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REDUCTION OF GHG EMISSIONS FROM SHIPS

Report of the Comprehensive impact assessment of the basket of candidate GHG reduction mid-term measures – full report on Task 2 (Impacts on the fleet)

Note by the Secretariat

SUMMARY

Executive summary:	This document provides the full report on Task 2, Assessment of the impacts on the fleet, of the comprehensive impact assessment of the basket of candidate GHG reduction mid-term measures as conducted by DNV.
Strategic direction, if applicable:	3
Output:	3.2
Action to be taken:	Paragraph 2
Related documents:	MEPC 80/17, MEPC 80/17/Add.1; MEPC 81/7, MEPC 81/7/Add.1; MEPC 82/7, MEPC 82/7/1, MEPC 82/7/2, MEPC 82/7/4; MEPC 82/7/4/Add.1, MEPC 82/7/4/Add.2, MEPC 82/7/4/Add.3, MEPC 82/7/4/Add.4, MEPC 82/INF.8, MEPC 82/INF.8/Add.2, MEPC 82/INF.8/Add.3 and MEPC.1/Circ.885/Rev.1

Introduction

1 The Comprehensive impact assessment of the basket of candidate mid-term GHG reduction measures consists of five distinct and interrelated tasks (MEPC 82/7/4, paragraph 5). This document provides the full report of the assessment of the impacts on the fleet conducted by DNV, as set out in the annex.

Action requested of the Committee

2 The Committee is invited to take into account the information provided in this document, when considering documents MEPC 82/7/4 and MEPC 82/7/4/Add.2.

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COMPREHENSIVE IMPACT ASSESSMENT OF THE BASKET OF CANDIDATE MID-TERM GHG REDUCTION MEASURES – TASK 2: ASSESSMENT OF IMPACTS ON THE FLEET

Final report

International Maritime Organization (IMO)

Report no.: 2024-1567, Rev. 4
Date: 2024-07-27

Project name:	Comprehensive impact assessment of the basket of candidate mid-term GHG reduction measures – Task 2: Assessment of impacts on the fleet	
Report title:	Final report	
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Objective:

The overall goal of this study is to assess the impacts on the fleet of the basket of candidate measures designed to achieve the GHG reduction goals set out in the 2023 IMO GHG Strategy.

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Keywords
IMO; Impact assessment; GHG emission reduction

Rev. no.	Date	Reason for issue	Prepared by	Verified by	Approved by
0	2024-06-03	Draft final report			
1	2024-06-25	Updated based on review			
2	2024-07-12	Final report			
3	2024-07-20	Corrected errors			
4	2024-07-27	Updated disclaimer			

DISCLAIMER

This report has been completed by DNV. It contains the report on Task 2 on the assessment of the impacts of the candidate measures on the fleet of the Comprehensive impact assessment of the basket of mid-term GHG reduction measures.

Whilst this report has been commissioned by the International Maritime Organization (IMO), the information contained within this report represents the view of its authors only. It should not be interpreted as representing the views of the IMO, or the Steering Committee on the comprehensive impact assessment of the basket of candidate mid-term measures, or the States that are represented on the Steering Committee.

This comprehensive impact assessment of the basket of mid-term GHG reduction measures consists of five distinct but interrelated tasks for which different reports have been prepared. Task 2 of the Comprehensive impact assessment of the basket of candidate mid-term GHG reduction measures is being undertaken solely to assist IMO's Marine Environment Protection Committee (MEPC) in making evidence-based decisions. Any information included in this report is provided solely for analytical purposes and should not be interpreted as suggestions or recommendations for how the basket of mid-term GHG reduction measures should be designed. The policy combination scenarios and any other information included in this report are provided solely for analytical purposes and should not be interpreted as suggestions or recommendations for how the basket of mid-term GHG reduction measures should be designed.

The designations employed and the presentation of material on any map in this report do not imply the expression of any opinion whatsoever on the part of the United Nations concerning the legal status of any country, territory, city or area or of its authorities, or concerning the delimitation of its frontiers or boundaries.

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ACKNOWLEDGEMENTS

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- the external QA/QC reviewers Matthew Herbert (UK), Ng Szu Hui (Singapore), Vasileios Tzelepis (USA), Shi Xun (China) and Yujiro Wada (Japan), for their critical review and valuable comments to the final report;
- the 160 stakeholders from across the maritime value chain that participated in review workshops and provided feedback on the inputs and assumptions used in this report; and
- the members of the Steering Committee for their constructive comments throughout the study on the inception, interim and final reports.

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EXECUTIVE SUMMARY

This study assesses the impacts on the fleet of the basket of candidate measures designed to achieve the greenhouse gas (GHG) reduction goals set out in the 2023 IMO Strategy on Reduction of GHG Emissions from Ships (IMO GHG Strategy). It comprises Task 2 of the IMO's comprehensive impact assessment of the basket of candidate mid-term GHG reduction measures.

The study defines two well-to-wake GHG emission trajectories to 2050, named as *Base* and *Strive* in this report, according to the indicative checkpoints and the IMO GHG Strategy's level of ambition to reach net-zero GHG emissions by or around, i.e. close to, 2050, and taking into account well-to-wake GHG emissions.

The *Base* trajectory reflects the lower ends of the indicative checkpoints, in other words to reduce the total annual GHG emissions from international shipping by 'at least' 20% by 2030 and by 'at least' 70% by 2040, both compared to 2008. The *Strive* trajectory reflects the upper ends of the indicative checkpoints, in other words 'striving for' reductions of 30% by 2030 and 80% by 2040 compared to 2008.

16 policy combinations (basket of measures) have been modelled for each trajectory for a total of 32 policy combination scenarios which are compared to a BAU (business-as-usual) scenario with currently adopted policy measures. All follow a projection of low growth in seaborne trade.

The proposed policy measures address well-to-wake GHG emissions or tank-to-wake GHG emissions with sustainability criteria. However, for the purposes of the modelling, this study defines the GHG emission trajectories in a well-to-wake scope which should be followed regardless of the scope of the policy measures, in order to make the scenarios comparable.

Key findings

Impact on costs

- The **cost intensity of the fleet**, measured in USD per tonne-mile, is expected to increase relative to a BAU scenario by 16% to 47% in 2030, 56% to 80% in 2040, and 71% to 85% in 2050.
- **In 2030,** the cost intensity of the fleet is expected to increase relative to a BAU scenario by **16% to 40%** across 16 policy combinations following the *Base* GHG emission trajectory of 20% reduction from 2008, and by **26% to 47%** across 16 policy combinations following the *Strive* GHG emission trajectory of 30% reduction from 2008.
- The lowest increases in cost intensity in 2030 are found in scenarios with a GHG Fuel Intensity (GFI) flexibility mechanism and no levy or feebate, while the highest increases are in scenarios with a 150–300 USD per tonne of carbon dioxide equivalent (tCO_2eq) levy due to the direct cost of the levy.
- **In 2040,** the cost intensity of the fleet is expected to increase relative to a BAU scenario by **56% to 71%** following the *Base* GHG emission trajectory of 70% reduction from 2008, and by **65% to 80%** following the *Strive* GHG emission trajectory of 80% reduction from 2008.
- The lowest increases in cost intensity in 2040 are found in scenarios with a GFI flexibility mechanism and a 30–120 USD/tCO_2eq levy. The range of cost-intensity increase is less in 2040 than in 2030 as the reductions in energy use across the policy combination scenarios are more similar, driven mainly by the increased costs of meeting the GFI requirements and to a lesser degree by the cost of the levy/feebate.
- **In 2050,** the cost intensity of the fleet is expected to increase relative to a BAU scenario by **71% to 85%** following the *Base* GHG emission trajectory, and by **73% to 83%** following the *Strive* GHG emission trajectory.

- The *Base* and *Strive* GHG emission trajectories have similar ranges of cost-intensity increases as they both achieve close to net-zero GHG emissions in 2050. The lowest increases in cost come in scenarios with a levy and a GFI flexibility mechanism.
- The aggregated cost per tonne GHG emission reduced over the whole period **from 2023 to 2050** ranges from **292 to 354 USD/tCO_2eq**. The lowest costs per tonne of GHG emission reduction are in the scenarios following the *Strive* GHG emission trajectory and in scenarios with a GFI flexibility mechanism.

Impact on energy use, fuels, and technologies

- The results show **a diverse mix of fuels and solutions** both within and across scenarios where electrofuels (e-fuels) and onboard carbon capture and storage (CCS) appear to be the two most prevalent decarbonization solutions. Biofuels also have a significant contribution towards 2040 and 2050 across all policy scenarios. It should be noted that the modelled use of different feedstocks is to a large degree a result of the assumed supply constraints on bio- and blue fuel feedstocks, and also the assumed lack of constraints on e-fuels and carbon storage capacity. The projected feedstock supply and carbon storage capacity and the share available for shipping are very uncertain.
- To achieve the GHG emission trajectories within the assumed supply constraints all fuel feedstocks need to be used, complemented by onboard CCS and reduction in energy use by way of energy-efficiency measures and speed reductions. In 2030, the uptake of low GHG emission fuels is between 0.3 and 2.9 exajoules (EJ), or about 7–69 million tonnes oil-equivalents, with the lowest uptake in scenarios with high reduction in energy use or high uptake of onboard CCS. In most scenarios, except those with high reduction in energy use, the total **feedstock supply and carbon storage capacity** exceed the median estimated projections in the literature.
- **Reduction of energy use** in the fleet can significantly reduce the need for low GHG emission fuels and onboard CCS, which will reduce overall costs and increase the ability to reach the GHG emission trajectories under fuel feedstock supply constraints. There are barriers to implementation of energy-efficiency measures and speed reductions. A high GHG price or following the more stringent *Strive* GHG emission trajectory seem to increase the costs sufficiently to incentivize energy-efficiency improvements in the early period to 2030.

Impacts of different policy combinations

- Applying a **tank-to-wake scope with sustainability criteria or a well-to-wake scope** did not result in any significant differences in cost intensity as the scenarios follow the same well-to-wake GHG emission trajectory. The well-to-wake scope scenarios combined with a levy have a slightly higher cost because the absolute cost of the levy is higher when well-to-tank GHG emissions are included.
- A **GHG Fuel Intensity flexibility mechanism** can reduce the total cost per tonne of GHG reduction from 2023 to 2050 by about 6%. The GFI flexibility mechanism has the greatest effect when there are capital-intensive solutions – such as ammonia or methanol engines or onboard carbon capture systems – that enable ships to run on fuels with lower prices than drop-in fuels such as bio- and e-MGO. Towards 2050, the cost impact of the flexibility mechanism is lower.
- The GFI flexibility mechanism may also be beneficial during the build-up of production and infrastructure for alternative fuels when such fuels have limited global availability. Ships that cannot find adequate fuels may exchange emission units (i.e. join in a compliance pool) with ships trading in areas where low GHG emission fuels are more readily available. The modelling in this study does not quantify this effect.
- The **levy and feebate mechanisms** generally increase the cost intensity in 2030 due to the direct cost of the levy and fee, and limited reward for eligible fuels. Scenarios with a 150–300 USD/tCO_2eq levy have a higher reduction in energy use in 2030, which counters the additional cost to some degree. Towards 2040, as the GHG emission reduces and the uptake of eligible fuels increases, the total impact on cost intensity is less.

Other than the reward for eligible fuels, it should be noted that no other disbursement of revenues to shipping are included in the modelling.

- **Significant revenues** can be generated by the levy or feebate mechanisms, ranging from 17 to 127 billion US dollars per year (BUSD/year) in the period 2027–2030 before these revenues decrease gradually with reduced GHG emissions towards 2050. It is estimated that about 2 to 35 BUSD/year in 2027–2030 and 15 to 42 BUSD/year in 2031–2040 will be distributed back to shipping as reward for eligible fuels. Remaining funds are available for other disbursement purposes. The GFI flexibility mechanism could also raise revenues through sale of Remedial Units to ships.
- The **reward for eligible fuels** in the levy and feebate mechanisms incentivizes uptake of e-fuels, in particular e-ammonia and e-LNG. Together with bio-LNG they have the highest uptake in scenarios with a levy in combination with a reward mechanism. The modelled uptake of fuel types is very sensitive to relatively small changes in the levy and reward levels.
- The modelling indicates that if **R&D spending** can result in two to three years' earlier availability of technologies as well as 20% less capital cost, the cost per tonne of lowering GHG emissions over the period 2023–2025 can be reduced by 4%. It has not been possible to ascertain the magnitude of R&D spending required to achieve the effect assumed in the modelling.

Key uncertainties

- The **main uncertainty** which has the most significant impact on the results are future fuel prices. Using the projected range of fuel prices from literature, the cost intensity increases relative to BAU in 2030 ranges from 12% to 60%, somewhat larger than the range due to varying the policy combinations. Towards 2040 and 2050, the uncertainty over fuel prices increases. The cost intensity increases between 47% and 109% by 2040, and between 46% and 129% by 2050. The total cost per tonne of GHG reduction within the projected range of fuel prices ranges from 210 to 487 USD/tCO_2eq.
- The **number of retrofits** to other fuel technologies or onboard CCS in the scenarios are significant, peaking between 2,000 and 3,600 retrofits per year. Due to the complexity of retrofitting ships to alternative fuel technologies and onboard CCS, it remains uncertain if these numbers are feasible for the yards and equipment manufacturers to deliver. The implication that such retrofit rates are unfeasible is that more ships have to run on more expensive drop-in fuels such as bio-MGO and e-MGO.

Approach

This study applies a scenario-based framework to model the effect of various policy combinations and assess the impacts on the fleet. The high-level method applied can be divided into three main steps.

In the first step, a Baseline fleet for 2023 is established using the MASTER (Mapping of Ship Tracks, Emissions and Reduction potentials) model, where energy consumption and ship activity are calculated based on global ship-tracking data from the Automatic Identification System (AIS) combined with ship specific data from other sources.

This forms the starting point for step two, the simulation of the future fleet year-by-year towards 2050 using the GHG Pathway model. For each year, the model evaluates all available GHG emission reduction solutions for each individual ship built that year or in operation. The evaluation simulates the decision from a shipowner's perspective on the use of alternative fuels, onboard carbon capture, energy-efficiency packages, and speed reduction. The proposed basket of measures is modelled in policy combination scenarios as input on regulatory requirements, costs and rewards. The ships are fitted with the most cost-effective, feasible combination of measures that fulfil the regulatory requirements.

Finally, in the third step, the scenario outputs are analysed with regard to GHG emission trajectories; change in cost intensity and total cost per tonne of GHG reduced relative to a BAU scenario; energy use; speed reduction; fuel mix; and revenue streams from economic elements.

Candidate mid-term GHG emission reduction measures

The candidate mid-term GHG reduction measures (hereafter called policy measures) assessed in this study are:

- A GHG Fuel Intensity (GFI) requirement
- A GFI flexibility mechanism
- A levy mechanism
- A feebate mechanism.

The policy measures assessed in this study are based on the proposals provided up until MEPC 80, as well as input provided by the Steering Committee. The descriptions and assumptions of the policy measures are adapted to align similar concepts and terminology across the proposals, and with the method applied in this study for modelling the policy measures. The descriptions and assumptions should not be construed as suggestions or recommendations for how the policy measures should be designed, but rather as necessary adaptations for the purpose of modelling and analysis which requires specific inputs and definitions.

Fleet in scope: For the purposes of the modelling in this study, we assume that the fleet in scope of the new policy measures will be same as for Chapter 4 of MARPOL Annex VI. They will take effect on the fleet from 2027.

Well-to-wake (WtW) or tank-to-wake (TtW) scope with sustainability criteria: The GHG emissions in scope for the policy measures in this study can either be WtW or TtW with sustainability criteria.

GFI requirement: The GFI is a requirement on annual GHG emissions per energy unit used (gCO_2eq/MJ). The GFI requirement, applying a WtW or TtW scope, will gradually become more stringent ensuring that the WtW GHG emission trajectories are met.

GFI flexibility mechanism: The GFI can be implemented with a flexibility mechanism which provides alternative options for compliance. The first option is for ships with attained GFI below required GFI (positive compliance balance) to sell excess emission units to, or join a pool with, ships with attained GFI above required GFI (negative compliance balance). The second option is for ships with positive compliance balance to sell excess emission units (termed as Surplus Units, SU) to a Revenue body at a set SU price, and for ships with negative compliance balance to buy deficit units (termed Remedial Units, RU) from a Revenue body at a set RU price. The SU and RU prices are set as a percentage of the estimated annual emission unit exchange price in this study.

Levy mechanism: The levy mechanism consists of two elements. The first is the levy, which is a predetermined price set by the IMO, or by criteria in the regulation, on annual GHG emissions (USD/tCO_2eq) from a ship, collected by a Revenue body. The second element is a reward which is a predetermined rebate to ships per energy unit of eligible fuel used (USD/GJ). The total reward is distributed from the Revenue body to the ships using eligible fuels at the end of the year, based on the reported annual consumption.

Feebate mechanism: The feebate mechanism consists of two elements, a reward (rebate) to ships using eligible fuels, and a fee per tonne GHG emitted (USD/tCO_2eq). The mechanism is similar to the levy with the key differences that the fee is calculated based on the total reward and that the revenues and expenses balance each other, as opposed to the levy, which is determined in advance and which can raise additional revenue.

Revenue body: The GFI flexibility, levy, and feebate mechanisms all rely on a body to manage collection and disbursement of revenues. The setup of this body is yet to be determined and since it is not expected to have a material impact on the assessment in this study, it is generically referred to as the *Revenue body* in this report.

Eligible fuels and cost gap: The levy and feebate mechanisms provide a reward for ships using certain fuels. As no criteria were available at the time of the study, we apply a simplified criterion for fuels eligible for rewards based on fuel feedstock. We assume all e-fuels as eligible for the reward, and the reward is set as a percentage of the cost gap between the lowest cost e-fuel (i.e. e-ammonia) and the lowest cost biofuel (i.e. bio-LNG).

Revenue streams and disbursements: The GFI flexibility, levy, and feebate mechanisms will provide a revenue stream which can be distributed according to seven revenue disbursement categories (D1 to D7). Of these, D1 (research, development & deployment – RD&D) and D4 (reward for eligible fuels) would have an impact on the shipping fleet and are relevant for this study. Due to a knowledge gap that has meant that the impacts of a certain amount of R&D spending cannot be modelled, D1 disbursement is set to zero for all scenarios (see Section 6.4, Impact of research and development, for an explanation). Disbursement for other categories (D2–D3 and D5–D7) is passed to UNCTAD for incorporation into the modelling of impact on states in Task 3 of the comprehensive impact assessment.

Well-to-wake GHG emissions in 2008 and 2023, and trajectories to 2050

This study assesses the impact on the fleet under the scope of Chapter 4 of MARPOL Annex VI[1] of following two WtW GHG emission trajectories (*Base* and *Strive*) according to the ambitions and indicative checkpoints of the IMO GHG Strategy. The *Base* trajectory is based on the lower ('at least' hence *Base*) targets, and the *Strive* trajectory on the higher ('striving for') targets of the indicative checkpoints for GHG emission reduction by 2030 and 2040 compared to 2008. Both the *Base* and *Strive* trajectories include the ambition to reach net-zero GHG emissions by or around, i.e. close to, 2050.

The proposed policy measures may address well-to-wake (WtW) GHG emissions or tank-to-wake (TtW) GHG emissions with sustainability criteria. However, the IMO GHG Strategy states that the levels of ambition and indicative checkpoints should take into account the well-to-wake GHG emissions. So, for the purposes of the modelling, this study defines the GHG emission trajectories in a WtW scope which should be followed regardless of the scope of the policy measures, in order to make the scenarios comparable.

[1] All ships under the scope of Chapter 4 of MARPOL Annex VI, which are ships above 400 GT except ships solely trading domestically and ships not propelled by mechanical means, and platforms including FPSOs and FSUs and drilling rigs, regardless of their propulsion.

The ambitions related to carbon intensity and the uptake of zero or near-zero GHG emission technologies, fuels and/or energy sources in 2030 are, for the purposes of the modelling in this study, not included as mandatory targets and may not be reached in the modelled scenarios.

To set the trajectories for 2030 and 2040 relative to 2008 for the fleet in scope of this study, we estimate the WtW GHG emissions for 2008 for the fleet based on the TtW GHG emission estimate for international shipping in 2008 from the Fourth IMO GHG study, and we add the WtT GHG emissions based on the estimated fuel mix in 2008 from the Third IMO GHG study.

The WtW GHG emission for the fleet in scope of this study is estimated to be 964 $MtCO_2eq$ in 2008 and to have reduced by 3.6% to 928 $MtCO_2eq$ in 2023. The emissions are projected to increase to 994 $MtCO_2eq$ and 1,383 $MtCO_2eq$ in 2050 in the low- and high-growth BAU scenarios, respectively. This corresponds to a 3% increase in the low-growth BAU scenario and 43% under high-growth BAU, both compared with 2008.

Following the *Base* trajectory, the WtW GHG emissions targets for the fleet in scope of this study are 771 $MtCO_2eq$ in 2030 and 289 $MtCO_2eq$ in 2040. For the *Strive* trajectory, the targets are 674 $MtCO_2eq$ in 2030 and 193 $MtCO_2eq$ in 2040. The target for 2050, which is the same for both trajectories, is set close to zero; but, due to a small amount of methane (CH_4) and nitrous oxide (N_2O) emissions from internal combustion engines, which with current technologies and knowledge cannot be eliminated, the emissions are not set to exactly zero.

Table 1 shows the estimated WtW GHG emissions in 2008 and 2023, and the *Base* and *Strive* GHG emission reduction trajectories for the fleet in scope of this study, compared to the projected GHG emissions according to the results from the two BAU scenarios in 2030, 2040, and 2050.

Table 1 Estimated well-to-wake (WtW) GHG emissions in 2008 and 2023, and the *Base* and *Strive* GHG emission reduction trajectories for the fleet under the scope of Chapter 4 of MARPOL Annex VI, compared to the projected business-as-usual (BAU) GHG emissions in 2030, 2040, and 2050; percentage reductions are relative to 2008.

WtW GHG emissions ($MtCO_2eq$)	2008	2023	2030	2040	2050
BAU low growth	964 (reference)	928 (–3.7%)	959 (–0.5%)	1,020 (+12%)	994 (+3%)
BAU high growth			1,079 (+12%)	1,290 (+34%)	1,383 (+43%)
Base trajectory			771 (–20%)	289 (–70%)	~0 (–100%)
Strive trajectory			674 (–30%)	193 (–80%)	~0 (–100%)

Scenarios

The study is based on 16 policy combinations scenarios, assessing the impact of following the *Base* (numbered 21 to 36) and *Strive* (numbered 41 to 56) GHG emission trajectories to 2050 using a low seaborne trade growth projection, for a total of 32 scenarios. These scenarios are compared to a BAU scenario with currently adopted policies using the same low-growth assumption (BAULG). A BAU scenario with high-growth seaborne trade (BAUHG) has also been included and is used for comparison with relevant scenarios in the sensitivity analysis. The scenarios are listed in Table 2.

To assess the sensitivity of key inputs and assumptions beside the policy combinations, 36 additional sensitivity scenarios have been run. These investigate 9 different changes in input, combined with 4 representative policy scenarios (numbered 23, 32, 46 and 55). In addition, 18 preliminary scenarios (numbered 1 to 18 – not included in Table 2) were initally run during the study. However, inputs on fuel prices and policy combinations were updated together with other adjustments in subsequent scenarios, and the results presented in this study are based on scenarios 21 to 56 only. In total, 88 scenarios have been modelled in this study.

Table 2 List of the 2 BAU scenarios and 32 policy scenarios analysed in this study; the policy codes are according to the Working Document on Value Ranges for Scenario Development (MEPC 81/7, Annex 4).

Scenario number	Emission trajectory	Seaborne trade growth	Policy combination						
			Policy code	GFI scope	GFI flexibility		Levy		Feebate
					RU % of price	SU % of price	Levy USD/ tCO_2eq	Reward % of cost gap	Reward % of cost gap
BAULG	BAU	Low	None						
BAUHG	BAU	High	None						
21	*Base*	Low	X.1	TtW	No flexibility		No levy		No feebate
22	*Base*	Low	Y.1	WtW	No flexibility		No levy		No feebate
23	*Base*	Low	X.4	TtW	120%	80%	No levy		No feebate
24	*Base*	Low	Y.4	WtW	120%	80%	No levy		No feebate
25	*Base*	Low	X.2	TtW	No flexibility		150–300	90% to 65% to 2040	No feebate
26	*Base*	Low	Y.2	WtW	No flexibility		150–300	90% to 65% to 2040	No feebate
27	*Base*	Low	X.5	TtW	120%	80%	150–300	90% to 65% to 2040	No feebate
28	*Base*	Low	Y.5	WtW	120%	80%	150–300	90% to 65% to 2040	No feebate
29	*Base*	Low	X.2	TtW	No flexibility		30–120	105% to 2040	No feebate
30	*Base*	Low	Y.2	WtW	No flexibility		30–120	105% to 2040	No feebate
31	*Base*	Low	X.5	TtW	120%	80%	30–120	105% to 2040	No feebate
32	*Base*	Low	Y.5	WtW	120%	80%	30–120	105% to 2040	No feebate
33	*Base*	Low	X.3	TtW	No flexibility		No levy		105% to 2040
34	*Base*	Low	Y.3	WtW	No flexibility		No levy		105% to 2040
35	*Base*	Low	X.6	TtW	120%	80%	No levy		105% to 2040
36	*Base*	Low	Y.6	WtW	120%	80%	No levy		105% to 2040
41	*Strive*	Low	X.1	TtW	No flexibility		No levy		No feebate
42	*Strive*	Low	Y.1	WtW	No flexibility		No levy		No feebate
43	*Strive*	Low	X.4	TtW	120%	80%	No levy		No feebate
44	*Strive*	Low	Y.4	WtW	120%	80%	No levy		No feebate
45	*Strive*	Low	X.2	TtW	No flexibility		150–300	90% to 65% to 2040	No feebate
46	*Strive*	Low	Y.2	WtW	No flexibility		150–300	90% to 65% to 2040	No feebate
47	*Strive*	Low	X.5	TtW	120%	80%	150–300	90% to 65% to 2040	No feebate
48	*Strive*	Low	Y.5	WtW	120%	80%	150–300	90% to 65% to 2040	No feebate
49	*Strive*	Low	X.2	TtW	No flexibility		30–120	105% to 2040	No feebate
50	*Strive*	Low	Y.2	WtW	No flexibility		30–120	105% to 2040	No feebate
51	*Strive*	Low	X.5	TtW	120%	80%	30–120	105% to 2040	No feebate
52	*Strive*	Low	Y.5	WtW	120%	80%	30–120	105% to 2040	No feebate
53	*Strive*	Low	X.3	TtW	No flexibility		No levy		105% to 2040
54	*Strive*	Low	Y.3	WtW	No flexibility		No levy		105% to 2040
55	*Strive*	Low	X.6	TtW	120%	80%	No levy		105% to 2040
56	*Strive*	Low	Y.6	WtW	120%	80%	No levy		105% to 2040

Key: business-as-usual (BAU); BAU high growth (BAUHG), BAU low growth (BAULG); GHG Fuel Intensity (GFI); Remedial Units (RU); Surplus Units (SU); tank-to-wake (TtW); well-to-wake (WtW)

Impacts on costs

Figure 1 shows the range of increases in cost intensity in 2030, 2040, 2050 and the cost per tonne of GHG reduced in the period 2023–2050 relative to BAU for the 16 policy combination scenarios for each of the *Base* and *Strive* trajectories (blue boxes) and the 36 sensitivity scenarios (whisker diagrams). The cost intensity is the annual total cost, which includes annualized capital, operational, and fuel expenses, as well as regulatory incomes and expenses imposed by the policy measures, divided by the total transport work (based on cargo carried).

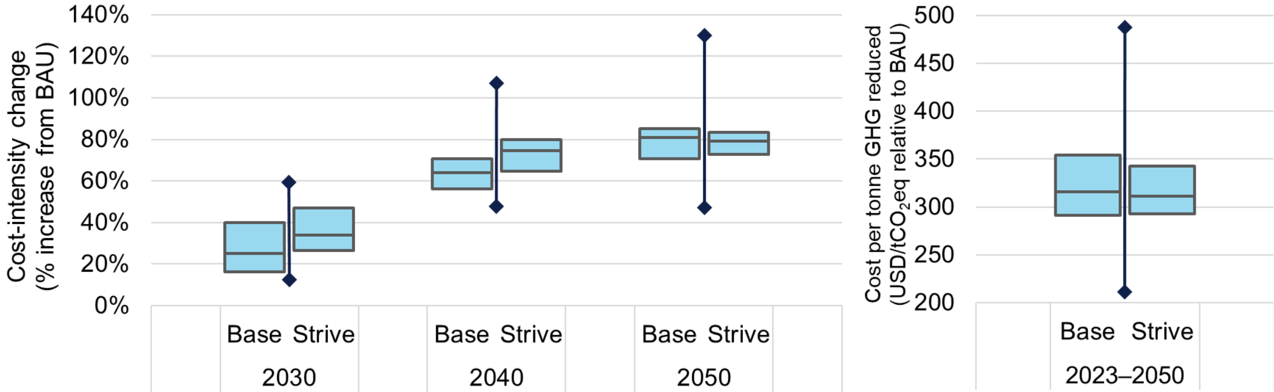

Figure 1 Range of cost-intensity increases in 2030, 2040, and 2050 (left panel) and cost per tonne of GHG reduced in the period 2023–2050 (right panel) and relative to BAU. The blue boxes show the range and median of the 16 policy combination scenarios for each of the *Base* and *Strive* trajectories, while the whiskers show the minimum and maximum of the 36 sensitivity scenarios, regardless of emission trajectory.

The increase in cost intensity, measured in cost per tonne-mile relative to BAU, of achieving the *Base* GHG emission trajectory across the 16 policy combination scenarios, is 16% to 40% in 2030, increasing to 56% to 71% in 2040 and 71% to 85% in 2050. Similarly, for achieving the *Strive* GHG emission trajectory, the increase in cost intensity is 26% to 47% in 2030, increasing to 65 to 80% in 2040 and 73% to 83% in 2050. The cost per tonne of GHG reduced over the entire period 2023–2050 is between 292 and 354 USD/tCO_2eq.

The lowest increases in cost intensity in 2030 are found in scenarios with a GFI flexibility mechanism and no levy or feebate, while the highest increases are in scenarios with a 150–300 USD/tCO_2eq levy due to the direct cost of the levy. The range in cost-intensity increase is less in 2040 than in 2030 as the reductions in energy use across the policy combination scenarios are more similar, driven mainly by the increased costs of meeting the GFI requirements and to a lesser degree by the cost of the levy/feebate.

Both the *Base* and *Strive* GHG emission trajectories achieve close to net-zero GHG emissions in 2050 and have similar ranges of cost-intensity increases. However, the scenarios following the *Strive* GHG emission trajectory can in some cases result in lower costs due to the trajectory leading to an earlier uptake of energy-efficiency measures and fuel technologies. The lowest increases in cost come in scenarios with a levy and a GFI flexibility mechanism.

The aggregated cost per tonne of GHG emission reduced over the period 2023–2050 ranges from 292 to 354 USD/tCO_2eq. The lowest cost per tonne of GHG reduced are in the scenarios following the *Strive* GHG emission trajectory and in scenarios with a GFI flexibility mechanism.

While the other sensitivities investigated can have a significant impact, the minimum and maximum costs are determined by the variation in fuel prices. If including the changes in inputs and assumptions from the sensitivity scenarios, the cost intensity change in 2030 ranges from 12% to 60%, somewhat larger than the range due to the various policy combinations. Towards 2040 and 2050 the uncertainty of the fuel prices increases. The range in cost intensity change increases to between 47% and 109% in 2040 and to between 46% and 129% in 2050. The total cost per tonne of GHG reduced over the period 2023–2050 ranges from 210 to 487 USD/tCO_2eq.

Impact on energy use, fuels, and technology uptake

Figure 2 shows the range of reductions in speed and energy use, and on the use of ammonia, methanol, methane/LNG and onboard CCS for the 16 policy combination scenarios for each of the *Base* and *Strive* trajectories (blue boxes) and the 36 sensitivity scenarios (whiskers).

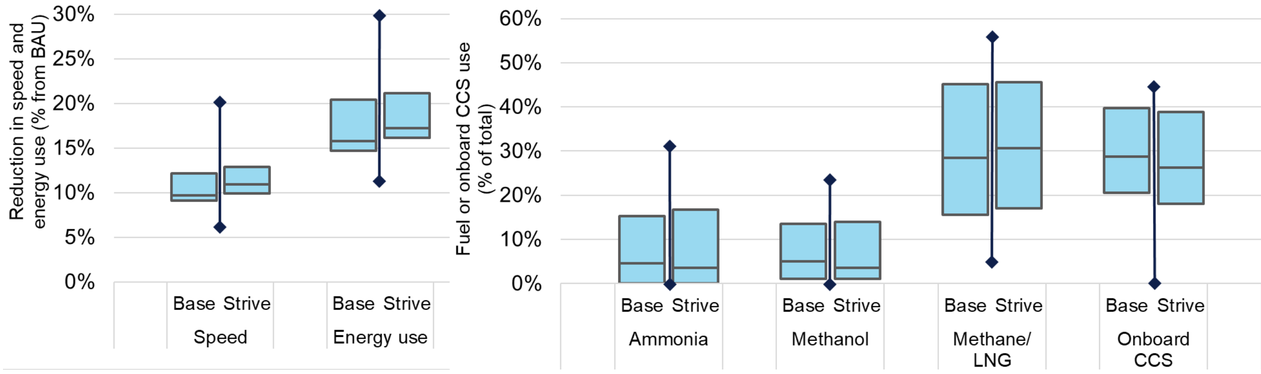

Figure 2: Range of reduction in speed and energy use relative to BAU (left panel) and in fuel uptake relative to total energy use and onboard CCS use relative to GHG emission reduced (right panel) in the period 2023–2050. Blue boxes show the range and median of the 16 policy combination scenarios for each of the *Base* and *Strive* trajectories, while the whiskers show the minimum and maximum of the 36 sensitivity scenarios, regardless of emission trajectory.

The average speed across the period 2023–2050 is reduced by 9% to 13% relative to BAU while energy use is reduced by 15% to 21% across all policy combination scenarios. It is notable that the GFI requirement does not directly incentivize improvements in energy efficiency. Initially, to 2030, the GFI requirements under the *Base* GHG emission trajectory are not sufficient to increase the total fuel costs to incentivize the uptake of energy-efficiency measures. The *Strive* trajectory scenarios have a somewhat greater reduction in speed and energy while the differences in fuel mix is small, indicating that the required amount of low GHG emission energy to reach the GFI requirements and related costs may be sufficient to drive a higher uptake of energy-efficiency measures and speed reduction. Towards 2050, the difference between the *Base* and *Strive* trajectory scenarios become smaller. This indicates that there are barriers to implementation of energy-efficiency measures and speed reductions. Other policy measures, beyond those investigated in the scenarios, to overcome these barriers have not been investigated in this report.

With the sensitivity scenarios, the speed reduction ranges from 6% to 20% while the reduction in energy use is between 11% and 30%. The upper range is determined by the forced uptake of energy-efficiency measures and speed reduction, while the lower range is determined by low fuel prices. Forcing the uptake of speed reduction and energy-efficiency packages has a significant impact leading to a 15% reduction on cost per tonne of GHG reduction, and a lower use of methane/LNG and onboard CCS.

The uptake of ammonia and methanol, regardless of feedstock, in the policy combination scenarios is between 0% and 17% of total energy use, while for methane/LNG it is between 16% and 46%. The uptake of onboard CCS is between 18% and 40% in term of CO_2 captured relative to total GHG emission reduced. In the sensitivity scenarios, the uptake of ammonia can reach 31% if onboard CCS is not available; methanol can reach 24% with lower fuel prices; and with high fuel prices, methane/LNG can reach 57% and onboard CCS use can reach 45%.

Removing the option of onboard CCS in the sensitivity scenarios on average increases the cost intensity in 2030 as ships must instead use low GHG emission fuels, which are more expensive initially. Over time, as these fuels decrease in cost, the impact is reversed, with a lower cost-intensity increase in 2050. The overall cost per tonne of GHG reduction in the period 2023–2050 increases by 1% if the CCS option is removed.

Onboard CCS remains a viable option even if it becomes 50% more expensive, though its use is then about halved. Ammonia and methanol are used more, to replace onboard CCS, while methane/LNG use is reduced as these fuels are used in combination with onboard CCS. For some of the sensitivity scenarios with high use of onboard CCS, the cost intensities and total cost increase, and are even higher than in the scenarios where onboard CCS is not an option. This indicates a certain lock-in effect where ships choose onboard CCS initially because it has a lower cost than other options. Over time, as the price of other low GHG emission fuels such as e-ammonia reduces, onboard CCS is not the most optimal solution in a total cost perspective. However, ships that have installed this solution remain committed to it, meaning that the capital cost of changing solution is too high.

The scenarios analysed here include constraints on feedstock supply with the bio- and blue fuel prices adjusted to be on a par with those of e-fuels. This results in a diverse fuel mix where e-fuels and onboard CCS appear to be the two most prevalent decarbonization solutions across all policy scenarios. However, biofuels also have a significant contribution toward 2040 and 2050. It should be noted that this fuel mix is to a large degree a result of the supply constraints on bio- and blue fuel feedstocks, and also the lack of constraints on e-fuels and carbon storage capacity.

In 2030, the uptake of low GHG emission fuels is between 0.3 and 2.0 EJ in the *Base* trajectory scenarios, and 1.5 to 2.9 EJ in the *Strive* trajectory scenarios. The lowest uptakes are seen in *Base* trajectory scenarios with high reduction in energy use (scenarios with 150–300 USD/tCO_2eq levy) or high uptake of onboard CCS (TtW scenarios and scenarios with a GFI flexibility mechanism). In most scenarios, except those with high reduction in energy use, the total feedstock supply and carbon storage capacity exceed the median estimated projections in the literature.

To achieve the GHG emission trajectories under the assumed constraints, all available fuel feedstocks would need to be used, complemented by onboard CCS and reduction in energy use by uptake of energy-efficiency measures and speed reductions.

Impact of policy combinations

Well-to-wake and tank-to-wake GHG emissions scope

There are only small differences between the cost intensities in the well-to-wake and tank-to-wake scenarios because they follow the same GHG emission trajectory taking into account WtW GHG emissions, The WtW scenarios combined with a levy have a slightly higher cost, as the absolute cost of the levy is higher in WtW scenarios due to the levy also covering WtT GHG emissions. This also causes a slightly higher reduction in speed and energy use in the WtW scenarios compared to the TtW scenarios.

Levy and feebate mechanisms

Figure 3 shows the range of changes in cost intensity in 2030, 2040, and 2050, and the total cost per tonne of GHG reduced for the period 2023–2050 relative to business-as-usual across the policy combinations having a levy or feebate mechanism and scenarios without such mechanisms.

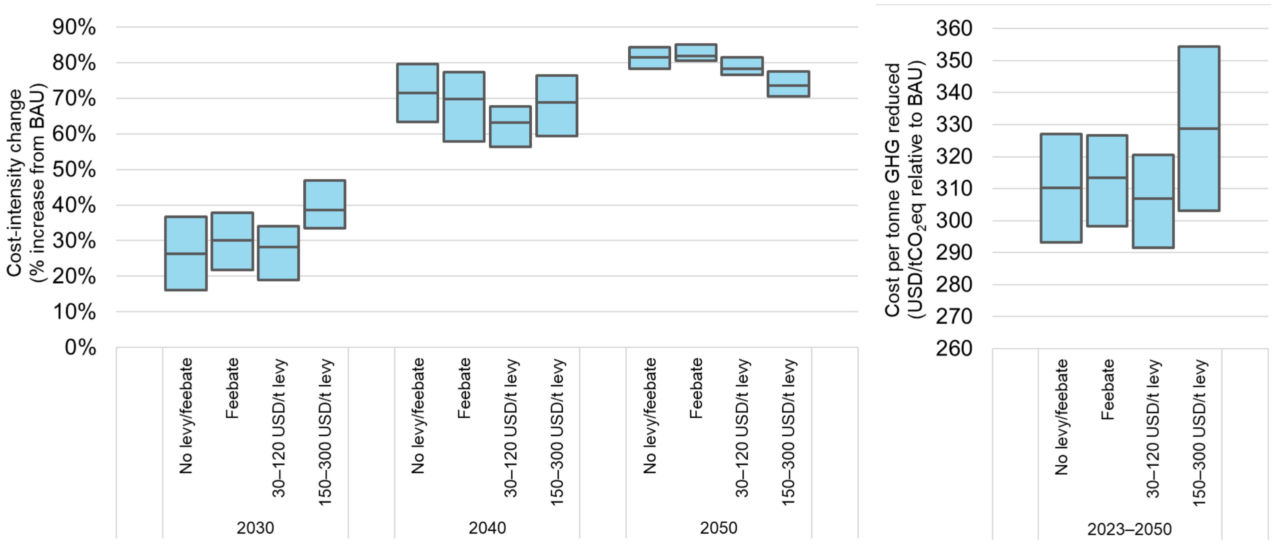

Figure 3 Range of cost-intensity increases in 2030, 2040, and 2050 (left panel), and total cost per tonne of GHG reduced in the period 2023–2050 (right panel) and relative to business-as-usual (BAU) for each levy/feebate mechanism, and without a levy/feebate mechanism.

It should be noted that the feebate scenarios result in a fee of 40 to 56 USD/tCO_2eq in 2030, increasing to 72 to 144 USD/tCO_2eq in 2040. The fee is generally lower than the levy in the scenarios with a 30–120 USD/tCO_2eq levy.

Scenarios with a 150–300 USD/tCO_2eq levy have a significantly higher cost intensity in 2030 with a 33% to 47% increase compared to 16% to 38% for the other scenarios. In 2040, scenarios with a levy of 30–120 USD/tCO_2eq have the lowest cost-intensity increase of 56% to 68% compared to 58% to 80% for the other scenarios. In 2050, scenarios with a levy have a lower cost intensity increase of 71% to 81% while the feebate scenarios and scenarios without any levy or feebate mechanism see an increase of 78% to 85%. Overall, the 303 to 354 USD/tCO_2eq cost per tonne of GHG reduced is higher for the scenarios with a 150–300 USD/tCO_2eq levy, while the other scenarios have a cost of 292 to 327 USD/tCO_2eq reduced.

If only considering the abatement costs and not the costs and rewards from the economic elements (i.e. the cost of the levy and Remedial Units, and the income from the reward and sale of Surplus Units), the cost-intensity increase in 2030 in scenarios with a 150–300 USD/tCO_2eq levy following the *Base* GHG emission trajectory would be only 1% to 9%. This is due to the lower energy use and consequently lower requirement for uptake of low GHG emission fuels. In the scenarios with a 150–300 USD/tCO_2eq levy following the *Strive* GHG emission trajectory, the abatement cost in 2030 is higher due to the greater uptake of low GHG emission fuels, which again leads to a lower cost of the levy and a higher reward for eligible fuels. It should be noted that the effect of the economic elements is necessary in the modelling to achieve the reduced abatement costs, but it illustrates the potential for lower abatement costs through reduced energy use.

Figure 4 shows the range of reductions in speed and energy use, and in the use of ammonia, methanol, methane/LNG and onboard CCS across the policy combinations having a levy or feebate mechanism and scenarios without such mechanisms, in the period 2023–2050.

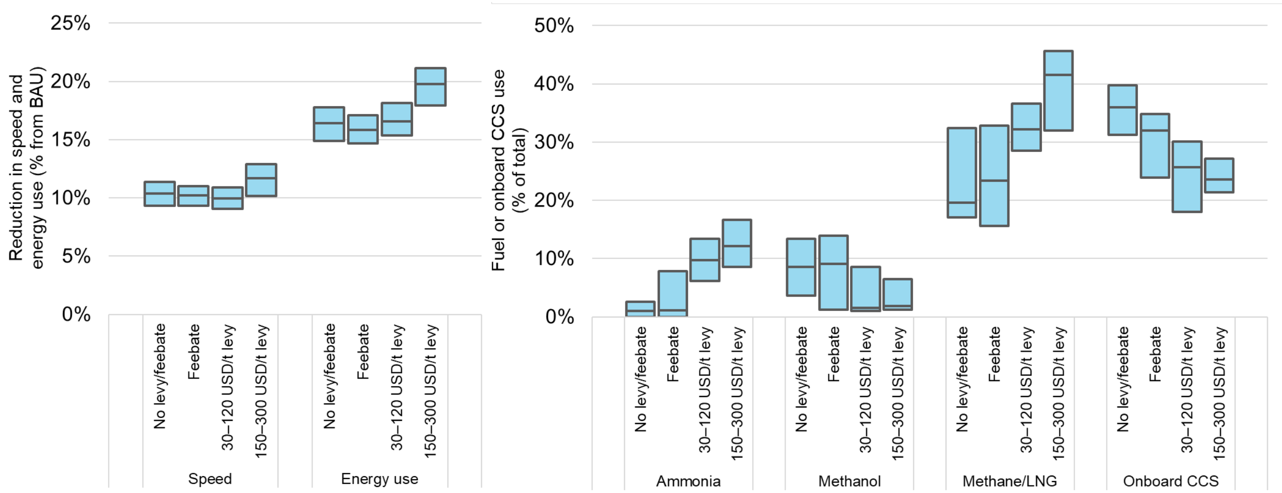

Figure 4: Range of reduction in speed and energy use relative to BAU (left panel); range of fuel use relative to total energy use, and of onboard CCS use relative to GHG emission reduction (right panel) – all charts for the period 2023–2050 for each levy/feebate mechanism, and without a levy/feebate mechanism.

The feebate and 30–120 USD/tCO_2eq levy mechanism have little impact on the speed and energy use compared to the scenarios without such mechanisms, and all result in a 9% to 11% speed reduction and 15% to 18% less energy use. The scenarios with a 150–300 USD/tCO_2eq levy show a higher speed reduction of 10% to 13% and energy use reduction of 18% to 21%. The primary reason for this is the implementation of speed reductions as soon as the levy is introduced. The lower energy use reduces the need for low GHG emission fuels to reach the GHG trajectory in 2030. Towards 2040 and 2050, and in the *Strive* trajectory scenarios in 2030, the effect of the levy and feebate mechanism on energy use is less pronounced. As the GHG trajectories become more stringent, the energy use is reduced in all scenarios regardless of policy combination. The cost impact of the levy is also reduced with lower GHG emissions.

The reward for eligible fuels in the levy and feebate scenarios incentivizes uptake of e-fuels. Together with bio-LNG, e-ammonia and e-LNG seem to be the fuels with the highest uptake in scenarios with a levy in combination with a reward mechanism. The use of ammonia, regardless of feedstock, is between 6% to 17% of total energy use, while the use of methane/LNG is between 29% to 46% in the levy scenarios. The use of onboard CCS is also much lower in these scenarios, providing 18% to 30% of the GHG emission reduction compared with 31% to 40% when there is no levy or feebate mechanism. The reason is likely to be that, unlike other carbon-based biofuels and e-fuels, e-ammonia cannot be combined with onboard CCS. In scenarios with a feebate mechanism, the use of ammonia and methane/LNG is lower, while the use of methanol is up to 14%. The use of onboard CCS is between 24% and 35%.

Regardless of the mechanism, the uptake of the various fuel types is very sensitive to relatively small changes in the levy and reward levels. The reward rate relative to the cost gap would need to be set precisely to give the necessary incentive for uptake of eligible fuels. If it is set too low, no eligible fuels are taken up. If it is set too high, the uptake exceeds what is available for rewards.

GHG Fuel Intensity flexibility mechanism

Scenarios with a GFI flexibility mechanism have on average about 4% lower cost intensity in 2030 compared to scenarios without the flexibility mechanism. In 2040 and 2050, the effect of the flexibility mechanism is less, with about 1% lower cost intensity on average. The aggregated impact is about a 6% lower cost per tonne of GHG reduced compared with the scenarios without the flexibility mechanism.

The reason for the lower cost is that with the flexibility mechanism, initially, relatively few ships can install, for example, ammonia or methanol fuel technologies, or onboard carbon capture, and run fully on fuels with lower cost (e.g. e-methanol has lower costs than e-MGO), instead of all ships having to reduce GHG intensity individually by going for more expensive drop-in fuels such as bio- and e-MGO.

Towards 2040 and 2050, the effect of the flexibility mechanism is reduced because with more stringent requirements, each ship must reduce its own emissions further before being able to contribute emission units to other ships. The impact of the flexibility mechanism on energy efficiency and speed reduction is small.

The flexibility mechanism may also be beneficial during the build-up of production and infrastructure for alternative fuels when such fuels have limited global availability. Ships that cannot find adequate fuels may exchange emission units (i.e. join in a compliance pool) with ships trading in areas where low GHG emission fuels are more readily available. This effect has not been quantified in the modelling.

Revenue streams and disbursements

Figure 5 shows the range of average annual revenues from the levy/feebate mechanism and from sale of Remedial Units (RU) under the GFI flexibility mechanism in the three periods 2027–2030, 2031–2040, and 2041–2050.

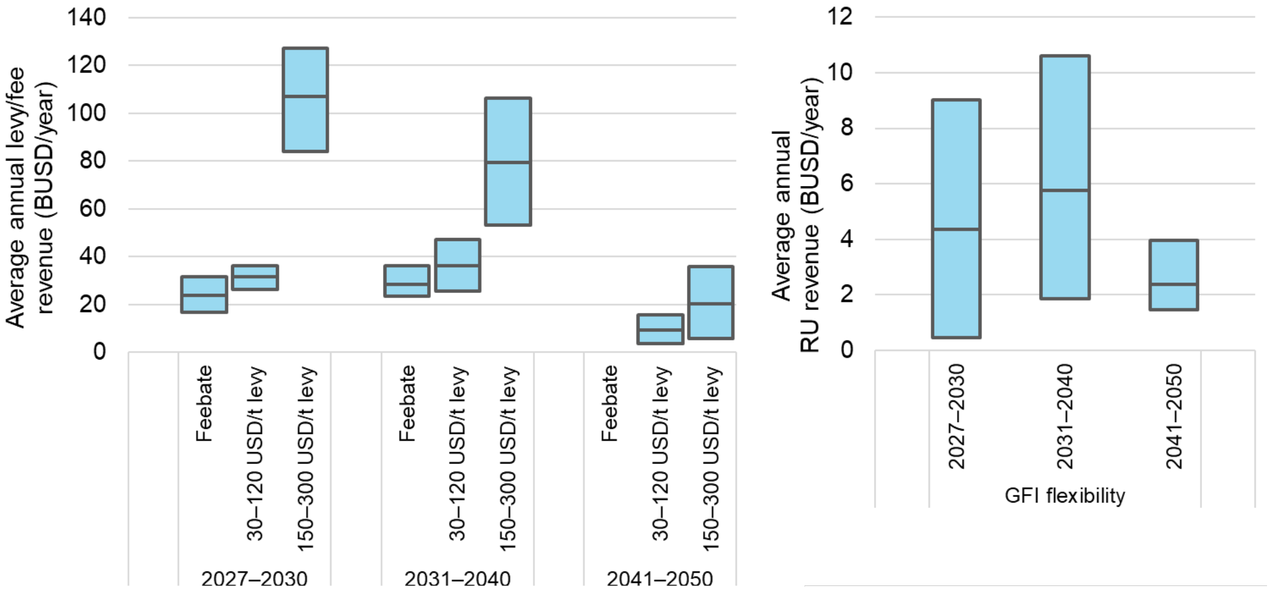

Figure 5: Range of average annual revenues (billion USD) from the levy/feebate mechanism (left panel) and sale of Remedial Units (RU) under the GHG Fuel Intensity (GFI) flexibility mechanism (right panel) in the periods 2027–2030, 2031–2040, and 2041–2050; note the difference in the scale of the y-axis between the two panels.

A levy of 150–300 USD/tCO_2eq results in an average annual revenue stream of 84 to 127 BUSD/year in the period 2027–2030, decreasing to 53 to 106 BUSD/year in 2031–2040, and to 6 to 36 BUSD/year in 2041–2050.

A levy of 30–120 USD/tCO_2eq creates an average annual revenue stream of 26 to 36 BUSD/year in the period 2027–2030, increasing to 25 to 47 BUSD/year in 2031–2040, and then decreasing to 3 to 16 BUSD/year in 2041–2050.

The feebate mechanism creates an average annual revenue stream of 17 to 32 BUSD/year in the period 2027–2030, increasing to 23 to 36 BUSD/year in 2031–2040 before it is stopped from 2041 onwards.

The GFI flexibility mechanism could also raise revenues through sale of Remedial Units to ships. We have applied a simplified method for estimating the potential revenue where sale of Remedial Units results in an average annual revenue stream of 0.5 to 9 BUSD/year in the period 2027–2030, increasing to 2 to 11 BUSD/year in 2031–2040 and then decreasing to 2 to 4 BUSD/year in 2041–2050.

Figure 6 shows the range of average annual disbursements for reward for eligible fuels and for purchase of Surplus Units under the GFI flexibility mechanism (D4 category), and for other disbursement categories (D2–D3 and D5–D7) in the periods 2027–2030, 2031–2040 and 2041–2050. Note that disbursement for RD&D (D1) is set to zero as further explained in Section 6.4 Impact of research and development.

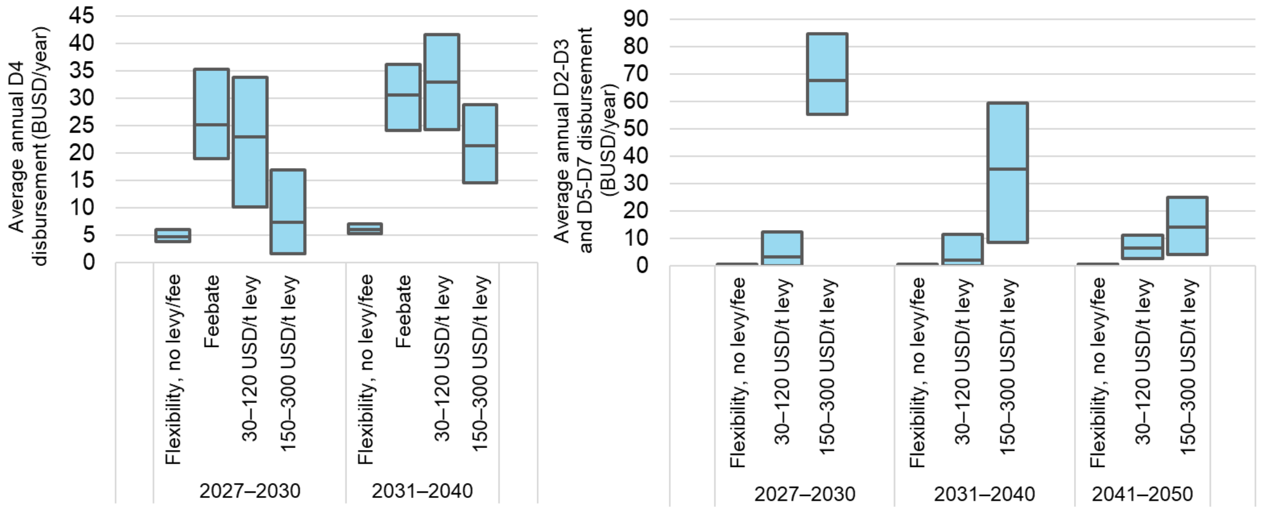

Figure 6: Range of average annual disbursement for reward for eligible fuels and for purchase of Surplus Units under the GFI flexibility mechanism (D4) (left panel), and other disbursements (D2–D3 and D5–D7) (right panel) for groups of scenarios in the periods 2027–2030, 2031–2040, and 2041–2050.

The D4 disbursement for eligible fuels and Surplus Units is lower in the scenarios with a 150–300 USD/tCO_2eq levy at 2 to 17 BUSD/year in 2027–2030 and 15 to 29 BUSD/year in 2031–2040, compared to scenarios with a feebate mechanism or a 30–120 USD/tCO_2eq levy which see disbursement of 10 to 35 BUSD/year in 2027–2030 and 24 to 42 BUSD/year in 2031–2040. The disbursement for Surplus Units in scenarios without a levy or feebate is 4 to 6 BUSD/year in 2027–2030 and increasing to 5 to 7 BUSD/year in 2031–2040.

The reason for the lower D4 disbursement is that the reward is set to a lower percentage of the cost gap between the lowest cost e-fuel (e-ammonia) and lowest cost biofuel (bio-LNG). Otherwise, in combination with the high levy, the cost gap between fossil fuels and bio- and e-fuels would be more than covered, leading to an accelerated uptake of low GHG emission fuels and GHG emissions beyond the trajectory and likely beyond the capacity to produce such fuels.

The amount available for other disbursements (D2–D3 and D5–D7) are significantly higher in scenarios with a 150–300 USD/tCO_2eq levy at 55 to 85 BUSD/year initially in 2027–2030, then decreasing to 9 to 59 BUSD/year in 2031–2040 and 4 to 25 in 2041–2050. The scenarios with 30–120 USD/tCO_2eq levy see a disbursement from 0 to 12 BUSD/year across all periods.

The disbursement from scenarios with only a GFI flexibility mechanism is in the range 0.1 to 0.2 BUSD/year. For the feebate scenarios, the revenues raised equal the rewards for eligible fuels exactly and there are no other disbursements in these scenarios except if combined with the flexibility mechanism.

Other impacts

Number of newbuilds and retrofits

The scenarios see a peak of around 1,700 and 3,100 annual newbuilds, with the highest peak seen in scenarios with large speed reductions to compensate for lost transport work. The average number of newbuilds delivered from 2002 to 2022 was 2,053 vessels per year, peaking at 3,965 ships in 2010, indicating that the number of newbuilds required in the scenarios should be within the capacity of the yards, given time to scale up the production.

The retrofitting of fuel technologies and onboard CCS peaks between 2,000 and 3,600 ships per year, while retrofitting to energy-efficiency packages peaks between 400 and 1,900 ships per year. The peak annual number of retrofits to other fuel technologies or onboard CCS, and to some degree energy-efficiency measures, are significant. Due to the complexity of retrofitting ships to these technologies it remains uncertain if these numbers are feasible for the yards and equipment manufacturers to deliver. The implication if these retrofit rates are not feasible is that more ships have to run on more expensive drop-in fuels such as bio-MGO and e-MGO.

Impact of research and development

It has not been possible based on a literature review to determine an explicit link between a certain magnitude of spending for R&D and the effect it would have on technology maturity and costs, and consequently to quantify the effect it would have on the cost intensity of the fleet. Given this knowledge gap, to maintain comparability between the scenarios which will raise very different amount of revenues, we have set the D1 disbursement to zero for the purposes of this modelling; and, all revenues beyond those required for D4 are allocated to the other disbursements categories (D2–D3 and D5–D7) which are taken into account in the modelling by UNCTAD.

To provide an indication of the potential cost savings that can be achieved with increased R&D spending, we have instead run sensitivity scenarios where we made assumptions about certain conditions, such as accelerated technology development and learning effects, that are achieved through R&D funding.

The sensitivity scenarios indicate that if the R&D spending results in two to three years' earlier availability of technologies and 20% reduced capital costs, the cost per tonne of GHG reduced can reduce by 4%. This amounts to about 200 BUSD saved over the whole period 2023–2050. It has not been possible to ascertain the magnitude of spending required to achieve the effect assumed in the sensitivity scenarios.

Carbon intensity and uptake of zero or near-zero GHG emission technologies, fuels, and/or energy sources in 2030

The ambitions related to carbon intensity and the uptake of zero or near-zero GHG emission technologies, fuels, and/or energy sources in 2030 are not included as mandatory targets and may not be reached in the modelled scenarios. The majority of scenarios achieve both 40% carbon intensity reduction and the 5%, striving for 10%, uptake of zero or near-zero GHG emission technologies, fuels, and/or energy sources. Scenarios 46 to 48, each with a 150–300 USD/tCO_2eq levy, have a high reduction in energy use and do not need to meet the 5% uptake ambition in order to reduce GHG emissions to below the trajectory. Scenarios 43 and 44, which include a GFI flexibility mechanism and no levy or feebate, have a high uptake of onboard CCS in 2030 and are very close to or do not meet the carbon intensity reduction ambition.

Uncertainties

Although the inputs and assumptions are within likely ranges as provided in literature and by the stakeholder feedback, there are significant uncertainties when modelling the fleet emissions and impact of policy measures 27 years into the future. The main uncertainties which could have a significant impact on the results are future fuel prices; availability of low GHG emission fuel feedstocks and carbon storage capacity; uptake of energy-efficiency measures; seaborne trade growth; cost and availability of onboard CCS; and yard retrofit capacities.

The results from one specific scenario should not be considered a most likely outcome, as the inputs and assumptions provide only a snapshot of one possible future. As each scenario is given equal weight, the set of scenarios cannot be used to establish a likelihood distribution of the impacts.

The 88 scenarios run during the course of the study give a good basis for assessing the impact of various policy combinations through analysing the differences between groups of scenarios. Although, the sensitivity analysis has not investigated the full expected range of all inputs and assumptions, it covers a likely range of fuel prices identified as the most sensitive input parameter.

The results of the sensitivity scenarios provide a likely range of impact for some key indicators such as total cost, cost intensity, and energy use. For other indicators, such as the uptake of certain fuels and technologies, the sensitivity analysis has shown that small changes in inputs on fuel prices and policy combinations such as the levy and reward levels can give very different outputs. Also, the potential constraints of feedstock supply and carbon storage capacity indicate that the results are less robust on the energy mix and uptake of onboard CCS.

NOMENCLATURE

AIS	Automatic Identification System
BAU	Business as usual
BUSD	Billion US dollars
CAPEX	Capital expenditure
CCS	Carbon capture and storage
CII	Carbon Intensity Indicator
CO_2eq	CO_2-equivalent
DWT	Deadweight tonnage
EE	Energy efficiency
EEDI	Energy Efficiency Design Index
EEOI	Energy Efficiency Operational Indicator
EEXI	Energy Efficiency Existing Ships Index
EJ	Exajoule. 1 EJ = 23.88 million tonnes oil-equivalents
EU/EEA	European Union / European Economic Area
FPSO	Floating Production, Storage and Offloading
FSU	Floating Storage Unit
GFI	GHG Fuel Intensity
GHG	Greenhouse gas
GT	Gross Tonnage
IMO	International Maritime Organization
LH_2	Liquid hydrogen
LHV	Lower Heating Value
MEPC	Marine Environment Protection Committee
MUSD	Million US dollars
NPV	Net present value
OPEX	Operational expenditure
PP	Percentage points
RD&D	Research, development and deployment
RU	Remedial Units
SEEMP	Ship Energy Efficiency Management Plan
SR	Speed reduction
SU	Surplus Units
TtW	Tank-to-wake
UNCTAD	United Nations Conference on Trade and Development
WMU	World Maritime University
WtT	Well-to-tank
WtW	Well-to-wake

1 INTRODUCTION

Following the request from the Marine Environment Protection Committee (MEPC) at its 80th session, the International Maritime Organization (IMO) has initiated a comprehensive impact assessment of the basket of candidate mid-term GHG reduction measures and established a Steering Committee to act as a focal point for the MEPC during the conduct of the study. The comprehensive impact assessment will inform IMO's further development of the basket of mid-term measures to be adopted in 2025. The comprehensive impact assessment consists of five tasks, and DNV has been commissioned by the IMO to conduct *Task 2: Assessment of impacts of the basket of candidate mid-term measures on the fleet*. This is the final report of Task 2.

Whilst this report has been commissioned by the IMO, the information contained within this report represents the view of its authors only. It should not be interpreted as representing the views of the IMO, the members of the Steering Committee for the comprehensive impact assessment, or the States that are represented on the Steering Committee. Task 2 of the comprehensive impact assessment is being undertaken solely to assist the members of the IMO's Marine Environment Protection Committee (MEPC) in making evidence-based decisions. The policy combination scenarios and any other information included in this report are provided solely for analytical purposes and should not be interpreted as suggestions or recommendations for how the basket of mid-term GHG reduction measures should be designed.

1.1 Goal and approach

The overall goal of this study is to assess the impacts on the fleet of the basket of candidate measures designed to achieve the GHG reduction goals set out in the 2023 IMO GHG Strategy (hereafter called IMO GHG Strategy).[2]

The study defines two well-to-wake (WtW) GHG emission trajectories to 2050, named as *Base* and *Strive* in this report[3], according to the indicative checkpoints and the level of ambition to reach net-zero GHG emissions by or around, i.e. close to, 2050 of the IMO GHG Strategy, and taking into account WtW GHG emissions. We apply a scenario-based framework to model the effect of various policy combinations, and assess impacts on the fleet. See Chapter 4 for a description of the scenarios.

The policy combination scenarios are compared with a business-as-usual (BAU) scenario to estimate the possible impact of the proposed candidate policy measures. The impacts on the fleet have been assessed in three target years: 2030, 2040, and 2050 with regard to:

- GHG emission trajectories
- Change in cost intensity relative to a BAU scenario
- Energy use and fuel mix, including comparison with expected fuel feedstock supply and carbon storage capacity
- Revenue streams from economic elements
- Other impacts such as feedstock supply and carbon storage capacity, and number of newbuilds and retrofits compared with expected yard capacity.

The methods, inputs and assumptions in this study draw on a wide range of previous DNV work and resources, literature review, industry input and external data sources, relevant for modelling the impact of the basket candidate measures on the fleet:

- The GHG Pathway model, a cost-based modelling tool for developing scenarios for decarbonization of shipping towards 2050 and beyond. The model simulates the fleet on an individual ship level year-by-year to evaluate

[2] Resolution MEPC.377(80): 2023 IMO Strategy on Reduction of GHG Emissions from Ships.

[3] The use of the terms *'Base'* and *'Strive'* is simply a naming convention being used for the purposes of this report.

the effect of the proposed candidate measures, including with the option of pooling compliance across a fleet of ships.

- The MASTER (Mapping of Ship Tracks, Emissions and Reduction potentials) model, which uses global ship-tracking data from the Automatic Identification System (AIS), enriched with ship-specific data from other databases, to model baseline fuel consumption and emissions from individual ships and fleets.
- State-of-the-art databases maintained by DNV, covering technical and operational energy-efficiency measures, fuel and onboard carbon capture and storage (CCS) technologies, alternative fuels projects and infrastructure (afi.dnv.com). and prices for fuels and technologies.
- External databases with ship data (IHS, Clarkson), global ship traffic data (AIS), ocean and atmospheric data, and well-established models and tools for efficient data processing and visualization.

Throughout this report, we refer to and use the same methods and assumptions as described in the following reports:

- Comprehensive impact assessment of the basket of candidate mid-term GHG reduction measures – Task 2: Assessment of impacts on the fleet: Inception report – draft methods and inputs (DNV, 2024a).
- Comprehensive impact assessment of the basket of candidate mid-term GHG reduction measures – Task 2: Assessment of impacts on the fleet: Interim report – preliminary results (DNV, 2024b).
- Comprehensive impact assessment of the basket of candidate mid-term GHG reduction measures – Task 2: Assessment of impacts on the fleet: Second interim report – preliminary results (DNV, 2024c).
- Study on the readiness and availability of low- and zero-carbon ship technology and marine fuels (Ricardo & DNV, 2023).
- Assessment of the impact on the fleet of short-term GHG measures in MEPC 76/INF.68/Add.1 (Longva & Sekkesæter, 2021).
- Fourth IMO GHG study 2020 in MEPC 75/7/15 (Faber, et al., 2020).

DNV's Management process has been applied to ensure quality assurance and control, which is described in Appendix F.

1.2 Scope and key assumptions

The following Sections contain descriptions of the scope and key assumptions used in this study. Further details on the inputs and assumptions can be found in Appendix B.

1.2.1 Candidate mid-term GHG reduction measures

The candidate mid-term GHG reduction measures (hereafter called policy measures) assessed in this study are:

- A GHG Fuel Intensity (GFI) requirement
- A GFI flexibility mechanism
- A levy mechanism
- A feebate mechanism.

The policy measures in this study have been described and defined (see Chapter 3) including necessary adaptations for the purpose of the modelling and analysis which requires specific inputs and definitions. Some proposed features have not been modelled, while others have had to be assumed or simplified. The descriptions should not be interpreted as suggestions or recommendations for how the policy measures should be designed, and the results should be regarded with these assumptions and simplifications in mind.

1.2.2 GHG emission trajectories

The study defines two well-to-wake GHG emission trajectories to 2050, named as *Base* and *Strive* in this report, according to the indicative checkpoints and the IMO GHG Strategy's ambition to reach net-zero GHG emissions by or around, i.e. close to, 2050, and taking into account WtW GHG emissions. The *Base* trajectory reflects the lower ends of the indicative checkpoints, namely to reduce the total annual GHG emissions from international shipping by 'at least' 20% by 2030 and by 'at least' 70% by 2040, compared to 2008. The *Strive* trajectory reflects the upper ends of the indicative checkpoints, namely 'striving for' reductions of 30% by 2030 and 80% by 2040, compared to 2008. 16 policy combinations (basket of measures) have been modelled for each trajectory for a total of 32 policy combination scenarios which are compared to a business-as-usual scenario with currently adopted policy measures.

