LNG as a marine fuel in the EU

Market, bunkering infrastructure investments and risks in the context of GHG reductions

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Preface

This report has been written by a team of experts from UMAS for Transport & Environment. The views expressed are those of the authors, not necessarily of the client.

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About UMAS

UMAS undertakes research using models of the shipping system, shipping big data (including satellite Automatic Identification System data), and qualitative and social science analysis of the policy and commercial structure of the shipping system. Research and consultancy is centred on understanding patterns of energy demand in shipping and how this knowledge can be applied to help shipping transition to a low-carbon future. UMAS is world-leading on two key areas; using big data to understand trends and drivers of shipping energy demand or emissions and using models to explore what-ifs for future markets and policies. For more details visit www.u-mas.co.uk

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List of abbreviations:

BAU – Business as Usual
CAPEX – Capital Expenditures
CEF – Connecting Europe Facility
CH4 – Methane
CO_2 – Carbon Dioxide
CO_2eq – Carbon dioxide – Equivalent
EC – European Commission
ECA – Emission Control Area
EEDI – Energy Efficiency Design Index
EIB – European Investment Bank
EP – European Parliament
EU – European Union
GHG – Greenhouse Gases
GloTraM – Global Transport Model of energy and emissions of shipping
Gt – Gigaton
GWP – Global Warming Potential
H2020 – Horizon 2020
HFO – Heavy Fuel Oil
IMO – International Maritime Organization
IRR – Investment Return Rate
km – Kilometer
kW – kilowatt
LNG – Liquified Natural Gas
LSHFO – Low Sulphur Heavy Fuel Oil
m3 – Cubic Meter
MARPOL – International Convention for the Prevention of Pollution from Ships
MBM – Market Based Mechanism
MDO – Marine Diesel Oil
MEPC – Marine Environment Protection Committee
MGO – Marine Gas Oil
MJ – Megajoule
mmtpa – Million Metric Tons Per Annum
MT – Megaton
MW – Megawatt
N2O – Nitrous Oxide
NDC – Nationally Determined Contribution
NPV – Net Present Value
NOx – Nitrogen Oxides
OPEX – Operating Expenditures
RCP – Representative Concentration Pathways
Sc – Scenario
SOx – Sulphur Oxides
STS – Ship-To-Ship
t – Tone
TEN-T – The Trans-European Transport Networks
TPS – Terminal-To-Ship
TTM – Tank to Motion
TTS – Truck-To-Ship
TTT – Terminal to Tank
UK – United Kingdom
USA – United States of America
WTM – Well to Motion
WTT – Well to Terminal

1 Executive summary

In light of the recently adopted initial IMO strategy on reduction of GHG emissions and the Paris Agreement, there is a need to better understand the potential market for LNG as a marine fuel, bunkering infrastructure investments required and associated risks in the context of shipping GHG reduction.

This report attempts to assess the prospective future public and private financial investments by EU member states into LNG port/bunkering infrastructure consistent with EU plans to foster the widespread uptake of LNG as a means of decarbonising the shipping sector up to 2050. Consequently, the study aims to ascertain the cost/benefit of investing in LNG bunkering infrastructure from a GHG abatement perspective (invested \$/tonne CO_2 abated) and in addition, the proportion of these costs that would potentially be funded through EU funding programmes and by EU member states.

The analysis uses a combination of techno-economic modelling and cash flow analysis in a scenario based approach to understand the different uncertainties in future LNG demand by ships calling at EU ports, with associated CO_2eq emissions and financial assumptions. The study proposes four scenarios for future LNG demand by the international maritime industry and covers the historic and future demand for the period 2010-2050, detailed in 3. In the "High Gas" scenario, investment in LNG grows gradually over time. In "Limited Gas", LNG demand and investment flows in quickly initially, but with the development of zero emissions fuels, the demand for LNG soon peaks and declines. In the "Transition" scenario, the investment in LNG is gradual and in-line with the anticipated small role of LNG as a marine fuel. With respect to the regulations in the four scenarios, the Business as Usual (BAU) assumes no environmental policies being implemented beyond those already agreed and in place (e.g. existing MARPOL commitments: EEDI, SOx, NOx regulations). The remaining three decarbonisation scenarios in this study can be considered consistent with the levels of ambition expressed in the initial IMO strategy on reduction of GHG emissions from ships, in that they represent an absolute reduction of GHG emissions of 57% by 2050 compared to 2008 emissions (IMO requires cuts of "at least" 50%). However, given that the IMO does not prescribe a peak year, an emissions pathway and leaves the exact emission reduction target ambiguous (anywhere between 50-100% by 2050 compared to 2008), this study's decarbonisation scenarios represent just one of the many pathways that could be compatible with the IMO's initial strategy.

1.1 Key Findings

The scale of the potential LNG marine fuel market, and its potential for GHG emission reduction:

- There is no significant CO_2eq. reduction achieved through the use of LNG as marine fuel relative to the reduction required to achieve the IMO's 2050 objectives. This is consistent with many other studies, and particularly when including upstream emissions and all sources of GHGs. Depending on the fuel's supply chain and use, a switch to LNG can even increase GHG emissions relative to conventional fuels in a Business as Usual scenario.
- Reducing total annual emissions from shipping in-line with the initial IMO strategy objective of at least 50% GHG reduction by 2050 on 2008 levels, and the Paris temperature goals, is only possible with a switch to increased use of non-fossil fuel sources (hydrogen, ammonia, battery electrification, biofuel) from 2030 and with rapid growth thereafter, as explored in two of the decarbonisation scenarios "Limited Gas" and "Transition". Providing sustainable biofuels can be sourced, these could be a growing part of the fuel mix, for example as part of blends, before 2030, which could help to increase the timescale for the introduction of synthetic fuels.
- Judging by the variability in the results from the three decarbonisation scenarios, there is a very uncertain future demand for LNG as a marine fuel over the next 10 years. On the one hand, it is an option for complying with the 2020 sulphur cap, but as it cannot enable the GHG reductions that have been committed to in the IMO's initial strategy for GHG reduction and the Paris temperature goals more generally, it is clear its role can only be transient and not transitional.

- The growth and duration of LNG's viability as a marine fuel is influenced both by whether it is possible to rapidly ramp-up LNG and achieve the returns needed on these investments over the period that it remains in demand, and by the extent that shipping's required GHG reductions are derived from in-sector reduction efforts or through a market based mechanism enabling carbon market linkage.
- Relying more heavily on the use of linkages to other (non-shipping) carbon markets may increase the growth and duration of the LNG as a marine fuel market, but this is dependent on the linkages providing sufficient access to low cost out of sector emissions reductions, something which is currently highly uncertain. In addition, the letter and spirit of IMO's at least 50% absolute reduction commitment by 2050 requires absolute in-sector reductions without market linkages.
- In the two scenarios where there is penetration of non-fossil fuel sources, there is no development of a significant market for LNG as a marine fuel, as these new fuel sources require significant demand growth from 2030 at the latest to meet the GHG reduction objectives.

The scale of investment and potential losses, under different LNG marine fuel market scenarios, for investments in LNG infrastructure:

- To date, it is estimated that over $500 million has been invested in the EU through TEN-T and CEF funding for marine bunkering LNG projects. It is estimated that $230m is from EU public funding sources and the remainder from other sources (including private sources).
- Total CAPEX investment in LNG infrastructure needed in Europe for the different decarbonisation scenarios are $22.2 bn, $5.5bn and $3 bn for "High Gas", "Limited Gas" and "Transition" respectively. The overall payback time on "High Gas" is longer than the "Transition" scenario - approximately 30 years. There does not appear to be stranding of these LNG assets over the period to 2050, however given that transition to non-fossil fuels is likely to be inevitable, evaluation past 2050 could show some degree of asset stranding at some point in the future.
- The occurrence of a stranding of assets means the cash flow for the "Limited Gas" scenario is strongly negative (NPV of -211 million), which can be considered a direct investment loss by 2050. This scenario illustrates the risk of investing strongly, whether private or public funding, under Directive 2014/94/EU guidelines, if LNG does not then develop as a significant marine fuel.

The cost-effectiveness of LNG related abatement, and the implications of achieving GHG reductions above the IMO's minimum stated level of ambition:

- By considering LNG as achieving abatement of CO_2eq relative to MDO through its substitution, the total cumulative abatement in the decarbonisation scenarios varies between 23 and 460 million tonnes, over the period 2015-2050, depending on the scenario and assumptions on the baseline fuel.
- Estimating the abatement cost associated with LNG infrastructure, this is calculated as between 51 and 85 $/t of CO_2eq abated, depending on the scenario. The highest abatement cost is associated with the "limited gas" scenario.
- If investments are made expecting development of a large LNG market, but the evolution of LNG follows the "transition" or "limited gas" scenarios which are consistent with the penetration of non-fossil fuels in shipping, then significant numbers of infrastructure assets (feeders, barges and storage tanks) will become redundant prematurely, and would be likely to incur significant negative cashflow for their financiers in the period out to 2050.
- Taking the higher levels of ambition, which will be considered in further "Roadmap" development, including 100% decarbonisation by 2050, will make the establishment of a significant market for LNG now, even more challenging for the transition of the industry. These higher levels of ambition in combination with significant growth of LNG investment in the short-term, will increase the risks relative to those described in this study.
- Given that the estimations did not include investment in LNG-powered ships, the level of stranded assets would likely be larger for the maritime sector as a whole.

2 Introduction

Under the “Paris Agreement” the signatories, which include the European Union, and its member states, state a long-term goal of keeping the increase in global temperatures well below 2°C in comparison to pre-industrial levels[1] whist also aiming at limiting this increase to 1.5°C. Under Article 4 of the agreement it is envisioned that by the second half of this century net anthropogenic GHG emissions should be zero (‘…balance between anthropogenic emissions by sources and removals by sinks of greenhouse gases…’) [2]. If the commitments under the “Paris Agreement” are to be met, all sectors, including maritime and inland shipping should contribute their fair share to the overall global emission reduction efforts. The Paris Agreement’s temperature goals are now starting to be reflected at the International Maritime Organisation (IMO) for international shipping – the IMO’s Initial GHG Reduction Strategy commits the IMO to reduce total GHG emissions by “at least” 50% by 2050 on 2008 levels, whilst pursuing efforts to reduce in line with the Paris temperature goals e.g. 100% reduction by 2050.

Maritime shipping is a significant contributor to global anthropogenic GHG emissions and as such has an important role to play in contributing to the “Paris Agreement” abatement goals. Emissions from international shipping could increase from 2-3% in 2012 to 6-14% of global anthropogenic emissions by 2050 (IMO, 2015), showing how important it is for shipping to abate as much as possible.

In the debate around decarbonisation and shipping, LNG as a marine fuel has been mentioned by industry and policy leaders alike as a potential alternative to conventional HFO (Heavy Fuel Oil) and MDO/MGO (Marine Diesel Oil/Marine Gas Oil) based fuels. Within the maritime shipping industry, LNG (Liquefied Natural Gas) has since its first usage outside of LNG carriers in 2000 become considered as an alternative fuel option, partly due to its perceived environmental benefits. LNG can lead to a net decrease in SOx of up to 100% and NOx emissions up to 90% compared to HFO[3]. However, depending on the levels of methane slippage considered, these figures can be far lower and in some cases emissions can be even 17% higher compared to distillate fuels[4]. In addition, depending on the evolution of prices, LNG may be marginally cheaper than low sulphur (0.5%) marine fuels. Low sulphur fuels are set to become the primary fuel of the shipping industry by 2020 with the implementation of the global 0.5% sulphur cap under MARPOL Annex IV of the IMO.

However, the actual utility of LNG from a decarbonisation point of view remains to be seen as the overall benefits are generally small[5][6], and the total GHG savings of LNG are highly dependent on the rates of methane leakage within the LNG supply chain and during ship operation. In addition, LNG ships are more expensive to build and maintain due to the unique safety requirements, fuel storage equipment, more expensive engines.

