWh shaft output) from the DNV report with the energy cost calculated from this study.

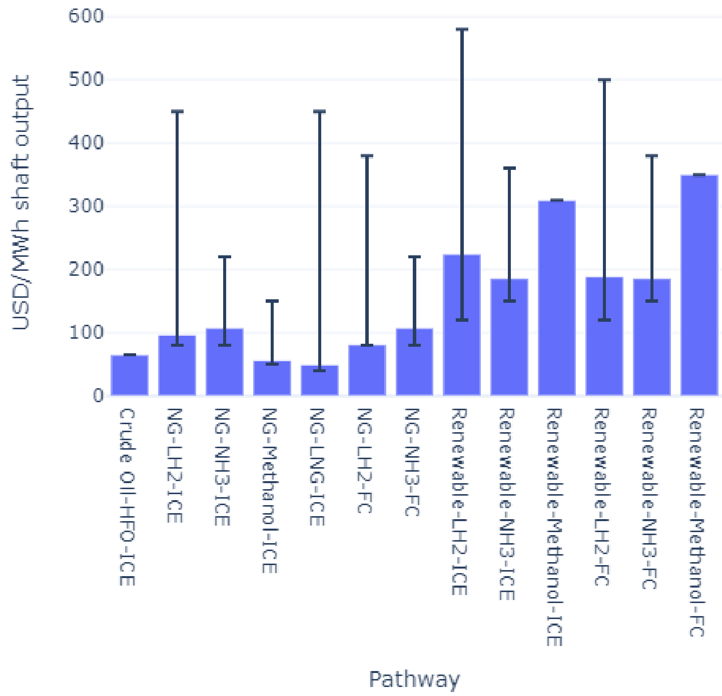


Figure 42 Validations of Energy Cost with DNV result in black ranges

According to the DNV report, LNG and (conventional) methanol from natural gas are competitive in energy costs, while hydrogen and ammonia-based pathways are significantly more expensive. The energy cost (USD/MWh) is highest for hydrogen-based pathways, followed by ammonia and then (conventional) methanol, with LNG being the cheapest option. The energy cost ranking aligns well with the findings from this study, as shown in Figure 42. Another thing to note is that the result from the sLCOE model is closer to the lower range of the DNV estimates. This is because the DNV report provided wide ranges, using electricity costs ranging from USD 20 to 60/MWh, whereas the sLCOE model used USD 31/MWh for renewable electricity costs.

3.2 Total Cost of Ownership

To evaluate the economic impact of alternative fuel technologies, I developed the total cost of ownership models for various pathways for this study. The goal is to provide realistic and reasonable cost estimation for alternative fuel-based vessels over the lifetime of vessels to get accurate estimations from the economic modeling process. The total cost of ownership (TCO) is an asset's purchase price plus operation costs. The TCO includes both the short-term and the long-term costs and expenses incurred during the system's useful life, representing the overall value of a product or system. At a high level, the purchase cost is categorized as capital expenditures

(CAPEX), and the costs of operations and maintenance are grouped as operating expenditures (OPEX). The TCO is commonly used as a framework to holistically assess the value of a system (Investopedia, 2021).

3.2.1 Assumptions for the Renewable Electricity Price and the Fuel Cost

I used the fuel cost calculated from the sLCOE models for the TCO analysis. I validated the sLCOE model with IEA results with the same assumption of USD 31/MWh for renewable electricity price in Section 3.1. The average U.S. industrial electricity price on the grid was USD 68.4/MWh from 2010-2020 (EPA, 2022), as presented in Table 20, which is used as the upper bound in the sensitivity analysis.

Table 20 Average Electricity Price (Cents/kWh), reproduced from (EPA, 2022)

Year	Residential	Commercial	Industrial	Transportation	Total
2010	11.54	10.19	6.77	10.56	9.83
2011	11.72	10.24	6.82	10.46	9.90
2012	11.88	10.09	6.67	10.21	9.84
2013	12.13	10.26	6.89	10.55	10.07
2014	12.52	10.74	7.10	10.45	10.44
2015	12.65	10.64	6.91	10.09	10.41
2016	12.55	10.43	6.76	9.63	10.27
2017	12.89	10.66	6.88	9.68	10.48
2018	12.87	10.67	6.92	9.70	10.53
2019	13.01	10.68	6.81	9.66	10.54
2020	13.15	10.59	6.67	9.90	10.59

The IEA's Future Hydrogen Report (2019) used USD 31/MWh as the long-term projection for variable renewable electricity prices, which is chosen as the lower bound in the sensitivity analysis. As a reasonable estimate for the renewable electricity price, the middle value of the upper and lower bound has been chosen, which is USD 50/MWh, to be a proxy cost for the renewable electricity price.

For the natural gas price, the average monthly natural gas price between May 2020 and May 2022 has been used (U.S. EIA, 2022), which is USD 3.7/MMBtu.

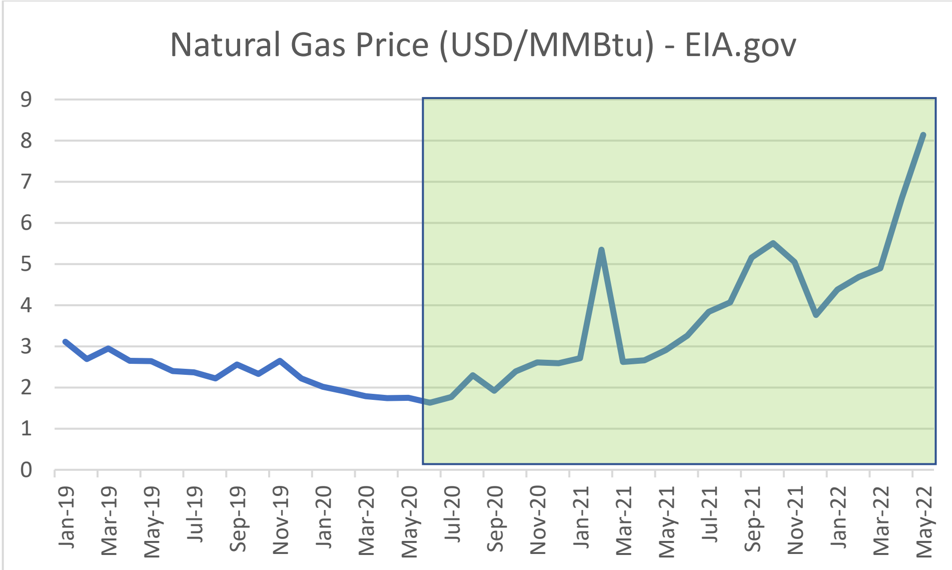


Figure 43 Natural Gas Price, adapted from: EIA.gov (U.S. EIA, 2022)

With USD **50/MWh** of renewable electricity price and USD **3.7/MMBtu** of natural gas, the following fuel cost can be calculated using the sLCOE models presented in Section 3.1. Under these assumptions, renewable ammonia is the lowest cost option among renewable fuels, and renewable methanol is the most expensive option, with a markup of 6.41.

Table 21 Summary of Fuel Cost used for the TCO model

Feedstock	Fuel	Fuel Cost of Production (USD/t)	Fuel Cost (USD/GJ)	Markup above Reference (HFO)
Crude Oil	HFO	376.00	9.00	1.00
NG	LH_2	877.55	7.32	0.81
NG	NH_3	296.79	15.85	1.76
NG	Methanol	176.22	8.90	0.99
NG	LNG	318.00	6.13	0.68
Renewable	LH_2	4515.69	37.67	4.18
Renewable	NH_3	682.47	36.46	4.05
Renewable	Methanol	1143.50	57.75	6.41

3.2.2 The TCO Framework for Shipping Vessels

I constructed the following TCO framework to represent the simplified cost components of a typical shipping vessel. As shown in Table 22, I divided the TCO model into two segments, CAPEX and OPEX.

Table 22 Example TCO framework for shipping vessels

Type	Component	Unit
CAPEX	Base Ship	$
	Powertrain Upgrades	$
	Emission Control	$
	Storage Systems	$
	Ship Upgrades (Supporting Systems)	$
OPEX (Labor, Non-Fuel)	Main Engine	$/year
	Ship Maintenance	$/year
	Emission Control	$/year
OPEX (Fuel)	Fuel Cost	$/year
Total Cost of Ownership	CAPEX + OPEX	$ $/km

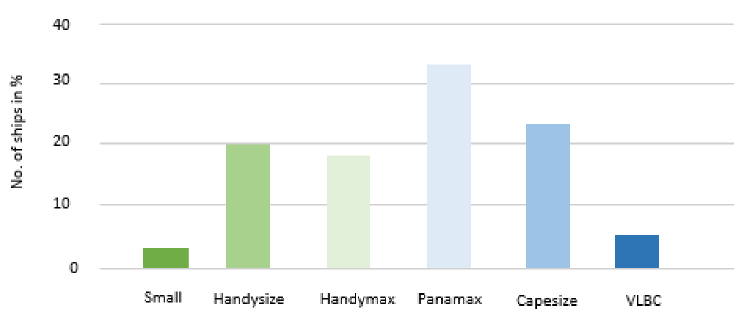
Under CAPEX, the main powertrain component represents the cost of the powertrains such as ICE and FC. The emission control system is included under CAPEX as more stringent regulations to reduce NOx emissions require the installation of NOx emission control systems. The storage systems represent the cost of installing a new storage tank for alternative fuels to account for the increased storage space requirement with lower volumetric densities of most alternative fuels compared to HFO. The ship upgrades include the estimation of the supporting systems that are necessary to operate the new powertrains. Under OPEX, the main component is the fuel cost. I used the combined fuel cost derived from the previous section (Section 3.1) to estimate each vessel's fuel cost per year. Other components of OPEX include the maintenance and operation of various components of ships, such as the main engine, emission control system, and overall maintenance.

3.2.3 Selection of Vessel Class for TCO analysis

As presented in Table 1, bulk carriers account for the largest proportion of the world's total fleet in deadweight tonnage (DWT), constituting 43% of the total fleet. Accordingly, CO_2 emissions from bulk carriers are estimated to be around 47% of the total emissions from the world's shipping vessels (Shell, 2020). Due to their importance in the shipping industry, bulk carriers have been selected for the TCO analysis.

Bulk carriers are one of the three major merchant ship types with tankers and containers. Bulk carriers are loaded with bulk cargo, or loose cargo, which refers to a shipment such as oil, grain, ores, beans, cement, etc., not carried in barrels or containers but instead in bulk. The cargo carried on bulk carriers has been going up with the globalization and economic growth that requires trading raw materials (MAN Energy Solutions, 2019).

Bulk carriers have been divided into different classes based on DWT, as shown in Figure 44. More than 40% of the total bulk carriers are smaller than 55,000 DWT (MAN Energy Solutions, 2019). For the TCO analysis, bulk carriers with around 50,000-60,000 DWT (Class Handymax or Class Supramax) will be mainly used as they represent the medium size bulk carrier types. I assumed this medium size to be more practical for the future applications of alternative fuel options.



Class	Size (DWT)
Small	10000
Handysize	10-35000
Handymax	35-55000
Panamax	55-80000
Supramax	60000
Capesize	80-200000
Very Large Bulk Carrier (VLBC)	>200000

Figure 44 Typical bulk carriers classes and distribution, reproduced from (MAN Energy Solutions, 2019)

3.2.4 Assumptions for Reference Bulk Carrier

Table 23 lists key assumptions for a reference bulk carrier (Class HandyMax or Class Supramax). This vessel type represents a conventional ICE-based bulk carrier fueled with the reference HFO fuel, with medium DWT capacity (between 50,000-60,000 DWT), assumed to have 25 years of lifetime. Fuel costs for HFO fluctuate over time, and in this study, $376/tonne of HFO is used, the global average over the last two years.

Table 23 List of assumptions for the conventional bulk carrier, adapted from (de Vries, 2019) (Ship and Bunker, 2022)

Assumptions	Reference Bulk Carrier - Class HandyMax
Engine Type	Slow-speed two-stroke diesel engine (ICE)
Installed main engine (kW)	16,080
Design point main engine (kW)	12,942
Main Engine output (kW/year)	84,123,000
HFO consumption (tonne/year)	14,492
Main Engine efficiency (%)	50
Distance Travelled per year (km/yr)	176,444
Effective Cargo (DWT)	54,000
Lifetime (yr)	25
Power density (kW/tonne)	35
NOx Emission Control ($/MWh)	5

Fuel Cost - HFO ($/tonne)	376-500
CO_2 Emissions (g/gHFO)	3.114

The base bulk carrier ship's market price has been extracted from various sources to estimate the base ship's capital cost. The recent market data (Sasvata and Claudia, 2022a) (Intermodal Shipbrokers Co, 2021) for bulk carrier sales between 2021 and 2022 are presented in Figure 45.

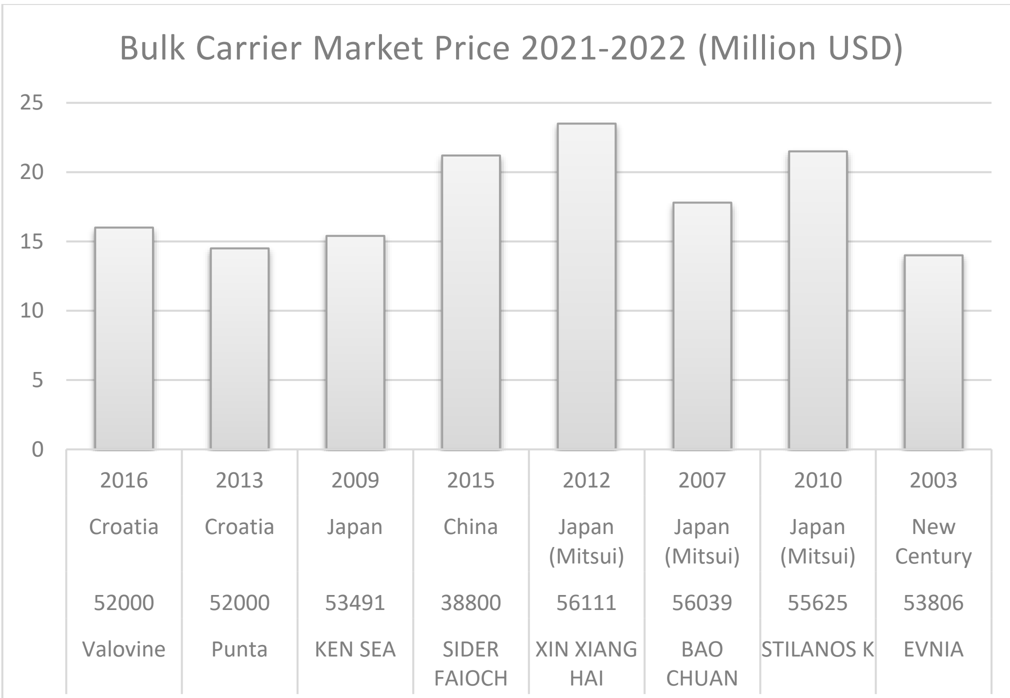


Figure 45 Bulk Carrier Market Price, adapted from (Sasvata and Claudia 2022a)

The market price for bulk carriers is presented on the y-axis, with each bar described with the year built, yard, DWT, and vessel name. The market price of each vessel varies depending on the year built and DWT. Typically, the bulk carriers in Handymax or Supramax sizes (between 50,000 DWT to 60,000 DWT) that are 10-15 years old are valued between USD 15 MM and USD 23 MM. Newly built bulk carriers tend to be 10%-15% more expensive than vessels that are five years old (Sasvata and Claudia, 2022a). According to the market research data (Sasvata and Claudia, 2022a) (Intermodal Shipbrokers Co, 2021), the average newly built bulk carrier of Class Handymax/Supramax with 56,000 DWT in 2021 was USD 26 MM. As such, for the TCO model, USD 26MM will be used as the cost estimation for the base ship.

The TCO model construction in the following section will use similar assumptions as the reference bulk carrier, including DWT, powertrain output, and power demand. I calculated the final TCO in USD per distance traveled, in USD/km, to compare TCO across different types of vessels with varying power output.

3.2.5 Methodology for TCO Model Construction

I developed the TCO models to estimate the lifetime cost of a shipping vessel in bulk carrier class. As described in the previous section, I constructed the model to take a few assumptions specific to a bulk carrier vessel. Other external inputs, more specific to fuel pathways, are also factored into the TCO model. The TCO model can take the following inputs:

- Power (kW): Engine or Fuel Cell's power capacity
- Shaft Power Output (kWh/yr, MJ/yr): The total amount of energy delivered for shaft output per year. This input is used to calculate the fuel consumption per year. The conversion between MJ and kWh is as follows:

$$1\ MJ = 0.278\ kWh$$

- Efficiency (%): The energy efficiency of a vessel as described in Section 3.1.7. The higher the efficiency, the less fuel consumption is required to deliver the same power output.
- Fuel consumption (tonne/yr): This is calculated based on Shaft Power Output, Efficiency inputs and Fuel's energy density using the following equation:

$$Fuel\ Consumption\ (ton/yr) = Shaft\ Power\ Output\ (MJ/yr) * \frac{100\ (\%)}{Efficiency (\%)} * \frac{1}{Energy\ Density} \left(\frac{kg}{MJ}\right) * 0.001\ (\frac{ton}{kg})$$

- Distance Travelled (km/yr): Distance traveled by a shipping vessel per year. The IEA report in the transportation section (IEA, 2020a) uses assumptions of 1715 MJ/km for ICE powertrains and 1600 MJ/km for Fuel cell systems, and the same number was used for the TCO model. The distance traveled is calculated using the following equation:

$$Distance\ Travelled\ per\ year\ (\frac{km}{yr}) = \frac{Shaft\ Power\ Output\ \left(\frac{MJ}{yr}\right)}{Power\ Consumption\ (\frac{MJ}{km})}$$

- Renewable Electricity Price (USD/MWh): A model user can change this input. This input is used to calculate green fuel's production cost using the sLCOE model. See Section 3.1.3 for the sLCOE model description.

- CO_2 Cost (USD/tonne CO_2): A model user can change this input. This input is used to calculate green methanol cost using the sLCOE model.
- Natural Gas Price (USD/MMBtu): A model user can change this input. This input is used to calculate grey fuel production costs.
- Green NH_3 Fuel Cost (USD/tonne NH_3): This is the output of the sLCOE model
- Green MeOH Fuel Cost (USD/tonne MeOH): This is the output of the sLCOE model
- Green H_2 Fuel Cost (USD/tonne H_2): This is the output of the sLCOE model
- HFO Cost (USD/tonne HFO): A model user can change this input.
- Base ship (USD): Used the average cost of newly built bulk carriers. Accounts for CAPEX.

The TCO model has the following outputs:

- CAPEX (USD, USD/km): The capital cost of a vessel over 25 years of lifetime in USD. CAPEX in USD/km is CAPEX divided by the product of Distance Travelled per year and the lifetime of a vessel.

$$CAPEX\ (USD) = Baseship\ (USD) + Emission\ Control\ (USD) + Storage\ System\ Upgrade\ (USD) + Ship\ Upgrades\ (USD) + Powertrain\ Upgrade\ (USD)$$

$$CAPEX\ \left(\frac{USD}{km}\right) = \frac{CAPEX\ (USD)}{Distance\ Travelled\ \left(\frac{km}{yr}\right) * Lifetime\ of\ a\ vessel\ (yr)}$$

- OPEX- Non-Fuel (USD, USD/km)

$$OPEX\ Non\ Fuel\ (USD) = \left(Main\ Engine\ Maintenance\left(\frac{USD}{yr}\right) + Ship\ Maintenance\ \left(\frac{USD}{yr}\right) + Emission\ Control\ \left(\frac{USD}{yr}\right)\right) * Lifetime\ of\ a\ vessel\ (yr)$$

- OPEX-Fuel (USD, USD/km)

$$OPEX\ Fuel\ (USD) = \frac{Fuel\ Cost}{yr}\ (\frac{USD}{yr}) * LIfetime\ of\ a\ vessel\ (yr)$$

- Total Cost of Ownership (USD, USD/km)

$$Total\ Cost\ of\ Ownership\ (USD) = CAPEX\ (USD) + OPEX\ Non\ Fuel\ (USD) + OPEX\ Fuel\ (USD)$$

$$Total\ Cost\ of\ Ownership\ \left(\frac{USD}{km}\right) = \frac{Total\ Cost\ of\ Ownership\ (USD)}{Distance\ Travelled\ per\ year\ \left(\frac{km}{yr}\right) * Lifetime\ of\ a\ vessel\ (yr)}$$

- The markup above Reference (HFO-ICE):

$$Markup\ above\ Reference\ (HFO - ICE) = \frac{TCO\ of\ an\ alternative\ pathway\ (\frac{USD}{km})}{TCO\ of\ the\ Reference\ Pathway\ (\frac{USD}{km})}$$

3.2.6 TCO Model for the Conventional Bulk Carrier Class HandyMax

The TCO for the conventional bulk carrier using the assumptions listed above is estimated in Table 24. Assuming 25 years of the vessel's lifetime, the TCO for a conventional Bulk Carrier – HandyMax is estimated to be around $182M, or $41.36/km. The storage system or supporting system upgrades are not needed for the traditional bulk carrier, so the figures are assumed to be 0. Due to the NOx emission control regulations, the emission control system needs to be added for practical applications in the near term and is included in the CAPEX. CAPEX total is the sum of the base ship and the cost of the emission control system, and the main powertrain (ICE) is assumed to be already included in the base ship cost. The cost of the main powertrain is used to calculate OPEX (Non-Fuel), which is proportional to the cost of the main powertrain. The TCO is the sum of CAPEX, OPEX (Non-Fuel), and OPEX (Fuel) over 25 years.

Table 24 TCO for a conventional bulk carrier

Type	Component	Unit	Figure	Ref	Amount ($) - 25 yrs
	Main Powertrain (Included in Baseship)	$/kW	428	(de Vries, 2019)	6,882,240
	Baseship	$		(Sasvata and Claudia, 2022b)	26,000,000
	Emission Control	$/kW	42.8	(de Vries, 2019)	688,224
	Storage Systems Upgrades	$	N/A		
	Ship Upgrades (Supporting Systems)	$	N/A		
CAPEX	CAPEX total	$			**26,688,224**

	Main Engine	% CAPEX/year	2.5	(de Vries, 2019)	4,301,400
	Ship Maintenance	% CAPEX/year	1		1,720,560
	Emission Control	$/MWh/year	6.42	(de Vries, 2019)	13,501,742
OPEX (Non-Fuel)	OPEX (Non-Fuel) total	$			**19,523,702**
OPEX (Fuel)	Fuel Cost total	$/tonne/year	376	(Ship and Bunker, 2022)	**136,228,293**
Total Cost of Ownership	CAPEX + OPEX	$/kW			11,345
		$/km			41.36
		$			182,440,219

3.2.7 TCO Model for Bulk Carrier Class HandyMax using Ammonia-ICE

This section presents the TCO model for Bulk Carrier using ammonia as an alternative fuel with ICE powertrains. In this model, the type of vessel is an ammonia carrier with the same ship dimensions as the reference bulk carrier vessel for comparison. Ammonia can be supplied two ways – from an ammonia storage tank or cargo. The former requires an additional capital cost to install the storage tanks, and the latter does not require additional costs for the fuel tank, as ammonia can be supplied from the cargo at the expense of the reduced cargo. A recent study that performed economic evaluations to compare the two ways of storing ammonia in bulk carriers revealed little difference (0.8%) in the storage costs (Seo and Han, 2021). Therefore, the model assumes that ammonia is supplied from a fuel tank to an ammonia-based ICE engine. This assumption leads to no additional cost to upgrade the storage systems, as the existing fuel tank in the ammonia carrier can be utilized. Table 25 lists the assumptions for the ammonia carrier. The fuel cost using green ammonia is assumed to be USD 682/tonne, as described in previous section 3.1.