The proposed policy measures address WtW GHG emissions or tank-to-wake (TtW) GHG emissions with sustainability criteria. However, for the purposes of the modelling, this study defines the GHG emission trajectories in a WtW scope which,should be followed regardless of the scope of the policy measures, in order to make the scenarios comparable.

The ambitions related to the carbon intensity and the uptake of zero or near-zero GHG emission technologies, fuels, and/or energy sources in 2030 are, for the purposes for the modelling in this study, not included as mandatory targets and may not be reached in the modelled scenarios.

As we expect that there will be some methane (CH_4) and nitrous oxide (N_2O) emissions from combustion engines in 2050 regardless of the fuel – because current technology and know-how cannot eliminate such emissions – we allow for a small amount (< 2 gCO_2eq/MJ) of GHG emissions in 2050. It should be noted that TtW CO_2 emissions in the modelling may be negative due to onboard CCS (see Section 1.2.7 for assumptions regarding onboard CCS).

1.2.3 Ship type and size scope

For the purposes of enabling the modelling in this study, we assume that all of these new policy measures will be implemented with a similar scope as Chapter 4 of MARPOL Annex VI (Regulation 19.1 and 19.2), though some measures can have further limitations on ship type and size. This study will assess the impact on ships within the same scope, which includes ships above 400 GT – except those solely trading domestically and ships not propelled by mechanical means, and platforms including FPSOs and FSUs and drilling rigs, regardless of their propulsion.

1.2.4 Greenhouse gases scope

The GHG emissions in this study include carbon dioxide (CO_2), nitrous oxide (N_2O), and methane (CH_4), and are calculated as CO_2-equivalents (CO_2eq) using the Global Warming Potential (GWP) over a 100-year horizon (GWP100), The GWP values[4] used in this study are 28 for CH_4 and 265 for N_2O based on the IPCC's Fifth Assessment Report (IPCC, 2014), which are also used in the IMO life cycle assessment (LCA) guidelines[5].

[4] The GWP values are unitless values indicating the equivalent global warming potential of a unit of GHG relative to a unit of CO_2 over the given time horizon.
[5] Resolution MEPC.391(81): 2024 Guidelines on life cycle GHG intensity of marine fuels (LCA Guidelines).

1.2.5 Fuels and fuel costs

For the purpose of the modelling in this study, we broadly categorize fuels according to fuel type (i.e. molecules such as methanol and ammonia, or electricity) and feedstock category: fossil fuels, biofuels, e-fuels (from renewable electricity), and blue fuels (reformed fossil natural gas with CCS).

The fuel bunkering costs are derived as follows:

- 2023: where available, we use reported average price of fuels and feedstocks in 2023. When reported average price is unavailable, we use estimated bunkering cost from a review of literature sources.
- 2030, 2040, and 2050: for non-fossil fuels we use projected bunkering cost estimates from a review of literature sources. Projected fossil fuel bunkering costs are based on historical price relationships with crude oil or natural gas.

To ensure internal consistency between fuel types in the fuel bunkering cost projections, we only use selected sources that cover a wide range of different fuel-types within a given feedstock category (e.g. e-fuels). The detailed method and sources used can be found in Appendix B.7.1.

The fuel bunkering costs used in this study are shown in Table 1-1.

Table 1-1 Fuel bunkering cost trajectories by year, in USD/GJ.

Fuel-type	Fuel cost (USD/GJ)			
	2023	2030	2040	2050
HFO	12.1*	10.5	9.5	8.5
VLSFO/MGO	15.9*	14.4	13.1	11.7
LNG	15.9*	10.3	10.2	10.1
LPG	10.6*	11.7	10.6	9.5
Fossil hydrogen (liquefied)	30.0	22.6	23.0	23.7
Fossil ammonia	29.3*	20.7	20.4	20.1
Fossil methanol	16.2*	11.9	11.7	11.5
Blue hydrogen (liquefied)	37.0	32.6	32.0	32.2
Blue ammonia	36.0	29.9	28.4	27.3
bio-LNG	24.1	26.5	30.2	34.3
bio-MGO	28.2*	30.9	35.1	39.6
bio-methanol	59.6*	30.8	34.2	38.6
e-hydrogen (liquefied)	56.4	50.8	44.1	36.8
e-LNG	65.1	58.0	50.5	42.6
e-methanol	72.4	61.2	53.3	45.0
e-ammonia	55.0	46.5	39.1	31.2
e-MGO	91.7	80.7	70.6	59.3
Electricity (from shore)	26.7	24.6	22.0	18.3

* Based on reported average price in 2023

Key: Biofuel (bio-); electrofuel (e-); fossil fuel with CCS (blue); heavy fuel oil (HFO); liquefied petroleum gas (LPG); liquefied natural gas (LNG); marine gas oil (MGO); very low sulphur fuel oil (VLSFO);

It should be noted that the fuel costs in 2023 are based on actual prices while from 2030 they are based on projections. For the intermediate years, the prices are interpolated. In several instances, such as for bio-methanol, the fuel costs decrease sharply from 2023 to 2030. The current market for these fuels is limited and the prices reflect limited availability and low volumes. Scenarios 1 to 18 uses the fuel costs as given in Table 1-1. For scenarios 21 to 56, we assume that the total demand for low-emission fuels exceeds the supply for bio- and blue fuel feedstocks and we adjust the fuel prices of all the fuel types made from those feedstocks to the equivalent cost, in terms of energy and emissions, of the e-fuel of the same type.

The equivalent price will take into account the difference in emissions and any rewards and levy. For example, if the bio-LNG emissions are lower than the e-LNG emissions, the equivalent price for bio-LNG will be higher as less of that fuel is required to reach the same GFI requirement, and the levy incurred is lower. The bio- and blue fuel prices are never adjusted below the projected costs shown in Table 1-1.

As an example, the fuel price for bio-LNG in 2030 is 26.5 USD/GJ while it has 8.3 gCO_2eq/MJ less WtW GHG emissions (see Section 1.2.6). In WtW scenarios without any reward for e-fuels (see Sections 3.3 and 3.5.1), the bio-LNG price is adjusted to the bunkering cost of e-LNG which is 58.0 USD/GJ and an additional 9%, which gives a price of 64 USD/GJ. The 9% is arrived at through dividing 8.3 by 91 gCO_2eq/MJ, which is the additional reduction provided by bio-LNG compared to fossil fuels – i.e. one would need 9% less bio-LNG compared to e-LNG to achieve the same attained GFI). In WtW scenarios with a 60 USD/tCO_2eq levy and a 21 USD/GJ reward for e-fuels in 2030, the resulting bio-LNG price is 40 USD/GJ, which is the e-LNG bunkering cost minus the reward (21 USD/GJ) plus the additional benefit from a lower levy cost (60 USD/tCO_2eq multiplied by 8.3 gCO_2eq/MJ, which is 0.5 USD/GJ).

The feedstock supply used as thresholds in this study are based on the median estimates available for shipping in Ricardo & DNV (2023). The numbers for 2030 are based on actual announced fuel production projects while the numbers for 2040 and 2050 are based on projections in the literature. The two methods may not provide a consistent development between 2030 and 2040, and we, for example, see a much higher biofuel availability than e-fuels in 2040 compared 2030. Table 1-2 shows the median estimates, with the BAU to high estimates in parentheses.

Table 1-2: Median of estimated feedstock supply and carbon storage capacity available for shipping in 2030, 2040, and 2050; the ranges in parentheses indicate the BAU to high estimates (Ricardo & DNV, 2023).

	2030	2040	2050
Biofuels (advanced)	0.4 EJ (0.1–0.4 EJ)	2.0 EJ (0.3–3.6 EJ)	3.2 EJ (0.5–7.0 EJ)
Blue fuels	0.1 EJ (0.0–0.2 EJ)	0.5 EJ (0.0–0.9 EJ)	1.3 EJ (0.0–2.3 EJ)
E-fuels	0.8 EJ (0.0–1.5 EJ)	1.1 EJ (0.1–1.9 EJ)	3.9 EJ (0.2–5.0 EJ)
Carbon storage capacity	13 $MtCO_2$ (0–26 $MtCO_2$)	158 $MtCO_2$ (0–238 $MtCO_2$)	300 $MtCO_2$ (0–420 $MtCO_2$)

We assume that the total uptake of bio- and blue fuels cannot exceed the total estimated availability limit of the same feedstock category. We do not include an upper limit on the amount of e-fuel supply or carbon storage capacity in the modelling. E-fuels are unconstrained as at least one fuel must be made available for the model to find a compliant solution for all ships. Onboard CCS is also unconstrained as this solution has no expected constraints on fuel feedstock availability (i.e. fossil), but it can experience constraints on storage capacity. However, we could not find a rationale for increasing the deposit costs to the equivalent e-fuel price as these are two very different markets. For this reason, we chose to leave availability of storage unconstrained and the deposit cost of onboard CCS as is, and to instead investigate the potential impact through sensitivity scenarios.

The uptake of both e-fuels and carbon storage demand will be compared with estimated supply/capacity in the analysis. It should be noted that other constraints such as technological maturity and retrofit capacity for any technology are not covered by this method but will be commented on in the analysis. Further, beyond the assumption on adjusting the fuel prices due to supply constraints, we assume that the availability of fuels and carbon storage are independent of the prices and policy measures.

1.2.6 Well-to-tank GHG emissions factors

The IMO LCA guidelines contain only default WtT GHG emission factors for three fossil fuel pathways. To ensure applying a consistent set of factors, we use the default WtT GHG emission factors provided in FuelEU Maritime for all fossil fuels.[6]

For non-fossil fuels, we make no assumptions on sustainability aspects or criteria which are currently only described in the IMO LCA guidelines. However, we only include non-fossil fuels that can significantly reduce the WtW GHG emissions below the upper bounds set by various fuel-emission standards, incentive schemes, and regulations, as described below.

For the WtT GHG emission factors for non-fossil fuels, we generally rely on the literature assessment by Ricardo & DNV (2023), supplemented by other reports for blue fuels. The upper bounds in this assessment were set on the expectation that future fuels for any sector will be produced (i.e. WtT GHG emissions) at minimum, according to certain standards and as a result of various incentive schemes and regulations.[7] The lower bounds were made based on what the literature review found.

We set the WtT GHG emission factors according to the mid-point of this range. For biofuels, we use the range provided for advanced biofuels, which excludes food and feed crops. Further, we assume that the upper bound decreases towards the lower bound in 2040 and also that biofuels can reach zero WtT GHG emissions in 2050. Blue fuels are, as stated in the Ricardo & DNV report, constrained by the emissions from extraction of fossil fuels as well as the carbon capture rate with a lower bound of 28 gCO_2eq/MJ for these fuels. However, other reports (MMMCZCS, 2024; LR and UMAS, 2020) suggest that blue fuel can reduce down to about 15 gCO_2eq/MJ, which we use as a lower bound for blue fuels in this study. For electricity, we assume that it is produced from renewable sources with zero WtT GHG emissions. According to the revised 2024 IMO LCA guidelines, this is now possible when the electricity is delivered through a power purchase agreement.[8] The WtT GHG emission factors by fuel type and feedstock category used in this study are given in Table 1-3.

Table 1-3: WtT GHG emission factors by fuel type and feedstock category used in this study; based on FuelEU Maritime (fossil fuels), MMMCZCS (2024), LR & UMAS (2020) and Ricardo & DNV (2023) for non-fossil fuels.

Feedstock category	Fuel type	WtT GHG emission factors (gCO_2eq/MJ)			
		2023	2030	2040	2050
Fossil	HFO	13.5	13.5	13.5	13.5
Fossil	VLSFO/MGO (based on MGO)	14.4	14.4	14.4	14.4
Fossil	LNG	18.5	18.5	18.5	18.5
Fossil	LPG	7.8	7.8	7.8	7.8
Fossil	Methanol	31.3	31.3	31.3	31.3
Fossil	Ammonia	121	121	121	121
Fossil	Hydrogen	132	132	132	132
Biofuel	MGO, methane and methanol	13.3	9.4	2	0
E-fuel	MGO, methane and methanol	29	17.1	0	0
E-fuel	Hydrogen and ammonia	20.5	12.1	0	0
Blue fuel	Hydrogen and ammonia	28	22.6	15	15
Electricity from renewable sources	Electricity	0	0	0	0

We recognize that there may be non-fossil fuels which fall outside the upper bounds as described above and could also fulfil future sustainability criteria. The assumptions in this study and resulting WtT emission factors in Table 1-3 should

[6] Regulation (EU) 2023/1805 of the European Parliament and of the Council of 13 September 2023 on the use of renewable and low-carbon fuels in maritime transport, and amending Directive 2009/16/EC. Note that FuelEU Maritime refers to the EU's Renewable Energy Directive (Directive (EU) 2018/2001) which uses GWP values from IPCC AR4 as opposed to AR5 used in IMO's LCA Guidelines.

[7] These include clean hydrogen under the US Inflation Reduction act, renewable fuels of non-biological origin under the EU Renewable Energy Directive, clean hydrogen according to the China Hydrogen Alliance, and clean and low-carbon hydrogen according to CertifHy.

[8] The 2024 Guidelines on life cycle GHG intensity of marine fuels (2024 LCA guidelines), adopted by Resolution MEPC.391(81), allows for use of PPA to certify actual GHG intensity for electricity (paragraph 10.6).

not be construed as, for example, e-fuels generally having higher WtT emissions than biofuels before 2040. Nor should it be construed that all e-fuels can be produced with zero WtT emissions from 2040, or that the blue fuels cannot reduce emissions beyond the lower bound. However, it is beyond the scope of this study to assess all possible fuels and fuel pathways that can contribute to achieving the GHG emission trajectories today and towards 2050.

1.2.7 Onboard carbon capture and storage (CCS)

Although the IMO has not yet decided how to include onboard CCS in its regulatory framework, we have included it in this study. We assume that the captured CO_2 is delivered to shore and permanently stored, but do not include any emissions from these activities. Further, we assume that stored CO_2 from biogenic sources or from direct air capture results in negative CO_2 emissions. The calculation of the GHG emissions takes into account the increased fuel consumption from the onboard capture and storage process, while deducting the captured and subsequently permanently stored CO_2. In order to have an equal comparison with other solutions, the GHG intensity is calculated relative to the energy used without the additional fuel consumption needed by the onboard carbon capture plant.

1.2.8 Definitions

The following definitions in Table 1-4 are used in this study:

Table 1-4: Definitions of terms used in this study.

Term	Definition
Biofuels	Fuels made from biomass.
Blue fuels	Fuels made from fossil feedstocks with carbon capture and storage of CO_2 emitted during production.
CO_2 equivalent emissions (CO_2eq) and Global Warming Potential (GWP)	CO_2 equivalent emission is the amount of CO_2 emission that would cause the same integrated radiative forcing or temperature change, over a given time horizon, as an emitted amount of a GHG or a mixture of GHGs. The CO_2 equivalent emission is obtained by multiplying the emission of a GHG by its global warming potential (GWP) over a certain time horizon. This study applies a 100-year horizon (GWP100).
Compliance balance	The difference in total GHG emission between attained and required GHG Fuel Intensity for a ship. A ship with attained GFI below required GFI has a positive compliance balance.
E-fuels	E-fuels or electrofuels are based on hydrogen produced by electrolysis primarily using renewable or nuclear electricity. These are sometimes referred to as renewable fuels of non-biological origin (RFNBO), green, or synthetic fuels depending on the electricity source. The hydrogen can be combined with biogenic carbon or carbon from direct air capture to produce carbon-based e-fuels (e.g. e-methanol).
Remedial Units (RU)	Emission units purchased by ships with negative compliance balance from the Revenue body at a set price under the GHG Fuel Intensity flexibility mechanism.
Surplus Units (SU)	Emission units sold by ships with positive compliance balance to the Revenue body at a set price under the GHG Fuel Intensity flexibility mechanism.

Term	Definition
Revenue body	Several candidate policy measures rely on a body to manage collection and distribution of revenues. The set-up of this body is yet to be determined and since it is not expected to have a material impact on the assessment in this study, it is generically referred to as the Revenue body in this report.

1.3 Content of this report

The structure of this report is given in Table 1-5 below:

Table 1-5: Report structure.

Chapter	Content
Chapter 2 Method	Description of overall methods used for modelling the impact of the basket of candidate measures on the shipping fleet. Detailed descriptions of methods, tools, and models are provided in Appendix A, while key inputs and assumptions are provided in Appendix B. A description of the Quality Assurance (QA) process is provided in Appendix F.
Chapter 3 Candidate measures	Description of the candidate mid-term GHG reduction measures assessed in this study.
Chapter 4 Scenarios	Description of the scenarios run during the study.
Chapter 5 Baseline GHG emissions and trajectories	Description of projected business-as-usual emissions and required emission trajectories based on the ambitions and indicative checkpoints in the IMO GHG Strategy.
Chapter 6 Impacts	Results of the scenario analysis with impacts of the candidate mid-term GHG reduction measures. Detailed results are provided in Appendix D while the GFI requirements and levy/reward inputs and resulting fee are provided in Appendix C.
Chapter 7 Sensitivity analysis and uncertainties	Analysis of the model sensitivities, a discussion of key uncertainties, and comparison with findings from World Maritime University's literature review. Detailed results from the sensitivity scenarios are provided in Appendix E along with a discussion of uncertainties.
Chapter 8 Conclusion	Concluding remarks.
Chapter 9 References	List of references used in the report.

2 METHOD

This chapter provides a high-level overview of the method used to assess the impacts on the fleet. For further details, we refer to Appendix A for a detailed description of the methods, tools, and models used, and Appendix B for details on inputs and assumptions. We include a description of the stakeholder review process and a summary of updates made on key inputs and assumptions. We then comment on the findings of a literature review by the World Maritime University. Finally, we provide a list of data gaps identified during the study.

2.1 General approach

When establishing long-term decarbonization pathways for shipping, there are significant uncertainties around many factors, including a range of policy options and combinations, which influence projected fuel and technology uptake and costs for the fleet. This study applies a scenario-based framework to explicitly reflect on these uncertainties and which can provide valuable insight into the impact of the proposed policy measures. A scenario describes a path of development under anticipated frame conditions, leading to a particular outcome. It is not intended to represent the full and 'most likely' description of the future, but instead intends to highlight central elements of a possible future and to draw attention to the key factors that will drive the future developments. Chapter 4 provides more details on the scenarios to be run in the study.

The high-level method and tools used for the study are illustrated in Figure 2-1, and consist of the following three steps:

1. *Baseline fleet for 2023 using the **MASTER model***: Global ship-tracking data from AIS, enriched with ship-specific data from other sources, is used to model baseline energy use and activity data from individual ships in scope of this study for the reference year 2023. The baseline fleet is used as input to the GHG Pathway model in step 2, serving as a starting point for the first simulation year.

2. *Fleet modelling from 2023 to 2050 using the **GHG Pathway model***: The future fleet is simulated on an individual ship level year-by-year to 2050. The model evaluates available GHG emission reduction solutions for newbuilds and existing ships, including alternative fuels, onboard carbon capture, energy-efficiency packages and speed reduction. Based on net present value (NPV) calculations, the ships are fitted with the lowest cost, feasible combination of measures that fulfil regulatory requirements imposed as input. The model keeps track of the costs of the ships as well as the revenue streams for the economic elements of the policy measures. Scenarios are developed and defined to investigate the costs and other impacts of the range of policy options and combinations, as well as uncertainty of other inputs. Datasets for each simulated scenario are generated for further analysis in step 3.

3. *Scenario analysis*: The scenario outputs from 2023 to 2050 are analysed with regard to the overall cost intensity levels, energy use, fuel mix, revenue streams and other effects of imposing various policy combinations and compared with business-as-usual scenarios. The uncertainties and sensitivities of key inputs are also analysed and discussed.

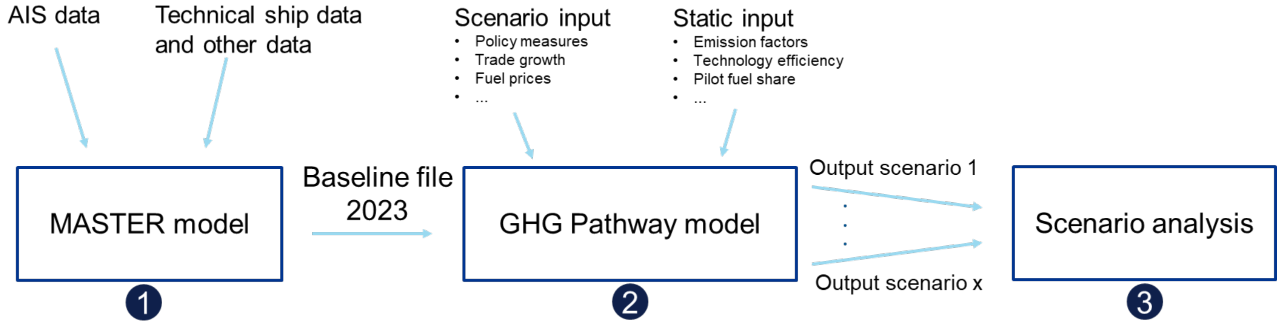

Figure 2-1: Illustration of the high-level approach for modelling the impact on the fleet of the basket of candidate mid-term GHG reduction measures from 2023 to 2050.

Steps 1 and 2 of the modelling approach, the MASTER model and GHG Pathway model, are further described in Appendix A. In the following, we describe step 3 with the main elements in the assessment of the scenario output from the GHG Pathway model.

2.2 Scenario analysis

The GHG Pathway model provides output for each scenario, which includes, for example, fleet activity and composition, fuel and energy-efficiency technology uptake, energy use, GHG emissions, and costs. The impacts on the fleet of implementing combinations of candidate policy measures (described in Chapter 3) and following two GHG emission trajectories will be assessed in three target years: 2030, 2040, and 2050, with regard to:

- Change in cost intensity and total cost per tonne of GHG reduced relative to a BAU scenario
- Energy use and fuel mix, including comparison with expected feedstock supply and carbon storage capacity
- Number of newbuilds and retrofits compared to expected industry capacity
- Revenue streams from economic elements.

The change in cost intensity is a key parameter in the assessment. The cost intensity is the total annual cost (see Appendix A.2.3 for a detailed description), including annualized capital costs, operational and fuel expenses, and regulatory incomes and expenses imposed by the policy measures, divided by the total transport work in a year. All costs in this report are given in real prices (2023 prices). The change is cost intensity for a target year is calculated relative to the cost intensity of the corresponding (i.e. same seaborne trade growth) BAU scenario in the target year. This is illustrated in Figure 2-2.

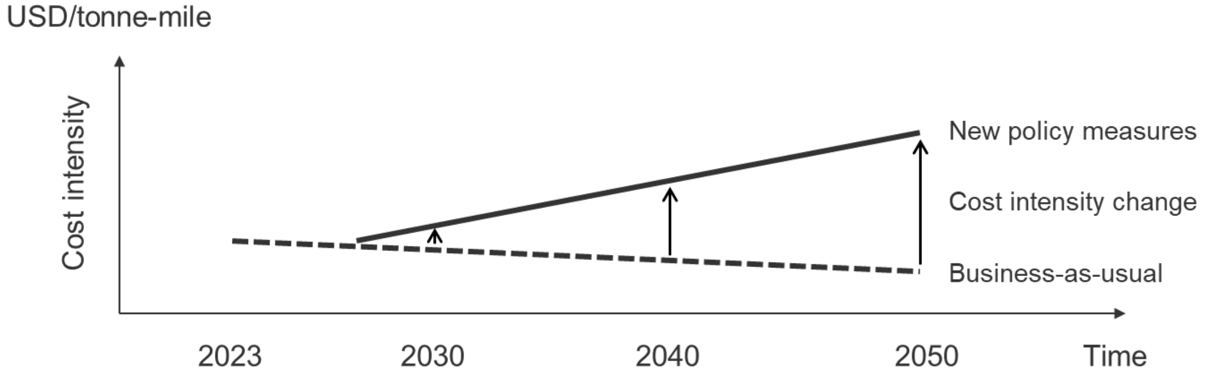

Figure 2-2: Illustration of the cost intensity metric used in this study.

The regulatory revenue streams for ships imposed by the economic elements of the policy measures will be provided in detail per target year. This includes expenses due to a levy, a fee or purchasing Remedial Units (RU), and income from rewards and selling Surplus Units (SU). We will also estimate the market price (as USD/tCO_2eq) for ships exchanging emission units in a flexibility mechanism allowing for compliance across a fleet of ships. This will be part of the cost for compliance of ships not choosing to implement reduction measures, as well as a reduction of costs for ships opting for measures going beyond compliance. See Chapter 3 for further description of the candidate measures and economic elements.

The revenue streams (in USD/year) collected from ships will be distributed according to agreed purposes as described in Section 3.5.3. The revenue streams and disbursements will be presented for each scenario. Revenues used for research, development and deployment (RD&D) purposes are not considered in the modelling of cost intensity in the fleet (see Section 3.5.3).

Each scenario is assessed on feasibility with regard to fuel availability and capacity to build and retrofit ships with new technologies at the pace required. Using the results from Ricardo & DNV (2023), the uptake of fuels in each scenario will be evaluated against the potential supply in the target years; as well as whether the fleet renewal and technology uptake require a ship repair (for retrofit) or ship build capacity (for newbuilds) beyond the expected capacity of the yard and equipment manufacturer industry.

2.3 Review of input data

The inputs and assumptions used in the modelling are described in Appendix B. The key input data needed for the modelling has been reviewed and updated since the inception report (DNV, 2024a). The input review has been conducted in consultation with the Steering Committee and included a virtual review workshop on 26 January 2024 with a geographically and technically representative group of stakeholders, as well as the literature review conducted by WMU as part of Task 1 of the Comprehensive Impact Assessment. Furthermore, areas of missing data affecting the impact assessment have been identified and analysed. This section describes the process and outcome of the review.

DNV greatly appreciates all the comments and suggestions made and would like to thank all the contributors.

2.3.1 Stakeholder review process

During the review process, stakeholders have been consulted using:

- Email exchanges allowing stakeholders to provide input in their own time.
- Two virtual workshop sessions allowing a large number of stakeholders to provide input at one time, and allowing questions to be asked about the context in which the data will be used.
- Bilateral discussions with stakeholders to support more complex discussions and include stakeholders reluctant to share information in a workshop.

First, DNV used its extensive global contacts across the maritime value chain to identify a geographically and technically representative review group. A list of proposed stakeholders was shared with the Steering Committee on 8 January 2024. Additional stakeholders were proposed by the Steering Committee to ensure a sufficiently representative review group from across the regions. The review group covers stakeholder categories such as shipowners and managers, fuel production and supply, technology providers, research institutes, finance, ship builders/yards, ports and government.

An invitation to participate in the review process was sent to the updated list of stakeholders on 12 January 2024. Documentation describing key aspects of DNV's inputs and assumptions for the fleet modelling was shared with the registered participants on 19 January 2024 (upon completion of the Inception report).

Two virtual stakeholder review workshops were held on 26 January 2024 to accommodate for different regions. Invitations to both workshop sessions were sent to all registered stakeholders but attendance was optional. Around 160 stakeholders from across the maritime value chain participated in the workshops. Before, during, and after the workshops, input from the stakeholders was collected through an online feedback form. The stakeholders also had the opportunity to provide input by email or meetings with the DNV project team.

The following key inputs and assumptions for the fleet modelling have been updated based on the feedback received.

Fuel prices and GHG emission factors

- The fuels assessed in this study are, in addition to fuel type, further split on general feedstock pathway (e.g. bio-LNG, e-LNG, or fossil LNG). Fuel costs and GHG emission factors are updated to reflect the revised categorization.

- Additional fuel types have been added to the study, including fossil liquefied hydrogen, fossil ammonia, fossil methanol and blue liquefied hydrogen.
- To ensure internal consistency in applied fuel costs for this study, we only use selected recent industry and literature sources. These sources have transparent input assumptions across fuel types within a feedstock pathway, providing consistent input assumptions.
- For fuel bunkering costs in 2023, we now use reported average prices where available. For several bio-, e- and blue fuels with low WtT GHG intensity, reported price data is unavailable. This has been added to the list of data gaps of the comprehensive impact assessment.

Fuel technology prices including onboard CCS

- We have decreased the ammonia pilot fuel energy share from 23% to 12%. We received inputs on pilot fuel shares ranging from 5% to 15%, and we use a value towards the higher end of the range as we have to consider both 2-stroke and 4-stroke engines, as well as variable load during the year.
- We received several comments regarding costs related to loss of cargo space due to fuels with low volumetric density (e.g. ammonia and hydrogen) and onboard carbon storage. Newbuilds can be designed for a certain cargo capacity and with fuel tanks for a required range. Vessels built with ammonia, hydrogen, LNG or methanol fuel systems incorporate the necessary tanks into the design, but typically reduce range by about 30% compared to vessels built for conventional fuel oil. We assume this does not have a significant impact on operations. For retrofitting fuel systems, we assume the retrofit cost to be 50% higher than the additional cost for a newbuild.
- For onboard CCS, we now include only one capture rate (75%) for onboard carbon capture technology, and assume a fuel penalty of 30%, which is at the high end of the range of values given by the industry. We assume that the storage tanks should be large enough to store CO_2 from 25% of the total fuel capacity. This may impact the operations for the ship when the full capacity of the capture plant needs to be utilized. Costs for this are not included in the modelling, beyond the cost for depositing the carbon dioxide.

Energy-efficiency measures

- We now include the possibility to retrofit energy-efficiency measures on existing ships in the modelling, with a 50% additional cost relative to implementing the energy-efficiency packages at newbuild stage.
- A description of how the energy-efficiency packages should be understood has been added to the text. This explains that not all measures in a package have necessarily been applied on all ships of a certain generation, but that these are the typical measures applied and the total reduction is an average of all ships having implemented a set of measures in that package. The energy-efficiency gains have been validated against reported data for ships of the different generations.
- We received several proposals to move hard sails or wings to the *Enhanced* energy efficiency (EE) package as this can be considered as a mature technology. However, we have selected to keep this in the *Advanced EE* package which is available from 2025, as wind-assisted propulsion is still not considered a standard design applied on a significant number of newbuilds.
- Several adjustments have been made to the individual energy-efficiency measures, with increased effect of hard sails/wings, reduced effect of waste-heat recovery on deep-sea bulk, reduced effect due to autonomization, inclusion of after propeller Propulsion Improving Devices (PIDs) and shifting wind turbine and heat pump to being available from 2025. To reflect new and more modern hull management practices, advanced anti-biofouling management system has been added as a measure to be available from 2020 in the *Enhanced EE* package.

- The newbuild prices and operational costs have been updated based on the average reported costs and prices between 2018 and 2023. These are used to calculate the cost of building and operating new ships to replace lost transport capacity when reducing speed.

2.3.2 Literature review by WMU

In Task 1 of the Comprehensive Impact Assessment, WMU (2024) has conducted a literature review to provide relevant background information for the assessment.

The input data and assumptions used in this study are generally in line with the cost, effect, and applicability ranges in the literature review. The literature review revealed a scarcity in sources of information on the costs of retrofitting or renewing the existing fleet with fuel technologies. This is also reflected in our data gap identification and analysis.

Compared to the alternative fuel and energy prices provided by WMU (Table 25), the fuel bunkering costs we apply for fuels with low WtW GHG intensities are significantly higher, particularly for e-fuels, but also for biofuels.

A comparison of the results of this study compared with WMU's findings in the literature can be found in Section 7.3.

2.3.3 Data gaps

During the review of input data, areas of missing data affecting the impact assessment have been identified and analysed. The identified data gaps include the following:

- **Current and historic fuel-price data for fuels with significant WtW GHG reduction.** Due to low transparency and low production volumes. The added value of closing this data gap is more accurate short-term bunkering cost figures.
- **Existing energy-efficiency measures on vessels.** Due to low transparency and existing databases being incomplete. The added value of closing this gap is more precise knowledge about the current uptake and effect, and consequently the potential effect of further implementation.
- **Impact of alternative fuel technologies and onboard CCS on cargo space and bunkering frequency**. Due to little operational experience beyond using LNG. The added value of closing this data gap is that costs associated with low energy density of fuels and loss of cargo space can be taken into account.
- **Operating expenses for alternative fuel technologies**. Due to little operational experience, especially for ammonia and hydrogen technologies. The added value of closing this data gap is more accurate fuel technology costs.
- **Capital expenditure for alternative fuel technologies.** Due to low maturity, especially for ammonia and hydrogen technologies. The added value of closing this data gap is more accurate fuel technology costs.
- **R&D spending and the effect it would have on technology maturity and costs.** Limited information in literature sources which can be used to estimate the effect of R&D on ship technologies. The added value of closing this data gap would be to quantify the effect of a certain amount of R&D spending on the technology uptake and cost intensity of the fleet.

3 CANDIDATE MID-TERM GHG REDUCTION MEASURES

This chapter describes the combinations of candidate policy measures assessed in this study which are used when defining the scenarios in Chapter 4. The policy measures as described here are based on the proposals provided up until MEPC 80[9], as well as input provided by the Steering Committee[10]. The descriptions of the policy measures are adapted to align similar concepts and terminology across the proposals and with the method for modelling the policy measures. In addition to the mechanisms of the policy measures, we also describe certain elements common across the policy measures: eligible fuels; the cost gap between fossil and eligible fuels; Revenue body; and revenue streams and disbursements.

The descriptions in this study should not be construed as suggestions or recommendations for how the policy measures should be designed, but rather as necessary adaptations for the purposes of modelling and analysis which require specific inputs and definitions. Appendix A.2.2 contains more details on how the various mechanisms in the policy measures are implemented in the GHG Pathway model.

3.1 GHG Fuel Intensity (GFI) requirement

This is a requirement on annual WtW GHG emissions or TtW GHG emissions with sustainability criteria, per energy unit used on board ships (gCO_2eq/MJ). The GFI requirement will gradually become more stringent, ensuring that the GHG emission trajectories (as defined in Chapter 5) are met considering WtW GHG emissions, both under a WtW and TtW GFI scope. When using onboard CCS, the additional energy used for the carbon capture is not included in the GFI denominator (i.e. per energy unit used) as calculated in this study. If including the additional energy for onboard CCS in the denominator of the GFI, the total GHG emissions would be higher for a ship using onboard CCS compared to a ship using low GHG emission fuels even if they have the same attained GFI. Not including this additional energy in the attained GFI ensures that, regardless of the solution selected for compliance, the resulting absolute GHG emissions are the same.

Under a TtW scope, the GHG emissions are calculated according to the method for TtW value 2 in the IMO LCA guidelines, where the CO_2 emissions depend on the carbon source for fuels of biogenic origins or made from direct captured carbon. To take into account WtW GHG emissions and ensure consistency between the achieved GHG emission reductions under WtW and TtW scopes, we apply a simplified fuel categorization based on the WtW GHG emission intensity for fuels. We consider that any fuel with a WtT GHG emission intensity below the required GFI requirement under a WtW scope can use the TtW value 2 according to the LCA guidelines. Certain fuels which will not have sufficiently low WtT GHG emission intensity to contribute to reaching the ambitions will be considered to be unavailable for use. These include fossil ammonia and hydrogen from 2030, and blue ammonia and hydrogen from 2045. When using fossil fuels with onboard CCS, the WtT emissions of fossil fuels are taken into account to calcuate the amount of carbon required to be captured to achieve the same attained GFI. We have not included any sustainability criteria other than the categorization based on WtW.

These are simplifications and assumptions for the purpose of the modelling in this study.

The GFI requirement proposals include variants which are not modelled in this report, such as a route-based differentiation on the GFI requirement, or correction factors in the range of 5% to 10% for serving eligible ports. For the TtW scope, further categories of fuels with different timelines for phase-out are also proposed.

[9] The descriptions are based on proposals in ISWG-GHG 15/3 (Feebate), ISWG-GHG 15/3/1 (GFI requirement and flexibility mechanism – WtW scope), ISWG-GHG 15/3/1 (Levy), ISWG-GHG 15/3/7 (Levy), ISWG-GHG 16/2/14 (GFI requirement and flexibility mechanism – TtW scope).

[10] Working Document on Value Ranges for Scenario Development as well as input during the fourth Steering Committee meeting on 30 to 31 January 2024.

3.2 GFI flexibility mechanism

The GFI requirement can be implemented with a flexibility mechanism which provides alternative options for compliance.

The first option is for ships with attained GFI below required GFI (positive compliance balance) to sell excess emission units to ships with attained GFI above required GFI (negative compliance balance). The emission unit exchange price would be set between the two parties exchanging emission units. A variant of this is a pooling mechanism where ships with positive and negative compliance balances can join in a pool where all ships are considered compliant if the total compliance balance of the pool is equal to or greater than zero. Also, in this variant there will be a financial settlement between the ships in the pool, considered as a price per emission unit (USD/tCO_2eq). We consider these two variants sufficiently similar to not distinguish between them in the analysis. We do not include any transaction costs for emission-unit trading in the modelling.

The second option is for ships with positive compliance balance to sell excess emission units (termed Surplus Units, SU) – to a Revenue body at a set SU price, and for ships with negative compliance balance to buy remaining units (termed Remedial Units, RU) from a Revenue body at a set RU price. The SU and RU prices are predetermined by the IMO or by criteria in the regulation, taking into account the cost gap between fossil and non-fossil fuel. The proposed SU price levels range from 20% to 80% of the cost gap, which could decrease over time, as well as having no SU. For the RU price, the proposals range from 50–350 USD/tCO_2eq (assumed to be between 40% to 200% of the cost gap), which also could decrease over time.

Due to the granularity of the modelling, which does not include local and regional availability and price of fuels, and which further assumes a global emission-unit exchange market with perfect information and no transaction costs, we are not able to accurately model the application of RU and SU by ships. A simplified method is used where we assume that 10% of the positive compliance balance is not exchanged with other ships but is sold to the Revenue body at the SU price. Similarly, 10% of the negative compliance balance is compensated by purchasing RUs from the Revenue body. This means that there is a balance in emission units and the resulting emission trajectories remain the same and comparable across scenarios.

For the purpose of setting the SU and RU prices, instead of using a cost gap we set the prices as a percentage of the estimated emission-unit exchange price which is determined by the model. As the RUs should always be priced higher than the SUs, there are excess revenues for further disbursement.

The GFI flexibility mechanism works similarly under a WtW and a TtW GHG emissions scope.

3.3 Levy and reward

The levy and reward mechanism (hereafter referred to as levy) consists of two elements, a levy on all GHG emissions from ships and a reward to ships using eligible fuels (see Section 3.5.1 for definition).

The first element is the levy, a predetermined price set by the IMO or by criteria in the regulation, on annual GHG emissions (USD/tCO_2eq) from a ship, collected by a Revenue body. The levy applies to the GHG emissions in a WtW or TtW scope, which for the scenarios in this study is aligned to have the same scope as the GFI requirement (see Section 3.1).

The second element is a reward mechanism for ships using certain eligible fuels. The reward is a predetermined rebate to ships per energy unit of eligible fuel used (USD/GJ). The total reward is distributed from the Revenue body to the ships using eligible fuels at the end of the year based on the reported annual consumption. The revenue from the levy would need to be sufficient to cover the costs of the reward.

The levy proposals range from 2–300 USD/tCO_2eq and can also increase during the period to 2050. The reward rates have not been specifically proposed, other than it should be between 0% and 100% of the total revenue raised. For consistency across policy combinations, we assume a similar range as proposed for the feebate mechanism (see Section 3.4) of between 50% to 105% of the cost gap taking into account the additional cost imposed on emissions by the levy (see Section 3.5.1 for an explanation of going above 100%). Some proposals also apply the levy only to GHG emissions above the GFI requirement. We have not analysed this variant in this report.

3.4 Feebate

The feebate mechanism consists of two elements, a reward (rebate) to ships using eligible fuels, and a fee per tonne of GHG emitted (USD/tCO_2eq). The mechanism is similar to the levy, the key difference being that the fee is calculated based on the total reward and the revenues and expenses balance each other, while the levy is determined in advance and can raise additional revenue.

The reward is a predetermined rebate, set by the IMO or by criterion in the regulation, to ships per energy unit of eligible fuel used (USD/GJ). The eligibility criterion will be the same as for the levy mechanism (see Section 3.5.1 for definition). At the end of the year based on the reported annual consumption, the total reward is distributed from the Revenue body to the ships using eligible fuels.

To cover the reward costs, the fee is calculated based on total cost of rewards for the Revenue body divided by the total GHG emission during the year (USD/tCO_2eq), and will be required to be paid by ships based on their reported WtW or TtW GHG emissions. Note that the exact fee will only be known after the annual reporting period, and for the purpose of the decisions on uptake of abatement measures, the previous year’s fee is used.

The proposed reward ranges from 50% to 100% of the cost gap (see Section 3.5.1). The cost gap will be calculated without considering the fee level as this is not known at the time of setting the reward rate. In cases where the eligible fuels have higher WtW GHG emissions than other low GHG emission fuels such as biofuels, more than 100% of the cost gap may need to be covered to compensate for the additional amount of eligible fuels needed to comply with a certain GFI requirement. Note that this is a result of assuming that all e-fuels are eligible for reward and that WtT GHG emission factors for e-fuels are higher than for biofuels over a certain period of time. The range is therefore expanded up to 105%. From 2041 onwards, the reward and consequently the fee are suspended.

3.5 Common elements

3.5.1 Fuels eligible for reward

The levy and feebate mechanisms provide a reward for ships using certain fuels. Care needs to be taken when combining a reward with a levy or fee, and also with the flexibility mechanism having the option to exchange emission units at set prices, to ensure that the incentives do not overlap and that the total cost for the Revenue body does not exceed the revenues.

Several eligibility criteria have been proposed. One is based on a WtW GHG emission intensity threshold (CO_2eq/MJ), while others suggest that the reward rate should be expressed in USD/tCO_2eq, which implies a differentiated rate based on the WtW or TtW GHG emission intensity of the fuel.

However, as we do not model detailed fuel pathways with specific WtW GHG intensities and prices in this study, we instead use the feedstock pathway as a simplified criterion for the initial scenarios applying a flat rebate per unit of energy. We assume all e-fuels to be eligible for the reward, with the aim that the lowest-cost e-fuel (i.e. e-ammonia) should be on par with the lowest-cost biofuel (i.e. bio-LNG). It should be noted that due to not having more than one pathway and WtT emission factor per feedstock and fuel type, the eligible e-fuels may in some cases have a higher WtT GHG emissions than, for example, biofuels. The assumption on eligibility is made only for the purposes of this modelling, with the intention of investigating how such a mechanism would work rather than investigating specifically if e-fuels were to be regarded as eligible and with the assumed WtT emissions.

Further, since the cost gap is based on two specific fuels, it will be more than covered for some fuel types and not at all for others. The levy or fee in combination with any rewards should not make using fossil fuels more expensive than non-fossil fuels. This restriction is included because the model, if the fossil fuels are more expensive, would rapidly transition to the non-fossil fuels regardless of the GFI requirements and probably well beyond the supply of such fuels. In such cases, it is highly likely that the fuel prices would increase due to the increased demand. This interaction between levy, reward, GFI requirements, fuel supply and demand, and fuel prices is a key part of the analysis in the study.

The cost gap for the reward under a levy or feebate mechanism will be calculated as the difference between the cost per energy unit (USD/GJ) of e-ammonia and bio-LNG. This calculation is performed prior to adjusting the prices of bio- and blue fuels (see Section 1.2.5).

3.5.2 Revenue body

The GFI flexibility, levy, and feebate mechanisms all rely on a body to manage collection and disbursement of revenues. The set-up of this body is yet to be determined and because it is not expected to have a material impact on the assessment in this study, it is generically referred to as the *Revenue body* in this report.

3.5.3 Revenue streams and disbursements

The proposals for policy measures consider seven categories for disbursement of revenues, as listed in Table 3-1.

Table 3-1: Revenue disbursement categories according to Working Document on Value Ranges for Scenarios (MEPC 81/7, Annex 4).

Category	Purpose
D1	Research, development and deployment (RD&D)
D2	Capacity building and negative impact mitigation
D3	Address disproportionate negative impacts as appropiate
D4	Reward for eligible fuels
D5	General GHG mitigation and adaptation
D6	Equitable transition
D7	Administration

The total revenue streams due to the GFI flexibility, levy, and feebate mechanisms will be modelled and provided for each scenario as follows:

- Exchange of emissions units between ships, explicitly or through pooling under a GFI flexibility mechanism (market price and volume)
- The revenue consisting of income from:
    - Remedial Units purchased by ships under a GFI flexibility mechanism
    - The levy mechanism
    - The fee under the feebate mechanism

- The revenue disbursement consisting of:
    - D1 category disbursement for RD&D
    - D4 category disbursement which is calculated based on
        - Surplus Units sales by ships under the GFI flexibility mechanism
        - Reward as part of the levy or the feebate mechanisms
    - D2, D3, D5, D6 and D7 category disbursements using the remaining revenues

Although the share of revenues for the D4 category disbursement has been indicated, this cannot be precisely determined in advance. Since the reward level is predetermined to provide predictability to the industry, the disbursed revenue is decided by the uptake of eligible fuels. The D4 share can be determined only by adjusting the reward levels and the levy through iteration.

Disbursements for RD&D (D1) can reduce the cost intensity either indirectly via R&D spending, or directly to deployment of fuels to ships, which would be equivalent to D4 disbursement under the condition that it results in direct cost reduction for ships. We do not go further into how such a direct disbursement to deployment can be achieved in this study, beyond what is already included as D4 disbursements in the modelling.

For D1 disbursement to R&D, it has not been possible to determine, based on literature sources, an explicit link between a certain magnitude of spending for R&D and the effect it would have on technology maturity and costs, and consequently on quantifying the effect on the cost intensity of the fleet. To maintain comparability between the scenarios, we instead set the amount of D1 disbursement to zero for all scenarios, and all revenues beyond those required and allocated for D4 are allocated to the other disbursement categories (D2–D3 and D5–D7) which are taken into account in the modelling by UNCTAD.

To provide an indication of the potential cost savings that can be achieved by R&D, we have instead run sensitivity scenarios where we made assumptions about certain conditions that are achieved through R&D funding, such as accelerated technology development and learning effects (see Section 6.4).

The revenue streams are illustrated in Figure 3-1:

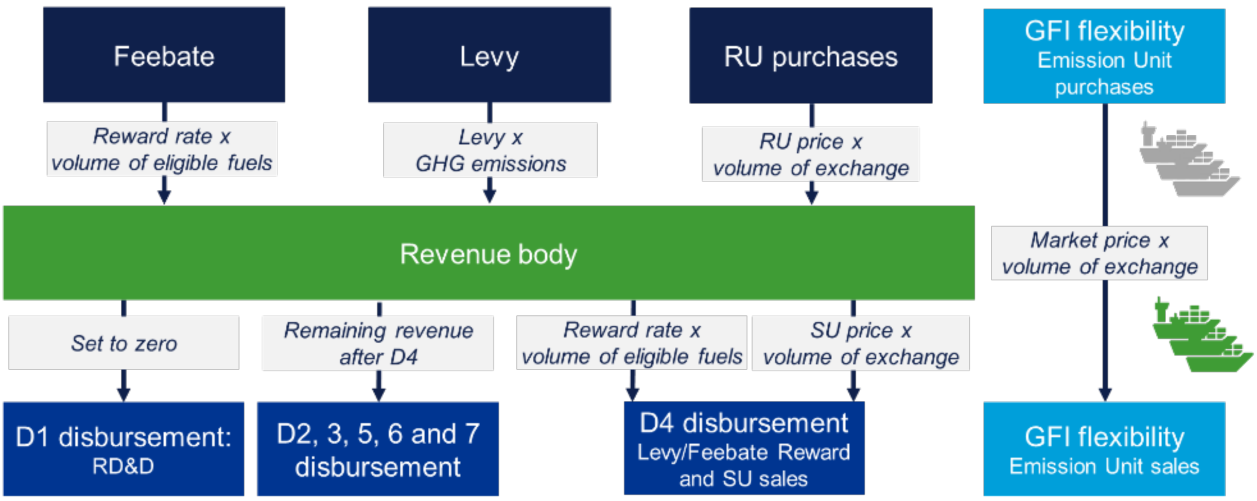

Figure 3-1: Revenue streams generated by the policy measures.

3.6 Summary of policy combinations and ranges

The initial policy combinations with policy codes are listed in Table 3-2, according to the proposals in Working Document on Value Ranges for Scenario Development (MEPC 81/7, Annex 4).

Table 3-2: Policy combinations with input ranges according to Working Document on Value Ranges for Scenario Development (MEPC 81/7, Annex 4).

Policy code	GFI scope	GFI flexibility		Levy		Feebate
		SU % of price	RU % of price	Levy USD/tCO_2eq	Reward % of cost gap	Reward % of cost gap
X.1/Y.1	WtW/TtW	No flexibility		No levy		No feebate
X.2/Y.2	WtW/TtW	No flexibility		2–300	50% to 105%	No feebate
X.3/Y.3	WtW/TtW	No flexibility		No levy		50% to 100%
X.4/Y.4	WtW/TtW	None or 20% to 80%	40% to 200%	No levy		No feebate
X.5/Y.5	WtW/TtW	None or 20% to 80%	40% to 200%	2–300	50% to 105%	No feebate
X.6/Y.6	WtW/TtW	None or 20% to 80%	40% to 200%	No levy		50% to 100%

Cost gap: Calculated as the difference between the cost per energy unit (USD/GJ) of e-ammonia and bio-LNG.
Price: Estimated emission unit exchange price under the flexibility mechanism, which is determined by the model.

4 SCENARIOS

This chapter describes the set of scenarios analysed in this study based on the proposed policy combinations and input ranges in Chapter 3.

It is not feasible to define and model scenarios that cover all possible emission trajectories, policy combinations, and input ranges while also taking into account the likely range and uncertainty of other key inputs when looking more than 20 years into the future. The set of scenarios assessed in this report has been carefully and systematically selected to ensure that total impact of achieving the IMO GHG Strategy ambitions, and the relative impacts between the various policy combinations, can both be understood.

In total, 88 scenarios have been run during the course of the study:

- 2 BAU scenarios (BAULG and BAUHG) projecting emissions given currently adopted policies according to low- and high-growth seaborne trade growth.
- 32 scenarios (21 to 36, and 41 to 56), with various policy combinations, assessing the impact of following the *Base* (numbered 21 to 36) and *Strive* emissions (numbered 41 to 56) trajectories according to a projection of low-growth seaborne trade.
- 36 sensitivity scenarios (not included in Table 4-1), where 9 different input changes have been combined with 4 representative policy scenarios (numbered 23, 32, 46 and 55), to assess the sensitivity of key inputs and assumptions besides the policy combinations.
- 18 preliminary scenarios (numbered 1 to 18) were also run during the first phase of the study. These scenarios did not include any constraints on bio- and blue fuel feedstock supply and consequently no impact on the fuel prices of these fuels. The inputs and assumptions were updated for subsequent scenarios, including also the levy and reward rates in the policy combinations.

The results in this study are based on scenarios 21 to 56 and the sensitivity scenarios. However, results from scenarios 1 to 18 are included in the discussions where relevant for comparison. All scenarios except the sensitivity scenarios are listed in Table 4-1, while the sensitivity scenarios are further described in Appendix E.1.

Table 4-1: List of 52 scenarios analysed in this study. This list does not include the 36 sensitivity scenarios. The policy codes are according to Working Document on Value Ranges for Scenario Development (MEPC 81/7, Annex 4).

Scenario number	Emission trajectory	Seaborne trade growth	Policy combination						
			Policy code	GFI scope	GFI flexibility		Levy		Feebate
					RU % of price	SU % of price	Levy USD/tCO_2eq	Reward % of cost gap	Reward % of cost gap
BAULG	BAU	Low	None						
BAUHG	BAU	High	None						
First set of scenarios without adjusted fuel prices									
1	*Base*	Low	X.1	TtW	No flexibility		No levy		No feebate
2	*Base*	Low	Y.1	WtW	No flexibility		No levy		No feebate
3	*Strive*	Low	X.1	TtW	No flexibility		No levy		No feebate
4	*Strive*	Low	Y.1	WtW	No flexibility		No levy		No feebate
5	*Base*	Low	X.2	TtW	No flexibility		30–120	80% to 40%	No feebate
6	*Base*	Low	Y.2	WtW	No flexibility		30–120	80% to 40%	No feebate
7	*Base*	Low	X.2	TtW	No flexibility		100	80% to 40%	No feebate
8	*Base*	Low	Y.2	WtW	No flexibility		100	80% to 40%	No feebate
9	*Base*	Low	X.3	TtW	No flexibility		No levy		70% to 2040
10	*Base*	Low	Y.3	WtW	No flexibility		No levy		70% to 2040

Scenario number	Emission trajectory	Seaborne trade growth	Policy combination						
			Policy code	GFI scope	GFI flexibility		Levy		Feebate
					RU % of price	SU % of price	Levy USD/ tCO_2eq	Reward % of gap	Reward % of gap
11	*Base*	Low	X.4	TtW	Flexibility		No levy		No feebate
12	*Base*	Low	Y.4	WtW	Flexibility		No levy		No feebate
13	*Base*	Low	X.5	TtW	Flexibility		30–120	80% to 40%	No feebate
14	*Base*	Low	Y.5	WtW	Flexibility		30–120	80% to 40%	No feebate
15	*Base*	Low	X.5	TtW	Flexibility		100	80% to 40%	No feebate
16	*Base*	Low	Y.5	WtW	Flexibility		100	80% to 40%	No feebate
17	*Base*	Low	X.6	TtW	Flexibility		No levy		70% to 2040
18	*Base*	Low	Y.6	WtW	Flexibility		No levy		70% to 2040
Scenarios with adjusted fuel prices following the *Base* GHG emission trajectory									
21	*Base*	Low	X.1	TtW	No flexibility		No levy		No feebate
22	*Base*	Low	Y.1	WtW	No flexibility		No levy		No feebate
23	*Base*	Low	X.4	TtW	120%	80%	No levy		No feebate
24	*Base*	Low	Y.4	WtW	120%	80%	No levy		No feebate
25	*Base*	Low	X.2	TtW	No flexibility		150–300	90% to 65% up to 2040	No feebate
26	*Base*	Low	Y.2	WtW	No flexibility		150–300	90% to 65% to 2040	No feebate
27	*Base*	Low	X.5	TtW	120%	80%	150–300	90% to 65% up to 2040	No feebate
28	*Base*	Low	Y.5	WtW	120%	80%	150–300	90% to 65% up to 2040	No feebate
29	*Base*	Low	X.2	TtW	No flexibility		30–120	105% up to 2040	No feebate
30	*Base*	Low	Y.2	WtW	No flexibility		30–120	105% up to 2040	No feebate
31	*Base*	Low	X.5	TtW	120%	80%	30–120	105% up to 2040	No feebate
32	*Base*	Low	Y.5	WtW	120%	80%	30–120	105% up to 2040	No feebate
33	*Base*	Low	X.3	TtW	No flexibility		No levy		105% to 2040
34	*Base*	Low	Y.3	WtW	No flexibility		No levy		105% to 2040
35	*Base*	Low	X.6	TtW	120%	80%	No levy		105% to 2040
36	*Base*	Low	Y.6	WtW	120%	80%	No levy		105% to 2040
Scenarios with adjusted fuel prices following the *Strive* GHG emission trajectory									
41	*Strive*	Low	X.1	TtW	No flexibility		No levy		No feebate
42	*Strive*	Low	Y.1	WtW	No flexibility		No levy		No feebate
43	*Strive*	Low	X.4	TtW	120%	80%	No levy		No feebate
44	*Strive*	Low	Y.4	WtW	120%	80%	No levy		No feebate
45	*Strive*	Low	X.2	TtW	No flexibility		150–300	90% to 65% up to 2040	No feebate
46	*Strive*	Low	Y.2	WtW	No flexibility		150–300	90% to 65% up to 2040	No feebate
47	*Strive*	Low	X.5	TtW	120%	80%	150–300	90% to 65% up to 2040	No feebate
48	*Strive*	Low	Y.5	WtW	120%	80%	150–300	90% to 65% up to 2040	No feebate
49	*Strive*	Low	X.2	TtW	No flexibility		30–120	105% up to 2040	No feebate
50	*Strive*	Low	Y.2	WtW	No flexibility		30–120	105% up to 2040	No feebate
51	*Strive*	Low	X.5	TtW	120%	80%	30–120	105% up to 2040	No feebate
52	*Strive*	Low	Y.5	WtW	120%	80%	30–120	105% up to 2040	No feebate
53	*Strive*	Low	X.3	TtW	No flexibility		No levy		105% up to 2040
54	*Strive*	Low	Y.3	WtW	No flexibility		No levy		105% up to 2040
55	*Strive*	Low	X.6	TtW	120%	80%	No levy		105% up to 2040
56	*Strive*	Low	Y.6	WtW	120%	80%	No levy		105% up to 2040

The following describes the main features of the scenarios:

Currently adopted measures: All scenarios include currently adopted requirements: the EEDI, CII, and EEXI, as well as the adopted regional measure EU ETS from 2024 and FuelEU Maritime from 2025 (see Appendix B.3).

BAU scenarios: In order to create a reference to compare the impacts of the policy measure combinations on the fleet using the same underlying activity growth, we provide two business-as-usual (BAU) scenarios assuming Low and High growth in seaborne trade.

The proposed inputs for the various economic elements are based on the ranges provided in Section 3.6 and input from the Steering Committee.

Levy and feebate mechanism: For the levy mechanism we use two variants: The first is a levy starting at 150 and increasing to 300 USD/tCO_2eq with a reward rate of 90% decreasing to 65% of the cost gap. In scenarios 1 to 18, a fixed levy of 100 USD/tCO_2eq was used instead. The second levy variant starts at 30 increasing to 120 USD/tCO_2eq with a reward rate of 105% of the cost gap. For the feebate mechanism we use a reward rate of 105% of the cost gap.[11] The reward levels are set thus to create a demand for eligible fuels while also ensuring that the levy is sufficient to cover the cost of the reward.

GFI Flexibility and RU/SU prices: Scenarios 1 to 18 did not model SU and RU prices. For scenario 21 and onwards, we use a simplified approach for RU and SU, as described in Section 3.2, assuming that ships corresponding to 10% of the negative compliance balance will sell SUs to the Revenue body, and that ships corresponding to 10% of the positive compliance balance will purchase RUs from the Revenue body. The SU price is set to 80% of the emission-unit exchange price, while the RU price is set to 120% of the exchange price. The exchange price is determined by the model.

Revenue distribution: For all scenarios, we assume that no revenues go to D1 disbursement (RD&D) (see Section 3.5.3). It should be noted that it is not possible to determine levy and reward rate inputs that provide an exact percentage of D4 distribution relative to the total revenues. The D4 disbursement depends on the uptake of eligible fuels, while the revenue also depends on the total GHG emissions, which may change due to the uptake of abatement measures incentivized or required by the policy measures (see Section 3.5.3).

The detailed input parameters used for the scenarios are provided in Appendix C.

[11] For scenarios 1 to 18, the cost gap is calculated differently than in the subsequent scenarios and consequently the percentage values used are different but approximately equivalent. The absolute reward rates in USD/GJ are provided in Appendix C.

5 BASELINE GHG EMISSIONS AND TRAJECTORIES

This chapter presents the estimated WtW GHG emissions for 2008 and 2023 and the *Base* and *Strive* emission trajectories to 2050 following the indicative checkpoints and ambitions of the IMO GHG Strategy. The results from the modelled BAU scenarios are included for comparison.

5.1 GHG emissions in 2008 and 2023

The WtW GHG emission in 2023 from the fleet under the scope of Chapter 4 of MARPOL Annex VI[12] is estimated to be 928 $MtCO_2eq$, of which 17% were WtT GHG emissions (153 $MtCO_2eq$), 0.9% were CH_4 (7.9 $MtCO_2eq$) and 1.2% N_2O (11.2 $MtCO_2eq$).

The IMO GHG Strategy sets ambitions for international shipping relative to 2008. The Fourth IMO GHG study provides a TtW GHG emission estimate for international shipping in 2008 according to the voyage-based method – i.e. only including international voyages – for ships above 100 GT. This scope is different than the fleet and emissions scope assessed in this study, which are WtW GHG emissions from ships under the scope of Chapter 4 of MARPOL Annex VI.

To set correct targets for 2030 and 2040 relative to 2008 for the fleet in scope of this study, we estimate the WtW GHG emissions for 2008 for the fleet in scope of this study according to the method provided in Appendix A.3. The estimated historical (2008) and current (2023) WtW GHG emissions are provided in Table 5-1, showing that the fleet, assuming that both scopes have reduced with the same relative share, has reduced GHG emissions by 3.6% from 2008 to 2023.

Table 5-1: Estimated WtW GHG emissions in 2008 for international shipping (Faber, et al., 2020; Smith, et al., 2014) and in 2023 for international shipping and the fleet in scope of Chapter 4 of MARPOL Annex VI (estimated by this study). The GHG emission in 2008 for the fleet in scope of Chapter 4 of MARPOL Annex VI is calculated assuming the same share of emissions between the two scopes as in 2023.

Scope	2008 ($MtCO_2eq$)	2023 ($MtCO_2eq$)
International shipping[13]	934	900
Chapter 4 of MARPOL Annex VI (this study)	962	928

5.2 *Base* and *Strive* GHG emission trajectories to 2050

The study defines two well-to-wake GHG emission trajectories to 2050, named as *Base* and *Strive* in this report, according to the IMO indicative checkpoints and the IMO GHG Strategy's ambition to reach net-zero GHG emissions by or around, i.e. close to, 2050, and taking into account WtW GHG emissions. The *Base* trajectory reflects the lower ends of the indicative checkpoints, namely to reduce the total annual GHG emissions from international shipping by 'at least' 20% by 2030 and by 'at least' 70% by 2040, both compared to 2008. The *Strive* trajectory reflects the upper ends of the indicative checkpoints, namely 'striving for' reductions of 30% by 2030 and 80% by 2040, compared to 2008.

Table 5-2 and Figure 5-1 show the *Base* and *Strive* GHG emission reduction targets and resulting trajectories to 2050, compared to the projected GHG emissions according to the results from the two BAU scenarios with low and high growth in seaborne trade under current policies.

WtW GHG emissions for the fleet under the scope of Chapter 4 of MARPOL Annex VI are expected to increase to 994 $MtCO_2eq$ and 1,383 $MtCO_2eq$ respectively in the low- and high-growth BAU scenarios. This corresponds to 7% and 49% increases, respectively, compared with 2023, and 3% and 43% increases, respectively, compared with 2008. Small,

[12] Ships above 400 GT except ships solely trading domestically and ships not propelled by mechanical means, and platforms including FPSOs and FSUs and drilling rigs, regardless of their propulsion.

[13] Ships above 100 GT and according to the voyage-based method – i.e. only including international voyages.

temporary reductions of WtW GHG emissions are seen in 2040, 2045, and 2050 in the BAU scenarios due to the ships sailing in EU/EEA complying with the FuelEU Maritime requirements. The modelled WtW GHG emissions in the EU region were about 16% of the global emissions in 2023.

Following the *Base* trajectory, the WtW GHG emissions targets for the fleet in scope of this study are 771 $MtCO_2eq$ in 2030 and 289 $MtCO_2eq$ in 2040, while for *Strive* trajectory the targets are 674 $MtCO_2eq$ in 2030 and 193 $MtCO_2eq$ in 2040. The target for 2050 is the same for both trajectories. It is set close to zero but due to a limited amount of CH_4 and N_2O emissions from combustion, which with the current technologies and knowledge cannot be eliminated, they are not set to exactly zero.

Table 5-2: WtW GHG emission levels for the fleet under the scope of Chapter 4 of MARPOL Annex VI under the BAU scenarios and targets used for the scenarios in this study for the *Base* and *Strive* GHG emission trajectories based on reductions relative to 2008, in 2030, 2040, and 2050.

WtW GHG emissions	2030 ($MtCO_2eq$)	2040 ($MtCO_2eq$)	2050 ($MtCO_2eq$)
BAU low growth	959 (–0.5%)	1,020 (+12%)	994 (+3%)
BAU high growth	1,079 (+12%)	1,290 (+34%)	1,383 (+43%)
Base trajectory	771 (–20%)	289 (–70%)	~0 (–100%)
Strive trajectory	674 (–30%)	193 (–80%)	~0 (–100%)

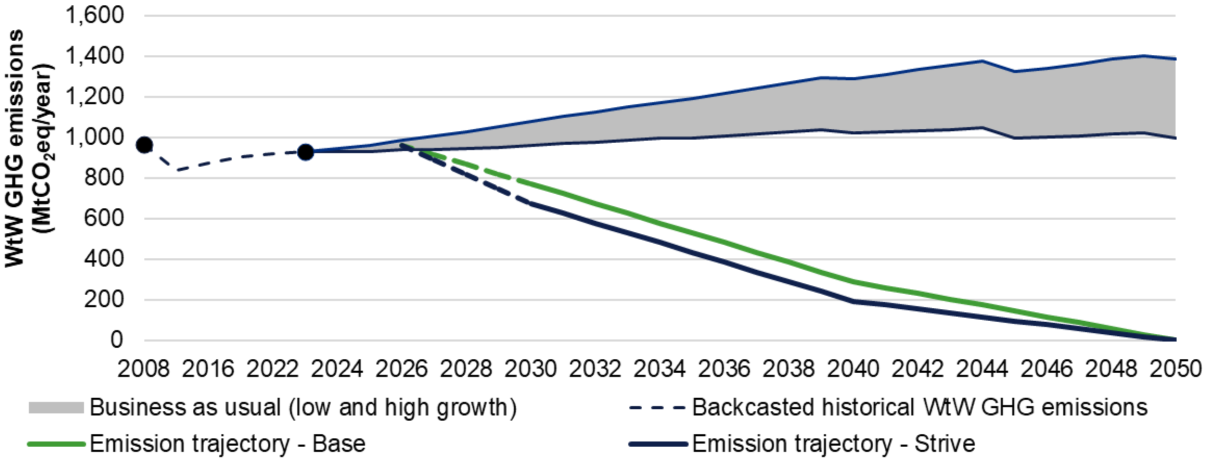

Figure 5-1: WtW GHG emissions for the period 2008–2023, and projected WtW GHG emissions according to the BAU scenarios and *Base* and *Strive* GHG emission trajectories to 2050 for the fleet under the scope of Chapter 4 of MARPOL Annex VI.

6 IMPACTS OF CANDIDATE MID-TERM GHG REDUCTION MEASURES

This chapter presents the overall results and analysis of the modelling of the 32 policy combination scenarios (numbered 21 to 36 and 41 to 56) as described in Chapter 4. The detailed results from the individual scenarios are provided in Appendix D.

All the scenarios in this section are assessed by analysing the difference between groups of scenarios with regard to:

- differences between GHG emissions trajectories: *Base* and *Strive*;
- differences between various policy combinations: TtW and WtW scope; the levy and feebate mechanisms; and the GFI flexibility mechanism;
- revenue streams and disbursements;
- assessment of newbuild and retrofit requirements; and
- impact of research and development.

Except for Figures 6-1 and 6-3, the results from the modelled scenarios are not presented individually but as ranges reflecting the variation for a selected group of scenarios. A group can, for example, be the scenarios following the *Base* GHG emission trajectory (scenarios 21 to 36) or the scenarios following the *Strive* GHG emission trajectory (scenarios 41 to 56). The line in the blue boxes in the charts presented throughout this chapter indicates the median result of the scenarios in the group. Table 6-1 contains an explanation of each indicator used in this chapter.

Table 6-1 Explanation of indicators used in the results chapter.

Indicator	Unit	Explanation
Cost	USD	The total cost for ships includes annualized capital (newbuild and retrofit costs), operational, CO_2 deposit and fuel expenses, as well as regulatory incomes (reward, SU sales, and pool income) and expenses (levy, fee, RU purchases, and pool expenses) imposed by the policy measures. See Appendix A.2.3.
Cost intensity	USD/tonne-mile	Annual total cost (as defined above) divided by the total transport work (based on cargo carried) in a specific year (2030, 2040, 2050).
Cost intensity change	%	Change in cost intensity relative to the BAU scenarios in a specific year (2030, 2040, 2050).
Cost per tonne of GHG reduced	USD/CO_2eq	Calculated as the aggregated difference in cost, divided by the aggregated GHG reduced, both relative to the BAU scenario for each year between 2023 and 2050.
Speed reduction	%	Weighted average speed reduction relative to the BAU scenario, for each ship and year between 2023 and 2050. The average is weighted on distance.
Energy-use reduction	%	Aggregated reduction in energy use relative to the BAU scenario, for each year between 2023 and 2050. Additional energy use for onboard CCS is not included as the intention is to compare uptake of energy efficiency, including speed reduction between scenarios.
Ammonia, methanol, and methane/LNG use	%	Aggregated energy use of the respective fuel type, regardless of feedstock (fossil, bio-, blue and e-) relative to the total energy use for each year between 2023 and 2050. Additional energy use for onboard CCS is not included in the total.
Onboard CCS use	%	Aggregated carbon captured relative to the total GHG emissions in the BAU scenarios for each year between 2023 and 2050. 30% of the carbon captured is deducted to take into account the additional GHG emissions due to the fuel penalty.

