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Supplementary information

Role of biofuels, electro-fuels, and blue fuels for shipping: Environmental and economic life cycle considerations.

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This supplementary information covers details on the method, materials, case study vessels, technical descriptions of technologies, life cycle inventory data, and other detailed results from life cycle assessment.

A combined assessment of environmental and economic performance from a life cycle perspective is performed in the study. As explained in the main article an integrated life cycle framework adopted from study [1] is used. The pLCA used in this study is used to assess emerging technologies when the knowledge is sparse [2] and considers the environmental performance at a time in the future when the technology is likely to get developed. Similarly, LCC is a tool for assessing the economic dimension of sustainability and is capable of supporting decision-making at different stages of the life cycle, and also aligned with the LCA study with a life cycle thinking [1]. For the LCC and pLCA evaluation to be conducted without inconsistencies during the inventory assessment phase, it is crucial to consistently choose parameters for each technology/process, such as efficiency, energy use, and material consumption. The problem with using common inventories is that the flow parameters differ for cost and environmental impact assessments. To accomplish this, all parameters are calculated using Python codes written to perform cost calculation and integrate impact assessment calculation in openLCA.

Figure S 1: The midpoint indicators used in this study for impact assessment.

The midpoint level is used for the impact assessment and the sixth assessment report of the Intergovernmental Panel on Climate Change (IPCC) is used for calculating GWP100 [3] and other impact categories are assessed based on LCIA methods according to Environmental Footprint (EF) 3.0 recommended by the European Commission's Joint Research Centre [4] as shown in Figure 8.

S1 Method

S1.1 Size calculation

The propulsion system for each vessel is calculated based on the present installed capacity of the ships. Based on the present installed capacity the power required from the energy efficiency of components in the current installation. The components vary on the type of technical system considered in the study, termed configuration in the main article. Figure S2 shows the sizing of the component for different configurations.

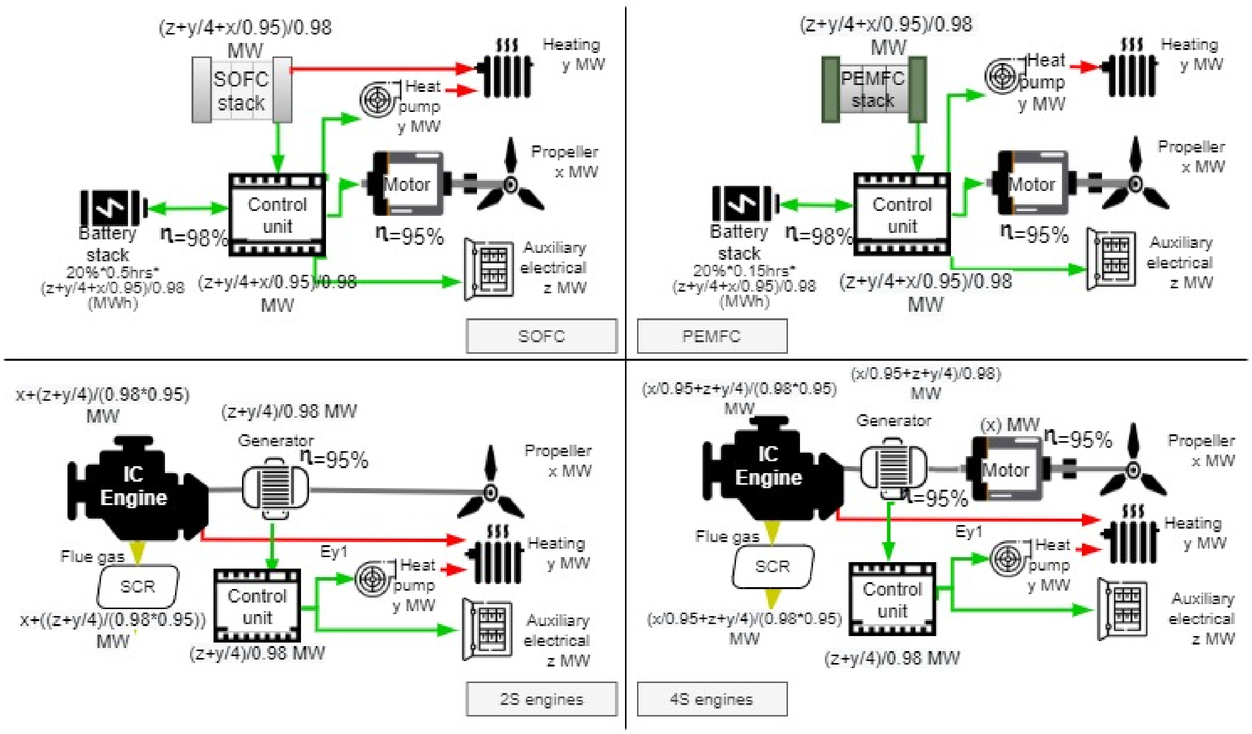

Figure S 2: The calculations for the sizing of the component for different configurations.

S1.2 Fuel production cost.

The cost of e-fuels, biofuels, and blue fuels (CF_{LC}) is calculated by dividing it into capex cost, fixed OPEX cost, and variable OPEX. The capex cost (annualized capital cost) is calculated by converting the total investment to net present value using the capital recovery factor (crf) mentioned in the main article section 2.2.4. The investment costs for different processes in the fuel production pathways are taken from the literature review and the assumed costs are given in Table 4 of the main article. The higher and lower limits of the investment cost considered in the uncertainty analysis are given in Table S 6. The maximum fuel production capacity for all fuels assumed is 10000GJ/day and the investment cost is calculated towards these fuel production capacities using specific investment costs mentioned in Table 4 to get the total investment cost. The CAPEX is calculated for each of the production pathways separately. The same method is used for calculating the CAPEX for DAC and ASU, however the production capacity assumed is 50t/day. CAPEX varies usually with the economy of scale, however that is not considered. The fixed OPEX is calculated from the investment cost as these are yearly costs and are assumed to be directly related to the investment cost. These are also listed in Table 4. The variable operation cost is associated with the costs linked to the feedstock price e.g. energy, material, consumables, etc… which varies with the production output and also the process efficiencies.

S1.3 Replacements

The number of replacements is determined by comparing the life time of components and ships ($N_{repl,i}$). The degradation of FCs is approximated at 0.4 percent per 1000 hours of operation, with the FC being deemed replaceable at the point of capacity loss of 20 percent. In uncertainty analysis, a higher degradation of 0.6 percent per 1000 hours of operation is considered. For battery replacement, a simplified assumption of ten years with a 60% depth of charge (DOC) as numerous factors influencing battery life (e.g., usage duration, charging cycles, and battery charging technology) are unknown and will only become apparent during the detailed design phase. SCR life is considered as 15 years as a simplified assumption for replacement.

S1.4 Normalization and weighting

The environmental impact results in the article are converted to a single score based on the normalization factors and weighing factors in Table S1. The global normalization factors (NFs) are taken from EF 3.0 [5]. Global NFs represent the relevance of the total environmental impact in a certain category in a global context [5]. The weighting factors are taken from the weighing approach suggested in EF 3.0 [6].

Table S 1:Normalization factors and weighing factors used in the study.

	Normalization Factors [5]	Weighing Factors [6]
Acidification	5.56E+01	6.2
Ecotoxicity, freshwater	4.27E+04	1.92
Eutrophication, freshwater	1.61E+00	2.8
Eutrophication, marine	1.95E+01	2.96
Eutrophication, terrestrial	1.77E+02	3.71
Human toxicity, cancer	1.69E-05	2.13
Human toxicity, non-cancer	2.30E-04	1.84
Ionizing radiation	4.22E+03	5.01
Land use	8.20E+05	7.94
Ozone depletion	5.36E-02	6.31
Particulate matter	5.95E-04	8.96
Photochemical ozone formation	4.06E+01	4.78
Resource use, fossils	6.50E+04	8.32
Resource use, minerals & metals	6.37E-02	7.55
Water use	1.15E+04	8.51
IPCC 2021 GWP 100	8.10E+03	21.06

S1.5 IAM prospective scenarios

SSP scenarios are developed by IAM community to structure the uncertainty around socio-economic developments such as national GDP, education and demographics. In this study SSP2 'Middle-of-the-Road' socio-economic pathway is considered, and this pathway describes development in line with historically observed. Table S2 summarize the IAM prospective scenarios considered in the study and is adopted from [7, 8]

Table S 2: IAM prospective scenarios considered in the study [7, 8].

SSP/RCP scenario	GMST increase by 2100	Society/economic trend	Climate policy	Model name
SSP2-None	~2.5 °C	Extrapolation from historical developments.	Nationally Determined Contributions (NDCs).	REMIND SSP2-NDC
SSP2-RCP2.6	1.6-1.8 °C	Extrapolation from historical developments.	Paris Agreement objective.	REMIND SSP2-PkBudg1150
SSP2-RCP1.9	1.2-1.4 °C	Extrapolation from historical developments.	Paris Agreement objective.	REMIND SSP2-PkBudg500

S2 Technological system description

S2.1 Fuel production

All e-fuel production pathways except for e-methane are based on our previous studies [9, 10].

E-methane can be produced from electricity from renewable, e-hydrogen, and captured CO_2 [11]. The study assumes that methane is produced by the Sabatier reaction process, which requires 2.939 kg of carbon dioxide, 0.506 kg of hydrogen, and 0.33 kWh of electricity and heat [11]. Hydrogen is assumed to come from electrolysis and CO_2 is assumed from DAC as modeled in our previous studies [9, 10]. Liquefaction of methane is assumed to require 0.292 kWh of electricity per kg of methane [12]. The infrastructure for the e-methane synthesis is adopted from [13] and for liquefaction is from Ecoinvent 3.8.