Table 25 List of assumptions for ammonia carrier, adapted from (de Vries, 2019)

Assumptions	Bulk Ammonia Carrier - HandyMax
Engine Type	Ammonia engine (ICE)
Installed main engine (kW)	**16,080**
Design point main engine (kW)	12,942
Main Engine output (kW/year)	84,123,000
Ammonia Consumption (tonne/year)	30,675
Main Engine efficiency (%)	50
Effective Cargo (DWT)	54,000
Lifetime (yr)	25
Power density (kW/tonne)	35
Nox Emission Control ($/MWh)	5

Fuel Cost - Ammonia ($/tonne)	682

With the assumptions above, Table 26 presents the TCO model breakdown for an ammonia bulk carrier with a similar spec as the reference bulk carrier. The TCO for the ammonia-ICE vessel is $577M, or $137.76/km, which is about 3.3 times more expensive than the reference vessel.

Table 26 TCO model for ammonia carrier using ammonia-ICE

Type	Component	Unit	Figure	Ref	Amount ($) - 25 yrs
	Baseship	$		(Sasvata and Claudia, 2022b)	26,000,000
	Ammonia ICE Powertrain	$/kW	428	(de Vries, 2019)	6,882,240
	Emission Control	$/kW	42.8	(de Vries, 2019)	688,224
	Storage Systems Upgrades	$/MWh			-
	Ship Upgrades (Ammonia ICE)	$/kW	489.17	(de Vries, 2019)	7,000,000
CAPEX	CAPEX total	$			**33,688,224**
	Main Engine	% CAPEX/year	2.5	(de Vries, 2019)	4,301,400
	Ship Maintenance	% CAPEX/year	1		1,720,560
	Emission Control	$/MWh/year	6.42	(de Vries, 2019)	13,501,742
OPEX (Non-Fuel)	OPEX (Non-Fuel) total	$			**19,523,702**
OPEX (Fuel)	Fuel Cost total	$/tonne	682		**523,380,759**
		$/kW			38,987
		$/km			**137.76**
Total Cost of Ownership	CAPEX + OPEX	$			**576,592,684**

3.2.8 TCO Model for Bulk Carrier Class HandyMax using Ammonia-SOFC

Another ammonia pathway is using a direct ammonia fuel cell as a powertrain. The TCO model has been developed to estimate its lifetime cost with an ammonia fuel cell.

Table 27 Assumptions for NH_3-FC bulk carrier, adapted from (de Vries 2019

Assumptions	Bulk Ammonia Carrier - HandyMax
Engine Type	Direct Ammonia FC (SOFC)
Installed main engine (kW)	**15,000**
Design point main engine (kW)	13,122
Main Engine output (kW/year)	85,293,000
Ammonia Consumption (tonne/year)	27,316
Main Engine efficiency (%)	60
Distance Travelled (km/yr)	191,756
Effective Cargo (DWT)	50,790
Lifetime (yr)	25

The TCO for ammonia fuel cell bulk carrier is shown in Table 28. There is a new component in CAPEX: the ship upgrades cost from installing an electric motor and the supporting systems to enable propulsion by using the electricity generated from the SOFC. Only the difference between the cost of the SOFC and the ICE powertrain has been added to the CAPEX calculation. The total cost of ownership is estimated to be $635M over 25 years, around $133/km.

Table 28 TCO model for Ammonia-FC bulk carrier

Type	Component	Unit	Figure	Ref	Amount ($) - 25 yrs
CAPEX	Main Powertrain (Ammonia SOFC)	$/kW	5350	(de Vries, 2019)	80,250,000
	Baseship	$		(Sasvata and Claudia, 2022b)	26,000,000
	Evaporator	$		(de Vries, 2019)	2,850,480
	Ship Upgrades (Electric Motor)	$/kW	800	(de Vries, 2019)	12,893,500
	CAPEX total	$			**115,111,740**
OPEX (Non-Fuel)	SOFC Maintenance	% CAPEX/year	2.5	(de Vries, 2019)	50,156,250
	Evaporator	% CAPEX/year	1	(de Vries, 2019)	712,620
	Electric system	% CAPEX/year	1		3,223,375
	OPEX (Non-Fuel) total	$			**54,092,245**
OPEX (Fuel)	Fuel Cost total	$/tonne	682		**466,056,075**
Total Cost of Ownership	CAPEX + OPEX	$/kW			42,350
		$/km			**132.51**

		$			**635,260,060**

3.2.9 TCO Model for Bulk Carrier Class HandyMax using Methanol-Dual Fuel Engine

The cost of a new build of a 10MW vessel using MAN engines has been extracted from the FCBI Methanol Fuel report (Andersson, 2015). Out of two powertrain options using methanol as fuel, only a Dual-Fuel engine has been analyzed because the Dual-Fuel engine is already operational and technically more mature than direct methanol fuel cell powertrains, still in development for maritime applications.

Table 29 Assumptions for methanol-based Dual-Fuel engine vessel adapted from (Andersson, 2015)

Assumptions	Bulk Carrier - HandyMax Powered by Methanol/HFO
Engine Type	Dual Fuel Engine (HFO, Methanol)
Installed main engine (kW)	**15,000**
Power Delivered (GJ/year)	561,600
Main Engine efficiency (%)	52
HFO Consumption (tonne/yr)	0
Methanol Consumption (tonne/yr)	27,251
Distance Travelled (km/yr)	163,601
Lifetime (yr)	25

For methanol-based Dual Fuel engines, it is assumed that 100% of the power delivered comes from methanol. If HFO is assumed to be used, each fuel consumption can be calculated in the TCO model.

Table 30 TCO model for methanol-based Dual-Fuel vessel

Type	Component	Unit	Figure	Ref	Amount ($) - 25 yrs
	Baseship	$		(Sasvata and Claudia, 2022b)	26,000,000
	Dual Fuel Engine Upgrade	$/kW	82.5	(Andersson, 2015)	1,237,500
	Powertrain (Same as Reference)	$/kW	428	(de Vries, 2019)	6,420,000
	Supporting System	$/kW	190	(Andersson, 2015)	2,850,000
CAPEX	CAPEX total	$			**30,087,500**
OPEX (Non-Fuel)	Operation and Maintenance	% CAPEX/year	2	(Andersson, 2015)	**5,549,310**
	Fuel Cost (HFO)	$/tonne/year	376		-
	Fuel Cost (Methanol)	$/tonne/year	1143		782,242,792
OPEX (Fuel)	Fuel Cost total	$			**782,242,792**

		$/kW			54,525
		$/km			**200.3**
Total Cost of Ownership	CAPEX + OPEX	$			**819,369,042**

The renewable methanol cost of production of $1143 from Section 3.1 is used to calculate the methanol fuel cost. The total cost of ownership is estimated to be $819MM, or $200/km.

3.2.10 TCO Model for Bulk Carrier Class HandyMax using Hydrogen-PEMFC

Finally, the TCO model for hydrogen-fueled PEMFC-based vessels has been constructed. PEMFC was considered for the analysis of various fuel cell systems because PEMFC technology is in the most advanced stages of development, especially for a maritime environment (Horvath et al., 2018). The system efficiency of PEMFC is estimated to be lower than that of SOFC, according to various sources (Manoharan et al., 2019) (Horvath et al., 2018) (IEA, 2015).

Table 31 Assumptions for hydrogen-FC bulk carrier vessel, adapted from (Manoharan et al., 2019) (Horvath et al., 2018) (IEA, 2015)

Assumptions	Bulk Ammonia Carrier - HandyMax
Engine Type	Proton Exchange Membrane Fuel Cell
Installed main engine (kW)	**15,000**
Main Engine output (kW/year)	85,293,000
Power Delivered (MJ/year)	56,160,000
LH_2 Consumption (kWh/year)	156,000,000
LH_2 Consumption (tonne/year)	5,119
Main Engine efficiency (%)	50
Distance Travelled (km/yr)	191,756
Effective Cargo (DWT)	50,790
Lifetime (yr)	25

In CAPEX, the cost for the storage system has been added, as liquid hydrogen requires a cryogenic tank to store large volumes of hydrogen fuel. In the technology roadmap for hydrogen fuel cells report, the storage cost for liquid hydrogen was estimated to be around USD 800-1000/MWh. The same report also estimated USD 3000-4000/kW for the cost of PEMFC (IEA, 2015). The fuel cell price is expected to decrease in the future as the technology advances, with a wide range of predictions found in the literature, to around 1500 USD/kW (Horvath et al., 2018) and even to USD 700/kW by 2030 (IEA, 2015). For this study, the current performance and realistic cost estimation, USD 3000/kW, is chosen. The same assumption was used for the ammonia-based SOFC powertrain option for the electric motor cost. For OPEX, the storage system maintenance cost is factored in, as well as electrical systems operation & maintenance. Finally, the cost of green hydrogen at USD 4.5/kg H_2 was used to calculate the total fuel cost.

Table 32 TCO for hydrogen-FC bulk carrier vessels

Type	Component	Unit	Figure	Ref	Amount ($) - 25 yrs
	Main Powertrain (LH_2 PEMFC)	$/kW	3000	(IEA, 2015)	45,000,000
	Baseship	$		(Sasvata and Claudia, 2022b)	26,000,000
	Storage	$/kWh	0.831	(IEA, 2015)	129,636,000
	Ship Upgrades (Electric Motor)	$/kW	800	(de Vries, 2019)	12,000,000
CAPEX	CAPEX total	$			**205,753,760**
	PEMC Maintenance	% CAPEX/year	2		22,500,000
	Storage System Maintenance	% CAPEX/year	1		32,409,000
	Electric system	% CAPEX/year	1		3,000,000
OPEX (Non-Fuel)	OPEX (Non-Fuel) total	$			**57,909,000**
OPEX (Fuel)	Fuel Cost total	$/tonne	4516		**579,090,000**
		$/kW			56,100
		$/km			**177**
Total Cost of Ownership	CAPEX + OPEX	$			**848,396,123**

The TCO for hydrogen-based PEMFC-powered bulk carrier vessels is USD 848 MM, or USD 177/km.

3.2.11 Comparison of TCO for Alternative Fuel Pathways

So far in this chapter, I selected the four most promising pathways – NH_3-ICE, NH_3-FC, Methanol-Dual Fuel Engines, and LH_2-FC. I also developed and presented these pathways' total cost of ownership model. For the TCO analysis, I assumed that alternative fuels had been produced using renewable energy and clean electricity at USD 58/MWh. Table 33 summarizes the TCO model results and presents the mark-up above the reference vessel (HFO-ICE).

Table 33 Summary of TCO Models for Bulk Carriers

Type	Component	Unit	HFO-ICE	NH_3-ICE	NH_3-SOFC	Methanol-Dual Fuel Engine	LH_2-PEMFC
Power	Engine	kW	16,080	16,080	15,000	15,000	15,000
CAPEX	Baseship	$	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000

	Main Powertrain	$	6,882,240	6,882,240	80,250,000	6,420,000	45,000,000
	Emission Control	$	688,224	688,224			
	Evaporator	$			2,850,480		
	Storage System Upgrades	$				2,850,000	129,636,000
	Ship Upgrades	$		7,000,000	12,893,500	1,237,500	12,000,000
	CAPEX Total	$/km	6	8	24	7	43
	CAPEX Total	$/kW	1,660	2,095	7,674	2,006	13,717
OPEX (Non-Fuel)	Main Engine	$	4,301,400	4,301,400	50,156,250	3,828,750	22,500,000
	Ship Maintenance	$	1,720,560	1,720,560	712,620	1,720,560	32,409,000
	Electrical system	$			3,223,375		3,000,000
	Emission Control	$	13,501,742	13,501,742			
	OPEX (Non-Fuel) Total	$/km	4	5	11	1	12
	OPEX (Non-Fuel) Total	$/kW	1,214	1,214	3,606	370	3,861
OPEX (Fuel)	Fuel Cost	$	136,228,293	523,380,759	466,056,075	782,242,792	577,851,123
	OPEX (Fuel) Total	$/km	31	125	97	191	121
	OPEX (Fuel) Total	$/kW	8,472	32,549	31,070	52,150	38,523
Total Cost of Ownership	CAPEX + OPEX	$/km	**41.36**	**137.76**	**132.51**	**200.33**	**176.97**
		$	182,440,219	576,592,684	635,260,060	819,369,042	848,396,123
Mark-up above Reference (HFO-ICE)		$/km	**1**	**3.33**	**3.2**	**4.84**	**4.28**

Based on the TCO model results, green methanol is more expensive than green ammonia or green hydrogen as fuel. The methanol pathway is the most costly option, about 4.8 times the cost of the reference case. The ammonia-ICE pathway is about 3.3 times more expensive than the reference case, and the Ammonia-FC pathway is ranked the cheapest among the alternative fuel pathways.

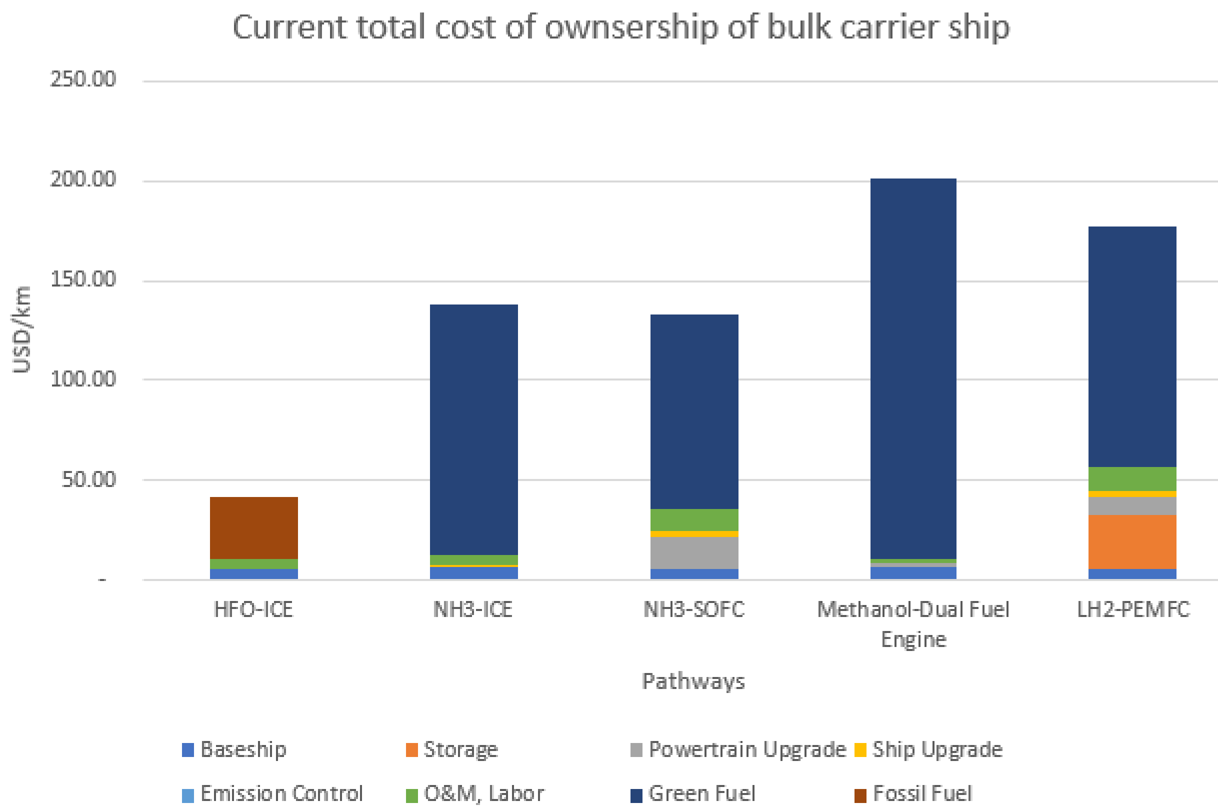


Figure 46 TCO of Alternative fuel pathways (RE price: USD 50/MWh, Green NH_3: USD 682/tonne, Green H_2: USD 4516/tonne, Green Methanol: USD 1143/tonne)

I illustrated the breakdown of cost components in Table 34 and Figure 47. With the current high-cost level of green fuels, the OPEX is dominated by fuel costs over the vessel's long lifetime. The initial capital is costly for the NH_3-SOFC pathway, as the SOFC is around ten times more expensive than ICE per kW (de Vries, 2019) and more expensive than PEMFC per kW. The CAPEX for the hydrogen-FC pathway is the highest, as hydrogen requires special storage tanks to contain large volumes of hydrogen fuel in the liquid state. In contrast, ammonia and methanol storage is not as difficult. In the TCO model, cargo loss due to increased required space from additional storage or powertrain system upgrades has not been factored in.

Table 34 Cost components in TCO for alternative fuel pathways

Cost Component	HFO-ICE	NH_3-ICE	NH_3-FC	MeOH-Dual Fuel	LH_2-PEMFC
Capital ($/km)	6	8	24	7	43
Labor O&M ($/km)	4	5	11	1	12
Fuel ($/km)	31	125	97	191	121

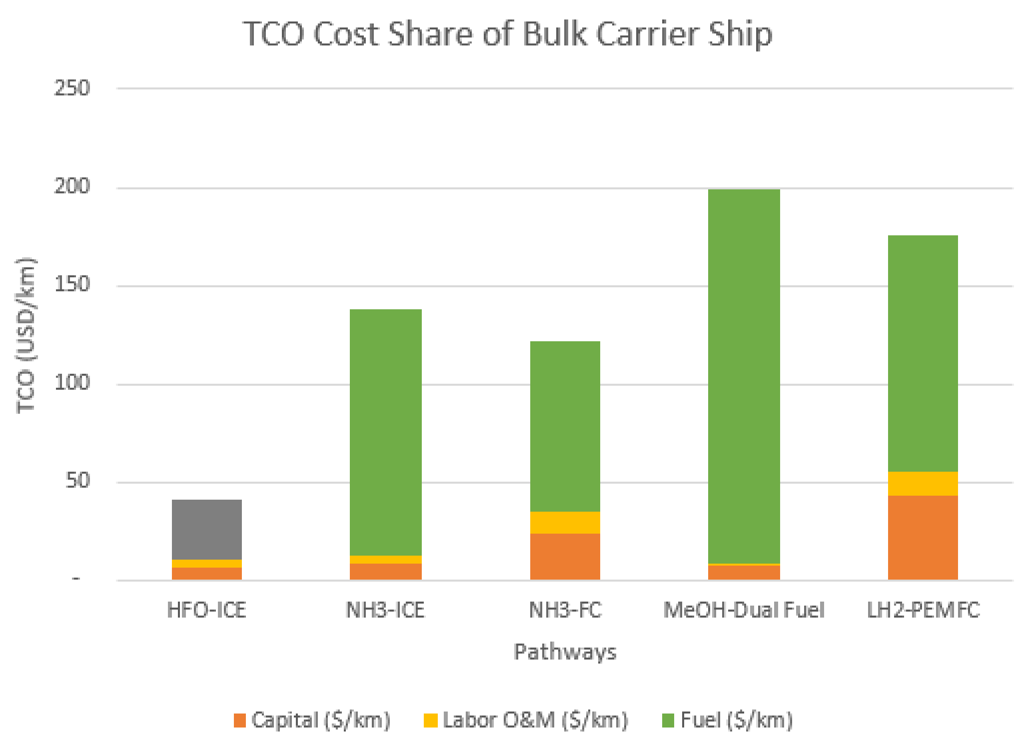


Figure 47 TCO Cost-share of a bulk carrier ship

3.2.12 Validations of the TCO Model

Validations for Ammonia-based pathway: For ammonia-based TCO model validations, a study on ammonia as a marine fuel by de Vries (de Vries, 2019) has been used as a similar approach for the TCO model was used based on the 25-year lifetime of bulk carrier vessels. The difference is that this study assessed the actual cost of the vessel, whereas de Vries model only focused on the marginal change in cost among different options. In the conclusion section of the report, it was stated that the ammonia-powered option is more expensive in terms of TCO, about 3.2 times the expenses of the conventional option (HFO-ICE), based on the fuel cost of 850 euro/tonne of ammonia and 500 euro per tonne of low sulfur HFO. In the TCO model developed for this study, the result for NH_3-ICE was about 3.59 times more expensive than the reference case, with the fuel cost assumed as $766/tonne of ammonia and $376/tonne of HFO as calculated using the sLCOE model. The difference in methodologies is that the fuel cost used for this study is not the market price of fuel but a cost of production estimation and de Vries thesis used the estimate for the market price of fuel. For a direct comparison to validate the TCO model, I ran the TCO model with the same input fuel cost assumptions (850 euro/tonne ammonia, 500 euro per tonne of HFO), and I estimated that the NH_3-ICE options are about three times more expensive than the reference case

(USD/kW), which aligns with the result of the report (de Vries, 2019).

Validations for Cost Shares: Another data source has been used to validate the TCO model. The IEA has published the chart to illustrate the current and future total cost of ownership of fuel/powertrain alternatives in a bulk carrier ship (IEA, 2019b).

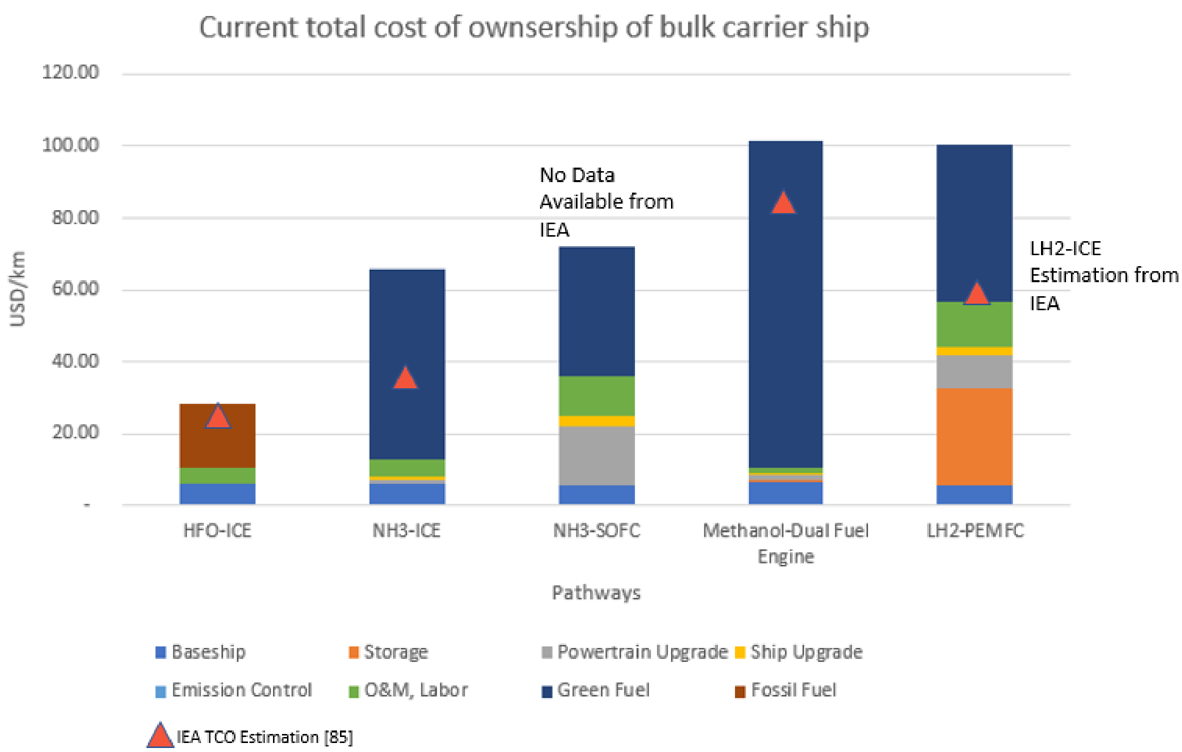


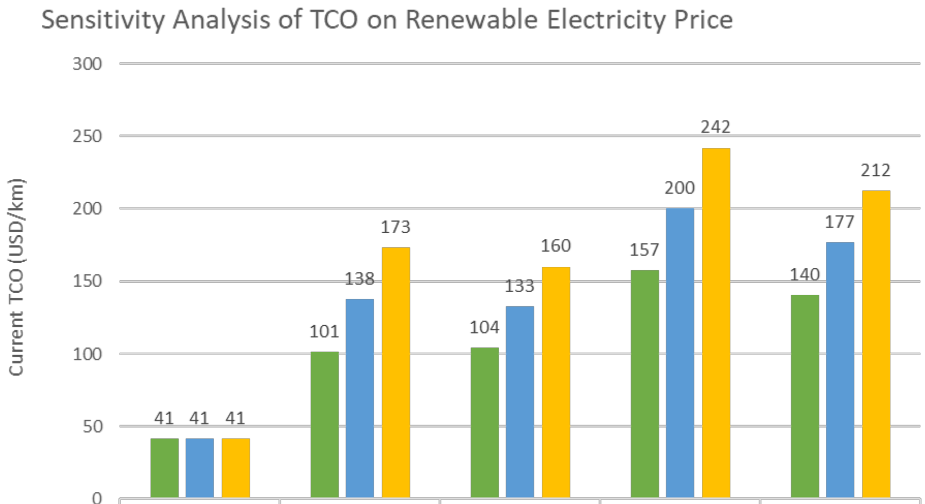
Figure 48 TCO (USD/km) of bulk carriers with alternative pathways - TCO cost breakdown; TCO adjusted to match IEA assumptions for comparisons using USD 31/MWh RE price

Figure 48 compares similar alternative options in the same vessel category using the metric (USD/km). Therefore, the relative TCO of alternative options can be compared with this study. The IEA chart shows that synthetic fuel is the most expensive, followed by ICE-Hydrogen and ICE-Ammonia. It could not be determined what powertrains have been assumed for the synthetic fuels in the IEA report, but it has an annotation of "air capture" for CO_2 sourcing which is required for green methanol production. As such, the IEA result implies that using green methanol fuel is more expensive than the ICE-Ammonia pathway. These alternative options are more costly than ICE-VLSFO, comparable to this study's reference case (ICE-HFO). The results are well aligned in the relative comparisons of TCO calculations. Figure 48 has been created to compare the cost shares of the TCO model to match IEA's breakdown (Base ship, Storage, Powertrain Upgrade, Fuel Cost). The assumptions and inputs have been adjusted to match IEA's assumptions where applicable, but there are several differences, including the lifetime assumptions (IEA used 15 yrs) and Distance Travelled (IEA used 100,000 km/yr) the base ship cost. This difference in assumption implies that IEA's reference vessel for the TCO calculation is smaller in scale compared to the one used for this study, with a shorter lifetime (60%), distance (60%), and cheaper base ship cost (50%). Due to the longer lifetime assumption of 25 years in the TCO model for this study, the fuel cost share is larger than the IEA result. Despite several limitations, the relative ranking order of each pathway is still the same, with the ammonia-based pathway being the cheapest option with the lowest markup above the reference case, and the TCO results (USD/km) are aligned within the order of magnitude.