6.1 *Base* and *Strive* GHG emission trajectories

Figure 6-1 shows the change in cost intensity relative to BAU in 2030, 2040, and 2050 for each individual scenario. The costs related to regulatory incomes and expenses imposed by the policy measures are shown separately from the abatement costs (additional capital, operational, and fuel expenses) as a light-blue bar. Annual required GFI limits are determined by iteration, and the resulting GHG emissions align within ±5% to the required GHG trajectories. The differences in the GHG trajectories will affect the other results, including the differences in the estimated cost-intensity changes between scenarios.

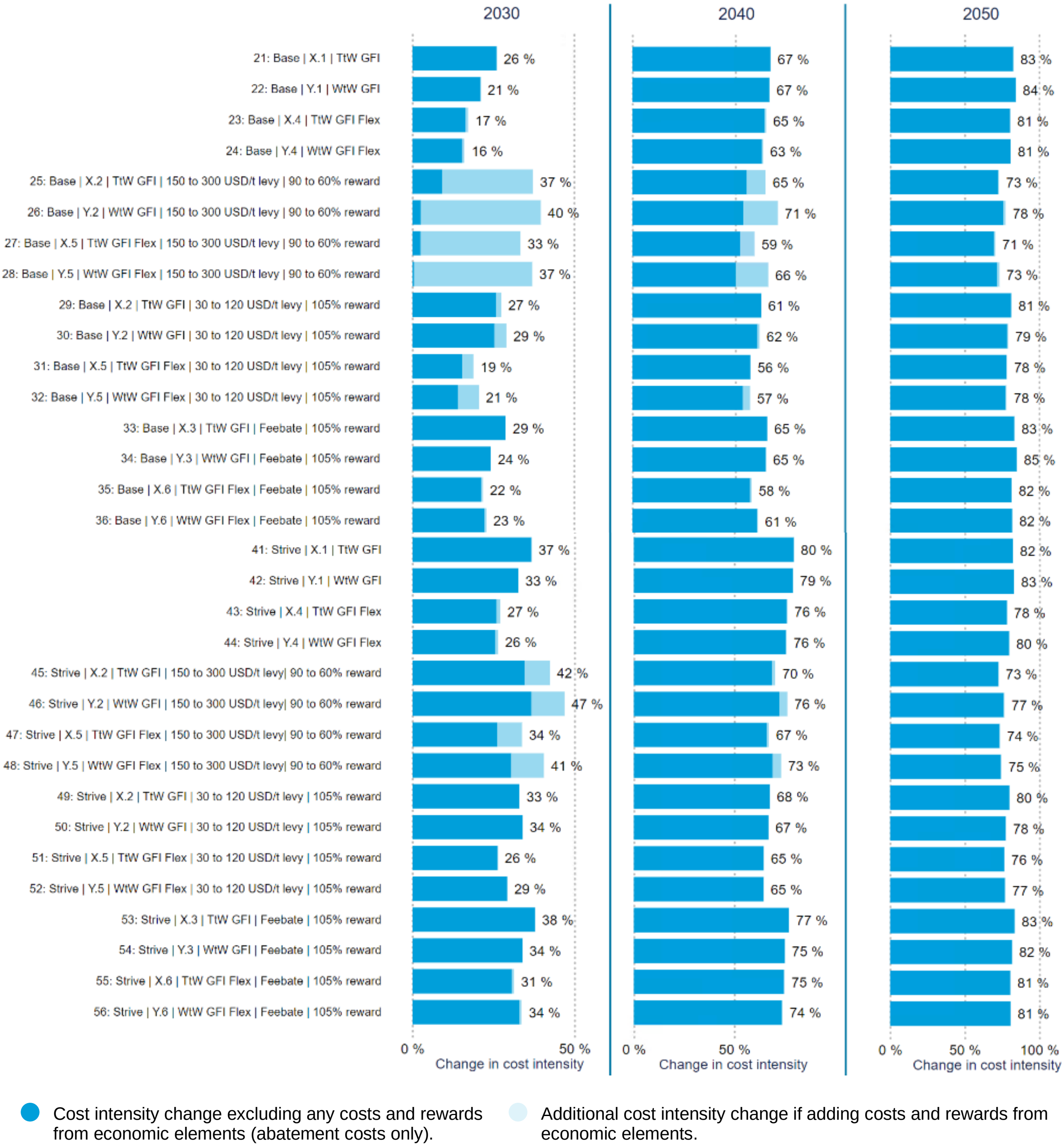

Figure 6-1: Cost intensity changes per policy scenario relative to BAU in 2030, 2040, and 2050. The light-blue bars show the part of the cost-intensity increase related to regulatory incomes and expenses imposed by the policy measures in the scenarios with levy or GFI flexibility mechanism (rewards for eligible fuels and sale of SUs).

Figure 6-2 shows the range of changes in cost intensity in 2030, 2040, and 2050 (as shown in detail per scenario in Figure 6-1) and the total cost per tonne of GHG reduced for the period 2023–2050 relative to BAU for the scenarios following the *Base* or *Strive* GHG emission trajectories.

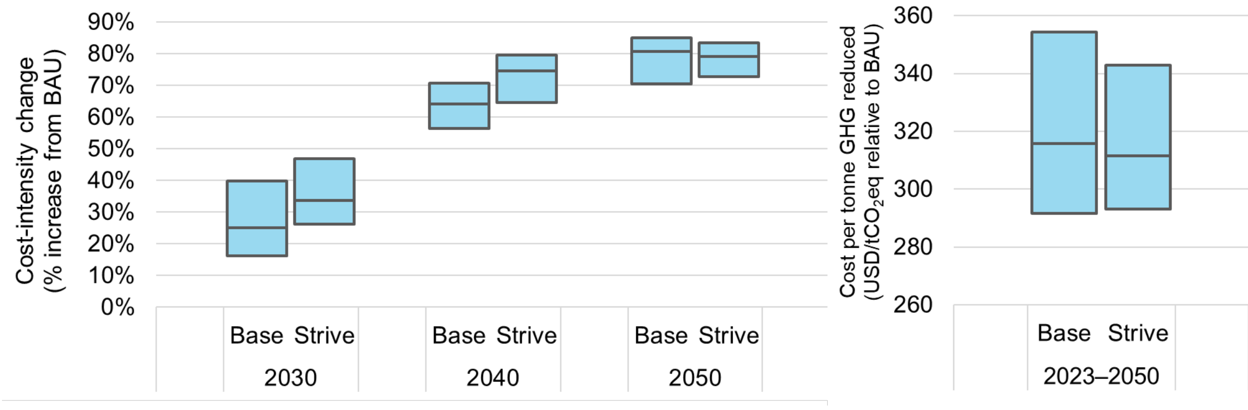

Figure 6-2: Range of cost-intensity changes in 2030, 2040, and 2050 (left panel) and total cost per tonne of GHG reduced in the period 2023–2050 (right panel) relative to BAU, for the *Base* and *Strive* GHG emission trajectory scenarios.

The increase in cost intensity relative to the BAU scenario of achieving the *Base* GHG emission trajectory is 16% to 40% in 2030, increasing to 56% to 71% in 2040 and 71% to 85% in 2050. Similarly, for achieving the *Strive* GHG emission trajectory, the increase in cost intensity is 26% to 47% in 2030, increasing to 65% to 80% in 2040 and 73% to 83% in 2050.

It should be noted that the GHG emission levels achieved in 2030 and 2040 can vary about 5% from the target trajectory between the scenarios. The aggregated additional cost per tonne of GHG reduced relative to BAU in the period 2023–2050 is in the range 292–354 USD/tCO_2eq.

Toward 2050, with higher GHG reductions, the cost intensity continues to increase relative to BAU, though at a slower pace. The majority of reductions are achieved in 2040 with 70% to 80% reduction, and the cost of low-GHG fuels decreases relative to fossil fuels.

Although the scenarios following the *Strive* GHG emission trajectory have a higher cost-intensity increase in 2030 and 2040, the total cost per tonne of GHG reduced is almost the same. The *Strive* trajectory scenarios have a higher early GHG emission reduction, which over the period 2023–2050 provides a higher accumulated reduction. They also have a reduction in energy use, which mitigates the increase in total cost from the more expensive low GHG emission fuels.

Figure 6-3 shows the reduction in energy use relative to BAU in 2030, 2040, and 2050 for each individual scenario. The light-blue bars show the reduction in energy achieved without considering the additional energy required for onboard CCS.

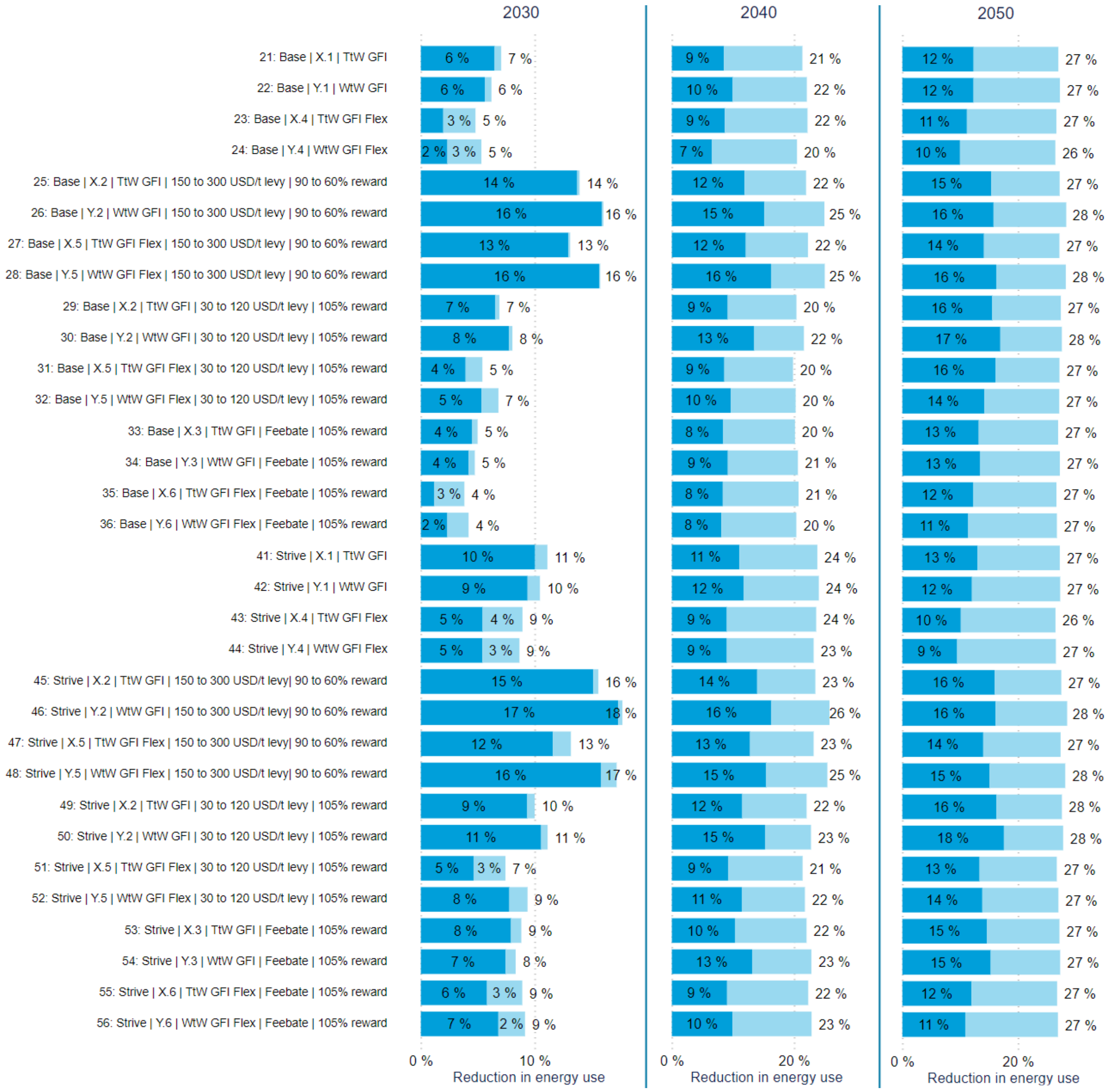

Figure 6-3: Reduction in energy use relative to BAU (low growth) in 2030, 2040, and 2050, per scenario. The light-blue bars show the potential additional reduction in energy use without the energy needed for onboard CCS.

Figure 6-4 shows the range of reductions in speed and energy use, and of the use of ammonia, methanol, methane/LNG and onboard CCS across the *Base* and *Strive* trajectory scenarios in the period 2023–2050. The fuel types cover all feedstocks, including fossil, bio-, blue and e-fuels.

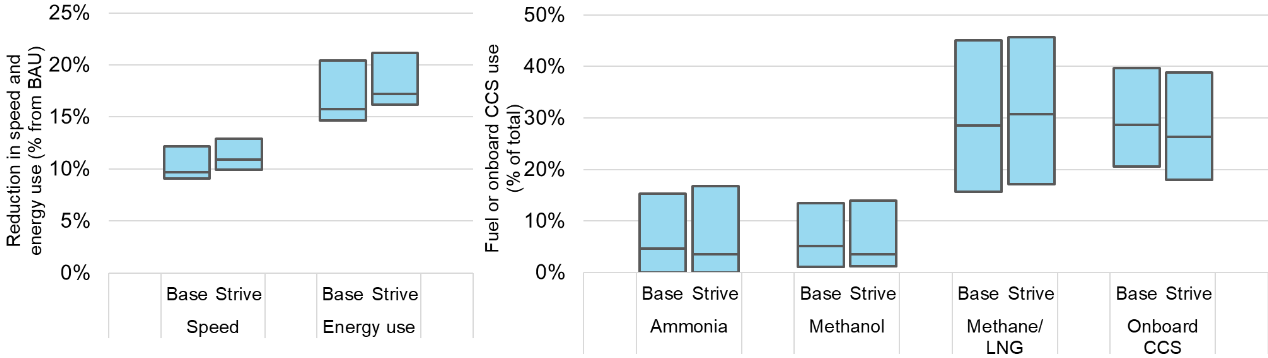

Figure 6-4: Span of reduction in speed and energy use relative to BAU (left panel) and fuel and onboard CCS use relative to total energy use / GHG emission reduced (right panel) in the period 2023–2050 for the *Base* and *Strive* trajectory scenarios.

Speed is reduced by 9% to 13% relative to BAU while energy use is reduced by 15% to 21% across both the *Base* and *Strive* trajectory scenarios. It is notable that the GFI requirement does not directly incentivize improvements in energy efficiency. Initially, to 2030, the GFI requirements under the *Base* GHG emission trajectory are not sufficient to increase the total fuel costs to incentivize the uptake of energy-efficiency measures. The *Strive* trajectory scenarios have a somewhat higher speed and energy reduction. This indicated that the required amount of low GHG emission energy to reach the GFI requirements and related costs may be sufficient to drive a higher uptake of energy-efficiency measures and speed reduction.

The uptake of ammonia and methanol, regardless of feedstock, in the policy combination scenarios is between 0% and 17% of total energy use, while for methane/LNG it is between 16% and 46%. The uptake of onboard CCS is between 18% and 40% in term of CO_2 captured relative to total GHG emission reduced. The differences in the fuel and onboard CCS use between the *Base* and *Strive* GHG emission trajectory scenarios are small.

The scenarios analysed here include constraints on feedstock supply, and the fuel prices of bio- and blue fuels are adjusted up to the cost of e-fuels. This results in a diverse fuel mix where e-fuels and onboard CCS appear to be the two dominant decarbonization solutions across all policy scenarios given the inputs and assumptions (see Figures D-31 to D-32 and D-45 to D-46 in Appendix D). However, biofuels also have a significant contribution toward 2040 and 2050 (see Figures D-30 and D-44 in Appendix D). It should be noted that this fuel mix is to a large degree a result of the supply constraints on bio- and blue fuel feedstocks, and also the lack of constraints on e-fuels and carbon storage capacity.

In 2030, the uptake of low GHG emission fuels is between 0.3 and 2.0 EJ in the *Base* trajectory scenarios, and 1.5 to 2.9 EJ in the *Strive* trajectory scenarios. The lowest uptakes are seen in *Base* trajectory scenarios with high reduction in energy use (scenarios with a 150–300 USD/tCO_2eq levy) or high uptake of onboard CCS (TtW scenarios and scenarios with a GFI flexibility mechanism). In most scenarios, except those with high reduction in energy use, the total feedstock supply and carbon storage capacity exceed the median estimated projections in the literature.

To achieve the GHG emission trajectories within the assumed supply constraints, all fuel feedstocks need to be used, complemented by onboard CCS and reduction in energy use by way of energy-efficiency measures and speed reductions.

6.2 Policy combinations

In this section we compare the impact of the various policy combinations – TtW and WtW scope, the levy and feebate mechanisms, and the GFI flexibility mechanism – followed by an overview of the revenue streams and disbursements.

6.2.1 TtW and WtW scope

Figure 6-5 shows the range of changes in cost intensity in 2030, 2040, and 2050 and the total cost per tonne of GHG reduced for the period 2023–2050 relative to BAU across the policy combinations with a TtW and WtW scope.

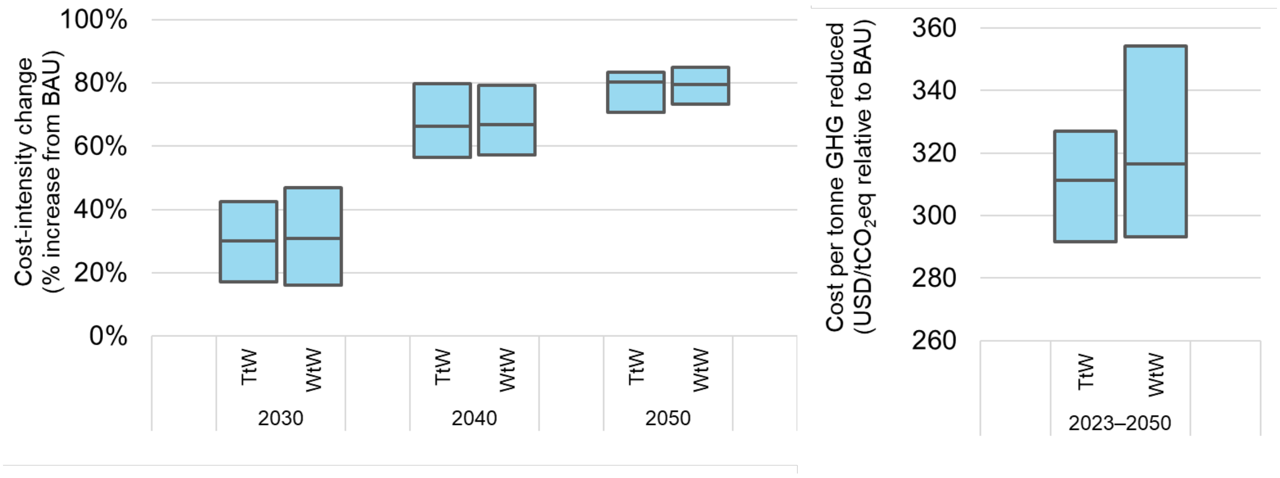

Figure 6-5 Range of cost-intensity increases in 2030, 2040, and 2050 (left panel) and total cost per tonne of GHG reduced in the period 2023–2050 (right panel) and relative to BAU, for the TtW and WtW scope scenarios.

The cost intensities in 2030, 2040, and 2050 show small differences between the TtW and WtW scenarios. The WtW scenarios have a slightly higher median cost per tonne of GHG reduced, and also a higher maximum across the scenarios. This is because when applying the same levy in USD/tCO_2eq, the absolute cost is higher in the WtW scenarios as the WtT emissions are also included.

Figure 6-6 shows the range of reductions in speed and energy use, and on the use of ammonia, methanol, methane/LNG and onboard CCS across the policy combinations with a TtW and WtW scope, in the period 2023–2050.

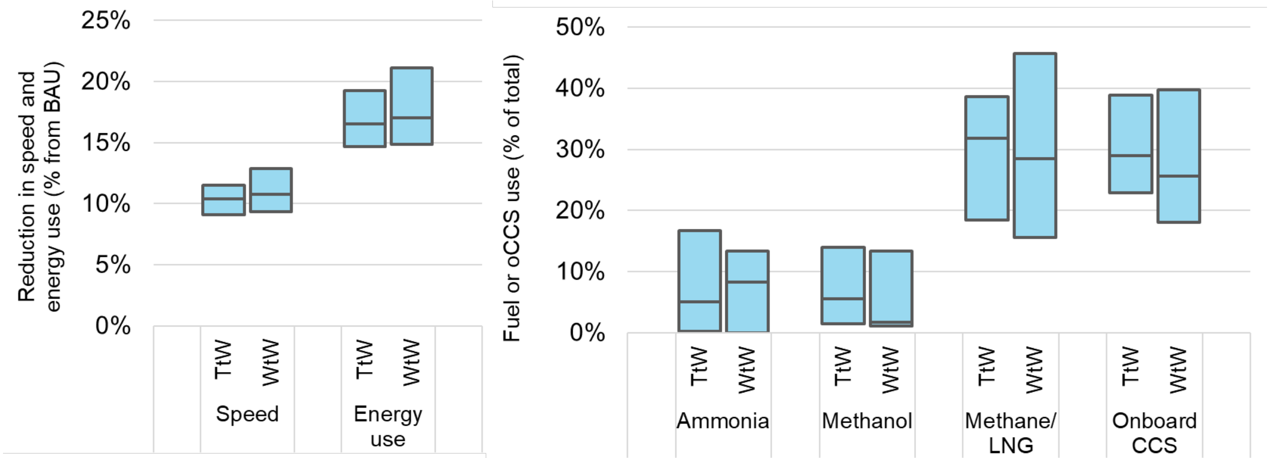

Figure 6-6: Range of reduction in speed and energy use relative to BAU (left panel) and fuel and onboard CCS use relative to total energy use / GHG emission reduced (right panel) in the period 2023–2050, for the TtW and WtW scope scenarios.

The WtW scenarios show a slightly greater reduction in speed and energy use, likely to be due to the higher absolute cost of the levy, as indicated above. The WtW scenarios generally have a higher uptake of ammonia, while TtW scenarios have a higher uptake of methanol, methane/LNG, and onboard CCS. However, the variations within the groups are large, as shown by the ranges, indicating that there are other mechanisms, such as the levy and feebate mechanism, that have a significant impact on the fuel and technology choice.

6.2.2 Levy and feebate mechanism

Figure 6-7 shows the range of changes in cost intensity in 2030, 2040, and 2050 and the total cost per tonne of GHG reduced for the period 2023–2050 relative to BAU across the policy combinations having a levy or feebate mechanism, and for scenarios without such mechanisms.

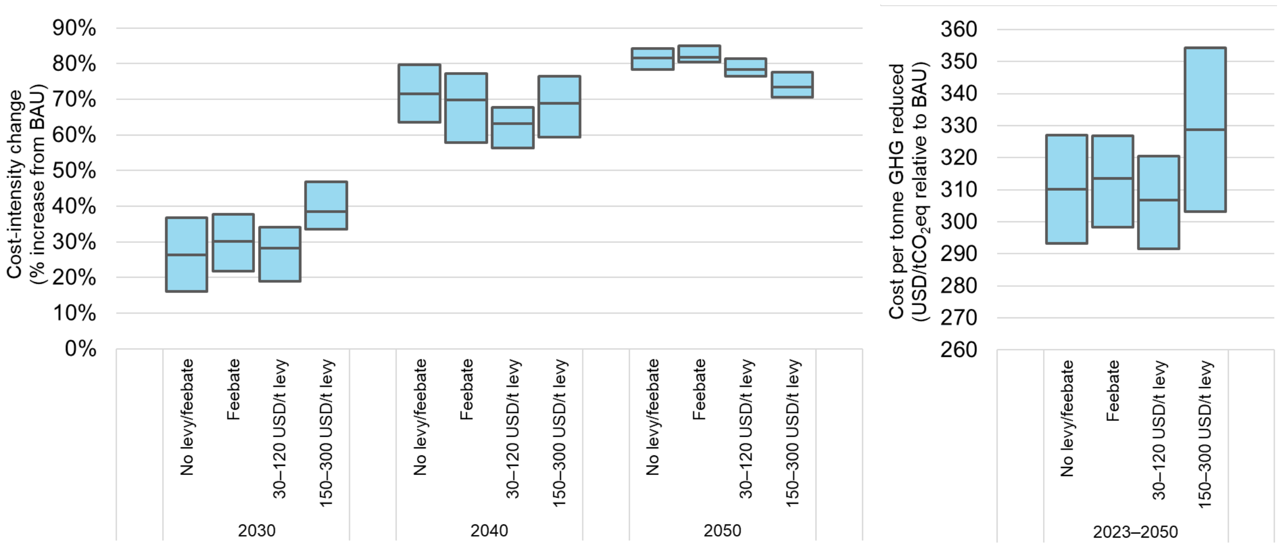

Figure 6-7: Range of cost-intensity increases in 2030, 2040, and 2050 (left panel) and total cost per tonne of GHG reduced in the period 2023–2050 (right panel) and relative to BAU, for each levy/feebate mechanism.

It should be noted that the feebate scenarios result in a fee of 40–56 USD/tCO_2eq in 2030, increasing to 72–144 USD/tCO_2eq in 2040, before it stops from 2041 onwards (see Appendix C.2). The fee is generally lower than the levy in the scenarios with a 30–120 USD/tCO_2eq levy.

Scenarios with a 150–300 USD/tCO_2eq levy have a significantly higher cost intensity in 2030 with a 33% to 47% increase compared with 16% to 38% for the other scenarios. In 2040, scenarios with a levy of 30–120 USD/tCO_2eq have the lowest cost-intensity increase, 56% to 68%, compared to 58% to 80% for the other scenarios. In 2050, scenarios with a levy have a lower cost intensity increase of 71% to 81% while the feebate scenarios and scenarios without any levy or feebate mechanism see an increase of 78% to 85%. This is due to a lower energy use in the scenarios with a levy. The incentive for reduction in energy use is lower in the feebate scenarios due to the lower cost of the fee and also that the fee level is not decided before the following year based on the amount of rewards distributed. Towards 2050, as the GHG emissions reduce, the cost of the levy also decreases, reducing the cost impact in the levy scenarios and in the feebate scenarios where the fee is stopped from 2041 onwards.

In scenarios with a 150–300 USD/tCO_2eq levy following the *Base* GHG emission trajectory the cost-intensity increase in 2030 is 33% to 40%. If considering only the abatement costs, and not the costs and rewards from the economic elements (i.e. the cost of the levy and RUs, and the income from a reward and sale of SUs – indicated by the light-blue bars in Figure 6-1), the cost-intensity increase would be only 1% to 9% due to the lower energy use and consequently lower requirement for low GHG emission fuels. This is lower than in any other scenario, including those lacking any economic element (scenarios 21 and 22). In the scenarios with a 150–300 USD/tCO_2eq levy and following the *Strive* GHG emission trajectory, the abatement cost in 2030 is higher due to the greater uptake of low GHG emission fuels, which again leads to a lower cost of the levy and a higher reward for eligible fuels. It should be noted that the effect of the economic elements is necessary in the modelling to achieve the reduced abatement costs, but it illustrates the potential for lower abatement costs through reduced energy use.

Overall, the cost per tonne of GHG reduced is higher at 303–354 USD/tCO_2eq for the scenarios with a 150–300 USD/tCO_2eq levy, while the other scenarios have a cost of 292–327 USD/tCO_2eq reduced.

Figure 6-8 shows the range of reductions in speed and energy use, and in the use of ammonia, methanol, methane/LNG and onboard CCS across the policy combinations with a levy or feebate mechanism and in scenarios without such mechanisms, in the period 2023–2050.

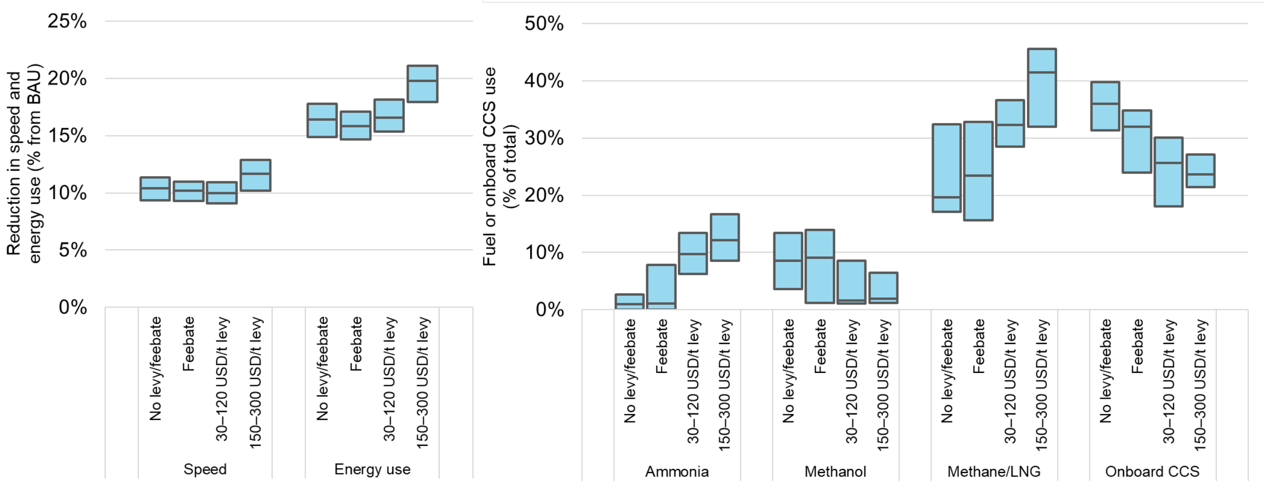

Figure 6-8: Range of reduction in speed and energy use relative to BAU (left panel) and fuel and onboard CCS use relative to total energy use / GHG emission reduced (right panel) in the period 2023–2050, for each levy/feebate mechanism.

The feebate and 30–120 USD/tCO_2eq levy mechanism have little impact on the speed and energy use compared to the scenarios without such mechanisms, and all result in a 9% to 11% speed reduction and a 15% to 18% energy use reduction. The scenarios with a 150–300 USD/tCO_2eq levy show a higher speed reduction of 10% to 13% and an energy use reduction of 18% to 21%. The primary reason for this is the implementation of speed reductions as soon as the levy is introduced. The lower energy use reduces the need for low GHG emission fuels to reach the GHG trajectory in 2030. Towards 2040 and 2050, and also in the *Strive* trajectory scenarios in 2030, the effect of the levy and feebate mechanism on energy use is less pronounced. As the GHG trajectory become more stringent, the energy use is reduced in all scenarios regardless of policy combination. The cost impact of the levy is also reduced with lower GHG emissions.

Towards 2040 and 2050, and also in the *Strive* trajectory scenarios in 2030 (see Figure D-25 and Figure D-39 in Appendix D), the effect of the levy and feebate mechanism on energy use is less pronounced. As the GHG trajectory becomes more stringent, the energy use is reduced in all scenarios regardless of policy combination. The absolute cost of the levy is also reduced with lower GHG emissions.

When modelling the feebate scenarios, the uptake of energy-efficiency measures and speed reductions in the model are decided taking into account the fee from the previous year as a GHG price, as opposed to the levy scenarios where the GHG price is known every year. This delays the impact by one year in the feebate scenarios relative to the levy scenarios.

The reward for eligible fuels in the levy and feebate scenarios incentivizes uptake of e-fuels. Together with bio-LNG, e-ammonia and e-LNG seem to be the fuels with the highest uptake in scenarios with a levy in combination with a reward mechanism. The use of ammonia, regardless of feedstock, is between 6% to 17% of total energy use, while the use of methane/LNG is between 29% to 46% in the levy scenarios. The use of onboard CCS is also much lower in the levy scenarios providing 18% to 30% of the GHG emission reduction, while without any levy or feebate mechanism the uptake is 31% to 40%. The reason is likely to be that, unlike other carbon-based bio- and e-fuels, e-ammonia cannot be combined with onboard CCS. In scenarios with a feebate mechanism, the use of ammonia and methane/LNG is lower, while the uptake of methanol is up to 14% of total energy use. The use of onboard CCS is between 24% and 35% of the GHG emission reduction. The higher uptake of methanol in the feebate scenarios seems to be caused by a lower fee which favours onboard CCS, with which methanol can be combined.

Regardless of mechanism, the uptake of the various fuel types is very sensitive to relatively small changes in the levy and reward levels. The reward rate would need to be set precisely relative to the cost gap to give the necessary incentive for uptake of eligible fuels. If it is set too low, no eligible fuels are taken up; if it is set too high, the uptake exceeds what is available for rewards.

6.2.3 Flexibility mechanism

Figure 6-9 shows the range of cost per tonne of GHG emission reduced in the period 2023–2050 and the increases in cost intensity in 2030, 2040, and 2050 relative to BAU across the scenarios with and without a GFI flexibility mechanism.

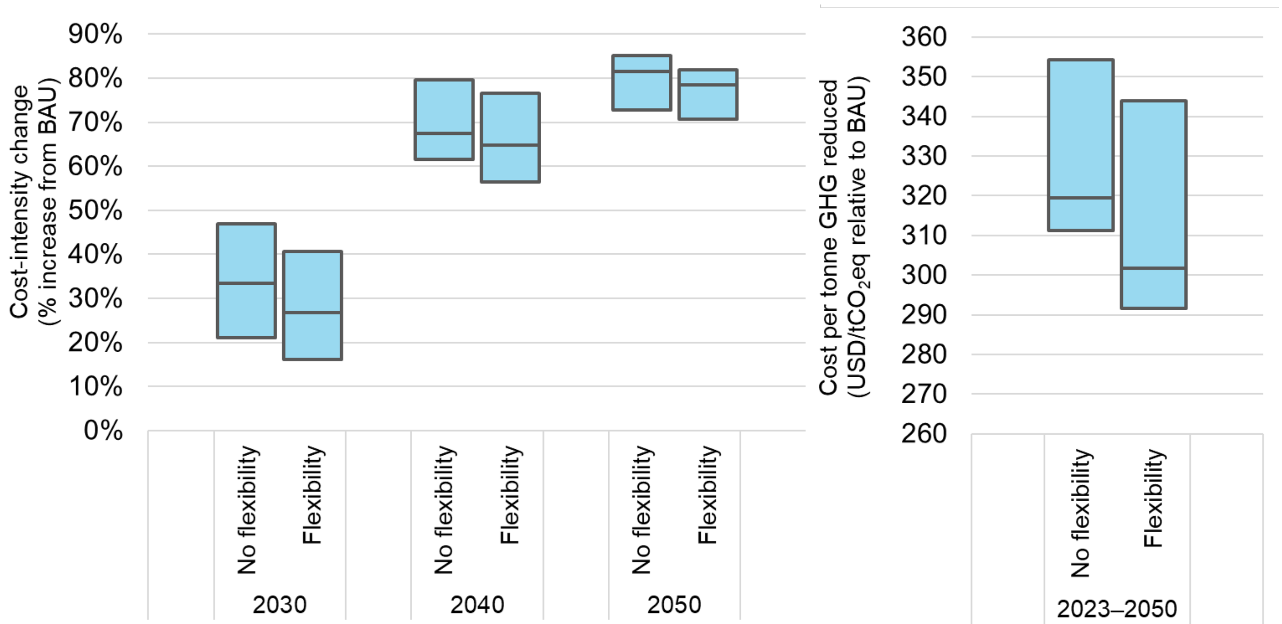

Figure 6-9: Range of cost-intensity increases in 2030, 2040, and 2050 (left panel) and total cost per tonne of GHG reduced in the period 2023–2050 (right panel) and relative to BAU, for scenarios with and without a GFI flexibility mechanism.

Scenarios with a GFI flexibility mechanism have about 4% lower cost intensity compared to scenarios without the flexibility mechanism in 2030. In 2040 and 2050, the effect of the flexibility mechanism is less, with about 1% lower cost intensity. The aggregated impact is about a 6% lower cost per tonne of GHG reduced compared with the scenarios without the flexibility mechanism.

Figure 6-10 shows the range of reductions in speed and energy use, and in the use of ammonia, methanol, methane/LNG and onboard CCS across the scenarios with and without a GFI flexibility mechanism, in the period 2023–2050.

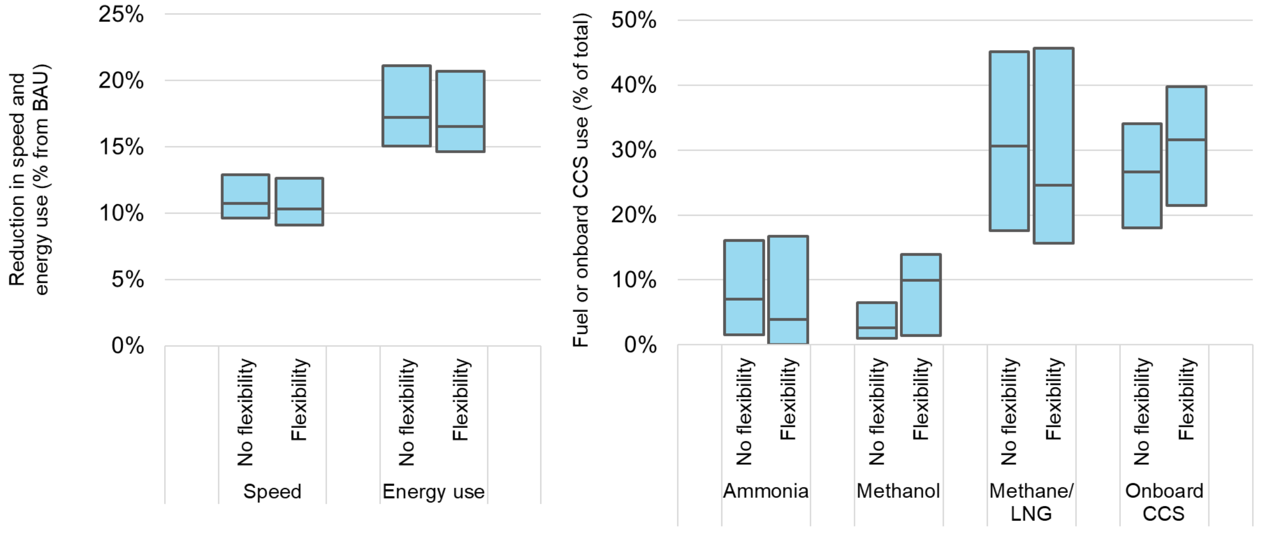

Figure 6-10: Range of reduction in speed and energy use relative to BAU (left panel) and fuel and onboard CCS use relative to total energy use / GHG emission reduced (right panel) in the period 2023–2050, for scenarios with and without a GFI flexibility mechanism.

The reason for the lower cost intensity is that with the flexibility mechanism, initially a relatively small amount of ships can install, for example, ammonia or methanol fuel technologies or onboard carbon capture systems and run fully on lower-cost fuels (e.g. e-methanol has lower costs than e-MGO), instead of all ships having to reduce GHG intensity individually. This is seen by the increased use of methanol and onboard carbon capture systems. Towards 2040 and 2050, the effect of the flexibility mechanism is reduced because, with more stringent requirements, each ship must reduce its own emissions further before being able to contribute emission units to other ships. The impact of the flexibility mechanism on energy efficiency and speed reduction is small. It should be noted that since most ships that install onboard CCS in 2030 under a scenario with a flexibility mechanism use it at full capacity, as opposed to without the flexibility mechanism, the demand for carbon storage is up to three times (+200%) the expected capacity available for shipping.

The flexibility mechanism does not require that all ships acquire and use low GHG emissions fuels to comply with the GFI. This may be beneficial during the build-up of production and infrastructure for alternative fuels when such fuels have limited global availability. Ships that cannot find adequate fuels may exchange emission units with ships trading in areas where low GHG emission fuels are more readily available. The modelling in this study does not quantify this effect as we do not include regional fuel availability or prices.

The annual trading volume or emission units that are exchanged (see Figure D-14 and Figure D-31 in Appendix D) peaks around 2035 with the average for the period 2031–2040 being 82–178 $MtCO_2eq$/year. This represents about 9% to 18% of the annual GHG emissions for the whole fleet in the BAU scenario. In scenarios without a levy or feebate, the average annual emission unit exchange prices (Figure D-15 and Figure D-30 in Appendix D) start at 717–811 USD/tCO_2eq in the period 2027–2030 before reducing to 608–712 USD/tCO_2eq in 2031–2040 and increasing again to 705–758 USD/tCO_2eq in 2041–2050. The driver for the exchange price is the cost of switching from fossil LSFO/MGO to bio-MGO. The price differential in 2030 is about 71 USD/GJ, giving a WtW GHG reduction of about 80 gCO_2eq/MJ, which is a cost of about 890 USD/tCO_2eq reduced. For ships trading in the EU, the ETS cost of 135 USD/tCO_2eq reduces the switching cost to 755 USD/tCO_2eq.

With a levy or feebate in combination with a reward for eligible fuels, the price is reduced significantly in the periods to 2030 and 2040, depending on the levels of the levy and the reward. A 21 USD/GJ reward and a 60 USD/tCO_2eq levy reduces the switching cost from fossil LSFO/MGO to e-MGO to around 420 USD/tCO_2eq. However, the exchange cost is lower in scenarios with a 30–120 USD/tCO_2eq levy at 285–324 USD/tCO_2eq indicating that the switching cost to e-ammonia, including any capital costs, is possibly even lower. Compared to scenarios without a levy and reward, the exchange price takes into account both the higher cost of using fossil fuels (i.e. the levy) and the lower cost of eligible fuels (i.e. the reward). In scenarios 27 and 28 with a 150–300 USD/tCO_2eq levy, there is no exchange of units in the period 2027–2030 because all ships are already incentivized to comply individually due to the high levy, and the price remains lower through to 2050.

6.2.4 Revenue streams and disbursements

Figure 6-11 shows the range of average annual revenues from the levy/feebate mechanism and the GFI flexibility mechanism in the periods 2027–2030, 2031–2040, and 2041–2050.

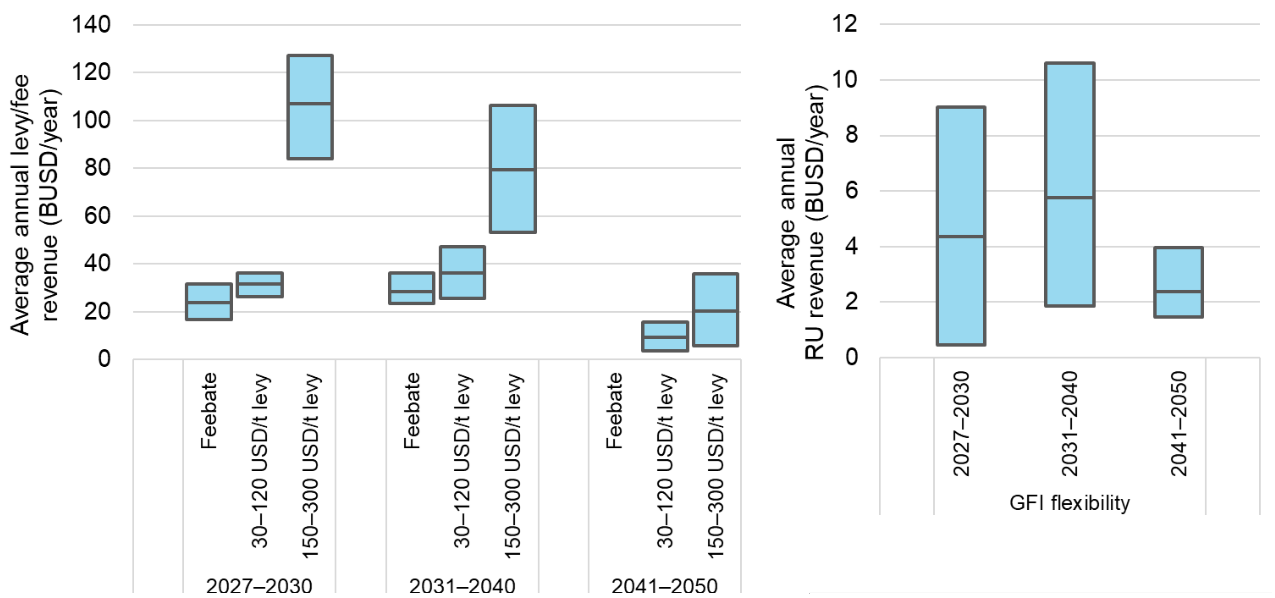

Figure 6-11: Range of average annual revenues from the levy/feebate mechanism (left panel) and the GFI flexibility mechanism (right panel) in the periods 2027–2030, 2031–2040, and 2041–2050; note the difference in the scale of the y-axis between the two panels.

A levy of 150–300 USD/tCO_2eq as results in an average annual revenue stream of 84–127 BUSD/year in the period 2027–2030, decreasing to 53–106 BUSD/year in 2031–2040 and to 6–36 BUSD/year in 2041–2050. A levy of 30–120 USD/tCO_2eq creates an average annual revenue stream of 26–36 BUSD/year in the period 2027–2030, increasing to 25–47 BUSD/year in 2031–2040, then decreasing to 3–16 BUSD/year in 2041–2050. The feebate mechanism creates an average annual revenue stream of 17–32 BUSD/year in the period 2027–2030, increasing to 23–36 BUSD/year in 2031–2040, before it is stopped from 2041 onwards.

The GFI flexibility mechanism could also raise revenues through sale of Remedial Units to ships. Applying an RU and SU price could significantly impact the emission trajectories as ships would prefer to either exceed the emission reduction requirements if the SU price is set sufficiently high, and conversely fail to achieve the trajectory if the RU price is set too low. For this reason, we have applied a simplified method for estimating the potential revenue, without changing the emission trajectory.

In scenarios with a GFI flexibility mechanism the revenue from sale of RUs creates an average annual revenue stream of 0.5–9 BUSD/year in the period 2027–2030, increasing to 2–11 BUSD/year in 2031–2040, then decreasing to 2–4

BUSD/year in 2041–2050. The range is large due to the difference in the amount of trading or pooling in the different scenarios.

Figure 6-11 shows the range of average annual disbursements for reward for eligible fuels and for purchase of Surplus Units under the GFI flexibility mechanism (D4 category), and for other disbursement categories (D2–D3 and D5–D7) in the periods 2027–2030, 2031–2040, and 2041–2050. Note that disbursement for RD&D (D1) is set to zero. Section 6.4 includes a discussion on the potential impact of R&D spending provided certain outcomes on technology maturity and learning effects can be achieved.

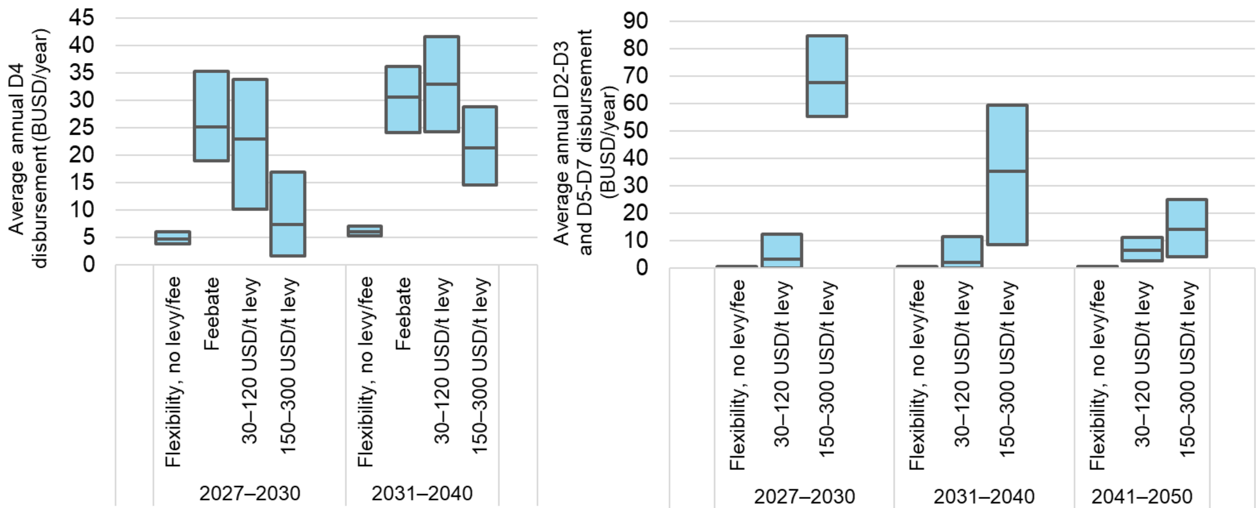

Figure 6-12: Range of average annual disbursement for reward for eligible fuels and for purchase of Surplus Units under the GFI flexibility mechanism (D4) (left panel), and other disbursements (D2–D3 and D5–D7) (right panel) for groups of scenarios in the periods 2027–2030, 2031–2040, and 2041–2050.

For the feebate scenarios, the revenues raised exactly equals the reward for eligible fuels and there are no other disbursements in these scenarios except if combined with the flexibility mechanism.

Although scenarios with a 150–300 USD/tCO_2eq levy raise a larger amount of revenues, the reward is set to a lower percentage of the cost gap between the lowest-cost e-fuel (e-ammonia) and lowest-cost biofuel (bio-LNG). Otherwise the cost gap between fossil fuels and bio- and e-fuels would be more than covered, leading to an accelerated uptake of low GHG emission fuels and likely beyond the capacity to produce such fuels.

Due to this, and also because the energy use and share of eligible fuels needed are lower, the D4 disbursement is less in these scenarios, at 2–17 BUSD/year in 2027–2030 and 15–29 BUSD/year in 2031–2040, compared to scenarios with a feebate mechanism or a 30–120 USD/tCO_2eq levy, which see disbursement of 10–34 BUSD/year in 2027–2030 and 24–42 BUSD/year in 2031–2040. The amount available for other disbursements (D2–D3 and D5–D7) is significantly higher in scenarios with a 150–300 USD/tCO_2eq levy; it is initially 55–85 BUSD/year in 2027-2030, decreasing to 9–59 BUSD/year in 2031–2040 and 4–25 BUSD/year in 2041–2050. The scenarios with 30–120 USD/tCO_2eq levy see a disbursement of 0–12 BUSD/year in all periods. The D4 disbursement for Surplus Units in scenarios without a levy or feebate is 4–6 BUSD/year in 2027-2030, increasing to 5–7 BUSD/year in 2031-2040, while disbursement for other categories is 0.1–0.2 BUSD/year throughout all periods.

6.3 Number of newbuilds and retrofits

As the scenarios all follow the same seaborne trade growth trajectory, the variation in number of newbuilds required in each policy scenario is mainly a function of speed reduction. Greater speed reduction leads to more newbuilds to replace the lost transport capacity (see Appendix B.6.5). The variation in number of retrofits in each scenario is mainly due to incentives provided by the levy/feebate mechanisms, with the additional cost leading to more energy-efficiency retrofits and the reward for e-fuels leading to more uptake and retrofit to ammonia. Figure 6-13 shows the range of the maximum number of new annual number of newbuilds, energy-efficiency retrofits, and fuel technology / onboard CCS retrofits in the period 2023–2050 for all scenarios and for each levy/feebate mechanism. The various scenarios may have a peak in different years, but the intention is to show the peak capacity needed for newbuilds and retrofitting.

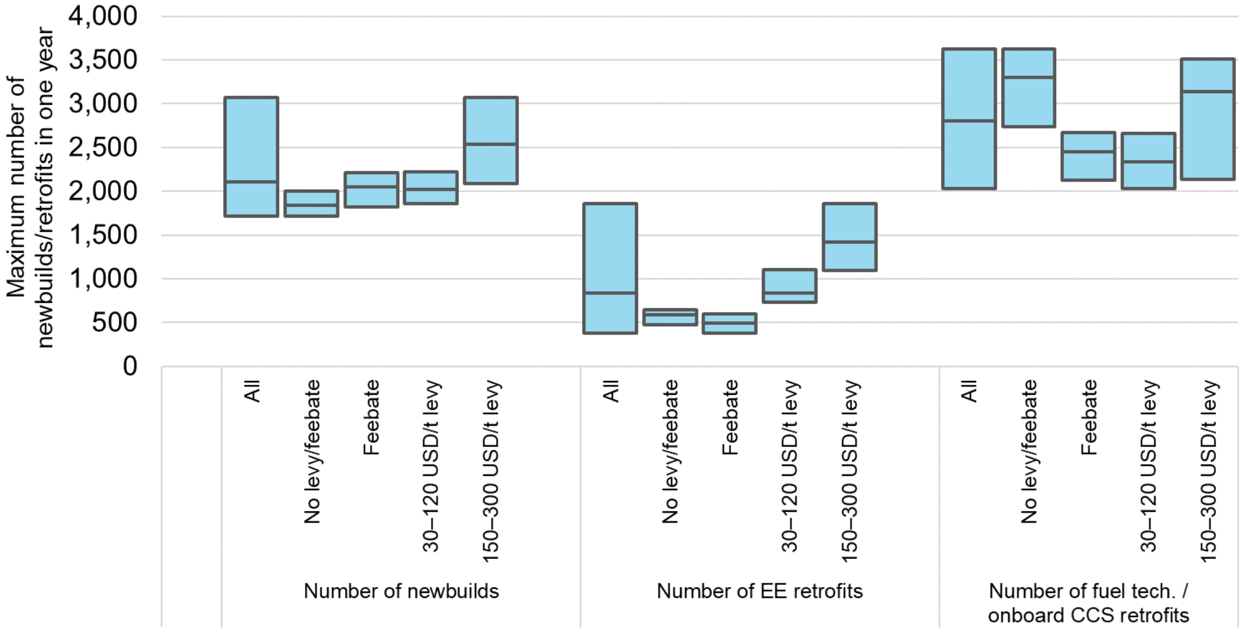

Figure 6-13: Range of maximum annual number of newbuilds, energy-efficiency retrofits, and fuel technology / onboard CCS retrofits in the period 2023–2050 for all scenarios and for each levy/feebate mechanism.

The scenarios see a peak of around 1,700 and 3,100 annual newbuilds, with the highest being in scenarios with a 150–300 USD/tCO_2eq levy. This is due to the sudden demand for new ships because of speed reduction driven by the high levy. The variation in the other scenarios is smaller. A similar trend is seen for retrofitting of energy-efficiency packages, which for scenarios with a 150–300 USD/tCO_2eq levy peaks at 1,100 to 1,900 annual retrofits, while scenarios with a 30–120 USD/tCO_2eq levy peak at 700 to 1,100 retrofits. Scenarios with a feebate or without a levy/feebate peak at around 500 to 600 annual retrofits.

Retrofitting of fuel technologies or onboard CCS peaks between 2,000 and 3,600, with a large variation for scenarios with a 150–300 USD/tCO_2eq levy. For scenarios with no levy or feebate mechanism, the retrofitting to onboard CCS is higher than in the other scenarios, which leads to a higher peak than for scenarios with a 30–120 USD/tCO_2eq levy or feebate.

The average number of newbuilds delivered from 2002–2022 was 2,053 vessels per year, peaking at 3,965 ships in 2010 (Ricardo & DNV, 2023), indicating that the number of newbuilds required in the scenarios should be within the capacity of the yards given time to scale up the production.

The peak annual number of retrofits to other fuel technologies or onboard CCS, and to some degree energy-efficiency measures, are significant. Due to the complexity of retrofitting ships to these technologies it remains uncertain if these numbers are feasible for the yards and equipment manufacturers to deliver. For reference, the number of retrofits to scrubbers peaked at more than 2,400 in 2019 (AFI, 2024), a level which is exceeded in more than half of the scenarios. It should be noted that retrofitting technologies such as ammonia and onboard CCS may be more extensive than retrofitting to scrubbers. Lloyds' Register (2023) indicates a current capacity of 308 fuel retrofits per year. Our modelling has not included any constraints on the number of retrofits each year, or that this could lead to longer off-hire period.

The implication if these retrofit rates are not feasible is that more ships will have to run on drop-in fuels such as bio-MGO and e-MGO, potentially resulting in higher costs.

6.4 Impact of research and development

Disbursements for RD&D (D1) can reduce the cost either indirectly via research and development (R&D) spending, or directly via deployment of fuels to ships. The latter would be equivalent to D4 disbursement under the condition that it results in direct cost reduction for ships. We do not go further into how such a direct disbursement to deployment can be achieved in this study beyond what is already included as D4 disbursements in the modelling.

For D1 disbursement to R&D, it has not been possible based on a literature review to determine an explicit link between a certain magnitude of spending for R&D and the effect it would have on technology maturity, improvements, and costs Consequently, it has not been possible to quantify the effect on the cost intensity of the fleet of such spending. To provide an indication about the potential cost savings that can be achieved by R&D, we have instead run sensitivity scenarios where we made assumptions about certain conditions that are achieved through R&D funding, such as accelerated technology development and learning effects. For this reason, these sensitivity scenarios are specifically discussed in this section.

We assume that the development and commercialization of ammonia and hydrogen dual-fuel internal combustion engines, fuel cells, onboard carbon capture, and the *Cutting-edge* energy-efficiency package, are all accelerated, and that the technologies become available one to two years earlier than in the main scenarios (see Appendix E for the exact assumptions). Further, we assume that through, for example, large-scale piloting, a learning effect is achieved for later commercial installations, resulting in a 20% lower capital cost for the same technologies. It should be noted that the accelerated learning effect only impacts the capital cost of the early installations and does not change the capital cost achieved at the stage when the technologies are fully matured – in other words, the same learning effect applies as in the main scenarios, but we start at a more advanced stage of learning. We do not assume any changes to the energy saving potentials of the energy-efficiency packages.

Figure 6-14 shows the impact on key indicators as the average difference across the four representative scenarios for which the sensitivity scenarios are run, provided the assumed conditions on availability and cost reductions above are achieved.

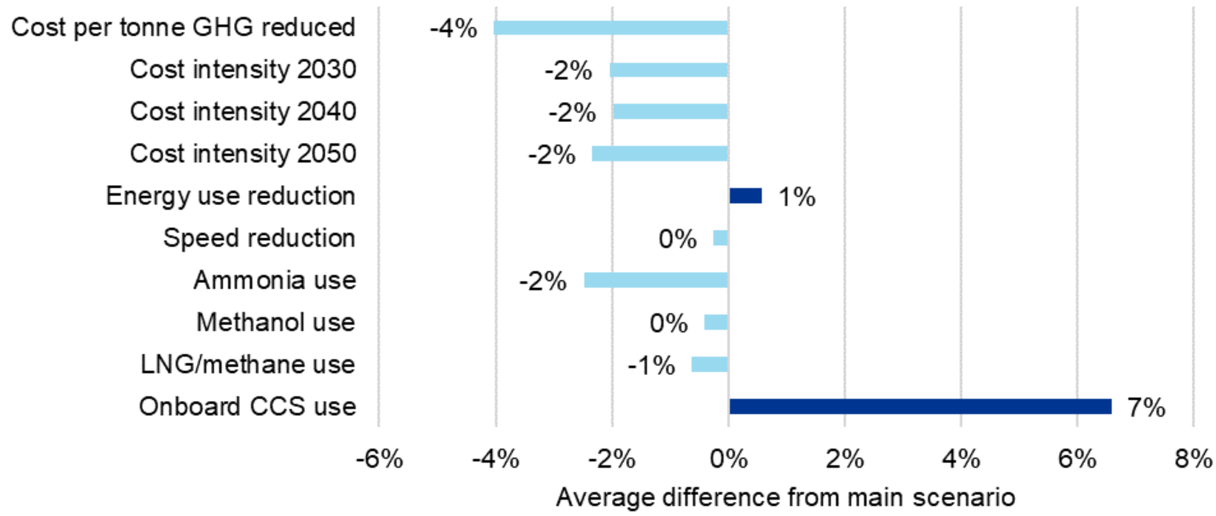

Figure 6-14: Average difference for the representative scenarios (23, 32, 46 and 55) with accelerated maturity and learning effects relative to the same scenario with the main assumptions. The impact on cost per tonne of GHG reduced is given in per cent, while for the other indicators it is given in percentage points.

The cost-intensity increase is reduced by two percentage points in all target years (2030, 2040, 2050) and the total cost per tonne of GHG reduced is 4% lower. The energy use and speed reduction see small changes, while the use of onboard CCS increases. This is due to the CCS technology becoming available from 2028, at which point the cost of low emission fuels is at its highest and onboard CCS is the most competitive technology. The effects are similar across the four representative scenarios for which the sensitivity is run (see Appendix E).

The sensitivity scenarios indicate that there is a potential for reducing the cost on the fleet by R&D spending if this results in earlier availability of technologies and reduced capital costs. A 4% reduction in cost amounts to about 200 BUSD saved over the whole period 2023–2050. It has not been possible to ascertain the magnitude of spending required to achieve the effect assumed in the sensitivity scenarios. It should be noted that these scenarios do not assess the feasibility of feedstock supply or carbon storage capacity to support these solutions, or whether accelerating the technologies and learning effects is achievable.

6.5 Carbon intensity and uptake of zero or near-zero GHG emission technologies, fuels, and/or energy sources in 2030

The ambitions stated in the IMO GHG Strategy to reduce the carbon intensity as well as the uptake of zero or near-zero GHG emission technologies, fuels, and/or energy sources in 2030 are not included as mandatory targets in the scenario modelling (see Section 1.2.2). Figure 6-15 shows the carbon-intensity reduction relative to 2008 and the uptake of what is termed low GHG emission fuels and onboard CCS in 2030 for each of the 32 modelled policy combination scenarios.

The carbon intensity is measured using the demand-based metric based on the IMO Energy Efficiency Operating Indicator (EEOI) expressed as gCO_2/tonne-mile and calculated dividing the total TtW CO_2 emissions by the total transport work for the fleet. Note that any carbon captured is not deducted from the TtW CO_2 emissions for the purpose of this calculation, as it is not clear how this is to be taken into account for measuring the demand-based carbon intensity or in the EEOI calculation. The reduction is calculated relative to the EEOI for 2008 of 17 gCO_2/tonne-mile stated in MEPC 81/6/1.[14] It should be noted that the scope of the fleet and method for calculating the EEOI in 2008 may differ from the calculation presented here and the resulting achieved reductions should be considered as an indication only.

There is no agreed definition of "*zero or near-zero GHG emission technologies, fuels and/or energy sources*" as stated in the IMO GHG strategy. In Figure 6-15, we show in the left panel the uptake of bio-, e- and blue fuels, and in the right panel the uptake of the same fuels and including the energy used in conjunction with onboard carbon capture. In both cases the uptake is calculated relative to the total energy use, which also includes the additional energy used for carbon capture.

[14] MEPC 81/6/1 - Report on annual carbon intensity and efficiency of the existing fleet (Reporting years: 2019, 2020, 2021 and 2022), Note by the Secretariat.

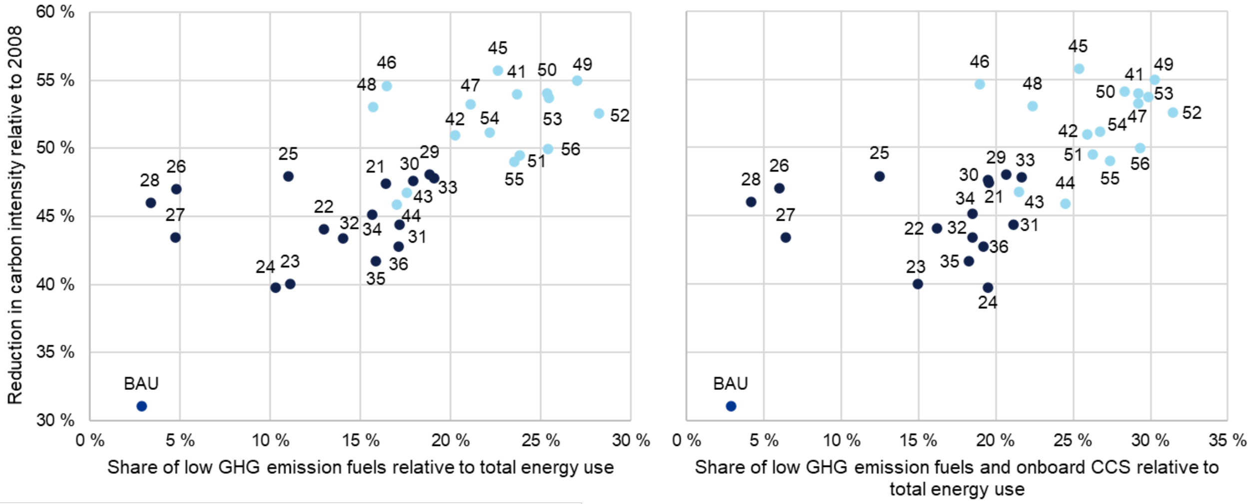

Figure 6-15 Share of low GHG fuels and onboard CCS relative to the total energy use in 2030 (x-axis) and reduction in carbon intensity relative to 2008 (y-axis) per scenario. The left panel includes only low GHG fuels, while the right panel includes both low GHG fuels and onboard CCS in the x-axis. The labels show the scenario number (see Table 4-1).

Figure 6-15 shows that the majority of scenarios achieve both 40% carbon-intensity reduction and the 5%, striving for 10%, uptake of zero or near-zero GHG emission technologies, fuels, and/or energy sources. Scenarios 26 to 28, which have a 150–300 USD/tCO_2eq levy, show a high reduction in energy use and do not need to meet the 5% uptake ambition in order to reach the *Base* trajectory of 20% GHG emissions reduction in 2030. Scenarios 23 and 24, which include a GFI flexibility mechanism and no levy or feebate, have a high uptake of onboard CCS in 2030 and are very close to, or do not meet, the carbon-intensity reduction ambition.

7 SENSITIVITY ANALYSIS AND UNCERTAINTIES

This chapter contains an analysis of the model sensitivities based on 36 sensitivity scenarios, a discussion of key uncertainties, and a comparison of the results with the findings from the World Maritime University's (WMU) literature review. Detailed results from the sensitivity scenarios, and further discussion of uncertainties, are provided in Appendix E.

7.1 Sensitivity analysis

The results from the 32 scenarios indicate the impact of various policy combinations while keeping other inputs and assumptions fixed. In this section, we analyse the sensitivity of the modelled results with respect to other input data and assumptions. We run sensitivity scenarios where we systematically change one input variable at a time. The changes in the parameters should be in the lower or upper end of an expected range, but not reflect the extreme range of possibilities (see the discussion of uncertainties in Section 7.2 and Appendix E.2).

It was not feasible within the scope and timeframe of this study to investigate all possible sensitives of the modelling work in combination with all policy scenarios. In discussion with the Steering Committee, nine sensitivities as listed in Table 7-1 were selected to run in combination with four representative scenarios (23, 32, 46 and 55 as listed in Table 7-2) covering the *Base* and *Strive* GHG emission trajectories and different policy combinations. The detailed results from the sensitivity scenarios are provided in Appendix E.

Table 7-1: List of inputs/assumptions and associated change investigated in the sensitivity analysis.

Input/assumption	Changed inputs	Reason
Low fuel prices	The e-fuel production prices follow the lowest trajectory provided in the literature sources (see Appendix B.7) The prices are about 20% to 45% lower than the base assumptions. Biofuel and blue fuel prices are adjusted according to the lower e-fuel prices (see Section 1.2.5).	Fuel prices are expected to be the input with the greatest impact on the resulting total cost and cost intensity, and this sensitivity investigates a low fuel-price development.
High fuel prices	The e-fuel production prices follow the highest trajectory provided in the literature sources (see Appendix B.7). The prices are about 20% to 55% higher than the base assumptions. Biofuel and blue fuel prices are adjusted according to the higher e-fuel prices (see Section 1.2.5).	Fuel prices are expected to be the input with the greatest impact on the resulting total cost and cost intensity, and this investigates a high fuel prices development.
High bio- and blue fuels availability	The bio- and blue fuel availability are according to the high estimated supply (see Table 1-2).	The feedstock supply projections are highly uncertain. This sensitivity investigates how much a higher bio- and blue fuel availability – while keeping the adjusted fuel prices – would influence the cost.
Strengthened uptake of energy-efficiency measures	All ships will implement a 30% speed reduction, the highest speed reduction included in the modelling, and will retrofit	Many scenarios do not show a large uptake of energy-efficiency measures in the early stage, and the intention is to investigate the

Input/assumption	Changed inputs	Reason
	to the Enhanced or Advanced EE package. All newbuilds will implement the Advanced EE package.	potential cost saving if all measures were applied.
No onboard CCS	Onboard CCS is not available as a GHG-reduction option.	Onboard CCS is a prevalent solution in all scenarios, and this sensitivity investigates the impact if this technology fails to mature sufficiently for commercial deployment, if the reception and storage infrastructure is not available for shipping, or if the solution is not being accepted in regulations.
50% higher onboard CCS costs	Capital costs, fuel penalty, and deposit costs increased by 50%, which generally cover the cost range reported in literature (see Appendix E.2.5)	Onboard CCS is a prevalent solution in all scenarios, and this sensitivity investigates the impact if the solution is more costly.
High seaborne trade growth	Seaborne trade growth is set according to scenarios SSP2_RCP2.6_L from the Fourth IMO GHG study (see Appendix B.2).	A higher shipping activity would make it more difficult to reach the absolute emission targets, and this sensitivity investigates the potential costs.
No regional requirements from 2030	EU ETS and FuelEU Maritime are no longer in effect from 2030 and onwards.	This investigates the impacts in case the EU sunsets its GHG emission-reduction policies for shipping (i.e. EU ETS and FuelEU Maritime).
R&D – accelerated maturity and learning	Ammonia internal combustion engine (ICE) available from 2025; onboard CCS, hydrogen ICE, and fuel cells available from 2028. Cutting Edge energy-efficiency package available from 2028. All technologies have 20% lower capital costs.	As we do not provide a direct link between a certain spend on R&D (D1 disbursement) and the effect on technology maturity and costs, we instead investigate the potential cost savings on the condition that certain outcomes are achieved through R&D funding related to accelerated technology development and learning effects including large-scale demonstrations and pilots.