2.1 European Union and LNG as a marine fuel

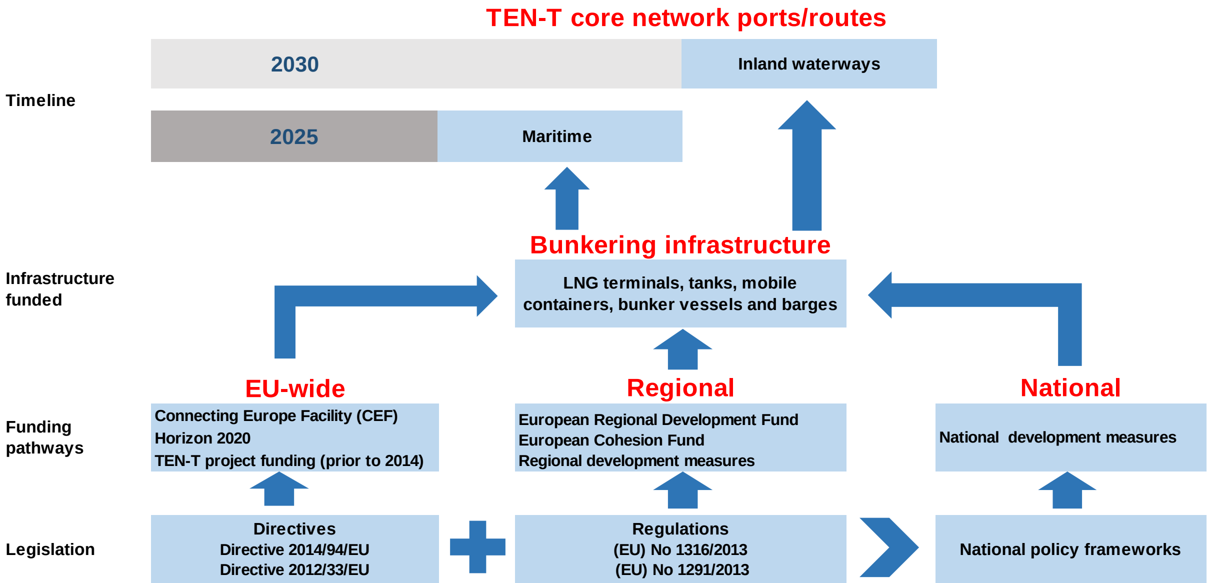
The EU has considered itself to be at the forefront of international efforts to mitigate domestic GHG emissions from all industrial sectors and transport modes. In March 2015, the EU submitted its intended Nationally Determined Contribution (NDC) to the Paris Agreement and has taken steps to reduce its emissions by 40%, by 2030, compared to 1990. Whilst this NDC does not include international shipping, it points to the general aim of achieving substantial decarbonisation in order to start aligning the European economy with the Paris Agreement. In addition, the EU has stated in its 2011 White Paper, its intention to cut its emissions from maritime shipping by 40% (if feasible 50%) by 2050 compared to 2005 levels[7]. Over the past several years, this point has been reiterated by the Commission, stating

[1] UNFCC (2015) “Paris Agreement” Article 2, Paragraph 1, Section a)
[2] UNFCC (2015) “Paris Agreement” Article 4, Paragraph 1
[3] Kristensen (2010) Energy demand and exhaust gas emissions of marine engines
[4] TNO (2011) Environmental and Economic aspects of using LNG as a ship fuel in the Netherlands
[5] Anderson et al. (2015) Particle- and Gaseous Emissions from an LNG Powered Ship.
[6] Corbett et al. (2015) Methane Emissions from Natural Gas Bunkering Operations in the Marine Sector: A Total Fuel Cycle Approach
[7] European Commission (2011) White paper on transport, pg 8, Paragraph 29

that "EU is calling for a global approach to reducing greenhouse gas emissions from international shipping" [8]

A significant legislative contribution to the promotion of LNG as a marine fuel with the EU, came with the adoption of the EU 'Alternative fuels directive' (Directive 2014/94/EU) in 2014. The EU has been aiming to increase its usage of alternative fuels in transport for almost a decade since Directive 2009/28/EC set the market share target for alternative fuels at 10%. Directive 2014/94/EU obligates member states to make available bunkering infrastructure for LNG as marine fuel in their territory and allows for their funding principally through the CEF (Connecting Europe Facility) which replaced the TEN-T funding facility in 2014. In addition, funding is available through the Horizon 2020 programme, but with a higher emphasis on research and innovation rather than infrastructure construction; and through regional and national level funding programmes. Additional financing is available under the European Fund for Strategic Investments and the EIB (European Investment Bank) (Figure 1).

Figure 1 EU funding pathways for LNG bunkering infrastructure



Through the mentioned funding sources, the EU has created a regulatory obligation for the development of an LNG bunkering infrastructure network along the TEN-T core shipping and inland waterway corridors. In addition, it could be argued that Directive 2014/94/EU opens the door for the funding of significant LNG bunkering infrastructure beyond the core TEN-T networks contingent on future LNG demand.

Depending on the future take-up of LNG as a marine fuel and the EU member states' willingness to invest in LNG bunkering infrastructure, the EU member states could end up investing significant amounts of taxpayer funds into LNG bunkering infrastructure along Europe's inland (rivers, bays and lakes) and maritime waterways. However, at the same time the EU has committed itself under the 2011 White Paper to cut GHG emissions from maritime shipping by 40% by 2050 and the initial IMO strategy objective is to cut them by least 50%. In light of the limited climate benefits of LNG as a marine fuel in terms of its GHG abatement potential (ranging from -17% to +5% depending on the bunkering pathways, upstream emissions and methane slippage) [9], yet with the likely high costs of development of LNG bunkering infrastructure, ranging from US$ 22.2 billion to 3 billion per pathway based on this

http://ec.europa.eu/transport/sites/transport/files/themes/strategies/doc/2011_white_paper/white-paper-illustrated-brochure_en.pdf
[8] European Commission (2017), Reducing emissions from the shipping sector, https://ec.europa.eu/clima/policies/transport/shipping_en
[9] ICCT (2013): Assessment of the fuel cycle impact of liquefied natural gas as used in international shipping

study, it is important to understand the financial implications of investing in EU maritime and inland waterway LNG bunkering infrastructure.

2.2 Objective of the analysis

The objective of this study is to assess the prospective future public and private financial investments by EU member states into LNG port/bunkering infrastructure consistent with EU plans to foster the widespread uptake of LNG as a means of decarbonising the shipping sector up to 2050.

This study aims to assess the investment cost of LNG infrastructure assumed to be built in the EU under a well below 2°C global decarbonisation scenario following the “Paris Agreement”. The implications for the likelihood of future stringency increases in the IMO GHG strategy towards 100% GHG reduction by 2050 are not assessed quantitatively in this study, but are interpreted qualitatively from the results. Consequently, the study aims to ascertain the cost/benefit of investing in LNG bunkering infrastructure from a GHG abatement perspective (invested $/tonne CO2 abated). In addition, the proportion of these costs that would potentially be covered/funded through EU funding programmes and by EU member states is estimated.

This report presents a comprehensive analysis of the total LNG bunkering infrastructure costs within the European Union, under different future global LNG fuel demand scenarios based on different possible abatement futures. The analysis uses a combination of maritime transport modelling and cash flow analysis to understand the different uncertainties in future LNG demand by ships calling at EU ports, with associated CO_{2eq} emissions and financial assumptions. This report aims to expand the understanding of the economics of LNG bunkering infrastructure investments within the EU’s maritime sector.

The focus of the report is to provide a detailed insight into the following:

1. Future demand for LNG by the international shipping industry in EU.
2. Cumulative EU/regional costs of LNG bunkering infrastructure for international shipping. (liquefaction, small and medium size terminals, LNG storage, bunkering/de-bunkering facility, etc.).
3. Cumulative EU bunkering expenditures for shipping to be covered by private and public financing (EU and member states) (as % of total estimated LNG bunkering infrastructure costs in the EU).
4. The value of potentially stranded LNG bunkering infrastructure assets once the use of LNG (in line with 2-degree pathways) is no longer consistent with EU decarbonisation commitments (total investment, total numbers-barges, feeder vessels, small storage terminals etc.).

3 LNG demand scenarios- 4 possible futures

This study proposes four scenarios for future LNG demand by the international maritime industry for the period 2010-2050. The scenarios offer four possible futures in which LNG plays varying roles of importance within shipping. With the adoption of the IMO’s Initial GHG Reduction Strategy, the scenarios could be interpreted as framing the lowest level of ambition (assuming shipping’s share of global emissions will increase) and lowest rates of decarbonisation that will arise from that strategy (i.e. 50% absolute CO_2 emission reduction by 2050), and subsequent significant increases in stringency of that ambition, towards 100% absolute emission reduction by 2050 which could be committed to as early as 2023.

3.1 Scenario method

The LNG demand scenarios are calculated using GloTraM, a holistic model developed by the UCL Energy Institute. The model inputs use a sophisticated suite of data and models which is leveraged with the most up-to-date work to analyse the evolution and development of the shipping industry, its demand for different fuels, its future growth and GHG emissions. GloTraM performs a holistic analysis of the global shipping system to understand how future developments in fuel prices and environmental regulations can affect the shipping industry. The modelling period of GloTraM is 2010-2050, with the validation scenario running from 2008-2015, before starting the main scenario runs out to 2050. The LNG demand figures for this report take 2015 as a starting year, due to limited (in some niche markets) utilisation of LNG prior to this date. A conceptualisation of the modelling framework is available in Appendix A. GloTraM and its input assumptions use a “profit maximising approach” from the ship owner/operator perspective, whilst including market barriers and failures as model functionalities which match observed data. A detailed model methodology is described in Smith et al. (2013) and “Global Marine Fuel Trends” in collaboration with Lloyd’s Register (2014).

3.2 Scenario input assumptions

GloTraM is used to prepare four different global fuel demand scenarios covering the 2010-2050 period, and the results are represented from 2015 onwards, since the 2010-2015 period had almost no LNG demand. The scenarios represent four different views on the role that LNG could play in the future assuming the “Paris Agreement” temperature goals are to be met and shipping contributes its fair share to the 2°C temperature goal, using different assumptions for LNG price, GHG regulations and fuel options. The key assumptions and parameters used in each scenario are available in Table 1 below. The assumptions are based on a range of data gathered from existing literature and discussions with relevant experts.

Table 1 Fuel demand scenario descriptions

	Regulation scenario			Demand	Techno economic						
	Fair share derived CO_2 budget (2010-2100)	MBM start year	Out-sector offsets	Trade scenario	Fuels option	Fuel price	Bio availability scenario	Slow Steaming constraint	NPV year	b.tc	Technology cost
SCEN 1 BAU	-	-	-	Per annum growth in demand	All fuels excluding H2	2-degree price	Lower bound	Very limited	3	50%	Full
SCEN 2 HIGH GAS	33 Gt	2025	30%	Per annum growth in demand	All fuels excluding H2	low LNG price	Low-bound	Limited	3	50%	Full
SCEN 3 TRANSITION	33 Gt	2030	20%	Per annum growth in demand	All fuels	Low H2 price	Lower bound	Limited	3	50%	Full
SCEN 4 NO GAS	33 Gt	2025	30%	Per annum growth in demand	All fuels	Low H2,and oil	Mid-range	Limited	3	50%	Full

The first scenario is Business-as-Usual “BAU” and assumes no environmental policies being implemented beyond those already agreed and in place (existing MARPOL commitments: EEDI, SOx, NOx regulations). The decarbonisation scenarios in this study can be considered consistent with the levels of ambition expressed in the initial IMO strategy in that they represent an absolute reduction of GHG emissions of 57% by 2050 compared to 2008 emissions (IMO requires cuts of “at least” 50%). However, given that the IMO does not prescribe a peak year, an emissions pathway and leaves the exact emission reduction target ambiguous (anywhere between 50-100% by 2050 compared to 2008), this study’s decarbonisation scenarios represent just one of the many pathways that could be compatible with the IMO’s initial strategy.

All scenarios assume, in addition to the adoption of alternative fuels such as LNG, the introduction of MBMs (Market Based Measures) within the modelling simulations. The start year of MBMs regulations can vary, Sc2 and Sc4 assume the start year of this regulation in 2025 and Sc3 in 2030. In addition, a percentage of total revenue derived from MBM carbon pricing (the MBM mechanism of choice) can be used in unspecified carbon market linkage. The amount of potential linkage is constrained to a maximum of 30% for Sc2 and Sc4 and at 20% for Sc3 respectively.

All three non – “BAU” scenarios assume a single transport demand projection, as in all the three projections, the world is assumed to have the same pattern of macroeconomic development. The demand projection is called “2-degree low demand growth”, which reflects the demand projections driven by curves RCPs 2.6 as described in the Third IMO GHG Study 2014, in combination with low trade growth. The consequence is annual trade growth of approximately 3.5% as an aggregate across all commodities, an annual growth rate that is broadly representative of the 2008-2016 period. The RCPs 2.6 curve projects a declining demand for transport of crude oil and coal since it is broadly consistent with a 2° C target. The demand growth is driven by increasing population and wealth, increasing demand for some bulk commodities and container shipping's services (approximate growth in demand of 4% per annum for container shipping, growth for dry bulk of 2.5% per annum, and a halving of demand for oil over the period -3.5% per annum – driven by the increasing decarbonisation of the global economy). All scenarios apart from Sc4, assume a lower bound bioenergy availability whereas Sc4 assumes a mid-range availability. All scenarios apart from "BAU" assume a "limited" slow steaming constraint which allows shipping to use lower speeds to reduce carbon intensity, but represents an operational limit reduction of installed power to a minimum of 20% (the same limit is relaxed further to 1% in the "BAU" scenario). For example, a 10MW engine is assumed able to be operated as low as 2MW power output (20%) or in the extreme assumption 100kW of power output. These limits are theoretical in order to test whether very low operating speeds appear to be required, but the results show that the lowest of these limits (1%) is not approached in the scenarios simulated.

3.3 Fuel price projections and assumptions

The fuel price projection (all fuels, including LNG) is called the "2-degree price" and is kept constant in all scenarios apart from modification to the LNG price in Sc2 and H2 price in Sc3 and Sc4. The "2-degree price" is obtained using the output of the model TIAM-UCL, a linear programming cost optimisation model that generates equilibria between supply and demand for each commodity of the global energy system. The modified LNG price in Sc2 is called "LNG low".

LNG price projections are divided into two periods. The first period from 2015 to 2020 assumes that the LNG bunkering price is linked to the HFO price. From 2020 onwards, the price is linked to the TIAM-UCL price projections for other bunkering fuels (hydrogen, HFO and MDO). Initially the price in the first period is obtained by calculating the "LNG price parity" that is the LNG price equal to HFO on an energy basis. Later this price is discounted by a representative coefficient of $30/tonne. These prices are in line US Henry Hub (NYMEX) natural gas prices for delivery in Europe, a system that is generally used to estimate LNG delivery prices. The "LNG Low" price follows the same assumptions as the "2-degree price" but is discounted by 10% up to 2035, and 20% thereafter to reflect the reality of a high LNG diffusion scenario, which would be in part driven by more favourable price spreads between LNG and MDO. The higher discount beyond 2035, is in line with the expected fall in bunkering costs once LNG bunkering facilities are better utilized and fixed operating expenditures spread over a higher LNG volume.