Validations for Relative Ranking: A similar study (Stolz et al., 2022) was used for validation of the TCO models. The relative TCO using green renewable fuels is compared against the reference case (fossil diesel, or HFO). The renewable electricity price was assumed to be between EURO 40/MWh (lower bound) to EURO 83/MWh (upper bound). It can be noted that e-methanol (green methanol) is more expensive than e-hydrogen, and e-hydrogen is more costly than e-ammonia (green ammonia), which is in line with the results from this study. The markup for these two options implies that green methanol and green ammonia are 5-6 and 3-4 times more expensive than the reference case. Also, it is shown that fuel-cell pathways are generally more costly than ICE options based on renewable fuels. Overall, the results from the source (Stolz et al., 2022) align closely with the findings from this section.

3.2.13 Sensitivity Analysis of TCO models

Sensitivity on Renewable Electricity Price: The TCO over 25 years is primarily dominated by fuel cost. Especially for green fuels, the fuel cost determines the huge portion of OPEX. As presented in Section 3.1, green fuel costs are sensitive to renewable electricity prices. Therefore, in this section, a similar approach was taken to illustrate the sensitivity of alternative pathway TCO to varying renewable electricity prices. The current estimate of USD 50/MWh is shown in the blue bar, with the upper and lower bounds for renewable electricity prices. At the upper bound of renewable electricity price, it is notable that the TCO of the ammonia-FC pathway becomes lower than the ammonia-ICE pathway, which changes the ranking order compared to the lower bound condition. This is because the high efficiency of SOFC (efficiency: 60%) enables less fuel consumption than ICE (efficiency: 50%), which leads to reduced fuel cost, OPEX, and TCO.



	HFO-ICE	NH3-ICE	NH3-SOFC	MeOH-ICE	LH2-PEMFC
RE Price $31/MWh	41	101	104	157	140
Baseline: RE Price $50/MWh	41	138	133	200	177
RE Price $68.4/MWh	41	173	160	242	212

Figure 49 Sensitivity Analysis of TCO on Renewable Electricity Price

Sensitivity on Efficiency of Fuel Cell: The Ammonia-SOFC pathway is sensitive to the performance of SOFC. The higher the efficiency of SOFC, the lower the fuel consumption, and thus the lower TCO of the ammonia-SOFC pathway. The SOFC technology using ammonia as a fuel is still under development and needs further optimization for the best performance (Gray et al., 2021). As such, the future projection of SOFC efficiency has uncertainty, with some literature estimating up to 80% efficiency (DNV GL AS Maritime, 2019). With the 80% efficiency, the markup of the NH_3-SOFC pathway can be reduced to 2.62.

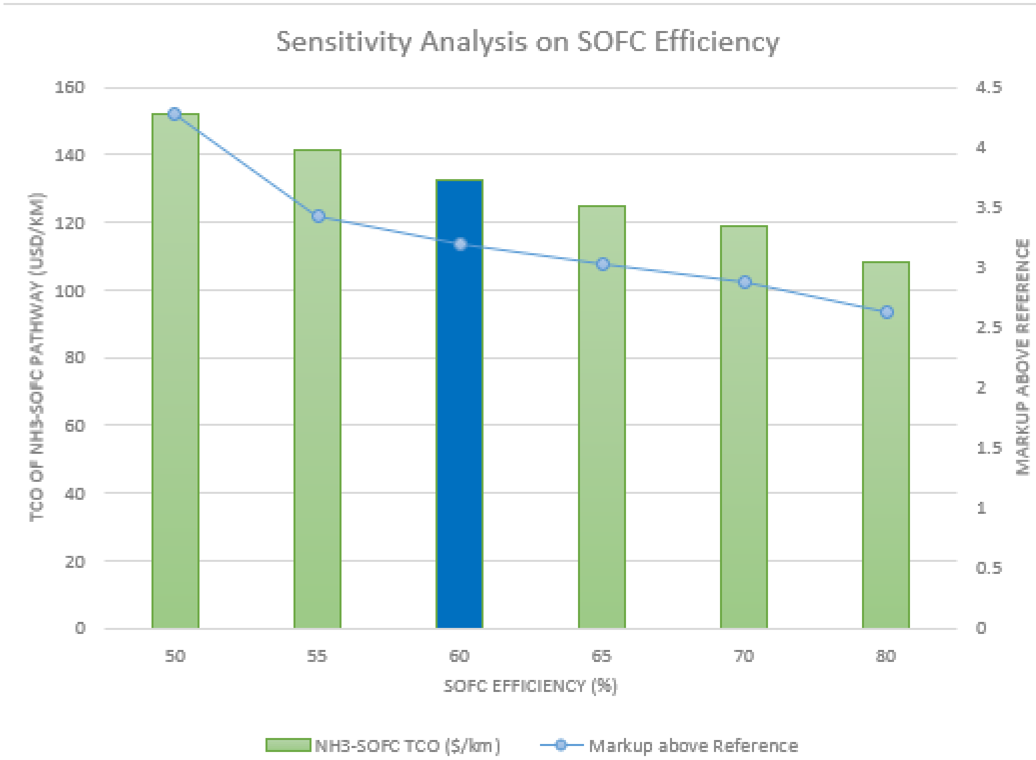


Figure 50 Sensitivity Analysis of SOFC efficiency

3.2.14 Summary of Cost Model Results

The EPPA model requires cost inputs of backstop technologies to assess the economic implications and project future outcomes based on policy scenarios. The cost models developed and illustrated in this section, including the sLCOE and TCO model, have been used to generate the cost shares of three components that constitute the total cost of ownership. The cost components are capital, labor, and O&M (OPEX – Non-fuel) and OPEX (fuel). The results from cost models are summarized in Table 35.

Table 35 Summary table of cost modeling results

Cost Component	HFO-ICE	NH_3-ICE	NH_3-FC	MeOH-Dual Fuel	LH_2-PEMFC
Capital ($/km)	0.15	0.06	0.20	0.04	0.24
Labor O&M ($/km)	0.10	0.04	0.09	0.01	0.07
Fuel ($/km)	0.76	0.91	0.71	0.96	0.69
Markup above Reference (HFO-ICE)	**1**	**3.33**	**3.2**	**4.84**	**4.28**

Key Assumptions (See section 3.2.1 for more details)

- Renewable Electricity: USD 50/MWh
- CO_2 Cost: USD 10/tonne CO_2
- HFO: USD 376/tonne HFO
- Green NH_3: USD 682/tonne
- Green MeOH: USD 1143/tonne
- Green H_2: USD 4516/tonne
- Natural Gas Price: USD 3.7/MMBtu
- Lifetime: 25 years

3.3 Trade-Off Analysis of Alternative Fuel Pathways and Recommendations

Based on the current estimates of cost using the TCO models and literature survey on emissions and fuel properties, the trade-off between cost and utility of alternative pathways has been generated. Using the Trade-Off analysis method as illustrated in the System Engineering textbook (Kossiakoff et al., 2020), I created a tradespace of alternative fuel pathways using the two most important metrics in tension in the system – Cost and Utility. The tradespace analysis aims to evaluate different decision pathways for alternative fuels on these two axes at a system level. I followed the Trade-off analysis steps (Kossiakoff et al., 2020) in the subsequent sections:

1. Define the objective: The objective is to select the best option that maximizes the multi-attribute utility with minimum cost
2. Identify qualified alternative candidates: From Chapters 2 and 3, several promising green fuel alternative pathways and conventional pathways have been selected
3. Define selection criteria: For this study, cost and multi-attribute utilities are the selection criteria
4. Assign weights to selection criteria in terms of their importance to the decision
5. Identify or develop a value rating for each decision
6. Calculate comparative scores for each alternative's criterion; combine the evaluations for each alternative
7. Analyze the basis and robustness of the results

3.3.1 Cost

The first axis represents the cost of each pathway using the TCO markup above the reference case (HFO-ICE). As such, the cost of the reference case is 1, and the TCO markup for other pathways has been calculated in Chapter 3. For the LNG pathway, the TCO markup was extracted from the IEA's estimation of the current total cost of ownership of LNG bulk carrier ships (IEA, 2019b).

According to the estimation, the markup for LNG above the reference case (VLSFO) was 1.052. For alternative fuel pathways, the markup is based on the TCO model results: Using renewable sources, NH_3-ICE is 3.33, NH_3-SOFC is 3.2, MeOH-ICE is 4.84, and LH_2-PEMFC is 4.28.

For natural gas feedstock, the sLCOE models are used to calculate the fuel cost based on the natural gas price of USD 3.7/MMBtu. The fuel costs from the sLCOE models are as follows: NH_3 – USD 297/tonne, MeOH – USD 176/tonne, LH_2 – USD 877/tonne. Based on these numbers, the TCO markups are as follows: NH_3-ICE is 1.62, NH_3-SOFC is 1.88, MeOH-ICE is 0.95, and LH_2-PEMFC is 1.93. The markup represents the relative lifetime cost of owning a bulk carrier vessel with each fuel-powertrain pathway to the reference case (HFO-ICE). The green methanol-ICE (dual fuel engine) pathway is the costliest option, as the fuel cost to produce green methanol is the most expensive per energy unit, even though the upfront capital cost of upgrading to a methanol-based dual fuel engine is relatively economical (USD 2,006/kW), around 20% higher than the traditional ICE, compared to fuel cell options with 4-500% higher upfront cost. The cheapest option is LNG, with the lowest fuel cost. Among green fuel options, the most economical pathway is the NH_3-FC pathway, with less lifetime fuel consumption due to the high efficiency of ammonia-fed SOFC (60%).

3.3.2 Multi-Attribute Utility

The second axis represents a multi-attribute utility that combines utilities from several metrics that can measure the success of alternative fuel pathways in the shipping environment. The metrics combined are emission reduction, infrastructure availability, the safety of fuels, required scalability, and technology readiness level. These individual attributes are then aggregated with weights to compute the multi-attribute utility score from 0-10 using the following equation:

$$\begin{aligned} &Multi\ Attribute\ Utility\ (0-10) \\ &\quad = Emission\ Reduction\ Utility * Weights_{emission} \\ &\quad + Infrastructure\ Availability\ Utility * Weights_{infrastructure} \\ &\quad + Safety\ Utility * Weights_{safety} + Scalability\ Utility * Weights_{scalability} \\ &\quad + Technology\ Readiness\ Level * Weights_{technology} \end{aligned}$$

where

$$Weights_{emission} = 70\%$$

$$Weights_{infrastructure} = 10\%$$

$$Weights_{safety} = 5\%$$
$$Weights_{scalabiltiy} = 5\%$$
$$Weights_{technology} = 10\%$$

The weights are determined based on the relative importance of meeting the climate mitigation goals of achieving Net-Zero emissions with other factors that play a significant role in the practical deployment of pathways. Each utility has a scale of 0-10, with the higher utility score implying better performance in each category than the lower utility score. The calculations of individual utility based on these metrics are described below.

Emission Reduction Utility: Emission reductions are calculated based on emission factors (gCO_2e/MJ) for each pathway extracted from the sources of lifecycle emission using well-to-wake accounting methodology (Gray et al., 2021) (Methanol Institute, 2021a) as illustrated in Chapter 2. For LNG, an additional 14% of GHG emissions have been added to the emission factor to realistically represent the amount of methane slip of the well-to-wake lifecycle based on literature ((Alvarez et al., 2018) (Pavlenko, 2020)) which results in 87.21 gCO_2e/MJ. For validation, this number was compared to the source (Methanol Institute, 2021a), in which the lifecycle emission of LNG is estimated to be around 90 gCO_2e/MJ. In addition to the reference fuel (HFO) and LNG, alternative fuels from the renewable source (solar) as well as from natural gas feedstock have been selected for lifecycle emission comparison. Next, emission reduction has been calculated for each pathway relative to the emission factor from the reference case's emission factor. For example, the ammonia-SOFC pathway has an emission factor of 8.33 gCO_2e/MJ, and the reference (HFO-ICE) has an emission factor of 94 gCO_2e/MJ. The emission reduction for the ammonia-SOFC pathway is 94-7.33 = 86.67 gCO_2e/MJ, and 86.67/94 * 100 = 92.2%. This indicates there is a 92.2% reduction from the reference case. The emission reduction percentage is converted to an emission reduction score of 9.22 by multiplying 0.1 on a scale of 0-10. For alternative fuels from natural gas feedstock, the lifecycle emission factor is greater than that of HFO except for methanol as shown in Figure 51 and Figure 25.

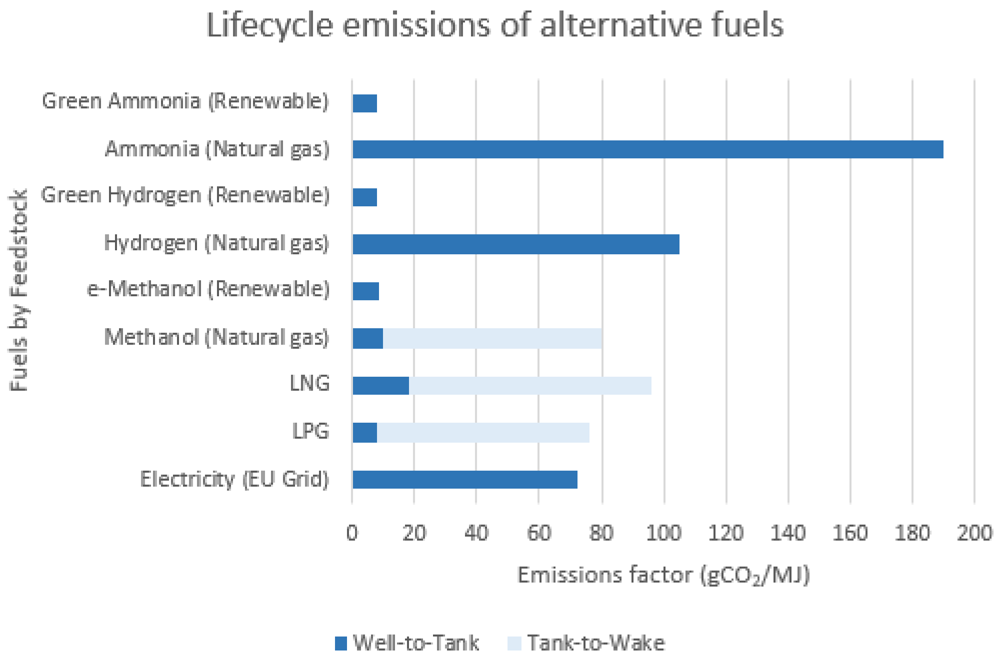


Figure 51 Lifecycle emissions of alternative fuels adapted from (Methanol Institute, 2021a) (Pavlenko, 2020)

For example, using conventional methodologies, hydrogen, and ammonia produced from natural gas feedstock generate 105 and 190 gCO_2e/MJ, respectively (Methanol Institute, 2021a), which implies that these pathways have negative reductions or increases in emission factors compared to that of HFO. Therefore, an additional conversion step was added to scale the emission reduction score from 0-10, with a lower bound of 0.1 for a visualization purposes. Using this methodology, I estimate the NG-ammonia-SOFC pathway has an emission factor of 190 gCO_2e/MJ, which results in a -10.21 emission reduction score relative to HFO. This score can be converted to 0.1 in Emission Utility. The emission factors (gCO_2e/MJ) for all pathways are summarized in the table below.

Infrastructure availability: Infrastructure availability of fuels has been compiled from various sources (DNV GL AS Maritime, 2019) (Hord, 1978) (de Vries, 2019) as described in Chapter 2. I qualitatively mapped to a utility score between 0-10 based on the relative order, with HFO scoring ten as it is currently available. Infrastructure availability mainly represents the availability of bunkering infrastructure and transport and handling of fuels. For LNG, dedicated LNG bunkering infrastructure is currently limited but improving rapidly, according to the DNV report (DNV GL AS Maritime, 2019). LNG has the most available infrastructure for bunkering facilities compared to other options and therefore was given a score of 7. Hydrogen's infrastructure and bunkering facilities for ships are currently not developed (DNV GL AS Maritime, 2019). However, in the future, hydrogen can be produced locally distributed, which might improve the bunkering flexibility at ports. Hydrogen’s limited infrastructure led to a low score of 3 in infrastructure availability utility. Ammonia has an existing infrastructure for transport and handling thanks to its global use case as fertilizers, but the bunkering infrastructure is still not mature. As such, ammonia was given a score of 5. Methanol’s bunkering infrastructure is also limited, but there is an existing global terminal infrastructure, with the first methanol infrastructure chain already launched in an operating environment to fuel methanol-based vessel in Germany (DNV GL AS Maritime, 2019). Also, since methanol is liquid at room temperature, transport and handling are easier than other alternative options. Therefore, methanol was given a score of 6, which is higher than ammonia and hydrogen but lower than LNG.

Safety: The safety of each fuel is determined by toxicity and flammability, which relate to the safe application of handling onboard ships. Based on the literature review, including the DNV report (DNV GL AS Maritime, 2019), flash point, autoignition temperature, and flammability have been compiled in Table 36. The flash point indicates how easy a chemical may burn, so a lower flash point implies a higher risk in the absence of additional safety measures (DNV GL AS Maritime, 2019). The flammability limit represents the vapor concentrations of a chemical over which a flammable mixture of gas in the air can be ignited under atmospheric conditions (DNV GL AS Maritime, 2019), and a wide range represents a higher risk. Finally, toxicity measures how toxic a chemical is. Acute toxicity describes the adverse effects of a substance that result from single/multiple exposures in a short period (GHS, 2018). The safety utility aggregates these four metrics qualitatively and scores between 0 and 10. Due to its high toxicity, ammonia has the lowest safety utility score of 4, and due to its high flammability, hydrogen has a score of 6, compensated by low toxicity. The traditional HFO has low acute toxicity and flammability and a high safety utility score of 9. LNG is comparable to HFO in terms of safety applications, as it is not toxic and has a low range for flammability limits. Methanol has low acute toxicity with a medium range for flammability, so has scored 7 in the safety utility, the highest among alternative fuel options.

Table 36 Overview of the safety of fuels adapted from sources below

Source: (DNV GL AS Maritime, 2019) (Mercuria Energy Trading, 2015)

	Flash Point (˚C)	Autoignition Temperature (˚C)	Flammability Limits (volume % in air)	Toxicity	Safety Utility (0-10)
Ammonia	132	630	20 (low range)	Highly Toxic	4
LNG	-188	537	10 (low range)	Not Toxic	8

Methanol	11	47	25 (med range)	Low acute toxicity	7
Hydrogen	N/A	500	40 (wide range)	Not Toxic	6
HFO	61	210 (sailor et al., 2019)	6.2 (low range)	Low acute toxicity	9

Scalability: Scalability is a measure of how much each fuel option needs to scale, and it has been computed based on the current production of each fuel (hydrogen, ammonia, methanol) compared to the estimated annual demand required from the source (McKinlay et al., 2021). Figure 52 below compares how much the production of each fuel needs to scale up to meet the demand for 50,000 ships. According to the study, hydrogen has the lowest current production amount, but due to its high gravitational density, the required amount is the lowest. Each fuel's required scalability in % of the current production amount has been calculated based on the actual production numbers. Methanol needs to scale the most in terms of percentage from the current supply (859%), so the lowest scalability score of 0.5 was given. HFO has a score of 10, as it already exists in the market to meet the demand. Ammonia and hydrogen's scalability utility score was calculated based on the ratio of the scalability percentage relative to that of methanol and scaled between 0.5 and 10. For example, ammonia needs to scale 391%, so (859-391)/859 * 10 + 0.5 = 5.95 was given as a scalability utility score. Hydrogen has higher scalability utility score of 8.5, which implies that scaling the production would be less daunting to meet the future demand.

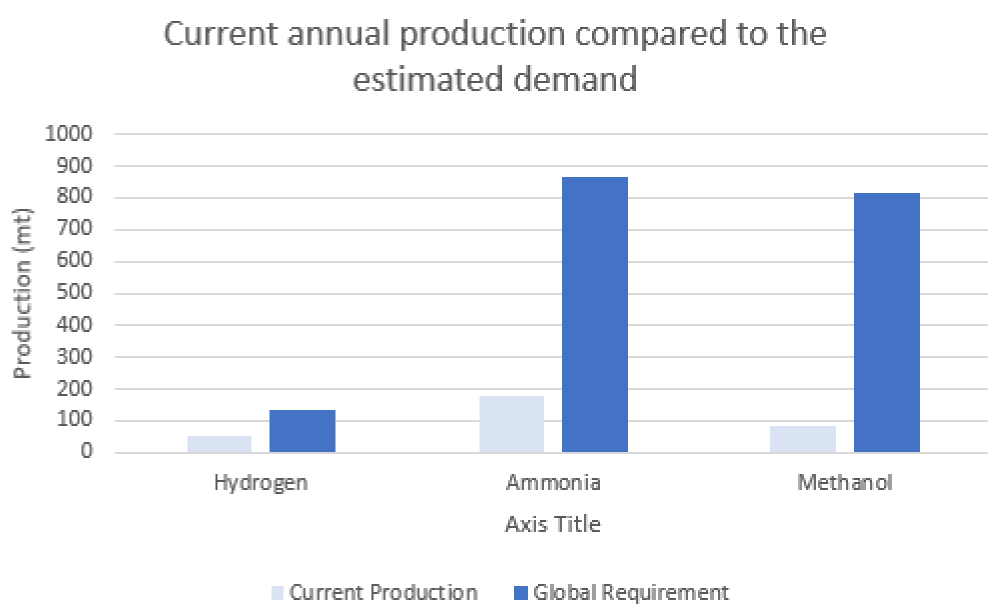


Figure 52 Current annual production compared to the estimated demand reproduced from (McKinlay et al., 2021)

Technology readiness level (TRL): TRL of each pathway was assessed based on the green fuel's readiness as well as the technical readiness of alternative fuel-based powertrains for the maritime operation environment based on the literature review in Chapter 2 (DNV GL AS Maritime, 2019) (McKinlay et al., 2021). LNG ships are already operating, so the technology readiness level of 9 was given. Methanol is the fourth largest fuel used in the maritime industry as introduced in Chapter 2, and a few commercially operating methanol dual fuel engines are in order or operation, so a technology readiness level of 8 was given. Ammonia pathways' technology readiness level depends on the powertrain options. SOFC has lower TRL than ammonia ICEs (de Vries, 2019) and is a newer technology than PEMFC (Gray et al., 2021).