Table 7-2: List of the four representative scenarios for which sensitivities are investigated.

Scenario number	Emission trajectory	Seaborne trade growth	Policy combination						
			Policy code	GFI scope	GFI flexibility		Levy		Feebate
					RU % of price	SU % of price	Levy USD/tCO_2eq	Reward % of gap	Reward % of gap
23	*Base*	Low	X.4	TtW	120%	80%	No levy		No feebate
32	*Base*	Low	Y.5	WtW	120%	80%	30–120	105% to 2040	No feebate
46	*Strive*	Low	Y.2	WtW	No flexibility		150–300	90% to 65% to 2040	No feebate
55	*Strive*	Low	X.6	TtW	120%	80%	No levy		105% to 2040

7.1.1 Changes in key indicators per sensitivity

Figure 7-1 shows the changes in key indicators (as explained in the introduction to Chapter 6) for the period 2023–2050 as an average of change for the four representative scenarios for each of the nine sensitivities analysed. Note that the change in cost per tonne of GHG reduced is given in per cent, while for the other indicators the changes are given in percentage points.

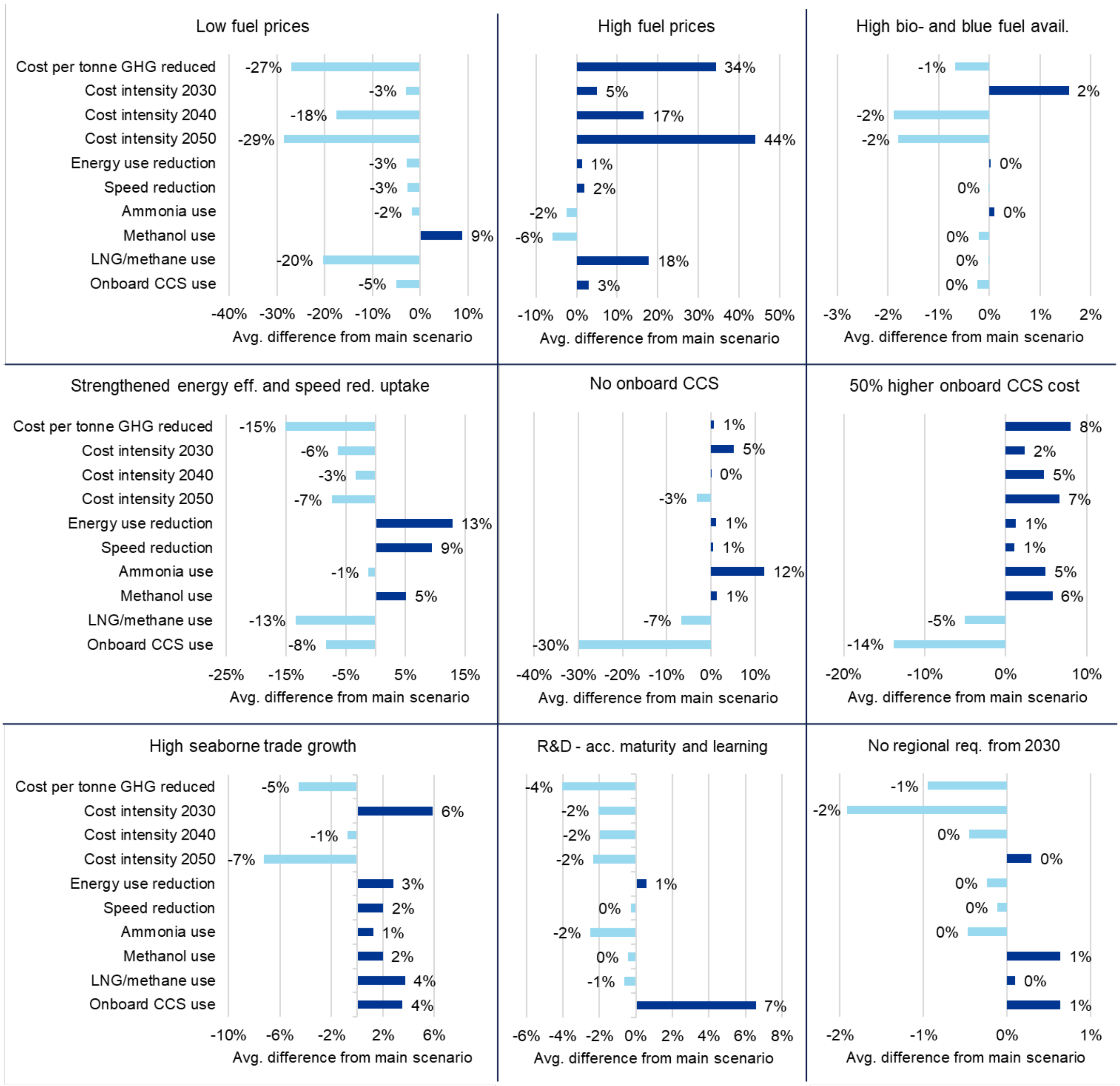

Figure 7-1: Changes in key indicators for the period 2023–2050 as an average of change for the four representative scenarios for each of the nine sensitivities analysed. Note that the change in cost per tonne of GHG reduced is given in per cent, while for the other indicators the changes are given in percentage points, all relative to the respective main scenario results. Note also that the x-axis scales differ per sensitivity.

The modelled results are very sensitive to changes in fuel costs, with the low fuel prices resulting in a 27% reduction in cost per tonne of GHG reduced while the high fuel prices resulted in a 34% higher cost. High fuel prices also lead to higher uptake of methane/LNG and to some degree onboard CCS, while lower fuel prices lead to significantly lower use of methane/LNG and somewhat higher use of methanol. The remaining changes in the fuel mix would be on MGO, but are not shown in the charts.

The cost intensity is significantly higher in scenarios 21 to 56, compared to scenarios 1 to 18 which, due to supply constraints, do not include adjusted fuel prices for bio- and blue fuels. The average cost intensity is about 40% higher in 2050 and the total cost per tonne of GHG reduced in the period from 2023–2050 is almost 60% higher in scenarios 21 to 56 with adjusted fuel prices than in scenarios 1 to 18.

Increasing the availability of biofuels leads to only minor changes with a 1% reduction in total cost per tonne of GHG reduced.

Forcing the uptake of speed reduction and energy-efficiency packages also has a significant impact. The speed is reduced by 20% and total energy use by 30%, relative to BAU, compared to 11% and 13%, respectively, without the change in input. This leads to a 15% reduction on cost per tonne of GHG reduced, and a lower use of methane/LNG and onboard CCS.

Removing the option of onboard CCS increases the use of ammonia and reduces the use of methane/LNG as this fuel is used in combination with onboard CCS. The cost intensity in 2030 increases by five percentage points to 34% relative to BAU as the low GHG emission fuels are more expensive initially and ships are forced to choose these fuels if onboard CCS is not an option. Over time, the impact is reversed, with a three percentage point lower (down to 76%) increase in cost intensity relative to BAU in 2050 as the low GHG emission fuels have a much lower cost at this stage. The overall cost per tonne of GHG reduced sees a 1% increase for 2023–2050 if removing the option of CCS.

If onboard CCS becomes 50% more expensive, it still remains a viable option although its use is about halved from 30% to 14% of total reduced GHG emissions. Ammonia and methanol see an increased use to replace onboard CCS, while methane/LNG is reduced as this fuel is used in combination with onboard CCS. For some of the sensitivity scenarios with high use of onboard CCS, the cost intensities and the total cost increase and are even higher than in the scenarios where onboard CCS is removed as an option. This indicates a certain lock-in effect where ships choose onboard CCS initially because it has a lower cost than other options. Over time, as the prices of other low GHG emission fuels such as e-ammonia reduce, onboard CCS is not the most optimal solution in a total cost perspective (i.e. including CAPEX and OPEX). However, ships that have installed this solution remain committed to it, meaning that the capital cost of changing solutions is too high.

The results of the sensitivity scenarios also show some differences in impact between the four representative scenarios with regards to onboard CCS. A 50% higher cost of onboard CCS for scenarios 23 and 55 had a larger impact on the cost-intensity increases in 2050 and also the uptake of methanol. These two TtW scenarios have a higher uptake of onboard CCS also in the sensitive scenarios, and are impacted more compared to scenarios 32 and 46 where the uptake of onboard CCS is replaced by uptake of ammonia.

With a higher seaborne trade growth, the cost per tonne of GHG reduced goes down. The reason is that in these scenarios there is a higher number of newer and more energy-efficient ships in the fleet, which is indicated by the higher reduction in energy use. The cost intensity increase in 2030 is six percentage points higher, as with a higher activity each ship would need to reduce emissions more to meet the target trajectories in total. For 2030, the impact of higher seaborne trade is greater than the impact of high fuel prices. In 2040 and 2050, the cost-intensity increases are lower at one and seven percentage points, respectively, as the early GHG emission and energy-use reduction achieved takes effect, and the GHG intensity reductions required under low-growth and high-growth scenarios become the same. It should be noted that the high-growth scenarios are compared with the BAU scenario with the same growth assumptions (BAUHG).

If the regional requirements (EU ETS and FuelEU Maritime) are removed from 2030, the impact is small with a 1% reduction in total cost per tonne of GHG reduced.

Impacts of accelerated R&D are discussed in Section 6.4.

7.1.2 Resulting range in key indicators

Figure 7-2 shows the range of increases in cost intensity in 2030, 2040, and 2050 and cost per tonne of GHG reduced in the period 2023–2050, relative to BAU. The blue boxes, with the median indicated, show the range (minimum to maximum) of the 32 policy combination scenarios, while the whiskers show the range of the 36 sensitivity scenarios, which are the focus in this section.

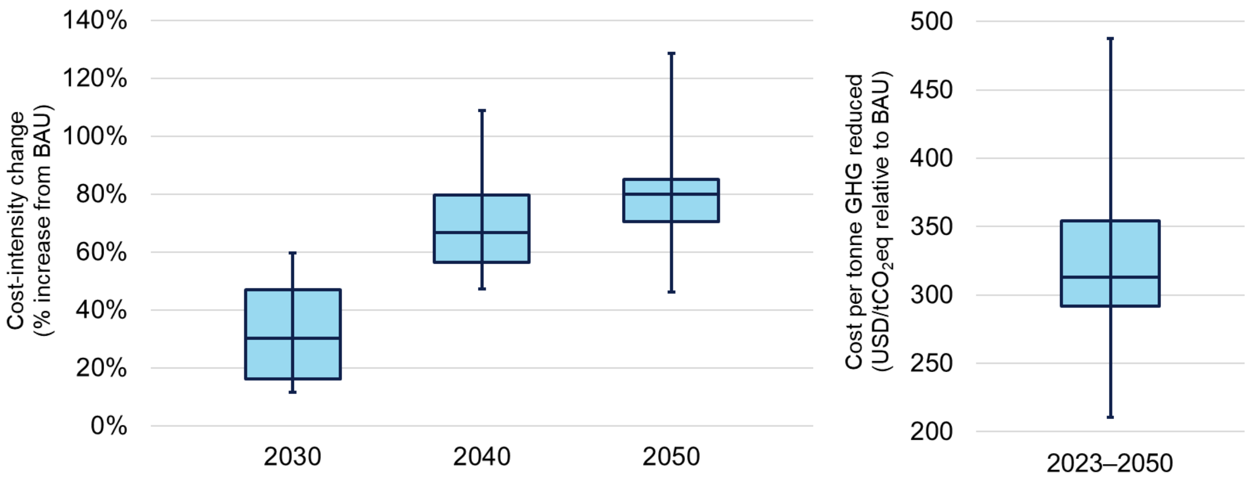

Figure 7-2: Range of cost-intensity increases in 2030, 2040, and 2050 (left panel) and total cost per tonne of GHG reduced in the period 2023–2050 (right panel) and relative to BAU. The blue boxes, with the median indicated, show the range of the 32 policy combination scenarios, while the whiskers show the minimum and maximum of the 36 sensitivity scenarios.

The cost-intensity increase in 2030 ranges from 12% to 60% when including all sensitivity scenarios. This is not much wider than the range resulting from the policy combination scenarios only. In 2040, the cost-intensity increases between 47% and 109%, and in 2050 between 46% to 129%. The range is significant mainly due to the uncertainty in fuel prices and the potential reduction in energy use. The total cost per tonne of GHG reduced is in the range 210–487 USD/tCO_2eq.

Figure 7-3 shows the range of reductions in speed and energy use, and in the use of ammonia, methanol, methane/LNG and onboard CCS for the 32 policy combination scenarios and the 36 sensitivity scenarios.

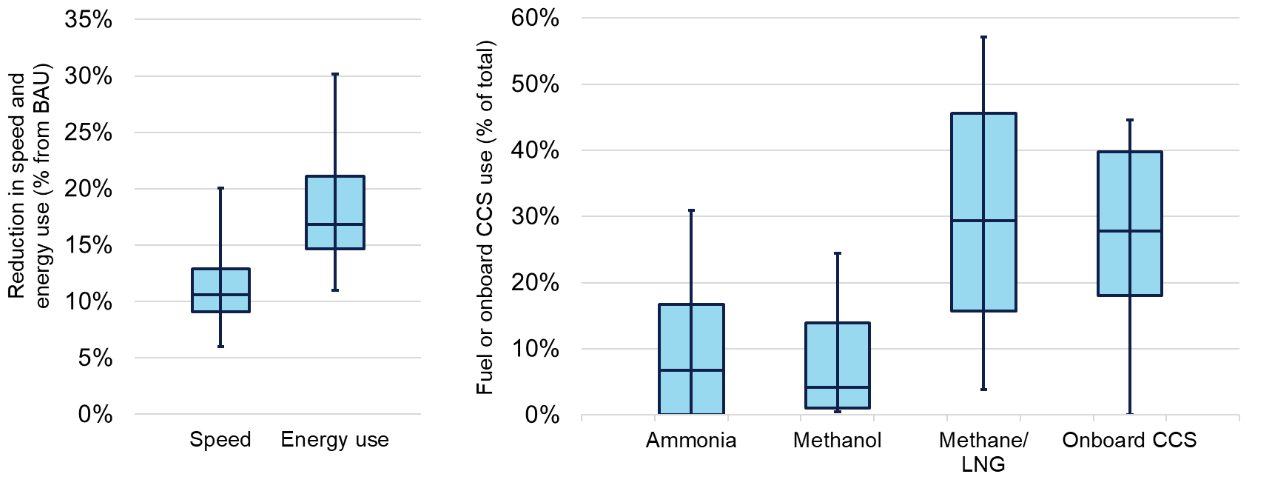

Figure 7-3: Range of reduction in speed and energy use relative to BAU (left panel) and fuel and onboard CCS use relative to total energy use / GHG emission reduced (right panel) in the period 2023–2050. The blue boxes, with the median indicated, show the range of the 32 policy combination scenarios, while the whiskers show the minimum and maximum of the 36 sensitivity scenarios.

If excluding the sensitivity scenarios where the uptake of energy-efficiency measures and speed reduction is forced, the reduction in speed ranges from 6% to 15% and the reduction in energy use ranges from 11% to 23% in the period 2023–2050. The lowest reductions are reached in scenarios with low fuel prices, and the highest reduction in the high seaborne trade scenarios. If including the sensitivity scenarios with forced uptake of energy-efficiency measures and speed reduction, the speed reduction reaches 20% and energy-use reduction 30%.

The fuel mix is diverse both within and across the scenarios with large ranges for all fuel types. Ammonia ranges from 0% to 31% of the total energy use, methanol from 0% to 25%, methane/LNG from 4% to 57%, and onboard CCS use from 4% to 45% of total GHG reduced (except in the scenarios where the technology is not available).

7.2 Uncertainties

In this section, we discuss the main uncertainties in the results due to the method, inputs, and assumptions. We assess the potential impact that the uncertainties have on the results and, where relevant, take into account the sensitivity analysis in Section 7.1 and Appendix E.1. A detailed discussion on the uncertainties is presented in Appendix E.2.

This study applies a scenario-based framework that can provide valuable insight into the impact of the proposed policy measures. The scenarios simulate the potential impact on the fleet given the policy measures, the inputs, and the assumptions.

Although the inputs and assumptions are within likely ranges as provided in literature and by the stakeholder feedback, there are significant uncertainties when modelling the fleet emissions and impact of policy measures 27 years into the future. The results from one specific scenario should not be considered a ‘most likely’ outcome, as the inputs and assumptions only provide a snapshot of one possible future. As each scenario is given equal weight, the set of scenarios cannot be used to establish a likelihood distribution of the impacts (Yuan, Ng, & Sou, 2016).

The 88 scenarios run during the course of the study give a good basis for assessing the impact of various policy combinations through analysing the difference between groups of scenarios. Although the sensitivity analysis has not investigated the full expected range of all inputs and assumptions, it covers the likely range of fuel prices identified as the most sensitive input parameter. The results of the sensitivity scenarios provide a likely range of impact for some key indicators such as total cost, cost intensity, and energy use. For other indicators, such as the uptake of certain fuels and technologies, the sensitivity analysis has shown that small changes in inputs on fuel prices and policy combinations such as the levy and reward levels can give very different outputs. Also, the potential constraints of feedstock supply and carbon storage capacity indicate that the results are less robust on the energy mix and uptake of onboard carbon capture.

The key uncertainties, with an assessment of the potential impact on the results, are provided in Table 7-3:

Table 7-3: Key uncertainties and an assessment of the potential impact on the results.

Input/assumption	Impacts
2008 reference and 2023 baseline WtW GHG emissions and in particular identifying international voyages	The uncertainty in determining the share of international can impact achieved GHG emission reduction in 2023 and consequently the *Base* and *Strive* GHG trajectories to 2030 and 2040. The identified share increased from 67.7% in 2022 to 71.9% in 2023 which leads to a 6% higher emission estimate for international shipping.
Seaborne trade growth	This study relies mainly on a low seaborne trade growth scenario. Increased shipping activity due to growth in seaborne trade demand would make the absolute emission targets in 2030 and 2040 more difficult to reach. The high seaborne trade growth scenario resulted in a six percentage points (pp.) greater cost-intensity increase in 2030, and then 1 pp. and 7 pp. lower cost-intensity increase in 2040 and 2050, respectively. Toward 2050, the GHG-intensity reductions required under low-growth and high-growth scenarios become the same, but the effect of more modern and energy-efficient ships in the fleet dominates and reduces the cost-intensity increase.
Fuel prices	Changes in fuel prices would have a significant impact on costs. Using low to high fuel prices from literature results in a range of 27% lower to 34% higher cost per tonne of GHG reduced.
Fuel feedstock supply and carbon storage capacity	There are significant uncertainties about supply of fuel feedstock and carbon storage capacity available for shipping. Supply constraints may lead to increased energy prices with impact as for fuel prices above. As there are several feedstock pathways and onboard CCS as an alternative solution, a constraint on one feedstock or carbon storage capacity alone may not have a large impact. However, in most scenarios, except those with high reduction in energy use, the total feedstock demand and carbon storage requirements exceed the median estimated supply and capacity projections in the literature. To achieve the GHG emission trajectories within the assumed supply constraints all fuel feedstocks need to be used, complemented by onboard CCS and reduction in energy use by way of energy-efficiency measures and speed reductions.
Fuel technology costs	There are uncertainties related to future costs of new fuel technologies, the impact of loss of cargo space due to fuels with lower energy density, and extrapolating cost assumptions based on a few segments to all segments. The loss of cargo space, and a possible reduced range for ships, could impact on operations and consequently costs. 20% lower capital cost and earlier availability of fuel, onboard CCS and energy efficiency technologies could lead to 4% lower cost per tonne of GHG reduced.
Energy-efficiency costs and potential	Changing the capital costs of energy-efficiency measures by 25% is expected to have a small impact on costs as CAPEX in total is only about 20% of total costs. Increasing the uptake of energy-efficiency measures and speed reduction can lead

Input/assumption	Impacts
	to an additional 20% reduction in energy use, decreasing by 15% the cost per tonne of GHG reduced. The potential cost savings, which are not realized in other scenarios, indicate that there are significant financial and non-financial barriers to the uptake, such as split incentives. Other policy measures, beyond those investigated in the scenarios, to overcome these barriers have not been investigated in this report.
Onboard CCS costs and effect	The impact of loss of cargo space, shorter range, and operational expenses besides the fuel penalty are not included in our assumptions. Both the loss of cargo space and the required rerouting for offloading could impact on operations and consequently costs. There are also uncertainties related to the maturity of the technology, required infrastructure, and lack of regulations. 50% additional costs (CAPEX, fuel penalty, and deposit costs) could lead to a halving of the uptake of CCS and an 8% higher cost per tonne of GHG reduced. If onboard CCS is not available, the cost-intensity increase is higher in the short term, by 5 pp. in 2030. Over time, the impact is reversed with a 3 pp. lower cost-intensity increase in 2050, and the overall cost per tonne of GHG reduced sees only a 1% increase.
Feasibility of retrofitting and newbuild capacity	There are no constraints on the number of newbuilds and retrofits in the modelling. Constraints on retrofitting capacity for fuel technologies and solutions such as ammonia, methanol, and onboard CCS may lead to more ships having to run on drop-in fuels such as bio-MGO and e-MGO, potentially resulting in higher costs.
Modelling the GFI flexibility mechanism	The modelling of RU revenues and SU disbursements are based on a simplified method and the results should be seen as an indication of the revenue stream given the assumptions. Using the marginal cost of the last ship implementing a measure in a pool is likely not a very good indicator for the emission unit exchange price for all ships in the pool. The actual price is likely lower as many ships will also have lower abatement costs. The modelling of the flexibility mechanisms did not include any transaction costs for emission unit exchange. Adding this could lead to a lower volume of trading and less cost reductions from the flexibility mechanism.
Solutions for reaching net-zero GHG emissions	There are currently no known solutions to remove the remaining CH_4 and N_2O emissions from internal combustion engines. If no abatement solution is found towards 2050, or unless all ships convert to, for example, fuel cells, it could lead to 20–30 $MtCO_2eq$ remaining GHG emissions in 2050. With a flexibility mechanism, these emissions could be balanced by more onboard CCS.
Measures not included	New measures to reduce GHG emissions could emerge in the next decades; for example, onboard nuclear power, liquid organic hydrogen carrier (LOHC), wave powering of ships, ballast-free ships, and fully wind-powered autonomous vessels. This may lead to significant cost savings compared to the fuels and technologies included in this study, but these technologies are current insufficiently mature to assess their potential.

Input/assumption	Impacts
Other uncertainties	A premium on low GHG emission services paid by the cargo owner could decrease the cost for the shipowner in the short term. However, as all ships need to reduce GHG emissions towards 2050, this effect is removed. This study does not model an uptake of shore power based on cost but assumes an uptake of 5% of total energy use from auxiliary engines. This is in the lower end of projected potential and a higher uptake would reduce the need for other low GHG emission fuels and likely reduce cost.

7.3 Comparison of results with the literature review

In Task 1 of the Comprehensive Impact Assessment, WMU (2024) has conducted a literature review which includes the result of studies providing projections of energy use and fuel mix in shipping to 2050. Table 7-4 shows the comparison of key results from this study with the findings from the literature review.

Table 7-4: Comparison of key results in this study with finding from WMU's literature review (WMU, 2024).

Item	WMU literature review	This study
Transport work in 2050	100,000–150,000 billion (bn) tonne-miles	Low growth: 85,000 bn tonne-miles High growth: 104,000 bn tonne-miles (only provided in sensitivity scenario)
Energy use in 2050	3.5–17.0 EJ	10.8–11.9 EJ with CCS fuel penalty 9.4–9.7 EJ without CCS fuel penalty
Energy intensity in 2023	0.17 MJ/tonne-mile	0.172 MJ/tonne-mile
Energy intensity in 2050	0.064–0.105 MJ/tonne-mile	0.133–0.146 MJ/tonne-mile with onboard CCS fuel penalty 0.115–0.118MJ/tonne-mile without CCS fuel penalty 0.096 MJ/tonne-mile in the sensitivity scenario with the lowest energy intensity.
Fraction of zero or near-zero GHG emission fuels in 2030	10% to 20% of total energy use	3% to 28% of total energy use
Fraction of zero or near-zero GHG emission fuels in 2040	27% to 100% of total energy use	32% to 59% of total energy use 77% to 94% if including onboard CCS
Ammonia uptake in 2050	40% to 100% of total energy use	0% to 21% of total energy use
Methanol uptake in 2050	2% to 20% of total energy use	3% to 24% of total energy use

The comparison shows that the assumed growth in seaborne trade in this study is lower than transport work projections in the literature (reported by IEA and IRENA). The impact of a higher seaborne trade growth is covered in Section 7.2.

The energy use reported in the literature varies widely and the results in this study are in the middle of this range, in which the majority of studies reported by WMU also lie. The energy intensity measured in MJ per tonne-mile in 2023 in this study matches the reported intensity in literature (reported by Clarksons). However, in 2050 the lowest energy intensity found in this study is greater than the highest intensity reported in literature (reported by IEA and IRENA). The energy-intensity improvement from 2023 to 2050 reported by literature is 38% to 62%, while in this study we indicate an improvement of 33% in the same period. With the forced uptake of all energy-efficiency measures and a 30% speed reduction, we achieve a 38% improvement in energy intensity. It is not clear how the energy-intensity improvements are achieved in the reports from the literature review.

The share of zero or near-zero GHG emission fuels in 2030 reported by literature is 10% to 20% of total energy use, while in this study we estimate between 3% to 28% uptake. In 2040, the share reported by literature is 27% to 100%, while in this study we estimate 32% to 59% if including only low GHG emission fuels, and 77% to 94% if also including onboard CCS.

The largest deviation is on the uptake of ammonia in 2050. In the literature, it is reported to be 40% to 100% of total energy use, while in this study we have an uptake between 0% to 21%. For methanol, the reported uptake in 2050 is 2% to 20%, which is close to the 3% to 24% uptake in this study.

The highest uptake of ammonia is 43%, which is in the sensitivity scenario with no onboard CCS in combination with a 150–300 USD/tCO_2eq levy and no GFI flexibility mechanism (scenario 46). For other sensitivity scenarios, the largest uptakes of ammonia are when onboard CCS is not an option. This indicates that onboard CCS, even in the sensitivity scenarios where it has a 50% higher cost, is the main reason for the lower uptake of ammonia compared to the reports in the literature review.

8 CONCLUSIONS

This study has assessed the impacts on the fleet of the basket of candidate measures designed to achieve the GHG reduction goals set out in the 2023 IMO Strategy on Reduction of GHG Emissions from Ships (IMO GHG Strategy). The study comprises Task 2 of the IMO's comprehensive impact assessment of the basket of candidate mid-term GHG reduction measures. We have applied a scenario-based framework, modelling 88 scenarios to analyse the effects of various policy combinations and to assess impacts on the fleet to 2050.

The key findings of the study are:

Impact on costs

- The **cost intensity of the fleet**, measured in USD per tonne-mile, is expected to increase relative to a BAU scenario by 16% to 47% in 2030, 56% to 80% in 2040, and 71% to 85% in 2050.
- **In 2030,** the cost intensity of the fleet is expected to increase relative to a BAU scenario by **16% to 40%** across 16 policy combinations following the *Base* GHG emission trajectory of 20% reduction from 2008, and by **26% to 47%** across 16 policy combinations following the *Strive* GHG emission trajectory of 30% reduction from 2008.
- The lowest increases in cost intensity in 2030 are found in scenarios with a GHG Fuel Intensity (GFI) flexibility mechanism and no levy or feebate, while the highest increases are in scenarios with a 150–300 USD per tonne of carbon dioxide equivalent (tCO_2eq) levy due to the direct cost of the levy.
- **In 2040,** the cost intensity of the fleet is expected to increase relative to a BAU scenario by **56% to 71%** following the *Base* GHG emission trajectory of 70% reduction from 2008, and by **65% to 80%** following the *Strive* GHG emission trajectory of 80% reduction from 2008.
- The lowest increases in cost intensity in 2040 are found in scenarios with a GFI flexibility mechanism and a 30–120 USD/tCO_2eq levy. The range of cost-intensity increase is less in 2040 than in 2030 as the reductions in energy use across the policy combination scenarios are more similar, driven mainly by the increased costs of meeting the GFI requirements and to a lesser degree by the cost of the levy/feebate.
- **In 2050,** the cost intensity of the fleet is expected to increase relative to a BAU scenario by **71% to 85%** following the *Base* GHG emission trajectory, and by **73% to 83%** following the *Strive* GHG emission trajectory.
- The *Base* and *Strive* GHG emission trajectories have similar ranges of cost-intensity increases as they both achieve close to net-zero GHG emissions in 2050. The lowest increases in cost come in scenarios with a levy and a GFI flexibility mechanism.
- The aggregated cost per tonne GHG emission reduced over the whole period **from 2023 to 2050** ranges from **292 to 354 USD/tCO_2eq**. The lowest costs per tonne of GHG emission reduction are in the scenarios following the *Strive* GHG emission trajectory and in scenarios with a GFI flexibility mechanism.

Impact on energy use, fuels, and technologies

- The results show **a diverse mix of fuels and solutions** both within and across scenarios where electrofuels (e-fuels) and onboard carbon capture and storage (CCS) appear to be the two most prevalent decarbonization solutions. Biofuels also have a significant contribution towards 2040 and 2050 across all policy scenarios. It should be noted that the modelled use of different feedstocks is to a large degree a result of the assumed supply constraints on bio- and blue fuel feedstocks, and also the assumed lack of constraints on e-fuels and carbon storage capacity. The projected feedstock supply and carbon storage capacity and the share available for shipping are very uncertain.
- To achieve the GHG emission trajectories within the assumed supply constraints all fuel feedstocks need to be used, complemented by onboard CCS and reduction in energy use by way of energy-efficiency measures and

speed reductions. In 2030, the uptake of low GHG emission fuels is between 0.3 and 2.9 exajoules (EJ), or about 7.2–69 million tonnes oil-equivalents, with the lowest uptake in scenarios with high reduction in energy use or high uptake of onboard CCS. In most scenarios, except those with high reduction in energy use, the total **feedstock supply and carbon storage capacity** exceed the median estimated projections in the literature.

- **Reduction of energy use** in the fleet can significantly reduce the need for low GHG emission fuels and onboard CCS, which will reduce overall costs and increase the ability to reach the GHG emission trajectories under fuel feedstock supply constraints. There are barriers to implementation of energy-efficiency measures and speed reductions. A high GHG price or following the more stringent *Strive* GHG emission trajectory seem to increase the costs sufficiently to incentivize energy-efficiency improvements in the early period to 2030.

Impacts of different policy combinations

- Applying a **tank-to-wake scope with sustainability criteria or a well-to-wake scope** did not result in any significant differences in cost intensity as the scenarios follow the same well-to-wake GHG emission trajectory. The well-to-wake scope scenarios combined with a levy have a slightly higher cost because the absolute cost of the levy is higher when well-to-tank GHG emissions are included.
- A **GHG Fuel Intensity flexibility mechanism** can reduce the total cost per tonne of GHG reduction from 2023 to 2050 by about 6%. The GFI flexibility mechanism has the greatest effect when there are capital-intensive solutions – such as ammonia or methanol engines or onboard carbon capture systems – that enable ships to run on fuels with lower prices than drop-in fuels such as bio- and e-MGO. Towards 2050, the cost impact of the flexibility mechanism is lower.
- The GFI flexibility mechanism may also be beneficial during the build-up of production and infrastructure for alternative fuels when such fuels have limited global availability. Ships that cannot find adequate fuels may exchange emission units (i.e. join in a compliance pool) with ships trading in areas where low GHG emission fuels are more readily available. The modelling in this study does not quantify this effect.
- The **levy and feebate mechanisms** generally increase the cost intensity in 2030 due to the direct cost of the levy and fee, and limited reward for eligible fuels. Scenarios with a 150–300 USD/tCO_2eq levy have a higher reduction in energy use in 2030, which counters the additional cost to some degree. Towards 2040, as the GHG emission reduces and the uptake of eligible fuels increases, the total impact on cost intensity is less. Other than the reward for eligible fuels, it should be noted that no other disbursement of revenues to shipping are included in the modelling.
- **Significant revenues** can be generated by the levy or feebate mechanisms, ranging from 17 to 127 billion US dollars per year (BUSD/year) in the period 2027–2030 before these revenues decrease gradually with reduced GHG emissions towards 2050. It is estimated that about 2 to 35 BUSD/year in 2027–2030 and 15 to 42 BUSD/year in 2031–2040 will be distributed back to shipping as reward for eligible fuels. Remaining funds are available for other disbursement purposes. The GFI flexibility mechanism could also raise revenues through sale of Remedial Units to ships.
- The **reward for eligible fuels** in the levy and feebate mechanisms incentivizes uptake of e-fuels, in particular e-ammonia and e-LNG. Together with bio-LNG they have the highest uptake in scenarios with a levy in combination with a reward mechanism. The modelled uptake of fuel types is very sensitive to relatively small changes in the levy and reward levels.
- The modelling indicates that if **R&D spending** can result in two to three years' earlier availability of technologies as well as 20% less capital cost, the cost per tonne of lowering GHG emissions over the period 2023–2025 can be reduced by 4%. It has not been possible to ascertain the magnitude of R&D spending required to achieve the effect assumed in the modelling.

Key uncertainties

- The **main uncertainty** which has the most significant impact on the results are future fuel prices. Using the projected range of fuel prices from literature, the cost intensity increase relative to BAU in 2030 ranges from 12% to 60%, somewhat larger than the range due to varying the policy combinations. Towards 2040 and 2050, the uncertainty over fuel prices increases. The cost intensity increases between 47% and 109% by 2040, and between 46% and 129% by 2050. The total cost per tonne of GHG reduction within the projected range of fuel prices ranges from 210 to 487 USD/tCO_2eq.
- The **number of retrofits** to other fuel technologies or onboard CCS in the scenarios are significant, peaking between 2,000 and 3,600 retrofits per year. Due to the complexity of retrofitting ships to alternative fuel technologies and onboard CCS, it remains uncertain if these numbers are feasible for the yards and equipment manufacturers to deliver. The implication that such retrofit rates are unfeasible is that more ships have to run on more expensive drop-in fuels such as bio-MGO and e-MGO.

Although the inputs and assumptions are within likely ranges as provided in literature and by the stakeholder feedback, there are significant uncertainties when modelling the fleet emissions and impact of policy measures 27 years into the future. The main uncertainties that could have a significant impact on the results are future fuel prices; availability of low GHG emission fuel feedstocks and carbon storage capacity; uptake of energy-efficiency measures; cost and availability of onboard CCS; and yard retrofit capacities.

The results from one specific scenario should not be considered a most likely outcome, as the inputs and assumptions provide only a snapshot of one possible future. As each scenario is given equal weight, the set of scenarios cannot be used to establish a likelihood distribution of the impacts.

The 88 scenarios run during the course of the study give a good basis for assessing the impact of various policy combinations through analysing the difference between groups of scenarios. Although, the sensitivity analysis has not investigated the full expected range of all inputs and assumptions, it covers a likely range of fuel prices, which are identified as the most sensitive input parameter.

The results of the sensitivity scenarios provide a likely range of impact for some key indicators such as total cost, cost intensity, and energy use. For other indicators, such as the uptake of certain fuels and technologies, the sensitivity analysis has shown that small changes in inputs on fuel prices and policy combinations such as the levy and reward levels can give very different outputs. Also, the potential constraints of feedstock supply and carbon storage capacity indicate that the results are less robust on the energy mix and uptake of onboard CCS.

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APPENDIX A
Methods, tools, and models

This appendix provides a description of the methods, tools and models applied in this study.

A.1 Baseline fleet for 2023 using the MASTER model

DNV's MASTER model (Mapping of Ship Tracks, Emissions and Reduction potentials) uses global ship-tracking data from AIS, enriched with ship-specific data from other sources, to model energy use from individual ships. Use of the MASTER model has been described previously in (e.g. (Bingjie Guo, 2022; DNV GL, 2019; Mjelde et al., 2019; Mjelde et al., 2014)

AIS-data provide a detailed and high-resolution overview of current sailing speeds, operating patterns, sailed distances (nautical miles) and time spent at sea by each vessel. The information from AIS-data is combined with technical databases (e.g. IHS Markit (2023)) for detailed information on the individual ships, such as installed power on main and auxiliary engines and boilers, machine configuration (diesel-electric versus diesel-mechanical / direct-driven, and fuel used), specific fuel consumption, ship design speed, tonnage, etc.

These data form the basis for calculating energy use and operational characteristics for individual ships, with breakdown on operations modes such as transit, manoeuvring and in port. Separate calculations are made for main engines, auxiliary engines, and boilers for each individual ship.

The ship main engine energy demand is modelled using two modelling approaches, dependent on ship type. One approach is the power model used mainly for tank, bulk and container vessels, where ship resistance modelling (calm water resistance, air resistance, etc.) is used to estimate power requirements for the ship main engine. The other approach is the cubic rule method used for other ship types, where the main engine power requirement at given service speed is calculated as the cube of the ratio between the reported ship speed and the service speed of the vessel multiplied with the maximum continuous rating (MCR) of the vessel. The auxiliary and boiler energy use are derived from reported data and depends on operation mode and port operations (e.g. under loading and unloading of cargo, crane operations, etc.).

The output of the MASTER model has been validated against actual reported distance sailed and fuel consumption from around 5,000 vessels of all types, showing an overall good correlation with a deviation of less than 1% for distance sailed and 5% for fuel consumption (Longva & Sekkesæter, 2021).

Output from the MASTER model is used to generate a data file with aggregated data for 2023 for each ship in the scope, including values such as fuel system, total energy use and total distance sailed, which serves as a starting point for the simulations in the GHG Pathway model.

A.2 Fleet modelling to 2050 using the GHG Pathway model

DNV's GHG Pathway model, as illustrated in Figure A-1, is a cost-based modelling tool for developing scenarios for decarbonization of shipping, which will be used to model the fleet and the uptake and cost of mitigation options to comply with the proposed regulations to meet the GHG targets towards 2050 (DNV, 2022b; Longva & Sekkesæter, 2021; DNV GL, 2019; Eide, Chryssakis, & Endresen, 2013; Eide, Longva, Hoffmann, & Endresen, 2011; Longva, et al., 2024).

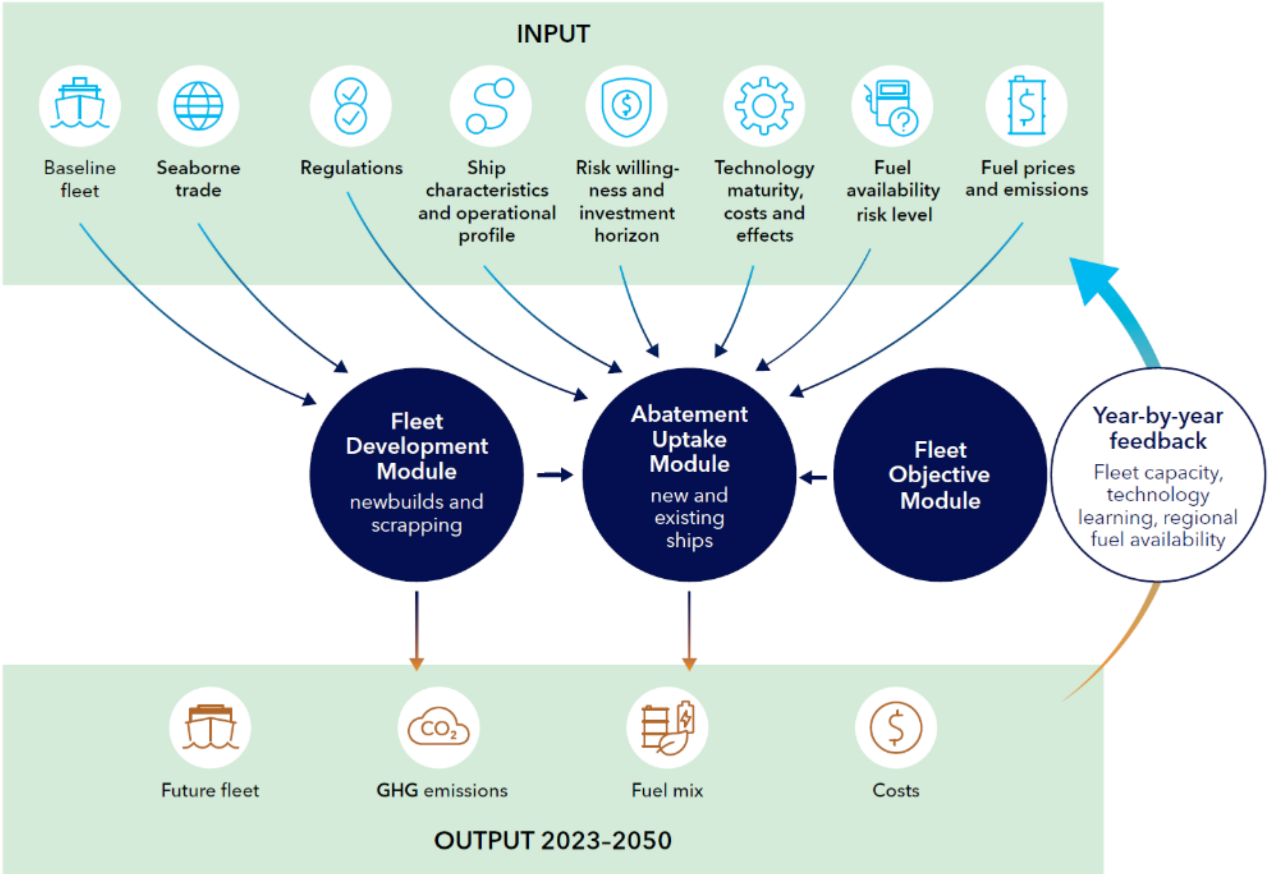


Figure A-1: Overview of the GHG Pathway model displaying input data, calculation modules, and output data.

The GHG Pathway model comprises the following three core evaluation modules:

- **The fleet development module,** in which the future fleet is simulated by adding and removing ships year-by-year towards 2050. The objective is to provide the fleet supply capacity corresponding to the seaborne-trade demand projections used as input, taking into account a scrapping rate and lost capacity through speed reduction in the fleet. The starting point for the fleet development is the baseline file generated by the MASTER model with the ship activity in 2023. The fleet develops according to the seaborne trade demand provided as input per ship segment. Each newbuild is modeled as a copy of a random ship from the same segment in the 2023 baseline, including its operational profile, technical particulars, and energy need, adjusted for assumed increase in the average size of newbuilds.
- **The abatement uptake module** in which the model evaluates available solutions for GHG emission reduction on all existing vessels and newbuilds for each year, including alternative fuels, energy-efficiency measures, and speed reduction. The ships are fitted with the most cost-effective feasible combinations of measures that fulfil regulatory requirements imposed as input. Possible fuel transitions achieved through drop-in fuels or retrofit of engine and fuel system are added to the model input. The model takes into account measures already implemented since the base year.
- **The fleet objective module** interacts with the fleet abatement module. Instead of finding the compliant abatement measures each year with the highest net present value (NPV) for the individual ship, the module takes into account objectives on a fleet level to identify and implement the set of abatement measures that has, for example, the lowest annualized cost across the fleet while the fleet in total complies with a certain requirement.

The model includes **three feedback loops**, where the choices made by shipowners a given year affects the situation in the following year. First, if **speed reductions** are adopted by a ship, thereby reducing the trading capacity of the fleet, the fleet development module ensures that additional ships are built to replace the lost capacity. The loss of trading capacity (and consequential fleet replacement) for a given speed reduction can be adjusted. In a second feedback loop, uptake of technical measures and fuel technologies results in year-by-year **technology learning**, which reduces the investment costs for future installations. In the third feedback loop, the availability risk levels of emerging fuels are updated year-by-year based on the fuel uptake. The fuel availability risk level simulates the **development and maturity of fuel production and bunkering infrastructure** for alternative fuels. Shipowners with high-risk willingness (see Appendix B.5) will see fuels at any availability level (level 1 through 3) to be available and feasible for newbuilds or retrofits. More risk averse owners will only consider fuels with higher availability (2 or 3). The availability level per fuel in each region (this version of the model uses two regions: Europe and Rest of the world) is updated year-by-year, following how the uptake of fuel develops in that region. With increasing availability, an increasing share of shipowners will consider the fuel a feasible option for their investments.

A full description of the GHG Pathway model is not included here, but in the following the main features relevant for this study are described, including how the proposed policy measures are handled in the modelling of the scenarios.

A.2.1 Abatement uptake evaluation based on groups of measures

Uptake of abatement measures are evaluated both for newbuilds and for existing ships. For each newbuild, the GHG Pathway model evaluates all available and compliant measure groups, which are combinations of energy-efficiency packages, speed reductions, onboard carbon capture, fuels and fuel systems. Based on the capital, operational, lost opportunity and fuel cost, as well as regulatory expenses and incomes the model selects the compliant combination with the highest NPV over a certain investment horizon (see Chapter B.5). A newbuild can for example be equipped with the measure group *Advanced EE (energy efficiency measure package) + 0 % SR (speed reduction) + VLSFO/MGO (conventional fuel and fuel technology)*. See Chapter B.6 for explanation of various measures comprising a group.

A similar evaluation is done for all existing ships. Every year the ships can change speed reduction, or switch fuel (drop-in fuel on existing converter), while every fifth year during dry-docking ships can retrofit fuel system (converter and fuel), energy-efficiency package, and/or an onboard carbon capture and storage system. The model selects the compliant combination with the highest NPV over a certain investment horizon (see Chapter A.2.3.1).

The model takes into account upcoming regulations when evaluating abatement measures on individual ships. The fuel system and energy-efficiency package are selected based on the requirements, for example the GHG fuel intensity, a levy or a feebate, at the end of the shipowner's investment horizon. When these have been selected, the lowest cost compliant combination of speed reduction and fuel mix (considering both the optimal fuel mix for ships with dual fuel engines and blending of low emission fuels) are selected based on the requirements for the current year in the model run. A ship may then, for example, install dual-fuel ICE ammonia in 2025 to be prepared to meet the compliance requirements 10 years ahead in 2035, but will use only MGO in the initial years before it becomes necessary to use an increasing share of bio-, e- or blue fuels, or a higher degree of onboard carbon capture, to comply with regulations. In the case of a GFI flexibility mechanism, the model seeks to optimize the uptake of abatement measures across the fleet (see Appendix A.2.2.2).

A.2.2 Compliance with regulations

The abatement uptake module takes into account the effect of GHG emission reduction requirements. The Energy Efficiency Design Index (EEDI) and Carbon Intensity Indicator (CII) requirements are modelled as described in the comprehensive impact assessment on the short term GHG measures (Longva & Sekkesæter, 2021). As the modelling uses 2023 as baseline, most ship will already have implemented the Energy Efficiency Existing Ship Index (EEXI). In the following we describe in detail how the proposed policy measures: the GHG Fuel Intensity (GFI) requirement, the GFI flexibility mechanism, the levy and the feebate mechanism will be evaluated in the GHG Pathway model.

The GFI flexibility, levy and feebate mechanisms all rely on a body to manage collection and distribution of revenues, expected to be established by the IMO as part of the mechanisms. This body is termed as the Revenue body in this study. The modelling will keep a track of all expenses and revenues for the Revenue body, but we will not further describe any functions of the Revenue body in this study.

A.2.2.1 GHG Fuel Intensity (GFI) requirement

The proposed GHG Fuel Intensity (GFI) requirement is based on WtW emissions or on TtW GHG emissions. For a GFI requirement without any flexibility mechanism, the model ensures that each ship implements measures that provide a WtW or TtW intensity, measured in total GHG emissions divided by total energy used (CO_2eq/MJ), below the required level.

The additional cost for the ship under a GFI requirement is the cost of implementing the required abatement measure (see Chapter A.2.3.2).

A.2.2.2 GFI flexibility mechanism

The GFI requirement can be implemented with a flexibility mechanism. As a basis for the flexibility mechanism an annual compliance balance (CB) is calculated for each ship, measured in tonnes CO_2eq. This is calculated as the difference between the required and attained GFI multiplied by the total energy used by the ship (Equation 1).

$$\mathrm{CB} = \left(GFI_{Required} - GFI_{Attained}\right) \times Energy \qquad \text{Equation 1}$$

A ship with a $GFI_{Attained}$ below the required $GFI_{Required}$ will have a positive compliance balance, while ships not reaching the requirement will have a negative compliance balance.

The flexibility mechanism provides alternative options for compliance consisting of two elements, as illustrated in Figure B-1:

1. An option for ships with positive compliance balance (green ships) to sell excess emission units to ships with negative balance (grey ships). The price would be set by the two parties exchanging emission units. A variant of this is a pooling mechanism where ships with positive and negative compliance balances can join in a pool and all ships are considered compliant if the total compliance balance of the pool is equal or greater than zero. Also, in this variant there will be a price per emission unit, and we consider these two variants to work similarly.

2. An option ships for ships with positive compliance balance to sell excess emission units – termed Surplus Units (SU) – to the Revenue body at a set SU price, and for ships with negative compliance balance to buy remaining emission units – termed Remedial Units (RU) – from the Revenue body at a set RU price. The RUs and SUs are units of GHG emissions given in tonnes CO_2eq, and there is no requirement that the number of RUs purchased by the Revenue body should be the same as SUs sold. The SU and RU prices, in USD/tCO_2eq, are fixed prices that are predetermined each year by the IMO or by a method set by the regulation.

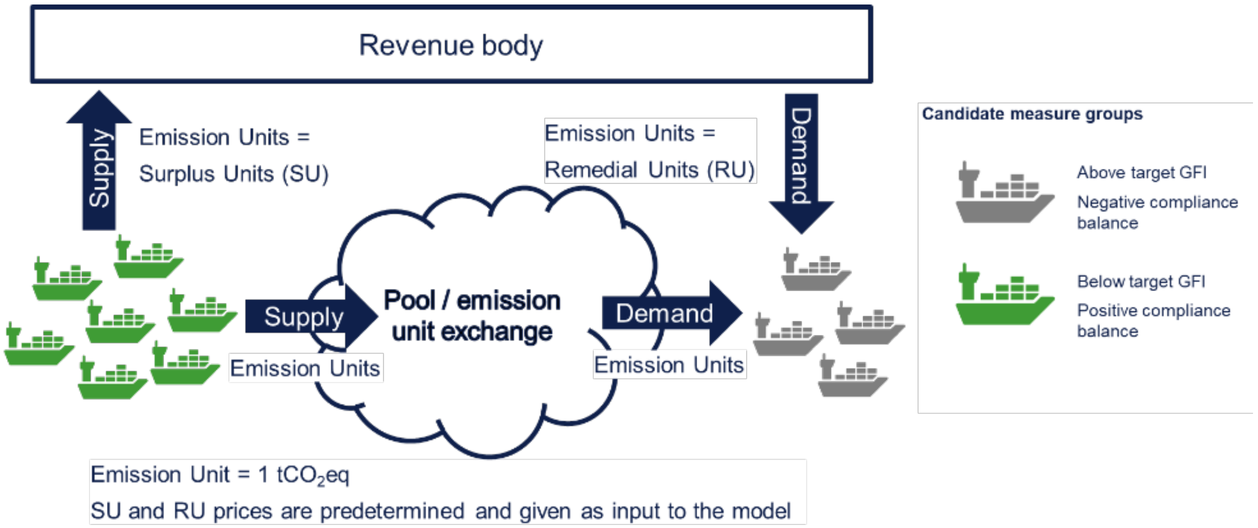


Figure A-2: Overview of the GHG flexibility mechanism.

This study considers the GFI flexibility mechanism as a global market of emission units where each emission unit is equal to one tonne of CO_2eq. In the modelling, all ships in the fleet are considered as one potential pool, or market under a global GFI requirement. The model calculates the compliance balance and annualized cost for all candidate measure groups (see Chapter A.2.1 for an explanation of the measure groups) for all ships in the fleet. It identifies the optimal set of measures to be implemented that minimizes the total costs for all ships that year, with the constraint that the total compliance balance should be positive. This is an iteration where the model selects the ship and candidate measure with the lowest marginal cost (total additional cost of the measure divided by the additional GHG emission reduction). The compliance balance for the pool is then updated and the model continues to select new ships and measures until the compliance balance is positive. A this stage the pool should consist of a group of ships that have implemented measures and achieved a positive compliance balance, and a group of ships which did not implement anything, or not sufficient measures to achieve the required GFI and which will have negative compliance balance.

The ships in the pool/market with positive compliance balance have incurred a higher cost in order to reduce the GFI and are expected to be compensated by ships with a negative compliance balance which can run at a lower cost. The emission unit price is determined by the supply and demand of units. The model estimates the emission unit price according to the marginal cost of the last ship in the pool that was selected to implement an additional measure. All transactions of emission units between ships in the pool/market will be based on this unit price.

The total cost for each ship in the pool (*GFIFlexibilityEx*) can be expressed as a function of the emission unit price (*EUP*) and the compliance balance (*CB*) for the ship as given in Equation 2:

$$GFIFlexibilityEx \; = - \, CB \; x \; EUP \qquad \text{Equation 2}$$

This approach assumes perfect competition[15] between all the ships in the pool/market and no transaction costs. This is an ideal result, while in reality there are barriers in the market, such as lack of information and transaction costs for joining pools/markets, preventing a fully optimal solution. Ships are likely to join in smaller pools/markets with different costs.

For the purpose of assessing regional requirements, in case the GFI requirement is more stringent than the regional requirement (FuelEU Maritime) only the global requirement will be considered. In case the global GFI requirement do

[15] In a market with perfect competition there is a large number of buyers and sellers of an identical product. All actors have perfect information about the production of the product (i.e. implementation of abatement measures) and will maximize its profits. None of the actors can influence the price.

not include a flexibility mechanism, the ships sailing in the EU region are considered as a pool under the regional requirement and the same method as described above is applied for this pool.

The second element of the flexibility mechanism allows exchanging emission units with the Revenue body. The SU and RU prices act as a floor and ceiling respectively on the emission unit price in the pool/market. In case the RU price is lower than the emission unit price, ships will rather buy RUs from the Revenue body than buying units from other ships, meaning the total GFI requirement will not be met. Whenever the emissions unit price is lower than the SU price, ships will sell their compliance balance to the Revenue body, and the fleet achieves a GFI below the requirement. In case the emission unit price is between the RU and SU price, there are no transactions with the Revenue body and all transactions takes place between ships in the pool/market. This implies that the emission unit price in the market is always between the SU and RU prices.

The additional cost for the ship under a GFI with a flexibility mechanism is the cost of implementing the optimal abatement measure in a fleet perspective, and the cost or income from exchanging emission units in a pool/market or with the Revenue body (*GFIFlexibilityEx*) (see Chapter A.2.3.2).

The total expense for the Revenue body (*GFIFundEx*) can be determined based on the total compliance balance for the fleet according to Equation 3. If the compliance balance is positive ships have sold emission units to the Revenue body, and conversely, if the compliance balance is negative ships have bought emission units from the Revenue body.

$$GFIFundEx = \begin{cases} \sum_{Ship_i} CB \ x \ SU_{Price} & if \ \sum_{Ship_i} CB > 0 \\ \sum_{Ship_i} CB \ x \ RU_{Price} & if \ \sum_{Ship_i} CB < 0 \\ 0 & if \ \sum_{Ship_i} CB = 0 \end{cases} \qquad \text{Equation 3}$$

The total volume of units, in tonnes CO_2eq, exchanged in the pool/market is the sum of the absolute compliance balances for all ships. The amount of units exchanged with the Revenue body which is the absolute value of the total compliance balance of the fleet is subtracted. As this including both the supplied and demanded amount the exchange volume is found by dividing it by 2. This can be expressed as given in Equation 4:

$$PoolingVolume = \frac{\sum_{Ship_i}|CB| - \left|\sum_{Ship_i} CB\right|}{2} \qquad \text{Equation 4}$$

This can be illustrated by an example with a fleet consisting of two ships, with Ship A having a compliance balance of 1000 tCO2eq and Ship B a compliance balance of -2000 tCO2eq. The two ships join in a pool where Ship B buys 1000 units from Ship A, and the remaining 1000 units are bought from the Revenue body to bring the total compliance balance to 0. The total units exchanged in the pool is (1000 + 2000 – 1000) / 2 = 1000.

A.2.2.3 Levy mechanism

The levy mechanism consists of two elements:

1. A predetermined levy, set by the IMO or by criteria in the regulation, on annual WtW or TtW GHG emissions from a ship, collected by a Revenue body. The yearly levy rate in USD/tCO_2eq will be given as an input to the model and increases the NPV of abatement measures that reduces emissions relative to measures with less emission reduction or not implementing measures.

2. A reward mechanism for ships using certain eligible fuels. The reward is a predetermined rebate to ships per energy of eligible fuel used (USD/GJ). The total reward is distributed from the Revenue body to the ships using eligible fuels at the end of the year based on the reported annual consumption.

The additional cost for the ship in case of a levy mechanism is the change in cost of implementing a different abatement measure (due to the reward and increased GHG emission cost), and the GHG levy (*GHGLevyEx*) less the reward (*GHGReward*) (see Chapter A.2.3.2). The income for the Revenue body is the sum of *GHGLevyEx* for all ships, while the cost if the sum of *GHGReward.*

A.2.2.4 Feebate mechanism

The feebate mechanism consists of two elements:

1. A predetermined (by the IMO or the regulation) rebate given in USD/GJ to ships using eligible fuels. The total rebate (*GHGReward*) is distributed from the Revenue body to each ship at the end of the year based on the reported consumption of eligible fuels by this ship.
2. To cover the costs of the rebate, a GHG fee rate in USD/tCO_2eq is calculated by the Revenue body based on total rebate costs from the Revenue body divided by the total GHG emission during the year from the fleet. The GHG fee expenses (*GHGFeeEx*) will be required to be paid by ships based on the GHG fee rate and their GHG emissions.

The GHG rebate is implemented as a reduced cost for eligible fuel when evaluating abatement measures in the modelling. But since the exact fee will not be known before after the reporting period, shipowners will then need to make an estimate on future GHG fees when making decisions on which measure to implement. For the modelling, an estimate (*GHGFeeExEstimated*) is used when deciding on which measure to implement. For the first year of the mechanism, the assumed GHG fee rate is given as an input to the model while in subsequent years it is the actual fee for the previous year.

The additional cost for the ship under a feebate mechanism is the change in cost of implementing a different abatement measure (due to the reward and increased GHG emission cost), and the actual GHG fee (*GHGFeeEx*) less the reward (*GHGReward*) (see Chapter A.2.3.2). The total income and expenses for the Revenue body for this mechanism is always equal to zero.

A.2.3 Cost calculations

The model uses two parallel cost calculations, both given in USD. The first is the calculation of a net present value (NPV) for each measure group (NPV_{mg}) which is used internally in the model as basis for the shipowner's decision to implement measures; the second is the total annual cost for the fleet of applying the reduction measures which is the output analysed in this study. The main differences between the two calculations are:

- For speed reduction we use a lost opportunity cost[16] to estimate the cost for a single shipowner in the NPV calculation, while for the annual cost for the fleet we use the direct cost of building and operating new vessels, including the newbuild cost, crewing, maintenance and fuel costs.
- For the feebate mechanism the GHG fee is not known at the time of the investment decision and an estimated fee is used for the NPV calculation, while for the total annual cost for the fleet, the actual fee is used.
- For the GFI flexibility mechanism, the pooling cost is not included in the NPV calculation as this is determined by finding the minimum NPV. The cost of emission unit exchange/pooling is included in the annual costs for the fleet. In case there are no transactions with the Revenue body this will be zero for the whole fleet, although it may be positive or negative for individual ship segments.

[16] Lost opportunity cost can be defined as the potential losses or benefits a decision maker has when choosing one alternative over another.

A.2.3.1 Net present value for investment decisions for ships

To evaluate which emission reduction measures to implement each year, a net present value (NPV_{mg}) is calculated for each vessel according to Equation 5 for each available and compliant measure group (*mg*). This calculation is based on the capital cost (*CapEx*), operational cost (*OpEx*), CO_2 deposit costs (*DepositEx*), lost opportunity cost related to speed reduction (*SpeedLO*), fuel cost (*FuelEx*), and the regulatory expenses from the GHG levy (*GHGLevyEx*), an assumed GHG fee (*GHGFeeExEstimated*) and a rebate (*GHGRebate*). The NPV is calculated over the shipowner's investment horizon (*p*) with discount rate (*r*) assuming no residual value at the end of the horizon (see Section B.5).

$$NPV_{mg} = -\,CapEx - (OpEx + FuelEx + DepostiEx + SpeedLO + GHGLevyEx + GHGFeeExEstimated - GHGReward) \times \frac{1-(1+r)^{-p}}{r} \quad \text{Equation 5}$$

Capital expenses include the additional cost of energy-efficiency measures, energy converter, fuel system and fuel-storage costs (see Section B.6). Operational expenses include all additional costs of operating the equipment, while the fuel expenses (see Section B.7.1) include the additional or reduced fuel cost. The CO_2 deposit cost reflects the cost of depositing the captured CO_2, including discharging from the ship and transport to, and storage in, a geological storage site. (see Section B.6.2) The lost opportunity cost is an estimated cost to the shipowner of reducing speed used for the purpose of deciding on the optimal speed for the shipowner (see Section B.6.5). The regulatory expenses are further described in Section A.2.2. The costs are relative to a ship with baseline energy-efficiency measures, no speed reduction and a conventional VLSFO/MGO diesel engine.

A.2.3.2 Total annual cost for the fleet

The annual cost for a single shipowner (Equation 6) includes the cost for building ($CapEx_{NB}$) and operating the ship ($OpEx_{Base}$), the total fuel costs (*FuelEx*), the CO_2 deposit costs (*DepositEx*), the cost impact due to new requirements (CapEx, OpEx) and the regulatory incomes and expenses (*GHGLevyEx, GHGFeeEx, GHGReward and GFIFlexibilityEx*). When aggregated to all ships in the fleet (Equation 7) it will also include the cost for building and operating additional ships to replace lost transport capacity resulting from reduced speed.

The capital costs are annualized over 20 years using a 4% cost of capital (Longva, et al., 2024; Faber, et al., 2020) and a 30% residual value (balloon) – i.e. disregarding the investment horizon of each individual shipowner. The annual costs consist of the principal downpayment and the interest. The remaining principal and interest are also estimated for the existing fleet in 2023. $OpEx_{Base}$ include manning, insurance, stores & spares, lubricating oils, repair & maintenance and drydocking and management and administration (Drewry, 2023). The actual GHG fee (*GHGFeeEx*) is used in this case, as opposed to the NPV_{mg} calculation in Equation 6, and the costs or income of the GFI flexibility mechanism (*GFIFlexibilityEx*) incurred either by joining a pool or buying or selling emission units from a fund. The GHG flexibility is described in detail in Section A.2.2.2.

$$AnnualCost_{ship} = (CapEx_{NB} + CapEx)_{Principal+Interest} + OpEx_{Base} + OpEx + FuelEx + DepositEx + GHGLevyEx + GHGFeeEx - GHGReward + GFIFlexibilityEx \quad \text{Equation 6}$$

$$AnnualCost_{fleet} = \sum_{ship} AnnualCost_{ship} \quad \text{Equation 7}$$

A.3 Method for establishing required GHG emission trajectories

The IMO GHG Strategy sets ambitions for international shipping relative to 2008. The Fourth IMO GHG study (Faber, et al., 2020) provides a TtW GHG emission estimate for international shipping in 2008 according to the voyage-based method – i.e. only including international voyages – for ships above 100 GT. This scope is different than the fleet and emissions scope assessed in this study which are WtW GHG emissions from ships under the scope of Chapter 4 of MARPOL Annex VI.

To set correct targets for 2030 and 2040 for the fleet in scope of this study, we first estimate the WtW GHG emissions in 2008 based on the TtW GHG emissions estimate in the Fourth IMO GHG study (Faber, et al., 2020), and adding the WtT GHG emissions using the fuel mix from the Third IMO GHG study (Smith, et al., 2014). We use the WtT GHG emission factors as provided in Section 1.2.6.

We then estimate the WtW GHG emissions from international shipping in 2023 using the same fleet scope and method as by the Fourth IMO GHG study[17]. The Fourth IMO GHG study estimated and filled data gaps for ships without matching IMO and MMSI numbers and ship marked as active in the IHS database but without registered AIS data. To be consistent with the method of the Fourth IMO GHG Study for international shipping, this study adds Type 3 and Type 4 type ships in the 2023 estimate for the relevant segments according to the share relative to Type 1 and 2 ships given in the detailed results table for 2018 in the Fourth IMO GHG Study (Table 35).

Having the WtW GHG emissions for the same scope and definition of international shipping in both 2008 and 2023, we calculate the achieved WtW GHG emissions reduction, and the further reduction required to achieve the ambitions in 2030 and 2040 relative to 2023.

We then apply the same required reduction targets relative to 2023 to set the required emission trajectory for the fleet in scope of this study. This assumes that the relative difference in emissions between international shipping and the scope of MARPOL Annex VI remains the same.

The steps are illustrated in Figure A-3. It should be noted that the top line decreases by the same percentage relative to 2008 as the bottom line, but due to starting higher, it is steeper.

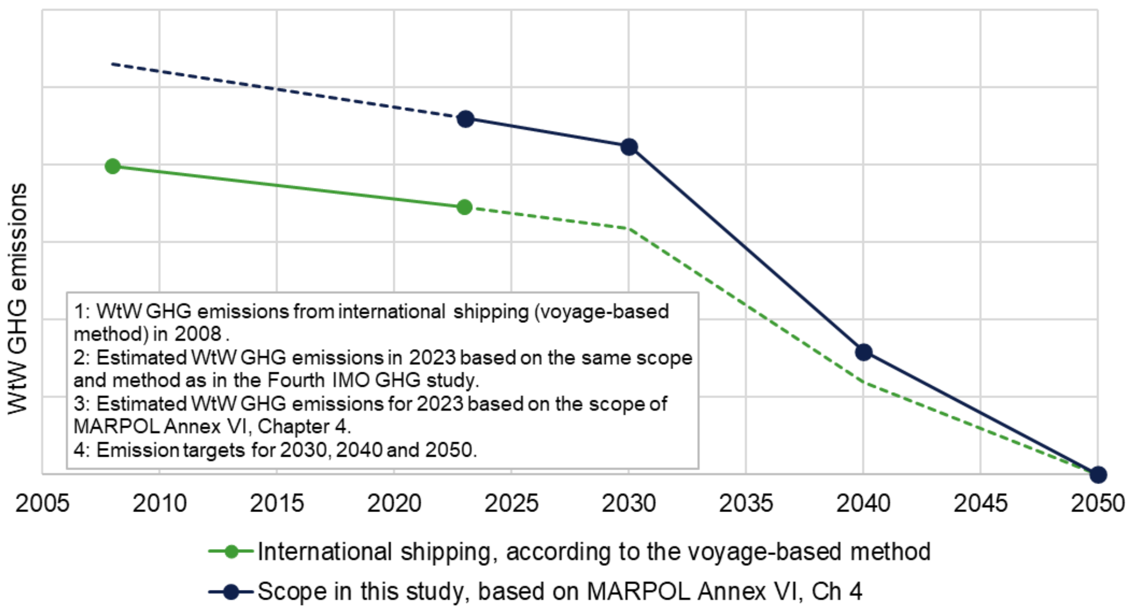


Figure A-3: Illustration of how the required emission trajectories (solid blue line) are calculated to be applicable for the fleet in scope for this study.

[17] Ships above 100 GT and according to the voyage-based method – i.e. only including international voyages.

The Fourth IMO GHG study estimated the TtW GHG emissions from international shipping in 2008 to 794 $MtCO_2eq$. The Third IMO GHG Study, applying a different method, estimated the TtW GHG emissions to 940 $MtCO_2eq$ and the CO_2 emissions to 921 $MtCO_2$, including a split between HFO, MDO and LNG. To estimate the WtT emissions for the same method as in the Fourth IMO GHG study, we scale down the HFO, MDO and LNG emissions assuming the same relative difference between the TtW GHG emissions in the two studies.

The calculation steps are shown in Table A-1 giving a total WtW GHG emissions for international shipping of 943 $MtCO_2eq$.

Table A-1: Calculation of WtT GHG emissions from international shipping for 2008. Based on TtW emissions from the Fourth IMO GHG study and fuel mix from the Third IMO GHG study, in combination with the WtT emission factors in this study (see Section 1.2.6).

	TtW total $MtCO_2eq$	Scaled down TtW total $MtCO_2eq$*	Lower heating value MJ/g fuel	CO_2 factor gCO_2/g fuel	WtT factor gCO_2eq/MJ	WtT total $MtCO_2eq$
HFO	803	678	40 200	3.114	13.5	140
MDO (MGO)	103	87	42 700	3.206	14.4	20
LNG	15	13	48 000	2.75	18.5	5
Total	921	778	-	-	-	165

*) Scaled down by 794 $MtCO_2eq$ divided by 940 $MtCO_2eq$ which are the GHG emissions in 2008 according to the Fourth and Third IMO GHG studies respectively applying different methods.