Liquid blue-hydrogen is generated through the process of methane reforming of natural gas, along with CO2 capture and storage. Methane reforming of natural gas can be achieved through either steam methane reforming or auto-thermal reforming. Simulation results from the study [14] show that auto-thermal reforming can attain high CO_2 capture rates, hence auto thermal reforming is considered. Amine-based absorption is being considered for CO_2 capture technology with a 90% capture rate. The inventory data for blue hydrogen is sourced from the LCA study [14]. The data for natural gas is taken from Ecoinvent 3.8 (market group for natural gas, high pressure | natural gas, high pressure). 1.5% methane leakage is considered in the supply chain for natural gas till the production plant. The captured CO_2 is transported from the facilities to the port, then transferred by tanker to an injection site located 1000 km away from the port, where it is injected into geological storage. Inventory data for CO_2 transport and injection is extracted from the study [15]. The infrastructure for the blue hydrogen is considered from [14] and from Ecoinvent 3.8. The hydrogen liquefaction is modeled as in previous studies [9, 10].

Blue-ammonia is produced from the reforming of methane from natural gas and combined with CO_2 capture and storage similar to blue hydrogen. However, additional energy is required for the Haber Bosch process, and operation of ASU is assumed from renewable electricity. Parameters for auto-thermal reforming, CO_2 capture technology, CO_2 transport, and storage are assumed similar to the blue hydrogen production mentioned above. The infrastructure for the blue ammonia production plant is adopted from the study [16].

Bio-methanol is assumed to be produced from biomass using biomass gasification technology where biomass is converted to syngas and is taken from the study[17] and summary is shown in Figure 3. Residual biomass from the sustainably managed forest is assumed as feedstock for gasification where the inventory data is taken from Ecoinvent. Dried biomass is subjected to gasification with steam in a high-pressure gasifier. Heat pipes transfer the heat from the combustor to the gasifier to facilitate the endothermic steam gasification reactions. Char, a byproduct of the gasification process, is burned along with extra wood in the combustion chamber using air. The syngas produced is nearly nitrogen-free due to the separation of the two chambers. It is assumed that for processing 1 kg dry biomass 0.5 kg water, 0.33kg Olivine (bed material), 0.002 kg ammonia, and 0.0008 kg sulphur are required [18, 19]. The raw syngas is treated using acid gas removal and waste gas shift and are sent to the methanol synthesis plant for production of the methanol. It is assumed that except for the carbon that flows into the methanol, all remaining carbon in the biomass is emitted as CO_2. The overall efficiency of the process is assumed 60% and total biomass needed is 1.79 kg per tonne of biomethanol.

Liquid bio-methane is also produced similarly to bio-methanol except that the treated syngas is sent to methanation for the production of methane gas. Similar to bio-methanol it is assumed that the remaining carbon in the biomass other than that flows into methane is emitted as CO_2. The overall efficiency of the process is assumed 60% and total biomass needed is 4.50 kg per tonne of biomethane. bio-methane is then upgraded and liquefied (same process as mentioned in e-methane) to produce liquid biomethane.

Liquid bio-hydrogen is also produced using similar process as shown in Figure S3. However, syngas is treated differently at acid gas removal and waste gas shift where the H_2 concentration in treated syngas is maximised during syngas treatment. Afterwards, the treated syngas containing raw H_2 is purified and separated in pressure swing adsorption to obtain hydrogen with a purity of >99.97% [17]. The tail gas from pressure swing adsorption is combusted with air in the gasification combustion chamber to recover energy. The carbon in the biomass is assumed to be emitted as CO_2 into atmosphere. The overall efficiency of the process is assumed 55% and total biomass needed is 11.79 kg per tonne of biohydrogen. The hydrogen is then liquified similar to the liquid e-hydrogen which is mentioned in previous studies [9, 10].

Bio-ammonia is assumed to be produced from bio-hydrogen and nitrogen using Haber Bosch process as shown in Figure x. The electricity required for Haber Bosch process and ASU is assumed similar to the e-ammonia pathway with only difference that hydrogen comes from biomass gasification route. The infrastructure for Haber Bosch and the ASU is also same from previous study[9, 10].

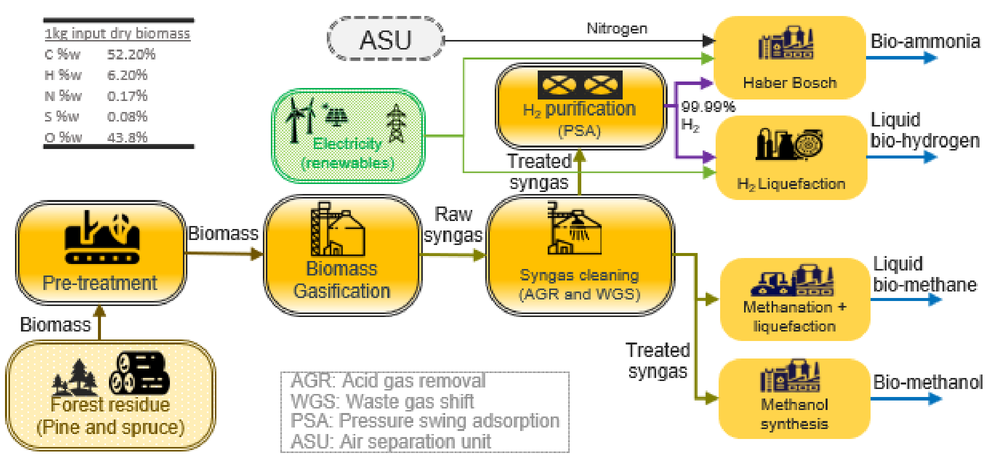

Figure S 3: Biofuel production pathway considered in the study.

S2.3 Power train system

Engine and SCR: Engine configuration depends on the type of ship and also on the fuel type. Vessel operating long distance are often 2 stroke engine with slow speed, 4S engines with medium speed engines, and diesel electric which is usually 4S engines with generator and electric motors. The material data for the engine, selective catalytic reduction, batteries, electric motor, PEMFC, SOFC are assumed same as in our previous study [9, 10]. MeOHICE is a propulsion option fueled by methanol in a dual-fuel engine and the pilot fuel is MGO. To meet the Tier III requirement, 2 stroke engine requires SCR as NOx abatement technology. 4S engine have lesser NOx emissions than 4S engine but still requires SCR for NOx abatement system however need lesser urea. The NH3ICE and H2 ICE are also dual fuel engine which also includes gas injection system, and the pilot fuel is MGO. The emissions are assumed based on stoichiometric efficiencies, percentage of pilot fuel, and also comparing to gas engine parameters. The exhaust of NH3 ICEs contains unburned NH3 and NOx emissions because of fuel-bound nitrogen [32, 33]. The SCR system can convert NOx emissions by utilizing NH3 in the exhaust. Experts recommend that fine-tuning the engine to optimize NH3 combustion can effectively reduce NOx in SCR and meet tier III standards. It is assumed that the NH3 and NOx emissions post-SCR would be comparable to emissions from existing SCR systems. An uncertainty analysis is conducted in this study to assess the impact of nitrous oxide emissions on GWP. For methane and LNG, low pressure dual fuel (LPDF) engine is considered technology for 4S engine, SCR is not required for this type of engine. However, for 2S LNG/methane engine SCR is considered for meeting tier III requirement. Methane slip is main concern for methane/LNG engine and uncertainty analysis is conducted in this study to assess the impact of methane slip on GWP.

S3 Ship details

Table S 3: Statistics of the ship used in the study

		Bulk carriers	Container ships	Cruise ships
	Row Labels	25000 - 49999 GT	50000 - 99999 GT	>= 100000 GT
Average statistics	**No of IMO's**	6,434	1,049	103
	Avg ME kw Installed	8,990	52,650	67,300
	Avg design speed (Knop)	14.2	24.1	21.1
	Avg DWT	65,500	85,670	
	Avg gross tonnes	36,740	75,790	143,550
Average time in each mode	**Maneuvering**	5.8 %	8.4 %	6.3 %
	Harbour	44.5 %	30.5 %	35.2 %
	At sea	49.7 %	61.1 %	58.5 %
Total Operations	**Sum of Distance (NM)**	562,833,937,000	158,802,147,000	15,210,943,000
	Sum of AIS Hours	52,236,000	8,779,000	877,000
FUEL totals per consumer (tonne)	**Sum of (Total Fuel Consumption (MetricTon)**	28,107,100	20,158,000	3,737,300
	Sum of (ME Fuel Consumption (MetricTon)	23,994,900	16,182,800	2,940,900
	Sum of (AE Fuel Consumption (MetricTon)	3,339,100	3,562,300	702,300
	Sum of (Boiler Fuel Consumption (MetricTon)	773,100	412,900	94,200
Fuel totals per mode (tonne)	**At sea (ME+AE)**	24,845,100	17,417,000	3,281,200
	Harbour (AE+B)	2,598,800	1,800,000	348,900
	Maneuvering (ME+AE+B)	663,200	941,000	107,200

S4 Summary of Technological Readiness Level

Summary of technology readiness level (TRL) of different technologies are given in Figure S4. It is crucial to acknowledge that technologies are currently at different stages of readiness, and the advancement in technological development is influenced by investment choices. In the assessment, it is assumed that all technologies will have reached maturity by 2035. This assumption is crucial in conducting a prospective life cycle assessment, as it allows for a comprehensive understanding of the impact of each technology when fully developed. This understanding is essential in making informed decisions regarding investment.