3.3.3 Tradespace Recommendation

Table 37 summarizes cost and utility calculation results for various pathways, including the reference case (HFO-ICE). Figure 53 represents the tradespace of alternative fuel pathways on the Cost and Utility axes.

Table 37 Cost vs Utility tradeoff

Pathway	**Feedstock**	**Cost (TCO Markup)**	Emission (gCO2e/MJ)	Emission Reduction Score Relative to HFO	Emission Utility (0-10)	Infrastructure Availability (0-10)	Safety (0-10)	Required Scalability (%)	Scalability (0-10)	TRL (1-10)	**Multi-Attribue Utility (0-10)**
HFO-ICE	Fossil Fuel	1	94	0.10	5.33	10	9	0	10.00	10	6.68
Green NH3-SOFC	Renewable	3.2	8.33	9.11	9.91	5	4	391	5.95	4	8.33
Green NH3-ICE	Renewable	3.33	8.33	9.11	9.91	5	4	391	5.95	5	8.43
Green MeOH-DFICE	Renewable	4.84	8.44	9.10	9.90	6	7	859	0.50	8	8.71
Green LH2-PEMFC	Renewable	4.28	6.67	9.29	10.00	3	6	171	8.51	5	8.53
LNG	Fossil Fuel	1.0522	87.21	0.72	5.65	7	8		9.00	9	6.41
NG NH3-SOFC	Fossil Fuel	1.88	190	-10.21	0.10	5	4	391	5.95	5	1.57
NG NH3-ICE	Fossil Fuel	1.62	190	-10.21	0.10	5	4	391	5.95	6	1.67
NG MeOH-DFICE	Fossil Fuel	0.95	80	1.49	6.04	6	7	859	0.50	8	6.00
NG LH2-PEMFC	Fossil Fuel	1.93	105	-1.17	4.69	3	6	171	8.51	6	4.91
Weight					70%	10%	5%		5%	10%	

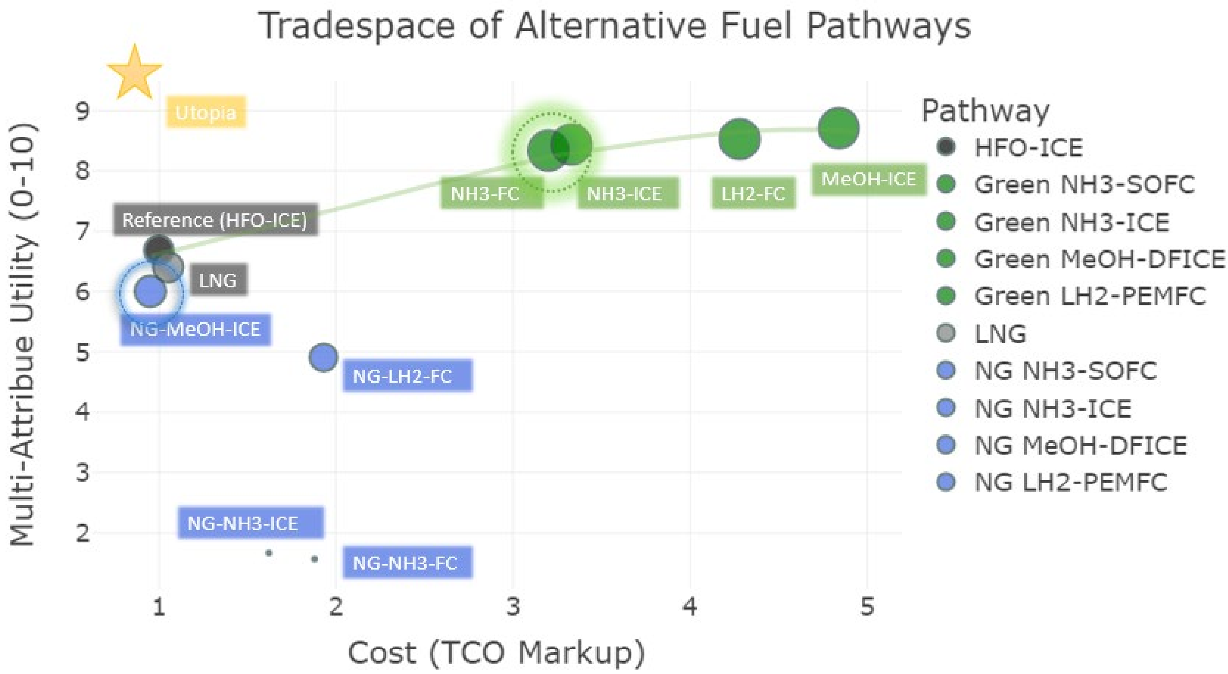


Figure 53 Tradespace of alternative fuel pathways; Sizes of data points are proportional to emission reduction utility

Among the alternative fuel pathways, the ammonia-SOFC pathway, the hydrogen-PEMFC pathway, and the methanol-Dual Fuel ICE pathway using renewable sources are on the Pareto front. The hydrogen pathway has demonstrated high utility, which stems from the greatest emission reduction potential and the high level of current production amount. However, due to the current low-level infrastructure availability compared to ammonia and methanol, the actual implementation of the hydrogen pathway faces a challenging hurdle, which was not fully reflected in the tradespace as the utility score from emission reduction has the highest weight (70%) due to the climate change mitigation imperative. The methanol-ICE pathway from renewable sources presents high potential, as demonstrated by the highest utility among alternative fuel pathway options. Still, the current high cost of green methanol production is positioned as the costliest option using the current estimates.

The alternative fuel pathways with fuels made from natural gas feedstock have lower utility than the traditional fuels (HFO, LNG) due to their high lifecycle emissions using fossil fuels. Specifically, NG-NH_3-ICE and NG-NH_3-FC pathways have the lowest utility, as their lifecycle emissions are the highest due to the energy and emission-intensive Haber-Bosch process powered by fossil fuels. However, the methanol pathway from natural gas feedstock (NG-MeOH-ICE) can be a viable near-term option for decarbonizing the shipping industry, with its TCO markup lower than the reference case (HFO) with a lower emission factor. The utility of NG-MeOH-ICE is currently lower than that of HFO, as methanol as a fuel is not as widely available as HFO. As the green methanol pathway has a high potential, transforming the base ships for a methanol-based propulsion system in the near term can potentially support the long-term (by 2050) pathway toward Net-Zero emissions using green methanol as fuel without worsening the greenhouse gas emissions. For Net-Zero emissions, it is essential to use fuels made from renewable sources to decarbonize the shipping industry truly.

With current estimates, the green ammonia-SOFC pathway has the lowest markup among green alternative fuel pathways above the reference case. Therefore, I chose it as a carbon-free option for the maritime shipping pathway for the economic analysis. The future pathways remain solution-neutral, as there is large uncertainty in the future technical development for each pathway, and the cost markup can change depending on various assumptions, as illustrated in this chapter. LNG is often considered a near-term option toward reducing emissions due to its lower tank-to-wake emission than the reference fuel (HFO). However, with other metrics factored in, such as infrastructure availability and methane slip, the total utility of the LNG pathway is lower than the reference case. Given the fact that the lifetime of a shipping vessel is around 25 years for bulk carrier ships, the decision to develop infrastructure and invest in the capital will have a long-lasting and irrevocable impact in the future. To achieve the goal of net-zero emissions by 2050, we need to make intermediate plans that align with the ultimate net-zero emission pathways by doing it right the first time using alternative fuels, instead of focusing on partially reducing the emissions at the risk of potentially decreasing the chance of going net-zero by 2050.

All alternative fuel pathways deserve further research and development, considering comparable utility across different options. Nevertheless, all four alternative pathways have huge potential to limit global temperature rise, as they generate very low well-to-wake emissions, with almost zero tank-to-wake emissions. Therefore, transitioning to alternative fuel pathways is inevitable to increase climate change mitigation in the shipping industry. The practical question still remains, given the high markup to implement this new pathway, and the question will be further analyzed in the next chapter.

Chapter 4 – Economic Model and Projections for Alternative Fuel Pathway

To evaluate the economic implications of the alternative marine fuel pathway under various policy scenarios, the MIT Economic Projection and Policy Analysis (EPPA) model has been used for analysis. The EPPA model is part of the MIT Integrated Global Systems Model (IGSM) that represents the human systems (Paltsev et al., 2021). The EPPA model has been widely used in assessing the potential impacts of energy transition, land use, technology, and climate policy proposals (Chen et al., 2022). One of the major focuses of the EPPA model is to produce decades-long projections under various decarbonization scenarios (Chen et al., 2022). Therefore, for this study, the EPPA model is applied to assess the economic impacts of the shipping industry's advanced technology pathway (represented by a so-called "backstop technology", i.e., a technology that does not exist in a base year of the model, but it has a potential to replace a corresponding conventional technology).

4.1 EPPA Model Overview

The EPPA model is a recursive-dynamic, multi-region, multi-sector, dynamic computable general equilibrium model of the world economy that is designed to develop projections of economic growth, energy transitions, and anthropogenic emissions of greenhouse gas and air pollutants (Paltsev et al., 2021). The EPPA model projects the world as 18 regional trading economies, each with 22 sectors and four primary factors, as shown in Figure 54.

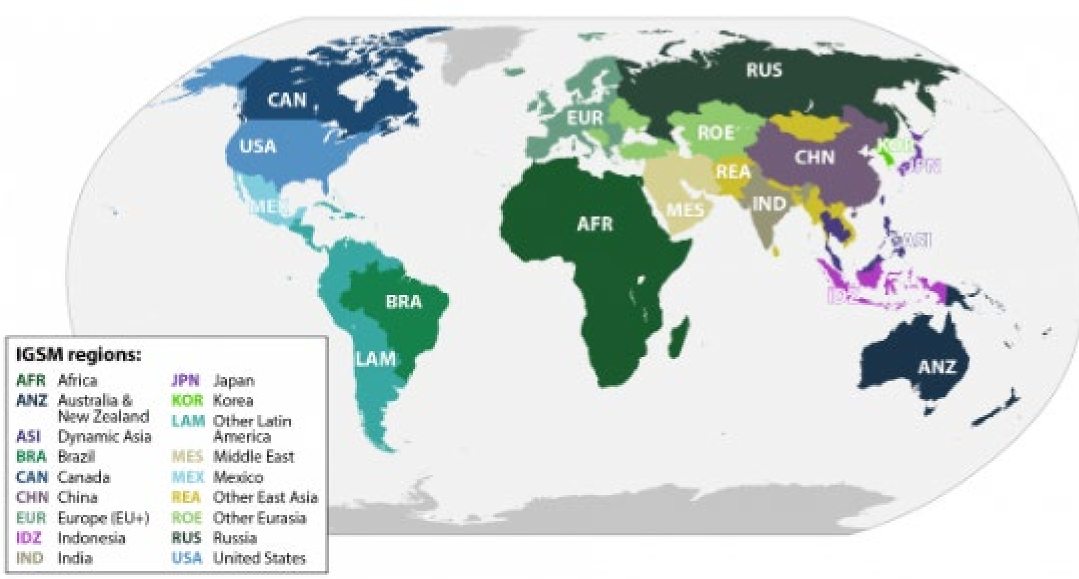


Figure 54 EPPA model regions, adapted from (MIT Joint Program on the Science and Policy of Global Change, 2022)

One of the key features in the EPPA model is that it can represent technology change that is currently unused, as backstop technologies, which come into play as supplies of current energy resources deplete, causing price rise or as policies penalize the GHG emission conventional energy sources. The time of entry for backstop technologies depends on the relative cost markup of the current fuel option (Paltsev et al., 2021). To evaluate the pathways for the shipping industry in this study, I used the relative cost markup for the backstop technology calculated using the TCO and sLCOE model presented in Chapter 3. The EPPA model formulates an optimization problem based on the computable general equilibrium model, and solutions to the problem are sought via solving large non-linear programming using a mixed complementarity approach in which an objective function is maximized/minimized subject to a set of constraints (Paltsev et al., 2021). The latest version of the EPPA model, EPPA7, is used for the analysis in this study in which a water transportation sector is separated from the existing transportation sector. To make economic projections of an alternative fuel pathway, its cost functions, constraints, and various input/output structures are incorporated into EPPA 7 as part of this study.

4.2 EPPA Model Policy Scenarios

4.2.1 Reference Scenario

In the *Reference* scenario, only existing plans or targets on renewables, bio-electricity, and nuclear power are included in the model (Chen et al., 2022). Advanced technologies such as negative emission power generation option or biomass with carbon capture and storage are assumed to be not technically available at a commercial scale until 2055.

4.2.2 Paris Forever Scenario

In the *Paris Forever* scenario, it is assumed that commitments under the Paris Agreement by 2030 are implemented, and the policies are continued thereafter, with no additional policy action (Paltsev, 2021). Under the Paris Forever scenario, climate change is neither stabilized nor limited, despite the global commitment to limit greenhouse gas emissions.

4.2.3 Paris 2C Scenario

In the *Paris 2C scenario*, it is assumed that policy actions beyond the current Paris Agreement commitments are ensured to limit the Earth's average surface temperature rise to 2C. In this scenario, the mitigation is assumed to be achieved through global economy-wide carbon pricing after 2030. The policy actions are aimed at deep emission reductions after 2030 to stabilize global temperature rise at 2C with a probability of 50% (Paltsev, 2021).

4.2.4 Accelerated Actions Scenario

In the *Accelerated Actions* scenario, much more aggressive emission targets are imposed on countries. The additional emissions reductions by countries represent an illustrative pathway of significant mitigation. Therefore, it is assumed that global GHG emissions in 2030 are lower by almost 20% compared to the current pledges for 2030 (Paltsev, 2021). This scenario is more aggressive in the short-term up to 2025 but less aggressive in the long term until 2050, with a goal of achieving 1.5C temperature stabilization with a 50% probability.

4.3 EPPA Model Enhancement for Alternative Fuel Pathway

The EPPA model's block diagram for this study is illustrated in the simplified diagram shown in Figure 55.

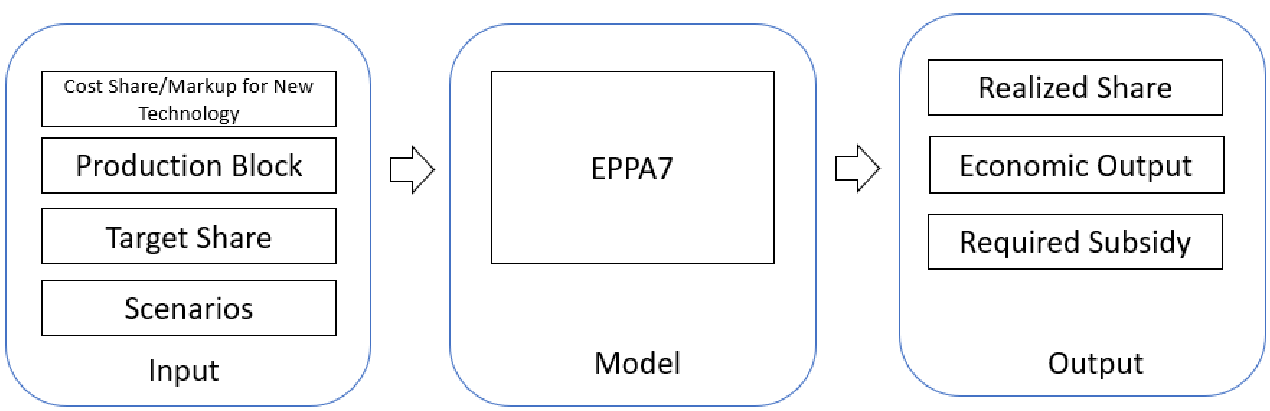


Figure 55 EPPA Model Diagram for Advanced Shipping application

For inputs, cost share and markup for the advanced shipping technology, I used the values from the cost models developed for this study. With this cost share information, a production block is created in EPPA 7 that generates cost functions for the optimization model. In addition, a control to add subsidy has been added to the model to analyze the economic implications of the advanced shipping pathway. In such a case, various scenarios for target market shares have been defined in the model. The pre-defined EPPA model scenarios are used as a baseline scenario, and the advanced shipping-specific constraints such as subsidies and target market shares are incorporated into the model.

For outputs of the model, the main components for analysis are the realized share, economic output, and the required investment. With the new backstop technology available in the shipping sector and the subsidy to reach the target share by 2050, the model can project what level of additional investment is required to achieve the goal, along with the economic output generated by the advanced shipping pathway.

4.4 EPPA Model Inputs and Outputs

4.4.1 Cost Shares and Markup for Alternative Pathway

The first step to running the EPPA model with a new backstop technology for the shipping sector is to provide cost share inputs and the markup to create a production block for the pathway. For EPPA modeling and assessment, I selected the ammonia-fuel cell pathway (NH_3-FC) because it is currently the most economical option, as discussed in Section 3.3. This pathway is labeled "low-emission shipping." Table 38 presents the low-emission shipping pathway's cost share compared to the TCO model's reference. Each cost share sums up to the TCO markup, which is 3.2 for the low-emission shipping pathway. This information will be used as one of the inputs to the EPPA model in the next chapter.

Table 38 Cost share for the low-emission shipping pathway

Final Cost Share (Sum to 3.2 = markup)	HFO-ICE	Low-emission shipping
CAPEX	0.15	0.58
OPEX (Labor)	0.10	0.27
OPEX (Fuel)	0.76	2.35
Total TCO Markup	1	3.20

In the EPPA model, a production block generates a cost function by using relevant variables, including inputs and outputs for a backstop technology defined within the block. The TCO model directly extracts capital and labor shares from CAPEX and OPEX (Labor) breakdown. To utilize the EPPA model's pre-defined production price parameters, I further disaggregated the fuel cost share using the sLCOE model for Renewable NH_3 using the calculations below:

Simple Levelized Cost of Production for NH3 via Electrolysis		
	Periods (yrs)	25.00
	Discount Rate	0.08
	CRF	0.09
	Capacity Factor	0.90
	Electricity Consumption (GJ/tNH3)	37.80
	Natural Gas Consumption (GJ/tNH3)	0.00
	Renewable Electricity Price ($/MWh)	50.00
	Natural Gas Price ($/Mbtu)	3.70
	Electricity Price ($/GJ) - Conversion	13.89
Input	Natural Gas Price ($/GJ) - Conversion	3.51
	Overnight Capital Cost ($M)	N/A
CAPEX	Overnight Capital Cost ($/kg NH3)	1.16
	Fixed O&M Cost (% of CAPEX)	1.50
Fixed OPEX	Fixed O&M Cost($/ kg NH3 -yr)	0.02
	Variable O&M Cost Multiplier	1.00
	Variable O&M Cost ($/kg NH3)	0.02
	Natural Gas Cost ($/kg NH3)	0.000
	Electricity Cost ($/kg NH3)	0.53
Variable OPEX	Total Feedstock Cost ($/kg NH3)	0.53
	sLCOE ($/kg NH3)	0.68
	sLCOE($/ton NH3)	682.47

	Final Cost Share (Sum to 3.2 = markup)		
		HFO-ICE	NH3-FC
CAPEX		0.146284762	0.580572225
OPEX (Labor)		0.107014241	0.272817134
OPEX (Fuel)		0.746700997	2.35
Total TCO		1	3.203968127
sLCOE Model			Green NH3
Fuel Capex ($/kg)			0.120741537
Fuel Opex ($/kg)			0.036733333
Fuel Electricity ($/kg)			0.525
Fuel Total ($/kg)			0.682474871
Fuel Capex			0.42
Fuel Opex			0.13
Fuel Electricity			1.81
Fuel Total			2.35

Figure 56 Fuel Cost disaggregation for NH_3-FC (1) sLCOE model for renewable NH_3 (2) Cost disaggregation to calculate input shares

- Fuel_Capital ($/kg) = Overnight Capital Cost * CRF / Capacity Factor = 0.1207
- Fuel_Labor (Fixed O&M + Variable O&M) ($/kg) = Fixed O&M/Capacity Factor + Variable O&M = 0.0367
- Fuel_Electricity ($/kg) = Electricity Cost = 0.525
- Fuel_Capital_share = OPEX (Fuel) share from the TCO model * Fuel_Capital ($/kg) / Fuel_Total ($/kg) = 2.35 * 0.12 / 0.68 = 0.42
- Fuel_Labor_share = OPEX (Fuel) share from the TCO model * Fuel_Labor ($/kg) / Fuel_Total ($/kg) = 2.35 * 0.04 / 0.68 = 0.13
- Fuel_Electricity_share = OPEX (Fuel) share from the TCO model * Fuel_Electricity ($/kg) / Fuel_Total ($/kg) = 2.35 * 0.53 / 0.68 = 1.81

Using the calculations above, I present the input structure for the low-emission shipping pathway production block for the EPPA model in the following form in Table 39.

Table 39 Production block for Low-emission shipping pathway

Production Block	Low-emission Shipping
Capital	0.58
Labor	0.27
Fuel Capex	0.42
Fuel Labor	0.13

Fuel Electricity	1.81
Markup	3.20

4.4.2 Target Market Share [%]

I explored different shares of low-emission shipping in the total shipping industry. The model defines the target market share of the advanced shipping technology in the Water Transportation sector (WTP) for each period across the regions as inputs. It is assumed that all regions have the same market share targets. In 2020, the share was assumed to be 1%, growing linearly to the target share defined by each scenario.

4.4.3 Constraints

A new constraint has been added to the model for the advanced shipping pathway to project the required investments (or government subsidy) over time. The constraint specifies that the realized share of the advanced shipping pathway out of the total WTP is greater than or equal to the target market share defined in the model.

4.4.4 Realized Market Share [%]

The realized market share is the actual market share of the advanced shipping technology in the WTP sector measured in %. This variable is checked against the input constraint, the target market share. It is expected that the realized market share meets the input constraint of the target market share.

4.4.5 Economic Output [USD 10 billion]

The economic output of the advanced shipping technology is calculated from the model in USD 10 billion. This value represents the value generated from the advanced shipping technology defined in the production block.

4.4.6 Required Investment Amount [USD 10 billion]

Additional investments for the advanced shipping pathway are added to the model. Additional investments can be either enabled or disabled based on the scenario. When additional investments are enabled, the constraint will be used to solve the model such that the realized market share is greater or equal to the target share. When additional investments are disabled, this constraint will be non-binding. The additional investment outputs are in the investment amount [USD 10 billion].