APPENDIX B
Input data and assumptions used in the modelling

This appendix describes key input parameters and assumptions applied in the modelling work, including fleet scope, emission trajectories, seaborne trade, ship characteristics, fuel prices, regulatory requirements and other relevant data.

B.1 Baseline fleet for 2023

We assume that the new policy measures will be implemented with a similar scope as Chapter 4 of MARPOL Annex VI, although some measures can have further limitations on ship type and size. This study will assess the impact on ships within the same scope which will include ships above 400 GT except ships solely trading domestically and ships not propelled by mechanical means, and platforms including FPSOs and FSUs and drilling rigs, regardless of their propulsion. This scope is applied when generating the baseline file with data on the fleet.

We use the same segmentation for the fleet as in the Third IMO GHG study (Smith, et al., 2014) adding an additional segment for container of 19000 TEU and above, as shown in Table B-1, along with corresponding ship categories used to group the segments when presenting the results from this study.

Table B-1: Ship segmentation used in this study.

Ship segment	Ship category
Bulk carrier 0–9999 dwt	Short sea – bulk carrier
Bulk carrier 10000–34999 dwt	Short sea – bulk carrier
Bulk carrier 35000–59999 dwt	Deep sea – bulk carrier
Bulk carrier 60000–99999 dwt	Deep sea – bulk carrier
Bulk carrier 100000–199999 dwt	Deep sea – bulk carrier
Bulk carrier 200000– dwt	Deep sea – bulk carrier
Chemical tanker 0–4999 dwt	Short sea – tanker
Chemical tanker 5000–9999 dwt	Short sea – tanker
Chemical tanker 10000–19999 dwt	Short sea – tanker
Chemical tanker 20000– dwt	Deep sea – tanker
Container 0–999 TEU	Short sea – container
Container 1000–1999 TEU	Short sea – container
Container 2000–2999 TEU	Deep sea – container
Container 3000–4999 TEU	Deep sea – container
Container 5000–7999 TEU	Deep sea – container
Container 8000–11999 TEU	Deep sea – container
Container 12000–14500 TEU	Deep sea – container
Container 14500-18999 TEU	Deep sea – container
Container 19000- TEU	Deep sea – container
General cargo 0–4999 dwt	Other
General cargo 5000–9999 dwt	Other
General cargo 10000– dwt	Other
Liquefied gas tanker 0–49999 cbm	Liquefied gas
Liquefied gas tanker 50000–199999 cbm	Liquefied gas
Liquefied gas tanker 200000–+ cbm	Liquefied gas
Oil tanker 0–4999 dwt	Short sea – tanker
Oil tanker 5000–9999 dwt	Short sea – tanker
Oil tanker 10000–19999 dwt	Short sea – tanker
Oil tanker 20000–59999 dwt	Deep sea – tanker
Oil tanker 60000–79999 dwt	Deep sea – tanker
Oil tanker 80000–119999 dwt	Deep sea – tanker
Oil tanker 120000–199999 dwt	Deep sea – tanker
Oil tanker 200000– dwt	Deep sea – tanker

Ship segment	Ship category
Other liquids tanker tankers dwt	Deep sea – tanker
Ferry-pax only 0–1999 GT	Other
Ferry-pax only 2000– GT	Other
Cruise 0–1999 GT	Other
Cruise 2000–9999 GT	Other
Cruise 10000–59999 GT	Other
Cruise 60000–99999 GT	Other
Cruise 100000– GT	Other
Ferry-ropax 0–1999 GT	Other
Ferry-ropax 2000– GT	Other
Refrigerated bulk 0–1999 dwt	Other
Ro-ro 0–4999 dwt	Other
Ro-ro 5000– dwt	Other
Vehicle 0–3999 vehicle	Other
Vehicle 4000– vehicle	Other
Yacht 0– GT	Other
Service tug 0– GT	Other
Miscellaneous fishing 0– GT	Other
Offshore 0– GT	Other
Service other 0– GT	Other
Miscellaneous other 0– GT	Other

B.2 Seaborne trade

This study uses SSP2_RCP2.6_L for the high seaborne trade growth scenario, and OECD_RCP2.6_G for the low growth scenario from the Fourth IMO GHG study (Faber, et al., 2020). OECD_RCP2.6_G projects a 39% growth and SSP2_RCP2.6_L an 81% growth in seaborne trade from 2023 to 2050. Table B-2 shows the growth projections. These two scenarios are selected as they provide a reasonable range on expected future shipping activity.

The Fourth IMO GHG study projects seaborne transport demand from 2018 to 2050. As this study uses 2023 as the base year, we use the estimated seaborne trade level in 2023 from Clarkson (2024), and then apply the same annual growth rates per segment as in the Fourth IMO GHG study demand projections from 2023 to 2050. This means that the projected seaborne transport demand in 2050 will be lower than projected in the Fourth IMO GHG study, in particular for the high growth scenario, as the actual seaborne transport demand in 2023 was also lower than projected.

Table B-2: Current (Clarksons Research, 2024) and projected seaborne transport demand in 2050 (Faber, et al., 2020) per cargo type for the low and high growth scenarios.

Cargo type	Current	Low growth OECD_RCP2.6_G				High growth SSP2_RCP2.6_L			
	Transport work in 2023 [bn tonne-miles]	Growth 2023-2030 [% p.a]	Growth 2031-2040 [% p.a.]	Growth 2041-2050 [% p.a.]	Transport work in 2050 [bill tonne-miles]	Growth 2023-2030 [% p.a.]	Growth 2031-2040 [% p.a.]	Growth 2041-2050 [% p.a.]	Transport work in 2050 [bn tonne-miles]
Bulk	30 135	1.7 %	1.7 %	1.4 %	45 900	3.4 %	2.6 %	2.4 %	61 258
Tank	15 906	-0.3 %	-0.3 %	-0.7 %	14 188	0.7 %	0.2 %	-1.2 %	13 650
Gas	2 542	1.4 %	0.7 %	-0.4 %	2 886	4.6 %	3.6 %	1.8 %	5 926
Container	8 682	2.5 %	1.8 %	1.3 %	14 059	4.2 %	3.0 %	2.3 %	19 556
Other unitized	5 035	2.3 %	1.8 %	1.4 %	8 099	1.1 %	-0.5 %	-2.3 %	3 949
Total	62 301	1.4 %	1.2 %	0.9 %	85 132	2.8 %	2.1 %	1.6 %	104 339

B.3 Adopted regulations

The modelling will take into account the effect of currently adopted GHG emission and carbon intensity reduction requirements. These include the global regulations mandated by Chapter 4 of MARPOL Annex VI, the regional regulations adopted by the EU in 2023.

We assume that there will be no further EEXI requirements. The EEDI phase 3 starts for the remaining ship types in 2025, but no further phases are included.

Strengthened CII reduction factors is expected to be established from 2027 until 2030 based on the upcoming CII review.[18] We assume the IMO will increase the CII reduction requirement relative to the segment specific reference line by 2 percentage points per year, reaching 19% reduction in 2030. This is the same increase in the rate as between 2023 and 2026. From 2030 and onwards the CII requirement stays at the same level. We assume no changes to the scope of the CII, on ship types, sizes and emissions.

Ships above 5000 GT transporting cargo or passengers into and out of the EU and within EU are subject to the EU ETS from 2024.[19] EU ETS addresses GHG emissions in a TtW perspective for the shipping sector. However, the EU ETS encompasses almost 50% of the total GHG emissions in the EU and covers, in addition to shipping, a wide range of sectors including refineries and the chemical and power sectors which are vital for the production of hydrogen, ammonia and methanol. As such, for fuels produced in the EU, the ETS covers the emissions in a WtW perspective. The cost of EU ETS comes in addition to any levy or fee imposed by the policy measures investigated in this study.

The allowance price at the start for 2024 is around USD 90/tCO_2 and is expected to increase. We assume the allowance prices will increase according to the Announced Pledges Scenario (APS) by IEA (2023b), to USD 200/tCO_2 in 2050. The model does not take into account all derogations (e.g. for ice class or ships trading to the outmost regions). The carbon-based bio- and e-fuels modelled in this study have WtW GHG emission below the required threshold according to the Renewable Energy Directive[20], and are assumed to emit zero CO_2 emissions under this regulation. We assume the ships have to pay 40% of the emissions when trading within region Europe in 2024, 70% in 2025 and 100% from 2026.

Ships above 5000 GT transporting cargo or passengers into and out of the EU and within EU are subject to the FuelEU Maritime regulations from 2025.[21] The reduction requirement is set relative to the average well-to-wake fuel GHG intensity of the fleet in 2020 of 91.16 gCO2e/MJ, starting at a 2% reduction in 2025, increasing to 6% in 2030, and accelerating from 2035 to reach an 80% reduction by 2050. The regulation also allows for compliance across a group of ships, meaning that one vessel in a pool of ships can over-achieve on the well-to-wake GHG intensity, allowing for the other ships to continue to use fossil fuels.

The model distributes the emissions across 10 regions based on voyages. For voyages between regions, 50% of the emissions are assigned to the region where the ship departs from, and 50% is assigned to the region where it arrives to.

A summary of the inputs and assumptions on adopted GHG requirements are provided in Table B-3.

Table B-3: Summary of inputs and assumptions on adopted GHG requirements.

[18] According to Resolution MEPC.338(76): 2021 Guidelines on the operational carbon intensity reduction factors relative to reference lines (CII reduction factors guidelines, G3)

[19] Directive 2003/87/EC of the European Parliament and of the Council of 13 October 2003 establishing a system for greenhouse gas emission allowance trading within the Union and amending Council Directive 96/61/EC

[20] Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources

[21] Regulation (EU) 2023/1805 of the European Parliament and of the Council of 13 September 2023 on the use of renewable and low-carbon fuels in maritime transport, and amending Directive 2009/16/EC.

GHG requirement	Inputs and assumptions
EEDI	Phase 3 starts for remaining ship types in scope from 2025. No further phases included.
EEXI	No further requirements
CII	2023–2026: 5% reduction from the CII reference line based on 2019 data. Increasing by 2 percentage points per year until 2026. 2027–: Assumed to continue to increase by 2 percentage points per year until 2030 then constant from 2030 and onwards.
EU ETS	ETS allowance prices for ships when operating in region Europe (IEA, 2023b): 2023–2030: USD 90/tCO_2eq to 135/tCO_2eq (linear increase) 2031–2040: USD 135/tCO_2eq to 170/tCO_2eq (linear increase) 2041–2050: USD 170/tCO_2eq to 200/tCO_2eq (linear increase) For 2024, 40% of CO_2 emissions are included, and for 2025, 70% of CO_2 emissions. 100% included from 2026 and onwards. CH_4 and N_2O are included from 2026
FuelEU Maritime	Average well-to-wake fuel GHG intensity requirements for ships or pools when operating in region Europe: 2025–2029: 89.3 gCO_2eq/MJ 2030–2034: 85.7 gCO_2eq/MJ 2035–2039: 77.9 gCO_2eq/MJ 2040–2044: 62.9 gCO_2eq/MJ 2045–2049: 34.6 gCO_2eq/MJ 2050– : 18.2 gCO_2eq/MJ

B.4 Ship characteristics and operational profile

B.4.1 Ship size growth

We expect ship sizes to increase gradually by 15% for LNG tankers, 11% for container ships and 4% for bulkers between 2018 and 2050. The sizes of other types of ships are assumed to remain as today. The increases in ship sizes are in line with the assumptions made in the Fourth IMO GHG study. This is implemented by increasing the size of newbuilds relative to the original ship that they are copied from. Note that the newbuilds remains in the same segment as the original ships, meaning that the size of newbuilds can be above the size range for their segment.

B.4.2 Annual scrap rate and minimum ship age for scrapping

The GHG Pathway model takes into account the scrapping of vessels before new vessels are added to match projected demand. Based on historical data the last 20 years (IHS Markit, 2024) and taking into account the range of new regulations (e.g. ballast water, sulphur limits) we assume that each year up to 1.5% of the ships in a segment are scrapped, in terms of transport capacity, with the oldest ships scrapped first.

A minimum scrap age of five years below the historical average scrap age is set for each segment. Only ships that are older than this minimum, can be scrapped. This is implemented to avoid that ships in young segments are scrapped at unreasonably low ages. Also, the model will not consider a ship for scrapping based on cost of compliance relative to cost of building a new ship.

B.4.3 Utilization of fleet

The assumptions on logistical improvements in the supply chain are based on the ship productivity indices provided in the Third IMO GHG study (Smith, et al., 2014). Between 2018 and 2050 we expect gradual improvements in the supply chain to increase vessel utilization by a total of about 16% for tank and small containers; 4% for bulk; 20% for gas and large containers.

B.5 Risk willingness, investment horizon and discount rate

Risk willingness and investment horizon are key factors that influence selection of abatement measures, fuels, and fuel technologies in the model.

The investment horizon together with a 4% discount rate (Faber, et al., 2020) are used in the NPV calculations for the decarbonization measures, as described in Section A.2.3.1. A shipowner's investment calculation is usually shorter than in a societal perspective that would include the full lifetime of the vessels and measures. In the model, each vessel is randomly assigned an investment horizon based on the distribution for its segment as shown in Table B-4. The investment horizon used when evaluating measure for existing ships is half the length as when evaluating for newbuilds, assuming that newbuild investments are more long term than subsequent investments (see e.g. Stott 2013).

The investment horizon distribution used in the modelling is intended to capture two barriers. The first is the split-incentives barrier (see e.g. Rehmatulla and Smith (2020) and ITF/OECD (2018)) where the shipowner that invests in energy-efficiency measures or alternative fuels does not get the full benefits from future fuel cost savings, or higher market rates for ships that perform beyond minimum compliance. The second barrier is access to finance and length of charter contracts which prevents investing in efficient tonnage and alternative fuels (DNV GL, 2017).

The fuel availability risk level simulates shipowners' risk willingness to invest in fuel systems that run on fuels with low availability. It is analogous with an S-shaped pattern of fuel adoption (see e.g. (Odenweller, 2022)), with some owners as first movers, others as early followers and late followers. The shipowners are divided into three risk levels randomly according to the distribution in Table B-4 and in line with the investment horizon. The shipowners on risk level 3 will only be able to invest in fuel systems for the fuels with highest availability, level 3, the shipowners on risk level 2 can invest in fuel systems for the fuels at level 2 and 3, and lastly the shipowners on risk level 1 can invest in any fuel systems. See Section B.7.2 for the assumptions on availability per fuel type. The risk level does not consider the maturity and availability of fuel systems and converters which are further described in Section B.6.1.

The distribution used in this study, as given in Table B-4, is based on a survey (DNV, 2012) and covers both the risk willingness and investment horizon. A shipowner that has a long-term view is also assumed to be able to ensure long-term supply for alternative fuels and would be willing to invest also in fuel types with limited availability in the region(s) it operates (see Section B.7.2). The distribution generally aligns with the type of contracts and longer-term perspectives seen in the cruise and container segments compared to the bulk and tank segments.

Table B-4: Distribution per segment of investment horizon for newbuilds (NB) and retrofits (RF) and risk levels used by this study; based on (DNV, 2012). Ships with a certain risk level can only implement fuel systems running on fuel types in a region with matching or higher fuel availability.

Segment	NB: p=20 years RF: p=10 years Risk level 1	NB: p=10 years RF: p=5 years Risk level 2	NB: p=4 years RF: p=2 years Risk level 3
Container and vehicle carriers	20%	60%	20%
Cruise	50%	40%	10%
All other segments and ship types	10%	60%	30%

B.6 Technology maturity, costs and effects

Below, we describe key input data on all abatement options used in the GHG Pathway model, including fuel technologies, onboard carbon capture, energy-efficiency measure packages, and speed reduction.

B.6.1 Fuel technology options

There are many different fuels and fuel technologies that can enable decarbonization of shipping towards 2050, e.g. ammonia, hydrogen, and marine fuel cells.

As input to the GHG Pathway model, there are 8 different fuel types (i.e. fuel molecules) along with 10 different fuel technology systems. The model allows for fuels of different feedstock categories within the same fuel type (e.g. LNG, bio-LNG or e-LNG). Table B-5 gives an overview of the fuel types and fuel technology systems considered in this study.

Table B-5: The energy converters, fuel types, and transitions allowed in the GHG Pathway model.

Engine, fuel cell and fuel system	Fuel type / fuel molecule							
	HFO	VLSFO/ MGO	LNG (methane)	LPG	Methanol	Ammonia	Hydrogen	Electricity (grid)
MF ICE								
MF ICE with scrubber								
DF LNG ICE								
DF LPG ICE								
DF methanol ICE								
DF ammonia								
DF hydrogen ICE								
Hydrogen FC								
Ammonia FC								
Battery EM								

Abbreviations: dual-fuel (DF); electric motor (EM); fuel cell (FC); internal combustion engine (ICE); liquefied natural gas (LNG); liquefied petroleum gas (LPG); mono-fuel (MF)

Retrofit
Drop-in

B.6.1.1 Cost of implementing fuel technologies

Investment costs are different for each engine/fuel cell and fuel system shown in Table B-5. The input is based on i) cost for the engine/fuel cell and fuel system and ii) cost for the fuel storage system.

Estimated cost-data are based on a review of literature (see e.g. MMMCZCS (2022b), Taljegard (2014); FCBI (2015); de Vries (2019)), reported newbuild prices for vessels running on alternative fuels, and communication with industry actors.

In Table B-6, we indicate the total additional newbuild CAPEX for example vessels in selected vessel segments (bulk, tank, container, liquefied gas, and other). The estimated additional newbuild CAPEX applies to an average vessel within each segment, with respect to total installed power and fuel storage capacity. Each value has been rounded to the nearest million USD.

Table B-6: Total additional investment cost by fuel technology for example vessels in selected segments.

Segment	NB price*	Total additional CAPEX (million USD)								
		MF ICE w/scrubber	DF ICE LNG	DF ICE LPG	DF ICE Methanol	DF ICE Ammonia	DF ICE LH2	DF FC Ammonia	MF FC LH2	EM Electricity
Short-sea bulk (10000–34999 dwt)	24	3	4	2	2	4	8	37	16	N/A
Deep-sea bulk (200000–+ dwt)	60	4	11	5	4	8	26	115	47	N/A
Short-sea tank (10000–19999 dwt)	31	2	4	2	2	3	8	35	16	N/A
Deep-sea tank (200000–+ dwt)	108	5	16	8	6	11	38	155	65	N/A
Short-sea container (1000–1999 TEU)	27	4	5	4	3	4	14	75	27	N/A
Deep-sea container (14500-18999 TEU)	139	10	22	13	10	17	60	335	120	N/A
Liquefied gas tanker (50000–199999 cbm)	219	5	15	7	6	10	34	145	60	N/A
Other vessels (Vehicle carrier 0–3999 vehicles)	63	3	10	8	5	9	16	50	21	N/A

Abbreviations: dual-fuel (DF); electric motor (EM); fuel cell (FC); internal combustion engine (ICE); liquefied natural gas (LNG); liquefied petroleum gas (LPG); mono-fuel (MF)
**Newbuild price as shown in Table B-14, provided as reference*

We have not considered opportunity costs related to loss of cargo-space due to additional volume required for fuel storage, nor lost income during installation. Newbuilds can be designed for a certain cargo capacity and with fuel tanks for a required range. Vessels built with ammonia, hydrogen, LNG or methanol fuel systems incorporate the necessary tanks into the design, but typically reduce range by about 30% compared to vessels built for conventional fuel oil. We assume this does have a significant impact on operations. For retrofitting fuel systems, we assume the retrofit cost to be 50% higher than the additional cost for newbuilds. This is line with reported figures by MMMCZCS (2022b) of 11% additional cost relative to the newbuild price, for a methanol fueled large container ship fitted at new build stage and between 14% and 16% additional cost for a retrofit depending on the preparedness level included at the newbuild stage.

For onboard CCS, we assume that the storage tanks should be large enough to store CO_2 from 25% of the total fuel capacity. This may impact the operations for the ship but costs for this are not included in the modelling beyond the cost for depositing the CO_2.

We include a learning effect of 5% cost reduction for every doubling of installations for combustion engines except for conventional MF ICE and 10% for fuels cells. This is somewhat lower that what is reported in other studies on maritime technologies which is between 10 and 20% (DNV, 2012; Wang, Faber, Nelissen, Russell, & St Amand, 2011).

B.6.1.2 Availability

Several of the fuel technologies given in Table B-5 face many different barriers that prevent large-scale uptake in the short-term (see e.g. Ricardo & DNV (2023); DNV (2022b)), and they are expected to reach a level of maturity sufficient for commercial application at different times.

We assume that all fuel technologies shown in Table B-5 are available from the first year of modelling (2023), with the following exceptions:

- From 2026: DF ammonia ICE
- From 2030: DF hydrogen ICE, Hydrogen FC and Ammonia FC, onboard carbon capture and storage

B.6.1.3 Pilot fuel share

Dual fuel marine engines are engines that can operate on two different types of fuel, typically diesel in combination with an alternative fuel such as methanol or methane. For most current dual fuel engine designs, pilot fuel is used to ignite the alternative fuel in the engine. The energy share of pilot fuel oil in the engine depends on engine design, fuel type, and engine load. For all fuel technologies involving dual fuel internal combustion engines covered in this study, we assume that a fixed share of the energy demand has to be supplied via pilot fuel oil. The share covers both 2-stroke and 4-stroke engines and takes into account that ship will have a variable load during the year. Pilot fuel may be supplied via fossil VLSFO/MGO, bio-MGO or e-MGO. Table B-7 shows the minimum pilot fuel shares used in this study.

Table B-7: Minimum pilot fuel share required by fuel technology, in terms of pilot fuel energy relative to alternative fuel energy (DNV, 2021a).

Fuel technology	Share of pilot fuel
DF LNG ICE	3 %
DF LPG ICE	3 %
DF Methanol ICE	9 %
DF NH_3 ICE	12 %
DF LH2 ICE	3 %

Abbreviations: dual-fuel (DF); internal combustion engine (ICE); liquid hydrogen (LH2); liquefied natural gas (LNG); liquefied petroleum gas (LPG); ammonia (NH_3)

It is important to note that the share of pilot fuel oil given in Table B-7, represents the minimum amount of fuel oil required to run on the given alternative fuel. Beyond this, the model allows vessels with dual fuel capability to use as much fuel oil as is deemed economically feasible by cost calculations (see Section A.2.3).

B.6.2 Onboard carbon capture and storage

Onboard carbon capture and storage (onboard CCS) allows for continued use of fossil energy directly on ships, with significantly reduced CO_2 emissions assuming that the CO_2 is delivered to a storage facility to be permanently stored and not released to the atmosphere later. A maritime CCS system comprises of the following sub-systems:

- Capture: The marine energy system exhausts are cleaned from CO_2 at a dedicated carbon capture unit. The clean gas leaves to the atmosphere.
- Treatment: The CO_2 by-product is treated and converted into storage conditions.
- Storage: The treated CO_2 stream is stored onboard in dedicated tanks/containers.

The onboard technologies for CO_2 capture can be based on post-combustion, pre-combustion, or oxy-fuel combustion. Among them, the most popular option is post-combustion, as it has minimum intervention with the engine and, for this purpose, it is also attractive for ships (DNV, 2021b; DNV, 2024e). From this technology category, liquid absorption, adsorption, membranes and their combinations or variants are the most relevant technologies for ship use.

In the GHG Pathway model, we include a post-combustion onboard CCS system with amine-based absorption with maximum 75% CO_2 capture rate. The capture rate refers to the share of total CO_2 emissions that is captured from the vessel's exhaust. The rate is not equal to the total GHG abatement from using onboard CCS which also need to consider the additional energy required and related emissions.

Below, in Table B-8, we give the estimated additional CAPEX cost for onboard CCS systems for representative vessels within selected segments.

The additional investment cost for an onboard CCS system is divided into i) CAPEX for the capture unit and ii) CAPEX for the CO_2 storage. The CAPEX for the capture unit is calculated using a specific cost (in USD per kW) for the capture unit, multiplying it with the capture unit size (total installed power) and capture rate. The CO_2 storage tank CAPEX is calculated by estimating the CO_2 storage tank capacity (in m^3) based on the vessel's fuel tank capacity, multiplying this with a specific tank cost (in USD per m^3). Based on discussions with equipment manufacturers and shipowners, we assume that the CO_2 storage tanks/containers should be large enough to contain all CO_2 emissions emitted when consuming an equivalent of about 25% of the capacity of the fuel storage tanks onboard the vessel. This may impact the operations for the ship when the full capacity of the capture plant needs to be utilized, but costs for this are not included.

Retrofitting an onboard CCS system is assumed to cost an additional 50% which is the same assumption as for retrofitting of fuel technologies. We have not considered opportunity costs related to loss of cargo-space due to additional volume required for fuel storage, nor lost income during installation.

The assumed specific costs for onboard CCS are based on discussions with industry actors and industry literature (see e.g. OGCI & Stena (2021)). The cost estimates are uncertain as the technology is not yet mature for onboard use and is at a Technology Readiness Level (TRL) of 7-8 (Ricardo & DNV, 2023). We assume that the onboard CCS becomes commercially available (TRL at 9) in 2030. We also take into account the CAPEX will reduce further due to learning effects. We do not include any further learning effects for the onboard CCS technology and the CAPEX stays fixed at this level to 2050.

Table B-8: Estimated additional CAPEX for onboard CCS for example vessels within selected ship segments. Based on discussions with industry actors and industry literature (e.g. OGCI & Stena (2021)) and taking into account additional learning effects.

Ship category	NB price* (million USD)	Additional CAPEX (million USD)
Short-sea bulk (10000–34999 dwt)	24	4
Deep-sea bulk (200000–+ dwt)	60	15
Short-sea tank (10000–19999 dwt)	31	3
Deep-sea tank (200000–+ dwt)	108	16
Short-sea container (1000–1999 TEU)	27	8
Deep-sea container (14500-18999 TEU)	139	28
Liquefied gas tanker (50000–199999 cbm)	219	15
Other vessels (Vehicle carrier 0–3999 vehicles)	63	5

** Newbuild price as shown in* Table B-14*, provided as reference*

The fuel penalty is the additional energy used to capture CO_2 when operating at the design maximum carbon capture rate. The fuel penalty depends on the capture rate of the CCS system. We assume 30% fuel penalty for the 75% capture rate system (DNV, 2021b). We assume that any additional OPEX associated with the operation of onboard CCS system, are captured by the fuel consumption penalty.

A CO_2 deposit cost is added to take into account permanent storage of the CO_2. The CO_2 deposit cost reflects the cost of depositing the captured CO_2, including discharging from the ship and transport to, and storage in, a geological storage site. We assume an initial deposit cost of 80 USD/tonne CO_2 capture, falling to 60 USD/tonne CO_2 in 2050. Costs are based on communication with industry actors and literature (see e.g. IEA (2020a)).

A comparison of the assumptions in this Section with reported values from the literature is provided in Appendix E.2.5.

B.6.3 Shore power

Shore power uptake is not modelled explicitly as part of the cost calculations in this study but included based on an assumed uptake. This study assumes that the use of shore power increases from 1% of total energy use from auxiliary engines in 2023 to 5% in 2050 which is in the lower end of an estimated potential to replace 30 to 70% of energy use at berth (Ricardo & DNV, 2023; DNV GL, 2017).

B.6.4 Energy-efficiency measures

This study uses data from DNV's abatement database for different ship types and sizes which covers costs, emission reduction potential, and TRL for more than 50 technical and operational measures, allocated into predefined ship categories. Data on costs and reduction effects for operational and technical measures are based mainly on data from available literature (e.g. Hüffmeier J(2021); Bouman et al. (2017); Smith et al. (2014)); more than 30 three-phased energy management projects; fuel consumption data from ship reports; DNV's Technology Outlook activities (DNV GL, 2018; DNV GL, 2019; DNV GL, 2020; DNV, 2021a; DNV, 2022b; DNV, 2023) and COSSMOS[22] modelling and simulation projects (e.g. Dimopoulos (2014); (2016); and Stefanatos (2015)). For the cutting-edge EE package, we have also considered more recent work (Joao L.D. Dantas, 2023; Ziajka-Poznanska & Montewka, 2021; Kosmadakis, Meramveliotakis, Bakalis, & Neofytou, 2024; Wang, Yan, Yuan, & Li, 2016).

The GHG Pathway model does not evaluate the uptake of each single energy-efficiency measure (e.g. waste-heat recovery, air lubrication system) as the application of individual energy-efficiency measures on a specific ship, as well as interactions between the measures, are complex to model. We instead compile the energy-efficiency (EE) measures into five internally consistent packages, reflecting the timeline for new generation of energy efficient ship designs. Some of the measures in a package are overlapping or even mutually exclusive. Depending on the ship type and operational profile, a ship will implement most, but not necessarily all, individual measures in a package and as a result will achieve an average improvement in energy efficiency.

The average energy-efficiency improvements of the packages have been validated based on reported data for built before 2015, between 2015 and 2020 and after 2020.

The packages are described in Table B-9.

[22] Developed by DNV GL Strategic Research & Innovation DNV COSSMOS is a computer platform that models, simulates and optimises complex and integrated ship machinery systems with respect to energy efficiency, emissions, costs and safety.

Table B-9: Energy-efficiency packages used in the GHG Pathway model.

EE package	Availability	Explanation
Baseline EE	Before 2015	Typical energy-efficiency measures on vessels built before 2015. Includes basic operational measures such as standard hull cleaning, propeller polishing, engine auto tuning and optimization of cargo handling systems.
Basic EE	From 2015	Typical energy-efficiency measures on existing vessels built after 2015. Includes hull form optimization, basic machinery improvements, Variable-frequency drive, shaft generator power take-out/in (PTO/PTI), and measures to improve hydrodynamic propulsion, such as Propulsion Improving Devices before and after the propeller and high-efficiency propellers and rudders. All ships built after 2015 will at the start of the modelling in 2023 have the Basic EE package installed.
Enhanced EE	From 2020	Energy-efficiency measures expected to be mature for vessels built after 2020. Includes optimized bow shapes for real sea states, variable engine speed, steam plant operation improvement, air lubrication system, and battery hybridization.
Advanced EE	From 2025	Energy-efficiency measures expected to be mature for vessels built after 2025. It includes wind-assisted propulsion, solar panels, waste heat recovery systems (via e.g. power turbine), wind turbines, reversible high-temperature heat pump / Organic Rankine Cycle (ORC), and aerodynamic optimization of superstructures.
Cutting-edge EE	From 2030	Measures that are expected to mature for vessels built after 2030 are placed in the 'cutting edge' package. Model-based simulation and optimization which can improve hull and machinery performance further, autonomization and reduced ballast design are placed in this package of measures.

Based on cost of individual measures in each EE package, a total CAPEX, annual OPEX, and fuel saving potential have been estimated. The measures included in the different EE packages will depend on the applicability for the ship type in question. Fuel saving potential varies with type, size, as well as the operational profile of a vessel and the values used indicates and average effect. Installation costs have been included in CAPEX estimates.

For retrofitting of EE measures we assume a 50% additional cost, which is the same assumed for retrofitting of fuel technologies and onboard carbon capture systems. In addition to the machinery-related energy-efficiency measures we assume an incremental improvement of efficiency in internal combustion engine for newbuilds of 0.5% p.a., without any additional costs, until 2036. This is based on the annual improvement of the specific fuel consumption for a slow speed engine running on HFO between 1983 and 2001 (Faber, et al., 2020). After 2036, we assume that the efficiency is constant.

We include a learning effect of 10% cost reduction for every doubling of installations for energy-efficiency measures. This is in the lower end of what is reported in other studies on maritime technologies which is between 10 and 20% (DNV, 2012; Wang, Faber, Nelissen, Russell, & St Amand, 2011).

Below, we provide accumulated CAPEX, accumulated OPEX, and total fuel saving by EE-package for example vessels for selected segments (see Table B-1). Accumulated values are given, in order to give the total delta cost relative to a vessel with the basic energy-efficiency package. One table is given per main ship type considered; Table B-10 (bulk carriers), Table B-11 (tankers), Table B-12 (container), and Table B-13 (liquefied gas carriers and other).

Table B-10: CAPEX, OPEX, and total fuel saving potential by EE-package for example deep-sea and short-sea bulk carriers. Fuel savings and cost are given relative to the Baseline EE package. Sources are provided above. Acc. = accumulated.

EE package	Deep-sea bulk (example 200 000+dwt)			Short-sea bulk (example 10000-34999 dwt)		
	Acc. CAPEX (USD)	Acc. OPEX (USD per year)	Fuel saving (total %)	Acc. CAPEX (USD)	Acc. OPEX (USD per year)	Fuel saving (total %)
Baseline EE (before 2015)	-	-	-	-	-	-
Basic EE (available from 2015)	-	-	17 %	-	-	16 %
Enhanced EE (available from 2020)	4 600 000	170 000	24 %	2 400 000	80 000	25 %
Advanced EE (available from 2025)	11 500 000	480 000	31 %	5 600 000	180 000	32 %
Cutting-edge EE (available from 2030)	20 500 000	530 000	40 %	10 600 000	230 000	39 %

Table B-11 CAPEX, OPEX, and total fuel saving potential by EE-package for a deep-sea and a short-sea example tanker. Fuel saving and cost are given relative to the Baseline EE package. Sources are provided above. Acc.: accumulated.

EE package	Deep-sea tank (example 200 000+ dwt)			Short-sea tank (example 10000-19999 dwt)		
	Acc. CAPEX (USD)	Acc. OPEX (USD per year)	Fuel saving (total %)	Acc. CAPEX (USD)	Acc. OPEX (USD per year)	Fuel saving (total %)
Baseline EE (before 2015)	-	-	-	-	-	-
Basic EE (available from 2015)	-	-	16 %	-	-	16 %
Enhanced EE (available from 2020)	4 200 000	170 000	24 %	2 500 000	100 000	24 %
Advanced EE (available from 2025)	12 100 000	210 000	30 %	6 700 000	110 000	30 %
Cutting-edge EE (available from 2030)	27 100 000	260 000	37 %	11 700 000	160 000	36 %

Table B-12 CAPEX, OPEX, and total fuel saving potential by EE-package for a deep-sea and a short-sea example container vessel. Fuel saving and cost are given relative to the Baseline EE package. Sources are provided above. Acc.: accumulated.

EE package	Deep-sea container (example 14500 - 18999 TEU)			Short-sea container (example 1000 - 1999 TEU)		
	Acc. CAPEX (USD)	Acc. OPEX (USD per year)	Fuel saving (total %)	Acc. CAPEX (USD)	Acc. OPEX (USD per year)	Fuel saving (total %)
Baseline EE (before 2015)	-	-	-	-	-	-
Basic EE (available from 2015)	-	-	15 %	-	-	15 %
Enhanced EE (available from 2020)	4 200 000	140 000	24 %	2 300 000	90 000	24 %
Advanced EE (available from 2025)	13 600 000	170 000	28 %	5 300 000	100 000	27 %
Cutting-edge EE (available from 2030)	33 600 000	220 000	35 %	10 300 000	150 000	33 %

Table B-13 CAPEX, OPEX, and total fuel saving potential by EE-package for a liquefied gas carrier and a vehicle carrier example vessel. Fuel saving and cost are given relative to the Baseline EE package. Sources are provided above. Acc.: accumulated.

EE package	Liquefied gas carrier (example 50 000 - 199999 cbm)			Other vessels (example 0-3999 vehicle)		
	Acc. CAPEX (USD)	Acc. OPEX (USD per year)	Fuel saving (total %)	Acc. CAPEX (USD)	Acc. OPEX (USD per year)	Fuel saving (total %)
Baseline EE (before 2015)	-	-	-	-	-	-
Basic EE (available from 2015)	-	-	17 %	-	-	13 %
Enhanced EE (available from 2020)	3 700 000	110 000	25 %	3 200 000	80 000	24 %
Advanced EE (available from 2025)	8 100 000	120 000	28 %	5 800 000	80 000	25 %
Cutting-edge EE (available from 2030)	37 100 000	170 000	35 %	13 800 000	130 000	31 %

B.6.5 Speed reduction

The model applies four different levels of speed reduction: 0%, 10%, 20% and 30%. The speed reduction is relative to the design speed of the fleet in 2015. The resulting reductions in main-engine power for an individual vessel are estimated using the ‘Cubic Rule’ method where the engine power increases with speed raised to the third power.

The impact of speed reduction on transport work is complex to model as it inherently changes the transport chain. Partly, speed reduction can be accommodated by more efficient port operations without the need for adding new ships to replace the capacity. It can also be achieved by synchronizing ship and port operations enabling the ships to slow down and arrive just in time (e.g. (Andersson, 2017; Longva T. , 2011; HSBC, 2023)). Ships that reduce transit speeds will do fewer voyages per year with less time in port and can use that time for sailing instead (CE Delft, 2012). Ultimately, timetables and schedules must be changed, and more ships deployed to maintain the total transport capacity.

By analysing AIS-data from 2019 to 2023 we have compared the changes in annual average speed and distance sailed for individual vessels from one year to another. We included ships that reduced speed by 8 to 12% from one year to the next, excluding ships sailing less than 1000 nm in either of the two years being compared.

There were large variations in the change in annual distance sailed independent of the change in speed. For ships that reduced speed by 8 to 12%, tank and bulk vessels on average reduced distance sailed by 6-7%; container ships reduced distance on average by 10% and other vessels reduced by 3%. Liquefied gas tankers actually reduced distance by more than the reduced speed which could indicate changes in the trading pattern or other market or infrastructure related impacts (e.g. due to more waiting).

Based on this AIS analysis, we assume that the need for new transport capacity is proportional to the reduction in distance sailed – e.g. a 10% speed reduction for short sea tank and bulk vessel lead to a 6% reduction in transport capacity. For liquefied gas carriers the reduction is capacity is kept at 10% and for 3% for ships in the Other category.

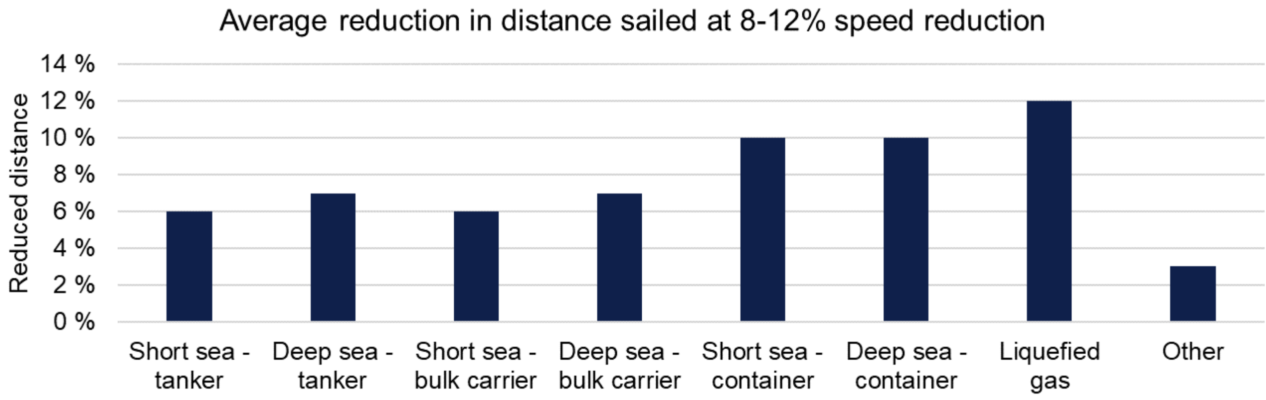


Figure B-1: Average reduction in annual distance sailed of ships reducing average speed by 8% to 12% from one year to the next between 2019 and 2023. Based on AIS-data from 10,500 ships. Ships sailing less than 1,000 nautical miles in either of the two years being compared have been excluded.

For the individual shipowner the speed reduction results in a lost opportunity cost (see Section A.2.3.1). As the transport capacity of the vessel is reduced, its earning capacity also declines. More vessels would have to be built and operated to cover for the lost capacity. In addition, the cargo owner has increased costs due to capital being tied up through longer sailing times. The lost opportunity cost has been derived through an iterative process where the model was run at different speed reduction cost levels, keeping all other input factors constant such as regulations and fuel costs. The objective of the iterations was to find the equilibrium where the speed observed in the AIS baseline would be retained by the model through the NPV calculations. The method is further described in Longva and Sekkesæter (2021).

The direct costs for the fleet of speed reduction in our modelling are calculated as the cost of replacing the lost transport capacity including the cost for building and operating additional ships less the fuel cost savings for ship reducing speed (see Section A.2.3.2). Table B-14 shows the newbuild cost and operational expenses per segment. The basic newbuild cost is the average newbuild cost for the segment) between 2019 and 2023 (Clarksons Research, 2024). Operational expenses include all costs of running the vessel, such as crew, maintenance and so on (Drewry, 2023). The operational costs are differentiated on the age of the vessel. Newbuild prices and operational costs are not included for cruise and ro-ro passenger vessels. These segments have a substantial cost element related to services offered to passengers with great variation in operational profiles. Including the newbuild and operational costs which is used to estimate of the cost of speed reduction through additional ships to replace lost capacity, would therefore be challenging for these segments.

Table B-14: Basic newbuild prices (Clarksons Research, 2024) and operational expenses (Drewry, 2023). Numbers marked with * are extrapolated based on the price/cost of smaller or larger ships of the same type.

Segment	CAPEX Newbuild (mill USD)	OPEX 0–4 yrs (USD/day)	OPEX 5–9 yrs (USD/day)	OPEX 10–14 yrs (USD/day)	OPEX 15–19 yrs (USD/day)	OPEX 20 yrs (USD/day)
Bulk carrier 0–9999 dwt	19*	3 552*	4 192	4 360	4 624	4 720
Bulk carrier 10,000–34,999 dwt	24	4 440	5 240	5 450	5 780	5 900
Bulk carrier 35,000–59,999 dwt	27	4 700	5 570	5 820	6 140	6 270
Bulk carrier 60,000–99,999 dwt	46	5 570	6 100	6 350	6 730	6 890
Bulk carrier 100,000–199,999 dwt	31	5 910	6 900	7 170	7 610	7 780
Bulk carrier 200,000–+ dwt	60	6 230	7 260	7 560	8 010	8 189
Chemical tanker 0–4999 dwt	10*	3 832*	4 336	4 552	4 824	4 856
Chemical tanker 5,000–9,999 dwt	12*	4 790	5 420	5 690	6 030	6 070
Chemical tanker 10,000–19,999 dwt	15	5 440	6 150	6 430	6 810	6 960
Chemical tanker 20,000– dwt	30	6 800	7 670	7 970	8 360	8 510

Segment	CAPEX Newbuild (mill USD)	OPEX 0–4 yrs (USD/day)	OPEX 5–9 yrs (USD/day)	OPEX 10–14 yrs (USD/day)	OPEX 15–19 yrs (USD/day)	OPEX 20 yrs (USD/day)
Container 0–999 TEU	16	4 150	4 680	4 900	5 200	5 350
Container 1,000–1,999 TEU	27	5 020	5 670	5 910	6 220	6 400
Container 2,000–2,999 TEU	36	5 020	5 670	5 910	6 220	6 400
Container 3,000–4,999 TEU	49	5 790	6 500	6 780	7 190	7 370
Container 5,000–7,999 TEU	81	6 420	7 160	7 440	7 880	8 070
Container 8,000–11,999 TEU	113	7 380	8 270	8 590	9 120	9 310
Container 12,000–14,500 TEU	125	7 890	9 030	9 430	10 012	10 220
Container 14,500-18999 TEU	139	7 970	9 200	9 590	10 182	10 394
Container 19,000-+ TEU	186	8 040	9 600	10 007	10 624	10 846
General cargo 0–4999 dwt	20*	3 136*	3 416	3 576	3 792	3 904
General cargo 5,000–9,999 dwt	25*	3 920	4 270	4 470	4 740	4 880
General cargo 10,000–+ dwt	31	4 490	4 950	5 180	5 450	5 610
Liquefied gas tanker 0–49,999 cbm	49	5 040	5 880	6 160	6 520	6 720
Liquefied gas tanker 50,000–199,999 cbm	219	13 310	14 280	14 620	15 474	15 949
Liquefied gas tanker 200,000–+ cbm	285	17 303	18 564	19 006	20 117	20 734
Oil tanker 0–4999 dwt	20*	3 369*	3 901	4 070	4 301	4 398
Oil tanker 5,000–9,999 dwt	24*	4 211*	4 877	5 088	5 376	5 498
Oil tanker 10,000–19,999 dwt	31*	5 264*	6 096	6 360	6 720	6 872
Oil tanker 20,000–59,999 dwt	38	6 580	7 620	7 950	8 400	8 590
Oil tanker 60,000–79,999 dwt	50	7 050	8 250	8 600	9 080	9 310
Oil tanker 80,000–119,999 dwt	59	7 460	8 680	9 060	9 610	9 830
Oil tanker 120,000–199,999 dwt	72	8 020	9 430	9 820	10 380	10 600
Oil tanker 200,000–+ dwt	108	8 310	9 800	10 190	10 750	10 970
Other liquids tanker tankers dwt	24*	4 211*	4 877	5 088	5 376	5 498
Ferry-pax only 0–1999 GT	-	-	-	-	-	-
Ferry-pax only 2000–+ GT	-	-	-	-	-	-
Cruise 0–1999 GT	-	-	-	-	-	-
Cruise 2000–9999 GT	-	-	-	-	-	-
Cruise 10000–59999 GT	-	-	-	-	-	-
Cruise 60000–99999 GT	-	-	-	-	-	-
Cruise 100000–+ GT	-	-	-	-	-	-
Ferry-RoPax 0–1999 GT	-	-	-	-	-	-
Ferry-RoPax 2000–+ GT	-	-	-	-	-	-
Refrigerated bulk 0– dwt	31*	4 490*	4 950	5 180	5 450	5 610
Ro-ro 0–4,999 dwt	55*	4 520*	4 970	5 200	5 520	5 680
Ro-ro 5,000–+ dwt	68	4 520	4 970	5 200	5 520	5 680
Vehicle 0–3,999 vehicle	63*	4 750	5 210	5 420	5 710	5 890
Vehicle 4,000–+ vehicle	79	6 270	6 880	7 140	7 510	7 690
Yacht 0–+ GT	-	-	-	-	-	-
Service tug 0–+ GT	-	-	-	-	-	-
Miscellaneous fishing 0–+ GT	-	-	-	-	-	-
Offshore 0–+ GT	-	-	-	-	-	-
Service other 0–+ GT	-	-	-	-	-	-
Miscellaneous other 0–+ GT	-	-	-	-	-	-

B.7 Fuel costs and availability

B.7.1 Method for deriving fuel bunkering costs

Below, we describe the methodology applied for developing a future marine fuel cost trajectory for the fuel types and feedstock categories included in the study.

In principle, the price of a fuel is a function of the cost of raw material, production and distribution of the fuel and the relationship between supply and demand in the market. Historically, we have seen large variations in prices. Because of this, it is hard to predict future fuel prices for marine fuels, not least, because prices will vary between the different bunkering hubs and due to supply and demand both from the shipping industry and other sectors.

The fuel bunkering cost trajectories applied in this study are derived as follows:

- 2023: where available, we use reported average price of fuels and feedstocks in 2023. In case reported average price is not available, we use estimated bunkering cost from a review of literature sources.
- 2030, 2040, and 2050: for non-fossil fuels we use projected bunkering cost estimates from a review of literature sources. Projected fossil fuel bunkering costs are based on historical price relationships with crude oil or natural gas.

To ensure internal consistency between fuel types in the fuel bunkering cost projections, we only use selected sources that cover a wide range of different fuel-types within a given feedstock category (e.g. e-fuels):

- MMMCZCS (2024) is a fuel cost calculator from the Mærsk Mc-Kinney Møller Center for Zero Carbon Shipping, covering the time period from 2023 to 2050. It covers a wide range of low carbon fuel types produced via sustainable biomass, renewable electricity, and natural gas with carbon capture and storage. Default input assumptions on key parameters such as renewable electricity price and natural gas are provided and used for generating fuel costs in this study[23]. We use average fuel costs across the different regions covered.
- CONCAWE (2022) analyses pathways for different e-fuels produced in the Middle East and North Africa as well as Europe from a techno-economic perspective from 2020 to 2050. We apply fuel pathways with production in the Middle East and North Africa, with transportation and distribution to Europe.
- DNV (2022b) projects fuel bunkering costs for a wide range of low carbon fuels, including e-fuels, biofuels, and blue fuels, across different regions, using DNV’s Fuel Price Mapper. The fuel bunkering costs are aligned with DNV’s Energy Transition Outlook model, simulating the global energy system towards 2050. We use the average cost across the different regions in this study.
- LR & UMAS (2020) projects fuel prices from 2020 to 2050 for several low carbon fuel pathways. Prices for e-fuels and blue fuels are based on the estimated levelized cost of production, whereas biofuel prices are projected considering supply constraints on bioenergy. A lower bound and upper bound fuel price scenario is provided, and in this study, we use the average between the lower bound and upper bound of the fuel price range.

For each source, we only consider fuel pathways with significant well-to-wake GHG intensity reduction. For example, for e-fuels, CONCAWE (2022) gives a WtW GHG intensity range of 6-9 gCO2-eq./MJ in 2050, for fuels produced in the Middle East and Africa, and transported to Europe. Using default assumptions, MMMCZCS (2024) gives a WtW GHG intensity for analysed e-fuels in the range of 3-17 gCO2-eq./MJ in 2023, reducing to 2-8 gCO2-eq./MJ in 2050. LR & UMAS (2020), meanwhile, gives a WtW GHG intensity of zero for e-fuels. For blue fuels, WtW GHG intensity ranges from 15-20 gCO2-eq./MJ in 2023, to about 15 gCO2-eq./MJ in 2050 (LR and UMAS, 2020; MMMCZCS, 2024). Biofuels

[23] For renewable electricity prices, we use high prices, since these are most consistent with electricity prices applied in other sources.

produced from advanced feedstocks range from a maximum WtW GHG intensity of 36 gCO2-eq./MJ in 2023, to a maximum of 15 gCO2-eq./MJ in 2050.

In all of the applied sources for fuel bunkering costs, renewable electricity costs are assumed to decrease from today towards 2050. Between 2023 and 2050, the assumed price in USD/GJ changes from 15 to 13 (CONCAWE, 2022); 21 to 10 (LR and UMAS, 2020); 18 to 11 (MMMCZCS, 2024); 19 to 15 (DNV, 2022b). Natural gas prices (with the exception of 2023), range from about 6 – 8 USD/GJ in 2030, 2040, and 2050.

Projected biofuel bunkering costs are sensitive to the assumed cost of biomass feedstock. Costs are likely to vary significantly between different feedstock types (e.g. waste and wood residuals). DNV (2022b) and MMMCZCS (2024), depending on biofuel production pathways, consider an increase in the cost of biomass in the future, reflecting either an increase in biomass supply cost and/or higher biomass prices. LR and UMAS (2020) considers an explicit price increase for biofuels to reflect supply constraints on the production of biofuels.

For carbon-based e-fuels (e-LNG, e-methanol, and e-MGO), the source of carbon and its associated cost of extraction is a key factor determining fuel bunkering cost. While LR and UMAS (2020) and assumes that carbon is extracted from direct air capture (DAC), bunkering cost estimates from DNV (2022b) and CONCAWE (2022) assume use of point sources (e.g. from biofuel production facilities) before a shift towards DAC in 2040 and 2050. The bunkering costs applied from MMMCZCS (2024), considers use of a point source for carbon.

Description of methodology for assessing bunkering and feedstock costs for each fuel and feedstock is given in Table B-15.

Table B-15: Sources and assumptions used for projecting future fuel bunkering cost from 2023 to 2050, per fuel-type.

Fuel/feedstock	Method for assessing bunkering/feedstock cost
HFO	**2023:** HFO bunkering cost in 2023 is based on reported bunkering price for HSFO (ARA[24]) from Clarksons Research (2024). **Future (2030, 2040, 2050):** We assume that HFO-cost is equivalent to the crude oil price multiplied by a factor 0.81 (on a per unit of energy basis). The factors are derived from the relationship between historic crude oil price and HFO-price from 2020 to 2023.
VLSFO/MGO	VLSFO/MGO is calculated as a weighted average cost, assuming a split of 33% (MGO) and 67% (VLSFO). The split is based on the relative amount of reported consumption of MGO and LFO in 2022 (IMO, 2023). **2023:** VLSFO/MGO bunkering cost in 2023 is based on reported VLSFO and MGO bunkering price (ARA) from Clarksons Research (2024). **Future (2030, 2040, 2050):** We assume that VLSFO/MGO bunkering cost is equivalent to the crude oil price multiplied by a factor 1.13 (on a per unit of energy basis). The factor is derived from the relationship between historic crude oil price and VLSFO and MGO bunkering prices from 2020 to 2023.

[24] Antwerpen-Rotterdam-Amsterdam

Fuel/feedstock	Method for assessing bunkering/feedstock cost
LNG	**2023:** LNG bunkering cost in 2023 is based on reported estimated LNG bunkering price (ARA) from Clarksons Research (2024). **Future (2030, 2040, 2050):** We assume that the LNG bunkering cost is equivalent to the assumed natural gas price, with an added distribution cost of 3 USD/MMBtu (or 2.8 USD/GJ) (CE Delft, 2020).
LPG	**2023:** LPG bunkering cost in 2023 is based on reported estimated LPG bunkering price (USG [25]) from Clarksons Research (2024). To make the bunkering cost geographically consistent with other fossil fuel prices, we add a transport and distribution cost of 2.5 USD/GJ (based on historic price difference between ARA and USG). **Future (2030, 2040, 2050):** We assume that LPG bunkering cost is equivalent to the crude oil price multiplied by a factor 0.90 (on a per unit of energy basis). The factor is derived from the relationship between historic crude oil price and estimated LPG bunkering prices from 2021 to 2023.
Fossil LH2	Fossil LH2 bunkering cost is assumed to have the same relative cost-difference to fossil ammonia, as for blue LH2 and blue ammonia.
Fossil ammonia	**2023:** Fossil ammonia bunkering cost is based on reported fossil ammonia price in NWE[26] from data on DNV's Alternative Fuels Insights platform provided by Argus Media. **Future (2030, 2040, 2050):** We assume that the fossil ammonia bunkering cost is equivalent to the cost of natural gas multiplied by a factor of 2.8 (on a per unit of energy basis). The factor is derived from the relationship between historic natural gas price and price of fossil ammonia in 2021 and 2023 (2022 excluded due to abnormal gas prices).
Fossil methanol	**2023:** Fossil methanol bunkering cost is based on reported fossil ammonia price in NWE from data on DNV's Alternative Fuels Insights platform provided by Argus Media. **Future (2030, 2040, 2050):** We assume that the fossil methanol bunkering cost is equivalent to the cost of natural gas multiplied by a factor of 1.6 (on a per unit energy basis). The factor is

25 United States Gulf
26 North Western Europe

Fuel/feedstock	Method for assessing bunkering/feedstock cost
	derived from the relationship between historic natural gas price and price of fossil methanol in 2021 and 2023 (2022 excluded due to abnormal gas prices).
Blue LH2	Blue LH2 bunkering cost is assumed to have the same relative cost-difference to blue ammonia, as for e-ammonia and e-LH2.
Blue ammonia	Blue ammonia bunkering cost is based on average reported cost in literature (DNV, 2022b; MMMCZCS, 2024; LR and UMAS, 2020).
Bio-LNG	Bio-LNG bunkering cost is based on average reported cost in literature (DNV, 2022b; MMMCZCS, 2024; LR and UMAS, 2020). Since LR and UMAS (2020) does not provide fuel price projections for bio-LNG, we assume that bio-LNG follows the same relative price development as for bio-methanol from wood.
Bio-methanol	**2023:** Bio-methanol bunkering cost is based on reported estimated bio-methanol price in ARA from data on DNV's Alternative Fuels Insights platform provided by Argus Media. **Future (2030, 2040, 2050):** Bio-methanol bunkering cost is based on average reported cost in literature (DNV, 2022b; MMMCZCS, 2024; LR and UMAS, 2020).
Bio-MGO	**2023:** Bio-MGO bunkering cost is based on reported advanced B100 biodiesel price in ARA from data on DNV's Alternative Fuels Insights platform provided by Argus Media. **Future (2030, 2040, 2050):** Bio-MGO bunkering cost is based on average reported cost in literature (DNV, 2022b; MMMCZCS, 2024; LR and UMAS, 2020). LR and UMAS (2020) only provides fuel price projections for bio-MGO made from oil crops, with limited WtW GHG reduction potential. As such, we disregard the specific projection for bio-MGO made from oil crops. Instead, we assume that bio-MGO follows the same relative price development as for bio-methanol from wood.
e-ammonia	e-ammonia bunkering cost is based on average reported cost in literature (CONCAWE, 2022; DNV, 2022b; LR and UMAS, 2020; MMMCZCS, 2024)
e-LH2	e-LH2 bunkering cost is based on average reported cost in literature (CONCAWE, 2022; DNV, 2022b; LR and UMAS, 2020; MMMCZCS, 2024)
e-LNG	e-LNG bunkering cost is based on average reported cost in literature (CONCAWE, 2022; DNV, 2022b; LR and UMAS, 2020; MMMCZCS, 2024)

Fuel/feedstock	Method for assessing bunkering/feedstock cost
e-methanol	e-methanol bunkering cost is based on average reported cost in literature (CONCAWE, 2022; DNV, 2022b; LR and UMAS, 2020; MMMCZCS, 2024)
e-MGO	e-MGO bunkering cost is based on average reported cost in literature (CONCAWE, 2022; DNV, 2022b; LR and UMAS, 2020; MMMCZCS, 2024)
Electricity from shore	Supply cost for electricity from shore is assumed to be proportional to the cost of renewable electricity. To account for additional grid costs, including intermittency grid costs, we add 50% to the cost of renewable electricity.
Renewable electricity (feedstock)	Cost of renewable electricity is based on average renewable electricity cost used in literature (CONCAWE, 2022; DNV, 2022b; LR and UMAS, 2020; MMMCZCS, 2024).
Natural gas (feedstock)	**2023:** Cost of natural gas based on average reported natural gas price (TTF[27]) from (Trading Economics, 2024a). **Future (2030, 2040, 2050):** Cost of natural gas is based on averaged assumed natural gas cost in literature (DNV, 2022b; MMMCZCS, 2024; LR and UMAS, 2020).
Crude oil (feedstock)	**2023:** Cost of crude oil based on average reported brent crude oil price from (Trading Economics, 2024b). **Future (2030, 2040, 2050):** Cost of crude oil is based on the IEA's World Energy Outlook, announced pledges (AP) crude oil scenario (IEA, 2023b).

Table B-16 gives the cost of feedstock energy sources, from 2023 to 2050, applied in the study. The values are based on averages from the selected literature sources unless otherwise indicated.

Table B-16: Cost of feedstock energy sources applied in this study.

Feedstock	Cost (USD/GJ)			
	2023	2030	2040	2050
Renewable electricity	17.8	16.4	14.7	12.2
Natural gas	8.5*	7.4	7.3	7.2
Crude oil	14.2*	12.6	11.4	10.2

*) Based on reported average price in 2023

[27] Title transfer facility

B.7.2 Fuel infrastructure availability

The fuel infrastructure availability level simulates the development and maturity of regional bunkering infrastructure for alternative fuels. Each fuel type is given a fuel infrastructure availability level of 1 (low), 2 (medium), or 3 (high) per region. The initial availability level of VLSFO/MGO (all feedstock categories) and electricity are set to 3, since they can use the existing distribution and bunkering infrastructure of liquid fossil fuels. All feedstock categories of LNG are set at initial level 2, while LPG, hydrogen, ammonia and methanol are at availability level 1.

The fuel infrastructure availability level is updated each year based on the fuel energy consumption in the particular region. The fuel in question moves to the next availability level if the consumption passes different thresholds. For level 1 fuels to move to level 2, the threshold is 2%, for level 2 to move to level 3, the threshold is 5%. With increasing infrastructure availability, an increasing share of shipowners will consider the fuel a feasible option for their operation.

B.8 Tank-to-wake GHG emission factors

The tank-to-wake GHG emissions for ships built to 2022 are calculated based on emission factors from the Fourth IMO GHG study (Faber, et al., 2020), with some adjustments due to availability of data. For CO_2, the emission factors are a direct function of the carbon content of the fuel, while also taking into account that CO_2 emissions from biogenic carbon or carbon from DAC are zero. This is consistent when using TtW value 2 according to the IMO LCA guidelines (see Section 3.1) and also for WtW calculations where the CO_2 emissions from biogenic carbon or carbon from DAC are not deducted for the WtT GHG emissions factors (see Section 1.2.6).

For CH_4 and N_2O the emission factors are dependent on the engine type and engine load. For LNG fuelled ships we distinguish between 4-stroke Otto cycle engines, 2-stroke low pressure Otto cycle engines, 2-stroke high pressure diesel cycle engines, and steam turbines. All auxiliary power is assumed to be produced by 4-stroke engines. We have not applied a correction factor to take into account that emissions of CH_4 and N_2O may increase at lower engine loads.

For CO_2 and N_2O, the same emission factors are used also for ships built from 2023 to 2050. The CH_4 emissions for LNG fuelled engines are improving and for all ships built from 2023 and onwards we use reduced emissions factors for Otto cycle engines, based on a report by Sphera (2021). Based on the default factors in FuelEU Maritime, we have assumed the same CH_4 and N_2O emission factors as for LSFO/MGO except for CH_4 for hydrogen and ammonia ICE which are set to zero. Fuel cell CH_4 and N_2O emissions factors are set to zero. The TtW emission factors for CO_2, CH_4 and N_2O are provided in Table B-17.

Table B-17 Tank-to-wake emission conversion factors used in this study (Sphera, 2021; Faber, et al., 2020).

Fuel	Engine type	CO_2 gCO_2/g fuel		CH_4 gCH_4/kWh		N_2O gN_2O/kWh
		Fossil	Non-fossil	Built -2022	Built 2023-	All
HFO	All	3.114	0	0.01	0.01	0.031
VLSFO/MGO	All	3.206	0	0.01	0.01	0.03
LNG	Otto 4-stroke	2.75	0	5.5	4	0.02
	Otto 2-stroke Low Pressure	2.75	0	2.1	1	0.02
	Diesel 2-stroke High Pressure	2.75	0	0.2	0.2	0.02
	Turbine	2.75	0	0.04	0.04	0.02
LPG*	All	3.00 (propane)	0	0.01	0.01	0.031
Methanol	All	1.375	0	0.001	0.001	0.003
Ammonia*	ICE	0		0	0	0.031
	Fuel Cell	0		0	0	0
Hydrogen*	ICE	0		0	0	0.031
	Fuel Cell	0		0	0	0

APPENDIX C
Detailed scenario parameters

This appendix includes the GFI requirements, levy and reward rates used as input for the scenarios. It also include the resulting fee for scenarios which includes the feebate mechanism.

C.1 GFI requirements

The GFI requirements in scenarios 32 to 56 are set so that the WtW GHG emission trajectories as defined in Section 5.2 are followed both under a WtW and TtW scope. As the GFI requirement is measured in GHG emission per unit of energy, the resulting GHG emission will depend on the energy used which again is dependent on the energy use of the fleet. As such the GFI requirements need to be different depending on the emission trajectory (*Base* and *Strive*), seaborne trade growth (Low and High), whether the required GFI is based on a WtW or TtW scope, and other factors that impact the energy use such as the levy/feebate.

Annual required WtW and TtW GFI limits to 2050 are determined by iteration where all scenarios are run with an estimated GFI and then based on the energy use per scenario they are adjusted and the scenarios and re-run. The resulting GHG emissions align within ±5% to the required GHG trajectories. To reach the targeted emission level several iterations may be needed. The targets are shown in Table C-1. The targets for 2050 are set to 2.0 gCO_2eq/MJ which would cover a limited amount of CH_4 and N_2O emissions remaining from MGO, methanol and ammonia used in dual fuel internal combustion engines, and from LNG used in 2-stroke diesel high pressure dual fuel internal combustion engines (see appendix B.8). This result in about 98% reduction from the GHG intensity of LSFO/MGO.

Table C-1: GFI requirements in 2030, 2040 and 2050 used in the policy scenarios in order that the emission trajectories are met.

Scenario	GFI requirement (gCO_2eq/MJ)		
	2030	2040	2050
21: *Base* | X.1 | TtW GFI	58.1	23.3	2.0
22: *Base* | Y.1 | WtW GFI	74.3	30.1	2.0
23: *Base* | X.4 | TtW GFI Flex	57.2	23.5	2.0
24: *Base* | Y.4 | WtW GFI Flex	73.7	29.6	2.0
25: *Base* | X.2 | TtW GFI | 150–300 USD/t levy | 90 to 60% reward	66.8	24.2	2.0
26: *Base* | Y.2 | WtW GFI | 150–300 USD/t levy | 90 to 60% reward	88.0	32.2	2.0
27: *Base* | X.5 | TtW GFI Flex | 150–300 USD/t levy | 90 to 60% reward	64.4	25.6	2.0
28: *Base* | Y.5 | WtW GFI Flex | 150–300 USD/t levy | 90 to 60% reward	87.8	32.3	2.0
29: *Base* | X.2 | TtW GFI | 30–120 USD/t levy | 105% reward	58.9	23.0	2.0
30: *Base* | Y.2 | WtW GFI | 30–120 USD/t levy | 105% reward	75.8	29.9	2.0
31: *Base* | X.5 | TtW GFI Flex | 30–120 USD/t levy | 105% reward	58.7	22.9	2.0
32: *Base* | Y.5 | WtW GFI Flex | 30–120 USD/t levy | 105% reward	74.9	29.5	2.0
33: *Base* | X.3 | TtW GFI | Feebate | 105% reward	57.1	22.9	2.0
34: *Base* | Y.3 | WtW GFI | Feebate | 105% reward	73.4	29.5	2.0
35: *Base* | X.6 | TtW GFI Flex | Feebate | 105% reward	56.6	23.1	2.0
36: *Base* | Y.6 | WtW GFI Flex | Feebate | 105% reward	72.8	29.5	2.0
41: *Strive* | X.1 | TtW GFI	52.0	16.0	2.0
42: *Strive* | Y.1 | WtW GFI	68.6	20.6	2.0
43: *Strive* | X.4 | TtW GFI Flex	51.1	16.0	2.0
44: *Strive* | Y.4 | WtW GFI Flex	67.8	20.4	2.0
45: *Strive* | X.2 | TtW GFI | 150–300 USD/t levy | 90 to 60% reward	55.2	15.9	2.0

Scenario	GFI requirement (gCO2eq/MJ)		
	2030	2040	2050
46: *Strive* | Y.2 | WtW GFI | 150–300 USD/t levy | 90 to 60% reward	74.4	21.1	2.0
47: *Strive* | X.5 | TtW GFI Flex | 150–300 USD/t levy | 90 to 60% reward	53.6	15.9	2.0
48: *Strive* | Y.5 | WtW GFI Flex | 150–300 USD/t levy | 90 to 60% reward	73.7	21.0	2.0
49: *Strive* | X.2 | TtW GFI | 30–120 USD/t levy | 105% reward	52.0	15.7	2.0
50: *Strive* | Y.2 | WtW GFI | 30–120 USD/t levy | 105% reward	69.5	20.3	2.0
51: *Strive* | X.5 | TtW GFI Flex | 30–120 USD/t levy | 105% reward	50.4	15.6	2.0
52: *Strive* | Y.5 | WtW GFI Flex | 30–120 USD/t levy | 105% reward	66.5	20.0	2.0
53: *Strive* | X.3 | TtW GFI | Feebate | 105% reward	51.8	15.7	2.0
54: *Strive* | Y.3 | WtW GFI | Feebate | 105% reward	68.9	20.3	2.0
55: *Strive* | X.6 | TtW GFI Flex | Feebate | 105% reward	51.1	15.7	2.0
56: *Strive* | Y.6 | WtW GFI Flex | Feebate | 105% reward	67.2	20.3	2.0

C.2 Levy, fee and reward levels

Table C-2 provides the detailed parameters for levy and reward rates used in the scenarios, as well as the resulting fee levels. The reward rates are given both in USD/GJ and the equivalent USD/tCO2eq reduced based on the WtW emission of e-ammonia compared to fossil MGO.

Table C-2: Detailed inputs used in the scenarios. The levy and reward rates are linearly interpolated between the years indicated.

Item	Applies to scenario(s)	2027	2030	2035	2040	2045	2050
Levy (USD/tCO2eq)	25 to 28 and 45 to 48	150	180	225	250	275	300
	29 to 32 and 49 to 52	30	60[28]	95	120	120	120
Fee (USD/tCO2eq)*	33	0.4	56	64	144	-	-
	34	9	36	43	87	-	-
	35	0.4	47	73	100	-	-
	36	2	40	48	72	-	-
	53	1	88	106	370	-	-
	54	10	58	77	195	-	-
	55	1	81	109	336	-	-
	56	2	71	56	155	-	-
Reward rate (USD/GJ / USD/tCO2eq)**	25 to 28 and 45 to 48	22 / 294	18 / 232	12 / 145	5 / 61	-	-
	29 to 36 and 49 to 56	26 / 352	21 / 270	15 / 177	10 / 107	-	-

* Note that the fee is calculated by the model as required to cover the cost of the reward and is not given as an input.
** The reward rate is converted to USD/tCO2eq by dividing the reward rate with the reduction in WtW GHG emission of e-ammonia relative to fossil MGO.