Table 2 TIAM-UCL price projections for LNG, $/tonne

Scenario price:	2015	2020	2025	2040	2050
LNG Price	398	362	515	641	744
LNG Price "Low"	398	405	463	513	595

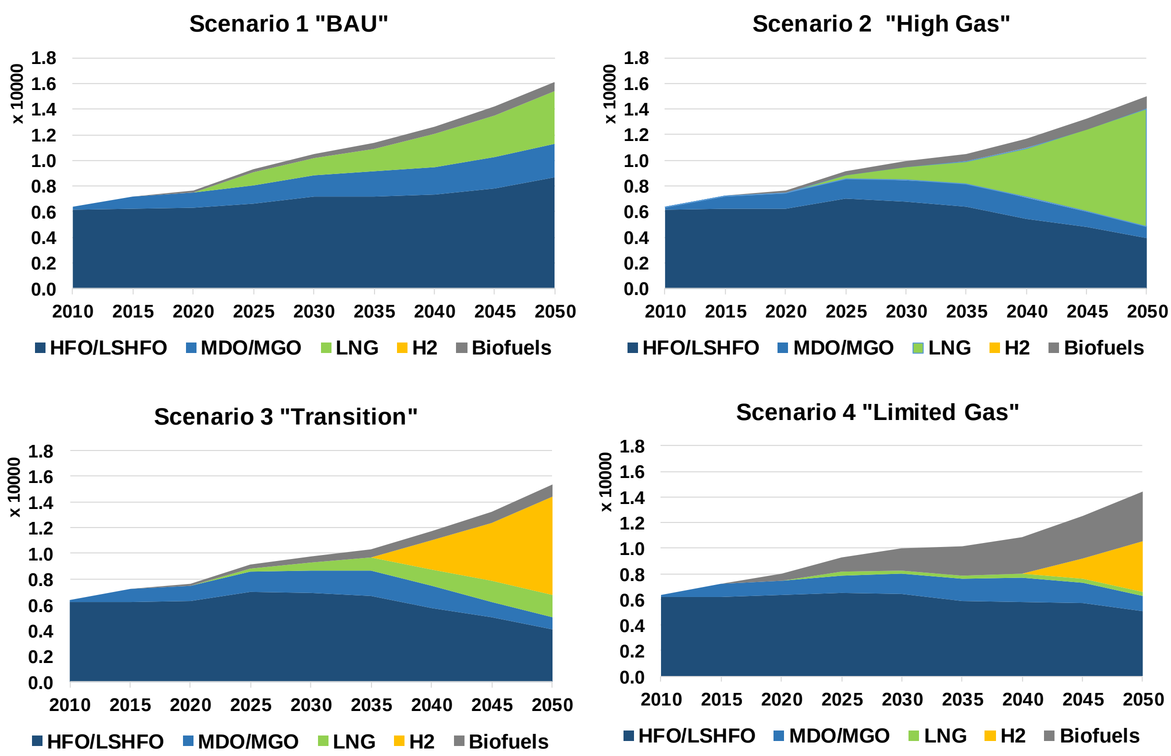
The LNG bunkering price is in line with other studies carried out on usage of LNG as a ship fuel (Appendix C). However, both price scenarios are at the lower end of prices stated in other studies. This is because some of the comparative studies are of an older date (2012, 2014) and since then the forecasted futures prices for natural gas and crude oil have been lowered due to a weaker than expected global economic recovery, oversupply of hydrocarbons and continuing geopolitical uncertainty affecting global growth forecasts. The LNG price forecasts used in this study are in line with previously stated LNG distribution costs to smaller scale LNG storage facilities (estimated at 207 $/t[10]), the relatively low

[10] MAN (2013) - Costs and benefits of LNG as a ship fuel for container vessels

LNG distribution costs are due to the expectation that most bunkering will be carried out through the most cost-efficient manner (as explained in Section 4).

3.4 Overview of scenarios

Figure 2 Global fuel demand outputs per scenario, PJ of energy[11]



Scenario 1- "BAU"

The BAU scenario only assumes the continuation of existing environmental regulatory arrangements (i.e. MARPOL commitments: EEDI, SOx and NOx regulations), but no further GHG policy developments such as a global MBM for shipping, measures to deliver immediate reductions or those pursuant to the recently agreed commitment to reduce CO2 by at least 50%. All other assumptions on market development, investment and transport demand are made at this 'baseline' level. This scenario is not in-line with the IMO's Initial GHG Reduction Strategy or the "at least 50%" reduction commitment.

Scenario 2- "High Gas"

The carbon budget in shipping is derived from the 2∘C target based under the 'Paris Agreement' requirements. The MBM expected for maritime shipping starts in 2025 achieving reductions within the maritime shipping sector and the remaining reductions of CO2 are achieved out of sector through purchase of emission reduction permits using up to 30% of the revenue generated from carbon pricing. Sustainable biofuel's market penetration into shipping is low due to an assumption of low availability. Slow steaming is assumed to take place, but is limited by equipment and safety constraints. The LNG price is lower than in other scenarios, allowing for a high take-up of LNG as a marine fuel. It is assumed that in a "High Gas" scenario, a low LNG market price would be achievable since in the early years the LNG demand would be low enough not to significantly impact a price rise (as is the case in the "BAU" scenario, which has a higher LNG demand in the early years), and that in the later years the price would still remain lower since is assumed that other sectors would start to decarbonize and move away from natural gas opening up more gas supply for shipping. Hydrogen is not available as an alternative in this

[11] Full figures of emissions and offsets are available in Appendix B

scenario. Due to the high uptake of LNG, total GHG operational emissions continue to grow beyond 2050, so most of the offsetting would have to be achieved in other sectors.

Scenario 3- “Transition”

The carbon budget in shipping is derived from the 2°C target under the ‘Paris Agreement’ commitment. The MBM expected for maritime shipping starts in 2030 and allows for 20% of the revenue generated from carbon pricing to be used out of sector in order to achieve remaining reductions of CO_2. The offsetting is lower than in Scenarios 2 and 4, since it is assumed that a “Transition” world would require this additional regulatory modification post-2030 to move away from LNG. Biofuels market penetration into shipping is low. Slow steaming is allowed, but limited. The LNG price is set higher than in Scenario 2 since it is assumed that under a “Transition” scenario the overall supply of LNG to the economy would be lower due to decreased investment into hydrocarbon extraction and LNG carrier shipping. This higher price still allows for a relatively high initial take-up of LNG as a marine fuel. However, unlike in Scenario 2, hydrogen is available as an alternative and since this scenario allows less offsetting in other sectors, once the carbon price increases sufficiently synthetic renewable fuel becomes the fuel of choice for compliance outperforming LNG. This scenario achieves decarbonization mostly through reduction of emissions in-sector and partly through an unspecified linkage to other sectors.

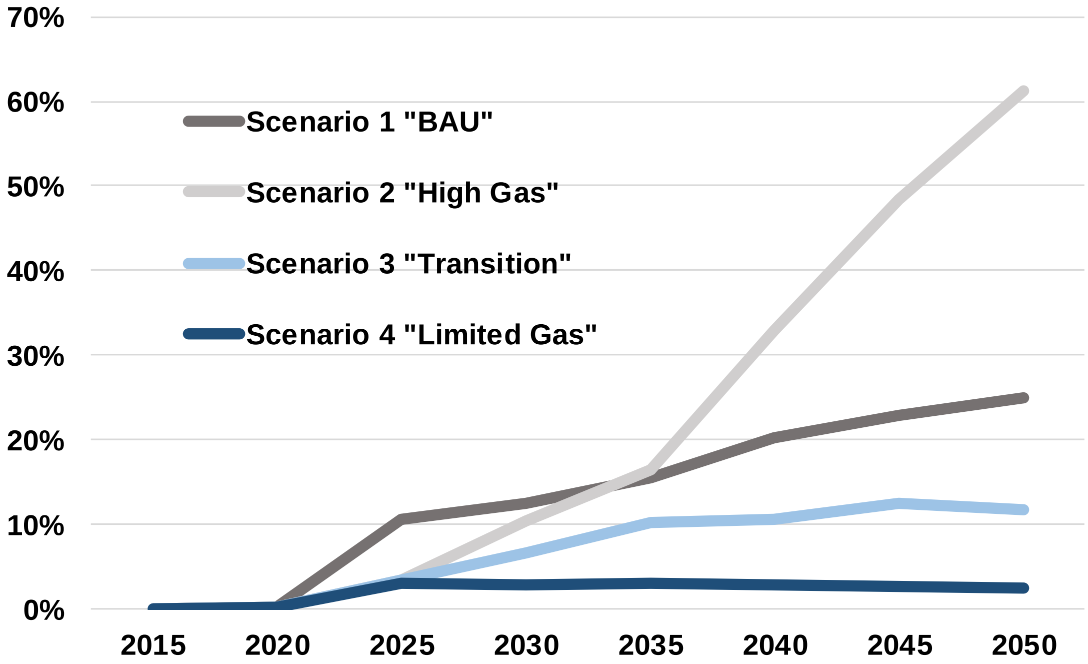
Scenario 4- “Limited Gas”

The carbon budget in shipping is derived from the 2° C target based under the ‘Paris Agreement’ pledges. The MBM expected for maritime shipping starts in 2030 and buying off-sets of CO_2 out-of-sector is allowed for 30% of the revenue generated from carbon pricing. Biofuels market penetration into shipping is mid-range. Slow steaming is allowed, but limited. The LNG price is higher than in Scenario 2, which still allows for a relatively high initial take-up of LNG as a marine fuel. However, unlike in Scenario 2, hydrogen is available as an alternative and since less offsetting in other sectors is available, once the carbon price becomes sufficiently high, hydrogen becomes the fuel of choice for compliance, outperforming LNG. This scenario again achieves decarbonization mostly in-sector and partly through offsetting in other sectors.

4 LNG Bunkering infrastructure projections

The development and spread of LNG as a marine fuel will require the construction and development of dedicated bunkering infrastructure, including within the EU. Total bunkering infrastructure necessary to meet the marine industry demand for LNG was estimated based on the most economically cost-efficient manner of bunkering. The study assumes the main intention of the investor (as outlined in EU legislation) is to invest in LNG bunkering facilities capable of supplying LNG volumes sufficient for a large-scale take up of LNG (i.e. utilisation by vessels with tank sizes up to 10,000 m3), even if in the early years this leads to overcapacity. The purpose of this analysis is to estimate the cost and size of bunkering infrastructure likely to be funded by public and private actors by 2050. The analysis also estimates the proportion of infrastructure likely to be (at least partially) publicly funded through EU and EU member state funds. The study assumption is that Directive 2014/94/EU implies the necessity for the construction of sufficient bunkering infrastructure by 2025/30 (maritime and inland waterways respectively) to allow for LNG to become a significant part of the EU maritime fuel mix.

Figure 3 Proportion of LNG in total maritime fuel demand mix, %



The global demand for LNG is taken as a starting point in projecting the necessary LNG bunkering infrastructure. LNG demand figures provided by GloTraM estimate global LNG demand, EU demand share is then calculated based on DNV GL projections[12] of the total number of LNG fuelled vessels in operation by 2015 and on order by 2020. The estimated and projected regional share of vessels operating in EU over this period is taken as a proxy for EU LNG fuel demand over 2010-2015. This share is then decreased annually following a linear decline until 2025; and is kept constant thereafter. The decrease is based on the growing number of non-EU orders for LNG fuelled vessels, leading to gradual decrease in the overall percentage of global marine LNG demand attributed to the EU as the LNG fleet of other regions grows.

4.1 LNG bunkering system boundary and bunkering pathways

As can be seen from Figure 4, this analysis of LNG bunkering infrastructure is centred on the costs of 'Midstream' LNG bunkering infrastructure. These are costs associated with delivering LNG from import hubs (i.e. large LNG import terminals or domestic liquefaction plants) to the end-consumer (LNG fuelled vessels). The costs include all the associated capital and operating expenditures relating to this process.

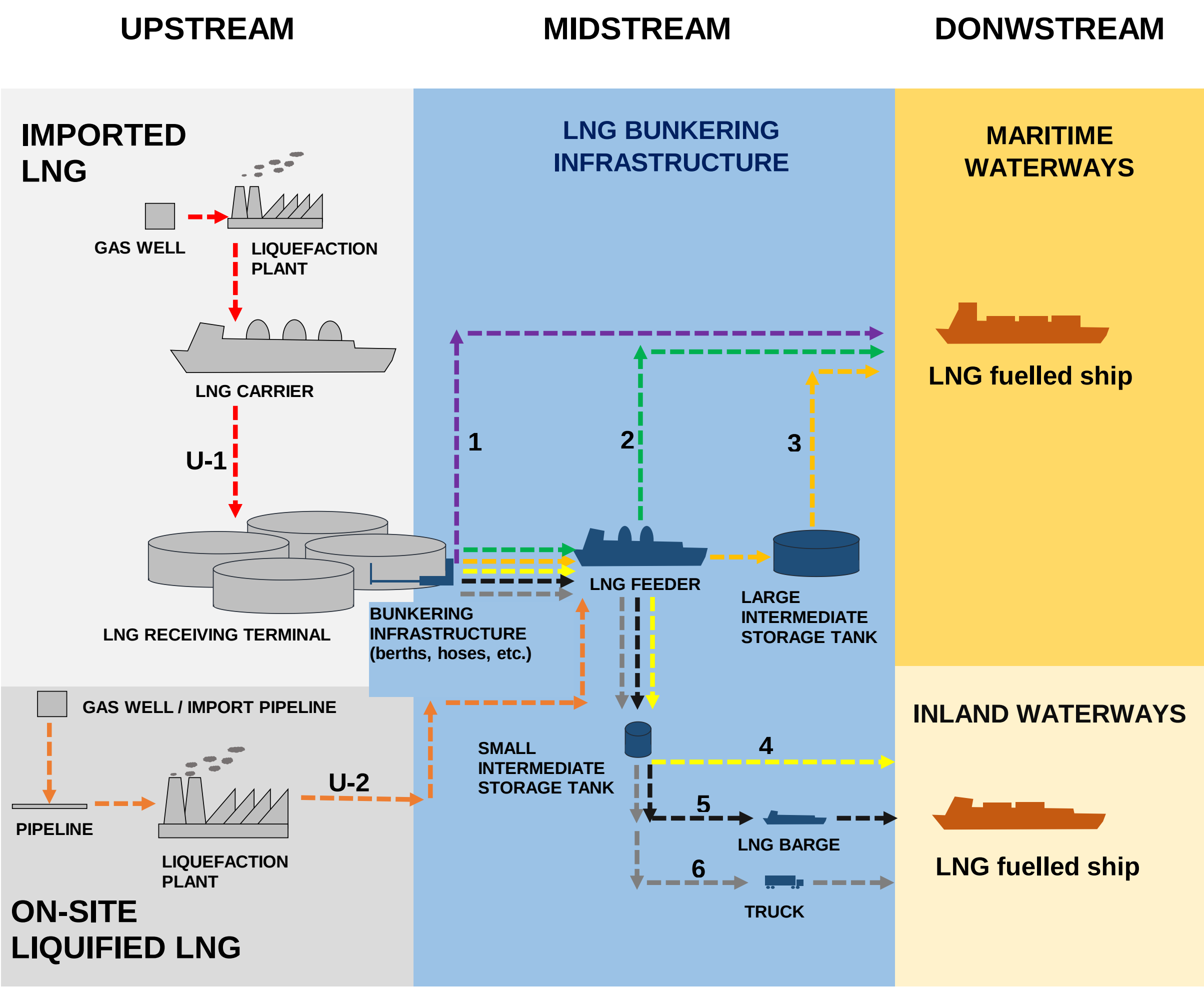
However, the costs of construction or operation of the large LNG import terminals or of the "Upstream" infrastructure are not reflected in this analysis, these are reflected in the price of the LNG contracts. The large-scale LNG import terminals are assumed to serve the whole economy, of which marine LNG is only a relatively small component. In each scenario the shipping LNG share is assumed to reflect developments in the wider economy with respect to usage of fuels.