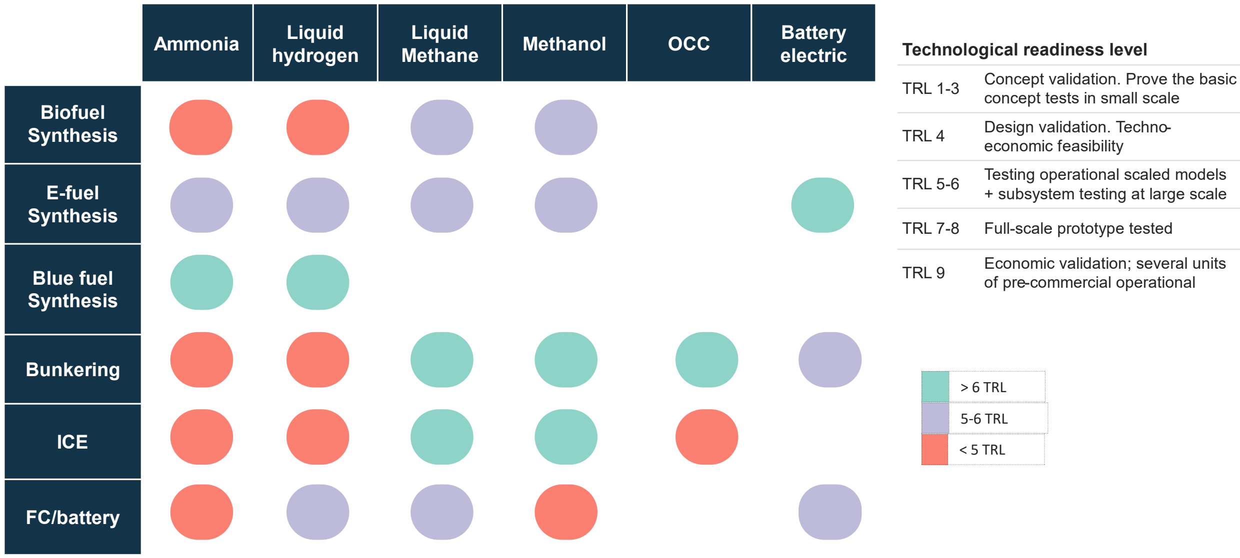

Figure S 4: Technological readiness level of different pathways

S5 Uncertainty analysis

As the evaluated technologies are immature, performance parameters may undergo different changes as they mature. We ran a Monte Carlo simulation uncertainty analysis to see how results would change if the parameters were changed compared to the base assumptions could have affected the outcomes. A developing scenario method is used (Figure S2) where ranges of parameters in different development pathways are considered. In the article, the lower range is named the pessimistic scenario, and the high range is the optimistic scenario. For base value, the parameter in between is considered is considered. The values for these parameters are considered from the literature review. Tables S3 to S6 show ranges of the values for different key parameters considered in the study. Apart from the parameters listed in the Tables, emissions from the ammonia and LNG/LMG engine operation are also varied as given below.

- Ammonia engines: Nitrous oxide emission range min 0.03 max 0.2g/kWh
- LNG/LMG 2S engines cruising: Methane emission range min 0.1; max 0.5g/kWh
- LNG/LMG 2S engines maneuvering: Methane emission range min 1; max 10g/kWh
- LNG/LMG 4S engines cruising: Methane emission range min 2; max 6g/kWh
- LNG/LMG 4S engines maneuvering: Methane emission range min 10; max 25g/kWh

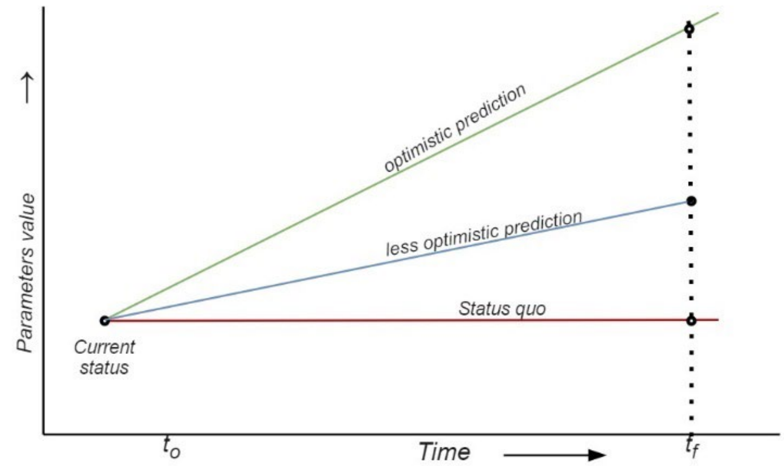

Figure S 5:Different development pathways possible for emerging technologies [1]

Table S 4: Ship parameters considered in uncertainity analysis.

Parameter	unit	Base value	Pessimistic value	Optimistic value	Ref
2SICE_eff_cru		0.48	0.46	0.5	[9, 20]¤
2SICE_NH3_eff_cru		0.46	0.44	0.48	[9, 20]¤
4SICE_eff_cru		0.46	0.44	0.48	[9, 20]¤
4SICE_NH3_eff_cru		0.44	0.42	0.46	[9, 20]¤
2SICE_eff_man		0.42	0.4	0.44	[9, 20]¤
2SICE_NH3_eff_man		0.4	0.38	0.42	[9, 20]¤
4SICE_eff_man		0.4	0.38	0.42	[9, 20]¤
4SICE_NH3_eff_man		0.38	0.36	0.4	[9, 20]¤
OCC_el_MGO_2S	kWh/kWhoutengine	0.059	0.06	0.058	[21-24]¤
OCC_el_LNG_2S	kWh/kWhoutengine	0.03	0.031	0.029	[21-24]¤
OCC_el_MGO_4S	kWh/kWhoutengine	0.062	0.064	0.06	[21-24]¤
OCC_el_LNG_4S	kWh/kWhoutengine	0.029	0.03	0.028	[21-24]¤
OCC_th_MGO_2S	kWh/kWhoutengine	0.19	0.18	0.2	[21-24]¤
OCC_th_LNG_2S	kWh/kWhoutengine	0.11	0.1	0.12	[21-24]¤
OCC_th_MGO_4S	kWh/kWhoutengine	0.15	0.14	0.16	[21-24]¤
OCC_th_LNG_4S	kWh/kWhoutengine	0.06	0.06	0.07	[21-24]¤
PEMFC_eff		0.55	0.53	0.57	[9, 10]
SOFC_NH3_eff		0.58	0.56	0.6	[9, 10]
SOFC_CH4_eff		0.6	0.58	0.62	[25]¤
SOFC_MeOH_eff		0.58	0.56	0.6	[9, 10]
2SMGO_CCS_capacity	kgCO2/h/kW	0.57	0.59	0.55	*
2SLNG_CCS_capacity	kgCO2/h/kW	0.44	0.46	0.42	*
4SMGO_CCS_capacity	kgCO2/h/kW	0.59	0.61	0.57	*
4SLNG_CCS_capacity	kgCO2/h/kW	0.44	0.46	0.42	*

**Own calculations, ¤adapted*

Table S 5: Costs associated with component and fuel distribution considered in uncertainty analysis

Parameter	unit	Base value	Pessimistic value	Optimistic value	Ref
Battery cost	€/kWh	200	500	150	[9]
OCC cost	€/kgCO2/h	2000	1600	3500	[21, 22]
ICE opex cost	% annual	0.02	0.02	0.02	[9]
NH3_distribution	€/GJ	1.20	1.20	1.20	[26]
MeOH_distribution	€/GJ	0.60	0.60	0.60	[26]
LH2_distribution	€/GJ	14.00	14.00	14.00	[26]
LNG_distribution	€/GJ	4.69	4.69	4.69	[26]
MGO_distribution	€/GJ	0.20	0.20	0.20	[26]
Elec_distribution	€/GJ	10.20	10.20	10.20	[27]

Table S 6: Parameters of fuel production pathways used in uncertainty analysis.

Parameter	unit	Base value	Pessimistic value	Optimistic value	Ref
Electricity: DAC	kWh/kgCO2	0.875	1.23	0.6	[28, 29]
Electricity: Alkaline electrolysis	kWh/kg fuel	50	53	47	[30, 31]
KOH consumption: AEC	g/kgfuel	1.25	2	1	[30]
Water consumption: Electrolysis	kg/kgfuel	10	10	9	[10]
Electricity: H2 liquefaction	kWh/kg fuel	7	8	6.5	[32]
Electricity: NH3 synthesis	kWh/kg fuel	0.472	0.874	0.333	[31, 33, 34]
Electricity: eMeOH synthesis	kWh/kg fuel	0.858	1.292	0.437	[31, 35, 36]
Electricity: eMG synthesis	kWh/kg fuel	0.440	0.960	0.330	[11, 37]
Electricity: BioH2 synthesis	kWh/kg fuel	2.2401	2.4643	2.0539	[17, 38-40]
Biomass: BioH2 synthesis	kg/kg fuel	11.79	12.97	10.81	[17, 38-40]
Water consumption: BioH2 synthesis	kg/kgfuel	5.895	6.485	5.405	[17, 38-40]
Electricity: BioMeOH synthesis	kWh/kg fuel	0.3401	0.3724	0.3135	[18, 19, 41]
Biomass: BioMeOH synthesis	kg/kg fuel	1.79	1.96	1.65	[18, 19, 41]
Water consumption: BioMeOH synthesis	kg/kgfuel	0.895	0.98	0.825	[18, 19, 41]
Electricity: BioLMG synthesis	kWh/kg fuel	0.856	0.934	0.790	[18, 42]
Biomass: BioLMG synthesis	kg/kg fuel	4.505	4.914	4.158	[18, 42]
Electricity: upgrading and liquefaction Methane	kWh/kg fuel	0.478	0.515	0.440	[12, 40]
Water consumption: BioLMG	kg/kgfuel	2.252	2.457	2.079	[18, 42]
Electricity: BlueNH3	kWh/kg fuel	0.957	1.3	0.957	[16, 34, 43]
Natural gas: BlueNH3	MMBTU/kg fuel	0.0278731	0.044776119	0.027873134	[16, 34, 43]
Electricity: BlueH2	kWh/kg fuel	-0.4164	-0.4164	-0.4164	[14, 17]
Natural gas: BlueH2	MMBTU/kg fuel	0.1462836	0.146283582	0.146283582	[14, 17]
Water consumption: BlueNH3	kg/kgfuel	4.10421	4.10421	4.10421	[16, 34, 43]
MEA consumption: BlueNH3	kg/kgfuel	0.01755	0.01755	0.01755	[16, 34, 43]
Activated carbon: BlueNH3	kg/kgfuel	0.08775	0.08775	0.08775	[16, 34, 43]
CO_2 transportation and storage: BlueNH3	kg/kgfuel	1.17	1.17	1.17	[16, 34, 43]
Water consumption: BlueH2	kg/kgfuel	7.536	7.536	7.536	[14, 17]
CO_2 transportation and storage: BlueH2	kg/kgfuel	6.1536	6.1536	6.1536	[14, 17]