[28] 80 USD/tCO2eq in 2032, and then interpolated linearly.

APPENDIX D
Detailed scenario results

This appendix presents the results from the modelling the 2 BAU scenarios and 50 policy combination scenarios (numbered 1 to 18, 21 to 36 and 41 to 56) as described in Chapter 4. The scenarios are assessed in three target years (2030, 2040 and 2050) with regards to GHG emissions, change in cost intensity relative to the BAU scenario, energy use and fuel mix, including comparison with expected supply, number of newbuilds and retrofits compared with expected industry capacity, and revenue streams from economic elements.

Further analysis, including the remaining scenarios and the uncertainty and sensitivity analysis, is provided in Chapter 6.

D.1 Results from scenarios 1 to 18

This Section presents the results and analysis of the modelling of 2 BAU scenarios and 18 policy combination scenarios, numbered 1 to 18. Scenarios 1 to 18 did not include any constraints on bio- and blue fuel feedstock supply and consequently no impact on the fuel prices of these fuels. The observations made regarding these results are from the first interim report (DNV, 2024b).

Annual required GFI limits are the same for the *Base* and *Strive* GHG trajectory scenarios respectively, resulting in different GHG emissions. The differences in the GHG trajectories will affect the other results, including the differences in the estimated cost intensity changes between the scenarios.

D.1.1 GHG emissions

Figure D-1 shows the *Base* and *Strive* GHG emission trajectories towards 2050 compared to the projected GHG emission according to the two BAU scenarios which shows expected emissions under current policies and a low and high seaborne trade growth.

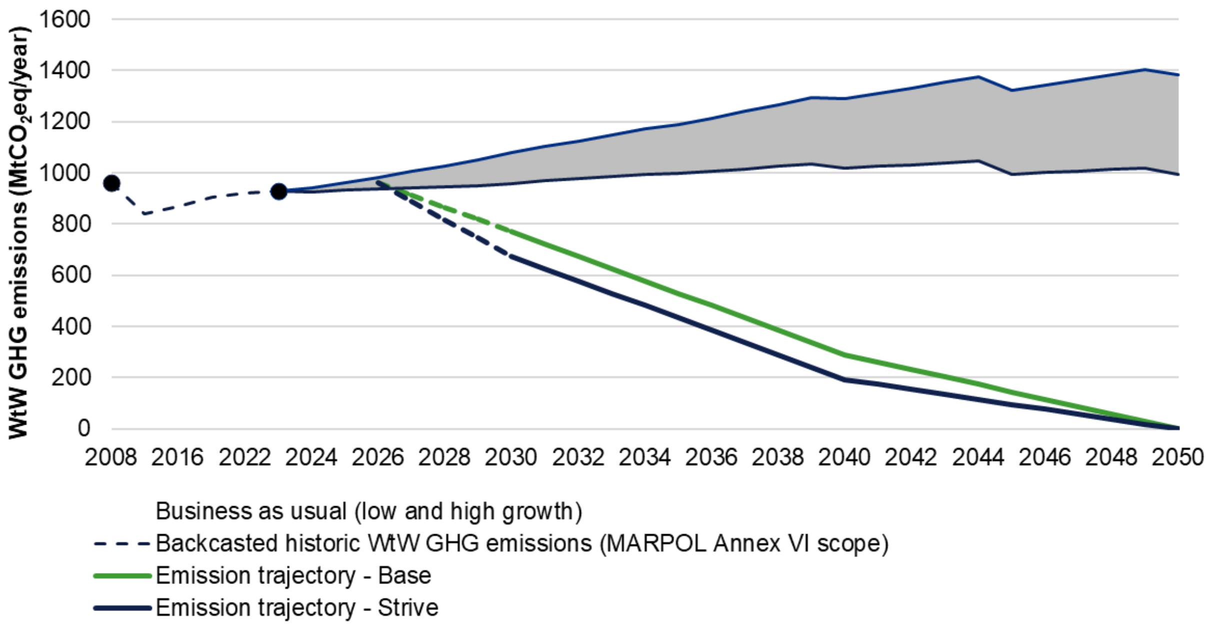


Figure D-1: **WtW GHG emissions for the period 2008–2023, projected WtW GHG emissions according to the BAU scenarios and required emission trajectories towards 2050 used for the scenarios in this study.**

The following observations are made from Figure D-1:

- To 2050, in the low and high growth BAU scenarios the WtW GHG emissions are expected to increase to 994 $MtCO_2eq$ and 1383 $MtCO_2eq$ respectively, which is a 7% to 49% increase compared with 2023, and a 3% to 44% increase if comparing with 2008.
- A slight reduction of WtW GHG emissions is seen in 2040, 2045 and 2050 in the BAU scenarios due to the ships trading in the EU complying with the FuelEU Maritime requirements. The WtW GHG emissions in the EU region was about 16% of the global emissions in 2023.

Figure D-2 shows the WtW GHG emission levels in 2030, 2040 and 2050, split on WtT GHG, TtW CO_2, TtW N_2O and TtW CH_4 emissions for the 18 policy combination scenarios.

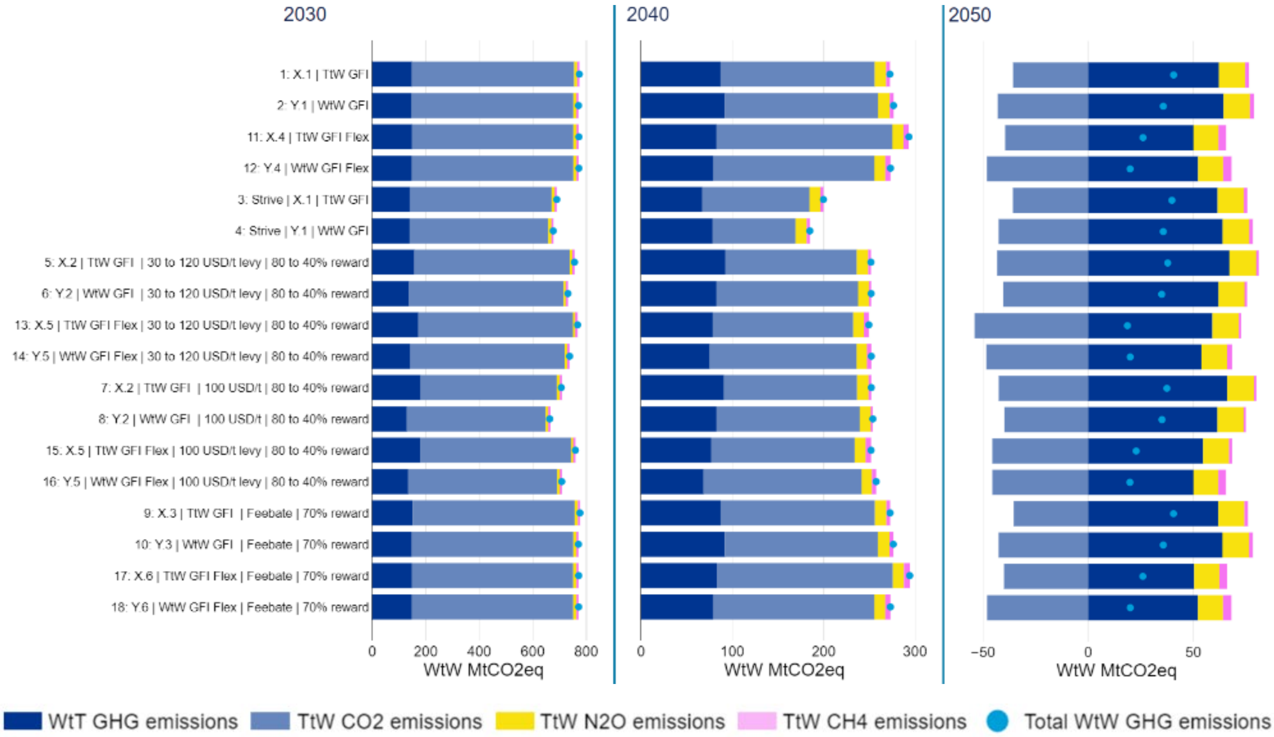


Figure D-2: **WtW GHG emissions per scenario, split on WtT GHG, TtW CO_2, TtW N_2O and TtW CH_4 emissions, in 2030, 2040, and 2050. The *Total WtW GHG emissions* markers indicate the total GHG emissions after subtracting emissions captured by onboard CCS and subsequently stored. Note that the scale of emissions varies.**

Figure D-3 shows the total WtW GHG emissions in 2030, 2040 and 2050 for the 18 policy combination scenarios compared to the GHG emission targets (see Table 5-2).

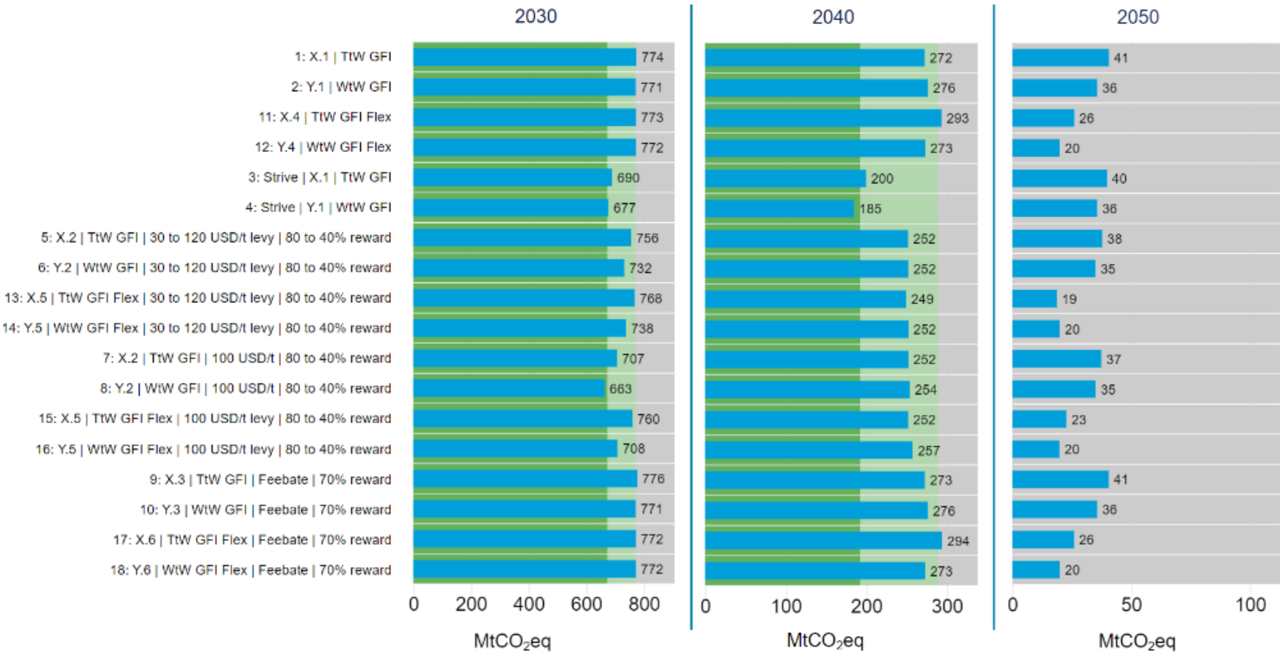


Figure D-3: **WtW GHG emission levels in 2030, 2040, and 2050 for the policy scenarios, compared to the emission targets. The dark-green to light-green boundary indicates the *Strive* target (scenarios 3 and 4) and the light-green to grey boundary indicates the *Base* target (all other scenarios).**

The following observations are made from Figure D-2 and Figure D-3:

- In all scenarios the TtW CO_2 emissions are negative in 2050. This is due to captured emissions by onboard CCS from bio- or e-fuels, having carbon from biogenic sources or from direct air capture.
- A certain amount of GHG emissions remains in 2050 for all scenarios as we expect that there will be some CH_4 and/or N_2O emissions from combustion engines in 2050 regardless of the fuel.
- A levy of 100 USD/tCO_2eq in scenario 7 to 8 and 15 to 16 give a lower GHG emission trajectory in 2030 and 2040 compared to the corresponding scenarios 1 to 2 and 11 to 12 with only the GFI.
- The TtW scenarios with a levy have a slightly higher emission level in 2030 as the TtW emissions are lower than WtW emissions in absolute terms, giving a lower levy cost. This effect is not apparent in 2040 or 2050.
- In 2040 the scenarios with a levy (scenarios 5 to 8 and 13 to 16) generally have lower emissions, while the scenarios with a feebate (9 to 10 and 17 to 18) are comparable to the scenarios without a feebate as the fee is less than 2 USD/tCO_2eq.
-

D.1.2 Cost impact

Figure D-4 shows the cost intensity change relative to low growth BAU for each policy scenario. The cost intensity is the total annual cost, including capital, operational and fuel expenses, as well as regulatory incomes and expenses imposed by the policy measures, divided by the total transport work in a year. The change is cost intensity for a target year is calculated relative to the cost intensity of the corresponding (i.e. same seaborne trade growth) BAU scenario in the target year.

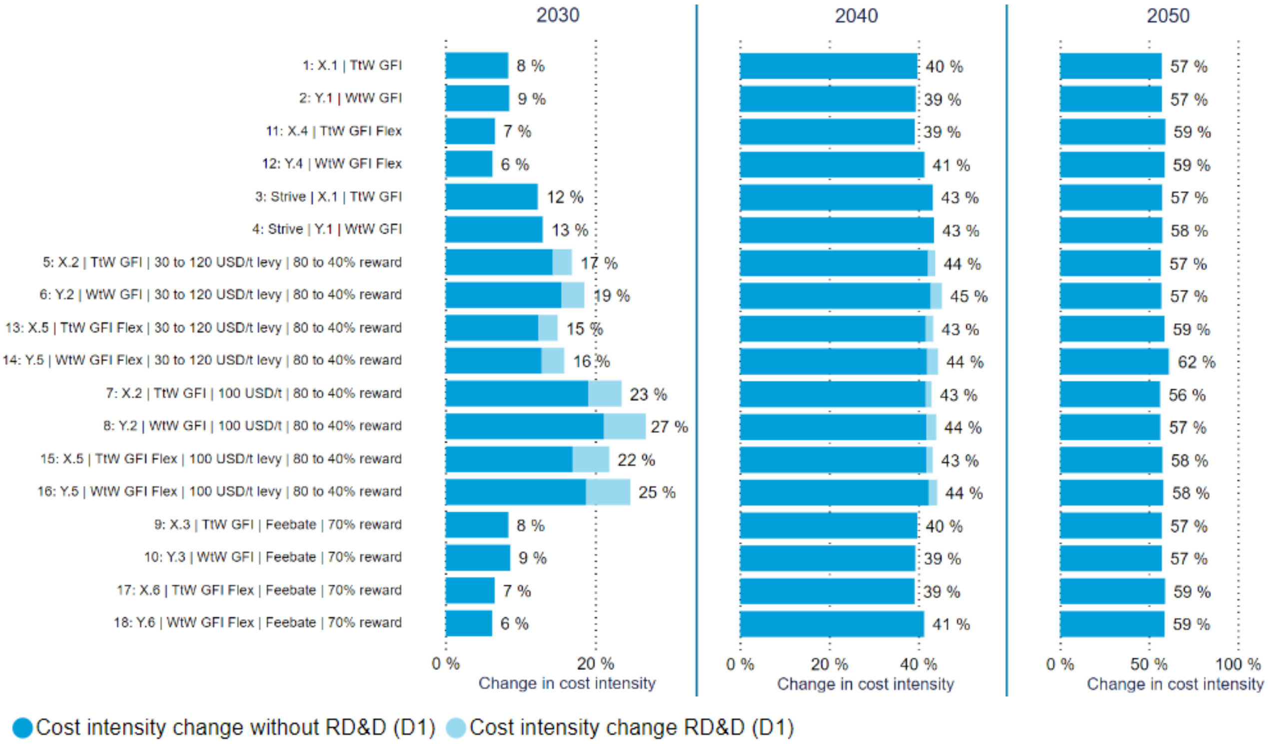


Figure D-4: **Cost intensity change per policy scenario relative to business-as-usual with low seaborne trade growth in 2030, 2040, and 2050. The light-blue bar in the scenarios with levy shows the part of the cost that is expected to be reimbursed back to the industry through RD&D.**[29]

Figure D-5 shows the aggregated costs from 2023 to 2050 split on annual capital costs, operational costs, fuel costs, CO_2 deposit costs and regulatory expenses, including levy/fee and rewards (left panel), and the additional costs per tonne of GHG reduced from 2023 to 2050 relative to BAU (right panel).

[29] Note that this chart was made prior to the assumption that D1 disbursement should be set to zero.

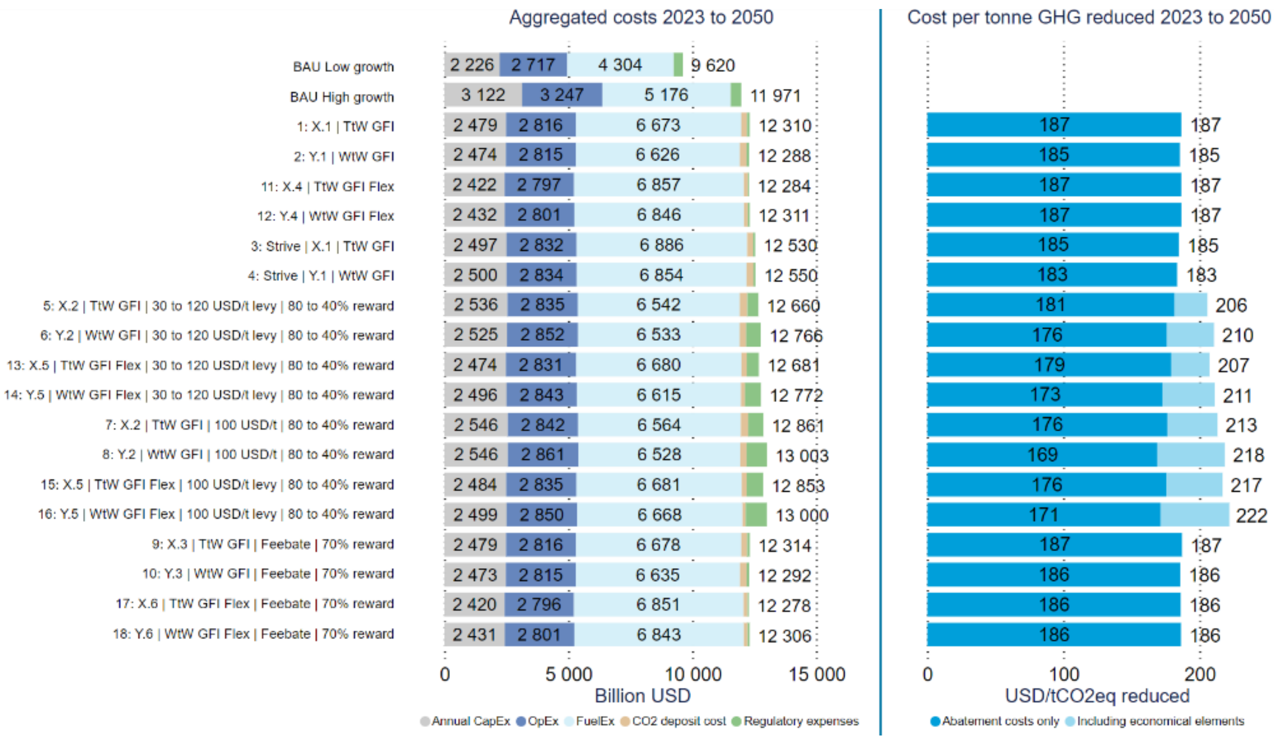


Figure D-5: Total aggregated costs split on annual capital costs, operational costs, fuel costs, CO_2 deposit costs and regulatory expenses, including levy/fee and rewards (left panel), and total additional cost per tonne of GHG reduced relative to BAU (right panel), from 2023 to 2050, per scenario. The light-blue bars in the right panel show the part of the cost-intensity increase related to regulatory incomes and expenses imposed by the policy measures in the scenarios with levy or GFI flexibility mechanism (rewards for eligible fuels and sale of SUs).

The following observations are made from Figure D-4 and Figure D-5:

- The increase in cost intensity of achieving the *Base* GHG emission trajectory under a Low seaborne trade growth without any economic policy elements (scenarios 1 and 2), compared to the low growth BAU scenario, is about 8-9% in 2030, increasing to about 39-40% in 2040 and about 57% in 2050.
- The increase in cost intensity of achieving the *Strive* GHG emission trajectory under a Low seaborne trade growth without any economic policy elements (scenarios 3 and 4), compared to the low growth BAU scenario, is about 12-13% in 2030, increasing to about 43% in 2040 and about 57-58% in 2050.
- A levy may have a large impact on the cost intensity in 2030 and 2040. A levy of 100 USD/tCO_2eq (scenarios 7 and 8) results in a cost-intensity increase of 23-27% in 2030. Towards 2040 and 2050 the effect is less pronounced as the absolute cost the levy reduces with lower emissions. Part of this revenue is anticipated to be reimbursed to the industry through RD&D (light blue bars).
- Scenarios 6 and 8 with a levy under a WtW scope results in a larger increase in cost intensity than in scenarios 5 and 7 with a TtW scope. The reason is that the total levy cost will be higher since the WtW emissions are higher than TtW emissions in absolute terms.
- Scenarios 11 to 18 with a GFI flexibility mechanism generally result in 1-3 percentage points lower cost-intensity increase in 2030 compared to the same scenarios without the flexibility mechanism. In 2050 the cost-intensity increase is generally higher for scenarios with a flexibility mechanism. However, they also have a lower GHG emission level and the aggregated cost per tonne CO_2eq reduced is very similar for the scenarios without a levy.

- Fuel costs is the cost element that increases the most with around 55-58% relative to BAU. Scenarios with a levy general has lower fuel costs due to lower energy use.
- The aggregated cost per tonne reduced GHG emission for the whole period from 2023 to 2050 is very similar at 181 to 187 USD/tCO_2eq for all scenarios without a levy. For scenarios with a levy the abatement cost (i.e. the cost of ships, fuels and technologies) is lower, however the cost of the levy increases the total cost for the ship to above those with a levy.

Figure D-6 shows the cost intensity change for scenarios 1 and 2 per ship category relative to business-as-usual with low seaborne trade growth in 2030, 2040 and 2050.

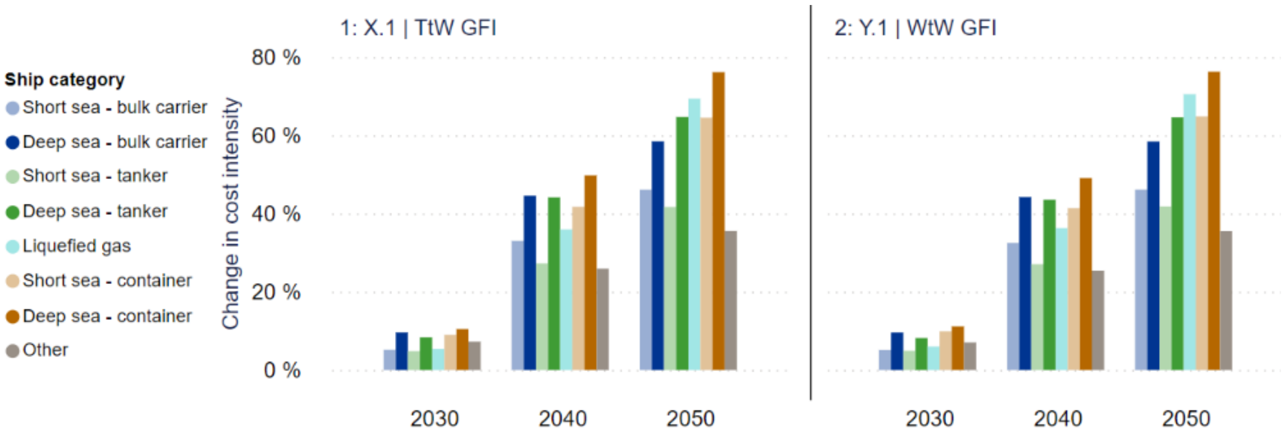


Figure D-6: **Cost-intensity change for scenarios 1 and 2 per ship category relative to business-as-usual with low seaborne trade growth in 2030, 2040, and 2050.**

The following observations from Figure D-6 are made:

- Segments with a higher share of time in the EU region, typically short-sea shipping and segments in the *Other* category, have a lower cost impact increase as they are already required to reduce GHG emissions due to FuelEU Maritime and EU ETS which are also included the BAU scenarios.
- Container ships have the highest change in cost impact as well as deep sea ship categories compared to short sea, likely due to fuel consumption being a larger share of the total cost.
- There is a larger difference in impact between the short sea and deep-sea categories of tankers, than for bulk and container categories.
- There are no significant differences between scenario 1 with a TtW scope and scenario 2 with a WtW scope.

D.1.3 Energy use and fuel mix

Figure D-7 displays a comparison of energy use per fuel feedstock while Figure D-8 shows the same per fuel type, across the different scenarios for the years 2030, 2040 and 2050.

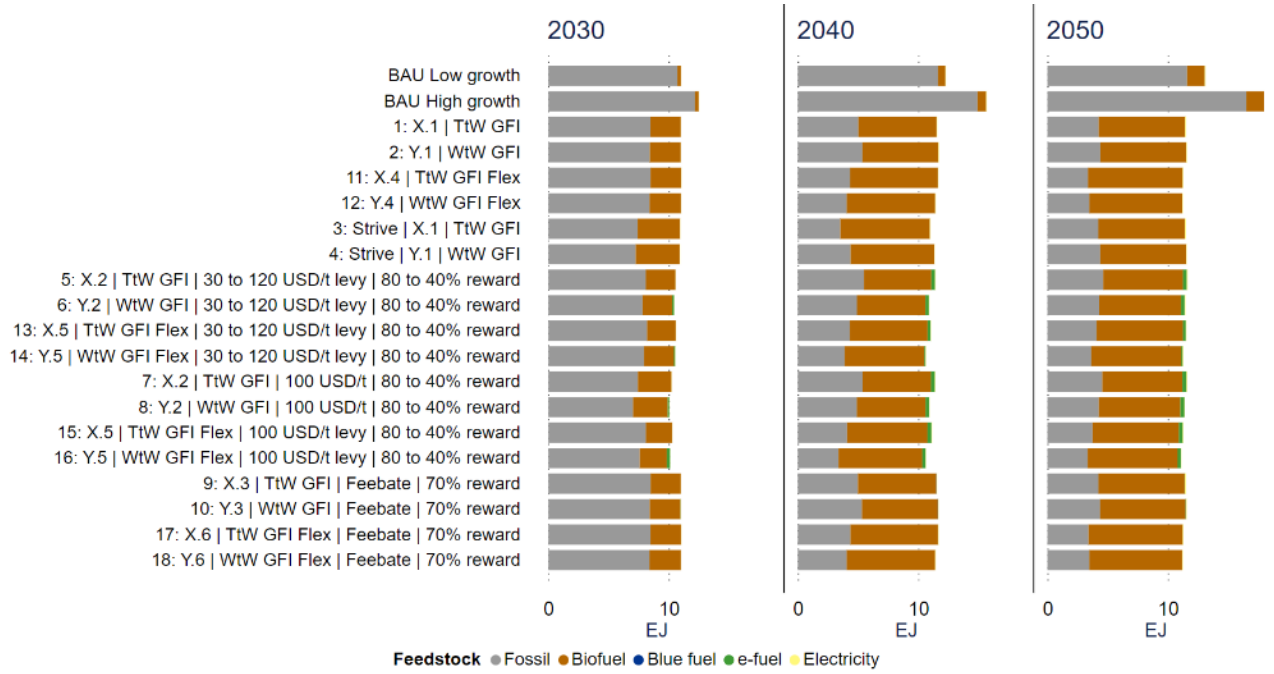


Figure D-7: **Energy use per fuel feedstock (of any fuel type) in 2030, 2040, and 2050, per scenario.**

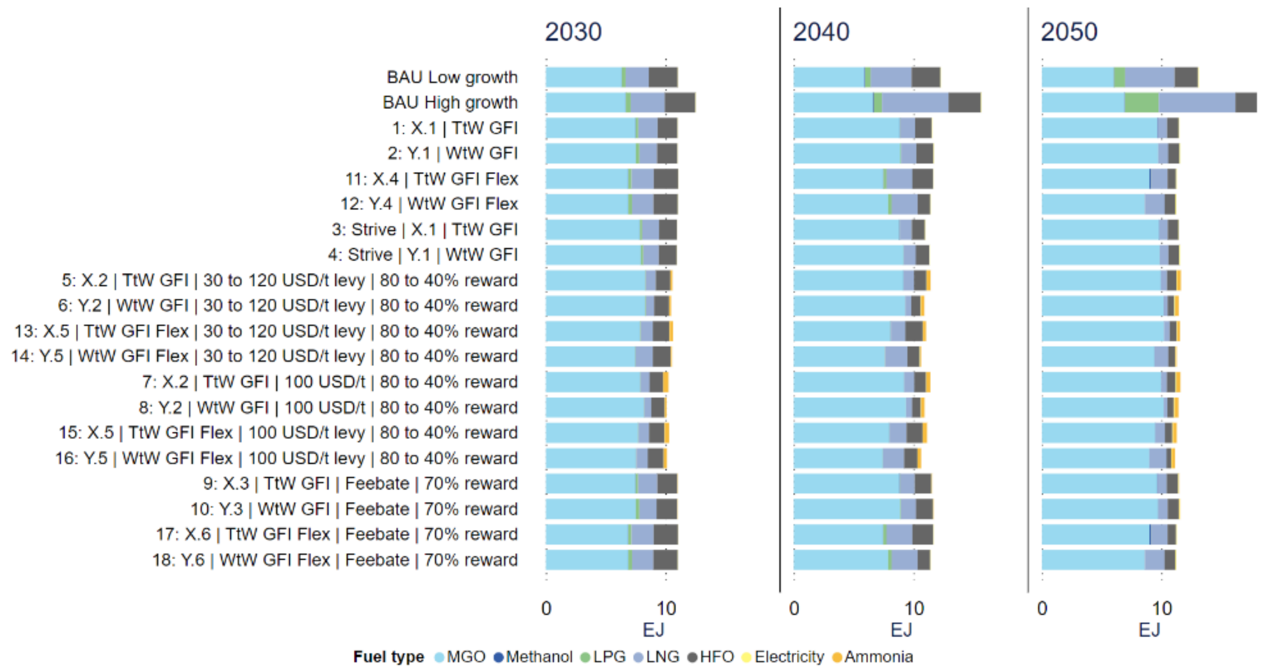


Figure D-8: **Energy use per fuel type (of any feedstock) in 2030, 2040, and 2050, per scenario.**

The following observations from Figure D-7 and Figure D-8 are made:

- The BAU scenarios see a significant uptake of LNG and LPG to 2050, likely due to lower fuel costs. LPG also has relatively low WtT emissions and has a moderate uptake in the WtW scope scenarios (even numbers) in 2030.

- Biofuels and onboard CCS (as seen from the use of fossil fuels towards 2050) are the two dominating decarbonization solutions across all policy scenarios given the input assumptions. About 2/3 of the reduction in 2050 comes from biofuels and the remaining from onboard CCS.
- The majority of biofuels are drop-in bio-MGO which can be used on conventional machinery. FuelEU Maritime and EU ETS ensures some uptake of biofuels also in the BAU scenarios.
- The reward to eligible fuels provides some incentive for e-ammonia in scenarios 5 to 10 and 13 to 18 but is not sufficient to provide a significant uptake of e-fuels.
- The scenarios with a flexibility mechanism (scenario 11 to 18) generally have a higher uptake of LNG and biofuels. Scenarios with a levy (scenarios 5 to 8 and 13 to 16) generally have a lower uptake of LNG.

Figure D-9 displays the reduction in energy use relative to BAU (low growth) in 2030, 2040 and 2050.

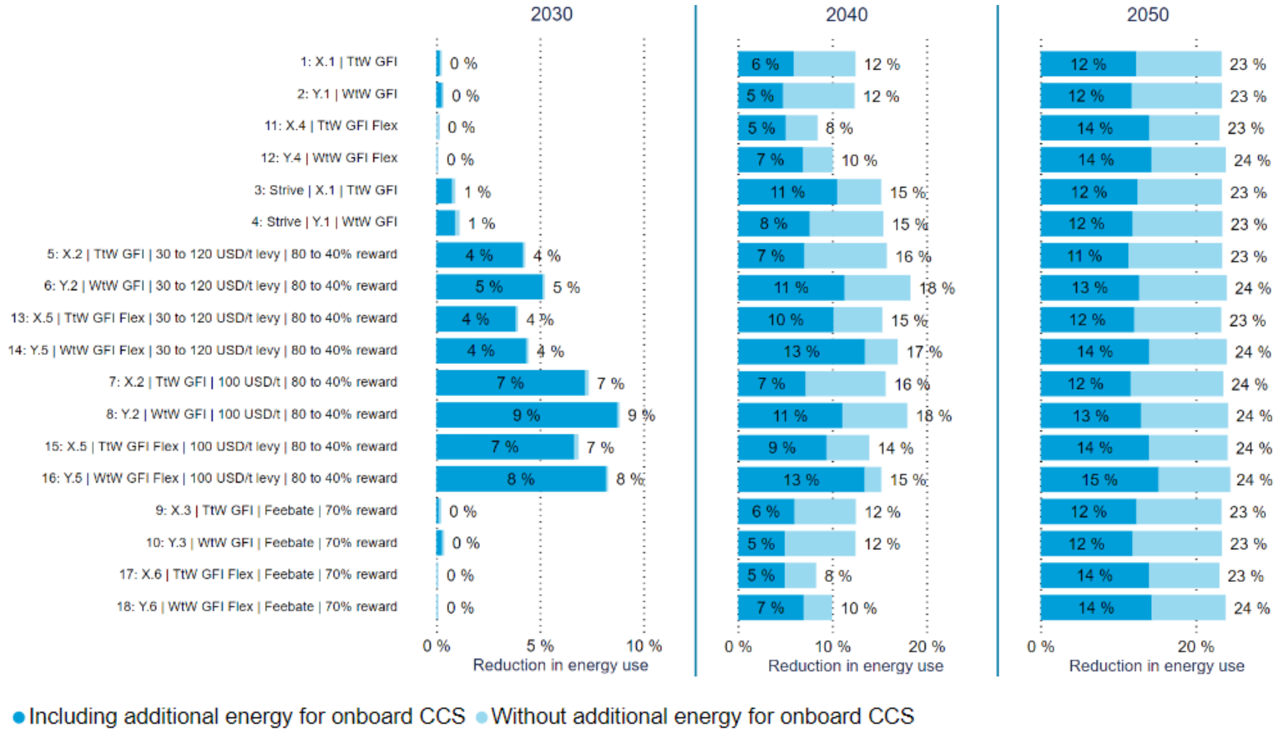


Figure D-9: **Reduction in energy use relative to BAU (low growth) in 2030, 2040, and 2050, per scenario. The dark-blue bar shows the reduction taking into account the additional energy needed for onboard CCS.**

The following observations from Figure D-9 are made:

- Scenarios 5 to 8 and 13 to 17 having a levy incentivize reduction in energy use with a up to 9% lower energy use in 2030 than in BAU. The primary reason for this is the implementation of speed reductions as soon as the levy is introduced. The fee in scenarios 9 to 10 and 17 to 18 with a feebate is less than 2 USD/tCO_2eq and too low to incentivize energy-efficiency improvements.
- The WtW scenarios with a levy have a higher reduction in energy use as the total levy cost will be higher since the WtW emissions are higher than TtW emissions in absolute terms.
- For the other scenarios the reduction in energy use is very small in 2030. It is also notable that the GFI requirement does not directly incentivize improvements in energy efficiency.

- To 2040 and 2050, the energy use can be significantly reduced compared to BAU. However, the total energy use remains on about the same level as in 2023 for Low seaborne trade growth scenarios as the growth nullifies the energy-efficiency gains.
- The reduction in energy use in 2050 is very similar across all scenarios.
- The use of onboard CCS will have a significant impact on energy use due to the fuel penalty.

The following figures show the demand for biofuels (Figure D-10), e-fuels (Figure D-11) and captured carbon storage demand (Figure D-12) for each scenario in 2030, 2040 and 2050, compared with the estimated supply/capacity.

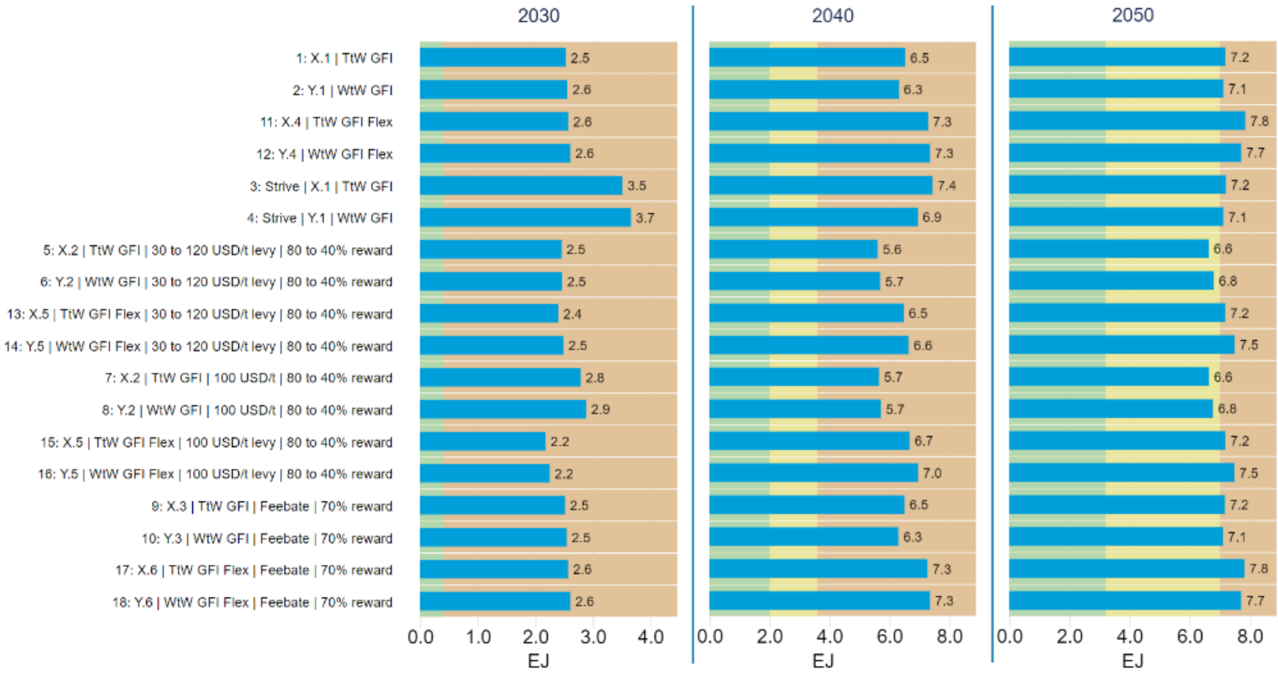


Figure D-10: **Biofuel demand in blue bars for each scenario compared to the estimated supply of advanced biofuels available for shipping in 2030, 2040, and 2050, per scenario. The green to yellow boundary indicates the median estimated supply and the yellow to red boundary indicates the high estimated supply** (Ricardo & DNV, 2023)**.**

Figure D-11: **E-fuel demand in blue bars for each scenario, compared to estimated supply in 2030, 2040, and 2050, per scenario. The green to yellow boundary indicates the median estimated supply and the yellow to red boundary indicates the high estimated supply** (Ricardo & DNV, 2023)**.**

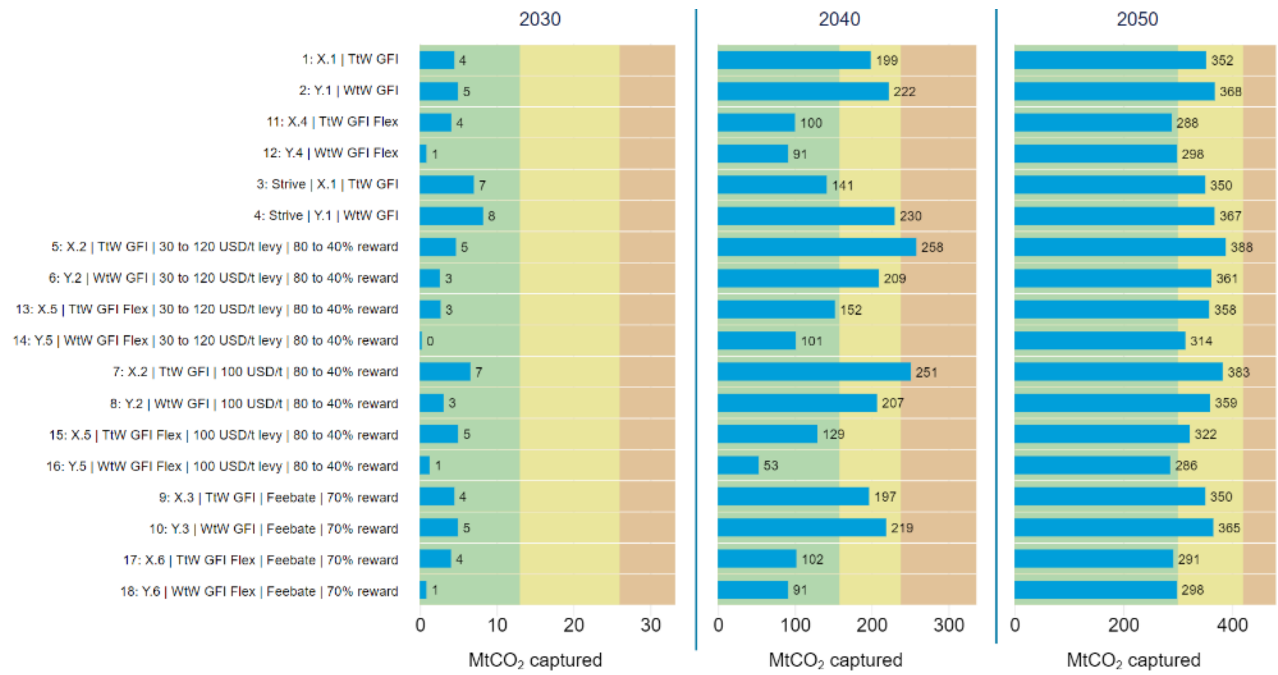


Figure D-12: **Captured-carbon storage demand in blue bars compared to estimated carbon storage capacity available for shipping in 2030, 2040, and 2050. The green to yellow boundary indicates the median estimated capacity available for shipping and the yellow to red boundary indicates the high estimated capacity available for shipping** (Ricardo & DNV, 2023)**.**

The following observations are made from Figure D-10, Figure D-11 and Figure D-12:

- The demand for biofuels in all scenarios exceeds the high estimated supply of advanced biofuels in 2030 and 2040 and are close to the high estimate in 2050. The consequence is that the biofuel prices are likely to increase toward the blue fuel and e-fuel prices, and that some of the biofuel demand would be provided by these fuels.
- The demand for e-fuels is well below the estimated supply available for shipping in 2030, 2040 and 2050. There is very limited demand for blue fuels in any of the scenarios (this chart is not shown).
- The use of onboard CCS is about 10-20% higher in 2050 in most TtW scenarios with a levy or a flexibility mechanism (scenarios 5, 7, 11, 13 and 15) compared to the similar WtW scope scenarios. The demand for carbon storage is below the expected capacity available for shipping in 2030 and between the median and high expected capacity in 2050 for most scenarios.
- Even if some of the biofuel demand was shifted to e-fuels and blue fuels, it would not be sufficient to cover the required demand for zero or near-zero emission fuels in 2030 which would be close or above the combined high estimate supply in 2040 for all feedstocks. To achieve the GHG emission trajectories all fuel feedstocks need to be used, complemented by onboard CCS and reduction in energy use by way of energy-efficiency measures and speed reductions.
- A higher uptake of energy-efficiency measures and speed reduction to reduce the total energy used, combined with an increased uptake of onboard CCS, may be sufficient to achieve the GHG emission trajectories in 2030.

D.1.4 Number of newbuilds and retrofits

The highest annual number of newbuilds (any technology) and retrofits (to another fuel system, onboard carbon capture or energy-efficiency package) in the periods 2027–2030, 2031–2040 and 2041–2050 are shown in Figure D-29.

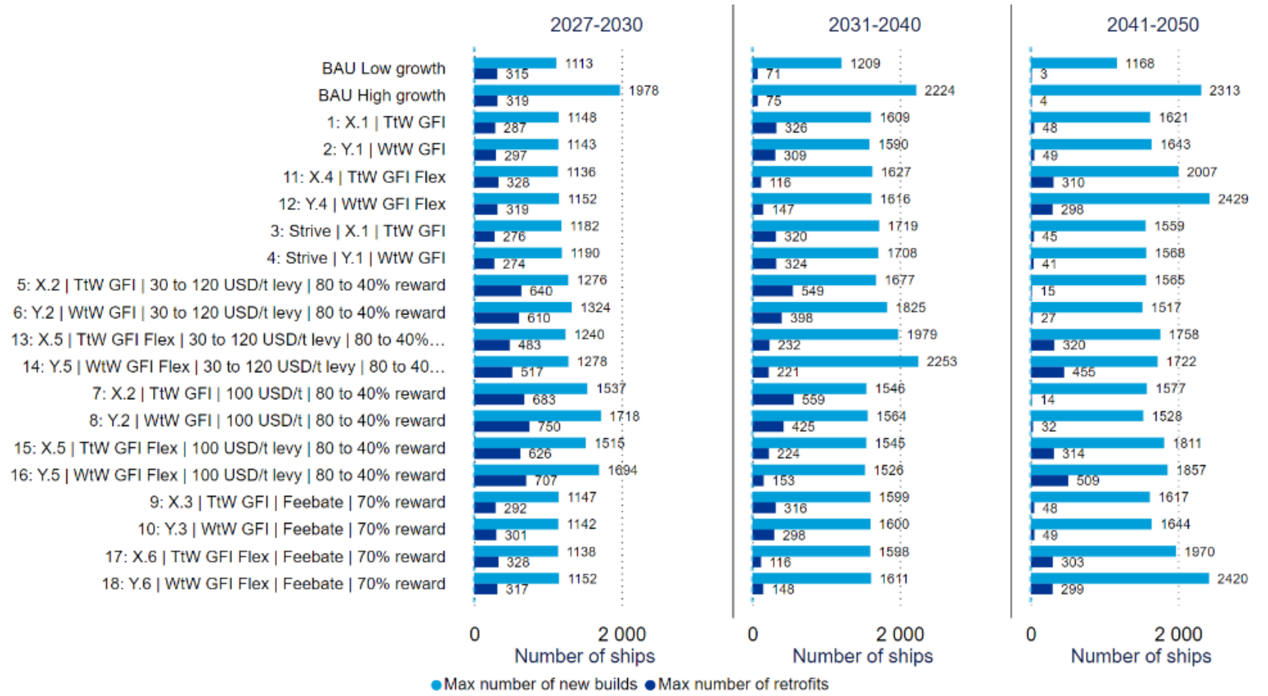


Figure D-13: **Peak annual number of newbuilds and retrofits (to another fuel system, onboard carbon capture or energy-efficiency package) for 2027–2030, 2031–2040, and 2041–2050, per scenario.**

The following observations are made from Figure D-13:

- In scenarios 7 to 8 and 15 to 16, the introduction of a 100 USD/tCO_2eq levy in 2027 results in speed reduction, which consequently results in spikes in newbuilds to compensate for the lost transport work.
- Scenarios 11 to 18 with a GFI flexibility mechanism have a higher peak of newbuilds and retrofits in the period from 2041–2050 compared to those without the mechanism.
- The average number of newbuilds delivered from 2002 to 2022 was 2053 vessels per year, peaking at 3965 ships in 2010 (Ricardo & DNV, 2023). The number of newbuilds and retrofits calculated by the model, should then be within the capacity of the yards.
- The number of retrofits to scrubbers peaked at more than 2400 in 2019 (AFI, 2024) which is well above the maximum annual retrofits required in any of the scenarios. It should be noted that retrofitting technologies such as ammonia and onboard CCS may be more extensive than retrofitting to scrubbers. Lloyds' Register (2023) indicates a current capacity of 308 fuel retrofits per year.

D.1.5 Flexibility mechanism

Figure D-14 shows the average annual exchange of emission units or trading volume and Figure D-15 shows the average annual emission unit price per scenario in the periods 2027–2030, 2031–2040 and 2041–2050.

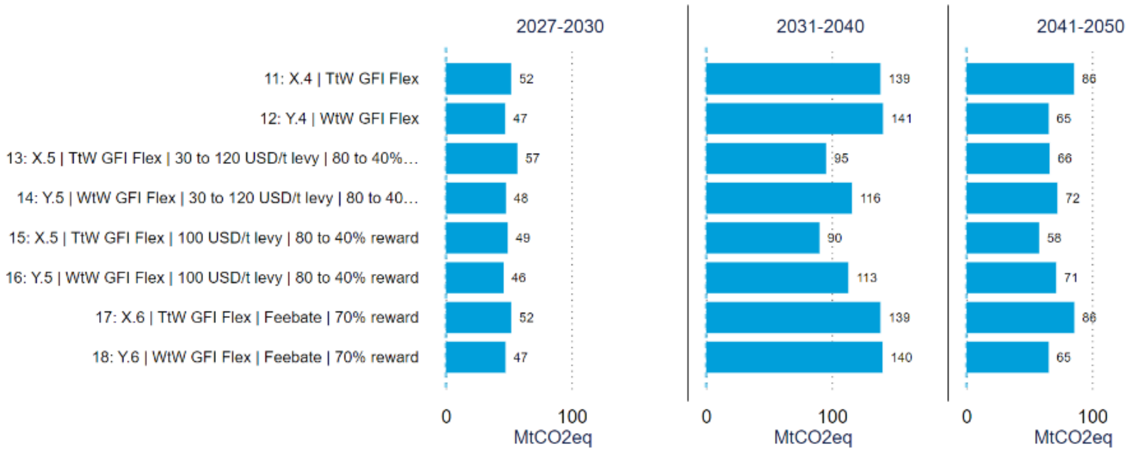


Figure D-14: **Average annual exchange of emission units (in MtCO_2eq) under the GFI flexibility mechanism for scenarios 11 to 18 for 2027–2030, 2031–2040, and 2041–2050.**

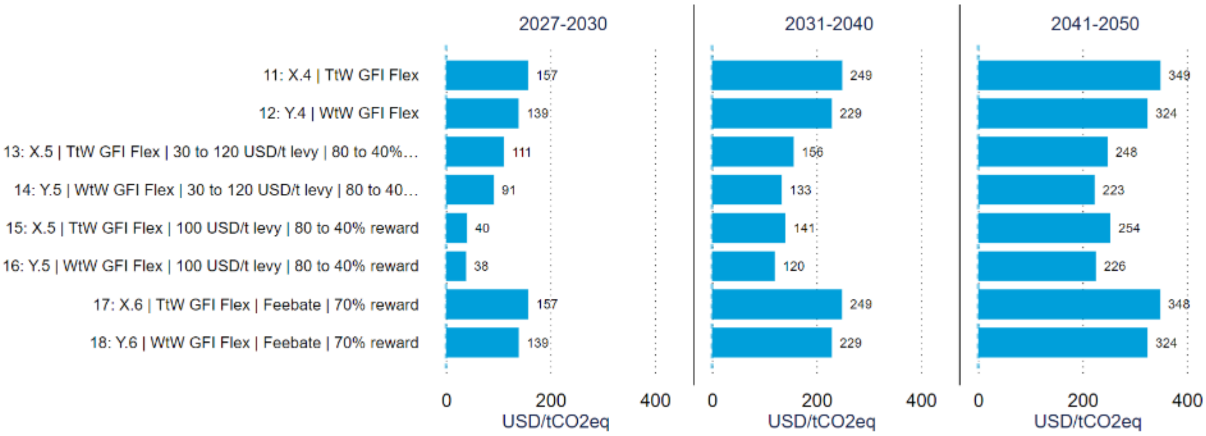


Figure D-15: **Average annual emission unit exchange price (in USD/tCO_2eq) under the GFI flexibility mechanism for scenarios 11 to 18 for 2027–2030, 2031–2040, and 2041–2050.**

Figure D-16 shows the annual exchange of emission units per fuel technology from 2027 to 2050 for scenarios 11 and 12. Ships having technologies providing negative compliance balance sell emission units to ships having technologies with positive compliance balance. The chart will not show ships and technologies that have a zero compliance balance and do not exchange emission units.

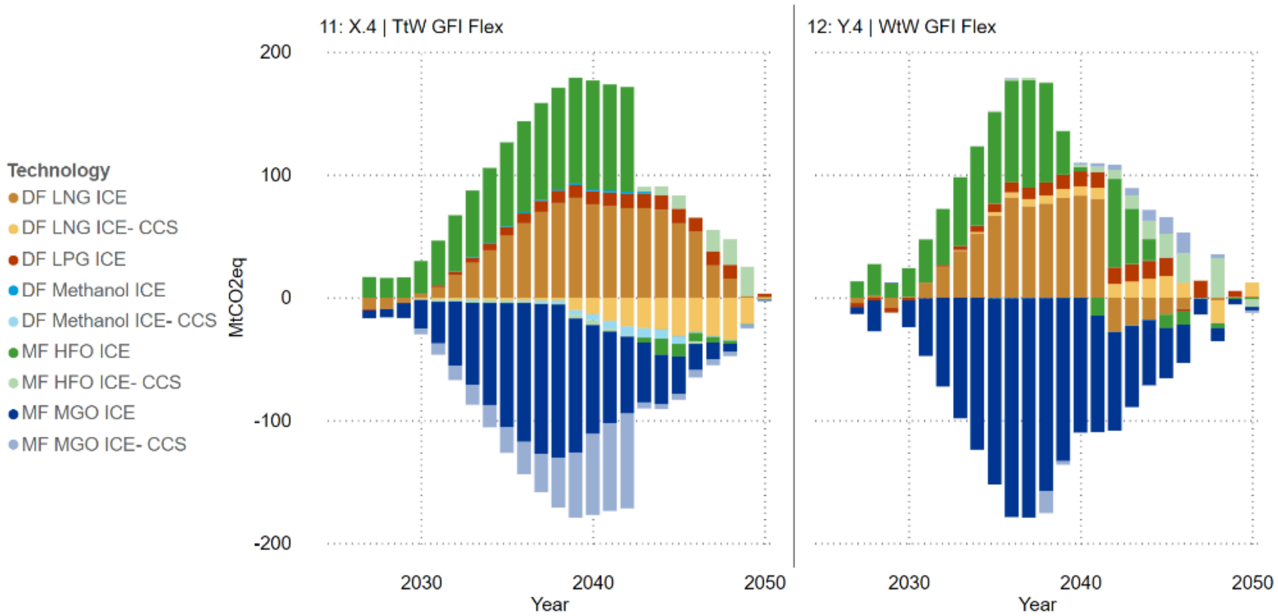


Figure D-16: **Annual exchange of emission units per fuel technology from 2027 to 2050 for scenarios 11 and 12. Ships having technologies providing negative compliance balance sell emission units to ships having technologies with positive compliance balance.**

The following observations from Figure D-14, Figure D-15 and Figure D-16 have been made:

- The emission unit price reflects the cost of the last emission reduction required to reach the annual GFI requirement. The emission unit exchange prices in scenarios without a levy increase from 139-157 USD/tCO_2eq in the period 2027–2030, to 229 to 249 USD/tCO_2eq in the period from 2031–2040 and to 324 to 349 USD/tCO_2eq in 2050.

- Scenarios with a levy have a lower emission unit exchange price corresponding to the level of the price on GHG emissions. The fee in scenarios with a feebate (17 and 18) is below 2 USD/tCO_2eq and have no impact on the emission unit price.

- The TtW scenarios (odd numbered) have a higher unit price than the corresponding WtW scenarios (even numbered) as the reduction cost remains the same but are spread on a lower absolute amount of emissions (i.e. TtW emissions are lower than WtW emissions in absolute terms)

- The trading volume or emission units that are exchanged peaks at around 180 MtCO_2eq in or just before 2040, representing about 50 to 65% of the annual GHG emissions for the whole fleet.

- The scenarios with GFI flexibility see a higher number of ships with dual fuel LNG (see Figure D-24). Initially these ships contribute with negative compliance balance, but towards 2040 they buy emission units from ships using bio-MGO in order to continue running on fossil LNG. The TtW scenario 1 also has a number of ships with onboard CCS with a negative compliance balance.

- Toward 2050 the emission unit exchange price increases sufficiently that also the LNG fuelled ships switch to bio-LNG, and the trading volume decreases again. The technology with the highest final reduction costs in 2050 are ships with onboard CCS. Towards 2050, these ships cannot use fossil fuel to comply with the requirement and will have to switch to a certain amount of biofuels. However, the trading volume is not very high.
- The impact on cost intensity of the flexibility mechanism (see Figure D-20) is limited likely due to bio-MGO and bio-LNG being the most competitive reduction solutions which are drop-in option without any investment costs. The flexibility mechanism may have a larger impact on in cases when investing in alternative fuel technologies, such as ammonia and methanol, enable ships to run on lower costs fuels.
- Applying RU and SU would have a significant impact on the emission trajectories as ships would prefer to either exceed the emission trajectory if the SU price is set sufficiently high, and conversely fail to achieve the trajectory in case the RU price is set too low. For example, a SU price of 174 USD/tCO_2eq in 2027, which is 80% of the cost gap, resulted in 50% emission reduction. A RU price of 270 USD/tCO_2eq in 2040 which is 120% of the cost gap resulted in a doubling of the emission level. For this reason the RU and SU prices were not included in the modelling in the final results presented here.
-

D.1.6 Revenue streams and disbursements

Figure D-17 shows the average annual revenue streams and disbursements for scenarios 5 to 10 and 13 to 18 in the periods 2027–2030, 2031–2040 and 2041–2050. The other scenarios do not have any economic elements and have no revenue streams. Note that these charts include disbursement for D1.

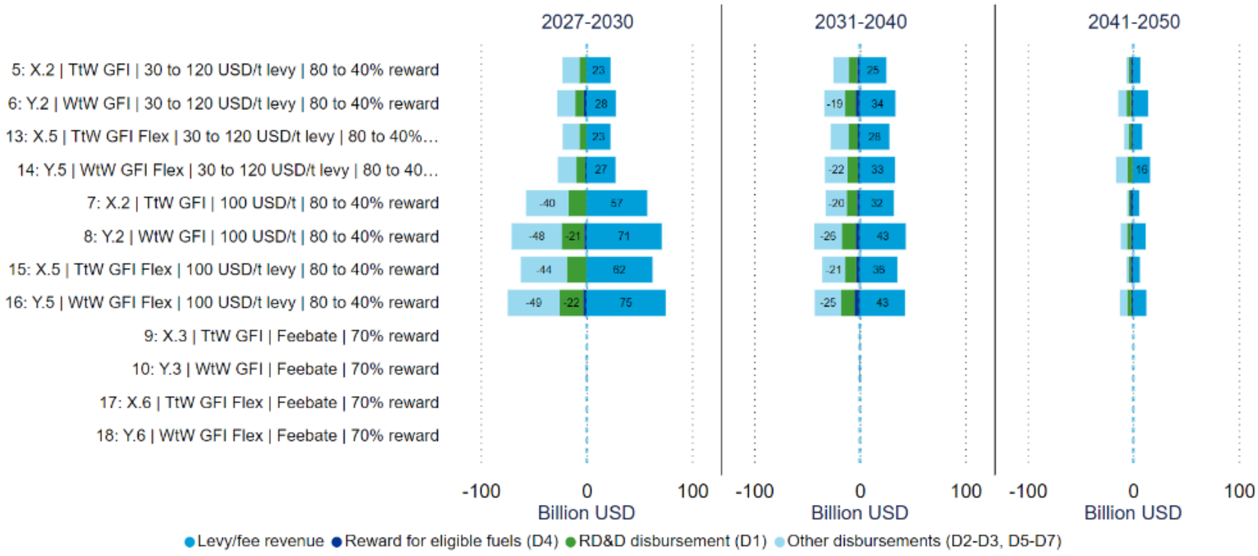


Figure D-17: **Average annual revenue streams and disbursements for scenarios 5 to 10 in periods 2027–2030, 2031–2040, and 2041–2050. Positive numbers are revenues from ships to the Revenue body, while negative numbers are disbursements.**

The following observations from Figure D-17 have been made:

- A levy of 100 USD/tCO_2eq as used in scenarios 7 to 8 and 15 to 16 create an average annual revenue stream of 57 to 75 BUSD/year in the period 2027–2030, decreasing to 32 to 43 BUSD/year in 2031–2040.

- A levy of 30–120 USD/tCO_2eq as used in scenarios 5 to 6 and 13 to 14 create an average annual revenue stream of 23 to 28 BUSD/year in the period 2027–2030, and as emissions decrease and the levy increases, the annual average revenue only slightly increases to 25 to 33 BUSD/year in 2031–2040.
- In 2041–2050 the GHG emission is reduced almost to zero and the revenue from a levy is very low. A limited amount of the revenue is redistributed as reward for eligible fuels (not visible in the figure)
- In Scenarios 9 to 10 and 17 to 18 applying a feebate mechanism the revenue stream is dependent on the uptake of eligible fuels which is almost zero. The revenue in 2030 (not visible in the figure above) is 0.1 to 0.6 BUSD/year all of which are provided a reward to eligible fuels. The resulting fee is about 0.8 USD/tCO_2eq in 2030 increased to 2.6 USD/tCO_2eq in 2039, before it is discontinued from 2040.
- The reward for eligible fuels of 40 to 80% of the cost gap down to bio- and blue fuels as modelled in scenarios 5 to 10 and 13 to 18 provide some incentive to use e-ammonia, but the percentage would need to be further increased to increase the uptake. The reward rate would need to be set precisely relative to the cost gap to give the necessary incentive for uptake of eligible fuels. If it is set too low, no eligible fuels are taken up and if it is set to high, the uptake exceeds what is available for rewards.
- The economic elements of the proposed policy measures can, if set sufficiently high, more than close the cost gap between fossil and non-fossil fuels. If fossil fuels become more expensive the model would, regardless of the GFI requirements rapidly transition to the non-fossil fuels, likely well beyond the supply of such fuels. In such cases it is highly likely that the non-fossil fuel prices would increase due to the increased demand from shipping.
- Scenarios 11 to 18 with a GFI flexibility mechanism could also raise revenues through sale of Remedial Units. However, this has not been included in the modelling.

D.2 Results from scenarios 21 to 36, 41, 42, 55 and 56

This Section presents the results and analysis of the modelling of 20 policy combination scenarios, numbered 21 to 36, 41, 42, 55 and 56, including comparisons with scenarios 1 to 18. For these scenarios we assume that the total demand for low emission fuels exceeds the supply for bio- and blue fuel feedstocks and we adjust the fuel prices of all the fuel types made from those feedstocks to the equivalent, in terms of energy and emissions, cost of the e-fuel of the same type. The observations made regarding these results are from the second interim report (DNV, 2024c).

Annual required GFI limits are determined by iteration and the resulting GHG emissions align within ±5% to the required GHG trajectories. The differences in the GHG trajectories will affect the other results, including the differences in the estimated cost intensity changes between the scenarios.

D.2.1 GHG emissions

Figure D-18 shows the WtW GHG emission levels in 2030, 2040 and 2050, split on WtT GHG, TtW CO_2, TtW N_2O and TtW CH_4 emissions for the 20 policy combination scenarios.

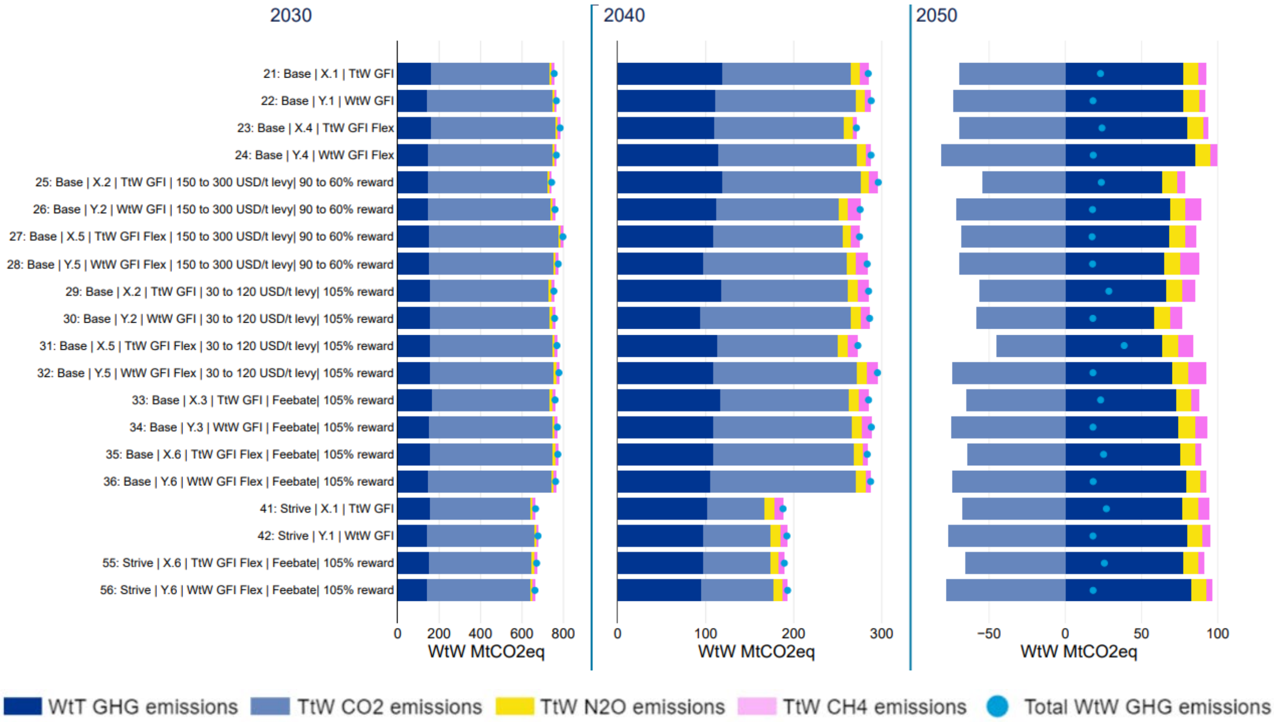


Figure D-18: WtW GHG emissions per scenario, split on WtT GHG, TtW CO_2, TtW N_2O and TtW CH_4 emissions, in 2030, 2040, and 2050. For the TtW CO_2 emissions, CO_2 emissions captured by onboard CCS and subsequently stored are subtracted. The *Total WtW GHG emissions* markers indicate the total GHG emissions. Note that the scale of emissions varies between the three years.

Figure D-19 shows the total WtW GHG emissions in 2030, 2040, and 2050 for the 20 policy combination scenarios compared to the GHG emission targets (see Table 5-2).

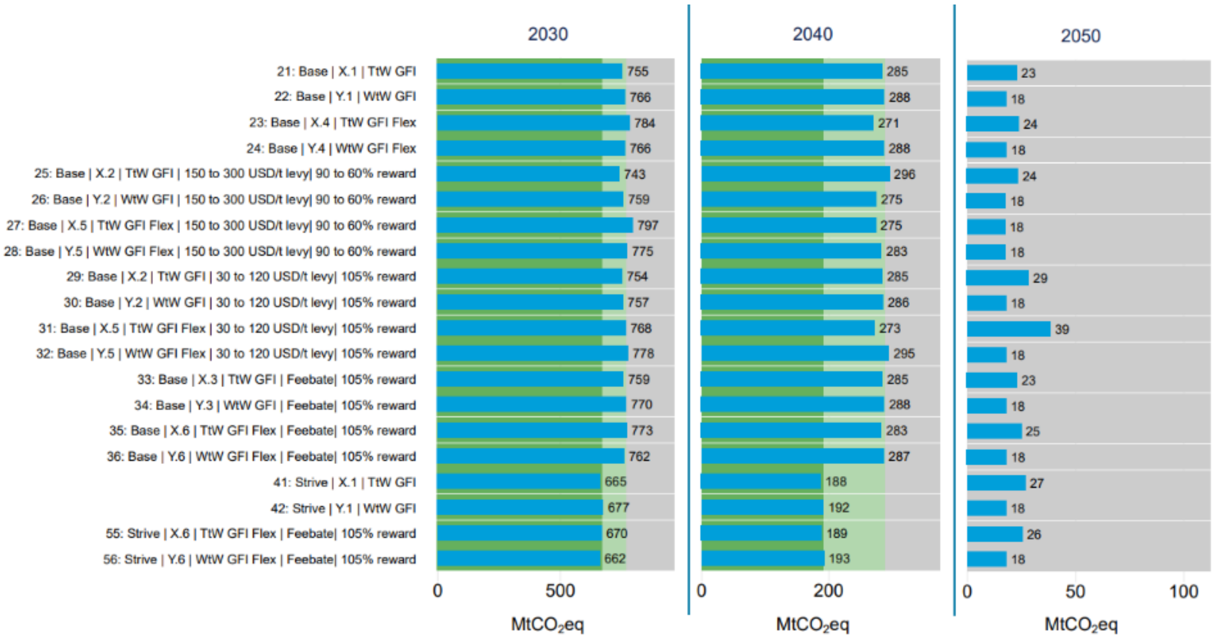


Figure D-19: WtW GHG emission levels in 2030, 2040, and 2050 for the policy scenarios, compared to the emission targets. The dark-green to light-green boundary indicates the *Strive* target (scenarios 41, 42, 55 and 56) and the light-green to grey boundary indicates the *Base* target (all other scenarios). A certain amount of GHG emissions remains in 2050 for all scenarios due to remaining CH_4 and/or N_2O emissions from combustion engines.