The current import demand for LNG by the EU, stands at 32.6 MT[13], and according to some IEA estimates, this figure could almost double within the next decade[14] to over 65 MT. Our 'High Gas' scenario 2025 LNG maritime demand is 5.5 MT of LNG, which is below 9% of overall projected demand

[12] DNV GL (2015) In focus - LNG as a ship fuel, No.1 2015
[13] IGU (2017) World LNG Report, International Gas Union, 2017
[14] European parliament (2015) Liquefied Natural Gas in Europe, EPRS | European Parliamentary Research Service Author: Alex Benjamin Wilson Members' Research Service PE 571.314

for LNG by the economy, a tangible, but still relatively small proportion. Therefore, it is assumed that the construction of the large-scale LNG import infrastructure would follow a similar path irrespective of the developments and diffusion of LNG as a marine fuel. Analysis assumes in its four LNG diffusion scenarios described in Chapter 3, that if LNG would become the fuel of choice of the maritime industry, it would also be highly diffused within other transport modes and industry sectors in the EU so that a substantial further development of LNG import infrastructure would be necessary, irrespective of its usage in shipping. The same assumptions of different LNG diffusion levels are followed for the other 3 scenarios.

Figure 4 Likeliest LNG bunkering pathways for maritime and inland waterways



"Upstream" LNG delivery scenarios/ supply of LNG

US-1 Scenario

US-1 import scenario is assumed to be the principal source of fuel for the future maritime LNG bunkering industry in the EU. The scenario assumes that LNG liquefied and produced overseas in large LNG liquefaction facilities and imported through an LNG carrier to large EU-based import terminals. This type of industrial production of LNG is assumed to be the most cost-efficient due to the economies of scale involved in liquefying and transporting large volumes of LNG in comparison to domestic liquefaction of pipeline gas on-site in Europe which would create higher costs. Currently, large scale LNG import terminals exist throughout the EU (i.e. UK, Belgium, Netherlands, Spain, Portugal, Poland, Italy, Greece) with more planned to be built over the following decade (i.e. France, UK, Germany, Baltic

States, Cyprus)[15]. Western Europe is likely to meet most of its expected growth in demand for natural gas through existing terminals whereas Mediterranean and Baltic-Scandinavian states could see new demand met through additional terminals. In the Baltic States the construction of new terminals will likely be driven by energy diversification pressures resulting from national security concerns.

A substantial number of these terminals are currently used for LNG re-gasification and further transport via pipelines to end-consumers and as such cannot be directly used for maritime purposes. However, the construction of associated LNG specific infrastructure, in-situ when they are located next to large ports, could provide some ships with cost-effective on-site bunkering. Most other bunkering would involve the development of a system of feeder ships transferring LNG from large LNG terminals to smaller LNG storage tanks located at ports where the need arises or directly to the LNG fuelled vessels.

US-2 Scenario

US-2 scenario assumes the demand for LNG being met through on-site liquefaction or re-liquefaction of LNG from EU national gas networks. Due to the smaller scale of such liquefaction activities, this scenario is expected to play only a minor role in this study, since the costs of LNG liquefaction in smaller facilities are substantially higher than those from imported LNG (ranging from 160[16]-1,200[17] $/t). In addition, in many places the gas utilised from the natural gas grid would not be domestically produced, but already re-gasified (previously imported from the LNG import terminals) which would have to be re-liquefied creating a double liquefaction pathway with significant increases in well-to-propeller emissions and LNG delivery prices. Some of the gas could be imported from Western Siberia or Caspian Sea Basins via pipelines, but it is assumed that pipeline gas will mostly be used to meet land-based demand (i.e. industry, district heating) and that small-scale liquefaction of this supply would be to too expensive for most maritime purposes. With EU domestic natural gas production falling off and expectations of further growth in the share of natural gas from LNG imports in domestic gas grids[18], this scenario is expected to become even less economically feasible in the future than it is now.

Possible "Midstream" LNG bunkering scenarios

We discuss six realistic LNG bunkering 'Midstream' scenarios which include the supply of LNG from the domestic supply point (whether the liquefaction facility or large-scale LNG import terminal). The bunkering scenarios are summarised above and illustrated in Figure 6. As explained previously, Scenario 2, is expected to be the scenario of choice for most of the maritime shipping industry under this study due to its cost-effectiveness and supply flexibility. In addition, Scenarios 1 and 3, are assumed to play an important role in meeting marine and inland shipping bunkering demand in the future, if LNG is to become a widely available and financially viable choice for the maritime industry. Scenarios 4-6 are more expensive, but are better suited for the supply of smaller LNG volumes at places where large LNG feeders could not navigate, such as inland waterways.

Scenario 1

In Scenario 1, LNG fuelled vessels are directly bunkered on-site at the LNG import terminal through a tailor-made facility utilising a purpose-built pipeline and berth. This scenario would be called TPS (terminal-to-ship via pipeline) and is a practical bunkering solution for all sizes of LNG fuelled vessels. This is an especially attractive option for recurring customers, such as liner cargo ships calling at a port

[15] European Parliament (2015). Liquefied Natural Gas in Europe, EPRS | European Parliamentary Research Service Author: Alex Benjamin Wilson Members' Research Service PE 571.314
[16] DMA (2012) North European LNG Infrastructure Project, Danish Maritime Authority, Copenhagen, March 2012
[17] Songhurst, B (2014) LNG Plant cost escalation, OIES PAPER: NG 83
[18] IEA (2017) Gas 2017, Analysis and Forecasts to 2022, Market Report Series, European Parliament (2015). Liquefied Natural Gas in Europe, EPRS | European Parliamentary Research Service Author: Alex Benjamin Wilson Members' Research Service PE 571.314

close to an LNG bunkering terminal (e.g. port of Rotterdam). It is expected to be used primarily for larger bunker volumes.

Scenario 2

In Scenario 2, LNG is loaded onto a large LNG feeder vessel (10,000 m3) for delivery to a ship at a remote location. This scenario is called STS (ship-to-ship) bunkering, and under this study is expected to be the bunkering method of choice for the majority of LNG fuelled vessels. It is specifically well suited for customers requiring over 100m3 of bunker volume. The scenario assumes a relatively short turnaround time for customers. The scenario envisions no need for the development of local storage facilities.

Scenario 3

In Scenario 3, LNG is delivered by a large LNG feeder vessel (10,000m3) from the LNG import terminal to medium-sized LNG storage tanks (50,000m3) from which using a terminal-to-ship (TPS) bunkering method LNG can be off-loaded to maritime customers. This scenario is most cost-efficient for relatively small vessels (up to 200m3) operating at specific ports and requiring regular re-fuelling at fixed locations (e.g.ro-ro ferries, short sea shipping). The scenario includes higher capital expenditures (CAPEX) than Scenario 2 and is expected to form only a minor part of the total LNG bunkering supply network. This is because all scenarios assume most LNG demand will be met from medium to large vessels in the future, for which Scenario 2 is a better option in most cases.

Scenario 4

In Scenario 4, LNG is delivered by a smaller LNG barge (3,000m3) from the LNG import terminal to small-sized LNG storage tanks (700m3) from which using a TPS method LNG can be off-loaded to customers. This scenario is most cost-efficient for relatively small vessels (up to 200m3) operating on specific routes where there is limited navigability for larger vessels (i.e. inland waterways) requiring regular re-fuelling at fixed locations. The scenario includes higher capital expenditures than Scenarios 1-3 and under this study is only expected to be a viable bunkering option for inland waterways.

Scenario 5

In Scenario 5, LNG is delivered by a smaller LNG barge (3,000m3) from the LNG import terminal for delivery to a ship at a remote location. This scenario utilizes STS (ship-to-ship) bunkering, and is the most cost-efficient for relatively small vessels (up to 200m3) operating at specific routes, with limited navigability for larger vessels (i.e. inland waterways) requiring regular re-fuelling at fixed locations. The scenario includes higher capital demand expenditures than Scenarios 1-3 and under this study is only expected to be a viable bunkering option for inland waterways. It is assumed to be used in combination with Scenario 4.

Scenario 6

In Scenario 6, LNG is delivered by a small LNG barge (3,000m3) from the LNG import terminal to small-sized LNG storage tanks (700m3) from which using a LNG transport truck (i.e. TTS - Truck-to-Ship method) LNG can be off-loaded to customers at specific berths. This scenario is a relatively viable option for small vessels (up to 200m3) operating on tramp routes, or routes where no other form of LNG bunkering infrastructure exists, where there is limited navigability for larger vessels (i.e. inland waterways). The scenario includes higher capital demand expenditures than all other scenarios and under this study is not expected to be a viable large-scale bunkering option. Consequently, this scenario, even though discussed, is not modelled within the analysis. Over the longer term this study assumes that on all routes where LNG becomes an established fuel, Scenario 6 would be replaced by Scenarios 4 and 5 due to the high bunkering cost of Scenario 6 and associated volume and time constraints (i.e. inherent low fuel transfer rate).

Upstream pathway assumptions

The upstream scenario chosen US-1 involves the utilisation of LNG from imported countries via LNG carriers supplying large European LNG terminals with LNG. This is assumed to be the most cost-efficient way of importing LNG due to the economies of scale involved in liquefying and transporting large volumes of LNG in comparison to domestic liquefaction of LNG on-site. On-site liquefaction is assumed to play a minor role in the process of LNG supply due to the relatively high costs of LNG re-liquefaction estimated at a minimum 150 $/t[19]. It is assumed that most LNG imports up to 2020 will originate from Qatar, beyond 2020, 25% of LNG is assumed to originate in the USA. This is substantiated by the fact that most UK Grain LNG Terminal long-term contracts are tied to LNG imports from the USA, and a similar scenario is assumed for the rest of the EU.

4.2 Bunkering pathway assumptions

The best solution for bunkering will be different for each ship type and journey type, involving LNG bunkering volumes, vessel size, fuelling frequency, pre-existing distribution networks, safety, regulatory considerations and local environmental concerns. However, the main aim of this study is not to estimate the exact ideal combination of different bunkering options, but to estimate the required investment by the EU into the generally most cost-effective bunkering solution necessary to create sufficient bunkering infrastructure capable of meeting LNG demand from maritime shipping. The study assumes the aim of the LNG public funding is to support LNG becoming a substantial fuel used by ships calling at EU ports, and therefore of the global maritime shipping industry as well.

This analysis assumes that most maritime bunkering will take place through Scenario 2, with Scenarios 1 and 3 playing a supporting role due to this combination being the most cost-efficient and meeting the needs of the vast majority of ship types. It assumes that 80% of the total demand will be met through Scenario 2, with the remainder equally distributed between 1 and 3, based on the analysis of historical shipping routes, demand for LNG from different maritime industry segments (by ship type and LNG tank size) and GloTraM projections of future LNG demand by ship segment.

As this analysis assumes investments into LNG with the investor's principal aim being the propagation of a technological transition of shipping towards LNG, it is understood that most fuel demand would come from large container vessels operating on global liner and tramp routes into the EU, with a smaller proportion from domestic (intra-EU) liner routes, reflecting the nature of the global shipping industry. Most of this demand is projected to be met through Scenario 2, which offers a simple way to refuel a ship of a given size and at a relatively small cost (no additional LNG storage facilities needed).

Some of the LNG demand from large ships entering ports which already have LNG import terminals could be met through Scenario 1, but even those ships are mainly expected to utilise Scenario 2, at least for some of their voyage needs. A combination of Pathway 2 and 3 is estimated to be utilised by ships with smaller LNG tanks (below 300m3) which require regular refuelling at multiple locations. In addition, pathway 2 offers the least number of environmental and regulatory difficulties from an infrastructure development perspective, since the development of LNG storage facilities generally involves public consultations and addressing concerns from the public could prolong the site selection process and permit application timelines.

[19] DMA (2012) North European LNG Infrastructure Project, Danish Maritime Authority, Copenhagen, March 2012

4.3 LNG bunkering input assumptions

Infrastructure unit costs and operating expenditures

The bunkering infrastructure estimate in this study is based on the calculated total annual demand for LNG as a ship fuel within the EU per the GloTraM model under the four different scenarios. This demand is taken as a starting point under the scenario pathways explained above to estimate the total infrastructure costs of LNG bunkering costs are calculated annually, based on the total annual requirements for LNG bunkering infrastructure under LNG demand projections. The calculations assume fixed unit and operating costs for different infrastructure segments (Table 3).