4.5 EPPA Model Results

4.5.1 Total GHG Emissions from Base Scenarios

To illustrate the differences in the implications of base scenarios, the total GHG emissions projections until 2050 from the EPPA7 model are presented in Figure 57. The reference case without any carbon tax or additional policies will result in a steady increase in global GHG emissions until 2050, summing up to more than 70 Gt of CO_2 equivalent emissions by 2050. Under the *Paris Forever* scenario, the total GHG emissions are projected to be reduced by around 22% by 2050 compared to the reference case but showed an increase in the total GHG emissions by around 16% in 2050 compared to 2014 levels under the same scenario. *Accelerated Actions* scenario has a significantly decreasing GHG emissions projection until 2050, resulting in about 66% reduction compared to the reference case at the 2014 level. The reduction in GHG emissions stems from more aggressive measures to limit the global temperature rise by 1.5°C with a 50% probability.

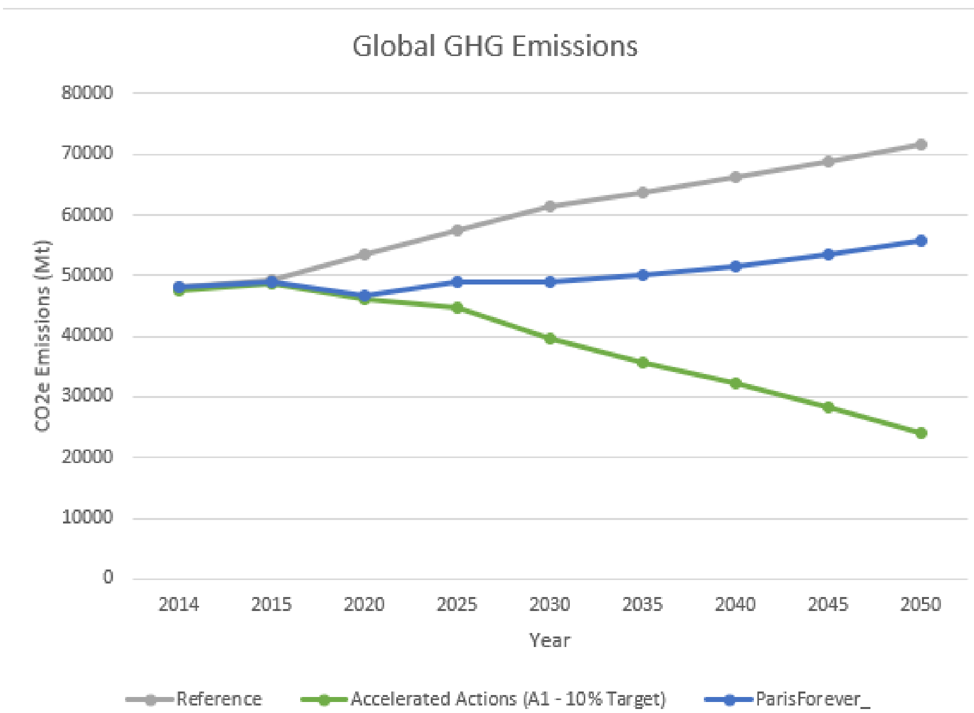


Figure 57 Global GHG emissions for base scenarios from EPPA7

4.5.2 Low-emission Shipping Scenarios

I constructed several scenarios to evaluate the economic implications of the advanced shipping pathway ("Low-emission shipping") based on the EPPA model's base climate scenarios (Paltsev, 2021). I first ran the *Paris Forever* scenario to assess the market penetration of the new pathway. Under the *Paris Forever* scenario, the low-emission shipping pathway would not penetrate the market under less aggressive policy measures. Therefore, the base scenario used is the *Accelerated Action* scenario described in Section 4.2.4. Scenario A0 represents a case where there are no additional investments for the low-emission shipping pathway, although the technology became available in 2020. Scenarios A1, A2, and A3 stipulate that the low-emission shipping pathway and additional investments become available from 2020 to reach target market shares of 10%, 25%, and 50%, respectively. The focus is to find out how much additional investments will be required for the low-emission shipping pathway to achieve the target market share from 2020 to 2050. The scenarios for the low-emission shipping pathway are summarized in Table 40.

Table 40 Low-emission shipping scenarios for the EPPA model

Run Name	**Low-emission Pathway**	**Description**
A0	No Additional Investment	Accelerated Action Scenario with 1.5°C goal (50% Prob), with Low-emission tech available but without any investments
A1	Additional Investment Available Target: 10% Market Share	Accelerated Action Scenario with 1.5°C goal (50% Prob), with Low-emission tech and investments available
A2	Additional Investment Available Target: 25% Market Share	Accelerated Action Scenario with 1.5°C goal (50% Prob), with Low-emission tech and investments available
A3	Additional Investment Available Target: 50% Market Share	Accelerated Action Scenario with 1.5°C goal (50% Prob), with Low-emission tech and investments available

4.5.3 Realized Market Share

The results from the EPPA model have generated various economic projections from 2020 to 2050. The model case files assumed that the advanced shipping technology would be available from 2020 with subsidies imposed. One of the outputs of the model, the realized market share of the advanced shipping pathway in the Water Transportation (WTP) sector, is presented in Figure 58.

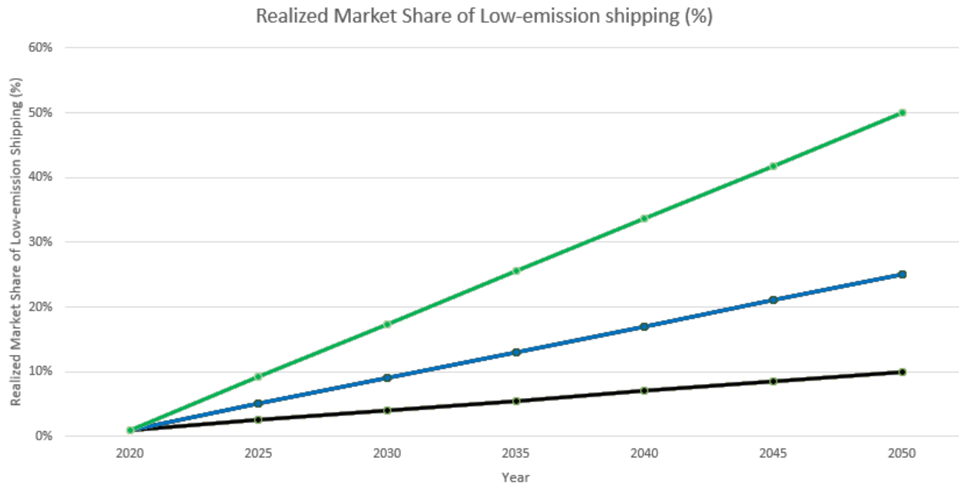


Figure 58 Realized market share of Low-emission shipping pathway

Under scenario A0, without additional investments in the advanced shipping pathway, the new pathway would not be able to penetrate the market as it is not economically viable, so the realized market share is projected to remain essentially zero until 2050. The constraint for the target market share is set to be non-binding when additional investments are not activated. This result implies that without any economic incentive from the government, the ammonia pathway will not be economically feasible in the shipping industry market due to its high markup.

Under the scenarios with the additional investment imposed, the advanced shipping pathway would be able to achieve the realized market shares for A1, A2, and A3 targets of 10%, 25%, and 50%, respectively, by 2050 based on the constraints. The intermediate realized market share results can be used to assess the economic output in any time period before 2050.

4.5.4 Global Economic Output Projections for Low-emission Shipping

Given the realized market shares of the advanced shipping pathway, the global economic output of shipping from the pathway is projected until 2050, as shown in Figure 59. Under A0 scenario, without additional investments, the market share would be zero, resulting in zero economic output from the advanced shipping pathway. This result reiterates an important point that additional investments are critical to enabling the commercialization of the low-emission shipping pathway. Under A1, with a 10% market share, the global economic output from the new pathway would be around USD 49 billion and USD 160 billion in 2030 and 2050, respectively. Under the A2 scenario with a 25% market share, the global economic output would reach USD 400 billion by 2050, an increase of around 144% from the A1 scenario. Under the A3 scenario, the global economic output from the advanced shipping pathway would be approximately USD 770 billion by 2050, which is around 380% greater than the A1 scenario.

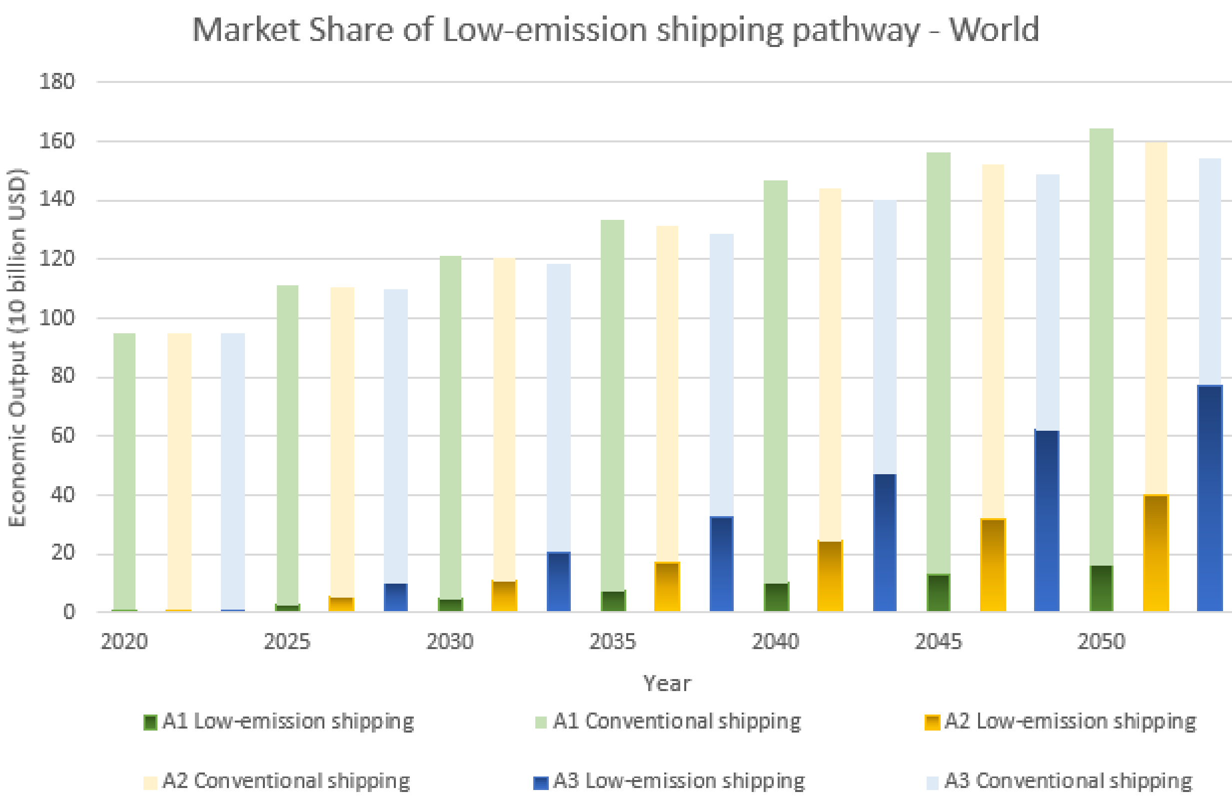


Figure 59 Global economic output of Low-emission shipping pathway - World

4.5.5 Economic Output Projections for Low-emission Shipping – USA

In the U.S. market, the economic output projections from the advanced shipping pathway demonstrate a similar uptrend as the global output shown in Figure 60. Under the A1 scenario, the economic output would reach USD 5 billion by 2035 and USD 12 billion by 2050. Under the A2 scenario, the economic output would reach USD 10 billion before 2035 and result in more than USD 30 billion by 2050. This result is around a 150% increase in the economic output by 2050 compared to the A1 scenario. Under the A3 scenario, the economic output would surpass USD 1 billion before 2030 and reach around USD 60 billion by 2050. With the most aggressive target share, the A3 scenario demonstrates that the advanced shipping pathway's economic output would be around 370% higher than that of the A1 scenario. Overall, the USA region follows the global trend and accounts for approximately 8% of total water transport output in 2050.

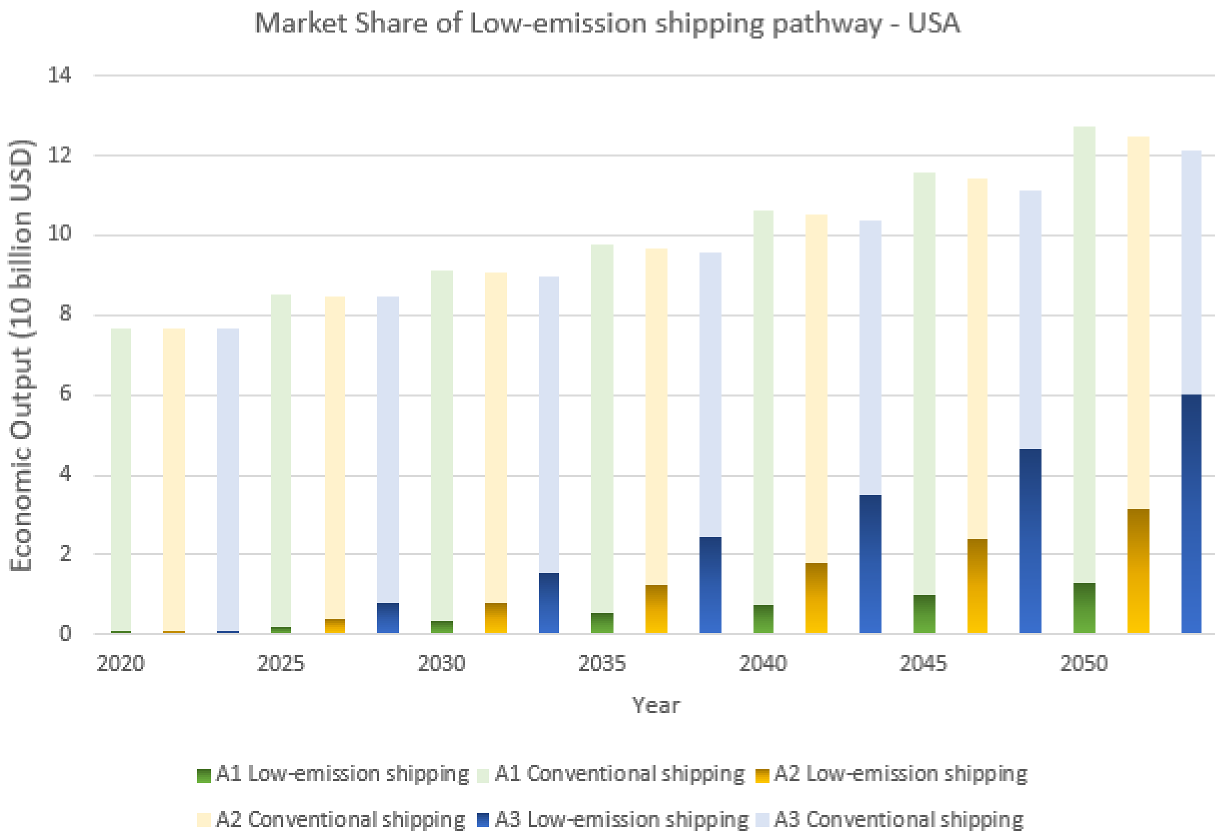


Figure 60 Economic output projections of Low-emission shipping pathway - the USA

4.5.6 Economic Output Projections for Low-emission Shipping – EUR

Another key region, EUR, shows a similar trend as the global output, as shown in Figure 61. Under the *Accelerated Action* scenario, the economic output from the conventional water transportation sector decreases over time. Still, the economic output from low-emission shipping increases to meet the target share. By 2050, under the most aggressive A3 scenario, low-emission shipping is projected to gain 50% market share in the EUR region, equivalent to around USD 200 billion. This result is about 25% of the global low-emission shipping output and is approximately three times greater than the USA's low-emission shipping output.

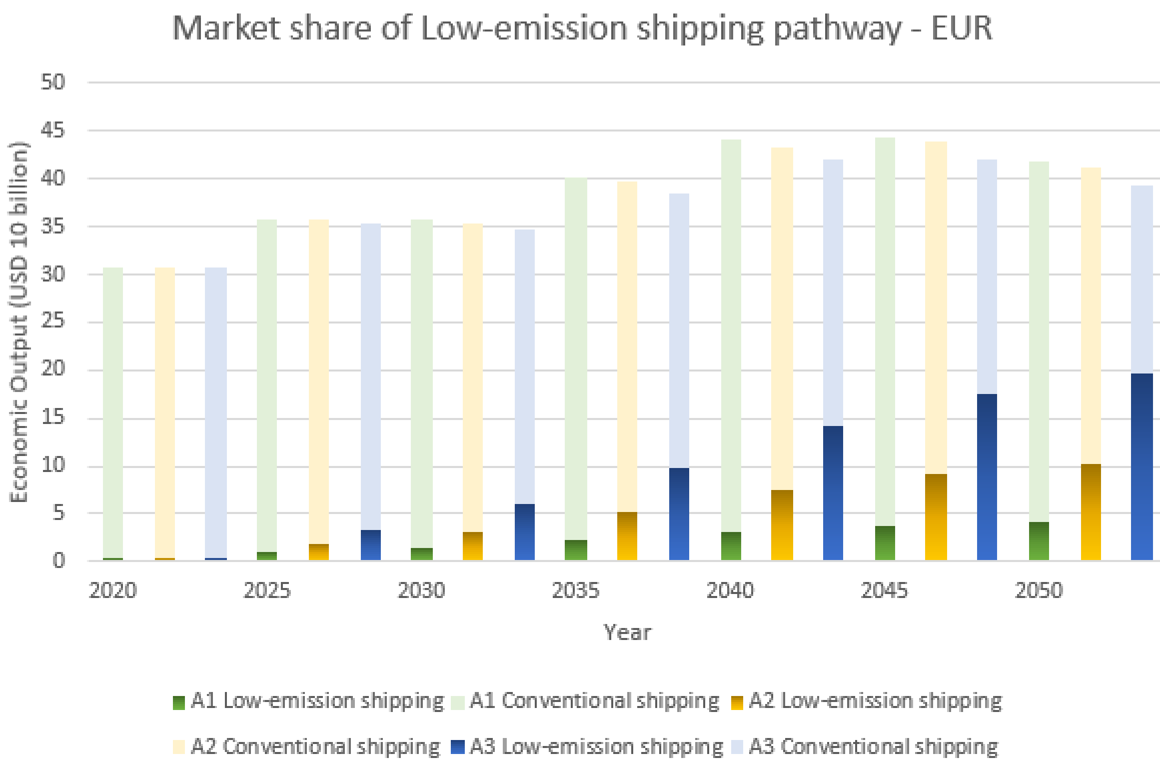


Figure 61 Economic output projections of Low-emission shipping pathway - EUR

4.5.7 Required Investment Amount (USD)– World

I presented the aggregation of required investments across all regions in the EPPA model in Figure 62. According to the IEA's shipping analysis (IEA, 2021b) mentioned at the beginning of this study in the Introduction section, to achieve Net-Zero emissions by 2050, low and zero-carbon fuels should account for at least 15% of the total shipping fuel consumption. Suppose the fuel consumption can be interpreted as the market share of alternative fuel pathways. Then, the investment required to achieve Net-Zero emissions can be inferred from the EPPA's simulation result. By 2030, under the A3 scenario, the market share of advanced shipping with zero-carbon emissions is projected to reach around 17%, which meets the IEA's Net-Zero emission target for the shipping industry. The economic implication of this market share from the advanced shipping pathway amounts to USD 570 billion of investment globally by 2030, which is greater than the GDP of Sweden in 2020 (USD 541 billion) (The World Bank, 2020a). The required investment amounts to USD 2.3 trillion in 2050 and cumulatively USD 7.2 trillion from 2025 to 2050 to decarbonize at least half of the shipping industry by 2050, as stated by the IMO's GHG strategy.

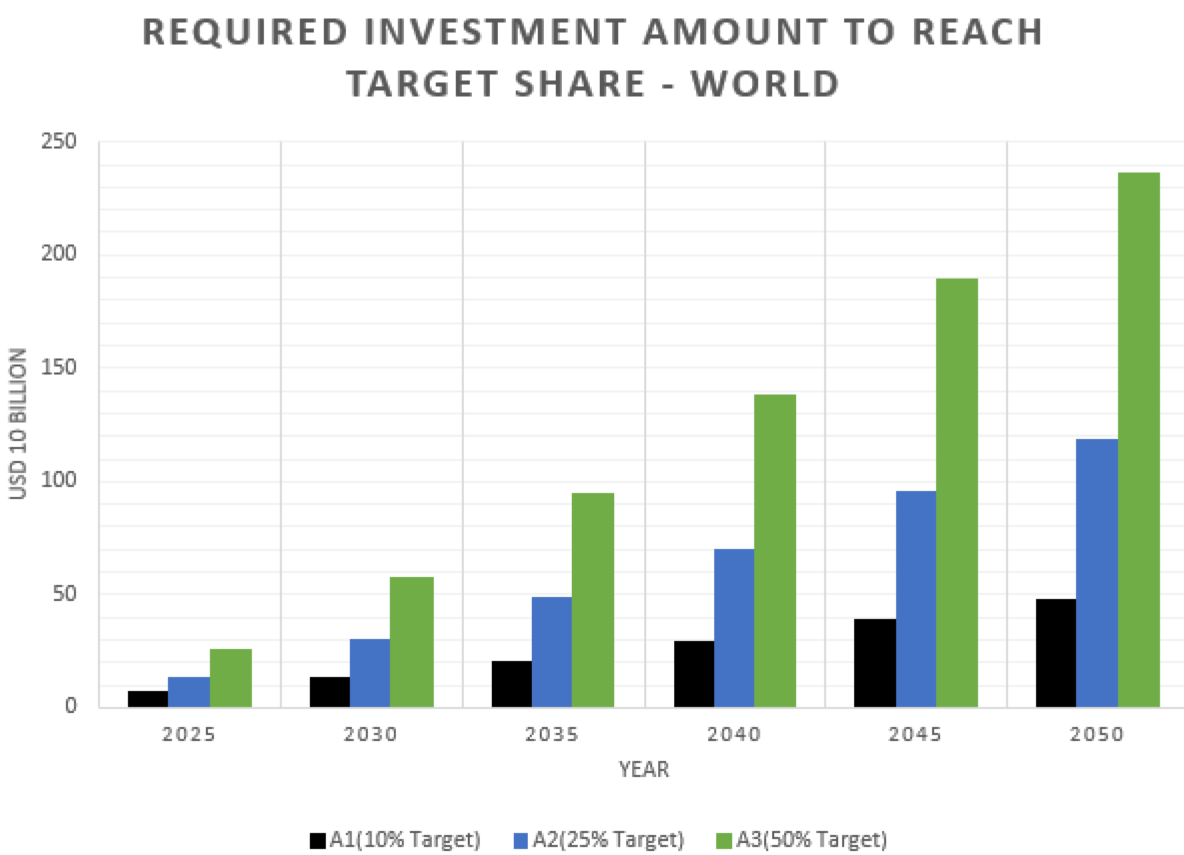


Figure 62 Required investment amount - World

4.5.8 Required Investment Amount (USD) - USA

Required investment amounts in USD are calculated from the model based on the investment and the economic output. Figure 63 illustrates the projection of investment amount for the advanced shipping pathway until 2050 in the USA region. In addition to the *Accelerated Action* scenario's aggressive policy and measures, I observed that a vast investment amount would be required with an increasing trend. Under the A1 scenario, by 2030, the required investment to reach a 10% market share amounts to almost USD 10 billion in the U.S. market, and by 2050, the investment needs to increase to USD 47 billion, which is a 370% increase from the 2030 level. Under the A2 scenario, the investment would need to reach USD 20 billion by 2030 and around USD 110 billion by 2050. The increase in investment is most dramatic under the A3 scenario, with the most aggressive 50% market share target as expected. Under A3, the investment would need to increase to USD 40 billion by 2030 and around USD 230 billion by 2050, which is more than the GDP of Portugal in 2020 (The World Bank, 2020a).