Table S 7: Cost parameters of the fuel production considered in the uncertainty analysis

Parameter	unit	Base value	Pessimistic value	Optimistic value	Ref
Interest rate	%	0.05	0.10	0.03	*
Electricity cost	€/MWh	50	70	30	*
Natural gas cost	€/MMBTU	8	12	4	*
Biomass cost	€/tdrybio	130	200	50	*
MGO price	€/tMGO	600	800	500	*
Capacity factor	%	0.90	0.85	0.95	*
Technical life time	years	30	25	40	*
CO2 transportation and storage	€/tCO2	20	25	10	[44]
ASU Plant investment cost	k€/(tN2/day)	87.58	87.58	87.58	[34]
ASU Fixed O&M cost	% CAPEX	0.05	0.05	0.05	[34]
DAC Plant investment cost	k€/(tCO2/day)	270	300	200	[29, 45]
DAC Fixed O&M cost	% CAPEX	0.05	0.05	0.05	[29]
Technical life time Alkaline	years	25	20	30	[10]
Electrolysis Plant investment cost	€/kWel	460	570	350	[10]
Electrolysis Fixed O&M cost	% CAPEX	0.05	0.05	0.05	[10]
LH2 Plant investment cost	€/tLH2/day	2100000	2250000	2100000	[32, 46]
LH2 Fixed plant O&M cost	% CAPEX	0.04	0.04	0.04	[46]
NH3 N2 consumption	kg/kgfuel	0.823	0.823	0.823	*
NH3 Plant investment cost	€/tfuelpd	174000	215000	160000	[31, 33, 34]
NH3 Fixed O&M cost	% CAPEX	0.05	0.05	0.05	[9]
eMeOH Plant investment cost	€/tfuelpd	69100	138200	46100	[31, 35, 36]
eMeOH Fixed O&M cost	% CAPEX	0.05	0.05	0.05	[9]
eMG plant investment cost	€/tfuelpd	145000	260000	75000	[11, 37]
Methane liquefaction investment cost	€/tfuelpd	64000	66000	60000	[37]
eLMG Fixed O&M cost	% CAPEX	0.05	0.05	0.05	[37]
BioH2 plant investment cost	€/tfuelpd	2777000	3194000	2500000	[20, 37, 47]
BioH2 Fixed O&M cost	% CAPEX	0.05	0.05	0.05	[20, 37, 47]
BioMeOH gasification & synthesis plant investment cost	€/tfuelpd	529000	900000	414000	[18, 19, 41]
BioMeOH Fixed O&M cost	% CAPEX	0.05	0.05	0.05	[18, 19, 37, 41]
BioMG gasification and synthesis plant investment cost	€/tfuelpd	1157000	1331000	1041000	[18, 37, 42]
BioLMG Fixed O&M cost	% CAPEX	0.05	0.05	0.05	[37]
LNG price	€/tLNG	500	800	400	*

BlueH2 Plant investment cost	€/tfuelpd	250000	400000	230000	[44, 48]
BlueH2 Fixed O&M cost	% CAPEX	0.05	0.05	0.05	[44, 48]
BlueNH3 Plant investment cost	€/tfuelpd	325000	325000	325000	[16, 34, 43]
BlueNH3 Fixed O&M cost	% CAPEX	0.04	0.04	0.04	[16, 34, 43]
**Own assumptions/calculations based on market*					

Weight of the components used to calculate the capacity loss is shown in Table S8.

Table S 8: The specific weight and volume of components used for the calculation of the weight and volume of power train components including fuel storage.

	m3/kW	*kg/kW*
Engine	*0.0229*	*13*
PEMFC	*0.0067*	*3.75*
SOFC	*0.15*	*30*
Alternator (kW)	*0.005*	*2.5*
Electric motor (kW)	*0.005*	*2.5*
Heat pump (kW)	*0.0657072*	*2.5*
Gear box (kW)	*0.00125*	*0.8*
Battery (kWh)	*0.002*	*5*
LNG OCC (KW)	*0.0374*	*14.96*
MGO OCC (KW)	*0.04845*	*19.38*
	m3/GJ	*kg/GJ (with fuel)*
NH3 (liquid) tank	*0.096083631*	*68.64173726*
CH2 (700 bar) tank	*0.417899486*	*190.5723906*
LH2 tank	*0.158730159*	*64.20634921*
LMG tank	*0.061387354*	*34.42602824*
MeOH tank	*0.069513958*	*57.54292295*
MGO tank	*0.02*	*27.25788027*
LNG tank	*0.061387354*	*35.25936157*
CO2 tank (/tonne CO2)*	*1.1*	*1290*

S5 Results

S5.1 Environmental impacts

The LCA results for impact categories other than GWP are shown in figures S5 to S19 for bulk carrier. All results including life cycle cost, life cycle impacts for all categories for all assessed ship types are attached in supplementary excel files.