Table 3 Cost assumptions for LNG bunkering infrastructure components*

Component	Unit cost/ million $	OPEX $/t	Annual capacity /mmtpa
Pipeline (1km)	0.6	0.1	0.90
Terminal extraction fee	N/A	2.48	N/A
LNG Storage Tank (50,000 m3)	120	18.7	0.91
LNG Storage Tank (700 m3)	9	0.2	0.01
LNG Feeder vessel (10,000 m3)	60.7	2.7	1.84
LNG Bunker vessel (3,000 m3)	41.9	2.2	0.60
Truck (50 m3)	0.22	0.04	0.04
Other (Berth, Hoses, Services, Administration.)	40.8	0.4	0.90

Sources: DMA 2012, EP 2015, TNO 2017

The economic lifetime of LNG storage tanks is taken to be 40 years and that of LNG bunkering vessels, 20 years. These lifetimes are taken as standard values and it is expected that investment in vessels and tanks with shorter lifetimes would not significantly lower CAPEX. The operational costs are adjusted for capacity utilisation based on historical figures obtained from reputable sources and estimates based on likely utilisation rates under the 4 different scenarios. LNG feeder vessels, assumed to be the main mode of bunkering (through Scenario 2), can range in size from 700 m3 - 10,000 m3. This analysis assumes that bunker vessel volumes for maritime bunkering will tend toward the higher end of the scale due to expectations of higher marine LNG demand in the future. However, the size of storage tanks and vessels is adjusted to reflect the realistic expected demand via different pathways. This estimate assumes EU investment into bunkering infrastructure involves significant financial commitments to build infrastructure for a long-term transition to LNG rather than emphasizing shorter term financial returns.

As for LNG feeder vessels, intermediary LNG terminals are expected to be also constructed at the higher capacity end of the scale (50,000 m3) in order to be available for potential future demand. These are assumed to be stationary onshore LNG tanks in close proximity (within 1km) of ports where TPS bunkering can take place. Annual capacities of different vessels and terminals are based on maximum obtainable capacity utilisation factors (90-95%) gathered from literature, considering net-capacity, vessel availability, turnover time and potential set-backs.

Operating expenditures include fuel costs, running costs, as well as terminal extraction fees, which in some cases can form a sizeable proportion of total OPEX. Pipeline costs include average annual operating costs of a pipeline of 1km (estimated the average pipeline length from large LNG terminal to LNG bunkering vessel berth) based on likely construction of such facilities at existing North European LNG import terminals (Zeebrugge, Rotterdam). Pipeline costs also include costs of manifold connections. Other costs include costs of constructing a bunkering quay, engineering works at the quay (lighting, electricity), supervision and documentation cost as well as the necessary license application cost, all of which are adjusted for the relative size of the facility in terms of annual LNG bunkering capacity (Table 3). The calculations of total numbers of infrastructure segments are then carried out based on the projected future annual capacity required from the GloTraM model for LNG. These figures are adjusted to reflect the annual capacity construction needed to meet an initial small, but geographically widespread demand (with low capacity utilisation factors i.e. 20%) growing to a higher capacity utilisation as LNG demand catches up with infrastructure. The study does not assume any additional dredging, land reclamation or quay development infrastructure costs.

Capacity utilisation rates

The total capacity demand to be constructed by 2030 in the three non - "BAU" scenarios is based on the LNG demand scenario "High Gas". This is based on the statement made in the Directive 2014/94/EU that: "*A core network of refuelling points for LNG at maritime and inland ports should be available at least by the end of 2025 and 2030, respectively*." The "High Gas" scenario LNG demand for 2030 is presumed to be equivalent to the potential demand to be covered by the core TEN-T network of LNG refuelling points. This is because the "High Gas" scenario in 2030 is at the early stage of a transition towards LNG becoming a major marine fuel (beyond ECA areas) within all TEN-T core ports. The 2030 LNG capacity demand, rather than 2025 is taken as the baseline capacity due to the understanding that the built capacity has enough redundancy to meet projected growing demand 5 years into the future (observed timeline necessary to construct new capacity, from planning-licensing-construction).

Financial assumptions

The necessary annual capital expenditures associated with construction of LNG bunkering infrastructure to meet demand are amortized over a 20-year period, assuming a 5% annual interest rate. The revenues from the investor's perspective are calculated based on the LNG price projections used for each of the four scenarios, assuming an operating profit margin of 5%, which is based on observed historical operating profit margins of ship operators (ranging from 1.5% to 20%). The obtained revenue streams are then subjected to a cash-flow analysis, under a standard discount rate of 10% to assess the profitability of the project from the long-term perspective of the investor, in this case the EU project funders and other private-public partnerships. The aim of this analysis is to determine the relative profitability of each one of the four scenarios assuming an initial set of capital investments (up to 2025) based on the "High Gas" scenario capacity, thus the payback times for the investments are not set as inputs, but are outputs.

4.4 Inland waterways input assumptions

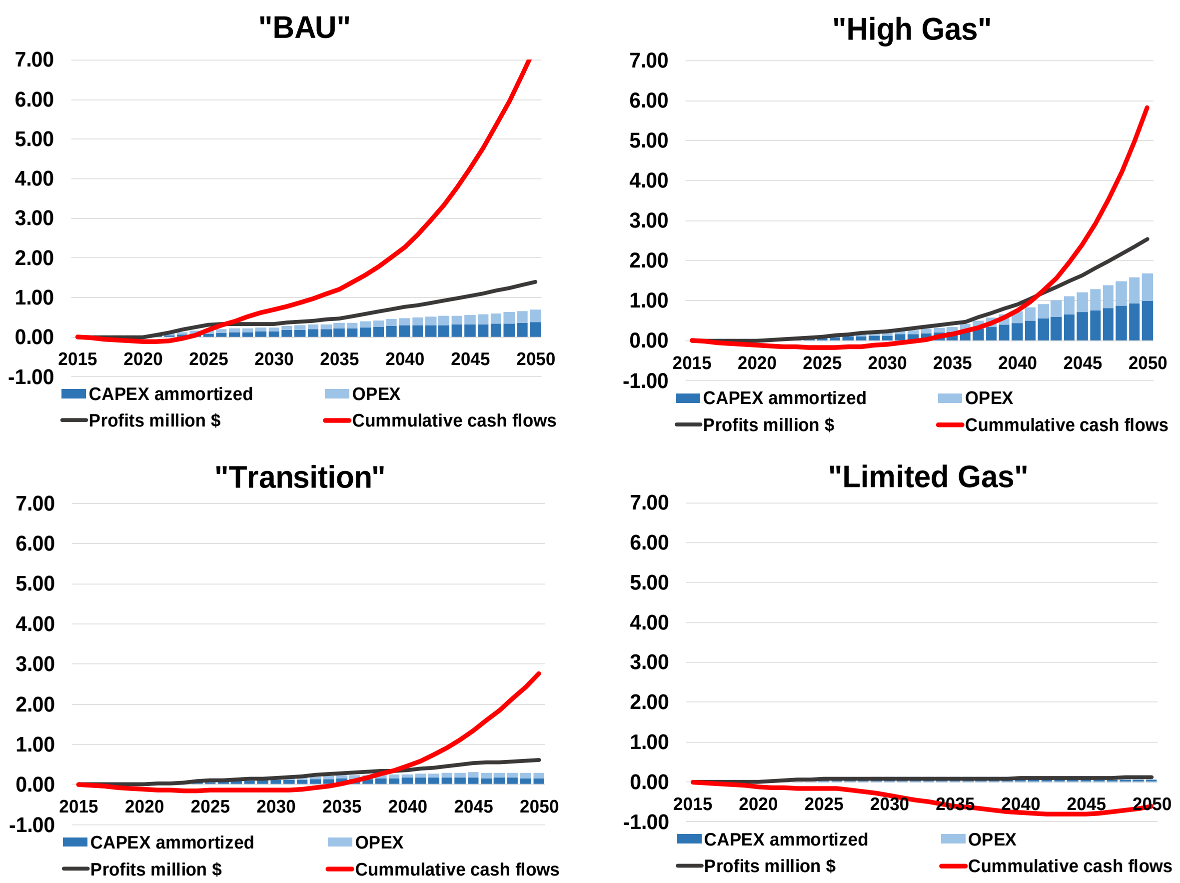
This study also includes the estimate of LNG bunkering infrastructure for inland waterways. The bunkering scenarios for inland waterways have been outlined in the previous chapter. This study assumes that the most economically cost effective bunkering pathway would be an even combination of Scenarios 4 and 5 and uses the same LNG demand methodology as outlined for the maritime transport demand to calculate the corresponding bunkering infrastructure. The EU has already observed the development of LNG barges for usage on EU inland waterway, with current examples coming from the port of Rotterdam.

In addition, the LNG demand figures from GloTraM only cover maritime shipping and do not include demand from inland waterways. The demand from inland waterways was calculated based on the total historical shares (Eurostat, 2017) over 1995-2014 of EU inland waterway freight transport (in billion t-km) compared to EU freight transport over the same period, which gives a steady figure of 13%. This figure is taken as a rough proxy for the percentage of LNG inland waterway demand in comparison to maritime waterways as obtained from GloTraM.

4.5 Outputs- bunkering infrastructure cash-flow analysis

A cash flow analysis was carried out for all four scenarios, the results are shown in Figure 8 and Table 4. The cash flow analysis shows that apart from the “Limited Gas” scenario, all other three scenarios show that by 2050 a return on the initial capital investment into LNG bunkering infrastructure would be achieved. The “BAU” scenario as expected, shows the highest IRR and NPV values, as it is not constrained by any MBM measures after 2025 and is not on course to meet the “Paris Agreement” pledges or EU maritime reduction goal compared to the other scenarios which are shaped more by the “Paris Agreement” pledges. As a result, LNG is taken up relatively quickly in the early years. Consequently, the highest amount of infrastructure necessary to be built by 2025/30 is in the “BAU” scenario. In “BAU” there is no redundant infrastructure and a relatively healthy LNG price allows for an early return on investments.

Figure 5 Cash flow analysis of the four LNG demand scenarios, billion $



The cash flows for the “High Gas” and “Transition” scenarios, show a lower return on investment than under the “BAU” scenario. In both cases the payback time would be longer than in the “BAU” scenario. The “High Gas” scenario has a considerably longer payback time of 31 years compared to 19 for the “Transition” scenario, even though the “High Gas” scenario assumes a far higher adoption of LNG by 2050 (10,000 PJ compared to 1,800 PJ). This is because the difference in LNG adoption between the two scenarios is noticeably smaller before 2030 (under half) leading to similar capital investments over this period. However, in later years, the higher revenue of “High Gas” compared to “Transition” is assumed to be due to the higher LNG adoption by 2050 (over three times total fuel demand, 2015-2050) which is partially offset by the discounting rate on future revenues (10% per annum) and lower LNG price in the “High Gas” scenario. Therefore, the “High Gas” scenario is marginally more profitable than the “Transition” scenario, but the return on this investment takes 12 years longer. From the perspective of an investor looking at long-term societal returns such as a public funding body (i.e. EU member states), this is not necessarily in its own right a deterrent to investments. The “Transition” and “High Gas” scenarios imply that investment into LNG bunkering infrastructure under a 2°C target will have relatively long investment return periods which are financially justifiable dependent on how the investment (beyond financial returns) such as societal and environmental benefits are judged.

Table 4 Results of LNG demand scenario cash flow analysis

Cash flow component	"BAU"	"High Gas"	"Transition"	"Limited Gas"
NPV TOTAL (million $)	395	52	58	-211
NPV CAPEX (million $)	968	622	315	-100
IRR % TOTAL	22%	14%	12%	NO IRR
IRR % CAPEX	36%	25%	21%	NO IRR
Payback time (years)	11	31	19	55
Payback time CAPEX (years)	7	11	11	53
CAPEX* (million $)	10,584	22,205	5,524	2,937

**Amortized at 5% discount rate over 20 years, "TOTAL" includes both CAPEX and OPEX*

The cash flow for the “Limited Gas” scenario is strongly negative with an NPV of -211 million $ (-100 million $ if only CAPEX is considered, which is the stranded investment aspect of the cost), which can be considered a direct investment loss by 2050. This scenario shows the potential risk of investing strongly in LNG bunkering infrastructure under Directive 2014/94/EU guidelines, if LNG is not taken up as a marine fuel by the maritime industry. As a result of a higher take up of biofuels and hydrogen (both of which also fall under Directive 2014/94/EU), and a strong push to lower in-sector GHG emissions from shipping, LNG never becomes heavily diffused into the shipping industry.

Table 5 Required bunkering infrastructure by 2050, number of units

Type of unit:	"BAU"	"High Gas"	"Transition"	"Limited Gas"
Feeders	30	54	17	6
Barges	6	11	4	3
Large storage tanks	8	17	4	2
Small storage tanks	213	481	111	59

The analysis outlined in Figure 10, presents the total number of different bunkering units needed to be built within the EU by 2050 to meet the total LNG bunkering demand (assuming initial construction up to 2030 under a “High Gas” scenario for non-BAU scenarios, and construction to meet demand under “BAU”). These numbers assume an equal geographic LNG demand distribution and thus assume an even capacity utilisation for all regions of the EU. Based on the described “Midstream” pathway scenarios 2,3,4,5; the feeder vessels and large storage tanks are generally used to meet maritime LNG demand, whereas small storage tanks and barges meet inland waterway LNG demand.