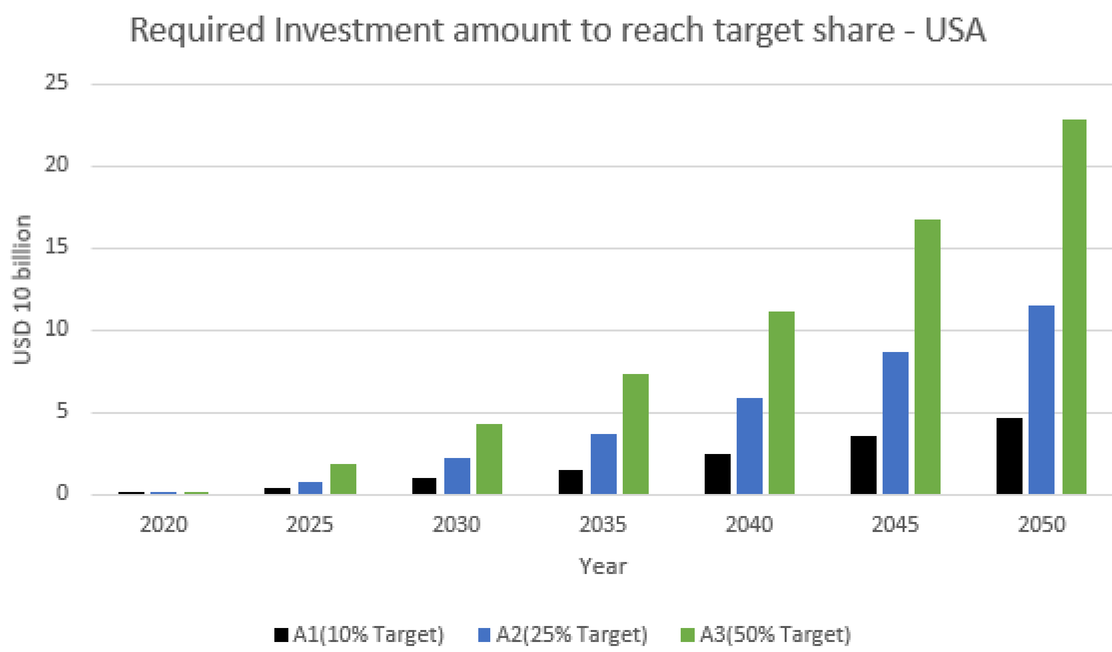


Figure 63 Required investment amount – USA

4.5.9 Required Investment – Regional Trends

Investments required to reach the target market share for the advanced shipping pathway show similar uptrends across most regions, as shown in Figure 64, which illustrates the regional variations in four regions – the USA, European Union (EU), Russia (RUS), China (CHN) and Korea (KOR).

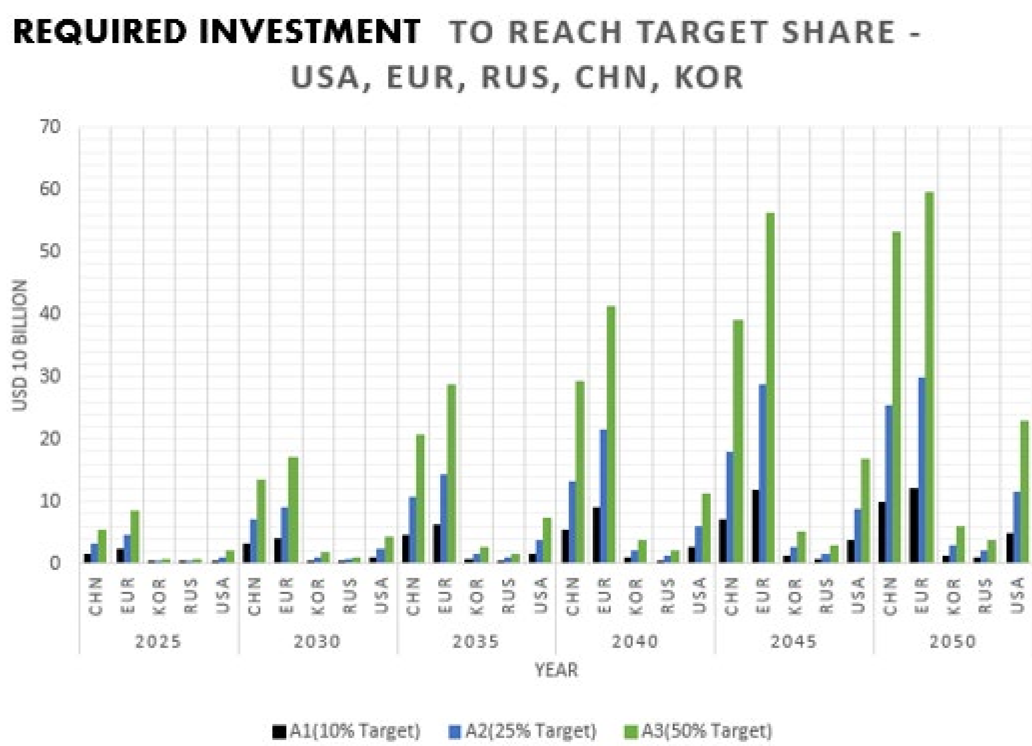


Figure 64 Required Investment - Regional trends

I observed that across all four regions, the additional investment amount is projected to increase under varying target share scenarios. The European Union would need the highest amount of investments in low-emission shipping by 2050, around USD 120 billion, to meet the 10% market share target from the advanced shipping pathway. This result stems from the fact that the economic output from the water transportation sector is highest in the EUR region. The result also indicates that the USA, EUR, RUS, and CHN would need a 374%, 206%, 216%, and 211% increase in subsidies from 2030 to 2050 to achieve a 10% market share.

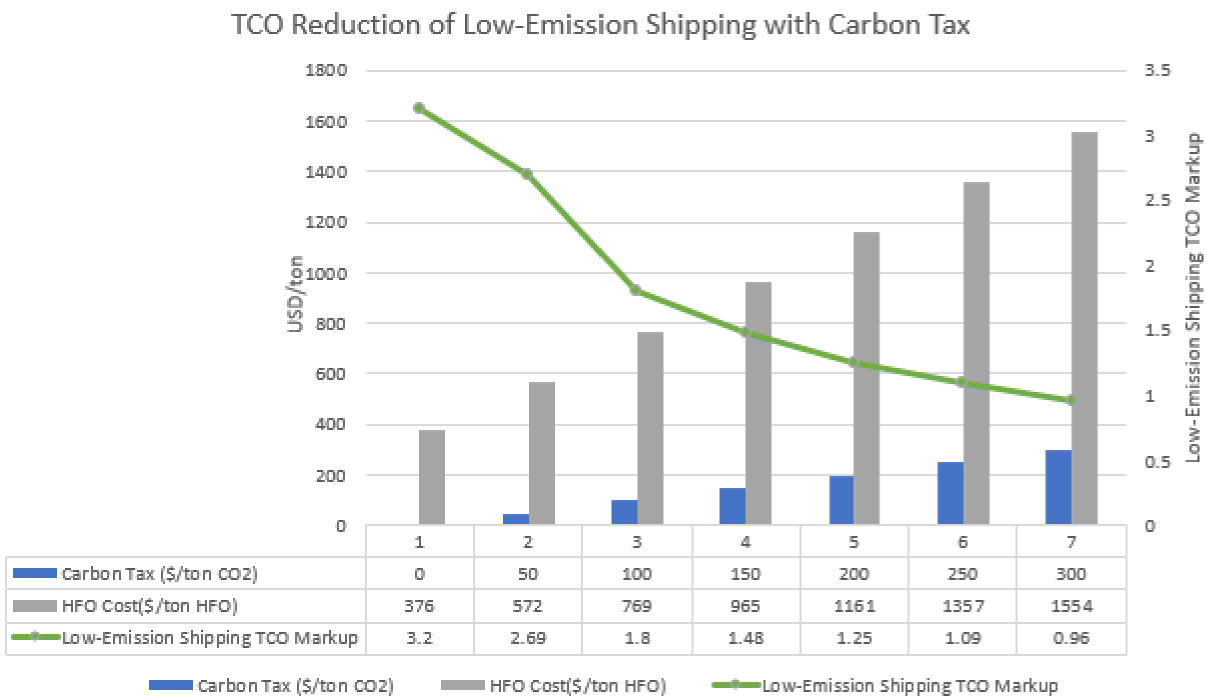
Chapter 5 – Discussion

In the previous chapters, I presented cost models for green fuel production and the total cost of ownership for low-emission shipping. I analyzed the economic implications of alternative fuel pathways under different policy scenarios. In this chapter, I explore several policy actions and potential technological breakthroughs and their impacts on TCO reduction using cost models. Next, I make projections on the required investments with the lower TCO using the EPPA model. I state the limitations of the results and ways to strengthen the analysis in the future. Finally, I propose high-level near-term, medium-term, and long-term pathways for decarbonizing the shipping industry and summarize insights for industry experts and decision-makers.

5.1 TCO Reduction Pathways

5.1.1 Carbon Emission Tax

Carbon emission tax, or carbon tax, is one way of implementing carbon pricing, which sets a price on carbon or the carbon content of fossil fuels. Another approach to reduce emissions is through emissions trading systems, sometimes called cap-and-trade systems, which limits the total level of GHG emissions and allows entities with low emissions to trade extra allowances to another (The World Bank, 2020b). In the shipping industry, currently, there is no carbon pricing imposed. However, there was a recent development on carbon pricing in the maritime industry from the 12th session of the Intersessional Working Group on Reduction of GHG Emissions from Ships (ISWG-GHG 12). In this meeting in May 2022, ISWG-GHG 12 agreed to advance towards GHG reduction through carbon pricing (IMO, 2022). The details of the draft are still under development from the IMO, but this agreement is meaningful in that it is the first consensus that countries reached on pricing carbon after more than ten years of deadlock. With the cost models I developed, as presented in Ch. 3, I ran the sensitivity analysis on Carbon Tax of the total cost of ownership of green ships using the NH_3-FC pathway as an example of low-emission shipping pathways. The relationship between carbon tax, HFO cost (USD/t), and the TCO markup of the low-emission shipping pathway are presented in Figure 65.



	1	2	3	4	5	6	7
Carbon Tax ($/ton CO2)	0	50	100	150	200	250	300
HFO Cost($/ton HFO)	376	572	769	965	1161	1357	1554
Low-Emission Shipping TCO Markup	3.2	2.69	1.8	1.48	1.25	1.09	0.96

Figure 65 TCO reduction pathway - carbon tax

With USD 200/tCO_2 carbon tax, the TCO markup of ships using green ammonia as fuels is reduced from 3.2 (when no carbon tax imposed) to 1.25. With USD 300/tCO_2 carbon tax, the TCO markup of green ships can reach below 1, implying that green ships can be cost competitive with the reference vessel using HFO. In this analysis, a carbon tax is assumed to be only limited to the maritime industry, specifically on the fuel HFO, and the electricity required to make green fuel is assumed to be free of the carbon tax. In the case of a global carbon tax, all production sectors, including electricity from the grid, will be subject to the carbon tax.

With carbon tax on HFO, low-emission shipping can enter the market as it becomes an economical option compared to the reference (HFO-ICE) in terms of TCO. For low-emission shipping technology to enter the market, a carbon tax is an effective economic measure that helps lower the TCO of green ships.

5.1.2 Technological Breakthroughs - Reduction in Green Fuel Production Cost

In the TCO model I developed, green fuel cost constitutes more than 70% of the TCO cost breakdown over the lifetime of green ships. With the current estimates, the green fuel cost is 4-6 times more expensive than HFO per energy unit. For example, I estimate green ammonia costs USD

36/GJ, green hydrogen costs USD 38/GJ, and green methanol costs USD 58/GJ using the cost model, whereas HFO costs USD 9/GJ and LNG costs USD 6/GJ using the recent two years average market price. There are many areas that are under development for technical breakthroughs that can lead to lowering green fuel costs, including an increase in electrolyzer capacity and efficiency, commercialization of direct air capture for CO_2, and more efficient renewable electricity production. Although the details of these technologies are outside of the scope of my study, I found that these factors are critical inputs to the cost model for green fuel cost estimations. Therefore, it is evident that improvement in the technology will lower the cost of green fuels, and I estimate the corresponding reduction of the TCO of green ships using the cost model as illustrated in Figure 66.

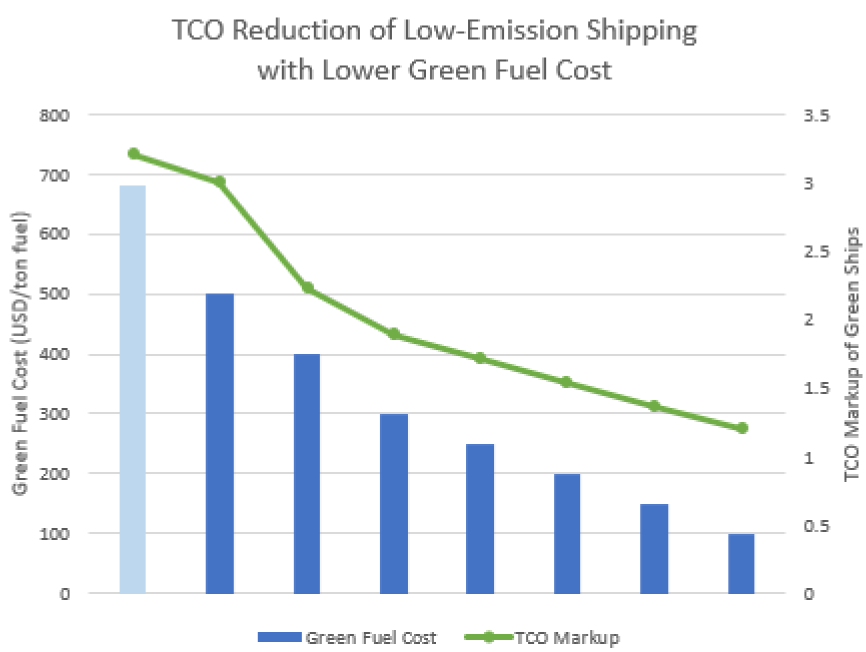


Figure 66 TCO reduction pathway - lower green fuel cost

Under current assumptions, the most economical green fuel, ammonia, costs USD 682/tonne with a TCO of 3.2. If the green fuel cost is reduced to USD 300/tonne, then the TCO markup will decrease to 1.89, and if the green fuel cost is further reduced to USD 150/tonne, then the TCO markup will decrease to 1.37. This significant reduction in green fuel cost can potentially enable low-emission shipping to enter the market. It would be beneficial if these technological advancements occurred sooner, accelerating the market adoption of low-emission shipping. Therefore, government support for research and development focused on green marine fuels is important to accelerate the decarbonization of the global shipping industry.

5.1.3 Technological Breakthroughs - Increased Fuel Cell Efficiency for Green Ships

As an example of a low-emission shipping pathway, the Ammonia-SOFC pathway is used for sensitivity analysis of the performance of SOFC. The higher the efficiency of SOFC, the lower the fuel consumption, and thus the lower TCO of the ammonia-SOFC pathway. The SOFC technology using ammonia is still under development and needs further optimization for the best performance (Gray et al., 2021). As such, the future projection of SOFC efficiency has uncertainty, with some literature estimating up to 80% efficiency (DNV GL AS Maritime, 2019). With the 80% efficiency, the markup of the low-emission shipping pathway can be reduced to 2.62.

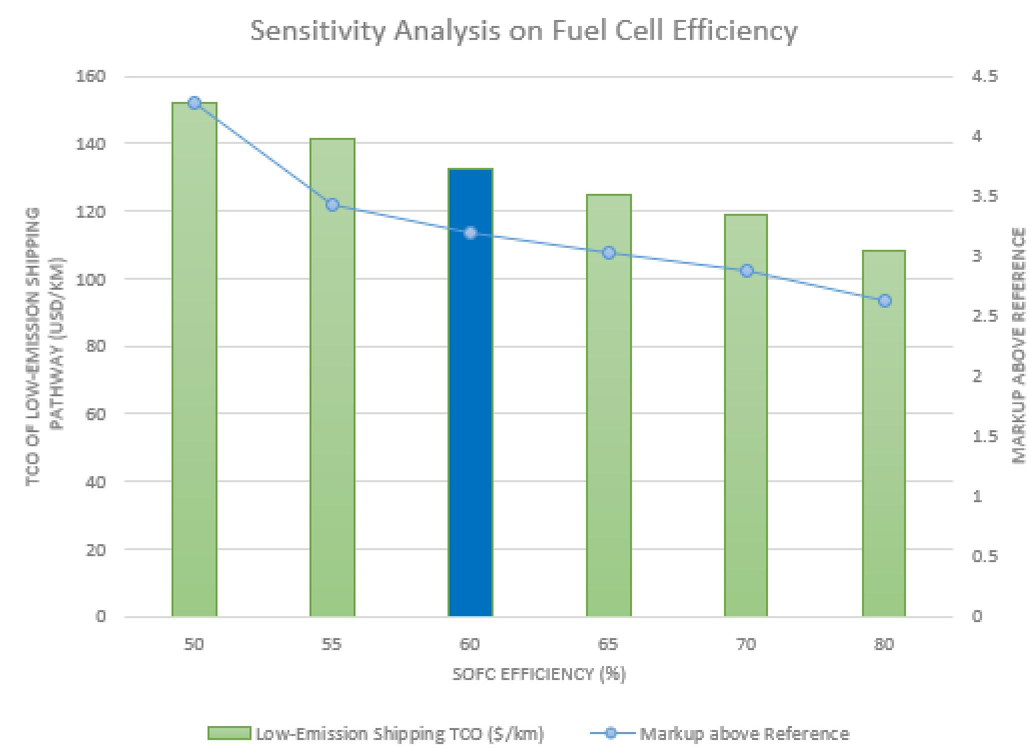


Figure 67 TCO reduction pathway - increase in fuel cell efficiency

The technological improvement in the efficiency of fuel cells alone can result in the reduction of the TCO of green ships. However, additional reductions in TCO are necessary for the low-emission shipping transition. Therefore, research and development on improving the efficiency of the fuel cell are needed to occur in parallel with other technological breakthroughs.

5.1.4 Technological Breakthroughs - Reduction in Capital Cost for Alternative Fuel Vessels

One of the inputs to the TCO model and the second largest cost driver for the TCO is capital costs for ship and powertrain upgrades, which account for around 20% of the total cost. With technological advancement, powertrain options utilizing various green fuels can help reduce the total TCO over time. For methanol, dual-fuel engines are already commercially available, making it an attractive option for the near-term transition, as the ability to use the existing conventional fuel can bridge the current infrastructure and fuel availability gaps. I estimate the cost of capital for ship upgrades to methanol-based dual fuel ICE is the most economical option among alternative fuel pathways. For fuel cell systems, the capital cost is highly dependent on the fuel cell and its supporting electrical system upgrades, whose cost is related to the scalability and operationalization of the technology.

5.1.5 Economic Implications of Lower TCO

I illustrated a few options for the TCO reduction for low-emission shipping pathways. Using the EPPA model, I made economic projections for low-emission shipping with varying TCO markup assumptions from 2020 to 2050, as shown in Figure 68. In the following projections, I assumed that there are no other policy measures, such as government subsidies or other support for green shipping investments. I imposed a global carbon tax of USD 100/tCO_2 starting in 2020, which will increase annually to around USD 300/tCO_2 by 2050.

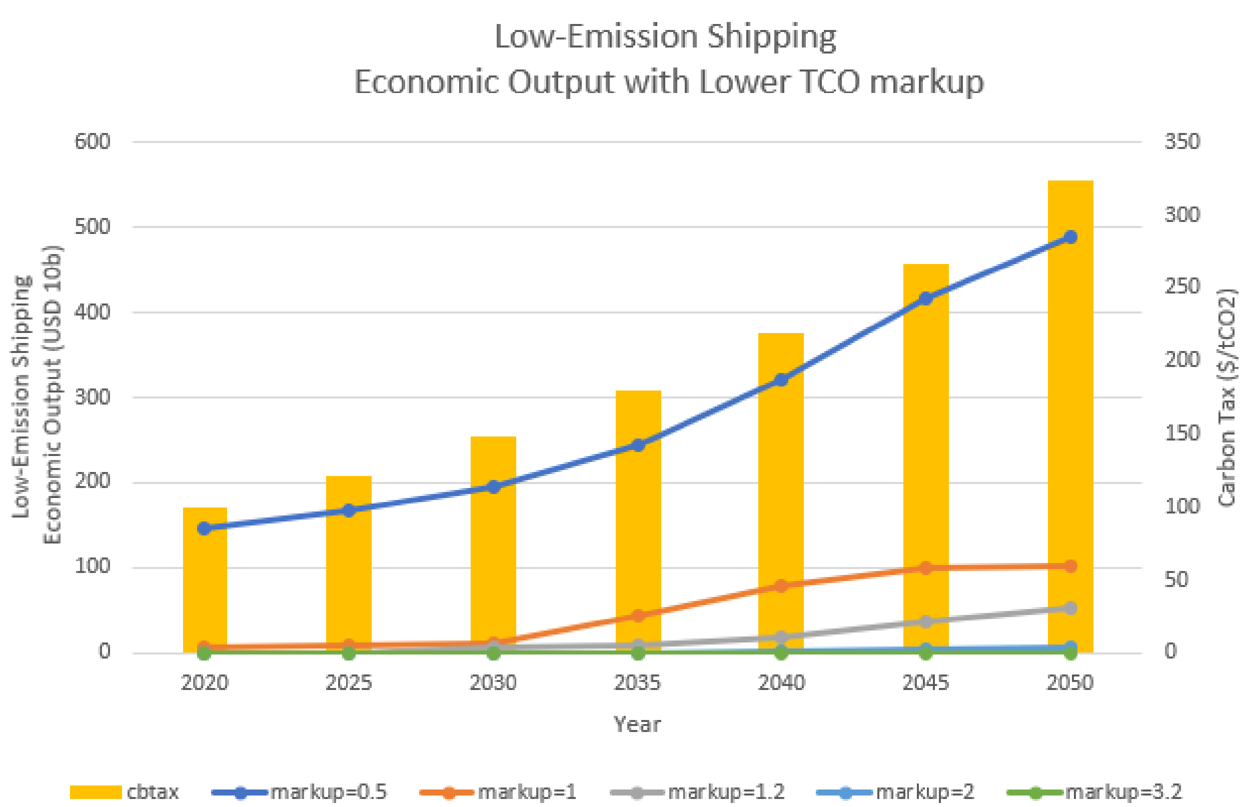


Figure 68 Global economic output of low-emission shipping with lower TCO

With a TCO markup above 3, the low-emission shipping pathway is projected to not enter the market, even with the presence of a global CO_2 emission tax. This result stems from the fact that in the model, the global CO_2 emission tax is also imposed on other production sectors in the economy, such as electricity generation, which also drives up the cost of the low-emission shipping pathway. With a TCO markup of 2, the low-emission shipping enters the market at a limited extent around 2045 due to its high cost over a lifetime.

With a TCO markup of 1, the low-emission shipping pathway started to enter the market in 2030, reaching USD 1 trillion of economic output by 2050, with a USD 300/tCO_2 global carbon tax. In a hypothetical case with a TCO markup of 0.5, the low-emission shipping pathway dominates the market, with 100% market share in the water transport sector in all regions.

The market penetration of the low-emission shipping pathway is difficult with a higher TCO than that of the reference option, without any additional investments or subsidies. Based on the current TCO estimates, the market penetration of the low-emission shipping pathway is not economically competitive without maritime-specific fuel (or carbon) tax. Therefore, to allow the low-emission shipping pathway to enter the market, additional policy measures will be required: Additional investments to economically incentivize the adoption of the low-emission shipping, a maritime-specific carbon tax on fossil-fuel-based maritime fuels (including HFO, LNG, and VLSFO), and regulatory mandates. These policy measures will be challenging to implement but they are necessary to substantially decarbonize the shipping industry. There is no silver bullet that would provide a single answer to make low-emission shipping available in the market economically and technically due to huge uncertainties in costs and utility. Therefore, combinations of policy measures and technical flexibility to allow multi-fuel pathways will be the key to decarbonization of the shipping industry.