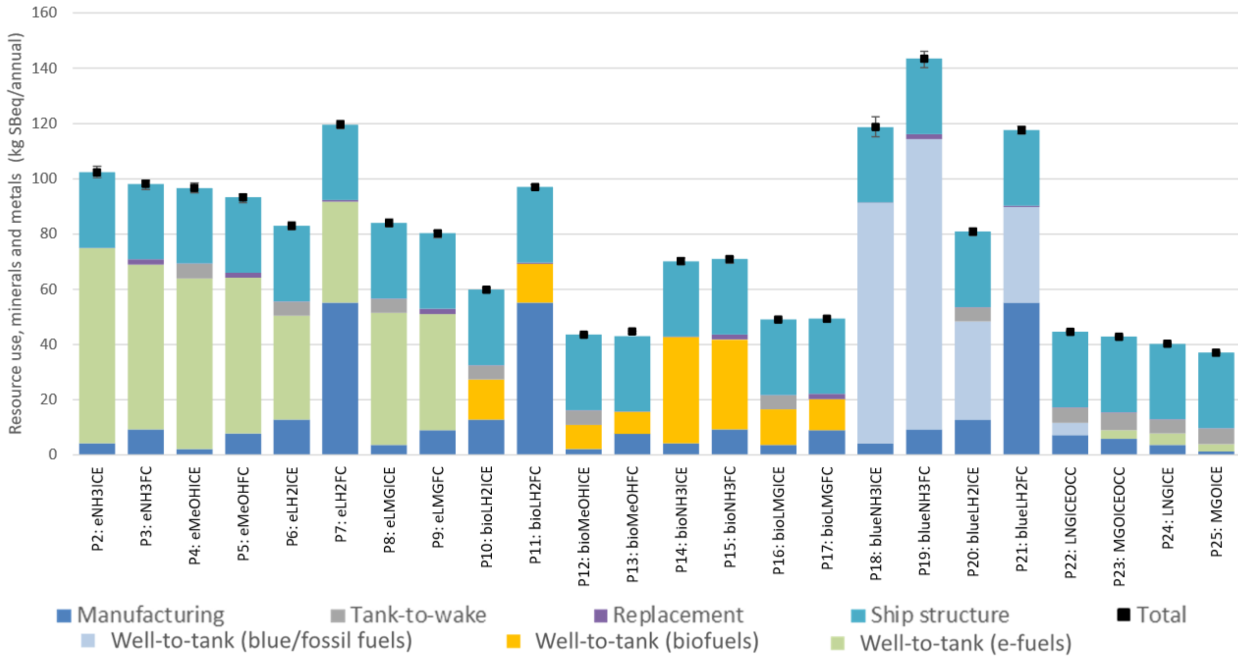

Figure S 6: LCA result on impact category resource use, minerals and metals

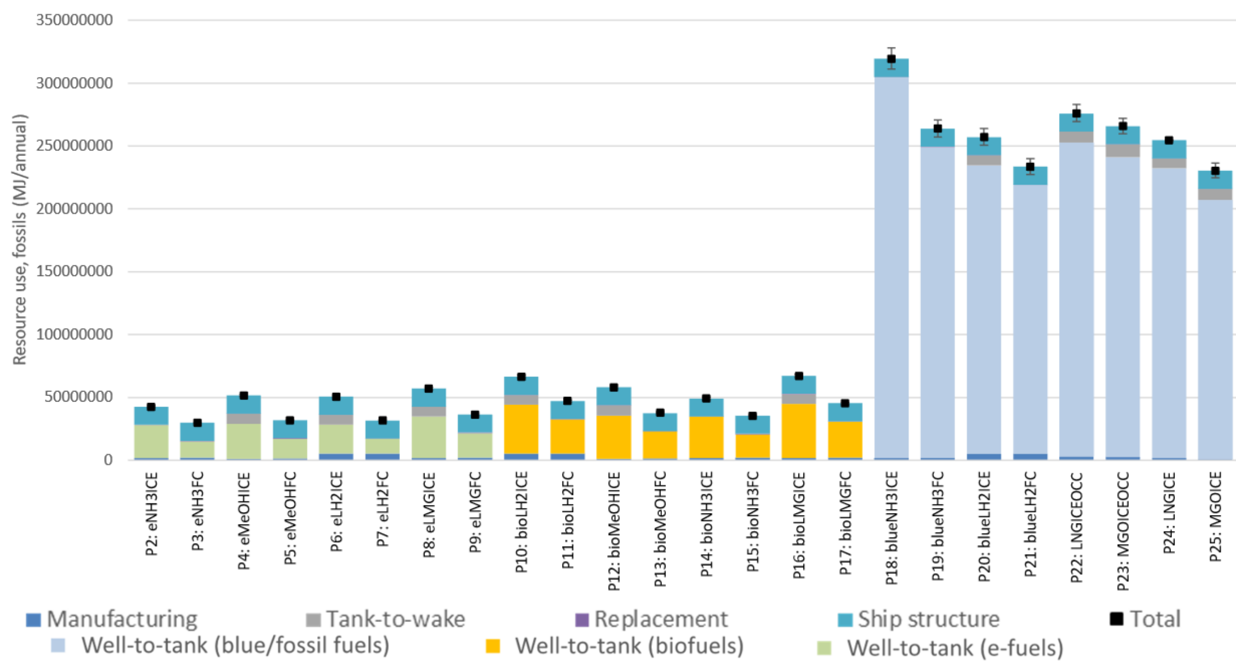

Figure S 7:LCA result on impact category resource use, fossils

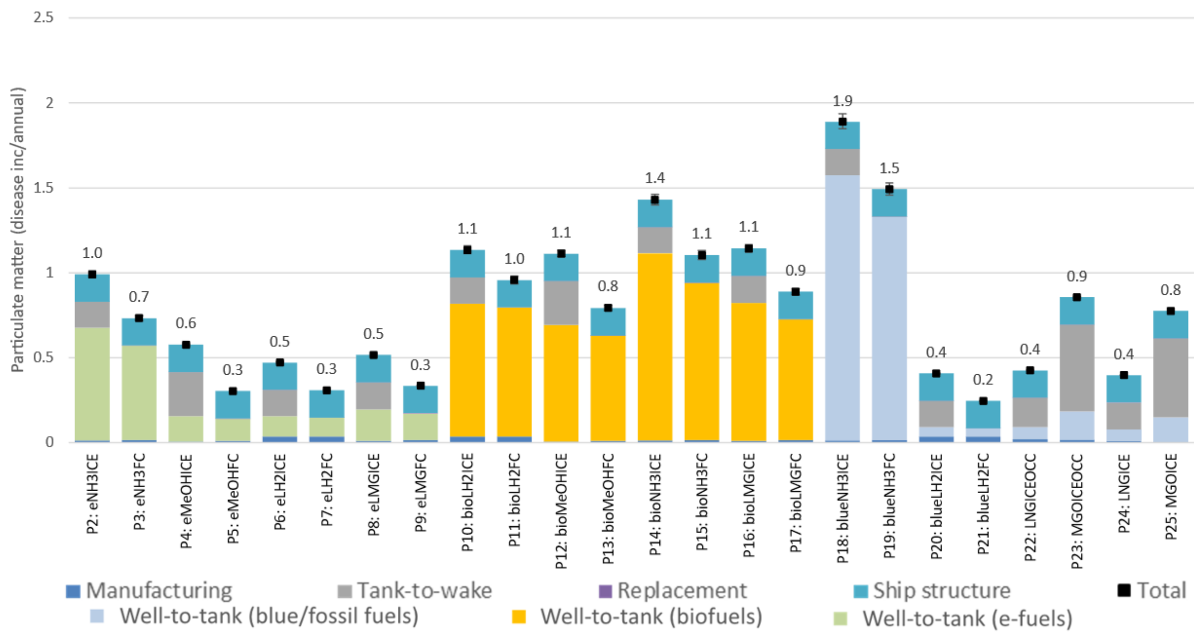

Figure S 8:LCA result on impact category Particulate matter

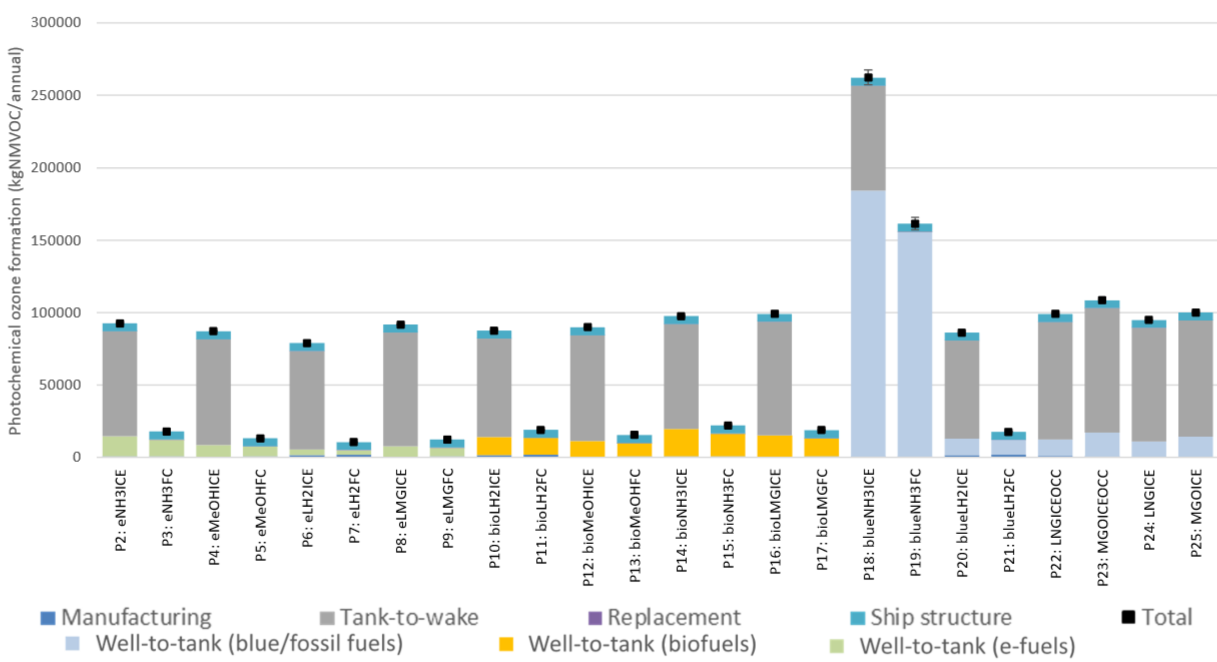

Figure S 9: LCA result on impact category- Photochemical ozone formation

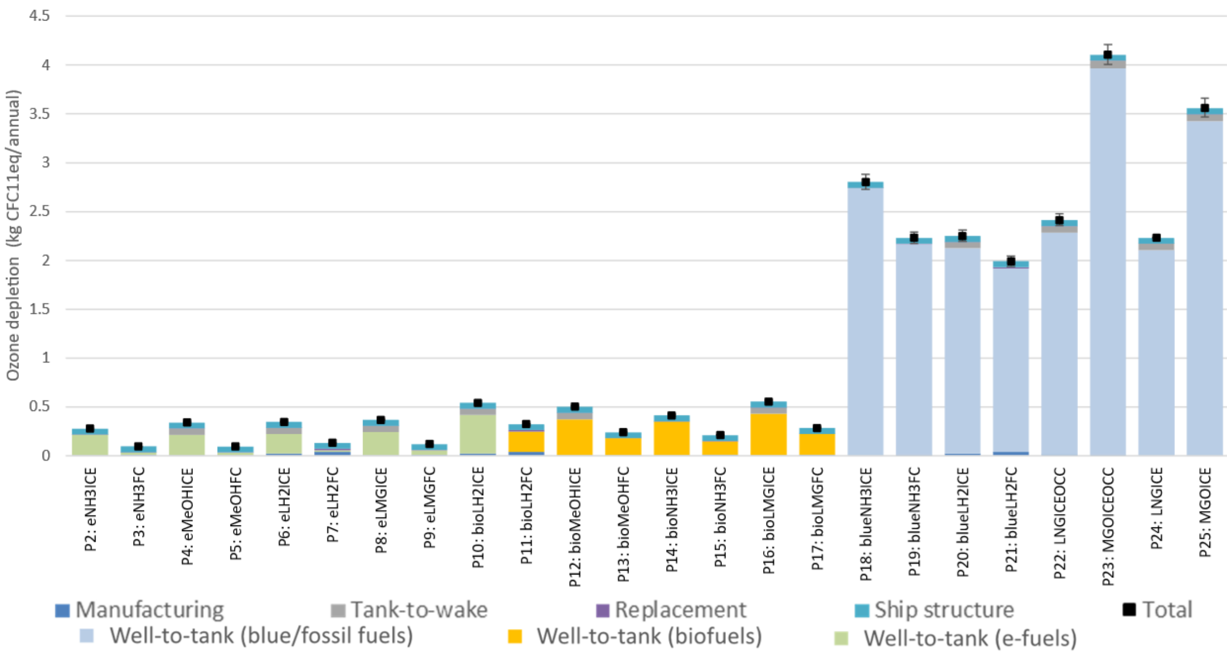