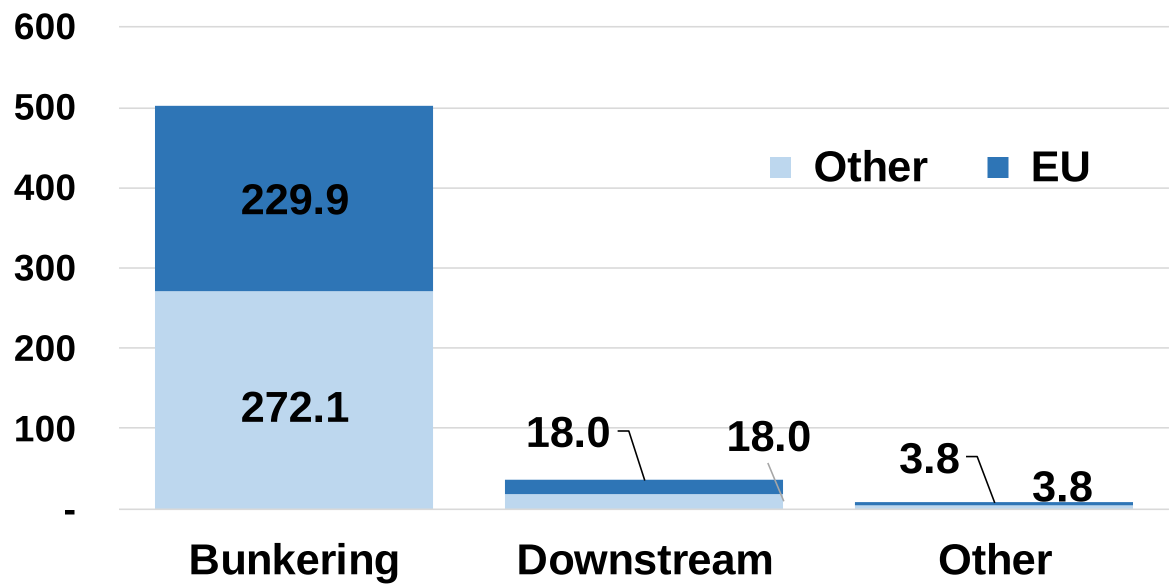
Table 6 Expected redundant capacity by 2050, number of units

Type of unit:	"BAU"	"High Gas"	"Transition"	"Limited Gas"
Feeders	0	0	2	10
Barges	0	0	1	3
Large storage tanks	0	0	1	2
Small storage tanks	0	0	15	49

Following from the cash-flow analysis and calculation of infrastructure units necessary to meet bunkering demand, the total “redundant” overcapacity of built infrastructure under the four scenarios can be expressed in terms of LNG bunkering infrastructure units. The analysis outlined in Table 6 shows that under the "BAU" and "High Gas" scenarios no redundant capacity exists as there is a continued growth in LNG demand with no overcapacity existing by 2050. In the "Transition" scenario there is some overcapacity, resulting from the early construction of a large amount of bunkering infrastructure over a large geographic area, some of which is not expected to be fully utilized. In the "Limited Gas" scenario, there is considerable overcapacity built because the total demand for LNG by 2050 is considerably below the "High Gas" scenario demand in 2030 (almost 70% lower). This overcapacity figure considers the retirement of LNG barges and feeders (assuming a 20-year lifetime) constructed prior to 2030. It could be argued that this overcapacity in the "Limited Gas" scenario equates to stranded bunkering infrastructure assets in 2050.

4.6 Outputs- EU bunkering investments per scenario

Figure 6 Historical TEN-T and CEF funding for marine LNG projects, million $*



**Source: European Commission*

Based on the total projected amortized CAPEX to be spent on bunkering infrastructure, the EU member state funding share has been estimated. Many uncertainties are associated with such an estimation. Firstly, there are several different funding schemes, as explained in Chapter 1 and described in Figure 1, that can constitute EU member state funding under Directive 2014/94/EU. These include CEF, regional and national funds in the form of grants, all of which could potentially fund a different share of the overall cost of various bunkering projects. This study estimates the proportion of EU bunkering infrastructure capital costs to be funded publicly by EU and member states at 45%. This figure is based on a literature review of all historical and existing TEN-T and CEF projects that mainly fund activities surrounding the development of LNG as a marine fuel. The figure was calculated based on the average EU funding share for the listed projects.

Table 7 Estimated share of future EU and member state investments into LNG bunkering infrastructure, million $

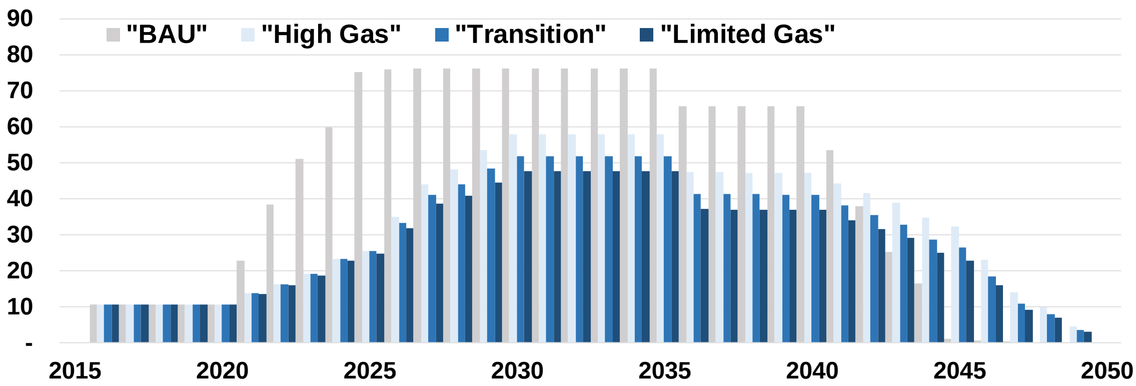
Funding:	"BAU"	"High Gas"	"Transition"	"Limited Gas"
Private funding:	4,296	11,055	2,002	957
EU-2050:	4,763	9,992	2,486	1,028
EU-2025/30:	1,525	1,158	1,036	952
Total:	10,584	22,205	5,524	2,937

**Amortized at 5% discount rate over 20 years*

The total amortized infrastructure CAPEX is estimated for all four scenarios is used to calculate the public funding component (EU and member state funding). Two possible future public funding scenarios are explored. The first assumed that all public funding for LNG bunkering facilities will cease after 2025/30, since the TEN-T core network of facilities is constructed. The second scenario assumes that public funding will continue up to 2050. In both scenarios, the calculations assume a 20-year amortization of CAPEX (Table 7). The scenarios imply that even if public funding ceased by 2025/30, total public infrastructure expenditures over this period would still amount to US$ 0.95-1.5 billion; this is at least a five-fold increase from what has already been spent on LNG bunkering infrastructure under CEF and TEN-T projects.

It should be noted that, perhaps somewhat counterintuitively, the “BAU scenario” which assumes lower LNG uptake, than the “High Gas” scenario, still has higher infrastructure costs. This is because up to the 2030s, the “BAU” scenario assumes higher LNG demand compared to the “High Gas” scenario, and the “High Gas” scenario make up in terms of overall demand for LNG in these later years compare to “BAU”. Since “BAU” requires higher infrastructure construction rates (and consequently higher associated costs) in the early years compared to “High Gas”, the discounting rate applied in the analysis affects the “High Gas” infrastructure developed in later years more than the bulk of “BAU” infrastructure developed in the earlier years leading to a higher infrastructure cost for “BAU”.

Figure 7 Amortized EU and member state bunkering infrastructure costs 2015-2050, million $



5 Upstream, Midstream and Downstream/Operational emissions

The GloTraM scenario LNG demand analysis considers operational and upstream emissions for each potential fuel type to project global shipping emission trajectories up to 2050 in order to calculate relative fuel demand trajectories under different carbon budgets. Fuel consumption data for different vessel types has been used in combination with emission factor data (in units of kg of emission per GJ of fuel consumed) to estimate the well-to-motion (WTM) emissions for each vessel type. The data is based on published state of the art information and direct communications with industry stakeholders. The GloTraM analysis considers emissions of CO2, methane (CH4) and nitrous oxide (N2O) then converts them into total CO2 equivalent (CO2eq) emissions using the latest Global Warming Potential (GWP) values for CH4 and N2O (IPPC, 2014). Methane slip emissions are also included.

Based on the system boundary as explained in Figure 6, “Upstream” and “Midstream” bunkering components would have associated emissions relatable respectively to well-to-terminal (WTT) and terminal-to-tank (TTT), whereas “Downstream” would be equivalent to tank-to-motion (TTM) emissions. In this study WTT are labelled as “Upstream” emissions, TTT emissions as “Midstream” emissions and TTM are referred to as “Downstream” emissions. Whereas entire lifecycle emissions are referred to as well-to-motion (WTM) emissions. Similar analyses are conducted for other available fuels in the four different scenarios.

5.1 Upstream emissions- Well-to-Terminal (WTT)

WTM emissions for LNG fuelled ships contain a high degree of uncertainty and are very sensitive to several factors. Main practices that effect emission factors are: types of upstream well extraction methods, energy used during upstream liquefaction, treatment of boil-off-gas and choice of powertrain technology. The Upstream LNG bunkering scenario UP-1, as described in Chapter 4, is assumed to be the preferred choice for LNG imports. The scenario assumes most LNG will come from overseas imports via LNG carriers with a smaller proportion coming from domestic production via pipelines. In this analysis a base case approach to emissions is taken based on current trends and likely future practice evolution in the LNG sector. The base-case assumes that most LNG imports come from Qatar in 2015-2020, 25% of all LNG is assumed to originate from the USA beyond 2020. This is supported by the fact that most of the capacity holders at the Isle of Grain have already bought long-term LNG export volumes from the United States.

LNG in the United States is extracted from several small gas fields and therefore has higher WTT emissions – 20.1 gCO_{2eq}/MJ compared to 12.8 gCO_{2eq}/MJ for Qatar LNG as is further explained in the UCL ETI 2016 Report. On an EU-wide level based on the JEC, 2013[20] study there is wide range in WTT emissions per upstream pathway, ranging from 7.76 gCO_{2eq}/MJ for shale gas to 22.57 gCO_{2eq}/MJ for natural gas imported from Russia. The GloTraM, Upstream emission factor (WTT) is set at 6.87 gCO_{2eq}/MJ, on the lower side, as it excludes TTM emissions (included in WTM), and assumes that LNG bunkering demand will be met with limited usage of LNG storage tanks, the main source of LNG "Midstream" emissions. In addition, the emission factor used assumes that some of the LNG demand will be met through liquefied gas produced on site from more local source (i.e. North Sea) with estimated lower "Upstream" emission factors.

5.2 Midstream emissions-Terminal-to-Tank (TTT)

LNG bunkering emissions, or TTT emissions have been calculated on an emission factor basis using assumptions on the likeliest combination of scenario pathways as described in Chapter 4. The assumption is that 70% of overall LNG bunkering demand (87% of marine demand) will be met though LNG feeder vessels supplying ships and the remainder (including inland waterways) through a combination of medium and small sized LNG storage tanks and small LNG barges. The TTT emissions cover:

- LNG transfer emissions from terminal to LNG feeder.
- LNG feeder transport emissions to ship for refuelling.
- Energy use during LNG feeder loading and unloading.
- Methane emissions from LNG feeder transport and stationary operations (i.e. venting and boil-off gas).

LNG feeders are assumed to transport LNG to the end-consumers (LNG fuelled ships) or coastal LNG storage tanks. The emission factors in GloTraM account for LNG feeder emissions and energy used by the station for pumping LNG into the ship. Under our scenario the TTT emissions for LNG dispensed to ships amount to ca. 2.1 gCO_{2eq}/MJ in 2020 and decreases down to 1.2 gCO_{2eq}/MJ in 2035, mostly due to the decarbonisation of the EU electricity grid. TTT emissions are generally mostly made up of filling station emissions which can vary based on assumptions on infrastructure development, utilisation rates and choice of standard station practices. In some cases, poor environmental practices and low turnover can result in LNG emissions of up to 26 gCO_{2eq}/MJ in 2020. TTT emissions are assumed to decrease over time with increased station utilisation rates and in the pathway scenario of this study (combination of Scenario 1,2,3 and 4, with 70% attributed to Scenario 2, and the rest distributed amongst the rest, based on likely sizes of vessels, inland waterways and routes), it is assumed that only a limited amount of LNG bunkering demand (30%) will require the usage of LNG filling terminals.

[20] JEC (2013) Well-To-Tank Wheels analysis. Well-To-Wheels analysis of future automotive fuels and powertrains in the European Context.

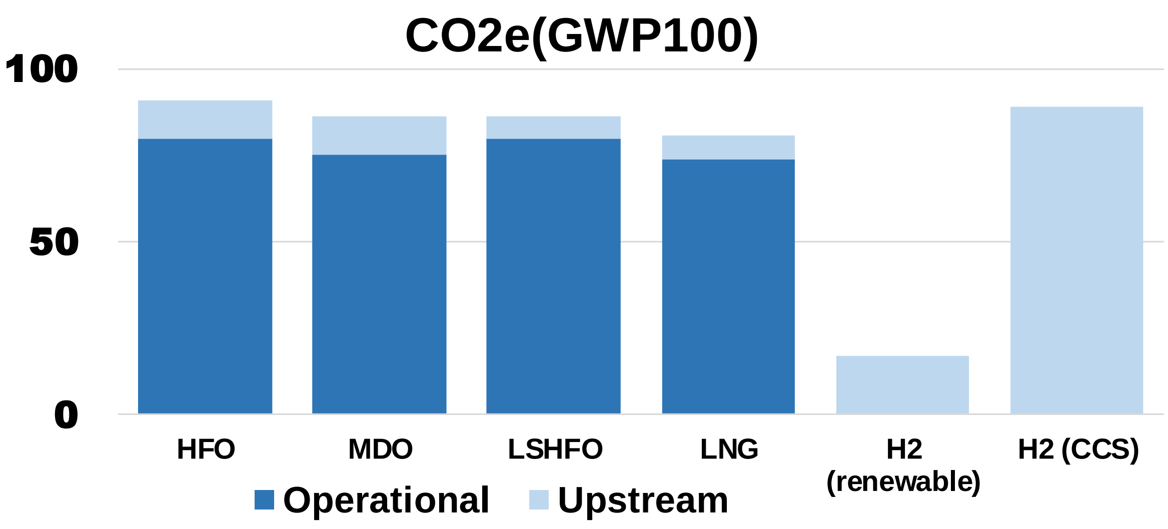
Table 8 Estimates of Well-To-Motion emissions for LNG fuelled vessels, gCO2eq/MJ

Source:	WTM GHG emissions, gCO2e/MJ	Assumptions
GloTraM	80.9	LNG from imports
ICCT, 2013	72.1	LNG from imports- TPS bunkering
ICCT, 2013	73.5	LNG from imports-STS, TPS combo
DNV GL, 2015	80.2	LNG (Qatar to Europe)
TNO, 2011	80.2	LNG (Qatar to Europe)
TNO, 2011	92.6	LNG NL PIPELINE

5.3 Downstream-TTM and total WTM emissions

The "Downstream" emissions ecomaps the TTM (Tank-to-Motion) part of the life-cycle emission pathway for LNG bunkering. The pathway encompasses tailpipe emissions including methane slip. There is no capture of N2O emissions by the model, as no robust methodology has been developed for it, but its potential to greatly increase emissions is noted. TTM emissions consider LNG engine efficiency losses, methane slip and diesel substitution rate. The resulting combination "Downstream" and "Midstream" emissions used in this calculation is estimated at 74.1 gCO_{2eq}/MJ, including methane slip[21]. Using these assumptions LNG can result in a decrease of GHG emissions of 6% to 11% based on GloTraM emission factors compared to MDO, HFO or LSHFO. Consequently, the total WTM GHG emissions are estimated in GloTraM at 80.9 gCO_{2eq}/MJ, which is in line with other estimates assuming similar "Upstream" and bunkering LNG pathways.