The shipping industry is a complex socio-technical system with multiple stakeholders with different needs, long lifetimes of vessels, and huge uncertainties in the technology for alternative-fuel development. As such, the key primary stakeholders in the shipping industry, such as ship owners, charters, flag states, and regulatory bodies, should reach a consensus on carbon pricing, stricter GHG emission controls, and economic incentives promptly to deploy low-emission shipping pathways. In addition, governments and private industries should invest in the research and development of low-emission shipping technologies that can unlock the full potential of the energy transition in the shipping industry.

5.2 Limitations

- The analysis focused mainly on the global shipping sector, and deeper investigations into regional differences are limited.
- Also, in the EPPA model, I imposed a global economy-wide carbon tax as one of the scenario policy measures. An analysis can be expanded by implementing a localized carbon tax for conventional fuels in the shipping industry to be more practical.
- I evaluated the most economic low-emission shipping pathway in the economic modeling but comparing other low-emission shipping pathways for economic implications can provide additional insights.
- Along the same line, I focused on the most promising alternative fuel pathways and did not include all available alternative fuel pathways to evaluate utilities in this study, such as biofuel or bio-LNG, or other types of powertrain systems such as methanol direct feed fuel cell systems due to limited availability of data.
- Since the field of advanced fuel technology is developing, the TCO model is limited by future uncertainty and changes in various assumptions. I captured the current cost estimates using the most up-to-date data from the literature, but the result will certainly change in the future. Additional investigations can strengthen the analysis by incorporating various uncertainty modeling.

5.3 Proposed Pathways for Low-emission Shipping

Two critical tasks need to occur in parallel to decarbonize the shipping industry. First, existing ships should be upgraded to utilize alternative fuels, and newly built ships should have new powertrain systems that can use alternative fuels for propulsion. Second, alternative fuels must be produced with net-zero carbon emissions. These alternative fuels have to be available globally in different ports. To successfully reach the Net-Zero emission goal from the shipping industry by 2050, near-term actions should be aligned with the medium-term and long-term plans, as the lifetime of ships is long, and the decisions made now will have a long-lasting impact on the decarbonization journey. The near-term, medium-term, and long-term plans are illustrated on top of the tradespace in black arrows, as shown in Figure 69.

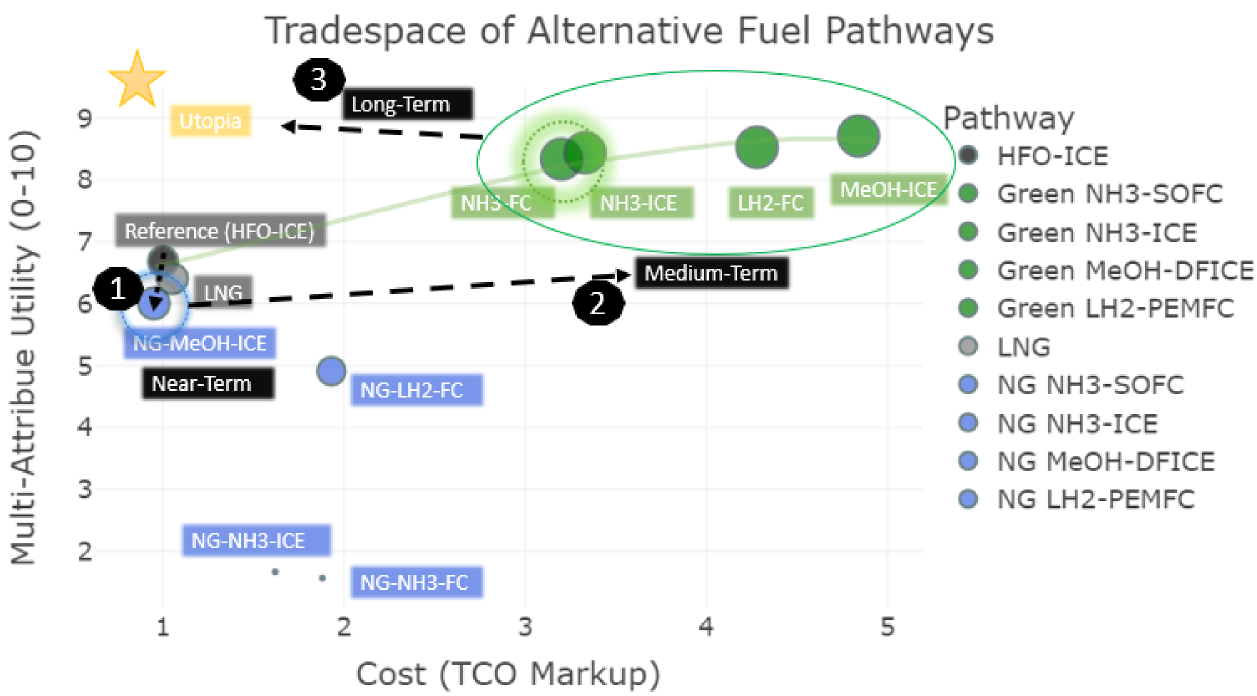


Figure 69 Near-term, medium-term, and long-term plans for low-emission shipping

5.2.1 Near-term (2022-2025)

Existing ships should be retrofitted, and newly built ships should include a new powertrain system to be able to use alternative fuels such as methanol, ammonia, and hydrogen. Methanol dual-fuel engines are commercially available with the least expensive capital cost required, so it is the most realistic option for shipowners. Moreover, methanol made from natural gas has lower lifecycle emissions than that of HFO, while other alternative fuels, namely ammonia, and hydrogen, have higher carbon intensity if made from natural gas. Other dual-fuel engines using ammonia and hydrogen should still be considered, as the technology development might enable these alternative fuels to be more technically mature and economically viable in the long term. As I illustrate in the tradespace, the multi-attribute utility of these green fuel pathways is comparable. And considering the huge uncertainty in the nascent technology in many areas, including green fuel production, fuel cell efficiency, and alternative fuel-based fuel cell operations, it is too early to choose a winner. More importantly, it is better to stay solution-neutral to encourage further development of multiple alternative low-emission pathways. Due to the scalability and availability of alternative fuels, more than one type of fuel will likely have to share the market for the low-emission shipping pathway, which is different from the current market situation in which HFO dominates nearly all fuel consumption from the vessels.

Although green methanol is currently costly and not an economic choice in comparison to conventional fuels, once the ships are upgraded to methanol dual-fuel engines, they can take advantage of cheaper methanol produced from natural gas in the near-term. This would help to accelerate a deployment of green shipping infrastructure. These upgraded ships would be ready to provide more aggressive decarbonization when green methanol becomes available at a cheaper cost in the medium term or long term. With dual-fuel engines, these ships can also overcome any lack of bunkering infrastructure that might be a barrier to long-distance operation, as they can rely on conventional fuels if needed. Although methanol from natural gas production and the partial use of conventional fuels will emit GHG, these near-term actions are aligned with the long-term decarbonization goal as there is a green methanol option in store. However, the use of ammonia and hydrogen produced from natural gas in dual-fuel engines should be deferred at a later stage, as they have higher lifecycle carbon emissions and thus lower utility than HFO. This plan does not mean that new powertrain systems using ammonia and hydrogen should be discouraged. As green alternatives exist for these fuels, new powertrain systems development should still be pursued to drive down the TCO markup and make technology more mature in an operational environment at scale. Still, the actual use of these systems should not be operationalized until these ships can be fueled by green ammonia and green hydrogen to prevent adding unnecessary GHG to the atmosphere and giving false impressions of a green shipping operation.

Along the same line, unless LNG ships are decommissioned by 2050, modified to use other alternative fuels, or the whole value-chain of LNG production can be decarbonized, transitioning to LNG ships will not directly help with the long-term decarbonization goal to achieve true net-zero. LNG ships using LNG as a fuel will emit GHG and require investment in ship upgrades in the near term. However, it might be a practical near-term strategy for shipowners to temporarily reduce carbon emissions at a cheaper cost, assuming switching to LNG alternatives does not cause new LNG fleet orders. For example, shipowners may choose to increase the number of LNG ships in their fleet by purchasing existing LNG vessels with a plan to decommission them by 2050. Still, to align with the long-term decarbonization goal, shipbuilders should not add a significant number of LNG ships to the global fleet. The issue is that there is currently no “Green LNG” fuel option available that these LNG ships can switch to for cleaner alternatives in the future, unlike methanol, hydrogen, or ammonia. Shipowners should wisely invest capital in fully decarbonizing their fleet with a far-sighted vision. If regulations become more stringent to account for the lifecycle emissions of fuels, LNG might not be able to satisfy the requirement in the long term. Without additional advancements in offset strategies and the certification of negative emissions from bio-LNG (or Renewable Natural Gas) production in an economical way, there is only a slight chance that LNG can remain in the final decarbonization pathway.

5.2.2 Medium-term (2025-2030)

In the medium-term, both existing and newly built ships should be more actively transitioning to alternative fuel-based powertrain systems, including fuel cells. By 2030, fuel cell technology may be more technically mature, and more options will be available to use multi-fuel for fuel-cell propulsion, including direct-feed ammonia and methanol fuel cell systems. Since the lifetime of vessels is 25 years or more, the newly built ships from this period should have at least some form of alternative-fuel-based powertrain system to achieve the decarbonization goal by 2050. Regulatory bodies should implement regulations to make alternative-fuel power propulsion systems required for newly built ships. A significant amount of additional investment from governments will be required at this stage to allow shipowners to comply with these new regulations. Switching to fuel-cell-based systems will enable zero emissions from tank-to-wake, which is more beneficial than dual-fuel ICEs in reducing emissions. During this period, dual-fuel ICE engines should start fully operating based on alternative fuels without utilizing HFO, increasing infrastructure and bunkering facilities around the global ports. In the meantime, more research and development should focus on decarbonizing alternative fuel production and making green fuels more cost competitive than the near-term level.

5.2.3 Long-term (2030-2050)

From 2030 onwards, all ships should be transitioning to green ships using alternative fuels. Existing green ships should start to fully utilize green fuels instead of alternative fuels made from natural gas. During this period, the goal should be to bring down the cost of green fuel should to an economic level, so the TCO markup is comparable to that of the reference vessel. Ships that have transitioned to alternative fuel-based propulsion systems can now start to utilize green fuels at cheaper costs or through government subsidies or investments. Additional investments should be used to make renewable electricity cheaper for green fuel production, incentivize green ship upgrades, and empower research and development toward fuel cell technology for a commercially operational scale. Existing ships with only an HFO-ICE-based propulsion system should retire over this period through regulatory mandates. Or, to accelerate retirements, they can be partially subsidized to replace with new green ships through a governmental program such as “Cash for

Clunkers" for ships. During this period, a multi-fuel pathway will be widely used, with green fuels optimized for production based on local supply infrastructure and demands. A variety of green ships – ammonia-based fuel cell ships, methanol-based fuel cell ships, hydrogen-based fuel cell ships or a combination of multi-fuel ships should be in operation to meet the needs of shipowners and adapt to the bunkering availability.

5.2.4 Insights for Industry Experts and Decision Makers

Based on my analysis, I propose the following insights for decarbonizing the global shipping industry.

Update on International Maritime Regulations to include lifecycle carbon accounting: It is critical to take the lifecycle emissions into account to accurately monitor and manage carbon emissions from ships, which are also called well-to-wake emissions, instead of limiting carbon accounting to tank-to-wake emissions. This change in regulation will help with the deployment of green fuel, which has nearly zero well-to-wake emissions and shape the right pathway from the early stage. Accounting only tank-to-wake emissions might shift the responsibility of emissions to the upstream production process and influence shipowners and key shipping industry stakeholders to make decisions that can risk the decarbonization goal in the near term and the long term.

Required Investment: Based on the projections made with the economic projection and policy analysis modeling tool, given the current cost estimates for the total cost of ownership of vessels, the required investments for low-emission shipping are massive. I estimate that around USD 2.3 trillion would be needed by 2050 to decarbonize half of the global shipping industry. The required investment will need to take incremental steps from 2025 to 2050 and cumulatively might amount to USD 7.4 trillion. With the advancement of technologies and policy measures such as carbon emission tax, the markup of green ships compared to the conventional option is expected to decrease over time. Still, the decarbonization of the shipping industry has enormous economic implications. It is critical to start investing or subsidizing the decarbonization effort to create demand for green fuels and advance the technology breakthroughs.

Carbon Emission Tax: A carbon emission tax can be an effective policy measure to close the gap between HFO and green fuels to accelerate the deployment of green fuels. Using the cost models, I estimate carbon tax of at least USD 200/tCO_2 will lower the markup of green ships to be comparable to the conventional options, allowing the low-emission shipping pathway to enter the market. The revenue from the carbon emission tax can be assigned to further research and development of more efficient green fuel production to lower the green fuel cost or alternative fuel-based propulsion technologies to expand the green ships in the market. As countries agreed to carbon pricing in the shipping industry (IMO, 2022), a practical strategy to implement carbon pricing effectively should be facilitated and taken into effect promptly. Flag states should also collectively and voluntarily comply with the new carbon pricing regimes once the strategy is published.

Use of offsets: The shipping industry needs to explore sustainable carbon offsets schemes (such as land restoration and afforestation), including their biodiversity implications. Carbon offsets can be used to reduce the high costs of emission mitigation in shipping, as long as these offsets bring net climate benefits. Currently, carbon offsets still have intended or unintended negative consequences. Hence, the shipping industry should support the enhancement of the offsets regulations to properly measure the amounts of carbon being stored. This is especially important for forest carbon offsets that are difficult to measure and certify. The use of carbon offsets should not replace emission mitigation efforts by the shipping industry, but they can complement cost-effective mitigation options.

Multi-fuel pathways: The transition to green ships will likely follow multi-fuel pathways. From the utility perspective, the alternative green fuels – ammonia, hydrogen, and methanol – deliver comparable utilities and reduce lifecycle emissions to the nearly same extent. From the cost perspective, currently, I estimate green ammonia to be the most economical option. Still, the cost estimations can certainly change in the future depending on the technology improvement of the decarbonization of the fuel production process. All three alternative fuels deserve more research and development, as there is no silver bullet to solve the complex problem in the shipping industry. Unlike HFO, which is cost-effective and widely available around the world and hence dominates the market, none of the alternative fuels can solely meet the demands of the market at the current production level. Bunkering facilities and infrastructure should be further developed for all three alternatives, and the pace of the development will depend on a variety of factors, including the local accessibility to fuel plants, transportation of fuel, and the types of ships with specific powertrain systems.

Upgrade for ships using alternative fuels: In parallel to decarbonizing the green fuel production process, existing and new vessels should be modified or built with a new powertrain system that can take alternative fuels. In the near term, methanol dual-fuel engines will be a practical choice as a bridge option to minimize the risk of operation loss, reduce GHG emissions, and potentially align with the long-term decarbonization goal by transitioning to green methanol in the future. Eventually, more advanced technologies such as fuel-cell-based propulsion systems can dominate the powertrain systems as they can result in zero well-to-wake emissions, lower fuel consumption, and higher efficiency. Flexibility is critical in building the ships with the new powertrain systems, as green ships should be able to accommodate multiple fuel types and quickly adapt to the energy transition process.

Chapter 6 – Conclusions and Recommendations for Future Work

6.1 Conclusion – Key Findings

1. The shipping industry is indispensable in the global economy, and the demand for shipping is expected to grow until 2050. The shipping industry accounts for 2-3% of global greenhouse gas emissions.

2. Currently, the shipping industry's fuel consumption is dominated by fossil fuel-based conventional fuels, and bulk carriers account for the largest share of CO_2 emissions among vessel types.

3. The shipping industry is a complex socio-technical system with multiple international stakeholders. Regulatory control is challenging to implement and enforce globally, as vessels are registered with flag states that exercise regulatory controls over vessels, and often flag states differ from the shipowners' country. International cooperation among multiple stakeholders is required to reach a consensus on key greenhouse gas emission reduction efforts. Flag states should collectively and voluntarily ratify the treaties the International Maritime Organization implemented.

4. Multiple alternative fuels are currently under development to be used as maritime fuels, such as ammonia, methanol, and hydrogen. Ammonia and methanol are presently widely used for non-maritime industrial applications, so they have some (but not enough) existing infrastructure for transportation and distribution. The handling and safety of these alternative fuels are more complicated than the conventional fuels, so additional safety standards and controls must be implemented in the future for maritime applications. These fuels are mostly "clean-burning fuels" with low tank-to-wake emissions, but the well-to-wake emissions can be higher than conventional fuels depending on the production process.

5. Alternative fuel-based powertrain propulsion systems include internal combustion engines, fuel cell systems, and dual-fuel engines. Technology readiness level is the lowest for ammonia or methanol direct feed fuel cell systems and higher for internal combustion engines. More research and development are required to operate these systems for long-distance shipping.

6. I estimated the cost of alternative fuel per energy unit using the cost model: Among green

alternative fuels, assuming USD 50/MWh of renewable electricity price, ammonia is currently the most economical option with USD 36/GJ, followed by hydrogen with USD 38/GJ. The most expensive option is green methanol, with USD 58/GJ of the estimated cost. Alternative fuels made from renewable electricity cost 2-6 times more costly than those made from natural gas.

7. I estimated the total cost of ownership of four alternative fuel pathways using the total cost of ownership model over 25 years of the vessel's lifetime. The pathway with green ammonia with fuel cell powertrains is estimated to have the lowest markup of the total cost of ownership relative to the conventional option using heavy fuel oil, but still 3.2 times more expensive. The pathway with green methanol with a dual fuel engine has the highest markup of 4.84 due to the high cost of green methanol production. The pathway with hydrogen using a proton exchange membrane fuel cell system has a markup of 4.28 above the conventional case. The total cost of ownership is dominated by fuel cost, which accounts for more than 70% of the cost share. Therefore, the total cost of ownership is highly sensitive to green fuel cost, the price of renewable electricity, and the overall system efficiency of the powertrain.

8. I evaluated the utilities of alternative fuel pathways using key metrics in the shipping industry. I found the optimal low-emission shipping pathway using green fuels with the current estimates that provide the best combination of cost and utility: green fuel pathways (ammonia, hydrogen, and methanol) have higher utilities than fuels made from fossil fuels, as they have low well-to-wake emissions, and the green ammonia pathway currently has the lowest estimated TCO cost. Ammonia produced from natural gas has the highest well-to-wake emissions and thus has the lowest utility, although economical. Methanol and LNG from fossil fuels have slightly lower well-to-wake emission factors than conventional heavy fuel oil. Therefore, methanol has the potential to become a bridge fuel in the near term as its green alternative is also available.

9. Life cycle carbon accounting is essential in evaluating marine fuels to set the right strategies for decarbonizing the shipping industry. Alternative fuels have considerable variations in emission factors depending on the production process. Regulations need to account for well-to-wake emissions, instead of only considering tank-to-wake emissions, to avoid shifting of emissions instead of truly reducing them.

10. Using the EPPA model, I found the low-emission shipping pathway would not penetrate the market without policy measures. In the *reference* case, low-emission shipping cannot enter the

market without a carbon tax and additional investment due to the high total cost of ownership.

11. Under the *Accelerated Action* climate scenarios which aim to limit the global temperature rise by 1.5°C, it is possible to enable the low-emission shipping pathway to enter the market, but it requires huge investment. The economic implications of decarbonizing half of the global fleet using the low-emission shipping pathway are estimated to be around USD 2.3 trillion in 2050, cumulatively USD 7.2 trillion from 2025 to 2050.

12. There are several ways to lower the Total Cost of Ownership markup of the low-emission shipping pathway, including carbon emission tax, technological advancement in fuel cell efficiency, and lower green fuel costs.

13. I estimated that with USD 200/tCO_2 carbon tax, the TCO markup of green ships using green ammonia as fuels can reach 1.25. With USD 300/tCO_2 carbon tax, the TCO markup of green ships can reach below 1, implying that green ships can be cost competitive with the reference vessel using HFO at this level of a carbon tax.

14. I proposed a discussion of pathways to decarbonize the shipping industry with near-term, medium-term, and long-term action plans. In the near term, ships need to be built or upgraded with dual-fuel engines that can take alternative fuels (methanol) and conventional fuel for a smooth transition to overcome the lack of bunkering infrastructure and the economic barrier without sacrificing the emission reduction. In the medium-term, ships must start utilizing alternative fuel-based fuel cell systems, and dual-fuel engines should begin fully operating on alternative fuels. Additional investment will be required to incentivize shipowners to upgrade ships and use green fuels for operation economically. In the long term, all new ships should be built with alternative fuel-based powertrain systems. Existing vessels run with conventional fuels need to retire or be replaced through governmental regulations and industry support programs. The use of carbon offsets should not replace emission mitigation efforts by the shipping industry, but they can complement cost-effective mitigation options. With more technological advancement and infrastructure investment, multiple green fuels should be available to be used in the shipping industry.

6.2 Recommendations for Future Work

1. Regional sensitivities to the decarbonization of the shipping industry: In this study, I primarily focused on the global shipping industry for cost modeling and economic projections. It would be beneficial to investigate regional sensitivities to craft specific decarbonization plans by considering regional differences.

2. Projections of additional investment required with the presence of localized carbon tax for the shipping industry: I used a policy measure of global economy-wide carbon tax in the model to assess market penetrations, but a carbon tax targeted to the shipping industry can be added in the analysis.

3. Estimation of required investments by incorporating more than one alternative fuel pathway to investigate the possibility of multi-fuel pathways. Additional exploration of potential cost reductions of global low-carbon shipping would be beneficial for developing realistic strategies for shipping industry and government decision makers.

References

Abrahams, L.S., Samaras, C., Griffin, W.M., Matthews, H.S., 2015. Life Cycle Greenhouse Gas Emissions From U.S. Liquefied Natural Gas Exports: Implications for End Uses. Environ. Sci. Technol. 49, 3237–3245. https://doi.org/10.1021/es505617p

ACS, 2021. Ammonia [WWW Document]. American Chemical Society. URL https://www.acs.org/content/acs/en/molecule-of-the-week/archive/a/ammonia.html (accessed 5.20.22).

Alvarez, R.A., Zavala-Araiza, D., Lyon, D.R., Allen, D.T., Barkley, Z.R., Brandt, A.R., Davis, K.J., Herndon, S.C., Jacob, D.J., Karion, A., Kort, E.A., Lamb, B.K., Lauvaux, T., Maasakkers, J.D., Marchese, A.J., Omara, M., Pacala, S.W., Peischl, J., Robinson, A.L., Shepson, P.B., Sweeney, C., Townsend-Small, A., Wofsy, S.C., Hamburg, S.P., 2018. Assessment of methane emissions from the U.S. oil and gas supply chain. Science 361, 186–188. https://doi.org/10.1126/science.aar7204

University College of London, 2020. Ammonia Toxicity [WWW Document]. URL https://www.ucl.ac.uk/~ucbcdab/urea/amtox.htm (accessed 5.20.22).

Andersson, K., 2015. Methanol as a Marine Fuel Report [WWW Document]. URL https://www.methanol.org/wp-content/uploads/2018/03/FCBI-Methanol-Marine-Fuel-Report-Final-English.pdf (accessed 6.3.22).

Ansell, D.V., Dicks, B., Guenette, C.C., Moller, T.H., Santner, R.S., White, I.C., 2001. A Review of the Problems Posed By Spills of Heavy Fuel Oils. International Oil Spill Conference Proceedings 2001, 591–596. https://doi.org/10.7901/2169-3358-2001-1-591

Chen, H., Paltsev, S., Gurgel, A., Reilly, J.M., Morris, J., 2022. The MIT EPPA7: A Multisectoral Dynamic Model for Energy, Economic, and Climate Scenario Analysis [WWW Document]. URL https://globalchange.mit.edu/sites/default/files/MITJPSPGC_Rpt360.pdf (accessed 6.16.22).