Figure S 10: LCA result on impact category-Ozone depletion

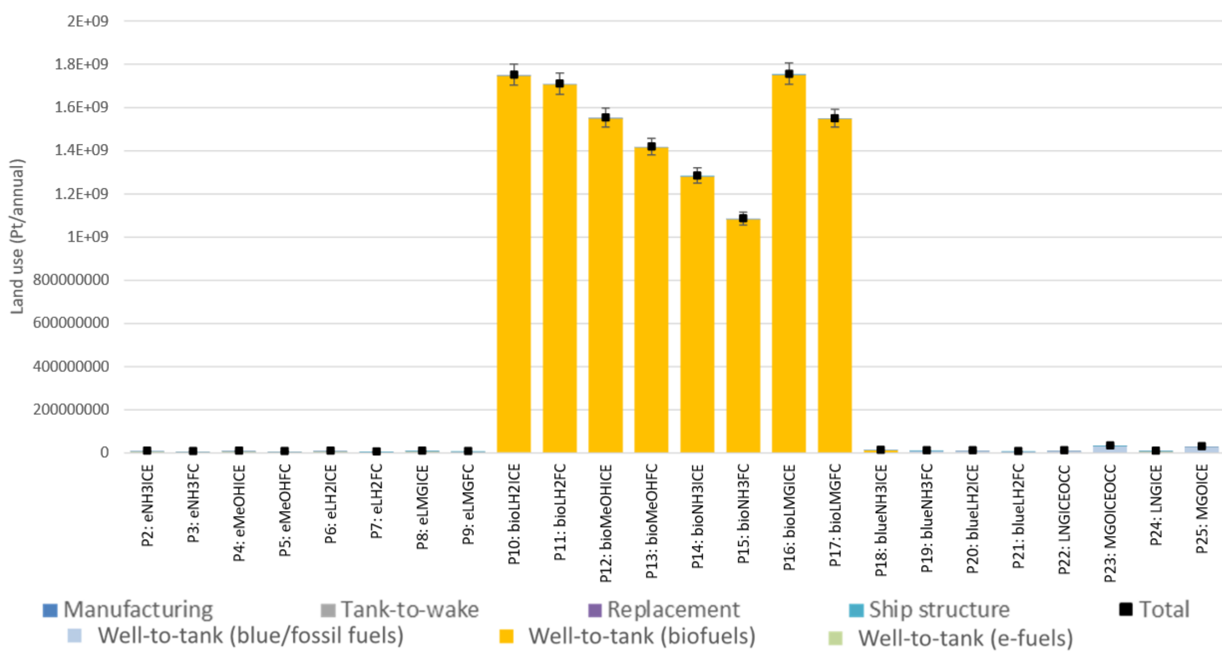

Figure S 11: LCA result on impact category-Land use

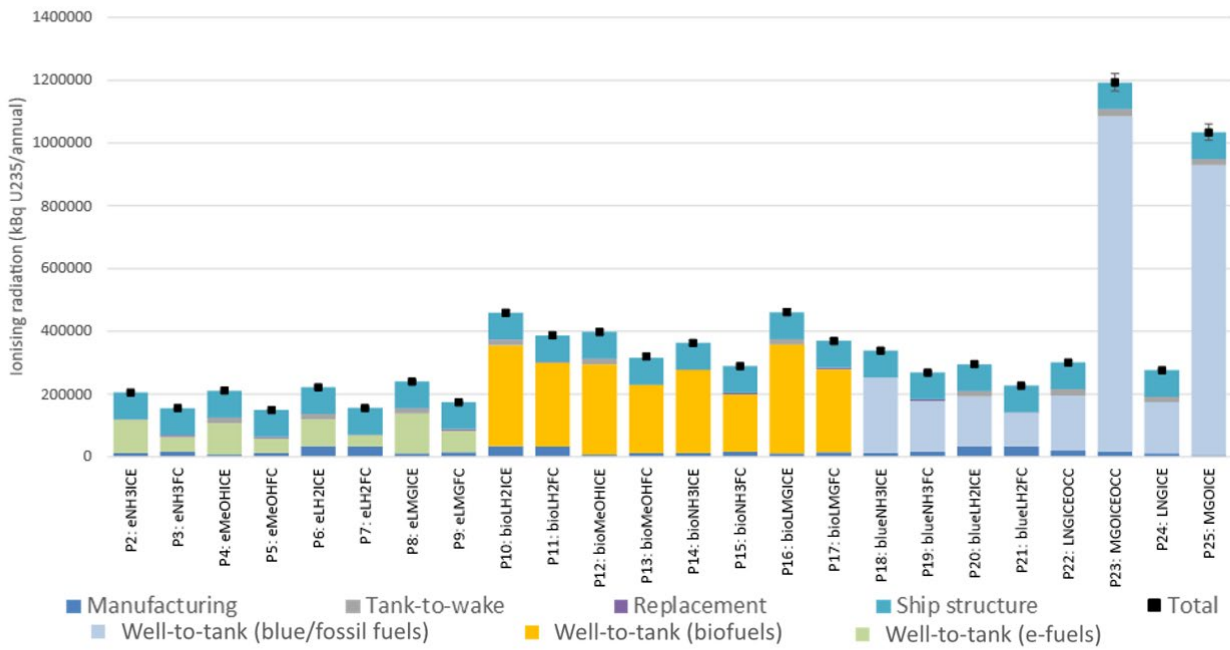

Figure S 12: LCA result on impact category-ionising radiation

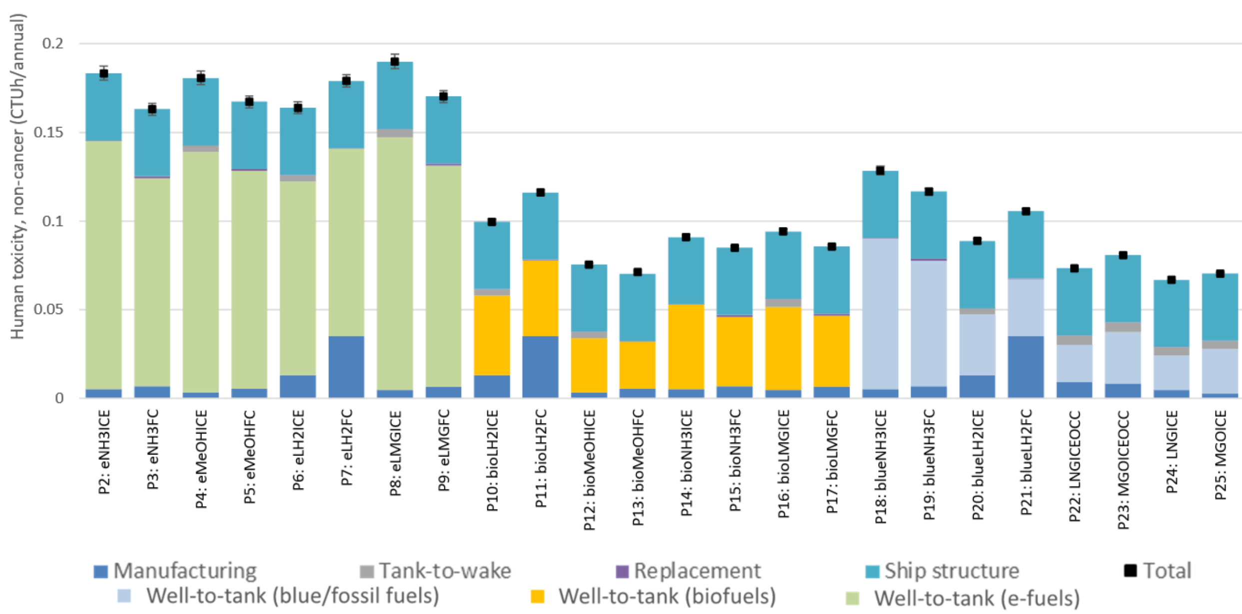

Figure S 13: LCA result on impact category-Human toxicity, non cancer

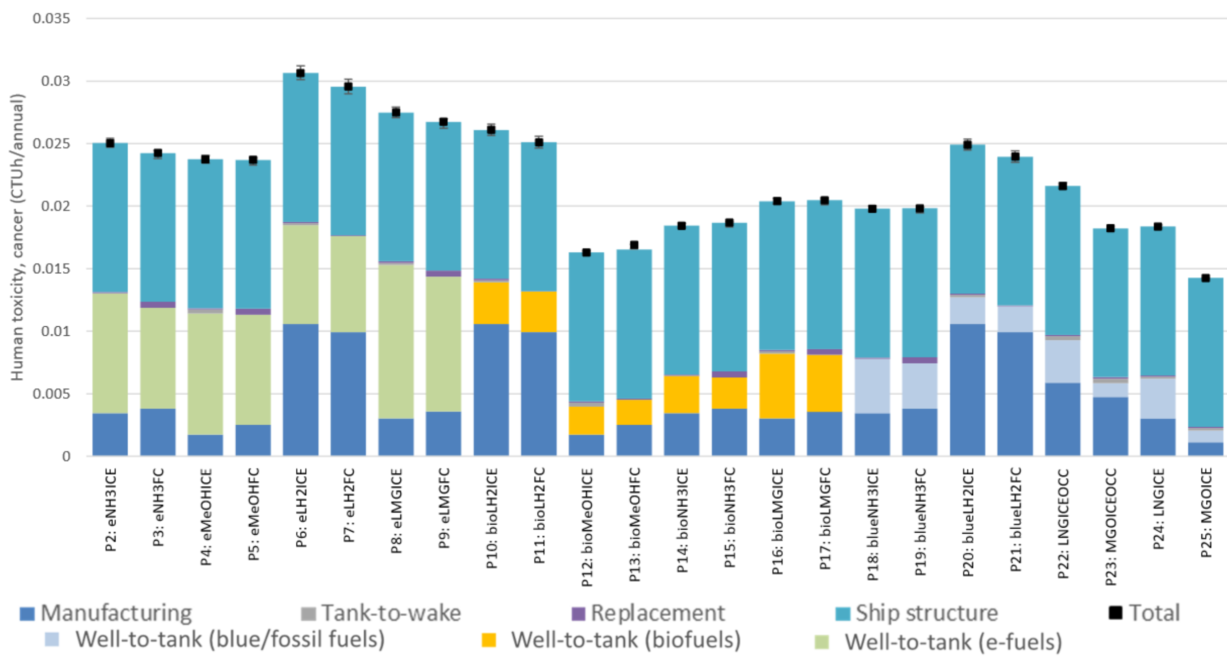

Figure S 14:LCA result on impact category-Human toxicity cancer