Figure 8 WTM emissions for LNG demand analysis per available fuel, gCO_{2eq}/MJ,



5.4 Methane slip assumptions

Methane slip, or emissions of unburnt methane, are the operational and upstream emissions associated with the methane that escapes into the atmosphere during LNG combustion. Methane is an incredibly potent GHG so any net abatement benefits from using LNG as a marine fuel can be undone by methane slip.The distinction should be made between "Upstream + Midstream" bunkering leakages and "Downstream" methane slip, using the terminology described for the six bunkering pathways in Chapter 4.

[21] Raucci et al. (2018) The potential for LNG as a marine fuel in the contest of shipping's low carbon transition', UMAS, London

The "Upstream and Midstream" methane leakage refers to methane slip occurring during upstream natural gas extraction liquefaction and delivery to the LNG import terminal. The "Midstream" component refers to methane slip occurring during LNG storage in small scale storage terminals, during transportation by LNG feeder/barges and within the process of LNG bunkering. Methane can leak through several different components in the LNG bunkering systems, based on ICCT (2013), four specific leakage sources:

1. Losses due to heat absorption and venting from storage tanks over time.
2. Venting of displaced vapour when filling a storage tank.
3. LNG liquid and vapour purged from hoses and lines after fuelling a vessel.
4. Flash losses created from precooling lines and storage tanks or from transferring LNG from a high pressure to a low-pressure tank.

Flash losses were expected to be insignificant and are not measured in the ICCT (2013) study. With respect to downstream or operational methane slip, methane can leak from the LNG fuelled vessel's fuel system during operation. Corbett et al. (2015) identifies effective control of boil-off gas as the key to minimizing methane emissions from storage and transport through the LNG bunkering chain and downstream operations. As can be seen from Table 9, there is a range of different estimates for both "Upstream + Midstream" methane leakage and "Downstream" or operational methane slip emissions. The large range of variation in the three cases indicate a significant amount of uncertainty in carrying out emission estimates for methane slip.

Table 9 Methane emissions, for LNG fuelled vessels TTM (tank-to-motion) and WTT+ TTT (well-to-terminal + terminal-to-tank), gCO2eq/MJ

Source:	TTM CH4 emissions, gCO2e/MJ	WTT CH4 emissions, gCO2e/MJ	Assumptions:
GloTraM	23.3	1.1	LNG from imports, combined bunkering
Brynolf et al., 2014		0.62	Dual fuel engine (1% MGO as pilot fuel)
Brynolf et al., 2014		0.91	Spark ignition gas engine
Corbett et al., 2015	15.6		Lean-burn Otto cycle engine
Corbett et al., 2015	15.6		Dual-fuel gas engine (gas mode)
Corbett et al., 2015	2.2		Diesel cycle gas engine
ICCT, 2013	10.6	1.6	LNG from imports- TPS bunkering, 1.8% methane slip rate
ICCT, 2013	10.6	1.6	LNG from imports-STS, TPS combo,1.8% methane slip rate
Nielsen and Stoersen, 2010	70.0		Load 25%
Nielsen and Stoersen, 2010	47.7		Load 50%
Nielsen and Stoersen, 2010	33.6		Load 75%
Nielsen and Stoersen, 2010	31.4		Load 100%
TNO, 2011	13.0	1.7	LNG QATAR
TNO, 2011	13.0	1.4	LNG NL PEAK SHAVE
TNO, 2011	13.0	5.9	LNG NL PIPELINE

The GloTraM LNG fuel demand analysis uses a methane emission factor of 1.1 gCO2eq/MJ. This emission factor is a mid-to-high-end estimate, based on a literature review and expert consultation of historical methane leakage during bunkering and engine operations. Most of the methane slip emissions we account for are assumed to take place during ship operations. Bunkering leakage is estimated to be relatively low as the STS pathway is considered to be relatively efficient. In addition, no truck transport is assumed to take place, minimizing leakage from smaller scale operations.

The operational methane slip emissions are assumed to be in line with some higher-end emission estimates. This follows the expectation that most LNG vessels will be powered using dual fuel engines, since they offer higher flexibility in operations over the medium term, until LNG bunkering is not readily available. These engines can meet IMO Tier III requirements[22][23], but tend to be highly sensitive to methane slip[24].

Table 10 GloTraM emission assumptions (gCO2eq/MJ)

Fuel	Emission type:	WTT+TTT (gCO2eq/MJ)	TTM (gCO2eq/MJ)	TOTAL (gCO2eq/MJ)
LNG	CO2eq	5.8	50.7	56.5
	CH4 leakage	1.1	23.3	24.4
HFO		11.1	79.9	91
MDO		10.9	75.5	86.4
LSHFO		6.2	80.2	86.4

5.5 LNG emissions and LNG-related abatement per scenario

Using the emission factor assumptions outlined earlier in the chapter the total amount of LNG emissions in each scenario can be calculated. The total GHG emissions for LNG per scenario can then be compared (using the emission factors for HFO, MDO, LSHFO) to currently available fuels to obtain a broad understanding of the potential total abatement achievable using LNG as a marine fuel. This estimate is limited to a relatively simple calculation and does not consider a range of variables such as breakdown of LNG fleet by ship engine type, vessel size and type. Such a more granular and complex analysis is beyond the scope of this research project.

[22] Anderson et al. (2015) Particle- and Gaseous Emissions from an LNG Powered Ship. Environmental Science & Technology, 49(20), pp.12568-12575

[23] SINTEF (2017) GHG and NOx emissions from gas fuelled engines Mapping, verification, reduction technologies, Stenersen, D.Thonstad, O.,SINTEF Ocean AS Maritim

[24] SINTEF (2017) GHG and NOx emissions from gas fuelled engines Mapping, verification, reduction technologies, Stenersen, D ,Thonstad, O.,SINTEF Ocean AS Maritim

Figure 9 Absolute global emissions over 2015-2050 and EU abatement from LNG[25], tonnes

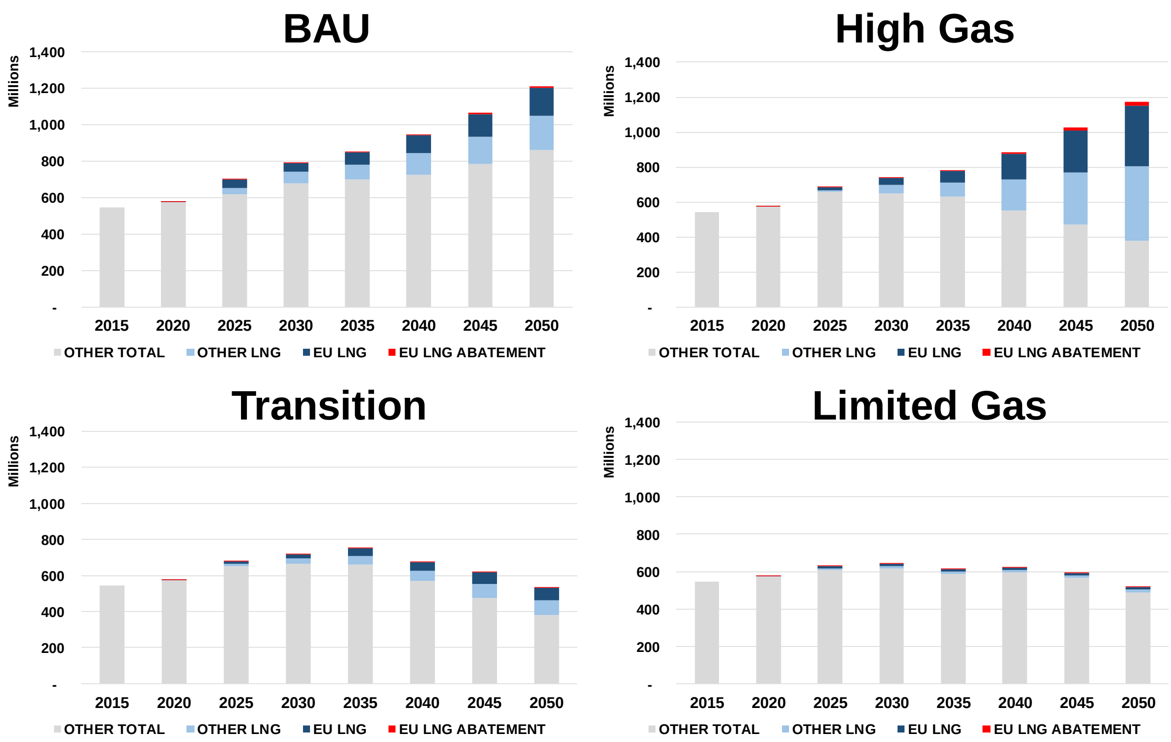


Figure 9, shows that under our base-case assumptions on emission factors for LNG and conventional maritime fuels (HFO, MDO, LSHFO), the take up of LNG under the four different scenarios could result in 6-10% relative GHG abatement, in comparison to using diesel based fuels. In absolute terms a range of 23-458 MT CO2eq could be abated over 2015-2050 from switching to LNG. This abatement is relatively small, and does not allow shipping to contribute its fair share emission reductions to a 2º degree climate goal without carbon market linkage to other sectors. This goes contrary to the desires and aspirations expressed by the European Commission[26]. This analysis also shows that a switch to LNG without a widespread further uptake of another alternative fuel (i.e. hydrogen, or biofuels with low upstream emissions) EU shipping cannot reach the goal of decreasing emissions by at least 50% by 2050 compared to 2008 levels without offsetting outside of maritime shipping. In addition, as was shown in chapter 5.4., a significant amount of uncertainty remains surrounding methane slip emissions, and a slightly higher level of methane slip emissions than currently estimated could significantly adversely affect the abatement numbers in Figure 18.

Using the estimated average abatement figures for each scenario and the estimated EU member state investment figures from Chapter 4., it is possible to make a broad estimate of how much CO2eq has been abated over 2015-2050 in terms of invested capital ($/CO2eq abated) (Figure 19). The estimate show that abatement costs for the EU and its member states can vary greatly over the four scenarios (4-36 $/CO2eq abated) and depending on whether investments are expected to continue beyond 2025/30. The calculations all assume varying amounts of carbon market linkage, and an assumed price for the CO2 abated through that linkage. If that linkage price increases then scenarios that rely heavily on the use of linkage to achieve emissions reductions will have proportionately lower cost-benefit. The current EUA permit price (EU "carbon price") is around 10-15 $/t, which is in the same range as the lower end of the abatement cost estimates.

[25] EU ABATEMENT FROM LNG- refers to lower emissions from using LNG in place of MDO, including methane slip
[26] European Commission (2017), Reducing emissions from the shipping sector, https://ec.europa.eu/clima/policies/transport/shipping_en

Table 11 Abatement costs in terms of EU member state bunkering infrastructure investments over 2015-2050, $/CO2eq abated

Infrastructure funding:	"BAU"	"High Gas"	"Transition"	"Limited Gas"
Total:	44	60	51	85
EU-2050:	20	27	22	36
EU-2025/30:	7	4	11	34

**Figures include: TEN-T and CEF funding from historic and on-going projects*

Only under the "High Gas" scenario and when assuming no EU member state public investments beyond 2025/30, is the current investment in line with abatement costs as monetized by the EUA market. This assumption presupposes that LNG infrastructure would still be built beyond 2025/30 through private funding to meet "High Gas" LNG demand. In the case that the "High Gas" scenario is not reached and LNG does not become a significant part of the maritime fuel mix ("Limited Gas") or EU member states continue subsidizing LNG bunkering infrastructure beyond 2030, the abatement costs from the EU member state perspective could easily approach 40 $/CO2eq abated.

However, if overall WTM LNG emissions were higher (i.e. higher methane slip and larger imports with higher upstream emissions such as US shale gas). the actual abatement investment could go beyond 100 $/CO2eq. These figures seem to imply that for the investment into LNG bunkering infrastructure to return high GHG abatement volumes at a low capital investment in terms of $/CO2eq abated, LNG should be taken up as the main fuel of the EU maritime industry. However, under such a case the EU will not reach the IMO strategy objective of lowering GHG emissions from shipping by at least to 50% by 2050 compared to 2008 without out-sector offsets, and shipping emissions will not contribute their fair share to a 2º global warming cap.