The following observations are made from Figure D-18 and Figure D-19:

- In all scenarios the TtW CO_2 emissions are negative in 2050. This is due to captured emissions by onboard CCS from bio- or e-fuels, having carbon from biogenic sources or from direct air capture. The chart shows the resulting TtW CO_2 balance– i.e. total CO_2 emissions from some ships subtracted by the total carbon captured from other ships as indicated in Figure D-28.
- With the GFI requirements set individually per scenario, the GHG emission levels are closely aligned across the scenarios with a deviation of ±5% from the indicative checkpoints in 2030 and 2040. A certain amount of GHG emissions, about 2-4% of the 2008 reference, remains in 2050 of for all scenarios as we expect that there will be some CH_4 and/or N_2O emissions from combustion engines in 2050 regardless of the fuel used.

D.2.2 Cost impact

Figure D-20 shows the cost intensity change for each policy scenario. The cost intensity is the total annual cost, including capital, operational and fuel expenses, as well as regulatory incomes and expenses imposed by the policy measures, divided by the total transport work in a year. The change in cost intensity for a target year is calculated relative to the cost intensity of the corresponding (i.e. same seaborne trade growth) BAU scenario in the target year.

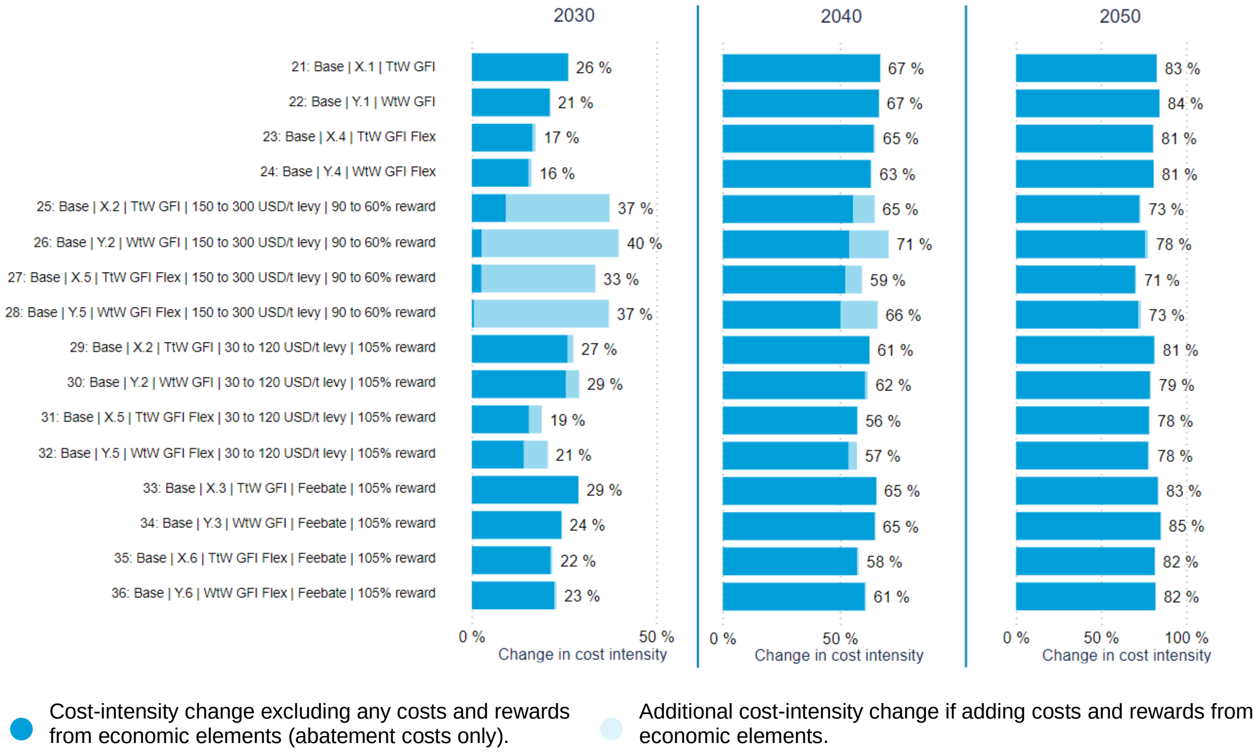


Figure D-20: Cost-intensity change per policy scenario relative to business-as-usual with low seaborne trade growth in 2030, 2040, and 2050. The light-blue bars show the part of the cost-intensity increase related to regulatory incomes and expenses imposed by the policy measures in the scenarios with levy or GFI flexibility mechanism (rewards for eligible fuels and sale of SUs).

Figure D-21 shows and the aggregated costs from 2023 to 2050 split on annual capital costs, operational costs, fuel costs, CO_2 deposit costs and regulatory expenses, including levy/fee and rewards (left panel), and the additional costs per tonne of GHG reduced from 2023 to 2050 relative to BAU (right panel).

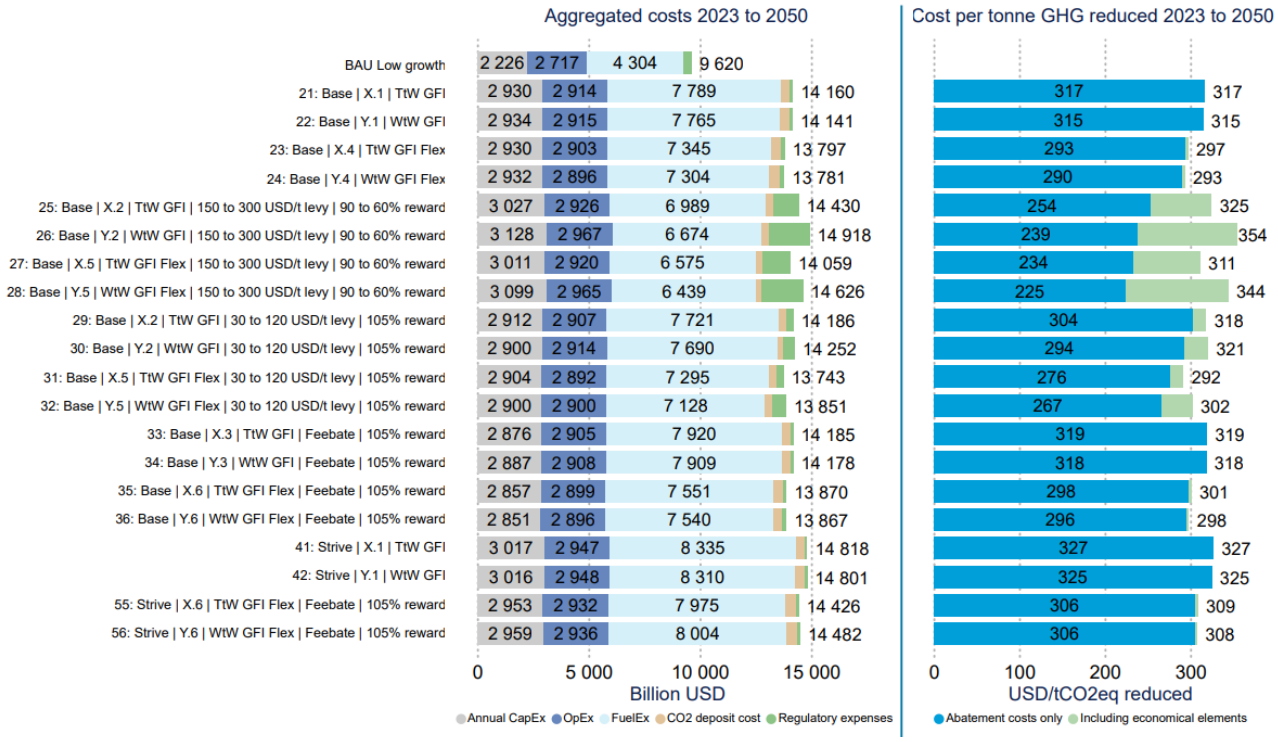


Figure D-21: Total aggregated costs split on annual capital costs, operational costs, fuel costs, CO_2 deposit costs and regulatory expenses, including levy/fee, rewards and RU/SU transactions within a pool or the Revenue body (left panel), and total additional cost per tonne of GHG reduced relative to BAU (right panel), from 2023 to 2050, per scenario. The green bars show the part of the cost-intensity increase related to regulatory incomes and expenses imposed by the policy measures in the scenarios with levy or GFI flexibility mechanism (emission unit exchange in a pool, rewards for eligible fuels and sale of SUs).

The following observations are made from Figure D-20 and Figure D-21:

- The increase in cost intensity (relative to the low growth BAU scenario) of achieving the *Base* GHG emission trajectory under a *Low* seaborne trade growth without any economic policy elements (scenarios 21 and 22) is about 21-26% in 2030, increasing to about 67% in 2040 and about 83% in 2050. Similarly, for the *Strive* GHG emission trajectory (scenarios 41 and 42), the increase in cost intensity is about 33-37% in 2030, increasing to about 79-80% in 2040 and about 82-83% in 2050.

- The cost-intensity increases are significantly higher in scenarios 21 to 42 and 55 to 56, compared to scenarios 1 to 18 in the first interim report which were about 8-13% in 2030, increasing to about 39-43% in 2040 and about 57-58% in 2050. These scenarios did not include supply limitations on bio- and blue fuels and with adjusted fuel prices these fuels are significantly more expensive.

- A levy may have a large impact on the cost intensity in 2030 and 2040. A levy of 150–300 USD/tCO_2eq (scenarios 25 to 28) results in a cost-intensity increase of 33-40% in 2030, while a levy of 30–120 USD/tCO_2eq (scenarios 29 to 32) results in a cost-intensity increase of 19-29% in 2030. Towards 2040 and 2050 the effect is less pronounced as the absolute cost of the levy reduces with lower emissions. However, the increase in cost intensity in 2050 is generally lower for scenarios with a levy due to lower energy use (see Figure D-25 for observations on energy use).

- In 2030, if the costs and rewards from economic elements is not included (i.e. looking at abatement costs only), the cost-intensity increase would be reduced to 1-9% with a levy of 150–300 USD/tCO_2eq (scenarios 25 to 28) and 14-26% with a levy of 30–120 USD/tCO_2eq (scenarios 29 to 32). It should be noted that the effect of the economic elements is necessary to achieve the reduced abatement costs, but these numbers are included here to illustrate the potential for lower abatement costs.
- The feebate scenarios (scenario 33 to 36) result in a fee of 40 to 56 USD/tCO_2eq in 2030, increasing to 72 to 144 USD/tCO_2eq in 2030. It is generally lower than the levy in the scenarios with a 30–120 USD/tCO_2eq levy, except for scenario 33 in in 2040.
- Scenarios with a levy under a WtW scope generally have in a larger increase in cost intensity than in scenarios with a TtW scope. The reason is that the total levy cost will be higher since the WtW emissions are higher than TtW emissions in absolute terms.
- Scenarios with a GFI flexibility mechanism generally result in 3 to 8 percentage points lower cost-intensity increase in 2030 compared to the same scenarios without the flexibility mechanism. The reason is that with the flexibility mechanism, a relatively small amount of ships can install capital intensive solutions, for example ammonia, methanol or onboard carbon capture and run fully on lower cost fuels (e.g. e-methanol have lower costs than e-MGO), instead of all ships having to reduce GHG intensity on its own. Towards 2040 and 2050 the effect of the GFI flexibility mechanism is reduced.
- In scenarios 1 to 18, the flexibility mechanism resulted in only 1 to 3 percentage points lower cost in 2030. The reason is that with biofuels having a lower cost, bio-MGO was a preferred solution which can be used as a drop-in fuel on existing machinery without any investments. The advantage of the flexibility mechanism is then much lower.
- Fuel cost is the cost element that increases the most with around 70 to 77% relative to BAU. Scenarios with a levy generally has lower fuel costs due to lower energy use.
- The aggregated cost per tonne reduced GHG emission over the whole period from 2023 to 2050 is similar across all scenarios ranging from 292 to 354 USD/tCO_2eq. Scenarios with a GFI flexibility generally have a lower aggerated cost per tonne. For scenarios with a levy the abatement costs (i.e. the cost of additional ships, fuels and technologies required to achieve the reduced emissions) are generally lower, but when adding the cost of the economic elements (levy and RU purchases subtracted by the reward and SU sales) the reduction costs are higher than the other scenarios.

Figure D-22 shows the cost intensity change for scenarios 21 and 22 per ship category relative to business-as-usual with low seaborne trade growth in 2030, 2040 and 2050. Scenarios 21 and 22 are representative for the differences between ship categories.

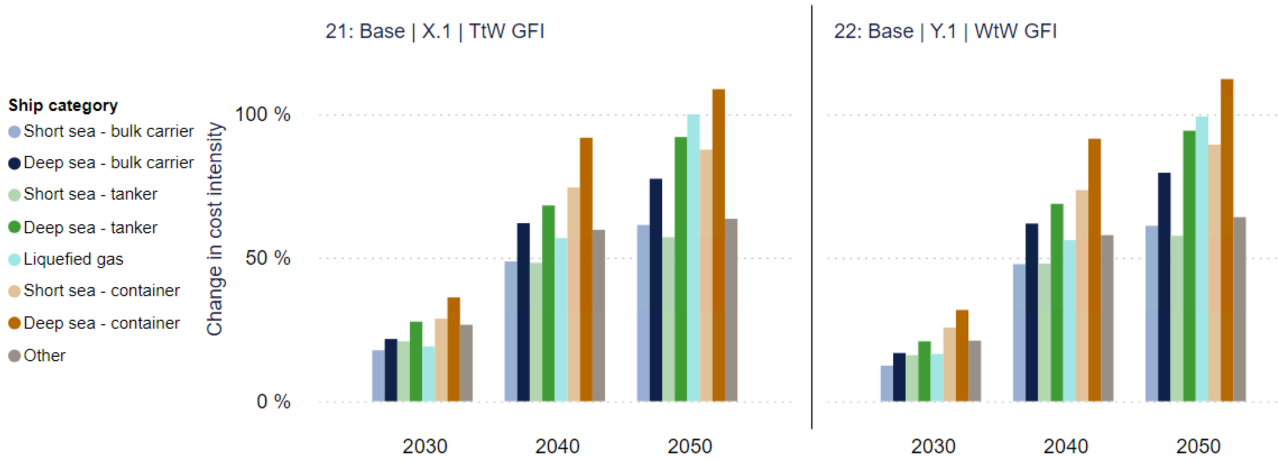


Figure D-22: Cost-intensity change for scenarios 21 and 22 per ship category relative to business-as-usual with low seaborne trade growth in 2030, 2040, and 2050.

The following observations from Figure D-22 are made:

- Segments with a higher share of time in the EU region, typically short sea shipping and segments in the *Other* category, have a lower cost impact increase as they are already required to reduce GHG emissions due to FuelEU Maritime and EU ETS which are also included the BAU scenarios.
- Container ships have the highest change in cost impact as well as deep sea ship categories compared to short sea, likely due to fuel consumption being a larger share of the total cost.
- There is a larger difference in impact between the short sea and deep-sea categories of tankers, than for bulk and container categories.
- There are no significant relative differences between segments when considering the TtW scope in scenario 21 and the WtW scope in scenario 22.

D.2.3 Energy use and fuel mix

Figure D-23 displays a comparison of energy use per fuel feedstock while Figure D-24 shows the energy use per fuel type, across the different scenarios for the years 2030, 2040 and 2050.

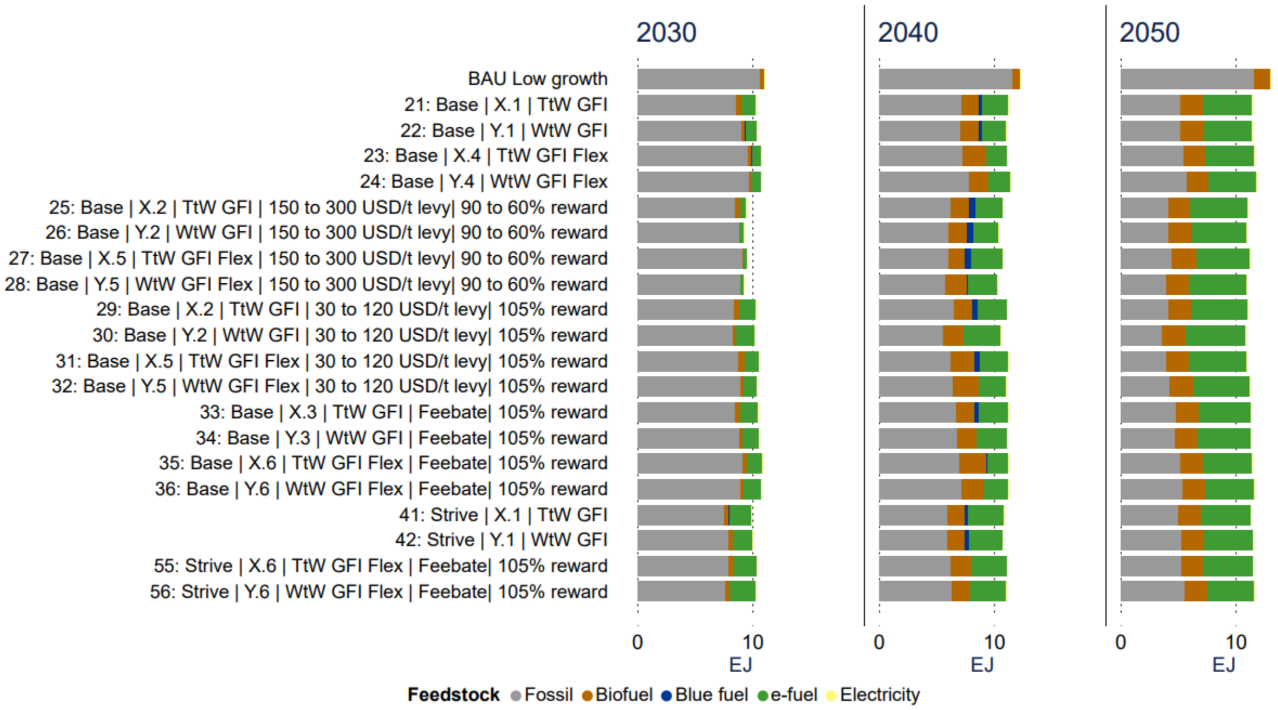


Figure D-23: Energy use per fuel feedstock (of any fuel type) in 2030, 2040, and 2050, per scenario.

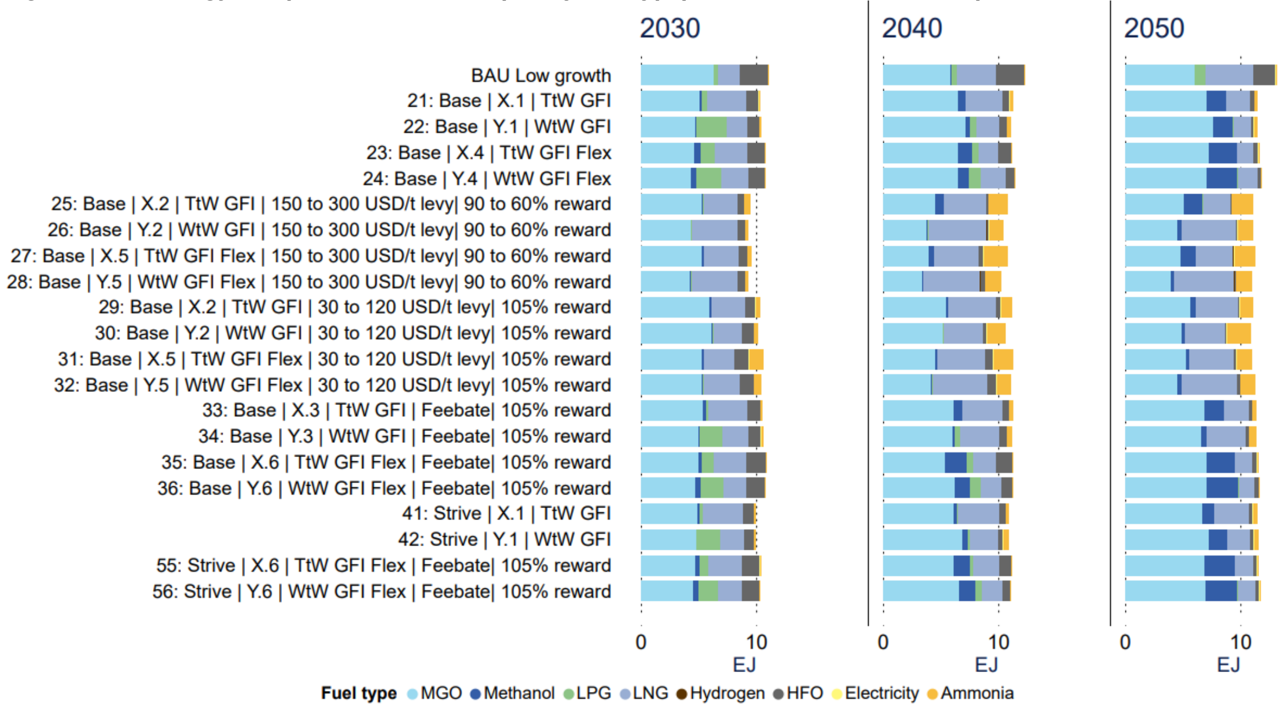


Figure D-24: Energy use per fuel type (of any feedstock) in 2030, 2040, and 2050, per scenario.

The following observations from Figure D-23 and Figure D-24 are made:

- The BAU scenarios see a significant uptake of LNG and LPG to 2050, likely due to lower fuel costs compared to LSFO/MGO. FuelEU Maritime and EU ETS ensures some uptake of biofuels also in the BAU scenarios.
- Applying feedstock supply constraints and adjusted fuel prices to the modelling results in a more diverse fuel mix. E-fuels and onboard CCS (as seen from the use of fossil fuels towards 2050) appear to be the two

dominating decarbonization solutions across all policy scenarios given the input assumptions. However, biofuels also have a significant contribution toward 2040 and 2050. In scenarios 1 to 18 with no adjustment of fuel prices, biofuels and onboard CCS were the two dominating decarbonization solutions across all policy scenarios.

- Across all scenarios, around half of the energy in 2050 is supplied by MGO from either bio, e- or fossil feedstocks. MGO can be used as drop-in fuel on conventional machinery without any additional capital expenses and can also be used on conjunction with onboard CCS.

- Blue fuels do not see a large uptake, with some uptake in scenarios with a levy in 2040. The reward makes e-ammonia more competitive which drives the uptake of ammonia engines and again the use of blue ammonia. However, the reward will also reduce the e-fuel price below the production costs of blue fuels (this effect does not apply to biofuels because the production costs are lower) and blue ammonia will not be competitive. Without a reward (scenarios 21 to 24 and 41 to 42) neither blue nor e-ammonia are prevalent fuels. Towards 2050 the assumed WtT emissions of blue fuels are also too high to be used for compliance under the more stringent GFI requirements.

- The reward for eligible fuels incentivizes uptake of e-ammonia and e-LNG which, together with bio-LNG seem to be the fuels with the highest uptake in scenarios with levy in combination with a reward mechanism. In scenarios with a feebate, in which the fee is generally lower than the levy, there are lower uptake of ammonia, but higher uptake of e- and bio-methanol. The uptake of the various fuel types seems to be very sensitive to relatively small changes in the levy and reward levels.

- The scenarios with a flexibility mechanism generally have a higher uptake of fuels requiring capital intensive installations, such as ammonia, methanol and LNG, as well as onboard carbon capture (see observations to Figure 6-4 and Figure D-21). Scenarios with a levy generally have a higher uptake of LNG.

Figure D-25 displays the reduction in energy use relative to BAU (low growth) in 2030, 2040 and 2050.

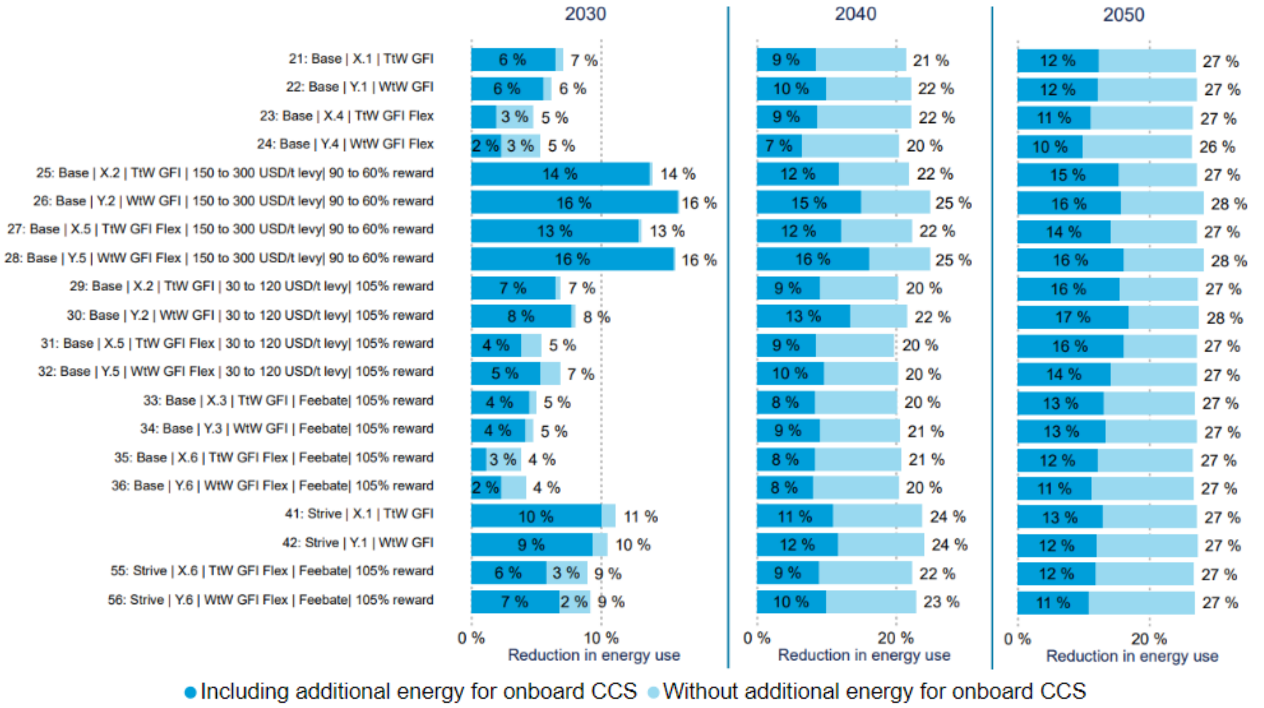


Figure D-25: Reduction in energy use relative to BAU (low growth) in 2030, 2040, and 2050, per scenario. The dark-blue bar shows the reduction taking into account the additional energy needed for onboard CCS.

The following observations from Figure D-25 are made:

- Scenarios 25 to 28 with 150–300 USD/tCO_2eq levy incentivize uptake of energy-efficiency measures and speed reduction with a up to 16% lower energy use in 2030 than compared to BAU. The primary reason for this is the implementation of speed reductions as soon as the levy is introduced. It is notable that the GFI requirement does not directly incentivize improvements in energy efficiency.
- Scenarios with a 30–120 USD/tCO_2eq levy or a feebate (scenarios 29 to 36) have about 4 to 7% lower energy use, when not considering the additional energy for onboard carbon capture. The reason is that with both a lower levy and a reward on eligible fuels the total energy cost is not sufficient to drive further energy-efficiency improvements.
- The *Strive* trajectory scenarios 41 and 42 show a reduction of energy use in 2030 of 10 to 11% without imposing a levy or fee, indicating that the required amount and cost of low emission energy are sufficient to drive energy-efficiency improvements without an additional levy.
- The scenarios with GFI flexibility have less reduction in energy use in 2030 compared to those without the mechanism. The exception is the scenarios with a 150–300 USD/tCO_2eq levy.
- The WtW scenarios with a levy have a somewhat higher reduction in energy use in 2030 and 2040, as the total levy cost will be higher since the WtW emissions are higher than TtW emissions in absolute terms.
- To 2040 and 2050, the energy use is significantly reduced compared to BAU across all scenarios, although in scenarios with a levy (scenarios 25 to 32) the reduction is higher.
- Without the use of onboard CCS the total energy reduction could be 26 to 28% in 2050. The use of onboard CCS will have a significant impact on energy use due to the fuel penalty halving the effect of other energy-efficiency improvements. The additional energy can be supplied from fossil feedstocks.

The following figures show the demand for biofuels (Figure D-26), e-fuels (Figure D-27) and captured carbon storage demand (Figure D-28) for each scenario in 2030, 2040 and 2050, compared with the estimated supply/capacity (see Section 1.2.5).

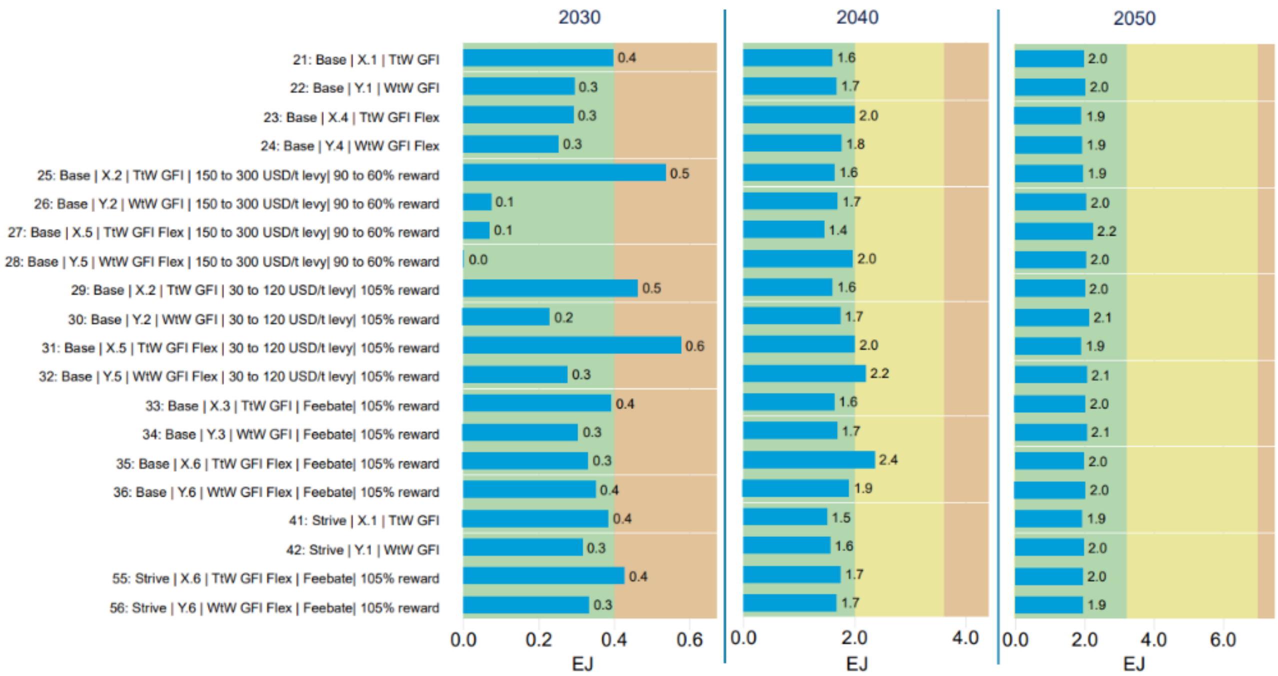


Figure D-26: Biofuel demand in blue bars for each scenario compared to the estimated supply of advanced biofuels available for shipping in 2030, 2040, and 2050, per scenario. The green to yellow boundary indicates the median estimated supply and the yellow to red boundary indicates the high estimated supply (Ricardo & DNV, 2023). Note that the x-axis scale changes between the years.

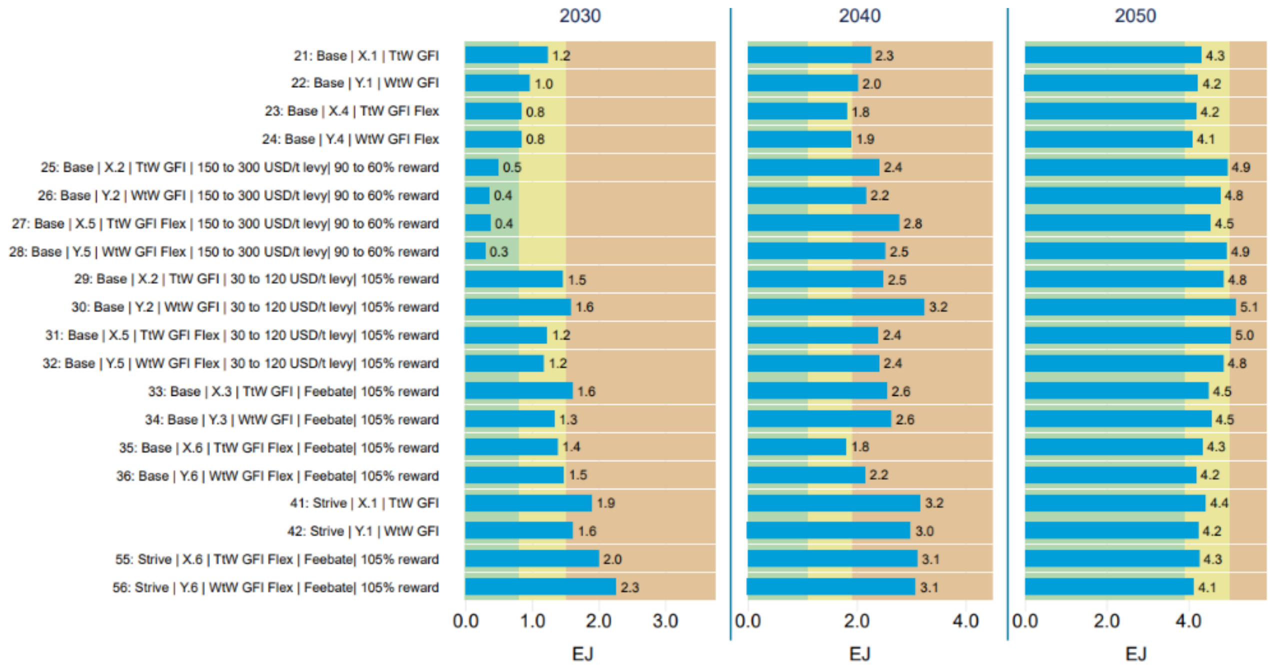


Figure D-27: E-fuel demand in blue bars for each scenario compared to the estimated supply of e-fuels available for shipping in 2030, 2040, and 2050, per scenario. The green to yellow boundary indicates the median estimated supply and the yellow to red boundary indicates the high estimated supply (Ricardo & DNV, 2023). Note that the x-axis scale changes between the years.

Figure D-28: Captured carbon storage demand in blue bars compared to estimated carbon storage capacity available for shipping in 2030, 2040, and 2050. The green to yellow boundary indicates the median estimated capacity available for shipping and the yellow to red boundary indicates the high estimated capacity available for shipping (Ricardo & DNV, 2023). Note that the x-axis scale changes between the years.

The following observations are made from Figure D-26, Figure D-27 and Figure D-28:

- In these scenarios, the demand for biofuels has been constrained to about 0.36 EJ in 2030. Some scenarios have a slightly higher uptake. In 2040 and 2050, with a few exceptions in 2040, the uptake is lower than the median estimate.[30]

- The demand for e-fuels is generally above the median estimate, but below the high estimate in 2030. In 2040, most scenarios show an uptake of e-fuels beyond the high estimated supply, while in 2050, the e-fuel uptake in most scenarios fall between the median and high supply estimate, and with some falling above the high supply estimate.

- The use of onboard CCS is higher in most scenarios with a flexibility mechanism but without a levy in 2030, exceeding the expected capacity. In scenarios without a flexibility mechanism the ships which retrofits onboard CCS will not use it to its full capacity before the regulations require it. With the flexibility mechanism, these ships use the systems to full capacity and sell excess emission units to other ships.

- In scenarios with a 150–300 USD/tCO_2eq levy (scenarios 25 to 29) both the demand for e-fuels and carbon storage is low, likely due to energy efficiency reducing the need to low emission fuels and solutions.

- The fuel mix is to a large degree a result of the supply constraints on bio- and blue fuel feedstocks, and also the lack of constraints on e-fuels and carbon storage capacity.

- To achieve the GHG emission trajectories within the assumed supply constraints all fuel feedstocks need to be used, complemented by onboard CCS and reduction in energy use by way of energy-efficiency measures and speed reductions.

D.2.4 Number of newbuilds and retrofits

The peak annual number of newbuilds (any technology) and retrofits (to another fuel system, onboard carbon capture or energy-efficiency package) in the periods 2027–2030, 2031–2040 and 2041–2050 are shown in Figure D-29.

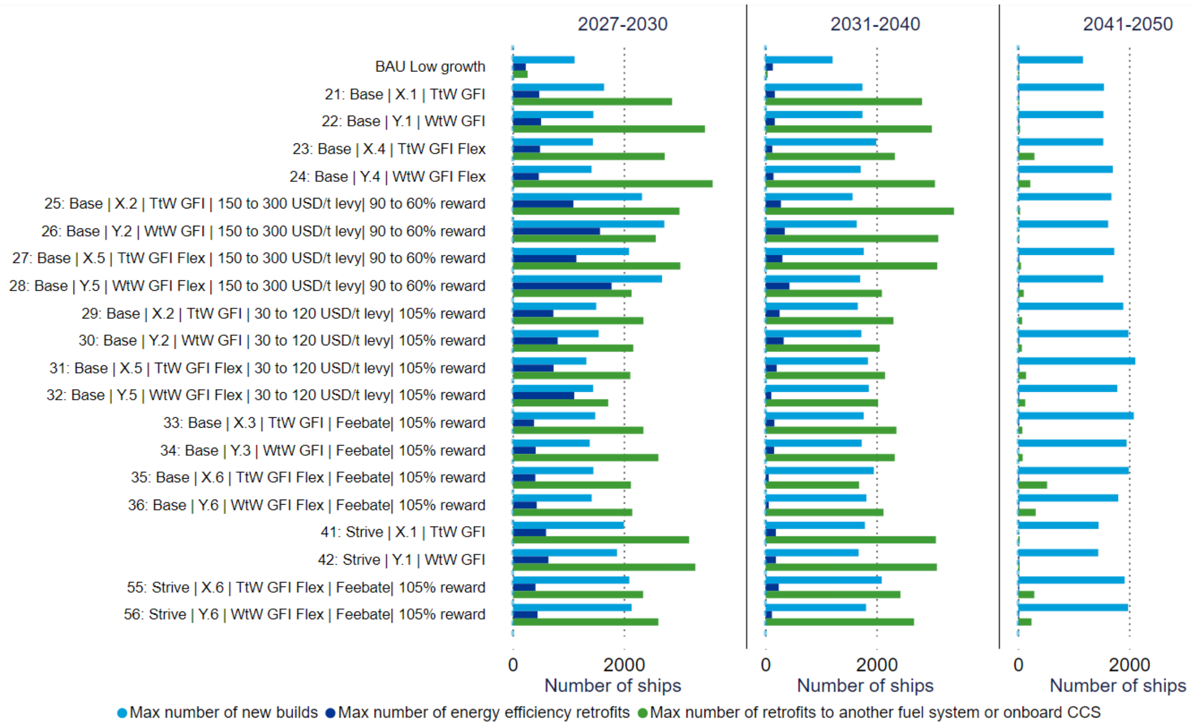


Figure D-29: Peak annual number of newbuilds, retrofits to another fuel system or onboard CCS, and retrofit to another energy-efficiency package in the periods 2027–2030, 2031–2040, and 2041–2050, per scenario.

[30] The reason for the discrepancy between the actual uptake and maximum availability is that the model assigns feedstock availability to ships in advance every year based on expected uptake and energy use. Due to improvements in energy efficiency and ships selecting, for example, onboard carbon capture in combination with fossil fuels, the uptake cannot be set exactly at the maximum supply allowed. This is particularly evident for biofuels in 2050.

The following observations are made from Figure D-29:

- Scenarios with a levy (scenario 25 to 32) see a peak of around 700 and 1600 annual retrofits to another energy-efficiency package in the early period 2027–2030. For the other scenarios the peak is at around 400 retrofits in one year. Similarly, the number of newbuilds increases to between 2200 to 2800 in scenarios 25 to 28 to compensate for lost capacity due to speed reduction. The same increase is seen in scenarios 41 to 42 and 55 to 56 following the *Strive* emission trajectory. The other scenarios with a *Base* emission trajectory see an annual newbuilding rate peaking at 1300 to 1400 ships.
- The number of retrofits to another fuel system or onboard CCS sees the highest peak in scenarios without a levy or feebate mechanism (scenarios 21 to 24) and in scenarios with a 150–300 USD/tCO_2eq levy (scenarios 25 and 28), with 3000 to 3600 annual retrofits in the periods 2027–2030 and from 2031–2040. About the same rates are seen in scenarios 41 and 42 following the *Strive* emission trajectory. For other scenarios the annual retrofit rate generally peaks at around 2000 ships.
- Scenarios with a GFI flexibility mechanism have a lower peak of retrofits to other fuel systems or onboard CCS in the earlier periods 2027–2030 and 2031–2040, but a higher peak in the last period from 2041–2050, compared to those without this mechanism. This is because less ships are required to retrofit initially, and more ships await technical modifications to the later periods as they can rely on buying emission units for compliance.
- The average number of newbuilds delivered from 2002 to 2022 was 2053 vessels per year, peaking at 3965 ships in 2010 (Ricardo & DNV, 2023), indicating that the number of newbuilds required in the scenarios should be within the capacity of the yards.
- The peak annual number of retrofits to other fuel technologies or onboard CCS and to some degree energy-efficiency measures are significant and due to the complexity of retrofitting ships to these technologies it remains uncertain if these numbers are feasible. For reference, the number of retrofits to scrubbers peaked at more than 2400 in 2019 (AFI, 2024) which is exceeded in more than half of the scenarios. It should be noted that retrofitting technologies such as ammonia and onboard CCS may be more extensive than retrofitting to scrubbers. The implication if these retrofit rates are not feasible is that more ships have to run on drop-in fuels such as bio-MGO and e-MGO, potentially resulting in higher costs.

D.2.5 Flexibility mechanism

Figure D-30 shows the average annual emission unit price and Figure D-31 shows the average annual exchange of emission units or trading volume in the periods 2027–2030, 2031–2040 and 2041–2050 for scenarios with a GFI flexibility mechanism. Both the exchange volume and unit price are calculated by the model based on the cost and reduction potential of the various solutions (see Appendix A.2.2.2). The emission unit exchange price reflects the cost of the last emission reduction required to reach the annual GFI requirement and should not be mixed with the total cost of reduction per total CO_2eq reduced.

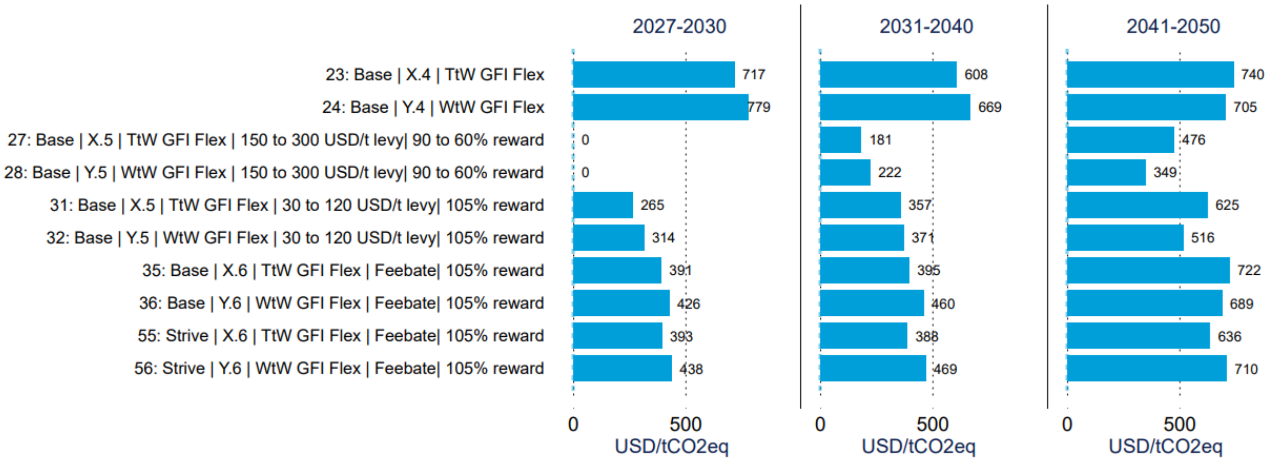


Figure D-30: Average annual emission unit exchange price (in USD/tCO_2eq) in the periods 2027–2030, 2031–2040, and 2041–2050, for scenarios with a GFI flexibility mechanism.

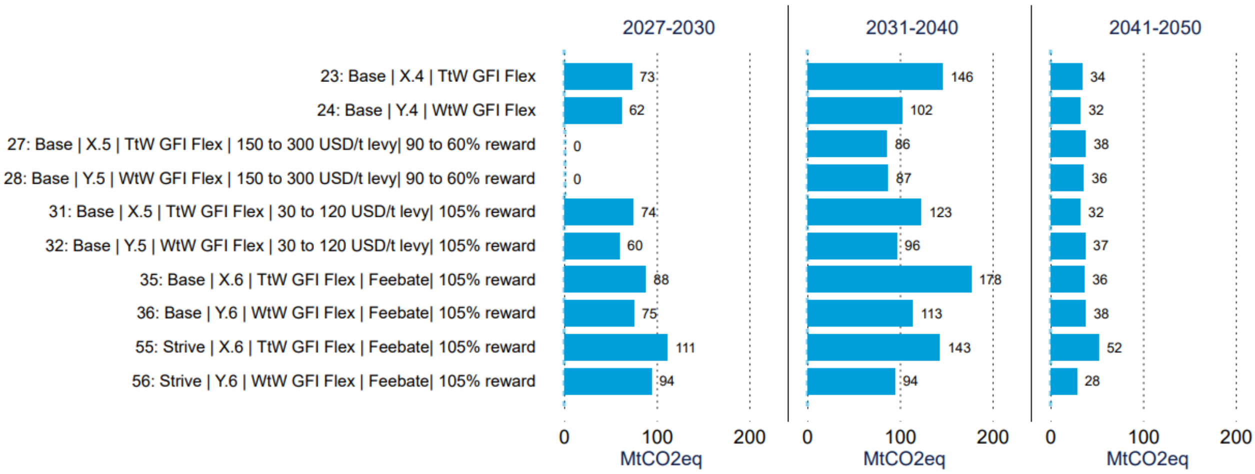


Figure D-31: Average annual exchange of emission units (in MtCO_2eq) in the periods 2027–2030, 2031–2040, and 2041–2050, for scenarios with a GFI flexibility mechanism.

Figure D-32 shows the annual exchange of emission units per fuel technology from 2027 to 2050 for scenarios 23, 24, 31 and 32. Ships with technologies and fuels that provide negative compliance balance sell emission units to ships with technologies and fuels that results in positive compliance balance. The chart will not show ships and technologies that have a zero compliance balance and do not exchange emission units.

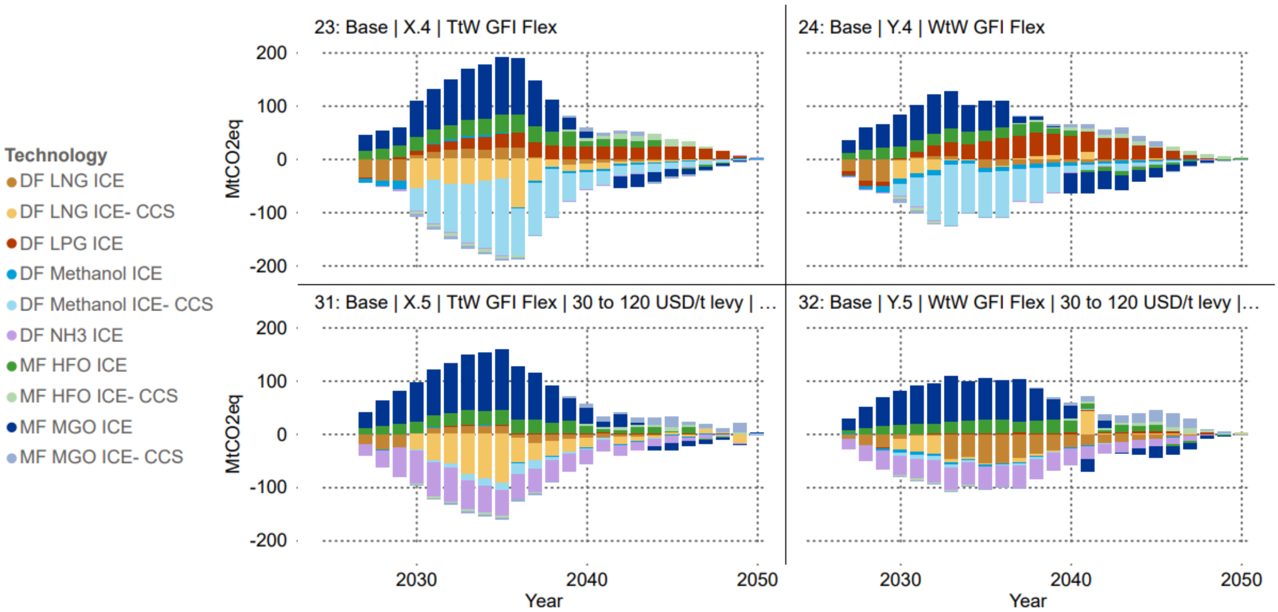


Figure D-32: Annual exchange of emission units per fuel technology from 2027 to 2050 for scenarios 23–24 and 31–32. Ships having technologies providing negative compliance balance sell emission units to ships having technologies with positive compliance balance.

The following observations are made from Figure D-31, Figure D-30 and Figure D-32:

- In scenarios without a levy or feebate, the average annual emission unit exchange prices start at 717 to 779 USD/tCO_2eq in the period 2027–2030 before reducing to 608 to 669 USD/tCO_2eq in 2031–2040 and increasing again to 705 to 740 USD/tCO_2eq in 2041–2050.
- With a levy or feebate in combination with a reward for eligible fuels, the price is reduced significantly in the periods to 2030 and 2040, depending on the level of the levy and the reward. Compared to scenarios without a levy and reward, the exchange price takes into account both the higher cost of fossil fuels and the lower cost of low emissions fuels. In scenarios 27 and 28 with a 150–300 USD/tCO_2eq levy there is almost no exchange of units in the period 2027–2030 as due to the high levy all ships are complying individually, and the price remains lower to 2050.
- The trading volume or emission units that are exchanged peaks around 2035 with the average for the period 2031–2040 being 86 to 178 MtCO_2eq. This represents about 9 to 18% of the annual GHG emissions for the whole fleet in the BAU scenario.
- TtW scenarios generally have a higher trading volume than WtW scope scenarios. This is specifically seen for TtW scope scenarios 23 and 35 which has a larger number of ships with LNG and onboard CCS with a negative compliance balance resulting in higher trading volume than WtW scope scenarios 24 and 36.
- It should be noted that the indicated trading volumes assume that all ships optimize the compliance balance and trades emission units at the price in the market. In reality, shipowners with large fleets are likely to arrange for the required compliance balance within their fleet without trading outside the company with other ships. There is also transaction cost with joining such a market, which are not include in our modelling. This implies that the trading volume in a market is likely lower, and that many shipowners can exchange units internally at lower prices. This does not impact the total cost level as all exchange are done between ships, although in our method, the assumed use of RUs and SUs are dependent on the trading volume.

- The scenarios with GFI flexibility see a higher number of ships with either ammonia, methanol and/or onboard CCS (see Figure D-24 and Figure D-28). In scenarios 21 and 22 without a levy/feebate mechanism LNG and methanol fuelled ships with onboard CCS contribute with negative compliance balance, while in scenarios 35 and 36 with a 30–120 USD/tCO_2eq levy and reward mechanism ammonia and bio- and e-LNG replace onboard CCS as the main solutions contributing with negative compliance balance.
- The technology with the highest marginal reduction costs in 2050 are ships with onboard CCS. Towards 2050, these ships cannot use fossil fuel to comply with the requirement and will have to switch to a certain amount of bio- or e-fuel. However, the trading volume is not very high. It should also be noted that this marginal cost only applies for the remaining reduction after using the onboard carbon capture plant at full capacity with fossil fuels only. The total reduction cost per tonne CO_2eq reduced is lower than the marginal cost.

D.2.6 Revenue streams and disbursements

Table D-1 shows the average annual revenue streams and disbursements for scenarios 23 to 32, 35 to 36 and 55 to 56 in the periods 2027–2030, 2031–2040 and 2041–2050. The other scenarios do not have any economic elements and have no revenue streams.

The D4 disbursement is a derived quantity depending on the modelled uptake of eligible fuels and the amount of surplus units purchased by the Revenue body. RD&D disbursement (D1) is set to zero. Distribution for other purposes (D2–D3 and D5–D7) is determined as the remainder of the total revenue after D4 has been distributed, and the total is passed to UNCTAD for incorporation into the modelling of impact on states in Task 3.

Table D-1: Average annual revenue streams and disbursements (in BUSD/year) for relevant revenue generating scenarios in the periods 2027–2030, 2031–2040, and 2041–2050. The percentages show the relative share of each disbursement to the total revenue. The numbers and percentages may not add up due to rounding errors.

Scenario	Period	Revenues (BUSD/year)		Disbursements (BUSD/year)	
		Levy/fee	Remedial Unit sale	Reward, and surplus unit purchase (D4)	Other disbursements (D2-D3, D5-D7)
23: *Base* | X.4 | TtW GFI Flex	2027-2030	-	6.3	4.2 (67%)	2.1 (33%)
	2031-2040	-	10.6	7.1 (67%)	3.5 (33%)
	2041-2050	-	3.0	2.0 (67%)	1.0 (33%)
24: *Base* | Y.4 | WtW GFI Flex	2027-2030	-	5.8	3.8 (67%)	1.9 (33%)
	2031-2040	-	8.2	5.4 (67%)	2.7 (33%)
	2041-2050	-	2.7	1.8 (67%)	0.9 (33%)
25: *Base* | X.2 | TtW GFI | 150–300 USD/t levy | 90 to 60% reward	2027-2030	92.9	-	2.2 (2%)	90.7 (98%)
	2031-2040	69.3	-	17.4 (25%)	52.0 (75%)
	2041-2050	16.8	-	-	16.8 (100%)
26: *Base* | Y.2 | WtW GFI | 150–300 USD/t levy | 90 to 60% reward	2027-2030	127.2	-	5.8 (5%)	121.4 (95%)
	2031-2040	102.8	-	14.5 (14%)	88.3 (86%)
	2041-2050	35.7	-	-	35.7 (100%)
27: *Base* | X.5 | TtW GFI Flex | 150–300 USD/t levy | 90 to 60% reward	2027-2030	97.8	-	1.7 (2%)	96.1 (98%)
	2031-2040	76.7	1.9	18.5 (24%)	60.1 (76%)
	2041-2050	11.7	2.2	1.4 (10%)	12.4 (90%)
	2027-2030	127.0	-	4.1 (3%)	122.9 (97%)
	2031-2040	106.3	2.3	16.8 (15%)	91.9 (85%)

Scenario	Period	Revenues (BUSD/year)		Disbursements (BUSD/year)	
		Levy/fee	Remedial Unit sale	Reward, and surplus unit purchase (D4)	Other disbursements (D2-D3, D5-D7)
28: *Base* | Y.5 | WtW GFI Flex | 150–300 USD/t levy | 90 to 60% reward	2041-2050	32.4	1.5	1.0 (3%)	32.9 (97%)
29: *Base* | X.2 | TtW GFI | 30–120 USD/t | 105% reward	2027-2030	28.9	-	16.3 (56%)	12.6 (44%)
	2031-2040	33.3	-	24.2 (73%)	9.0 (27%)
	2041-2050	7.0	-	-	7.0 (100%)
30: *Base* | Y.2 | WtW GFI | 30–120 USD/t | 105% reward	2027-2030	36.3	-	22.4 (62%)	13.8 (38%)
	2031-2040	46.3	-	28.7 (62%)	17.6 (38%)
	2041-2050	15.8	-	-	15.8 (100%)
31: *Base* | X.5 | TtW GFI Flex | 30–120 USD/t | 105% reward	2027-2030	29.5	2.4	10.1 (32%)	21.8 (68%)
	2031-2040	33.6	5.3	32.5 (84%)	6.4 (16%)
	2041-2050	5.7	2.4	1.6 (20%)	6.5 (80%)
32: *Base* | Y.5 | WtW GFI Flex | 30–120 USD/t | 105% reward	2027-2030	36.0	2.2	20.2 (53%)	18.0 (47%)
	2031-2040	47.0	4.3	24.6 (48%)	26.8 (52%)
	2041-2050	15.4	2.3	1.5 (9%)	16.2 (91%)
33: *Base* | X.3 | TtW GFI | Feebate | 105% reward	2027-2030	18.9	-	18.9 (100%)	-
	2031-2040	25.1	-	25.1 (100%)	-
	2041-2050	-	-	-	-
34: *Base* | Y.3 | WtW GFI | Feebate | 105% reward	2027-2030	19.8	-	19.8 (100%)	-
	2031-2040	24.0	-	24.0 (100%)	-
	2041-2050	-	-	-	-
35: *Base* | X.6 | TtW GFI Flex | Feebate | 105% reward	2027-2030	19.2	4.1	22.0 (94%)	1.4 (6%)
	2031-2040	24.8	8.4	30.4 (92%)	2.8 (8%)
	2041-2050	-	3.2	2.1 (67%)	1.1 (33%)
36: *Base* | Y.6 | WtW GFI Flex | Feebate | 105% reward	2027-2030	16.5	3.8	19.1 (94%)	1.3 (6%)
	2031-2040	23.4	6.3	27.6 (93%)	2.1 (7%)
	2041-2050	-	3.1	2.1 (67%)	1.0 (33%)
55: *Strive* | X.6 | TtW GFI Flex | Feebate | 105% reward	2027-2030	31.7	5.2	35.2 (95%)	1.8 (5%)
	2031-2040	30.7	6.7	35.1 (94%)	2.2 (6%)
	2041-2050	-	4.0	2.7 (67%)	1.3 (33%)
56: *Strive* | Y.6 | WtW GFI Flex | Feebate | 105% reward	2027-2030	29.7	5.0	33.0 (95%)	1.7 (5%)
	2031-2040	29.5	5.3	33.0 (95%)	1.8 (5%)
	2041-2050	-	2.4	1.6 (67%)	0.8 (33%)

The following observations from Table D-1 have been made:

- A levy of 150–300 USD/tCO_2eq as used in scenarios 25 to 28 creates an average annual revenue stream of 93 to 127 BUSD/year in the period 2027–2030, decreasing to 69 to 106 BUSD/year in 2031–2040 and to 12 to 36 BUSD/year in 2041–2050.

- A levy of 30–120 USD/tCO_2eq as used in scenarios 29 to 32 creates an average annual revenue stream of 29 to 36 BUSD/year in the period 2027–2030, increasing to 33 to 47 BUSD/year in 2031–2040 and then decreasing to 6 to 16 BUSD/year in 2041–2050.

- In scenarios with a flexibility mechanism the revenue from sale of RUs creates an average annual revenue stream of 0 to 6 BUSD/year in the period 2027–2030, increasing to 2 to 11 BUSD/year in 2031–2040 and then decreasing to 2 to 3 BUSD/year in 2041–2050.

D.3 Result charts from scenarios 43 to 54

This Section presents the result charts from the modelling of 12 policy combination scenarios (numbered 43 to 54) all following the *Strive* GHG emission trajectory. For these scenarios we assume that the total demand for low emission fuels exceeds the supply for bio- and blue fuel feedstocks and we adjust the fuel prices of all the fuel types made from those feedstocks to the equivalent, in terms of energy and emissions, cost of the e-fuel of the same type. Due to time limitations during the conduct of the study, these scenarios have not been included in previous reports and therefore no observations or analysis are included in this appendix. The results are included in the discussion and analysis in Chapter 6.

Annual required GFI limits are determined by iteration and the resulting GHG emissions align within ±5% to the required GHG trajectories. The differences in the GHG trajectories will affect the other results, including the differences in the estimated cost intensity changes between the scenarios.

D.3.1 GHG emissions

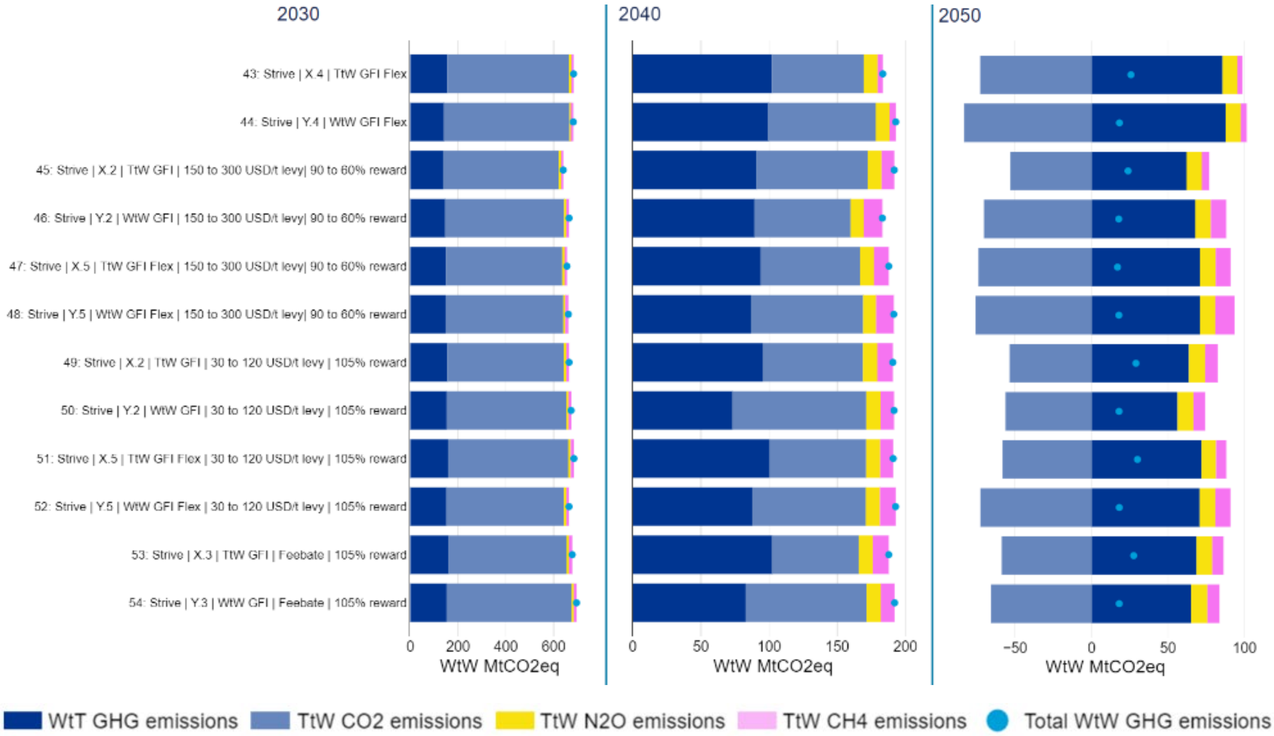


Figure D-33: WtW GHG emissions per scenario, split on WtT GHG, TtW CO_2, TtW N_2O and TtW CH_4 emissions, in 2030, 2040, and 2050. For the TtW CO_2 emissions, CO_2 emissions captured by onboard CCS and subsequently stored are subtracted. The *Total WtW GHG emissions* markers indicate the total GHG emissions. Note that the scale of emissions varies between the three years.

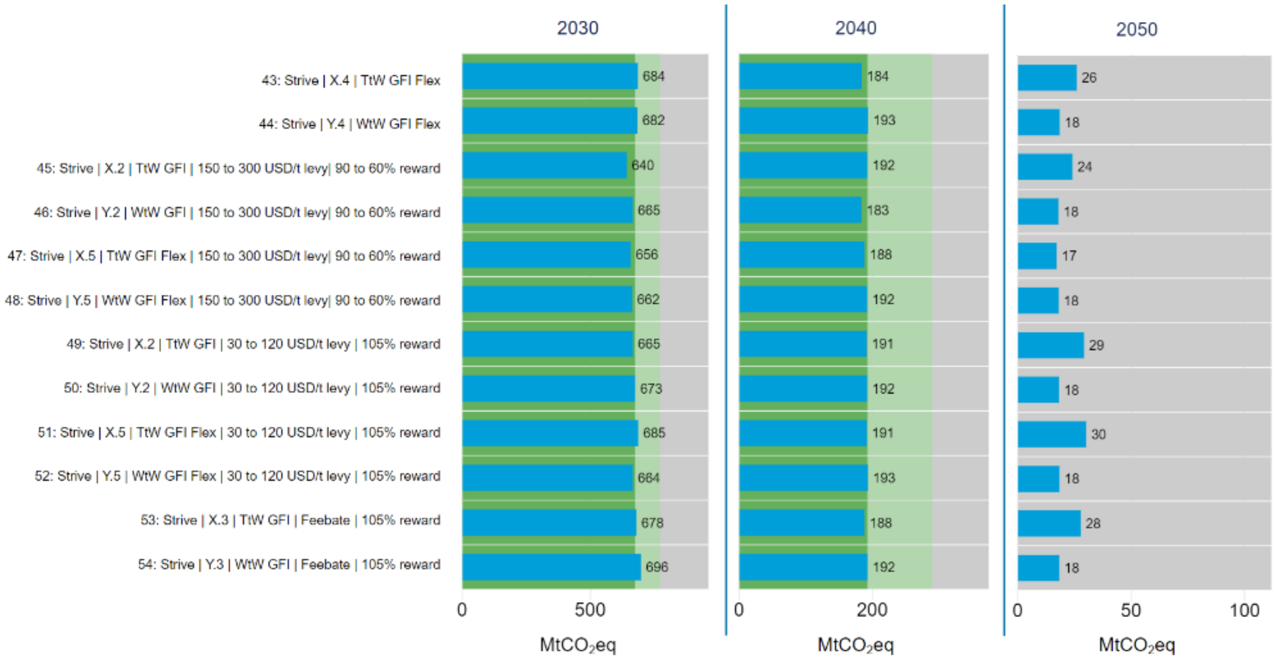


Figure D-34: WtW GHG emission levels in 2030, 2040, and 2050 for the policy scenarios, compared to the emission targets. The dark-green to light-green boundary indicates the *Strive* target (scenarios 41, 42, 55 and 56) and the light-green to grey boundary indicates the *Base* target (all other scenarios). A certain amount of GHG emissions remain in 2050 for all scenarios due to remaining CH_4 and/or N_2O emissions from combustion engines.