Climate Watch, 2021. | Greenhouse Gas (GHG) Emissions | Climate Watch [WWW Document]. URL https://www.climatewatchdata.org/ghg-emissions?breakBy=sector&chartType=percentage&sectors=agriculture%2Cindustrial-processes%2Cland-use-change-and-forestry%2Cbuilding%2Celectricity-heat%2Cfugitive-emissions%2Cmanufacturing-construction%2Cother-fuel-combustion%2Ctransportation%2Cwaste (accessed 7.14.22).

Collodi, G., Azzaro, G., Ferrari, N., Santos, S., 2017. Demonstrating Large Scale Industrial CCS through CCU – A Case Study for Methanol Production. Energy Procedia 114, 122–138. https://doi.org/10.1016/j.egypro.2017.03.1155

Crawley, E.F., Cameron, B., Selva, D., 2016. System architecture: strategy and product development for complex systems. Pearson, Boston.

Mitsui O.S.K. Lines, 2021. Current status and future prospects of LNG fuel for ships [WWW Document]. URL https://www.mol-service.com/blog/lng-as-ships-fuel (accessed 6.1.22).

de Vries, N., 2019. Safe and effective application of ammonia as a marine fuel.

Degnarain, N., 2020. What Is Heavy Fuel Oil, And Why Is It So Controversial? Five Killer Facts. [WWW Document]. Forbes. URL https://www.forbes.com/sites/nishandegnarain/2020/08/14/what-is-heavy-fuel-oil-and-why-is-it-so-controversial-five-killer-facts/ (accessed 5.12.22).

DNV GL AS Maritime, 2019. Comparison of Alternative Marine Fuels [WWW Document]. URL https://sea-lng.org/wp-content/uploads/2020/04/Alternative-Marine-Fuels-Study_final_report_25.09.19.pdf (accessed 5.21.22).

EIA, 2021e. Hydrogen explained - U.S. Energy Information Administration (EIA) [WWW Document]. URL https://www.eia.gov/energyexplained/hydrogen/ (accessed 11.8.21).

EIA, 2021b. Production of hydrogen - U.S. Energy Information Administration (EIA) [WWW Document]. URL https://www.eia.gov/energyexplained/hydrogen/production-of-hydrogen.php (accessed 11.9.21).

EIA, 2021d. U.S. energy facts explained - consumption and production - U.S. Energy Information Administration (EIA) [WWW Document]. URL https://www.eia.gov/energyexplained/us-energy-facts/ (accessed 6.1.22).

EIA, 2021a. International - U.S. Energy Information Administration (EIA) [WWW Document]. URL https://www.eia.gov/international/data/world/natural-gas/dry-natural-gas-production?pd=3002&p=00g&u=0&f=A&v=mapbubble&a=-&i=none&vo=value&vb=10&t=C&g=00000000000000000000000000000000000000000000001&l=249-ruvvvvvfvtvnvv1vrvvvvfvvvvvvfvvvou20evvvvvvvvvvnvvvs0008&s=315532800000&e=1609459200000&ev=true (accessed 7.7.22).
EIA, 2021c. Price of Liquefied U.S. Natural Gas Exports (Dollars per Thousand Cubic Feet) [WWW Document]. URL https://www.eia.gov/dnav/ng/hist/n9133us3A.htm (accessed 5.24.22).
Energy.gov, 2022. Liquefied Natural Gas (LNG) [WWW Document]. Energy.gov. URL https://www.energy.gov/fecm/liquefied-natural-gas-lng (accessed 6.1.22).
Engineering Toolbox, 2022. Combustion of Fuels - Carbon Dioxide Emission [WWW Document]. URL https://www.engineeringtoolbox.com/co2-emission-fuels-d_1085.html (accessed 7.7.22).
EPA, 2021. An Overview of Renewable Natural Gas from Biogas 56.
EPA, 2022. EPA [WWW Document]. URL https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.eia.gov%2Felectricity%2Fannual%2Fxls%2Fepa_01_02.xlsx&wdOrigin=BROWSELINK (accessed 6.15.22).
MIT Joint Program on the Science and Policy of Global Change, 2022. EPPA Model Structure | MIT Global Change [WWW Document]. URL https://globalchange.mit.edu/research/research-tools/eppa (accessed 6.16.22).
Frazier, S., 2017. True Cost of Energy Comparisons – Apples to Apples - Oklahoma State University [WWW Document]. URL https://extension.okstate.edu/fact-sheets/true-cost-of-energy-comparisons-apples-to-apples.html (accessed 6.3.22).
GHS, 2018. GHS Classification Criteria for Acute Toxicity [WWW Document]. URL https://www.chemsafetypro.com/Topics/GHS/GHS_classification_criteria_acute_toxicity_category.html (accessed 6.21.22).
Gielen, D., 2022. Methanol as a scalable zero emission fuel [WWW Document]. URL https://www.globalmaritimeforum.org/news/methanol-as-a-scalable-zero-emission-fuel (accessed 7.7.22).
Ship and Bunker, 2022. Global Average Bunker Price Bunker Prices [WWW Document]. Ship & Bunker. URL https://shipandbunker.com/prices/av/global/av-glb-global-average-bunker-price (accessed 5.24.22).
Goldmann, A., Sauter, W., Oettinger, M., Kluge, T., Schröder, U., Seume, J.R., Friedrichs, J., Dinkelacker, F., 2018. A Study on Electrofuels in Aviation. Energies 11, 392. https://doi.org/10.3390/en11020392
Gray, N., 2021. Decarbonising ships, planes and trucks: An analysis of suitable low-carbon fuels for the maritime, aviation and haulage sectors | Elsevier Enhanced Reader [WWW Document]. https://doi.org/10.1016/j.adapen.2021.100008
Gray, N., McDonagh, S., O'Shea, R., Smyth, B., Murphy, J.D., 2021. Decarbonising ships, planes and trucks: An analysis of suitable low-carbon fuels for the maritime, aviation and haulage sectors. Advances in Applied Energy 1, 100008. https://doi.org/10.1016/j.adapen.2021.100008
Guo, W., Zhang, K., Liang, Z., Zou, R., Xu, Q., 2019. Electrochemical nitrogen fixation and utilization: theories, advanced catalyst materials and system design. Chem. Soc. Rev. 48, 5658–5716. https://doi.org/10.1039/C9CS00159J
HG, 2022. Ship Registration Law - HG.org [WWW Document]. URL https://www.hg.org/ship-registration.html (accessed 7.5.22).
Hord, J., 1978. Is hydrogen a safe fuel? International Journal of Hydrogen Energy 3, 157–176. https://doi.org/10.1016/0360-3199(78)90016-2
Horvath, S., Fasihi, M., Breyer, C., 2018. Techno-economic analysis of a decarbonized shipping sector: Technology suggestions for a fleet in 2030 and 2040. Energy Conversion and Management 164, 230–241. https://doi.org/10.1016/j.enconman.2018.02.098
Hunt, M.O.-F., Lee, D., 2021. Open Ship Registries and Implications for the Maritime Community [WWW Document]. Lexology. URL https://www.lexology.com/library/detail.aspx?g=082c4d0e-f5b2-42f5-a867-b8c52b9cad0d (accessed 7.6.22).

Hydrogen and Fuel Cell Technologies Office, 2020. Fuel Cells [WWW Document]. Energy.gov. URL https://www.energy.gov/eere/fuelcells/fuel-cells (accessed 12.3.21).
ICS, 2020a. International Chamber of Shipping (ICS) - Explaining shipping [WWW Document]. URL https://www.ics-shipping.org/explaining/ (accessed 7.6.22).
ICS, 2020b. About ICS [WWW Document]. URL https://www.ics-shipping.org/about-ics/ (accessed 7.6.22).
IEA, 2015. Technology Roadmap Hydrogen and Fuel Cells 81.
IEA, 2021b. International Shipping – Analysis [WWW Document]. IEA. URL https://www.iea.org/reports/international-shipping (accessed 2.6.22).
IEA, 2021c. Net Zero by 2050 - A Roadmap for the Global Energy Sector 224.
IEA, 2021a. International shipping - Fuels & Technologies [WWW Document]. IEA. URL https://www.iea.org/fuels-and-technologies/international-shipping (accessed 2.6.22).
IEA, 2021d. Ammonia Technology Roadmap – Analysis [WWW Document]. IEA. URL https://www.iea.org/reports/ammonia-technology-roadmap (accessed 5.19.22).
IEA, 2019a. IEA - The Future of Hydrogen 203.
IEA, 2020b. Natural Gas Information – Analysis [WWW Document]. IEA. URL https://www.iea.org/reports/natural-gas-information-overview (accessed 7.7.22).
IEA, 2020a. IEA-The-Future-of-Hydrogen-Assumption [WWW Document]. URL https://iea.blob.core.windows.net/assets/29b027e5-fefc-47df-aed0-456b1bb38844/IEA-The-Future-of-Hydrogen-Assumptions-Annex_CORR.pdf (accessed 5.11.22).
IEA, 2020c. Global average levelised cost of hydrogen production by energy source and technology, 2019 and 2050 – Charts – Data & Statistics [WWW Document]. IEA. URL https://www.iea.org/data-and-statistics/charts/global-average-levelised-cost-of-hydrogen-production-by-energy-source-and-technology-2019-and-2050 (accessed 5.24.22).
IEA, 2019b. Current and future total cost of ownership of fuel/powertrain alternatives in a bulk carrier ship Data & Statistics [WWW Document]. IEA. URL https://www.iea.org/data-and-statistics/charts/current-and-future-total-cost-of-ownership-of-fuel-powertrain-alternatives-in-a-bulk-carrier-ship (accessed 6.8.22).
IEA, NEA, 2020. Projected Costs of Generating Electricity [WWW Document]. URL https://iea.blob.core.windows.net/assets/ae17da3d-e8a5-4163-a3ec-2e6fb0b5677d/Projected-Costs-of-Generating-Electricity-2020.pdf (accessed 6.6.22).
IMO, 2022. ISWG-GHG 12: Reducing GHG Emissions from Ships [WWW Document]. URL https://imopublicsite.azurewebsites.net/en/MediaCentre/PressBriefings/pages/ISWGHGMay2022.aspx (accessed 7.12.22).
IMO, 2020a. IMO - Fourth Greenhouse Gas Study [WWW Document]. URL https://www.imo.org/en/OurWork/Environment/Pages/Fourth-IMO-Greenhouse-Gas-Study-2020.aspx (accessed 3.22.22).
IMO, 2020b. Fourth IMO GHG Study - Full report and annexes [WWW Document]. URL https://wwwcdn.imo.org/localresources/en/OurWork/Environment/Documents/Fourth%20IMO%20GHG%20Study%202020%20-%20Full%20report%20and%20annexes.pdf (accessed 5.16.22).
IMO, 2020c. IMO 2020 – cutting sulphur oxide emissions [WWW Document]. URL https://www.imo.org/en/MediaCentre/HotTopics/Pages/Sulphur-2020.aspx (accessed 5.16.22).
IMO, 2018. Initial IMO GHG Strategy [WWW Document]. URL https://www.imo.org/en/MediaCentre/HotTopics/Pages/Reducing-greenhouse-gas-emissions-from-ships.aspx (accessed 3.21.22).
Intermodal Shipbrokers Co, 2021. Intermodal Market Report [WWW Document]. URL https://cyprusshippingnews.com/wp-content/uploads/2021/07/Intermodal-Report-Week-28-2021.pdf (accessed 6.8.22).
International Transport Forum, 2019. ITF Transport Outlook 2019, ITF Transport Outlook. OECD. https://doi.org/10.1787/transp_outlook-en-2019-en
Investopedia, 2021. Total Cost of Ownership (TCO): Asset Costs Over the Long Term [WWW Document]. Investopedia. URL https://www.investopedia.com/terms/t/totalcostofownership.asp (accessed 5.26.22).
IPCC, 2022a. Chapter 1: Framing, Context and Methods 142.

IPCC, 2022b. IPCC_AR6_WGII_SummaryForPolicymakers.pdf [WWW Document]. URL https://www.ipcc.ch/report/ar6/wg2/downloads/report/IPCC_AR6_WGII_SummaryForPolicymakers.pdf (accessed 5.14.22).
IRENA, 2021. Innovation Outlook: Renewable Methanol 124.
IRENA, 2019. Wind Power - IRENA [WWW Document]. /costs/Power-Generation-Costs/Wind-Power. URL https://www.irena.org/costs/Power-Generation-Costs/Wind-Power (accessed 6.6.22).
ISPT, 2017. Power to Ammonia: From renewable energy to CO2-free ammonia as chemical feedstock and fuel [WWW Document]. ISPT. URL https://ispt.eu/news/power-ammonia-renewable-energy-co2-free-ammonia-chemical-feedstock-fuel/ (accessed 5.26.22).
Jeerh, G., Zhang, M., Tao, S., 2021. Recent progress in ammonia fuel cells and their potential applications. Journal of Materials Chemistry A 9, 727–752. https://doi.org/10.1039/D0TA08810B
Kamarudin, S.K., Achmad, F., Daud, W.R.W., 2009. Overview on the application of direct methanol fuel cell (DMFC) for portable electronic devices. International Journal of Hydrogen Energy 34, 6902–6916. https://doi.org/10.1016/j.ijhydene.2009.06.013
Kavet, R., Nauss, K.M., 1990. The Toxicity of Inhaled Methanol Vapors. Critical Reviews in Toxicology 21, 21–50. https://doi.org/10.3109/10408449009089872
Kossiakoff, A., Biemer, S.M., Seymour, S.J., Flanigan, D.A., 2020. Systems engineering: principles and practice, Third edition. ed, Wiley series in systems engineering and management. John Wiley & Sons, Inc, Hoboken, NJ.
Levelized Cost of Energy (LCOE), 2022. 9.
DNV, 2021. LNG as marine fuel [WWW Document]. DNV. URL https://www.dnv.com/Default (accessed 5.24.22).
MAN Energy Solutions, 2021. Milestone Order for World's Largest Methanol Dual-Fuel Engine [WWW Document]. MAN Energy Solutions. URL https://www.man-es.com/company/press-releases/press-details/2021/08/25/milestone-order-for-world-s-largest-methanol-dual-fuel-engine (accessed 5.23.22).
MAN Energy Solutions, 2019. MAN Energy Solutions - Propulsion Trends in Bulk Carriers [WWW Document]. URL https://www.man-es.com/docs/default-source/document-sync/propulsion-trends-in-bulk-carriers-eng.pdf?sfvrsn=e284fa19_0 (accessed 5.26.22).
Manoharan, Y., Hosseini, S.E., Butler, B., Alzhahrani, H., Senior, B.T.F., Ashuri, T., Krohn, J., 2019. Hydrogen Fuel Cell Vehicles; Current Status and Future Prospect. Applied Sciences 9, 2296. https://doi.org/10.3390/app9112296
Martin, 2019. Climate Change. United Nations Sustainable Development. URL https://www.un.org/sustainabledevelopment/climate-change/ (accessed 5.13.22).
Mazloomi, K., Gomes, C., 2012. Hydrogen as an energy carrier: Prospects and challenges. Renewable and Sustainable Energy Reviews 16, 3024–3033. https://doi.org/10.1016/j.rser.2012.02.028
McKinlay, C.J., Turnock, S.R., Hudson, D.A., 2021. Route to zero emission shipping: Hydrogen, ammonia or methanol? International Journal of Hydrogen Energy 46, 28282–28297. https://doi.org/10.1016/j.ijhydene.2021.06.066
Mekhilef, S., Saidur, R., Safari, A., 2012. Comparative study of different fuel cell technologies. Renewable and Sustainable Energy Reviews 16, 981–989. https://doi.org/10.1016/j.rser.2011.09.020
Mercuria Energy Trading, 2015. Safety Data Sheet - Heavy Fuel Oil.
Methanex Corporation, 2020. Methanol and Energy | Methanex Corporation [WWW Document]. URL https://www.methanex.com/about-methanol/methanol-and-energy (accessed 3.22.22).
Methanol Institute, 2022a. About Methanol. METHANOL INSTITUTE. URL https://www.methanol.org/about-methanol/ (accessed 5.23.22).
Methanol Institute, 2021a. Methanol Institute - Measuring Maritime Emissions [WWW Document]. URL https://www.methanol.org/wp-content/uploads/2021/08/Methanol-Institute-Measuring-Maritime-Emissions-Policy-Paper-August-2021.pdf (accessed 6.28.22).
Methanol Institute, 2020. Methanol-as-a-marine-fuel [WWW Document]. URL https://www.methanol.org/wp-content/uploads/2020/01/Methanol-as-a-marine-fuel-january-2020.pdf (accessed 5.23.22).
Methanol Institute, 2021b. Methanol Production [WWW Document]. URL https://www.methanol.org/wp-

content/uploads/2016/06/MI-Combined-Slide-Deck-MDC-slides-Revised.pdf (accessed 5.25.22).
Methanol Institute, 2022b. MMSA-Monthly-Price-Forecast-for-Methanol-Institute [WWW Document]. URL https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.methanol.org%2Fwp-content%2Fuploads%2F2022%2F05%2FMMSA-Monthly-Price-Forecast-for-Methanol-Institute-2.xlsx&wdOrigin=BROWSELINK (accessed 5.24.22).
Morris, J., Farrell, J., Kheshgi, H., Thomann, H., Chen, H., Paltsev, S., Herzog, H., 2019. Representing the costs of low-carbon power generation in multi-region multi-sector energy-economic models. International Journal of Greenhouse Gas Control 87, 170–187. https://doi.org/10.1016/j.ijggc.2019.05.016
Nehrir, M.H., Wang, C., 2016. 6 - Fuel cells, in: Rashid, M.H. (Ed.), Electric Renewable Energy Systems. Academic Press, Boston, pp. 92–113. https://doi.org/10.1016/B978-0-12-804448-3.00006-2
NREL, 2022. Simple Levelized Cost of Energy (LCOE) Calculator Documentation [WWW Document]. URL https://www.nrel.gov/analysis/tech-lcoe-documentation.html (accessed 6.2.22).
OECD, 2019. Ocean shipping and shipbuilding - OECD [WWW Document]. URL https://www.oecd.org/ocean/topics/ocean-shipping/ (accessed 5.13.22).
Olmer, N., Comer, B., Roy, B., Mao, X., Rutherford, D., 2017. Greenhouse gas emissions from global shipping, 2013–2015 38.
Paltsev, S., 2021. 2021-JP-Outlook.pdf [WWW Document]. URL https://globalchange.mit.edu/sites/default/files/newsletters/files/2021-JP-Outlook.pdf (accessed 5.23.22).
Paltsev, S., Morris, J., Kheshgi, H., Herzog, H., 2021. Hard-to-Abate Sectors: The role of industrial carbon capture and storage (CCS) in emission mitigation. Applied Energy 300, 117322. https://doi.org/10.1016/j.apenergy.2021.117322
Pavlenko, N., 2020. The climate implications of using LNG as a marine fuel 40.
Ramsden, T., Steward, D., Zuboy, J., 2009. Analyzing the Levelized Cost of Centralized and Distributed Hydrogen Production Using the H2A Production Model, Version 2 (No. NREL/TP-560-46267, 965528). https://doi.org/10.2172/965528
Ratnasamy, C., Wagner, J.P., 2009. Water Gas Shift Catalysis. Catalysis Reviews 51, 325–440. https://doi.org/10.1080/01614940903048661
sailor, A.A. ardent, Techie, A., multitasking, A.W. has voyaged on a number of ships as a marine engineer officer H. loves, networking, creativity, troubleshooting H. is the one behind the unique, Insight, aesthetics at M., 2019. Marine Heavy Fuel Oil (HFO) For Ships – Properties, Challenges and Treatment Methods. Marine Insight. URL https://www.marineinsight.com/tech/marine-heavy-fuel-oil-hfo-for-ships-properties-challenges-and-treatment-methods/ (accessed 6.21.22).
Sasvata, J., Claudia, M., 2022a. RUMFORD MITERA MARIGO ELEKTRA 6.
Sasvata, J., Claudia, M., 2022b. RUMFORD MITERA MARIGO ELEKTRA 6.
Seo, Y., Han, S., 2021. Economic Evaluation of an Ammonia-Fueled Ammonia Carrier Depending on Methods of Ammonia Fuel Storage. Energies 14, 8326. https://doi.org/10.3390/en14248326
Shell, 2020. Decarbonising Shipping: All Hands On Deck 47.
Shell, 2017. Shell Hydrogen Study [WWW Document]. URL https://epub.wupperinst.org/frontdoor/deliver/index/docId/6786/file/6786_Hydrogen_Study.pdf (accessed 9.28.21).
Staffell, I., Scamman, D., Abad, A.V., Balcombe, P., E. Dodds, P., Ekins, P., Shah, N., R. Ward, K., 2019. The role of hydrogen and fuel cells in the global energy system. Energy & Environmental Science 12, 463–491. https://doi.org/10.1039/C8EE01157E
Stolz, B., Held, M., Georges, G., Boulouchos, K., 2022. Techno-economic analysis of renewable fuels for ships carrying bulk cargo in Europe. Nat Energy 7, 203–212. https://doi.org/10.1038/s41560-021-00957-9
Swanson, C., Levin, A., Stevenson, A., Mall, A., Spencer, T., 2020. LIQUEFIED NATURAL GAS IS NOT AN EFFECTIVE CLIMATE STRATEGY 30.
The Royal Society, 2020. Green ammonia | Royal Society [WWW Document]. URL https://royalsociety.org/topics-policy/projects/low-carbon-energy-programme/green-ammonia/ (accessed 5.19.22).

The World Bank, 2020a. GDP Sweden 2020 - The World bank [WWW Document]. URL https://data.worldbank.org/indicator/NY.GDP.MKTP.CD?locations=SE (accessed 6.30.22).
The World Bank, 2020b. Pricing Carbon [WWW Document]. World Bank. URL https://www.worldbank.org/en/programs/pricing-carbon (accessed 7.12.22).
UN, 2022. REVIEW OF MARITIME TRANSPORT 2021. UNITED NATIONS, S.l.
UN, 2015. UN [WWW Document]. URL https://unfccc.int/sites/default/files/english_paris_agreement.pdf (accessed 5.13.22).
UNCTAD, 2021. Merchant fleet – UNCTAD Handbook of Statistics. URL https://hbs.unctad.org/merchant-fleet/ (accessed 7.5.22).
U.S. Climate Change Science Program, 2007. Scenarios of Greenhouse Gas Emissions and Atmospheric Concentrations; and Review of Integrated Scenario Development and Application 164.
U.S. EIA, 2022. Henry Hub Natural Gas Spot Price (Dollars per Million Btu) [WWW Document]. URL https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm (accessed 6.7.22).
US EPA, O., 2018. Renewable Natural Gas [WWW Document]. URL https://www.epa.gov/lmop/renewable-natural-gas (accessed 6.17.22).
Williams, R., 2016. Evaluating the Air Quality, Climate & Economic Impacts of Biogas Management Technologies 101.
Yip, H.L., Srna, A., Yuen, A.C.Y., Kook, S., Taylor, R.A., Yeoh, G.H., Medwell, P.R., Chan, Q.N., 2019. A Review of Hydrogen Direct Injection for Internal Combustion Engines: Towards Carbon-Free Combustion. Applied Sciences 9, 4842. https://doi.org/10.3390/app9224842
Zamfirescu, C., Dincer, I., 2008. Using ammonia as a sustainable fuel. Journal of Power Sources 185, 459–465. https://doi.org/10.1016/j.jpowsour.2008.02.097
Zhang, H., Wang, L., Van herle, J., Maréchal, F., Desideri, U., 2020. Techno-economic comparison of green ammonia production processes. Applied Energy 259, 114135. https://doi.org/10.1016/j.apenergy.2019.114135
Zincir, B., 2022. Environmental and economic evaluation of ammonia as a fuel for short-sea shipping: A case study - 8803586.pdf [WWW Document]. URL https://www.reprintsdesk.com/userv3/fulltextreader.aspx (accessed 5.19.22).