6 LNG on-board infrastructure costs discussion

Based on data from industry stakeholders and relevant studies, it is evident that the average construction costs for an LNG fuelled vessel are higher than those for a MDO or HFO fuelled vessel fitted with scrubber technology (Table 12). This is primarily due to the higher engine costs, larger storage volume necessary for LNG (MDO/LNG energy density ratio at same volume is 1.6) than MDO for the same fuel energy value, leaving less room for cargo; In addition, for and LNG vessel, storage tank isolation costs, on-vessel pipelines, gas alarm systems, additional safety regulations and measures (LNG is highly combustible) have to be taken into account. The long-term profitability of LNG will depend primarily on the future price spread between LNG and diesel based alternatives, a positive regulatory environment promoting development of LNG and the widespread availability of LNG bunkering infrastructure.

Table 12 Cost of construction and retrofit of midsized bulk carrier, million $

Fuel	Cost:	Source:
MGO	125	HEC, 2015
MGO+HFO	126	HEC, 2015
HFO+Scrubber	135	HEC, 2015
LNG	146	HEC, 2015
LNG Retrofit	24	IEA, 2013

In addition to a higher cost of construction of LNG fuelled vessels compared to other alternatives (Table 12), the cost of LNG retrofits, is also high. Most early LNG retrofit and construction projects have been supported through public grants. In Norway, an early mover on LNG as a marine fuel, a significant number of LNG fuelled vessels were also subsidised through public funding grants, such as the 75%

subsidy through the Norwegian NOx fund for the LNG retrofit of the "Bit Viking," chemical product tanker, to run on LNG, with the total cost estimated at $10 million[27].

Table 13 Investment cost comparison for different new built and retrofit options under IMO Tier III NOx and SOx emission standard, $/kW

LNG Components:	Retrofit:	Construction:	Source:
LNG Four stroke spark-ignition engine	888	1560	SSPA,2012
LNG Low pressure dual fuel engine	888	1680	DMA,2012
LNG High pressure dual fuel engine	786	1680	SSPA,2012
LNG gas supply system+tank	294	294	DMA,2012
HFO-open scrubber	187	146	TNO,2017
HFO-open loop scrubber	240	120	TNO,2017
HFO- closed loop scrubber	480	240	TNO,2017
MGO/MDO-vessels	140	261	SSPA,2012; DMA,2012

[27] Johnsen, T. (2013) The Norwegian NOx Fund – how does it work and results so far.

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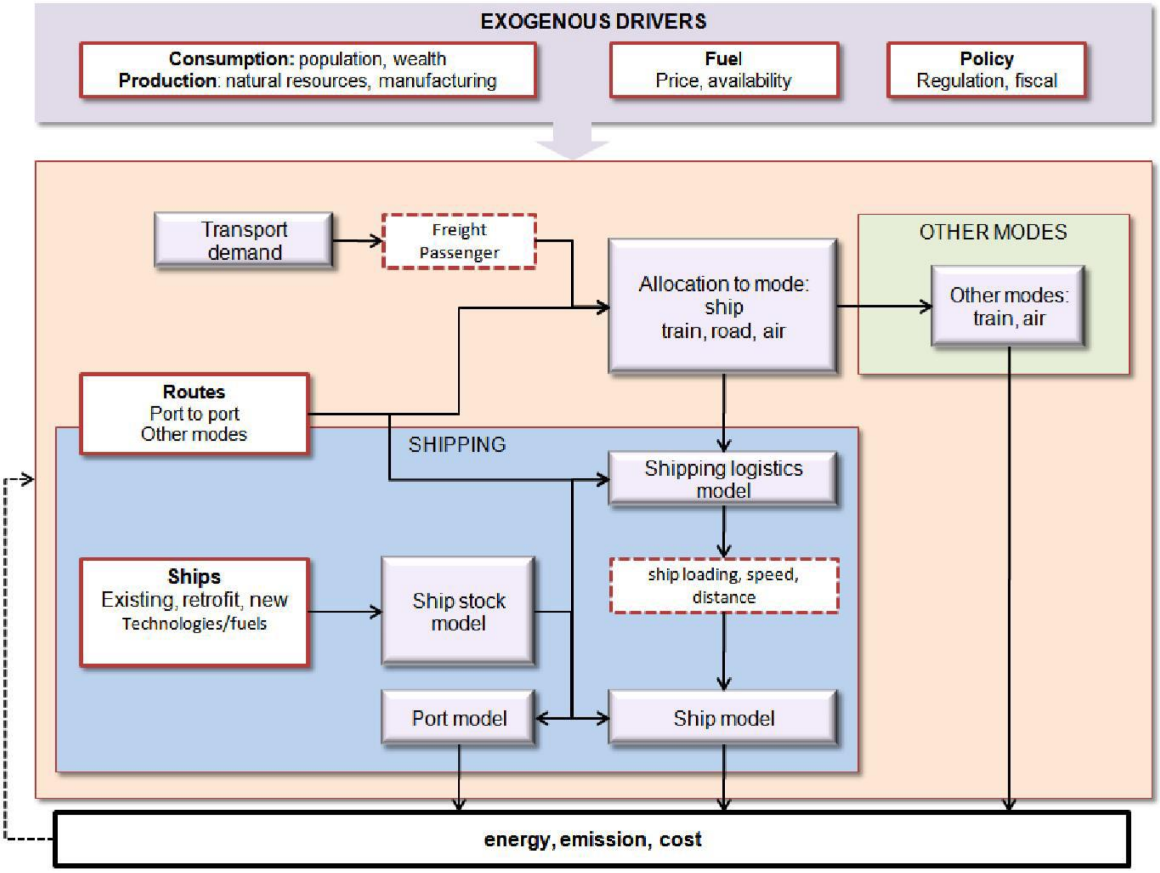
8 Appendix:

Appendix A Conceptualisation of the shipping system*



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Appendix B GHG emissions/savings and offsets 2010-2050, tonnes

Scenario 1: BAU	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
EU LNG related abatement* (CO2eq)	-	18,384.5	3,126,898.2	3,127,893.8	4,166,330.6	6,072,796.3	7,757,499.6	9,598,811.4
EU LNG related emissions (CO2eq)	-	292,374	49,727,757	49,743,591	66,258,082	96,577,030	123,369,242	152,652,033
non-EU LNG related emissions (CO2eq)	-	97,458	33,151,838	60,797,723	80,982,100	118,038,593	150,784,629	186,574,707
Other fuels related emissions (CO2eq)	544,699,841	575,449,044	618,883,974	680,344,805	701,895,904	726,908,974	785,426,809	863,773,131
Scenario 2: High Gas								
EU LNG related abatement* (CO2eq)	-	18,244.1	964,462.4	2,466,748.0	4,114,032.0	9,118,219.8	15,288,882.2	21,888,672.8
EU LNG related emissions (CO2eq)	-	290,139	15,338,060	39,229,241	65,426,367	145,009,077	243,142,495	348,100,434

non-EU LNG related emissions (CO2eq)	-	96,713	10,225,373	47,946,851	79,965,559	177,233,317	297,174,160	425,456,086
Other fuels related emissions (CO2eq)	544,699,841	573,599,250	657,682,393	651,924,989	632,313,783	551,951,082	470,581,514	378,707,066
Offsetting (CO2)	-	-	-	106,155,973	134,632,863	236,691,559	402,550,930	529,371,698
Scenario 3: Transition								
EU LNG related abatement* (CO2eq)	-	18,243.9	964,823.9	1,516,883.7	2,505,759.0	2,918,396.2	3,947,373.1	4,268,045.0
EU LNG related emissions (CO2eq)	-	290,138	15,343,809	24,123,339	39,849,643	46,411,904	62,775,952	67,875,669
non-EU LNG related emissions (CO2eq)	-	96,713	10,229,206	29,484,081	48,705,119	56,725,660	76,726,163	82,959,151
Other fuels related emissions (CO2eq)	544,699,841	572,912,698	653,667,071	663,981,053	660,880,830	571,073,985	477,046,398	381,504,113
Offsetting (CO2)	-	-	-	77,542,494	135,414,228	168,987,248	189,868,180	185,640,381
Scenario 4: Limited Gas								
EU LNG related abatement*(CO2eq)	-	15,753.8	859,032.1	676,383.3	694,330.2	727,571.2	747,054.3	842,315.7
EU LNG related emissions (CO2eq)	-	250,536	13,661,379	10,756,673	11,042,088	11,570,726	11,880,570	13,395,533
non-EU LNG related emissions (CO2eq)	-	83,512	9,107,586	13,147,045	13,495,885	14,141,998	14,520,697	16,372,318
Other fuels related emissions (CO2eq)	544,699,841	574,253,166	607,526,395	616,772,550	586,614,485	595,091,031	566,846,273	486,268,944
Offsetting (CO2)	-	-	-	-	105,497,385	161,643,509	244,462,703	252,747,715

**Abatement is in comparison to MDO*

Appendix C Historic LNG price projections, compared to GloTraM, $/t

Year	GloTraM	GloTraM (low)	DNV GL (2012)	DMA (2012)	DECC (2015)	DECC (2012)	MAN (2013)	Poten & Partners (2014)	Lloyd's Register (2012)	Rochayna et al. (2014)	European Parliament (2015)
2010			300				672				
			800								
2012				337			520.1	1034	664		
				471					498		
				610					829		
				337							
				471							
				610							
2014										827	466
											464
											384
2015	398	398			158	194			500		

					196	320			700		
					229	380			900		
2020	362	405			125	171	672	620.4	600		
					217	300			800		
					317	426			1000		
2025	515	463					672	672.1	800		
									900		
									1100		
2030	546	492			192	171	724				
					283	300					
					413	428					
2035	584	526	400								
			1200								

Appendix D Total 20-year amortized infrastructure cost, under EU-2050 assumption, million $

Year	"BAU"	"High Gas"	"Transition"	"Limited Gas"
2015	-	-	-	-
2016	23.5	23.5	23.5	23.5
2017	23.5	23.5	23.5	23.5
2018	23.6	23.6	23.6	23.6
2019	23.6	23.6	23.6	23.6
2020	23.7	23.7	23.7	23.7
2021	50.3	30.4	30.4	30.0
2022	85.0	36.2	36.2	35.4
2023	113.3	42.3	42.3	41.3
2024	133.0	51.7	51.7	50.4
2025	167.1	56.7	56.7	55.2
2026	168.4	77.5	74.0	70.4
2027	169.4	97.7	91.2	85.7
2028	169.4	106.9	97.7	90.6
2029	169.4	118.8	107.3	98.9
2030	169.4	128.6	115.1	105.8
2031	175.9	152.7	117.9	105.8
2032	186.5	167.1	123.5	106.6
2033	192.9	181.6	134.7	106.6
2034	198.7	191.8	140.3	106.7
2035	219.6	215.9	150.0	106.7
2036	220.2	248.2	141.4	86.7
2037	245.0	297.0	144.0	86.7
2038	255.9	345.9	161.0	86.8
2039	281.4	398.2	163.5	86.8
2040	293.0	437.4	166.0	86.9
2041	290.7	494.7	169.9	81.3

2042	271.2	549.6	170.5	75.9
2043	276.8	602.5	175.0	70.1
2044	273.5	658.6	176.9	61.0
2045	264.4	712.8	177.6	56.4
2046	288.4	755.2	162.6	41.4
2047	303.1	811.3	171.2	27.1
2048	318.8	865.3	166.4	22.5
2049	329.6	924.8	163.9	15.1
2050	359.8	981.6	161.1	8.5
2051	353.3	957.6	158.3	8.5
2052	342.7	943.1	152.7	7.7
2053	336.3	928.7	141.5	7.7
2054	330.5	918.4	135.9	7.6
2055	309.6	894.4	126.2	7.6
2056	285.5	838.6	111.3	4.1
2057	260.7	789.6	108.7	4.0
2058	249.7	740.7	91.6	3.9
2059	224.2	688.4	89.1	3.8
2060	212.5	649.1	86.5	3.7
2061	188.2	585.1	75.9	3.0
2062	173.0	524.5	69.5	2.9
2063	139.1	465.4	58.9	2.9
2064	122.7	399.9	47.6	2.8
2065	97.7	340.8	41.9	2.7
2066	72.4	277.6	39.6	2.5
2067	56.7	201.3	13.8	1.5
2068	41.0	138.0	12.2	1.2
2069	30.2	66.6	5.0	0.3
2070	-	-	-	-

Appendix E Total 20-year amortized infrastructure cost, under EU-2025/30 assumption, million $

Year	"BAU"	"High Gas"	"Transition"	"Limited Gas"
2015	-	-	-	-
2016	23	23	23	23
2017	24	24	24	24
2018	24	24	24	24
2019	24	24	24	24
2020	24	24	24	24
2021	50	30	30	30
2022	85	36	36	35
2023	113	42	42	41
2024	133	52	52	50
2025	167	57	57	55

2026	168	77	74	70
2027	169	98	91	86
2028	169	107	98	91
2029	169	119	107	99
2030	169	129	115	106
2031	169	129	115	106
2032	169	129	115	106
2033	169	129	115	106
2034	169	129	115	106
2035	169	129	115	106
2036	146	105	92	82
2037	146	105	92	82
2038	146	105	92	82
2039	146	105	91	82
2040	146	105	91	82
2041	119	98	85	76
2042	84	92	79	70
2043	56	86	73	64
2044	36	77	63	55
2045	2	72	58	51
2046	1	51	41	35
2047	0	31	24	20
2048	-	22	17	15
2049	-	10	8	7
2050	-	-	-	-
2051	-	-	-	-
2052	-	-	-	-
2053	-	-	-	-
2054	-	-	-	-
2055	-	-	-	-
2056	-	-	-	-
2057	-	-	-	-
2058	-	-	-	-
2059	-	-	-	-
2060	-	-	-	-
2061	-	-	-	-
2062	-	-	-	-
2063	-	-	-	-
2064	-	-	-	-
2065	-	-	-	-
2066	-	-	-	-
2067	-	-	-	-
2068	-	-	-	-
2069	-	-	-	-
2070	-	-	-	-