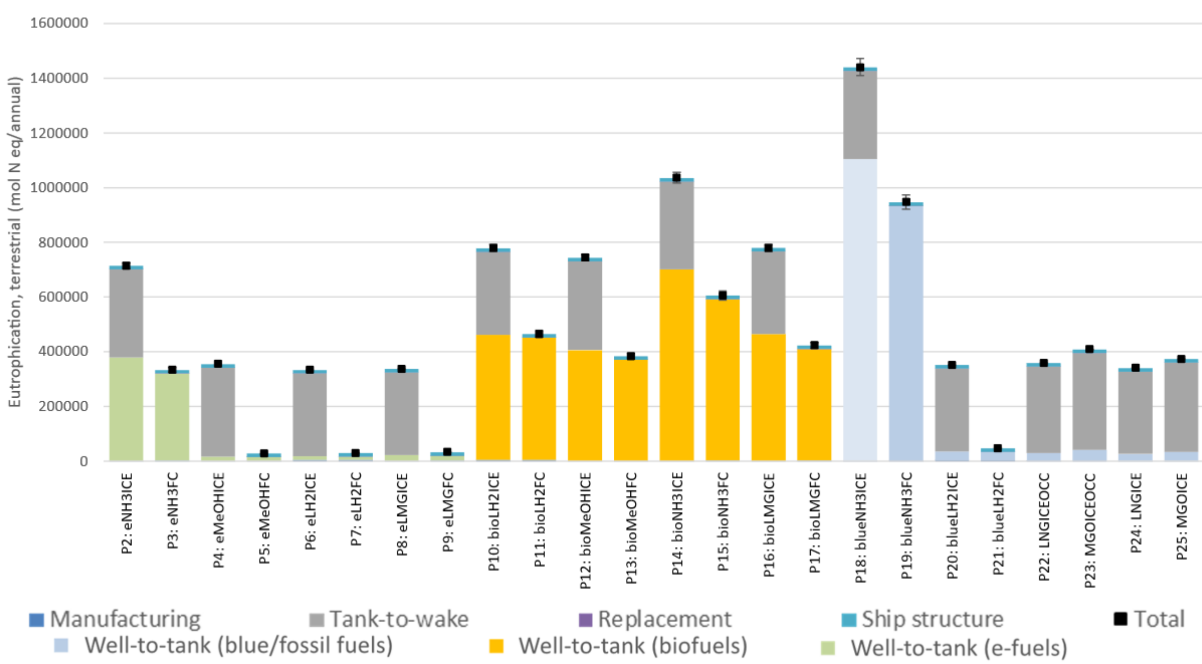

Figure S 15: LCA result on impact category- Eutrophication, terrestrial

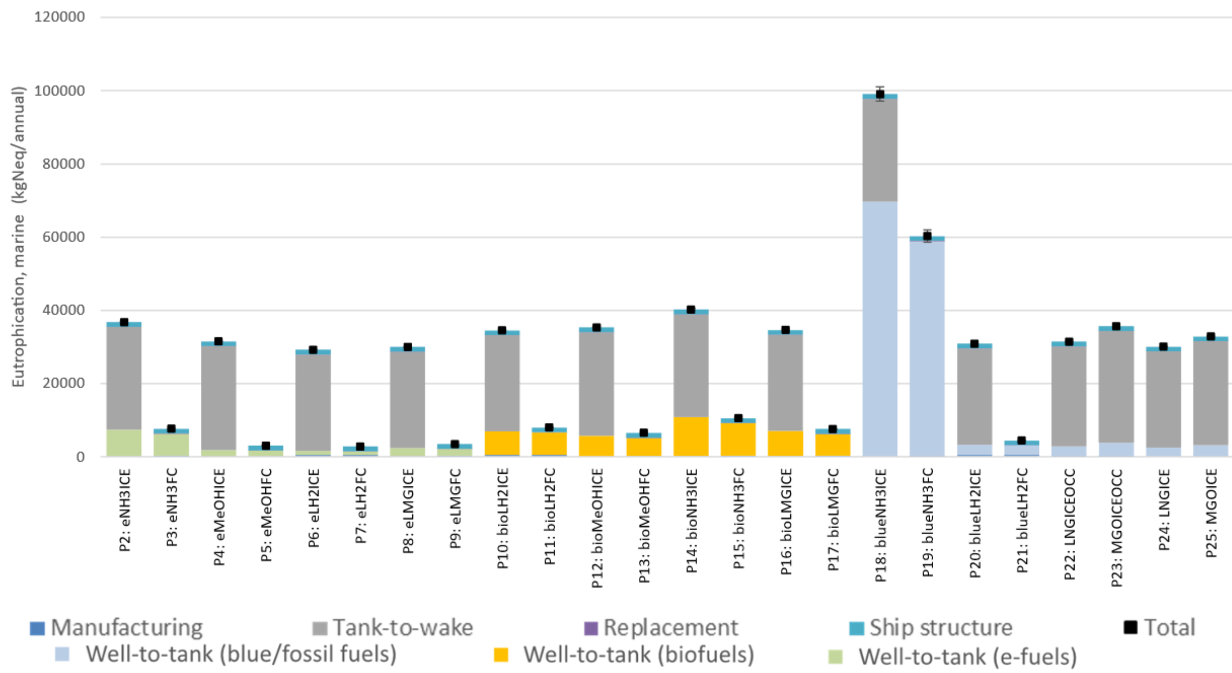

Figure S 16:LCA result on impact category-marine eutrophication

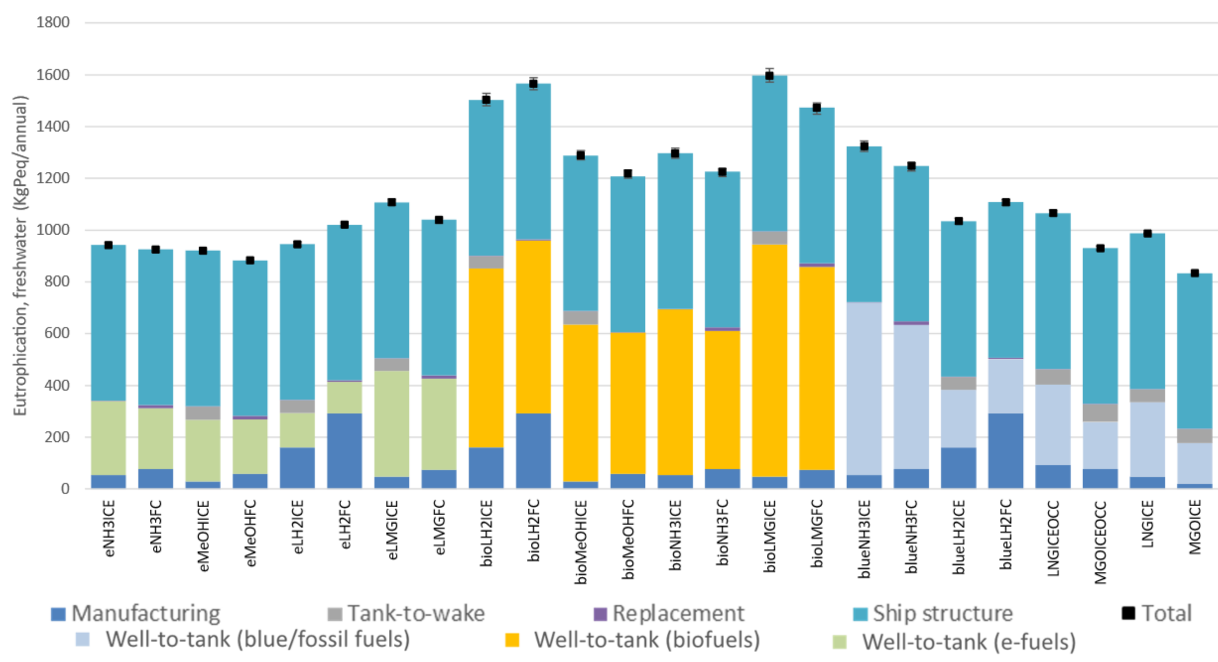

Figure S 17: LCA result on impact category-Freshwater eutrophication

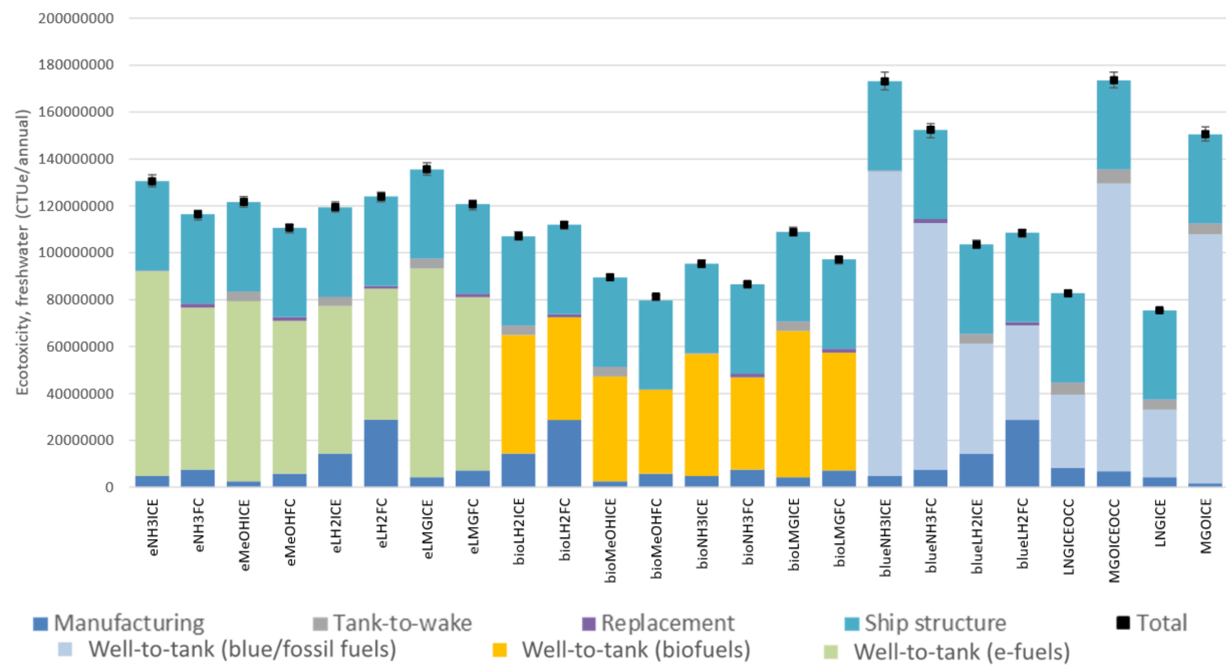

Figure S 18:LCA result on impact category-Ecotoxicity freshwater

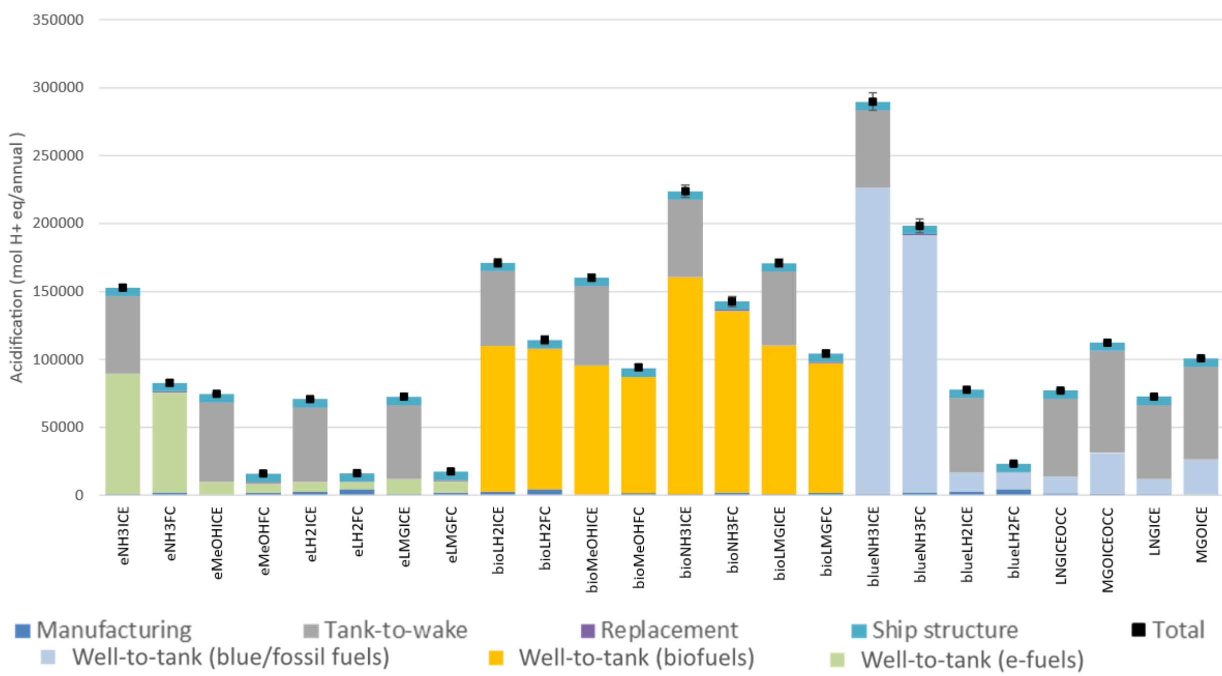