D.3.2 Cost impact

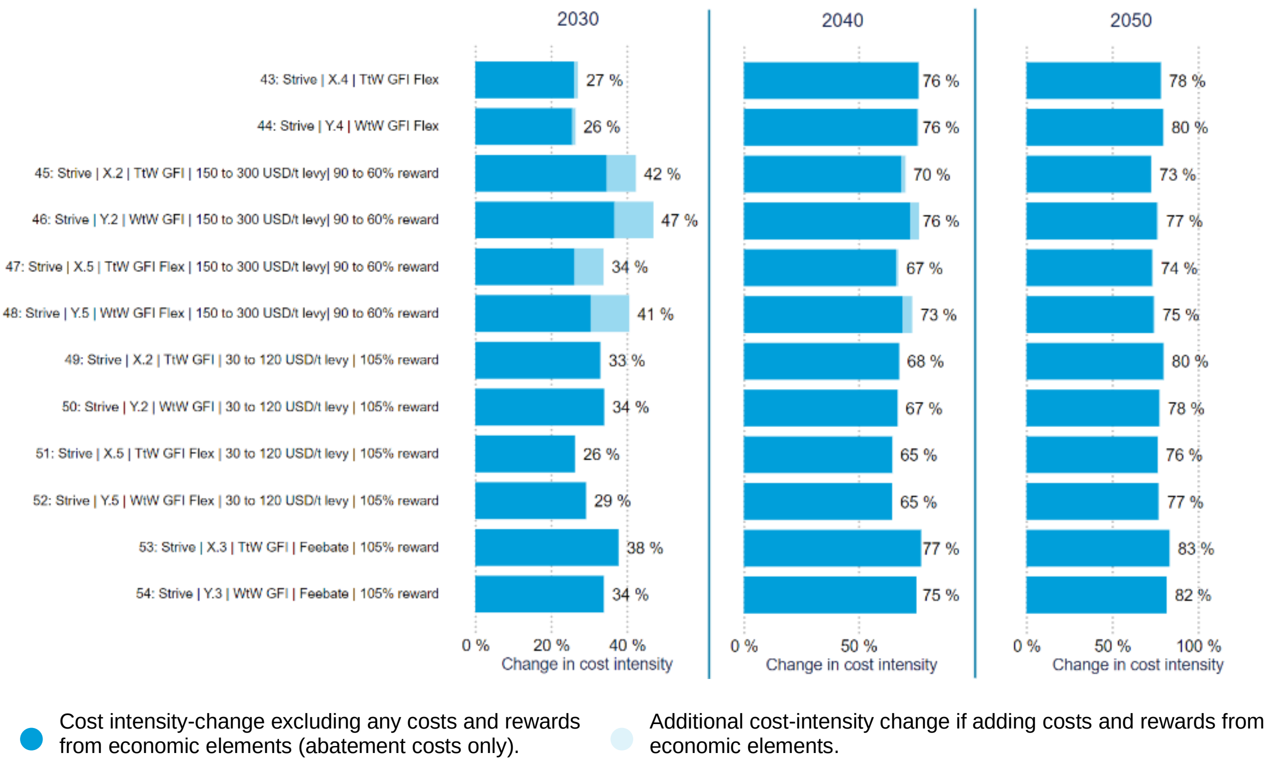


Figure D-35: Cost-intensity change per policy scenario relative to business-as-usual with *low* seaborne trade growth in 2030, 2040, and 2050. The light-blue bars show the part of the cost-intensity increase related to regulatory incomes and expenses imposed by the policy measures in the scenarios with levy or GFI flexibility mechanism (emission unit exchange in a pool, rewards for eligible fuels and sale of SUs).

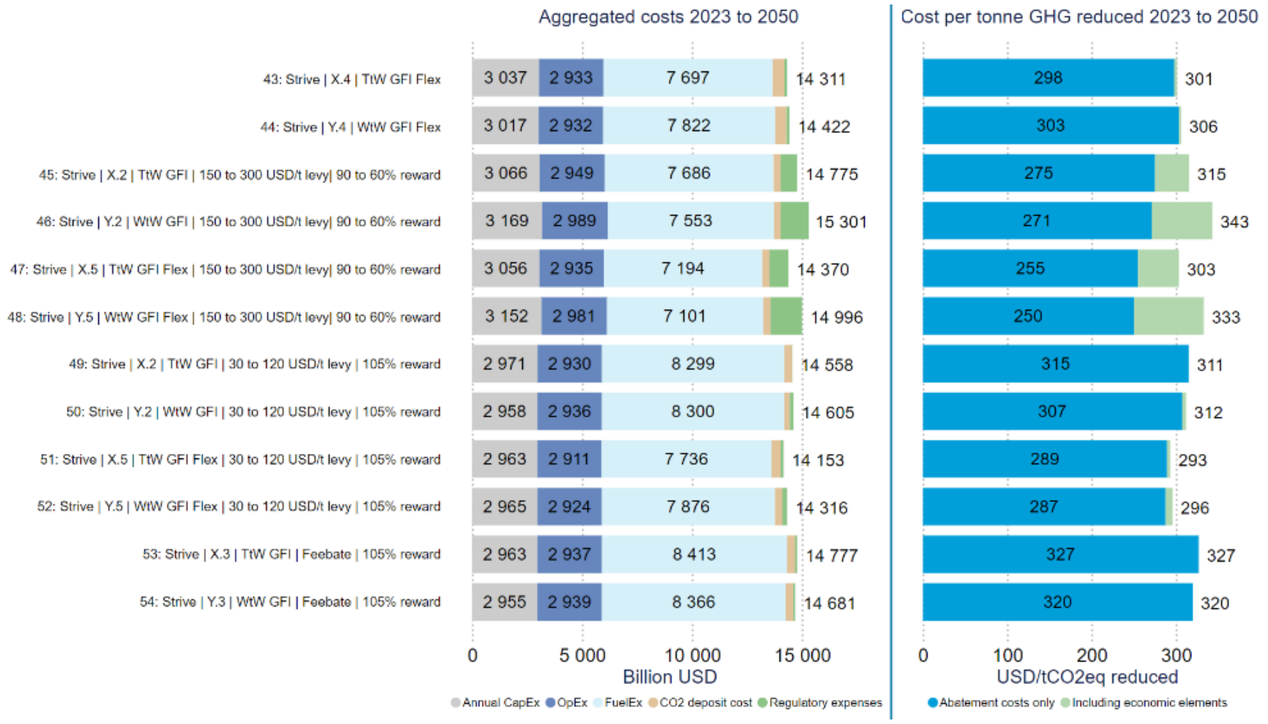


Figure D-36: Total aggregated costs split on annual capital costs, operational costs, fuel costs, CO_2 deposit costs and regulatory expenses, including levy/fee, rewards and RU/SU transactions with the Revenue body (left panel), and total additional cost per tonne of GHG reduced relative to BAU (right panel), from 2023 to 2050, per scenario. The green bars in the right panel show the part of the cost-intensity increase related to regulatory incomes and expenses imposed by the policy measures in the scenarios with levy or GFI flexibility mechanism (rewards for eligible fuels and sale of SUs).

D.3.3 Energy use and fuel mix

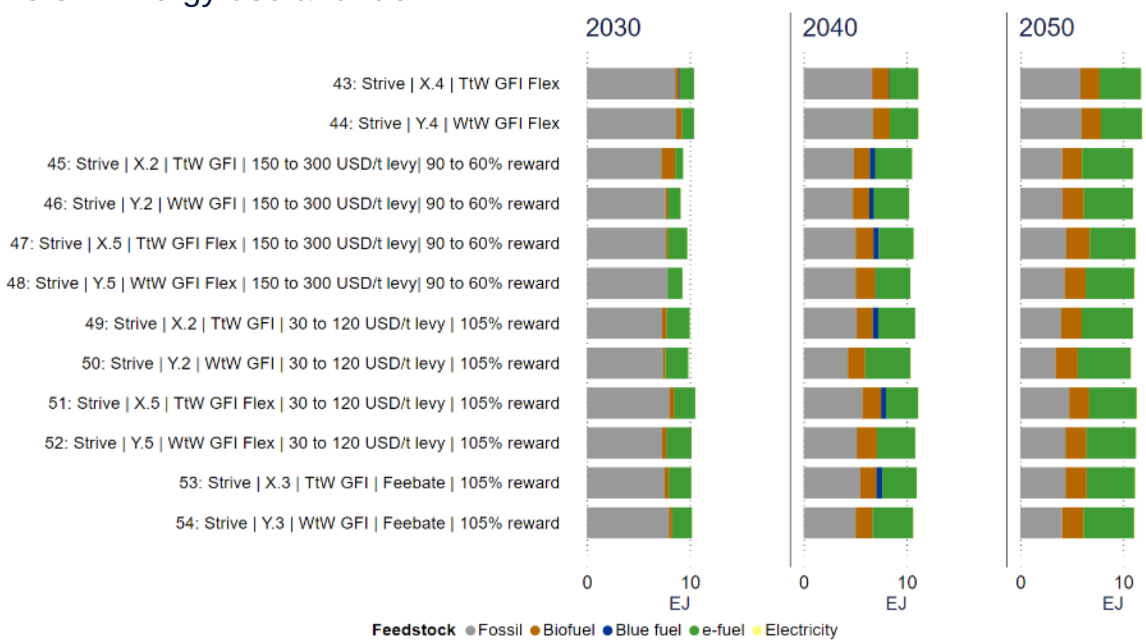


Figure D-37: Energy use per fuel feedstock (of any fuel type) in 2030, 2040, and 2050, per scenario.

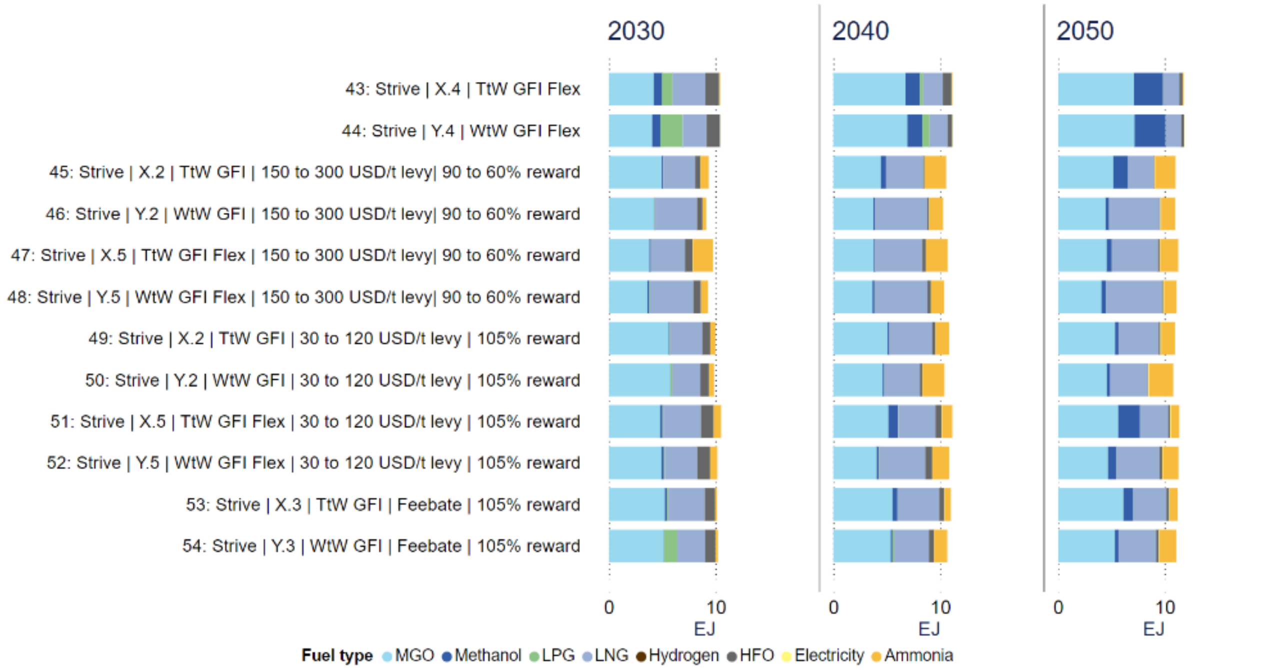


Figure D-38: Energy use per fuel type (of any feedstock) in 2030, 2040, and 2050, per scenario.

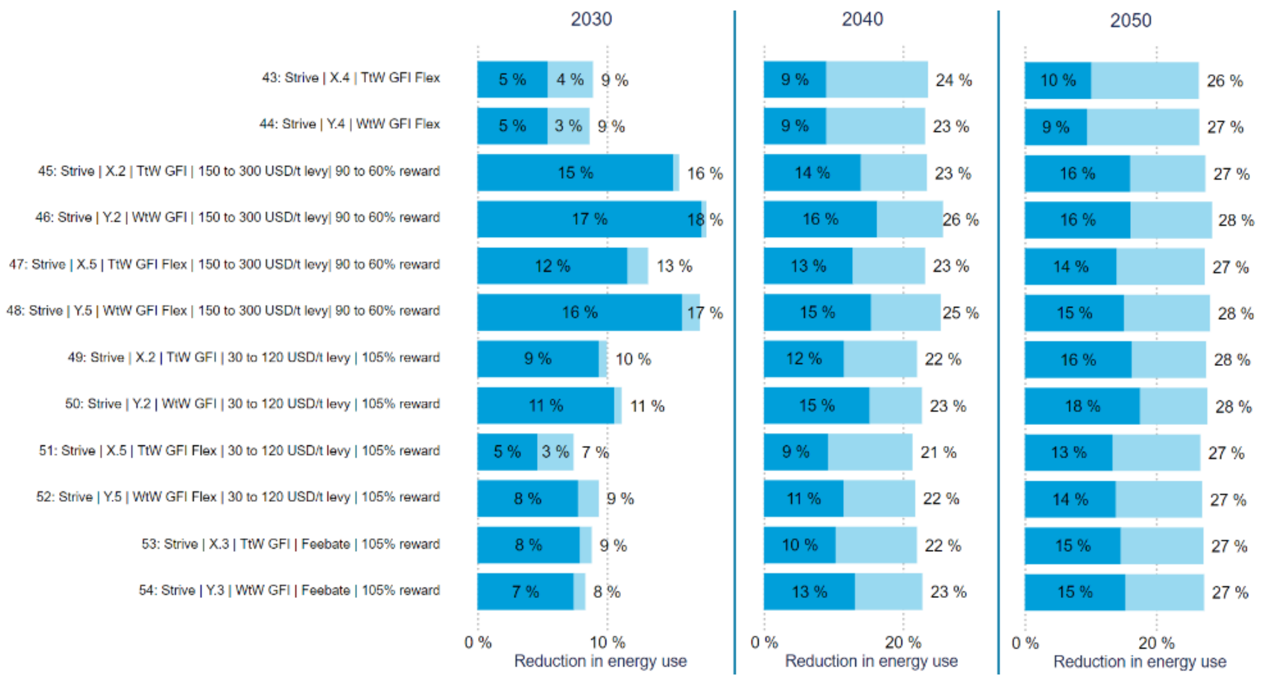


Figure D-39: Reduction in energy use relative to BAU (low growth) in 2030, 2040, and 2050, per scenario. The dark-blue bar shows the reduction taking into account the additional energy needed for onboard CCS.

Figure D-40: Biofuel demand in blue bars for each scenario compared to the estimated supply of advanced biofuels available for shipping in 2030, 2040, and 2050, per scenario. The green to yellow boundary indicates the median estimated supply and the yellow to red boundary indicates the high estimated supply (Ricardo & DNV, 2023). Note that the x-axis scale changes between the years.

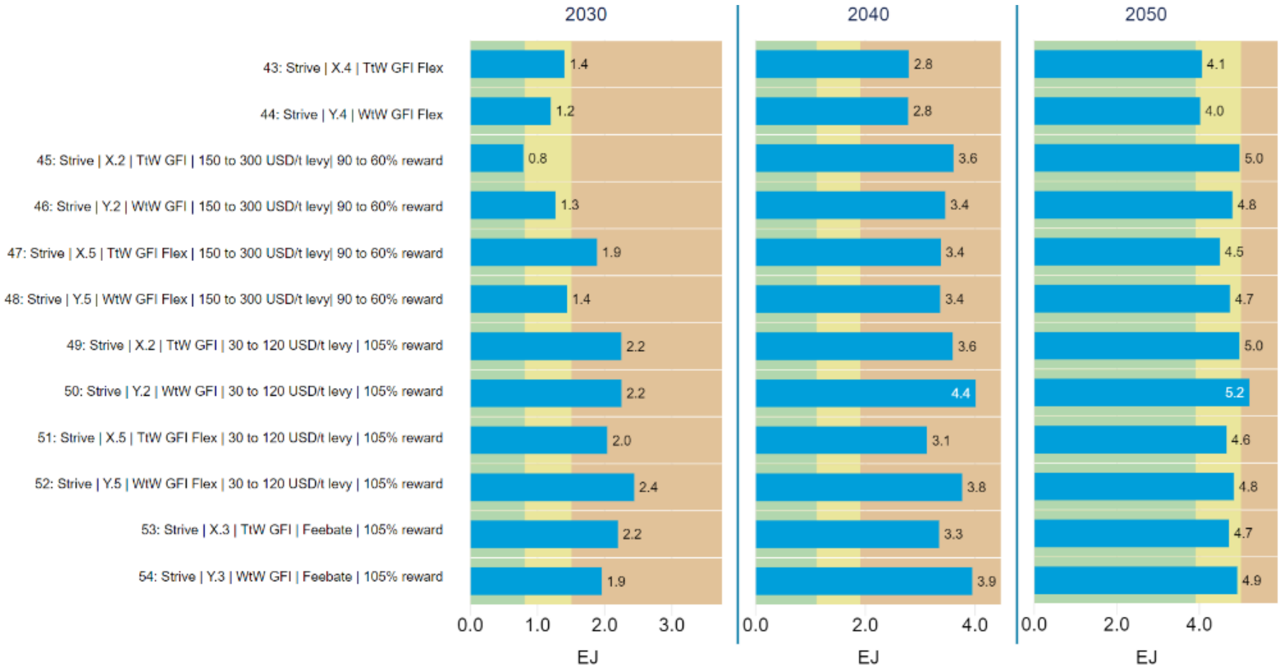


Figure D-41: E-fuel demand in blue bars for each scenario compared to the estimated supply of e-fuels available for shipping in 2030, 2040, and 2050, per scenario. The green to yellow boundary indicates the median estimated supply and the yellow to red boundary indicates the high estimated supply (Ricardo & DNV, 2023). Note that the x-axis scale changes between the years.

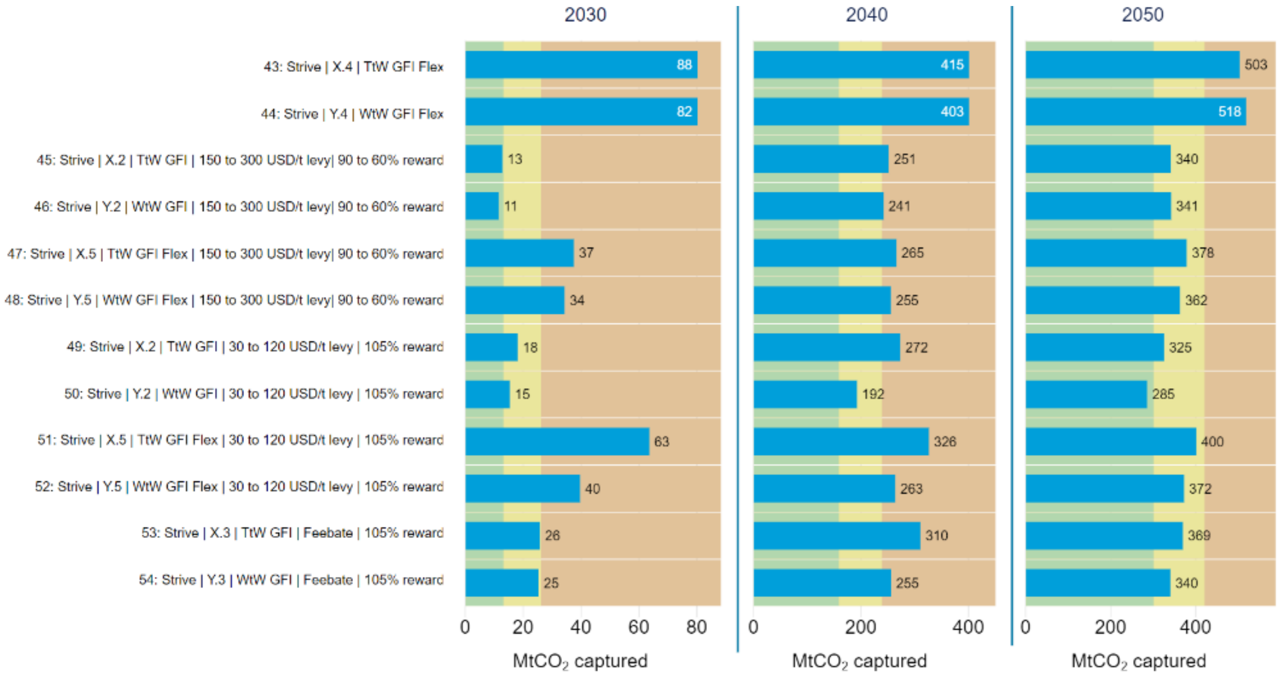


Figure D-42: Captured carbon storage demand in blue bars compared to estimated carbon storage capacity available for shipping in 2030, 2040, and 2050. The green to yellow boundary indicates the median estimated capacity available for shipping and the yellow to red boundary indicates the high estimated capacity available for shipping (Ricardo & DNV, 2023). Note that the x-axis scale changes between the years.

D.3.4 Number of newbuilds and retrofits

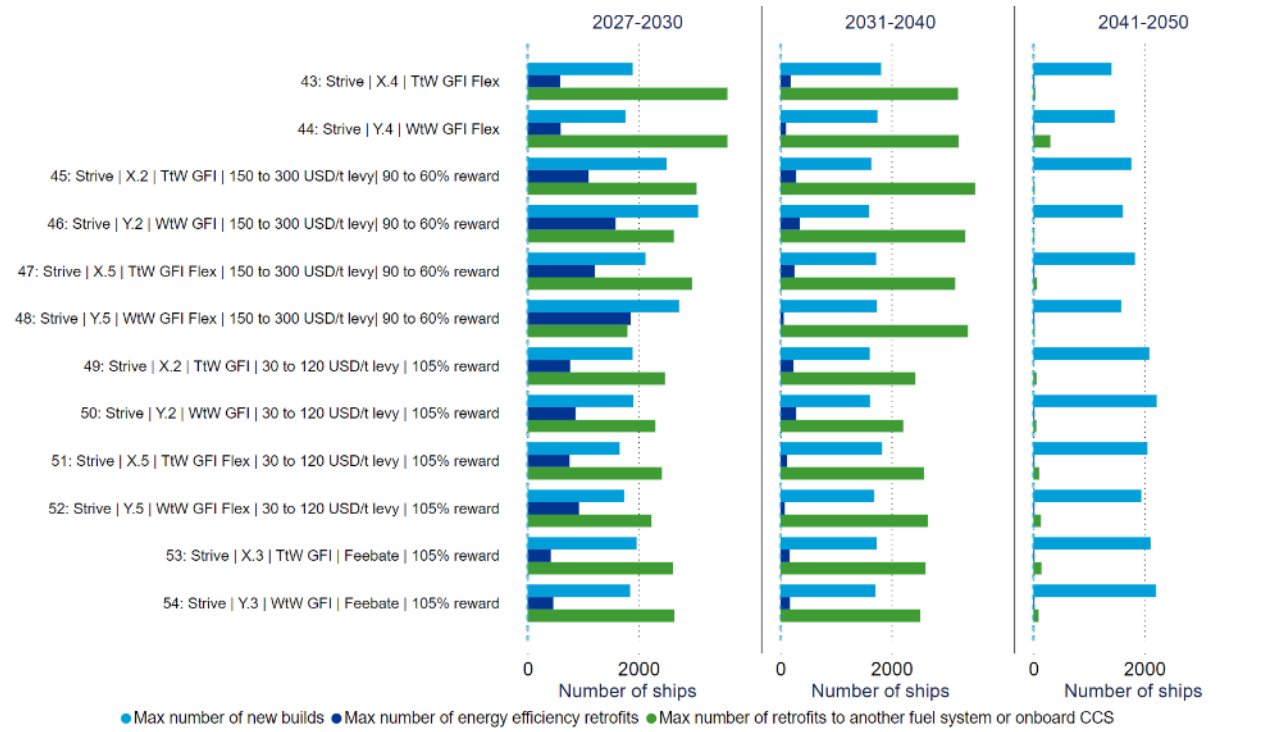


Figure D-43: Peak annual number of newbuilds, retrofits to another fuel system or onboard CCS, and retrofit to another energy-efficiency package in the periods 2027–2030, 2031–2040, and 2041–2050, per scenario.

D.3.5 Flexibility mechanism

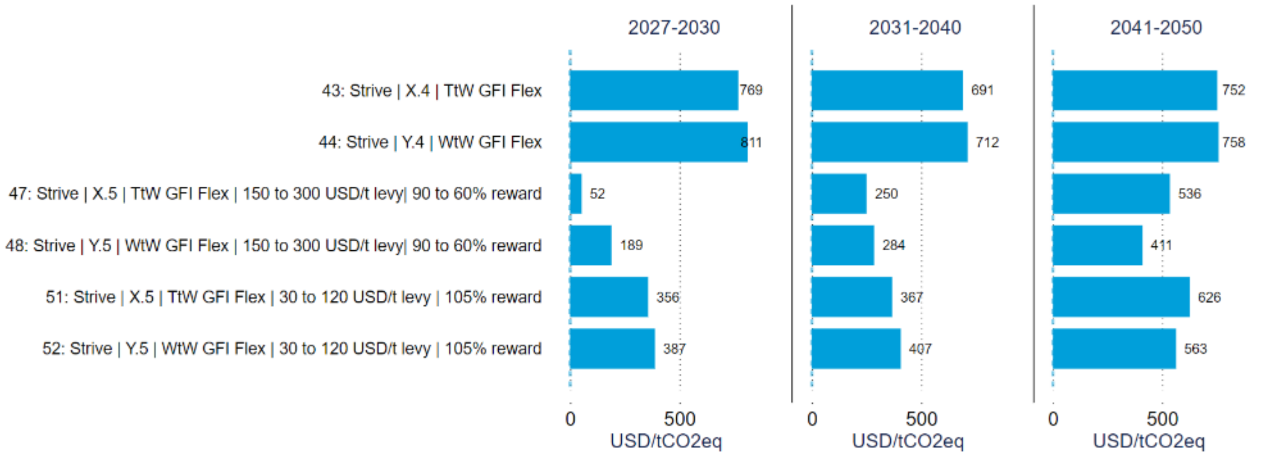


Figure D-44: Average annual emission unit exchange price (in USD/tCO$_2$eq) in the periods 2027–2030, 2031–2040, 2041–2050 for scenarios with a GFI flexibility mechanism.

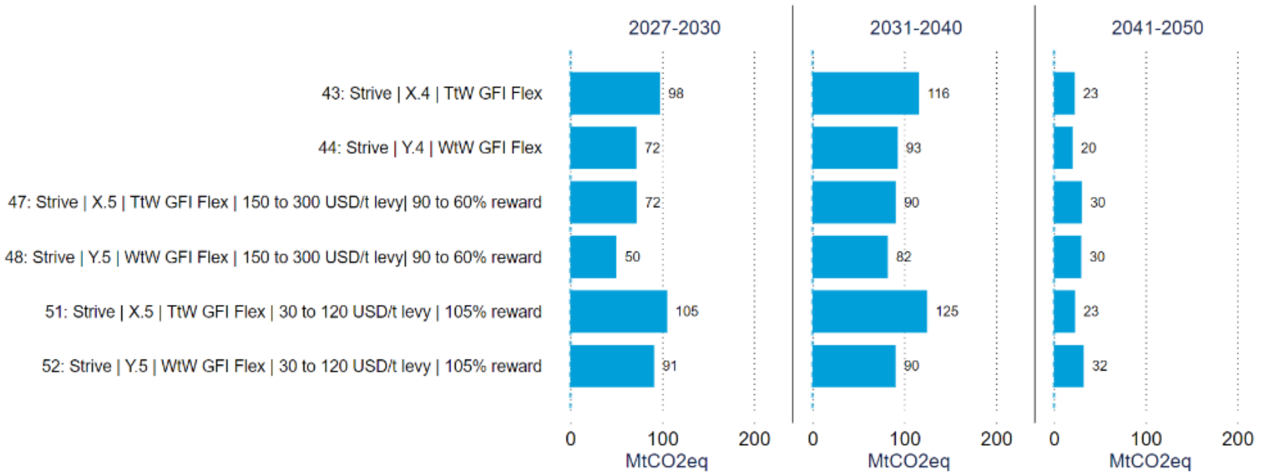


Figure D-45 Average annual exchange of emission units (in MtCO$_2$eq) in the periods 2027–2030, 2031–2040, 2041–2050 for scenarios with a GFI flexibility mechanism.

D.3.6 Revenue streams and disbursements

Table D-2: Average annual revenue streams and disbursements (in BUSD/year) for relevant revenue generating scenarios in the periods 2027–2030, 2031–2040, and 2041–2050. The percentages show the relative share of each disbursement to the total revenue. The numbers and percentages may not add up due to rounding errors.

Scenario	Period	Revenues (BUSD/year)		Disbursements (BUSD/year)	
		Levy/fee	Remedial Unit sale	Reward, and surplus unit purchase (D4)	Other disbursements (D2–D3 & D5–D7)
43: *Strive* | X.4 | TtW GFI Flex	2027-2030	-	9.0	6.0 (67%)	3.0 (33%)
	2031-2040	-	9.6	6.4 (67%)	3.2 (33%)
	2041-2050	-	2.0	1.4 (67%)	0.7 (33%)
44: *Strive* | Y.4 | WtW GFI Flex	2027-2030	-	7.0	4.7 (67%)	2.3 (33%)
	2031-2040	-	7.9	5.3 (67%)	2.6 (33%)
	2041-2050	-	1.9	1.2 (67%)	0.6 (33%)
45: *Strive* | X.2 | TtW GFI | 150–300 USD/t levy| 90 to 60% reward	2027-2030	83.8	-	3.5 (4%)	80.3 (96%)
	2031-2040	53.3	-	28.8 (54%)	24.5 (46%)
	2041-2050	9.9	-	-	9.9 (100%)
46: *Strive* | Y.2 | WtW GFI | 150–300 USD/t levy| 90 to 60% reward	2027-2030	117.5	-	16.8 (14%)	100.7 (86%)
	2031-2040	81.7	-	26.6 (33%)	55.2 (67%)
	2041-2050	23.7	-	-	23.7 (100%)
47: *Strive* | X.5 | TtW GFI Flex | 150–300 USD/t levy| 90 to 60% reward	2027-2030	91.8	0.5	8.7 (9%)	83.5 (91%)
	2031-2040	59.8	2.7	26.5 (42%)	36.1 (58%)
	2041-2050	5.8	2.0	1.3 (17%)	6.4 (83%)
48: *Strive* | Y.5 | WtW GFI Flex | 150–300 USD/t levy| 90 to 60% reward	2027-2030	117.2	1.1	16.0 (14%)	102.3 (86%)
	2031-2040	86.1	2.8	21.0 (24%)	67.8 (76%)
	2041-2050	25.0	1.5	1.0 (4%)	25.5 (96%)
49: *Strive* | X.2 | TtW GFI | 30–120 USD/t levy | 105% reward	2027-2030	26.4	-	25.0 (95%)	1.4 (5%)
	2031-2040	25.5	-	35.9 (141%)	-
	2041-2050	4.2	-	-	4.2 (100%)
50: *Strive* | Y.2 | WtW GFI | 30–120 USD/t levy | 105% reward	2027-2030	33.8	-	30.9 (91%)	3.0 (9%)
	2031-2040	37.3	-	41.6 (112%)	-
	2041-2050	10.6	-	-	10.6 (100%)
51: *Strive* | X.5 | TtW GFI Flex | 30–120 USD/t levy | 105% reward	2027-2030	27.5	4.5	24.2 (76%)	7.8 (24%)
	2031-2040	29.4	5.5	35.9 (103%)	-
	2041-2050	3.5	1.7	1.2 (22%)	4.0 (78%)
52: *Strive* | Y.5 | WtW GFI Flex | 30–120 USD/t levy | 105% reward	2027-2030	33.0	4.2	33.8 (91%)	3.4 (9%)
	2031-2040	35.8	4.4	40.4 (100%)	-
	2041-2050	11.5	2.2	1.5 (11%)	12.2 (89%)
53: *Strive* | X.3 | TtW GFI | Feebate | 105% reward	2027-2030	26.1	-	26.1 (100%)	-
	2031-2040	33.0	-	33.0 (100%)	-
	2041-2050	-	-	-	-
54: *Strive* | Y.3 | WtW GFI | Feebate | 105% reward	2027-2030	27.0	-	27.0 (100%)	-
	2031-2040	36.2	-	36.2 (100%)	-
	2041-2050	-	-	-	-

APPENDIX E
Sensitivity analysis and uncertainties

In this appendix we investigate the sensitivity of the modelled results with respect to input data and assumptions, followed by a discussion of uncertainties.

E.1 Sensitivity analysis

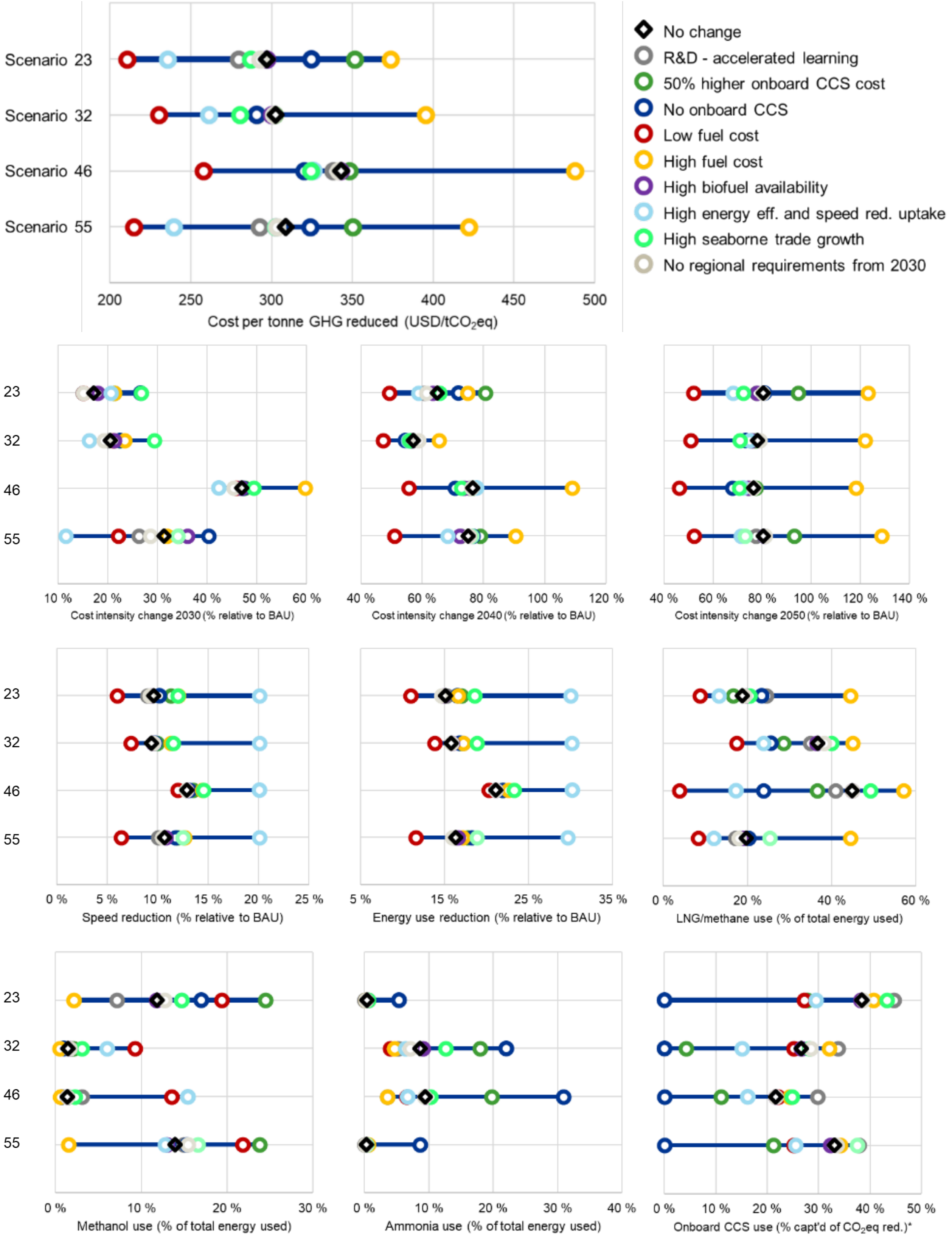
In this Section we provide an analysis of the sensitivities of inputs and assumptions in the modelling work. The sensitivity of a model is not the same as the uncertainty in the results produced by the model. A sensitivity analysis describes how a model responds to changes to key inputs and assumptions and the relative importance of the various inputs. It supports the discussion of the uncertainties by identifying which inputs and assumptions have the largest impact on the results given the expected uncertainty. We run sensitivity scenarios where we systematically change one input variable at a time. The changes in the parameters should be in the lower or upper end of an expected range, but not reflect the extreme range of possibilities.

Two recent studies and papers have investigated the sensitivities related to the Pathway model used in this study (Longva, et al., 2024; Longva & Sekkesæter, 2021). Both studies point to the general fuel cost level of low emission fuels as the main cost driver, while the difference between fuel types is of lesser importance for the total cost. Energy efficiency impacts the total cost, and the uptake appears to be sensitive to longer investment horizon reflecting removal of the barrier of split-incentives and short payback time requirements when investing in the fleet. Seaborne trade can also have an impact on the absolute costs of reduction as more energy will be required to run a larger fleet required to meet the higher transport demand.

It was not feasible within the scope and timeframe of this study to investigate all possible sensitives of the modelling work in combination with all policy scenarios. In discussion with the Steering Committee, nine sensitivities were selected to be run, in combination with four representative scenarios covering the *Base* and *Strive* GHG emission trajectories and different policy combinations.

The GFI requirement have been adjusted for each sensitivity scenario to align with the *Base* or *Strive* emission trajectory as relevant. However, in some sensitivity scenarios the changed inputs, such as lower fuel prices or forced uptake of energy-efficiency measures, the target trajectory are achieved without any GFI requirements.

Figure E-1 shows the results of the sensitivity analysis. We compare the sensitivity scenarios on changes relative to BAU on cost per tonne of GHG reduced; reduction in speed and energy use; ammonia, methanol, methane/LNG and onboard CCS use relative to total energy use/GHG emission reduced, in the period from 2023 to 2050; and cost-intensity increases in 2030, 2040, and 2050. The charts are provided without comments and the results are discussed in Section 7.1.



* For onboard CCS use 30% of the carbon captured is deducted to take into account the additional GHG emissions due to the fuel penalty.

Figure E-1: Changes for the period from 2023 to 2050 in cost per tonne of GHG reduced (top row), cost intensity in 2030, 2040 and 2050 (second row), energy use, speed reduction and onboard CCS use (third row),

LNG/methane use, methanol use and ammonia use (bottom row) for the four representative scenarios for each sensitivity.

E.2 Uncertainties

In this Section, we discuss the key uncertainties of the applied method, inputs and assumptions.

E.2.1 Baseline fleet GHG emission estimates

The starting point for the evaluation of GHG reductions and associated costs in this study is the baseline fleet energy use and GHG emissions levels estimated based on AIS data from 2023 using the MASTER model. The GHG emission level in 2023 also determines how much reduction has been achieved since 2008 and how much further reductions are needed to reach the *Base* and *Strive* GHG emission trajectories to 2050.

We apply three methods to evaluate the uncertainty in the 2023 fleet baseline:

- The baseline data for a set of ships is compared with reported and verified data for the same set of ships.
- The total baseline data for ships above 5,000 GT is compared with the total reported data from DCS.
- The share of international vs domestic voyage is compared across several years and method

Comparing modelled data with reported and verified data for the same set of ships

Based on comparing modelled data with reported data for the exact same set of ships, Longva & Sekkesæter (2021) find that the deviation in distance sailed calculated in the MASTER model is less than 1%. The deviation in modelled fuel consumption for a sufficiently large number of cargo-carrying ships over time is up to 5%, although for individual ships the deviation could be much larger. This deviation is well within the expected uncertainty on reported values which could be up to ±10% for an individual ship depending on monitoring method.

Comparing the total modelled data with reported data from DCS

Since DCS data from 2023 is not yet available, the uncertainty on the total baseline data is estimated by generating a baseline file using the same method on AIS data from 2022 for ships above 5000 GT, and comparing that baseline with DCS data from 2022.

Table E-1: Comparison of the modelled baseline data based on AIS with reported data from DCS from ships above 5,000 GT in 2022.

	Unit	Reported data from DCS in 2022	Baseline data from AIS in 2022	Difference
Fleet size	Number of ships	28 834	30 675	+6.4 %
Fuel consumption	mill tonnes	213	232	+8.9 %
Distance sailed	mill nm	1 521	1 652	+8.5 %
Fuel consumption per distance sailed	kg/nm	140.0	140.4	0.3 %

Table E-1 shows that the deviation in fuel consumption and distance sailed are similar at around 8.5 to 8.9% and that the number of ships captured by the AIS analysis are 6.4% higher than the number of ships that reported to DCS. Factoring out the difference in number of ships, the difference in the total fuel consumption per total distance sailed is 0.3%. This indicates that the difference is due to ships reporting DCS data to the IMO, most likely ships in exclusively domestic trades that are not required to report through DCS.

Comparing the share of international and domestic voyages

The method for identifying international voyages and the resulting difference in the share of GHG emissions from international voyages in the 2008 reference calculated by the Fourth IMO GHG Study, and the 2023 emission estimates in this study can have a large impact on the achieved GHG emission reduction in 2023 and consequently the GHG trajectories to 2030 and 2040 (see Appendix A.3)

We calculate the share of GHG emission from international voyage based on the proportion of distance sailed internationally compared to the total distance sailed, for each ship. Our estimate for 2023 indicates an emission reduction relative to 2008 of 3.6% for international voyages, whereas the corresponding reduction for all shipping activities, both domestic and international, is 6%. Comparing the calculated share of GHG emissions from international shipping for all ships above 100 GT in 2022 and 2023, we observe an increase from 67.7% to 71.9% which leads to a 6% higher emission estimate for international shipping.

The difference in reduction for international shipping and all shipping activities may be due to uncertainties related to the identification of international voyages. The MASTER model has recently been improved with a more precise voyage detection method where international voyages are better captured. By comparing an old version of the baseline file from 2022 compared to the baseline file for 2022 generated by an updated and improved method, we observe an increase in the share of distance on international voyages from 62.1% to 67.7% which leads to a 9% higher emission estimate for international shipping. The Fourth IMO GHG study estimated the TtW GHG emissions from international shipping in 2008 to 794 MtCO_2eq which when compared with the total GHG emissions from shipping (excluding fishing) of 1117 MtCO_2eq from the Third IMO GHG Study results in a 71% share for international shipping in 2008 which is the same as the share in 2023.

E.2.2 Seaborne trade growth

Increased shipping activity due to growth in seaborne trade would make the absolute emission targets in 2030 and 2040 more difficult to reach. This seaborne trade growth scenarios used in this study were made in 2020 as part of the Fourth IMO GHG Study This study relies mainly on a low seaborne trade growth scenario projecting 85,000 bill tonne-miles in 2050. In the hight growth scenario used for the sensitivity analysis projects 104 000 bill tonne-miles in 2050. WMU in their literature review (WMU, 2024) report a range of projected seaborne trade from IRENA and IEA's decarbonization scenarios of 100,000 to 150,000 bill tonne-miles. The comparison shows that the assumed growth in seaborne trade in this study is lower than the transport work projections in the literature of (reported by IEA and IRENA). (IEA, 2023b; IRENA, 2021).

E.2.3 Fuel prices and availability

Fuel prices, and in particular low GHG emissions fuels, is one of the most important factors determining the cost impact of decarbonization in shipping. The two key uncertainties that are expected to have a significant impact on fuel prices towards 2050 are:

- *Fuel production costs* which depend on factors such as the cost of feedstock used for fuel production (e.g. electricity, biomass, or natural gas) and CAPEX and OPEX needed for fuel production plants.
- *Fuel demand and supply balances*. For example, there can be local and regional supply shortages as well as global shortages in feedstocks and production capacity to cover the expected increase in demand, which leads to the increased fuel market prices.

The fuel prices used in this study are based on actual fuel prices for 2023 (where available) and a review of literature projecting internally consistent (i.e. for all fuel types within a feedstock) estimated fuel prices for 2030, 2040 and 2050 (see Appendix B.7.1 for more information).

A wide range of fuel price projections per fuel type and feedstock are reported in the literature, often using fuel production cost as a proxy for fuel price. For example, among the sources considered in this study[31], the estimated fuel price in 2050 ranges from 31 to 83 USD/GJ for e-methanol and 23 to 96 USD/GJ for bio-methanol. For ammonia, the price projections range from 21 to 55 USD/GJ for e-ammonia, and from 23 to 38 USD/GJ for blue ammonia in 2050 (CONCAWE, 2022; DNV, 2022b; MMMCZCS, 2024; LR and UMAS, 2020).

In Figure E-2, we compare the range in low GHG emission fuel prices from literature, with the base fuel prices applied in our study in 2050. Generally, our base fuel prices lie on the lower end of the ranges derived from relevant literature. One notable exception is blue LH_2, where only two of the literature sources provide a fuel price estimate.

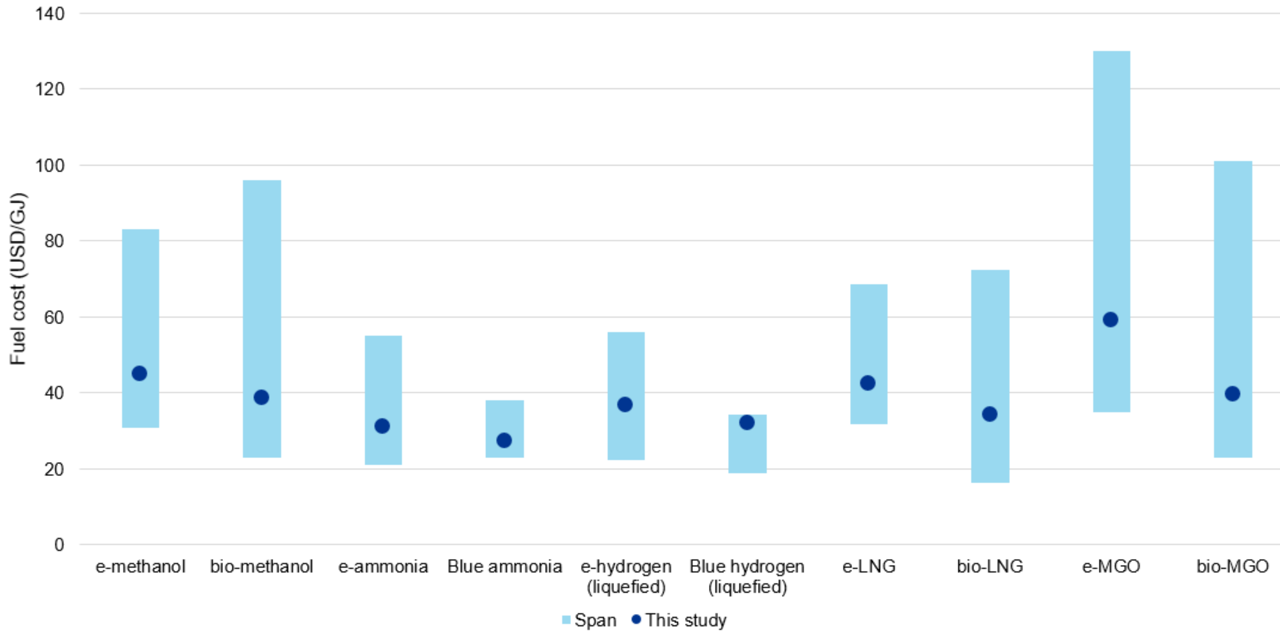


Figure E-2: Range (light-blue boxes) in estimated fuel price from literature, and base fuel price (dark-blue markers) applied in our study for 2050 (CONCAWE, 2022; DNV, 2022b; MMMCZCS, 2024; LR and UMAS, 2020).

The global availability of feedstocks and production capacity may have a significant influence on fuel market prices when the demand exceeds the supply. Ricardo & DNV (2023) estimates a range in low carbon fuel availability, based on feedstock category, of 0.1 – 0.4 EJ advanced biofuels, 0.0 – 1.5 EJ e-fuels and 0.0 – 0.2 EJ blue fuels in 2030, increasing to 0.5 – 7.0 EJ advanced biofuels, 0.2 – 5.0 EJ e-fuels and 0.0 – 2.3 EJ blue fuels in 2050. The estimates for 2030 are based on existing, planned, and announced fuel production projects relevant for the transport sector, while for 2040 and 2050 they are based on projections by energy system forecasting studies, see e.g. BP (2022); IRENA (2022); IEA (2022). A share of the projected fuel supply is assumed to be made available for shipping. Since the total energy use of the fleet in scope is estimated to be between 9.1 to 10.6 EJ in 2030, even with a share of 5% of low carbon fuels, feedstock availability and production capacity could limit supply of low carbon fuels to shipping, and consequently impact market prices.

To account for expected supply limitations, the bio- and blue fuel prices in the scenarios 21 and onwards are adjusted up to the cost of the e-fuel of the same fuel type (see Section 1.2.5 for more information). This study has not considered local or regional supply shortages or other variations in fuel prices for example due to distribution to smaller and remote

[31] For LR and UMAS (2020) we use the upper and lower bound in fuel cost provided for each fuel, not the average between upper and lower bound used to generate the base fuel costs in this study (see Appendix B.7.1 for more information). In addition, we include fuel cost estimates for biofuels from the same study, which take into account supply and demand imbalances that may increase costs. The fuel cost for bio-LNG and bio-MGO in 2050, is based on a similar cost development as provided for bio-methanol in the report.

fuel hubs. The emergence of green shipping corridors could also have a short-term impact on both availability and price of low carbon fuels in certain ports and regions.

Two sensitivity scenarios have been run investigation the impact of 45% lower and 55% higher fuel prices respectively reflecting the lower and higher end on the prices reported in the literature and used is this study, and one sensitivity scenario to investigate the impact of higher bio- and blue fuel feedstock availability, without changing the fuel prices. The results of the sensitivity scenarios are discussed in Section 7.1.

E.2.4 Energy-efficiency measures

Key sources of uncertainty in our modelling of energy-efficiency measures relate to fuel saving potential, cost of implementing measures (CAPEX and OPEX), as well as model uncertainty. Below, we describe each source of uncertainty in more detail.

Model uncertainty

Modelling uncertainties can arise from approximations we make when representing the impact of energy-efficiency measures on the cost intensity and total cost of decarbonization policy measures on the world fleet. The Pathway model does not evaluate the uptake of each single energy-efficiency measure. Instead, the measures are compiled into internally consistent and practical packages based on maturity and compatibility (ship-type and size-segment) with an aggregated cost and reduction potential (see Appendix B.6.4 for more details). We simplify the application of the energy-efficiency packages, by dividing the world fleet into a limited number of major ship-types and size-segments (see Appendix B.1 for more details). Interaction effects have been taken into account by removal of measures with a high degree of interaction effects in the packages. We therefore expect that the uncertainty on the aggregated costs and reduction potentials are less than if adding up the uncertainties of each individual measure.

Fuel saving potential

There are several factors that may impact the fuel saving potential of energy-efficiency measures, including for example: operational profile, age of vessel, ship-type, sea state, loading condition, and human factors. As a result, there is an inherent variation in the reduction potential of each individual energy-efficiency measure applied on specific ships and also the total energy-efficiency improvement. This is evidenced by the significant range in fuel saving potential from energy-efficiency measures reported by several studies, see e.g. (Bouman, 2017; Deng, 2023; Xing, 2020; Ricardo, 2022; IMarEST, 2011).

For all energy-efficiency measures, we have used typical saving potentials that for most measures fall well below the maximum reported savings from literature. For example, for wind-assisted propulsion fuel saving potential may vary from 1% to 50% while for advanced hull performance coating, the range is 1% to 10% (Bouman, 2017; Deng, 2023). Meanwhile, in our study, for an average cargo vessel (depending on segment) we assume a total reduction potential of about 5 to 6% for wind technology propulsion and about 3 to 4% for advanced hull performance coating.

Cost of implementing measures

The cost of implementing energy-efficiency measures includes both investment cost (equipment purchasing cost, installation cost, design and engineering cost) and operational costs (e.g. maintenance and crew training cost). The existing cost data does not provide a complete coverage for each ship type and size category, as some technologies are still undergoing testing and exploration and are only applied on a few ships. Some existing cost data is also not public, as several technology vendors do not want to disclose prices for commercial reasons.

The investment cost for some energy-efficiency measures varies significantly across ship-types. For example, Ricardo (2022) which applies a range of different studies, indicates an investment cost range of 0.1 – 3.4 MUSD for air lubrication systems and 0.3 – 3.0 million USD for wind assisted propulsion systems (different types) for all ship-types and sizes. Looking specifically at an Aframax tanker (80 to 120 000 dwt), Farrukh et al. (2023) reports an investment cost of about 3.5 MUSD for an air lubrication system and 2.8 MUSD for a wind propulsion technology (Flettner rotors) for an Aframax tanker. IMarEST (2011), an earlier study, gives a range of 1.5 – 2.1 MUSD (air lubrication) and 1.1 – 1.4 MUSD (wind propulsion technology) for Aframax tankers.[32] In comparison, for an average newbuild deep-sea tanker in our study, we assume an investment cost of 3 MUSD for an air lubrication system (part of the Enhanced EE package) and 3 MUSD for wind propulsion technology (part of the Advanced EE package).

This study has not run a sensitivity analysis on the cost and reduction potential of energy-efficiency measures and speed reductions. Previous sensitivity analyses of the Pathway model used in this study show only a small impact on cost intensity when changing the capital costs of energy-efficiency measures by 25%, while changing the speed reduction opportunity costs by ±25% resulted in a cost intensity change of about ±1 pp. from 16% in the reference scenario (Longva, et al., 2024; Longva & Sekkesæter, 2021). We have investigated the potential for reduction of total energy use by modelling a sensitivity scenario where all ships in operation will implement 30% speed reduction and retrofits to the Enhanced or Advanced EE package over a five-year period (coinciding with required dry-docking), and all newbuilds will implement the Advanced EE package. Results show a significant reduction on total energy use and cost (see Section 7.1 for more details).

E.2.5 Onboard carbon capture and storage

Onboard carbon capture and subsequent storage (CCS) is an emerging solution which relies not only on the onboard capture and storage units, but also of an infrastructure to receive the carbon from the ship and transport it to a site for permanent storage. As such there are many elements needed for this solution to be applicable for shipping. The main uncertainties related to onboard CCS are listed in Table E-2, comparing the assumptions used in this report with reported number from literature sources.

Table E-2: Uncertainty items related to onboard CCS, and comparison of assumptions used in this study with data from literature.

Item	Assumption used in this study	Range from literature
Technology and CO_2 capture rate	Post-combustion onboard CCS system with amine-based absorption. Maximum 75% CO_2 capture rate. Same assumptions for all applicable fuel types.	54% to 75% (Sustainable Ships, 2023) Higher rates of 90% possible at significant fuel penalty (Luo & Wang, 2017) Up to 82% (MMMCZCS, 2022a)
Technology maturity/availability	TRL 9 for all components in 2030	Amine-based onboard solutions in 2028 to 2030. Other elements reach TRL 9 around 2026. (MMMCZCS, The role of onboard carbon capture in maritime decarbonization, 2022a)

[32] Converted into 2023 US dollars

Item	Assumption used in this study	Range from literature
CAPEX onboard capture unit and storage, including installation.	Capture and storage: 430–680 USD/kW. 6% to 23% of newbuild cost The CO_2 storage tanks/containers should be large enough to contain CO_2 emissions from 25% of the fuel tank capacity.	260–290 EUR/kW (includes retrofit costs) (Sustainable Ships, 2023) 800–1,750 USD/kW (DNV, 2021c) 370–2,750 EUR/kW, 52% to 67% of total costs (CO2ASTS, 2020) 38% to 70% of newbuild cost (MMMCZCS, 2022a)
Retrofitting costs	50% additional CAPEX	~100% (Sustainable Ships, 2023)
Fuel penalty and OPEX	30% fuel penalty at 75% capture rate (CR). We assume that any additional OPEX are captured by the fuel consumption penalty.	No additional fuel penalty up to 50% CR through the use of waste heat and 6% to 9% (using LNG) and 8% to 12% (diesel) at 90% CR (Einbu, et al., 2022) Up to 40% additional energy at 82 % capture rate. 0.5 to 2 MEUR/year in OPEX, which is 30% of the total OPEX including additional fuel costs (MMMCZCS, 2022a)
Lost opportunity costs due to loss of cargo space	Not included.	25,000 to 550,000 EUR/year, 30% of total costs (CO2ASTS, 2020)
Deposit costs including delivery from the ship, transport and permanent storage.	80 USD/tCO_2 captured in 2030, decreasing to 60 USD/tCO_2 in 2050.	5–60 USD/tCO_2 (IEA, 2020b) 60–80 EUR/tCO_2 (Bellona, 2020)
CO_2 leakage during transport and storage-.	All captured CO_2 considered permanently stored.	4% loss of CO_2 during transport and storage (Bellona, 2020)

According to the data in Table E-2, a wide range of capital cost figures are reported. The assumption in this study is in the lower end of the reported data. Many of these reports are for smaller vessels and the reported capital costs for newer and larger vessels are lower indicating a learning and scaling effect. In this study we assume that all elements required for onboard CCS becomes commercially available (TRL at 9) in 2030, including onboard capture and storage systems and onshore reception and storage infrastructure. Until 2030 further R&D and large-scale piloting should reduce costs through learning effects, in line with the cost estimated assumed in this study. We do not include any further learning effects after 2030 for the onboard CCS technology and the CAPEX stays fixed at this level to 2050. We also do not distinguish between costs and effect of the onboard CCS between fuel types such as LNG, methanol and MGO which is reported in several sources that could have an impact on the system through available waste heat and requirement for precleaning the exhaust.

The assumed onboard capture rate in this study is well within reported numbers and should be achievable without incurring significant additional fuel penalties beyond 30% assumed in this study. Significant additional operational expenses are also reported which could be 30% of the total operational costs including the fuel penalty (MMMCZCS, The role of onboard carbon capture in maritime decarbonization, 2022a). The assumption used in this study is that the fuel penalty also covers additional operational costs, and given that the assumed fuel penalty in this study is in the mid to high end of the reported range, the additional operational expenses should also be covered. Similarly, the lost opportunity cost which is not included in the assumption in this study is of a similar order of magnitude.

There is limited data on the cost of transporting and permanently storing CO_2, but the assumption in this study at 60 to 80 USD/tCO_2 is about the same as estimated for the Northern Lights project (Bellona, 2020). Costs for establishing the reception facilities for ships would come in addition to these estimates.

We have investigated the impact of a 50% higher capital, operational and deposit costs of onboard CCS, as well as the removing onboard CCS as an option in the sensitivity analysis. The increase in costs should also cover aspects such as lost cargo space, operational expenses and the uncertainties in capital and deposit costs and the fuel penalty. Removing the option of onboard CCS would reflect a scenario where this technology and required infrastructure failed to be available for shipping. The results of the sensitivity scenarios are discussed in Section 7.1.

E.2.6 Fuel technology costs

The fuel technology cost data encompasses cost figures for various relevant fuels and technologies. The number of data points available for each fuel technology varies considerably, where emerging technologies such as ammonia and methanol dual fuel engines have fewer data points compared to established ones such as LNG dual fuel engines. The maturity levels, measured in Technology Readiness Levels (TRL) and Commercial Readiness Levels (CRL), also differ across the potential fuel technologies (Ricardo, 2023). Internal Combustion Engine (ICE) technologies typically exhibit greater maturity than fuel cell technologies for most fuels. Specifically, LSFO/MGO and LNG/methane lead in ICE technology readiness, followed by methanol, ammonia and hydrogen.

The existing cost data does not provide a complete coverage for each ship type and size category, as many technologies are still undergoing testing and exploration and are only applied on a few ships. To cover the entire spectrum of vessel types and sizes in the modelling, extrapolation of data points has been necessary, which introduces additional uncertainty. As an example, in DNV's database used to establish the assumptions in this study, the data points on the cost of ammonia ICE varies from 388 - 700 USD/kW depending on engine size and type. In our study, we apply a cost ranging from 500 – 650 USD/kW (including fuel supply system). For methanol ICE, the data points range of 300 – 720 USD/kW, applicable for engine sizes between 2 000 – 23 000 kW. In this study, we apply a cost of 360 – 510 USD/kW, depending on size.

Reported costs for fuel storage tanks vary significantly depending on size and fuel tank type. For example, in our database, the cost for LNG tanks varies from 300 – 3500 USD/m^3 (60 USD/GJ – 180 USD/GJ) for tanks with capacity of 2 000 – 6 000 m^3. In this study, we apply additional cost for fuel storage (relative to a conventional fuel oil vessel), ranging from about 60-120 USD/GJ (LNG), 20-30 USD/GJ (methanol), and 40 – 100 USD/GJ (ammonia), depending on tank size.

We anticipate that with increased experience in applying emerging technologies such as ammonia and hydrogen ICE and all fuel cell technologies, costs will decrease following a learning curve. However, the exact rate of this learning curve and the resulting capital costs at the point when the technology becomes commercially available at scale is uncertain.

In the sensitivity analysis we investigated the potential effect if ammonia and hydrogen ICE and fuel cells are accelerated and the technologies become available one to two years earlier and with 20% lower capital costs. The results of the sensitivity scenarios are discussed in Section 7.1.

E.2.7 Modelling the GFI flexibility mechanism

The GFI flexibility mechanism may raise revenues through sale of Remedial Units to ships. Applying an RU and SU price could significantly impact the emission trajectories as ships would prefer to either exceeds the emission reduction requirements if the SU price is set sufficiently high, and conversely fail to achieve the trajectory in case the RU price is set too low. For this reason, we have applied a simplified method for estimated the potential revenue, without changing the emission trajectory. 10% of the emission units are assumed sold to the Revenue body at 20% below the market price and an additional 10% are assumed purchased from the Revenue body at 20% above the market prices. However, ships owner would very likely have preferred to exchange these units in the market at better prices. The amount of revenues and costs from RUs and SUs should only be seen as an indication of the potential of the mechanism but not a modelled outcome.

Using the marginal cost of the last ship to implement a measure to determine a common emission unit exchange price for all ships in a pool showed that many ships implementing measures were overcompensated (i.e. including the compensation led to a total cost decrease). The marginal cost is likely not a very good indicator for the exchange price in a pool as many ships will have lower abatement costs.

The indicated trading volumes in scenarios with a GFI flexibility mechanism assume that all ships optimize the compliance balance and trades emission units at the price in the market. In reality, shipowners with large fleets are likely to arrange for the required compliance balance within their fleet without trading outside the company with other ships. There is also transaction cost with joining such a market, which are not include in our modelling. This implies that the trading volume in a market is likely lower, and that many shipowners can exchange units internally at lower prices. This does not impact the total cost level as all exchange are done between ships, although in our method, the assumed use of RUs and SUs are dependent on the trading volume.

E.2.8 Solutions for reaching net-zero GHG emissions

Internal combustion engines emit a small amount of CH_4 and N_2O during combustion regardless of the fuel, in the order of 1-2 gCO_2eq/MJ. There are currently no known solutions to remove this amount, and since it is not feasible to require all ship to convert to fuels cells, we allow for a small amount (< 2 gCO_2eq/MJ) of GHG emissions in 2050 in the modelling, which leaves a GHG emission of around 20 to 30 $MtCO_2eq$ in 2050. This is not an uncertainty due to the modelling, but a technology gap.

E.2.9 Feasibility of retrofitting and newbuild capacity

The peak annual number of retrofits to other fuel technologies or onboard CCS and to some degree energy-efficiency measures are significant and due to the complexity of retrofitting ships to these technologies it remains uncertain if these numbers are feasible. For reference, the number of retrofits to scrubbers peaked at more than 2400 in 2019 (AFI, 2024) which is exceeded in more than half of the scenarios. It should be noted that retrofitting technologies such as ammonia and onboard CCS may be more extensive than retrofitting to scrubbers. Lloyds' Register (2023) indicates a current capacity of 308 fuel retrofits per year. The implication if these retrofit rates are not feasible is that more ships have to run on drop-in fuels such as bio-MGO and e-MGO, potentially resulting in higher costs.

E.2.10 Measures not included

Several known potential emission reduction measures have not been included in the modelling as they not yet considered mature, and the uncertainty is too large on cost and potential. These include onboard nuclear power, liquid organic hydrogen carriers (LOHC), wave powering of ships, ballast free ships, fully wind powered, autonomous vessels.

The emergence and technical and commercial readiness of these measures are highly uncertainty but could potentially have a significant impact on the cost for reducing GHG emissions.

E.2.11 Other uncertainties

The modelling does not include a potential premium that cargo owner could be willing to pay for low GHG emission services. Such services are being offered by several shipping companies and could increase in the coming years (DNV, 2023). However, the level of the premium (i.e. the willingness to pay) and the volume is uncertain. A premium would decrease the cost for the shipping company. However, when shipping moves toward net-zero in 2050, the effect would be reduced and eventually eliminated as all ships need to reduce emissions and the premium has to be paid for all shipping services.

Using shore power while in port can reduce emissions both in a TtW and, depending on the production of the electricity, a WtW perspective. Many ports are building up the infrastructure and mandating ships to use shore power (e.g. in California and in the EU). IEA (2020) reports that shore power is available in more than 80 ports worldwide.

This study assumes that the use of shore power increases from 1% of total energy use from auxiliary engines in 2023 to 5% in 2050. This is in the lower end of an estimated potential to replace 30 to 70% of energy use at berth (Ricardo & DNV, 2023; DNV GL, 2017). A higher uptake would reduce the need to low GHG emission fuels and likely reduce costs, depending on the cost of shore electricity delivered to the ship.

APPENDIX F

Quality assurance and control

In this appendix, we present the quality assurance and control processes applied in the project.

The DNV Management System has been applied throughout this project, which is an integrated quality, HSE (health, safety and environment) and business administration management system. DNV's Management System is certified to ISO 9001, ISO 14001, ISO/IEC 27001 and ISO 45001. All certificates are issued by an accredited certification body.

The project organizational structure consisted of a project team, led by a project manager which reported to the IMO and the Steering Committee, and a Quality Assurance office independent from the project team. The project's QA office has been responsible for organizing the quality assurance of the work in support of the Project Manager. It was responsible for controlling all documents and deliverables and organizing effective and efficient review of deliverables by internal reviews. The review process is illustrated in Figure F-1.

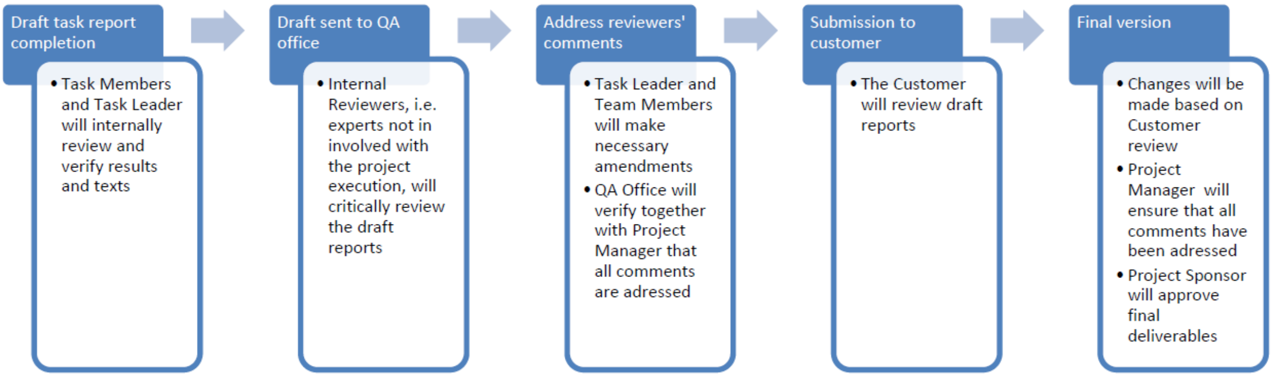


Figure F-1: General review process of work and deliverables in the project.

The project was further divided into three tasks focused on specific topics with a designated Task Lead for each subtask. The Task Leaders were subject matter experts in the topic of each Task and main responsible for ensuring the quality of the work carried out in their Task. Each Task Leader has also the relevant technical expertise to oversee the quality of the work done by the Task Members. Results were discussed periodically at project team meetings and actions were taken as necessary to improve and maintain quality.

The project team members working in each task were responsible for undertaking their parts of the project work within the schedule and budget limitations specified. Each team member conducted self-checks, verification, and approvals of all reports, and was an integral part of performing the work prior to verification. Everyone involved in a project, or an activity has the obligation to check his/her own work to remove mistakes and rule out incorrect results. Verification is done to confirm that the results of an assigned Task are conforming to the specified requirements.

As the analysis required further development and tailoring of the GHG Pathway model software tool, special efforts were taken to ensure sufficient quality of the software updates needed for this project. In general, all software changes have been tracked with a version control tool called GIT, which is widely used in the software industry. All software changes have also been peer reviewed, tested and verified within the software developer team throughout the development process. After all changes has been evaluated and accepted individually, final integration tests were carried out and peer reviewed to evaluate the final modelling results.

About DNV

DNV is the independent expert in risk management and assurance, operating in more than 100 countries. Through its broad experience and deep expertise DNV advances safety and sustainable performance, sets industry benchmarks, and inspires and invents solutions.

Whether assessing a new ship design, optimizing the performance of a wind farm, analysing sensor data from a gas pipeline or certifying a food company’s supply chain, DNV enables its customers and their stakeholders to make critical decisions with confidence.

Driven by its purpose, to safeguard life, property, and the environment, DNV helps tackle the challenges and global transformations facing its customers and the world today and is a trusted voice for many of the world’s most successful and forward-thinking companies.