Figure S 19: LCA result on impact category- Acidification potential

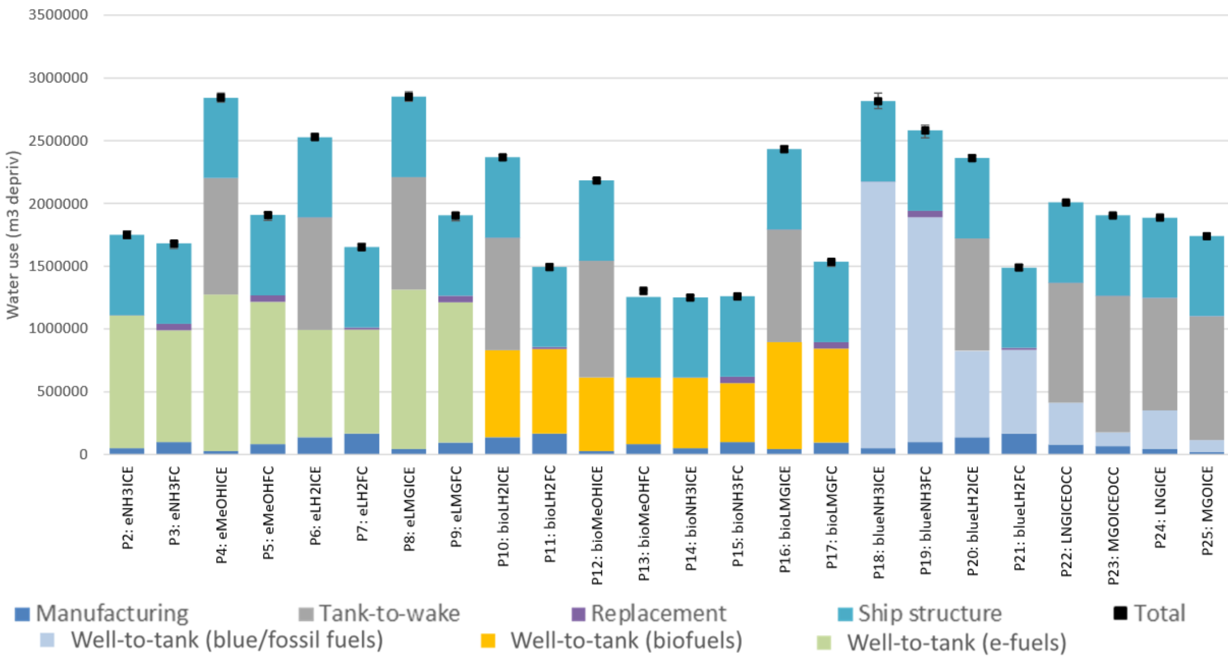

Figure S 20-LCA result on impact category- water use

S5.2 Monte-carlo simulation box plot for CAC

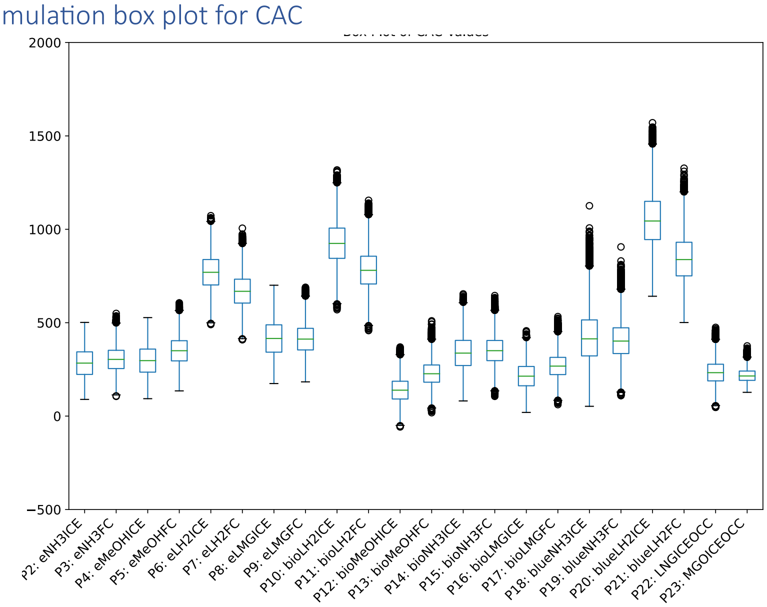

Figure S 21: CAC box plot for bulk carrier.

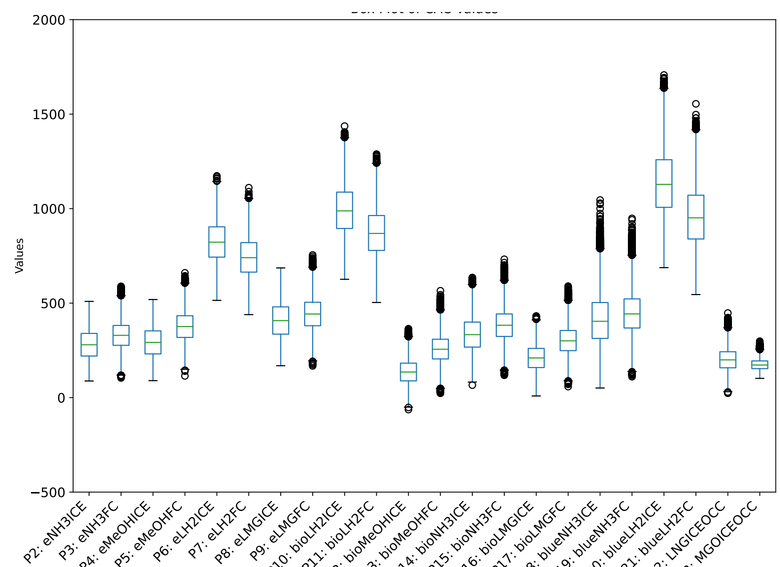

Figure S 22: CAC box plot for container

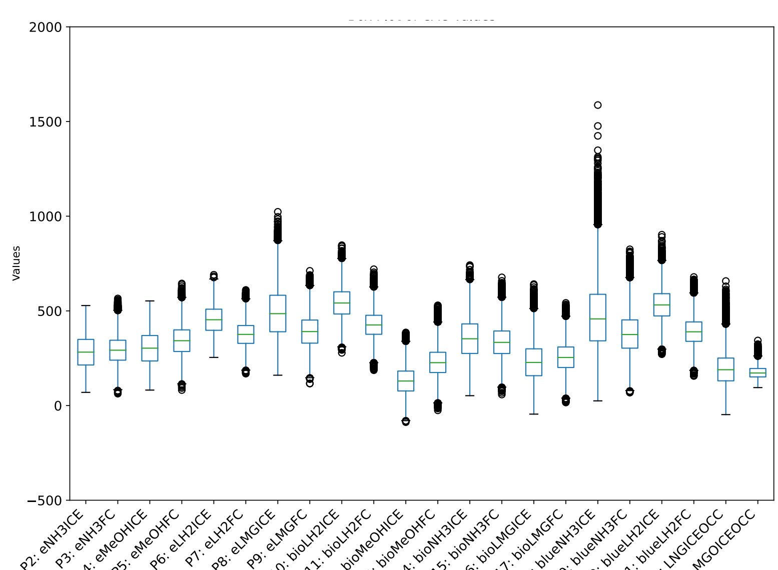

Figure S 23: Box plot for cruise ship.

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